Summer 2020 Balancing Costs

LCP Energy Analytics
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Introductions

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Who we are

- Financial services consultancy, based in London
- 700 staff and partners
- LCP Energy Analytics focusses on the GB and Irish electricity markets
- Combination of energy market expertise, mathematical modelling and new technological approaches
- Work closely with industry and decision makers
- Provide a range of services, from modelling support to market insight

We advise half of the FTSE100 firms

We have provided the modelling framework for a number of decision makers.

- We designed, developed and maintain BEIS' primary forecasting tool, the Dynamic Dispatch Model, used in all long term forecasting and policy impact analysis

- Ofgem uses our modelling to assess network charging reforms, including embedded benefits/TCR

- National Grid uses our modelling to support the annual capacity requirement recommendation, calculate EFCs and derating factors

- The LCCC uses our modelling to calculate the costs of the CfD framework, and to set the interim levy rate and total reserve amount.

ofgem

LOW CARBON CONTRACTS COMPANY

nationalgrid

Department for Business, Energy & Industrial Strategy

How we help our clients

Across GB and Ireland

- Energy market forecasting and scenarios
- Transaction support and generation asset valuations
- Capacity Market & Contracts for Difference advice
- Real-time trading visualisation and analytics
- Policy impact studies
- Market insight
- Commercial and operational optimisation
- Bespoke modelling solutions

Our experience

Examples of recent projects

GB and Irish assets due diligence support

Capacity market support

Provided modelling projections of the GB market to evaluate potential bidding strategies in the capacity market auctions to a number of large and small scale generators.

GB clients – Wind asset evaluations

Provided modelling and analysis to support business case for portfolio of wind assets.

Detailed locational modelling, to capture price cannibalisation and imbalance risk.

Impacts of COVID-19 and BSUoS

LCP have provided clients with short and long term forecasts assessing the impacts from COVID-19, including our own BSUoS forecast

GB power market portfolio forecasting

LCP provide a number of clients with regular GB power market forecasting, portfolio valuations, asset dispatch projections and associated cashflows.

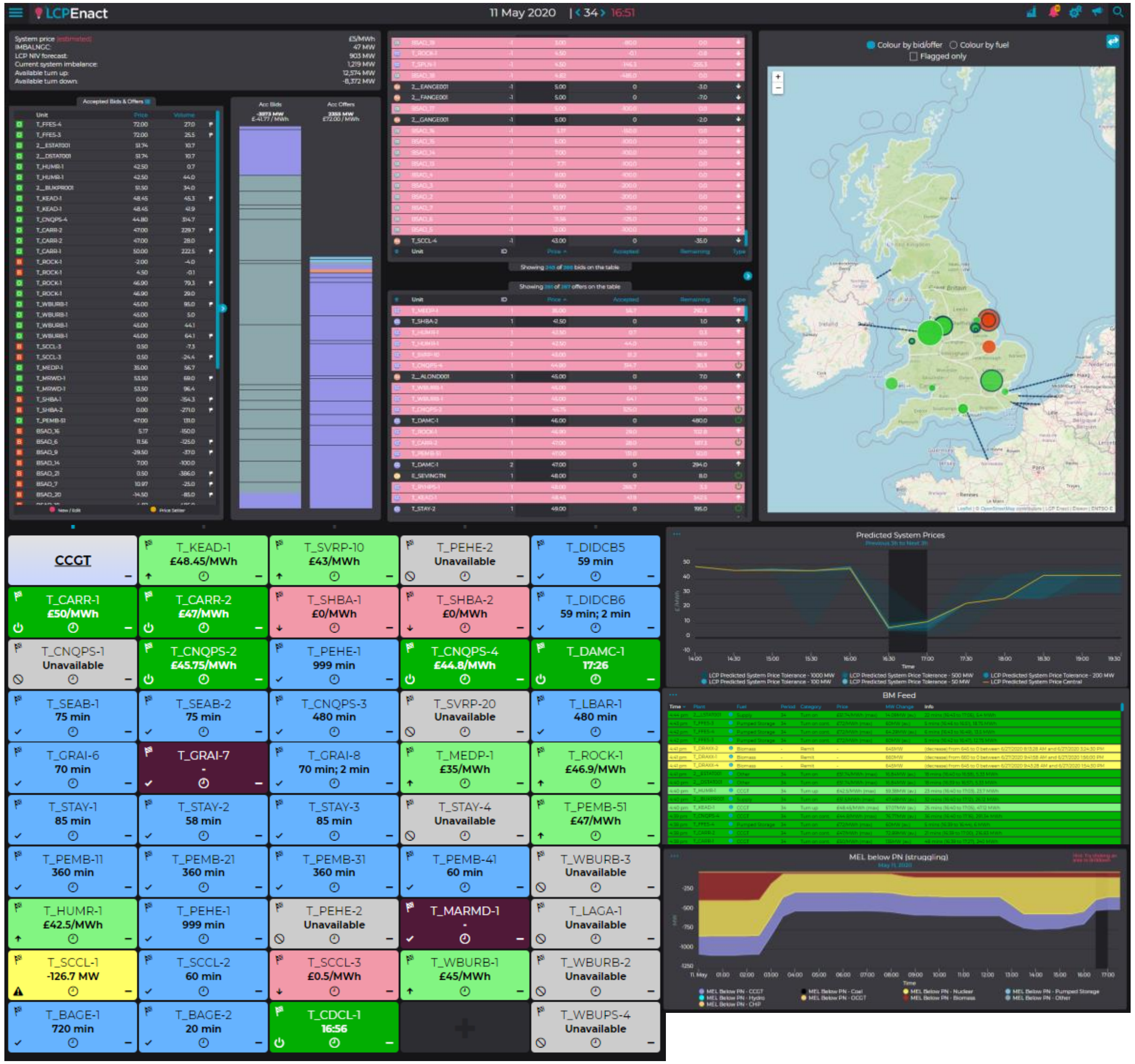
M&A

LCP has advised clients on M&A for multiple assets including: Flexible assets (gas & batteries), wind, CCGTs, small scale renewables and nuclear.

Provided wholesale, BM, CM, embedded benefit and ancillary service projections.

LCP Enact

Real time trading analytics for the GB electricity market



Data integration

LCP Enact brings in real time and historic data from a number of data sources, to allow traders and analysts to see one integrated market view

Cutting edge UI

This data is delivered through a web interface, using the latest technologies to allow easy visualisation of data, quick analysis and even mobile alerts

AI-powered forecasting

Enact provides a live 6 hour view of system imbalance (NIV) and system prices, allowing traders to help balance the system and realise the profitability of their assets. Our NIV forecast delivers a **£2/MWh profit** on trades executed 30 minutes before delivery

Agenda

Background

Backwards looking analysis

- Comparison of BSUoS charges in 2019/2020
- Average BSUoS charges vs HH volatility
- Key drivers of BSUoS

Forward looking analysis

- Analysis of BSUoS for summer 2020 and beyond
- NGESO BSUoS forecasts and sensitivities on these

What is BSUoS?

- **Balancing Services Use of System (BSUoS)** charges recovers the cost of the day-to-day operation, balancing and securing of the transmission system

- The BSUoS charge is a flat tariff paid by transmission connected generators and suppliers on an ex post basis

- The charge reflects the cost of balancing actions in that period, and is charged back to the active participants in the half hour on a £/MWh basis

What is BSUoS?

LCP INSIGHT CLARITY ADVICE

BSUoS Charge

System Balancing
(All actions taken to maintain stability – SO flagged actions, locational constraints, inertia)

Energy Balancing
(All actions taken to resolve energy imbalances i.e. when a generator hasn't produced enough power or a supplier has not bought enough power)

Additional costs
Ancillary services, internal costs etc

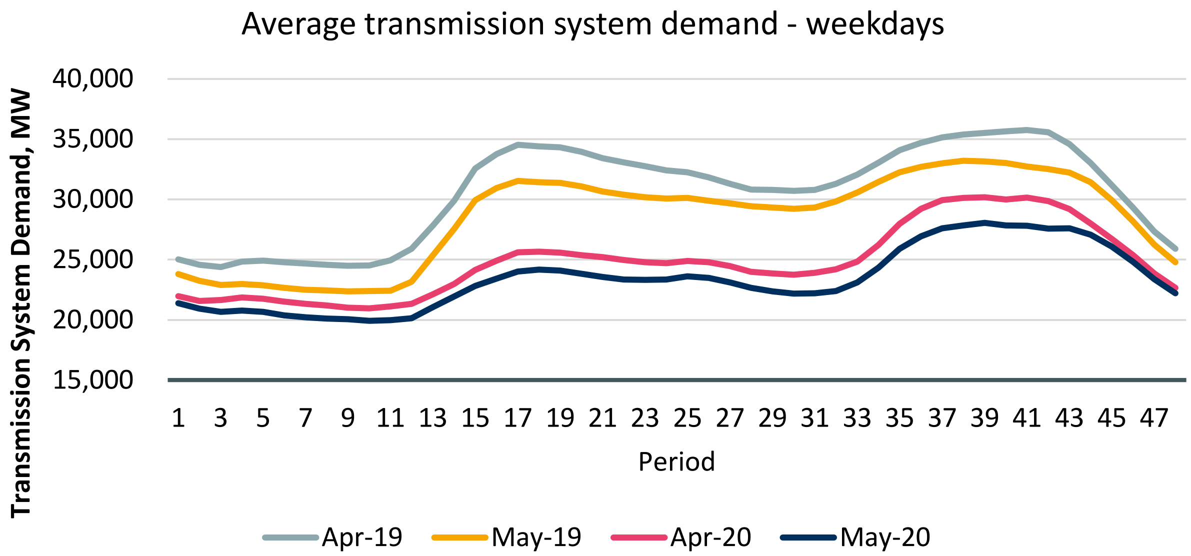
Cashout

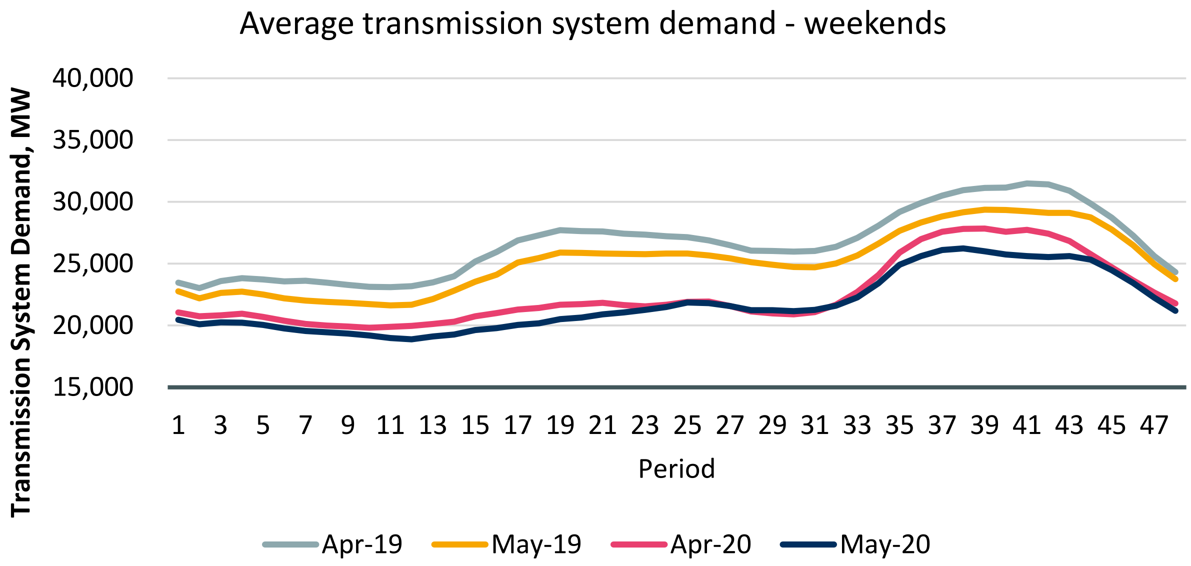
Residual Cashflow Reallocation Cashflow (RCRC)

Comparing last year to this year

Setting the scene

Lower demand

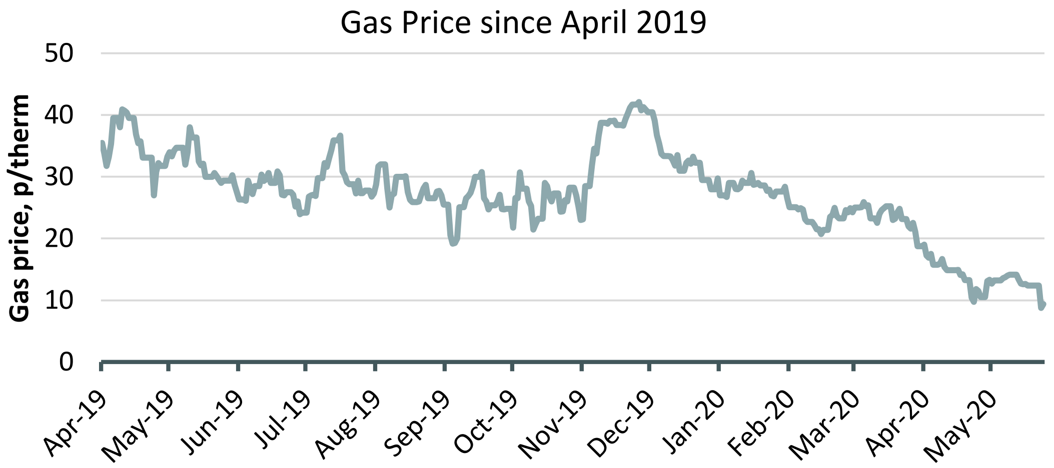




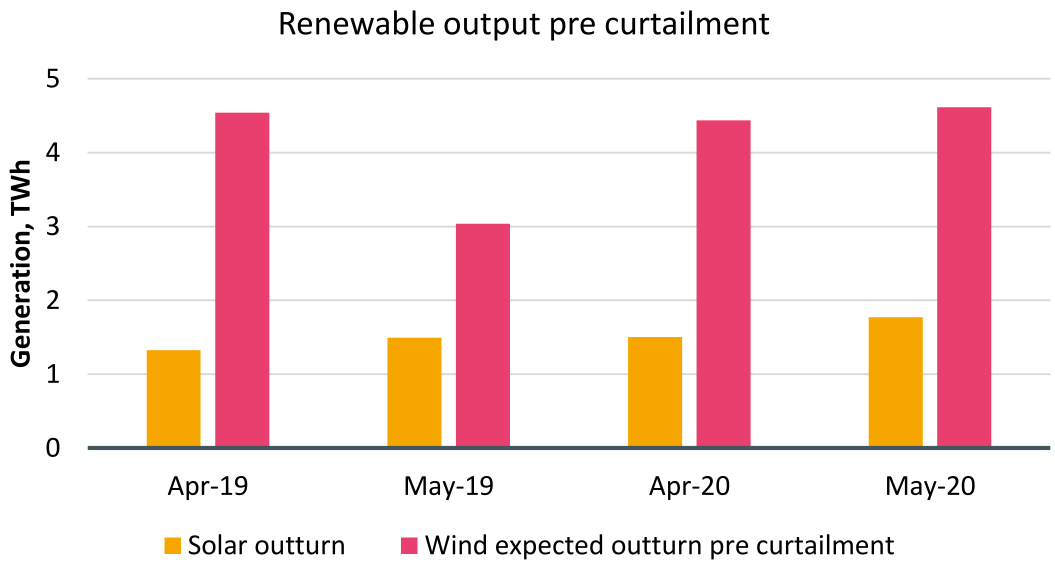
COVID-19 has resulted in a significant **decrease in demand**, and a flattening of the shape across the day, particularly the morning peak.

Setting the scene

Lower gas price, much windier May



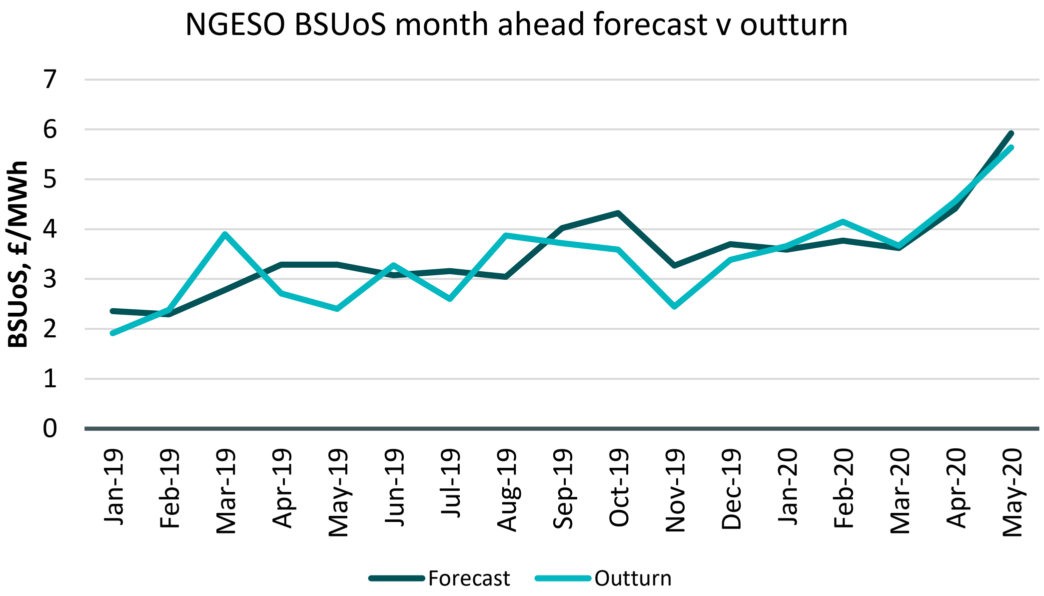
Gas prices have slumped since April 2019, particularly in the last 3-4 months



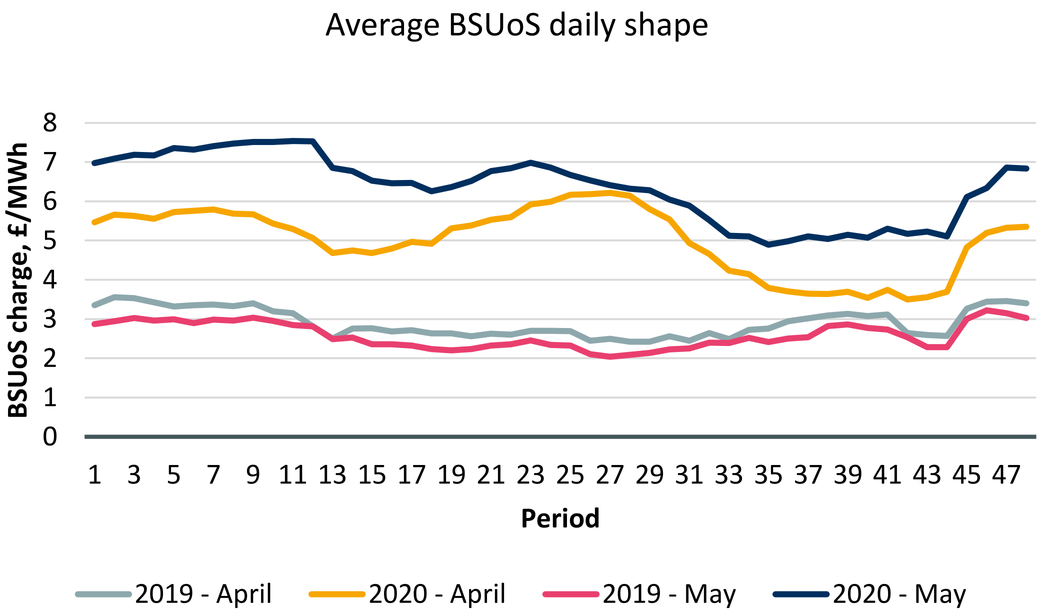
Renewable output

- April 2020 levels are broadly similar to the same month last year
- May has shown significantly higher wind output (pre curtailment) this year

BSUoS costs have been increasing



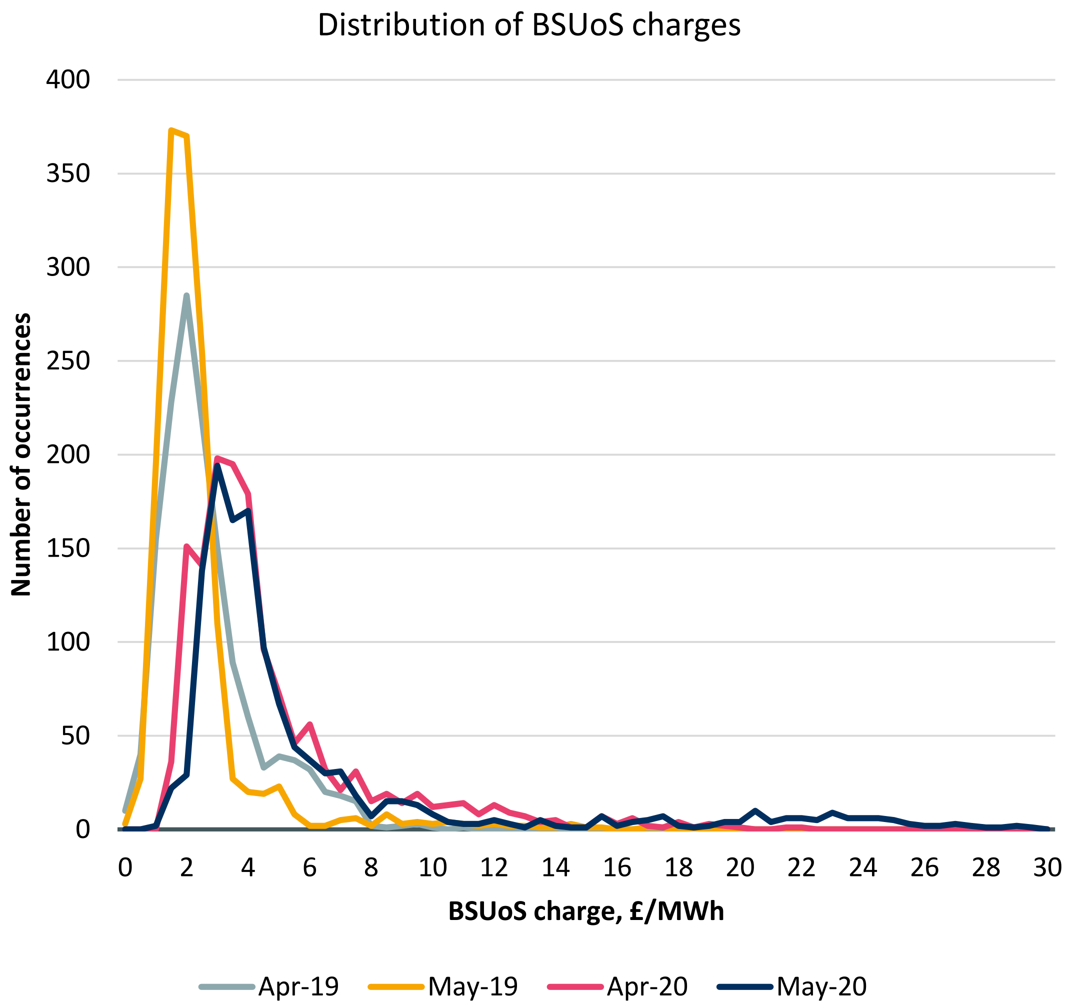
- BSUoS has sharply increased in the last two months
- NGESO monthly forecasts have so far been quite indicative



- BSUoS is higher across the day relative to a year ago, most notably during overnight periods and over the afternoon
- Lower demand has highlighted the influence of solar generation

BSUoS has increased, but so has its volatility

And it's becoming harder to predict

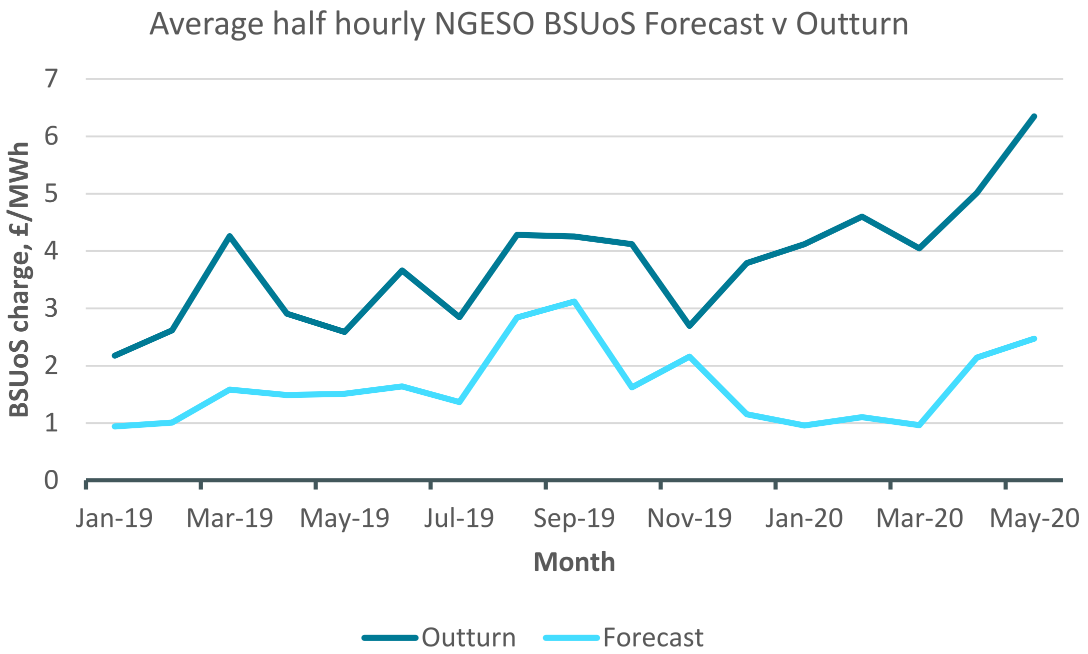


In recent months the BSUoS charge has both increased and become less predictable:

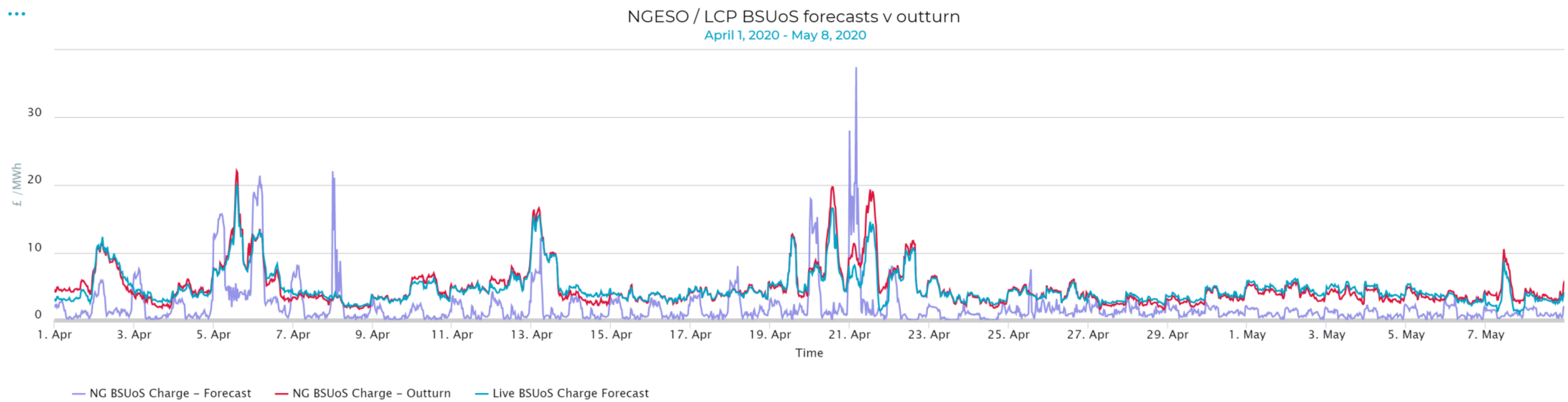
- The spread in the distribution of the half-hourly BSUoS charges has widened compared to last year
- The tail of the distribution has grown, in April and May 2020 BSUoS exceeded £10/MWh in 10% of all settlement periods
- This higher volatility is likely to be ultimately passed through to consumer bills due to higher risk premium

BSUoS has increased, but so has its volatility

And it's becoming harder to predict

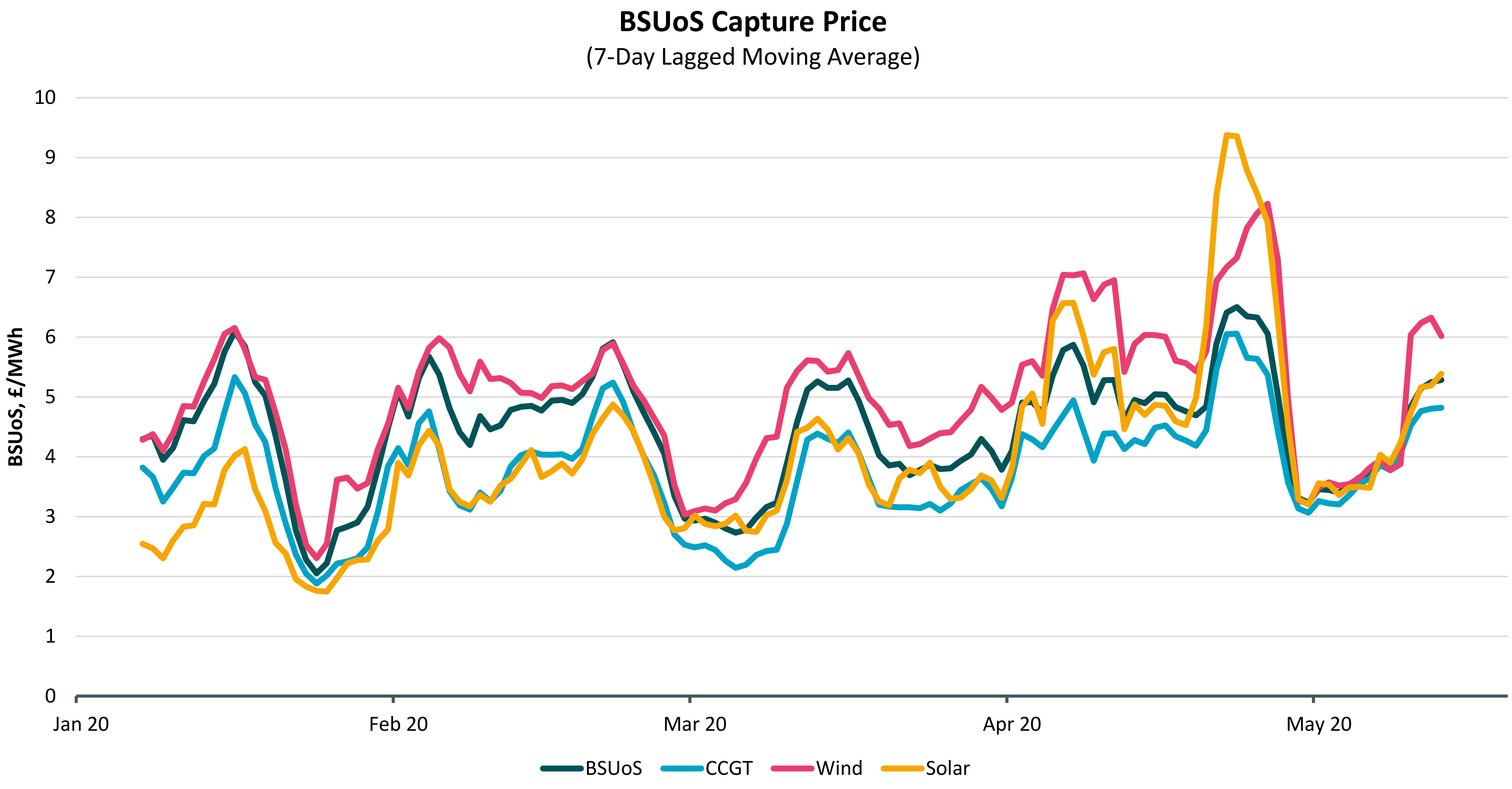


- NGESO's half hourly BSUoS forecast has not followed their monthly forecast and has been materially different from outturns
- This makes wholesale dispatch decisions and the pricing of bids and offers in the balancing mechanism more difficult



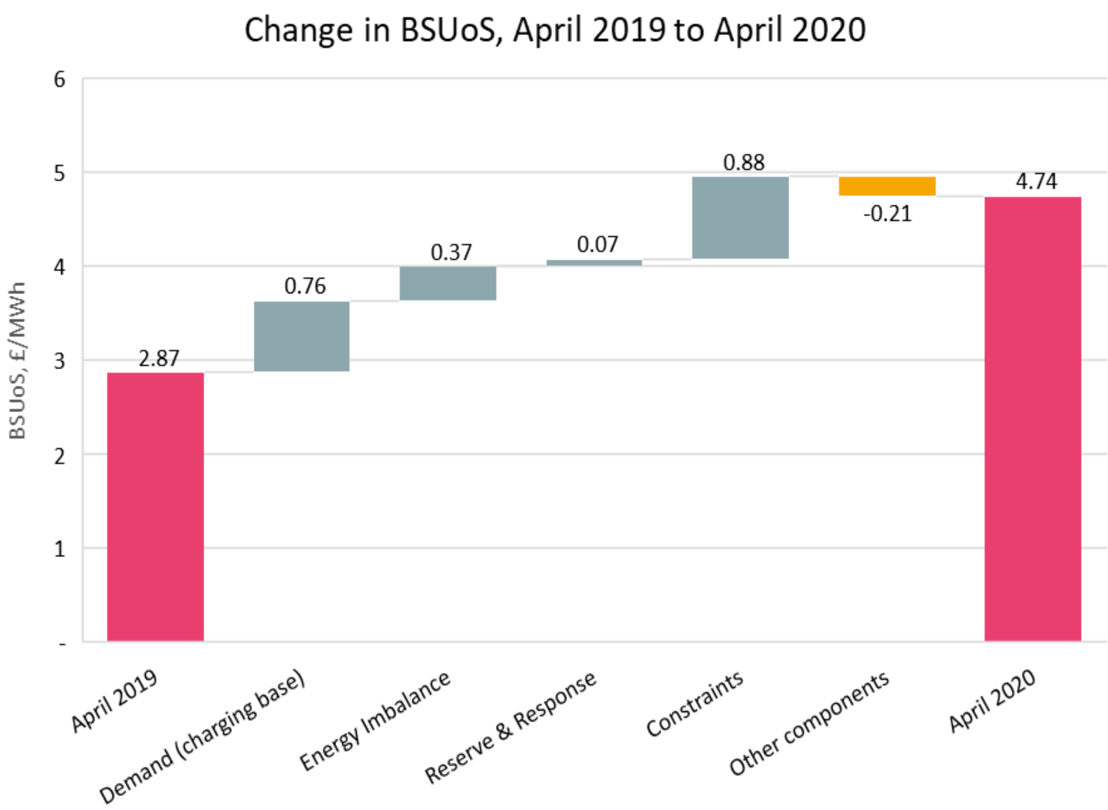
Captured BSUoS is important

Technologies are impacted by higher BSUoS differently



Why has BSUoS increased

Key drivers are lower charging base and constraints costs



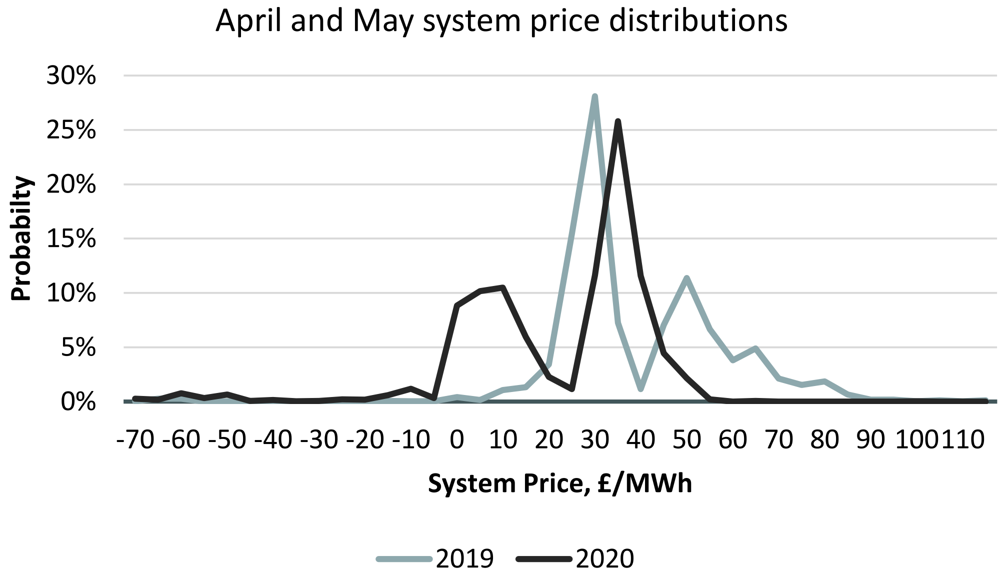
BSUoS charges have risen significantly under Covid compared to the same period last year.

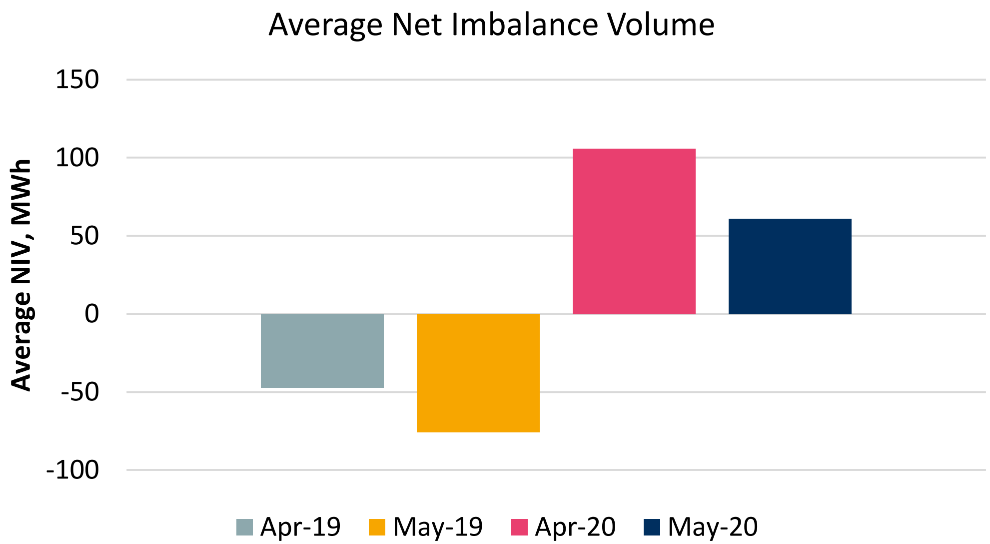
The key reasons for this were:

- Decrease in the **charging base**, as a direct result of decrease in overall levels of generation and demand
- An increase in **energy imbalance** costs, the cost associated with bids/offers accepted to satisfy the Net Imbalance Volume (NIV)
- An increase in **constraint** costs**.** This includes system actions to satisfy locational constraints and maintain system stability (e.g. inertia)

Increasing energy imbalance costs

The system is now short on average, as long system prices become more punitive





The system price is set by the most expensive turn up action in a short system, and the most expensive turn down action in a long system

2019

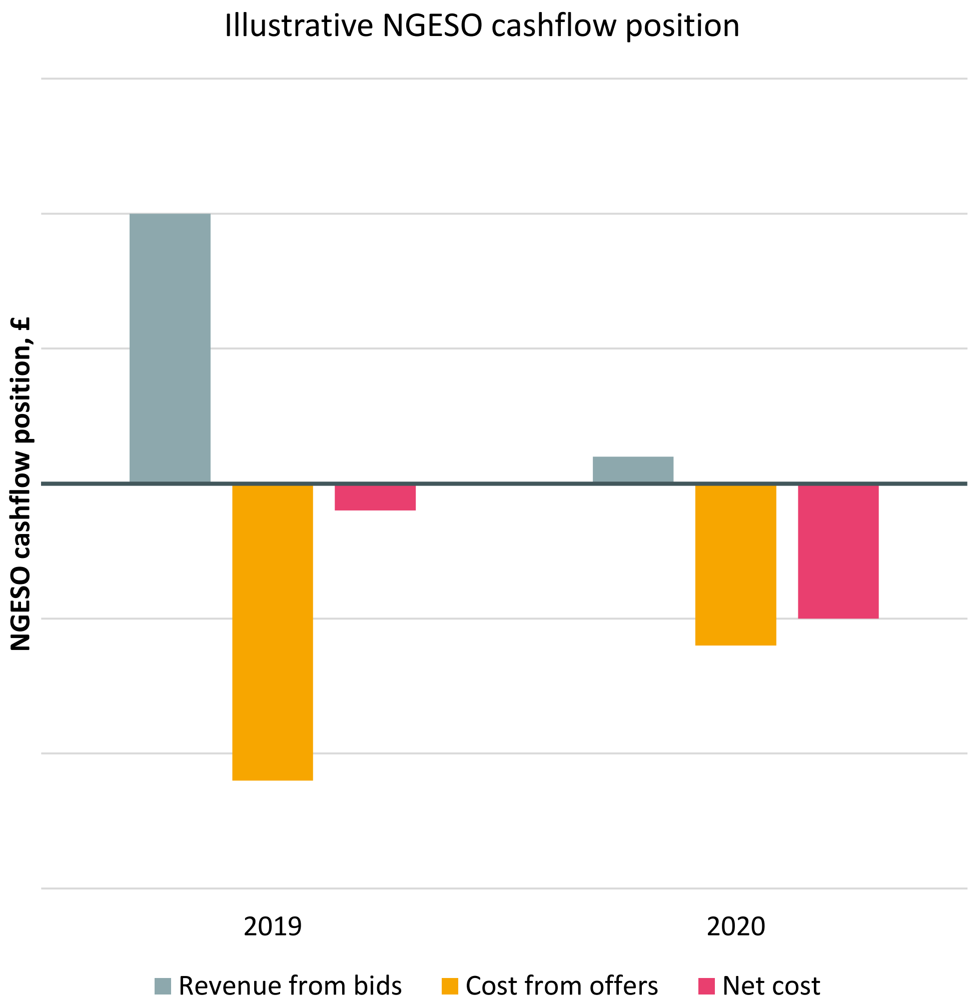
- Higher demand and higher gas prices meant turn ups were expensive and turn downs were cheap.
- This meant the system was on average long, to avoid facing a punitive short cashout price

2020

- Lower demand and lower gas prices have made turn ups cheaper (more CCGTs available to turn up) but bids more expensive
- It's now the long system price that is more punitive, so the system tends to stay short

Increasing energy imbalance costs

This means a material increase in energy imbalance costs



2019

- Long system
- On average, being paid to turn units down (bids ~ £20/MWh)
- Offset by fewer but more expensive offers (offers £60+/MWh)
- Nets out to near zero

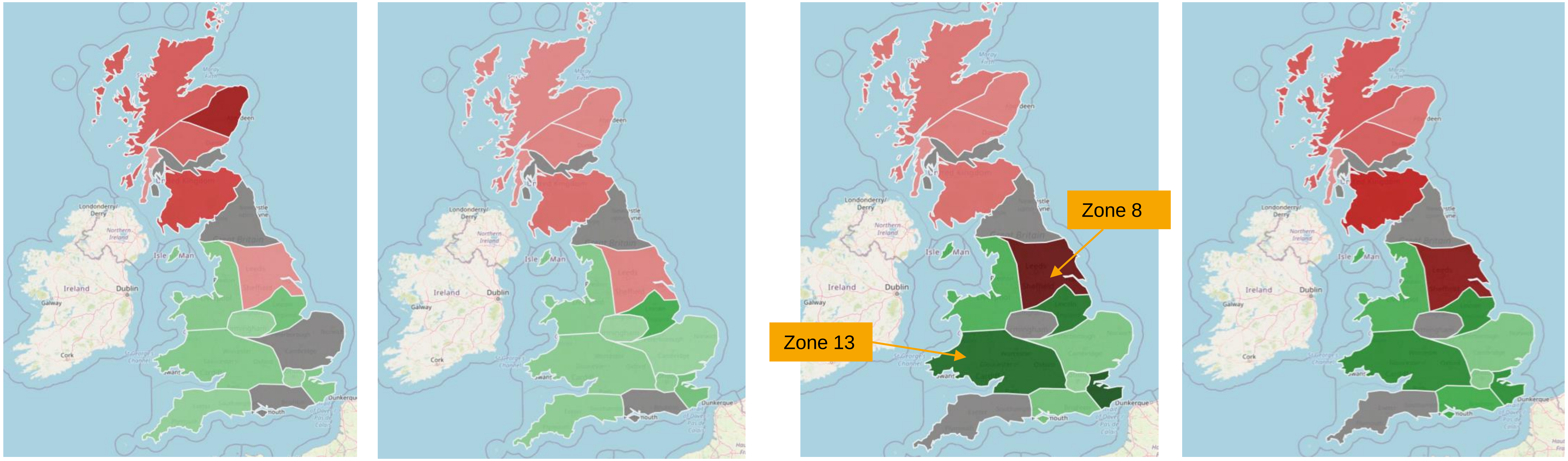
2020

- Short system
- On average, paying to turn units up (offers ~ £40/MWh)
- Bids are now closer to £0/MWh, so very little offset
- Nets out to a material cost

Note: RCRC should reimburse this cost to participants

Key drivers to BSUoS

System actions - locational constraints



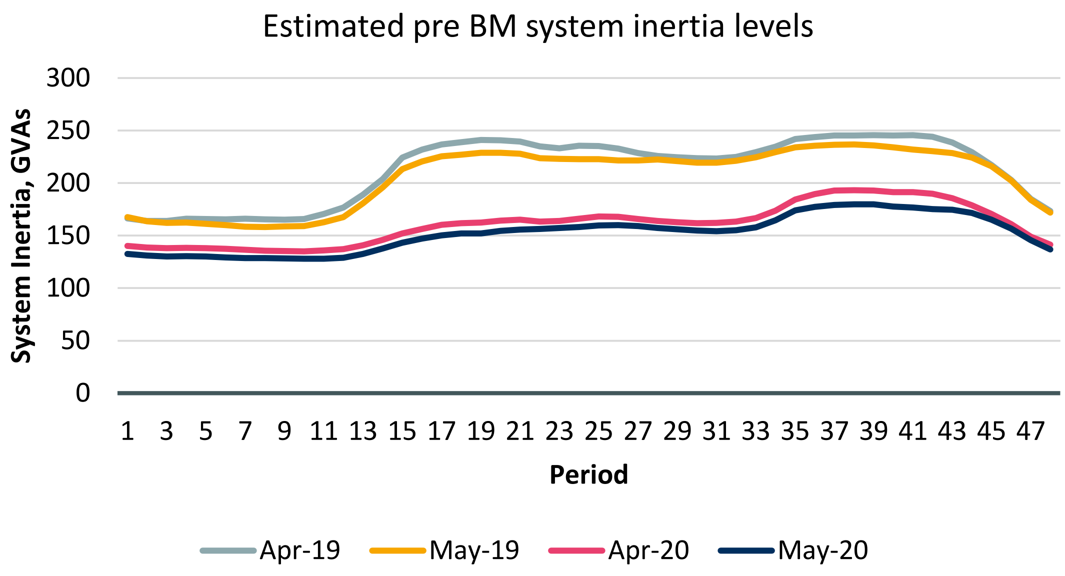
Apr 2019 **May 2019** **Apr 2020** **May 2020**

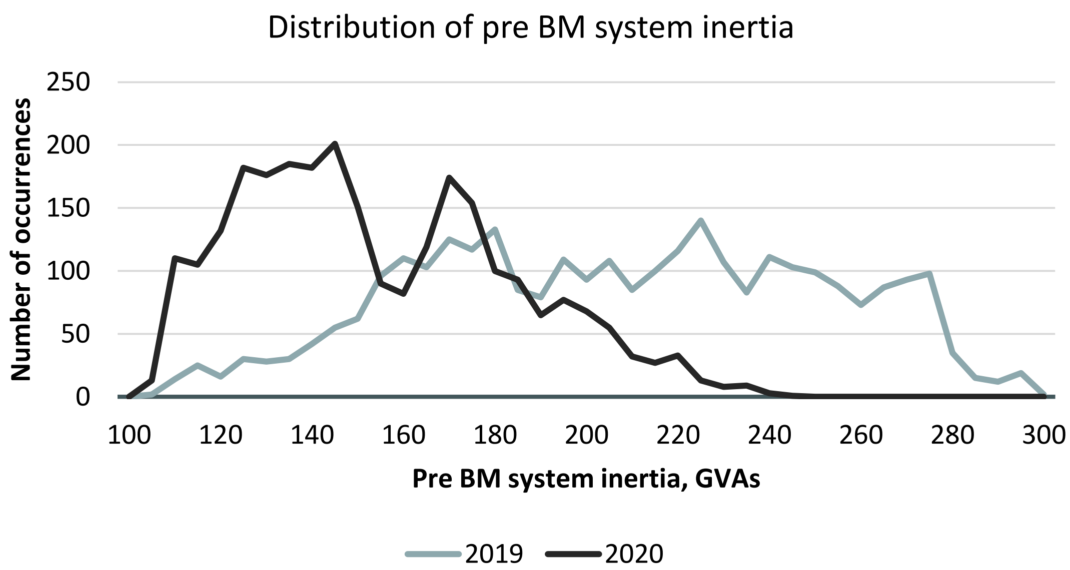
High SO Bid (turn-down) volume ***High SO Offer (turn-up) volume***

- The England/Wales constraint has been the largest contributor to BSUoS (**~50% of all balancing costs**)
- Low demand has exacerbated effects such as: offshore wind congestion, RoCoF management, congestion around the Humber area and voltage management
- Zone 8 received 22x the volume of accepted SO bids in Apr/May 2020 compared to the same period in 2019.
- Zone 13 received 10x the volume of accepted SO offers in Apr/May 2020 compared to the same period in 2019.

Key drivers to BSUoS

Inertia

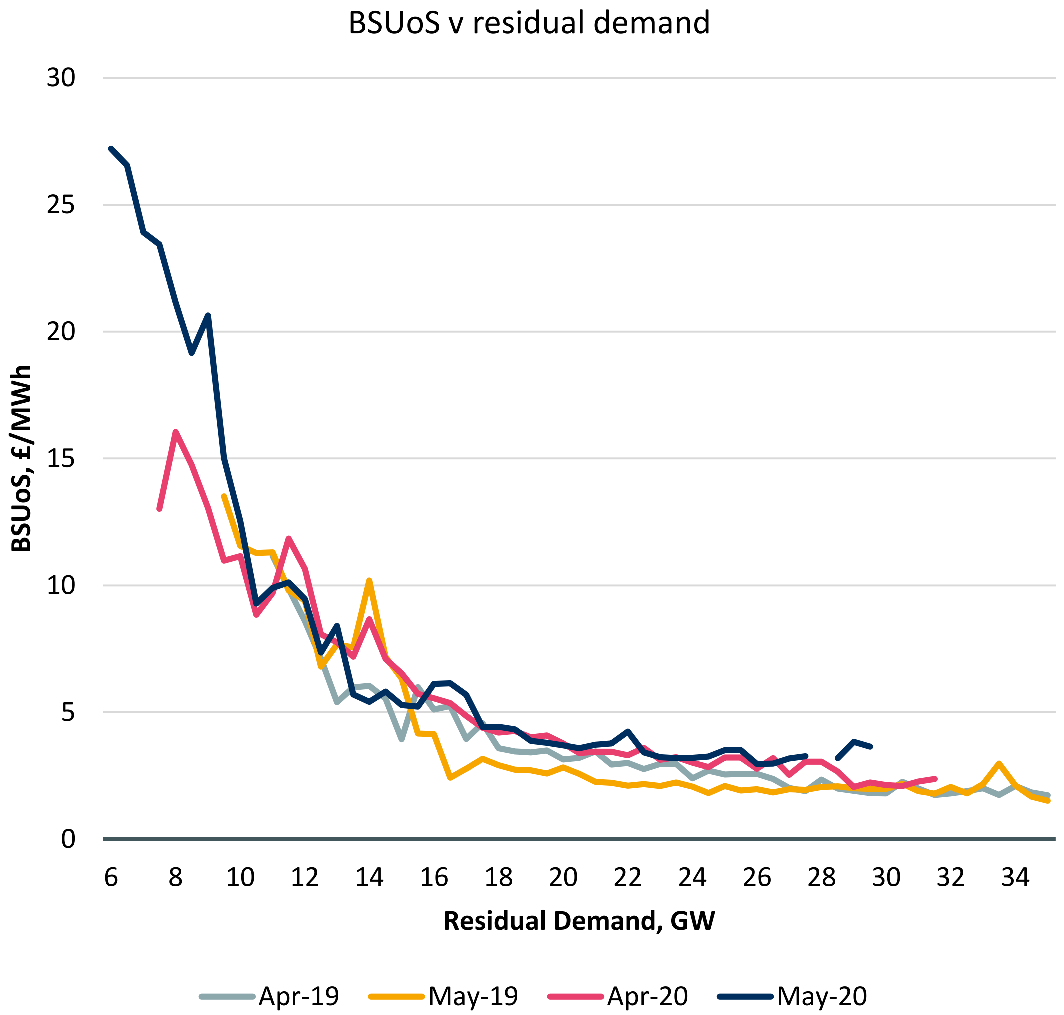




This year's system inertia levels are ***significantly*** *lower than the same time last year:*

- This is a result of low demand, high renewable output and less synchronous generation
- While NGESO do not separate out actions taken for maintaining inertia, it is clear that certain periods will have required an increase in system inertia

Bringing it all together



*All of these effects can be broadly captured by considering **residual demand:***

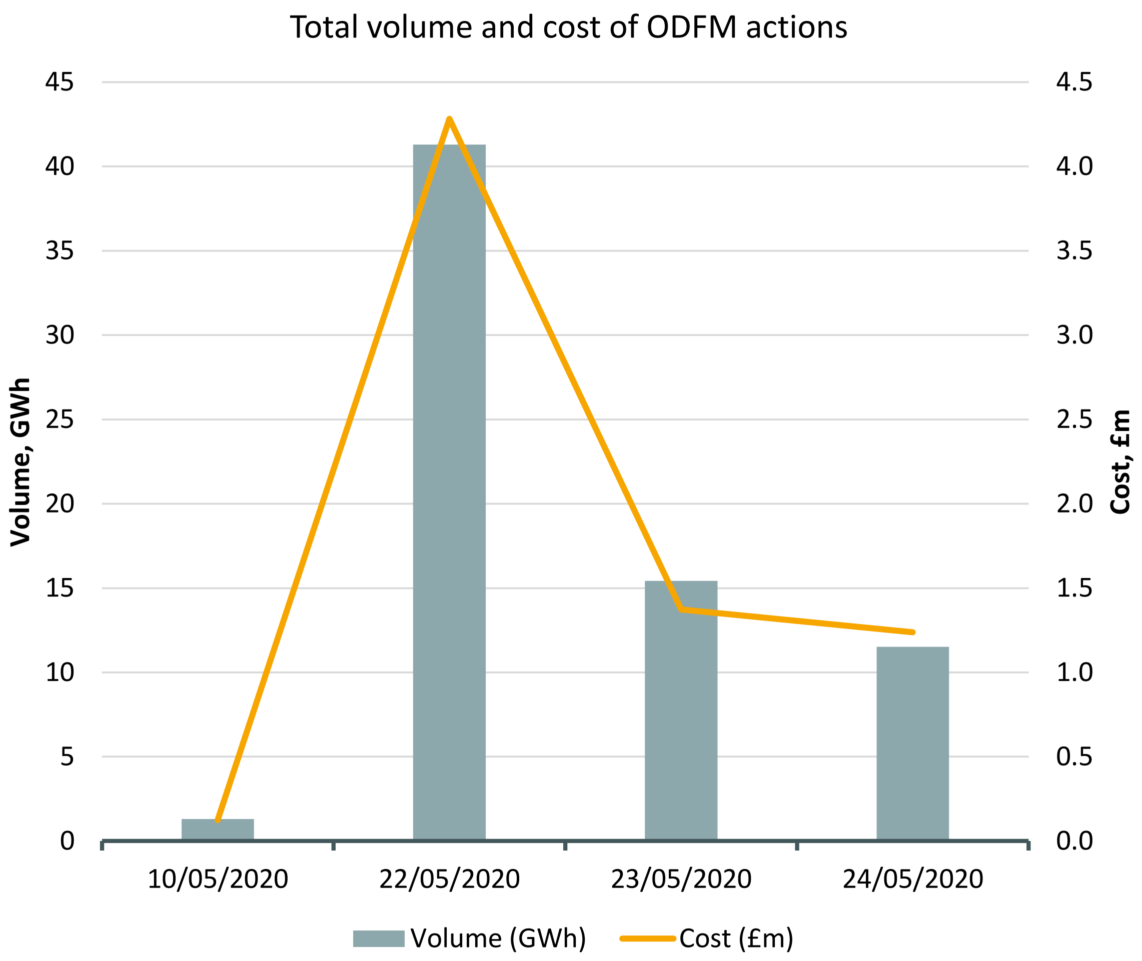
Residual Demand** = **Tx Demand** – **Tx Wind *(pre curtailment)*

- This shows a fairly consistent relationship with BSUoS to last year, suggesting we are not experiencing materially different costs for similar levels of residual demand
- We are simply extending the curve further to the left to low levels of residual demand we have not seen before

Non Market Based Tools

Non Market Based Tools

Optional Downward Flexibility Management (ODFM) and Sizewell B



- Allows the ESO to increase demand in low demand periods by turning off embedded generation or turning up embedded demand
- This flexibility is procured outside of the BM and other markets, effectively removing these actions from the BM.

ODFM is currently only set to last for summer

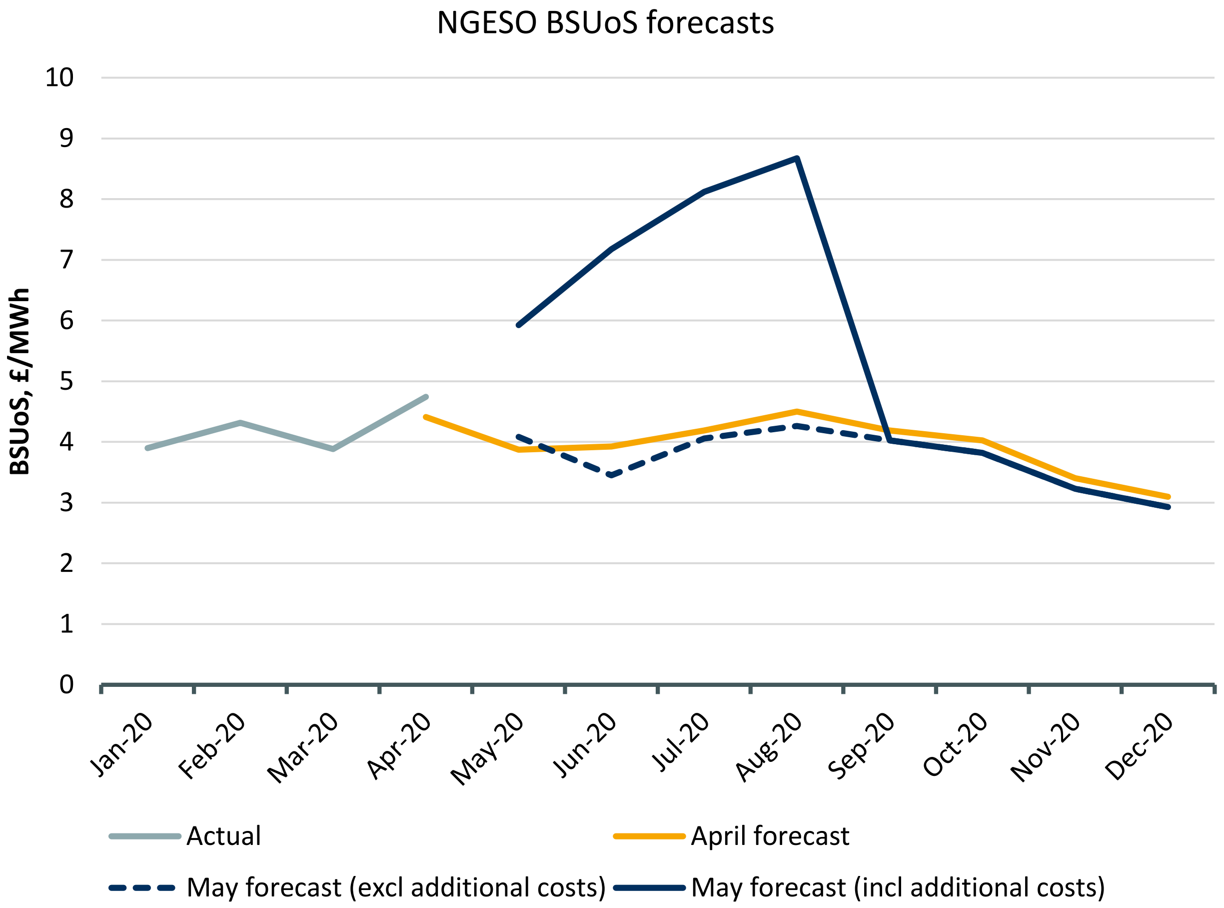
- Utilisation-based service fee (£/MW/hr).
- ODFM actions will not feed into cashout, with costs recovered through BSUoS.

National Grid ESO has also confirmed that it has agreed a “one off, fixed term” contract with Sizewell B instead of making daily payments to the generator via the Balancing Mechanism.

Looking forward

NGESO BSUoS forecasts

Projecting an additional £427m of balancing cost over the May-August 2020 summer period



NGESO published revised BSUoS projections on the 15th May, showing an additional £427m across the May-August summer period

This was based on modelling of low demand periods, specifically where transmission system demand is below 18GW and hence ESO intervention is required to ensure system stability.

NGESO used a wide range of demand simulations (30,000), but static assumptions on the bid/offers and required level of actions at each low demand level

NGESO BSUoS forecasts

NGESO have made a number of key assumptions about the costs of actions at low levels of demand

Bids / offers, £/MWh	Period	Demand (GW) 13	14	15	16	17	18
CCGT offer	All	80	80	80	80	80	80
Wind bid	Daytime	-150	-150	-150	-100	-70	-60
	Overnight	-80	-80	-80	-70	-60	-60
IC trade	All	-200	-100	-50	-50	-10	-10
New service	All	-200	-200	-200	-200	-200	-200
Market dispatch, MW	**Period**	**13**	**14**	**15**	**16**	**17**	**18**
CCGT dispatch	Daytime	918	1,192	1,490	1,706	2,759	3,863
	Overnight	187	187	357	1,004	1,674	1,474
Forecast wind	All	7,500	7,500	8,000	10,000	10,000	10,000
Forecast IC	All	500	500	500	1,000	2,000	2,000
Nuclear load	All	5,648	5,648	5,648	5,648	5,648	5,648
Pump storage	All	-556	-556	-556	-556	-834	-834
System requirement, MW	**Period**	**13**	**14**	**15**	**16**	**17**	**18**
CCGT requirement	Daytime	6,118	5,958	5,958	5,688	5,518	5,518
	Overnight	3,738	3,738	3,568	3,348	3,348	2,948
Max Wind	Daytime	900	2,187	3,383	4,579	6,274	7,470
	Overnight	3,093	3,990	5,286	6,608	7,505	8,731
IC requirement	All	-500	-500	-500	-500	-1,000	-1,000

- The assumed offer prices (the price at which a generator will either turn-on or increase its output) for CCGT across all the 13-18GW demand range seem high against a background of low gas and EU ETS prices and in comparison to recent BM activity.
- Wind bid prices (the price paid by a generator to reduce its output) seem very heavily negative, rising to the prices required by AR1 supported CfD generators to turn-down or off. This implies a significant level of turndown given the amount of wind capacity receiving lower levels of support.
- IC traded prices (price required in this instance to reverse flow across the interconnectors) seem to mirror the level of wind bids.

Sensitivities on NGESO BSUoS forecasts

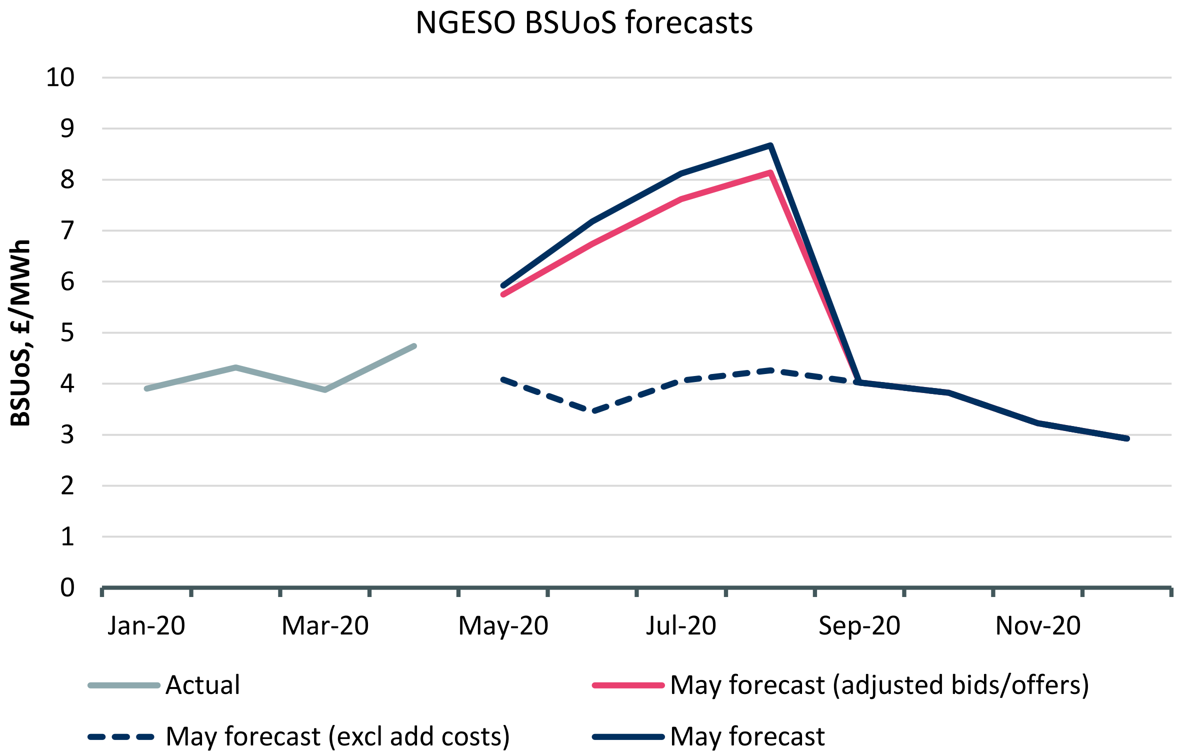
Adjusting CCGT & wind offers/bids based on recent observations

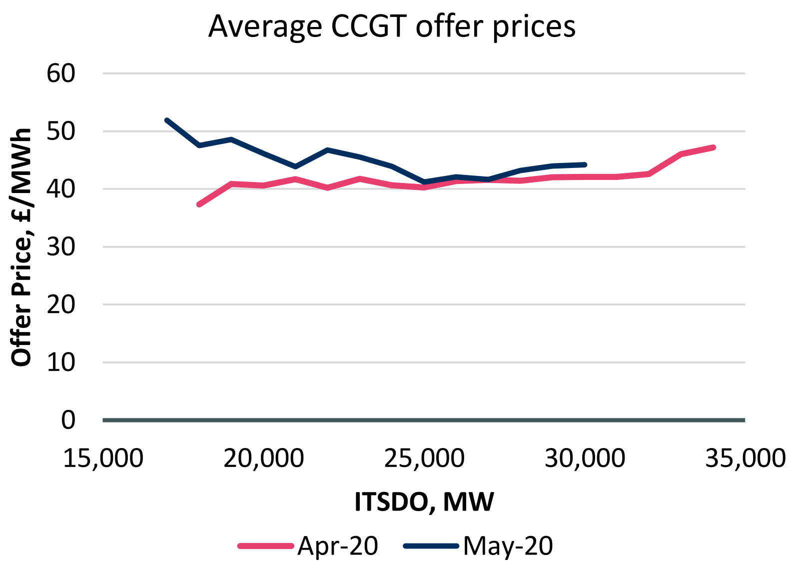
		Demand (GW)					
Bids / offers, £/MWh	Period	13	14	15	16	17	18
CCGT offer	All	50	50	50	50	50	50
Wind bid	Daytime	-195	-134	-131	-129	-73	-73
	Overnight	-131	-84	-73	-73	-73	-68

Using data on actual bid/offers from April/May May, have adjusted the assumptions for CCGT offer prices, down from £80/MWh to £50/MWh.

Doing same for wind (plus assumptions on the supply curve) aligns closely with NGESO assumptions.

This brings the BSUoS forecast down slightly.

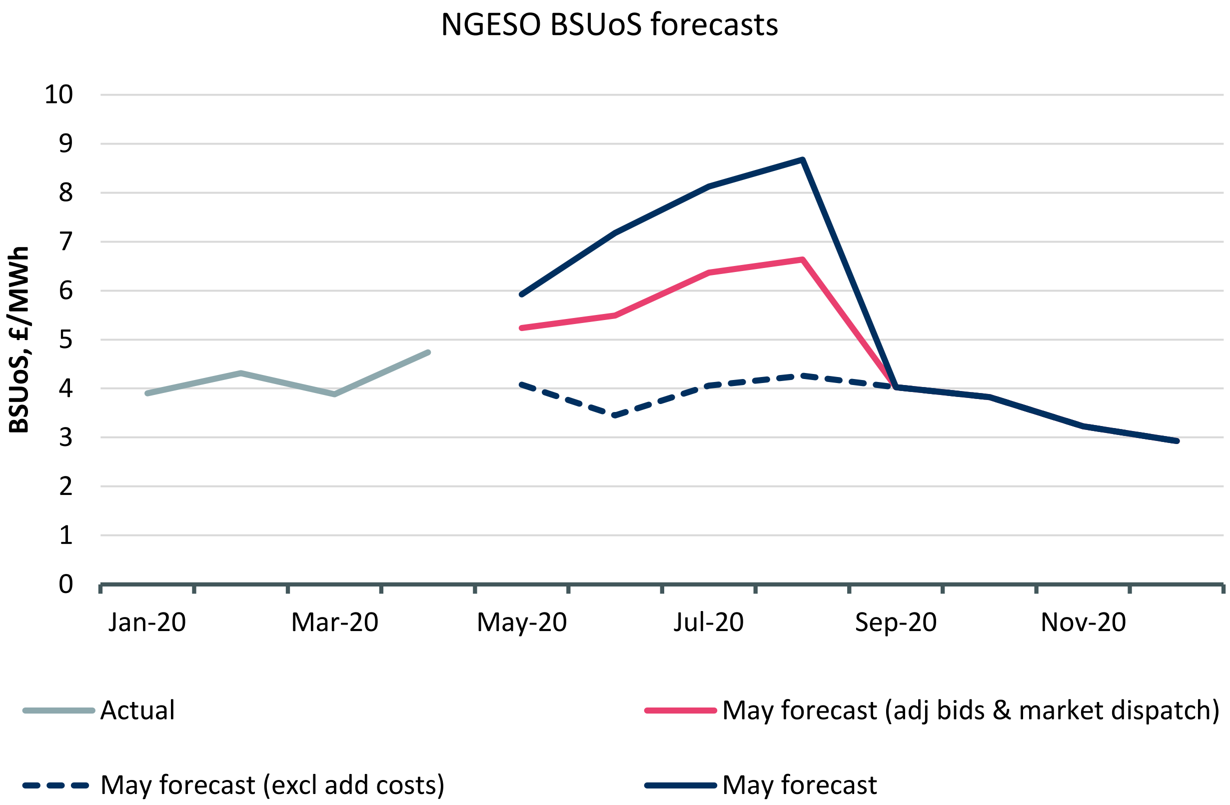




Sensitivities on NGESO BSUoS forecasts

Adjusting CCGT & wind market dispatch assumptions based on recent observations

Market dispatch, MW	Period	13	14	15	16	17	18
CCGT dispatch	Daytime	1,200	1,200	1,200	1,600	2,400	3,200
	Overnight	548	548	548	548	1,348	2,148
Forecast wind	All	6,000	6,000	6,000	6,000	6,000	6,000



We have also tested NGESO's projections using updated assumptions for the **market dispatch** of CCGT and wind.

The CCGT assumptions from NGESO appear reasonable, aligning closely to the level of dispatch observed at low levels of demand in recent months.

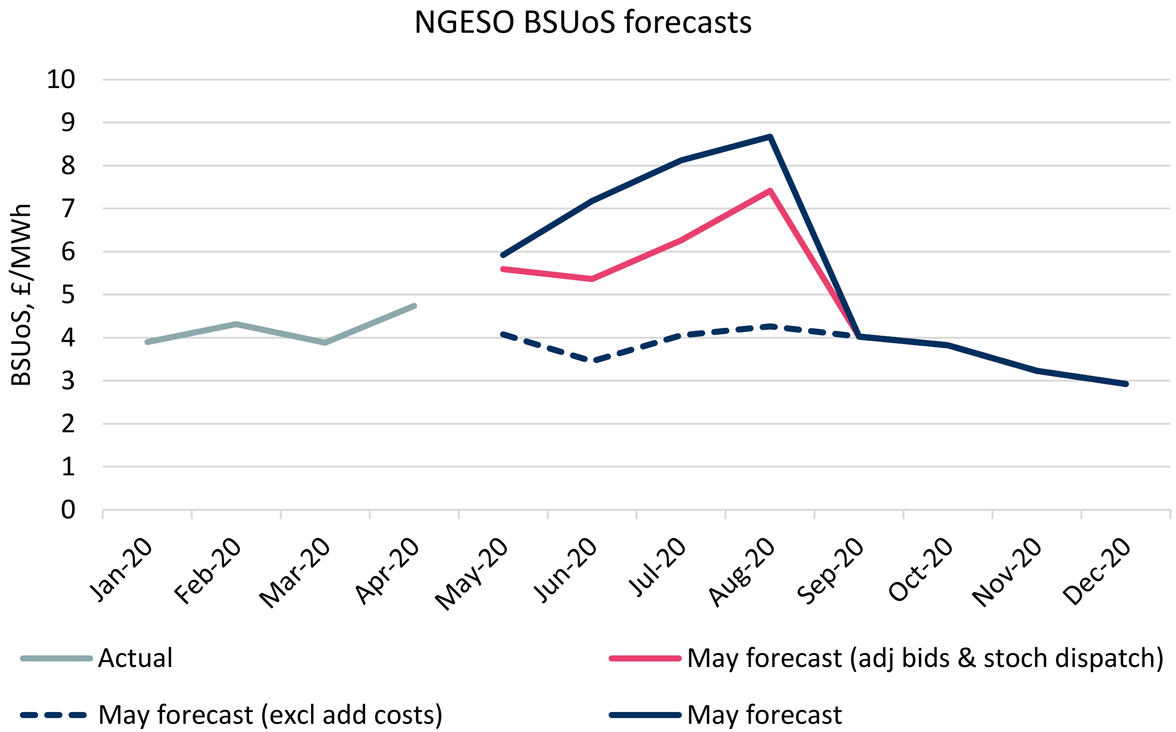
However, the wind forecast assumption of 10GW is relatively high, with low periods of demand averaging closer to 6GW output.

Reducing assumed wind output (before curtailment) to 6GW has a material impact on BSUoS forecasts, roughly halving the additional costs due to Covid-19 effects.

Sensitivities on NGESO BSUoS forecasts

Simulated wind and market dispatch stochastically

System requirement, MW	Period	13	14	15	16	17	18
CCGT requirement	Daytime	6,118	5,958	5,958	5,688	5,518	5,518
	Overnight	3,738	3,738	3,568	3,348	3,348	2,948
Max Wind	Daytime	900	2,187	3,383	4,579	6,274	7,470
	Overnight	3,093	3,990	5,286	6,608	7,505	8,731
IC requirement	All	-500	-500	-500	-500	-1,000	-1,000



NGESO's modelling uses a static view of market dispatch (though is run against a very large number of demand traces).

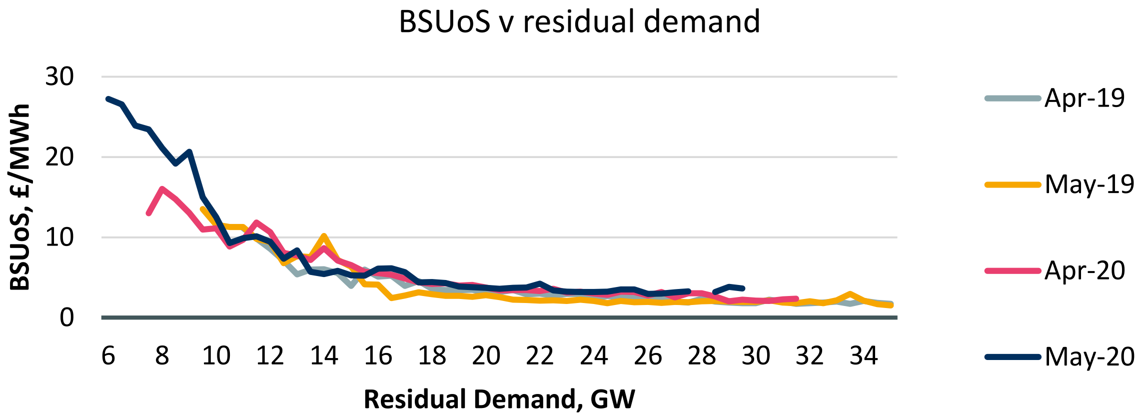
We have used LCP's dispatch model to also **stochastically simulate wind**, and the resulting market dispatch of other generation.

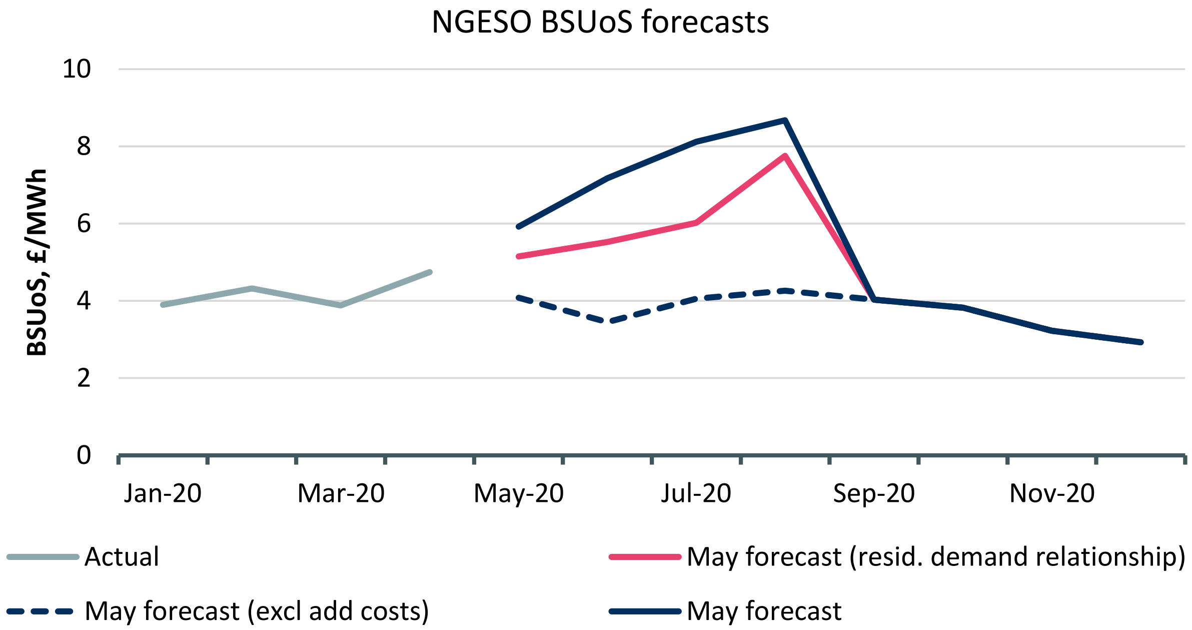
We have maintained NGESO's assumptions for the level of synchronous generation required at different demand levels.

This shows reasonably close alignment to the results using our updated dispatch and bid assumptions on the previous slide.

Sense check Grid numbers using relationship

Residual demand relationship established in backwards looking analysis



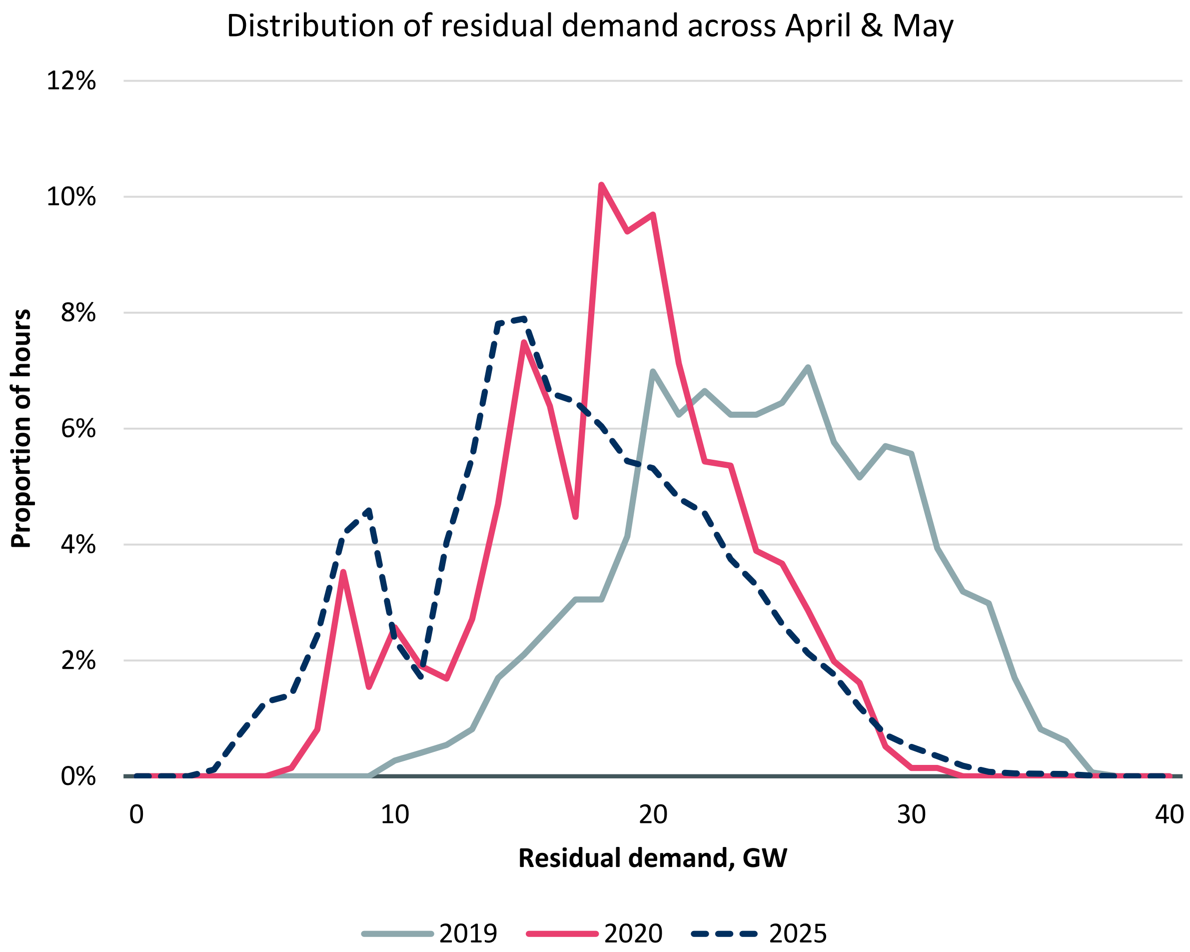


In the backwards looking analysis, we saw a strong relationship between **residual demand and BSUoS**

Applying this relationship against our simulations of wind & demand for May-Aug 2020 provides a useful sense check on the more detailed modelling.

The new normal?

Low residual demand levels will become commonplace in future years



The lower levels of residual demand under Covid-19 have led to increased BSUoS charges in 2020 relative to 2019.

However, these residual demand levels are likely to become normal in coming years.

Looking at the April-May period in 2025 (based on LCP modelling), residual demand levels are expected to be even lower than those seen in 2020. This is a result of higher levels of renewable generation rather than lower demand, so will not result in the same reduction of charging base. Nevertheless this will lead to high BSUoS charges.

In addition, higher commodity prices will increase the cost of system actions (as CCGTs are typically turned up) and increase BSUoS charges (all else remaining equal).

Conclusions

Under Covid-19, BSUoS charges have increased and become more volatile

- This is primarily due to **increased constraint costs** (for locational and system stability actions) and a **smaller charging base** – both of which are driven by lower levels of demand
- There is a particularly strong relationship observed between BSUoS charges and residual demand (transmission system demand net of wind)

NGESO's forecasts predict an additional ~£500m of costs this summer. However, these projections use some cautious assumptions, such as high CCGT prices, static market dispatch and one wind level over all simulations. Based on our analysis of recent market behaviour, stochastic analysis of summer and using NGESO's current expectations of the requirement for balancing actions at different demand levels, **we expect a lower additional cost than is currently forecast.**

- These forecasts are very uncertain due to high level of volatility in key inputs, uncertainty in market behaviour and new services being implemented by NGESO
- To truly capture the costs of summer, **a more detailed fundamentals-based approach is required**, due to a lack of historic data for the low levels of demand we expect to see and to fully capture locational impacts.

High, volatile BSUoS charges are expected to be a feature in the future

- Increased renewable penetration will drive low residual demand levels similar to those seen this summer
- A return to higher commodity prices would increased costs of system actions and could lead to higher BSUoS charges (all else remaining equal)
- An issue we have not covered is the increase in Scottish constraints. Though not a major driver for this summer's high costs, they are expected to become a significant cost in future years and drive high BSUoS charges outside of summer

Appendix: Future impacts of constraint management on BSUoS

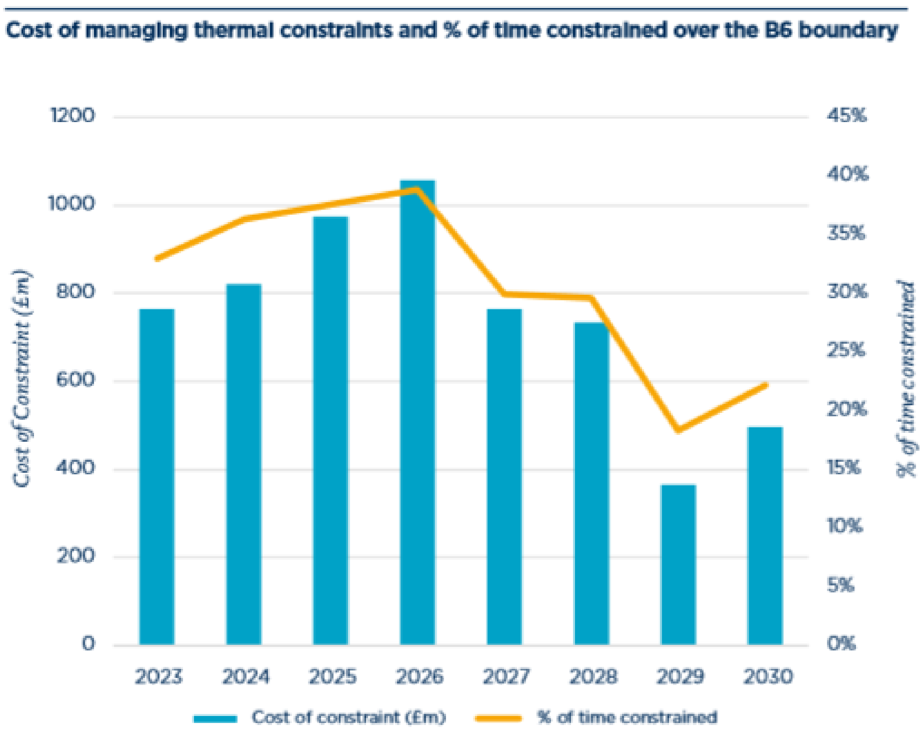
Impacts of constraint management on BSUoS

Analysis of constraint management between 2023 - 2030

We analysed the 2023 – 2030 period, which spans the period from the start of the constraint management service being procured by National Grid ESO until the end of the Network Options Assessment (NOA) period.

The graph shows LCP's constraint forecasts across just the B6 boundary between 2023 and 2030. Currently the ESO is spending about £450m a year on constraints across all of GB but **LCP forecast that by 2025 the ESO will be spending almost £1bn a year** across just the B6 transmission boundary.

40% of the time, the power transfer limit of this boundary will be exceeded. In other words**, 40% of the time renewable generation will have to be constrained off** and almost certainly replaced with carbon emitting generation sources south of this boundary.



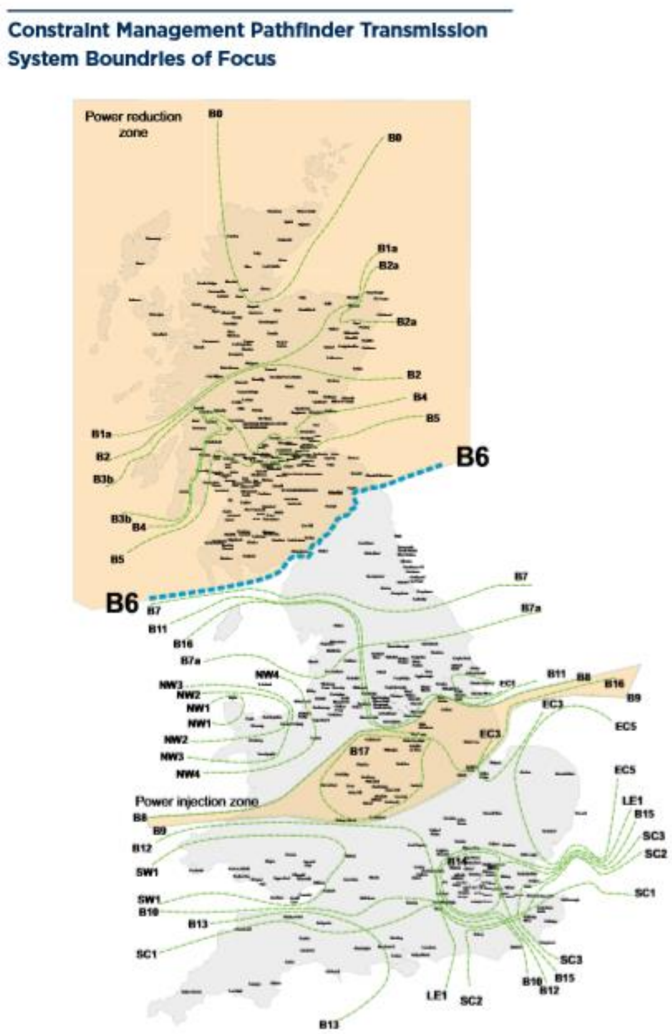
Impacts of constraint management on BSUoS

Analysis of constraint management between 2023 - 2030

We see significant drops in the cost of managing thermal constraints in 2027 and 2029 this is due to major transmission builds being completed. These are E2DC (a 2GW HVDC cable from Torness to Hawthorne Pit) and E4D3 (a 2GW HVDC cable from Peterhead to Drax).

Originally this transmission infrastructure was estimated for delivery in 2023 but despite the ESO recommending the construction of these links, the Transmission Operators (TO's) were not able to proceed with any preliminary work due to Ofgem not guaranteeing funding through the network price controls.

East Anglia and the South East coast also have constraint issues arising in the future.



National Grid constraint management pathfinder map

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