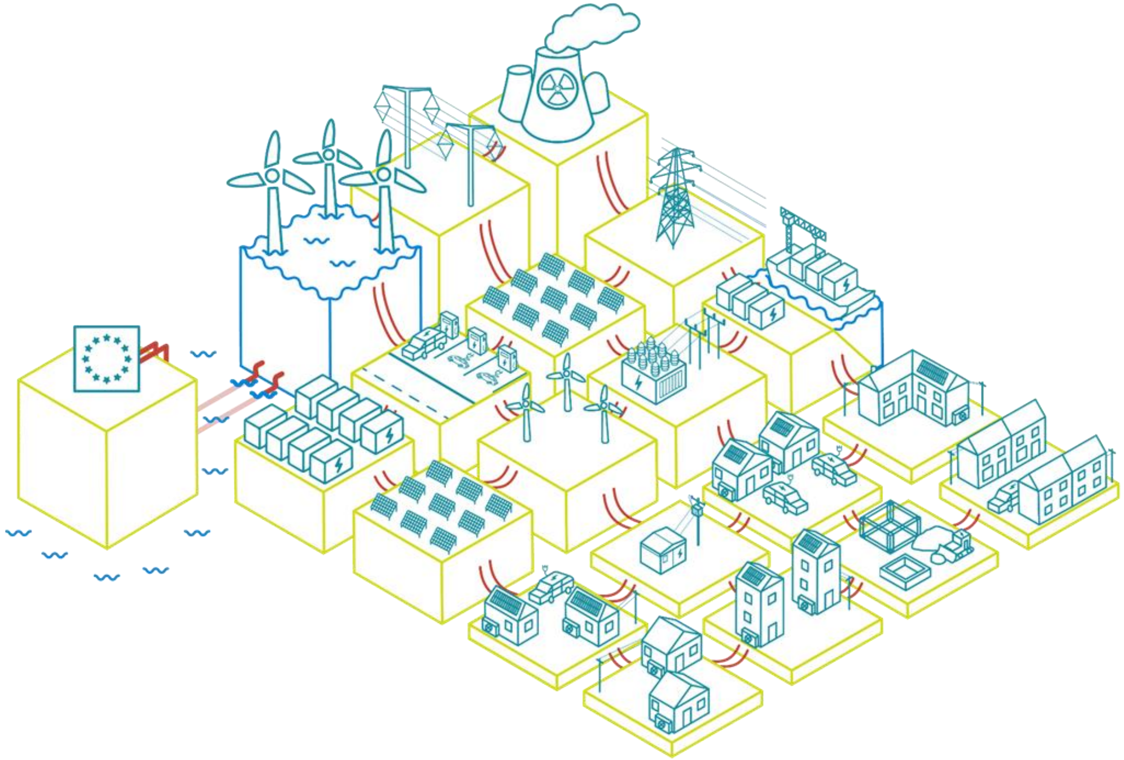
Energy Security and Net Zero Select Committee Briefing

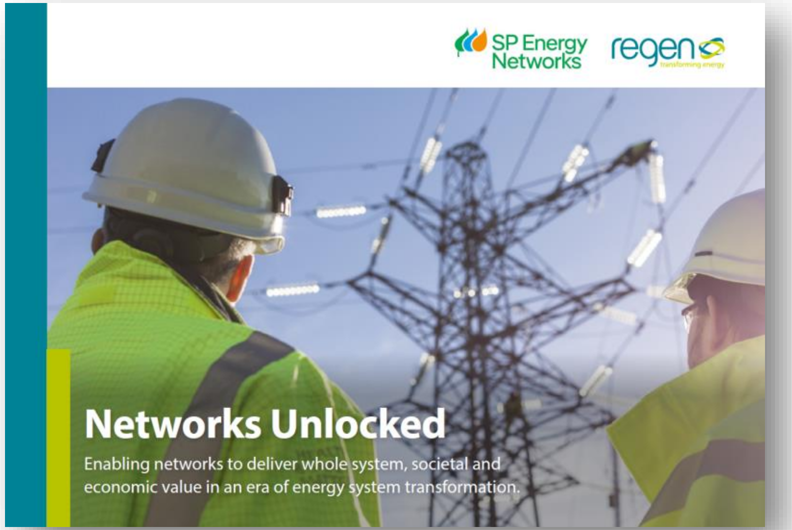
Managing Network Constraints

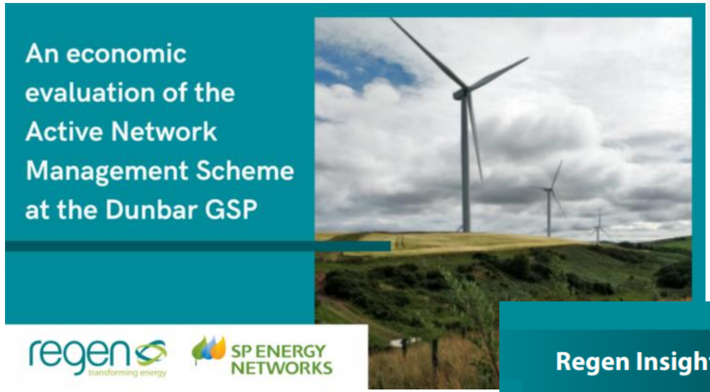


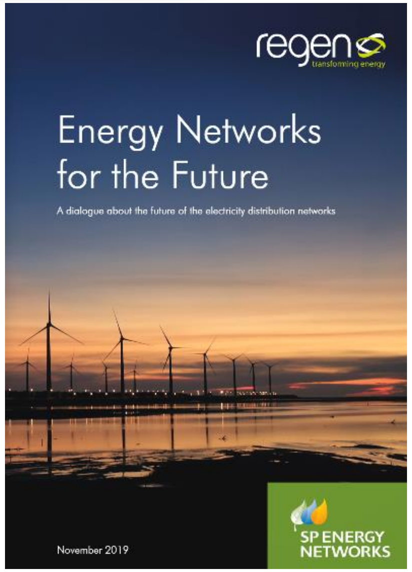
Johnny Gowdy and Ellie Brundrett

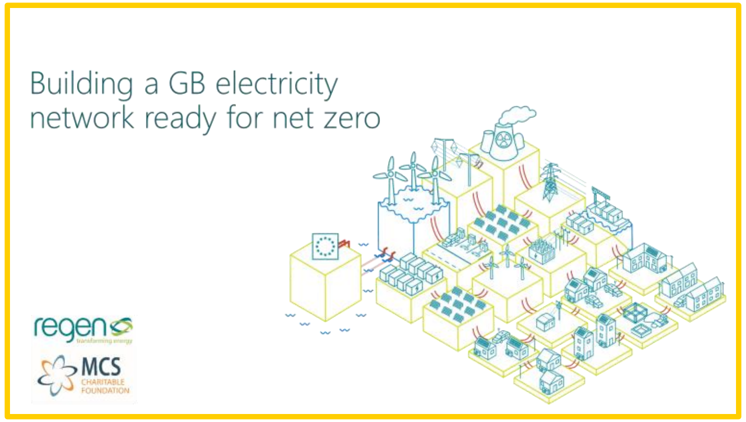
January 2024

Recent Regen publications on grid









Presentation summary – key discussion points

1. Generators must have **a firm connection agreement** with the networks to receive constraint payments. Wind farms cannot just build themselves without grid capacity and then receive constraint payments.
2. **No constraints would not be economically efficient** - ultimately the cause of constraints is the timing and alignment of network capacity changes in energy flows
3. In recent years generation **constraint volumes have not increased**, but **constraint costs have risen significantly** since the start of the energy crisis Sept 2021, with the price of gas.
4. **Scottish boundaries (B4 & B6)** are the most constrained during high wind periods, but there are also constraints across England and Wales
5. **Constraint Turn-Down payments** made to generators are limited by transmission licence condition to provide **lost revenue compensation only**.
6. The largest proportion of constraint costs **is to TURN-UP generation** (usually CCGT plants) to replace constrained generation. **We are replacing lower cost/carbon energy with higher cost gas generation**
7. Other options to provide Turn-up and Turn-down services are available – **notably batteries** – but control room processes and tools are **still geared to the use of large CCGT plant** – this is changing.
8. There **are lots of opportunities to better manage and reduce constraint costs**. Everything from better strategic planning, better forecasting and transparency, expansion and competition in the balancing mechanism, new constraint markets, more efficient control room functions etc etc – see Part 2

Agenda

Part 1 – Constraints facts and figures

- Where and why do we have constraints
- How much do they cost and why the increase
- Current constraint management

Part 2 – Constraints policy, reform and innovation

- Reducing the occurrence of constraints
- Reducing the cost of managing constraints
- A new energy system – **smart and progressive** market reform

Constraints where and why

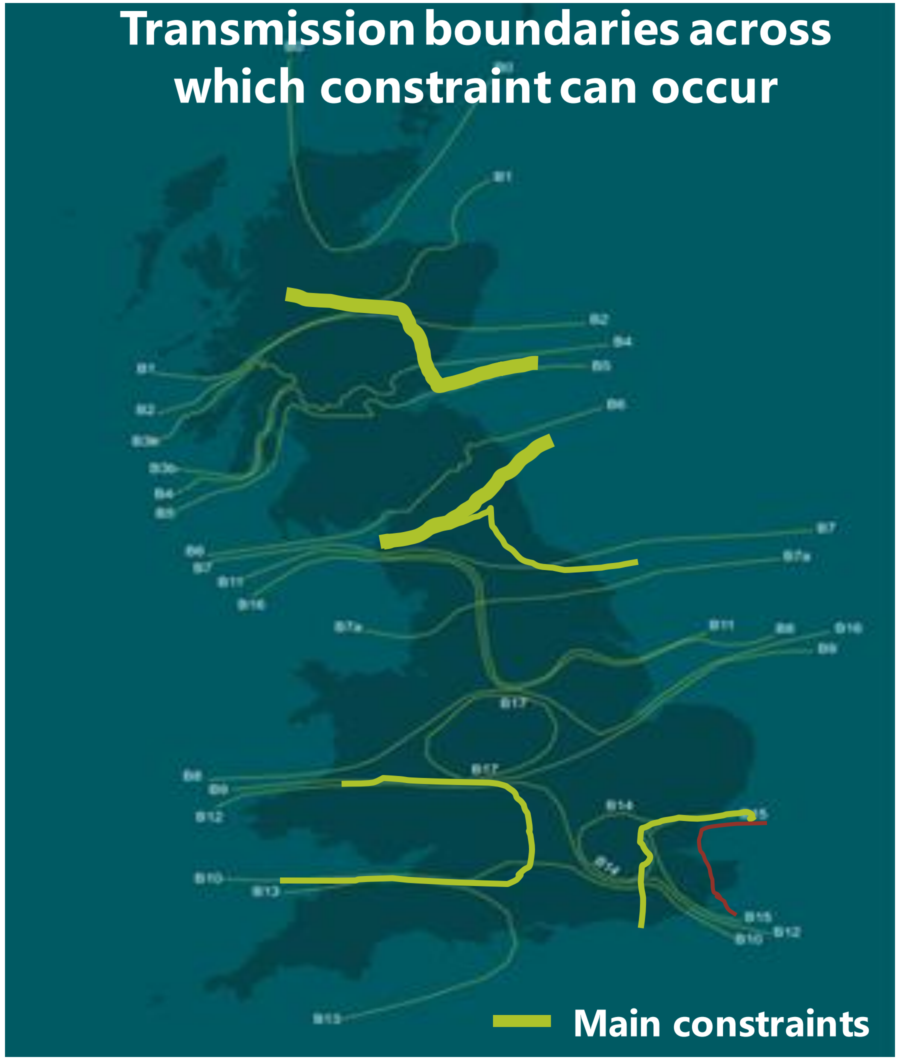
Networks can be constrained, with insufficient capacity, for generation and demand customers.

There will always be some potential for constraint on the electricity networks (both transmission and distribution).

A constraint-free system, i.e. meeting every load, at every location, at all times, would not be economically efficient.

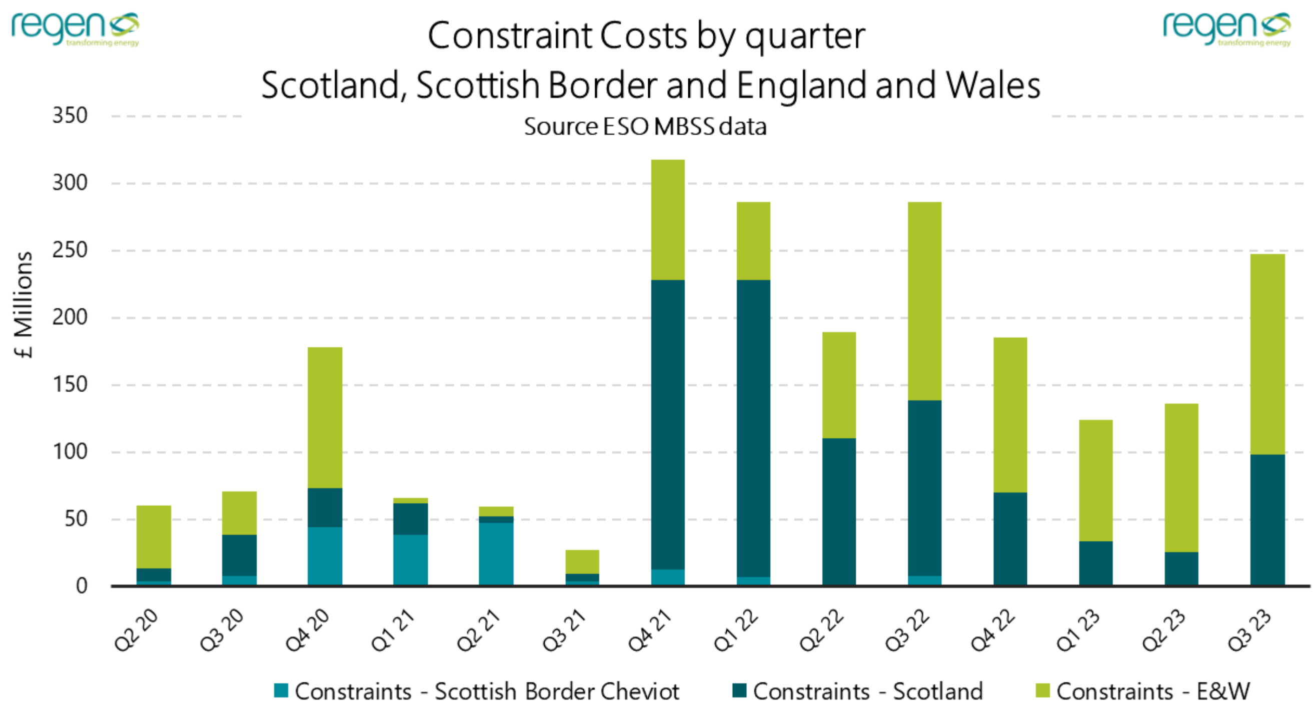
Constraints are ultimately caused by :

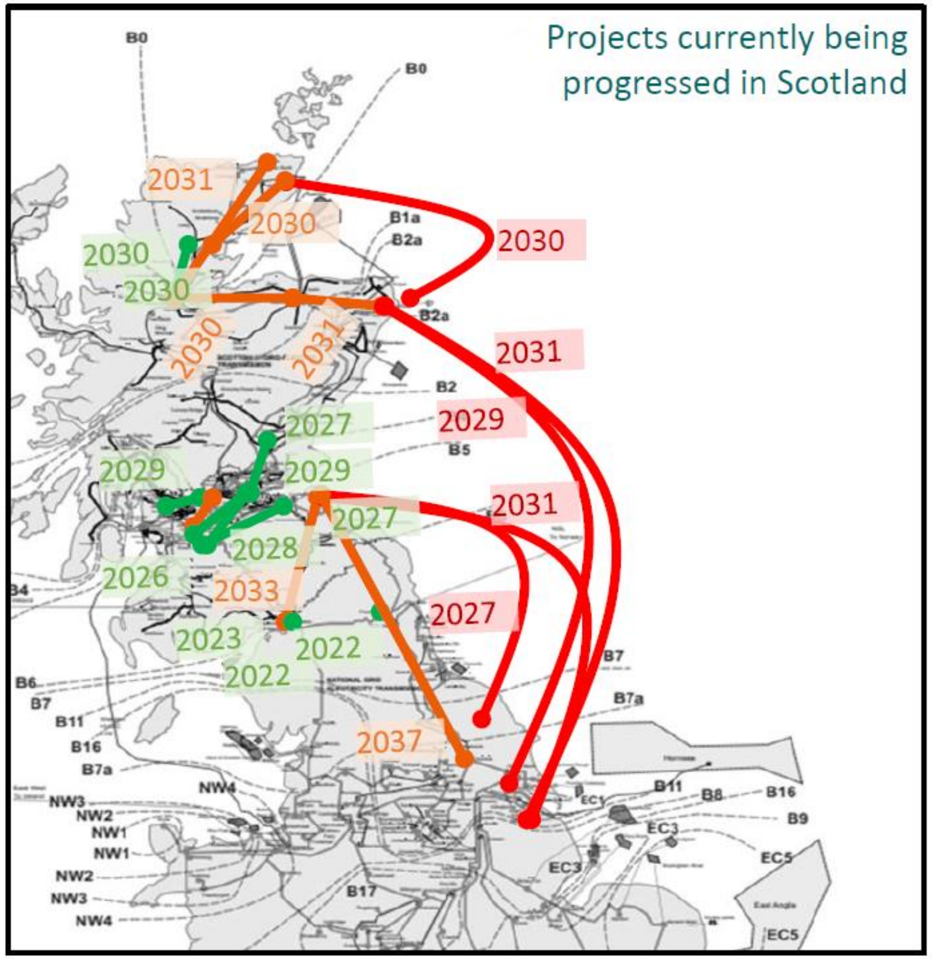
- **Planned delays in network upgrades** – networks / Ofgem run a CBA analysis and take a decision to accept a degree of constraint. 'Connect and manage' and Totex
- **Unplanned delays in network upgrades**
- **Unexpected/unplanned increase in network loads** – sometimes due to future forecasting errors or unexpected changes in energy demand or generation



Generation constraints have been across the Scottish boundaries, but also occur in England and Wales

- In 2021 and 2022, constraints costs were mainly incurred across the two main Scottish boundaries
- Since 2023 there has been a shift back to England and Wales, but in high wind periods Scottish boundaries still predominate





The location of constraints will shift as new network is built, and as new generation is added

Grid connections – quick explainer

There is a bit of a myth that the cause of constraints is wind and solar generation popping up in the wrong place without grid capacity and then claiming constraint payments. In fact, generators must have a grid connection agreement with the networks before connecting. This is usually obtained right at the start of a project, before planning consent and before applying for a CfD.

Generators apply for a grid connection from distribution or transmission network. They will likely have to pay an application fees.

Networks will then make a Connection Offer. This will have a connection date and any connection costs to be paid by the generator for network upgrades

At the moment, connection dates can be significantly delayed, 5-10 years is not uncommon.

For Distribution connections, the up front connection costs can be significant e.g. £60-120k per MW. For Transmission connection costs are less but ongoing network charges are higher

If generators accept the connection offer, they will have to pay securities and potentially an up-front contribution for network works. If a developer withdraws there will be termination fees

The constraint issue is closely related to connection queues – two sides of the same coin, network capacity.

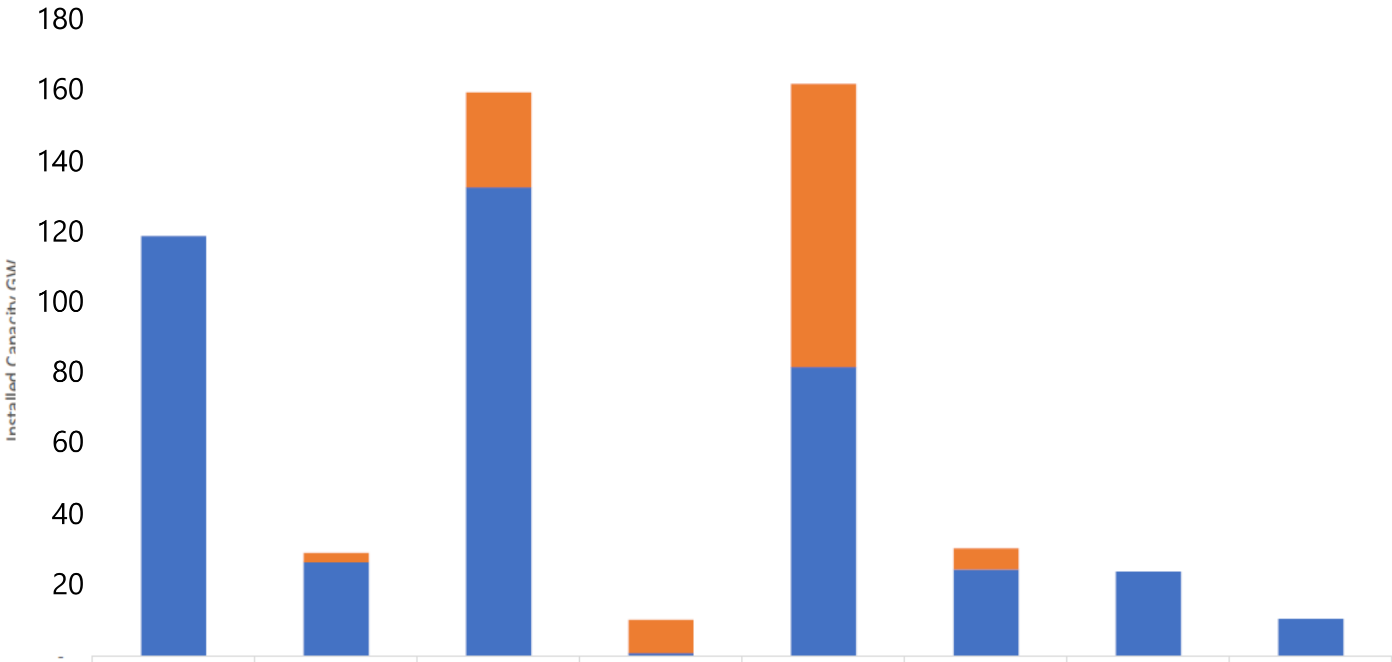
Constraints are closely tied to long connection queues.

Both are symptoms of misalignment between network capacity and load growth (albeit that the queues includes many speculative projects).

We can reduce constraints by delaying connections in the queue.

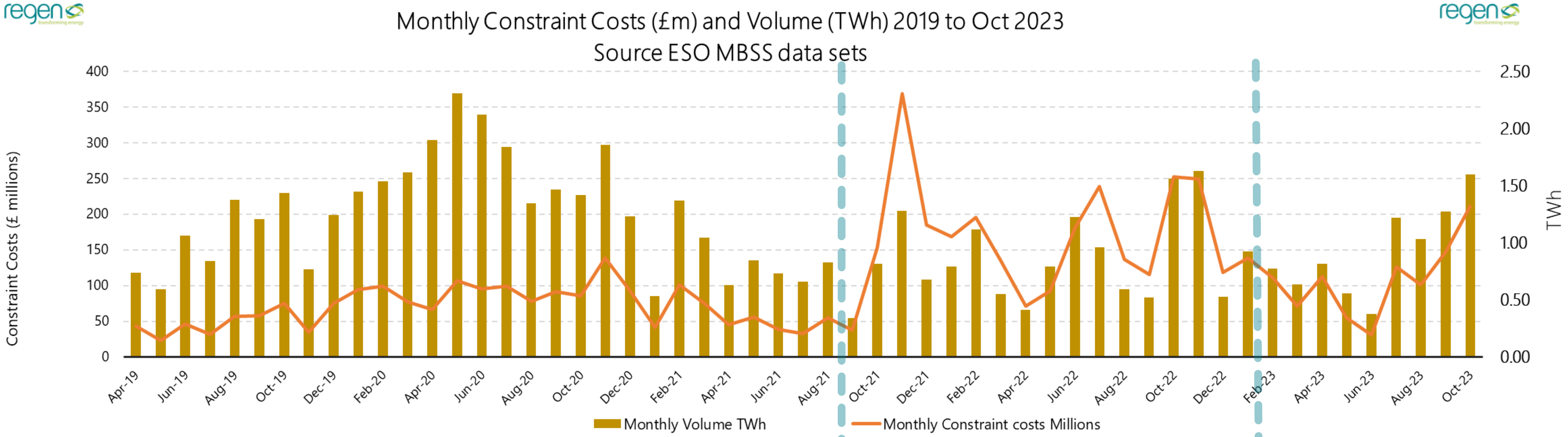
To an extent that is already happening as we move away from 'connect and manage'.

Connection Queue : transmission and distribution



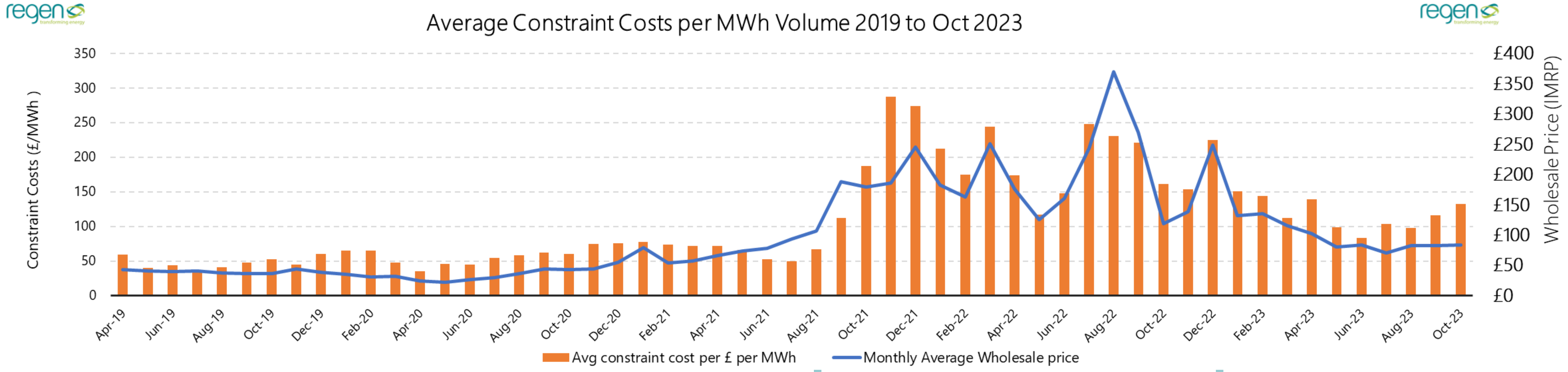
	Wind Offshore	Wind Onshore	Solar	Other Renewable	Storage	Non-Renewable	Interconnector	Nuclear	
Distribution	-	2,562	26,761	9,320	79,728	5,821	-	-	124 GW
Transmission	118,546	26,644	132,284	1,010	81,722	24,686	23,954	10,680	420 GW
	118.5	29	159	10	161.5	30.5	24	10.7	544 GW

Constraint costs and volume 2019 – Oct 2023



	Pre Energy Crisis Apr 2019-Aug 2021	Energy Crisis Period	Post(?) Crisis
Avg Monthly Constraint Volume TWh	1.24 TWh	0.86 TWh	0.94 TWh
Avg Monthly Constraint Cost (millions)	£70 m	£169 m	£111 m
Avg Constraint Cost per MWh	£56 / MWh	£196 / MWh	£120 MWh
Avg Wholesale Price per MWh	£48 / MWh	£198 / MWh	£97 MWh

There is a close correlation between constraint costs and the wholesale price



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What are the constraint management costs?

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There is generally two sides to a constraint management action

Generation Turn DOWN

ESO will instruct a generator to turn down within the constraint area e.g. wind in Scotland

Generator will pay its **BID price** to turn down

For wind, the Bid price is negative, so the generator receives a payment

Under **licence conditions** the wind Bid price can **ONLY reflect** lost marginal revenue or cost

For wind this is generally the RO lost or CfD payment, REGO plus some operational costs.

On average, for wind, this is around £40-50 per MWh

£

Generation Turn UP

ESO will also instruct a generator to turn up outside the constraint area to ensure that demand is met

Generator will receive its **OFFER price** to turn up – the majority of turn ups are **CCGT** plants

Offer prices reflect spot market prices and can be extremely high during peak price periods

During the energy crisis period Offer prices average around £200 MWh and sometimes much higher

Around 70-80% of constraint costs are to Turn UP energy!

£££

Average bid and offer prices for different technologies during the period March 21 - April 22

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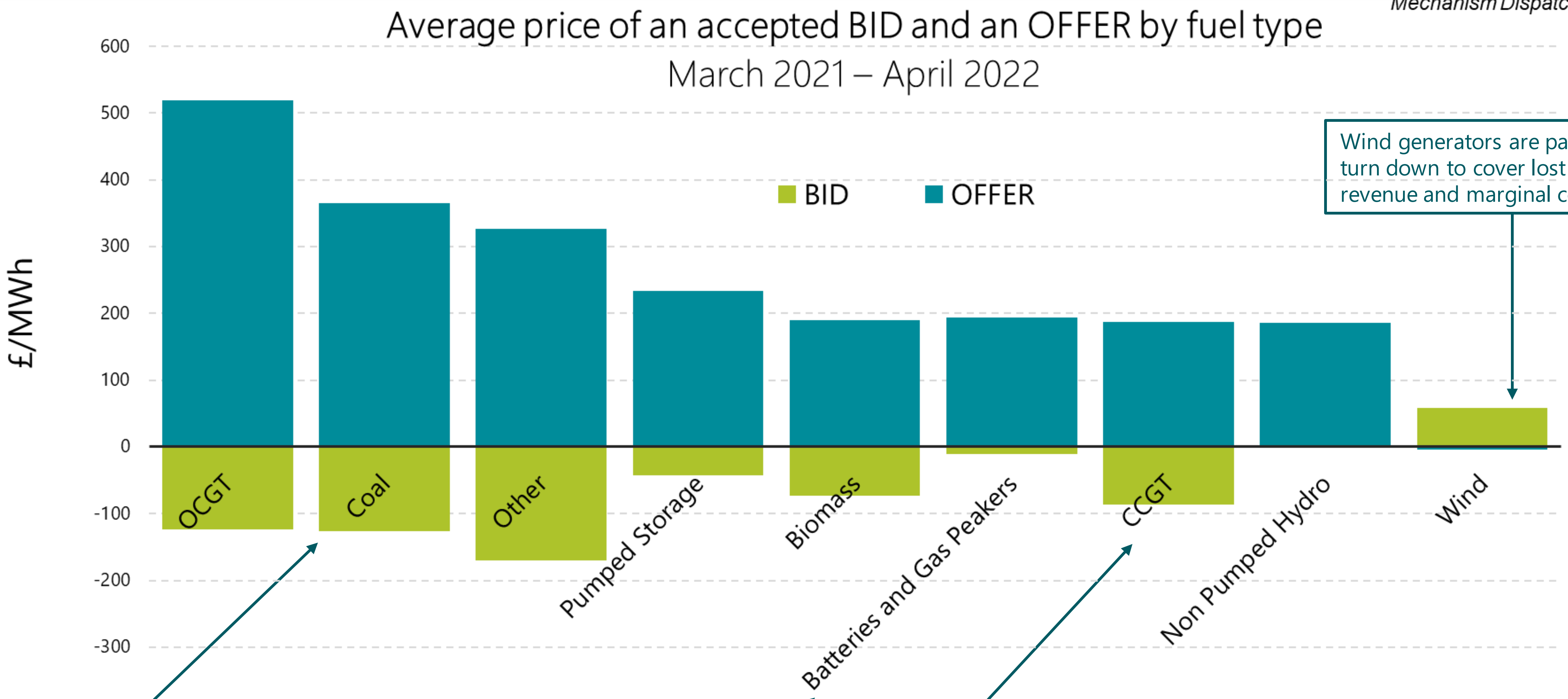
Source: ESO Balancing Mechanism Dispatch Data



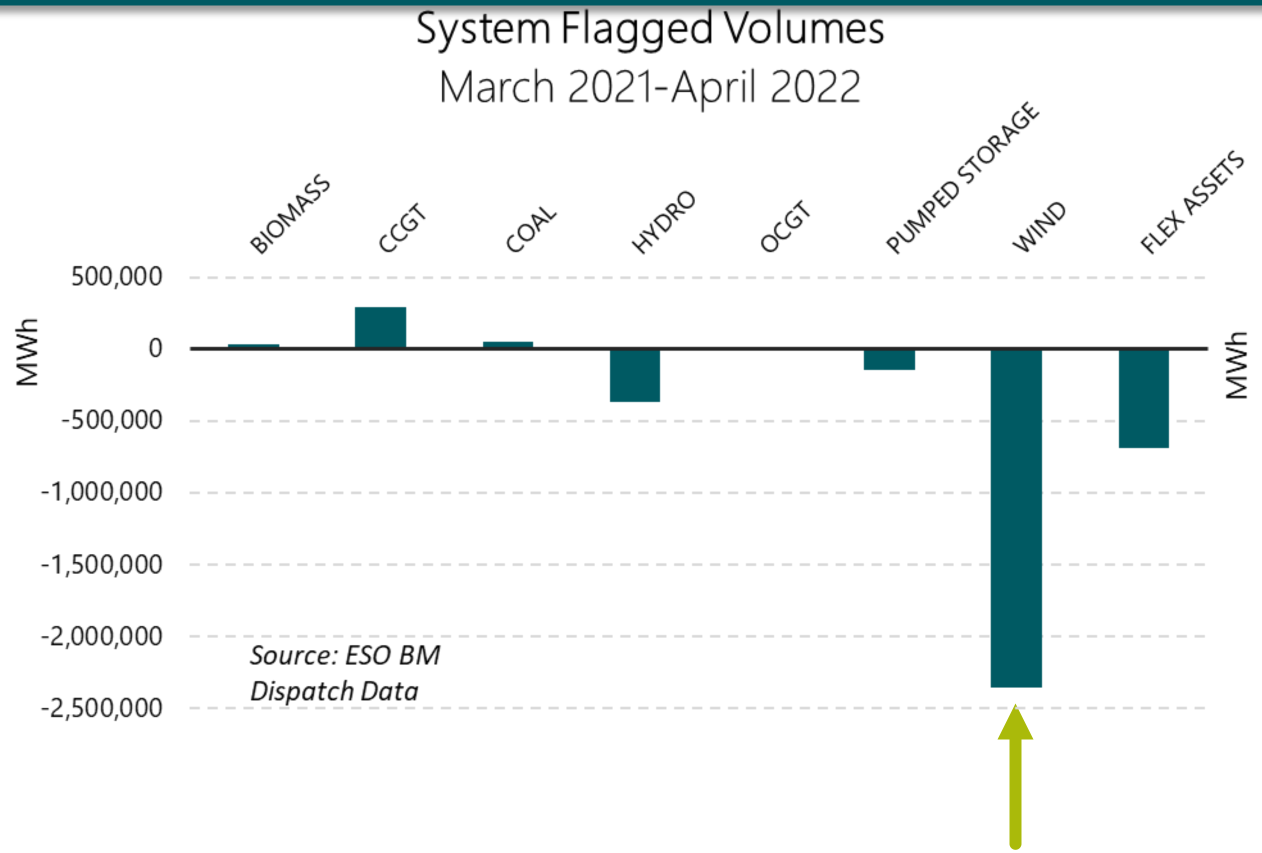
Wind generators are paid to turn down to cover lost subsidy revenue and marginal cost

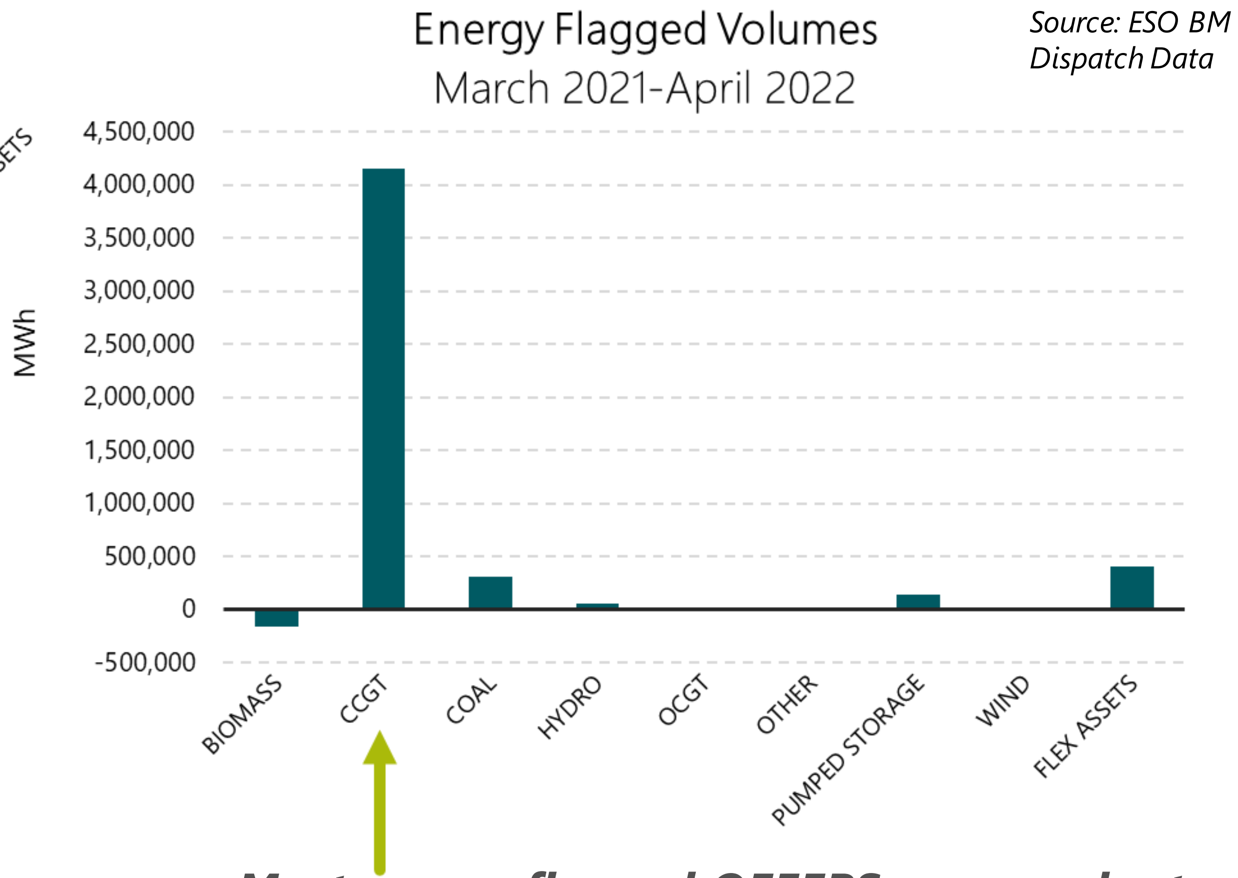
Fossil generators are willing to pay the ESO to turn down.

Putting gas peakers and batteries in the same category is very misleading

CCGTs, used for most 'turn up' balancing, have average prices in line with other technologies

The majority of turn up actions are CCGT plants





<u>Most</u> system flagged BIDS are wind farms – wind curtailment

<u>Most</u> energy flagged OFFERS are gas plants – gas 'fill-in' to make up for curtailed wind

Why is it we see a far larger volume of CCGT turn up, compared to wind turn down?

- Partially because CCGT assets have an average 'minimum non-zero time' of 4-6 hours

Gas CCGT plants still dominate the turn-up actions in the BM, which account for over 75% of constraint costs

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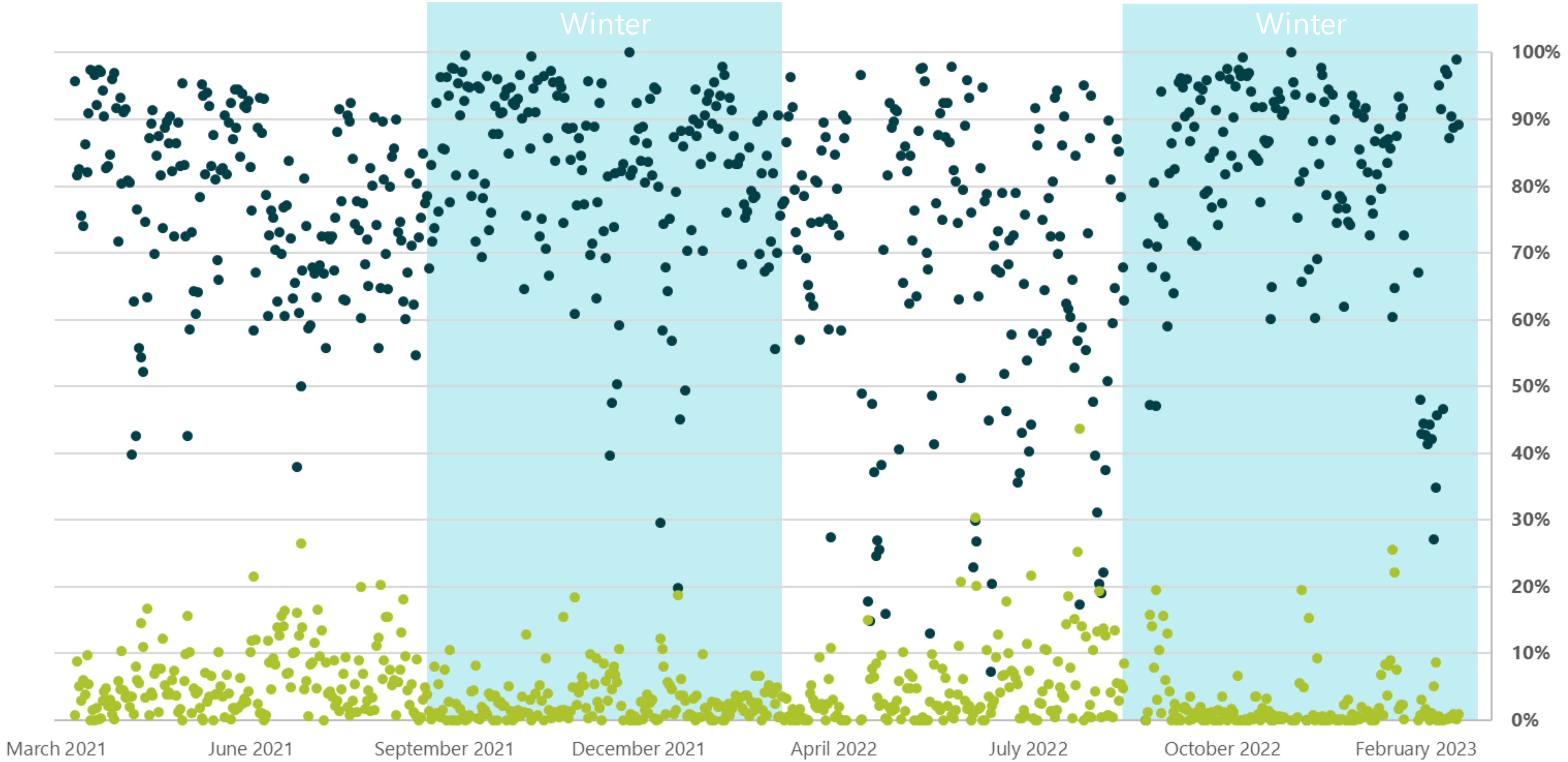
SOURCE: NG ESO Balancing Mechanism Dispatch Data, March 2023

Most of the turn up energy required to make up for curtailed wind power is provided by gas generators

Small flexible assets such as batteries play a secondary role, especially in winter when wind curtailment is high



Gas generators contribution to daily turn up energy (%)

Small flex assets contribution to daily turn up energy (%)

From Q2 2021 to Q4 2022, Gas Plants have provided between 74% and 88% of quarterly turn up energy with no consistent upward or downward trend

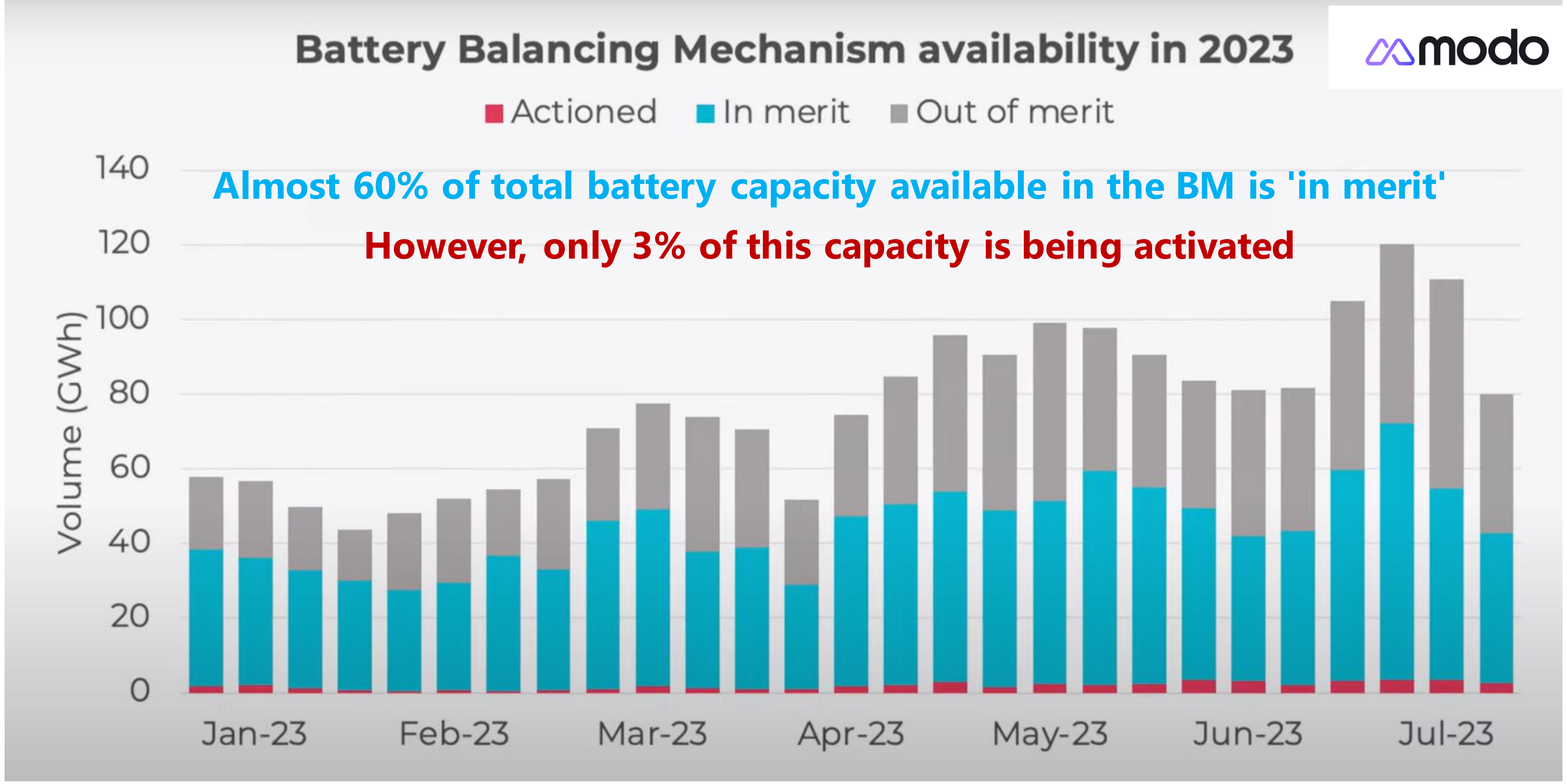
Barriers in the BM – 'skip rates' and limitations

'Skipped' when an asset with a lower 'bid' or 'offer' price (i.e. is 'in merit') is passed over for a more expensive asset, usually a CCGT.

The control finds it difficult to schedule many smaller battery assets within the BM action window.

Limitations with IT, data, automations

'15-minute rule' – batteries are currently dispatched for a maximum of 15 min duration because the control room does not have the data to determine the battery charge condition.



https://www.youtube.com/watch?v=1ZsUtKTJGXE

The ESO's Open Balancing Platform launched in December is intended to increase battery participation..

Agenda

Part 1 – Constraints facts and figures

- Where and why do we have constraints
- How much do they cost and why the recent increase
- Current constraint management approach using CCGT as mainstay

Part 2 – Constraints policy, market reform and innovation

- Reducing the occurrence of constraints
- Reducing the cost of managing constraints
- A new energy system – **smart and progressive** market reform

Opportunities to reduce the occurrence and cost of constraints

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Reducing the occurrence of constraints

1. Strategic national & regional planning with accelerated grid investment
2. Locational & constraint signals – aligned to plans
3. Forecasting, capacity optimisation & Active Network Management
4. Interconnector market reform

Reducing the cost of constraint management

5. Control room & dispatch functions – digital & automation
6. Balancing mechanism expansion & operation
7. New flex & local constraint markets (LCMs)
8. Competition & gaming – regulation & monitoring

Complete overhaul of strategic and regional planning – acceleration in grid infrastructure

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National and strategic planning

- Holistic Network Design (**HND**) for offshore assets
- Accelerated Strategic Transmission Investment framework (**ASTI**)
- Central Strategic Network Plan (**SCNP**)
- Strategic Spatial Energy Plan (**SSEP**) by 2025
- **Electricity Commissioner** report on accelerated investment to reduce lead time from12-14 years to 6-7 years
- New FSO functions to coordinate network plans inc. cross vector
- FES and DFES – evolving into national and regional pathways

Regional and local

- T & D Regional Development Plans (**RDP**)
- Regional Strategic Energy Planner (**RESP**) with regional governance
- Regional and Local Area Energy Plans (**LAEP**s)
- Community benefits for network investment
- Low voltage network investment strategy

Moving from 'connect, (delay) and manage' to a more strategic and proactive approach

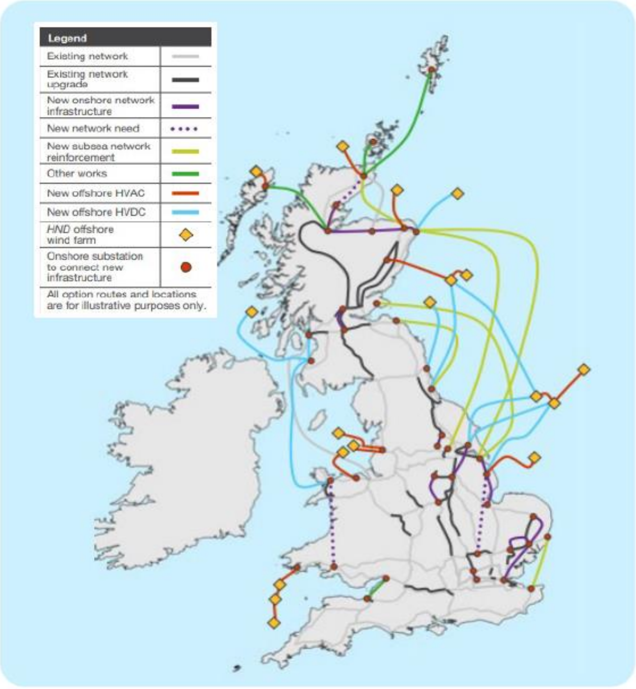


Figure 14: Holistic Network Design Pathway to 2030, project map.

The Pathway to 2030 Holistic Network Design

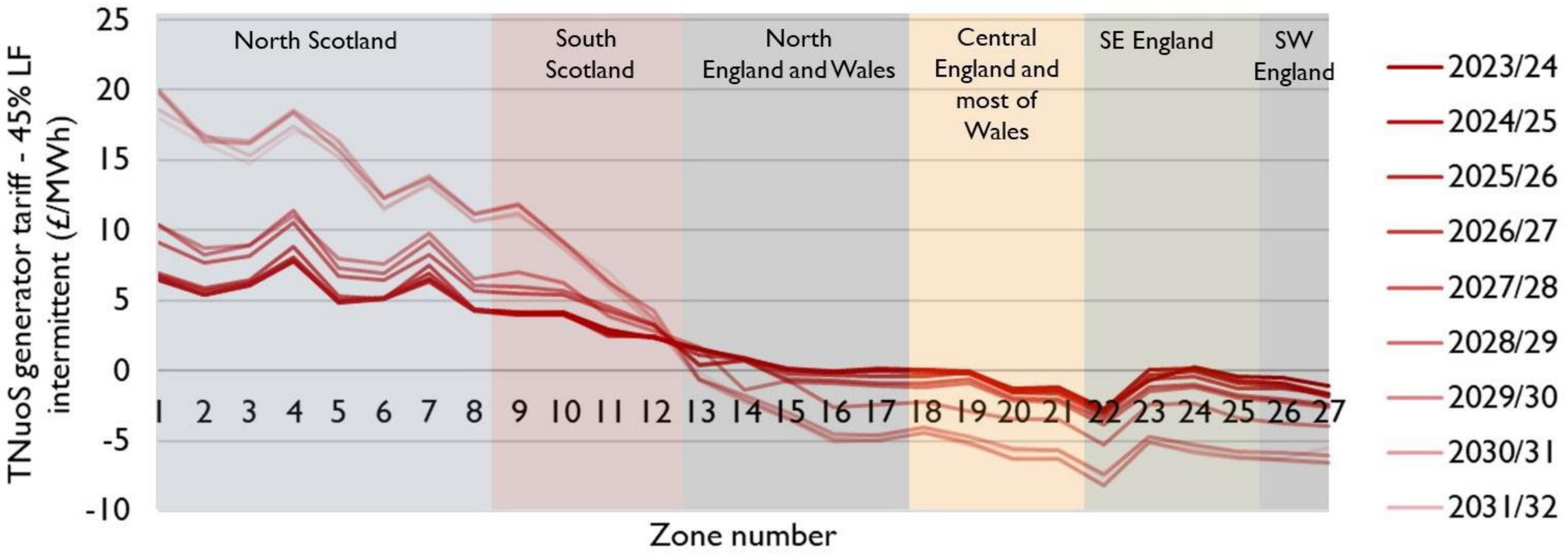
- 94 onshore network projects totaling £21.7 billion,
- £32 billion to build offshore transmission
- to deliver 50 GW of offshore wind.

"planning will evolve iteratively into a single Centralised Strategic Network Plan (CSNP)"

Expansion of HND to the CSNP and SSEP must include interconnectors, large scale onshore, storage, hydrogen & new nuclear

Effective locational constraint signals that are allied to strategic plans - Network Charge Reform

TNUoS Charges – 10 year projection



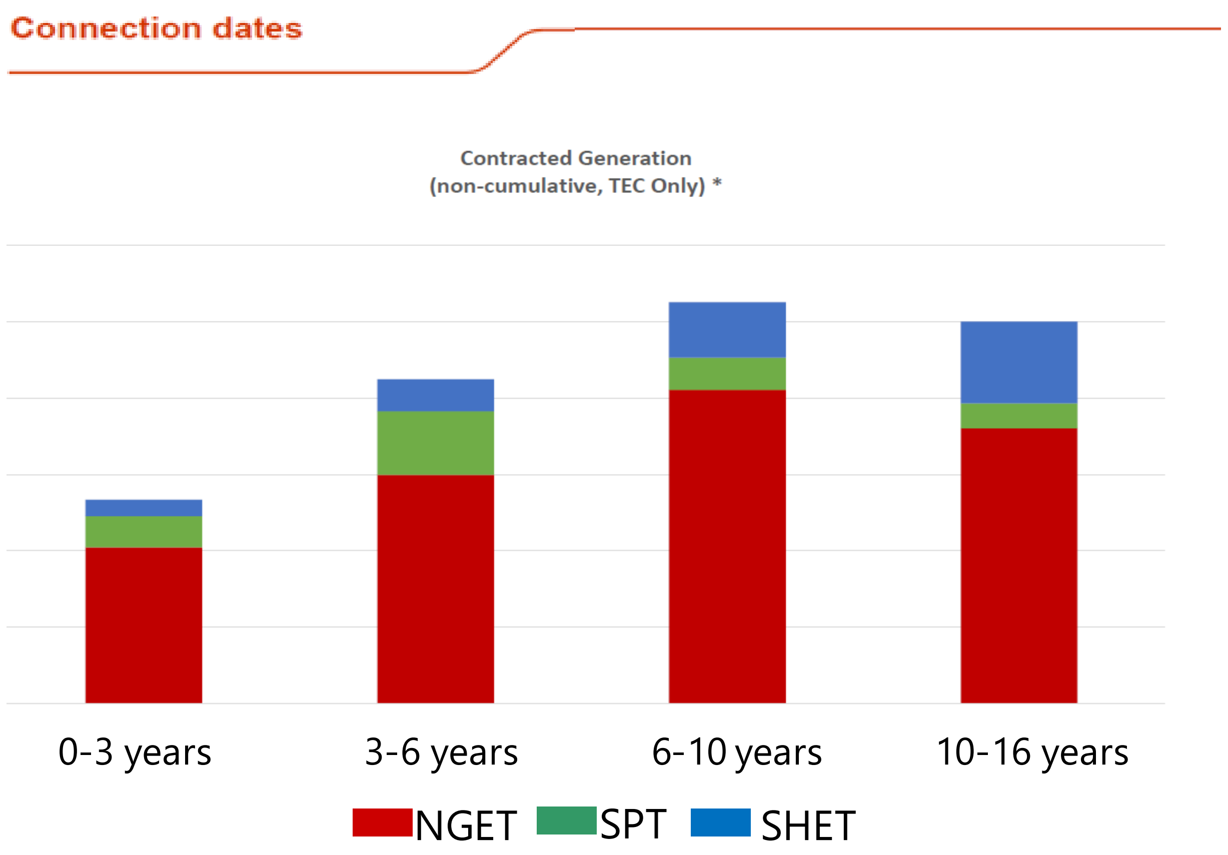
Network charging reform is urgent – current charge signals are very strong – too strong(?) – but are not effective.

TNUoS signals act as a deterrent but do not incentivise investment, they may work counter to energy strategy

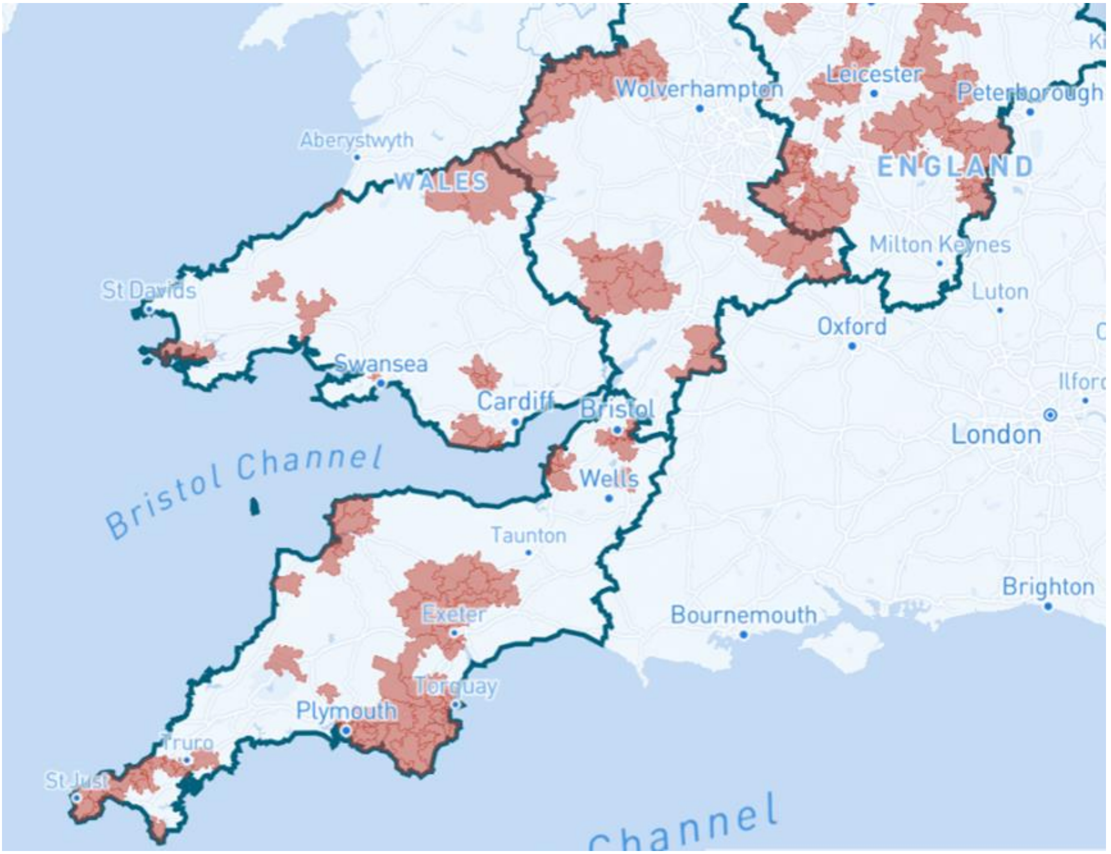
Should forward network charges include financing of capital investment? If so, how is the calculation made.

Other locational signals – connection dates and flexibility heat maps

Connection delay areas



NGED – Flexibility zone identification



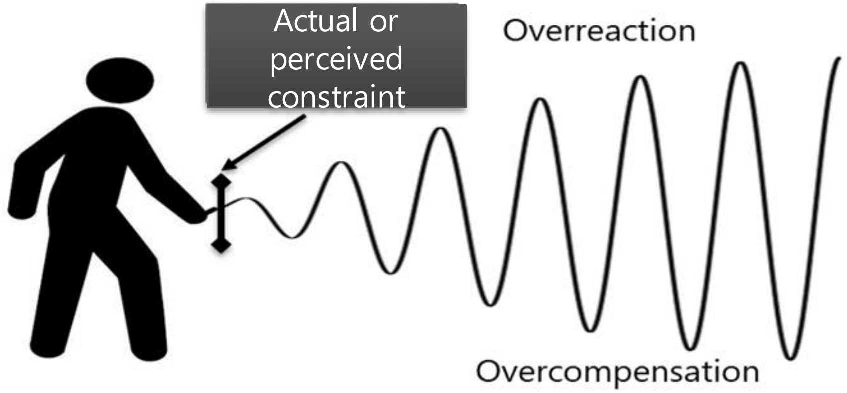
Should locational signals be added to other policy levers – e.g. CfDs, Capacity Market, Hydrogen grant and business models to recognise system costs and benefits

Forecasting, capacity optimisation and Active Network Management (ANM)

Traditional approach has been based on setting thermal and voltage limits...........

Conservative forecasts, engineering limits, capacity margins, lack of transparency, real-time data/analysis, plus use of clunky CCGT assets ....

may have led to higher constraint volumes and a 'bullwhip' effect response



https://www.nationalgrideso.com/document/291351/download

A smarter and proactive approach to manage constraint risk.....

Constraint Management Pathfinder – e.g. **Constraint Management Intertrip Service (CMIS)** more power to flow on the existing transmission infrastructure pre-fault, thus reducing the amount of generation being curtailed. First 10 months produced 32 GWh extra green energy

Active Network Management (ANM) – an approach that uses real time network monitoring and analysis tools to determine actual network conditions and optimise capacity utilisation across multiple loads

Outage Optimisation initiatives have saved up to £578m in balancing costs in 2023/24

ESO Forecasting working group – integrate best weather data into the BM

Steps to improve accuracy of **Physical Notifications** (Day ahead and at gate closure (FPN))

IT and automation in the control room, system planning and dispatch

The GB electricity grid is one of the most reliable in Europe, keeping the lights on 24/7, but its control room processes, and IT systems, are out of date compared to the level of digitalisation and automation in the electricity markets.

See Guy Martin's Great British Power Trip Channel 4 episode 2 – in the control room

Key features of the new digital energy system,

- Use of real time data & digital platforms to create new markets, improve situational awareness and aid system operation
- Automation to streamline the use of new services from thousands of system actors such as V2G, aggregated smart appliances
- Use of virtual energy systems with 'Digital Twin' simulation tools and AI to increase system learning and decision making
- Collaboration between transmission and distribution to ensure alignment of system actions and optimisation across networks
- Greater system integration with neighbouring energy systems in Ireland and the rest of Europe

The National Control Centre of the Future will be far smarter, more digitalised and automated. This will better enable controllers to optimise the use of all balancing assets and target actions using the least cost solution.

Expansion of BM and use of flex and storage offers most immediate way to reduce constraint costs

Batteries, DSR and peaking assets have complained that they do not have access to the BM and, when they do, they are not utilised.

In response the ESO has committed to **increase BM participation** and to develop in new tools and control room functions to increase the use of flexible assets.

But the BM is still dominated by the use of CCGT plants, even when these are more expensive. See previous slide on SKIP rates.

See letter from ESO to the Electricity Storage Network on Balancing Mechanism Reforms

See Ofgem Consultation on BM Reforms

Balancing Market Reforms

There is a big push now to improve control room capabilities and dispatch tools inc. IT, digitalisation and automation.

A major new, 18-month, Open Balancing Platform project to replace the Electricity Balancing System, Balancing Mechanism and the Ancillary Services Dispatch Platform.

Phase one of the OBP was activated in December 2023 and includes **Bulk Dispatch Optimiser,** an agile tool to allow control room send hundreds of instructions to smaller Balancing Mechanism Units and Battery storage.

The OBP is modular, future phases will include:

- Inclusion of a wider range of technologies
- Transfer of response and reserve services
- Integrated platform for energy forecasting PEF
- Zonal balancing with smaller assets

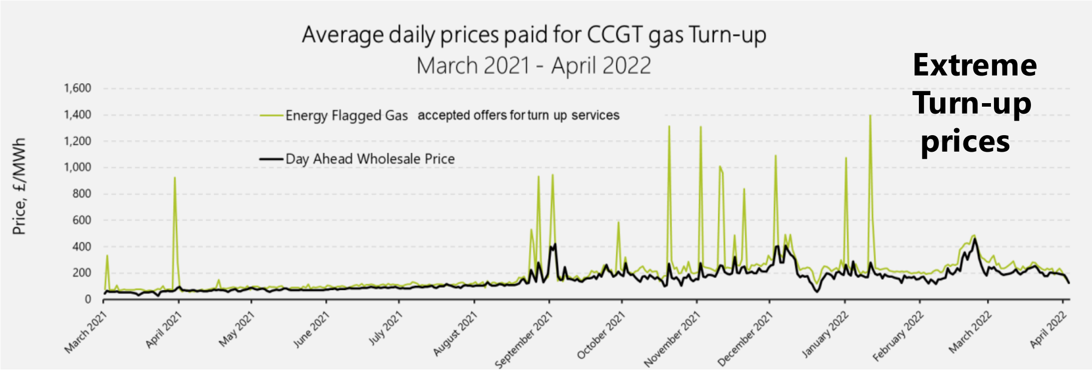
Additional data on state of charge is needed to remove restrictive run-time rules such as the "15 min rule"

Trading outside the BM and use of Local Constraint Management markets

Historically the ESO has mainly managed constraints within the BM market, using bid and offer prices

As the volume of system actions (re-dispatch) has increased, the reliance on the BM has created two related problems:

1) The time limitation to take system actions within a 1-hour window
2) The reliance on the BM 'spot' market has increased the market power of generators who are able to earn scarcity rents for turn up services



As well as BM expansion, to create more competition, secure lower prices and reduce operational pressure, the ESO has also begun to manage constraints outside of the BM.

This can be done by:

1) **Forward Trading ahead of gate closure (PGBT)** – the ESO already trades in the wholesale market giving it the ability to affect system balances. Trades in 2022/23 averaged around 400 GWh per month

2) **Procurement of flexibility services** – long term call-off arrangements similar to flexibility contracts currently in use by distribution networks

3) **Local Constraint Management (LCM) markets** – forward (e.g. day ahead and intra-day) markets to manage constraints at specific locations or across boundaries. See for example B6 Boundary trial with Piclo

Storage and flex providers would like to see an increase in flexibility markets to support investment

Interconnector market and operational reform is needed

The 1.4 GW [Viking Link](#)is now operational linking the GB market to Denmark

Potential problem

EU decoupling plus some restrictions/ misalignment on interconnector trading could lead to flows :

1. in the 'wrong' direction against market price signals
2. into areas of the grid that are constrained

One answer may be to reconfigure the GB market into zonal markets. Before then however, we need to look at a range of options:

a) A more strategic approach - interconnectors in the CSNP
b) EU recoupling arrangements that work for UK
c) Alignment of interconnector trading with GB markets
d) Interconnectors participating in the BM
e) ESO's ability to adjust interconnector capacity
f) ESO's ability to countertrade flows outside the BM

Use of non-firm connections

As a general rule, generators and demand customers want a firm connection agreement

Unless the degree of constraint is low <u>and</u> predictable, and time limited, getting finance for a non-firm project is very difficult

Non-firm connections can include capacity conditions around time of use, intertrips, peak loads and Active Network Management

Networks have however begun to explore how non-firm connections might speed up connections while keeping constraint costs low.

Battery storage providers could be offered a form of non-firm connection in order to reduce connection queue delays.

There are examples of generators accepting a non-firm offer, in order to get an early connection, but this is the exception and is usually time-limited while network upgrades are completed.

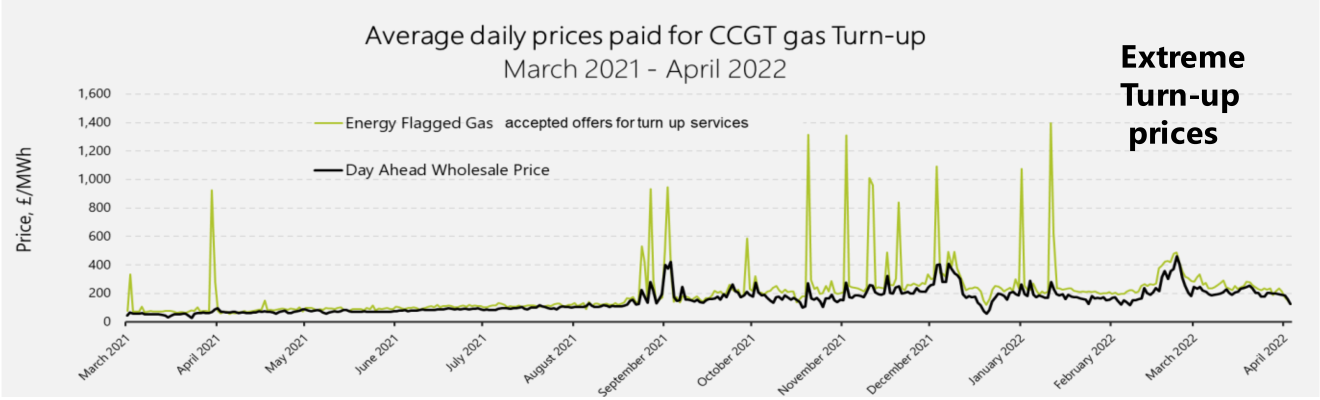
A good example is the Dunbar Active Network Management scheme which allowed four new projects, totaling 50MW of generation, to connect to SP Energy Networks 2-5 years ahead of a network upgrade.

Ofgem has supported the use of non-firm connections, on a time limited basis, in certain areas but is concerned that they could be exploited for the benefit of networks.

Competition, gaming and regulatory control

There are a number of market power and gaming challenges related to constraint management. For example:

1) **Gas generation plants exploiting scarcity rents** in the BM during periods of high wholesale prices for turn up services
2) Gas and other generation plants changing their **FPN or withdrawing plant** from services in order to manipulate the balancing market.
3) **Adherence to Transmission Constraint Licence Conditions (TCLC)** that prevents certain generators from making additional profits from being Turned Down.
4) **Wind generators over-estimating their generation forecast** in the expectation of being turned down.



Following an ESO review of BM activity in winter 2021, Ofgem issued an open warning letter to the industry regarding "generators submitting persistently high prices, inflexible and expensive offers, and intentionally exacerbating tight margins by scheduling to desynchronise their units with little notice just ahead of peak demand periods"

Drax fined £6m over TCLC compliance for its Cruachan pumped hydro plant, for submitting BID prices at (negative) £60 MWh. Ofgem now plans to tighten TCLC further

ESO to tighten monitoring of wind forecasts and notifications

But note; tightening or changing regulatory controls may have unintended consequences e.g. for battery and flex providers who must make a return on investment through arbitrage and system services. Gaming for some is a valid business model for others.

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