# Welfare Impacts of a Zonal Wholesale Market in Great Britain

Strommarkttreffen 17. Oktober 2025
50Hertz, Berlin

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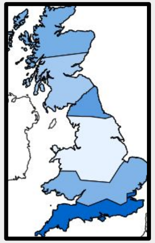
Working Paper Summary



[ Full Paper Link ]

[ Model Link ]

# A zonal electricity market, if implemented during 2022, 2023 and 2024, would have increased GB welfare by £2 billion

**Context**

Great Britain is considering moving from its current national electricity market to a zonal one. A zonal market would account for transmission constraints during wholesale trading, and thereby promises that better representation of local electricity abundance or scarcity would lead to more efficient operation and better siting of future assets.

However, studies come to varying conclusions on whether or not these benefits outweigh concerns about a more risky investment environment.

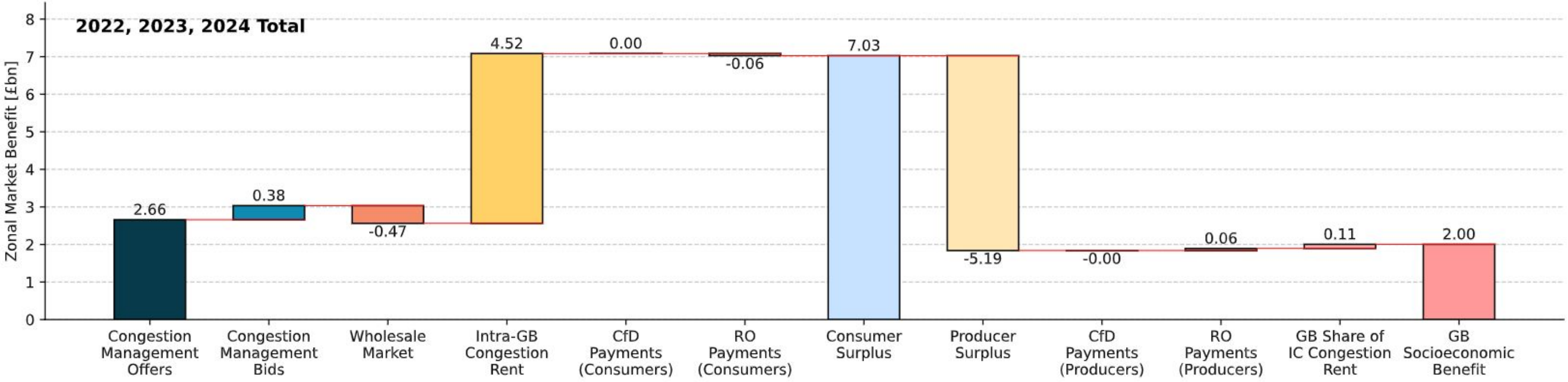
**This study**

estimates zonal market impacts in the **current system,** and provides a fully transparent analysis by *a)* making all of its code and data **fully open-source,** and *b)* basing its analysis in **historical years**, enabling it to calibrate model parameters such as curtailment volumes and other system quantities to match between the modelled and the real system.

The analysis is based on a half-hourly, unit-level, 300 node linear optimisation model that simulates wholesale and congestion management for a national and counterfactual zonal market layout.

**Findings**

We find that a zonal market would have improved GB welfare by £900mn in 2022, £380mn in 2023, and £720mn in 2024.

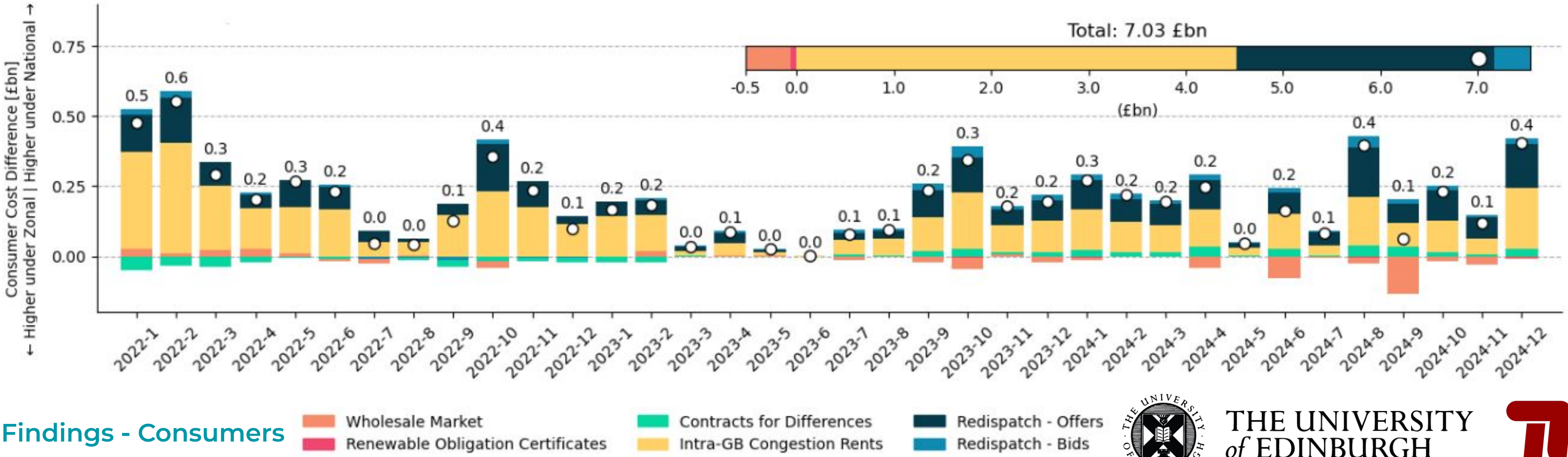


# From a consumers perspective, cost reductions are mainly driven by intra-GB congestion rents (£4.5bn) and efficiency gains in the balancing market (£3bn)

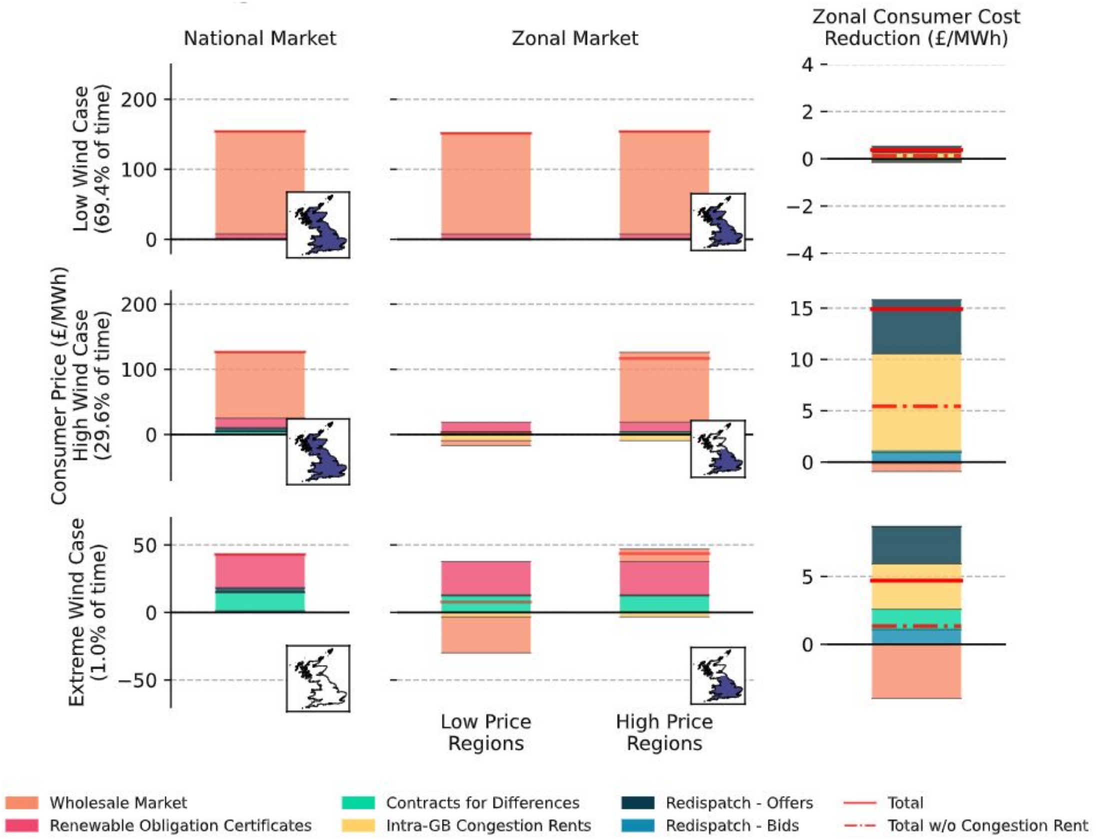
**Moving from a single national price to a six-zonal market** reduces the need for congestion management by around 82%. This saves costly short-term balancing dispatch, but slightly increases wholesale prices. Congestion rents accumulate due to a wholesale price spread between North and South when the grid is congested.

**Over 2022, 2023 and 2024,** the system accumulates £4.5 bn (≈£6.3/MWh) in congestion rent, and another £3 bn (≈ £3.1/MWh) from lower Balancing-Mechanism costs that offset a £0.5 bn rise in wholesale electricity cost.

**The dynamics driving cost reductions** vary between 2022 (mostly congestion rent) and 2024 (a larger share of balancing cost savings). In 2022, high fuel prices exacerbated the price gap between North and South, increasing congestion rent. In 2024, curtailment was unusually extensive, highlighting the existing balancing market's inefficiencies and growing problems relating to North-South congestion.



# The zonal market accumulates its benefits in around 30% of settlement periods - the ones with at least some grid congestion




**Most of the time nothing changes:** When wind is modest (≈ 69 % of hours) the grid stays uncongested, a single gas-set marginal price prevails nationwide. In that case, zonal pricing has basically no effect on what consumers pay.

**This changes under higher wind generation:** In the ~30 % of hours when wind is abundant, CfD turbines drive northern prices toward zero while gas still sets southern prices; the resulting £10/MWh of congestion rents plus ~£5/MWh lower BM costs deliver nearly all the zonal market impacts from the previous slide.

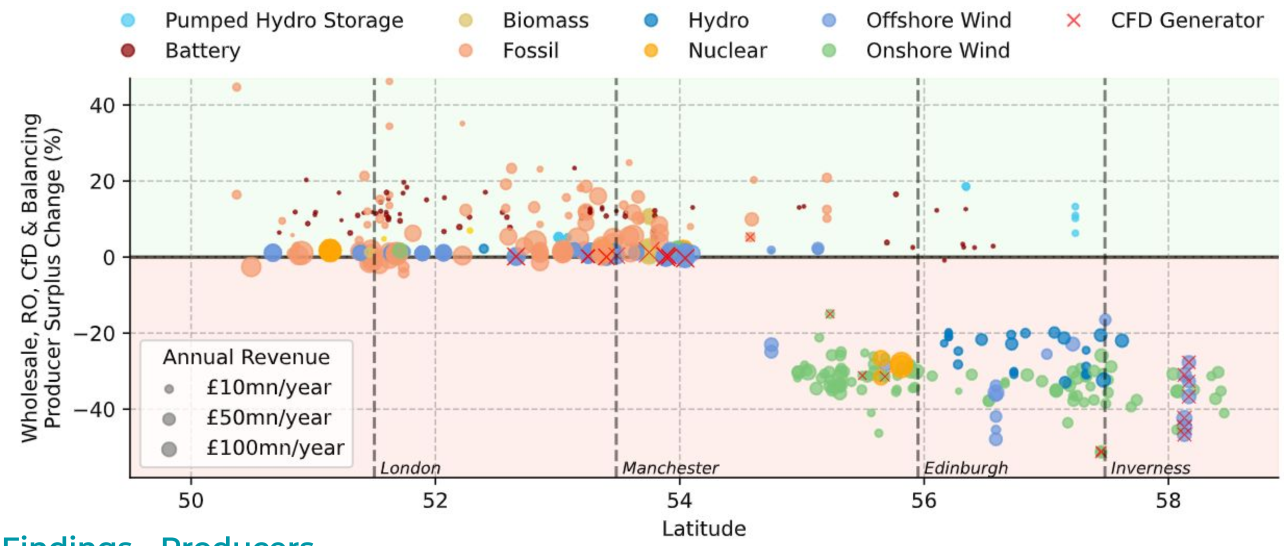
It appears plausible that **under extreme wind** (i.e. wind sets the national wholesale price, see bottom row), a zonal market could make the wholesale market substantially more expensive. This is because representing transmission constraints may assign high wholesale prices to a large part of generation. Such an effect was not observed here, as the spatial distribution of wind turbines appears sufficient for wind to set the price in almost all zones.

# If not mitigated through policy, existing northern generators could lose up 40% of their revenue, regardless of their subsidy scheme while most southern units increase their surplus. However, congestion rent could rebuild renewable revenues to up to around 97% of national market levels.

PyPSA

**Regional impact:** Zonal pricing strips about **30 ± 5 % of producer surplus from northern generators**, whereas southern assets suffer little or even gain slightly thanks to higher zonal prices that counterbalance any lost balancing-market rents.

**Technology impact:** Northern wind (RO ≈ price risk, CfD ≈ volume risk) and inflexible nuclear see the biggest hit, hydro loses a milder ~20 %, storage earns ~10 % more from added price volatility, and southern gas units can profit—though their outcome swings with the assumed £30/MWh balancing-premium.




**Thermal plants** see a range of outcomes depending on whether they are more active in wholesale or balancing markets. Southern wholesale prices are likely to increase under zonal, leading to higher surplus. In balancing however, we assume that units see significant surpluses in the national market design - surplus they forgo in zonal. For some units that loss offsets the gains made in wholesale.

**Grandfathering** could mitigate transitional risk for renewables. For instance, the estimated volume of inter-zonal congestion rents is such that, if it they were redirected to generators, they could restore up to **97 % of the revenues they received under the national market**, and would therefore all but neutralise the surplus reduction from zonal pricing.

**For a more elaborate discussion of transitional risk, we refer to the full text.**

Findings - Producers

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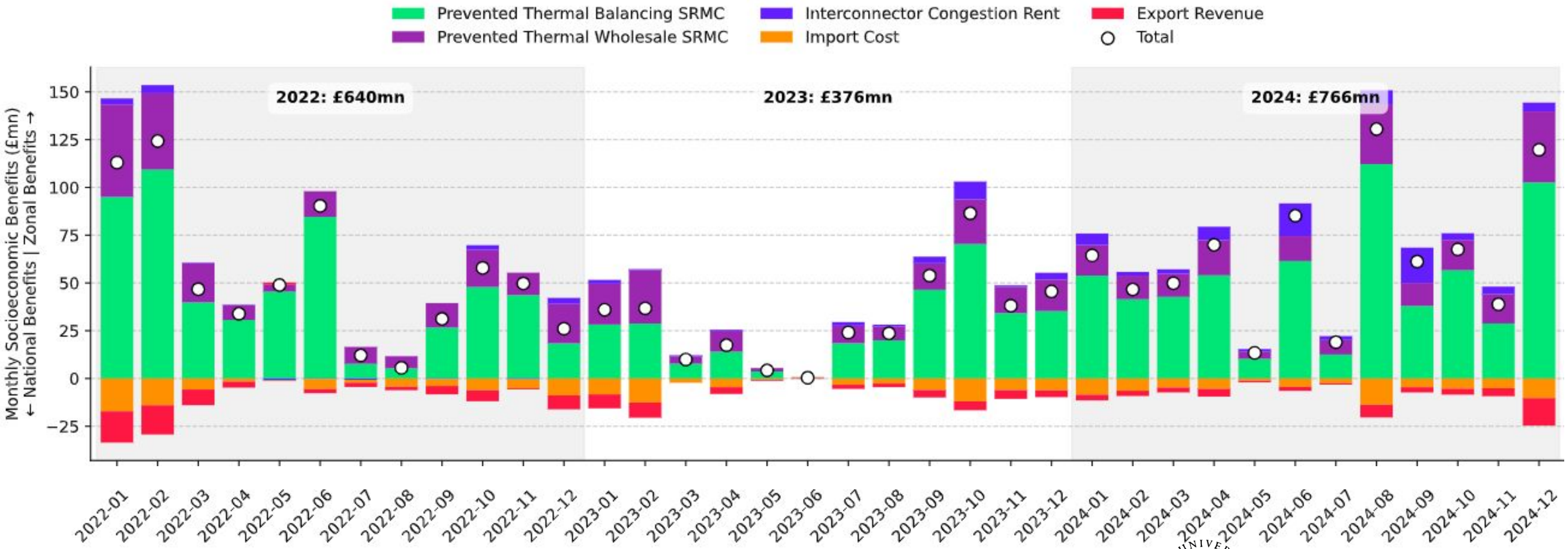
# A national market disguises electricity scarcity in southern GB causing interconnectors to export when they should import - selling expensive electricity at a low price

**In a national market,** high wind generation depresses wholesale prices more than the transmission capacity warrants.

This **prompts interconnectors to exports** at the low wholesale price, and only balancing reveals that southern GB was short. The short position, exacerbated by the export, is in reality met by thermal units on the balancing market at a high price.

**The price signals under a zonal market** prevents both; the lost export revenue is forgone (leading to a welfare loss), but more than offset by the prevented need for (mostly balancing) thermal generation. Southern GB scarcity is more readily met by interconnectors in wholesale.
Cutting thermal starts and balancing trades yields about **£640 m in 2022, £376 m in 2023, and £766 m in 2024 of welfare gain**, with congestion-rent shifts only a minor add-on*.






***The deviation for 2022 welfare gain from Slide 2 is likely due to highly fluctuating fuel prices, and visualises the margin of error**

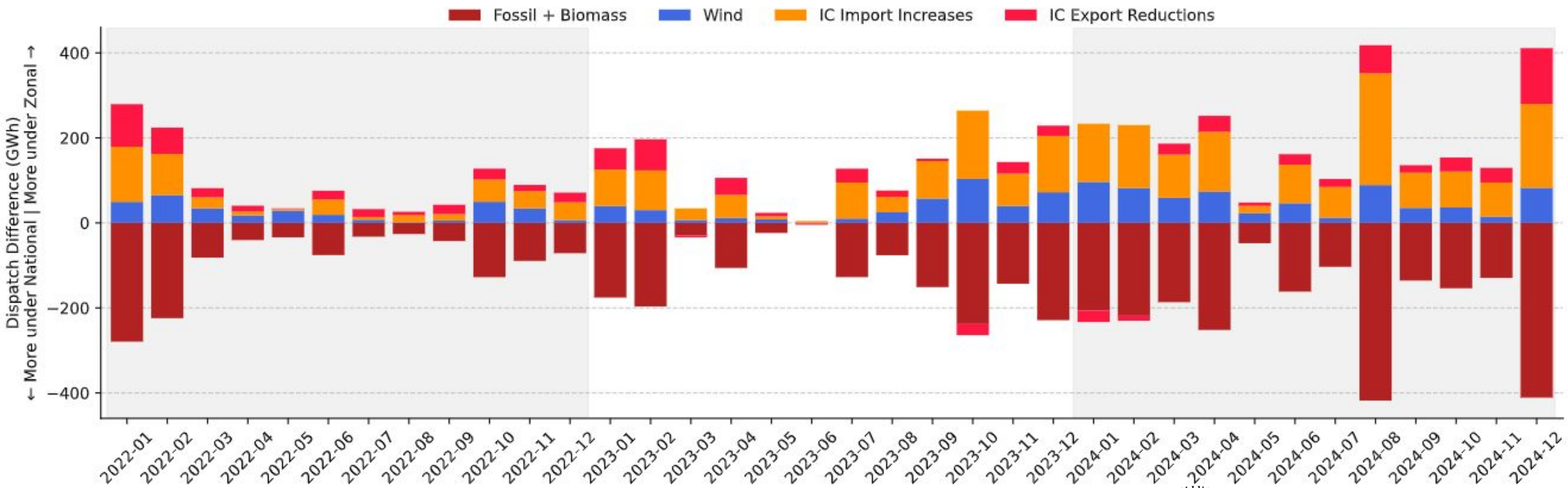
# Better interconnector operation drives the majority of benefit by visualising south GB electricity scarcity in wholesale

PyPSA

**The total dispatch volumes highlight this dynamic;** more domestic wind, higher interconnector (IC) imports, and fewer IC exports collectively displace thermal generation that would be dispatched under national pricing.

**Interconnector flows adapt to scarcity:** During congested periods (~10 % of settlement periods) at least one IC flips direction, mostly towards importing into southern zones.

**This does not explain the higher net dispatch of wind;** we assess that it is storage units that enable more efficient renewable dispatch, see the following slide.



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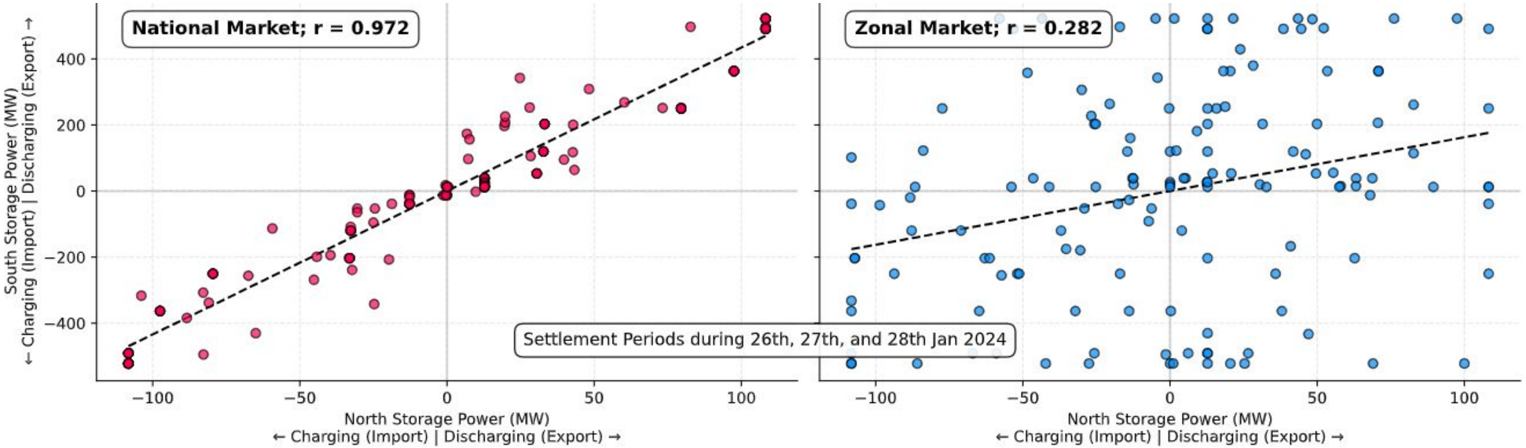
# Better zonal market price signals enable batteries to unlock an additional 1.37TWh of renewable generation over three years, saving around 0.25 million tonnes of carbon

**Under a national market,** the wholesale activity of storages is driven by the uniform price signal. We show this for three example days 26th, 27th and 28th Jan 2024, where over almost 150 settlement periods the *collective* charging and discharging pattern of storages North and South of the B6 are highly correlated (r=0.972).

**In a zonal market,** that correlation breaks down (r=0.282), and instead northern and southern units follow their zonal price signals, and are enabled to alleviate transmission bottlenecks instead of magnifying them.

The result is that on those three days, the zonal market is able to dispatch around **35GWh of additional wind generation** relative to the national market.
**Over 2022-24,** similar dynamics "unlock" 1.37 TWh of wind replacing mostly gas generation and avoiding roughly 0.25 million tonnes of $CO_2$.

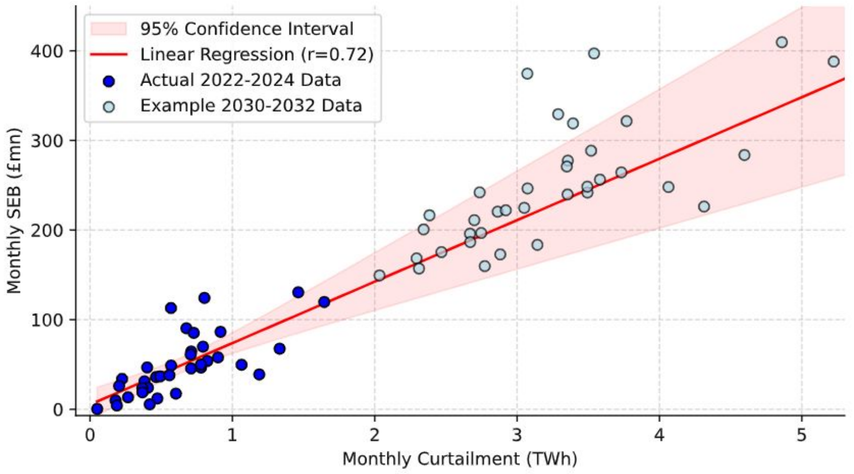
The present model assumes that storages use around 25% of their power and energy capacity on the wholesale market - different assumptions are likely to dampen or magnify this effect.




Findings - The Dynamics behind Welfare Gain

# System components enabling zonal market socioeconomic benefits (SEB) will intensify towards 2030, making annual (operational) welfare gains of £1-2 billion highly likely

**During the modelled months** we find that monthly welfare gain is highly correlated to curtailment (r=0.72 implies that curtailment explains around 50% of the SEB variance, see figure). Baringa and NESO (here) estimate that curtailment volumes will be five times as large in 2030 relative to 2024, suggesting that zonal market welfare gain will rise alongside them.



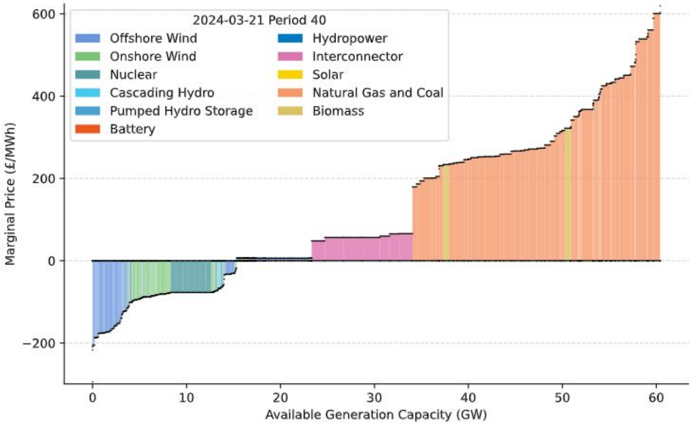

**The same logic applies to other drivers of zonal benefits:**

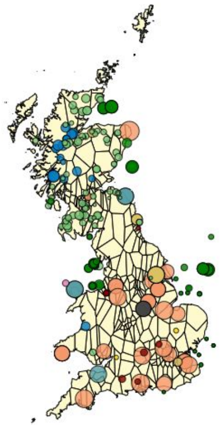
- Increasing wind generation capacity will further depress wholesale prices causing wrongful IC operation. **Wholesale prices are expected to vanish around 50% of the time by 2030** (see LCP Delta analysis).
- Future Energy Scenarios 2024 expects that by 2030, the system **storage capacity** will have increased to 20–27 GW, up from today's level of 5 GW.
- **Demand flexibility** adheres to the same logic as storage, and is also highly likely to see much larger uptake towards 2030.
- More **interconnectors** are being built, with the 500 MW Greenlink having launched in April 2025, and around 4 GW of additional capacity connecting to mainland Europe anticipated to come online before 2031.
- The expected trajectory of **carbon credit prices** are likely to increase under reducing UK emission caps towards 2030 or linkage with the European Emission Trading Scheme and further compound thermal generation costs.
- Wholesale contributions of thermal generators are projected to decline in the future system. As a result, **upward balancing will increasingly depend on starting additional plants** instead of ramping partially loaded ones, potentially increasing balancing costs per MWh of upward balancing energy provided by thermal units.

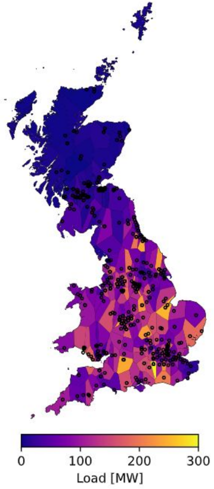
# The novel electricity market model GBPower bases its analysis on ELEXON, ENTSO-E and NESO data APIs to simulate the market using historical wholesale and balancing prices, power line thermal constraints, interconnectors and unit level prices and generation availability

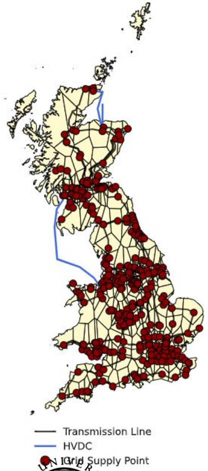
PyPSA

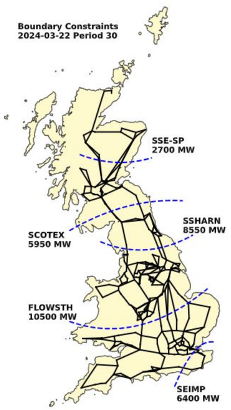
- **GBPower** model simulates the GB national electricity market, and a counterfactual six-zonal locational market layout.
- It is implemented in the open-source linear optimisation framework **Python for Power System Analysis (PyPSA)**.
- It is a back-casting model that **emulates historical days of the Great British wholesale and balancing markets** by inserting **unit-level marginal costs of and export availability**.
- The model calibrates line capacities such that the daily curtailment volumes match between model and reality.
- The model is subject to **limitations**, please find [the paper] for a discussion.
- The model contains data and estimates on **CfD strike prices and RO certificate prices** for all renewable units, and applies them in post-processing to estimate individual revenues and total system cost.
- **The present research** is based on model runs for every day between 2022-01-01 and 2024-12-31, one day at a time with 48 settlement periods each (i.e. in 30-minute intervals).
- The model is functional outside that span but constrained by the date range covered by the underlying **data APIs**, including Elexon, ENTSO-E, and NESO.
- **Interconnector** operation are included in the model based on EU country day-ahead prices and IC availability.






Modelling

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