You have been joined in listen only mode with your camera turned off

ESO Operational Transparency Forum

26th January 2022

nationalgridESO

Introduction | Sli.do code #OTF

Please visit www.sli.do and enter the code #OTF to ask questions & provide us with post event feedback.

We will answer as many questions as possible at the end of the session. We may have to take away some questions and provide feedback from our expert colleagues in these areas during a future forum. **Ask your questions early in the session to give more opportunity to pull together the right people for responses.**

To tailor our forum and topics further we have asked for names (or organisations, or industry sector) against Sli.do questions. If you do not feel able to ask a question in this way please use the email: box.NC.Customer@nationalgrideso.com

These slides, event recordings and further information about the webinars can be found at the following location:
https://data.nationalgrideso.com/plans-reports-analysis/covid-19-preparedness-materials

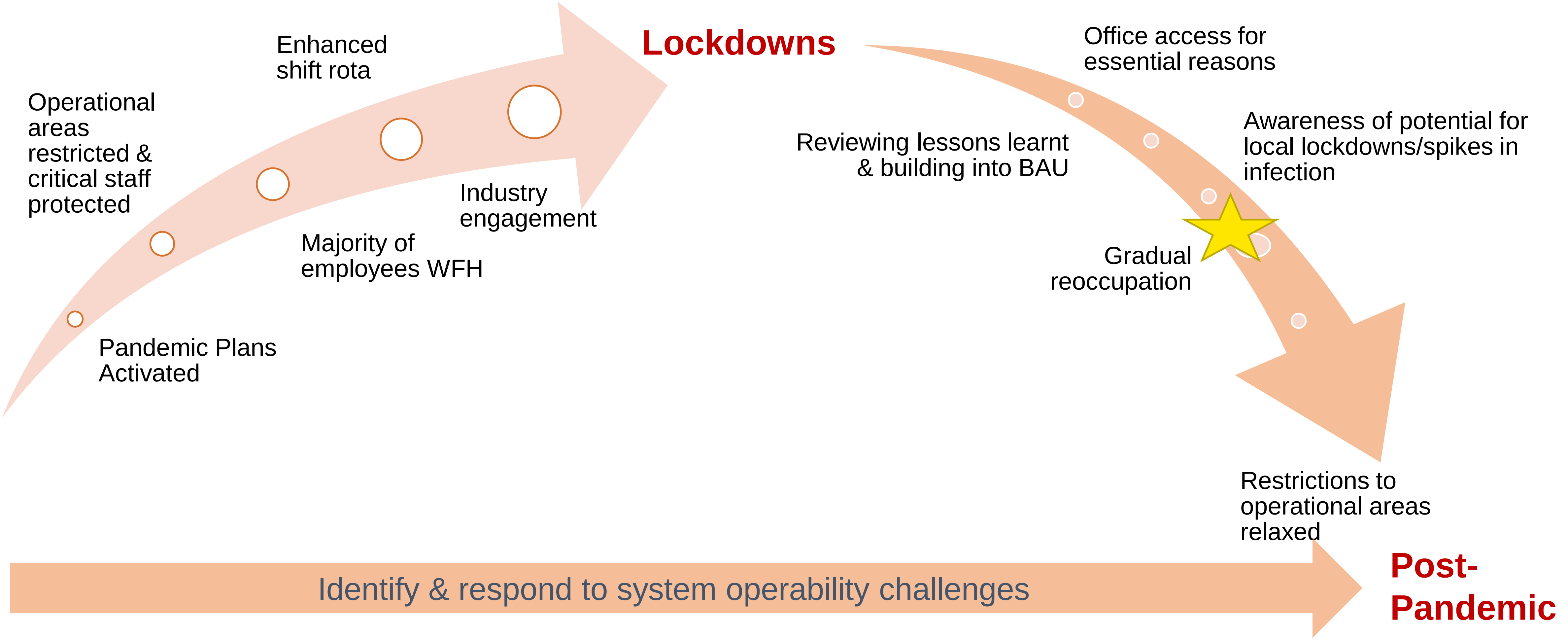
Regular Topics

- Questions from last week
- Business continuity
- Demand review
- Costs for last week
- Outlook
- Constraints

Focus Areas

BSUoS Forecasting

Protecting critical staff to maintain critical operations



Future forum topics

While we want to remain flexible to provide insight on operational challenges when they happen, we appreciate you want to know when we will cover topics.

We have the following deep dives planned:

February:

16th Feb: Balancing Services Adjustment Data (BSAD) Overview
Day in the life of SO-SO Trading

Manifest Error Process Overview

Sterilised Headroom Overview

Questions outstanding from last week

Q: When will your Real-time inertia measurement/ forecasting project by GE and Reactive Power, that was expected last Aug.21, go live?

A:The GE system has been up and running, looking at Scotland, for a number of months. As a “first-of-its-kind” operational installation we are validating the data, along with GE and an independent third party ahead of introducing it into our Control Room. We hope to do this in April and will extend the service to cover more of the GB network as NGET install more monitoring devices across their network.

The Reactive system has been delayed due to a number of technical issues associated with the super capacitor unit. Solutions are currently being deployed and it is hoped that testing can complete in late January and February. As with the GE system we will undertake a period of validation of the results ahead of introducing it into the Control Room however we hope this will be in a similar timescale to the GE system.

Q: For the new sync comps, I note some have FPN flag set to yes and some to no in their registration. Should the ESO opine on whether it is one or the other?

A: ESO generally only registers BMUs with an FPN flag of Y, however the Stability Pathfinder Phase 1 sync comp units are a new zero MW service with different registration requirements compared to a “standard” BMU. The Stability Pathfinder Phase 1 providers are required to be EDL but not EDT active which means the provider can register their unit with FPN flag N if no EDT submissions are planned, however one service provider also has the capability to provide MW services when they are not providing Stability Pathfinder Phase 1 services, other providers have opted to have EDT capability.

As the Pathfinder projects apply a learning by doing philosophy, the ESO view at this stage is to maintain flexibility in the Stability Pathfinder Phase 1 registration process to meet the provider requirements and also configure the units in the BM so they can be efficiently integrated into the Control Room operational tools and ESO settlement processes.

Questions outstanding from last week

Q: How long until FFR will be phased out? Thanks

A: There are several dependencies that need to be delivered before we completely cease the procurement of the monthly FFR tender. Full delivery of disarming and frequency measurement specification are two key deliverables under response reform that the ESO will be prioritising in 2022. Once the full functionality for the above has been delivered, we expect to increase the volume cap on DM and DR. This will enable a stepped decrease in the DFFR volume procured in the monthly FFR tenders.

Q: Can there be a forum to discuss the national grid bilateral trades?

A: Last week Tom Ireland presented on SO-SO trades and took the action away to come back with a “day in the life of SO-SO trades” – which we plan to present on 16 February

Q: Can GB to Ireland flows be seen ahead of real time? I can’t find them!

A: For the question regarding Island of Ireland Interconnector flow visibility; they are available on the SEMO market results website under: Interconnector Data>Market Coupling Flows: here and also on the ENTSO-E transparency Platform here, either as an aggregated value for both ICs under Transmission>Cross-Border Physical Flows>'Border - Bidding Zone' tab as IE (SEM) or you can look at individual flows on either Moyle or EWIC under 'Border - Control Area' here as either NIE or IE respectively

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Questions outstanding from last week

Q: Any update on publishing information of MFR instructions? Badly needed for transparency..

A: There are a number of publications which provide information related to our mandatory frequency response (MFR) spend actions, including the Monthly Balancing Services Summary and the Firm Frequency Response (FFR) Market Information report. We have captured the ask for real-time MFR instruction publication and have previously communicated that this is not something we are able to provide at this time. We would welcome any suggestions as to what else could be provided and will do our best to accommodate wherever possible. We also expect to be able to further increase our provision of data publication when our data and analytics platform is established.

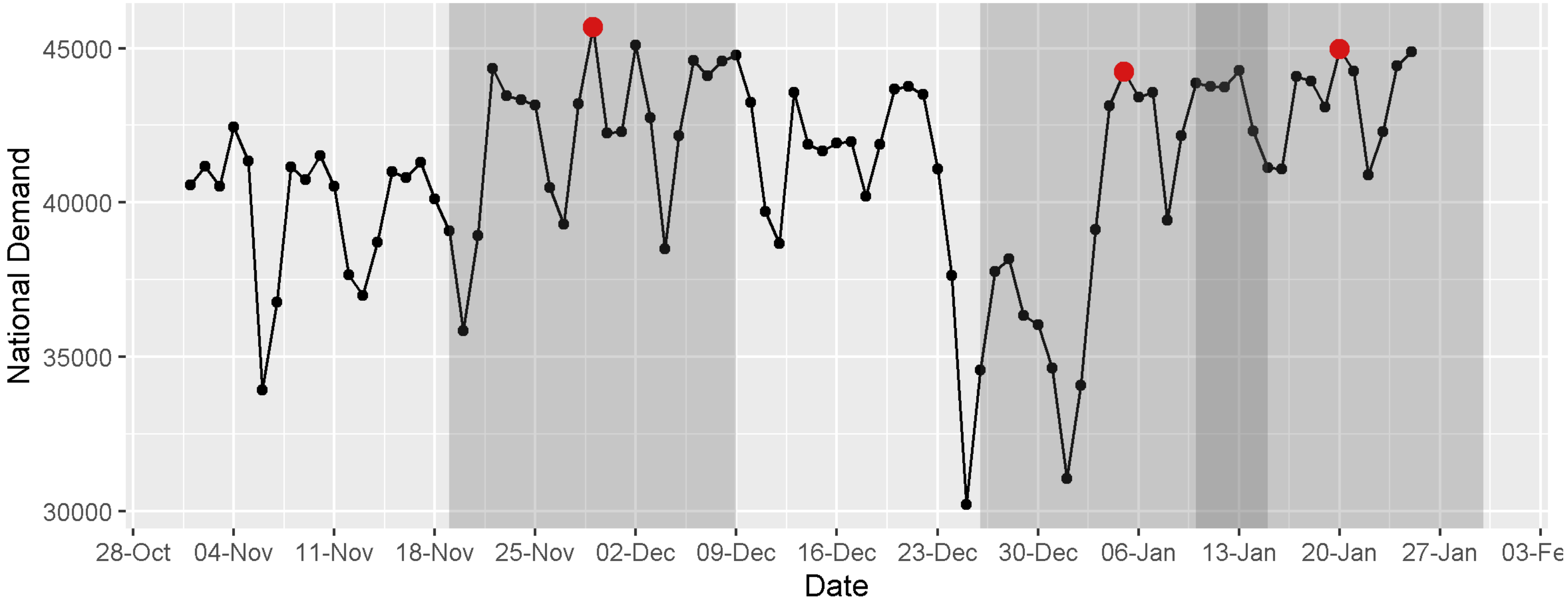
Q: would you be able to do a "day in the life of SO SO trading" by picking an interesting day and then explaining all the trade volumes, all the prices and then giving the reasons why those trades were made on that day and the timing of when they were made.

A: Yes – this is now scheduled in for 16 February

Q: Sorry, a bit late on. Looking at the forecasting slides is it worth emphasising that National Demand (AGCAD definition from way back) is GB Customer Generation Requirement? As against Customer Demand from Distribution. Perhaps OC1.6.1a could be clearer ?

A: National Demand relates to the part of GB total customer demand which is to be met by the transmission system (actually, by BM units). It is the BM generation requirement that is needed to meet this part of GB total customer demand. OC1.6.1a is clear, but could be re-written from a generation perspective rather than from a demand perspective.

Demand | Indicative Peak National Demand



ESO operational metering			
Date	Time (HH ending)	National Demand (MW)	Estimated triad avoidance (HH corresponding with the time of the peak) (MW)
29/11/2021	1730	45679	0
20/01/2022	1730	44977	400
05/01/2022	1800	44245	0

We present National Demand operational metering because triad demand is calculated on the basis of demand excluding interconnector exports. This definition of demand is neither National Demand nor Transmission Demand, but more closely tracked by National Demand.

National Demand does not include station load.

Indicative triad demand on Elexon's BMRS website quotes "GB Demand" which is based on the Transmission System Demand definition (it adds 500MW of station load onto the National Demand).
It shows time as half hour beginning.

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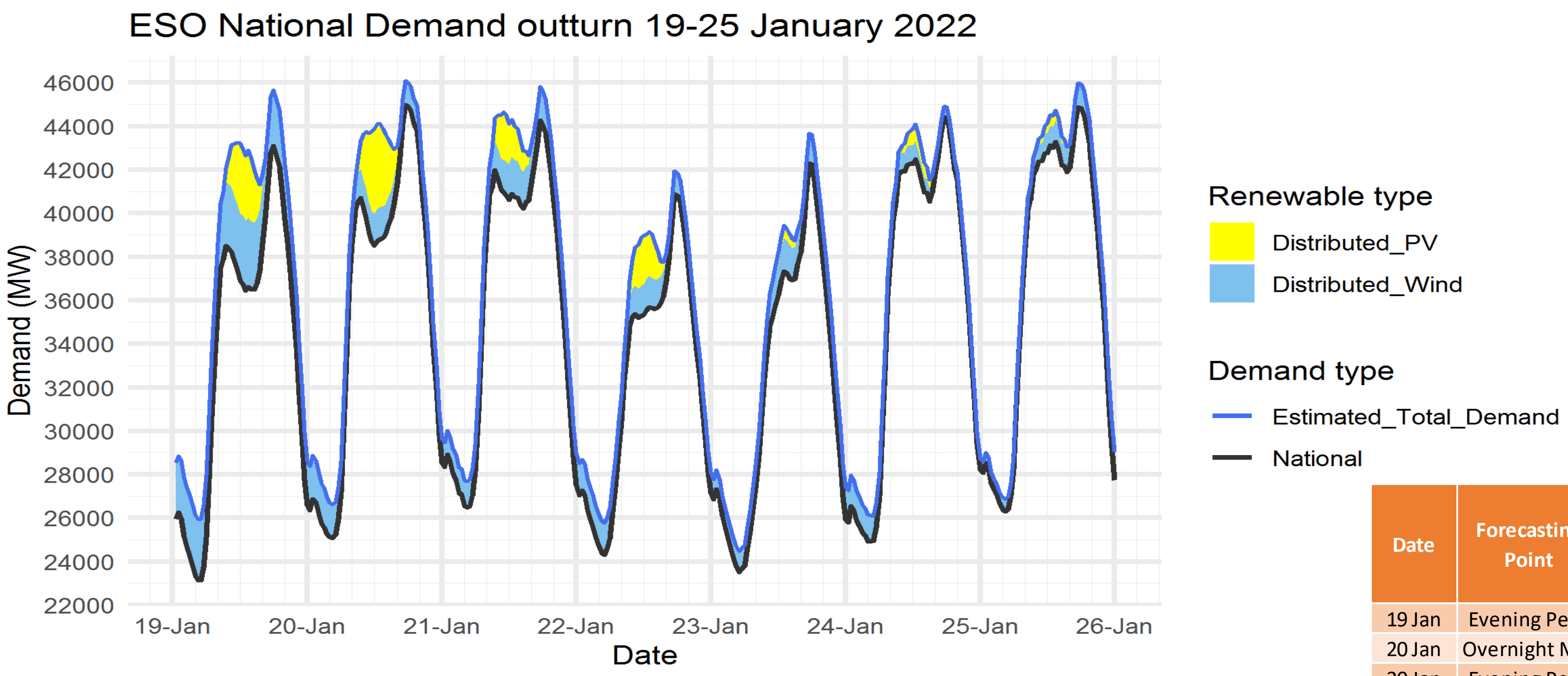
Demand | Last week demand out-turn

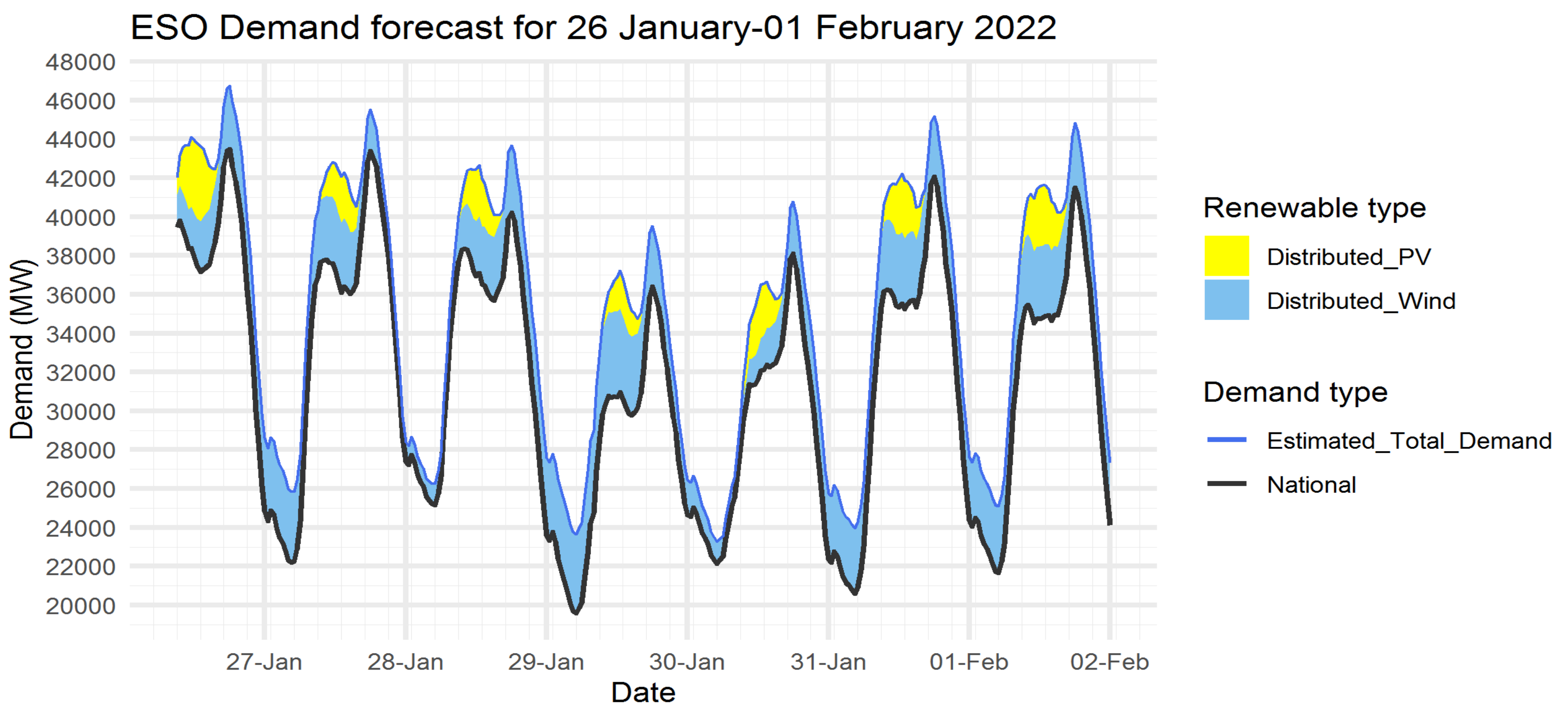


		FORECAST (Wed 19		OUTTURN			
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)	National Demand (GW)	Triad Avoidance est. (GW)	N. Demand adjusted for TA (GW)	Dist. wind (GW)
19 Jan	Evening Peak	43.2	2.6	43.1	0.0	43.1	2.6
20 Jan	Overnight Min	24.4	1.9	25.1	n/a	n/a	1.5
20 Jan	Evening Peak	45.6	1.3	45.0	0.4	45.4	1.1
21 Jan	Overnight Min	25.9	1.3	26.5	n/a	n/a	1.2
21 Jan	Evening Peak	43.8	1.5	44.3	0.8	45.1	1.6
22 Jan	Overnight Min	23.9	1.4	24.3	n/a	n/a	1.4
22 Jan	Evening Peak	40.8	1.0	40.9	0.0	40.9	1.1
23 Jan	Overnight Min	23.8	0.9	23.5	n/a	n/a	0.9
23 Jan	Evening Peak	41.9	1.2	42.3	0.0	42.3	1.4
24 Jan	Overnight Min	24.4	1.1	24.9	n/a	n/a	1.2
24 Jan	Evening Peak	46.5	0.8	44.4	0.0	44.4	0.5
25 Jan	Overnight Min	25.9	0.7	26.3	n/a	n/a	0.5
25 Jan	Evening Peak	46.2	1.0	44.9	0.3	45.2	1.1

The black line (National Demand) is the measure of portion of total GB customer demand that is supplied by the transmission network.

Blue line serves as a proxy for total GB customer demand. It includes demand supplied by the distributed wind and solar sources, but it does not include demand supplied by non-weather driven sources at the distributed network for which ESO has no real time data.

Demand | Week Ahead



		FORECAST (Wed 26 Jan)	
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)
26 Jan 2022	Evening Peak	43.5	3.3
27 Jan 2022	Overnight Min	22.2	3.6
27 Jan 2022	Evening Peak	43.4	2.1
28 Jan 2022	Overnight Min	25.2	1.1
28 Jan 2022	Evening Peak	40.2	3.5
29 Jan 2022	Overnight Min	19.6	4.1
29 Jan 2022	Evening Peak	36.4	3.1
30 Jan 2022	Overnight Min	22.1	1.1
30 Jan 2022	Evening Peak	38.1	2.7
31 Jan 2022	Overnight Min	20.6	3.4
31 Jan 2022	Evening Peak	42.0	3.1
01 Feb 2022	Overnight Min	21.7	3.4
01 Feb 2022	Evening Peak	41.5	3.3

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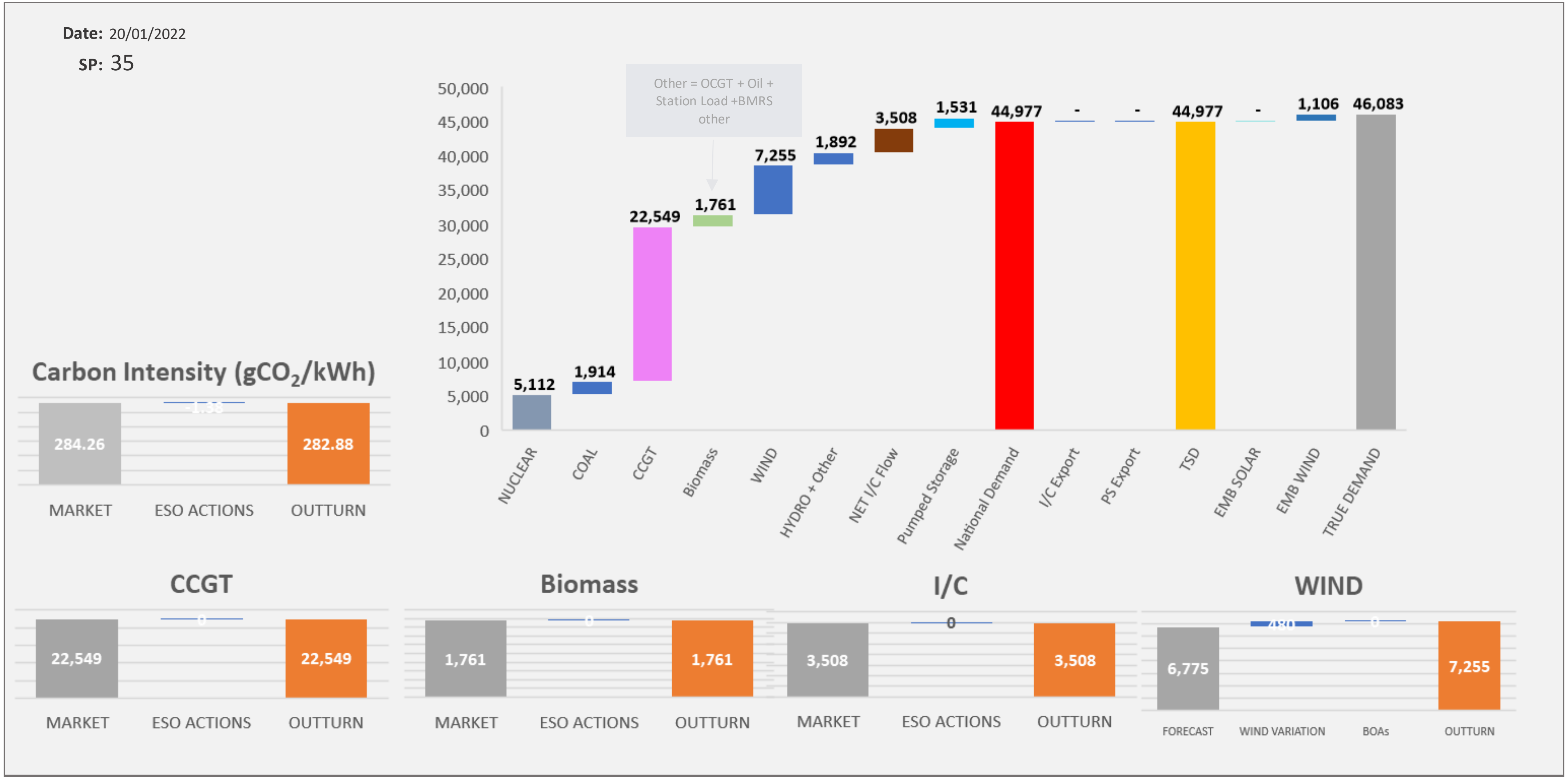
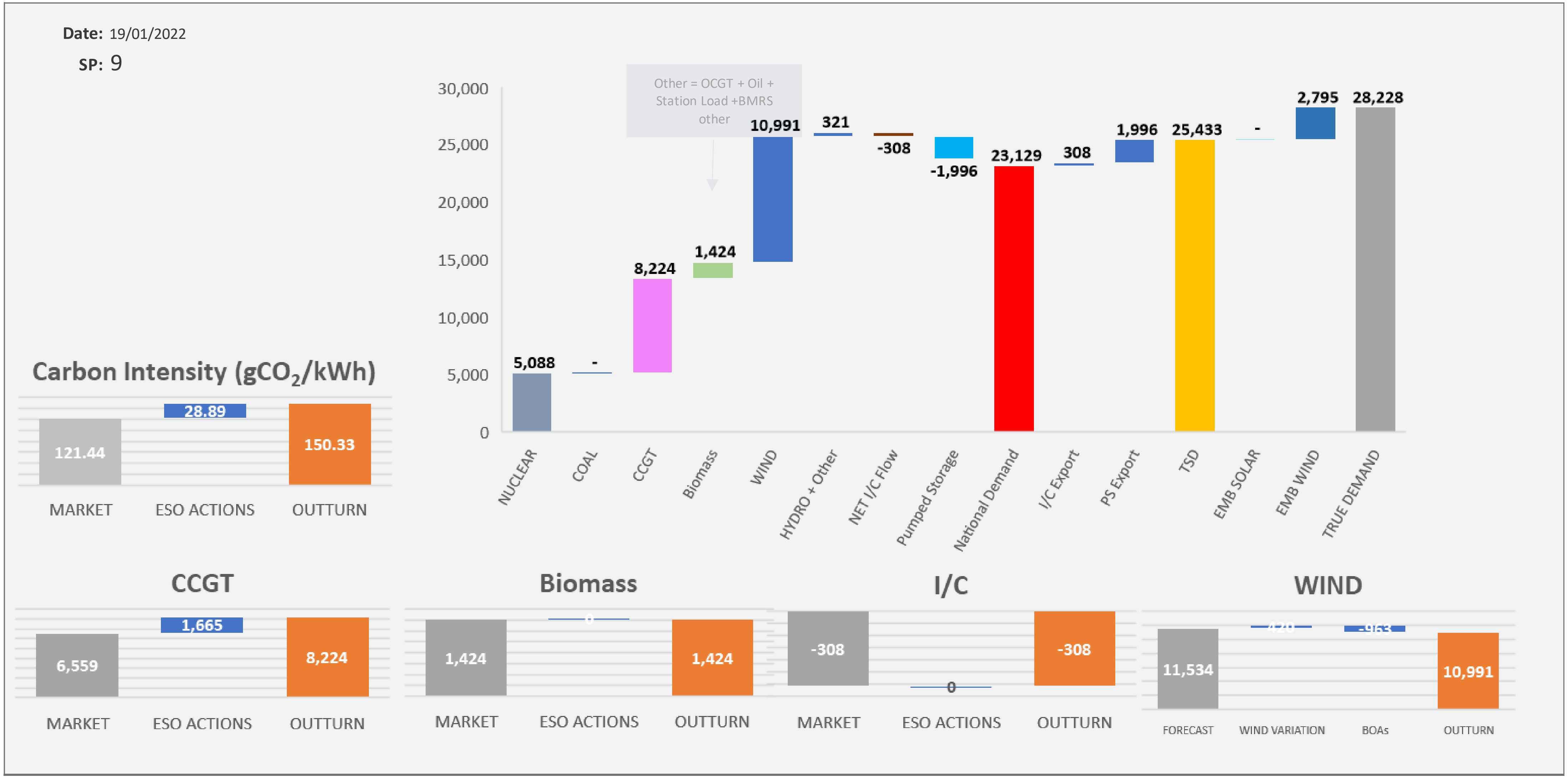
First time ESO shares its Triad Avoidance adjusted **National Demand** forecast is after 21:00 on D-1

ESO Actions | Thursday 20 January Peak



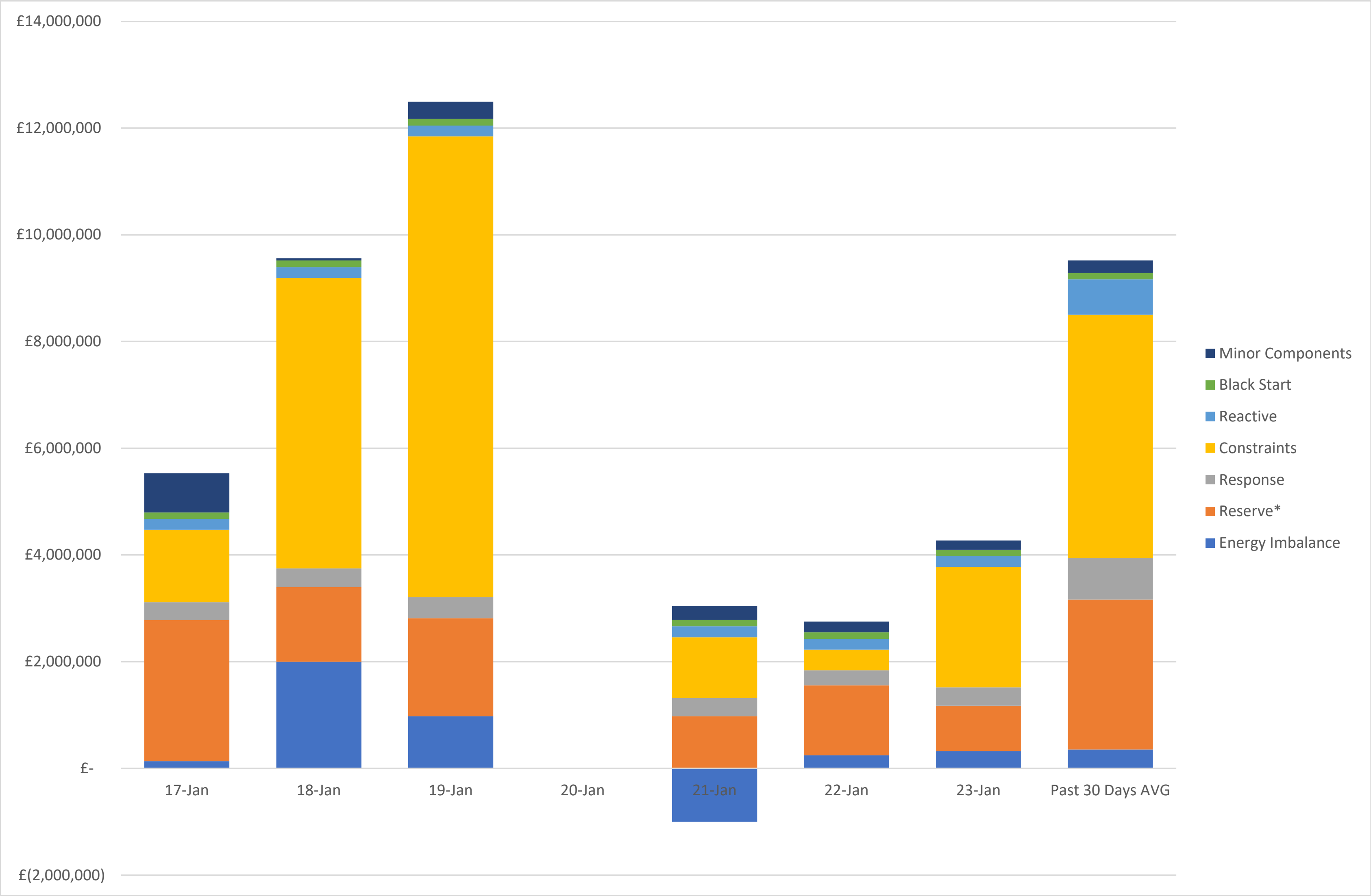
Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

ESO Actions | Wednesday 19 January Minimum



Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

Transparency | Costs for the last week



Daily Costs for Thursday 20th not available.

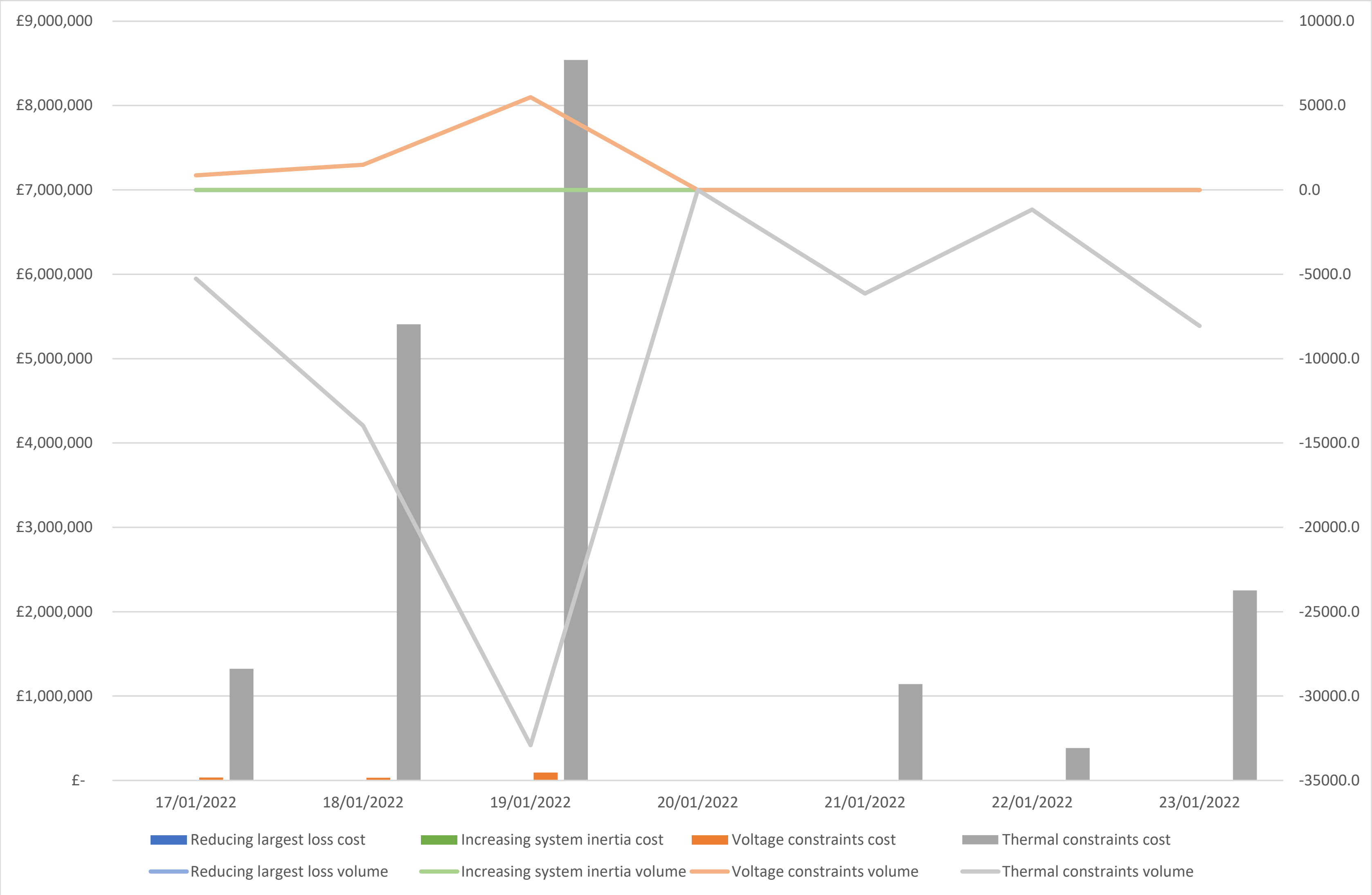
Tuesday 18th and Wednesday 19th were the most expensive days with daily costs of around £10m and £12m respectively.

Constraint costs was the main component on the high spend days.

Friday to Sunday, daily spend remained below or around £4m.

Past 30 Days Average added

Transparency | Constraint cost breakdown



Thermal
Throughout all days, actions were required to manage thermal constraints, with little intervention on Monday, Friday and Saturday. High volume of actions on Tuesday and Wednesday.

Voltage
Action taken to synchronise generation to meet voltage requirements between Monday and Wednesday.

Managing largest loss for RoCoF
No intervention required to manage largest loss on interconnectors.

Increasing inertia
No intervention required to increase minimum inertia.

https://data.nationalgrideso.com/balancing/constraint-breakdown

Operational margins: week ahead

How to interpret this information

This slide sets out our view of operational margins for the next week. We are providing this information to help market participants identify when tighter periods are more likely to occur such that they can plan to respond accordingly.

The table provides our current view on the operational surplus based on expected levels of generation, wind, imports and peak demand. This is based on information available to National Grid ESO as of 26 January and is subject to change. It represents a view of what the market is currently intending to provide before we take any actions.

The indicative surplus is a measure of how tight we expect margins to be and the likelihood of the ESO needing to use its operational tools.

For higher surplus values, margins are expected to be adequate and there is a low likelihood of the ESO needing to use its tools. In such cases, we may even experience exports to Europe on the interconnectors over the peak depending on market prices.

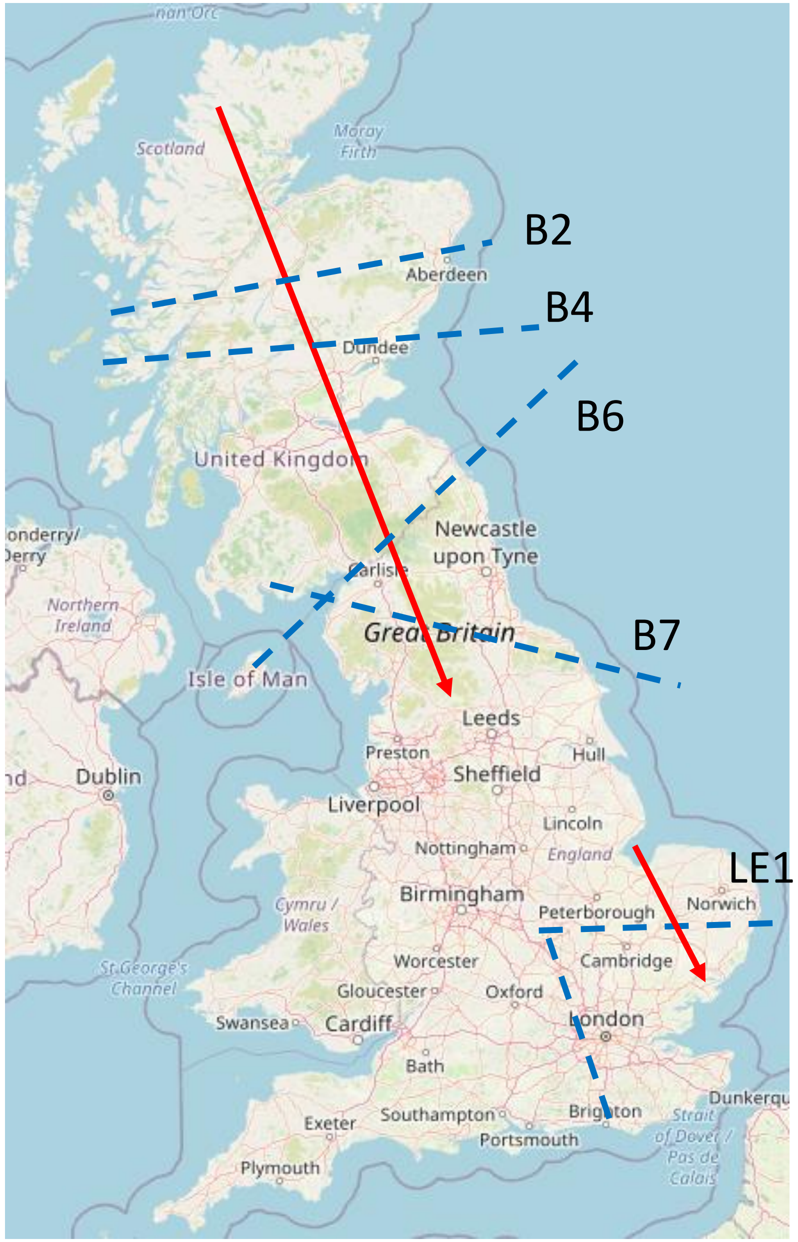
For lower (and potentially negative) surplus values, then this indicates operational margins could be tight and there is a higher likelihood of the ESO needing to use its tools, such as issuing margins notices. We expect there to be sufficient supply available to respond to these signals to meet demand.

Margins are adequate for the next seven days.

Day	Date	Notified conventional generation (MW)	Wind (MW)	Interconnector availability (MW)	Peak demand (MW)	Indicative surplus (MW)
Thu	27/01/2022	44199	10211	3400	43424	9960
Fri	28/01/2022	43463	13799	3900	41053	15341
Sat	29/01/2022	41331	13255	3900	37220	16659
Sun	30/01/2022	42143	10830	3900	38213	14285
Mon	31/01/2022	43088	13343	3900	42400	12681
Tue	01/02/2022	43658	13441	3900	43578	11688
Wed	02/02/2022	43832	9617	3900	43946	8276

Transparency | Constraint Capacity

100% transfer capacity (MW)	
B6	5400
B7	8250
B2/B4	2700



Day ahead flows and limits, and the 24 month constraint limit forecast are published on the ESO Data Portal:
https://data.nationalgrideso.com/data-groups/constraint-management

Transparency | CMN 24th January 2022

- On Monday lunchtime, margins were expected to be tight but manageable for the evening peak. The forecast De-rated Margins published on bmreports were around 1800MW at that time.

- The CMN system margin calculation at 13:30 was based on a similar total requirement to the other margin calculations (SOP and DRM), but when calculating the maximum generation expected to be available, it assumed that three large BMU's with a total expected availability of around 1.2GW would not be available for the evening peak. These units had withdrawn their PN's for the peak shortly before the calculation ran.

- The reason these units were excluded is due to the logic the calculation uses which tries to predict whether these units can be kept on, or if below SEL, whether there is time left to bring these units back on if they desynchronise before the peak. The data available to the system at the time resulted in the automated CMN being published.

- The calculation decided at that snapshot time that the units were ramping down below SEL and that there would not be time to bring them back on again in time for the peak after allowing for their minimum zero times (MZT). However, within the following half hour, the control room did instruct them to remain on by issuing BOAs to delay their desync times. The CMN was withdrawn when the data refreshed at 14.00.

- We are investigating further to see if the CMN logic needs to be updated . Any code changes to the MODIS system would not be implementable this winter, however we will also consider if any short term improvements are possible.

BSUoS Forecasting

BSUoS Forecasting Update

Balancing Services Use of System (BSUoS) charges are a tariff on users of the network to recover the costs we incur balancing the system.

We are committed to continually improving our forecasting and to provide greater insight to the market around changing BSUoS costs.

- We have been publishing more detailed BSUoS forecasts in recent years but we recognise that recently these have not been providing sufficient insight into costs and ultimately the charges system users will face.
- In our 5 point plan to manage constraints on the system we committed to improve transparency and insight into our forecasts of the costs incurred managing flows on the network.

To address these challenges we have now published a forecast based on a new improved methodology.

- This model moves away from the previous BSUoS forecasting linear model to a more comprehensive probabilistic model.
- It takes advantage of improved data inputs and we believe it will provide better insight into BSUoS costs over both short and longer timescales.
- We plan on making incremental improvements to the modelling and datasets included, including the 24month ahead Constraint Limit dataset. This will provide increased accuracy in our modelling forecast inputs.

We want to provide clarity to the changes for our customers and other users of the forecast.

- Please continue to feedback to us on your expectations in relation to the forecasts, this helps us present the information in a way that helps you and informs our future communications.

We would note that CMP381 has been approved from the 17th January 2022. This will place a cap of £20/MWh on BSUoS charges with any amounts above that being rolled into the 2022/23 charging year up to a maximum of £200m. The impact of this is not included in this month's forecast.

BSUoS Forecast for Feb-22

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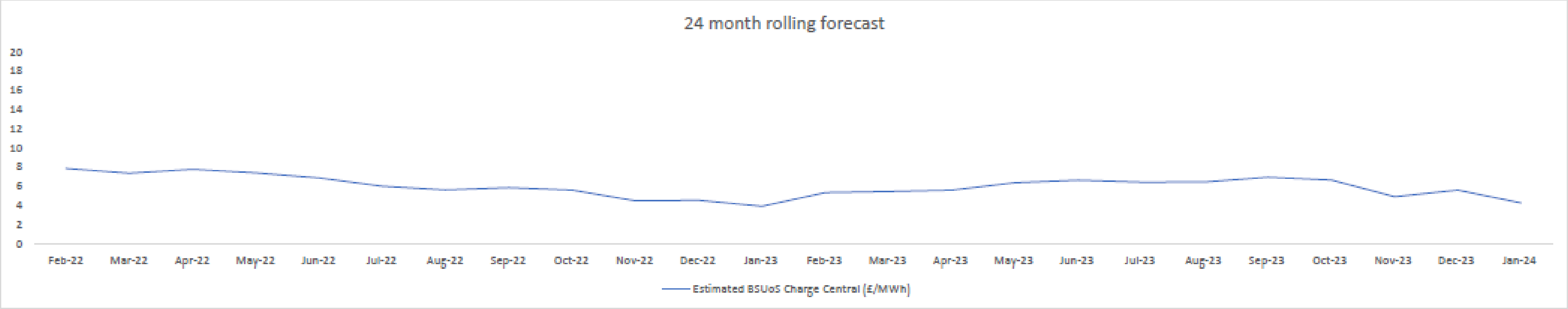


	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23
Balancing Costs (Central) £m	321	305	287	256	222	195	182	200	204	196	202	187
Estimated Internal BSUoS & ESO Incentive £m	21.71	24.04	23.26	24.04	23.26	24.04	24.04	23.26	24.04	23.26	24.04	24.04
BSUoS Cost Recovery £m	5.20	5.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALoMCP £m	1.67	1.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CMP345/350 Deferred Costs £m	1.66	1.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CMP381 Deferred Costs £m	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total BSUoS (Central) £m	351	338	310	280	245	219	206	223	228	219	226	211
Estimated BSUoS Volume (TWh)	44.70	45.99	40.04	37.86	35.66	36.44	36.73	38.17	40.75	48.75	49.68	53.73
Estimated BSUoS Charge Central (£/MWh)	7.86	7.36	7.75	7.40	6.88	6.01	5.61	5.85	5.60	4.50	4.55	3.93

	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24
Balancing Costs (Central) £m	217	227	201	217	213	210	213	242	247	216	254	205
Estimated Internal BSUoS & ESO Incentive £m	21.71	24.04	23.26	24.04	23.26	24.04	24.04	23.26	24.04	23.26	24.04	24.04
BSUoS Cost Recovery £m	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALoMCP £m	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CMP345/350 Deferred Costs £m	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CMP381 Deferred Costs £m	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total BSUoS (Central) £m	239	251	224	241	236	234	237	265	271	239	278	229
Estimated BSUoS Volume (TWh)	44.70	45.99	40.04	37.86	35.66	36.44	36.73	38.17	40.75	48.75	49.68	53.73
Estimated BSUoS Charge Central (£/MWh)	5.34	5.46	5.60	6.37	6.62	6.42	6.45	6.95	6.65	4.91	5.60	4.26

Our forecasts available at the ESO Data Portal:
https://data.nationalgrideso.com/balancing/monthly-balancing-services-use-of-system-bsuos-forecast-reports

Balancing Cost Forecast Modelling Overview

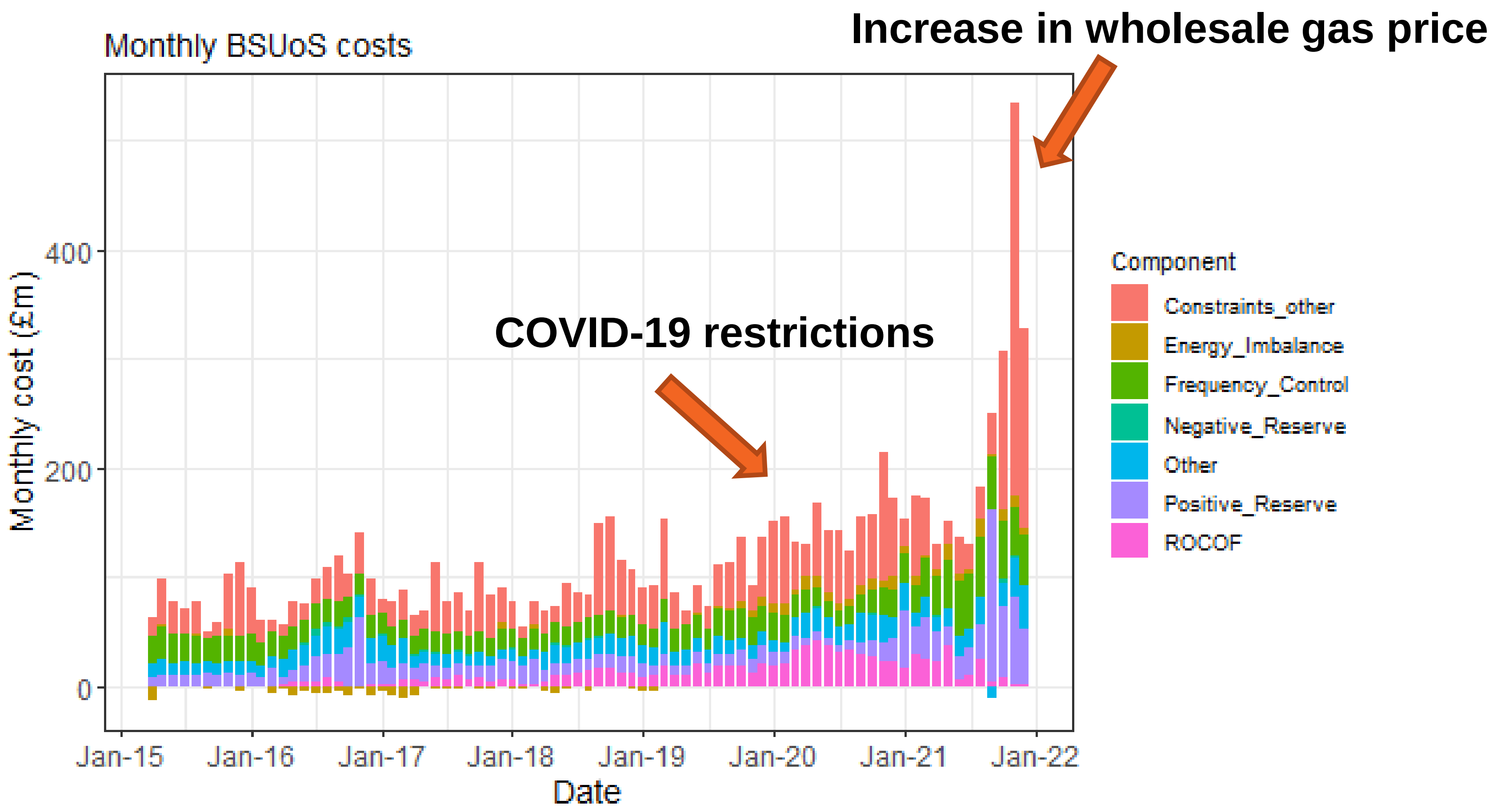
Our balancing cost forecast development seeks to produce a forecast with explanatory power, which has explicit drivers capturing what we know about future changes to the system and acknowledges the level of uncertainty driven by chance or unforecastable events and conditions.

- To forecast the overall costs, we model the different component costs, each with different drivers and magnitude of variability. Then aggregate to determine the total control room balancing cost.
  - The forecast is at monthly resolution with a horizon of up to 36 months.

- To forecast for a wide timescale, we use a blended output approach. This combines the output of different models capturing the variability over different time scales.

  - For shorter time scales the forecast is mostly dependent on time-series modelling using historic costs modified to reflect future conditions, and explanatory variables to capture weather and wholesale electricity price variability.
  - For longer time scales a forecast is made based on the central scenario of network and market development.
    - Monte Carlo techniques are then employed to find the variability around the central forecast, capturing the inherent variability driven by the explanatory variables and the uncertainty in the scenarios

Balancing Cost Variability



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Modelling Variability

Drivers of variability

We first identify the main drivers of cost variability.

- Wholesale electricity costs
- Government and Regulatory policy
- Network changes
- ESO Policies
- Weather variability
- Network and generator outages
- Large unexpected events

Impact of variability

- **Weather impacts:**
  - High wind output leads to higher constraint costs
- **Major outages** of generators, interconnectors or transmission equipment lead to higher management costs
- **Wholesale electricity costs**
  - Prior to recent increases we had made an assessment of reasonable variation
  - Subsequent to the gas price surge we have reassessed
- **Network improvements** alter constraint costs particularly
- Further ahead, uncertainty in **future regulatory changes or government and ESO policies** affect potential future costs

Drivers of variability

Driver	0-1 year	1-2 years	2-3 years
Wholesale electricity price	Variability due to weather and geopolitical factors		
Government Regulation and Policy	Known policies and details	Range of policies and regulation possible	
Network Changes	Network configuration known	Network upgrades known but completion date / delays unclear	
ESO policies	Known policies and details	Broad policy view, details tbc	Range of policies but no decision made
Weather variability	Weather variability: predictability approximately constant across all relevant lead times		
Network and generator outages	Planned outages known	All outages unknown	
Large unexpected events	Can occur at any time		

Time-series models

- Time-series models using historic costs and explanatory variables to capture the short-term cost variability.
- Two time series models used: Persistence and Auto-regressive integrated moving average with explanatory variables (ARIMAX).
- Explanatory variables used to capture the variability due to weather and wholesale electricity price.
- Large uncertainty in the explanatory variables at all time scales. It is not possible to accurately forecast the weather variables at lead times of greater than approximately 10-15 days.
- Monte Carlo simulation models utilise 50,000 simulations based on different magnitudes of the explanatory variables. They provide a representation of the uncertainty in the forecast.
- Residual variability (dependent on lead-time) added for each simulation to represent unexpected event variability.

Driver	0-1 year
Large unexpected events	Can occur at any time
Wholesale electricity price	Variability due to weather and geopolitical factors
Weather variability	Weather variability approximately constant across all lead times
Government Regulation and Policy	Known policy and details
Network Changes	Network configuration known
Network and generator outages	Planned outages known
ESO policies	Known policy and details

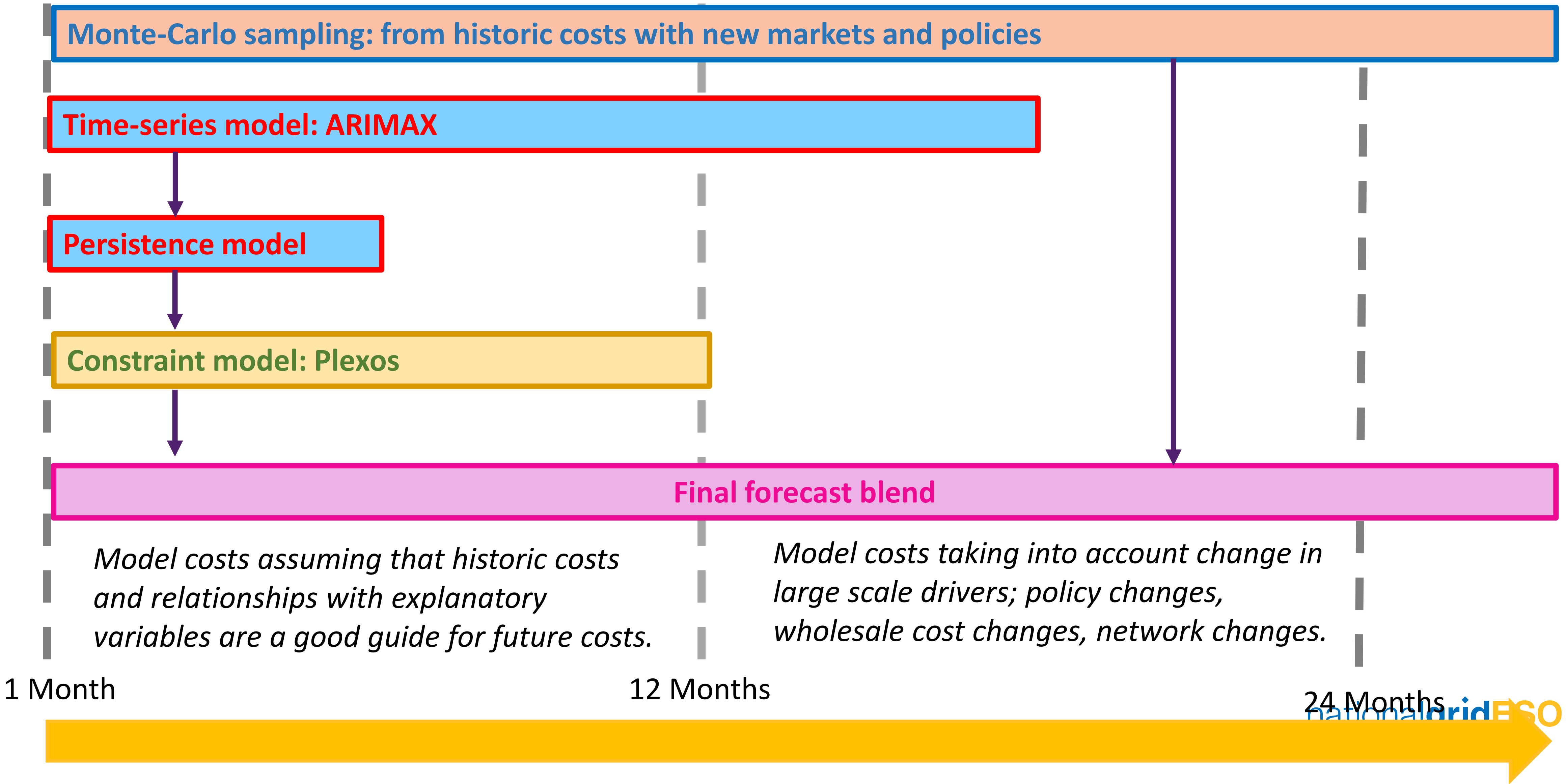
Long-term models

- Central forecast is made for each cost component based on the scenarios of network and market development.
- New costs are added for markets which are expected to develop over the forecast period based on NGESO policy.
- **Frequency control:** Central forecast based on scenarios (provided by ESO Structuring and Optimisation team) which outline DC pipeline etc.
- **Constraints:** Central forecast based on scenarios of proposed future network developments outlined in NOA6 study[1].
- **All other components:** central forecasts based on recent costs. No large-scale driver in the pipeline leading to shift in central cost.
- Monte Carlo techniques are employed to find range for each cost element, capturing the inherent variability driven by the explanatory variables.
- Residual variability (dependent on lead-time) added for each simulation to represent unexpected event variability.

Driver	1-2 years	2-3 years
Wholesale electricity price	Variability due to weather and geopolitical factors	
Government Regulation and Policy	Range of policies and regulation possible	
Network Changes	Network upgrades known but completion date and delays unclear	
ESO policies	Policy decided but details unclear	Range of policies but no decision made
Weather variability	Weather variability approximately constant across all lead times	
Network and generator outages	All outages unknown	
Large unexpected events	Can occur at any time	

1 https://www.nationalgrideso.com/document/194436/download

Blending of models: example



Summary of BSUoS Forecasting Modelling improvements

We are committed to continually improving our forecasting and to provide greater insight to the market around changing BSUoS costs.

- There are several drivers of variability inherent in forecasting BSUOS and each brings with it impacts on the overall variability of the forecast.

We have now published a forecast based on a new improved methodology.

- This model moves away from the previous BSUoS forecasting linear model to a more comprehensive probabilistic model.
- It takes advantage of improved data inputs and we believe it will provide better insight into BSUoS costs over both short and longer timescales.
- We plan on making incremental improvements to the modelling and datasets included, including the 24month ahead Constraint Limit dataset. This will provide increased accuracy in our modelling forecast inputs.

BSUoS Forecast Improvement Timescales

January 2022

Stakeholder engagement through OTF and Elexon circular

Review and act on feedback received

w/c 24 January
Publish February 2022 forecast using improved methodology

OTF deep dive on February forecast values and model

February 2022

Publish March 2022 forecast

Modelling development & enhancement:

Inclusion of Constraint Cost dataset as model input

March 2022

Publish April 2022 forecast

Consultation launches for balancing cost model approach and methodology

This to inform further developments of modelling for BSUoS tariff setting

September 2022

Model development completed

Fixed BSUoS tariffs published ahead of April 2023 implementation

Modelling development & enhancement

For any feedback on our approach and timescales for change please get in touch: .box.NC.Customer@nationalgrideso.com

Q&A

After the webinar, you will receive a link to a survey. We welcome feedback to understand what we are doing well and how we can improve the event ongoing.

Please ask any questions via Slido (code #OTF) and we will try to answer as many as possible now. If we are unable to answer your question today, then we will take it away and answer it at a later webinar.

Please continue to use your normal communication channels with ESO.

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Audience Q&A Session

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Q&A

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