REGEN

Turn down for what?

CONSTRAINTS INSIGHT SERIES: PART 1

Demystifying transmission constraints

Contents

1 Introduction **1**

2 How did we get here? **3**

3 Constraints on the transmission system **8**

4 What drives constraints today? **13**

- **How much grid capacity is available?** 14
- **Why are constraints concentrated in Scotland?** 16
- **How do market dynamics affect constraint costs?** 18
- **How efficiently does the balancing mechanism resolve constraints?** 22
- **Do interconnectors alleviate or add to constraint costs?** 24

5 Meeting the constraint challenge **25**

About Regen

Regen provides independent, evidence-led insight and advice in support of our mission to transform the UK's energy system for a net zero future. We focus on analysing the systemic challenges of decarbonising power, heat and transport. We know that a transformation of this scale will require engaging the whole of society in a just transition.

Foreword

The rise in constraint costs since the energy crisis brought about by Russia's invasion of Ukraine in 2022 has coincided with the UK government's commitment to accelerate investment in a clean power system. It has therefore been easy for the media and commentators to seize upon constraint costs as evidence that the UK energy strategy has gone awry. Why else would we be paying millions of pounds for wind farms to turn down? Why pay generators not to generate?

Whether from genuine concern about consumer costs or as a means to attack net-zero policies, the issue has become highly contentious. The political jeopardy has been increased by an analysis suggesting that constraint costs could rise further in the period to 2030.

If left unaddressed, constraint costs risk derailing the government's strategic plan to invest in new generation and network infrastructure for energy security and a low-carbon energy future.

It is therefore important to understand exactly why we have constraints – and why they have increased in both volume and cost.

The answers are more complex and nuanced than any newspaper headline, and can be traced to decisions made in the 2010s, as well as more recent drivers, including the price of gas and, more recently, a significant increase in network outages.

In this, the first of two papers on constraint costs, we trace the growth of constraints and explain the key drivers that determine where and how they occur.

In a second paper, we will further examine the measures that can be taken to reduce constraints in the context of a programme of progressive market reform. We will also set out an argument that UK policymakers and industry must be more ambitious, and how, with technology and market innovation, and coordinated management, the level of constraint costs can be reduced and then optimised, within an efficient clean power system.

Andrew Barry
Markets lead
abarry@regen.co.uk

Johnny Gowdy
Director
jgowdy@regen.co.uk

1 Introduction

Network constraint costs have become a defining issue in the UK's energy transition, yet the underlying causes and impacts of constraints are not well understood.

The GB power system has undergone a radical change over the last two decades, transitioning completely from coal to gas and renewables, enabling the grid's carbon intensity to drop by 60%.[1,2]

Renewable technologies generated over 44% of our power in 2025, with wind now the largest generation source, narrowly ahead of gas.[3] The clean energy sector now supports over 440,000 jobs, and in 2024, wholesale costs were 33% lower than they would have been without wind.[4,5]

At the same time, the electricity system is facing a growing challenge from rising constraint costs, adding to other pressures on electricity bills, including high gas prices and rising network investment.[6]

In its most recent analysis of balancing costs, the National Energy System Operator (NESO) reported that thermal constraint volume had risen to over 13.5 TWh in 2024/25. The cost of thermal constraint management – that is, to pay some generators to turn down and others to turn up to replace lost generation – now stands at £1.7bn per year, adding just under £20 to the average domestic bill.[7,8]

£20 might not seem much in the context of the overall rise in energy costs; however, with 11% of energy customers in fuel poverty, very high industrial electricity prices and the fact that these appear to be pure inefficiency charges for energy not delivered, constraint costs have become a hot topic for consumers and the industry.[9] The risk that they could rise further, potentially negating bill savings from lower wholesale prices, means the constraint issue is likely to remain at the forefront of the energy transition debate and a key priority for policymakers.

While the focus on constraint costs is positive and has led to greater transparency, the issue is complex and frequently mischaracterised. In the media, costs are often attributed solely to renewable generation, whereas in reality, network constraints are driven by a number of factors, including historic decisions about where to locate new generation and to delay the construction of adequate transmission network capacity.

More recently, the frequency and duration of network outages have been a significant constraint cost driver, as has the increased cost of turning

[1] UK to finish with coal power after 142 years, BBC News, 2024
[2] Yearly Electricity Data, Ember, 2026
[3] Britain's Energy Explained: 2025, NESO 2025
[4] Clean Energy Jobs Plan, Department of Energy Security and Net Zero, 2025
[5] Marginal Gains – how wind is pushing gas out of the power market and cutting costs, Energy & Climate Intelligence Unit, October 2025
[6] Clean Power 2030 Action Plan: A new era of clean electricity, UK government, December 2024
[7] 2025 Annual Balancing Costs Report, NESO, June 2025
[8] Roughly £6-7 per MWh average GB consumption
[9] Annual Fuel Poverty Statistics in England, DESNZ, 2025

up replacement generation, usually gas power generators, which accounts for the largest share of the constraint cost bill.

As policymakers and the industry work to deliver the clean power mission and Reformed National Pricing (RNP) reforms, which will require targeting future investment, market reforms and operational innovation, a clear understanding of how constraints arise and why their costs have increased is required.

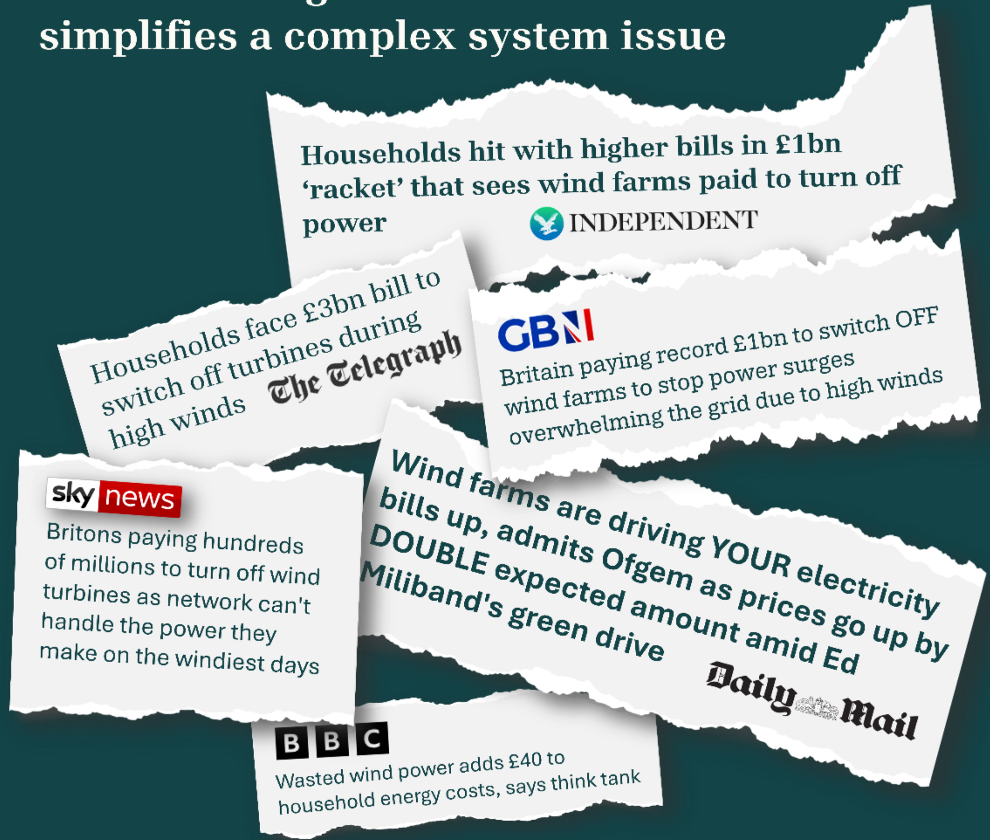
This paper examines the context, mechanics and drivers of transmission constraints in Great Britain. There are three key messages:

1. Rising constraint costs are the result of a combination of historic network investment decisions, operational factors such as outages and capacity limits, and market dynamics.
2. Some level of constraint is economically optimal, reflecting the trade-off between network investment, generation capacity, flexibility and system operation.
3. Addressing constraint costs requires coordinated action across networks, markets, regulation and system operation.

This paper builds on previous work by Regen, including our 2022 report on transmission constraint solutions and an industry roundtable held in December 2025.

Following publication of the government's RNP delivery plan, a second paper will examine potential solutions and policy options to reduce constraint costs.

Media coverage of constraint costs often simplifies a complex system issue



Constraint payments have become a politicised subject of media coverage. Headlines often frame costs as "paying wind farms to switch off". While this is part of the picture, such a simple narrative can obscure the underlying causes of network constraints and the role of transmission capacity.

2 How did we get here?

Network constraints didn't happen by accident; they are the result of decisions taken over the last decade to accelerate the build-out of new low-carbon generation while delaying the expansion of network capacity.

Network constraints are not new and, to some extent, are a fundamental feature of an optimised energy system. It would not be cost-effective to build a network capable of meeting all possible loads at all times for all future development pathways.

Within an operational timeframe, system operators must constantly manage power flows within safe technical limits, making real-time judgements about the movement of electricity across the network.

Within an investment timeframe, networks and regulators must decide when and where to reinforce infrastructure, based on projections of new generation and demand sources that may or may not materialise. Network development planning is therefore inherently uncertain, balancing the need to build capacity to support growing demand against the risk of over-investment that will increase consumer bills.

Historically, these trade-offs attracted little public attention. A lack of network capacity would be a frustration for individual projects, but generally, the economic impacts of network planning and constraints did not register for most consumers.

The energy transition has brought the issue of constraints, and more broadly, the need for major infrastructure investment, firmly into the public and political domain. The rise in constraint volumes and costs we see today is not the inevitable consequence of the growth of renewable energy, but the result of policy and regulatory decisions taken from 2010 to 2020.

Connect and manage

The government's 2007 Energy White Paper identified the need to remove barriers to connecting generation projects.[10] The White Paper led to the Transmission Access Review, which in turn led to the adoption by the 2010 coalition government of a 'connect and manage' approach to network access. In contrasted with the previous approach of "invest then connect", this meant that large-scale generation projects could connect before network reinforcements were completed – necessitating active management of the resulting network congestion.[11,12]

Though initially intended as an interim measure, subsequent detailed consultation and analysis by the Department for Energy and Climate Change (DECC) concluded that the benefits of the policy outweighed the

[10] Meeting the Energy Challenge – a white paper on energy, HM government, 2007
[11] Transmission Access Review – Final Report , Ofgem & BERR, 2008

[12] Note – Connect and Manage was applied to large-scale projects connecting to the transmission network. Smaller projects connecting at the distribution network voltages generally do need to wait for network capacity or accept a non-firm connection offer

temporary costs, provided these costs were managed, and there was closer alignment with future network investment.[13,14]

Connect and manage worked. The share of renewable capacity on Britain's electricity system grew quickly from 2010, with Ofgem reporting in 2015 that an additional 42.5 GW of large-scale generation projects had connected, avoiding nearly 6 Mt CO_2.[15] This helped reduce the wholesale price too – ECIU analysis estimates that wholesale prices in 2024 would have been 33% higher without the impact of large-scale wind, 60% of which connected between 2010 and 2020.[5,16]

Meanwhile, constraint costs grew modestly, to around £120m per year in 2015, in line with the costs modelled in DECC's original cost-benefit analysis.[14] Ofgem's forecast of future constraint costs anticipated that by 2018, constraint volumes would fall due to the completion of major transmission projects, before rising again, at a manageable rate, if the connect and manage policy continued.[15]

Initially, therefore, this approach was a success, delivering new renewable energy technologies that brought jobs, lower carbon emissions and lower wholesale prices. Of course, this optimistic forecast required network investment to keep pace with new generation and interconnection projects.

[13] Government Response to the technical consultation on the model for improving grid access, DECC, July 2010
[14] Proposals for improving grid access Impact Assessment, DECC, 2010

Connect and manage (2010)
policy introduced. Rapid renewables expansion and falling power sector emissions.

Imbalance (mid-late 2010s)
Network capacity delays; constraints rise. Low wholesale prices mask consumer impact.

Energy crisis (2022-23)
Energy crisis exposes cost sensitivity. Gas prices surge; constraint costs reach **£1.7bn.**

Transition (2023 - now)
Acceleration of grid build and Clean Power 2030. **Major outages** during reinforcement keep constraints elevated.

[15] Monitoring the "Connect and Manage" electricity grid access regime, Ofgem,2015
[16] Installed wind energy capacity by country, IRENA 2025, Our World in Data

Network capacity delay and misalignment

While connect and manage remained in place, a change in government in 2015 shifted the policy environment. Analysis from the Office for Budgetary Responsibility's 2015 Economic and Fiscal Outlook forecast a budget-breaking increase in expenditure on renewable energy subsidies.[17] This, combined with political concerns about the direction of energy policy, led to a decision to slow renewable energy deployment.

The Renewables Obligation (RO) was closed to new projects in 2017, leaving Contracts for Difference (CfD) as the main support mechanism.[18] However, new CfD allocation rounds were delayed and limited primarily to offshore wind. Meanwhile, changes to planning legislation in England introduced a de facto moratorium on new onshore wind projects outside of Scotland.[19]

The change in political support for renewables and concerns about consumer bills almost certainly affected network investment decisions. Instead of taking the opportunity to catch up, transmission reinforcement was delayed, and delivery timelines extended. Network build, particularly of the new 'boot-strap' transmission lines between Scotland and England, did not keep pace with the increase in generation.[20]

There may have been a cost-benefit justification for delaying network investment, but as a result, constrained volumes rose during the period from 2018 to 2020. The structural imbalance between generation growth and transmission capacity was building but not yet critical. Low wholesale gas prices muted the cost impact. Even as late as 2019, delaying network investment was still believed to be better for the consumer:

"Transient internal congestion and the associated remedial costs are an integral and explicit part of the way in which GB delivers an efficient and effective transmission system and system operation. This ensures the best value for consumers; as in some circumstances, short-term temporary congestion and the cost of remedial actions are more efficient than early transmission build."[21]

Energy crisis impact

The 2022 energy crisis, sparked by Russia's invasion of Ukraine, laid bare Britain's reliance on gas for its energy system. Constraints are not immune to this dynamic; constraint management relies heavily on gas generators when rebalancing constrained energy to meet demand.

While several major transmission projects were completed in the early 2020s, reducing constraint volumes, the cost of dispatching additional gas power to replace constrained energy ballooned and thermal constraint costs rose significantly.[22] Between April 2021 and March 2022 costs more than doubled against the previous financial year, reaching £1.1bn despite volumes being 25% lower. In 2022/23 as gas and power prices remained very high, constraint costs rose further to £1.7bn.[7]

[17] Office for Budgetary Responsibility, Economic and Fiscal Outlook, 2015
[18] Renewables Obligation closure, Ofgem, 2017
[19] Planning for Onshore Wind, House of Commons Library, 2024

[20] For example, proposed lines from Peterhead to Torness which will now be deployed by 2028 – see Transmission Network Unavailability, UKERC, 2025
[21] Annex 8, Bidding Zone Review – GB Submission to ENTSO, 2019
[22] The Western Link was delivered 2 years late in Summer 2019

Recognition and policy change

Higher constraint volumes may come with more variable generation and changes in demand, but the very high costs today reflect a prolonged misalignment between generation growth and network investment. Resolving that misalignment will take time, but it is essential if the full benefits of a clean power system are to be realised.

Following a 2023 review by the Electricity Networks Commissioner, energy policy shifted towards strategic planning, accelerated transmission build, and reform of the connection process.[23] This change in approach aims to better align investment and to give networks control over connection sequencing in line with a strategic network plan.

Although introduced by the Conservative government, the principles of strategic spatial planning and connection reform have underpinned the Clean Power 2030 mission, set out by the Labour government in 2024.[6]

One obvious result of the change in approach is a much more coordinated programme of network investment, including 86 major transmission network infrastructure projects that are being tracked and managed for delivery by 2030.

The system, however, is in a transitional phase. Timely delivery of network capacity will reduce operational costs, but grid upgrades are still playing catch-up, and major reinforcements require line outages, temporarily reducing available capacity. Meanwhile, we have not yet harnessed the full benefits of demand flexibility. Constraint volumes will, therefore, remain elevated until these solutions are put in place.

A structural shift in grid policy is underway

Networks Commissioner Report

Clean Power 2030

SSEP

Several key developments have occurred in network planning policy in recent years.

The 2023 Electricity Networks Commissioner review highlighted key issues and marked a shift towards building grid capacity ahead of, or aligned with, customer need – a clear departure from the previous policy.

Central to this reform are the **Strategic Spatial Energy Plan** and **Centralised Strategic Network Plan**, which will align generation and transmission strategy and delivery.

The **Clean Power Plan** is accelerating this shift, driving reform of the connections queue and fast-tracking more than 80 transmission projects. If delivered at pace, this anticipatory planning, controlled connections and coordinated network build will materially reduce network congestion over time.

[23] Electricity Networks Commissioner letter to DESNZ secretary, June 2023

Proposed reinforcement under Clean Power 2030[24]

A centrepiece of the shift to strategically planned network investment is the **Clean Power Plan**.

The Clean Power 2030 pathway identifies a major programme of transmission reinforcement to enable the next phase of the energy transition.

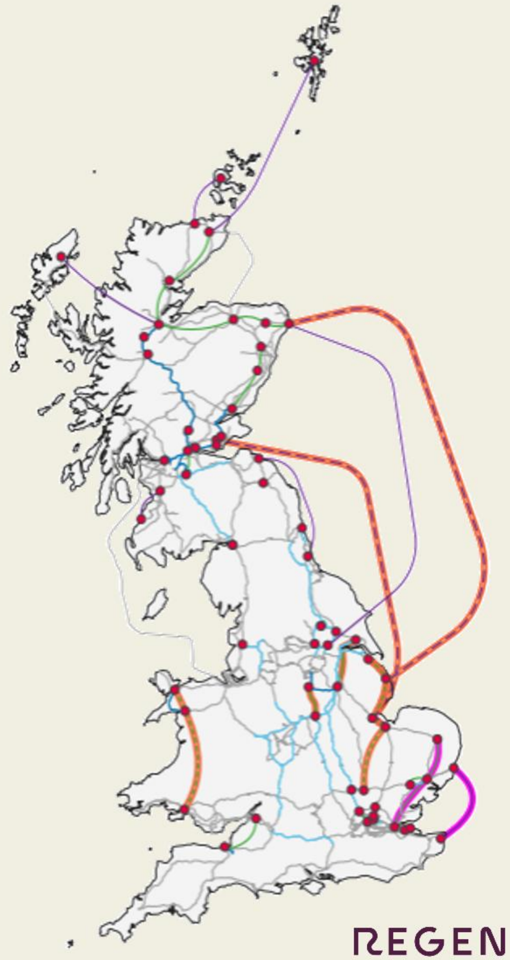
The plan includes over 80 onshore and offshore transmission projects designed to increase north-south transfer capacity.

The upgrades include a number of new transmission lines along the east coast and from East Anglia to the south east, and via interconnectors to Europe, which will be critical to reducing constraint costs and ensuring that the benefits of low-cost renewable generation can be fully realised across the GB electricity system.

NESO and the TOs are planning significant transmission network upgrades by 2030

Category	Key
New offshore network	purple line
New onshore network	green line
Voltage increase	blue line
Existing network upgrade	light blue line
Substation upgrade or new substation	red dot
Existing network	grey line
Network needed for CP30, currently scheduled post-2030	magenta line / orange line

Note: Illustrative routes.
Reproduced by Regen from NESO (Clean Power 2030 – advice on achieving clean power for Great Britain by 2030)



REGEN

[24] Clean Power 2030 – advice on achieving clean power for Great Britain by 2030, NESO

3 Constraints on the transmission system

Network generation constraints occur when electricity cannot flow freely from generating areas to demand areas.

This section sets out the basics of thermal constraints on the transmission network, what they cost us and what we are paying for. Section 4 explores some of the complexities which drive these costs.

What does the transmission network do?

The transmission network consists of 27,000 km of extra-high-voltage lines (typically at 400 kV, 275 kV, and, in Scotland, 132kV) and hundreds of HV substations. Its primary role is to transmit power over long distances from power generation sources to areas of demand, and down to the lower-voltage distribution networks that supply homes and businesses.

Historically, the transmission system was designed around the geographic location of large-scale thermal generators. Today, it must accommodate a far more diverse generation mix, including offshore wind farms, a wide variety of distributed renewables, new storage assets and growing interconnector capacity. Demand is also becoming more complex, with a reduction in traditional industrial loads but an increase in electrification across transport, heat, hi-tech industries and data processing.

What is a network constraint?

The Transmission Network is subject to operating constraints that limit its capacity, known as its 'capability', to transmit power. The two main constraint categories are thermal and voltage constraints.

Thermal constraints: Physical limits on cables and transformers where power flows approach levels that risk overheating.

Voltage constraints: Localised limits on voltage that must be maintained within regulatory Safety and Quality of Supply Standards.

Other constraints costs reported by NESO include stability (inertia) constraints and constraint limits related to the potential Rate of Change of Frequency.

An increase in **thermal constraints** limiting generation flows from areas of high generation has been the main cause of the rise in both constraint volume and costs in recent years.

Importantly, the transmission network's transfer capability is not simply the sum of the capacities of individual lines. Power flows across interconnected circuits must be managed dynamically, with contingency capacity required to ensure that every part of the system meets Security and Quality of Supply Standards(SQSS) to withstand faults and outages.

Combining operational requirements, variable power flows and weather with outages, the network's actual transfer capability varies significantly over time and location.

How much do constraints cost?

Total constraint costs have increased significantly over the past decade, from a few hundred million in 2010-2015 to **£1.9bn** in 2024/25.

Constraint costs are in part driven by the volume of constrained energy. The volume of **thermal constraints** fell between 2021 and 2022 but rose again, exceeding **13 TWh** in 2024/25.

Costs are also driven by the wholesale price of power needed to replace constrained energy. This was especially high during the energy crisis period from 2021 to 2022, reflecting the high cost of turning up gas generation to replace constrained, mainly wind, energy.

In 2024/25:

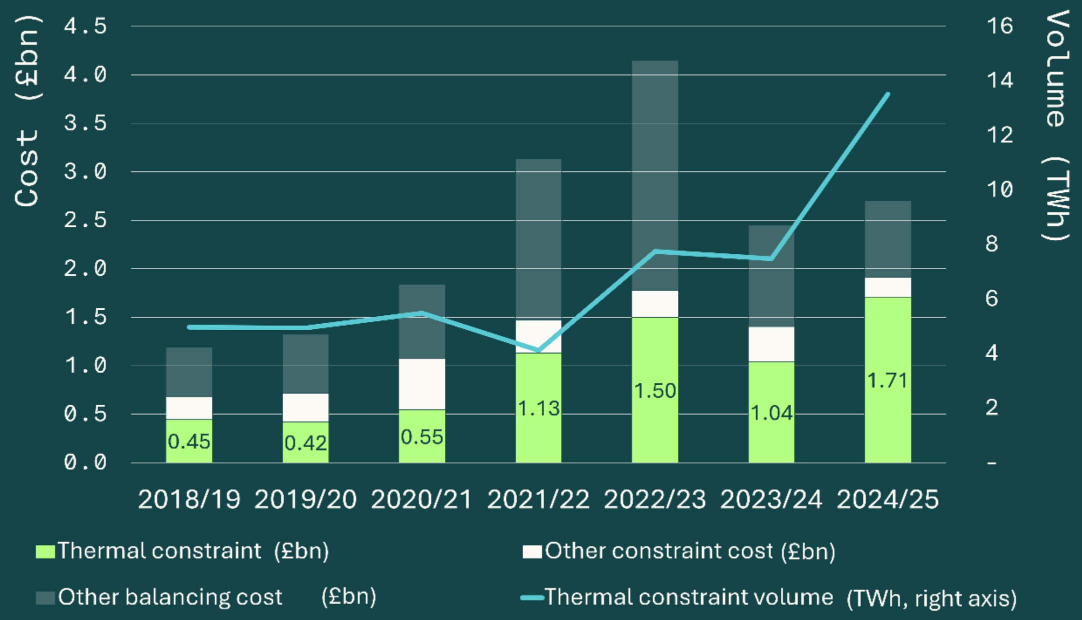
- **total balancing costs reached £2.7bn**
- **of which total constraint costs were £1.9bn**
- **of which thermal constraints were £1.7bn.**

Wind accounted for 56 % of the turn-down volume and £440 million turn-down cost, almost all of which occurred across the Scottish boundaries.

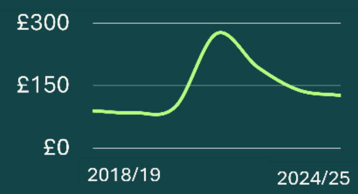
Constraint costs are recovered via system usage charges, which are passed to consumers by energy suppliers. Regen estimates the average domestic bill impact in 2024/25 was just under £20 per household per year.

Although a relatively small share of the total electricity bill, their visibility and potential to grow have heightened political and public awareness of this systemic problem.

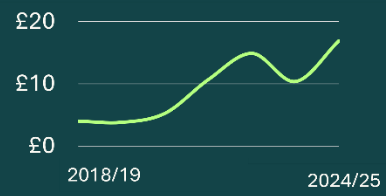
Constraint costs have risen significantly, driven both by rising volumes and unit costs



Average cost of thermal constraint management (£/MWh)



Illustrative domestic bill impact of thermal constraints (£)



Source: NESO annual balancing cost report data workbook, 2025
Note: Regen analysis and combination of multiple NESO tables.

REGEN

What are constraint costs?

Constraint costs are a subset of total balancing costs. Balancing costs are incurred when NESO takes real-time actions to maintain system operability. This includes balancing supply and demand, maintaining frequency and voltage within operational limits, securing sufficient inertia for system stability, and managing thermal constraints.

Typically, to manage a thermal constraint, the NESO control room will need to take two redispatch actions:

1) **A turn-down action** to reduce generation (or increase demand) in constrained area to keep power flows within operational limits
2) **A turn-up action** to increase generation (or reduce demand) outside the constrained area to rebalance the system and meet demand

Turn-down and turn-up actions are mainly procured via the balancing mechanism, through which NESO manages assets' power outputs to balance supply and demand. NESO can, however, also manage power flows by placing forward trades (or counter trades) in both the GB market and over interconnectors.

The system cost of managing constraints is the net incremental cost to NESO of these balancing actions: the cost of turning down generation in one location and replacing it with turn-up generation elsewhere.

The wholesale cost of constrained electricity already sold, and received as revenue by the generator, would have been incurred in the absence of the constraint, and is not therefore recovered or reported as a constraint cost. It is, however, a measure of the economic value of wasted constrained energy.

Constraint costs are the net cost of turn-up and turn-down actions in the balancing mechanism to resolve system constraints

NESO reported constraint costs

Turn-down cost	Turn-up cost
Net **bid prices** paid by market participants to reduce generation or increase demand	Net **offer prices** paid to market participants to increase generation or reduce demand
Forward trades in wholesale market	Forward trades in wholesale market
Interconnector trades (turn up or reverse imports)	Interconnector trades (turn down or reverse exports)
Turn down costs in local constraint markets	Turn down costs in local constraint markets

Net cost is recovered from suppliers via Balancing Services Use of System (BSUoS) charges and is ultimately reflected in electricity bills.

Wholesale costs are not reported by NESO as a constraint cost. Constrained power has already been sold in the wholesale market, so the cost would still be incurred absent the constraint. It is, however, a measure of the lost economic value of the constrained power.

What actions resolve constraints?

Constraint management involves both reducing generation behind network boundaries **('turn-down')** and increasing generation elsewhere **('turn-up')**. Analysis of balancing mechanism data shows that these actions are driven by the location and relative cost to redispatch different sources of generation, storage and demand.[25]

In 2024/25, wind accounted for around 56% of accepted turn-down volumes (9.4 TWh), with almost all wind turn down occurring in Scotland. Other assets that are regularly turned down include gas-fired generators, hydro, storage and interconnectors

Turn-up actions show the opposite pattern, with a continued reliance on gas generation. In 2024/25, NESO procured around 15.8 TWh of additional generation in the balancing mechanism, with more than 80% provided by gas power. Other technologies, including storage, currently play a smaller but nonetheless important role in system balancing.

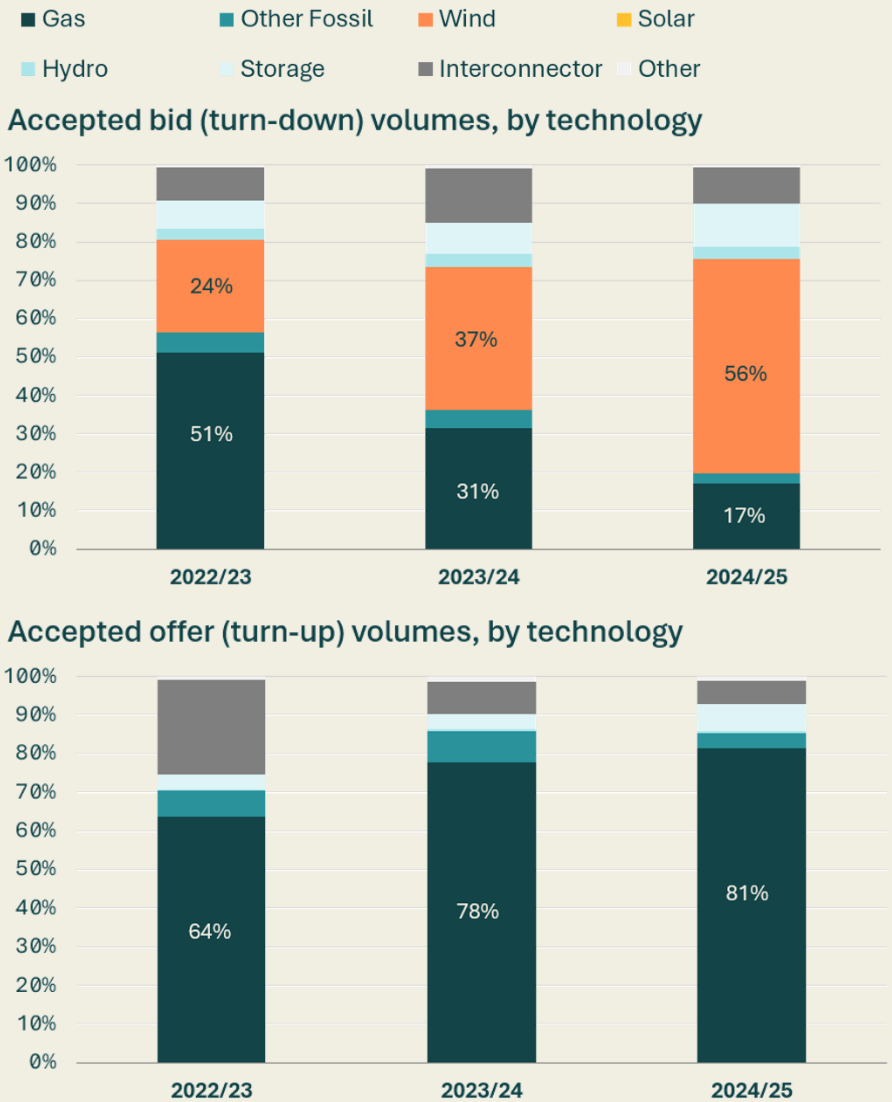
The mix of technologies used for redispatch is also influenced by fuel prices. During periods of high gas prices – as in 2022/23 – gas generators should submit higher positive bids (see "*How much does it cost to turn down generation*" below). This increases the likelihood that gas power will be constrained. At the same time, the cost of increasing gas generation rises, making them less competitive for turn-up actions.

While NESO aims to minimise cost, redispatch isn't purely an economic mechanism: assets may be dispatched ahead of cheaper alternatives ('skips'). Bid and offer price dynamics are explored further in section 4.

---

[25] NESO BOA Generation Mix Data, 2025 Annual Balancing Cost Report Data Workbook

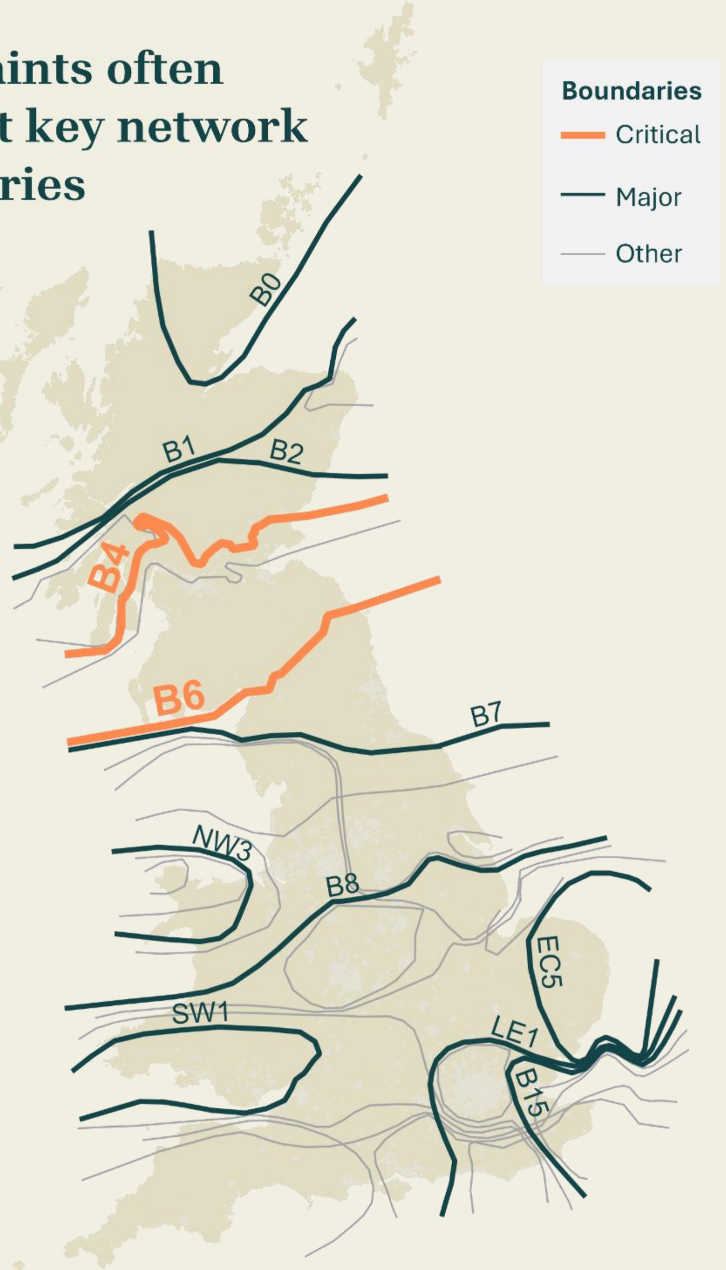
Most turn-down actions now come from wind while most turn-up is from gas



Source: NESO BOA Generation Mix data, 2025 Annual Balancing Cost Report Data Workbook

REGEN

Constraints often occur at key network boundaries



Note: Illustration digitised from NESO Electricity Ten Year Statement 2024. Transmission boundaries are non-physical analytical groupings of real network bottlenecks.

Where do constraints occur?

Constraints are often described as occurring across **transmission boundaries.** These are not physical borders, but topological (network power flow) boundaries representing critical transmission corridors and common 'pinch-points' that system operators habitually manage and report against.

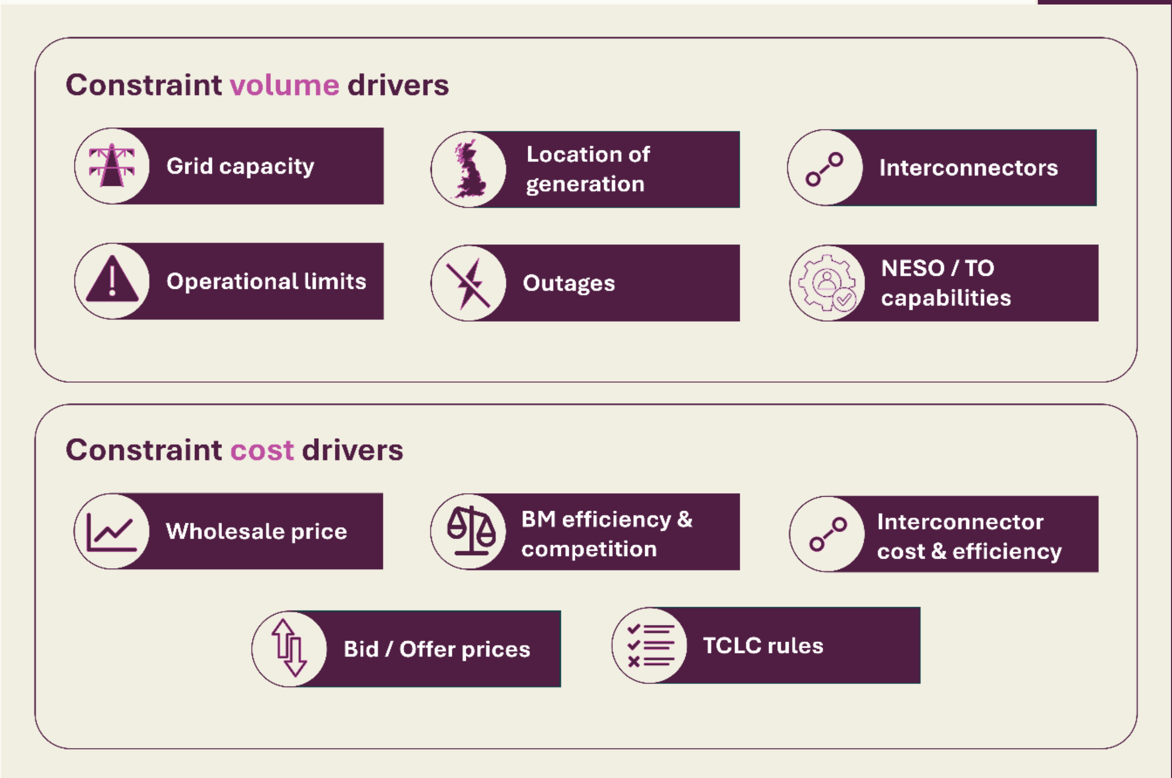
In reality, there are thousands of individual constraint points on the network. There are, however, around 30 key named transmission boundaries across Great Britain, of which roughly a dozen are regularly constrained. Today, the most critical are the 'B4' boundary between north and central Scotland and the 'B6' between Scotland and England.

While boundaries are a useful analytical tool, ascribing reported constraint costs to individual boundaries (or even generators) can be misleading for several reasons:

- The boundaries are summations of what is happening within the network. There are boundaries within boundaries, and so constraint volumes reported at, for example, the B4 boundary may be more properly related to the B0, B1 or B2 boundary, or to individual transmission lines within those boundary areas.
- Constraint actions taken by system operators to reduce flows at one boundary may be to alleviate constraints at another boundary. Conversely, relieving a constraint at one boundary may increase flows and constraints at another boundary.
- NESO is constantly considering the cost of constraint actions alongside system requirements. Contrary to common understanding, generators may regularly be the first to be constrained because they submit the cheapest bid to turn down, not because they are the specific cause of excess flows.

4 What drives constraints today?

Constraint costs are shaped by the complex interplay of several factors that influence power flows and the cost of managing them.



It can be useful to think of these factors as influencing either the **volume of energy constrained** or the **cost of managing those constraints**.

Volume drivers are the physical and operational factors that determine how frequently the system operator must intervene to manage power flows on the network, and therefore the volume of energy which is constrained. As shown in earlier sections, this has increased significantly in recent years.

Cost drivers determine how expensive those interventions are once they occur. These include prevailing wholesale electricity prices, the economics of different generation technologies, the behaviour of market participants and the rules governing redispatch in the balancing mechanism.

The following sections explore how these drivers interact in practice, and why constraint volumes and costs have risen in recent years.

How much grid capacity is available?

Capacity misalignment is the fundamental driver of saw-tooth constraint volumes

As discussed in section 2, the policy of "connect and manage" allowed renewables to connect ahead of the transmission reinforcement. This accelerated the deployment of low-carbon generation, but delays in network investment meant that transmission capacity lagged behind new generation connections, increasing the severity of constraints.

This reflects a broader feature of electricity system development: in the absence of an overarching strategic plan, new transmission capacity is rarely approved before a proven need. Instead, investment typically follows demand and generation growth, which, during a period of rapid transition, leads to increased constraint volumes.

At some point, these rising costs create the economic and regulatory case for network reinforcement. Once additional capacity is delivered, constraint volumes fall again until demand and generation grow, and the cycle repeats. Constraint costs, therefore, tend to follow a "saw-tooth" pattern over time.

NESO's own modelling shows that balancing costs are highly sensitive to the pace of transmission build-out, with projected constraint costs significantly lower in scenarios where recommended network reinforcements are delivered on time.[7]

Recent reforms aim to flatten this cycle by bringing forward strategic network investment. However, the current system is still operating within the legacy of past investment cycles, and until new transmission capacity is built, the system will continue to rely on operational constraint management.

Outages have increased constraint volumes

A number of recent reports have highlighted the growing role that outages play in driving constrained volumes.[26] Regen analysis of NESO operational data shows that during 2024 and 2025, key transmission boundaries' capacity limits were well below their nominal capacity and their historic trend.

Outages can occur for several reasons, including routine maintenance, reinforcement works and the connection of new assets. Transmission boundaries are groups of circuits rather than individual lines, meaning the boundary limits reflect the status of several network assets. System operators must also maintain contingency capacity to ensure system resilience in the event of faults. Boundaries, therefore, never operate at their theoretical "name-plate" maximum.

Nonetheless, the reduction in available capacity has been substantial. The B6 boundary, for example, has a nominal transfer capability (after contingency) of around 6.8 GW. For much of 2024 and 2025, the day-

[26] Transmission Network Unavailability – the Quiet Driving Force Behind Rising Curtailment Costs in Great Britain, UK ERC, 2025

ahead operational limit (per NESO's published data) has hovered around 4 GW, about 60% of its nominal capability.[27] This is markedly lower than in 2022 and 2023, when day-ahead limits tended to be closer to 5 GW (80%). A similar pattern can be observed for the B4 boundary.

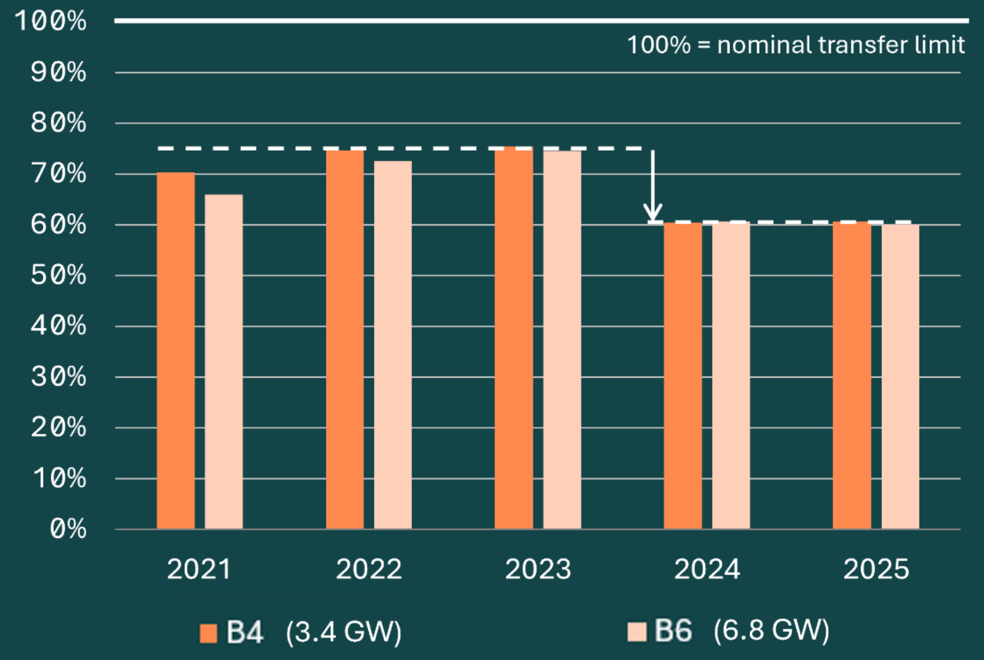
Periods of reduced network availability are strongly correlated with periods of high constraint costs. A simple "what if" analysis shows that, all else being equal, operating the B4 and B6 boundaries at 80% availability in 2024-25 would have reduced constraint volumes across those boundaries by 40-50%. An analysis by the UK Energy Research Centre yielded similar results.[26] In practice, all else is not equal; relieving a constraint at one boundary may shift congestion elsewhere in the network, but the analysis illustrates the significant impact of outages.

Significant outages occur when major reinforcement is being delivered in parallel. An unavoidable feature of the need to upgrade the transmission system after a period of underinvestment.

In response to the call for increased transparency and better forecasts, NESO is currently undertaking a process of System Access Reform, which will introduce the publication of planned network outages several years in advance. Conservative assumptions are used for system security, but improvements in data, forecasting and operational tools may allow these limits to better reflect real-time network capability and increase the operating limits of the existing network.

The B4 and B6 transmission boundaries operated with lower availability in 2024 and 2025 due to network outages

Average boundary limits relative to nominal transfer capacities (%)



Source: Regen analysis of NESO day-ahead boundary limits and flows dataset. Boundary transfer capabilities sourced from Regen analysis and NESO documentation.

REGEN

[27] Day Ahead Constraint Flows and Limits, NESO

Why are constraints concentrated in Scotland?

In 2024 and 2025, most constraint costs occurred on the boundaries between Scotland and England

NESO data suggests that around **75-80% of constraint costs** in 2024/25 originated in Scotland and the borders (sometimes known as the 'Cheviot' boundary). In previous years, there have been higher constraints in England and Wales.[28]

This reflects the geography of Great Britain, the location of generation and historic network investment. Most demand is in the southern parts of Britain, while a large share of renewable generation, particularly onshore wind, has been built in Scotland to make use of its natural resources and more favourable planning. As of 2024, Scotland had 3.7 GW of onshore wind, compared to 1.3 GW in England and Wales.[29] In total, Scotland has 10.2 GW of generation capacity, which in 2024 supplied 52 TWh of electricity. Meanwhile, Scottish annual demand was only 27 TWh, making it a significant net exporter.[30] [31]

In Scotland, 67% of generation capacity is variable (about 80% of which is wind power). As such, in the absence of increased storage capacity and flexible demand, Scotland will continue to be a net exporter, especially at times of high wind. This demonstrates the importance of transmission capacity between Scotland and England.

Constraint costs arise from mismatches between generation, demand, and network capacity. Today, that mismatch is seen in Scotland, but in future it is likely to shift to the south and east.

Why is one generator turned down but not another?

By volume, wind accounted for **55% of all turn-down** actions in the balancing mechanism in 2024/25.[25]

In the balancing mechanism, NESO selects assets to turn down based on both operational and economic considerations. Unless there is an operational imperative to do otherwise, the system operator will endeavour to constrain the cheapest assets located within the constrained boundary area(s).

As a result, analysing which generators are constrained can give a misleading impression of where constraints physically occur. There are exceptions, but constraints generally arise from limits on power flows over transmission lines and boundaries rather than individual generators.

Because many of the current network limiting constraints are located towards the north of Great Britain, much of the generation located behind those boundaries is wind. This means wind farms are frequently selected to turn down. If the limiting constraints were located further

[28] Monthly Balancing Services Summary Data, April 2024-March 2025, NESO
[29] Digest of UK Energy Statistics (DUKES) Table 5.8, DESNZ, 2025
[30] Scottish electricity generation and supply over time, Scottish Energy Statistics hub (Scottish Government), 2025
[31] It should be noted that Scotland has a relatively small share of both GB solar and offshore wind, which in concentrated in England and Wales

south, a wider mix of generation technologies would be located behind the boundary and would therefore compete in the balancing mechanism to resolve constraints.

Examining data on constrained generators shows that the top 10 most constrained wind farms in 2025 accounted for 80% of constraint volume. The map shows that all of these sit to the north of the B6 boundary, with most also north of B4. This reflects the large concentration of wind generation in northern Scotland relative to the transmission capacity connecting to demand centres further south.

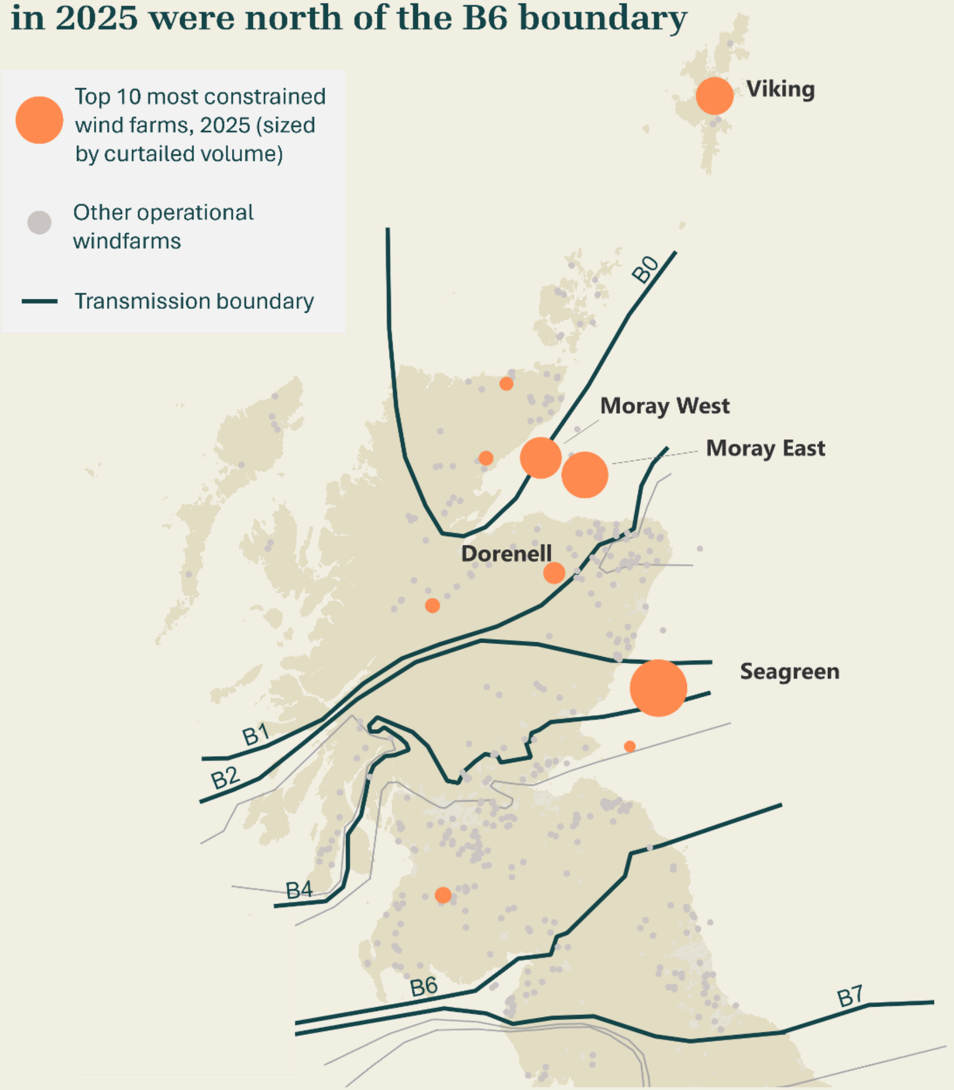
Analysis of their bid prices reveals that **these wind farms are often the most cost-effective source of turn-down volume.** This is particularly true for Seagreen and Viking wind farms (see "The cost of turning down wind "). This is an important nuance which is often overlooked in media commentary and online discourse that blames individual wind farms.

Location of future constraints

The location of constraints is expected to shift further south into the north of England, B7 and B8 boundaries, and significantly to the east coast and East Anglia at the EC1 and B15 boundaries. NESO has identified that network investments from East Anglia to the South East (see "*Proposed reinforcement under Clean Power 2030*" above) are vital to avoid spiralling constraint costs.

But many factors will determine where future constraints will occur. The rate of build of new transmission capacity will be critical, but with new offshore wind, nuclear and interconnectors, as well as shifting demand patterns, constraints could occur across the GB networks.

All of the top ten most constrained wind farms in 2025 were north of the B6 boundary



Source: Curtailment volumes from Robin Hawkes' Renewbles Map. Wind farm locations from Renewable Energy Planning Database. Boundary locations digitised from NESO Electricity Ten Year Statement 2024.

How do market dynamics affect constraint costs?

Constraint costs primarily arise from system actions taken in the balancing mechanism, where generators, storage assets or demand submit **bids** and **offers** to adjust their power output or demand:

Bid: A proposal to pay to **reduce generation output** (or increase demand), priced in £/MWh

Offer: A proposal to be paid to **increase generation output** (or reduce demand), priced in £/MWh.

When a constraint occurs, NESO accepts bids to reduce flows behind the constraint and accepts offers to rebalance the system elsewhere.

How much does it cost to turn down generation?

In 2024/25 the **net** cost of turning down generation was £92m. However, this includes payments from generators willing to pay to reduce output. The price of turn-down is primarily shaped by two factors: regulatory rules governing bid prices and the system operator's ability to take dispatch actions that minimise costs.

[32] Update to the TCLC guidance, Ofgem, June 2024

Transmission Constraint Licence Conditions (TCLC) require that bid prices submitted in the balancing mechanism do not provide excessive benefit.[32] This is taken to mean that the **bid price** should only compensate the generator for the lost revenue or increased cost of being constrained:

Generator or flex type	Typical bid price	TCLC explanation
Gas and other fuelled generators	**Positive bid** (generator pays to reduce output)	When constrained, the generator avoids fuel and operating costs, which increases profit. TCLC means generators should submit positive bids to return the benefit.
Storage and demand flex	**Usually a positive bid**	Storage will retain stored energy by being turned down.
Renewables (wind, solar)	**Negative bid** (generator is compensated to reduce output)	When constrained, generators are allowed to recoup revenue from CfD payments and other subsidies lost.[33]

NESO aims to minimise constraint costs by accepting the highest price bids first, subject to operational and locational criteria. Fuelled generators may therefore be turned down first, as they will pay. Storage and demand response bids typically sit between gas and renewables.

[33] There is an ongoing modification proposal (P462) that would remove subsidy payments from bid prices in order to make the BM more cost reflective.

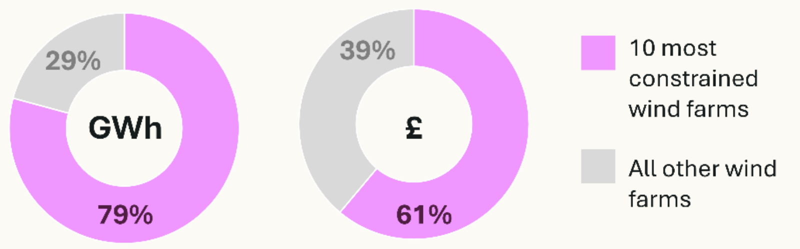
The cost of turning down wind

Turning down the lowest-cost generators first has led to a concentration of turn-down actions affecting specific wind farms with relatively low turn-down costs. Hence, the cheapest-to-turn-down wind farms in 2025 were also the most constrained.

This included Seagreen and Viking wind farms, whose bid prices were around minus £10 per MWh because they had not yet activated their CfD contracts and so did not recoup the loss of CfD payments. Overall, the weighted average price for turning down wind was approximately £38/MWh in 2025.[34]

The charts below show that the 10 most turned-down wind farms accounted for 79% of volume, while the cumulative cost of constraining them was only 61% of the total.

Breakdown of GB wind turn-down volume and cost, 2025

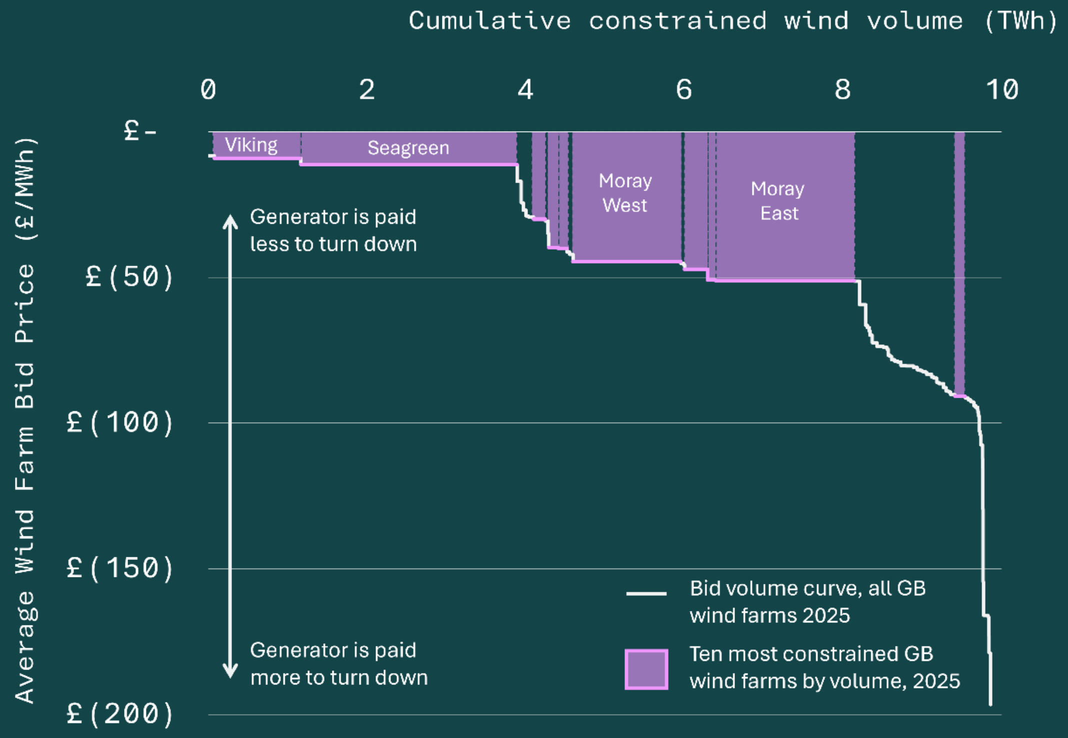


The bid curve in the graphic on the right orders wind farms by average bid prices, plotted against their cumulative constraint volume. It shows that a large share of constraint volume occurs among wind farms with relatively low bid prices.

[34] GB Renewables Map - curtailment, Robin Hawkes

The most constrained wind farms are often the cheapest to turn down

Distribution of average wind farm bid prices against cumulative constrained volume, 2025. Negative bid prices mean the generator is paid to turn down.



Source: Regen Analysis of wind farm bid price and volume data collated by Robin Hawkes for renewables-map.robinhawkes.com

Why should generators be compensated for being constrained?

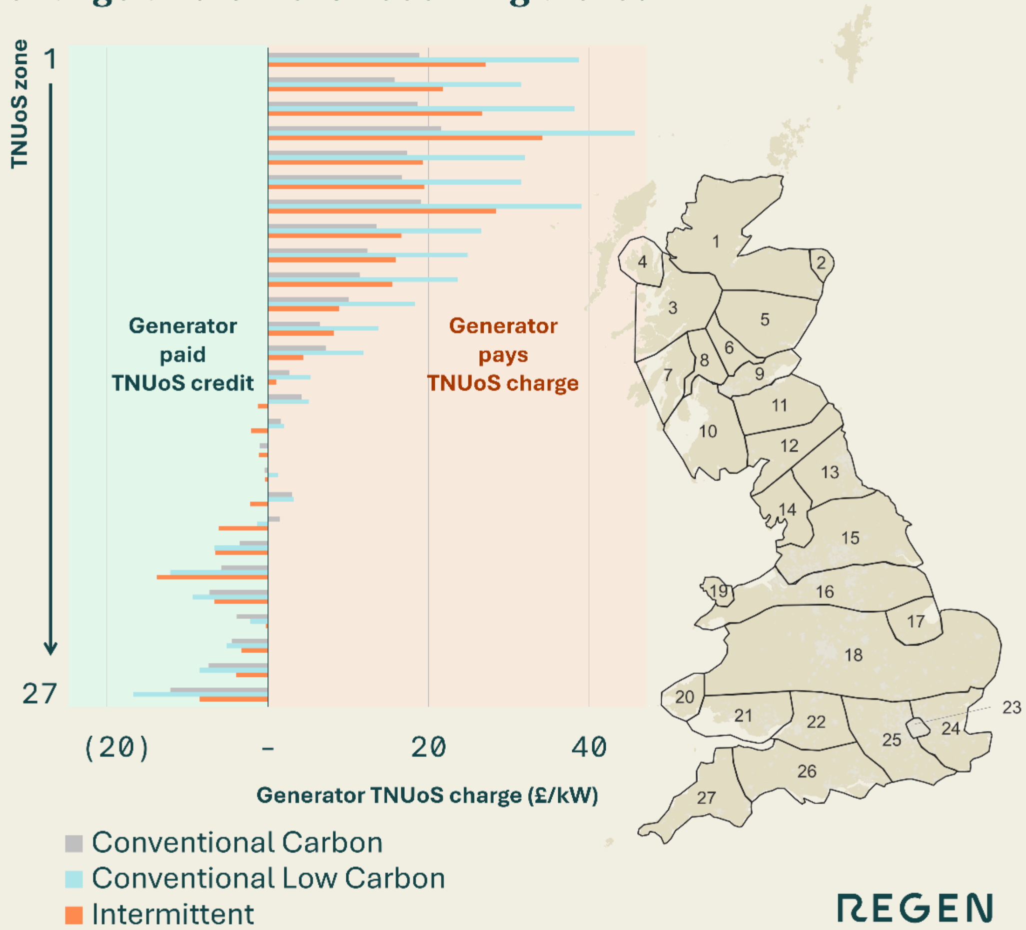
Some media commentary has questioned why generators should be paid when they are asked to reduce output and no electricity is delivered.

In some electricity markets, generators bear the risk of network constraints themselves. If the network cannot transport a generator's power, that is treated as a cost of doing business. However, this approach generally occurs in systems with low constraint levels. If generators are expected to face frequent constraints with no compensation, many would seek significantly higher subsidies, some other form of revenue guarantee, or would simply not invest.

In Great Britain, constraint levels are currently high and generators seek a firm connection before developing projects. Generators have some ability to choose their location, but they do not control decisions about when network upgrades will be delivered. Non-firm connection agreements can work when constraints are temporary and easily predicted. Shifting constraint risk fully onto generators would increase investment risk, which may make many projects unfinanceable.

A further rationale for compensating generators is that they are very likely already contributing to network reinforcement costs. Projects connecting to the distribution network will usually have paid substantial up-front connection charges to fund required upgrades. Generators connected at the transmission level, particularly in constrained areas such as Scotland, also pay high ongoing Transmission Network Use of System charges (TNUoS, see right), to contribute to network investment.

Generation TNUoS costs vary significantly across GB, with some generators paying a charge and others receiving a credit



REGEN

Source: Transmission Network Use of System (TNUoS) tariffs for 2026/27, NESO.
Note: Charges shown are indicative estimates published by NESO for generator categories/ Charges vary by project in reality.

Turn-up (offer) costs are highly sensitive to short-term wholesale prices and the price of gas power

NESO data shows that gas provided **81% of the balancing mechanism turn-up volume in 2024/25, which Regen estimates accounts for 72% of the turn-up costs.** Further Regen analysis estimates that combining turn-up and turn-down actions using gas power generators accounted for **67% of the total cost of thermal constraints.**

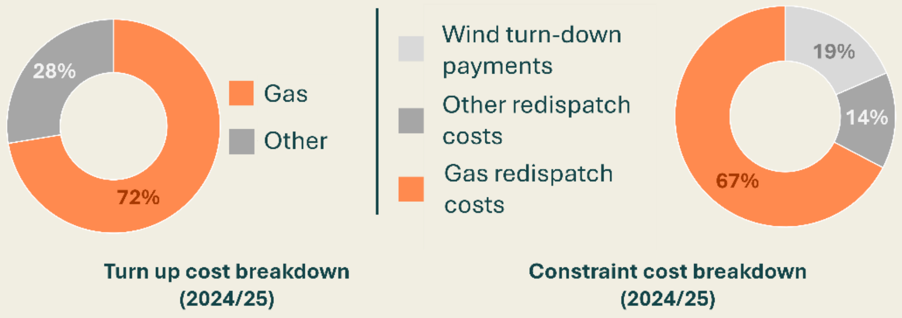
Data from 2022 to 2025 shows a strong relationship between wholesale electricity prices and the average price of accepted turn-up offers in the balancing mechanism. Gas offer prices closely track the average offer price on the system, reflecting the role of gas plants as the primary providers of turn-up actions.

Taken together, these dynamics mean that constraint costs are highly exposed to movements in wholesale electricity prices and, in particular, the cost of gas-fired generation.

This is a risk for consumers in Great Britain. The dynamic was clearly observed in 2022, after the Russian invasion of Ukraine. Although constraint volumes didn't change significantly year on year, the cost of constraint management rose to £1.5bn implying a significantly higher cost per MWh of constraint management, driven by the high price of gas.

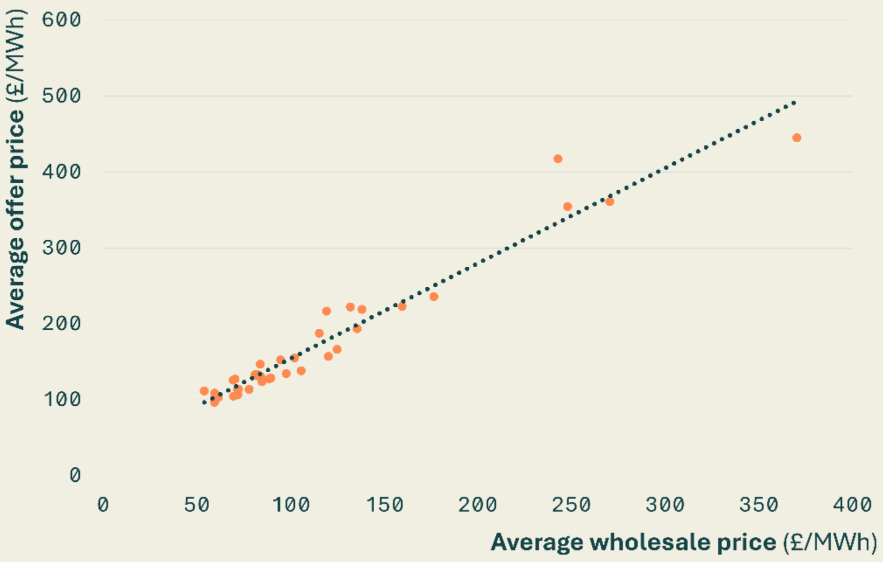
With the higher levels of constrained energy seen today, a further sustained gas price shock stemming from the war in the Middle East could lead again to a more acute rise in constraint costs.

Gas accounts for 72% of turn up costs and 67% of overall constraint costs



Source: Regen estimates combining NESO BOA generation mix data, NESO Stage-6 BOA price data, and wind bid data from renewables-map.robinhawkes.com.

Average offer prices were strongly correlated with the wholesale price between 2022 and 2025



Source: 2025 Annual Balancing Cost Report Data Workbook, NESO
Note: Monthly average values, 2022-2025

REGEN

How efficiently does the balancing mechanism resolve constraints?

NESO aims to resolve constraints at the least cost, but is limited by operational requirements and, in some cases, inefficient processes.

In principle, the balancing mechanism resolves constraints by accepting the lowest-cost bids and offers first. In *practice*, dispatch is influenced by more than price alone. Actions must satisfy locational requirements within the network, ensure sufficient system stability and respect operational limits on individual assets. As a result, the balancing mechanism operates as a 'constrained merit order', where the lowest-cost option is selected subject to additional operational considerations.

While economic dispatch remains the guiding principle, out of operational necessity, the system operator may accept higher-cost bids and offers. In addition to operational imperatives, the control room processes and IT systems may introduce additional inefficiencies, for example, when dispatching multiple smaller assets, which leads to higher levels of merit order 'skips' and sub-optimal dispatch.

The most economic unit is not always dispatched

As participation in the balancing mechanism has expanded to include storage, demand response and a wider range of distributed assets, it has become apparent that, even with allowance for operational requirements, dispatch does not always follow a strict price-merit order.

A 'skip' refers to a non-economic dispatch in which a lower-cost bid or offer is bypassed and a more expensive action is accepted instead.

Industry analysis has suggested skip rates exceeding 90% for certain technologies. Persistent skips increase balancing costs and weaken price signals for flexibility investment. They also carry a significant consumer cost. Data published by Kilowatts.io suggests the total cost of skips in 2025 was £54 million.[35]

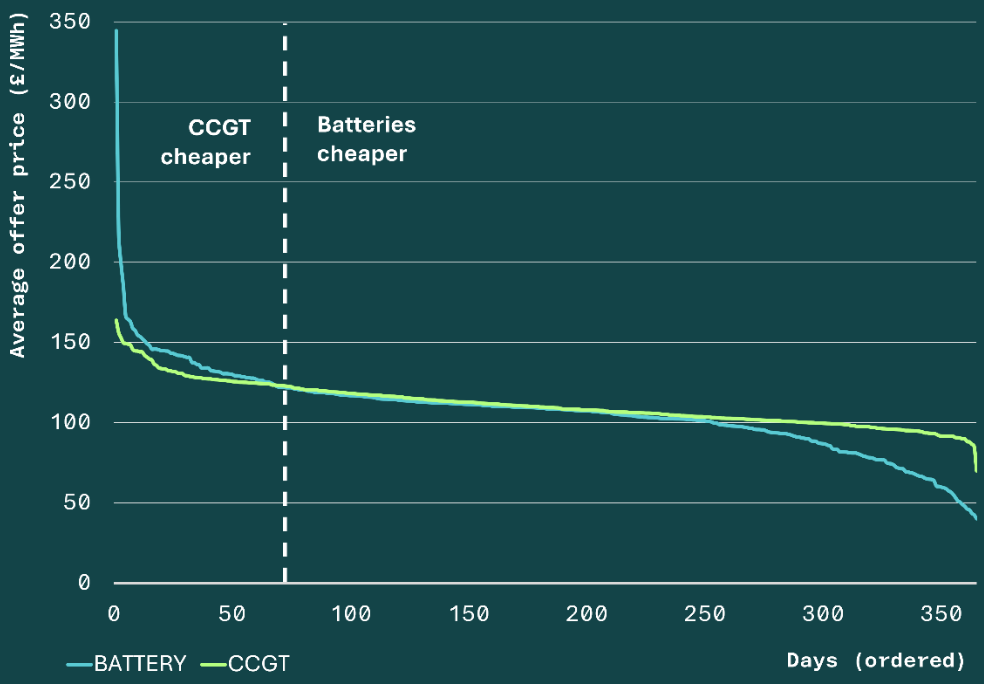
NESO has been taking action to address skip rates and engaging widely with industry on the topic. Its data shows a reduction in **energy-tagged** skip rates over 2025 –the monthly rate of feasible, in merit energy skipped, as a proportion of total energy dispatched – declining from 43% in January 2025 to 32% in December 2025.[36]

NESO's published data focuses on 'energy tagged' balancing mechanism actions, taken to resolve an energy imbalance on the system. Since constraints management actions are "system tagged" the published skip statistics do not yet provide a complete picture of how efficiently constraints themselves are resolved. NESO is developing a method for evaluating and reporting on skips behind constraints.[37]

[35] Monthly breakdown of out-of-merit dispatch costs for 2025, skipedia.kilowatts.io

[36] Skip Rates Dashboard, NESO
[37] NESO Dispatch Transparency Forum, January 2026

On average, accepted battery offers were lower than gas CCGT offers on 81% of days in 2025



Source: NESO skip rate data - stage 6 acceptance API.
Note: Data is post-processed balancing mechanism data, published by NESO for skip rate analysis and excludes all system-tagged actions, including redispatch behind constraints.
Prices reflect accepted dispatch rather than all submitted bids and offers; where assets have high skip rates, average accepted prices may be biased upward.

REGEN

[38]Skip Rates – stage 6 acceptance, NESO

The best use of storage and demand response could reduce constraint volumes and costs

Storage and demand response could play a greater role in resolving network constraints if used to their full potential. Storage can provide a cost-effective alternative to turning down generation and increasing supply to replace constrained generation. Accepted offer data from 2025 shows that batteries were competitive with CCGTs, being cheaper to dispatch on average on 81% of days, even with the effect of skips.[38]

Storage can also provide additional capabilities, including intertrip services and boundary smoothing, which help assets operate at higher capacities.

Demand response can also increase demand behind constraints, or reduce it in front of them. New local constraint markets and wider balancing mechanism participation could enable flexibility providers to respond directly to the value of constraint avoidance.

However, if incentives are misaligned, storage can sometimes increase constraint costs. For example, assets may discharge behind a constraint in response to wholesale price signals, or to manage their state of charge, even when this is not system optimal

This can lead to ‘repetitive re-trading’, where energy is repeatedly sold in the wholesale market and subsequently turned down in the balancing mechanism across successive periods, increasing system costs without resolving the constraint. With regulatory and operational reforms, the issue of repetitive retrading can, and should, be quickly solved.

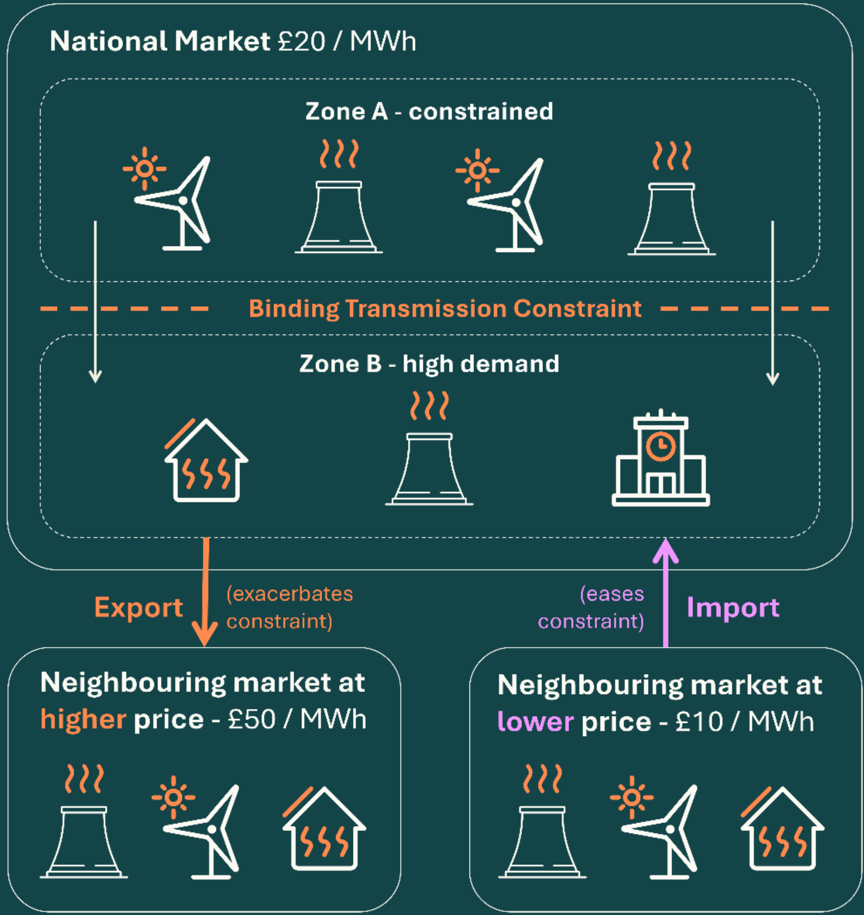
Do interconnectors alleviate or add to constraint costs?

Interconnectors connect the GB electricity system to neighbouring markets and play an important role in balancing supply and demand. They help reduce energy costs by allowing excess generation in one system to be exported, or by importing electricity from lower-cost markets when needed. Today, GB is a net importer, so interconnectors provide value to consumers by enabling lower-cost imports, but increasingly, they are exporting excess generation.[39, 40]

However, the interactions between interconnectors, wholesale trading and network constraints can be complex. In a national market, interconnector flows respond to wholesale price signals rather than local network constraints. As a result, electricity imports and exports do not necessarily reduce imbalance across constraint boundaries and may, at times, increase constraint volumes.

Controlling interconnector flows, primarily through countertrading, is more complex for the system operator than dispatching generation, as it involves trading with market participants and can affect balancing in neighbouring markets. Therefore, although NESO uses interconnector countertrading, it is not the preferred route for managing constraints. With closer cooperation between the UK and EU partners, there are opportunities to improve the efficiency of managing cross-border flows.

Interconnector flows respond to wholesale price signals rather than local network conditions



Depending on the relative wholesale prices in GB and its neighbouring markets, interconnector flows may help alleviate or increase the impact of boundary constraints.

---

[39] Initial Project Assessment of the Third Cap and Floor window, Ofgem, 2024

[40] Interconnectors in GB: how do they operate?, Modo, 2023

5 Meeting the constraint challenge

Constraints are inherent to energy systems, but must be managed to remain within an optimal range. That requires coordinated action by the system operator, industry and energy policymakers, as well as the best use of innovation and technology.

Projections of future balancing costs for 2030 have ranged widely, from £3-4bn per annum to as high as £8bn.[7,24] As a result of connection reforms and measures to align network investment, the risk of an £8bn annual cost now seems highly unlikely. However, the fact that this figure remains a theoretical outcome of policy and system failure has rightly drawn attention from policymakers and the media.

Recent analysis by LCP Delta suggests that a more likely worst-case outcome for constraint costs by 2030 would be in the range of £4-6bn per annum and that, with appropriate cost controls, innovation and reforms, the UK should be targeting a maximum range of constraint costs of between £2.3 and £3.8bn.[41] So higher than the current level, but with a much larger electricity system with higher levels of variable renewables.

Regen's analysis supports the view that constraints can and must be managed and that the goal of government, system operator, regulator and industry should be to keep peak constraints within a range of £2-£4bn in the period to 2030 and to an optimal level, which could be as high as £1-2bn, in subsequent years.

DESNZ will shortly publish proposals to reform energy markets and reduce constraint costs as part of the RNP delivery plan. In the area of constraints, we expect to see a range of initiatives, from better strategic alignment of network investment to reforms of the balancing mechanism and flexibility markets, as well as signposts to work being done by NESO and Ofgem to improve operational efficiency, market performance and regulation. A summary of the range of measures which could have a positive impact is given in the graphic on the next page.

We hope the RNP will present an ambitious, coordinated programme of reforms with clear accountability and governance for delivery. There is no single silver bullet to solve the constraint problem, but many individual and coordinated improvements will make a significant difference.

In our follow-up paper, *Meeting the Constraint Challenge*, we will review the RNP proposals and take a broader look at the policy interventions and reform levers that can reduce constraint costs and volumes. We will also consider the market innovations, technical and digital solutions that could provide a pathway to a more efficient and smarter energy system.

[41] From Bottlenecks to Balance, LCP Delta, March 2026

Solving the constraints problem will require co-ordinated effort across networks, markets, regulation and system operation

The government's forthcoming RNP delivery plan is expected to announce measures across all of these to address rising constraints. Regen's second paper, *Meeting the Constraints Challenge*, will review the RNP plan and explore the available options in depth.

Constraint volume levers

Clean Power 2030 network build
Accelerated transmission investment to increase north-south transfer capacity ahead of 2030

SSEP & CSNP
Long-term strategic plans (generation and network) should account for constraints

Locational signals for generation build
TNUoS, CfDs and planning rules can provide locational signals that should align with strategic plans

Interconnector strategy & capacity management
Align new ICs with SSEP & CSNP; and consider setting day-ahead transfer limits to manage constraints.

Improved outage coordination
Reducing concurrent outages and limiting duration

Control room operational capabilities
Improved forecasting, tools and operational decision making for system balancing

Network management - DLR, CMIS etc
Technologies which increase the usable capacity of existing network

SQSS review
Review of operational security standards which determine network limits.

Constraint cost levers

Increasing Balancing Mechanism access
Wider participation from storage, demand response and flexible generation

Skip rate reduction
Improved dispatch processes ensuring lower-cost balancing actions are used reliably.

Merchant wind bidding
Wind without subsidies (increasing in 2030s) will submit lower bids into the balancing mechanism

SO-SO interconnector trading
Cross border trading arrangement integrated with neighbour system operators.

Application of TCLC rules
Ensuring bids reflect genuine costs rather than exploiting constraint positions.

New constraint markets & flex services
Locational constraint management markets to reduce need for expensive redispatch

Forward balancing actions
Early redispatch and trading actions ahead of gate closure

Economic curtailment
Surplus generation could provide low-cost balancing actions to avoid economic curtailment.

Glossary

Term	*Definition*	*Notes / Link*
Balancing cost	Costs incurred by NESO to balance supply and demand and maintain system operability using the balancing mechanism, balancing services and energy trading.	NESO Balancing Costs
Balancing mechanism	NESO's primary real-time tool where bids/offers adjust generation or demand to maintain system balance and operability.	NESO: What is the Balancing Mechanism?
Bid	A proposal in the balancing mechanism by the generator to pay a specified price per MWh to reduce generation or increase demand. A negative bid price means the generator must be paid compensation for lost revenue or cost to turn down.	Elexon BSC: Electricity Trading Arrangements guide
Boundary (constraint boundary)	An analytical/topological division in the network against which constraints are reported and analysed. Typically consists of several real circuits.	
Boundary capacity / capability / limit	The upper limit of power flow across a section of the network including contingency for line faults and outages.	
CfD	Contacts for Difference. Revenue support mechanism guaranteeing generators a stable strike price, with a two-way payment or payback, via LCCC contracts.	GOV.UK CfD overview
Cheviot	Major Scotland–England border transmission constraint boundary area causing export limitations north-to-south. Sometimes also referred to as the "B6" boundary.	Energy Act 2010 Notes (96)
Clean Power Plan / Clean Power 2030	UK government mission targeting a 95% clean-power electricity system by 2030.	Clean Power 2030 Action Plan
Connect and manage	Policy allowing generators to connect before wider reinforcements, with only enabling works required.	Transmission Access Review 2010
Constraint	A limit preventing electricity from flowing freely due to thermal, voltage, or stability restrictions.	NESO: What are constraints payments?
Constraint volume	Total energy volumes (MWh) actively managed by NESO because of constraints.	
Centralised Strategic Network Plan (CSNP)	NESO's long-term whole-system network plan, which will dictate strategic investment in the transmission network.	NESO CSNP

Term	*Definition*	*Notes / Link*
DESNZ	UK Department for Energy Security and Net Zero; oversees national energy policy.	DESNZ: About us
Dispatch	The operational control and scheduling of electricity generating units to deliver power to the electrical power grid in real time.	Electricity dispatch
Distributed renewables	Decentralised renewable generation connected to the distribution network. Also known as embedded renewable generation.	
DLR	Dynamic Line Rating: The ability to monitor and adjust available transmission line capacity based on real-time conditions, including voltage and temperature.	ENTSO-E: Dynamic Line Rating
Economic curtailment	A reduction of generator output because the generator is unable to sell power at an acceptable price. Often associated with negative price periods. The word curtailment is often used interchangeably with reducing generation for network constraints management, but economic curtailment is a distinct concept.	Economic curtailment; understanding its scale and impact
Energy tagged (action)	An action in the balancing mechanism taken for balancing energy supply and demand.	National Grid: Tagging (System vs Energy actions)
Forward trades	Forward electricity contracts traded for future delivery (sometimes used to hedge price risk). NESO can also place forward trades to as a means to balance the system and manage constraints.	Emissions-EUETS forward markets
Frequency / frequency response	Electrical (AC) frequency of GB grid, nominal 50Hz, kept within tight limits by NESO balancing. NESO contracts frequency response services to achieve this.	NESO: What is frequency?
Inertia	Kinetic energy in rotating generators resisting frequency change.	NESO: What is inertia?
Interconnector	High-voltage cables linking GB with neighbouring grids and markets.	National Grid: What are interconnectors?
Intertrip Services (CMIS)	Constraints Management Intertrip Services. Fast response automatic disconnection service to manage constraints and faults.	NESO: CMIS NESO: Intertrips
Merchant generator	Generator selling into wholesale market at market prices.	Merchant generator definition
Merit order	Ranking of power plants by marginal cost or bid/offer price for dispatch.	Merit order
NESO	National Energy System Operator for GB, responsible for planning and delivering the energy system (electricity and gas).	About NESO
Offer	Balancing Mechanism price submission to increase generation or reduce demand.	Elexon BSC: Electricity Trading Arrangements guide
Ofgem	Office for Gas and Electricity Markets – independent energy regulator for the UK.	About Ofgem

Term	Definition	Notes / Link
Outage	A managed reduction in capacity, often for the purposes of system maintenance or connecting new assets. Outages can be unplanned too, but in this paper we refer primarily to managed outages.	NESO: Outages and System Access
Redispatch	NESO activated adjustment of generation or load to relieve grid congestion.	
Reformed National Pricing	Ongoing programme of government (DESNZ) work, following the 2025 decision to retain a single national wholesale price. Constraints management is a core theme.	REMA July 2025 update
REMA	UK Government's Review of Electricity Market Arrangements to reform the power market for a fair, efficient, decarbonised system.	GOV.UK REMA
Repetitive retrading	Repeated turn-down (bid acceptance) of an asset over multiple periods due to changing or misaligned system signals, resulting in increased constraint costs.	NESO RNP Call for Input (see p32)
ROC	Renewables Obligation Certificate issued to renewable generators for each MWh of eligible output. Closed to new capacity in 2017, but many generators still receive ROCs.	Renewables Obligation
Skip	Bypassing a cheaper balancing action for a more expensive one due to system or operational constraints.	NESO skip rates
Skip rate	Frequency at which cheaper balancing actions or assets are bypassed ('skipped') in dispatch decisions. Often expressed in terms of skipped energy volume (MWh) relative to total energy dispatched (MWh).	NESO skip rates
SQSS	Security and Quality of Supply Standard governing planning and operation of the GB transmission system.	NESO SQSS
Strategic Spatial Energy Plan (SSEP)	Maps future optimal locations and capacities of generation, storage, hydrogen and other technologies.	NESO SSEP
Stability	Ability of the power system to withstand disturbances and maintain stable frequency, voltage and power flows.	NESO Stability Market
Strategic planning	Long-term whole-system planning to identify energy system needs and guide future network design - particularly characterised by investment ahead of certain need.	NESO Strategic Planning
System operator	Entity responsible for balancing supply and demand and operating the electricity system in real time.	See NESO.
System tagged	A balancing action flagged as taken for system reasons rather than energy balancing.	National Grid: Tagging (System vs Energy actions)

Term	*Definition*	*Notes / Link*
TCLC	Transmission Constraint Licence Condition preventing generators from exploiting constraint periods for "excessive gain". Specifically Bid prices, to turn down, must reflect only lost marginal revenue and additional cost.	Ofgem TCLC guidance
Thermal Constraint	A limit where power flow would exceed safe thermal capacity of network assets.	NESO thermal constraints
Thermal constraint management	Actions taken by the operator to manage and mitigate thermal overloads on the transmission system.	NESO thermal constraint management note
TNUoS	Transmission Network Use of System charges covering costs of operating, maintaining, reinforcing and extending the transmission network.	NESO: TNUoS
TO	Transmission Operator. Organisation responsible for operating, maintaining and investing in transmission infrastructure.	e.g. National Grid Electiricty Transmission or SSEN-T
Transmission Network	High-voltage network transporting electricity over long distances.	ENA: energy networks explained
Turn-down action	Instruction to reduce generation or increase demand (acceptance of a bid).	See Elexon Balancing Mechanism guide
Turn-down cost	Net cost incurred when turning down generation or increasing demand (net payments of bids)	
Turn-up action	Instruction to increase generation or reduce demand (acceptance of offer)	
Turn-up cost	Net cost incurred when turning up generation or reducing demand (net payments of offers)	
Voltage constraint	Where forecasted system conditions will lead to voltage exceeding statutory limits. NESO must instruct generators to turn-up and down in order to avoid this.	NESO: Transmission Constraint Management
Wholesale market	The market where electricity is bought and sold between generators and suppliers. GB has a liberalised wholesale market with a number of distinct markets	NESO: Electricity Markets explained
Wholesale price	Price of electricity in the wholesale market. Normally refers to the day-ahead wholesale exchange market price or day-ahead market reference price, but could refer more generally to the wholesale market, including forward trades, intra-day price and PPAs, etc.	

REGEN

Regen
Bradninch Court,
Castle St,
Exeter
EX4 3PL

01392 494 399
www.regen.co.uk

Prepared by: Andrew Barry, markets lead
Approved by: Johnny Gowdy, director

March 2026