2021-22 Mid Year Report Evidence Chapters

25 October 2021

Contents

Role 1

Control Centre operations

Role 1: Control Centre Operations

Plan Delivery

- We have completed 25 out of the 47 milestones planned for this 6-month period. Of the 22 milestones which are not complete, 4 are ESO-related delays, 17 are outside of ESO control, and 1 is delayed in order to deliver an improved outcome for consumers
- Successfully operated the system under challenging conditions
- Provided more transparency via our Data Portal, meeting data best practice
- Refreshed our Digitalisation Strategy and Action Plan
- Continued to develop IT tools, completing the first inertia forecasting system
- Working with academia to design ESO-specific training modules
- Progressed our Distributed Restart project, which is now in its final demonstration phase

Metric performance

- Over the 6-month period:
- 1A Balancing costs: £966m vs benchmark of £562m (below expectations)
- 1B Demand forecasting: 2.2% vs benchmark of 2.1% (meeting expectations)
- 1C Wind generation forecasting: 3.7% vs benchmark of 4.7% (exceeding expectations)
- 1D Short notice changes to planned outages: 1.2 per 1000 outages vs benchmark of 1 to 2.5 per 1000 (meeting expectations)

Stakeholder evidence

Role 1 survey:

- 19% exceeding expectations
- 72% meeting expectations
- 9% below expectations

Highlights:

- Worked closely with our stakeholders to facilitate the work required to connect two new interconnectors, receiving positive feedback
- We met twice with our Technology Advisory Council, whose feedback is shaping our activities
- This year, our weekly Operational Transparency Forum received an average feedback score of 9 out of 10

Demonstration of plan benefits

- Control centre architecture and systems (A1) on track to deliver £305m consumer benefit over RIIO-2
- Control centre training and simulation (A2) on track to deliver £35m consumer benefit over RIIO-2
- Restoration (A3) on track to deliver £115m of net benefit from 2025 to 2050
- Delivered £57m of consumer benefit via our Trading activities

RREs:

- 1E Transparency of Operational Decision Making: 99.7% of actions have reason groups allocated
- 1F Zero Carbon Operability (ZCO) indicator: ESO has accommodated up to 84.6% zero carbon generation
- 1G Carbon intensity of ESO actions: Monthly average of 4.2gCO2/kWh of actions taken by the ESO
- 1H Constraints cost savings from collaboration with TOs: £499m
- 1I Security of Supply reporting: 0 incidents
- 1J CNI outages: 1 planned BM outage

Value for Money

- Our forecast total expenditure for role 1 in BP1 is £252m, which is 21% higher than the benchmark of £208m
- The main driver of the deviation is increased expenditure on the Balancing Programme, driven by improved understanding of cost and scope following detailed project planning during the last six months
- The changes we have made to the Balancing Programme are expected to deliver an additional consumer benefit of £27m per annum

A.1 Plan Delivery for Role 1

Deliverable progress

For role 1, the RIIO-2 Delivery Schedule received an ambition grading of 5/5, providing the ESO with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The ESORI guidance states that the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule.

During the first six months of the Business Plan 1 period, a few highlights of role 1 performance are:

Operating the system under challenging conditions:

- Over past six months we have continued to face the operational challenges of the changing energy landscape and changes in consumer behaviour as COVID-19 restrictions have been relaxed.
- We have seen significant swings in the proportion of generation provided by wind power. In May 2021, we saw a new record 62.5% of Great Britain's electricity being provided by wind generation, whereas in September 2021 we saw sustained periods of lower than normal wind output, with wind power providing less than 10% of overall generation at times. In early Autumn when demand typically starts to increase as the weather changes, in addition to low wind levels, there were reduced levels of power imported from Europe with the IFA interconnector on outage due to a fire, contributing to tight margins. As a result, the cost of operating reserve (scarcity pricing) increased, leading to us taking actions in the Balancing Mechanism to ensure our operational reserve levels remained adequate during this period. No system warnings have been issued within this performance year to date.
- Through the past six months we have seen an increase in wholesale power prices, driven by global gas supply shortages and the increasing cost of emissions. Many of the ESO's operability actions are impacted by these higher prices and therefore their costs have increased, although instructed volume is lower than this time last year.
- As government COVID-19 restrictions were relaxed, we began lifting the workplace safety measures via a staged approach. We have continued to keep precautionary controls in place in the control room whilst there is still a level of uncertainty over the expected course of the pandemic. The option to use Optional Downwards Flexibility Management (ODFM) was maintained this year in case of a potential repeat of the high winds and low demand we saw in 2020, but it was not necessary to use it.

Transparency and Data

- We continue to run our weekly Operational Transparency Forum, providing transparency of operational decisions and an opportunity for stakeholders to ask questions. These events continue to be shaped in response to participant feedback, with changes made to the format, topics, and published datasets.
- We have continued to publish the Dispatch Transparency data set on our Data Portal, giving transparency of whether plant is dispatched in merit order. This is also reported as part of Regularly Reported Evidence item 1E later in this report.
- We have been publishing information to support understanding of our data processing methods and algorithms such as the Dispatch Transparency Methodology[1] and Dynamic Containment Performance Monitoring scripts[2].
- We've listened to feedback and in June 2021, refreshed our Digitalisation Strategy and Action Plan. The updated plan gives us a clear roadmap that continuously improves our products and services.
- The ESO Data Portal continues to lead the way in the UK Energy Industry for access, use and understanding of energy data, and supports meeting the expectations of Data Best Practice. The number of datasets published on the Data Portal now stands at over 80.

[1] https://data.nationalgrideso.com/backend/dataset/93ebb15e-4c2c-4768-9750-45c2789f4186/resource/93abbdbf-06fa-4576-a94f-593d95b893c1/download/dispatch-transparency-methodology.pdf
[2] https://www.nationalgrideso.com/document/188431/download

IT tools

- The Network Control Management System Project has developed a vision and strategy for the core system. We have developed a set of requirements and are engaging with potential suppliers.
- The first provider's inertia forecasting solution is now complete. Following assessment of its results over the winter, it is expected to be used in the Control Room from Spring.
- We have started to develop infrastructure to support our new Enhanced Balancing Tool
- In April 2021, we signed a new agreement with NewGrid to continue the trial of the Transmission Network Topology Optimisation tool (which uses recommendations from an algorithm to reconfigure the transmission network to relieve constraints, and was mentioned in the 2020-21 End of Year Report)[3], to October 2022. We will continue to run the topology optimisation process on a best endeavours basis as we did last year, until additional FTE join to run the process.

Training

- We have started to work with academia, collaborating on the creation of ESO-specific modules within their Power Engineering courses to ensure that the correct skillsets are developed in the future.
- We are designing online training modules using animation, to enhance our existing training programmes and allow trainees to learn at their own pace.

Restoration

- Changes to the licence to implement the new Electricity System Restoration Standard (ESRS) came into effect from October 2021. We have engaged with key stakeholders on proposed industry working groups which are to be established to develop Code Modifications and services that will enable compliance with the ESRS. We have also started to scope the restoration decision making support tool and will initiate an IT project later in the year.
- The Distributed ReStart project is in its final demonstration phase. Through co-creation with our stakeholders, we've designed how a restoration process from DER would work in practice, along with commercial models and the procurement process. We have commissioned a supplier to build a prototype control system, and developed recommendations for issues such as who the lead procurement party should be, the contractual framework, funding, settlement and industry code modifications. We completed detailed study modelling on three case studies, and will take the learning from this into live trials, including testing full power island restoration from blackout, and the use of a grid-forming battery (the first time of using a grid-forming battery this way in GB).

Progress of our deliverables

Our RIIO-2 Deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables. The first column shows how our deliverables meet the requirements of the Roles Guidance set out by Ofgem.

For Role 1 (Control Centre Operations), the Delivery Schedule lists 44 deliverables in total, which is made up of 198 milestones. 47 of these milestones were due to be completed in the first six months of 2021-22, of which 25 are now complete. Of the 22 milestones which are not complete, 4 are ESO-related delays, 17 are outside of ESO control, and 1 is delayed in order to deliver an improved outcome for consumers. We provide detail below about those activities where milestones are not on track:

ESO-related delays:

- D1.4.4 Data and Analytics Platform (1 delayed milestone): the structure of our data models has been developed, but we are carrying out further work on the design to ensure that it meets stakeholder needs.
- A1.2 Enhanced Balancing Capability (3 delayed milestones): We expect to deliver the overall aims of this programme, although may deliver the milestones in a different order to that set out in the Delivery Schedule, due to our Agile approach to delivery. At each stage of the project, we will test our delivery roadmap with the Technology Advisory Council: the next iteration of this will happen in Q3 2021-22 once

[3] https://www.nationalgrideso.com/document/191446/download

the initial design phase has concluded. These engagements will continue to shape our activities. We provide more detail about this programme in our Value for Money chapter.

Delayed due to issues which are outside of ESO's control in the short term:

- D1.1.4 Liaison with ENTSO-E (2 delayed milestones): the milestones under this activity are no longer taking place as planned due to Brexit. Further details are set out in the following section.
- D1.2.2 Inertia Monitoring (3 delayed milestones): the second supplier's solution has experienced hardware issues which have in turn delayed testing. We now expect the solution to be completed in November 2021.
- A2 Control Centre training and simulation (6 delayed milestones): delays due to the availability of engineers who are authorised to work in the Control Room and impacts of COVID-19 which prevented us from visiting other industries.
- A3 Restoration (6 delayed milestones): our original timescales set out in our delivery schedule were based on the Restoration Standard going live in April 2021. Ofgem shared its final decision in August 2021 and the Secretary of State will direct the ESO to implement the new Restoration Standard in October 2021. This has therefore delayed our implementation plans.

Delayed in order to deliver an improved outcome for consumers:

- D3.1.5 Fully competitive black start procurement process (1 delayed milestone): The South East tender will be launched during 2022-23, rather than 2021-22. We believe that this is the most economic and efficient solution, given the delays to the approval of the restoration standard, and other expected new entrants not being available in the expected timescales and therefore reducing liquidity. This will also allow us to integrate the learnings from the Distributed Restart project.

New initiatives and changes

The RIIO-2 Delivery Schedule was originally published in October 2020. Since this, the ESO has continually prioritised its projects to deliver the best value for consumers. This has resulted in the following notable changes:

Brexit

Since the Delivery Schedule was published in October 2020, the Trade and Co-operation Agreement (TCA) has been finalised, defining the extent to which the UK can participate in European projects and initiatives. This impacts on several of our deliverables as listed below. Following the publication of this mid-year report, we will produce an updated version of the Delivery Schedule, which reflects the changes described below.

D1.1.4 Liaise with ENTSO-E (European Network for Transmission System Operators – Electricity) and Co-Ordination of Electricity System Operators (CORESO) on the ESO's European operations

The following milestones are no longer relevant:

- Q2 Common Grid Model Stage 3 (bespoke CORESO web reporting tool modifications fit for the NGESO control room) complete
- Q2 Become compliant with Common Grid Model requirements - Establishment of two-day ahead, day-ahead and intra-day congestion forecast (D2CF, DACF, IDCF) processes (depending on future trading relationship)

The following milestones will be delivered instead:

- Q4 European deliverables to meet the requirements of the Trade and Co-operation Agreement (TCA)
- Q3 Regional Security Co-ordinators (RSC) security analysis project
- Q3 Maintain day-ahead congestion forecast process whilst awaiting a decision on the new methodology of Capacity Calculation resulting from the TCA

D2.1.3 Monitoring and reporting of system performance to regulatory bodies and ENTSO-E.

- We note that Reporting to ENTSO-E will depend on the ESO's future relationship with ENTSO-E

Market surveillance

In April 2021, Ofgem introduced a new Licence obligation for the ESO to proactively monitor activity in Balancing Services markets. This obligation results from the EU Regulation on Wholesale Energy Market Integrity and Transparency (REMIT), under which the ESO is a Person Professionally Arranging Transactions (PPAT). The ESO has set up a new function to fulfil this requirement and recruited a small team of experienced staff to focus on developing tools and processes to fulfil our obligation. We engaged with consultants at KPMG who worked with us in scoping out the function, and we continue to engage with Ofgem throughout this process. Consistent with the KPMG's recommendations, we have prioritised monitoring the Balancing Mechanism (BM) by designing a tool which will extract data and query it against participants' submitted Dynamic Parameters in line with the Open Letter from Ofgem in September 2020.

Balancing Programme and Modern Dispatch Advisor

There have been changes to the scope of the Balancing Programme since the cost benchmark was set in the Final Determinations. This has resulted in increased forecast costs as described in our Value for Money chapter. A key change from our original plans is delivering a Modern Dispatch Advisor into our existing systems, rather than awaiting the implementation of future systems. This will mean that consumers will benefit from the new algorithm earlier.

Operability

Over the past few months, we have observed short-term operability issues on the Scottish network with some low frequency oscillations. The oscillations coincided with multiple outages both on the transmission system and across several generation plant. As soon as we became aware of the issue, we worked closely with both Scottish Transmission Owners to identify immediate remedies which included synchronising some synchronous units and changing the control modes of the Caithness-Moray link. We are still working closely with the Scottish TOs and in discussion with customers that have been directly affected by the oscillations to analyse the events, better understand their underlying reasons, and develop long term mitigation measures.

Changes to our suppliers

FATE (Frequency and Time Error) is an IT system used within the ENCC to support second-by-second energy/demand balancing functions. FATE has been developed and supported by our supplier, Staunton Systems Engineering (formerly Utility Telematics Ltd), since the early 2000s. In May 2021, Staunton Systems Engineering informed the ESO of a decision to step back from the FATE product from 31 August 2021. In response, the ESO has reviewed the internal support available, moved forward deliverables to further develop our systems in this area, and started a procurement process to secure a replacement product, which will be delivered in 2022.

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 1. Some of these projects are funded as part of the RIIO-2 price control, and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. Other projects were funded as part of the ESO's RIIO-1 innovation funding, but are included for completeness as they support some of the ESO's RIIO-2 deliverables. The references in the table below provide links to additional information about each project.

Innovation Project Name	Description	Deliverables supported	Status	Funding
Solar Nowcasting[4]	Research and Develop the use of machine learning & satellite images to nowcast PV at GSP-level.	D1.2.3	Initiation	RIIO-2

[4] https://smarter.energynetworks.org/projects/nia2_ngeso002/

Control REACT[5]	Provide information about forecast uncertainty, presented in real-time to Control Room engineers, to provide opportunities for them to make more economic and secure balancing decisions.	D1.2.3	Delivery	RIIO-1
Distributed Restart (NIC)[6]	Process and market for procuring restoration capability from distributed resources	D3.3.1, D3.3.2	Delivery	RIIO-1
Short-term System Inertia Forecast[7]	Proof of concept for an accurate day-ahead and intra-day system inertia forecast with multi-time resolution, that can be potentially used to support the day-ahead frequency response procurement and the real-time system operation.	D1.2.2	Delivery	RIIO-1
Dynamic Reserve Calculation[8]	Use AI and machine learning to set reserve levels dynamically, at the day ahead stage.	D1.2.3	Delivery	RIIO-2

Note that the Control REACT and Dynamic Reserve Calculation projects also feed into role 2.

[5] https://www.smarternetworks.org/project/nia_ngso0032

[6] https://www.smarternetworks.org/project/nic_esoen01

[7] http://www.smarternetworks.org/project/nia_ngso0020

[8] https://smarter.energynetworks.org/projects/nia2_ngeso003/

A.2 Metric Performance for Role 1

Table 1: Summary of metrics for Role 1

Metric	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Mid-year status
1A	Balancing Costs	£m	130	151	138	131	182	234	**Below** expectations
1B	Demand Forecasting	%	2.9%	2.6%	1.9%	1.6%	2.4%	2.0%	**Meeting** expectations
1C	Wind Generation Forecasting	%	3.5%	4.0%	4.4%	3.2%	3.2%	3.7%	**Exceeding** expectations
1D	Short Notice Changes to Planned Outages	#	0	0	3.7	2.4	0	1.4	**Meeting** expectations

Metric 1A Balancing cost management

April – September 2021-22 Performance

This metric measures our balancing costs based on a benchmark that has been calculated using the previous three years' costs and outturn wind generation (2018-19, 2019-20 and 2020-21). It assumes that the historical relationship between wind generation and constraint costs continues, recognising that there is a strong correlation between the two factors. Secondly, it assumes that non-constraint costs remain at a calculated historical baseline level. A more detailed explanation follows:

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

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

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

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

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

Total Balancing Costs *(£m)* = (Outturn Wind *(TWh)* x 12.16 *(£m/TWh)*) + 19.75 *(£m)* + 41.32 *(£m)*

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

ESO Operational Transparency Forum: The ESO hosts a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our National Control panel. Details of how to sign up and recordings of previous meetings are available here[9].

[9] https://data.nationalgrideso.com/plans-reports-analysis/covid-19-preparedness-materials

Figure 1: Monthly balancing cost outturn versus benchmark

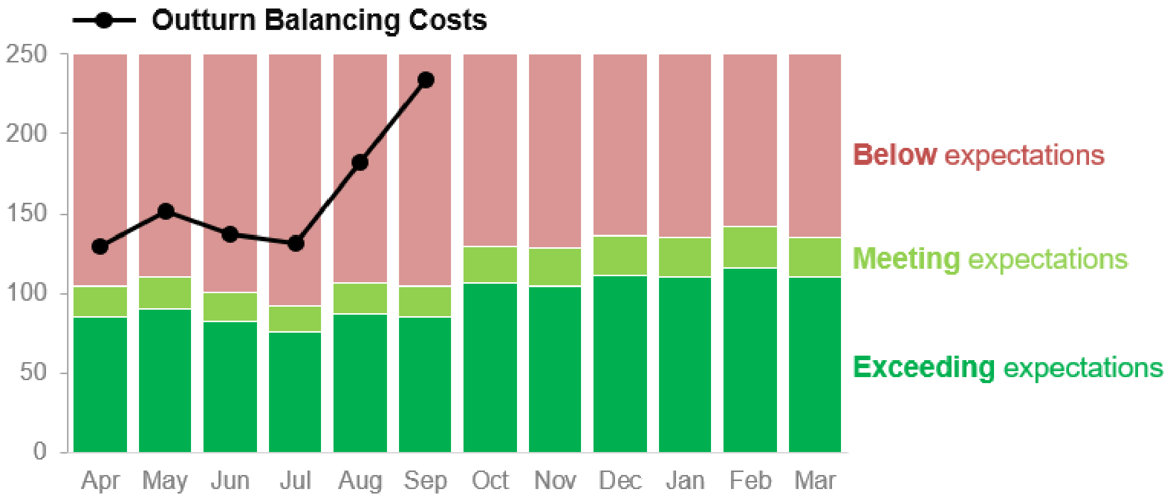


Table 2: Monthly balancing cost benchmark and outturn (Apr-Sep 2021)

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	41.3	41.3	41.3	41.3	41.3	41.3	247.9
Indicative benchmark: constraint costs (B)	59.9	50.6	52.3	49.2	58.4	66.9	337.1
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	585.1
Outturn wind (TWh)	2.8	3.2	2.5	1.9	3.0	2.8	16.1
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.9	42.5	55.7	53.4	314.0
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**	**83.8**	**97.1**	**94.8**	**561.9**
Outturn balancing costs [10]	**129.6**	**151.4**	**137.5**	**131.0**	**182.1**	**234.2**	**965.9**
Status	●	●	●	●	●	●	●

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

Performance benchmarks

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

[10] Please note that previous months' outturn balancing costs have been updated with reconciled values

Supporting information

Due to the complexity and importance of this metric, and in response to stakeholder feedback, below we provide a significant amount of detailed analysis and context which is set out as follows:

1. **Mid-year performance summary**
2. **Drivers of balancing costs**
3. **The ESO's approach to balancing actions**
4. **Actions taken by the ESO and their impact on balancing costs**
5. **Year-to-date performance – detail**
6. **September performance – detail**

1. Mid-year performance summary

Cumulative balancing costs across the past 6 months have been higher than those for the same period in 2020-21. These high balancing costs have been predominately driven by higher wholesale energy prices. As the cost of gas and emissions has gone up, we have seen significant increases to the day ahead power prices, resulting in higher system operating costs – through the cost of actions available to ESO.

Compared with the same period last year, April costs were higher than in 2020-21, costs between May and July were lower than the same period in 2020-21 but remain high, and August and September have seen higher costs than the previous year.

Increased day ahead power prices impact the costs of the actions we take to balance the system. This is most relevant when we are seeking to increase the output of generation (buy/offer). It is less relevant when we are seeking to decrease the output of generation (sell/bid), as these actions often involve renewable generation, which is not impacted by gas prices.

Over the six-month period we have seen significant variation in the proportion of generation provided by wind power. This ranged from a new record of 62.5% of overall generation in May, to September where wind power was at less than 10% of overall generation for sustained periods. Low wind generation output, combined with reduced levels of power imported from Europe due to interconnector outages, has also contributed to tight margins and high system prices at these times.

Following the implementation of Phase 1 of the Frequency Response and Control Risk Report (FRCR) recommendations in May 2021, the costs associated with reducing large losses based on Rate of Change of Frequency (RoCoF) risk have decreased to significantly below the spend in previous years. This is a direct result of the changes in the way we manage inertia. Over the four months of June to September, these costs were £72m lower than the same period last year. This is possible because of the Security and Quality of Supply Standards (SQSS) update through modification GSR027, a reduction in RoCoF and Vector Shift risk delivered through the Accelerated Loss of Mains Change Program (ALoMCP), and the introduction of the fast-acting Dynamic Containment product. Trading to reduce the flow on interconnectors to mitigate the RoCoF risk has occurred over the past six months, but the implementation of FRCR Phase 2 (on 7 October) will result in a significantly fewer market interventions to manage frequency.

The introduction of the Dynamic Containment service, as part of our changes to manage inertia as described above, has increased the volume of response we hold. This has offset some of the savings achieved by the implementation of FRCR Phase 1, and as a result we have observed increased response costs. These changes combined have enabled a risk-based approach to managing inertia, resulting in lower constraint costs. Overall, the FRCR is delivering a net reduction in frequency response spend by formalising the balance between the cost of securing the system and which risks are required to be secured operationally.

Constraint costs have decreased by around £270m compared with the same period last year, due to several factors including the changes to inertia management, low wind levels, good availability of the transmission network as well as the lack of COVID-19 mitigating measures (which had impacted on constraint costs last year).

Operability issues often require a number of actions to be taken to ensure requirements are met, and costs are optimised. This can involve working with network operators and generators to manage system operability. One example of this, that resulted in a circa £50m saving, relates to working with a Transmission Owner on a specific situation. In this case, due to planned system access and a fault condition, a voltage level just above the SQSS requirements would have occurred, in the event of a double circuit fault.

In order to solve this potential overvoltage situation, we had sought an agreement with a local generator which would mitigate the overvoltage and return the system to the SQSS requirements. The cost of this contract (due to very high electricity prices and the risk to the generator) would have been circa £50m. In parallel to this contract negotiation we worked with the Transmission Owner to fully understand what the risk was of operating over the SQSS limit (3-5kV) and any potential mitigations they could do, following a double circuit fault, to manage the resulting high volts.

We came to an agreement with the Transmission Owner which put in place pre-agreed reactive measures should the double circuit fault occur. As a result, the £50m contract was not required. In this way we were able to work across the industry to find an acceptable, cost saving option, with pragmatic challenge to the SQSS.

Although we put the ODFM (Operational Downward Flexibility Management) product in place again for 2021, there has been no need to enact this, or negotiate any other contracts to manage downward regulation to date. This has further contributed to the lower constraint costs seen at the midpoint of the performance year.

Procurement of volumes of Fast Reserve and Response products has increased over the past few years, in relation to the increase in the scale and volume of frequency risks which must be secured against (largely driven by the increase in renewable generation and interconnected networks).

Whilst power prices have continued to rise throughout the year, from August, balancing costs have escalated significantly. The day ahead power baseload averaged at £222/MWh in September 2021 versus £109/MWh in August 2021 – a £113/MWh increase in just one month. Carbon prices have also remained at near record highs, and combined with low wind levels this has led to tighter margins, scarcity pricing, and additional actions required to maintain Operating Reserve – resulting in high cumulative costs for system operation. The average monthly margin price increased substantially from £58 / MWh in August to £580 / MWh in September, with actions taken at a price of £4000/MWh during peak demand periods of the highest cost day on 15 September.

The actions which have the greatest impact on balancing costs are made in the longer-term timescales, outside of the Role 1 activities. Historic decisions have had a significant impact, for example the Connect and Manage regime has been successful in delivering the fastest decarbonising grid in the world. The impact of this regime is that the costs previously incurred in TNUoS are now realised in BSUoS, in the form of constraint costs and in more actions needing to be taken to manage inertia.

In summary, ESO's real time actions, trading activities and newly introduced changes for this year, such as FRCR Phase 1, have had demonstrable impacts on associated elements of costs and volumes of energy procured. However, whilst volumes procured were lower, the cost was higher per MWh, leading to higher overall balancing costs. The graphs and commentary below provide further detail, and a specific case study of trading activity is included in the Demonstration of Plan Benefits section. The ESO's trading activities are a key example of ESO taking a proactive approach to managing balancing costs.

2. Drivers of balancing costs

There are numerous factors that impact the level of balancing costs at any one time. The extent to which the ESO can control or influence these factors varies greatly and depends on the times scales in which the factors occur. Below we set out a high-level summary of the main drivers, within Role 1 timescales, and the extent to which the ESO can influence each one.

Factor	Level of ESO influence	Explanation
Balancing actions taken	High	The ESO is required to secure the system in line with the SQSS and therefore takes actions in a defined order to ensure operability. There may be limited options (and sometimes only one) to secure certain requirements, but the ESO will choose the actions to secure the system at the least cost to the consumer.

Operating margin	High	The ESO determines the level of operating margin required to cover demand changes or generation breakdowns. However, when margins are tight, options are limited.
Balancing Mechanism (BM) prices	Medium	BM prices are driven mainly by supply and demand, and generation fuel costs (gas/carbon) when supply is plentiful. Higher levels of competition lead to lower prices but due to complexities of the system, limited options for certain requirements can lead to higher costs. Scarcity prices can drive these prices when margins are tight.
Boundary availability *(including Transmission System Constraints)*	Medium	We work closely with the TOs to manage outages in order to maximise system availability. However, outages are necessary to maintain system operability and these have an impact on network capacity.
Wholesale prices	Low	Wholesale prices are set well in advance of the ESO role in operating the system and are based on supply, demand, the generation cost stack, and individual market participants' risk appetites. The ESO has some influence in prices by driving the availability of other markets for parties to participate in (e.g. Dynamic Containment)
Wind level	Low	Increasing levels of wind generation capacity mean the system is increasingly dependent on the weather. Low levels of wind can lead to tight margins.
Provider and Generation Outages	Low	Providers and generation (BM Units) determine when they will take outages in line with their own maintenance cycles and requirements. It may be possible for ESO to establish contracts with specific providers to move or delay outages if system operability is impacted.

3. The ESO's approach to balancing actions

In order to aid in the industry's understanding of our actions and the order in which they are taken, we presented a waterfall chart[11] at the Operational Transparency Forum on 11 August 2021 demonstrating the volume of actions required to meet all the operability challenges during a particular settlement period (settlement period 12 on 8 August). In this case, a number of actions were taken to synchronise conventional units in order to meet voltage requirements, whilst also trading on interconnectors to ensure enough downward volume was available.

4. Actions taken by the ESO and their impact on balancing costs

Below we set out some of the significant changes that have been implemented, and how these have impacted balancing costs over the last six months and/or will impact them in the future.

Action taken	Date	Forward Plan/Delivery Schedule reference	Impact on balancing costs
Changes to Loss of Mains protection	Changes began in August 2019 and have continued through the six-month period	RIIO-2 D15.3.2	The Loss of Mains changes have resulted in lower spending on inertia (falling from £20m per year to zero), and lower spending on constraining the largest loss. See Consumer benefit case study for Role 3: seeing the impact of Loss of Mains changes

[11] https://data.nationalgrideso.com/backend/dataset/b3c55e31-7819-4dc7-bf01-3950dccbe3c5/resource/090e7600-e65e-4a9a-805d-52046fae918f/download/ngeso-transparency-forum-21-08-11-vfinal.pdf

Stability Pathfinder Phase 1	Stability Pathfinder phase 1 awarded contracts to successful tenderers in January 2020.	Forward Plan Role 3	This project delivers a lower cost alternative for increasing inertia on the network until 2026 versus paying thermal generators. 12 contracts were awarded to a combination of new build and retrofitted synchronous compensators. 3 contracts are now operational with the remainder to go live over the following months. The consumer benefit of the Stability Pathfinder is discussed in RRE 3A.
Introduction of Dynamic Containment	DC launched in October 2020 with further product amendments over this year	Forward Plan Role 2	Increase in procured response to meet the total reserve requirement through our new fast-acting Dynamic Containment service. Procurement of Response (within the Balancing Mechanism) has been influenced by the higher costs experienced there over the past 6 months.
STOR Day Ahead procurement	April 2021	n/a	Day ahead markets for ancillary services lead to more volatile prices in those markets. This activity was carried out to allow STOR capacity to be secured in the Day-Ahead market, compliant with the clean energy package. Without this service the actions needed to access this reserve in the BM would have been more expensive.
Implementation of FRCR Phase 1	Phase 1 from May 2021 Phase 2 from October 2021	n/a	The implementation of FRCR Phase 1 included relaxing the normal infeed loss constraint (always securing a <=1000MW loss to 49.5Hz, and always securing infeed losses to the wider 49.2Hz limit) and recategorizing some loss risks that meant no additional actions are taken to secure these risks. This has resulted in a decreased spend in managing RoCoF risks as well as a reduction in the cost of procuring response to manage the normal infeed loss.
Contracts to secure against specific transmission constraints	July 2021	RIIO-2 D1.1.3	Contracts to secure against transmission constraints result in an increase in ancillary service costs.
Optimising balancing actions	Throughout the six-month period	RIIO-2 D1.1.3	Day to day actions in real time to ensure the most cost effective options are selected to meet all operability requirements and to optimise the balancing actions required.
Trading actions taken ahead of real time to drive competition in costs, and manage voltage requirements	Throughout the six-month period	RIIO-2 D1.1.8	Specific trading case study included in Consumer benefit case study for Role 1: ESO trading actions

Collaboration with Transmission Owners in planning timescales	Throughout the six-month period	RIIO-2 D16.1.1 Reported in RRE 1H	Indirect impact on costs through increasing available generation capacity – and reducing the need to pay to constrain generation. This is carried out through liaison with stakeholders and represents a total of 6,696,900MWh (approximately £499M) additional generation capacity over the past six months.
Optional Fast Reserve remaining open – reserve reform yet to deliver	Throughout the six month period	RIIO-2 D4.3.3	It is expected that the costs associated with Optional Fast Reserve will remain at the same level until reserve product reform delivers the benefits of opening the market to greater competition

5. Year-to-date performance – Detail

Breakdown of total costs vs previous year

Total balancing costs for April 2021 to September 2021 vs April 2020 to September 2020

Year-To-Date Balancing Costs variance (£m): 2021-22 vs 2020-21

		(a) 2020-21	(b) 2021-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	53.4	50.5	(2.9)	
	Operating Reserve	30.2	250.3	220.2	
	STOR	18.2	28.5	10.3	
	Negative Reserve	2.6	2.3	(0.4)	
	Fast Reserve	49.1	111.2	62.1	
	Response	52.5	175.2	122.7	
	Other Reserve	12.7	7.4	(5.3)	
	Reactive	30.6	57.9	27.3	
	Black Start	29.8	32.1	2.3	
	Minor Components	22.5	-14.2	(36.8)	
Constraint Costs	Constraints - E&W	78.9	22.2	(56.7)	
	Constraints - Cheviot	25.3	10.9	(14.4)	
	Constraints - Scotland	41.6	10.4	(31.2)	
	Constraints - Ancillary	95.4	38.9	(56.5)	
	ROCOF	208.5	112.0	(96.5)	
	Constraints Sterilised HR	86.7	70.4	(16.3)	
Totals	Non-Constraint Costs - TOTAL	301.7	701.2	399.5	
	Constraint Costs - TOTAL	536.4	264.8	(271.6)	
	Total Balancing Costs	**838.1**	**965.9**	**127.9**	

As shown in the total rows above, year-to-date non-constraints costs have increased by £399.5m compared with the same period last year. This is partly offset by a £271.6m fall in constraints costs. The net variance is a £127.9m increase, driven by the factors described in the summary section.

Constraint Costs vs Non-Constraint Costs

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.

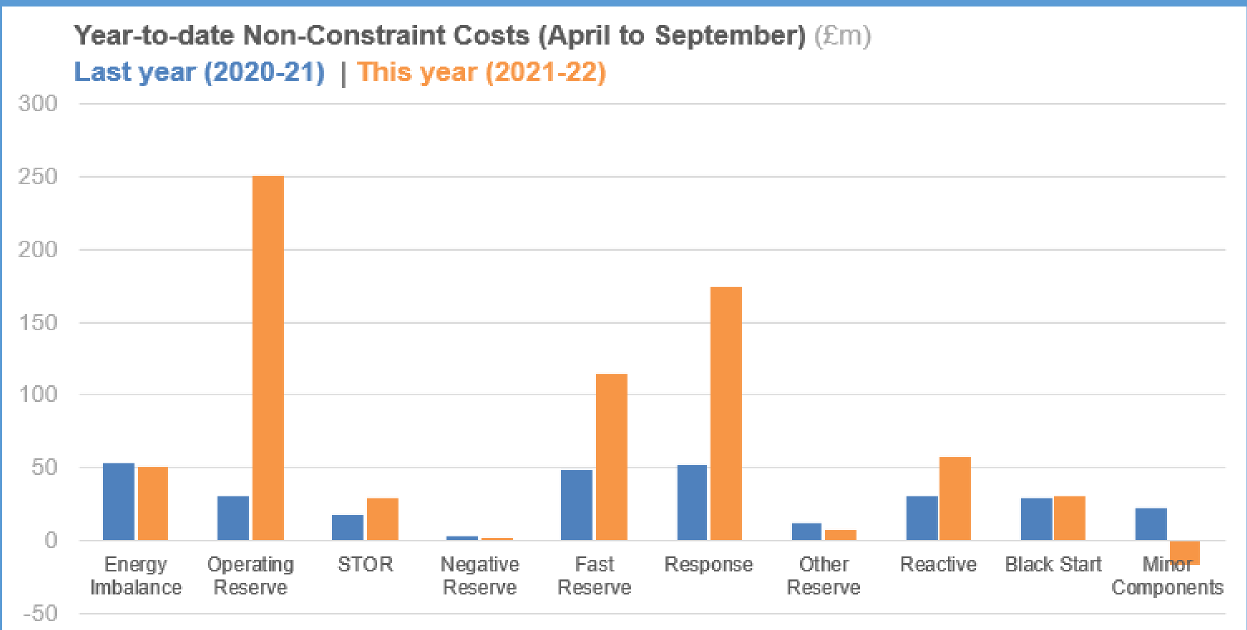
August and September balancing costs were significantly higher than the same period last year.

For the past six months, constraint costs have been consistently below the levels observed in the previous year. This is predominately due to higher, more typical demands, as demands during 2020-21 were suppressed due to the measures taken to limit the spread of COVID-19.

Overall, non-constraint costs have made up the larger proportion of total spend than in previous years due to higher Operating Reserve, Fast Reserve and Response costs.

From June, due to the implementation of phase 1 of the FRCR recommendations, the RoCoF costs have fallen considerably as a result of changes in the way we manage inertia. This is possible because of the reduction in RoCoF risk through the ALoMCP (Accelerated Loss of Mains Change Program) and the introduction of the Dynamic Containment service.

Constraint Costs Detail vs last year



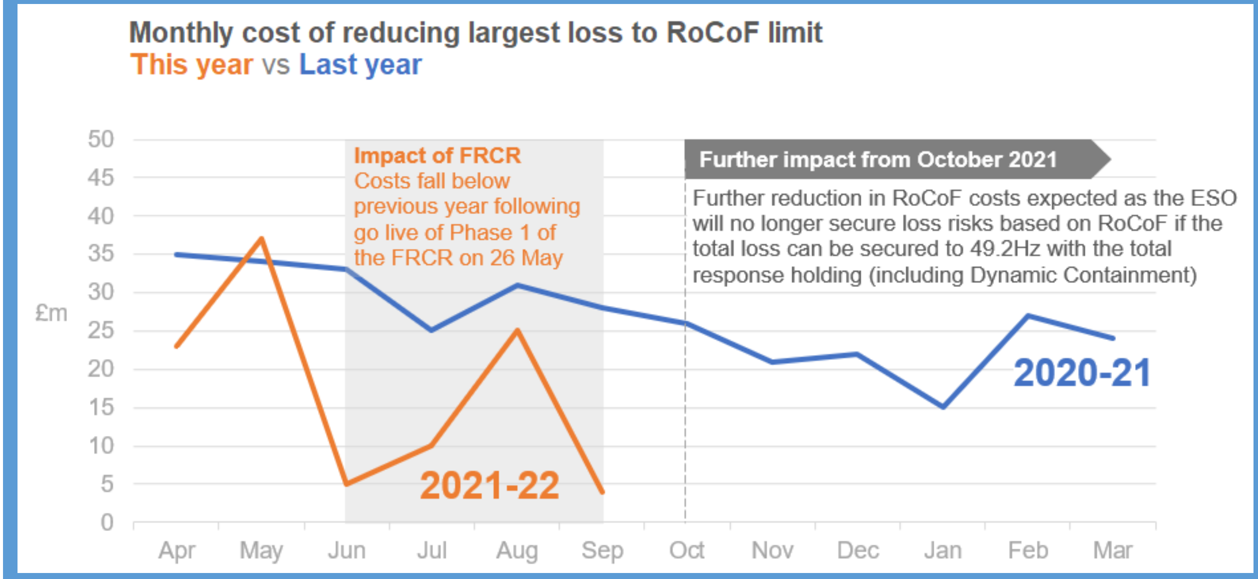
Comparing the past six months' energy costs with those of the first six months of last year, we can see that prices have risen across almost all categories:

- **Operating Reserve** costs have risen significantly over this period, with a further significant increase in September. This increase is driven by the higher cost of actions to maintain reserve available in the Balancing Mechanism, reflecting higher day ahead power prices than last year.
- **Response** costs have risen significantly in comparison to the previous year for the same period due to the introduction of the Dynamic Containment service. This, as part of the changes made to manage inertia has delivered lower constraint costs in managing RoCoF through a risk-based approach.

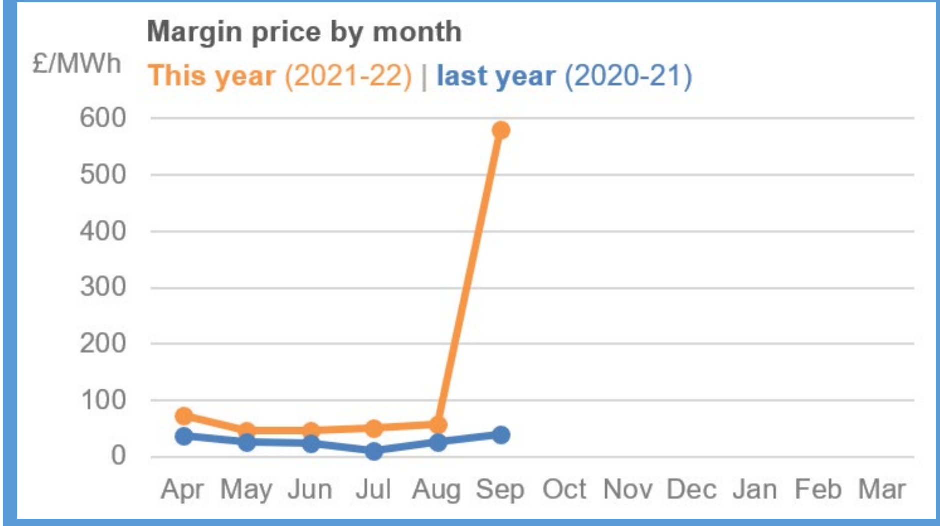
- **Fast Reserve** also increased. This is due to higher market prices and tighter margins driving the cost of Balancing Mechanism actions up, which in turn leads to higher costs for reserve.

FRCR Phase 1 implementation

The graph below shows the impact of FRCR on the cost of reducing the largest loss based on RoCoF. Phase 1 of the FRCR went live on 26 May 2021, leading to a marked reduction in costs from June. The next phase goes live on 7 October 2021.

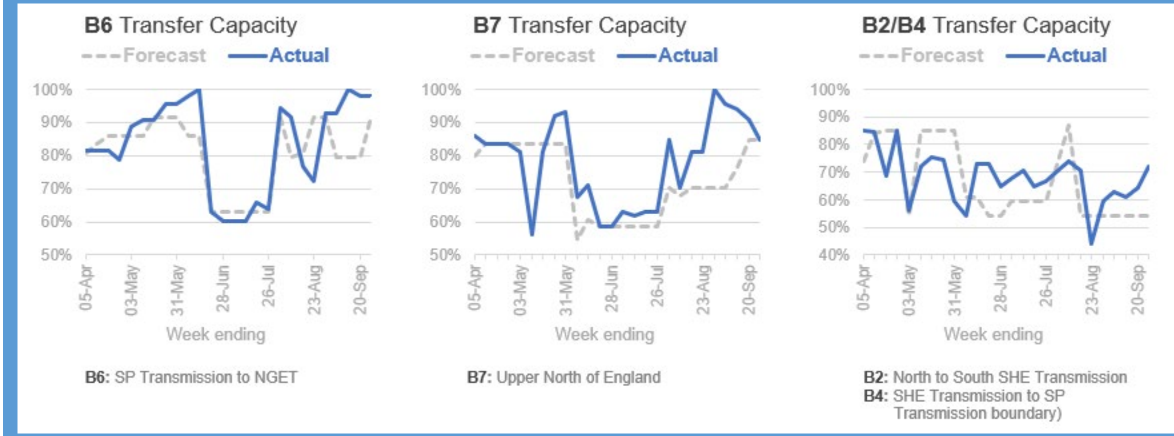


Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have been consistently higher through the six months when compared to the previous year. Due to tight margins and scarcity pricing, the margin price for September increased dramatically. Additional actions were taken to put on more generation to meet our operational margin requirements, and ultimately the required demand. For the highest cost day on 15 September 2021, actions were taken at a price of £4000/MWh during peak demand periods of the day.

Network availability, April 2021 – September 2021:



B6: SP Transmission to NGET

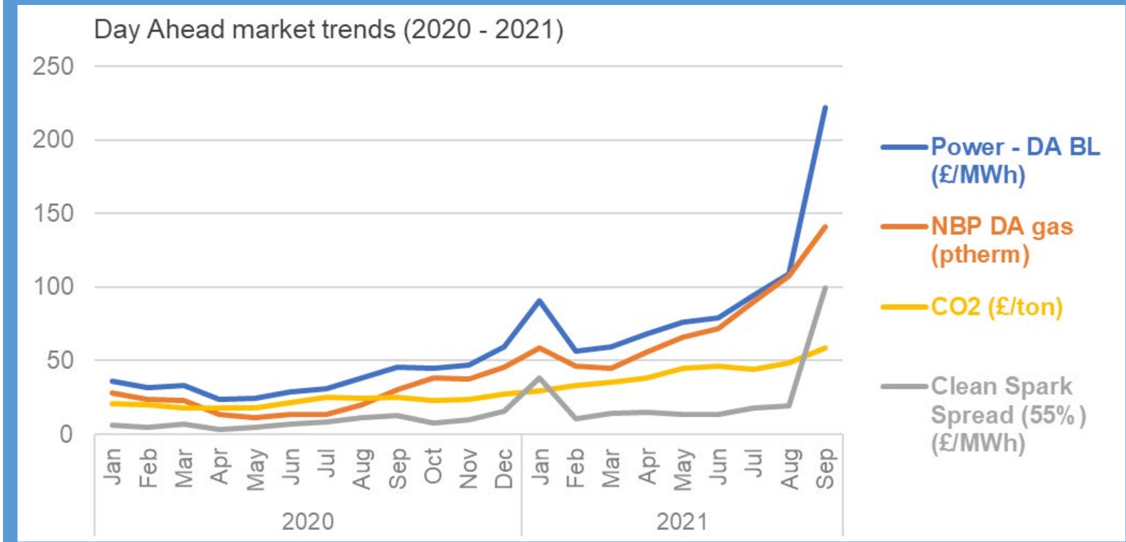
B7: Upper North of England

B2: North to South SHE Transmission
B4: SHE Transmission to SP Transmission boundary)

We have observed generally good availability of the network across the year to date. Low wind levels mean that constraints in specific areas are largely inactive and therefore are not significant cost drivers at this time.

Transfer capacity is now a standing item at the weekly Operational Transparency forum. Details of how to sign up, and recordings from previous meetings are available here.

Changes in energy balancing costs (2020-21)



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

Power day ahead prices have continued to rise throughout this reporting period from April 2021. This is driven by the rising gas and emissions costs and as discussed, has a direct impact on the price of actions that ESO has available to operate the system and manage the individual operability challenges.

The average day ahead power baseload averaged at £68.43/MWh in April 2021 compared to £221.86/MWh in September 2021 showing the significant increase in underlying cost drivers impacting on available actions, and ultimately the total balancing costs.

Daily costs trends

High costs have been incurred in both April 2021, and September 2021. Five of the six highest cost days fell within September and were directly attributable to high spend on Operating Reserve to provide additional generation at times of tight system margins. The table below shows the highest cost days from the six-month period. Note that where Operating Reserve is higher than the Total costs for the day, this is due to having taken additional actions to support Ireland through security of supply challenges. The value of those actions is recouped through SO-SO trades, which are part of 'Minor Components' on the cost summary table at the start of this section.

Date	Operating Reserve Spend (£m)	Total spend (£m)
15/09/2021	28.8	31.3
09/09/2021	34.3	24.2
12/04/2021	8.9	21.4
06/09/2021	19.2	19.8
07/09/2021	11.7	15.4
14/09/2021	20.8	14.4

In each of the September high cost days, the requirement for additional Operating Reserve to meet the margin requirement, combined with lower generator and provider availability meant that high, scarcity-driven prices dictated the costs of these Operating Reserve actions.

For the 12 April, the high costs were incurred due to a number of coinciding factors; significant demand uncertainty due to weather variability and the impact of the relaxation of COVID-19 restrictions, coupled with tight margins. As a result, high price Balancing Mechanism actions were required to ensure sufficient generation was available to meet the demand and reserve requirement.

High cost days are presented, and evaluated within our monthly reporting – but also at the weekly Operational Transparency Forum. 12 April 2021 high cost day was discussed extensively at the forum on 21 April 2021 and similar sessions have been run for the September days.

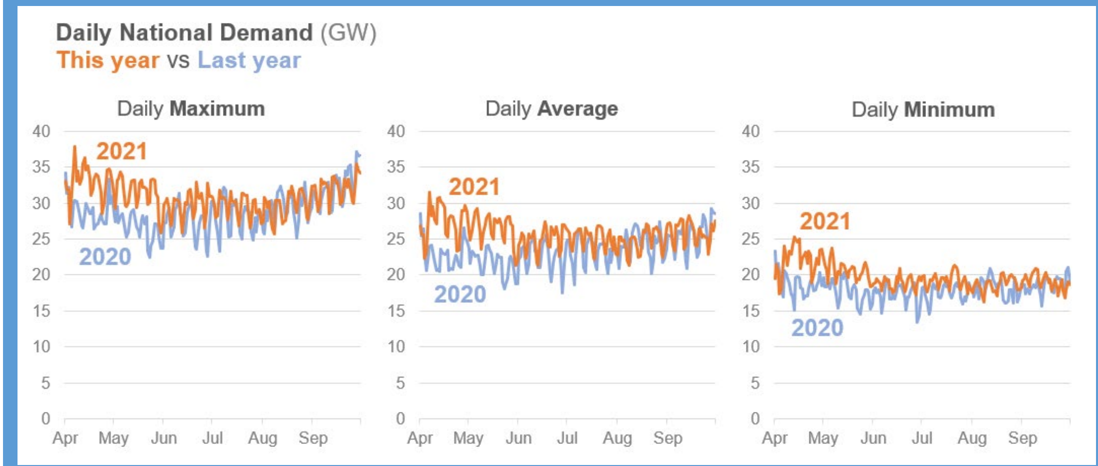
Significant cost days:

On Thursday 9 September 2021 we spent c£38.5m in the BM. This was partly offset by -£13.6 Ancillary Services spend, of which -£14.8m was SO-SO trades funded by Ireland who were in Amber status and had requested power flows from GB to Ireland.

The net impact of BM actions on the GB market was £24.2m (see table above). Although this is high, it is in line with recent balancing expenditure driven by scarcity pricing from thermal generators. On this day, the demand was within seasonal norms but wind generation was forecast to be low, and availability of conventional generators was also low due to outages. GB margins were tight but adequate, with higher prices being seen for generators for access to additional volume. As is standard practice, we assessed all available options and took high cost actions for peak demand on the day. SO-SO trades to Ireland prevented disconnection of Irish customers and this cost was passed onto the Irish market.

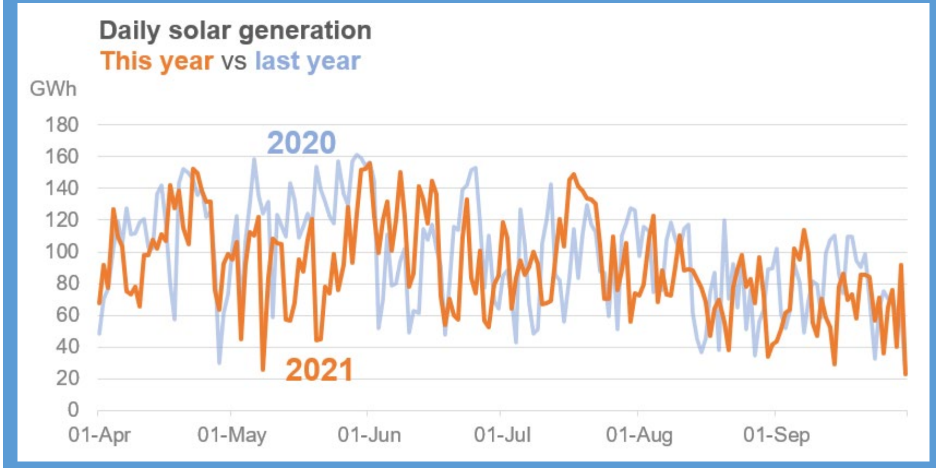
After reconciliation this will be reflected in the GB balancing costs for this day. Going forward we anticipate that this scarcity pricing will be present over the winter, but only at times of tight margins.

Outturn Demand vs 2020-21



Demand levels have been higher in 2021 than the previous year, driven by the relaxation of COVID-19 measures compared to the restrictions in place in 2020. From August onwards, the difference between this year and last year's demand reduces as lockdown measures eased in summer last year. The ODFM (Optional Downward Flexibility Management) service was reintroduced in case of very low demands however this was not required in 2021 as the daily minimums were higher than last year.

Solar generation - comparison against last year (April to September)



Over the six-month period, the solar output was 0.57TWh lower than last year.

Significant events

There were no significant events during the past six months that had a significant impact on balancing costs.

6. September performance - Detail

The balancing costs for September were £234m, which is £52m higher than August, and in the 'below expectations' range**.**

Most of this month's total increase of £52m is in non-constraint costs, which increased by £70m, compared to constraint costs which fell by £18m.

The main drivers of the changes this month were:

- **Operating Reserve: £118m increase.** Balancing Mechanism prices increased significantly, driven by higher Market prices and tight margins. On several occasions we have also provided assistance over the interconnectors which has led to an increase in Operating Reserve costs off-set by a reduction in Minor Components as the additional costs were recovered through the SO-SO trade mechanism.

- **Minor Components: £31.9m reduction.** The costs of trades between System Operators (SO-SO Trades) are contained within minor components. Where assistance has been provided by the ESO this will result in a negative cost to recover the cost of the additional actions required

- **RoCoF: £21.6m reduction**. Higher demands and reduced Interconnector capacities led to higher inertia levels and a lower volume of actions required to secure for RoCoF leading to lower costs.

Constraint Costs – September 2021

Compared with **last year** (September 2020)	Constraint costs remain below those of last year, and are lower in September 2021 than September 2020. This is due to low wind levels, good network availability and a reduction in spend against RoCoF, due to the implementation of Phase 1 of the FRCR recommendations. This trend in reduced RoCoF spend is forecast to continue with the implementation of FRCR Phase 2.
Compared with **last month** (August 2021)	Constraint costs are lower than in August as the cost of securing RoCoF fell due to higher inertia levels as a result of higher demand and reduced interconnector availability.

Non-Constraint Costs – September 2021

Compared with **last year** (September 2020)	Non-constraint costs are significantly higher than the same period last year. This is due, predominately, to the increase in energy prices in the Balancing Mechanism and Day Ahead Markets. The result of this is the cost of actions we took was much higher than in previous years even though the volumes of actions taken are significantly less than the previous year.
Compared with **last month** (August 2021)	For the month of September, non-constraint costs have risen significantly, from August's already high levels due to a further increase of required actions. This is due to the significant increase in Operating Margin costs this month, driven by scarcity pricing.

Metric 1B Demand forecasting accuracy

April – September 2021-22 Performance

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

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

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

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

Compared with last year's reporting (2020-21), there are two differences in relation to metric 1B. The first one is that the performance is reported as the mean absolute percentage error (APE) rather than mean average error expressed in MW. The second difference is that the accuracy is measured for each Settlement Period, rather than each Cardinal Point.

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

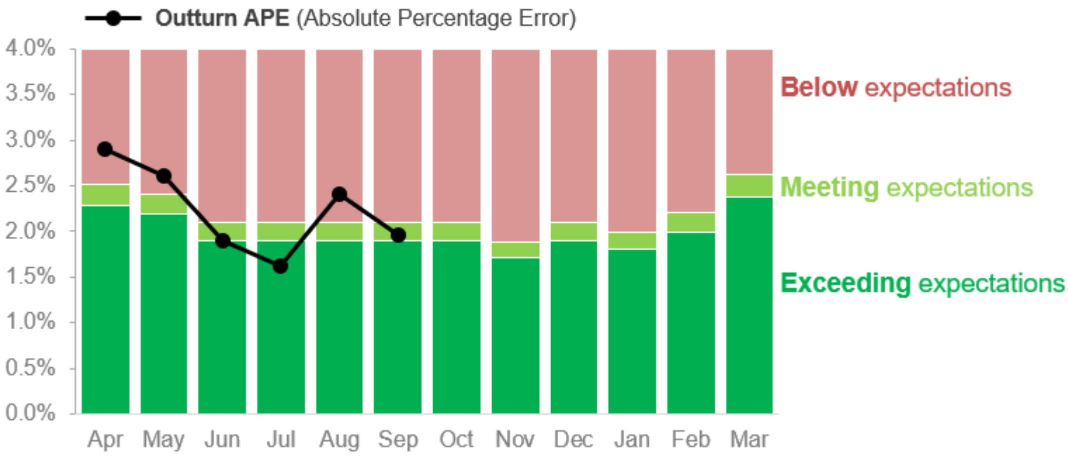


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr - Sep
Indicative benchmark (%)	2.4	2.3	2.0	2.0	2.0	2.0	2.0	1.8	2.0	1.9	2.1	2.5	**2.1**
APE (%)	**2.9**	**2.6**	**1.9**	**1.6**	**2.4**	**2.0**							**2.2**
Status	●	●	● [12]	●	●	●							●

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

[12] The June status has been corrected in this mid-year report as 'exceeding expectations'. Previous monthly reports showed the status as 'meeting expectations'

Supporting information

Year-to-date performance: Meeting expectations

Over the six-month period the average monthly APE (Absolute Percentage Error) is 2.2% compared to the half-yearly (Apr-Sep) average benchmark of 2.1%. Therefore, we are within 5% of the benchmark and “meeting expectations” for this metric.

Commentary for April 2021 to September 2021

April *Below expectations*	In April, the biggest errors coincided with Easter, and the weekend at the end of the school holiday following the Easter break. Clock change (late March) and Easter are typically the times in the Spring when the demand forecasting uncertainty is increased, and forecasting inaccuracies are at their highest. It was challenging to find a recent historical day on which to base the forecast, primarily as dates from 2020 were mainly affected by the COVID-19 demand suppression. The lower than normal temperatures in April, despite being one of the sunniest months on record, were an additional challenge.
May *Below expectations*	In May, the biggest errors at the day ahead forecasting horizon were mostly observed between 10:00 and 15:30, SP20 to SP31. Compared to long-term data and the historical weather records for May, May 2021 was unusually cold and wet, driving atypical demand behaviour across the month.
June *Exceeding expectations*	In June, our day ahead demand forecast indicative performance was within the exceeding expectations benchmark. Our new additional national demand forecasting (machine learning) model released in Q1 was incorporated into our processes from June, helping facilitate improved performance in June. The most challenging days in June were 1 June, the day after the Spring Bank Holiday (as either side of Bank Holidays it's more difficult to find a similar historic day to use as a basis for forecasting), and the weekend of 19/20 June due to unusual weather patterns. June performance was also supported by improvements delivered as part of the Platform for Energy Forecasting (PEF) project, allowing us to produce more forecasts, more frequently and at a higher level of detail.
July *Exceeding expectations*	In July, our day ahead demand forecast indicative performance was within the ‘exceeds expectations’ benchmark for the first time this year. The most challenging days to forecast in July were those with large solar PV forecast errors around midday and to a lesser extent in the afternoon, due to the weather being more overcast than forecast.
August *Below expectations*	In August, our day ahead demand forecast indicative performance was not within the benchmark. Forecasting performance in August was affected by the uncertainty related to the effect of “staycations,” the unusual Summer holiday pattern driven by changing travel restrictions in place to control the spread of COVID-19. The biggest errors at the day ahead forecasting horizon were observed on the Bank Holiday.
September *Meeting expectations*	Monday 27 September was the day when the biggest forecasting errors occurred in the month. The day started with a lot of rain across GB. From midday onwards it cleared more than expected at the time of the forecast preparation (publication by 09:00 at D-1). Solar generation was higher than anticipated, which resulted in less power being drawn from the transmission network. New national demand forecasting models were deployed at the end of August. We moved away from using a linear regression model and now use a technique called Generalized Additive Model (GAM). This was a major change as the previous forecasting method had been in place for a number of years. residual error. The new models display smaller residual error, and better reflect the varying pattern of demand caused by measures introduced to control the pandemic, e.g. national or local lockdowns.

In the first six months of 2021-22, 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 in the first six months of 2021-22.

Metric 1C Wind forecasting accuracy

April – September 2021-22 Performance

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

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

Figure 3: BMU Wind Generation Forecast APE vs Indicative Benchmark (2021-22)

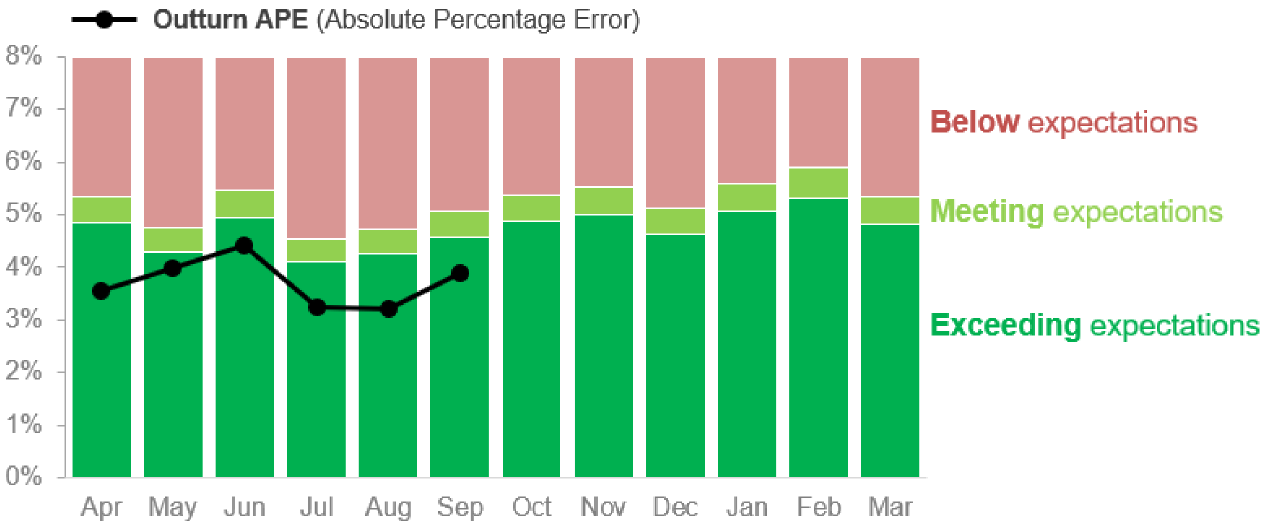


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr – Sep
BMU Wind Generation Forecast Benchmark (%)	5.1	4.5	5.2	4.3	4.5	4.8	5.1	5.3	4.9	5.3	5.6	5.1	**4.7**
APE (%)	**3.5**	**4.0**	**4.4**	**3.2**	**3.2**	**3.9**							**3.7**
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

Year-to-date performance: Exceeding expectations

Over the six month period the average monthly APE (Absolute Percentage Error) is 3.7% compared to the half-yearly (Apr-Sep) average benchmark of 4.7%, and we have exceeded expectations in all six months. Therefore, we are “exceeding expectations” for this metric.

Commentary for April 2021 to September 2021

April *Exceeding expectations*	**April** was characterised by very cool dry weather with clear skies and overnight frosts, with below average temperatures. Significant lightning activity happened several days in the month, indicating atmospheric instability which is commonly difficult to forecast.
May *Exceeding expectations*	**May** turned out to be one of the wettest on record, leading to larger than usual wind power forecasting errors. 11 out of the 31 days in May had significant lightning activity occurring across the UK, leading to greater wind power forecast errors. Despite these unusual weather conditions, the national weather forecasting input data combined with our forecasting models was relatively accurate.
June *Exceeding expectations*	Very stable weather conditions helped increase predictability, as such our weather service provider has been able to provide us with very accurate weather forecasts during this time. Other factors to consider include the impact of COVID-19, which has lessened the rate of construction of new wind farms reducing a source of forecasting error.
July *Exceeding expectations*	**July** saw some of the lowest wind speeds and lowest wind generation outputs in the past 10 years. Forecasting wind generation output is much easier when there is less wind: in those circumstances the likelihood of large errors is significantly reduced. The weather in July was very calm and settled and as a result, good wind generation forecast accuracy was achieved.
August *Exceeding expectations*	**August** was in line with the typical average weather for August in previous years, with relatively calm weather conditions interspersed with thundery showers. There were no named storms that passed over the UK during August and the weather forecasting at other times was accurate.
September *Exceeding expectations*	In **September**, our wind forecast indicative performance was within the ‘exceeding expectations’ target, with a MAPE (Mean Absolute Percentage Error) of 3.9% against a benchmark of 4.8%.

Based on the analysis conducted by the World Climate Service, April to September 2021 was the least windy such period for most of the UK in the last 60 years. This has contributed to the “exceeding expectations” scores for the first part of the year.

Wind farms with Contracts for Difference (CfDs) contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more.
Between April and September, there were no occasions when the electricity price went negative. The electricity price used for this analysis is the Intermittent Market Reference Price.
Market Price Data between April 2021 and September 2021 can be downloaded here.

During the first six months of 2021-22 there were no instances of missed or late publication of forecast data.

Metric 1D Short Notice Changes to Planned Outages

April – September 2021-22 Performance

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

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

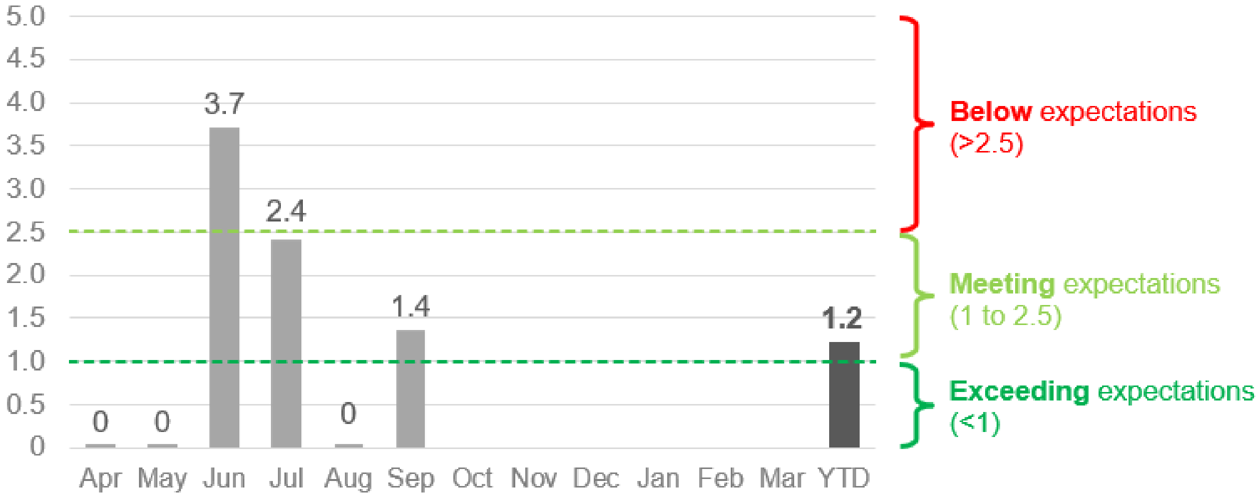


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	845	856	810	831	810	735							4,887
Outages delayed/cancelled	0	0	3	2	0	1							6
Number of outages delayed or cancelled per 1000 outages	0	0	3.7	2.4	0	1.4							1.2

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

September performance: Meeting Expectations

In September, the ESO successfully released 735 outages and there was a total of one delay or cancellation due to an ESO process failure. This gives a score of 1.4 per 1000 outages, which is within the ‘Meeting expectations’ range of 1 to 2.5 per 1000 outages.

Year-to-date performance: Meeting Expectations

For April-September 2021-22 as a whole, the total delays or cancellations due to an ESO process failure is 6 out of 4,887 outages. This gives a Mid-Year score of 1.2 per 1000 outages which is within the Meeting expectations range of 1 to 2.5 per 1000.

This is an improved performance compared to the same period last year April-September 2020-21 when there were 2.8 cancellations or delays per 1000 outages (12 cancellations/delays out of 4,348 outages).

The outage planning database TOGA was replaced with an enhanced database called eNAMS, this was delivered on 1 September 2021. At the Mid-Year point, it would be premature to infer any positive or negative influence on this metric.

Overall, the ESO is continuing to engage with the TOs and DNOs regularly through liaison meetings to maximize system access. This has been demonstrated by releasing a greater number of outages so far in 2021-22 of 4,887 than historic years and improved performance. (4,764 outages in 2019-20 and 4,348 outages in 2020-21 at the same points in the year)

Details of the 6 delays / cancellations due to an ESO process failure for September 2021 - April 2021

June 3 events	1. The first event was caused by a generator that was unaware of an outage which was going to impact them. We notified the generator within planning timescales but as no response was obtained, the outage was signed into plan rather than following up to seek agreement. An Operational Learning Note has been shared to ensure customer agreement is obtained before outages are agreed into the plan. 2. The second event was a planning error regarding a specific fault that would split a substation leading to an abnormal network configuration feeding DNO demand. We did not identify that the fault would split the substation nor the impact on DNO demand within planning timescales. Therefore, the DNO was notified of the outage but not the fact that it would be fed post fault from an abnormal network configuration. The ESO control room contacted the DNO the night before the outage was due to start, who requested additional time to study the impact on their demand. As a result, the outage was delayed. We will take account of this issue for similar outages in the future. 3. The third event involved a large generation group being put at a single circuit risk due to the nature of the requirements of a TO substation upgrade project. Shortly before the outage was due to start, we identified that the automatic protection scheme would not operate as expected and the generation group could not be secured without special action that could not be obtained in control timescales. This was due to the TO’s automatic protection scheme not being designed to cater for two out of three circuits being on outage simultaneously during the final project stage. This meant the control room was unable to release the outage. The outage has now been re-planned to avoid this issue.

July 2 events	1. The first event was caused by a modelling discrepancy between the software tools used by the planning department and those used by the control room. The studies undertaken within planning timescales did not identify any operability challenges associated with taking out of service the assets for which the outage was requested (a circuit and a Mesh Corner of a substation). However, when coming to release the outage within control room timescales, it was identified that there were unacceptable post-fault thermal overloads under certain contingencies. As this issue was driven by taking out one of the Mesh Corners in a substation, it was agreed with the relevant TO to release the circuit and leave the Mesh Corner in service until further analysis could be undertaken. The discrepancies between the planning and real-time software tools were investigated. 2. The second occasion was an outage that was delayed due to confusion based on conflicting internal advice on the suggested substation running arrangements for a specific circuit outage between the control room and planning department. As it was not clear how the substation was to be configured, the control room identified pre-fault thermal overloads prior to releasing the circuit. Therefore, a new running arrangement was identified that resolved the issues seen in real-time. However, the new running arrangement then had to be sent back to the planning department to check it against future weeks, as the outage had an Emergency Return to Service of On-completion (meaning that once released, it cannot be returned until completed). The analysis determined there were no operability concerns with the proposed substation configuration and the outage was eventually released. An Operational Learning Note is to be written to identify corrective measures.
September 1 event	1. This event was caused by a directly connected customer that was unaware of an outage which was going to impact them. The customer was notified within planning timescales but as no response was obtained, the outage was signed into plan due to the limited time restrictions during the Week Ahead timescales. There was an Operational Learning Note in place following event 1 in April (see above), however this September outage differed in that it was signed into plan as a result of human error.

A.3 Stakeholder evidence for Role 1

- The ESO Operational Transparency Forum has become an ongoing weekly event and continues to draw audiences of over 100 every week, with an average feedback score of 9 out of 10 for the six-month period and nearly 600 stakeholder questions answered.
- Independent stakeholder survey results showed 91% of responses were either meeting or exceeding expectations
- We have engaged with industry extensively on Distributed Restart, including the annual event in April 2021 which was an online podcast event with more than 1200 stakeholder registrations and 73% of respondents rating the event as ‘very good’ ‘or excellent’.
- Continued close collaboration with customers and stakeholders on North Sea Link (NSL) and ElecLink, with successful testing of NSL in challenging conditions
- Following our quarterly meetings with the Technology Advisory Council, we have acted on specific feedback in a number of areas

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, we report on our stakeholder satisfaction survey results, as well as describing how we have worked with stakeholders during the year.

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.

For role 1, the following question was asked:

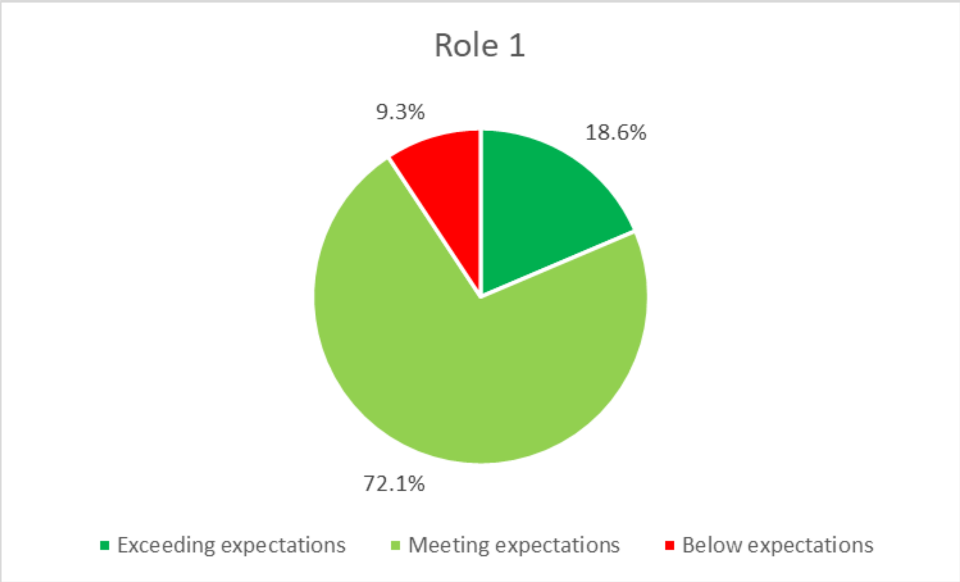
“One of the ESO Roles is focused on Control Centre Operations, which includes key activities such as real-time system operation, system restoration and provision of information, data and forecasting.
The ESO’s recent activity in this area includes awarding contracts for restoration and progressing the 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 that the ESO did that exceeded their expectations.

For Role 1, we contacted 107 stakeholders, and received 43 responses to this question, which were distributed as follows:

- 18.6 % exceeding expectations
- 72.1 % meeting expectations
- 9.3 % below expectations



The survey results indicate that the ESO is **meeting expectations** for role 1, although Ofgem will also take into account other stakeholder evidence. Our analysis of survey responses is summarised below:

“Exceeding Expectations” feedback

Overall, stakeholders who felt the ESO had exceeded expectations provided positive feedback primarily around transparency and forward thinking:

- Stakeholders commented positively on the increased transparency and data provision, with some highlighting that stakeholders were kept well informed of transmission network and system balancing activities.
- The forward thinking of the ESO was admired by stakeholders when we showed examples of considering innovation and new technologies in different ways, and our vision, willingness to change and modernise.
- A few stakeholders provided good feedback on our communications and speed of responding to network queries.

“Meeting Expectations” feedback

We asked all stakeholders who scored us as "meeting expectations" what would it take for the ESO to be exceeding expectations for them, here is a summary of that feedback for Role 1.

Stakeholders who score “meeting expectations” set out how they felt the ESO could exceed expectations in their feedback, with major themes covering our network operations, control room communications, and ESO-TO interactions:

- While it was recognised that the ESO achieves its activities as expected and meets the agreed processes described in the System Operator-Transmission Owner Code Procedures (STCPs), stakeholders felt the ESO could exceed expectations if a variety of areas relating to our network operations were improved, from reducing the increasing number of system disturbance events to making fewer changes to agreed planned outages.

- Many stakeholders felt the ESO would exceed expectations if communications with the ESO were improved, whether this was on providing greater clarity on outage planning/notifications or providing flexibility on the scheduling of phone calls with stakeholders. Stakeholders would like to ensure their needs as customers are met, with improved engagement with the control room.

- Some of the feedback for how we could exceed expectations provided by stakeholders focused on the ESO-TO interaction, and how the process between the ESO and TOs/interconnectors could be streamlined in terms of communication, documentation, and flexibility. Stakeholders also want the control room to engage more quickly with the TOs when system events occur.

- Other areas stakeholders fed back on for how we could exceed expectations included improving the change process, ensuring information provided remains accurate and transparent, and reporting data quicker. The high level of industry knowledge provided by the control room was praised by certain stakeholders

"Below Expectations" feedback

Stakeholder who scored "below expectations" identified themes around technical focus over commerciality, transparency, and the interaction between planned generation outages/system stability:

- Some feedback voiced concerns that there was a greater focus on commercial operations in contrast to the issues experienced by generators
- Comments highlighted the need for greater transparency and management of constraints.
- Some remarked that greater awareness of the interaction between planned outages and system stability in real time was needed to ensure there is sufficient restoration capability for all regions.

Over the coming months, we will seek to act on this feedback to improve stakeholder satisfaction with our activities.

Stakeholder engagement during the year

The Stakeholder Evidence criterion also takes account of the ESO's consultations and ad-hoc surveys throughout the year, whether the ESO has actively sought and taken into account the feedback of stakeholders throughout the business plan cycle, and the ESO's explanations for feedback received.

Ongoing activities

Electricity National Control Centre (ENCC) Stakeholder Engagement

ESO customers react to system conditions and make decisions on published available data. To facilitate this, the ESO has historically published key system alerts, warnings, and notifications to the BMRS system[13] and the GB Electricity Capacity Market Notices[14] website in as timely a manner as viable. Customers raised a Grid Code modification (GC0109) to specify some additional warnings, alerts and notifications which the ESO should publish and sought to codify the requirement to issue them all to the BMRS to ensure data parity for all industry stakeholders. We engaged with the customers and stakeholders through the Grid Code modification working group to agree the necessary changes. GC0109 was approved in July 2021, and the ESO implemented system and process changes to comply with the modification within the 30-day implementation window set by Ofgem.

DNO operational meetings have continued, having been reintroduced in January 2021 as feedback from customers had shown the benefit of the meetings. The Control Room provided guidance on where to find operational data using external sources to allow counterparties to make informed decisions.

The control room teams are fully engaged with the Operational Transparency Forum to increase the transparency of real time actions to our customers.

We have received the following feedback:

Connected TSO: *"ESO are a key stakeholder for us. We rely heavily on the flexibility and accommodating nature of ESO Engineers. It is my experience that ESO endeavours to provide excellent communication and customer service at a team and individual level."*

[13] https://www.bmreports.com/bmrs/?q=help/about-us

[14] For Capacity Market Notices only

Connected TSO: *"Control engineers are always polite and friendly and will always try their hardest to help us out if we need it. If the ideal solution for us cannot be accommodated, then ESO will always work with us to find a compromise. Great team to work with."*

Trading

The ESO trading team has engaged with industry stakeholders through several channels including bespoke surveys and the Operational Transparency Forum. Over the past 6 months, the trading team has continued to work with the Data Portal developers to publish further data from trading actions, and have been seeking feedback on the new data sets industry would like to see.

The traders now automatically keep a log of all historic trades, which gets updated to the Data Portal at 6am daily, rather than a manual upload once a month. All upcoming trades data has been relocated onto the Data Portal to align with all other data publications. All contract enactments, including SuperSEL, are now automatically updated to the Data Portal, removing the delays associated with the previous manual upload process. The traders have also introduced a data dictionary. We received the following feedback:

Supplier: *"I appreciate the work you put in reaching out to everyone in order to improve the transparency and access to data. The [Operational Transparency] forum is very useful".*

Supplier: *"The new website with the summary of trades is very useful, very well done for implementing it".*

Control Centre architecture and systems

Wider Access

The wider access API is the capability which smaller size participants can use for submission of market data to National Grid ESO. We responded to market participants' feedback about the requirement to have more detailed information for the Wider Access API by publishing a new API Specification document[15] in September 2021.

Power Available Phase 2

The ESO delivered Power Available Phase 2 in March. We presented at the Wind Advisory Group in May with an update on what Phase 2 delivered and the further changes we had planned to allow for better use of wind in response and reserve. We conducted an informal survey after the meeting with an average score of 8.5/10. Following the delivery of Phase 2, engagement with the Wind Advisory Group is likely to change to have a broader scope.

New interconnectors

The commentary below refers to the mid-year reporting period ending on 30 September 2021. Please note that commercial operations on North Sea Link (NSL) began on Friday 1 October.

As NSL approached go-live and ElecLink has started Railway Integration Testing, the first half of the year has seen an incredibly busy time for the Interconnector Programme. We have kept both interconnector deliveries on target through close collaboration with the customers and an agile internal programme to deliver all the functionality, documentation and training needed for new interconnectors.

For NSL we have agreed and signed the first Operating Protocol to allow the full commercial operations to begin as planned. There has been several rounds of IT development and delivery, each requiring integration testing between NGESO, NSL and Statnett to ensure the functionality works as expected and resolving defects where possible. Prioritisation has taken place with our customers on the services available at go-live and the IT functionality to deliver these to ensure customer go-live dates have been maintained. There has also been a focus on power system commissioning tests, with up to 1400MW flowing on the interconnector. This 1400MW flow was the first time the ESO has had a largest loss above 1320MW, and therefore we gave special consideration to system security issues.

[15] https://www.nationalgrideso.com/document/208206/download

Prior to commercial go-live of an interconnector, a series of commissioning tests are also conducted to ensure the asset meets manufacturer-set requirements and GB Grid Code obligations.

Due to system conditions it was difficult at times to secure specific testing requirements – i.e. large volume import/export testing. One particularly challenging test was the frequency injection test. During this testing a rapid change in metered volume would need to be recorded (instantaneous increase/decrease up to 150MW). Due to the high volume change, communication was required in real time between the ESO Control Room and NSL as the testing would make a noticeable difference to real-time system frequency.

During testing, there was a loss of a large Nuclear unit. Despite the loss, the ENCC was able to continue the testing schedule. The NSL commissioning team noted on more than one occasion that they were very impressed by the coordination and communication processes demonstrated during the frequency injection testing.

We were able to work closely with NSL to facilitate all the testing required ahead of the start of their commercial operations. We received the following feedback:

Interconnector owner: *"Please pass on thanks to all who are working so hard on this - it's much appreciated".*

With Eleclink the focus has been the facilitation of the Railway Integration Testing that has taken place throughout September. With an already full programme of interconnector work this meant timescales to meet customer requirements were exceedingly challenging. Great collaboration between the teams at the ESO, ElecLink and RTE ensured we were able to allow the Railway Integration Testing to start as planned at the beginning of September. This required the ESO to work in an agile way with the customer to put in place IT changes required and minimise any impact on power system security. Other ongoing work includes the agreement of the Operating Protocol and planning for formal commissioning to start. Further IT activities will be needed, including integration and user acceptance testing before ElecLink can start commercial operations.

Control Centre Architecture

Technology Advisory Council (TAC)

The Technology Advisory Council meets once per quarter to guide the ESO's digital, data and technological transformation. Below is a summary of how we have used their feedback.

March 2021 – Balancing and Network Control programmes

We presented an overview of our Balancing and Network control programmes. This included the current technology suite, our goals for 2025 and the five-year delivery roadmaps. The TAC was asked to provide the challenges, considerations and potential solutions, considering people, processes and technology. The top areas of feedback (as voted by the TAC) and how we have or will use it are shown below. Although this feedback was received in March, we have acted on it during this financial year.

TAC feedback	How we have used it or how we will use it
Technology and Operations collaboration Having technology and operations teams collaborate very closely leads to continuous improvement and feature development as well as an understanding of each other's challenges. It may not be possible to achieve this if technology build is outsourced **Collaborative Transformation** Transformations in other sectors, such as telecommunications and digital television, highlights the need to fully involve all operational teams from the start to get buy in. These programmes must be	The ESO Ways of Working (WoW) initiative has been in the pipeline since February and was launched in mid-March. The initiative is designed to implement a new way of working and create TechOps (technology and business operations) teams that are focussed on the customer to deliver products that are of value to them. The WoW initiative will accelerate the ESO's journey to adopting a digital and product model. In addition, we are embracing the Scaled Agile Framework (SAFe) approach and tools to ensure that the delivery of products is exactly in line with

seen as transformation approaches rather than technology programmes	the customer's expectations through constant feedback loops.
Start-up mentality Having a start-up mentality means being prepared to fail. Is this something the ESO is really empowered to do?	We are engaged with National Grid Digital Hub to run several Hack-a-Future sessions which embodies design thinking. These events will be fast, purpose driven events focussed on the future (the art of the possible) that will use, observe, ideate and review loops to continuously improve on our previous best. We will be running such events across the ESO for all roles in order to ensure that the start-up mentality is entrenched. For example, within the Future Balancing Programme and Electricity Market Reform (EMR) workstreams, we have worked, and are working, with the end-users to understand their needs and wants, plotting the user journey and prototyping solutions to provide tangible value-add outcomes.

June – Digital Engagement Platform (DEP) and Single Markets Platform (SMP)

We presented an overview of our plans for the Digital Engagement Platform (DEP) and Single Markets Platform. This included our high-level intention, the customer feedback that had informed this, and our digital design principles. Like in the previous meeting, we asked the TAC for their key challenges, considerations and potential solutions. The top feedback (as rated by TAC) is shown below.

TAC feedback	How we have used it or how we will use it
Don't try to build a perfect end to end solution that does many things poorly. Build core functionality that does limited things well and build from there.	The foundational release for SMP is being built on a core functionality to facilitate registration (provider and asset), accede to specific service terms and pre-qualify units. This will be for new and enduring Response and Reserve products initially prior to integration with downstream capabilities (such as auction capabilities) in the future and extension to wider balancing services markets.
Human interaction will continue to be important due to the complexity of the energy industry. Great platforms enable specialists in a company to do end-to-end customer journey management. The ESO needs people, and the associated technology, that guide users through the whole process.	DEP and SMP will adopt an approach that frees up specialists to provide more value add support to customers.
Linking up with industry initiatives such as Modernising Energy Data (MED) and Energy Data Visibility (EDVP) being coordinated by BEIS and IUK	We are engaging with the Modernising Energy Data (MED) and Energy Data Visibility (EDVP).
DEP and eso.com should be one. Data and information provided by the ESO is valuable in one place and alongside the systems that facilitate market participation.	We are scoping the DEP solution to replace the capability currently provided by the eso.com website.

September – Digitalisation Strategy and Action Plan (DSAP)

We presented the digitalisation strategy and aspects of our ways-of-working (WoW) at the TAC. Their feedback was constructive, positive, and confirmed that we are on the right track with our digital and product model and agile delivery method – with waterfall where necessary.

During the discussion the TAC were asked to provide suggestions on the points that we should focus on, some of which we discussed during the meeting. It is important to note that during our discussions they echoed the fact that this is a journey that will take years to fully embed.

At the end of the session the TAC voted on the key focus points and the results of the top four votes are shown below.

TAC feedback	How we have used it or how we will use it
One team - No split between business and IT and reduction of siloed working.	This reinforced our approach to build multidisciplinary TechOps teams where Technology (Tech) and ESO operations (Ops) work together to focus on outcomes for our customers.
Customer focus (Expert led to customer led) – Design with the customer in mind.	We have mapped our first two customer journeys in Roles 1 and 2. We will extend this to Role 3 in the coming months. Our digital engagement and single market platform investments are early adopters and have run a series of 1-2-1 user research sessions with 14 organisations to better understand why and how our customers and stakeholders engage with the ESO, what tasks they are trying to complete and some of the challenges that they face.
Make sure digitalisation and ways-of-working is not seen as an IT project	At the beginning of 2021-22, our ESO leadership team established a ways-of-working initiative which includes people from all aspects of ESO.
Empowerment - You need to ensure employees are empowered to think beyond the box, step up, explore new areas, be creative, share their experiences, etc. Employees need to know the company is behind them	We are developing a lean governance structure that will empower people to make decisions and know when to ask for help and guidance. Within this empowerment, we are also running a series of cultural behavioural sprints which will nudge us towards a more collaborative and innovative culture.

After the September meeting, we conducted an informal survey of TAC members. Their feedback was:

- The format of the TAC meetings enables them to input their thoughts and feedback
- Members need more confidence that we are listening to and acting upon their feedback

Further details are available on our website[16].

[16] https://www.nationalgrideso.com/who-we-are/stakeholder-groups/technology-advisory-council/documents

Restoration

Restoration standard

We have continued to engage with stakeholders through various industry forums whilst awaiting direction from BEIS. Industry workshops have been organised at the start of October to discuss the future industry working groups needed to identify the changes required in each sector to implement the Restoration Standard. A consultation will also be published towards the end of October.

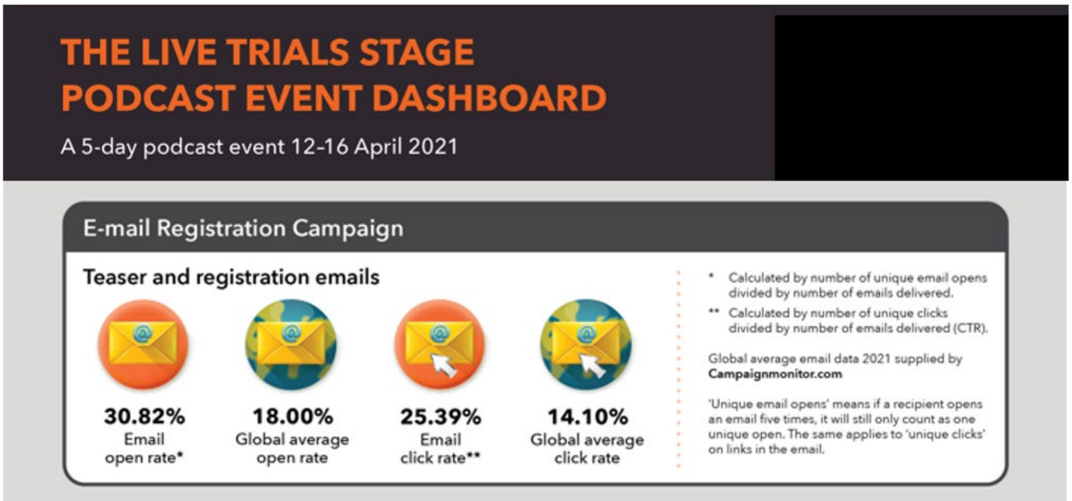
Innovation project in restoration

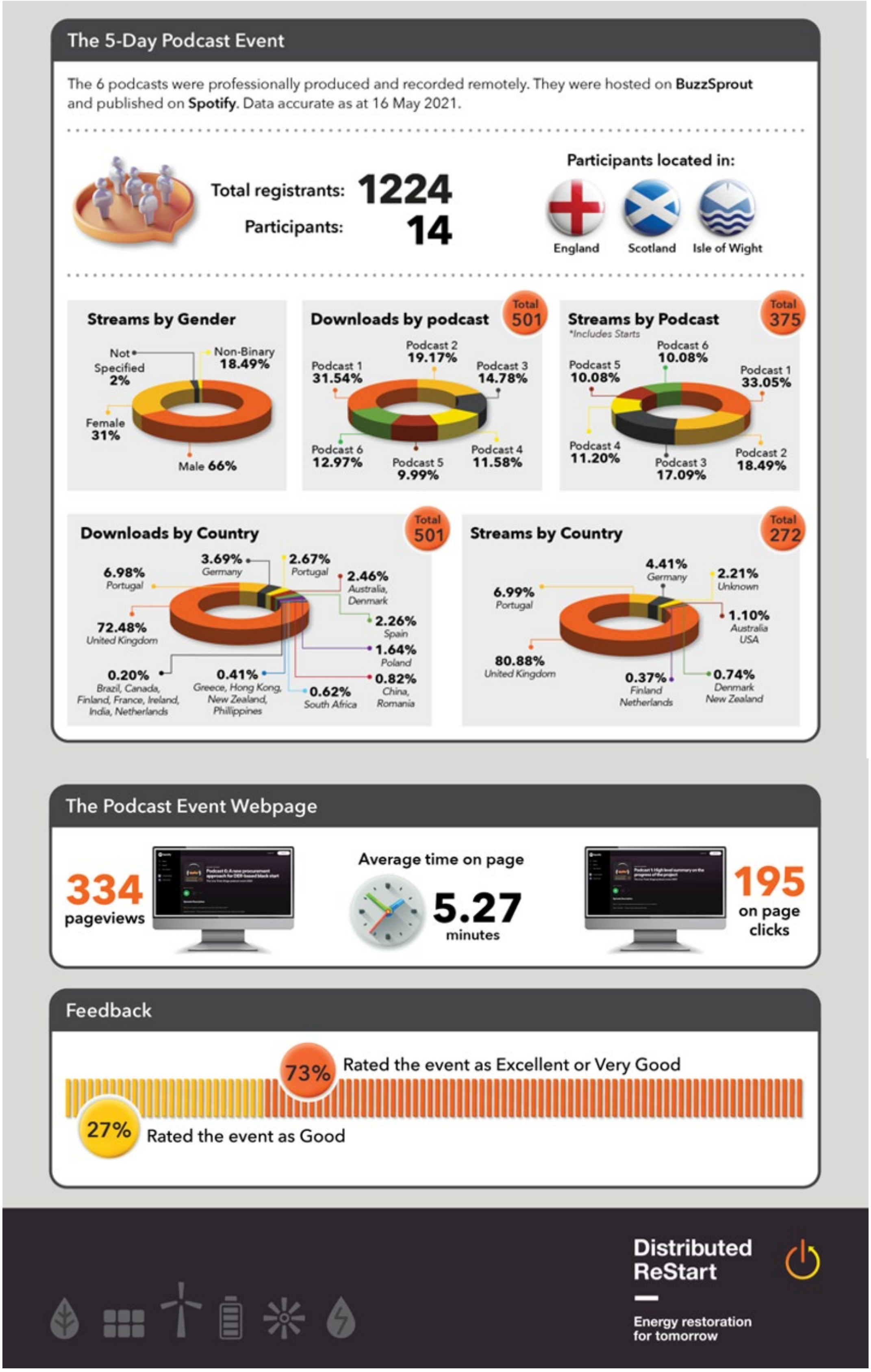
Distributed ReStart

Knowledge dissemination from project discovery has been carried out through various channels including social media, webinars, workshops, desktop exercises, conference presentations, project website postings, publication of milestone reports and promotional releases. Further detail is provided below. Utility Week will be publishing a report in November describing our project discoveries to its wide audience.

Distributed ReStart Annual Event

Distributed ReStart's annual event was a 5-day podcast event held from 12-16 April 2021. This year's event, 'The Live Trials Stage', followed on from last year's virtual conference, 'The Design Stage'. The series included in-depth interviews and a lively panel discussion with external industry experts. The podcast featured insights gained from the first live trial and described the plans for the upcoming trials. Below are some details of engagement during the event.





Quotes:

Consultancy: “*Surprisingly good. Informative and interesting in equal measure.”*

Distributed ReStart Webinar and desktop exercises

On 20 May we held a webinar[17] which provided an overview of our developments in procurement and compliance, as a commencement of our focussed engagement as we develop our process and thinking. We then invited Distributed Energy Resource (DER) participants for further 1-2-1 meetings to fully understand their requirements and seek feedback on our proposals. The first meeting was held on 27 May and further meetings were held in June.

Distributed ReStart delivered desktop exercises to test the proposed operational process for restoration through distributed energy resources. These exercises conducted across May-July involved control room representatives from all GB DNOs, TOs and ESO control engineering functions alongside 20 representative operators of DER units. This significant engagement exercise was aimed at identifying direct improvement opportunities for the procedural design leading to 10 changes being implemented as part of the final design presented in the Operating a Distribution Restoration Zone[18] report. This online co-creation session trailed the use of innovative bespoke developed software to enable different operators to participate on a single simulated restoration event, providing potential learnings for future cross industry training or service design activities.

We received a lot of excellent feedback from participants and the Engineering Advisory Council identifying potential improvements, which we've incorporated into our model. We published a milestone report in September summarising our recommendations. This has been backed up with a 1-hr podcast on Spotify to promote the publication's release.

Quotes:

DNO: *"I thought the technology developed for this exercise was excellent. It allowed a visual walkthrough of the whole process for the diverse range of stakeholders, all of whom would play a part in an [Electricity System Restoration] ESR. Given this is virtual and removes the need for travel as well as increasing the number of participants, I don't think we've previously had such a tool that demonstrates the enormity of the task and helps people think through what they would be faced with, but only takes a few hours, instead of 2 long days including travel and overnight accommodation, particularly for those of us from the north. Finally, well done to you and all the team. You recognised from the start that with this type of event where the discussion / feedback is the key output, you inevitably need more content than you can get through but struck the right balance of covering the essence without stifling the debate. In my experience, that is not easy."*

Test Procurement Event

From 2 August to 6 September, the Procurement and Compliance Workstream in the Distributed ReStart project ran a mock tender event from 2 August to 6 September for potential DER (Distributed Energy Resources) providers. The purpose of this test procurement event was to demonstrate a 'live procurement' exercise for potential providers in order for them to share readily available data around their assets. It was designed to give the participants a flavour of what could be required in a real restoration tender event. More importantly, from a project perspective we needed the mock data to test our assessment criteria, functional requirements, and associated costs on the DERs.

Our objective of getting sufficient information from a variety of different DER asset owners to stress test our proposals and formulate a feasible 'mock DRZ' (Distribution Restoration Zone) was met. The event attracted 14 providers and of those we have confirmed bids from five, whilst one is still pending and two stated they would have submitted if they had extra resource over the summer holidays. This is useful feedback that we will consider when scheduling future exercises. From the information received, we were able to produce a set of results and most importantly, we recognised areas for improvement alongside the feedback we had from our participants.

The five participants who submitted bids included aggregators offering battery storage solutions, flywheel technology providers and diesel-powered generators.

[17] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6255943776001

[18] https://www.nationalgrideso.com/future-energy/projects/distributed-restart/key-documents

We will continue to seek feedback and share lessons learned with participants. The outcomes will feed into our Final Procurement and Compliance Report.

We received the following feedback:

Aggregator: *"Having participated on the online "war gaming" event earlier in the summer, the requirement for service was understood. The information provided in the test procurement exercise is clear and the documentation easy to follow. The NGESO requirement is clearly specified. As the purpose of this exercise is testing procurement processes, I believe that the aims of this were well met."* (in response to the question "Did the information shared as part of this event made sense?")

Transparency and open data

Dispatch Transparency Tool

We launched the Dispatch Transparency dataset in Q4 2020-21. We covered the process in some detail through the Operational Transparency Forum over multiple weeks of this financial year, with the opportunity to ask questions and challenge and with additional deep dives into some of the more complex terminology and concepts. We also engaged with the Energy Storage Network in July to provide more detail on the tool and answer further questions.

We received the following feedback:

Supplier: *"The transparency data being published on the Data portal is extremely useful"*

ESO Transparency Forum (Operational Transparency Forum)

At the onset of COVID-19, the ESO set up a new weekly webinar to engage with industry-wide stakeholders and provide them with guidance on the operational decisions being made to manage through this period of uncertainty and low demand. As a result of feedback from stakeholders and continued strong attendance, this has been extended into an ongoing weekly event that continues to draw audiences of over 100 from a diverse group of stakeholders. It acts as a platform for continued and improved transparency of operational decisions and a weekly opportunity to ask questions through a public forum. These events continue to be shaped in response to direct feedback from participants, introducing changes to the delivery format, topics covered, and data sets published.

A weekly feedback cycle with 114 unique contributions across the past 6 months has drawn focus to topics of interest, questions requiring further clarity and thoughts on overall methods through which the forum can be improved. We use a combination of direct post event feedback and indirect monitoring of recurring question themes to structure the forum.

Weekly feedback monitoring

Our feedback score is composed of an average of three different metrics that we use to drive continuous improvement. Our average score over the last six months is 9 out of 10, which is an improvement on 2020-21 where the average score was 8.6 out of 10. The highest score to date was 9.6 out of 10, for the session on 16 June 2021.

The three metrics used to give our overall feedback score are overall quality of the event, quality of responses to questions, and relevance of topics discussed.

Figure 4: Weekly feedback score from the ESO Operational Transparency Forum

In order to complement these metrics that drive continuous improvement we also ran a Net Promoter Score survey with 32 responses achieving a score of +75 (out of a possible range of -100 to +100). This supports the wider findings from the weekly survey result and demonstrates a continued need for delivering these events.

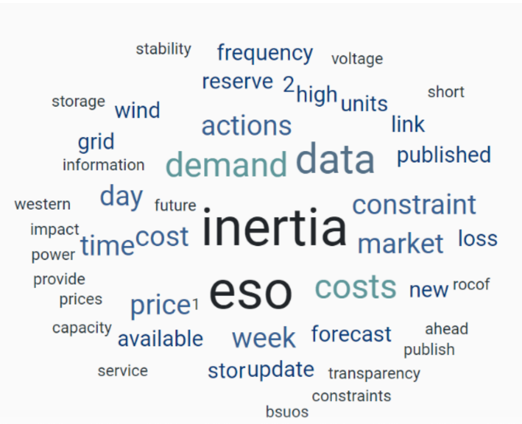
Q&A

A key benefit of this forum, for both ESO and its stakeholders, is the ability for stakeholders to ask questions of the ESO's panel of presenters. In the 6 months from 1 April to 30 September we answered 576 questions. Most of these questions are answered during the event, but where a question is too complex or does not have the relevant expert representative involved in the call these are provided at a later forum as a public response. We monitor popular themes of questions, and this informs future spotlight topics.

The word frequency diagram below shows general interest areas for the audience across the last 6 months, and our response to this is demonstrated by the core weekly content and the 'spotlight topics' covered.

Figure 5: Operational Transparency Forum – word frequency diagram

The more frequently the word occurs in stakeholder questions the larger the size on the diagram.



In response to questions and specific requests for spotlight topics we have covered many different operational processes carried out by ESO. Over the past 6 months this has included a new regular topic providing a forward look on constraints, creating greater transparency on operational boundaries and linking these to Electricity Ten Year Statement boundaries previously published.

Table 6: Topics Covered in the past 6 months in response to your feedback

Frequency	Topics Covered
Every Week	Revisiting any outstanding questions from the previous week
	Business Continuity arrangements in place, or imminent changes
	A week in review and a week's forward view of demand forecasts including monitoring of accuracy and highlighting likely periods of higher costs
	A review of the minimum and maximum periods of the week and the required ESO actions to meet this.
	A review of costs for the week including a detailed breakdown of constraint costs incurred.
	A forward look at the constraint forecast across key high cost boundaries
Spotlight topics in direct response to feedback and frequently asked questions	Multiple deep dive sessions on inertia Accelerated Loss of Mains Change Programme update Constraint management 5 point plan update Demand temperature sensitivity deep dive Dispatch Transparency Energy trading - Data transparency update Frequency Risk and Control Report Initial Demand Outturn Calculations Loss of Mains Change Programme Response reform update Thermal constraint costs and Network Options Assessment deep dive Trading transparency Transparency on system warnings Voltage Deep Dive

Overall, this event provides a platform to improve the transparency of our operational decision making by involving stakeholders in the prioritisation of data publication, providing a public response to industry questions and providing detailed discussion of actions taken by ESO to manage the electricity system. We continue to run the forums as a direct result of positive industry feedback that this remains useful to them:

We received the following feedback:

"Keep up the good work. Big fan of the weekly OTF!"

"Great session, clearly time constrained. Will look forward to the response to questions."

"I think this is the best comms that ESO do - you are all stars!!"

"These weekly sessions are very helpful so keep these up for now!"

"I firstly would like to say that the weekly updates are greatly appreciated, and I do enjoy the deep dives into precise topics such as this week's inertia topic."

"Great presentation today and some real good insights behind the drivers of constraint costs last week"

"Thanks for continuing these excellent forums. I can only occasionally attend, but find the slides and recordings great for catchup. Please continue the good work."

Data Portal

The ESO's Data Portal provides a range of information for our stakeholders, and continues to lead the way in the UK Energy Industry for access, use and understanding of energy data, and supports meeting the expectations of *Data Best Practice*[19] in several areas as outlined below.

- *Use common terms within Data Assets, Metadata and supporting information / Describe data accurately using industry standard Metadata / Enable potential Data Users to understand Data Assets by providing supporting information / Using and exchanging data: ESO ensures that its data is well-organised, accessible and shared proactively.*
    - For each of the 80+ datasets on the portal we provide a rich set of metadata, supporting finding, understanding, using and re-using our data.
    - We use standardised tags to allow for browsing between similarly tagged datasets in addition to enabling better discoverability through tag search and faceting by tags
    - The Data Portal supports configurable metadata elements and the provision of the Dublin Core Metadata Element Set as recommended by the Energy Data Taskforce.
    - For all suitable datasets we provide a detailed data dictionary to support a comprehensive understanding of our data.
- *Ensure data quality maintenance and improvement is prioritised by Data User needs*
    - We have engaged with users through several channels to identify and prioritise data quality improvements, and to inform the addition of new datasets.
    - We provide a dedicated support team for data portal queries.
    - We have transformed multiple machine non-readable datasets (pdf/xlsx) into machine-readable, comma separated (csv) files allowing our customers to download and analyse the data with greater ease and making the data available via our powerful API.
- *Ensure Data Assets are interoperable with Data Assets from other data and digital services*
    - Over 50% of the data on the energy data search engine[20] is currently retrieved from the ESO Data Portal, with the interoperability of the ESO Data Portal being referenced as an example of best practice for linked data.
    - We have used an open source platform (CKAN) for our data portal and our development has contributed to and created a number of extensions and improvements, which other energy industry parties have benefited from.
- *Creating energy system data as open for all to use by default.*
    - Over 90% of the data published on the ESO Data Portal is published under an open licence.

[19] https://www.ofgem.gov.uk/sites/default/files/docs/2021/05/data_best_practice_guidance_v0.3_0.pdf

[20] https://data.openenergy.org.uk/

Recent data sets added to the Data Portal include:

- Estimation of inertia (system and market supplied)
- Electricity Ten Year Statement (ETYS) spatial data, which was also used to power a prototype geospatial visualisation of the FES results[21].

In addition, our STA (Short Term Adequacy) model and data was provided to ENTSO-E to promote data transparency.

State of Energy signals workshop

We reached out to industry via the Operational Transparency Forum to seek input in shaping the State of Energy Signals work and held a session with interested parties on 13 September. This was aimed at understanding the current pain points for market participants, and what signals would be required both now and into the future to determine the technical availability of storage technology. The outputs of this session will be used to shape the next steps of this deliverable.

Inertia monitoring tools

We have given presentations to a number of industry forums about our new, first-of-their-kind, innovative inertia monitoring tools:

30 June 2021	North American SyncroPhasor Initiative (NASPI) System Inertia Monitoring presentation Quotes: *"very interesting presentation"* *"Wows, incredible effort / project"* *"Brilliant presentation on measuring grid inertia"*
14 July 2021	Operational Transparency Forum deep dive into inertia

Activities outside the Delivery Schedule

National Grid ESO joins global system operator consortium

We announced the launch of the Global Power System Transformation (G-PST) Consortium on 21 April 2021, this is a public-private partnership with other system operators from around the world to help accelerate the net zero transition. G-PST consists of the Australia Energy Market Operator, National Grid ESO, California Independent System Operator, Ireland's system operator (EirGrid), and Denmark's system operator (Energinet).

Powerloop Trial

The ESO is collaborating with Octopus Energy on a Vehicle to Grid (V2G) innovation project, where Octopus have secured funding with Innovate UK. The Powerloop trial will investigate the viability of V2G-enabled Electric Vehicles (EVs) participating directly in the Balancing Mechanism (BM).

Powerloop will help the ESO to meet its key ambitions and obligations under RIIO-2 for developing an electricity system that can operate carbon free, increasing competition and ensuring that the ESO is a trusted partner for all market participants.

Octopus Energy will publish a report on the viability of V2G asset participation in the BM, from which the learnings from this trial will be available to all interested parties. To support creation of the report, the ESO expects to provide findings and deliver evidence including:

[21] https://www.futureenergyscenarios.com/2021-FES/electricity-maps.html

- A detailed understanding of how the prequalification and registration process for V2G assets would work and any issues or blockers.
- A detailed understanding of blockers to the dispatch of instructions to V2G assets

The final report is due to be published in March 2022. This will give market participants an understanding of the pathway to V2G assets' participation in the Balancing Mechanism, allowing them to make informed decisions on how to utilise these assets as the market grows.

A.4 Demonstration of Plan Benefits for Role 1

The fourth evaluation criterion for the ESO incentive scheme is Demonstration of Plan Benefits, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 1 are:

- Control centre architecture and systems (A1)
- Control centre training and simulation (A2)
- Restoration (A3)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit[22]

We also provide a specific case study to quantify the benefit of Trading, which was not covered by the original Cost-Benefit Analysis document.

The Panel will also consider the ESO's Regularly Reported Evidence (RRE) as part of the Demonstration of Plan Benefits criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the ESORI guidance. For Role 1, the items of RRE reported at mid-year are:

- 1E. Transparency of operational decision making
- 1F. Zero Carbon Operability (ZCO) indicator
- 1G. Carbon intensity of ESO actions
- 1H. Constraints cost savings from collaboration with TOs
- 1I. Security of Supply reporting
- 1J. CNI outages

[22] On 10 November we revised the percentages of completed deliverables. We had previously rounded some of the percentages, but have now reported them more accurately for improved clarity.

CBA: Control centre architecture and systems (A1)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits to be £305 million over RIIO-2. This gives an NPV of £210 million over RIIO-2. The main areas of the quantitative benefit above are the following: • Estimating a five per cent improvement in managing constraints from enhanced situational awareness tools, delivering a gross benefit of £117 million. • Lowering consumer bills through unlocking the benefits of greater flexibility, delivering £109 million of gross benefit. • Reduced environmental damage from our control centre residual balancing actions, delivering a gross benefit of £51 million. • Upgrading our tools to better handle greater levels of interconnection, delivering £12 million of gross consumer benefit."
Role	1. Control Centre operations
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050
Key RIIO-2 Deliverables and progress	See activity tables below

Activity A1.2 – Enhanced Balancing Capability

Deliverable	Status
D1.2.1 Enhanced Balancing Tool	25% complete, 25% delayed, 50% not due to start yet, 0% on track
D1.2.2 Emergent technology and system management	14% complete, 18% delayed 23% not due to start yet, 45% on track
D1.2.3 Future innovation productionisation	Continuous activity

Activity A1.3 – Transform Network Control

Deliverable	Status
D1.3.1 Develop and deliver new real-time situational awareness tool	44% complete, 0% delayed, 36% not due to start yet, 20% on track
D1.3.2 Enhanced network modelling tools (modules for D1.3.1)	Continuous activity
D1.3.3 Upgraded control centre video walls and operator consoles	Not due to start yet
D1.3.4 Increased operational liaison with DNOs	50% complete, 0% delayed, 50% not due to start yet, 0% on track Continuous activity

Activity A1.4 – Control Centre Architecture

Deliverable	Status
D1.4.1 Creation of a data and analytics platform	12.5% complete, 12.5% delayed 50% not due to start yet 25% on track Continuous activity

D1.4.2 Technology Advisory Council	Continuous activity

Related metrics/ Regularly Reported Evidence

Metric/RRE	Status
Metric 1A Balancing costs	£966m vs benchmark of £562 (Below expectations)
Metric 1D Short notice changes to planned outages	1.2 per 1000 outages vs benchmark of 1 to 2.5 per 1000 (meeting expectations)
RRE 1F Zero Carbon Operability Indicator	ESO has accommodated up to 84.6% zero carbon generation
RRE 1G Carbon intensity of ESO actions	Monthly average of 4.2gCO2/kWh of actions taken by the ESO
RRE 1I Security of Supply	0 reportable voltage / frequency excursions
RRE 1J CNI outages	1 planned BM outage

Metric 1A and Metric 1D performance is expected to be favourably impacted by improvements to constraint management and by the benefits of greater flexibility. Note that that most of the benefit will be delivered in the latter years of RIIO-2, in line with our delivery schedule.

RRE 1F and RRE 1G are expected to improve because of reduced environmental damage from our control centre residual balancing actions.

RRE 1I would be adversely affected if new Control Centre Architecture were not put in place but are not expected to improve as a direct result of the "Control Centre Architecture and Systems" deliverables.

RRE 1J is expected to improve due to the delivery of our new control centre tools, but in our RIIO-2 CBA we estimated this benefit to start from 2025-26.

Sensitivity factors

The estimated consumer value we expect to deliver that is stated in the RIIO-2 CBA report was based on several assumptions. If those assumptions out turn different to expected, the actual consumer value delivered will be different to our original estimates, irrespective of the progress of our deliverables. The table below lists the assumptions made and notes whether the outturn is in line with our original estimates.

Sensitivity type	Factor	Assumption	Present	Commentary
Market	Constraint costs	£600m in 2021/22	£220m from April to September[23]	Slightly below assumptions, indicating lower benefit*.
	Cost of carbon	£14.70/tonne CO2 equivalent	£14.70/ tonne CO2 equivalent[24]	Consumer benefit expected to be in line with original assumptions (but see footnote below).
Delivery	Progress of deliverables	As per the RIIO-2 plan	As above	The deliverables are largely on track, in particular D1.2.1 and D1.3.1, which make up the bulk of the benefit.

[23] https://data.nationalgrideso.com/backend/dataset/fb56b46e-cef3-4eb8-9294-0ca19769b7eb/resource/419337fb-f609-45e3-9097-798a41b4b3de/download/constraint-breakdown-2021-2022.csv Sum of columns B, C, D, E from 01/04/2021 to 30/09/2021

[24] BEIS has not provided an update to its carbon prices for modelling purposes. It has, however, updated its carbon prices for policy appraisal. For 2020 to 2030, these are between three and 20 times larger than the previous values. If similar updates to the modelling figures are updated, it will significantly increase the estimated benefit in the "reduced environmental damage from our control centre residual balancing actions" area.

				We still anticipate the deliverables will provide the estimated amount of benefit.
	Carbon intensity of ESO actions and expected demand	Carbon intensity is from Steady Progression and Two Degrees in FES 2019 Expected demand is from Two Degrees in FES 2019	Updated figures from FES 2021, replacing Two Degrees with Leading the Way	The updated data would indicate a 50% decrease in the estimated benefits in the reduced environmental damage earlier (£26m from £51m). This would be offset by any increase in the carbon price (see above).
Third party	Interconnector volume	15GW – 16.5GW by 2030 (FES 2019)	15.9GW – 21.55GW by 2030 (FES 2021)	Slight increase on assumptions, indicating higher benefit

* Because these benefits are estimated from a fixed percentage of constraints costs, as these costs decrease the amount of benefit delivered decreases (and vice versa), irrespective of our delivery.

Summary

The main drivers of the A1 benefit case are deliverables D1.2.1 and D1.3.1 which are on track. In addition, the assumptions and sensitivities considered in our original estimates remain, on balance, valid. Therefore, we are on track to the deliver the benefits stated in our RIIO-2 plan.

The changes we have made to the balancing programme are expected to result in additional consumer benefit of £27m per annum: please see the Value for Money section for more details.

CBA: Control centre training and simulation (A2)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits to be £35 million over RIIO-2. This gives a net present value of £16 million over RIIO-2. The quantitative benefits stated above have been calculated by:

- Estimating a two per cent improvement in managing response and reserve, from enhanced training and simulation capabilities, combined with new tools, resulting in £28 million of gross benefit.
- Updating our shift patterns, working arrangements and training delivers gross benefit of £7 million over RIIO-2. This is against a baseline assumption of continuing with the as is state of limited training and simulation capability.

This activity is dependent on the following transformational activity:

1. A1 Control Centre architecture and systems (Theme 1) – Allowing high skilled engineers to use their training for zero carbon system operation This also enables, through a highly skilled workforce which can operate a complex decentralised and decarbonised electricity system, the following transformational activity:

2. A1 Control Centre architecture and systems (Theme 1) - Providing real world experience for training and simulations

Delivery of this activity could pass on benefits and costs to third parties. There may be a cost to DNOs and TOs for training their staff using our facilities. However, this would likely be offset by savings from not having to run some or all of their own training programmes. They will benefit from having a greater pipeline of resource due to our enhanced academic partnerships attracting talent to the industry. Greater co-ordination and collaboration of training will help the industry make better whole system decisions, particularly in areas such as restoration and disaster recovery.

Our analysis suggests that accounting for market, delivery and third-party uncertainty the net present value could credibly be between -£2 million and +£42 million."

Role

1. Control Centre operations

ESO Ambitions

- An electricity system that can operate carbon free
- A whole system strategy that supports net zero by 2050
- ESO is a trusted partner

Key RIIO-2 Deliverables and progress

Activity A2.2 – Enhanced training material

Deliverable	Status
D2.2.1 Development of new modules and qualifications in system operation	16% complete, 16% delayed 34% not due to start yet, 34% on track
D2.2.2 Enhanced training and simulation with DNOs and wider industry	0% complete, 60% delayed 20% not due to start yet, 20% on track

Activity A2.3 – Training simulation and technology

Deliverable	Status
D2.3.1 Upgrades to current simulators, ahead of developing new simulator capability	12.5% complete, 37.5% delayed 37.5% not due to start yet, 12.5% on track
D2.3.2 New training methods and platforms	40% complete, 0% delayed

	20% not due to start yet, 40% on track

Activity A2.4 – Workforce and change management

Deliverable	**Status**
D2.4.1 Personalised updates and automated shift logins	0% complete, 22.5% delayed 55% not due to start yet, 22.5% on track
D2.4.2 Content and infrastructure for personalised training plans	Continuous activity

Related metrics/ Regularly Reported Evidence

Metric/RRE	**Status**
Metric 1A Balancing costs	£966m vs benchmark of £562 (Below expectations)
RRE 1F Zero carbon operability indicator	ESO has accommodated up to 84.6% zero carbon generation
RRG 1G Carbon intensity of ESO actions	Monthly average of 4.2gCO2/kWh of actions taken by the ESO
RRE 1I Security of supply	0 reportable voltage / frequency excursions

Metric 1A is expected to be lower than would otherwise be the case as a result of our deliverables. New training and simulation capability will allow our control room engineers to make better decisions in a more complex operational environment. Note that most of the benefit is expected to come in the latter years of RIIO-2, in line with our Delivery Schedule.

RRE 1F, 1G, and 1I would be adversely affected if new training and simulation capability were not delivered but are not expected to improve because of it.

Sensitivity factors

The estimated consumer value we expect to deliver that is stated in the RIIO-2 CBA report was based on several assumptions. If those assumptions out turn different to expected, the actual consumer value delivered will be different to our original estimates, irrespective of the progress of our deliverables.

The table below lists the assumptions made and notes whether the outturn is in line with our original estimates.

Decreased training costs

Assumption	Status	Commentary
Reduction in training time from 7 months to 4 months	Reduction in training time from 9 months to 6 months	Consumer benefit expected to be in line with original assumptions
Training cost £75,000 per candidate, 30 candidates trained per year	Remains valid	Consumer benefit expected to be in line with original assumptions

Improved decision making

Assumption	Status	**Commentary**
Response and reserve cost £514m in 2021-22	£510m in 2020-21[25]	In line with estimates. We have used the figure for 2020-21 to account for seasonal effects, and will update this with the 2021-22 figure in the end of year report.
2% improvement in reserve and response spend	Remains valid	This assumption was based on evidence from the introduction of the DER desks in January 2019.

Summary Overall, the estimated benefits stated in our RIIO-2 plan remain valid. The delay to delivery has been due to capability and resource availability during the pandemic. We are now better resourced and are progressing well giving confidence that we will bring A2.2 and A2.3 back on track. A2.4 is currently delayed due to the change in the supplier’s circumstances. However, this has no impact externally and the additional work being created by the delay is being absorbed with no effect on budget or benefit delivery.

[25]Monthly Balancing Services Summary (MBSS) Mar-2021 https://data.nationalgrideso.com/backend/dataset/f89a12fc-94ef-4a09-bce2-c094c7212e1f/resource/931455ff-3de2-4aba-ac90-b48b3f9775fa/download/mbss-data-march-2021.xlsx Sum of “Operating Reserve”, “STOR”, “Negative Reserve”, “Fast Reserve”, “Response” and “Other Reserve” costs.

CBA: Restoration (A3)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits to be £5 million over RIIO-2. This gives a net present value of negative £8 million over RIIO-2. Despite our proposals having a negative net present value, it is important we open our restoration services to more providers including DER. We must also comply with the new restoration standard and build tools that can minimise restoration times. Given the £115 million net benefit from 2025 to 2050 of our DER NIC project, we expect our proposals to deliver net benefits over the period to 2050. This is against a baseline assumption of continuing with current Black Start procurement activities."
Role	1. Control Centre operations
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • ESO is a trusted partner • Competition Everywhere
Key RIIO-2 Deliverables and progress	It should be noted that whilst all the A3 transformation activities (i.e. A3.2 and A3.3) were considered when calculating the A3 net present value, the benefits are only derived from A3.3. This is because A3.2 (like the concept of restoration overall) serves as an insurance policy. We did not feel it was appropriate to calculate the benefits from faster restoration, given the high-impact, low-probability nature of a such an event.

Activity A3.2 - Restoration standard

Deliverable	Status
D3.2.1 Facilitate and compile, on behalf of the GB industry, the annual assurance process for GB Black Start.	0% complete, 28.5% delayed 0% not due to start yet, 71.5% on track
D3.2.2 Validate restoration timelines for GB using the assurance data.	16.5% complete, 16.5% delayed 0% not due to start yet, 67% on track
D3.2.3 Maintain obligations and requirements against the new standard for Black Start capability provision.	0% complete, 50% delayed 0% not due to start yet, 50% on track
D3.2.4 Restoration decision making support tool designed and developed to aid faster restoration times in line with stakeholder expectations.	0% complete, 0% delayed 80% not due to start yet, 20% on track

Activity A3.3 - Innovation project in restoration (Distributed ReStart)

Deliverable	Status
D3.3.1 Trial case studies based on different technology types.	25% complete, 25% delayed 0% not due to start yet, 50% on track
D3.3.2 (Subject to project findings) Proof of concept findings implemented and new system and communication methods implemented	0% complete, 0% delayed 70% not due to start yet, 30% on track

Related metrics/ Regularly Reported Evidence		
	Metric/RRE	**Status**
	Metric 1A Balancing costs	£966m vs benchmark of £562 (Below expectations)
	RRE 1F Zero carbon operability indicator	ESO has accommodated up to 84.6% zero carbon generation
	RRE 1G Carbon intensity of ESO actions	Monthly average of 4.2gCO2/kWh of actions taken by the ESO
	RRE 1I Security of supply	0 reportable voltage / frequency excursions
	Metric 2A Competitive Procurement	59% of all services procured through competitive means (meeting expectations)
	RRE 2B Diversity of Service Providers	Varying diversity across different markets – see RRE section for details

Metric 1A, 2A and RRE 2B – we would expect competitive restoration processes to improve these metrics. This will only be the case once the new contracts are operational. However, the CBA did not formally claim benefits in these areas.

RRE 1F and 1G – it is possible that the carbon intensity of our restoration actions may decrease because of competitive procurement. However, we did not formally claim benefits in these areas.

RRE 1I - If we do not undertake the restoration activities described in our Business Plan, this may result in worse performance for RRE 1I, as it would take longer to restore the system to within its frequency and voltage limits after a blackout. However, the CBA did not formally claim benefits in this area.

Sensitivity factors

Assumption	Status	Commentary
Industry participation in Black Start from DER project (Distributed Restart)	Better than expected	Benefits better than assumptions
Implementation of Restoration standard	Later than originally anticipated	Fewer benefits than expected
Industry participation in Black Start tenders	Our Northern tender received 22 submissions (see role 2 case study)	Consumer benefit expected to be in line with original assumptions

Summary

Given the progress of our deliverables, and the sensitivity factors described above, we are on track to deliver the consumer benefit set out in our RIIO-2 plan.

As the benefits we state here are only derived from A3.3 (as stated above), and the delays within these deliverables are only minor (restoration from DER services is still expected to go live in 2025/26), we do not expect this to impact on the delivery of consumer benefit.

Consumer benefit case study for Role 1: ESO trading actions

Activity

The ESO trading team negotiates trades with counterparties to meet key system requirements. This ensures that the system can be operated safely and securely, but also economically, or in other words at the lowest possible cost while remaining within operational limits. The team trades, largely with generators and interconnector capacity holders, ahead of time to help manage system constraints (whether for thermal, stability or voltage reasons) or to maintain our upward or downward operating margin for energy. We meet these requirements via trades when there is a clear economic benefit compared to the cost of the same or similar actions available to the control room in real time, or when there is no credible alternative available.

In the first half of this year, trading for system constraints (thermal and voltage) and upwards and downwards operating margin actions has delivered a saving of £57m when compared to the estimated cost for managing those requirements in the Balancing Mechanism (BM).

We have considered the example of a particular voltage constraint in the South East that usually requires a certain amount of thermal plant running to secure it. Ordinarily we might trade particular units ahead of the BM where it represents a substantial saving. Additionally, we may 'buy on' a unit at a 'Super SEL' (Stable Export Limit) level (when technically feasible) as this can deliver further savings against a unit's 'normal' SEL.

However, in mid-summer 2021 this constraint group was identified as having limited generating units available for a period due to a variety of planned and un-planned outages. These types of situations can leave the ESO with limited options and risks making us a 'distressed buyer' leaving us vulnerable to potentially escalating prices.

This was compounded as it was against a wider backdrop of escalating fuel and carbon costs. Throughout early summer the gas market was showing signs of continued upward price movement, partly driven by extensive periods of very low wind generation in Europe after a cold winter depleting storage sites, and higher global demand for LNG (Liquefied Natural Gas). Additionally, on carbon emissions, whilst now de-coupled from the wider EU ETS (European Union Emissions Trading Scheme), the carbon price on UK ETS (UK Emissions Trading Scheme) was also steadily rising due to the continued reliance on thermal generation to fill the lack of wind generation. Each year generators who produce carbon emissions must surrender sufficient carbon allowances to cover their emissions. A number of carbon allowances are granted to generators each year and any surplus or shortfall can be bought or sold under the UK ETS. These markets determine the 'carbon price'. The cost of fuel and emissions are key components of a thermal generator's cost of producing power.

In order to protect the ESO and the consumer from this scenario we sought a variety of actions in the short to medium term.

1. We negotiated **multi-day trades** up front with generating unit(s). This 'locked in' prices in the short term to protect against further price escalation.
2. We explored innovative options to optimise the voltage on the transmission system through **Interconnector (IC) Positioning** using trades. As a by-product of the normal functioning of the interconnectors' HVDC filters at the connection point, certain flow positions produce a different amount of Reactive Power, or MVARs. The amount of MVARs on the network determine the voltage. Therefore, by optimising the amount of MVARs indirectly through controlling the IC's flow, it is possible to negate the need for additional thermal plant.
3. In the medium term, we ran a **Contract Tender** for the remaining seven weeks to leverage the little remaining competition of thermal generating units.

ESO Ambitions

Primarily these actions were about promoting;

- Competition everywhere
- The ESO is a trusted partner

Whilst exploring innovative options towards;

- An electricity system that can operate carbon free
- A whole system strategy that supports net zero by 2050

Key RIIO-2 Deliverables

D1.1.3 Maintain the integrity of the transmission network, while managing the economical operation of the system.

Is the consumer benefit mainly this year or in future years?

The monetary benefit is delivered this year, but we also expect to see benefits in future years as a result of trialling innovative options for securing the system more economically. Examples of these innovative options include:

- Running contract tenders for commercial advantage and leveraging competition
- Reducing thermal plant requirements through exploring alternative means

Calculation of monetary benefit to consumers

As stated above, the trading team has so far delivered benefits of ~£57m from April to September 2021. However, this one case study focusing on the South East voltage constraint, delivered significant additional savings above this total. The combination of strategies detailed above, gave an estimated saving of **£6.4m** compared to simply 'day-to-day' trading (or £11.3m if compared to *doing nothing* or 'solving in the BM') over an eleven-week period in Summer.

This total saving can be broken down into the three parts of our strategy:

Action	**Total savings** compared against BM	Savings compared against day-to-day Trading	
	Total	Total	Per Day
1. Multi-day trades Concluded a series of multi-day trades to cover requirements for a total of 21 nights compared to a forecast cost of trading on a daily basis. Additionally, this can be compared to solving the requirement in the BM.	~ £1.3m	~ £640k	£31k
2. Interconnector Positioning Traded BritNed Interconnector to a favourable position for overnight voltage management for a total of 30 nights, negating the need for an additional thermal unit.	~ £3.3m	~ £2.1m	£69k
3. Contract Tender Outturn savings* based on 44 day firm contract(s)	~ £6.7m	~ £3.7m	£84k
Total savings	~ £11.3m	~ £6.4m	n/a

**due to an unforeseen outage extension the contract option was available for a shorter duration than planned and thus only delivered a saving over a shorter period.*

Assumptions made in calculating monetary benefit

The above calculations were made using the following assumptions;

1. **Multi-day trades**
   a) Trading savings: Assumed the cost of the most recent single day trade would prevail for the period of the multiday trade and compared this to the cost of the multiday trade.
   b) BM savings: Assumed that the cost of the alternative BM action for the relevant period prior to the multi-day trade would prevail for the period of the multi-day trade.

	2. **Interconnector Positioning** a) We traded BritNed for a total of 30 nights between 23:00 to 07:00 (8-hour period). An average of ~370MW sold per hour, assuming an average cash out price of ~£92/MWh for replacement energy b) The alternative action to selling on BritNed to move it to a favourable position was to either buy on a thermal unit in the BM or trade it as required c) It is also important to state that whilst positioning an interconnector in this way can deliver excellent value for money it is not always feasible as it needs particular conditions to be viable. It is also not firm enough to be relied upon as the primary means of voltage control. 3. **Contract Tender** a) £5.3m actual contract costs over the 44-day period (the Damhead Creek contract was 8 days shorter than planned due to unavailability) b) Against an assumed alternative cost of £9m for the same period, based on trading (through extended multiday trades) at a price of ~£190/MWh. This estimated price is based on a linear price progression pegged to average market prices of gas and carbon over the period. It was assumed that most generating parties exposed to higher BSUoS costs, especially during overnight periods, will intelligently forecast expected costs and will use all information available to them to do so, including; forward balancing services contract information and trade information published by the ESO on the data portal.
How benefit is realised in the consumer bill	The monetary benefits were realised through lower BSUoS. This is through reduced costs by spending less on like-for-like system security actions in securing the South East voltage constraint. These actions should have also delivered unquantifiable monetary benefits. This is due to: o Reduced uncertainty, securing a forward contract for longer duration in a wholly transparent way, gives increased certainty to the market of BSUoS costs for the contract period and protects against further price escalation. o Cost transparency, by taking action ahead of delivery and publishing the costs removes some guesswork for BMU parties that have to price in BSUoS risk ahead of time in their wholesale and BM prices. These indirect benefits should have resulted in (marginally) reduced wholesale and BM prices from generators during these periods.

Regularly Reported Evidence performance for Role 1

Table 7: Summary of RREs for Role 1

RRE	Title	Measure	Apr	May	Jun	Jul	Aug	Sep
1E	Transparency of Operational Decision Making	*% of actions with reason groups allocated*	99.6%	99.6%	99.7%	99.8%	99.8%	99.7%
1F	Zero Carbon Operability indicator	*the proportion of zero carbon transmission connected generation that the system can accommodate*	Q1: 85%			Q2: 77%		
1G	Carbon intensity of ESO actions	*gCO2/kWh of actions taken by the ESO*	2.1	6.2	4.5	4.5	6.9	1.0
1H	Constraints cost savings from collaboration with TOs	*Estimated £m savings in avoided constraints costs*	Q1: £337m			Q2: £162m		
1I	Security of Supply	*instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds, voltage excursions*	0	0	0	0	0	0
1J	CNI Outages	*Number and length of CNI system outages*	0	0	0	1	0	0

RRE 1E Transparency of operational decision making

April – September 2021-22 Performance

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

We publish the Dispatch Transparency[26] 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.[27]

Categories include:	System, Geometry, Loss Risk, Unit Commitment, Response, Merit
Reason groups include:	Frequency, Flexibility, Incomplete, Zonal Management

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

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

Table 8: Percentage of balancing actions taken outside of merit order in the BM

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

Supporting information

In September 89.1% of actions were taken in merit order or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis. We were unable to allocate reason groups for 0.3% of the total actions this month.

During April-September as a whole, we sent more than 215,000 BOAs (Bid Offer Acceptances), of these only 653 remain with no category or reason group identified, an average of 0.3%

[26] https://data.nationalgrideso.com/balancing/dispatch-transparency
[27] https://data.nationalgrideso.com/balancing/dispatch-transparency/r/dispatch_transparency_methodology

Throughout the first half of the year, following the Dispatch Transparency data going live on our Data Portal, we have used our weekly Operational Operational Transparency Forum to discuss instances where actions have been taken out of pure economic order, and we have covered the methodology applied through the Dispatch Transparency tool in detail.

This data is published as a result of our Forward Plan deliverable, “Data to support better understanding our dispatch decisions”.

RRE 1F Zero Carbon Operability Indicator

April – September 2021-22 Performance

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

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

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

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

Part 1 – Defining the maximum ZCO limit for BP1

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

Table 9: 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, stability market, the Accelerated Loss of Mains Change Programme, the implementation of the Frequency Risk and Control methodology, the voltage pathfinders and reactive reform. All of these developments are increasing our ability to operate a zero carbon system by either increasing the operability envelope where secure system operation is possible, or by enabling new zero carbon providers of ancillary services.

Part 2 – Regular reporting on actual ZCO

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

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

For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market in 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 7 and 8 on the next page show the underlying data by settlement period and highlights when the maximum monthly values occurred.

Table 10: 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	84.6%	91.5%	05 Apr / SP29
May	79.4%	89.2%	04 May / SP6
June	71.7%	75.1%	14 Jun / SP6
July	72.8%	85.7%	29 Jul / SP9
August	74.8%	92.7%	16 Aug / SP11
September	77.4%	88.9%	30 Sep / SP48

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

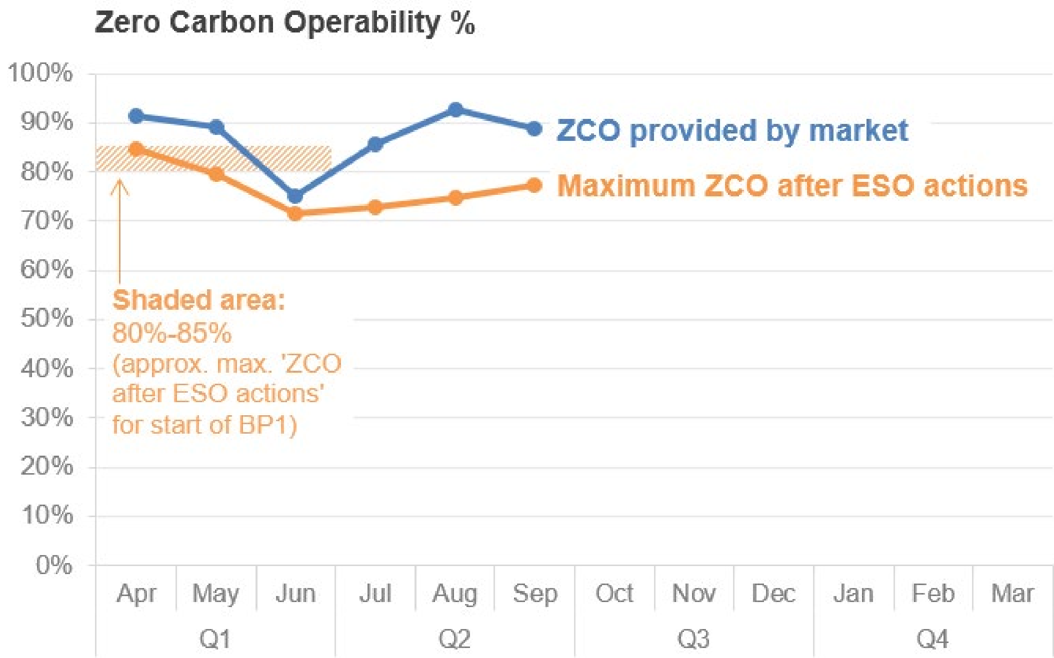


Figure 7: Q1 ZCO by Settlement Period, before and after ESO operational actions

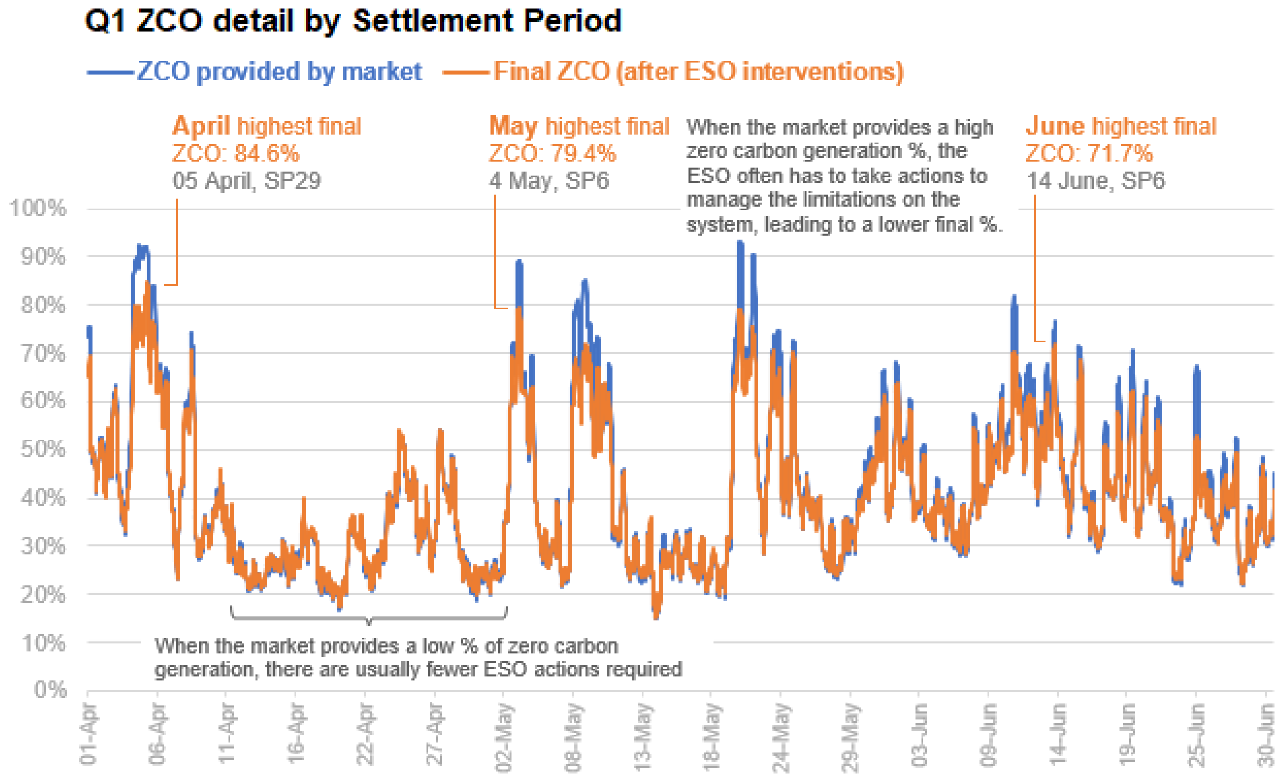
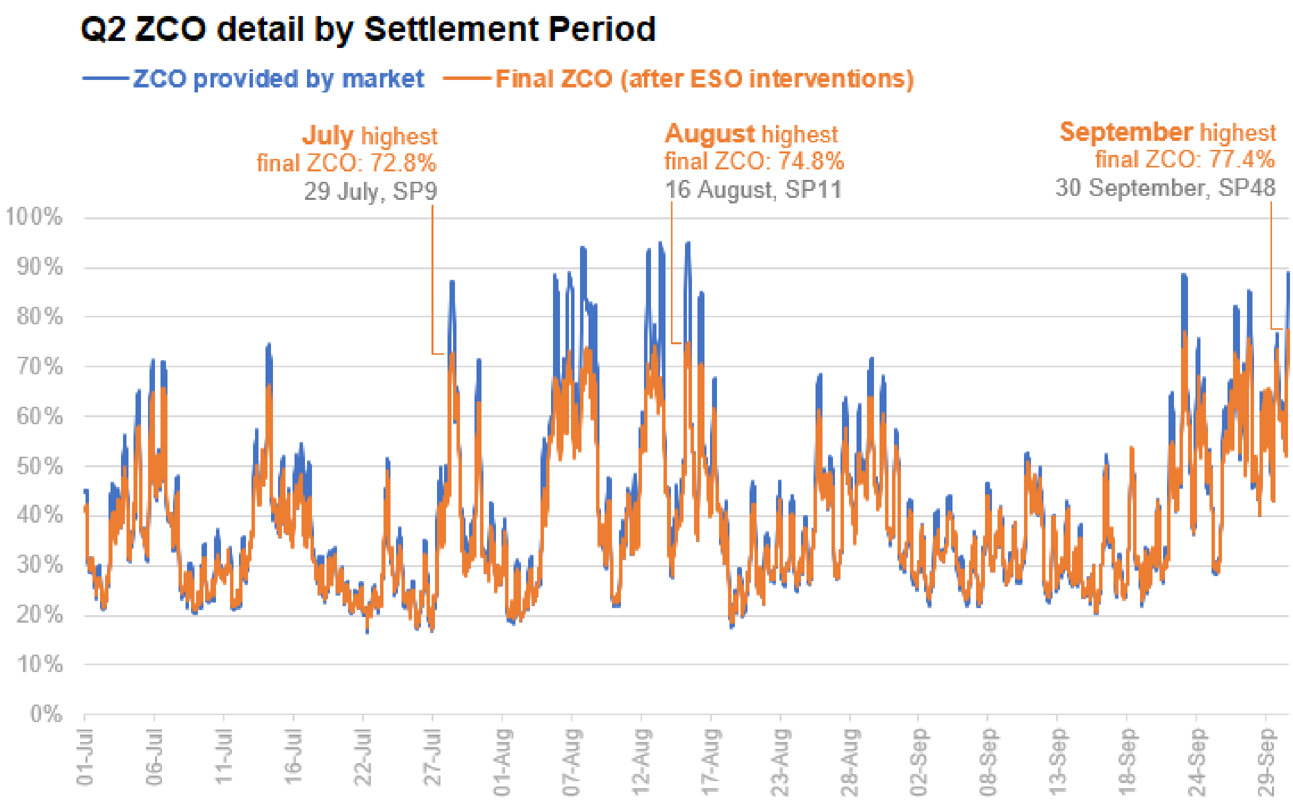


Figure 8: Q2 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

The highest zero carbon percentage outturn in Q1 and Q2, following ESO actions was 84.6%, which occurred on 05 April, Settlement Period (SP) 29. During that SP the market provided 91.5% ZCO, with actions taken by the ESO to manage the system reducing the final figure to 84.6%. This is broadly in line with our estimated maximum ZCO for Q1 of 80%-85%.

The start of April was cold but with high renewable output, which is why the ZCO figures post ESO actions were at their highest for the quarter. The maximum figures for May to September were lower than the maximum in April, because the demand (not shown on the graph above) was lower due to warmer weather. At times like those, 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) which represents a larger proportion of the overall amount of generation. The other point to note is how closely linked the ZCO figure is with wind output - the low wind spells during most of April and the start of May are clearly visible on the graph above where the ZCO% drops below 30%.

The maximum ZCO figures align with settlement periods of high renewable output, for example when it is windy. Usually (but not exclusively), these figures occur at times of low solar output. This is because the majority of solar generation is embedded and hence excluded from ZCO. Therefore, at times of high solar output operational actions will be still needed, even though the ZCO figure provided by the market will appear relatively low as it will not include the solar generation.

Going forward, the recent go live of Stability Pathfinder Phase 1 contracts are expected to facilitate a higher ZCO percentage in the future.

RRE 1G Carbon intensity of ESO actions

April – September 2021-22 Performance

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

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology[28] document. The monthly data can also be accessed on the Data Portal here[29]. 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[30].

Table 11: gCO2/kWh of actions taken by the ESO

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

Supporting information

Between April 2021 and September 2021 there has been an average difference between the carbon intensity of FPNs (Final Physical Notifications) and balancing actions of 4.23 gCO2/kWh.

The maximum difference was 74.42 gCO2/kWh which was seen in June 2021. The minimum was -21.24 gCO2/kWh which was seen in September 2021.

September 2021 had the lowest monthly average of 1.04 gCO2/kWh during the last 6 months. The significant drop between August 2021 and September 2021 could be explained by a drop in imports (in September 10% of the generation mix was imports, compared with 15% in August) and an increase in gas generation (41% of overall generation mix in September 2021, versus 36% in August 2021), meaning a lot of the gas generation that previously could have been bought on may already have been running, lowering the impact of balancing actions.

[28] https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions/r/eso_carbon_intensity_balancing_actions_methodology
[29] https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions
[30] https://www.nationalgrideso.com/document/183556/download

RRE 1H Constraints Cost Savings from Collaboration with TOs

April – September 2021-22 Performance

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

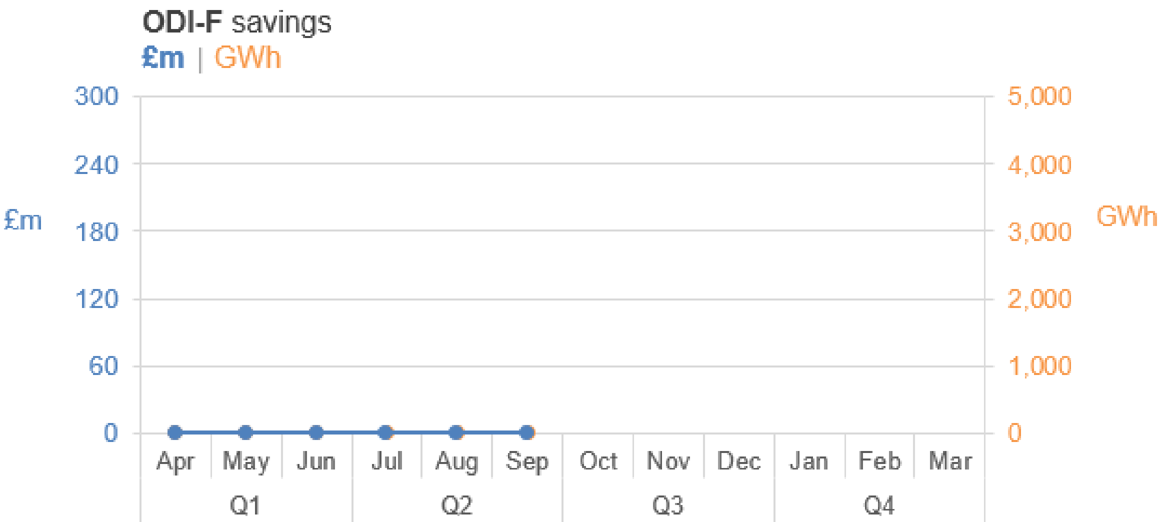
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

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

1. ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F
    - Output Delivery Incentives (ODIs) are incentives that form part of the TOs' RIIO-2 framework. They are designed to encourage licensees to deliver outputs and service quality that consumers and wider stakeholders want to see. These ODIs may be financial (ODI-F) or reputational (ODI-R).
    - One of these ODIs, the SO:TO Optimisation ODI-F, is a new two-year trial incentive to encourage the Electricity Transmission Owners (TOs) to provide solutions to the ESO to help reduce constraint costs according to the STCP 11-4[31] 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)

(Estimated savings in GWh are also shown for context)



[31] 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)

(Estimated savings in GWh are also shown for context)

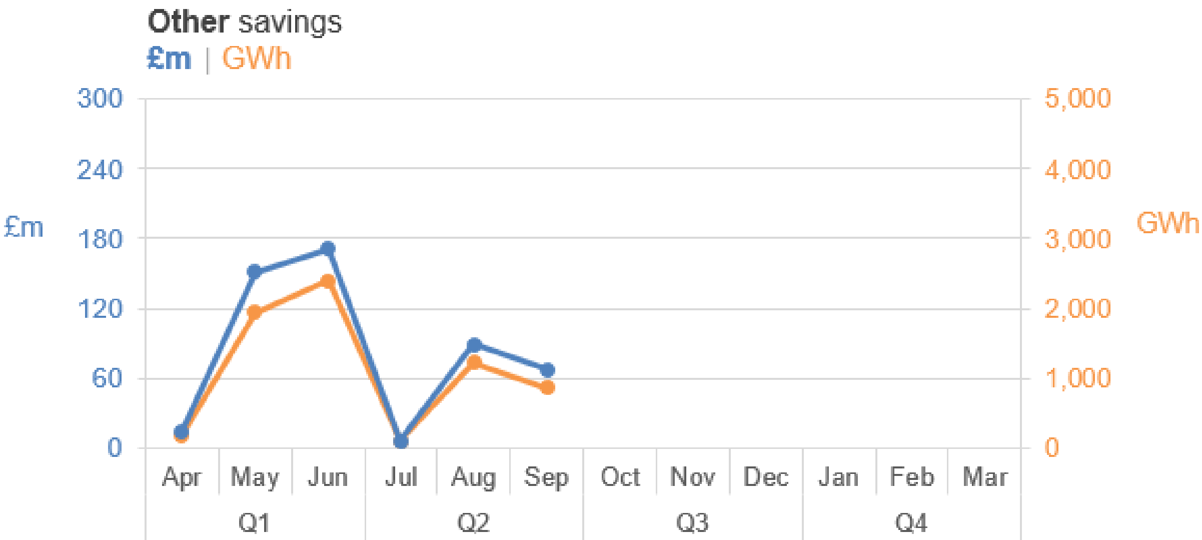


Table 12: Estimated £m savings in avoided constraints costs

		Apr	May	Jun	Jul	Aug	Sep	YTD Total
ODI-F savings	£m	-	-	-	-	-	-	**-**
Other savings	£m	15	151	171	6	89	67	**499**
ODI-F savings	GWh	-	-	-	-	-	-	**-**
Other savings	GWh	189	1,935	2,391	107	1,216	859	**6,697**

Please 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 four enhanced service provisions from TOs through STCP 11.4 that are expected to provide constraint cost savings this year. These opportunities are:

- Changing the overload protection setting on a circuit which is due to provide continuous improvement to the Dumfries and Galloway local export constraint costs.
- Increasing the rating on a circuit into the South East of England which allows an increase in the South-East import constraint limit.
- Increasing the rating on circuits to allow the final high-priority decommissioning of circuits in central London.
- The installation of an overload protection scheme which will allow increased flow across the B4/SSE-SP boundary

No constraint cost savings of this type were realised in the first half of 2021-22. This is due to these constraints not being active during this period, and therefore no enhancement to the summer rating of the circuits mentioned above was needed.

However, as it was likely that work on site would be needed to facilitate the opportunities for cost savings, identifying these opportunities early has meant that the cost saving actions will be available over the Autumn 2021 and Winter 2021 months when they are most valuable.

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

STCP 11-4 opportunities, also proposed by ESO, that are in progress with the relevant TOs and will most likely be active in Q3 2020-21 include:

- The temporary uprating on a circuit in Central Scotland to allow an increase in North-South flows in Scotland.
- Improved ratings on a Scotland – England boundary circuit which will increase the B6/SCOTEX boundary thermal limit.

There are initial discussions regarding uprating of a cable in South West Scotland which have proved promising. The NAP team are currently carrying out a cost-benefit analysis for this.

Other Savings:

The Network Access Planning team has made excellent progress over the last six months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded over 75 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.

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

Some examples of these instances include:

- The initial outage plan to deliver a new substation coincided with a maintenance outage which would have resulted in the wind generator being restricted to 0MW to avoid the risk of sub-synchronous oscillations. After extensive reorganisation of the outage plan, ESO determined that it was possible to separate both outages and remove the restriction from the wind generator during the outages. This resulted in the release of more than 140,000MWh of renewable energy.
- ESO facilitated the removal of a wind generator from an intertrip scheme which would have restricted the generator to 0MW for over 2 weeks for outages that trigger the intertripping scheme. This resulted in the removal of the restriction from the wind generator and the release of more than 2,000MWh of renewable energy.
- On 7 occasions, ESO optimised the outage plan by moving and rearranging scheme and maintenance outage dates to align with the customer's maintenance outages. These instances resulted in the release of more than 768,000MWh of renewable energy.
- A scheme outage on a Load Management Scheme for pre-commissioning works was requested by the TO and was expected to restrict 6 windfarms to 0MW export. ESO undertook extensive system studies, which determined that it was possible to release capacity to all generators in the group during certain low wind conditions. Through this approach we released about 1,500MWh of renewable generation to the market, creating considerable value for the end consumer.
- The initial outage plan to commission a new substation clashed with another scheme outage in the same geographical area. This caused a reduction of the thermal export capability of the group by 750MW for 13 days. ESO worked in partnership with the TO to review all possible options to deliver the work whilst reducing the impact on the system. After careful assessment and

optimisation, the clash was reduced to 5 days. This action released about 144,000MWh of renewable generation to the market.

- A combination of two outages caused a reduction of the thermal export capability of the group and a circuit overload following a double circuit system fault. After extensive system analysis, ESO placed another circuit in the group on open standby which increased the thermal export capability of the group by 200MW and alleviated the post fault circuit overload. This action released about 33,000MWh of renewable generation to the market.

These and many more represent a total of 6,696,900MWh (approximately £499M) of extra generation capacity in the first half of 2021, which would have otherwise been constrained at a cost to the consumer.

RRE 1I Security of Supply

April – September 2021-22 Performance

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

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

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

Deviation (Hz)	**Duration**	**Likelihood**
$f > 50.5$	Any	1-in-1100 years
$49.2 \le f < 49.5$	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

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

Table 13: Frequency and voltage excursions

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz)	0	0	0	0	0	0						
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	0	0	0	0	0	0						
Voltage Excursions defined as per Transmission Performance Report[32]	0	0	0	0	0	0						

Supporting information

There have been no reportable voltage or frequency excursions between April 2021 and September 2021.

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

RRE 1J CNI Outages

April – September 2021-22 Performance

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

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

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

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

Table 15: Planned CNI System Outages (Number and length of each outage)

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

Supporting information

There were no outages, either planned or unplanned, encountered during September 2021.

For the six-month period as a whole, there was one planned CNI system outage in July 2021. The outage, planned 6 months in advance, was a standard maintenance activity to ensure system resilience, which impacted the key BM Suite components used for scheduling and dispatch of generation.

The testing of this function is planned as an annual activity as it may be necessary to invoke the capability in the event of an incident.

As part of this outage, we were additionally able to plan and complete some maintenance and configuration tasks.

Role 2

Market development and transactions

Role 2: Market development and transactions

Plan Delivery

- We have completed 17 out of the 22 milestones planned for this 6-month period. Of the 5 milestones which are not complete, 2 are ESO-related delays, 2 are outside of ESO control, and 1 is delayed in order to deliver an improved outcome for consumers
- Awarded new competitive restoration contacts for Northern regions
- Launched Day-Ahead STOR product and auction platform for Dynamic Containment
- Progressed Net Zero Market Reform work
- Started innovation project for stability market design
- Continuous improvements to EMR activities
- Developed our Strategic Code Change roadmap
- Engaged with key stakeholders on potential areas for SQSS change

Metric performance

- 2A Competitive Procurement: 59% of all services procured through competitive means (meeting expectations)

Stakeholder evidence

Role 2 survey:

- 8% exceeding expectations
- 72% meeting expectations
- 19% below expectations

Highlights:

- Increased involvement in Open Networks
- Continued engagement with stakeholders on highly complex reserve and reactive reform
- Extensive stakeholder engagement for Whole System Technical Code and fixing BSUoS
- EMR team responded to customer feedback by involving customers in design and testing of new portal
- We're acting on stakeholder feedback relating to auction design for STOR and DC

Demonstration of plan benefits

- Build the future balancing service and wholesale markets (A4) on track to deliver £106m consumer benefit over RIIO-2
- Transform access to the Capacity Market (A5) on track to deliver £74m consumer benefit over RIIO-2
- Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5) on track to deliver £10m consumer benefit over RIIO-2
- Reforming Balancing Services Use of System (BSUoS) charges (A6.6), including fixing BSUoS and changing the charging base now expected to lead to benefits of ~£1.3bn by 2040
- Competitive contracts for Restoration in the Northern region are expected to save £14m over the next three years

RREs:

- 2B Diversity of service providers: Varying diversity across the different markets
- 2E Accuracy of forecasts for charge setting (BSUoS): Absolute percentage error of 16%

Value for money

- Our forecast total expenditure for role 2 in BP1 is £174m, which is 9% higher than the benchmark of £159m
- This is primarily due to improved visibility and clarity of costs for major IT programmes (Settlements, Charging and Billing, and Electricity Market Reform), which were early in the design phase at the time of submitting the Business Plan

B.1 Plan Delivery for Role 2

Deliverable progress

For role 2, the RIIO-2 Delivery Schedule received an ambition grading of 4/5, providing the ESO with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The Electricity System Operator Reporting and Incentives (ESORI) guidance states that the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule.

During the first six months of the Business Plan 1 period, a few highlights of role 2 performance are:

Progressing market reforms:

- We announced competitively procured contracts with providers for Restoration services in the Northern regions of Britain. These contracts were awarded as part of a new tender process, and represent a move away from bilateral agreements.
- We continued to engage with stakeholders for reactive reform, and launched an innovation project to explore a market-based solution for reactive power, taking on board learnings from previous projects such as Pathfinders.
- We implemented the Day-Ahead Short-Term Operating Reserve (STOR) product to ensure that the procurement was fully compliant with EU Regulations from April 2021 and to deliver consumer benefit through competitive auctions. The auction rules had a clear set of principles in order to ensure economic and efficient procurement, and we engaged with stakeholders on the inclusion of curtailable bids to mitigate the risk of higher clearing prices to meet the required capacity. Following the launch of the auction, we monitored the results, observed market behaviour and obtained feedback from Ofgem which led us to initiate a review of the auction rules and a decision to allow overholding and underholding when it is more economic to do so. Subject to consultation outcomes, we expect implementation to occur by late November.
- We launched the European Power Exchange (EPEX) auction platform for Dynamic Containment (DC) low frequency in September following approval by Ofgem of the Article 18 consultation. This introduces more granular, pay-as-clear procurement to deliver consumer benefits. However, Ofgem have raised concerns with the current design not allowing overholding. We have engaged with Ofgem and proposed a post-launch strategy to assess the auction results and determine if changes would be beneficial. We have received a strong steer from Ofgem to deliver this in a timely manner to ensure learnings can be applied to upcoming product launches.
- We have implemented the first phase of the recommendations of the Frequency Risk and Control Report, which are already resulting in lower balancing costs than would otherwise be the case (as explained in Role 1).

Developing a strategy for markets:

- We have taken a leadership role on European matters, working with European Network of Transmission System Operators for Electricity (ENTSO-E), Transmission System Operators (TSOs) and BEIS to document new post-Brexit working arrangements, and implementing Net Transfer Capacity arrangements to ensure that interconnectors can be correctly compensated for reductions in their capacity.
- As part of our Net Zero Market Reform work, we worked closely with BEIS and Ofgem to develop a compelling case for market reform, using our expertise to take a holistic view and provide thought leadership to the industry, proactively shaping wider market arrangements and industry frameworks.
- We have started to work on an innovation project for Stability Market Design. This project will consider the current stability arrangements and investigate the high-level best option for a potential

end-to-end stability market, building on our GB-wide regional requirements as published in phases 2 and 3 of our Stability Pathfinders.

Considering the whole system:

- We have increased our involvement in the Open Networks programme, with ESO colleagues now leading key products within its flexibility workstream, including work on Standard Agreements and Procurement Processes. This is in addition to our roles leading the project's Whole Energy System workstream and chairing the Energy Network Association (ENA) innovation managers' group as referenced in Role 3.
- We are working to improve consistency between distribution and transmission networks, for example standardising procurement processes, and making changes to our codes.
- Our Distributed Restart project is promoting the procurement of restoration services from distributed assets.

Continuous improvements to Electricity Market Reform (EMR)

- We worked closely with BEIS to draft and consult on the new Capacity Market (CM) rules and implemented these rules into our systems in advance of the rule change to ensure a smooth process for our customers.
- In a joint effort with Ofgem we updated the relevant Balancing Services within the CM rules, which means CM participants can also participate in the new response services; Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR).
- We have been working collaboratively with BEIS to deliver policy changes to the Contracts for Difference (CfD) Scheme for Allocation Round 4 in 2021, to ensure that CfD allocation rounds can continue to support an increase in the pace of renewable deployment needed to achieve the government's net zero ambition.
- Our EMR Projects team have been engaging regularly with our customers (Capacity Providers) to ensure the existing EMR Delivery Body portal, and the developing new portal, deliver on our customers' needs.
- We have worked with industry and our stakeholders to co-create prequalification guidance
- We have improved our EMR modelling and delivered the Electricity Capacity Report (ECR) 2021.

Codes and charging:

- We have iterated and built on our initial Strategic Code Change roadmap, engaging through the Markets Forum event with stakeholders on key transformation topics (such as Offshore Coordination and storage) and how these will impact codes.
- We have developed a list of potential issues relating to the Security and Quality of Supply Standard (SQSS) that may need to be addressed over the RIIO-2 period and engaged with industry to refine this list.
- The Charging Futures Forum on 22 September 2021 helped parties to learn, ask and contribute towards network charging reform, helping to progress the Targeted Charging Review.
- As part of Balancing Services and Use of System Charging (BSUoS) Reform (CMP308 and CMP361), we have been developing the proposed solution for CMP361 by actively listening to industry feedback and ideas to work through the significant complexity of creating a solution for fixing BSUoS.
- We established a new team to produce a rolling 24-month forecast of constraint costs. This will be based on the transmission and generation outage plans for within year and year ahead. We expect to start publishing the data in the second half of this performance year.
- Following the BSUoS billing error which occurred during 2020-21, we have worked with consultants PwC to review our key processes and controls and have focussed on enhancing

existing controls with improved governance and oversight. On an enduring basis, the replacement of our Charging and Billing (CAB) and Settlements systems will deliver further automation and enhance our overall controls landscape.

Progress of our deliverables

Our RIIO-2 Deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables. The first column shows how our deliverables meet the requirements of the Roles Guidance set out by Ofgem.

For Role 2 (Market development and transactions), the Delivery Schedule lists 23 deliverables in total which are made up of 113 milestones. 22 of these milestones were due to be completed in the first six months of 2021-22, of which 17 are now complete. Of the 5 milestones which are not complete, 2 are ESO-related delays, 2 are outside of ESO control, and 1 is delayed in order to deliver an improved outcome for consumers. We provide detail below about those activities where milestones are not on track:

ESO-related delays:

- A4 Build the future balancing service markets (2 delayed milestones): The Electricity Balancing Regulation (EBR) Article 18 consultation was expected to launch in October, however we have discovered complexities within the service design, such as how we procure a continuous service; these need to be resolved before we move to the next stage in our plan, which is to share our minded-to position with industry via informal consultation ahead of the EBR launch.

Delayed due to issues which are outside of ESO's control in the short term:

- D4.6.1 Development of competitive approaches to procurement of stability (1 delayed milestone): awarding contracts for Phase 2 of the Stability Pathfinder has been delayed to Q4 2021-22, as the number of submissions at the Expression of Interest stage was substantially more than originally anticipated.
- D6.2 EU code change and relationships (1 delayed milestone): due to Brexit, the ESO is no longer allowed to participate in Manually Activated Reserve Initiative (MARI).

Delayed to deliver an improved outcome for consumers:

- D6.5 Whole system grid code (1 delayed milestone): this has been delayed due to the high volume of industry engagement.

New initiatives and changes

The RIIO-2 Delivery Schedule was originally published in October 2020. Since this, the ESO has continually prioritised its projects to deliver the best value for consumers. This has resulted in the following changes:

Brexit

Since the Delivery Schedule was published in October 2020, the Trade and Co-operation Agreement (TCA) has been finalised, defining the extent to which the UK can participate in European projects and initiatives. This impacts on several of our deliverables as listed below. Following the publication of this mid-year report, we will produce an updated version of the Delivery Schedule, which reflects the changes described below.

D6.2 Continued facilitation of EU driven code changes into Great Britain market.

The following milestones are no longer relevant:

- Q2 2021-22 MARI Grid Code and Balancing Settlement Code (BSC) modifications complete
- Q3 2021-22 MARI implementation project – definitions of system changes
- Q4 2021-22 Implementation of Coordinated Security Analysis
- Q2 2022-23 Delivery of MARI
- Q2 2022-23 Implement harmonised Redispatching and Countertrading

- Q4 2022-23 Coordinated calculation of Interconnector capacity

Dependent on wider industry engagement across GB and the EU, and agreement with Ofgem and BEIS, the following milestones are expected to be delivered instead:

- Q4 2021-22 Develop a plan for implementing harmonised Redispatching and Countertrading as per the TCA
- Q3 2021-22 Develop a Technical Procedure for Day Ahead Capacity Calculation
- Q3 2022-23 Develop Technical Procedure for Cross Border Balancing and other time frame Capacity Calculation in collaboration with UK TSOs and EU TSOs

Net Zero Market Reform

We have now embarked on a program of broader market reform work, known as the Net Zero Market Reform project. This builds on our existing ESO market development activities, but looks much wider and longer term to provide a 'North Star' vision on how all GB electricity markets (including those that sit outside current ESO accountability, such as wholesale) need to reform to enable Carbon Budget 6 and Net Zero most efficiently.

Phase 1 of this project was carried out from January to March 2021 (outside of this reporting year), where we undertook a high-level review of GB market arrangements, as well as interviewing 25 stakeholders and researching international markets.

Phase 2 is currently underway where we are analysing the case for market reform – identifying current and future issues with the existing market design. We are also developing some assessment criteria to shortlist some packages of solutions that could tackle these issues.

Phase 3, beginning in November, will assess these solutions in detail and arrive at recommendations for preferred options.

Innovation projects

We are currently undertaking the following innovation projects, which relate to Role 2. Some of these projects are funded as part of the RIIO-2 price control and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. Other projects were funded as part of the ESO's RIIO-1 innovation funding but are included for completeness as they support some of the ESO's RIIO-2 deliverables. The references in the table below provide links to additional information about each project.

Innovation Project Name	Description	Deliverables supported	Status	Funding
Control Reactive Power Exchange Application Capability Transfer (REACT)[33]	To provide information about forecast uncertainty, presented in real-time to Control Room engineers, to provide opportunities for them to make more economic and secure balancing decisions.	D4.1	Delivery	RIIO-1
Dynamic Reserve Calculation[34]	Use AI and machine learning to set reserve levels dynamically, day ahead.	D4.1 D4.3.3	Delivery	RIIO-2
Crowdflex[35]	Assessing the amount of flexibility from domestic consumers, undertaking type testing as the most efficient and cost-effective path to simplifying access.	D4.5.1	Delivery	RIIO-2

[33] https://www.smarternetworks.org/project/nia_ngso0032
[34] https://smarter.energynetworks.org/projects/nia2_ngeso003/
[35] https://smarter.energynetworks.org/projects/nia2_ngeso001/

Stability Market[36]	Aims to create a number of options for the delivery of a short-term stability market for the UK, assess these options, and provide a recommendation.	D4.6.1	Initiation	RIIO-2
Reactive Power Design[37]	Investigating the possibility of a market-based solution to procure reactive power.	D4.6.2	Initiation	RIIO-2

Note that the Control REACT and Dynamic Reserve Calculation projects also feed into role 1.

[36] https://smarter.energynetworks.org/projects/nia2_ngeso005/
[37] https://smarter.energynetworks.org/projects/nia2_ngeso008/

B.2 Metric performance for Role 2

Table 16: Summary of metrics for Role 2

Metric	Title	Unit	Apr	May	Jun	Jul	Aug	Sep	Mid-year status
2A	Competitive procurement	%		Q1: 57%			Q2: 61%		Meeting expectations

Metric 2A Competitive Procurement

April- September 2021-22 Performance

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

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

- For **Restoration**, there may be a significant lag time between when a contract is agreed and when it comes into effect. Therefore, in some cases actions we take in the current quarter may not impact Metric 2A until months or years later.
- For **Frequency Response** (FR), a lower '% of services procured through competitive means (auctions and tenders)' may appear to indicate that the market has become less competitive but can actually be a sign of the opposite. When the market becomes more competitive, the market price drops. This can lead to a reduction in overall competitively procured spend and therefore a lower percentage of total services that are competitively procured.

Figure 11: Percentage of £m spend by procurement method (April 2021 to September 2021)

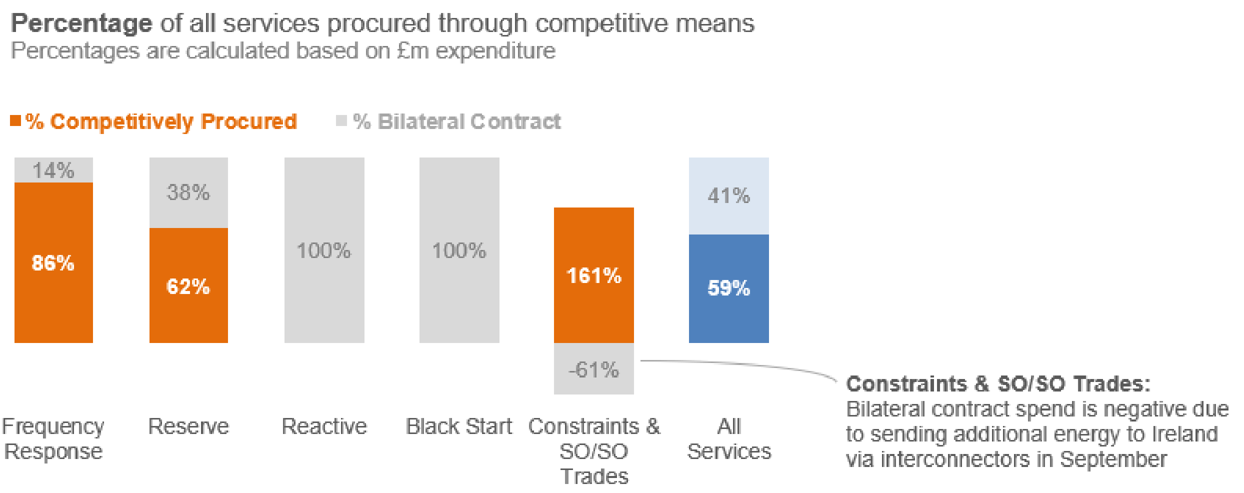


Figure 12: Absolute £m spend by procurement method (April 2021 to September 2021)

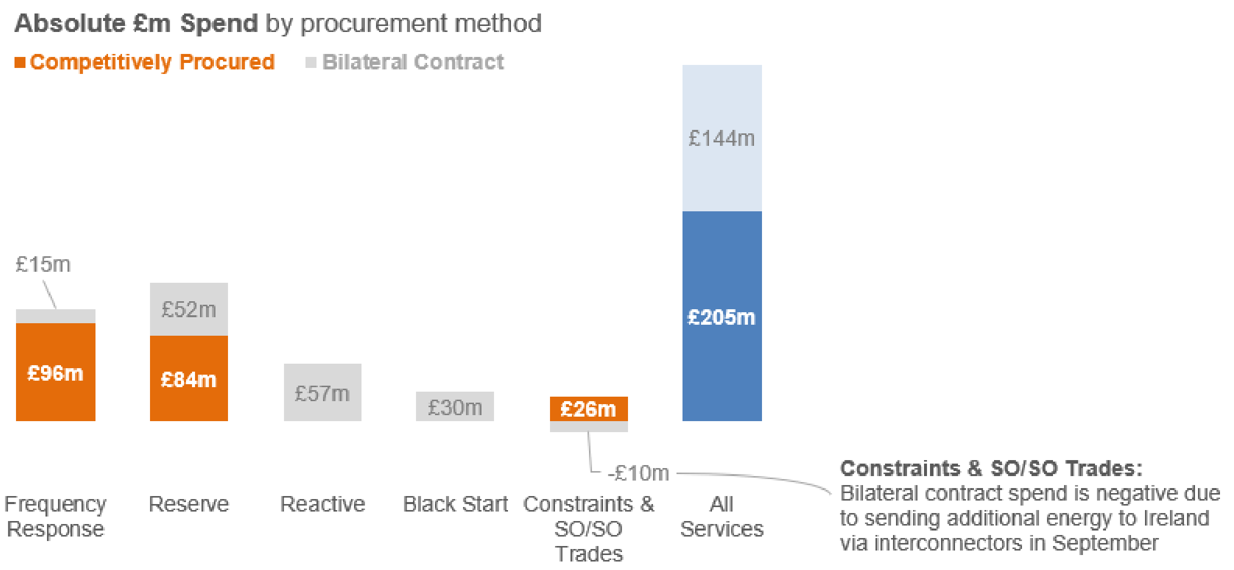


Table 17: Percentage of services procured through competitive means by Quarter

Services	Q1	Q2	Q3	Q4	YTD
Frequency Response	91%	83%			86%
Reserve	61%	62%			62%
Reactive	0%	0%			0%
Restoration	0%	0%			0%
Constraints & SO/SO Trades	89%	376% [38]			161%
All services	**57%**	**61%**			**59%**
Status (All services)	●	●			●

Performance benchmarks (Year 1)

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

Supporting information

Performance for April – September: Meeting expectations

The percentage of services procured through competitive means is 59%, which is in the 'meeting expectations' range of 50-60%. Both Q1 and Q2 performance meets expectations.

Average Market Prices

	Q1	Q2	Q3	Q4
DC (£/MW)	17	17		
FFR Weekly Auction - DLH (£/MW)	8.1	7.1		
FFR Weekly Auction - LFS (£/MW)	4.0	4.0		
Optional Fast Reserve (£/MWh)	102	123		
STOR DA (£/MW)	3.3	2.5		

Frequency Response

The DC market continues to clear at the price cap of £17/MW as we have not yet reached our volume requirement. As more battery assets are commissioned and more providers enter the market, we expect competition to increase and prices to start going down.

Reserve

The day ahead market for Short Term Operating Reserve (STOR) has seen prices drop over the summer due to increasing competition since its launch in April. However, this has been balanced by increased spend on Optional Fast Reserve through Q2, resulting in no appreciable movement in the metric. The metric of 62% for Q2 remains higher than the overall 2020/21 figure of 39%.

[38] The figure is greater than 100% as Bilateral contract spend is are 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.

Reactive

We continue to develop our thinking around market-based procurement of reactive power and have just concluded an RFI process to identify potential partner companies to run an innovation project. Contracts over summer 2021 for specific locational reactive constraints are reported under the Constraints category.

Restoration

Despite awarding contracts through open and competitive tenders for the South West and Midlands in 2020 and the Northern Region in early 2021, the spend associated with them will not appear until 2022 and therefore does not appear in this metric. We plan to launch a further competitive event in Q1 2022-23 for services in the South-East region.

Constraints & SO/SO Trades

Additional units that were successful in the Stability Phase 1 pathfinder have gone live which has increased competitive spend in this area. In addition, there have been large trades sending energy to Ireland during September (a gain of ~£17m in competitively procured spend), which has resulted in a significant change in the reported metric.

B.3 Stakeholder evidence for Role 2

- The whole system technical code (WSTC) project provided opportunities for us to carry out a series of engagements with a broad range of stakeholders, who provided input to our consultation
- We engaged extensively with Ofgem, generators, suppliers and other industry groups, to develop our solution for fixing Balancing Services Use of System (BSUoS) charges.
- We continued to improve the Embedded Capacity Register by providing locational asset data for Distribution Network Operators (DNOs).
- We held a successful, well-attended virtual Charging Futures Forum on 22 September 2021 which helped parties to learn, ask and contribute towards network charging reform.
- The Code Administrator held an external workshop inviting industry to comment on team improvement initiatives and co-create in developing tools such as the modification tracker. The event scored an average of 9.3/10 from attendees
- Our Electricity Market Reform (EMR) Projects team worked even more closely with stakeholders to develop and improve the new portal, following requests from our customers to have greater input in the design and testing.
- We launched a new programme looking at Net Zero Market Reform and have engaged over 500 stakeholders across several co-creation workshops and webinars, with an average score of 8/10
- Following on from the successful launch in March of the Markets Forum, we hosted the second event in June – bringing together over 200 participants from across the industry covering a number of topics, including Net Zero Market Design, Pathfinders, Strategic Code Change and the development of a Single Markets Platform.
- Following on from publishing the August Transmission Network Use of System (TNUoS) Tariff Forecast for 2022/23, we hosted a well-attended industry webinar to outline the forecast and improvements made to the tariff report and processes. The event scored 9/10 from attendees.
- Following implementation of our Short-Term Operating Reserve Day-Ahead (STOR DA) auction, we received feedback from Ofgem and stakeholders on the impact of not allowing overholding in the auction procurement. After significant engagement, we have acted upon the feedback to introduce overholding into STOR DA. We have set out a post-launch strategy for the Dynamic Containment (DC) European Power Exchange (EPEX) auction to consider similar feedback.
- We received feedback from stakeholders and Ofgem on our decision to procure our DC products at a Grid Supply Point (GSP) level with concerns around the impact this has on aggregation in the market. We committed to producing a paper on visibility to set out the operability challenges and intend to publish it in the autumn.

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, we report on our stakeholder satisfaction survey results, as well as describing how we worked with stakeholders during the year.

Stakeholder surveys

The ESO 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.

For role 2, the following question was asked:

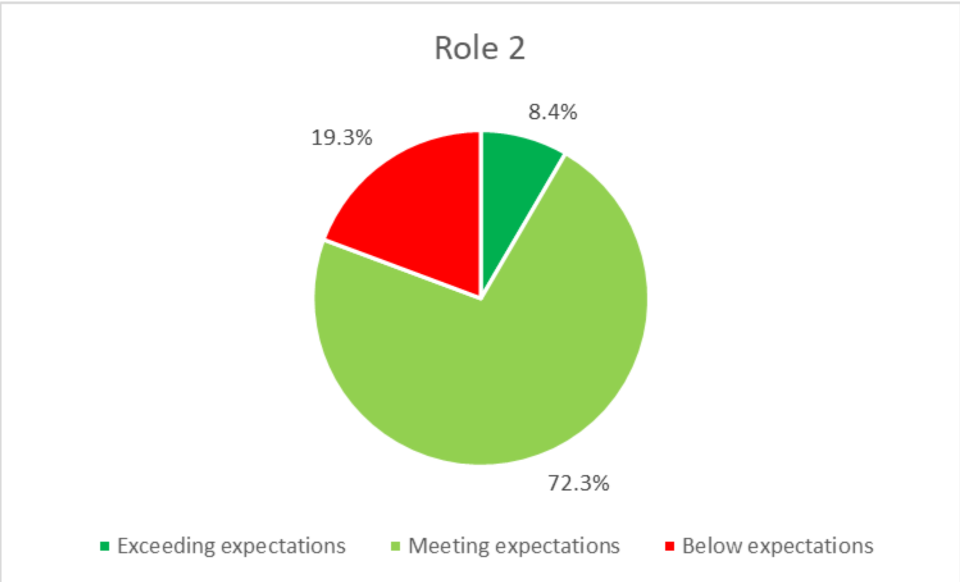
"One of the ESO Roles is focused on Market Development and Transactions, which includes key activities such as Market Design, Electricity Market Reform and Industry Codes and Charging. The ESO's recent activity in this area includes hosting workshops for Net Zero market reform, reserve reform and running a Capacity Market (CM) 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 that the ESO did that exceeded their expectations.

For Role 2, we contacted 261 stakeholders, and received 83 responses to this question, which were distributed as follows:

- 8.4 % exceeding expectations
- 72.3 % meeting expectations
- 19.3 % below expectations



The survey results indicate that the ESO is meeting expectations for role 2, although Ofgem will also take into account other stakeholder evidence. Our analysis of survey responses is set out below:

"Exceeding Expectations" feedback

Stakeholders who felt expectations had been exceeded generally expressed their satisfaction with the implementation and improvement of new products and services, in addition to good communication:

- We received positive feedback regarding the implementation of new products, and how we have improved services to run more efficiently.
- Communications with stakeholders, from 1:1 communication to our range of engagement events such as the Market Design forums, were highly rated for their quality and provision of excellent information. This included positive feedback for publications.

“Meeting Expectations” feedback

We asked all stakeholders who scored us as "meeting expectations" what would it take for the ESO to be exceeding expectations for them, here is a summary of that feedback for Role 2.

Stakeholders who felt the ESO meet its expectations provided positive feedback centred around the types of engagement to the quality of data provided. We were provided with valuable feedback for how stakeholders felt we could exceed their expectations, which focused on keeping to proposed timescales and greater transparency of decision making and data:

- Stakeholders were generally positive regarding the amount and type of engagement provided, and requested more, specifically workshop style engagements and social media output. Some feedback did reiterate the importance of working closely with customers, and ensuring all engagement is relevant to them.
- Stakeholders rated the quality of information provided highly, particularly the provision of accurate data for settlements and the industry forums. Stakeholders would like to see continuous improvements to the quality of some of the webinars, and for the ESO to ensure the website is up-to-date, and that information is streamlined and simplified where possible.
- Several stakeholders suggested the ESO could exceed expectations by ensuring that it kept to its proposed delivery schedules/timescales for products and services and felt the ESO was too slow to progress. Some stakeholders drew out specific cases where the ESO could improve the speed of delivery and communication, such as clarifying earlier the impact of Brexit on market developments and delivering market platforms and services including Quick Reserve.
- Stakeholders suggested the ESO could exceed expectations by taking a more proactive approach to determining the needs of the system vs a reactive approach, and to drive more action across multiple market aspects.
- A few stakeholders requested more frequent communications in line with a faster release of information, such as more regular communication regarding reserve reform, in order for the ESO to exceed expectations.
- Feedback for exceeding expectations regarding transparency was also raised by stakeholders, requesting better justification for delays to products and services, such as reserve reform and code change implementation. A couple of stakeholders also requested that more information is made available, such as the Data Exchange.

“Below Expectations” feedback

70% of the themes which came from stakeholders who scored “below expectations” were centred around a lack of consistency, reliability, and speed of progress:

- Stakeholders commented on the slow progress/delays of new products being brought to the market and expressed a desire for the ESO to ensure it delivers against its timelines.
- Some stakeholders expressed concerns regarding a lack of leadership in some areas of the ESO, where the expectation is for the ESO to drive the debate in addition to hosting and facilitating it. Frustrations for an inflexibility of the ESO to resolve issues for particular services was also expressed, with stakeholders desiring the ESO to consider their stakeholders’ needs more carefully.
- A few comments suggested a need for the ESO to consider the bigger picture, beyond the effects products/services have on industry but across other system capabilities and in terms of the wider context of achieving our Net Zero ambition.
- Some comments provided specific feedback on improving elements of our charging, code administration and the Capacity Market.

Over the coming months, we will seek to act on this feedback to improve stakeholder satisfaction with our activities.

Stakeholder engagement during the year

The Stakeholder Evidence criterion also takes account of the ESO's consultations and ad-hoc surveys throughout the year, whether the ESO has actively sought and considered the feedback of stakeholders throughout the business plan cycle, and the ESO's explanations for feedback received.

Build the future balancing service markets

Power Responsive

Virtual Summer Event

The virtual Summer Event was held on 9 September, where we hosted approximately 250 attendees providing opportunities for:

- network companies to discuss current and future market opportunities,
- aggregators to talk to DSR providers about what recent market changes might mean for them, and
- a ground level view of the current aggregator landscape.

We ran a survey with the attendees which received 11 responses, who scored primarily "extremely satisfied" followed by "somewhat satisfied" for the content, presenters, and length of the event. This engagement has helped provide a route for dialogue between the demand side community, and the ESO Subject Matter Experts (SMEs), ensuring the views of the demand side community are reflected in the development of new products and markets.

Steering Group Meeting

In April 2021, we chaired the 22nd Steering Group meeting, which focused on market reform up to 2050. Together, we explored Challenging Ideas' Re-costing Energy Project and the ESO's Net Zero Market Reform Project, which look to create a clear strategy for markets that support a net zero future. This was then followed by an overview of Power Responsive priorities and activities for the next 12 months along with BEIS and Ofgem's horizon scans. This provided a good opportunity to receive feedback and challenge from the group, as well as to discuss how we progress with the programme over the coming year.

Alignment of ESO-DSO flexibility markets

ENA Standard Agreement

We have continued to actively engage with the Distribution Network Operators (DNOs) in the Electricity Network Association (ENA) workstreams to produce a standardised contract for procuring flexibility. We used our experience of our existing agreement structures as a starting point, and then used an agile approach to develop the updated standard agreements. The contract terms were met with positive initial feedback from other network operators and all stakeholders are currently being consulted via an Open Networks consultation.

Data Transparency for DNOs

Building upon the work we have carried out alongside the DNOs to create a register of embedded assets; we have continued to improve the Embedded Capacity Register. We have provided the option for embedded assets to provide locational asset data, which was not previously held by DNOs.

In addition to this we have heard DNOs' requirement for more transparency of the locations of flexibility providers connected to their networks. In August 2021 we started to publish locational asset data for providers of Fast Frequency Response (FFR) and intend to extend this to other flexibility services in the future.

Deliver a single day-ahead response and reserve market

Reserve Reform Workshop

In May we held a series of co-creation webinars with industry to explore views and comments on the draft service design for these new products. At these workshops, we set out where our red lines were and why they existed for each aspect of the design. We then asked providers what our design should be within these boundaries. These workshops have helped inform our designs and approach to implementation. In September, we released a Product and Service Design Update[39], which sets out the high-level service criteria and the feedback our stakeholders provided us in these workshops.

Power Potential project with UK Power Networks (UKPN)

Following on from the Power Potential commercial market trials which ran from January to March 2021, we have carried out the following engagement working in partnership with UKPN:

- The project team hosted its quarterly Regional Market Advisory Panel (RMAP) meeting on 18 May 2021 and published the minutes on the project website[40]. At the 18 May 2021 RMAP meeting, there was a presentation of final trial results and a feedback session from Distributed Energy Resource (DER) on trials and the overall project.
- A final showcase event was held on 24 June 2021 with 194 registrations and 110 attendees excluding the project team. The introduction by Julian Leslie and Barry Hatton (directors at ESO and UKPN) celebrated the completion of the project and achievement of the learning objectives in a very challenging project and circumstances.

Response Reform webinar

On 29 April 2021, we ran a Response Reform webinar[41] in which we discussed our plan for Response Reform this year and provided the opportunity for stakeholders to help shape the new response services.

During the session, we shared the delivery plan for the launch of our two new response services - Dynamic Moderation (DM) and Dynamic Regulation (DR). We discussed the system need that drives the design of these services and asked attendees to provide feedback on the initial service design for both DM and DR.

Around 120 external attendees attended the webinar and provided an overall satisfaction score of 4.2 out of 5, with 44% of voters giving us a 5/5. We received much feedback during the session, which helped us to explore and challenge the service design.

Dynamic Containment (DC) Procurement webinar

In May 2021, following on from the Response Reform webinar, we hosted a further webinar to go into more detail on the proposed changes on how we procure DC. A mock auction was carried out with the attendees, providing an interactive opportunity for the participants to learn how the procurement of DC was changing in practice. The overall satisfaction rating for the webinar was scored 4/5 by attendees, with specific feedback for the communications around the mock auction including:

"All information we need is included. Very pleased that it has an easy to use API for automated retrieval."

"All comms were clear, with the initial invitation email laying out a clear timeline and supporting information."

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[39] https://www.nationalgrideso.com/industry-information/balancing-services/future-balancing-services
[40] https://www.nationalgrideso.com/future-energy/projects/power-potential
[41] https://www.nationalgrideso.com/research-publications/future-balancing-services

Deliver a single, integrated platform for ESO Markets

Single Markets Platform (SMP)

On 2 September we provided an update on the SMP which is a key enabler to our ambition of transforming the customer experience of our procurement activities through enabling the ESO to become a better buyer of balancing services. 15 participants shared their feedback, providing an average score of 8.5/10 for the session. This represented a significant improvement to the SMP webinar on 26 June that was given as a part of a wider Markets Forum and resulted in an average score of 6.5/10. We took the feedback from the June event to directly inform the scope of the September event to ensure that we also provided updates on ancillary services reform projects, such as Response and Reserve, in parallel with SMP.

Within the September event we also shared how we were intending to engage with the industry on an ongoing basis as we seek to co-create the development of SMP alongside our move to an agile way of developing IT solutions. We committed to introducing regular “show and listen” events (we show and we listen) to both take feedback on specific design questions but also to share wireframe designs and production level screens as we move towards the delivery of foundational functionality from February 2022.

Transform access to the Capacity Market

Electricity Market Reform Delivery Body

Capacity Market (CM) Launch Event and Applicant Guidance

In July 2021, the Electricity Market Reform (EMR) team hosted the CM Launch event in collaboration with BEIS, Ofgem and the Electricity Settlements Company (ESC). Based on feedback from stakeholders from the first virtual event in 2020, amendments were made for the 2021 CM Launch Event which included:

- Pre-recorded material produced by the EMR Delivery Body which covered aspects regarding Agreement Management, Registration and Prequalification, CM Auctions, Delivery Body Portal, and a CM Overview,
- We also provided material on CM Notices and further explanation of the Electricity Capacity Report,
- Our Delivery Partners ESC provided a pre-recorded video on Metering Aggregation.

All the above pre-recorded material was provided to Launch Event attendees prior to the event and is still available on the EMR Portal. This allowed attendees to listen to the pre-recorded material in their own time, rather than a one-day event where all the information was provided. We received feedback from participants that the pre-recorded element was also appreciated as it allowed the attendees to retain the information and ask more relevant questions during the Q&A element.

84 attendees actively engaged in the launch event poll questions, providing an overall satisfaction score which averaged out at 7.51 (out of 10). Some of the feedback we received from the attendees is summarised below:

“Move to new format was a good one. Right amount of content and relevant presentations. Thanks for putting the event together.”

“Much better than normal. Great idea to truncate while keeping the important parts (Q&A, BEIS, Ofgem, DB plan). Challenge is to make the Q&A more interactive and allow for probing of answers – difficult in current circumstances, but that is the place for further improvement.”

CM Prequalification

The Prequalification team created videos, which are accessible on YouTube and the EMR website[42], to provide visual guidance for Capacity Providers submitting a Prequalification Application for the upcoming Capacity Auctions. The videos have historically been very well received by Capacity Providers and provided a Step by Step process which helped to reduce the number of queries received from participants. This also included podcasts on some frequently asked questions.

Our Prequalification guidance was split into four documents rather than one document based on feedback received from Capacity Providers. This split meant a previous 270+ page guidance was now easier to navigate and digest for Capacity Providers and has been well received. This guidance was co-created with the industry and key stakeholders (such as Ofgem and BEIS). This meant we were able to seek feedback on how useful and helpful it was to customers and make changes ahead of the Prequalification Submission Window opening to ensure the guidance was fit for purpose.

The Prequalification Team endeavoured to answer all customer queries within 2 working days. Many queries were resolved on the day of receipt to support Applicants, with an overall average of 93% of queries being closed out within 5 working days.

CM Auctions

In the CM customer surveys, conducted after the 2020-21 auctions, the Auction Team received a score of 7.99 for the Pre-auction Activities documentation produced to help Prequalified applicants complete certain tasks prior to the Capacity Auctions. The feedback received has meant a split of the Guidance document into 5 different aspects, each covering a separate task. Alongside the documentation, the Auction Team is also developing some guidance videos to provide a visual aid alongside the Pre-Auction Activities.

The Auction Team also conducts a Training Auction for all Prequalified Applicants. This year, the applicants will receive refined Capacity Market Unit (CMU) lists which will align with their real portfolio to help aid their usage and understanding of the Auction System. The Auction Team plan to conduct a survey prior to the Capacity Auctions to ask participants "How prepared they feel for the auction." This will allow the team to receive feedback on the auction readiness materials produced and how they can be improved. A survey will be conducted following the auctions to receive feedback on applicants' experience of the auctions and their interactions with the auction team.

CM Agreement Management

Our Agreement Management team has worked closely with both customers and stakeholders to ensure more effective communication across the year, including:

- Creating personalised messages, based on feedback received from Capacity Providers on our blanket generic communication previously,
- Proactively calling customers to discuss what support could be offered for those that are close to missing a deadline,
- Creating a simplified customer deadline tool that is available on the EMR Portal, and
- Changing the frequency of our communications.

The Agreement Management Team have resolved 650 customer query calls during the period April to September, with over 95% being resolved in 5 working days. The team have also processed over 800 Agreement Management activities all within the CM Rules SLAs.

The team successfully supported Delivery Year start by proactively calling all customers that had not provided the required information in advance of the submission deadlines. This allowed the team to

[42] https://www.emrdeliverybody.com/sitepages/home.aspx

understand what external support was required by the team to ensure the deadline was effectively met and therefore maximising the capacity that could be included in Delivery Year 2021-22.

The team received positive feedback from customers highlighting that they have really appreciated the support from the team as well as the much deeper and more nuanced knowledge of the Rules. There has also been recognition that the approach of calling a customer in advance of a deadline was helpful.

Working collaboratively with BEIS to deliver policy changes to the Contracts for Difference (CfD) Scheme for Allocation Round 4 in 2021

Allocation Round 4 marks a step-change in the complexity and scale of government policy changes to the CfD scheme, compared to previous rounds. This is to ensure that CfD allocation rounds can continue to support an increase in the pace of renewable deployment needed to achieve the government's net zero ambition. Since mid-2020, we have worked collaboratively with BEIS to assess the complexity and deliverability of proposed scheme amendments and to support the rules drafting process for the Allocation Framework. SME input played a central role in helping BEIS resolve complex changes and find mutual solutions that ensured policy intent was correctly translated into practice in our business processes and systems. Close collaboration with BEIS has ensured timely implementation of all policy changes that will deliver benefit to CfD applicants, support the government target of procuring up to 12GW of renewable generation in Allocation Round 4 and delivering value to consumers. Our extensive engagement was positively received.

Electricity Capacity Report (ECR) 2021

On 28 May, we delivered the ECR 2021, which summarises the modelling undertaken by ESO in its role as EMR Delivery Body. BEIS provided positive feedback on the robustness of our analysis undertaken to prepare the report. We have also received positive feedback from the Panel of Technical Experts (PTE), published in their report on our ECR 2021:

"Overall, we were very pleased with the open and constructive process of engagement with National Grid ESO and BEIS. We thank them for their extensive efforts to develop clear and timely analysis and address many of the technical issues which we have raised. We have also taken note of various industry comments invited by National Grid ESO on the approach to interconnector derating estimation."

EMR Delivery Body portal

Our EMR Projects team have been engaging regularly with our customers (Capacity Providers) to ensure the existing EMR Delivery Body portal, and the developing new portal, deliver on our customers' needs. Co-creation with stakeholders is central to the success of each portal, and we endeavour to ensure a consistent consultation approach with more time to provide consultation feedback on our new products. As such, the EMR Projects team has evolved its approach from the engagement carried out on the current portal with requests from our customers to have greater input in the design and testing. Our user group, which was formed last year in anticipation of the new portal project, consists of 15 individuals spread across 11 market participant companies, has been key in tailoring our approach to engagement to ensure that we work together with our stakeholders to deliver the best outcome.

Since April 2021, the new portal project team have carried out the following activities:

- Kick-off meeting with the whole user-group
- Kick-off session with the sub-set of the user-group
- Industry communications/ podcast
- Workshops on individual portal designs
- Playback (following updates) of the portal design to the full user-group
- Testing walk-throughs and demonstration

The verbal feedback we have received has been positive with regards to the approach, customers have enjoyed our engagement approach and the ability to be involved in the process. Our sessions have highlighted further areas of change that are required in the design to best suit the needs of our customers. Some feedback from our customers is as below:

"Thanks for all your efforts and open discussion. Much appreciated!"

"Keep up the good work!"

Develop code and charging arrangements that are fit for the future

Code Administration

In 2020, results from our independent survey showed that we made significant improvements to our service as a Code Administrator. This was following disappointing scores that we received in Ofgem's annual Panels and Code Administration Code of Practice (CACoP) survey in 2019. In 2021, we remain committed to continuously improving code administration to drive maximum consumer benefit. We have listened to the feedback from the surveys as well as the continuous feedback we seek at our forums, workgroups, CACoP, to build our deliverables plan for 2021-22. We wrote to stakeholders in May 2021 to demonstrate how we have used their feedback to shape our plan for the next 12 months. The document[43] outlined our 6 key areas of focus which are: upskilling and recruitment, collaboration, better sight of cross code impacts, diversity and equality, rationalisation and digitalisation.

Our deliverables plan is growing and builds on the feedback we receive. We will take any areas of improvement from the 2021 CACoP survey and the ESO satisfaction survey and build this into our Deliverables plan for this year.

Code Administrator Workshop

Following on from sessions aimed at introducing the code change process to those new in the industry earlier in the year, we were keen to continue providing information to our stakeholders in this way to help wider engagement with our codes. We also wanted to offer opportunities to co-create. On 16 September 2021 we held a Code Administrator Workshop which was open to all interested parties to attend. In the workshop our aim was to provide an update but also to invite stakeholders to co-create. The sessions focussed on:

- our progress so far against our deliverables plan and what we plan to focus on next, as well as getting feedback from attendees on whether they agree with where we are focussing our efforts,
- an update on our commitment to improving our chairing capability; where we shared the changes we have so far made in this space and asked for feedback from stakeholders on what they think are the most important skills and techniques for great chairing, and
- a session for stakeholders to co-create with us on our modification tracker, which we publish monthly to keep stakeholders informed of change progress.

Stakeholder: *"Great stuff guys – thanks for hosting us. As offered on the call, shout if you want any support moving some of these initiatives forward"*

We asked stakeholders how likely they were to recommend the event to a friend or colleague on a scale of 1-10. The event was well-received with an average score was 9.3. We will continue to engage in this way to make sure that changes made are done in partnership with our stakeholders. We plan to host further workshops before the end of the calendar year.

[43] https://www.nationalgrideso.com/document/191576/download

Charging Futures Forum

We are the Lead Secretariat for Charging Futures which is a joint project with Ofgem and other parties which helps parties to learn, ask and contribute towards network charging reform. On 22 September 2021 we held a virtual Charging Futures Forum. The event was well attended with 158 attendees and the event scores were 8.7, and 8.3 for the event itself and the role of the secretariat respectively.

Grid Code Modifications

Three recent examples of code changes that have been progressed with the aid of close stakeholder engagement have been Grid Code modifications GC0134, GC0137 and GC0147.

- **GC0134**, which was approved by Ofgem in August, allows smaller users with system infeeds of less than 10MW dispensation from the requirement to have 24/7 telephony at their sites. The ESO supported this proposal, which was raised by a smaller generator, and assisted in forming a solution and engaging with an industry workgroup to deliver this.

- **GC0137**, Grid Forming is a key strategic piece of work which will be fundamental to ensuring system stability and facilitating the target of net zero carbon operation by 2025. There was wide stakeholder engagement in the development of the Grid Code modification, and there continues to be a high level of support. We have received positive feedback from stakeholders, who felt that the workgroup had been well run, and that the issues had been articulated in a helpful way.

- **GC0147** was a complex modification required to provide a permanent solution allowing the ESO, as a last resort in an emergency, to require DNOs to take control actions on distribution-connected generators. The ESO's proposals were presented at a number of forums including the weekly Operational Transparency Forum and the Grid Code Development Forum. The ESO also facilitated an industry workgroup and acted on a large number of consultation responses.

- **CUSC Modifications**

  CMP378 will facilitate cross-code coordination across the Market-wide Half Hourly Settlement (MHHS) Programme and is consistent with modifications being introduced to other MHHS impacted industry codes. Ofgem provided positive feedback on the ESO’s involvement with raising CMP378, which is an Authority Led CUSC modification proposal.

European Union (EU) code change and relationships

Trans European Replacement Reserve Exchange (TERRE) communication

Project TERRE has provided a key learning opportunity for increasing communication with our stakeholders when there are delays and changes to projects. The TERRE programme deployment was paused as a result of the revised legal agreements with the EU following Brexit. In March, we agreed via the industry working group, including BEIS and Ofgem, that we would appoint a third-party (AFRY) to carry out a revised cost-benefit analysis (CBA) benefit analysis on implementing a GB only version of the replacement reserve product. The outcome of this analysis is due in Q3 and will be presented back to industry to consider next steps.

The ESO has continued to engage with industry through the GB TERRE Implementation Group. We invited AFRY to present their proposed methodology to this group on 3 August 2021, and their draft findings on 24 August 2021. We invited feedback from stakeholders, which we factored into the final report which we published in October. Updates and minutes from the meetings are published here on our website[44].

[44] https://www.nationalgrideso.com/industry-information/balancing-services/reserve-services/replacement-reserve-rr

Clean Energy Package (CEP)

We have undertaken two webinars, various bilateral conversations with key stakeholders, and regularly liaise with Ofgem to develop a Pricing Proposal (PP) in order to comply with Article 6(4) of the CEP. This obliges TSOs to settle balancing energy (utilisation) on a pay-as-clear (PAC) basis for standard and specific balancing products. The first webinar, held on 18 September 2021, received an event satisfaction score of 7.25 out of 10 from stakeholders. The second webinar, held on 7 October 2021, received an event satisfaction score of 8 out of 10 (subject to further feedback).

We have also provided regular updates to stakeholders, including via the Joint European Stakeholder Group (JESG). All of this feedback collation has been vital in developing a consultation and proposal which is fit for purpose, addressing the key issues for the ESO and industry. This piece of work is an example of the co-creation approach we are embarking on with industry on key workstreams concerning compliance with the CEP. This engagement will continue, until we submit the proposal to Ofgem for their approval in November 2021.

We have also been working on enabling new balancing products, such as DM and DR, to be complaint with the CEP, or where it is more efficient (from a system or economic approach), seeking derogations from Ofgem. Derogations that are being developed are Article 6(2), around pre-determination of the price of balancing energy, and Article 6(9), which looks at bundling of upwards and downwards capacity (note that DM & DR will be bought at day ahead timescales). We have kept stakeholders updated at JESG on our progress with such issues, looking to arrive at the best solutions for consumers.

Trade and Cooperation Agreement (TCA)

We have received positive feedback on our work on the TCA Technical Procedures from UK Transmission System Operators (TSO), BEIS and Ofgem, who felt that we had taken a co-creation approach, and driven progress even when faced with blockers that are out of our control. ESO has continued to lead weekly workgroups with UK TSOs to drive this work forward. Specific feedback from stakeholders on the work that we have completed to date on the TCA included:

"I think the options assessment previously circulated and the summary below reflect the leading role NGESO has played in this area and is well set out."

"… good discussion earlier in the Steerco which is testament to the quality of the paper presented."

Industry revenue management

Under-recovery of Balancing Services Use of System (BSUoS)

Following the identification of the BSUoS under-recovery for Charging Year 20/21 at the end of March, we carefully considered the options of recovering the costs and the impact it may have had on the industry, in particular under the current COVID-19 pandemic situation. In April 2021, we engaged with the industry on this matter via a dedicated webinar[45], which helped inform the decision to defer the recovery of £10m ALoMCP costs to Charging Year 21/22. Following a separate CUSC mod the trading costs are to be recovered via the SF run, evenly across the same days as costs were originally incurred last year.

We took this incident very seriously and commissioned PricewaterhouseCoopers (PwC) to help review and improve our BSUoS charging processes and enhance our control environment to ensure that there is no such repeat of this incident in the future. We shared our key findings with industry in September.

Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025

[45] https://www.nationalgrideso.com/document/190426/download

Whole System Technical Code (WSTC) project

The WSTC project is a bold ambition in the rapidly changing space of industry codes, and ongoing stakeholder engagement and support will be critical in shaping and progressing this work successfully. We have engaged extensively with stakeholders, and are formally seeking feedback through a public consultation. Prior to the publication of the first consultation on 27 September, we carried out a series of engagements with a broad range of stakeholders; trade associations, Ofgem, government bodies, academia, wider industry players, consumer groups, and network operators. This took place via events such as electricity industry forums and specific WSTC webinars. To date, we have engaged with approximately 360 participants, and will keep these stakeholders updated as the project progresses. In addition, stakeholders were given the opportunity to provide comments on the draft consultation.

The summary below shows a sample of what stakeholders have said and how we have since acted on it.

Trade Association: "*An industry led approach is the best way forward. In the past, projects where industry has been involved throughout the cycle of the projects, have been more successful than those where NGESO went to industry with solutions."*

Network Operator: *''The document reads well. I understand the concept. Simplification and plain English are good ideas.''*

Consultant: *''Thank you for the approach of engaging with industry''*

We sought network operators' support in reaching out to their customers to respond to the consultation[46] published on 27 September. The responses will guide the definition of the WSTC scope, objectives and approach. The second consultation will be developed and published by the project members and the steering group (as informed by the first consultation) and will propose a detailed project scope.

Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges

BSUoS Reform

As part of BSUoS Reform (CMP308 and CMP361), the ESO has engaged extensively with Ofgem, generators, suppliers, and groups such as the Major Energy Users Council (MEUC) and Citizens Advice Bureau. The latter two demonstrate our commitment to engaging with stakeholders who would be impacted by BSUoS Reform, to ensure that a wide range of views have been incorporated into the reform. The MEUC appreciated the proactive engagement on these changes, as their members would be significantly impacted by the changes.

As there is significant complexity to be worked through to arrive at the solution for fixing BSUoS, we have ensured that we've been actively listening to industry feedback and ideas while developing the proposed solution for CMP361. One example of this is the proposed approach to providing information to industry. This received positive feedback from the industry workgroup, as it would help them understand what upcoming fixed BSUoS prices might look like and the magnitude of each of the components of those BSUoS prices (constraints, ancillary services etc.).

We have also incorporated industry feedback on the timescales to developing a BSUoS fund into our proposed solution for CMP361. This BSUoS fund would exist to help to reduce the likelihood of tariffs needing to be re-set within a fixed period. The compromise made, based on industry feedback, has been to extend the period over which this fund would be collected to reduce the initial increase to BSUoS charges. This would then reduce the impact to the end consumer.

[46] https://www.nationalgrideso.com/industry-information/codes/digitalised-whole-system-technical-code

BSUoS Clarification

We have received positive feedback on proposing CMP377, 'Clarification of Section 14 BSUoS Charging Methodology'. This Modification seeks to make the BSUoS Charging Methodology in the CUSC clearer and more accessible. The Modification was raised as a result of industry feedback, and throughout the process relevant stakeholders were consulted for their views.

Activities outside the Delivery Schedule

Net Zero Market Reform - Case for Change Workshops

Between 27-29 July, we held three virtual Case for Change workshops with breakout sessions focused on net zero market reform. These workshops were used to gather evidence for the case for market reform from an investment, flexibility and location perspective through open, co-creation-based discussions between stakeholders. In these sessions we discussed the following key questions:

Workshop 1 - Investment:

- "What, if any, are the key barriers in current market design for investment in assets needed for net zero?"
- ''Other than an ROI calculation, how would you evidence the case for change for market reform from an investment perspective?"

Workshop 2 - Flexibility:

- "What are the biggest market barriers/challenges to flexibility on the supply side?"
- "What are the biggest market barriers/challenges to flexibility on the demand side?"

Workshop 3 - Location:

- "What problems, if any, are there with current locational market signals?"
- "What principles and objectives should be considered when setting locational signals? What trade-offs are involved?"

71 participants rated the workshops an average score of 8.1/10. The following feedback shows the positive reception we received from participants:

"It was very respectful and inclusive."

"Really well facilitated and extracted some valuable qualitative areas for further exploration."

"Really useful discussion on some incredibly important topics which industry, government and regulators are wrestling with as we seek to design a market to enable net zero."

"Very well facilitated and got through a lot in short space of time. Excellent pace and no dead time. Highly productive."

"The interactive breakout sessions were the standout as it encouraged participation."

Net Zero Market Reform – project update

Following on from the case for change workshops, we ran a webinar session to provide an update to industry on the Net Zero Market Reform Project. The session covered the following topics:

Presentation by Market Strategy Team

- Re-cap and reflection of launch event in March
- An overview of the net zero market reform project including progress so far and future plans
- Future stakeholder engagement events.

Panel discussion

- Panel discussion between Kayte O'Neill (Head of Markets, ESO), Rob Hewitt (Deputy Director – Energy Security, BEIS) and Tom Corcut (Deputy Director – Wholesale Markets, Ofgem) giving their views on aspects of net zero market design and how ESO, BEIS and Ofgem can work in collaboration.

Q&A

We had a peak attendance of 196 participants, with average session satisfaction rating (out of 10) of 7.8, with 66% scoring an 8 or more. Our feedback from the participants is summarised below:

"Great openness about the issues we are facing"

"Great to have BEIS/OFGEM involved"

"Great insight into work carried out so far"

"Good level of debate"

"Liked: data driven insights and articulation of the case for change"

"Presenters were very knowledgeable and spoke very well"

Net Zero Market Reform – Market Design Options and Assessment Criteria Workshop

On 14 September we hosted our latest Net Zero Market Reform workshop looking at the range of possible market design options consistent with achieving net zero. The objective of the workshop was to develop a long list of possible options and discuss what assessment criteria should be used to assess the relative merits of the different options. We captured stakeholders' ideas and thoughts, which will be considered when we identify and assess the possible market design options. The workshop hosted 80 industry participants, who scored their overall satisfaction of the event an average of 4 out of 5. We received the following feedback from attendees:

"A well-structured event, with good questions and topical breakout session agendas. I enjoyed the discussions which emerged in the breakout sessions and these were complimented with a good agenda laid out."

"Always like to debate with others what we as an industry should do. The interactive sessions are interesting."

"Excellent consultation, very open. I am delighted that BEIS, Ofgem and NG are increasingly open to input from the industry. However, I am not convinced that they believe just how radical or urgent the need for change is."

B.4 Demonstration of Plan Benefits for Role 2

The fourth evaluation criterion for the ESO incentive scheme is Demonstration of Plan Benefits, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 2 are:

- Build the future balancing service and wholesale markets (A4)
- Transform access to the Capacity Market (CM) (A5)
- Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5)
- Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges (A6.6)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit[47]

We also provide a specific case study to quantify the benefit of competitive restoration tenders, which was not covered by the original Cost-Benefit Analysis document.

The Panel will also consider the ESO's Regularly Reported Evidence (RRE) as part of the Demonstration of Plan Benefits criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the Electricity System Operator Reporting and Incentives (ESORI) guidance. For Role 2, the items of RRE reported at mid-year are:

- 2B. Diversity of Service Providers
- 2E. Accuracy of Forecasts for Charge Setting – BSUoS

[47] On 10 November we revised the percentages of completed deliverables. We had previously rounded some of the percentages, but have now reported them more accurately for improved clarity.

CBA: Build the future balancing service and wholesale markets (A4)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits of the transformational activities set out in section 5.2.3 to be £106 million over RIIO-2. This gives a net present value (NPV) of £67 million over RIIO-2. The quantitative gross benefits were calculated by:

Considering the liquidity of the reserve and response market – about £500 million on a 12-year average. Based on our Power Responsive work we have seen prices drop and estimate that a further five per cent reduction is credible for these activities

We have looked at buying optimal volumes of response – about £190 million on a 12-year average. Again, based on our previous experience of moving closer to real time we estimate a further five per cent reduction is credible.

- This is against a baseline assumption of the existing participation in balancing and CMs without a single platform or reduced participant size to 1 MW."

Role

2. Market development and transactions

ESO Ambitions

- Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A4.3 - Deliver a single day-ahead response and reserve market

Deliverable	Status
D4.3.2 Day ahead market for frequency response	25% complete, 25% delayed 25% not due to start yet, 25% on track
D4.3.3 New Reserve Products	0% complete, 33% delayed 0% not due to start yet, 67% on track
D4.3.5 Auction capability	0% complete, 0% delayed 33% not due to start yet, 67% on track

Activity A4.4 - Deliver a single, integrated platform for ESO Markets

Deliverable	Status
D4.4.2 Common standards, including interoperable systems, a common data model and shared minimum specifications between ESO and other flexibility platforms as well as at the distribution level.	12% complete, 0% delayed 0% not due to start yet, 88% on track

Activity A4.6 - New services market development

Deliverable	Status
D4.6.2 Development of competitive approaches to procurement of reactive power	0% complete, 0% delayed 43% not due to start yet, 57% on track

Related metrics/ Regularly Reported Evidence

Metric/RRE	Status
Metric 1A Balancing Costs	£966m vs benchmark of £562 (Below expectations)
Metric 2A Competitive Procurement	59% of all services procured through competitive means (meeting expectations)

We would expect this activity to result in improved performance for Metric 2A due to allowing us to move greater volumes of products into competitive markets from

	bilaterally agreed contracts. This should then lead to lower Balancing Costs, as competition should place downwards pressure on the costs of ancillary services. We expect this to lead to lower constraint costs than would otherwise be the case, which will have an impact on metric 1A

Sensitivity factors

Assumption	Current status	Commentary
Participation would be increased	Launching more volume in Dynamic Containment	Consumer benefit expected to be in line with original assumptions
Value of the response and reserve market is £514 million per year	We spent £510m on response and reserve during 2020-21[48]	Consumer benefit expected to be in line with original assumptions
Our actions deliver a 5 % saving in the response and reserve markets	5% saving will be assessed once the new services are embedded.	Consumer benefit expected to be in line with original assumptions
Benefits delivered from year three of RIIO-2	This is a reasonable assumption at this stage	Consumer benefit expected to be in line with original assumptions

Summary

We are facing complexities with the design of Dynamic Moderation (DM) and Dynamic Regulation (DR), which need to be explored further before we take the next step in our co-creation phase, which is engaging on our minded-to position with industry ahead of formal consultation. At present, we still believe that our original benefits case remains valid.

[48] Monthly Balancing Services Summary (MBSS) Mar-2021 https://data.nationalgrideso.com/backend/dataset/f89a12fc-94ef-4a09-bce2-c094c7212e1f/resource/931455ff-3de2-4aba-ac90-b48b3f9775fa/download/mbss-data-march-2021.xlsx Sum of “Operating Reserve”, “STOR”, “Negative Reserve”, “Fast Reserve”, “Response” and “Other Reserve” costs.

CBA: Transform access to the Capacity Market (A5)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits of this activity to be £74 million over RIIO-2. This gives an NPV of £62 million over RIIO-2. We calculated these quantitative benefits by firstly considering the enhanced modelling capability. In our analysis we consider the two possible scenarios of reduced risk of our recommendations on the capacity to secure being too low or too high: 1. Reduced risk of recommendations being too low: Save consumers the equivalent of purchasing at four-year ahead (T-4) an additional 1 GW of capacity, instead of at year ahead (T-1) or short term balancing markets. 2. Reduced risk of recommendations being too high: Save consumers the equivalent purchase cost of 1 GW of capacity at T-4. Given the complexity (with limited data and more uncertainty) in determining scenario one's benefits we have used scenario two's benefit in our CBA calculation. The average clearing price over the four T-4 auctions held to date, £17.08/kW, applied to 1 GW this would save consumers £17 million per year. Secondly, by reducing barriers to entry, we will remove the need for unnecessary resource for the around 400 CM customers, and this saving will ultimately be passed through to consumers. This is against a baseline assumption of the existing participation in CMs and only ongoing modelling capability. This activity is dependent on the following transformational activity: 1. A4 Build the future balancing service and wholesale markets (Theme 2) – Sharing the single markets platform. All of the costs for the single markets platform are realised in this activity. In order to deliver this activity, we require third parties to fully engage with the new system. There may be small costs associated with adapting to these new arrangements, but we believe these are within the scope of third parties' ongoing investments. Our analysis suggests that, accounting for market, delivery and third-party uncertainty, the net present value could credibly be between £22 million and £94 million."
Role	2. Market development and transactions
ESO Ambitions	• An electricity system that can operate carbon free • The ESO is a Trusted Partner
Key RIIO-2 Deliverables and progress	See tables below

Activity A4.4 - Deliver a single, integrated platform for ESO Markets

Deliverable	Status
D4.4.1 A market platform through which market participants will be able to participate in balancing and CMs. The markets platform will cover the end to end process for market participation including: communications, data input and management, messaging and validation	12.5% complete, 0% delayed 0% not due to start yet, 87.5% on track

Activity A5.1 - Electricity Market Reform (EMR) Delivery Body

Deliverable	Status
D5.1.1 Continuation of EMR Delivery Body obligations	40% complete, 0% delayed 0% not due to start yet, 60% on track
D5.1.2 An improved prioritisation process in how we implement change in the EMR Delivery Body. This is about embedding the process and not the delivery of specific changes for each year	28% complete, 0% delayed 58% not due to start yet, 14% on track

Activity A5.2 - Deliver an enhanced platform for the Capacity Market within the single, integrated ESO markets platform

Deliverable	Status
D5.2 IT system to allow all participants in ESO markets (including CM and CfD) a single point of access for services and data	33.3% complete, 0% delayed 33.3% not due to start yet, 33.3% on track

Activity A5.3 - Improve our security of supply modelling capability

Deliverable	Status
D5.3 Use of enhanced modelling and more granular data sets to improve security of supply modelling.	25% complete, 0% delayed 50% not due to start yet, 25% on track

Related metrics/ Regularly Reported Evidence

Metric/RRE

RRE 2D EMR Demand Forecasting Accuracy	Note that this is an annual metric, and therefore not included in the mid-year report.

We would expect this activity to result in improved performance for RRE 2D, as improved models would lead to a better ability to forecast demand.

Sensitivity factors

The estimated consumer value we expect to deliver that is stated in the RIIO-2 CBA report was based on several assumptions. If those assumptions outturn different to expected, the actual consumer value delivered will be different to our original estimates, irrespective of the progress of our deliverables.

The table below lists the assumptions made and notes whether the outturn is in line with our original estimates. Overall, the estimated benefits remain in line with those stated in our RIIO-2 plan.

Assumption	Current status	Commentary
Clearing price of the T-4 Capacity Market is £17.08/kW per year.	Clearing price of most recent T-4 auction was £18.00/kW per year for delivery in 2024/25.	If lower clearing price, benefit will be smaller than originally thought If higher clearing price, benefit will be higher than originally thought
Our actions save consumers the equivalent of purchasing an additional 1 GW of capacity	This is still a reasonable assumption	Consumer benefit expected to be in line with original assumptions
Benefits delivered from year two of RIIO-2	Still correct- the improvement projects will not take effect until the 2022 Electricity Capacity Report (ECR) is delivered in 2022/23	Consumer benefit expected to be in line with original assumptions
Third parties will engage in the single markets platform	Third parties are engaging with this to date	Benefit still as expected if regulatory change to align CM concepts/data with other market data occurs.

Another sensitivity outside of the original CBA is that some participants do not meet their obligations in the CM, therefore the ESO will have to procure more capacity, leading to

	higher costs for consumers, which will offset some of the savings resulting from improved modelling.
Summary	We are still expecting to deliver the consumer benefits set out in the RIIO-2 business plan. Our assumptions still seem reasonable, and modelling improvements for 2022 are progressing in line with our plans.

CBA: Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025 (A6.5)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits of this proposal to be £10 million over RIIO-2. This gives an NPV of £4 million over RIIO-2. These quantitative benefits have been calculated by considering how the reduced barriers to entry will save resource for Grid Code users, as it will be less complicated and easier to navigate, find, and use the relevant information. We estimate there are around 800 potential projects, based on around 400 transmission applications and an additional estimated 400 from distribution applications, which would need to access the Grid Code per year. Each resource saving will ultimately be passed through to consumers. This is against a baseline assumption of the Grid Code not being digitalised, with access remaining as it is today. It would also not extend to consider the whole energy system."

Role

2. Market development and transactions

ESO Ambitions

- The ESO is a Trusted Partner
- Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A6.5 - Work with all stakeholders to create a fully digitalised, whole system Grid Code by 2025

Deliverable	**Status**
D6.5 The Grid code combines transmission and distribution codes in an IT system with AI-enabled navigation and, document and workflow management tools.	16.5% complete, 16.5% delayed 33.5% not due to start yet, 33.5% on track

Related metrics/ Regularly Reported Evidence

Metric/RRE	**Status**
RRE 2B Diversity of service providers	Varying diversity across different markets – see RRE section for details

RRE 2B is expected to improve due to the improvements that digitalisation will bring to code change.

Sensitivity factors

There have been no delays or changes to our deliverables, or external factors, that change the benefit we have forecast to deliver.

Assumption	Current status	Commentary
800 projects interacting with the whole system Grid Code per year	This is still a reasonable assumption in the future anticipated transformation of the Digitalised Whole System Technical Code	Consumer benefit expected to be in line with original assumptions
Our actions save one FTE month of time from each project	This is realistic assumption based on the reduction in time spent on the governance process today vs the future state of a digitalised code	Consumer benefit expected to be in line with original assumptions
Benefits delivered from year four of RIIO-2	This is a reasonable assumption at this stage	Consumer benefit expected to be in line with original assumptions

Summary

Due to the progress on deliverable D6.5 the project remains on track to deliver the benefits stated. Reform of industry codes is a concept that has gained increasing traction in industry, particularly since the BEIS/Ofgem Energy Codes Review consultation in 2019. Digitalisation of some codes is already being progressed within industry.

Industry engagement at various forums since June 2021 has been focussed on building awareness of the project. Early engagement with other code parties who have already digitalised their codes has also taken place. We are currently running an industry consultation.

CBA: Fixing one or more components of Balancing Services Use of System (BSUoS) charge (A6.6)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits of this activity to be £324 million over RIIO-2. This gives an NPV of £280 million over RIIO-2. These quantitative benefits have been calculated by considering the ongoing industry work that is focused on reducing BSUoS volatility and unpredictability. As this work is continuing – and we will work with industry and Ofgem to further refine it – we have used the lower estimates of gross benefits from the scenarios considered. This amounts to around £81 million per year in reduced risk premia held by industry. We also considered the higher ESO financing costs required to manage any new BSUoS arrangements – again to reflect the uncertainty – of around £4.8 million per year. This is an early estimate and is not reflected in our analysis of overall ESO financing costs, which is detailed in chapter 9 – Financing our plan. The difference in ESO financing costs, and benefits savings from reduced industry risk premia, is due to the number of parties that hold risk premia for BSUoS, which is now being managed though a single party, the ESO. This is against a baseline assumption of BSUoS arrangements remaining as they are today, with the price being set after the spending has taken place."

Role

2. Market development and transactions

ESO Ambitions

- The ESO is a Trusted Partner
- Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A6.1 - Code management / market development and change

Deliverable	Status
D6.1 Continued facilitation of industry changes to the Grid Code, Connection and Use of System Code (CUSC), System Operator Transmission Owner Code (STC) and Security and Quality of Supply Standards (SQSS). Also, delivery of Great Britain driven regulatory change through the open governance process.	16.5% complete, 0% delayed 50% not due to start yet, 16.5% on track

Activity A6.6 - Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS)

Deliverable	Status
D6.6 Look at fully or partially fixing one or more components of Balancing Services Use of System (BSUoS) charges	100% on track

Related metrics/ Regularly Reported Evidence

Metric/RRE	Status
RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS	Average absolute percentage error of 16%

RRE 2E is expected to improve due to the development of code modifications.

Sensitivity factors

The ESO has raised modifications CMP361 & CMP362 ('BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates') to introduce fixed BSUoS and has supported CMP308 ('Removal of BSUoS charges from Generation'), to enable full BSUoS Reform as per the recommendations of the BSUoS Task Force.

Since the analysis produced for the RIIO2 plan, Frontier Economics and LCP, independent consultants hired by Ofgem, have conducted analysis to indicate the

	consumer benefits of both CMP308[49] and CMP361 (available as an annex to the CMP361 workgroup consultation[50]). The results which were derived are: • Systems benefits up to £1,220m to 2040, when estimates of emissions across interconnectors are factored in, where these are not included systems benefits are up to £490m • Reductions in aggregated consumer bills of around £320- £370m over the period to 2040. The values from the first bullet point are based on Steady Progression from our Future Energy Scenarios– in the Consumer Transformation scenario they become £480m when estimates of emissions across interconnectors are factored in, and £290m when they are not. The analysis for CMP361 shows that the consumer benefits are around £10.2-10.8m based on a sample year 2025. Achieving this benefit every year would lead to net benefits of £140-148m by 2040 for fixing BSUoS. The benefits from CMP308 and CMP361 can be stacked to give the total benefits of BSUoS Reform.
Summary	The main drivers of the benefits forecasted are deliverables D6.1 and D6.6, which are on track. From a code modification perspective, we have raised CMP361 & CMP362 ('BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates') and created the detail supporting CMP308 ('Removal of BSUoS charges from Generation'). The ESO has been active in the workgroups for these modifications, developing proposed solutions for these modifications following engagement with industry and Ofgem. Internally, the ESO has begun to develop the detailed processes required to implement a fixed BSUoS solution for April 2023.

[49] https://www.ofgem.gov.uk/publications/reform-bsuos-charges-analysis-proposal-remove-bsuos-generation
[50] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp361-cmp362

Consumer benefit case study for Role 2: Restoration Northern contracts

Activity	Our Restoration Strategy (previously known as Black Start Strategy) gives us the ability to start up GB's electricity system following from a full de-energisation of the system. These services use auxiliary sources of generation to kick-start bigger units creating 'islands' of power which connect together on the main transmission network to gradually restore the grid. To meet our requirement, we reached out to stakeholders and interested parties by using the Operational forum and various webinars in the Summer of 2019 to highlight the requirement for Restoration Services in the Northern Region (Scotland, Northwest and Northeast) to commence in Summer 2022. As part of this process we identified opportunities to remove barriers to entry and foster greater competition. Subsequently we launched an Expression of Interest on 1 August 2019 where we received 22 submissions from various technology types, 21 of which were invited to tender in November 2019 and on 30 April 2021 we announced contracts with eight providers for these Restoration Services. The eight contracts, two of which are from new providers, total £53.8 million with each bid offering commercial benefits compared to other bidders and options.
Role	2. Market Development and Transactions
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • Competition Everywhere
Key RIIO-2 Deliverables	D3.1.5 Fully competitive Restoration procurement process with submissions from a wide range of technologies connected at different voltage levels on the network.
Is the consumer benefit mainly this year or in future years?	Mainly future years: The monetary benefit in the short term is negligible, but the medium-term cost savings are considered to be in the region of £13.7m over the next three years. The greater value however will be achieved in the long term as broadening participation in this market creates greater competition, which in turn will drive down prices for the service in the future to the benefit of the end consumer.
Calculation of monetary benefit to consumers	The contracts awarded in the Northern tender outturned to be approximately £53.8m for three years commencing from Summer 2022. The equivalent cost of continuing to bilaterally contract with the same service providers for the same service term would have been approximately £67.5m (based on current costs).
Assumptions made in calculating monetary benefit	The assessment of benefit was in comparison with the alternative cost of contracting with the existing providers, using an assumption that future costs would be similar. We used current prices of Restoration Services and compared them against the tendered prices of the new services to make the comparison.
How benefit is realised in the consumer bill	The costs of Restoration contracts form part of the Balancing Costs which are reported under metric 1A. A reduction in Balancing Costs feeds through into lower BSUoS charges that are ultimately passed on to the consumer bill.
Non-monetary benefits	**Reduced environmental damage** Removing barriers to entry and broadening participation has meant we have been able to diversify the portfolio of providers, many of which are either zero carbon or less emitting carbon producers, therefore there is an environmental benefit as well as benefit of reduced costs in the longer term. **Improved safety and reliability** Diversifying the portfolio of providers means the service will be more secure and resilient as we are not relying on one specific fuel type or technology.

	Benefits for society as a whole Diversifying the portfolio also supports the drive towards net zero operation which will benefit the environment and society.
Assumptions made in calculating non-monetary benefit	Five years ago, the make-up of Restoration service providers was primarily from coal/gas fired Combined Cycle Gas Turbines (CCGTs). The introduction of competitive tenders for restoration, particularly the Northern tender, means that there will be fewer carbon emitting providers contracted to deliver restoration services, leading to lower carbon emissions than would otherwise be the case.

Regularly Reported Evidence

Table 18: Summary of RREs for Role 2

RRE	Title	Measure	Unit	Apr	May	Jun	Jul	Aug	Sep
2B	Diversity of service providers	*Contracted volumes by service type*	n/a	Varying diversity across different markets					
2E	Accuracy of Forecasts for Charge Setting (BSUoS)	*Month ahead BSUoS forecasting accuracy (absolute percentage error)*	%	16%	17%	11%	0%	22%	31%

RRE 2B Diversity of Service Providers

April- September 2021-22 Performance

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

There are four services we report on below: Frequency Response (Mandatory Frequency Response, Enhanced Frequency Response, Firm Frequency Response, Dynamic Containment), Reserve (Short Term Operating Reserve, Fast Reserve), Reactive, and Constraints. Data on Restoration services is not included in this report due to the sensitive nature of the information, which will be provided to Ofgem separately.

Figure 13: Total contracted volumes by service type by quarter

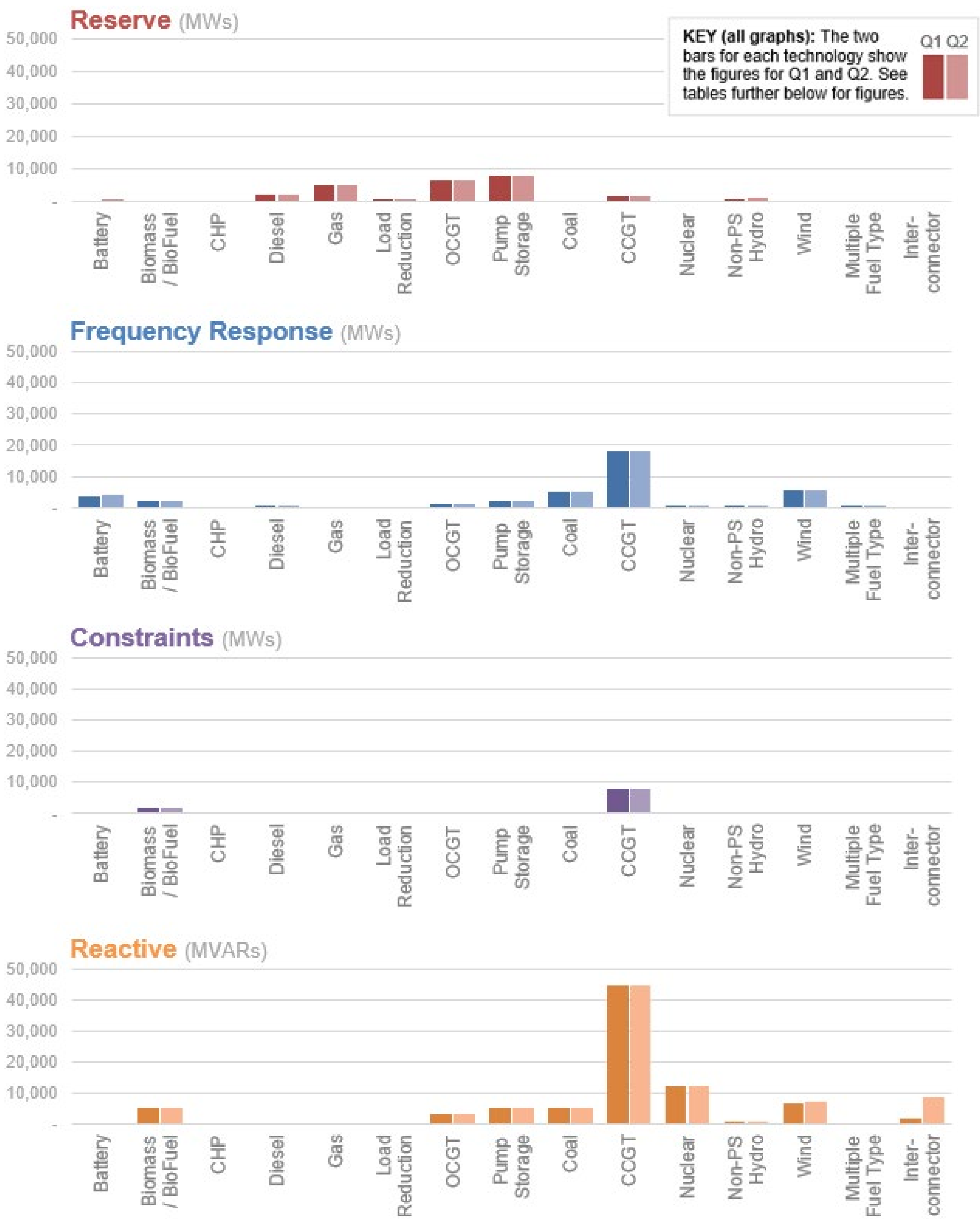


Table 19: Monthly contracted volumes provided to the ESO by service type

Reserve

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

Frequency Response

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

Constraints

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

Reactive

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

Supporting information

Reserve

On 1 April 2021 we commenced procurement of the firm Short Term Operating Reserve (STOR) product via daily auctions with ~ 1300MW procured each day. This is a very liquid market with over 240 individual units prequalified, and we see around 30 or 40 units bidding in each day. Due to the technical requirements (response time/delivery duration) the service continues to be delivered by the more traditional Diesel, Gas and Coal fuels.

With the forthcoming reserve products coming online through 2022, we would expect to see new technologies and smaller plant entering the market for the proposed slow and fast acting products, whilst retaining the existing players for the slower acting (upward) product. With the announcement that the Slow Negative product will be the first to launch, we expect to see providers that had previously offered the Optional Downward Flexibility Management (ODFM) service entering this new market. Existing STOR and Fast Reserve providers will continue to provide these products as they will continue in parallel until they are replaced by the other new products through 2022. For Fast Reserve, we continue to procure the optional service where units are contracted on the day to make their capacity available. The move away from a firm service and certainty of guaranteed availability payments, has seen the number of units offering their services to Fast Reserve reduce with the service delivered predominantly from Gas Reciprocating Engines.

Frequency Response

From October 2020 we launched Dynamic Containment (DC) which was the first of our new frequency product suite via daily auctions. This market is still growing with a market size of over 900 MW available to be procured daily. Over the past few years tendered frequency products have seen a significant change in the generation type delivering these services. Dynamic frequency response has seen a move away from the more traditional generation from Diesel, Gas and Hydro to more Storage assets and Demand Side Response (DSR). We are expecting this growth, partially in storage assets, to continue, as the technical and delivery requirements of the new services (1-second delivery) is more suited to these types of technology.

During 2022 we will continue to progress the transition from the existing legacy products Dynamic Firm Frequency Response (DFFR) and Static Firm Frequency Response procured through monthly tender to the new suite of response products of Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR). In November 2021 the procurement platform trial for Dynamic Low High (DLH) and Low Frequency Static procured through the weekly auctions will come to an end - any MW requirement will move to the Monthly FFR tender.

The introduction of DC has seen a reduction of units participating in the Monthly and Weekly frequency tenders as providers have moved their portfolios to provide this service, this can be seen in the drop in the volume of tendered MW in DFFR and DLH auctions since October 2020.

Constraints

Constraint costs are when the ESO pays generators to constrain their output due to network capacity limitations and typically for them to increase or decrease MWs on the system. This service is generally limited to the providers that are connected to the transmission system and generally localised, therefore there are limited options to provide the service. This would typically either be provided by Transmission Connected Combined Cycle Gas Turbine (CCGT) or Wind providers depending on where the constraint exists. When the Constraint Management Pathfinder goes live, this will potentially enhance the spread of technology types providing this service.

Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the Balancing Mechanism (BM), meaning the ESO has a means to instruct and settle reactive power services. Additionally, sometimes we have specific locational needs that cannot be accessed economically in the BM. We have recently launched Voltage Pathfinders, which attracted more diverse technologies to provide reactive power services and has proven that distribution network providers can also be effective to meet a transmission need.

RRE 2E Accuracy of Forecasts for Charge Setting - BSUoS

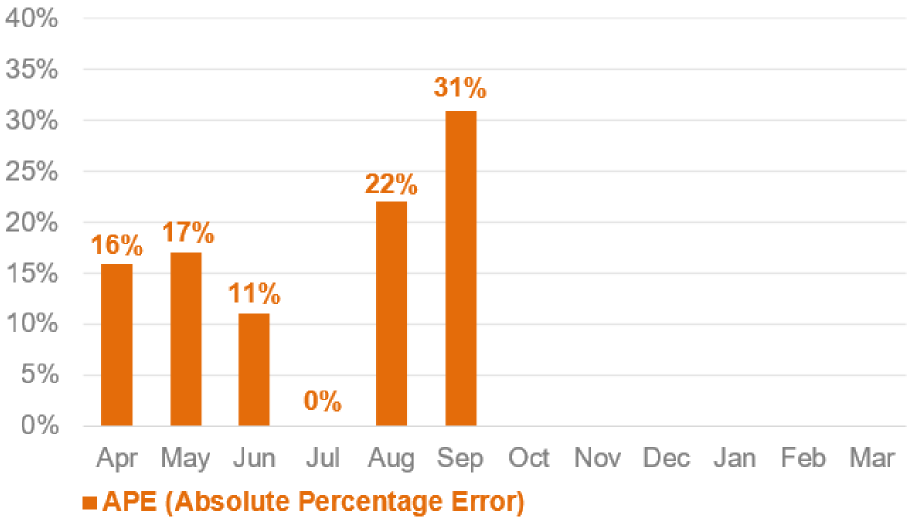
April- September 2021-22 Performance

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

Table 20: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

	Apr	May	Jun	Jul	Aug	Sep	Apr-Sep
Actual	3.8	4.5	4.6	4.2	5.8	6.9	n/a
Month-ahead forecast	3.2	3.7	4.1	4.2	4.5	4.7	n/a
APE (Absolute Percentage Error) [51]	**16%**	**17%**	**11%**	**0%**	**22%**	**31%**	**16%**

Figure 14: Monthly BSUoS forecasting performance (Absolute Percentage Error)



Supporting information

September performance:

BSUoS for September outturned at £6.90/MWh against a forecast of £4.70/MWh giving an APE of 31%

The outturn BSUoS for September was significantly higher than August. BM prices rose sharply due to higher wholesale prices and tight margins, leading to increases in the cost of securing reserve. Constraint costs fell due to higher levels of inertia and lower Rate of Change of Frequency (RoCoF) costs. The 'Minor Components' cost category became negative as neighbouring system operators requested SO-SO trades to assist their system operation. The total BSUoS volume was slightly higher than August.

Year to date performance:

The average APE for April to September is 16%. Forecasting BSUoS has been challenging as we emerge from COVID-19, given its impacts on recent historical Balancing Costs. Balancing Mechanism prices have risen sharply in response to rising wholesale prices and tight margins resulting in an increase in non-constraint balancing costs, particularly the cost of securing reserve which resulted in higher BSUoS charges.

[51] 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.

Role 3

System insight, planning
and network development

Role 3: System insight, planning and network development

Plan Delivery

- We have completed 34 out of the 43 milestones planned for this 6-month period. Of the 9 milestones which are not complete, 5 are ESO-related delays, 1 is outside of ESO control, and 3 are delayed in order to deliver an improved outcome for consumers
- Stability Pathfinder phase 1 contracts with Deeside went live in June- representing the first unit to convert a gas turbine rotor to provide stability services in synchronous compensation mode
- Stability Pathfinder phase 3 launched, learning from previous Pathfinders
- Launched commercial tender for Constraint Management pathfinder
- Conducted technical feasibility assessment on use of energy storage to manage transmission constraints
- Established new team to forecast constraint costs
- Providing expertise to Ofgem and BEIS reviews of network planning
- Progressed Regional Development Programmes, making significant progress towards the agreement of a basic Transmission Constraint Management service design..
- Progressed activities outside the Delivery Schedule including Offshore Co-ordination, Early Competition and additional operability work

Stakeholder Evidence

Role 3 survey:

- 18% exceeding expectations
- 58% meeting expectations
- 24% below expectations

Highlights:

- Launched interactive Future Energy Scenarios with virtual event and podcast
- Increased engagement for Regional Development Programmes, with positive feedback from DNOs
- Launched Distribution System Operation consultation
- Provided transparency around timeline for Stability Pathfinder phase 2

Value for money

- Our forecast total expenditure for role 3 in BP1 is £142m, which is 2% higher than the benchmark of £139m
- Increased expenditure due to Offshore co-ordination and Early Competition is offset by reduced IT expenditure in the Zero Carbon Operability and NOA projects

Demonstration of plan benefits

- Network Options Assessment (NOA) enhancements (A7-A11) on track to deliver £663m consumer benefit over RIIO-2
- Taking a whole electricity system approach to connections (A14) on track to deliver £8m consumer benefit over RIIO-2
- Taking a whole energy system approach to promote zero carbon operability (A15) on track to deliver £548m consumer benefit over RIIO-2
- Delivering consumer benefits from improved network access planning (A16) on track to deliver £224m consumer benefit over RIIO-2
- Loss of Mains changes are already saving consumers £20m/annum, and are expected to reduce our actions to manage RoCoF risk from 7.4TWh to 0.2 TWh per year

RREs:

- 3A Future savings from operability solutions: £27m saved balancing costs in 2021-22, £13m saved infrastructure costs for each of RDPs 1 and 2, carbon reductions of £66m from pathfinders (2020-21 to 2024-25) and £28m from RDPs
- 3B Consumer value from the Network Options Assessment (NOA): £58m from ad-hoc CBAs, NOA consumer benefit to be calculated for End of Year report
- 3C Diversity of technologies considered in NOA processes: 137 asset-based solutions (including 22 new options) and 9 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders

C.1 Plan Delivery for Role 3

Deliverable progress

For role 3, the RIIO-2 Delivery Schedule received an ambition grading of 4/5, providing the ESO with an ex-ante expectation of Ofgem's assessment of plan delivery if these deliverables are met. The ESORI guidance states that the Performance Panel should consider that the ESO has outperformed the Plan Delivery criterion if the ESO has successfully delivered the key components of a 4- or 5-graded delivery schedule.

During the first six months of the Business Plan 1 period, a few highlights of role 3 performance are:

Regional Development Programmes (RDPs) and Whole System:

- We have held two webinars with Distributed Energy Resources (DER) across the initial RDP regions to seek views on our proposed service design and have incorporated this feedback into our initial rollout (a Minimum Viable Product), where possible. We have also developed a product backlog of additional features that we will develop through further product releases, which we will continue to test with our stakeholders. We have made significant progress towards the agreement of the basic Transmission Constraint Management (TCM) service design.
- We have completed a series of detailed workshops with partner DNOs to refine the IT requirements for both UKPN and WPD RDP regions. This will enable the dispatch functionality of the new TCM service, and we are now beginning the development of key functionality across existing and new ESO IT systems.
- RDP project updates have been shared with all GB DNOs and the ENA through the monthly Joint Forum events hosted by the Whole Electricity System team. This is ensuring that RDPs develop in a consistent manner which is aligned with the ENA Open Networks project.
- Working closely with Scottish Power Transmission (SPT), we have finalised the ESO Technical Specification for the Generation Export Management Scheme (GEMS), which has enabled SPT to proceed to the procurement phase of the project.
- We have continued to participate strongly in Open Networks, leading key deliverables including the whole system CBA and primacy rules, as well as chairing the project's Whole Energy System workstream.
- We have engaged with stakeholders on our proposed approach to the DSO strategy, and with DNOs on the draft RIIO-ED2 business plans.

Connections:

- So far during 2021-22, we have received and processed a 40% higher volume of connection offers in the last six months than during the same period in previous years, whilst receiving positive feedback from our customers on how we are engaging with them throughout the process. This has been achieved by working closely with connecting customers, Transmission Owners, stakeholders, and setting up a dedicated team for GB Demand working with DNOs to better manage Distributed Energy Resources connections.
- We have made good progress on our Connections portal, which will allow customers to track the progress of their connection application, and give visibility of queue management where several customers have applied to connect at the same site.

Pathfinders:

- Contracts with gas turbine units at Triton Power's Deeside power station went live in June, delivering inertia, short circuit level and dynamic reactive power services as contracted under Stability Pathfinder Phase 1. Deeside was the first unit to convert a gas turbine rotor to provide stability services in synchronous compensation mode.
- We have reviewed the lessons learned from previous Pathfinders, for example Stability Phase 2 where parties applied for connection agreements before bidding for Pathfinder contracts, and over 1500 solutions were submitted, leading to potentially inefficient costs and interactions with the

queue for connection applications. We have made some changes to future Pathfinder processes to address these issues, for example capping the number of applications each party can make. However, we recognise that some of these changes have introduced new risks, and will continue to review the outcomes with a view to further improving processes in the future.

- We're also seeking to improve the balance between contractual obligations and making Pathfinders attractive to bidders, and investigating how we can compensate bidders whose assets deliver more capacity than originally anticipated. We're working closely with Ofgem to find suitable regulatory treatment for 0MW assets which provide services to the network. These considerations, which are part of our continuous development of Pathfinder processes, led to a conscious postponement of the launch of Stability Phase 3.
- We have launched our Stability Phase 3 Pathfinder, publishing documents for pre-tender consultation. Phase 3 introduces a new approach, where ESO will reserve capacity at the optimal locations, creating a level playing field and avoiding unnecessary connection applications. As part of this, ESO has proactively instructed NGET to construct new substation bays, which will be available for use by the successful bidder.
- The Pathfinders and Early Competition teams are working closely together to enable the use of competitive approaches ahead of the introduction of enabling legislation for competition in transmission.
- We are initiating work, using innovation funding, to explore a market-based solution to access reactive power. The market design project has been working closely with the teams which have been involved with the voltage pathfinder work, to ensure that learning points from the Pathfinders are captured.

Insights documents:

- We published the 2021 Future Energy Scenarios (FES) in July and held a week-long launch event
- We have continued to evaluate previous Future Energy Scenario demand data against outturn values, feeding this into the demand forecasts which are used for the Capacity Mechanism. This year, we have undertaken additional analysis to better understand the impact of COVID-19 on demand patterns.
- A major enhancement to last year's Future Energy Scenarios (FES) modelling was the introduction of a new Spatial Heat model. This substantially increased our ability to model domestic and commercial heat pathways.
- We have been working closely with the DNOs on their Embedded Capacity Registers. This is feeding into revised FES distributed generation backgrounds for this year.
- Responding to a stakeholder request, we added granularity to FES reporting, allowing TOs to view their split within the data.

NOA:

- We consulted on and finalised the Network Options Assessment (NOA) methodology for 2021-22. Key changes included reviewing and updating the Interested Persons' process, using the new Least Worst Weighted Regret technique which we trialled last year, and updating and refining the outages assessment process. We also clarified that the Interested Persons process will not assess storage options, which will instead be considered under a separate workstream as part of the ESO's 5-point plan. We also proposed to refine our framework for future methodology consultations.
- We continue to develop the analytical tools we use for NOA, making use of probabilistic modelling, and building on the outputs of our innovation projects to improve tools for stability and voltage modelling.

Constraints:

- We concluded the commercial tender for our Constraint Management Pathfinder and will be announcing the results and awarding contracts late November – Early December. We're seeking an intertrip solution, which will help transfer more generation and allow for more renewables to be connected to the system (rather than being taken off the system during peak generation periods).

We are future-proofing the solution, by including the facility to extend the intertrip to include more participants in the future allowing for the continued development of competition in the area.

- We are conducting a Technical Feasibility Assessment on how Energy Storage could help manage constraints on the Electricity Transmission Network between 2022-2030. Consultants were selected in July; the project will conclude in December.
- The ESO has established a new team to produce a rolling 24 month forecast of constraint costs. This will be based on the transmission and generation outage plans for within year and year ahead. We expect to start publishing the data in the second half of 2021-22.

Joining together Role 3 activities:

- We are contributing to two significant projects to review the network planning process: the Electricity Transmission Networks Planning Review (ETNPR) which is led by Ofgem; and the Offshore Transmission Network Review which is led by BEIS. For the ETNPR, we are leading two of its four workgroups: one on scenarios, analysis and decision making, and one on the breadth of solutions that could be brought forward, in a whole-system context, to meet transmission system needs. Our contribution to the Offshore Transmission Network Review is described below. Our involvement in these activities gives us the opportunity to take a strategic view of how the transmission network needs to evolve to meet the UK's target of achieving net zero emissions by 2050, using our experience of network operation. Given the importance of a coherent approach to establishing the required processes and capabilities across all these activities, we have initiated our own Network Planning Review project to support this aim.
- We had heard from our stakeholders that it was not clear how the different activities in Role 3 fitted together. We therefore held a deep dive as part of the Operational Transparency Forum in October (which we note is slightly outside of the timescales covered by this report), and will follow this up with a published document.

Progress of our deliverables

Our RIIO-2 Deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables. The first column shows how our deliverables meet the requirements of the Roles Guidance set out by Ofgem.

For Role 3 (System insight, planning and network development), the Delivery Schedule lists 62 deliverables in total which are made up of 225 milestones. 43 of these milestones were due to be completed in the first six months of 2021-22, of which 34 are now complete. Of the 9 milestones which are not complete, 5 are ESO-related delays, 1 is delayed for reasons outside of ESO control, and 3 are delayed to deliver an improved consumer benefit. We provide detail below about those activities where milestones are not on track:

ESO-related delays:

- D11.4 Improvements to assessments of stability requirements (2 delayed milestones): this work was delayed due to issues with sharing models securely whilst working remotely.
- D14.3.1 Improvements to the Connections process (1 delayed milestone): the delay was due to changes in team structure.
- A15 Taking a whole energy system approach to promote zero carbon operability: (2 delayed milestones):
    - D15.6.1 Phase 1 modelling scoping complete to feed into requirements and design stage of the data and analytics platform (foundation implementation): This activity depends on D1.4.1 Phase 1 modelling scope, which is still ongoing.
    - D15.7.1 Commence System State Targeted Monitoring and Control System (MCS) stage roll out - Phase 1 and Phase 2 Requirements and design: the delay in the start-up of the project has had a knock-on effect on the design phase.

Delayed due to issues which are outside of ESO's control in the short term:

- D8.1 Stability Pathfinder Phase 2 (1 delayed milestone): we published an update to industry in early June to explain the delay to the project. Having made the tender accessible to new participants and technologies, we received a substantial number of submissions at the Expressions Of Interest (EOI) stage. This caused us to review the timeline and the scope of the Connections Review work with the Transmission Owners, and therefore extend the overall timeline[52]. We have applied the learnings from this to future pathfinders, including phase 3 of the Stability Pathfinder.

Delayed to deliver an improved outcome for consumers:

- D7.1 ETYS and D11.2 Implement probabilistic modelling: (2 delayed milestones): proof of concept for probabilistic network analysis has been delayed so that this can be carried out alongside NOA7. This has benefits in that the new analysis techniques can be benchmarked and tested against our most recent NOA analysis.
- A15.5 Regional Development Programmes (1 delayed milestone): for RDP3, discussions are still ongoing with WPD to ensure that developments are consistent and informed by earlier RDPs, and we expect these to conclude shortly.[53]

New initiatives and changes

The RIIO-2 Delivery Schedule was originally published in October 2020. Since this, the ESO has continually prioritised its projects to deliver the best value for consumers. This has resulted in some new activities, which were not included in the RIIO-2 business plan, Delivery Schedule, or cost benchmark.

Offshore coordination:

Since the start of the RIIO-2 period the Offshore Coordination project has been working closely with BEIS and Ofgem to lead and deliver the parts of the Offshore Transmission Network Review (OTNR) that are within the ESO's remit.

In our published Deliverables Tracker, we provide an update on the deliverables which were listed in the Offshore Coordination Annex, which was published alongside Ofgem's Final Determinations. However, in some cases these deliverables have been superseded by more recent developments as part of the OTNR, which are described below. Following publication of this mid-year report, the deliverables from the Offshore Coordination Annex will be added to the main Delivery Schedule for completeness.

We are a project partner in the OTNR, which involves our active participation in OTNR governance groups and stakeholder engagement activities such as project webinars. Our work is across three main workstreams:

- Early Opportunities – We have worked closely and regularly with the onshore Transmission Owners (TOs) and developers of in-flight offshore projects (wind and interconnectors), to understand the costs, benefits, opportunities and blockers for greater coordination. We have completed detailed analysis and delivered to Ofgem and BEIS a project proposal pack for all projects that have been put forward for coordination. This informed the models proposed by Ofgem in their early summer consultation, which we are now in the process of assessing to understand the detailed codes, standards and ESO process changes required to facilitate them.
- Pathway to 2030 - We have been asked by BEIS and Ofgem to deliver a Holistic Network Design (HND) to provide a coordinated National Electricity Transmission System (onshore and offshore) to connect 40 GW of offshore wind by 2030. In order to deliver the HND we have formed and are leading the Central Design Group (CDG) and all its sub-groups (Commercial, Stakeholder and Communications, and Environment). For each group we have worked closely with the TOs to agree Terms of Reference (ToR) and to establish effective ways or working. Most of these groups are now in place and informing the delivery of the HND. During the first quarter of 2021-22 we

[52] https://www.nationalgrideso.com/document/192731/download
[53] Text amended on 9 November 2021 due to incorrect reference to N-3

provided comments to Ofgem on the six pre-consultation offshore delivery models. Supported by Imperial College London and the National HVDC Centre we also developed a generic offshore design planning tool for the calculation of network design costs, which will feed into the HND. Specialist consultants, appointed via a competitive tender process, have now started work on the HND, with the aim of delivering the design in early 2022.

- Enduring Regime – We have delivered a Strategic Network Planning Paper to BEIS and periodically provided views on potential Enduring Regime models to help inform their thinking, prior to the launch of the BEIS consultation on this topic. We have also worked with both The Crown Estate and Crown Estate Scotland to develop and agree separate Statements of Intent to consider options in relation to the Enduring Regime in respect of seabed leases and connections.

Early Competition:

In the past 6 months we have finalised and published the Early Competition Plan. We have also begun to progress 'low regrets' work, as agreed with Ofgem, ahead of their decision on whether to introduce Early Competition. As part of this further work, we have progressed our thinking on how projects will be identified for competition and interactions with other planning activities (such as pathfinders and Large Onshore Transmission Investments (LOTI)), and tested this thinking against projects in the 2021 Network Options Assessment. This includes beginning work on a methodology for the project identification Cost Benefit Analysis. We have also progressed assessment of the main areas where we think codes, licence and legislation may need to be amended, and we have further explored how network models could be made available to bidders.

In addition, we have progressed work around how we could begin to introduce the Early Competition model prior to the introduction of legislation. So far, we have mapped the differences between the Pathfinder and Early Competition processes and identified potential areas where the Early Competition model could be adopted. We have also supported Ofgem and BEIS as they progress their thinking, providing input to their consultations and to discussions on legislative change. Finally, we have also begun work to proposed modifications to support the potential application of the transmission-level Early Competition model to distribution.

Other pieces of work in role 3:

We have also initiated several smaller new pieces of work in role 3. Although these activities were not foreseen at the time of producing our Delivery Schedule, we believe they will drive additional benefits for consumers:

- Due to the increasing volume of connections, system studies had showed that, based on the existing approach, no further capacity was available on the South East Coast, until network reinforcements were completed later in the decade. Recognising that this would be highly discouraging to prospective customers, we initiated a project with consultants DNV to investigate whether any additional capacity could be released via innovative operational arrangements which could enable the connection of additional renewable generation while maintaining system integrity.
- Fault ride through issue: earlier this year we had observed a growing number of instances where generation and network licensees' assets failed to "ride through" faults on the transmission system. We issued an open letter[54] to the industry, requesting confirmation that all assets were compliant, and setting out the process which would be followed in the event of an unexpected generation loss or network asset trip. We have since been focused on reviewing the responses to enable ensure all generators are compliant with the "fault ride through" requirements. So far, we have received responses from 70% of the generators, and further reminders have been sent to the outstanding 30%. We have also engaged with the industry through the Grid Code modification GC0151, which address the post trip process that was highlighted in the ESO letter in May 2021. The Grid Code modification is currently undergoing industry consultation, to be followed by a decision by Ofgem.

Innovation projects

[54] https://www.nationalgrideso.com/news/open-letter-transmission-connected-generation

We are currently undertaking the following innovation projects, which relate to Role 3. Some of these projects are funded as part of the RIIO-2 price control and are therefore eligible for consideration as part of the RIIO-2 incentive scheme. Other projects were funded as part of the ESO's RIIO-1 innovation funding, but are included for completeness as they support some of the ESO's RIIO-2 deliverables. The references in the table below provide links to additional information about each project.

Innovation Project name	Description	Deliverables supported	Status	Funding
Optimal Outage Planning System[55]	Developing a tool for the outage planning process that facilitates the most efficient economic decision-making from the year-ahead plan to three-weeks ahead, and tracks risks from year-ahead to day-ahead.	D16.1.1, D16.1.2	Delivery	RIIO-1 and RIIO-2
Advanced Modelling for Network Planning Under Uncertainty[56]	Developing the LWWR (Least Worst Weighted Regret) tool that will help automate part of the Network Options Assessment (NOA) process to make more informed decisions, and be more economically efficient with network planning recommendations.	D7.2 D11.2	Delivery	RIIO-1
Resilient EV Vehicle Charging[57]	The project will analyse the impact of EV charging on grid short term frequency and voltage stability, and cascade fault prevention and recovery.	D15.1.2	Delivery	RIIO-2
DETECTS[58]	The project is seeking to understand the risk of converter instability by assessing the behaviour of actual manufacturer-provided converter models	D15.1.2	Delivery	RIIO-1
EFFS (WPD led)[59]	This project is to explore in detail the additional functionality required as a DSO, to evaluate the potential options and implement systems that provide that new functionality.	D15.9.1	Delivery	RIIO-1
Probabilistic planning for stability constraints[60]	Cutting-edge techniques combining traditional power systems stability analysis and statistical modelling, will allow the ESO to better understand the risk and uncertainty associated with angular stability on the GB electricity system	D11.4 D15.1.2	Delivery	RIIO-1

[55] https://www.smarternetworks.org/project/NIA_NGSO0037
[56] https://www.smarternetworks.org/project/nia_ngso0028
[57] https://smarter.energynetworks.org/projects/nia2_ngeso006/
[58] https://www.smarternetworks.org/project/nia_ngso0031
[59] https://www.westernpower.co.uk/projects/effs
[60] https://www.smarternetworks.org/project/nia_ngso0036

SHEDD[61]	Assessing better Low Frequency Demand Disconnection (LFDD) solutions	D15.1.2	Delivery	RIIO-1
TOTEM (SHET led)[62]	Developing and validating a full-scale model of electromagnetic transient (EMT) behaviour for the GB transmission system.	D15.1.2	Delivery	RIIO-1
VSM Battery[63]	The functional needs as defined in the VSM work group may be delivered in a variety of ways, this project will deliver the testing, modelling and specification need to ensure appropriate performance is delivered	D15.1.2	Delivery	RIIO-1
Year-round Voltage Assessment Tool[64]	Developing and testing convex optimisation models and machine learning algorithms that adequately represent voltage and reactive power in the system.	D11.3 D15.1.2	Closure	RIIO-1
Coordination of ANM schemes with Balancing Services markets[65]	Thorough review of existing Active Network Management (ANM) schemes and identification of any conflicts which have arisen historically. Developing a series of test cases which represent the range of different ANM scheme configurations and simulating the outcomes in different scenarios.	D4.5.1	Closure	RIIO-1

C.2 Metric performance for Role 3

There are no Metrics for Role 3

61 https://www.smarternetworks.org/project/nia_ngeso0034
62 https://www.smarternetworks.org/project/nia_shet_0032
63 https://www.smarternetworks.org/project/nia_ngso0026
64 https://www.smarternetworks.org/project/nia_ngso0029
65 https://www.smarternetworks.org/project/nia_ngso0035

C.3 Stakeholder evidence for Role 3

- Our Future Energy Scenarios (FES) 2021 was published as an interactive document. We launched a virtual event in addition to a Future of Energy podcast series.
- For the Regional Development Programmes (RDP) we have increased engagement. We sent out a survey to the DNOs, who said we were meeting their needs ‘very well’.
- We launched our Distribution System Operation (DSO) consultation, introducing our proposed approach to supporting the transition to DSO.
- We informed participants of the Stability Pathfinder Phase 2 that there had been an extension to the timeline.
- We received negative feedback from stakeholders on the eNAMS roll out delay and issues. Our strategy has been to fix any defects that come to light and we have been engaging extensively with industry to prioritise these.
- Over the last six months we have been engaging with industry through our ETYS and NOA methodology consultations.
- We have worked closely with Ofgem and Transmission Owners to resolve a number of regulatory and contractual issues, taking on board learnings from previous Pathfinders.

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, we report on our stakeholder satisfaction survey results, as well as describing how we have worked with stakeholders during the year.

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.

For Role 3, the following question was asked:

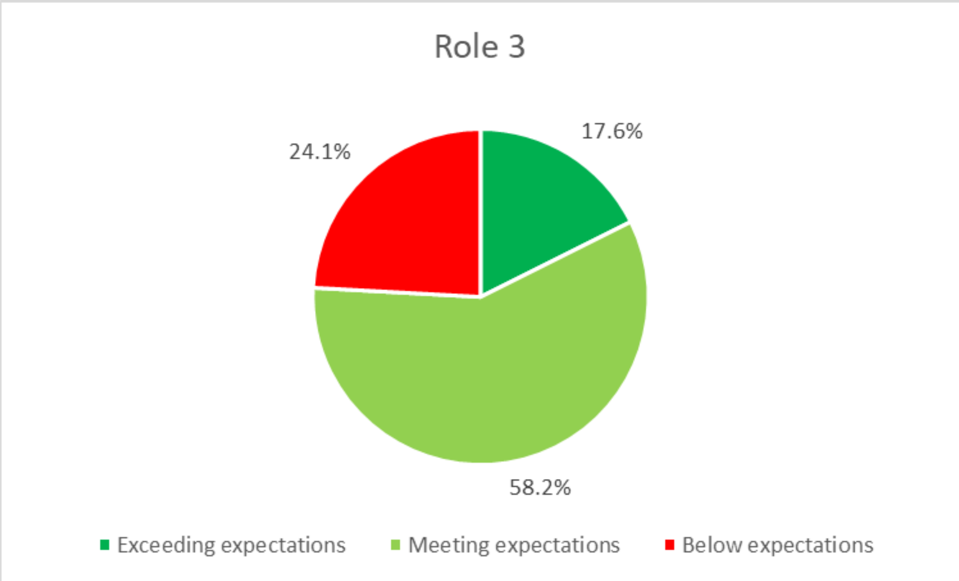
“One of the ESO Roles is focused on system insight, planning and network development, which includes key activities such as Connections and Network access, Strategy and Insight and long-term Network Planning. The ESO’s recent activity in this area includes progress on the Stability Pathfinder projects, 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 the new Regional FES programme 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 364 stakeholders, and received 91 responses to this question, which were distributed as follows:

- 17.6 % exceeding expectations
- 58.2 % meeting expectations
- 24.1 % below expectations



The survey results indicate that the ESO is meeting expectations for role 3, although Ofgem will also take into account other stakeholder evidence. Our analysis of survey responses has suggested the following themes:

Exceeding Expectations feedback

Role 3 received positive feedback relating to communication and engagement, which was mentioned by half of those giving a score of ''exceeding expectations''.

- Respondents generally felt that the ESO is thinking ahead by being open to new technologies and tool development, including application of advanced research techniques and models to practical applications.
- Future Energy Scenarios are comprehensive, and engagement around key projects has been very beneficial.
- We are managing issues and providing helpful, clear and timely responses with good guidance.
- It was felt that there has been significant improvement in communication.
- We are conducting a large number of new pathfinder and ground breaking projects and system analysis in a relatively short period of time.
- We are able to pass on network information with ease, but are also able to apply practical scenarios to aide understanding of the deliverability on the projects.
- The current collaborative approach and being in solution finding mode is extremely encouraging.

Meeting Expectations feedback

We asked all stakeholders who scored us as "meeting expectations" what would it take for the ESO to be exceeding expectations for them, here is a summary of that feedback for Role 3.

We received mixed feedback for those who felt the ESO ‘’meet its expectations’’, with positive feedback emerging from communication improving significantly, and the level of ambition and investment within the business. Improvements suggested were to focus on further clarity and more realistic scenarios.

- We should be setting out an agenda for what consultations are taking place and when these will be completed.
- More transparency to be provided on what the Regional FES program is trying to achieve.
- ESO should take a “helicopter view” of future network evolution, to ensure that the most economic solution is delivered.
- We should have a clear idea on how offshore coordination will work and affect new developers and generators in the region, and progress the work more rapidly.
- It was felt that there needs to be a more proactive approach to resolving the RDP for the North of Scotland.
- There was some frustration expressed around the eNAMS roll out delays.
- ESO should address issues more quickly, and be more willing to collaborate.

Below Expectations feedback

20% of those giving a score of “below expectations” were centred around Pathfinders performance.

- Suggestions to improve the Pathfinder projects included ensuring a level playing field, taking into account outage planning timescales, taking a longer-term view, and avoiding delayed timescales.
- There are many significant projects happening at the same time, more focus should be placed on fixing current issues with existing procedures and processes.
- We need to work within our statutory framework and follow the correct paths to change existing codes. Also, meeting the licence requirements should be a priority.
- Deliver commitments more effectively for individual projects.
- Have future sight into the impact of ESO actions, not just 'learn by doing'.

Over the coming months, we will seek to act on this feedback to improve stakeholder satisfaction with our activities.

Stakeholder engagement during the year

The Stakeholder Evidence criterion also takes account of the ESO’s consultations and ad-hoc surveys throughout the year, whether the ESO has actively sought and taken into account the feedback of stakeholders throughout the business plan cycle, and the ESO’s explanations for feedback received.

Pathfinders

Pennine Pathfinder

On 27 April we held a Technical Q&A webinar[66] for the High Voltage Pennine Pathfinder, with around 60 attendees. In September the legal terms and contract feedback was shared with participants. We have a commercial webinar scheduled for 14 October and a follow up Q&A webinar on 21 October.

Stability Pathfinder Phase 2

In June we informed participants of the Stability Pathfinder Phase 2 that there has been an extension to the timeline[67]. We have completed the Expression of Interest review of over 1500+ solutions and are carrying out Feasibility Studies and Connection reviews ahead of running the tender in Q4 2021-22. We have consulted with the market on several key documents such as the contract terms[68], technical specification

[66] https://www.nationalgrideso.com/document/189971/download
[67] https://www.nationalgrideso.com/document/192731/download
[68] https://www.nationalgrideso.com/document/191696/download

and assessment methodology[69] and the final versions of these have now been published. We have also engaged with them on changes to the contract length[70] and have updated them on the revisions.

The original contract was defined as a ten-year contract. Due to protracted negotiations which took six months, the contract award date was also pushed back by six months. The service end date consultation asked if providers would prefer the service end date to remain the same, or be extended by another six months to compensate for the delay with the TOs. The majority of respondents were supportive of the proposal to amend the service end date.

Lessons learned have been captured and incorporated into the Stability Phase 3 project.

Stability Pathfinder Phase 3

Pre-tender consultations are currently open with feedback due by October. The Stability Phase 3 Contract Terms webinar[71] was hosted on 17 September with an attendance of 43 people. The Technical and Connections webinar[72] was also held on 17 September with 95 attendees. We are currently seeking stakeholder feedback on these webinars.

Constraint Management Pathfinder

The Constraint Management Pathfinder entered the tender stage on 11 March 2021. During this time, there were the following consultations open at the same time:

- Draft contract terms consultation – the first consultation ended on 21 May and three parties responded with their comments. The ESO took the feedback on board and updated the contract terms. In July, we consulted on these revised contract terms, receiving two further comments which we subsequently incorporated.
- In May, we consulted on the Commercial Assessment methodology. Four clarifications were requested and provided, but no changes needed to be made.

As part of the tender, the expression of interest window was opened twice – 11 March to 16 April and 5 to 16 July: this was due to changes in the programme. During the tender, parties were approach on a 1-2-1 basis to ensure they fully understood the documentation and requirements, giving them an opportunity to ask any questions. The questions were released as an FAQs document[73] both in the tender platform as well as on the website. The tender ended on 1 October 2021 with results expected to be announced in end of November/ early December.

Accelerated Loss of Mains Change Programme

The Accelerated Loss of Mains Change Programme has increased engagement of electricity generators connected to the distribution network following the development of a new communication campaign in spring 2021. Using the message Future Proof Your Power, the campaign has created a simplified approach to raise awareness of the programme and clarify what action generation site owners need to take before the G59/3-7 compliance deadline of 1 September 2022. The campaign includes a new website, guidance materials, social media posts and online advertising which have all been created to assist stakeholders without the need to be a technical specialist. In a survey of applicants to round 7 of the programmes, 70% of responses found the ALoMCP process easy or somewhat easy.

Over 7,000 generation sites, representing 72% of the generation capacity at loss of mains risk, are now engaged with the programme and have achieved compliance or are currently undertaking the required loss of mains protection changes.

[69] https://www.nationalgrideso.com/document/197046/download
[70] https://www.nationalgrideso.com/document/197051/download
[71] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6273369889001
[72] https://players.brightcove.net/867903724001/default_default/index.html?videoId=6273369639001
[73] https://www.nationalgrideso.com/document/190281/download

Network Options Assessment (NOA)

ETYS and NOA methodology consultation.

Over the last six months we have been engaging with industry through our ETYS and NOA methodology consultations. The ETYS consultation sought feedback on the proposed structure of the 2021 ETYS through a survey which received a total of 6 responses. We received positive feedback on the proposed structure along with more detailed information stakeholders would like to see on system needs and development opportunities. We have since followed up with stakeholders and transmission owners in order to understand what further information could be published to facilitate the development of a carbon neutral system. Apart from the ETYS, we communicate additional system needs through the NOA Pathfinders, and we are reviewing if and how these needs can be integrated into the annual ETYS, whilst retaining flexibility to publish needs outside of the main publication.

In May, following discussions with the TOs and Ofgem, we consulted on our NOA 2021-22 methodology[74]. This document provides an overview of the aims of the NOA and details the methodology which describes how we assess the required levels of network transfer, the options available to meet this requirement, and recommends options for further development. We received a total of 5 responses. We consulted also on the NOA's form of report as part of our intention to improve accessibility for our audience. We have responded to every consultation response with a personalised letter addressing the comments made in more detail. Furthermore, we set up sessions with stakeholders in order to see where feedback could be actioned for this year's and next year's methodology. Of this year's respondents, three were TOs whose focus of feedback was the core NOA process and this contrasts with NOA Pathfinders that prompted less feedback (mainly from non-TO respondents) than last year. There were over 1500 email recipients of the methodology consultation in contrast with under 1300 last year and similarly the number of email clicks to download the methodology more than doubled to 189. We received encouraging feedback from stakeholders on our engagements during the consultation and some examples are:

Transmission Owner: *'I would like to acknowledge the continued effectiveness of ongoing engagement via the JPC sub-group which is focussed on delivery of both the ETYS and NOA. This has allowed us to contribute to the development of the proposed NOA methodology and continues to be a good example of co-ordination between the ESO and all TOs.'*

Investment company: *'We very much welcome and support the NOA for Interconnectors (NOA IC). The outputs from this analysis provide an independent and public dataset on which developers can consider taking projects forward.'*

NOA report format

Every year we undertake an ongoing process to make sure that we can make the NOA report as accessible to stakeholders as possible. In July we took the opportunity to seek feedback on the NOA report format via a pop-up survey on our website. We asked stakeholders about the current format and any further improvements that could be made for the next iteration. This method of engagement, which was a pilot exercise, proved to be a more effective way of obtaining feedback and we will look to utilise this approach with refined questions to receive better feedback around the time of the next NOA publication. We received a total of 27 responses which we have analysed, and we will now consider how to act on the feedback we have received.

NOA System Requirements Form (SRF)

We have also recently concluded our yearly System Requirements Form handover process which allows Transmissions Owners (TOs) to submit options to be assessed in the NOA. We have worked with the TOs to ensure that the process was smooth and introduced new ways of providing the options information through online forms. We have also revamped our Interested Persons' process, designed to increase the diversity of options considered within the NOA process through academic and industry participation. Following a pilot in 2020 and feedback we received from stakeholders, the process has been refined to make it more collaborative and increasing transparency for providers. Going forward, we want to continue

[74] https://www.nationalgrideso.com/document/191581/download

developing these processes, engaging with both TOs and third parties, to develop and improve our online forms and tools using innovative solutions and new technologies and services.

Transmission Owner: '*Many Thanks for your collaboration on this year's NOA process*.'

Network Development Newsletter

We have continued with our engagement through our Network Development newsletter by providing monthly updates to our subscribers. Our newsletter circulation has increased by 13% since our last reporting from 1400 subscribers to almost 1600 as of October. We will continue to develop our campaigns to ensure that stakeholders are kept up to date on the latest news in relation to ETYS and NOA.

Ad-hoc CBAs

Since our last reporting we have conducted various ad-hoc CBAs that look to provide a recommendation that is the best interest of consumers. We have been working closely with each stakeholder to ensure that we can provide a detailed understanding of the recommendations we make as part of this process. We're delighted about the level of engagement we have received and have been given very encouraging feedback from TOs:

Transmission Owner: *'Thanks for the sterling work you did (…) Your efforts are greatly appreciated.'*

Transmission Owner: *'You have been super helpful (…). Massive thank you'*

Transmission Owner: *'The report is just what I was after and the outcome is really clear, it gives us the assurance that we're doing the most cost-effective solution for the consumer.'*

Transmission Owner: *'My sincere appreciation for accommodating our CBA request and getting this done within tight duration.'*

We are looking to release a bespoke survey that will allow stakeholders to provide us with more detailed feedback on the process of the ad-hoc CBAs.

SQSS review

We have held one-to-one discussions with key stakeholders such as TOs, DNOs, Generators and academia representatives. We have also presented the list of potential issues for SQSS review to various forums including SQSS Review Panel, Open Networks Working Stream 1B (WS1B) meeting and Grid Code Development Forum. Further larger scale engagement activities are planned for the coming weeks.

Stakeholders have provided positive feedback on the selected topics and agreed that they are some of the key areas where changes can be made and in line with the interests of the industry. They also expressed concerns that the amount of effort to facilitate the changes would be significant, and asked how the workload would be managed to ensure the project remains on track. We reconfirmed with stakeholders that the prioritisation of the proposed changes would mean we will ensure that the most urgent and important needs of the industry will be satisfied in the early stages, and then more comprehensive review will take place with carefully defined terms of reference. The workgroups will be focused and efficient to tackle the problems.

Leading the debate

Carry out analysis and scenario modelling on future energy demand & supply

In April we published the 2021 Summer Outlook Report[75] setting out our view of electricity supply and demand for the coming summer months and the operational tools we will use to manage any challenges. On 24 June we published our Winter Review and Consultation[76]. This is an annual document which compares what we forecast in our Winter Outlook 2020-21[77] publication with what happened. It also provides an opportunity for stakeholders to share their views on the winter ahead and how we can approach any opportunities and challenges.

[75] https://www.nationalgrideso.com/document/189741/download
[76] https://www.nationalgrideso.com/document/195776/download
[77] https://www.nationalgrideso.com/document/178126/download

On Monday 12 July we published our Future Energy Scenarios (FES) 2021. FES is based on extensive stakeholder engagement, research and modelling and describes what the future of energy may look like between now and 2050. The full suite of FES documents which included the main FES interactive document, FES in 5, data workbook and modelling methods was published in the FES website[78].

We made changes to the FES website this year to share the key insight from the analysis on individual web pages, making it easier to understand the information, without the need to download individual documents.

To accompany the publication, we ran a virtual launch event[79] during the week to share the FES 2021 key messages, summary of the analysis and a series of deep dive sessions on a range of specific subjects. As part of this event, we set out how the outputs of the FES are taken forward by other ESO teams and external stakeholders, building on a bespoke webinar from earlier in the year. Following feedback from the previous year, we held virtual networking sessions during the deep-dive sessions for stakeholders to meet each other and the FES team. These were hosted by ESO colleagues and attended by 56 stakeholders.

Many of the statistics we use to monitor our performance for the publication improved this year compared with FES 2020 which was itself a record year. The virtual event during the week attracted over 400 stakeholders and our “on demand” presentations were viewed more than 140 times. During the first week of publishing FES 2021, we saw an increase of 90% compared to FES 2020 for the suite of documents on the website. The stakeholder satisfaction measure that we use on a regular basis – Net Promotor Score (NPS) - provided us with an overall score for the week of +37 which is classed as favourable and good.

We also launched a new podcast series[80] shortly after called The Future of Energy, where we talk to ESO experts about the big themes from FES 2021 including net zero, electric vehicles, renewables, heat and hydrogen.

Feedback: You Said	**Action to take forward: We will**
Some attendees commented that the questions weren’t answered sufficiently and needed more of a yes or no – the question was a challenge to the assumptions	We will ensure that a more thorough answer is provided in the future
Stakeholders would like more in depth information about the modelling and assumptions and less of a summary of what is already published in the FES report.	We will consider providing more information on the assumptions and modelling that is not covered in the main report
Some stakeholders have requested to have a session on some of the modelling methods used, for those interested in data science and modelling.	We will consider hosting a session specifically on modelling methods

Maintain external communication channels with consumers and stakeholders

We are driving regionalisation for our Future Energy Scenarios (FES) in the hope that it will support understanding of future energy policy at a local level, as well as simplifying and optimising the interface with the more bottom-up scenarios currently developed by gas and electricity network companies, such as the Distribution Future Energy Scenarios (DFES). This will build upon the information we currently produce and publish, such as the regional datasets that are used in the Electricity Ten Year Statement (ETYS) process. We are exploring the development of a set of consumer archetypes that can be used consistently by ESO and the network companies. We have engaged on this topic through our FES Network Forum and ENA Open Networks as well as directly with Ofgem and have gained broad support to kick off this piece of work.

78 https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021
79 https://www.nationalgrideso.com/future-energy/future-energy-scenarios
80 https://open.spotify.com/show/0hrpBYso1xXOFZKfy4jkjR?si=YEwJ0_ZnRz-s1304SS0VuA&dl_branch=1&nd=1

Stakeholder feedback points to several areas for the ESO to explore, including different ways to define regions and fuel interactions, having a whole system focus, and learning lessons from existing cross-fuel collaboration. There was a positive reaction to being able to get a better view of technology uptake and consumer/customer trends at a regional level. The insight received from these engagement exercises is being used to help shape the next steps in the project, building on an understanding of what stakeholders would value and how they want to be involved.

In addition to our engagement around regional development, structured interviews with ten external stakeholder groups, who receive data directly from our Future Energy Scenario modelling, were completed. This included Distribution Network Operators (DNOs), Gas Distribution Networks (GDNs), the Gas System Operator and Transmission Operators. These have been broadly positive particularly valuing the helpfulness of our people. However, these sessions have also indicated that improvements could be made. Stakeholders have said they would welcome a more granular view of whole system scenarios and agree it would increase the robustness of FES. A need has also been identified to ensure scenario creation is coordinated and that there isn't a duplication of effort. There also needs to be transparency of the assumptions driving the regionalisation of the FES, and potentially for feedback loops with stakeholders to sense-check outputs. There is broad support for closer collaboration on the creation of more granular scenarios. More interactive tools can make it easier to use FES outputs to generate relevant insights and more visibility of upcoming changes can help manage downstream impact.

Take a whole electricity system approach to connections

Provide contractual expertise and management of connection contracts including provision of connection offers to customers

We have worked closely with our customers and stakeholders to improve queue management and manage interactivity between different connection applications. This has included regular portfolio discussions with customers and TOs, and setting up a dedicated team to manage connections for Distributed Energy Resources. We have also made good progress on our Connections portal, which will allow customers to track the progress of their connection application. The Connections Portal concept and design is being developed with focus on the feedback that has been provided by customers on regular surveys. We have also engaged directly with some customers and stakeholders to better understand their feedback. The Project Team are planning to carry out User Acceptance Testing with customers in November 2021. Survey respondents scored the level of support received from the Connections team an average of 8.9 out of 10, which we are pleased with given that we have processed an increased volume of applications.

Further enhance the customer connection experience, including broader support for smaller parties

Customers have asked for a "who's who" in the Customer Connections Team to support interactions, we have taken this feedback on board and will issue a document. We are also planning to undertake face-to-face engagement with customers and stakeholders which shall be done with a regional and nature of application audience strategy, We have also successfully trialled monthly Portfolio meetings with customers with participation of all relevant stakeholders, including TOs. We will be issuing more external communications to address new processes such as queue management.

Regional Development Programmes

Develop Regional Development Programmes (RDPs)

For the Regional Development Plan (RDP) projects we held two webinars for Distributed Energy Resource (DER) in July, one in conjunction with WPD and the other in conjunction with UKPN. 75 people attended the webinars, which provided background context on RDPs and explained some specific connection conditions that have been placed on many DER parties in the RDP regions (South West and South East of England). We also set out a new thermal transmission constraint management service that we are developing to provide an alternative means to the Balancing Mechanism (BM) and Wider Access for smaller parties to provide constraint management services. We have a set of questions on our website inviting views from DER on this new service which we will use to develop it further.

We surveyed DNOs and TOs to ask them 'How well is the ESO currently meeting your needs in Regional Development Programme (RDP) development?' 75% of respondents said we were meeting their needs 'very well'.

We are holding monthly Whole Electricity Systems forums with all GB DNOs, the Energy Networks Association (ENA), Ofgem and BEIS. A primary focus for this forum is to share learnings from RDPs although we have recently expanded this scope to provide updates on ESO activities which are relevant to DSO, for example we recently provided updates on Distributed Restart and Early Competition. We provide a monthly update to Open Networks on this forum to ensure alignment with the ENA Open Networks project.

Support DSO and whole electricity system alignment

In April, we launched our Distribution System Operation (DSO) consultation[81], introducing our proposed approach to supporting the transition to DSO. Our consultation described a proposed ESO approach to support the DSO transition as well as a vision of how we will be working with DNOs in 2025.

Following the launch of our Distribution System Operation (DSO) consultation in April, we held a webinar on 6 May to allow stakeholders to hear from ESO colleagues around the ten coordinating functions we proposed in our consultation. The Association for Decentralised Energy (ADE) and Energy Networks Association (ENA) also presented their views on the importance of, and priorities for the DSO transition. Over 100 stakeholders attended the webinar to hear more on our approach and ask questions. We have now published responses to all questions raised[82] and the webinar recording is now available on our website[83] We're aiming to build on the collaborative work already underway to support the DSO transition, for example through forums such as the ENA's Open Networks project and the Whole Electricity System Joint Forum.

We received 15 responses to our request for feedback from stakeholders[84] including the following comments:

Energy Supplier – '*We welcome the ESO setting out its strategic vision for DSO and how this relates to other industry initiatives such as the Open Networks Project (ONP). This document is a useful starting point. At a high level, we support many of the principles in the proposed vision.'*

Industry participant – *'Overall we support the principles and approach to the DSO transition set out by the ESO. We particularly welcome the strong emphasis on closer ESO/DSO coordination – including in service procurement, dispatch and operations.'*

Industry body – '*We would like to see a far more ambitious and detailed set of targets for the transition. A lot of the actions outlined in the document seem to already be in place, such as regional development plans, rather than looking to achieve far more in the near term. There is also a need to set out in detail what is needed, not just that the various organisations will talk to each other.'*

Industry participant – '*We are pleased to see this consultation and the development of an approach for the ESO to support and enable the DSO transition. However, we recognise that the roles and responsibilities for ESO and DSO functions are still evolving and that there continues to be a lack of clarity as to the exact functions each party will undertake.'*

Transmission Owner – '*We agree in principal with the High Level vision. While we accept the reference to the current Ofgem position on DSO capabilities, we believe that working together with the ESO and our connected-customers, together we can devise the optimal plan for DSO and the wider system operation.'*

In August 2021, the ENA Open Networks project launched a consultation on the next version of its standard agreement for flexibility services, which seeks to further drive standardisation, consistency and transparency. This work, led by the ESO, will result in common arrangements for both DSO and ESO

81 https://www.nationalgrideso.com/document/190271/download
82 https://www.nationalgrideso.com/document/192106/download
83 https://players.brightcove.net/867903724001/default_default/index.html?videoId=6252928262001
84 https://www.nationalgrideso.com/research-publications/whole-electricity-system/document-library

services. The ESO is actively involved in consultation events including the ENA webinar held on 22 September.

Delivering consumer benefits from improved network access planning

We are engaging with the Transmission Owners, working with them on developing terms of reference for enhancing existing assets on the transmission system that may yield consumer benefit. This work continues through the SO-TO Code (STC) forums and the next development stage is the identification of system needs that can be examined to develop solutions for potential network constraint savings.

Fort Augustus Capacity Sharing

We worked with customers in Scotland to understand their planned generation patterns whilst substation reinforcements were taking place. We then ran the substation in a non-standard way, and agreed a programme of generation with our customers, releasing more capacity and easing constraint issues on the B4 (SSEN Transmission to SP Transmission) boundary.

Operational intertrip scheme in Scotland

During construction of a new 275kV substation in the SSEN Transmission area, we worked with the TO and large generator in the area to install an operational intertrip. This meant that the generator could continue to generate while the works were carried out, and the ESO also retained the contractual ability to reduce the power station's output at no cost to the consumer (using a reduction in Transmission Entry Capacity (TEC) rather than taking actions in the Balancing Mechanism).

Acceleration of Western HVDC link Run Back scheme

We recognised that when a large Scottish nuclear plant closes in January 2022, system issues (insufficient commutation) would mean that it would not be possible to run the Western HVDC link at full capacity, until reinforcement works are completed. ESO worked with SPT to accelerate a Run Back scheme to be active by the end of 2021, which will avoid the need to restrict the output of the Western HVDC link unless a fault occurs.

Electronic Network Access Management System (eNAMS)

eNAMS went live on 1 September 2021 after being delayed. Due to negative feedback regarding the delays and issues, the strategy has been to fix any defects that have come to light from when the application went into production and ensure that the system can be updated and maintained in the future. All the defects identified are targeted to be resolved over the eight weeks of Early Life Support (ELS), which completes at the end of October. The defect tracker is shared twice weekly with the main users; ESO, NGET, SPT and SHET. Weekly meetings are being held separately with the project team and NGET, SPT and SHET, to discuss progress on defect resolution and prioritising new defects raised.

Activities outside the Delivery Schedule

Early Competition

We have engaged with TOs, as key parties affected by competition, to make them aware of the work we're doing and to hear their feedback on current competitive processes (NOA pathfinders). We have also engaged with various code change forums to raise their awareness of early competition ahead of considering potential areas for code change. We have recently begun engagement with the ENA to understand modifications that would be required for distribution level competition. In addition, we held an engagement session at the request of stakeholders from the US, who were very interested to learn about competition here.

Ofgem and BEIS have both consulted with stakeholders on competition during this period. Therefore, our stakeholder engagement in this period has been targeted on affected parties rather than general sessions for broader stakeholders. However, we intend to run engagement webinars on our work for broader stakeholders in November. We have also kept our distribution list updated on relevant consultations and our upcoming engagement.

Offshore coordination

There is a need for all parties to work collaboratively and at pace to enable Great Britain to achieve its offshore wind targets and net zero ambition at least cost to consumers and with least impact on communities and the environment. Our stakeholders have a vital role to play in shaping and progressing the work required for a more coordinated approach offshore.

Over the last six months, we have worked closely with the stakeholders involved in the project workstreams – including BEIS, Ofgem, the onshore TOs, offshore project developers, The Crown Estate and Crown Estate Scotland, and other partners of the Offshore Transmission Network Review (OTNR) – to seek views and inform our approach. For the stakeholder groups who have been less actively engaged through OTNR channels, such as DNOs and OFTOs, we have attended forums to share progress updates, signpost relevant information and understand how they wish to be engaged in future.

Within the Early Opportunities workstream, we have been working closely with developers that have proposed coordination opportunities to understand their proposals, and assess their potential benefits and the challenges that need to be overcome, such as code or process changes. This detail was documented in a high-level summary, which was shared with our internal experts, the onshore TOs, The Crown Estate and Crown Estate Scotland, and informed Ofgem's early summer consultation on Early Opportunities, Pathway to 2030 and Multipurpose interconnectors.

Within the Pathway to 2030 workstream, we held the first of our monthly formal Central Design Group (CDG) meeting on 20 July 2021 and the group has met monthly since then. The purpose of this group is to act as a vehicle for the ESO to consult with the onshore TOs on the new Holistic Network Design (HND), and to consult with stakeholder groups as the HND is developed. We have also commenced monthly meetings for a commercial subgroup (whose role is to advise on the commercial impacts and interactions of the HND output) and a stakeholder and communications subgroup (whose role is to ensure coordinated engagement across different stakeholder groups and ensure feedback shapes the HND). Throughout the summer we have also engaged with offshore project developers and other interested stakeholders to keep them informed of progress. This includes publishing an open letter during September[85] to update offshore project developers and wider industry on the potential impact of the new approach in relation to Early Opportunities, Pathway to 2030 and Enduring Regime workstreams within the OTNR.

On 22 July 2021, we presented at the OTNR summer webinar to update industry stakeholders on our progress post completion of Phase 1 and specifically in the last quarter. This was attended by almost 350 delegates, with over 90 questions raised and answered by the ESO and the other OTNR partners.

[85] https://www.nationalgrideso.com/document/211251/download

C.4 Demonstration of Plan Benefits for Role 3

The fourth evaluation criterion for the ESO incentive scheme is Demonstration of Plan Benefits, where the Performance Panel will consider the actual benefits the ESO has realised from delivering its Business Plan, or any outputs additional to the Business Plan.

At the time of publishing our original RIIO-2 Business Plan in December 2019, we also published a Cost-Benefit Analysis (CBA) document to set out the expected consumer benefit of the activities in the RIIO-2 Business Plan. The relevant CBAs for Role 3 are:

- Network Options Assessment (NOA) enhancements (A7-A11)
- Taking a whole electricity system approach to connections (A14)
- Taking a whole electricity system approach to promote zero carbon operability (A15)
- Delivering consumer benefits from improved network access planning (A16)

In this section, we provide a progress update for each of the activities for which we originally provided a Cost-Benefit Analysis, setting out the progress of our deliverables, any relevant metrics and Regularly Reported Evidence, and describing any sensitivity factors which would impact on the delivery of the stated benefit[86]

We also provide a specific case study to quantify the benefit of the Loss of Mains changes, which was not covered by the original Cost-Benefit Analysis document.

The Panel will also consider the ESO's Regularly Reported Evidence (RRE) as part of the Demonstration of Plan Benefits criterion. The different RREs are reported either monthly, quarterly or every six-months in line with the ESORI guidance. For Role 3, the items of RRE reported at mid-year are:

- 3A. Future Savings from Operability Solutions
- 3B. Consumer Value from the NOA
- 3C. Diversity of Technologies Considered in NOA

[86] On 10 November we revised the percentages of completed deliverables. We had previously rounded some of the percentages, but have now reported them more accurately for improved clarity.

CBA: Network Options Assessment (NOA) enhancements (A7-A11)

Benefit described in RIIO-2 business plan

"The net-present value of our A8 - A11 NOA enhancements activities is £663 million over the RIIO-2 period and £1.3 billion over ten years. Sensitivity analysis suggests an NPV range of £463 million to £906 million over the RIIO-2 period.

Our proposed investment in extra resources will enable us to support at least twice as many tenders. It will ensure (parties who may submit an option) receive a quality service that encourages them to participate, offer and deliver competitive solutions. Solutions that will ensure we have a network that is always ready for the demands placed on it and can operate securely as we transition to a zero carbon electricity system. The £429 million gross benefit has been calculated by comparing the outputs of the NOA process with and without commercial solutions added in. We have used historic costs of previous commercial solutions as the benchmark for our analysis. This is against a baseline assumption of the current NOA process, without commercial solutions and only current network solutions considered, in line with our licence conditions."

Role

3. System insight, planning and network development

ESO Ambitions

- An electricity system that can operate carbon free
- A whole system strategy that supports net zero by 2050
- Competition Everywhere

Key RIIO-2 Deliverables and progress

Activity A7.1 - Analyse and communicate future network needs

Deliverable	Status
D7.1 Electricity Ten Year Statement (ETYS)	29% complete, 14% delayed 43% not due to start yet, 14% on track

Activity A7.2 - Advise on economic efficient ways to address networks needs

Deliverable	Status
D7.2 NOA Annual Report	33.5% complete, 0% delayed 50% not due to start yet, 16.5% on track

Activity A7.3 - Undertake ad hoc analysis in response to external requests

Deliverable	Status
D7.3 Strategic Wider Works (SWW) (or Large Onshore Transmission Projects (LOTI) for RIIO-2) projects, Connections and Infrastructure Options Note (CION) and Cost Benefit Analysis (CBA) for small schemes.	50% complete, 0% delayed 50% not due to start yet, 0% on track

Activity A8.1 - Rollout of pathfinder approach and optimise assessment and communication of future needs

Deliverable	Status
D8.1 New areas of need identified, and 3-6 tenders run.	10% complete, 0% delayed 40% not due to start yet, 50% on track

Activity A8.2 - Enhance tendering models

Deliverable	Status
D8.2 Improved tender approaches that enable more participants to enter the market.	Not due to start yet,

Activity A8.3 - Support Ofgem to establish enabling regulatory and funding frameworks

Deliverable	Status
D8.3 Frameworks based on competitive regime not monopoly regime.	33% complete, 0% delayed 0% not due to start yet, 67% on track

Activity A9.1 - Expand network planning processes to enable more connections wider works to be assessed

Deliverable	Status
D9.1 Developed and trialled connection wider works (CWW) processes with TOs.	0% complete, 33% delayed 67% not due to start yet, 0% on track

Activity A9.2 - Trial assessment of all connection wider works in one region

Deliverable	Status
D9.2 Completed and published connection wider works trials, in selected geographic regions, in NOA.	0% complete, 50% delayed 50% not due to start yet, 0% on track

Activity A9.3 - Expand to all Connections Wider Works (CWW)

Deliverable	Status
D9.3 Incremental expansion of the process (following trials) which results in making recommendations on all connections wider works in NOA 2026.	Not due to start yet

Activity A9.4 - Develop process with TOs to input into ESO analysis of end of life asset replacement decisions

Deliverable	Status
D9.4 Efficient planning process agreed with TOs	Not due to start yet

Activity A10.1 - Support DNOs to develop NOA type assessment processes

Deliverable	Status
D10.1 NOA expertise shared with DNOs	25% complete, 0% delayed 50% not due to start yet, 25% on track

Activity A11.1 - Refresh and integrate economic assessment tools to support future network modelling needs

Deliverable	Status
D11.1 Improved identification of when is the most economical time to invest and the most efficient solution	25% complete, 0% delayed 50% not due to start yet, 25% on track

Activity A11.2 - Implement probabilistic modelling

Deliverable	Status
D11.2 Improved identification of network needs	25% complete, 25% delayed 50% not due to start yet, 0% on track

Activity A11.3 - Build voltage assessment techniques into an optimisation tool

Deliverable	Status
D11.3 Improved assessment of voltage requirements, and ability to look across a range of network needs at the same time	0% complete, 0% delayed 80% not due to start yet, 20% on track

Activity A11.4 - Build stability assessment techniques into an optimisation tool

Deliverable	Status
D11.4 Improved assessment of stability requirements across the network.	0% complete, 40% delayed 60% not due to start yet, 0% on track

Related metrics/ Regularly Reported Evidence

Metrics/ RRE	Status
Metric 2A Competitive Procurement	59% of all services procured through competitive means (meeting expectations)
RRE 3A Future savings from operability solutions	£27m saved balancing costs in 2021-22, £13m saved infrastructure costs for each of RDPs 1 and 2, carbon reductions of £66m from pathfinders (2020-21 to 2024-25) and £28m from RDPs
RRE 3B Consumer Value from the NOA	£58m from ad-hoc CBAs, NOA consumer benefit to be calculated for End of Year report
RRE 3C Diversity of Technologies Considered in NOA	137 asset-based solutions (including 22 new options) and 9 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders.

We would expect enhancements to the NOA to lead to a higher consumer benefit being reported under RRE 3A (for Pathfinders) and RRE 3B (for other NOA processes). As we remove barriers to entry for pathfinders, we would also expect to report greater diversity of technologies under RRE 3C.

As we introduce more competitive processes, we would expect to report a higher percentage of competitive procurement under metric 2A.

Sensitivity factors

Over the last 6 months we have been working closely with our colleagues on the OTNR. A key deliverable of this work is the holistic network design (HND) which shares similar goals to the NOA. Alignment in terms of the methodology and messaging across both workstreams has been the focus of our attention as we prioritise the work needed to meet the 2030 government targets. The consumer value created by the work on the HND will far outweigh the benefit of other deliverables we have committed to and therefore we have prioritised this work above them. As a result, work on deliverable D9.1 has been pushed back to start in Q4 2021-22.

Assumption	Current status	Commentary
Facilitate competition by embedding pathfinding projects into the NOA		
Generic intertrip solution cost	Generic intertrip solution costs are broadly in line with expected costs.	Consumer benefit expected to be in line with original assumptions
Commercial solutions provide 1000MW from FY24 onwards	Procured total of 1.7GW capacity usable from FY23 onwards with more to follow.	Consumer benefit expected to be in line with original assumptions
Extending NOA to end of life asset replacement decisions		
TOs provide asset replacement data	This activity is planned to start later in the BP1 period	No update: benefit still as expected
Greater information provision will help the decision-making process	This activity is planned to start later in the BP1 period	No update: benefit still as expected
Extend NOA approach to all connections wider works		
TO will complete additional work through studying more boundaries and creating more options	This activity is planned to start later in the BP1 period	No update: benefit still as expected
We will find issues on the newly-created boundaries. We may find no issues, resulting in no benefits because no actions would be needed	This activity is planned to start later in the BP1 period	No update: benefit still as expected
Support decision making for investment at the distribution level		
Expected level of investment at the 132kV level is £40 million per year	This activity is planned to start later in the BP1 period	No update: benefit still as expected
60% of investment options would be on the optimal path	Based on latest NOA data this remains accurate	Consumer benefit expected to be in line with original assumptions
DNOs can take commercial actions against network costs	This assumption is still considered appropriate	Consumer benefit expected to be in line with original assumptions

Summary

Our deliverables are generally proceeding to plan, and we would therefore expect to deliver the consumer benefits originally set out. We will provide an update on NOA consumer value in RRE 3B as part of the end of year report.

We have now included activities listed under A7 in this report. Originally these activities were not included in the CBA for the business plan however we believe that it is relevant to include A7 activities as they also contribute to enhancements to the NOA and help remove barriers to entry.

We described the benefits of implementing commercial solutions in *Table 107: Benefits for Facilitate competition by embedding pathfinding projects into the NOA* in our ESO RIIO-2 Business Plan Annex 2 Cost-Benefit Analysis Report in January 2020. The total benefit reported of £429m across the RIIO2 period was based on NOA 2018-19 data. We undertake the NOA process each year which provides an updated set of investment recommendations using the latest Future Energy Scenarios. We believe it is therefore important to review the data previously presented and compare it with the latest NOA outputs. As we are currently undertaking NOA 2021/22 analysis we will report the latest commercial solution benefits in the end of year report and provide an update on our progress towards them.

The boundary B6 Constraint Management Pathfinder is providing the commercial solution referenced in the CBA annex by tendering for generating plants to be intertripped to increase the power transfer across the Anglo-Scottish boundary. Currently, the pathfinder is at the procurement stage with the commercial tender closing on 1 October. About 7.5GW of Scottish generation expressed an interest to fulfil the ESO's requirement of 800MW. The pathfinder was unable to provide consumer savings in FY 2021-22 for two reasons:

1) we focused our efforts on ensuring we deliver the right product that will maximise consumer benefit

2) there is insufficient lead time to develop and commission an extended intertrip scheme in conjunction with the TO.

The B6 Constraint Management Pathfinder is expected to award contracts in December 2021 that will take effect from October 2023. We therefore expect to realise consumer benefit from commercial solutions in FY 2023-24. In the meantime, the ESO is planning to approach parties already connected to the intertrip scheme and (if economical to do so), contract with existing providers who can already provide this capability. We are using our experience in developing this pathfinder and are considering expanding the approach to other constrained regions to alleviate network constraints and hence deliver additional consumer value. The remaining benefits from activities A9 to A11 have yet to start, hence there are no further updates to report at this stage.

CBA: Taking a whole electricity system approach to connections (A14)

Benefit described in RIIO-2 business plan

"We estimate the gross benefits to be £8 million over RIIO-2. This gives a net present value of £2 million over RIIO-2. Our proposal enhances and extends our current connections processes. It establishes new online systems to provide more support in coordination with distribution network organisations for parties wishing to connect to networks. They will benefit from easier access to front-line support and coordinated information, making it simpler to navigate around complex industry processes. These quantitative benefits have been calculated by considering the efficiency savings for customers who use the connections process (estimated at around 450 applications per year) and the resulting reduction in FTE requirements, with these savings being passed on to consumers. This is against a baseline assumption of continuing with our ongoing connections process, with no additional online support or connections hub. In order to deliver this activity, we will require customers to engage with the new hub and systems and that connections customers pass any reduced operational costs onto consumers. Our analysis suggests that accounting for market, delivery and third-party uncertainty the net present value could credibly be between -£2 million and +£3 million."

Role

3. System insight, planning and network development

ESO Ambitions

- Competition Everywhere
- The ESO is a Trusted Partner

Key RIIO-2 Deliverables and progress

Activity A14.1 - Provide contractual expertise and management of connection contracts including provision of connection offers to customers

Deliverable	Status
D14.1.1 Managing an increasing volume of connection offers for customers	Continuous activity
D14.1.2 Compliance monitoring of new connections in accordance with Grid Code provisions	Continuous activity

Activity A14.3 - Further enhance the customer connection experience, including broader support for smaller parties

Deliverable	Status
D14.3.1 Establish dedicated Distributed Energy Resource (DER) account management function	25% complete, 25% delayed 50% not due to start yet, 0% on track

Activity A14.4 - Facilitate development of the customer connections hub

Deliverable	Status
D14.4.1 Implement first phase of the ESO connections hub, including online account management and integration with other network organisation websites	25% complete, 0% delayed 62.5% not due to start yet, 12.5% on track
D14.4.2 Phase 2 of the connections hub concluded	Not due to start yet,

Related metrics/ Regularly Reported Evidence

N/A

Sensitivity factors

Assumption	Current status	Commentary
The number of connection applications grows 8 per cent per year	Recent data shows a much higher rate of growth of 40-47% (comparing latest 6 months in 2021 with 2020)	Consumer benefit expected to be higher than original assumptions
Roll out of our secure online account management (Customer Portal) facility in April 2025 brings a 30% cost saving	Progressing as planned; 1st User Acceptance Testing (UAT) in Nov 21	Consumer benefit expected to be in line with original assumptions
Information across the transmission distribution interface will reduce our direct resource requirements by 10% from 2022	Progress linked to Customer Portal	Consumer benefit expected to be in line with original assumptions

Summary

We are experiencing delays in activity A14.3, however we are generally on track to deliver the benefits originally set out, as our deliverables are progressing to plan to complete the first phase of the release of the Customer Portal by April 2022, with the first User Acceptance Testing (UAT) with customers planned for November 2021. Feedback from the UAT could have an impact to the target delivery date, depending on the amount of change or amendments required, however the focus will be on ensuring target delivery dates are achieved.

The assumptions we had originally made regarding the increase in customer connections applications have increased from an average growth of 8% to over 40% in the last six months. However, this has no impact on delivering the overall benefit. The increase in workload is helping discussions with TOs to look at strategies to improve the SO/TO relationship and management of offers.

We are also engaging with TOs to provide early visibility of the trends in the increase in the applications, identify peaks of workload and define strategies that address peaks, ability to meet licence conditions whilst ensuring that the quality of the connection customer offer is not compromised. We are also currently undertaking a review of the connections process to identify any process improvements which enable improvement of the customer experience and increase the team’s flexibility.

CBA: Taking a whole energy system approach to promote zero carbon operability (A15)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits in this area to be £548 million over RIIO-2. This gives a net present value of £466 million over RIIO-2. This is from quantifying benefits in two areas, RDPs and conducting a whole system operability NOA-type assessment. Regional Development Programmes (RDPs) RDPs provide significant value in this area. For future RDPs, we have assumed they deliver the same benefit from avoiding build costs as the RDPs in RIIO 1. This is £13 million and the carbon savings from the extra renewable generation of 278 MW. We have avoided 'double counting' by assuming half the RDPs have avoided build savings with the other half achieving carbon savings. This is against a baseline assumption of operating the system as today and not embedding RDPs. This gives gross benefits of £39 million over RIIO-2. More broadly, our responsibilities for system operability mean that we need to ensure we are looking for new ways of sourcing system needs. Increasingly we are considering market-based solutions and in a decentralised and digitalised future this provides many new opportunities. Examples of this work include Power Potential, where we are working with UK Power Networks to develop a coordinated market solution for transmission and distribution voltage needs. We are also exploring new markets through our voltage and stability pathfinder projects. Whole system operability NOA-type assessment The quantitative benefits for this area have been calculated by first considering the EFCC innovation, which forecasts benefits of £420 million over the RIIO-2 period. This gives a benchmark as to the scale of the benefits we could find in whole system operability. As EFCC provides a single aspect of system operability this CBA looks more generally at how system operability can be improved. This is by considering the cost of the current operability challenges, of around £600 million. As an example, in our recent stability pathfinder we estimate that these challenges could be solved with an investment of £2.25 billion. We further assume that this cost will be spread over a potential 40-year asset life, which leads to a discounted net benefit of around £10 billion over 40 years. To reflect the uncertainty here, we have assumed that 50 per cent of these net benefits are realised, giving £125.5 million a year net benefits from 2022/23, which equates to £503 million over RIIO-2. This is commensurate with the EFCC benchmark. Our work in this area depends on two other transformational activities: • A1 Control Centre architecture and systems (Theme 1) – ensuing the Control Centre has the tools required to operate a zero carbon system • A4 Build the future balancing service and wholesale markets (Theme 2) - ensuing the new markets have been developed to support zero carbon system operation In order to deliver in this area, we require third parties to deliver solutions, which could either be investment in assets or commercial solutions. Our analysis suggests that accounting for market, delivery and third-party uncertainty the net present value could credibly be between £331 million and £603 million."
Role	3. System insight, planning and network development
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • Competition Everywhere

Key RIIO-2 Deliverables and progress

A1.1.Ongoing activities

Deliverable	Status
D1.1.6 Assessment of future operability challenges communicated through the Operability Strategy Report	Continuous activity

Activity A4.6 - New services market development

Deliverable	Status
D4.6.1 Development of competitive approaches to procurement of stability	11% complete, 11% delayed 22% not due to start yet, 56% on track
D4.6.2 Development of competitive approaches to procurement of reactive power	0% complete, 0% delayed 43% not due to start yet, 57% on track

Activity A15.1 - Develop the System Operability Framework (SOF) and provide solutions up to real time of network related operability issues.

Deliverable	Status
D15.1.1 System Operability Framework (SOF) documentation	100% on track
D15.1.2 Innovation projects developing new operability solutions	100% on track

Activity A15.3 - Assess the technical implications of framework developments and implement changes into business procedures and systems.

Deliverable	Status
D15.3.2 Lead the Loss of Mains Protection setting programme	100% on track

Activity A15.5 - Develop Regional Development Programmes (RDPs)

Deliverable	Status
D15.11.1 Forward Plan 2020-21 RDP – N3	Delayed
D15.11.2 Forward Plan 2020-21 RDP - Generation Export Management Scheme (GEMS)	0% complete, 0% delayed 67% not due to start yet, 33% on track
D15.5.1 Start RDP1 of RIIO-2	25% complete, 0% delayed 50% not due to start yet, 25% on track
D15.5.2 Start RDP2 of RIIO-2	60% complete, 0% delayed 20% not due to start yet, 20% on track
D15.5.3 Start RDP3 of RIIO-2	0% complete, 17% delayed 83% not due to start yet, 0% on track
D15.5.4 Start RDP4 of RIIO-2[87]	0% complete,

[87] Percentages revised on 9 Nov 2021 due to calculation error.

	0% delayed 75% not due to start yet, 25% on track
D15.5.5 Development of roadmap to deliver GB rollout of functionality (visibility & control of DER) developed through initial RDPs.	0% complete, 0% delayed 50% not due to start yet, 50% on track

Activity A15.7 - Deliver an operable zero carbon system by 2025

Deliverable	Status
D15.7.1 Commence System State Targeted Monitoring and Control System (MCS) stage roll out[88]	12.5% complete, 12.5% delayed 62.5% not due to start yet, 12.5% on track

Activity A15.9 - Identify Future operability needs across whole energy system

Deliverable	Status
D15.9.1 Trial new innovation projects for whole energy system operability	100% on track

Related metrics/ Regularly Reported Evidence

Metrics/ RRE	Status
Metric 1A Balancing Costs	£966m vs benchmark of £562 (Below expectations)
Metric 2A Competitive Procurement	59% of all services procured through competitive means (meeting expectations)
RRE 1I Security of supply	0 reportable voltage / frequency excursions
RRE 1F Zero Carbon Operability indicator	Maximum proportion of 84.6% zero carbon transmission connected generation that the system can accommodate
RRE 1G Carbon intensity of ESO actions	Monthly average of 4.2gCO2/kWh of actions taken by the ESO
Metric 2A Competitive Procurement	59% of all services procured through competitive means (meeting expectations)
RRE 2B Diversity of service providers	Varying diversity across different markets – see RRE section for details
RRE 3A Future Savings from Operability Solutions	£27m saved balancing costs in 2021-22, £13m saved infrastructure costs for each of RDPs 1 and 2, carbon reductions of £66m from pathfinders (2020-21 to 2024-25) and £28m from RDPs
RRE 3C Diversity of technologies considered in NOA processes	137 asset-based solutions (including 22 new options) and 9 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders

Progress on Whole System Operability will lead to savings in balancing costs- leading to improvements in RRE 3A (in the short term) which will then flow through to improvements in Metric 1A (in the long term). It will also lead to increased competition for operability needs, which will lead to improvements in metric 2A. Where these activities lead to operability needs being provided by different technologies, this will lead to improvements in RREs 2B and 3C. Successfully addressing operability needs should enable us avoid voltage excursions, avoiding a deterioration in performance for RRE 1I.

[88] Note that the MCS project builds on the EFCC project referred to above. This is also linked to investment 500 ”Zero Carbon Operability”.

	Progress on Regional Development Programmes will lead to savings in infrastructure costs, which will be reported under RRE 3A (in the short term), and flow through to lower transmission and distribution network charges in the future. Progress on Regional Development Programmes and operability solutions will both lead to carbon reductions. This will be reported under RRE 3A (in the short term). This will also make it easier to operate a low carbon system, leading to improvements in RREs 1F and 1G as the ESO will be able to operate the system with a high proportion of renewable generation, without taking actions for operability reasons which lead to increased carbon emissions.
Sensitivity factors	Whole system operability NOA type assessment

Assumption	Current status	Commentary
Forecast operability costs of £596 million per year	Current operability costs are lower than forecast ~£410m in 2020/21	Operability challenges are expected to increase year on year due to the changing system conditions.
Cost of a 0.2 gigavolt ampere (GVA) solution is £25 million (£125m/GVA)	In the Phase 1 Stability Pathfinder, 12.5 GVA of additional inertia was procured for a cost of £328m (£26.4m/GVA).	Operability solutions are cheaper than anticipated, leading to a higher consumer benefit.
Solutions last 40 years	This is still current as per the Network Options Assessment methodology from July 2021[89].	Consumer benefit expected to be in line with original assumptions

Benefits of RDPs

Assumption	Current status	Commentary
Value of RDP avoided asset build is £12.9 million	This is still our most recent assessment	Consumer benefit expected to be in line with original assumptions
Additional renewable capacity unlocked by each RDP is 278 MW	RRE 3A states the following DER capacities have been unlocked by each RDP: WPD MW dispatch: 1242MW UKPN MW dispatch: 458MW	This suggests that each RDP unlocks on average 850MW, leading to a higher consumer benefit.
Carbon intensity assumption from FES 2019 Steady Progression	Carbon intensity from FES 2021 Steady Progression are between 20 and 50g CO_2/kWh lower	This reduces the estimated benefit from £7m to £4.5m. It would be offset by any increase to the carbon price (see below).
Six RDPs will be delivered over the RIIO-2 period	This is still our intention	Consumer benefit expected to be in line with original assumptions

[89] https://www.nationalgrideso.com/document/204196/download

BEIS short-term traded carbon values	In line with assumptions[90]	See footnote

General

Assumption	Current status	Commentary
Third parties contribute to asset/commercial solutions	We are working collaboratively with third parties to ensure delivery ahead of system need.	Consumer benefit expected to be in line with original assumptions

Summary

For RDPs, we are on track to deliver the benefits originally set out, as our deliverables are due to deliver ahead of system need, and the assumptions we had originally made have not materially changed.

For the Whole system operability NOA type assessment, our projects are on track, and we anticipate delivering a similar benefit to that originally set out.

[90] BEIS has not provided an update to its carbon prices for modelling purposes. It has, however, updated its carbon prices for policy appraisal. For 2020 to 2030, these are between three and 20 times larger than the previous values. If similar updates to the modelling figures are updated, it will significantly increase the estimated benefit from our RDPs.

CBA: Delivering consumer benefits from improved network access planning (A16)

Benefit described in RIIO-2 business plan	"We estimate the gross benefits to be £224 million over RIIO-2. This gives a net present value of £204 million over RIIO-2. Our proposal will bring significant benefits. For example, transmission and distribution connected parties will receive better notification of planned outages and their impacts on the networks. DNOs, meanwhile, will benefit from increased liaison, including greater procurement and coordination of flexibility services from DER. The quantitative benefits stated above have been calculated by taking the benefits realised though rolling this proposal out through Scotland then extrapolating that the percentage savings across England and Wales. This saving has been calculated at 11.5 per cent. Taking these percentage savings, we then used forecast constraint costs from NOA for England and Wales to estimate the consumer benefits. Further benefits could potentially be derived from extension of Network Access Planning (NAP) process across transmission and distribution. This is against a baseline assumption of not rolling out the STC cost recovery mechanism to England and Wales. This activity requires code modifications and financial arrangements to be in place to support it. We also require DNOs and TOs to engage with the new process, for which there may be a cost to implement the new arrangements. Our analysis suggested that accounting for market, delivery and third-party uncertainty the net present value could credibly be between £310 million and £98 million."
Role	3. System insight, planning and network development
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050 • Competition Everywhere
Key RIIO-2 Deliverables and progress	See below

Key RIIO-2 Deliverables and progress

Activity A16.1 - Manage access to the system to enable the TOs to undertake work on their assets, liaising with customers where access arrangements impact them.

Deliverable	Status
D16.1.2 Detailed week and day ahead operational documentation produced for National Control	Continuous activity

Activity A16.2 - Enhance the Network Access Policy (NAP) process with TOs

Deliverable	Status
D16.2.1 GB wide NAP process goes live including extension of the existing SO-TO payment mechanism to the whole of GB.	33.5% complete, 0% delayed 16.5% not due to start yet, 50% on track

Activity A16.3 - Work more closely with DNOs and DER to facilitate network access

Deliverable	Status
D16.3.1 Conclude trials on closer working relationships with DNOs and DER	67% complete, 0% delayed 0% not due to start yet, 33% on track
D16.3.2 Learnings from trials shared alongside recommendations for GB roll out such that best practice is applied to ongoing processes	0% complete, 0% delayed 33% not due to start yet,

	67% on track
D16.3.3 Finalise new processes in readiness for approval of code modifications to facilitate closer working relationships and data exchange/modelling. This will ensure that frameworks support any new enduring processes developed in A16.3.1 and A16.3.2	Not started
D16.3.4 Deeper access planning go-live	25% complete, 0% delayed 50% not due to start yet, 25% on track

Activity A16.4 - TOGA / Whole system outage notification

Deliverable	**Status**
D16.4.1 Scoping exercise concluded for delivery of enhancements to outage notifications	33% complete, 0% delayed 67% not due to start yet, 0% on track

Related metrics/ Regularly Reported Evidence

Metrics/ RRE	**Status**
Metric 1A Balancing Costs	£966m vs benchmark of £562 (Below expectations)
RRE 1H Constraints Cost Savings from Collaboration with TOs	£499m

RRE 1H is expected to improve because more than four enhanced service provisions from TOs through STCP 11.4 have progressed that are expected to provide constraint cost savings this year.

We expect this to lead to lower constraint costs than would otherwise be the case, which will have an impact on metric 1A.

Sensitivity factors

The ability of the DNOs to resource the activities required for enhanced data transfer should be noted as a sensitivity. DNOs are at varying levels of maturity with their engagement with DSO transition and deeper access engagement. The progress with the trial DNOs is showing positive results but draft code modifications are not due to take place until 2022-23.

The TOs’ ongoing engagement with the enhancements to the Network Access Planning (NAP) policy is a sensitivity but has been shown to be positive to date.

Assumption	Current status	Commentary
The same proportion (between 7% and 16%) of benefits could be realised in England and Wales as has been seen in Scotland	An equivalent proportion of benefits have not yet been realised. However, with the scheme in its infancy in England and Wales and with proposals being made regularly, the expectation is that this will be improved by year end.	Consumer benefit expected to be in line with original assumptions
England and Wales constraint costs of average £380m per year over the RIIO-2 period	Constraint costs during 2020-21 were £1070m	Consumer benefit expected to be higher than original assumptions
Code modifications and financial arrangements are in place	Code modifications have been made to the STCP.	Consumer benefit expected to be line

		with original assumptions
DNOs and TOs engage with the new process	Engagement levels vary across the DNO areas. However, some DNO areas show very high levels of engagement which is allowing us to progress trial and proof of concept. Engagement levels with TOs with STCP modifications is high across the board	Consumer benefit expected in line with original assumptions

Summary

We are on track to deliver the forecasted benefits given the progress of our deliverables and Regularly Reported Evidence (RRE).

The NAP team has made very good progress this year, the team in collaboration with our stakeholders (TOs and DNOs) identified and recorded over 82 instances where its actions directly resulted in adding value to end consumers and its innovative ways of working facilitated increased generation capacity to connected customers.

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

The improvement of the BAU activities around D16.4.1 coupled with the progress made with A16.3 are still expected to realise the consumer saving of £224m.

Consumer benefit case study for Role 3: seeing the impact of Loss of Mains changes

Activity

Loss of Mains protection is used to ensure that embedded generation is deenergised if it loses its connection to the transmission system. This ensures that embedded generation does not form power islands with local demand. This protection is required to be installed at all embedded generation sites in Great Britain, with the majority of plant fitted with either a Vector Shift (VS) protection function or Rate of Change of Frequency (RoCoF) protection function.

The reduced system inertia means that the type and settings of Loss of Mains protection that were previously appropriate, are becoming too sensitive. This could result in a large volume of embedded generation being disconnected unnecessarily, which would subsequently cause or exacerbate a frequency excursion. This problem has become increasingly prominent as the capacity of embedded generation has been increasing.

Since September 2019, the ESO has been working with Distribution Network Operators (DNOs), generators and the Energy Networks Association on the Accelerated Loss of Mains Change Programme (ALoMCP), which is offering funding for distributed generation owners to update their protection settings.

Before the programme began, the ESO did not have a clear view of the volumes of generation which had each type of protection, and therefore had to take a conservative approach to operating the system.

As the programme has progressed, it has delivered two objectives: replacing sensitive protection with protection with appropriate settings; and providing an improved view of the type and settings of Loss of Mains protection used across Great Britain's embedded generation fleet.

So far, generators have indicated that the protection settings have been changed for more than 10GW of generation capacity: this is currently being verified by DNOs. Meanwhile, a statistical approach is being used to estimate the reduction in generation capacity at risk of tripping, to take account of this data. The table below sets out the changes to protection settings which have been achieved via the programme.

	Total risk reduced up to April 2021	Total risk reduced up to Sep 2021
Generation capacity with VS protection	6,148 MW	7,073 MW
Generation capacity with RoCoF protection settings of at least 0.125Hz/s and below 0.2Hz/s	198 MW	260 MW
Generation capacity with RoCoF protection settings of at least 0.2Hz/s and below 0.5Hz/s	183 MW	326 MW

The improved knowledge of the type and settings of the Loss of Mains protection across the embedded generation fleet has allowed ESO to refine its assumptions and to update its models. This facilitates a better understanding of the risks that the network is exposed to if certain faults were to occur, and ensures that the actions taken to secure these faults are both proportionate and effective. Over time our view of the situation prior to the start of the ALoMCP has changed, the table below illustrates this.

	Situation before start of ALoMCP, as estimated at various points in time:		
	Estimate as at August 2019 (prior to start of ALoMCP)	Estimate as at April 2021	Estimate as at Sep 2021
Generation capacity with VS protection	12,510 MW	12,510 MW	18,217 MW
Generation capacity with RoCoF protection settings of at least 0.125Hz/s and below 0.2Hz/s	1,714 MW	1,183 MW	985 MW
Generation capacity with RoCoF protection settings of at least 0.2Hz/s and below 0.5Hz/s	1,286 MW	1,093 MW	1,036 MW

Even though we have revised our estimate of the generation capacity with VS protection from 12,510 MW to 18,217 MW, this does not mean that there was more risk than we had originally assumed, as we have been calibrating our estimates of the generation capacity against the volume that has tripped in particular situations. It simply means that, compared to our original view, there are in fact more relays which need to be changed, to completely eliminate the issue.

The combination of the risk reduction achieved through changing the protection relays/settings and improved knowledge means that our estimate of risk exposure has changed significantly.

The table below reflects the position today, taking into account our latest view of the situation pre-ALoMCP, and the changes we have made. The table looks at:

- Total Generation Capacity: how much generation of each type exists
- Peak risk: the maximum amount of generation of this type we expect to be generating at the same time
- Risk prevailing 50% of the time: for 50% of the time, the volume of generation of this type which is generating, is less than this amount.

	MW	Pre ALoMCP	Apr 2021	Sep 2021
Generation tripping for VS events	Total generation capacity	12510	7696	11143
	Peak risk	1197	504	626
	Risk prevailing 50% of the time	354	250	283
Generation tripping for RoCoF of at least 0.125Hz/s and below 0.2Hz/s	Total generation capacity	1714	991	725
	Peak risk	755	549	403
	Risk prevailing 50% of the time	349	246	175
Generation tripping for RoCoF of at least 0.2Hz/s and below 0.5Hz/s	Total generation capacity	1286	931	710
	Peak risk	566	472	370
	Risk prevailing 50% of the time	262	192	155

	The changes in the real time risk have allowed the ESO to change its operational policies over time, leading to benefits for consumers: • Since August 2020, the real-time Vector Shift risk has been lower than the RoCoF trigger level, meaning that it is only necessary to consider the RoCoF trigger level when assessing operational risk, and we no longer need to synchronise additional generation units to secure against Vector Shift events, saving consumers approximately £20m/annum. Since this change was made, relay changes to address Vector Shift risk will not deliver a cost saving, but they will improve system resilience. • The reduction in the RoCoF risk through the ALoMCP is one of three key factors, along with the introduction of Dynamic Containment (DC) and SQSS modification GSR027, which has allowed us to transform our policies and approach to managing frequency through the Frequency Risk and Control Report (FRCR). These changes have allowed us to set an expected level of both cost and risk on the system, and to target our balancing spend on good value-for-money actions. The reduction in our targeted actions is expected to be significant, from 7.4TWh per year before these changes to just 0.2TWh per year afterwards. • The sum of the peak real time risk for the two most critical RoCoF settings is now 773MW (403MW + 370 MW): a significant reduction from previous figures. This means that: o the volume of DC required to cover the RoCoF loss is now lower than it was in April: there is now sufficient DC capability to cover that loss o there is now an opportunity to evaluate and optimise our frequency response procurement strategy
ESO Ambitions	• An electricity system that can operate carbon free • A whole system strategy that supports net zero by 2050
Key RIIO-2 Deliverables	D15.3.2 Lead the Loss of Mains Protection setting programme
Is the consumer benefit mainly this year or in future years?	Today's consumers are already benefitting from the changes which have been made so far. Future consumers will continue to benefit from these changes, in addition to further changes that will be made to Loss of Mains protection settings ahead of the deadline in September 2022.
Calculation of monetary benefit to consumers	The projected short-term reduction in Vector Shift (VS) risk achieved through the Loss of Mains protection changes that the programme is making has meant that since August 2020 the ESO no longer takes actions to increase the system inertia. The ESO was previously spending up to £20m per annum on these actions, this has now dropped to zero. This figure is calculated by taking historic balancing costs from 2019-20 and applying them to today's policies. The changes to RoCoF relays are the enabler for policy changes as part of the FRCR, which allow us to set an expected level of both cost and risk on the system, and to target our balancing spend on good value-for-money actions. The reduction in our targeted actions is expected to be significant, from 7.4TWh per year before these changes to just 0.2TWh per year afterwards. However, it is difficult to calculate the financial saving associated with this, because the changes in balancing costs over this period of time have been driven by a range of factors.

Assumptions made in calculating monetary benefit	• Savings are based on the levels quoted in the 2021 Frequency Risk and Control Report • Further savings associated with the declining RoCoF risk could not be quantified as − There is currently no baseline to benchmark them against, especially as the DC service volumes available were, until recently, not sufficient to cover the RoCoF risk. − Further efficiencies will be unlocked following a review of how we procure different frequency response services
How benefit is realised in the consumer bill	The Loss of Mains changes have resulted in lower spending on inertia, and lower spending on constraining the largest loss. In the short term we have increased spending on frequency response, however this is expected to drop in the future as further changes are made. This will lead to lower balancing costs and therefore lower BSUoS charges.
Non-monetary benefits	**Improved safety and reliability:** the changes to protection settings and improved knowledge should reduce the risk of a significant change in frequency following a large generation loss or transmission fault, leading to improved system resilience and reliability of supply. **Reduced environmental damage:** the Loss of Mains changes allow us to operate the network with a higher proportion of renewable generation. **Improved quality of service:** we have engaged extensively both directly and indirectly with embedded generators, DNOs, equipment manufacturers and trade bodies to raise awareness of the LoM issue, and encourage embedded generators to apply for funding to update their settings ahead of the 1 September 2022 deadline required by the Distribution Code. The project has improved the quality of the data held about embedded generation, for both ESO and the DNOs.

Regularly Reported Evidence for Role 3

Table 21: Summary of RREs for Role 3

RRE	Title	Performance	
3A	Future savings from Operability Solutions	i) Saved balancing costs	Estimated £27m (2021-22)
		ii) Saved infrastructure costs	Estimated £13m (RDP avoided asset build)
		iii) Monetised carbon reductions:	Pathfinders: Estimated £66m (2020-21 to 2024-25). RDPs: Estimated £28m (2021-22 to 2025-26)
3B	Consumer Value from the NOA	£57.7m from ad-hoc CBAs, NOA consumer benefit to be calculated for End of Year report	
3C	Diversity of Technologies considered in NOA	137 asset-based solutions (including 22 new options) and 9 commercial solutions submitted to NOA 2021/22. A wide range of solutions were considered in NOA pathfinders.	

RRE 3A Future savings from Operability Solutions

April - September 2021-22 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 22: 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**

Supporting information

Stability Pathfinder Phase 1 and Mersey Voltage Pathfinder

We have implemented commercial service contracts under Stability Pathfinder phase 1 and the second year of the Mersey Voltage Pathfinder, and as a result, we have estimated balancing cost savings of £8.6m and £12.6m respectively for 2021-22.

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 6 years contract length, and Mersey Voltage contract was awarded in May 2020 with 9 years contract length. Both give estimated saving figures for 2021-22.

In the last 6 months, we have also made progress on the Pennine Voltage Pathfinder, Stability Pathfinder phase 2 (Scotland) and Stability Pathfinder phase 3 (England and Wales). The relevant balancing cost savings resulting from these will be reported in the End of Year report.

Loss of Mains programme

The Loss of Mains protection change programme has progressed well. So far, over 12.9GW of generation at over 7000 sites have now applied to the programme, with changes already made at sites with a combined capacity of over 10GW. With the addition of generators contacted and known to have achieved compliance, this takes the total engaged to 18.8GW, or 72% of the total generation capacity that is within scope. These changes have already impacted on Balancing Costs and give an estimated saving of £6m for 2021-22.

Method of calculating benefits

For the above three projects (Stability Pathfinder 1, Mersey Voltage Pathfinder, 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 solution 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[91]. 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 Year 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 more than 10 years to build. In order to ensure the optimal outcome for consumers, ESO is undertaking an enhanced operability assessment will explore an operational solution to connect this generation without the need for reinforcement works, which if successful will lead to savings in infrastructure costs. This will be updated in the End of Year report when the assessment outcome is concluded.

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	3.9
Carbon price (RIIO-2 CBA)	£/tCO2e	15.3	15.8	16.6	n/a
Savings	**£m**	**20**	**20**	**22**	**62**

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

Supporting information

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	TOTAL
CCGT generation output avoided in MW	MW	220	220	440
CCGT generation output avoided in GWh (220 nights at 8 hours per night)	GWh	387	387	774
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	n/a
CO2 in tonnes	tCO2	152,557	152,557	305,114
Carbon price (RIIO-2 CBA)	£/tCO2e	14.0	14.7	n/a
Savings[92]	**£m**	**2.1**	**2.2**	**4.4**

[92] 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

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.

An update of the calculations provided in the 2020-21 Mid-Year Report shows that the contract was enacted on 202 out of 334 nights studied: this is 60% of the time. When extrapolated to a full year, this gives the assumption that the contract is used 220 times over a year.

As above, we have used these figures to calculate the MWh of CCGT generation avoided. We have used 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.

Long-Term Mersey Pathfinder

There are no monetised carbon reductions for Mersey Long-Term Pathfinder for the period 1 April 2022 to 31 March 2031. The alternative to running the tender would have been TO build of a similar asset to that which was procured.

b) RDPs

Table 23: Carbon savings calculation for UKPN

UKPN	Unit	2021-22	2022-23	2023-24	2024-25	2025-26	TOTAL
Additional capacity connecting per year	MW	144	35	229	-	50	458
Cumulative additional capacity	MW	144	179	408	408	458	458
Additional capacity in GWh (8760 hours / year and Load factor of 40%)	GWh	504	627	1,430	1,430	1,605	5,597
Carbon intensity 'Steady Progression' (FES 21)	gCO2/kWh	111.9	88.4	89.1	88.1	85.6	n/a
CO2 in tonnes	tCO2	56,403	55,427	127,385	126,041	137,323	502,580
Carbon price (RIIO-2 CBA)	£/tCO2e	14.7	15.3	15.8	16.6	19.2	n/a
Savings	**£m**	**0.8**	**0.8**	**2.0**	**2.1**	**2.6**	**8.4**

[93] https://github.com/carbon-intensity/methodology/raw/master/Carbon%20Intensity%20Forecast%20Methodology.pdf
[94] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/794188/2018-short-term-traded-carbon-values-for-modelling-purposes.pdf

Table 24: Carbon savings calculation for WPD

WPD	Unit	2021-22	2022-23	2023-24	2024-25	2025-26	TOTAL
Additional capacity connecting per year	MW	157	364	286	151	283	1,242
Cumulative additional capacity	MW	157	522	807	958	1,242	1,242
Additional capacity in GWh (8760 hours / year and Load factor of 40%)	GWh	551	1,828	2,829	3,358	4,351	12,916
Carbon intensity 'Steady Progression' (FES 21)	gCO2/kWh	111.9	88.4	89.1	88.1	85.6	n/a
CO2 in tonnes	tCO2	61,596	161,616	251,912	295,909	372,233	1,143,267
Carbon price (RIIO-2 CBA)	£/tCO2e	14.7	15.3	15.8	16.6	19.2	n/a
Savings	**£m**	**0.9**	**2.5**	**4.0**	**4.9**	**7.2**	**19.4**

Supporting information

We have facilitated the connection of additional DER with visibility and control to the ESO via MW dispatch RDPs with UKPN and WPD. Carbon calculations are based on the volume of connecting and connected zero carbon DER in RDP areas, which it is assumed would displace other generation. Connected DER will be incorporated into the initial MW dispatch service in 2022.

RRE 3B Consumer Value from the NOA

April - September 2021-22 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 carries out considerable activities on behalf of the TOs and other stakeholders to ensure maximum value for the consumer.

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

This year's NOA analysis will commence imminently but will not conclude in this reporting window and therefore the NOA consumer value cannot be reported at this time. However, below we provide an update on the improvements made to the NOA process and the work done in the last 6 months that adds value for the consumer.

Supporting information

NOA Methodology improvements

For the NOA this year we have changed the way we assess outage requirements for NOA options, based on our experience with congested parts of the electricity transmission network. This means our recommendations will use a more realistic set of assumptions in relation to outages providing a more robust set of NOA recommendations hence supporting value for end consumers.

The Least Worst Weighted Regret (LWWR) process has been tested in NOA 2020/21 to support the NOA Committee in its scrutiny of marginal or sensitive NOA options. LWWR enables an exploration of the effect of changing the probability of each of the Future Energy Scenarios occurring, and is used to help in our decision making. LWWR gives confidence in our recommendations when a Least Worst Regret is marginal. This is now a permanent part of the process and ensures that NOA committee members can make well-informed decisions.

We currently consult on our proposed NOA methodology for six weeks starting in late spring each year, but our NOA methodology consultation process will be more flexible in the future to allow different parts to be consulted on at times that suit that process and stakeholders while meeting our C27 licence obligations. This will enable a more constant dialogue with our stakeholders, enabling the industry to have their say more easily. By improving the NOA methodology and its consultation process, we ensure we provide the consumer the maximum benefit from the NOA analysis.

Interested Persons' Process Improvements

A large improvement for the NOA 2021/22 methodology is the changes made to the NOA Interested Persons' process, based on our discussion with industry last year. 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.

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

Summary of results:

In the past six months, we conducted a total of four ad-hoc CBAs. By carrying out these assessments on behalf of the TOs, 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 £57 million.

We have calculated this saving by comparing our recommended option to the TOs' initial preferred option. In cases where there is no preferred option, we have used the difference between the worst and base case.

For example, the Bramford to Norwich circuit assessment has a consumer benefit of approximately £43 million. In this assessment, two options were considered. The TO's preferred option was not recommended as this would have cost at least £43 million more than the option we recommended.

Using this methodology, we recognise that the calculated consumer benefit for a CBA could be zero, if we recommend the option already favoured by the TO. However, we believe that in these circumstances our assessments still provide value as they reinforce the best investment option for the TO, ensuring the consumer is at the centre of investment decisions. However, it should be noted this cannot be reflected in the final consumer benefit value reported.

Illustrative example:

The following is a worked example using dummy data to illustrate our CBA methodology.

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 costly 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**

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**

Estimated consumer benefit from ad-hoc cost benefit analyses (CBAs)

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
Dinorwig to Pentir cable replacement programme	£400,000
Necton circuit assessment	£300,000
Bramford to Norwich circuit assessment	£43,000,000
Harker and Penwortham assessment	£14,000,000
Total	**£57,700,000**

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. This year, we have undertaken significant studies for all three TOs, to support them delivering the network capacity needed to enable the low-carbon transition. At this stage we cannot quantify the savings in terms of consumer benefit, however this will be possible once the projects are complete. Details of the specific schemes we have supported are:

- For all the TOs, we have worked extensively on the Final Needs Case for the first two Eastern HVDC links, as part of our continued work on the broader East Coast Strategy. These key links will provide around 4GW of capacity to transfer renewable electricity from Scotland to northern England, reducing constraints in a key part of the network from 2027 and 2029. Our independent and robust analysis is a detailed assessment of the suite of potential route options and timings, against the impact of the FES scenarios and other sensitivities. We compare the total capital cost of the schemes with the long run benefit the scheme provides in reducing constraints. Overall, we have demonstrated the benefit of delivering the required options on time saves the consumer hundreds of millions of pounds in avoided constraint costs.
- For NGET we have worked together to define the CBA for the Initial Needs Case for Yorkshire Green Energy Enablement project (a key onshore enabler for the Eastern Links) and undertaken detailed routing options studies for SEALink - a new HVDC route between Suffolk and Kent required to reinforce multiple network boundaries and to enable the connection of future generation and interconnectors off the East and South Coasts. 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.

- We have worked in close collaboration with SSEN Transmission to complete detailed analysis for the Initial Needs Cases for both Skye Reinforcement and the Argyll and Kintyre strategy. 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.
- 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 about 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.

Improvements to the Connections and Infrastructure Options Note (CION) process

The CION is the process the ESO follows to determine the most economic and efficient connection location for an individual offshore project (typically wind farms or interconnectors). In late 2020, BEIS and Ofgem initiated the Offshore Transmission Network Review (OTNR) to enable greater coordination in the connection of offshore projects.

It is not known at this point if the CION process will still exist (or perhaps be significantly changed) once the OTNR is complete, but one part of the OTNR is Pathway to 2030. In Pathway to 2030, a Holistic Network Design (HND) will be developed to connect a new group of offshore projects in a coordinated manner. Since this Pathway to 2030 process has captured most, if not all of the upcoming projects that would have otherwise required individual CIONs, no individual CIONs have been undertaken for those projects, and it is unclear if/when individual CIONs will resume.

For context, the consumer benefit calculated from CION process activities and reported in last year’s end of year report was greater than £900m.

Examples of Commercial Solutions proposed

Commercial solutions drive consumer value by providing an alternative to asset-based solutions. Currently, these take the form of intertrips (where we form an agreement with generation plant to alter their output if required) but in the future, there may be additional solutions. Commercial solutions are also highly useful as they can often be implemented more quickly than an asset can be built, meaning they can address the growth in network constraint costs sooner, saving consumers more money. It is however important to note that these solutions do not provide network resilience or help towards compliance with the SQSS. Commercial solutions should continue to be explored in a limited range of network conditions 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, these commercial solutions can be adapted more easily than asset-based solutions. We will be able to calculate the forecast consumer benefit from these customer solutions in the End of Year report.

RRE 3C Diversity of Technologies Considered in NOA

April - September 2021-22 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.

Where number and type of different solutions are not available because a NOA process has not occurred, we provide an update on actions we have taken over the preceding six-months to increase the pool of solutions.

We are currently in the process of conducting the NOA 2021-22 analysis. Following its completion at the end of this financial year, we will report on part iii above.

a) NOA

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

The table below shows the number of options submitted by participants in NOA 2021-22, 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.

Table 25: Options submitted by participants in NOA 2021-22

Technology Main Category	**Total Number** Submitted in NOA 21/22	Number that are **new** to NOA this year (included in total)
Circuit	111	20
Route modification	2	2
Transformers	3	-
Substation & switching	2	-
Flexible AC transmission system (FACTS)	19	-
New technology	0	-
Total asset-based solutions	**137**	**22**
Commercial solutions	9	1

Supporting information

Please note that the deliverables under activities A7 – A11 contribute to this consumer benefit as set out in the 'Consumer benefit from ad-hoc cost benefit analysis (CBA)' section.

b) NOA Pathfinders

	i) Express interest *(a count of how many expressions of interest)*	**ii) Are participants with NOA/NOA pathfinders** *(how many participated in the commercial tender)*	**iii) Are successful / receive contracts** *(how many contracts we awarded)*
Constraints management pathfinder	**TOTAL: 51** (7.4GW) Battery: **15** (1757.7MW) Hydro: **2** (2.6MW) Combined Heat and Power (CHP): **2** (12.7MW) Steam: **1** (15.4MW) Wind: **29** (4386MW) Combined Cycle Gas Turbine (CCGT): **2** (1.2GW) **Transmission / Distribution split:** Transmission-connected: **37** (7.0GW) Distribution-connected: **14** (331.4MW)	**TOTAL: 10** (1.7GW) Wind: **9** (1.7GW) Battery: **1** (50.0MW) The above is all connected to (or expecting to connect to) a Transmission breaker (132kV or 275kV or 400kV)	N/A
Stability phase 1	Synchronous: **104** Non-synchronous: **46** Hybrid: **6** Stability Pathfinder RFI feedback[95]	**46** bids were submitted by 11 different parties. TOs did not participate in the tender. Stability Phase 1 tender - results table[96]	**12 bids** were accepted from 5 parties
Stability phase 2	Synchronous machines: **514** Grid forming convertors: **723** Hybrid: **338**	N/A	N/A
Stability phase 3	Expression of interest window is currently open and will close on 22 October 2021.	One-stage tender window yet to open. This metric can be provided and confirmed in March 2022 following the tender submission deadline.	Not at this stage in the tender process. Phase 3 contracts will be awarded in 2022.
Voltage: Mersey	**40** Transmission connected solutions and **15** Distribution connected solutions	**40 bids** were submitted by 11 different parties. NGET were one party and offered 9 different solutions. Many different technology types connecting at different networks	2 successful contracts awarded
Voltage Pennine	**93** Transmission solutions[97] **13** Distribution solutions	**21** Participants including NGET	TBC

[95] https://www.nationalgrideso.com/document/185306/download
[96] https://www.nationalgrideso.com/document/185331/download
[97] On 10 November we revised the number of TO submission solutions, this was due to an error in calculation.

Supporting Information

The Pathfinders procurement strategy is deliberately technology neutral to ensure that innovative solutions that can demonstrate the ability to meet our requirements can participate in the tenders. The ESO has engaged with providers and the wider industry to help parties understand our technical requirements and evaluate whether potential solutions will be viable within the Pathfinder assessment and procurement process.

Value for money

Value for money

The ESO incentive arrangements for RIIO-2 include a new criterion, Value for Money. 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 and final numbers will be formally reported in the 2021-22 RRP which will be submitted to Ofgem in July 2022.

The reported spend to date 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 Cost and Outputs reporting. The ESO uses the methodology, as set out in the ESORI guidance, to allocate costs to each role.

The ESO's cost benchmark was set at £504.1m as part of the Final Determinations process. Final Determinations stated that Ofgem would consider adjusting the benchmark upwards following a future reassessment of the remaining £3.6m of uncertain capex, and £6.1m of other price control costs.

The £3.6m of uncertain capex relates to ENCC Capex (£2.0m) and Project TERRE (£1.6m), and the £6.1m relates to cyber security costs.

We have discussed with Ofgem, the need to revise the cost benchmark for the uncertain costs for future consideration as set out in final determinations. We have agreed to add £2.0m to the cost benchmark to include costs relating to upgrades and enhancements to the ENCC. Due to the uncertainties regarding the future use of the TERRE platform we have not updated the benchmark for the costs included in our original business plan.

We continue to discuss our evolving cyber security investments with Ofgem. In April 2021 we proposed a prioritised plan as part of the Cyber Reopener[98]; as part of this, some of the ESO-specific cyber investments were rephased and replanned based on engagement with Ofgem and we anticipate delivering against these commitments from Q4 2021-22 onwards. We are also developing an ESO-specific cyber strategy which will form the basis of our supplementary submission for Business Plan 2. We therefore do not consider it is appropriate to update the cost benchmark regarding cyber investment at this time.

The following table sets out the revised cost benchmark by role as well as our spend to date and forecast for the RIIO-2 BP1 period.

Role	Cost benchmark (£m)	Expenditure to date (up to end of September 2021) (£m)	Forecast expenditure for remainder of BP1 (£m)	Forecast total expenditure for BP1 (£m)	Forecast deviation from cost benchmark (%)
1	208.0	51.9	200.4	252.3	+21.3%
2	158.7	33.7	139.8	173.5	+9.3%
3	139.4	30.6	111.7	142.3	+2.1%
Total	506.1	116.2	451.9	568.1	+12.3%

[98] Note that ESO does not have a Cyber Reopener in the RIIO-2 period, but that ESO cyber investments have been reviewed as part of a wider co-ordinated programme of work which cover the requirements of all National Grid entities.

More detail about each role

Role 1 (Control centre operations) expenditure

For Role 1, we are currently forecasting to spend £44.3m more than the cost benchmark over the BP1 period. This is due to two main factors: increased balancing programme expenditure (accounting for an extra £44.6m of spend), and the new Market Monitoring activity resulting from the ESO's new market monitoring licence obligations, which were not included in the BP1 Delivery Schedule or cost benchmark (accounting for an extra £1.3m of spend). We provide more detail here about the main factors leading to the deviation from the benchmark.

Market Monitoring

Cost benchmark for BP1	£0m
Forecast expenditure over BP1	£1.3m

The ESO is covered by the "Person Professionally Arranging Transactions" (PPAT) under the EU Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) Regulations. In April 2021, Ofgem introduced a new Licence obligation for the ESO to proactively monitor activity in Balancing Services markets. This obligation results from the EU Regulation on Wholesale Energy Market Integrity and Transparency (REMIT), under which the ESO is a Person Professionally Arranging Transactions (PPAT).

The ESO has set up a new function to fulfil this requirement and recruited a small team of experienced staff to focus on developing tools and processes to fulfil our obligation. Within the new function, a high-level market monitoring strategy will be implemented, including automated tools, new policies, governance, processes and procedures, and communications with industry for increased awareness of monitoring. The cost is of this new function is forecast to be £1.3m.

Increased Balancing Programme expenditure

The Balancing Programme is a critical enabler to achieving the ESO's ambitions and in meeting the needs, wants and desires of our customers and stakeholders. The programme consists of several IT investment lines from the ESO's RIIO-2 Business Plan: Enhanced Balancing Capability (180), Balancing Asset Health (210), Forecasting Enhancements (260), and Ancillary Services Dispatch (480). We provide more detail about the overall programme here, and specific information about Enhanced Balancing Capability in the Amber Projects section below.

Cost benchmark for BP1	£28.1m
Forecast expenditure over BP1	£72.7m

The planned investments will provide increased tools and functionality to the Control Room, and will provide significant benefits to consumers. The Balancing Programme is responsible for maintaining the existing legacy balancing systems, making changes to the existing legacy environment to ensure that it is secure, stable and functions as required to meet changing market requirements, and also designing and developing the balancing systems of the future. A significant proportion of the Balancing Programme spend, and effort is, of course, focused on delivering future balancing capability. This future balancing work is held within project 180, Enhanced Balancing Capability, and was identified as a high-value project at the time of Final Determinations which Ofgem will track more closely due to the uncertainty of scope.

Since the cost benchmark was set in Final Determinations, there have been changes to the scope of the Balancing Programme. The changes to date are resulting in increased forecast costs (£44.6m higher than the cost benchmark for this activity within BP1). The £44.6m is broken down as follows:

- Future balancing – delivery of a Modern Dispatch Advisor (which was not included in the BP1 cost benchmark, and is currently forecast to cost £10.4m) and increase in costs to deliver future balancing capability (+£7.0m)

- Balancing (BM) Asset Health and Scheduling Enhancements (+£14.3m)
- Forecasting Enhancements (+£6.1m)
- Hosting of the Ancillary Services Dispatch Platform (+£6.8m)

Investment forecast against RIIO-2 BP1 benchmark (£m GBP 2018-19 pricing)

Investment (£m GBP)	RIIO-2 BP1 benchmark	Forecast for BP1	Explanation	Additional consumer benefit due to changes
Future balancing (180 Enhanced balancing capability)	20.3	37.7	**Modern Dispatch Advisor (BP1 forecast £10.4m):** Defining and implementing of one of the key modules within the Balancing Mechanism system, ahead of the implementation of the new systems. This follows successful proof of concept in 2020-21 and will deliver significant consumer value by reducing the cost of Balancing actions. The consumer value, which would be realised 3 years earlier than originally anticipated, is estimated as £12.6m per annum. **Enhanced Balancing Capability** (**BP1 forecast £27.3m**): For Future Balancing, we have completed the foundation stage and will have completed the blueprint stage at the end of October 2021. Through greater understanding of the transformation design required we are forecasting an increase in costs to deliver (£27.3m rather than £20.3m). However, the outcomes and consumer value remain significant and the business case to continue is robust and justified.	£12.6m per annum
Existing balancing (210 Balancing asset health)	2.8	17.1	**Balancing (BM) Asset Health and Scheduling Enhancements:** Balancing Asset Health maintains and delivers the enhancements for the control room on the systems which are currently in use (BM and EBS). The systems are updated incrementally to align with market developments: for example the scope of the Scheduling software (which provides plans for balancing actions to be taken, 8 hours ahead of real time) has been increased to deliver margin analysis for interconnectors and provide better optimisation of inertia alongside constraints and margin. These systems are also maintained regularly to ensure that they continue to be highly reliable. This will save the Control Room users 21k hours of manual work per annum and deliver consumer value of £14.5m per annum.	£14.5m per annum
260 Forecasting enhancements	0.5	6.6	**Forecasting Enhancements:** The costs of this activity have increased due to the increased complexity of required forecasting models. The forecast costs of implementing the new models into the live balancing systems has also increased due to a better understanding of our requirements. The	Ensures that benefits are realised and there is no consumer detriment

			consumer benefits of continuing with this work is £10m-20m per annum.	
480 Ancillary services dispatch	4.5	11.3	**Hosting Platform for Ancillary Services:** We are working through the potential requirement to make hosting and cyber security changes to ASDP. Should this not turn out to be a firm requirement then additional costs will not be required.	Improved cyber security
Total	28.1	72.7		

Role 2 (Market development and transactions) expenditure

For Role 2, we are currently expecting to spend £14.8m more than the cost benchmark over the BP1 period. This increase is primarily due to increased scope of several projects: Settlements, Charging and Billing, and Electricity Market Reform (EMR). We provide more detail here about the main factors leading to the deviation from the benchmark.

Settlements (+£4.0m)

Cost benchmark for BP1	£3.8m
Forecast expenditure over BP1	£7.8m

The Settlements system calculates payments for ancillary services provided to the ESO to operate the system. We are introducing a greater number of new services of varying complexities to meet the demand of an increase in industry participation and have identified consumer benefit from increasing the flexibility of the system to meet these needs. Creating a product that will be scalable and configurable will allow us to introduce new ancillary services to the market faster, and adapt existing services with far greater cost and time efficiency.

Over the next 5 years, this system replacement is expected to deliver consumer value through reduced ESO Totex spend.

Our forecast expenditure over the BP1 period is £4.0m more than set out in Final Determinations, principally due to the following reasons:

- **IT Delivery:** We have worked to confirm the high-level roadmap, timescales for delivery, appropriate resourcing models and greater clarity of costs to deliver a new solution. This will also see the utilisation of a shared platform between the new Settlements and Charging and Billing Replacement project, allowing greater efficiencies to be achieved, compared with the standalone replacement of each system.
- **Regulatory understanding**: Given this work, we have developed a greater understanding of the regulatory and market horizon and how the new system needs to adapt and fully support and accommodate the changing landscape. This will ensure we can settle the products and services of the future thus unlocking service provision from new providers.

Charging and billing (+£4.4m)

Cost benchmark for BP1	£3.0m
Forecast expenditure over BP1	£7.4m

The Charging and Billing (CAB) system manages the TNUoS, BSUoS and Connections charges. It generates invoices for market participants to pay these charges in accordance with the Charging and Connections methodology. We expect these charges to increase in complexity because of expected regulatory changes. We are therefore creating a sustainable and adaptable system that can more readily be reconfigured, allowing us to introduce new calculations quickly and at a lower cost to benefit consumers. It will provide an improved experience for our customers, as well as substantially increasing financial integrity with integrated controls.

Over the next 2 years, this system replacement will enable key regulatory charging reform, which will unlock material consumer value (including Fixed BSUoS and the Targeted Charging Reform (TCR) for TNUoS). and deliver consumer value through reduced ESO Totex spend. On a more enduring basis the system will provide the platform for wider reform, including change driven from the Access SCR and Market Wide Half Hourly Settlement.

Our forecast expenditure over the BP1 period is £4.4m more than set out in Final Determinations, principally due to the following additional scope:

- BP1 Final Determinations costs were based on re-engineering the existing system through major architectural changes, which is now not possible because the future complexity across the various revenue streams necessitates a scope which is not deliverable in the current system. The new system will be more robust and versatile helping ensure long-term value.
- Similarly, to the Settlements system, the cost benchmarks within Final Determinations were based on further progress of delivery of the enduring IT solution by the end of 2020-21, however, urgent regulatory changes were needed which took priority in 2020-21 and there was an impact from COVID-19. To ensure an optimal enduring solution, additional time was needed for solution selection, and this has resulted in work being carried forward into RIIO-2.

Electricity Market Reform (EMR) (+£9.8m)

Cost benchmark for BP1	£3.5m
Forecast expenditure over BP1	£13.3m

The ESO, as EMR Delivery Body, has an obligation to comply with the latest Ofgem and BEIS regulations to ensure compliant and effective management of the Capacity Market (CM) and Contracts for Difference (CfD) processes, including updating the IT platform to meet the latest rules and customer needs. As agreed with Ofgem, we are investing in a replacement system during 2021-22 and 2022-23 that will enhance the customer experience, whilst also ensuring that it can be updated quickly to implement new regulatory changes at an efficient cost.

Our forecast expenditure over the BP1 period is £9.8m more than set out in Final Determinations, principally due to the following additional scope:

- Development of the new EMR portal was pushed back from RIIO-1 into the RIIO-2 period. This development and investment was allowed for in RIIO-1, and not included in the RIIO-2 cost benchmark for BP1. In 2019-20 and 2020-21, The ESO was required to deliver a large volume of mandatory changes to the current EMR system to facilitate the restart of the Capacity Market following renewed State Aid approval, support customers through COVID-19, and implement regulatory changes required by BEIS and Ofgem. The ESO is returning unspent allowances for EMR through the RIIO-1 close-out process.
- Until the move to the replacement system is completed, the ESO must continue to invest in and support the current EMR portal in parallel with development of the new portal to ensure the current portal supports the ongoing delivery of CM and CfD processes, and remains compliant with regulatory changes required by BEIS and Ofgem.
- The volume of regulatory change for EMR in RIIO-2 is also greater than originally expected, including for CM auctions and agreement management as well as CfD Allocation Round 4.
- The EMR portal replacement is something our customers and stakeholders have been asking for and it will deliver significant improvements in user experience, flexibility and the speed of change.

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

For Role 3, we are currently expecting to spend £2.9m more than the cost benchmark over the BP1 period. This increase is primarily due to the ESO taking on new roles in Offshore Co-ordination and Early Competition. However, we are forecasting reduced IT expenditure in the Zero Carbon Operability and NOA projects. We provide more detail here about the main factors leading to the deviation from the benchmark.

Offshore co-ordination (+£4.5m)

Cost benchmark for BP1	£0.6m
Forecast expenditure over BP1	£5.1m

The ESO Offshore Coordination project has a key role in ensuring the government target of 40 GW of offshore wind by 2030 and net zero carbon emissions by 2050 are met. Although some Offshore Co-ordination activity, worth £0.6m was included in the original Delivery Schedule, this has since been superseded by a more significant piece of work.

We have worked closely with Ofgem to discuss the scope of our activity. Phase 2 of the project involves work across the Offshore Transmission Network Review (OTNR) workstreams plus supporting activities on internal strategy, policy input, stakeholder engagement and project management.

We forecast that this activity will cost £5.1m opex over the BP1 period, with a headcount of 36 Full Time Equivalents (FTEs). This is £4.5m more than was included in Final Determinations. In Final Determinations, we had only included the costs of 3 FTEs within the benchmark, as we were still working through the scope of the project with BEIS and Ofgem. Our current forecast is likely to increase further as the activity develops and future scope is defined.

Early Competition (+£2.3m)

Cost benchmark for BP1	£0m
Forecast expenditure over BP1	£2.3m

Early competition refers to competition that occurs prior to the detailed design, surveying and consenting phases of solution development. This means organisations could compete for the design, build and ownership of onshore transmission solutions. Early competition will help encourage new ways of working and aims to seek the best solutions at a fair cost for consumers. In April 2021, we submitted our Early Competition Plan to Ofgem, describing an end-to-end process of how early competition may work, proposing how models for early competition could be implemented and outlining the roles and responsibilities of all parties in the end-to-end process.

Due to the uncertainty of whether the ESO's Early Competition proposals would be implemented, no activities relating to Early Competition were included in the Delivery Schedule or cost benchmark for BP1. However, since submitting our Early Competition plan, we continue to progress low regret activities to maintain momentum whilst Ofgem decide whether to go ahead and implement Early Competition. This decision is expected in early 2022.

These low regret activities have been agreed with Ofgem and were included in Ofgem's update on Early Competition letter published in May 2021[99].

We forecast costs of £2.3m over the BP1 period. This includes spend for low regret activities, as well as for implementing the Early Competition proposals, which would require a ramping up of headcount for an internal team and further supporting consultancy spend.

Amber projects

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. These projects are Network Control, Enhanced Balancing Capability, Data and Analytics Platform, and Zero Carbon Operability. This follows on from Ofgem's assessment of ESO's IT projects, which is set out in Appendix 4 of Final Determinations[100].

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.

[99] https://www.ofgem.gov.uk/sites/default/files/docs/2021/05/early_competition_update_2021_0.pdf
[100] https://www.ofgem.gov.uk/system/files/docs/2021/02/final_determinations_-_eso_annex_revised.pdf

We are in-line with our investment benchmark of £9.0m for BP1 (£8.1m capex, £0.9m opex) and our RIIO-2 (2021-2026) investment plan of £30.0m (£27.0m capex, £3.0m opex).

We remain on target to deliver our milestones for the remainder of this financial year and into next. 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

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.

Our current investment forecast for BP1 is £37.7m which is higher than the Final Determinations position of £20.3m with the detail of the increase set out below. We have already completed the Foundation phase of the Balancing transformation programme. The foundation phase allowed us to better understand our customers, the Balancing Engineers – taking into account their needs, wants and desires for balancing capability. This facilitated design thinking, with the user, the Balancing Engineer, at the heart of what we deliver. So far, we have:

- Built a core team, adopted SAFe (Scaled Agile Framework) and embraced new ways of working to put the customer at the heart of the programme
- Used Design Thinking practices to understand pain points with existing user journeys and building Design principles for User experience,
- Captured existing balancing end to end business processes and created leaner, more flexible to-be business processes,
- Analysed and documented the component design of existing Balancing systems to understand the likely capabilities required in the future.
- Evaluated available state-of-the-art technologies and presented recommendations on which technologies would provide secure, high availability platforms to fulfil future business ambitions,
- To make these recommendations we built a proof of technology for the proposed technology choices, and delivered a high-level approach towards transformation.

During the Blueprint phase (completion at end of October 2021) we will have:

- Captured the personas and storyboards that enable the new way in which the Balancing Engineers will operate the system,
- Defined and prioritised requirements (epics and features) for the delivery backlog (which will be delivered against in the next phase which is called the Core phase),
- Built and agreed a functional roadmap for delivering the capabilities for the new Balancing platform,
- Defined the Application, Operational, Technical, Security and Performance architecture for the new Balancing platform and implement the architecture in the hosting environment,
- Specified the environments for prototype development and testing,
- Scoped the Core phase which will build the skeleton of the new Balancing system. This will provide the basic functionality of all the key components required for Balancing, upon which additional functionality can be added,
- Built a benefits realisation framework for tracking the value delivered by the Balancing programme,
- Further improved ways of working through involvement in the ESO's Ways of Working programme.

In addition, we plan to do the following during BP1:

- Implement into production, the new Modern Dispatch Advisor (MDA) that will replace the existing dispatch advisor 3 years earlier than anticipated within the RIIO2 business plan. Additional £10.4m in cost, which will deliver £12.6m consumer benefit per annum.
- Implement security changes to our hosting environments to accommodate MDA and Ancillary Services Dispatch Platform (ASDP)

The blueprint phase will give insights into complexity of delivering the solution. However, we will be reviewing the roadmap with the Technology Advisory Council (TAC) and obtaining their input before baselining the roadmap. During BP1, we are aiming to deliver the first application components of the new Balancing platform and continuing the agile delivery of the remaining scope. The deviation from the Final Determinations is driven by the following:

- Better understanding of the Transformation scope and therefore size of teams required to deliver it
- Cost of technologies required to deliver a modern Balancing platform that supports a decentralised and flexible functional architecture
- Cost of enabling the new CNI Data Centre for hosting the new Balancing platform
- Early replacement of the Dispatch Advice optimiser in the legacy Balancing Mechanism ahead of the new Balancing platform.

This supports the delivery of the following milestones:

- Role 1
    - A1.2 Enhanced Balancing Capability: D1.2.1

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.

Our current forecast is £12.1m which is £1.0m higher than the investment benchmark of £11.1m for BP1 (£8.9m capex, £2.2m opex) and our RIIO-2 (2021-2026) investment plan of £25.0m (£20.0m capex, £5.0m opex). 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

500 Zero Carbon Operability

Consistent with our proposal in Final Determinations, project 500 Zero Carbon Operability 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.

Our investment forecast for BP1 is £7.7m (totex) which is slightly below our investment benchmark of £10.2m for BP1 (£9.2m capex, £1.0m opex) and our RIIO-2 (2021-2026) investment plan of £24.9m (£22.4m capex, £2.5m opex). This supports the delivery of the following milestones:

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

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