national**grid**ESO

ESO Forward Plan 2020-21

Monthly Reporting: January

19 February 2021

Contents

Foreword

Welcome to our monthly performance report for January 2021. Each month, we report on a subset of metrics and performance indicators. This report provides an update on our monthly metrics, which are set out in the 2020-21 Forward Plan Addendum[1].

We report our progress against our deliverables on the Forward Plan tracker[2] which is updated monthly on our website. The Forward Plan tracker has been updated to take account of the revisions to deliverables set out in the Forward Plan Addendum.

Summary

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

- Supported the go-live of the IFA2 interconnector – This increases the amount of clean energy that can be shared between GB and France.
- Transmission Network Use of System (TNUoS) Final Tariffs published - In these Final Tariffs, we have applied our best view of the demand and generation forecast.
- Unlocked Balancing Mechanism (BM) Stacking in Dynamic Containment (DC) - This gives participants the ability to stack their revenue streams, with service providers able to tender for bids in both the BM and DC during the same periods.
- Power Potential technical trials - The Wave 2 commercial trials started successfully on Wednesday 6th January 2021.
- Accelerated Loss of Mains Change Programme (ALoMCP) update – By January 2021, 5994 sites, equating to 10.7GW of generation capacity have had their applications approved.
- Operability Strategy Report 2021 shared with industry – The report highlights the development and soft launch of DC, Power Potential projects, ALoMCP, and Distributed Restart.
- Network Options Assessment (NOA) 2021-22 published - NOA assessed a total of 171 options, of which 41 asset-based options are recommended to proceed. The NOA also recommends that four ESO-led commercial solutions proceed.
- Pennines Pathfinder update - A tender is expected to be published prior to the end of March 2021 which is expected to last up to 40 weeks, with an outcome no later than January 2022 for contract start in 2024.

Our performance is meeting expectations for balancing costs due to a significant reduction in constraint costs with the network more intact and relatively benign weather leading to less congestion on the Transmission system. The benchmarks for Energy Forecasting Accuracy and System Access Management were unfortunately not met. We did, however, meet our target for Right First Time Connection Offers. We exceeded expectations for Security of Supply and month-ahead BSUoS Forecasting.

[1] https://www.nationalgrideso.com/document/173131/download
[2] https://www.nationalgrideso.com/document/162046/download

A summary of our monthly metrics and performance indicators covering January is shown in Table 1 below.

Metric/Performance Indicator	Performance	Frequency	Status
Balancing Cost Management	£136.3m outturn against £133.2m benchmark	Monthly	●
Energy Forecasting Accuracy	Demand MMAE: 666MW; Wind MAPE: 6.99%	Monthly	●
Security of Supply	0 excursions for voltage and frequency	Monthly	●
System Access Management	2.56/1000 cancellations	Monthly	●
Month-ahead BSUoS Forecast	4% forecasting error	Monthly	●
Right First Time Connection Offers	96% first time connection offers	Monthly	●

Table 1: Summary of metrics and performance indicators

- ● **Exceeding expectations**
- ● **Meeting expectations**[3]
- ● **Below expectations**

You can find out about our vision, plans, deliverables and full metric suite in the Forward Plan pages of our website.[4].We welcome feedback on our performance reporting to box.soincentives.electricity@nationalgrideso.com

Gareth Davies

ESO Regulation Senior Manager

[3] We have updated the colour scheme for our metrics to give increased transparency of our performance, noting that meeting expectations still represents good performance. This should give a clearer representation of the status of our activities.

[4] https://www.nationalgrideso.com/our-strategy/forward-plan

Role 1 Control Centre operations

1A Balancing cost management

January 2021 Performance

The approach we use for measuring our Balancing Costs performance is based on a linear trend in a five year rolling mean, based on annual Balancing Services Costs (excluding Black Start). In order to meaningfully employ a linear trend, the data points need to handle one-off permanent changes to the system network which would not be captured by the five-year trend. So far, the only change modelled in this way has been the Western Link. We also make adjustments for significant events which we expect to have an impact on balancing costs, whether this is an upwards or downwards adjustment. These are trends which we would not expect to be captured in the 5-year rolling average, because they relate to either new assets or new trends in market behaviour. Additional information regarding balancing costs calculation and benchmark adjustment can be found on our website[5].

Low demand periods are challenging to manage, and the volume of actions required by the ESO to ensure the system remains secure lead to higher costs. During the period where demand is impacted by the COVID-19 pandemic, the ESO's balancing costs spend is expected to be significantly higher than the benchmarks stated here. During this period, we will continue to report our performance in comparison to the benchmark but will focus on providing a detailed narrative which explains the costs we have incurred. We also welcome Ofgem's review of costs incurred over the summer period and will be transparent with our stakeholders about the actions we have taken.

Please note that the benchmarks were re-calculated in July 2020 to remove the ElecLink adjustor since the interconnector go-live date has been delayed.

	Apr	May	Jun	Jul	Aug	Sep	Oct
Benchmark cost (£m)	67.0	48.2	82.6	65.5	102.0	103.7	126.9
Additional cost forecast due to WHVDC fault (£m)	0	0	0	0	0	0	0
Benchmark adjusted for WHVDC (£m)	67.0	48.2	82.6	65.5	102.0	103.7	126.9
Outturn cost (£m)	122.4	159.1	135.6	136.0	117.7	135.6	142.4
Status							

Table 2: Apr-Sep 2020 Monthly balancing cost benchmark and outturn.

	Nov	Dec	Jan	Feb	Mar	Total
Benchmark cost (£m)	82.8	126.6	133.2	142.5	118.3	1199.3
Additional cost forecast due to WHVDC fault (£m)	0	0	0	0	0	0
Benchmark adjusted for WHVDC (£m)	82.8	126.6	133.2	142.5	118.3	1199.3
Outturn cost (£m)	197.4	162.0	136.3			1444.5 [YTD]
Status						

Table 3: Oct-Mar 2020-21 Monthly balancing cost benchmark and outturn.

[5] https://www.nationalgrideso.com/document/166231/download

Supporting information

The balancing costs for January were lower than December and much closer to the benchmark. This was driven by a significant reduction in constraint costs; relatively benign weather and a more intact transmission network leading to less congestion on the Transmission system. The lower constraint costs were counteracted slightly by an increase in Energy costs; more specifically the cost of procuring operating reserve during tight margin periods during which the system prices were higher, especially on the tightest days.

Performance benchmarks

- **Exceeding expectations:** at least 10% lower than the figure implied by the benchmark.
- **Meeting expectations:** within 10% of the figure implied by the benchmark
- **Below expectations:** at least 10% higher than the figure implied by the benchmark.

1B Energy forecasting accuracy

January 2021 Demand Forecasting Performance

As outlined in the Forward Plan Role 1 Energy Forecasting Accuracy metric (Metric 1b), the ESO's forecasting performance will be assessed at the end of the performance year. Annual performance targets have been calculated with exceeding, in-line with and below expectations values set out. To allow transparency of our performance during the year, each month we will report an indicative performance for both metrics.

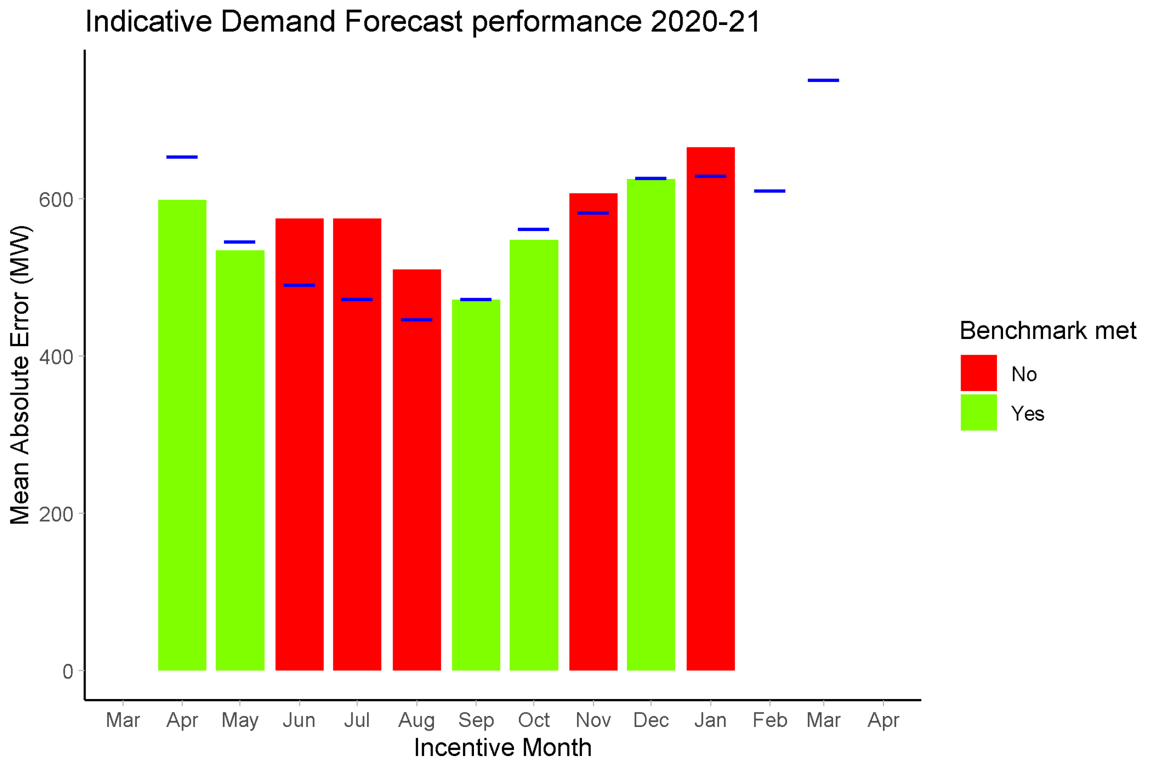

Figure 1: Demand Forecasting , shows our performance from April to October as the green histogram against the blue target line.

Day ahead demand forecast benchmarks for financial year 2020-21			
Month	**Benchmark (MW)**	**Month**	**Benchmark (MW)**
April	654	October	562
May	546	November	583
June	491	December	627
July	473	January	630
August	447	February	611
September	473	March	752

Table 4: Demand Forecasting Benchmarks

Supporting information

DA Demand Indicative Performance for November: 666MW

In January 2021, our day ahead demand forecast indicative performance was outside of the benchmark of 630MW. January’s MMAE (monthly mean average error) was 666MW, 36MW above the monthly target.

Demand forecasting in January was challenging due to several factors: the country moving into a third National lockdown shortly after the end of the Christmas and New Year holidays; the 2020/21 Triad season and cold weather with snow, impacting human behaviour as well as solar PV panel efficiency, making daytime cardinal point forecasts uncertain.

The Triads are the three half-hour settlement periods of highest demand on the GB electricity transmission system between November and February (inclusive) each year, separated by at least ten clear days.

Snow presents two issues for solar generation. The first one is when the snowfall starts and covers the panels, it acts like a blanket and obscures the access to the sunshine. Snowfall forecast is a subject to high levels of inaccuracy. The second difficulty is when the snow starts to melt and the panels start to generate again. ESO engaged with Sheffield Solar PV Live to discuss this topic and to establish if anything could be done to overcome the challenges presented by snowfall in relation to the solar generation forecast accuracy.

Across the month, the largest average absolute errors were observed during the afternoon peak, afternoon trough, darkness peak (DP) and late evening peak. The main contributing factor for the errors over the afternoon peak and trough was the performance of the solar generation forecast. The uncertainty in early January caused by the combination of the end of the school holidays followed very shortly by a third lockdown, in addition to the triad avoidance activity, was the main driver of the errors over DP and late evening peak.

January 2021 Wind Generation Performance

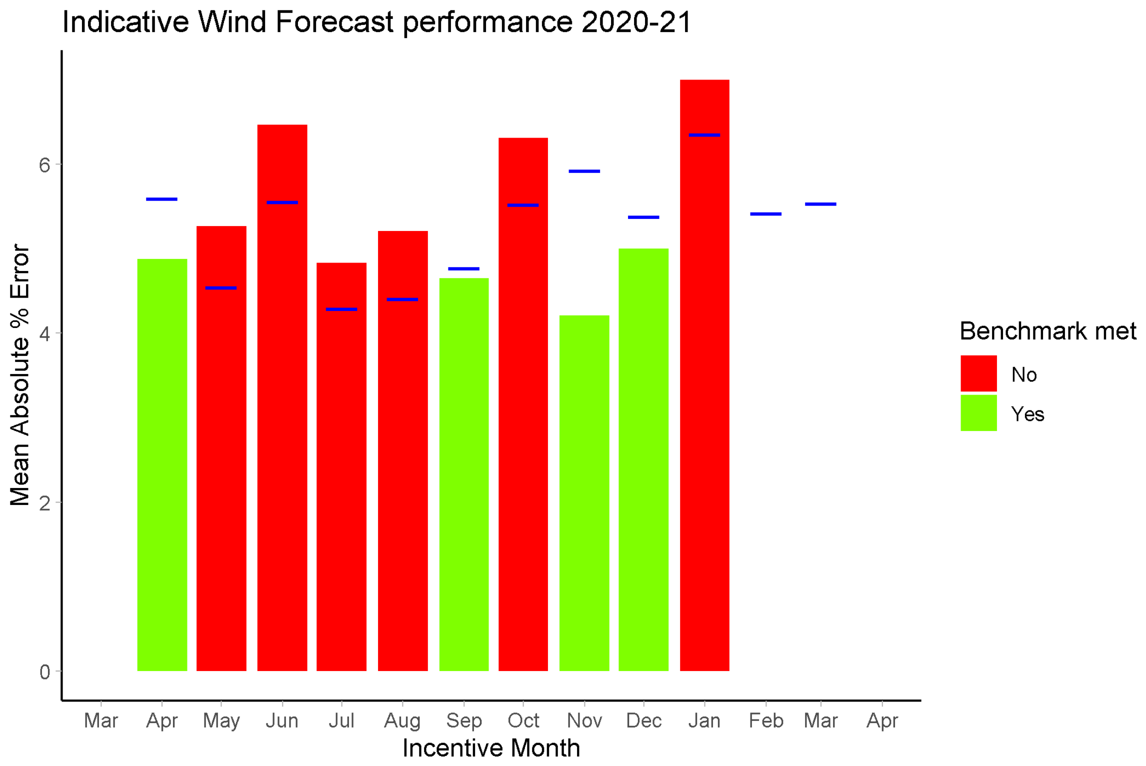

Figure 2 shows our performance this month as the green histogram, against the blue monthly target.

BMU wind generation forecast benchmarks for financial year 2020-21			
Month	**Benchmark (%)**	**Month**	**Benchmark (%)**
April	5.60	October	5.53
May	4.54	November	5.93
June	5.56	December	5.38
July	4.29	January	6.36
August	4.41	February	5.42
September	4.77	March	5.54

Table 5: Wind Forecasting Benchmarks

Supporting information

DA Wind Indicative Performance for November: 6.99%

In January 2021, our day ahead wind forecast indicative performance was outside of the MMAPE (monthly mean absolute percentage error) target of 6.38%. January's MAPE (mean average percentage error) achieved was 6.99%.

Significant errors coinciding, immediately preceding or after weather events mainly affected the second half of the month.

The low pressure weather front which passed over the UK on 13 & 14 January brought freezing rain and risk of ice on turbine blades. This effect can cause wind farm operators to stop their turbines for safety reasons, because of the possibility of large sheets of ice flying off the turbines: which can be dangerous to personnel and risks damage to assets. The ESO does not have visibility of the decision-making process followed by each wind farm operator, and the decision to stop turbines may depend on multiple factors. For example, for some turbines there is a heating element that heats up the blades, mitigating the effect of ice build-up.

On 20 & 21 January, Storm Christoph brought strong winds across the South, and a low pressure system which was deepened by the action of the Jet Stream. A few days later sleet, snow and windy conditions across Wales and central areas resulted in widespread snow cover across Wales and England. This is an indication of less predictable weather, and increases the chance of wind power forecast error.

Significant lightning activity coincided with some of the days when the forecasting errors were the greatest. As has been discussed in previous performance reports, lightning is a good indication of atmospheric instability, which is a cause of increased wind power forecast error.

There is no evidence of any negative electricity prices in the GB market during January. For the purposes of this report we examine historical electricity prices because negative electricity prices in the Day-Ahead market for a period of 6 hours or more will trigger a removal of subsidy from wind farms with CfD commercial arrangements. This in turn triggers these wind farms to reduce their output to zero for the duration of negative prices. Our wind power forecasting system does not take this into account, so these occasions can lead to very large wind power forecasting errors: but this issue did not arise in January.

Performance benchmarks

- **Exceeding expectations:** Error which is at least 5% lower than the benchmark
- **Meeting expectations:** Error which is within 5% of the benchmark
- **Below expectations:** Error which is at least 5% higher than the benchmark

1C Security of Supply

January 2021 Performance

Quality of service delivered in running the electricity network by providing the number of reportable voltage and frequency excursions that occurred during the previous month, and a total for the year to date.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Voltage excursions	0	0	0	0	0	0	0	0	0	0		
Frequency excursions	0	0	0	0	0	0	0	0	0	0		

Table 6: voltage and frequency excursions over 2020-21

Supporting information

There were no excursions on both voltage and frequency. Our performance was therefore exceeding expectations in January.

Performance benchmarks

- **Exceeding expectations:** 0 excursions for both voltage and frequency over 2020-21
- **Meeting expectations:** 1 excursion for either voltage or frequency over 2020-21
- **Below expectations:** More than 2 excursions in total over 2020-21

1D System Access Management

January 2021 Performance

Publishing this metric encourages the ESO to investigate the causes of outage cancellations and amend processes where appropriate to prevent a repeat. We will ensure that we seek to minimise costs across the whole system and all timescales when making a decision to recall or delay an outage on the transmission system.

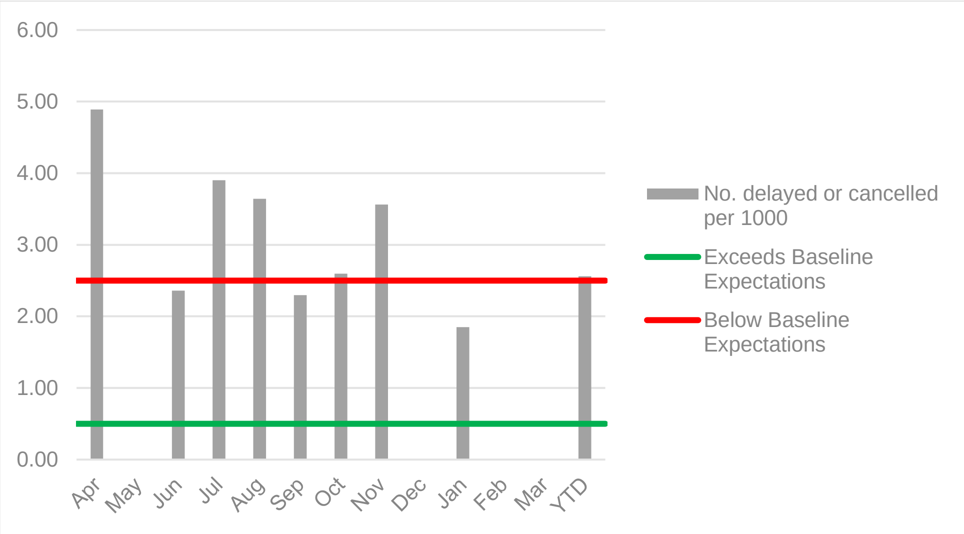

Figure 3: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Number of outages	Outages delayed/cancelled	Number of outages delayed or cancelled per 1000 outages
Apr	409	2	4.89
May	629	0	0
Jun	847	2	2.36
July	769	3	3.90
Aug	824	3	3.64
Sep	870	2	2.3
Oct	770	2	2.60
Nov	842	3	3.56
Dec	524	0	0
Jan	540	1	1.85
Feb			
YTD	7024	18	2.56

Table 7: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

Supporting information

For January, the number of delays or stoppages per 1000 outages has reduced further from 2.62 to 2.56, with one event occurring. This issue related to an outage booking for Transmission Owner (TO) works, which required an outage on both a 400kV circuit and a Supergrid Transformer (SGT). There were two outages due to be released, comprising of a 400kV circuit and a Supergrid Transformer (SGT). It was identified the day before the outages were to be released that these outages interacted with another planned outage, and would be very difficult to manage on two high power flow boundaries that had been overlooked. The only option to manage both boundaries was to constrain a significant amount of generation, and the control room reported that this would cause system margin issues. Therefore, the circuit was unable to be released. However, after communications with the TO, most of their planned activity related to work on the SGT, and the ESO was able to successfully release this outage to allow the work to go ahead. An Operational Learning Note (OLN) has been written highlighting the requirement of checking all boundaries that may be impacted by an outage, and putting further checks in place for potentially expensive outages.

Performance benchmarks

- **Exceeding expectations:** < 1 outage cancellations per 1,000 outages
- **Meeting expectations:** 1 - 2.5 outage cancellations per 1,000 outages
- **Below expectations:** > 2.5 outage cancellations per 1,000 outages

Notable events this month

IFA2 interconnector goes live

In January 2021 low carbon electricity started flowing at full capacity through IFA2. This is the second electricity interconnector linking the UK and France and is a joint venture between National Grid Ventures and French Transmission System Operator RTE. IFA2 increases the amount of clean energy that can be shared between the two countries. The first day of trading for the new interconnector, on 21 January, saw wholesale power traders buying up all the ‘day ahead’ capacity that was auctioned.

We supported IFA2 throughout go-live to ensure a smooth transition from commissioning to go-live for all parties. We assisted in ensuring all commissioning tests could be completed by IFA2, while also working to guarantee the security of supply. Whilst commissioning was underway, we continued to collaborate with NGIFA2 and RTE to ensure the IT systems and operational processes were enabled in order to send and receive communications with IFA2 and RTE, and to keep the market updated post go-live. Updates were also agreed and made to IFA2 documentation to reflect changes caused by Brexit.

Role 2 Market development and transactions

2E Month ahead forecast vs outturn monthly BSUoS

January 2021 Performance

BSUoS forecasts are important to our stakeholders, although we note that our ability to forecast BSUoS is impacted by factors outside of our control. BSUoS costs are factored into the wholesale price of energy charged by generators, and therefore a forecast is vital for those parties when working out where to price their generation.

As BSUoS costs can vary throughout the year, we report the percentage variance between our forecast and the outturn rather than the absolute variance. This metric does not just look explicitly at the volatility, but at the number of occurrences outside of a 10% and 20% band.

Month	Actual	Month-ahead Forecast	APE	APE>20%	APE<10%
April-20	4.77	3.69	23%	1	0
May-20	6.24	3.87	38%	1	0
June-20	5.17	7.18	39%	1	0
July-20	4.78	5.56	16%	0	0
Aug-20	4.18	5.61	34%	1	0
Sept-20	4.75	5.16	9%	0	1
Oct-20	4.27	4.24	1%	0	1
Nov-20	5.60	3.50	38%	1	0
Dec-20	4.16	3.97	5%	0	1
Jan-21	3.65	3.78	4%	0	1
Feb-21					
Mar-21					

Table 8: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

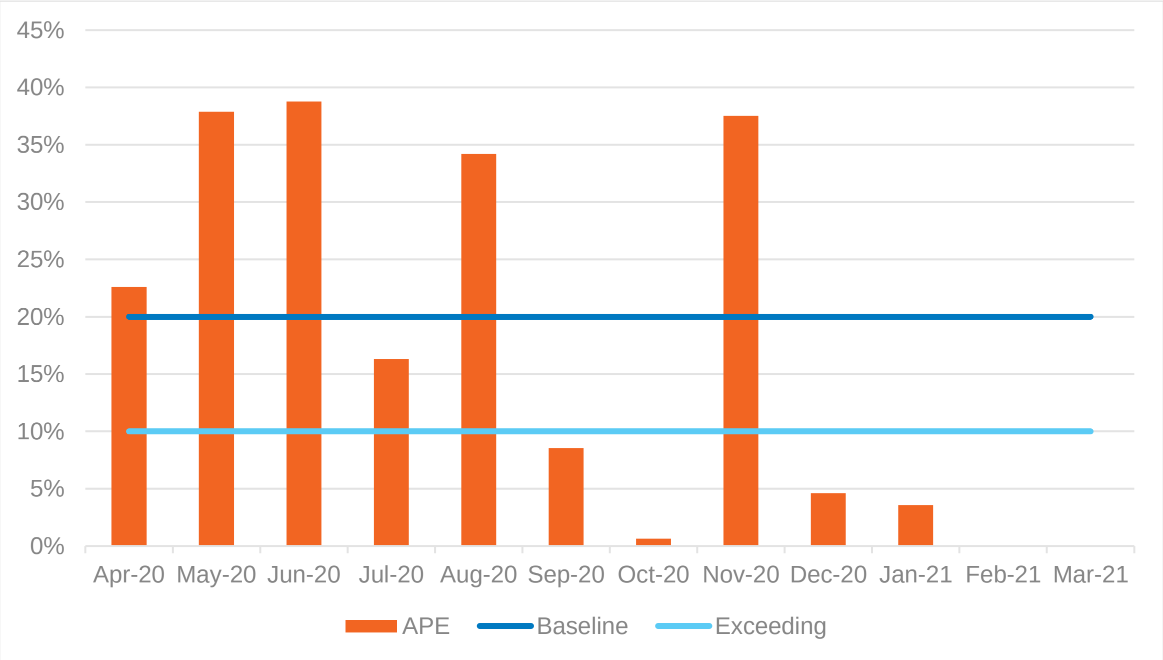

Figure 4: Monthly BSUoS forecasting performance

Supporting information

The outturn BSUoS costs for January were lower than December, driven by a reduction in constraint costs with the network more intact and less congestion on the system. However, the reduction in constraint costs was partially offset by an increase in the cost of operating reserve as tight margins drove prices up. Demand in January was also higher than December, despite the lockdown in January; this was due to the usual holiday demand suppression for Christmas which generally leads to lower demands in December than other winter months.

Our latest view of BSUoS can be found on our website[6].

Performance benchmarks

● **Exceeding expectations:** Less than 5 out of 12 monthly forecasts are above 20% Absolute Percentage Error, and 5 or more forecasts less than 10% Absolute Percentage Error

● **Meeting expectations:** Less than 5 out of 12 monthly forecasts are above 20% Absolute Percentage Error

● **Below expectations:** 5 or more out of 12 monthly forecasts above 20% Absolute Percentage Error

[6] https://data.nationalgrideso.com/balancing/bsuos-monthly-forecast

Notable events this month

Transmission Network Use of System (TNUoS) Final Tariffs published

On 30 January 2021 we published[7] the 2021-22 Final Tariffs for Transmission Network Use of System (TNUoS). This will be the first charging year in the new RIIO-2 price control period. In this report, the various parameters have been re-set in line with the CUSC (Connection and Use of System Code). We have also been closely monitoring the impact of COVID-19 on the transmission networks. In these Final Tariffs, we have applied our best view on the demand and generation forecast.

A number of regulatory changes have been implemented. Ofgem's decision on the Targeted Charging Review (TCR) affects TNUoS tariffs in two aspects, Transmission Generation Residual (TGR) and the Transmission Demand Residual (TDR). The TGR changes are to be implemented from April 2021 and affect generation residual tariffs, while the TDR changes are expected to be implemented from April 2022. As such, we have incorporated the decision of CMP317/327 for TGR in the Final Tariffs. In addition, we have also incorporated Ofgem's decisions on:

- CMP324/325 – Generation Rezoning
- CMP353 - Stabilising the Expansion Constant and non-specific Onshore Expansion Factors
- CMP355/356 – Updating the Indexation methodology for RIIO2.
- CMP357 – To improve accuracy of the Locational Security Factor

Total revenue to be collected is £3,318m based on Transmission Owners (TOs') and Offshore Transmission Owners (OFTOs') final submissions. It is an increase from 2020-21 but a decrease of £92m compared to the Draft Tariffs published on 30 November 2020. This is following Ofgem's Final Determination on the TOs' business plans.

Unlocking Balancing Mechanism (BM) Stacking in Dynamic Containment (DC)

As part of the continued development of the Dynamic Containment (DC) service through the soft launch, we are seeking to unlock stacking within the Balancing Mechanism (BM) as per our Wave 1 commitments[8]. We published a document[9] that outlined our plans to introduce this development and on 27 January 2021 we went live with the BM stacking alongside DC.

This gives participants the ability to stack their revenue streams, with service providers able to tender for bids in both the BM and DC during the same periods. From market engagement, we recognise the additional value that adding the ability to stack in the BM will offer and we anticipate this additional flexibility and revenue stacking will increase the efficiency of the assets delivering the service, increasing competition which would in turn reduce costs to consumers.

Given the crucial nature of the DC service, we have taken a cautious approach to implementing BM stacking. Those wishing to participate must ensure BM participation does not erode or compromise the ability to deliver Dynamic Containment.

We plan to include this capability for all new services that are introduced to the market, as we recognise the additional value that adding the ability to stack in the BM will offer.

Power Potential technical trials

Power Potential is currently running commercial market trials. The trials began on 6 January 2021 and we experienced some challenges which required implementing additional manual work in the first five weeks. By working in a trial environment we have been able to identify a number of learning points. UKPN found an error in the Distributed Energy Resources Management System (DERMS) so nomination was done manually from NGESO to UKPN, and this error was removed with the new software upgrade on 10 February 2021. The reliability of the end to end system was also lower than in the first period of the trials due to a loss of communication between the Platform for Ancillary

Services (PAS) and the DERMS system, and other reasons which we are continuing to investigate within DERMS.

The trials are ongoing and we will be sharing our final results in our Annual Progress Report on the Power Potential Project, which will be published at the end of April.

[7] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges
[8] https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/dynamic-containment
[9] https://www.nationalgrideso.com/document/184466/download

Role 3 System insight, planning and network development

3A Right First Time connection offers

January 2021 Performance

This metric measures whether the ESO aspects of connection offers were correct the first time they were sent out to customers.

Connections Offers	Results
Year to date number of connection offers	280
Year to date ESO related reoffers	12
Year to date percentage of Right First Time connections offers determined from ESO related reoffers	96%

Table 9: Connections re-offers data

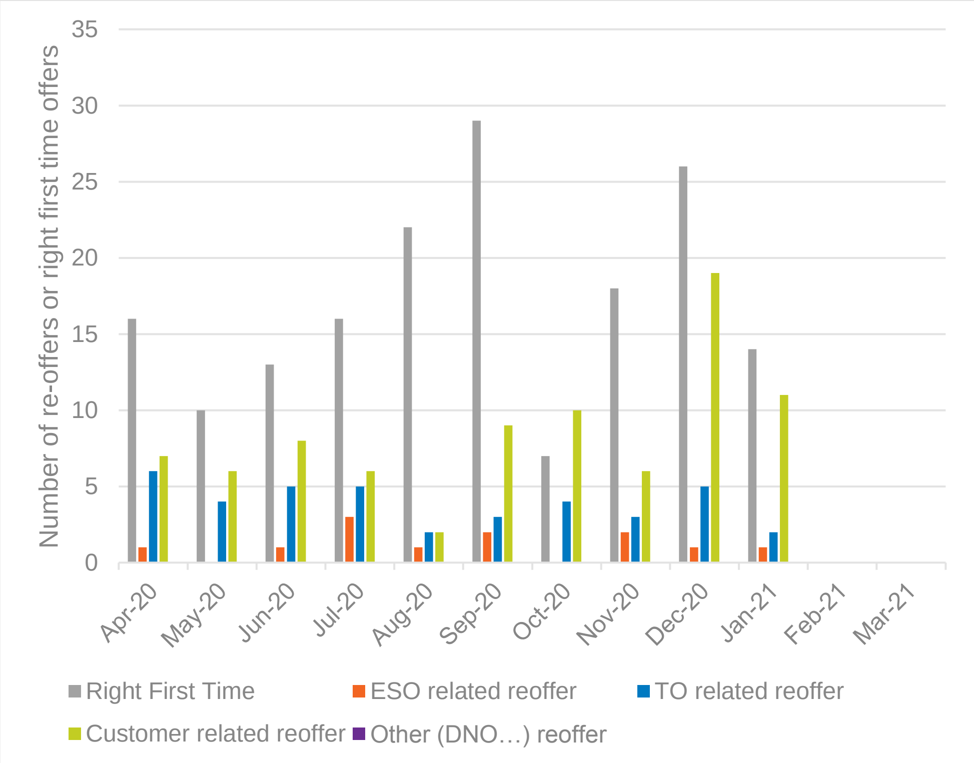

Figure 5: Connections offers monthly performance

Supporting information

We saw 25 new connection offers in January. There was one recorded ESO related re-offer on contracts signed in this period, which means that we are still meeting our target at 96% Right First Time.

The ESO related re-offer is regarding a Scottish connection offer. The changes involved correcting issues relating to the Construction Agreement and the project milestones.

Performance benchmarks

- **Exceeding expectations:** 100% of connection offers Right First Time (excluding those where the error was not due to the ESO)
- **Meeting expectations:** 95-99.9% of connection offers Right First Time (excluding those where the error was not due to the ESO)
- **Below expectations:** Less than 95% of connection offers Right First Time (excluding those where the error was not due to the ESO)

Notable events this month

Accelerated Loss of Mains Change Programme (ALoMCP) update

Loss of Mains protection is there to make sure generators shut down safely when needed. Generators can apply for funding to make the necessary Distribution Code changes to comply via the Accelerated Loss of Mains Change Programme (ALoMCP). The ESO's most recent update[10] stated that as of January 2021, 5994 sites, equating to 10.7GW of generation capacity (enough to power 20 million homes) have had their applications approved, equating to £20.2m in funding from the Programme. 5GW, 3134 sites, have already made the changes to their settings. To accelerate the rate at which generators make the changes, the Programme has introduced a 'fast track scheme' which pays generators, that meet certain criteria and have a minimum capacity of 500kW, additional remuneration if they are able to complete the work within four weeks of applying for funding.

The ALoMCP is boosting network resilience, reducing electricity system costs and allowing smaller, greener generators to play a greater role in balancing the grid.

Operability Strategy Report 2021 published

On Friday 8 January we shared our Operability Strategy Report[11] with industry. It explains the operability challenges we face in maintaining the electricity system. These are presented in the five key areas of frequency, stability, voltage, restoration and thermal. The highlights that are listed are the development and soft launch of Dynamic Containment (DC), Power Potential projects, Accelerated Loss of Mains Change Programme (ALoMCP), and Distributed Restart. We also provide an update on our progress through the Stability, Constraint management, and Mersey voltage Pathfinders.

These projects and developments represent key steps towards being able to operate the system with zero carbon. We continue to work closely with our stakeholders to ensure our approach is appropriate for systems, markets, policy, technology and innovation as we develop and deliver solutions to tackle the challenges ahead.

Network Options Assessment (NOA) 2021-22 published

In January 2021 we published the Network Options Assessment (NOA)[12] to share our recommendations for which reinforcement projects on the National Electricity Transmission System (NETS) should receive investment to help us deliver and operate a zero-carbon electricity network. Following the publication of the Electricity Ten Year Statement (ETYS), the TOs and ESO propose options for solving network challenges, which we then evaluate as part of the NOA. The demand and generation background that we use in the ETYS and the NOA come from the ESO Future Energy Scenario (FES) publication.

This year, the NOA assessed a total of 171 options. Of these options, the NOA recommends that 41 asset-based options proceed, with a total cost of £13.9bn and £183m to be invested this year. The NOA also recommends that four ESO-led commercial solutions (market-based approaches to transmission system issues, as opposed to new infrastructure) proceed which will deliver additional consumer benefit of up to £2.1bn.

The NOA's interconnector analysis suggests that a total interconnector capacity range of between 16.9 to 27.7GW by 2040, between GB and European market will maximise the amount of consumer benefit delivered.

For the first time, this year's NOA considers the economic benefits of offshore integration within its analysis. Having tested the benefit of a number of conceptual offshore options, solely against constraint reduction, the NOA has found that three conceptual options are economically viable in at least one of the FES scenarios. The NOA team is continuing to work with the Offshore Coordination Project and engage with industry to gather feedback on the NOA's offshore wider work results.

Pennines Pathfinder update

On Friday 29 January we provided an update to industry on the Pennines Pathfinder. A tender is expected to be published prior to the end of March 2021. The tender is expected to last up to 40 weeks with an outcome no later than January 2022 for contract start in 2024. Over the last two months we have been able to simplify and reduce levels of interactivity across the Pennine and North of England region such that we can tender for two distinct sub-regions. This simplifies what we will provide to the market and what we will ask of providers. As part of the tender pack, we will define exactly the two regions and specify the approach to assessing the effectiveness of connections within each of them (they may be different). We expect to tender for a minimum of 700MVAr across the two regions and that the tender will be open to both new and existing connections at transmission and distribution levels, including aggregators.

[10] https://www.nationalgrideso.com/news/helping-generators-change-their-settings-boost-network-resilience-and-encourage-zero-carbon
[11] https://www.nationalgrideso.com/document/183556/download
[12] https://www.nationalgrideso.com/document/185881/download

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