LCPDelta

From Bottlenecks to Balance

Impact of Reformed National Pricing (RNP) Measures on GB Grid Constraint Costs

March 2026

Background to the study

LCP Delta have conducted this study to understand how network constraints in Great Britain are expected to evolve over the 2026-2035 period, and to evaluate the potential impact of measures introduced under Reformed National Pricing (RNP) in reducing these constraints and their associated costs. The study has been completed ahead of the forthcoming RNP Delivery Plan, which the government is due to publish shortly.

The work has been supported by a group of 11 industry clients seeking to better understand the scale of constraints through to 2035 and the options available to mitigate then. We are grateful to these clients for their financial support and their active engagement throughout the study. The participating organisations are shown below.

This report represents LCP Delta's independent analysis and views. The findings and policy conclusions set out here do not necessarily reflect the positions of the participating organisations.

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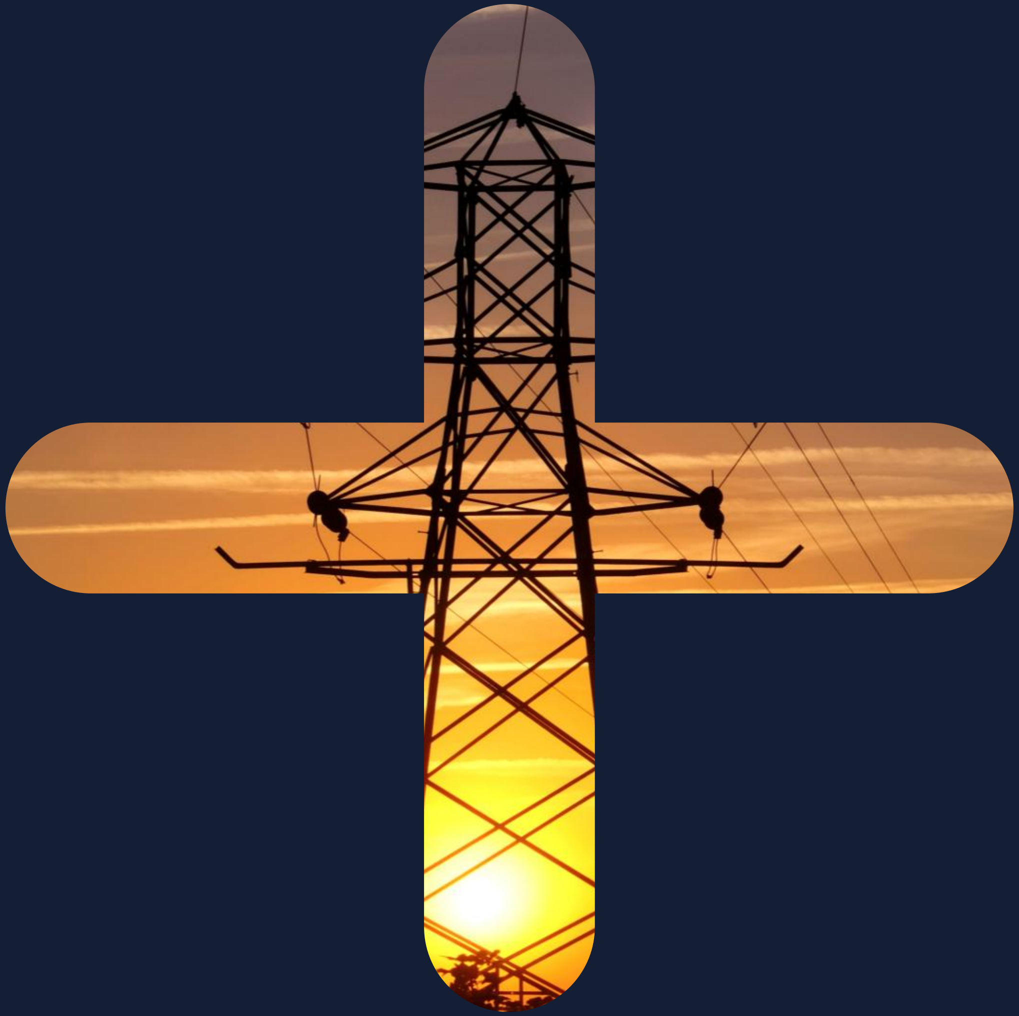


Executive Summary

Cutting constraint costs

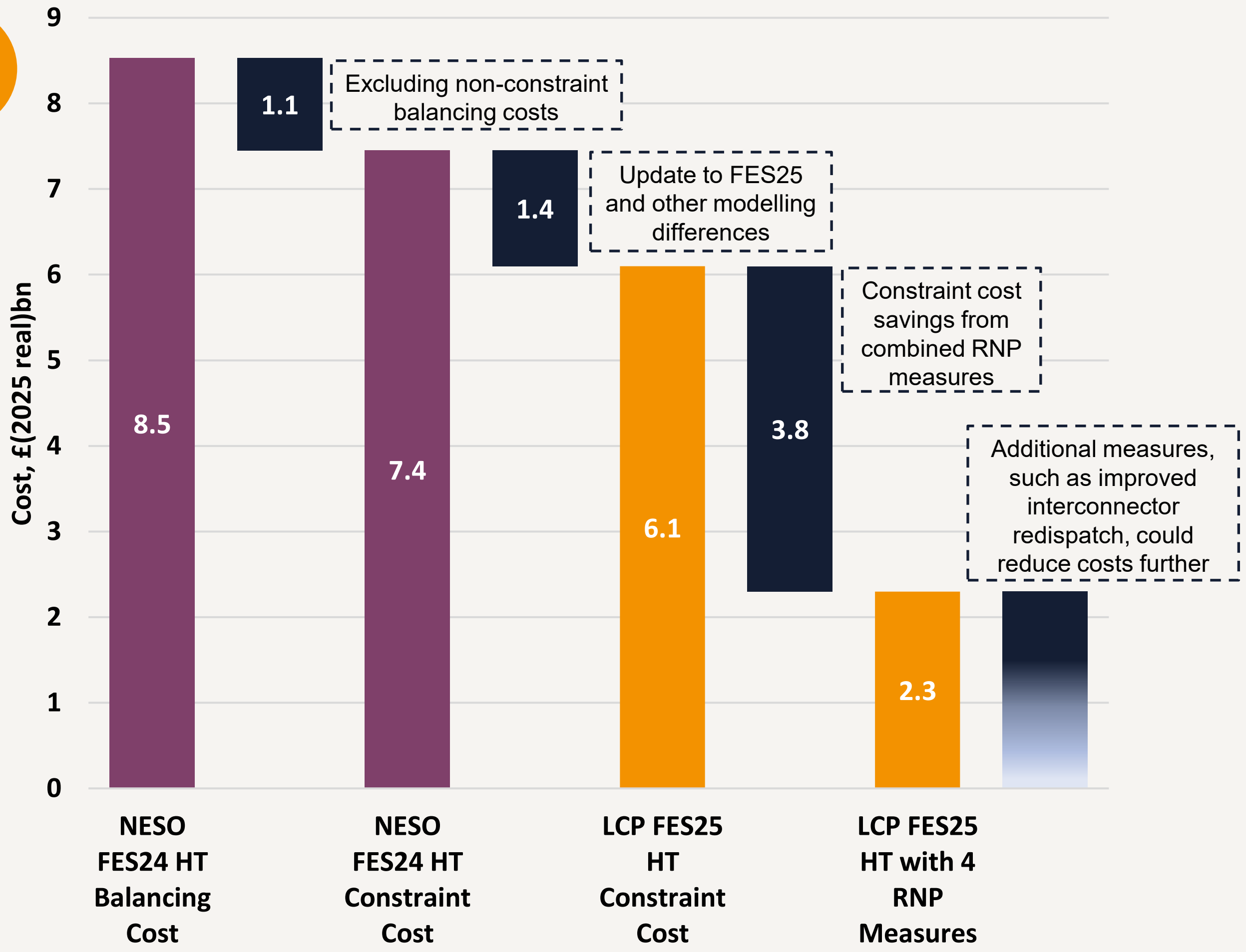
A combination of measures under RNP could reduce 2030 constraint costs by up to 60% and make CP2030 achievable

This report provides a detailed picture of how constraint costs and their drivers are likely to evolve over the next 10 years and the impact that Reformed National Pricing (RNP) measures could have on reducing them.

Key findings from this report show that under NESO's Holistic Transition (HT) scenario:

- NESO have projected a worst-case constraint cost of £7.4bn by 2030 under the 2024 version of HT from the Future Energy Scenarios, rising from £1.8bn in 2025. Constraint costs represent most of the total balancing cost in 2030.
- LCP Delta modelling of constraint costs under the same scenario, but updated to align with FES25, projects the 2030 constraint cost at a lower level at £6.1bn.
- The combination of four key measures under RNP could reduce the 2030 constraint cost by up to £3.8bn, a decrease of 60%. This would bring constraint costs down to £2.3bn and means costs into the early 2030s stay at a similar level to today, whilst significantly increasing levels of renewable energy.
- Other measures, such as improved interconnector redispatch, could reduce constraint costs even further, possibly to below current levels .
- The measures require less redispatch of gas in the Balancing Mechanism (BM) to deal with constraints reducing GB's reliance on imported gas. In 2030, use of unabated gas for power is reduced by 25TWh (33%).
- **This reduces power sector emissions by 4MTCO_2 (29%) and increases the percentage of generation from low carbon from 91% to 96%, a 5pp swing towards achieving the government's Clean Power 2030 (CP2030).**

Impact of RNP Measures on 2030 Constraint costs



Constraint cost uncertainty

Constraint costs are very sensitive to assumptions, so transparency on constraint cost projections is vital

Modelling has been undertaken under two market scenarios to understand how constraints costs are likely to evolve over the 2026-2035 period.

FES Holistic Transition Scenario

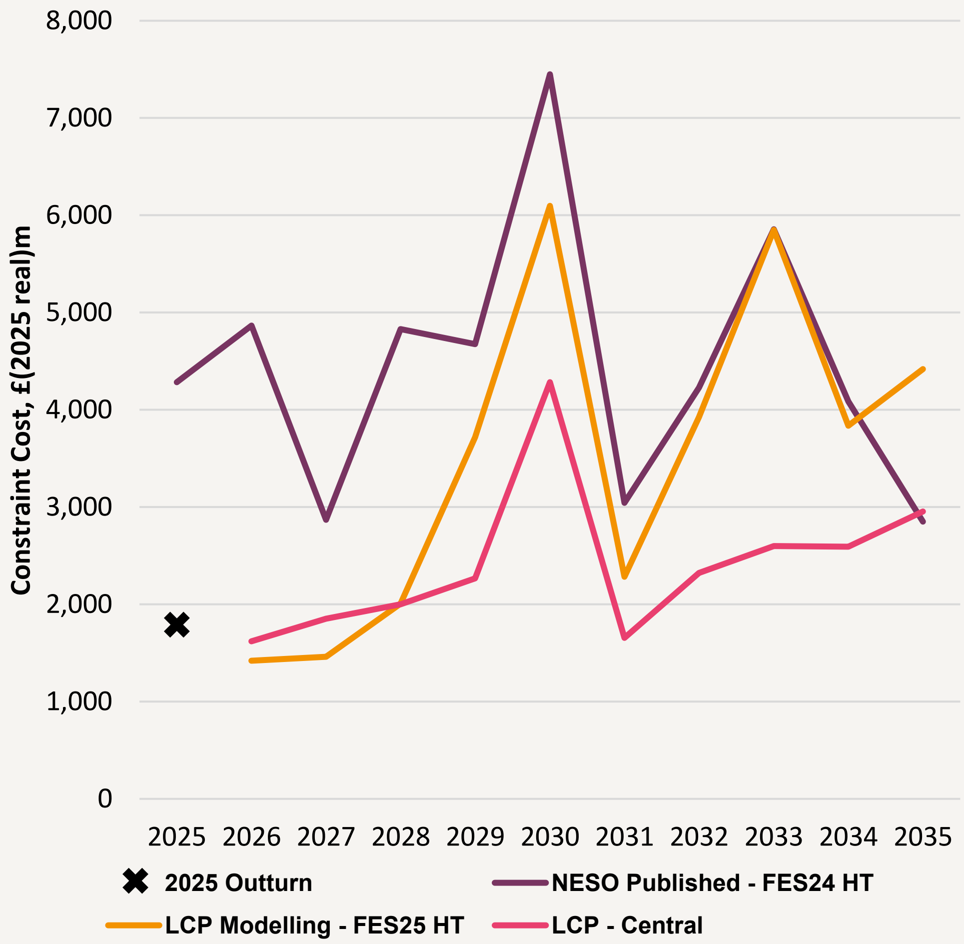
NESO's FES Holistic Transition (HT) is the key scenario used in NESO projections of constraint costs. LCP modelling of the HT scenario shows lower constraint costs in nearly all years compared to NESO projections. In 2030, LCP modelling shows a constraint cost of £6.1bn compared to £7.4bn in NESO projections.
Differences are mostly likely driven by LCP modelling updating HT from FES24 to FES25, which has a lower renewable buildout in the short term. However, the limited information published by NESO makes it difficult to provide a detailed account of the differences.

LCP Central / Current Trajectory

The LCP Central Scenario represents LCP Delta's independent view of the current trajectory of the GB power sector. It still assumes significant decarbonisation, including renewable build from the CfD AR7 results and additional deployment post 2030, but this is slower than the HT scenario. The slower buildout of renewable capacity in certain parts of the country (e.g. East Anglia and Scotland) under LCP Central allows boundary upgrades to better keep up with generation capacity. This leads to lower constraint costs from 2029 onwards with a lower peak cost of £4.2bn in 2030.

Given the significant differences in constraint costs between the scenarios modelled, it's important that NESO provide more transparency on their constraint cost projections and associated drivers in any future forecast. This will enable better industry engagement on constraints.

Baseline Constraint Costs under FES HT and LCP Central



RNP Measures to reduce constraint costs

Network improvement measures and reforms to interconnector redispatch have the largest impact

1 **Accelerated network upgrades in East Anglia**– Bringing forward East Anglia network upgrades from 2031 to 2030 leads to the highest single-year reduction of £2.8bn in FES HT and £1.3bn in LCP Central. This highlights the importance of building the network on time and in line with regional renewable capacity increases.

2 **Improvements to existing network carrying capacity** – Increased network availability leads to consistently high savings to 2035 with £1.1bn savings in 2030 in FES HT and LCP Central. This shows that how the current network capacity is utilised will be vital in managing constraints

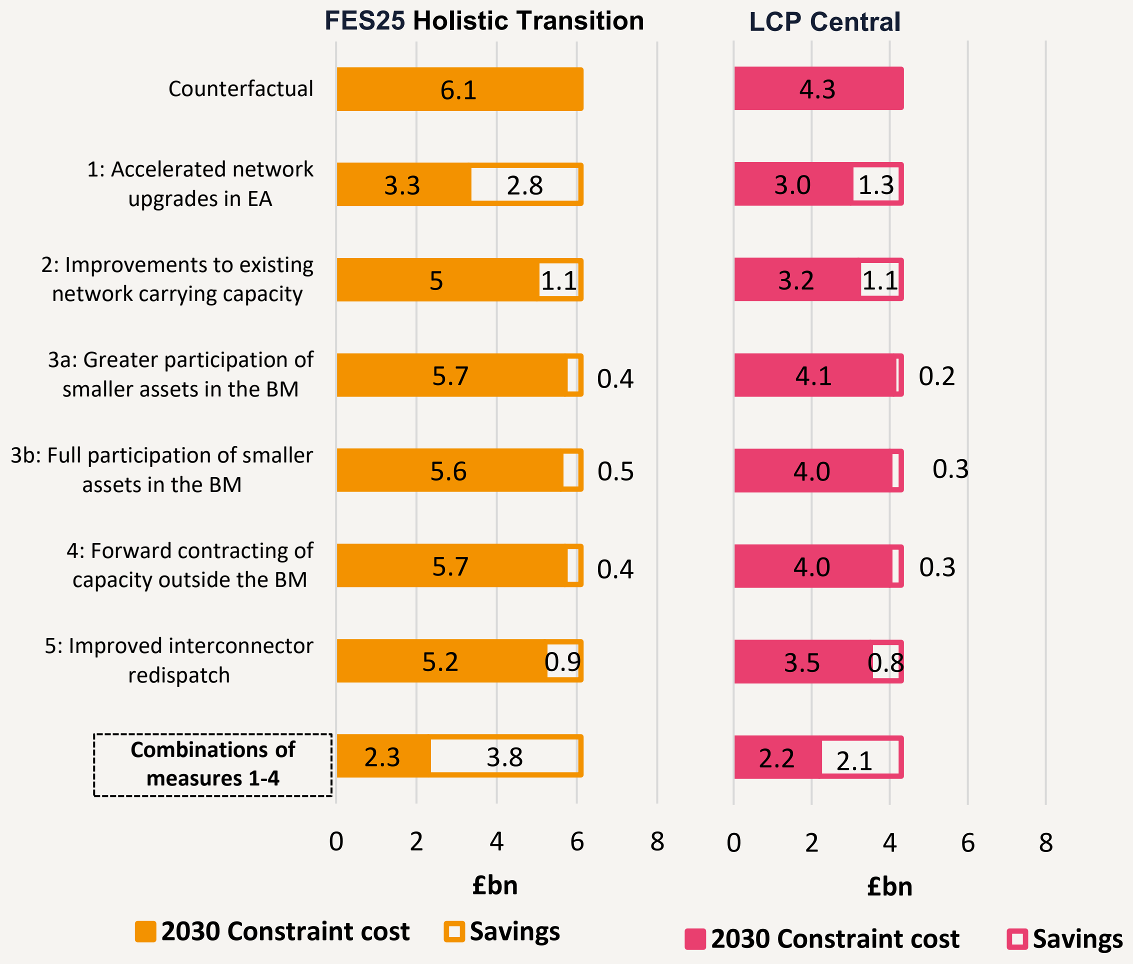
3 **Increased participation of smaller assets in the Balancing Mechanism (BM)** – Regulation and policy to incentivise participation of smaller assets in the BM (3a & 3b) reduces constraint costs by up to £0.5bn in FES HT. However, encouraging the first 50% to participate should be prioritised as they drive most of the benefit.

4 **Forward contracting of flexible capacity outside the BM** – Forward contracting of capacity to deal with the constraints through a constraints management market outside the BM could be an option to reduce the cost of expensive redispatch actions, saving up to £0.4bn in 2030 under FES HT.

5 **Improved interconnector redispatch** – While complex to implement, improving the redispatch of interconnector flows can reduce 2030 costs by £0.9bn in FES HT and £0.8bn in LCP Central. While achieving 100% efficient interconnector redispatch is unlikely, even partial improvements could have a significant impact.

Network | System Balancing | Interconnector

Reduction in 2030 constraint costs relative to counterfactual



RNP Measures to reduce constraint costs

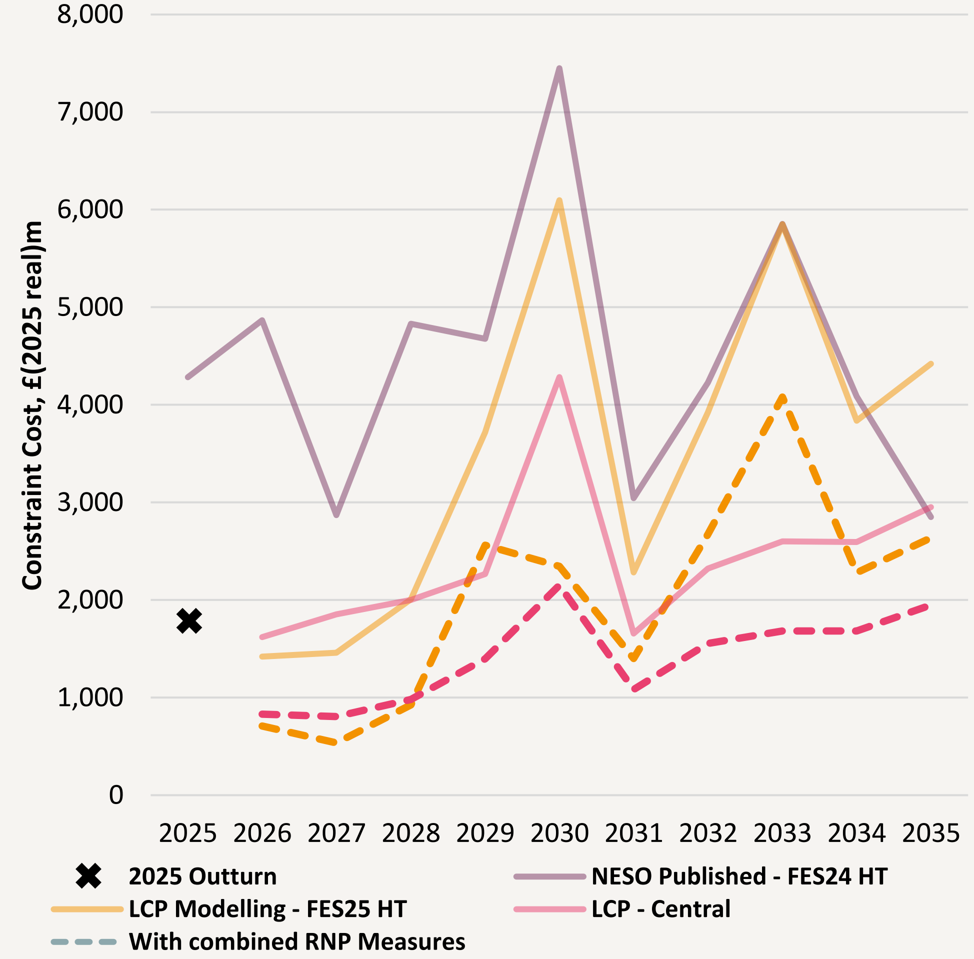
A combination of four potential RNP significantly reduces constraint costs as well as reducing gas use and emissions

A combination of the first four measures (excl. interconnector redispatch which could increase benefits) has a significant impact on reducing constraint costs and on the wider system:

	FES25 HT	LCP Central
Average constraint cost reduction from 2026 to 2035 due to measures	**44%** per year	**42%** per year
New max constraint cost to 2035 (compared to NESO published £7.4bn)	**£4.1bn** in 2033	**£2.2bn** in 2030
Constraint cost reduction in 2030 (from £6.1bn in FES HT & £4.3bn in LCP Central)	Up to **£3.8bn**	Up to **£2.1bn**
Reduction in gas used in GB power stations in 2030	**34%** 28TWh	**18%** 14TWh
Reduction in 2030 CO_2 emissions (from lower gas turn-ups to deal with constraints)	**29%** 4MTCO_2	**10%** 2MTCO_2
Increase in CP2030 target (change in % of generation from low carbon)	**5pp** increase	**3pp** increase

In both scenarios, constraint costs are less than £2.7bn in all years, except for 2033 in FES HT. The differences in costs between FES HT and LCP Central are quite similar showing that RNP measures can make constraint costs less dependent on underlying levels of renewables.

Constraint Costs under FES HT and LCP Central with all measures (excl. IC redispatch)



Recommendations

DESNZ and NESO should enact the below 6 recommendations in the RNP Delivery Plan to reduce constraint costs

1. Ensure timely delivery of network build

Ensuring the timely consenting and delivery of planned grid upgrades across Great Britain to align with increases in renewable capacity will be critical to managing constraint costs to 2030 and beyond.

2. Improve utilisation of existing network

More efficient use of our current network to increase carrying capacity and reduce outages should be a key priority, particularly given low network availability was a key driver of constraint in 2025.

3. Increase BM participation for smaller assets

Policy to incentivise participation of smaller assets in the BM should be implemented with measures for the participation of first 50% prioritised. Other system balancing improvements, such as forward contracting outside the BM, should also be considered.

4. Improve interconnector redispatch

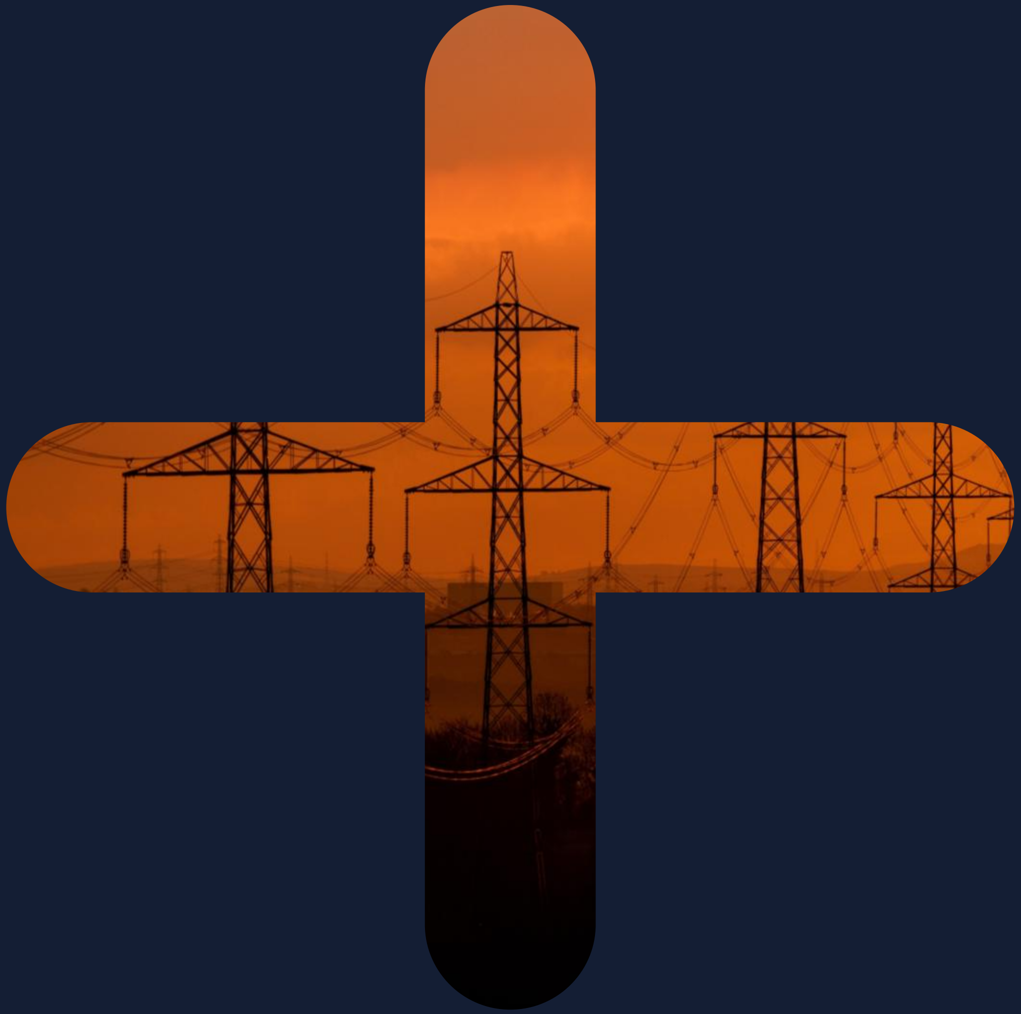
Efforts need to be made to improve redispatch of interconnector flows, such as improving the EU trading relationship. Even a partial improvement could lead to a significant reduction in interconnector flows exacerbating constraints.

5. Understand the optimal level of constraints

DESNZ and NESO should undertake more detailed analysis to understand the right balance between network build and constraint costs. Reducing constraint costs to zero would not be an optimal outcome for the system.

6. Improve transparency on constraint cost drivers

NESO should improve transparency of both historic data on constraints and their future projections of constraint costs to improve industry engagement. This will allow for a more detailed understanding of constraint drivers and uncertainties.



Introduction

The constraint cost problem

To date, network capacity has not kept pace with renewable build increasing constraints on the network

Network constraints on the system often mean that generation in certain parts of the country cannot be transported to demand centres. For example, some renewable generation from Scotland cannot be transported to demand centres in England and Wales due to network constraints between Scotland and England.

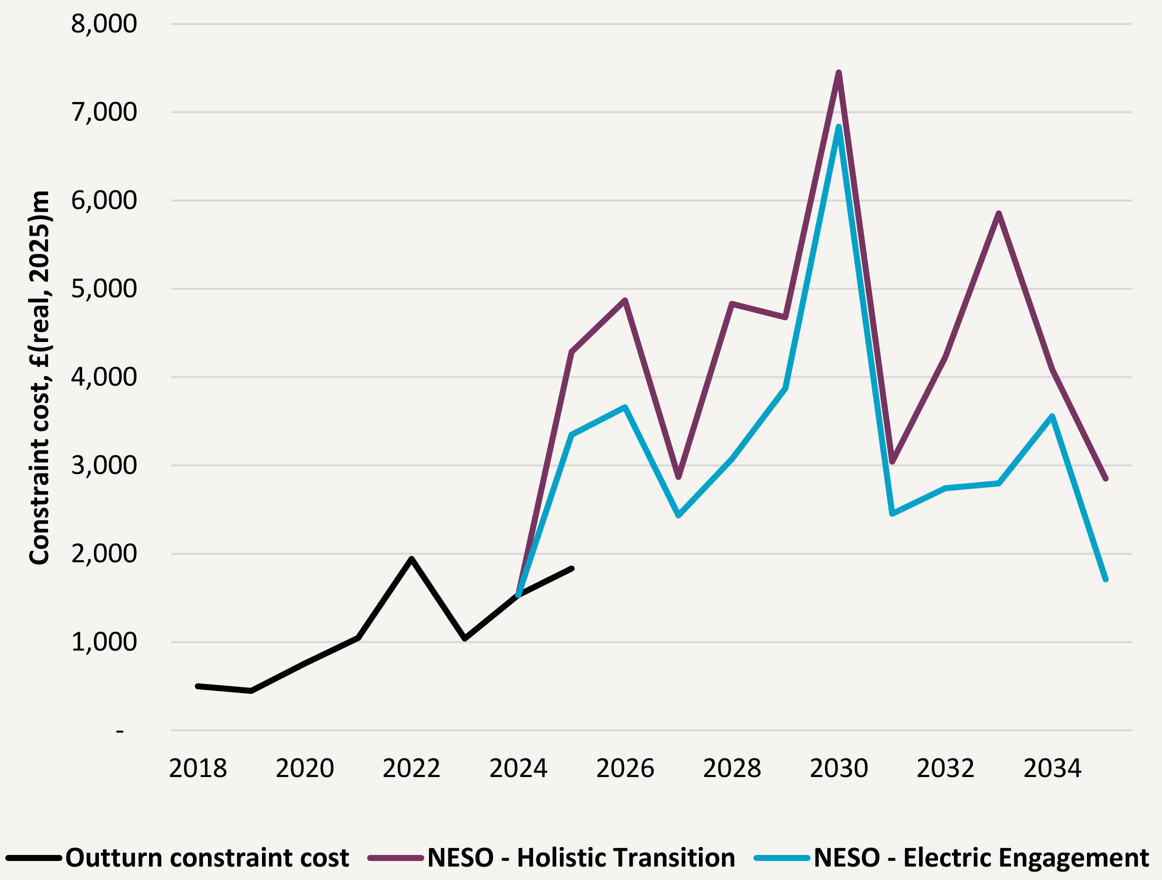
On these occasions, NESO uses the Balancing Mechanism (BM) to ask generators behind the constraint to 'bid' to reduce their output (turn-down) and generators closer to demand centres to 'offer' to increase their output. This ensures that supply equals demand across the country. The cost of redispatching assets is then passed onto consumers through constraint costs (via BSUoS* charges).

Constraints on the system have increased as renewable generation, particularly wind, has grown faster than network capacity. Renewable assets are often located where natural resources are most plentiful and where necessary planning consents can be obtained, which tends to be away from demand centres. This means increased network is needed to get supply from renewable rich areas to demand centres. But to date, network build has not matched renewable build, leading to more constraints.

In 2025, constraint costs reached £1.8bn. This was the highest since the gas price crisis in 2022 and a 4x increase on 2019 levels. NESO projections of future constraint costs, as published in the [2025 Annual Balancing Cost Report](), project costs to significantly increase reaching over £7bn by 2030.

Even though 2025 saw an increase in constraint cost, the £1.8bn outturn constraint cost was significantly lower than £4.3bn that NESO was projecting for 2025 of £4.3bn.

NESO Thermal Constraint Projections from the 2025 Annual Balancing Costs report under FES24 scenarios



* Balancing Services Use of System

Reducing constraint costs

The government is now looking at various measures to reduce constraints under Reformed National Pricing (RNP)

The Government's Review of Electricity Market Arrangements (REMA) was established in 2022 'to ensure our electricity market arrangements support a decarbonised, cost-effective, and secure electricity system fit for the future'. One of the main challenges that REMA has looked to address is options to reduce locational constraints on the network.

With zonal pricing ruled out by government in the latest REMA update, this has shifted focus to how constraints can be reduced under an RNP model. A RNP Delivery Plan is due to be published by government imminently which will outline more detailed plans on reforms to reduce constraints.

This will look to cover reforms to provide better locational investment signals and operational efficiency reforms to the balancing mechanism (BM) and constraint management. The key reforms under consideration are outlined in the graphic opposite.

With most investments to 2030 already determined, stronger locational investment signals are unlikely to have much impact on constraint costs in the short term. Therefore, the focus of this report is on operational reforms and other measures such as moving forward network upgrades that can be delivered quickly to mitigate increases in constraint costs before 2030.

Summary of Reformed National Pricing options to reduce constraints

Improved locational signals

To influence investment decisions on where new assets locate

- Strategic Spatial Energy Plan and associated levers
- Network Charging Reform

Operational Reforms

To reform the balancing market and improve how constraints are managed

- Increased participation from smaller assets in BM
- Constraints Collaboration Project Actions
- Technical measures on network carrying capacity
- Improving Interconnector flows

The focus of this report is on shorter term operational reforms that can impact by 2030

Study scope

The aim of the study is to understand the extent of the constraint costs problem to 2035 and assess how operational efficiency measures can reduce costs

With NESO projecting constraints costs reaching over £7bn by 2030 compared to £1.8bn in 2025, it is vital to understand whether this level of increase is likely to be realised, what drives the increase and what measures are available to reduce this cost. This requires detailed modelling of the GB power sector that captures the key network constraints on the system.

There are two key objectives of the study:

Objective 1: To understand how thermal constraints costs and their drivers are likely to evolve over the 2026-2035 period

Modelling is undertaken under two baseline scenarios to show the evolution of constraint costs over the 2026-2035 period and examine the major factors which will influence the path and scale of these costs. The two baseline scenarios are:

1. **NESO Holistic Transition (HT) Scenario** – To give a comparison to NESO constraint cost projections from the 2025 Annual Balancing Report, the Holistic Transition scenario from FES25 is modelled. This scenario assumes a faster level of decarbonisation to meet Net Zero and meets the government's Clean Power 2030 target with high renewable deployment.

2. **LCP Central Scenario / Current Trajectory** – This scenario reflects LCP's internal view of the current trajectory of the future GB power sector. This is Net Zero compliant but has a lower build of renewables to 2035 in line with AR7 results and so gives an alternative view on the evolution of constraint costs.

Objective 2: To assess the impact measures under Reformed National Pricing can have on reducing constraints

Under both baseline scenario, modelling is undertaken to examine the impact of various operational efficiency reforms on constraint costs over the modelled period. This includes the following measures:

Network:
- 1. Accelerated network upgrades in East Anglia
- 2. Improvements to existing network carrying capacity

System Balancing:
- 3a. Greater participation of smaller assets in the BM
- 3b. Full participation of smaller assets in the BM
- 4. Forward contracting of flexible capacity outside the BM

Interconnector:
- 5. Improved interconnector redispatch

Each measure is assessed individually with a further model run to assess the impact of a combination of the measures 1-4 collectively.

Methodology and assumptions

The study aims to use the same methodology and similar assumptions to NESO's modelling

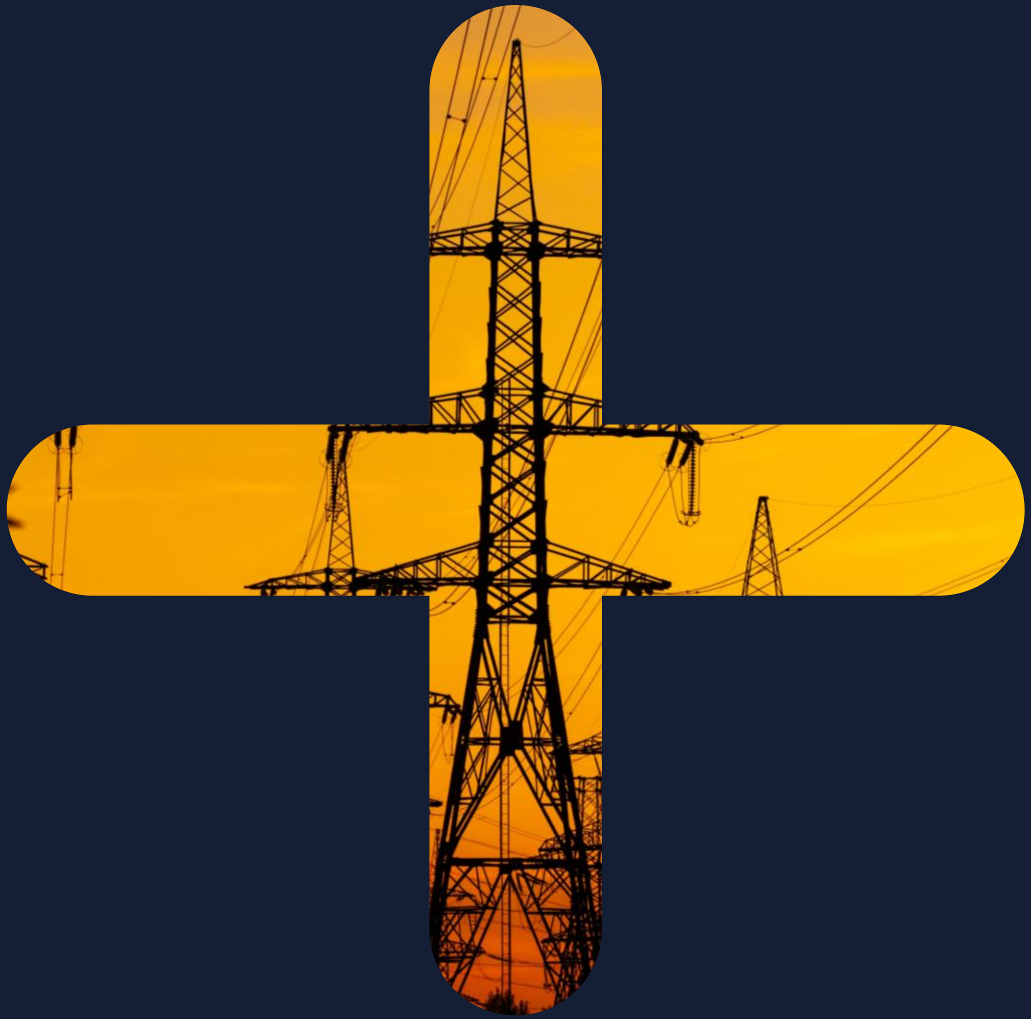
Modelling for this study has been conducted using LCP Delta's EnVision modelling framework. This has been used for various studies on the future of the GB power system including assessing the impacts of moving the GB market to zonal pricing for DESNZ.

The country is split into 12 zones which capture the key transmission network boundaries as shown in the map opposite. Network boundary capacity is taken from published NESO data in the Electricity Ten Year Statement (ETYS) and 'Beyond 2030' report.

We have aligned our methodology and assumptions as closely as possible with NESO, where required and the relevant information is available. This includes aligning our approach to calculating future constraint costs and on key assumptions for the FES Holistic Transition scenario such as location of capacity, network buildout and network availability. Where information was not publicly disclosed by NESO, we have used historical data and other public sources.

The report aims to be as transparent as possible on the underlying methodology and assumptions used in the modelling. Further details on modelling methodology and assumptions are outlined in the Appendix.

Modelled Network Boundaries



Constraint Costs in 2025

Historical constraint costs

The volume of constraints has continued to increase while the 2025 constraint cost is the highest since 2022

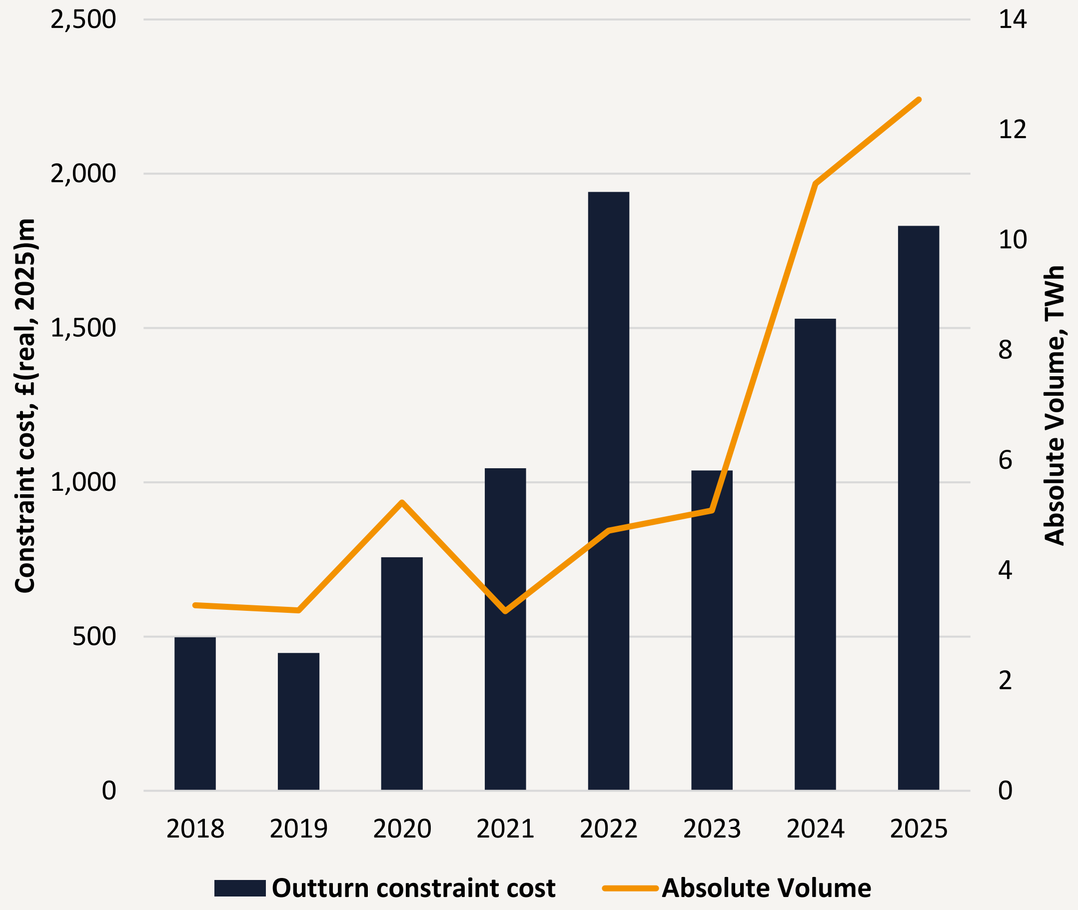
The constraint cost encapsulates both the cost of turning down generation in constrained areas (mainly wind) and the cost of turning up generation elsewhere (mainly gas). NESO publish daily data on the volume and cost of constraints to show the actions that they are taking to resolve constraint issues.

Analysis of this data shows that in 2025 constraint costs increased for the 3rd year in a row reaching £1.8bn. This is 4x the cost in 2019 and is the highest constraint cost since the height of the gas price crisis in 2022 (adjusting for inflation).

Constraint volumes (the amount of generation turned up/down) have also increased significantly reaching 12.5TWh, the highest levels we have ever seen.

The constraint cost in 2025 has largely been driven by high levels of constraint volume, in contrast to 2022, where the cost was driven by high gas prices leading to higher cost to turn up gas generation.

Outturn thermal constraint costs and volumes 2018-2025



Constraint volumes in 2025

Most constraint volume in 2025 was in Scotland, driven by low network availability

More detailed analysis of constraint volumes shows that in 2025, there was over 10TWh of renewable generation turn-down due to constraints. The majority of this was offshore wind (46%), onshore wind (29%) and a smaller volume from hydro (12%). Most of the turn-down generation occurred in Scotland, particularly in Northern Scotland above the B4 and B5 boundaries.

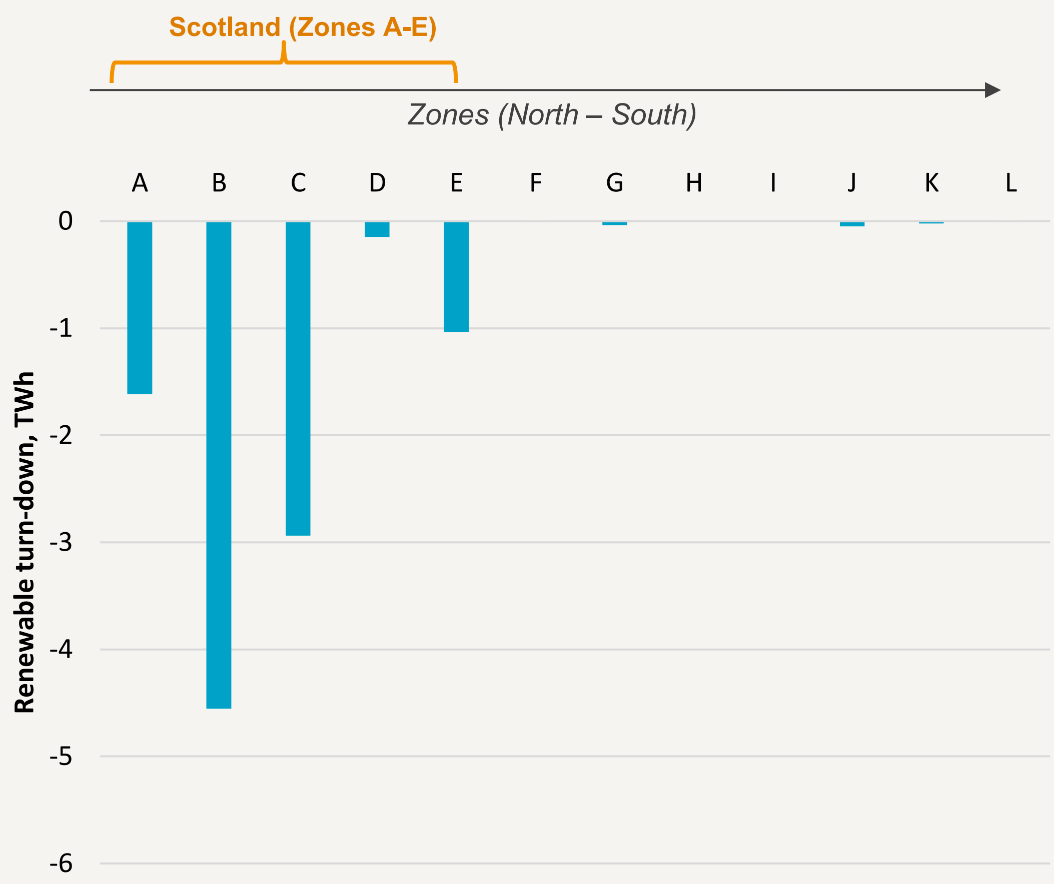
From NESO data, the % of periods where there were constraints on each of the key boundaries can be assessed. This shows that Northern Scottish boundaries (B2, B4, B5) were constrained for around 40% of periods with the B6 boundary between Scotland and England and the B7a boundary in North England constrained for around 30% of periods. Other boundaries show very little constraint.

Proportion of hours that key boundaries are constrained

Boundary	Location	% Constrained, 2025
B0	Northern Highlands	*n/a*
B2	Central Highlands	42%
B4	Southern Highlands	40%
B5	Central Belt	39%
B6	England-Scotland Border	31%
B7a	Northern England	28%
B8	Midlands, North	*n/a*
B9	Midlands, South	5%
EC5	East Anglia	*n/a*
NW2	Northwest Wales	4%
SC1	South Coast	*n/a*

Note that NESO does not publish data on all boundaries. Those without data are marked as n/a

Renewable turn-downs due to constraints by zone in 2025



Drivers of constraint in 2025

Some Scottish boundaries operated at ~50% of capacity in 2025 increasing constraint volumes

The primary driver of increased thermal constraint cost in 2024 and 2025, compared with previous years, has been the reduction in the availability of network carrying capacity. This is particularly true for the highly constrained boundaries in Scotland – B2, B4 and B6.

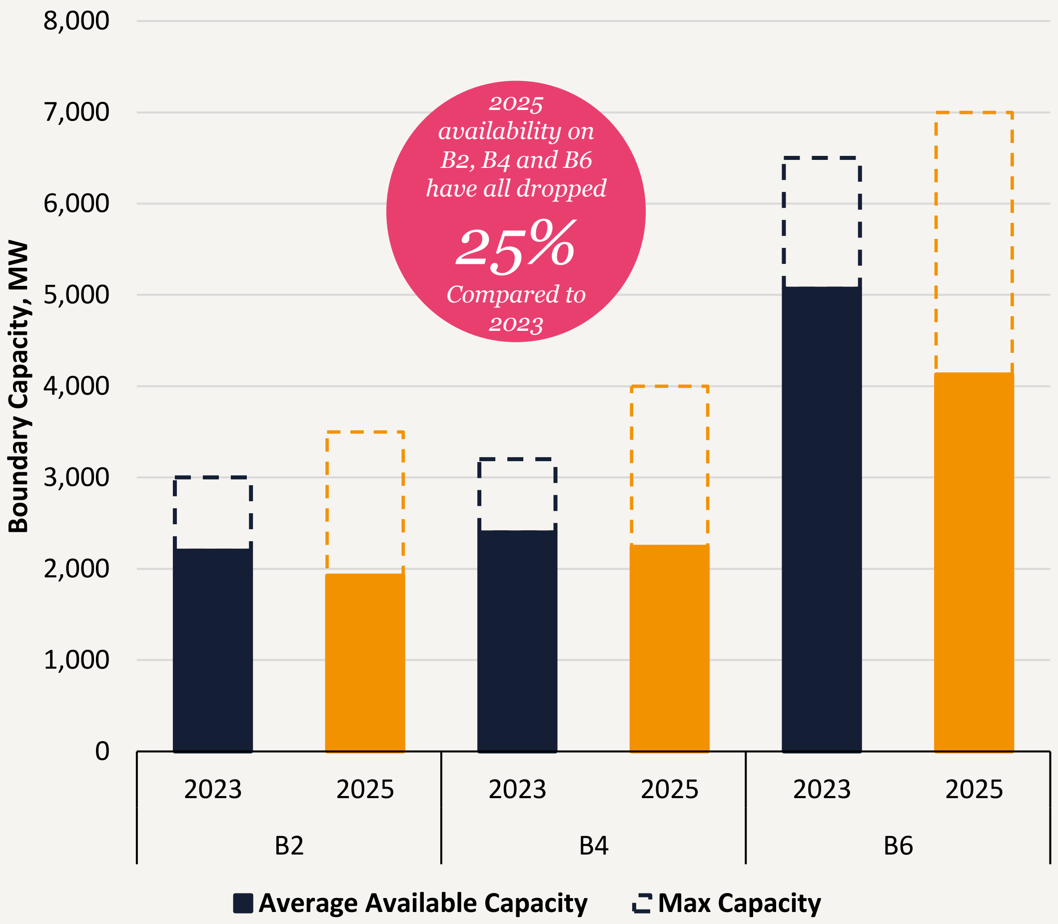
Although the maximum capacity of these boundaries has increased over the last three years, the actual average available capacity in 2025 has been lower compared to 2023, as shown in the chart on the right.

While average availability on the network is not expected to be at 100% due to general maintenance that is needed on the network, the availability seen in 2025 is much lower than is normally expected[1].

The reason for the lower availability is likely to be the ongoing work to upgrade networks which is significantly reducing the network availability, and with further upgrades planned, reduced availability may persist in the near term.

It should be noted that there is some uncertainty in this data with data from published NESO hourly data being quite different to what is shared in NESO's operational transparency forum slides. In addition, not all constraints are reported on in this data (e.g.: EC5 is missing). As this is a key driver of constraints, it is important that this data is reported on in a transparent and consistent way for all constraints where NESO have future projections.

Maximum capacity and average network availability of B2, B4 & B6*



*where data available

[1] Standard NESO assumptions assume that the network is 100% available in winter, 85% available in spring/autumn and 70% available in summer, so averaging 85% across the year.

Modelling 2025 constraint volumes and costs

LCP modelling results align closely with actual constraint volumes and costs

To test the robustness of the constraints modelling, backcasting was undertaken for 2025. Actual assumptions for 2025 have been used including commodity prices, network capacity and 2025 generation capacities/locations. A network availability has also been applied on a monthly basis based on historical data.

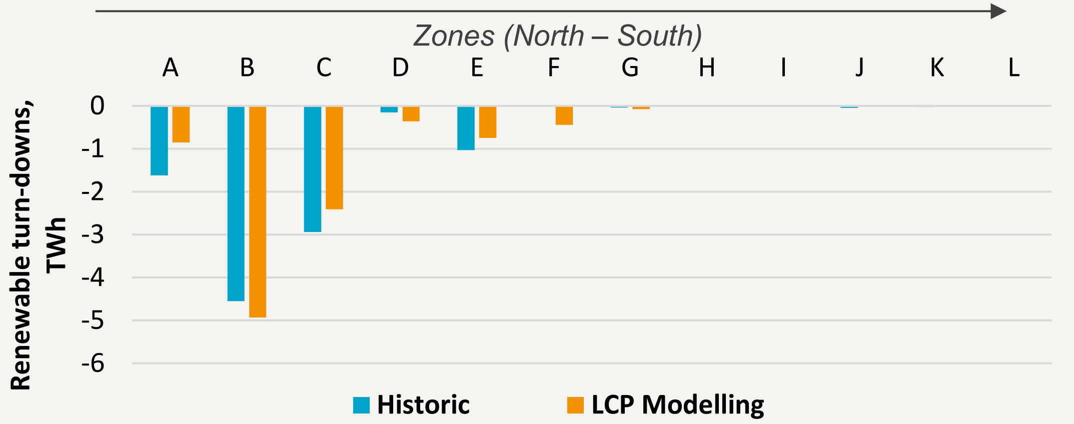
Thermal constraint volumes align closely with historic data in 2025 with a total of 9.8TWh of renewable turn-downs in the modelling compared to 10.4TWh in historic data. The location of turn-downs is also well aligned, with most turn-downs in Northern Scotland (Zones A-C).

Thermal constraint costs also show good alignment in 2025 with a total cost of £1.70bn in LCP backcasting compared to £1.83bn in historic data. This highlights the robustness of the LCP model in modelling constraints[1]. The minor differences between the actual and modelled values are likely due to:

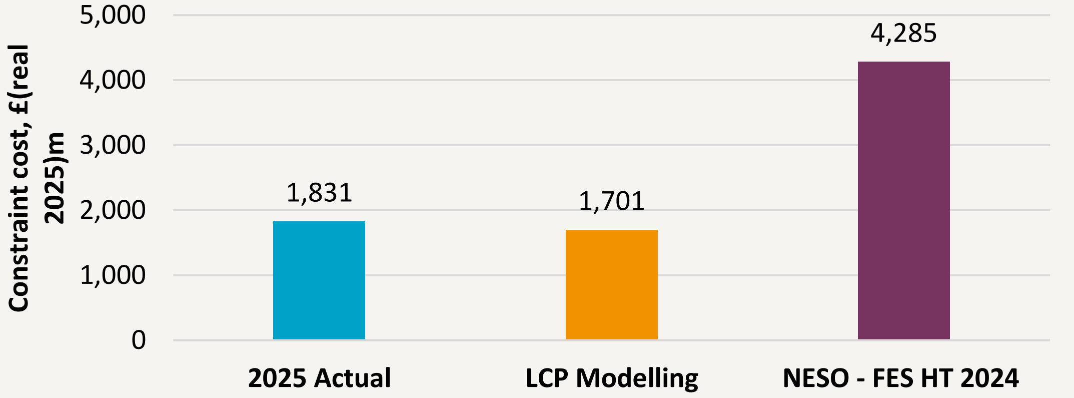
- The modelling includes the 11 major transmission network boundaries and does not capture every boundary within GB.
- The modelling does not capture any major short term network outages, e.g. due to extreme weather. This means we may not capture periods of deep constraint.
- We assume no foresight of constraints in wholesale market positioning

The actual 2025 cost is less than half of the £4.3bn projected by NESO in the [2025 Annual Balancing Cost Report] under the Holistic Transition scenario. While these were projections (as opposed to backcasting), this shows a significant difference in constraint cost compared to what NESO was expecting. To ensure confidence in their projections, NESO should explain what caused such a major difference in their 2025 projections compared to outturn.

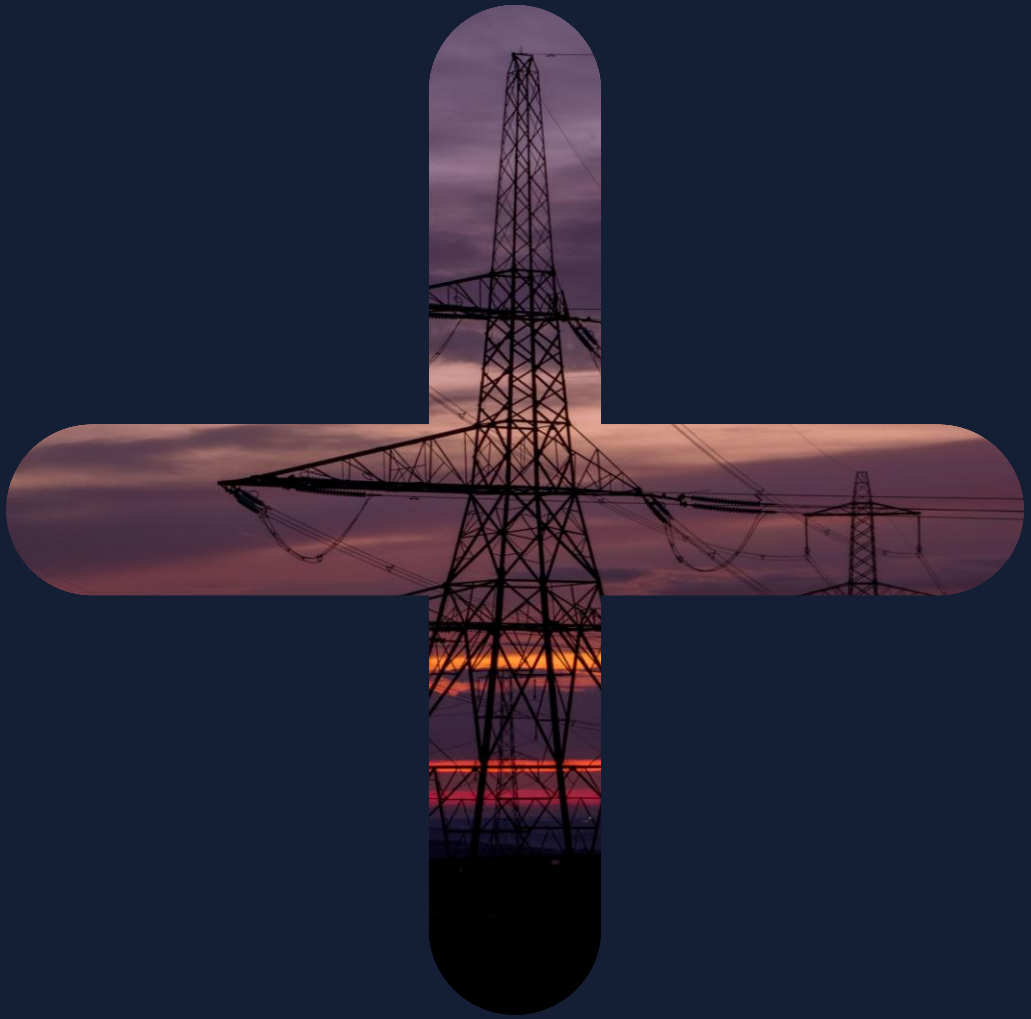
Constraint volumes of renewable generation under LCP Modelling and actual historic 2025 data



2025 Constraint cost under LCP backcasting, NESO projections in Holistic Transition scenario and actual historic data



[1] To calculate the constraint costs, we followed the same approach as NESO. A full breakdown of how the constraint cost is calculated and a breakdown of costs in 2025 can be found in the Appendix.



Baseline Constraint Costs to 2035

Constraints under NESO HT scenario

Updating HT assumptions to FES25 shows lower constraint costs in most years compared to NESO projections

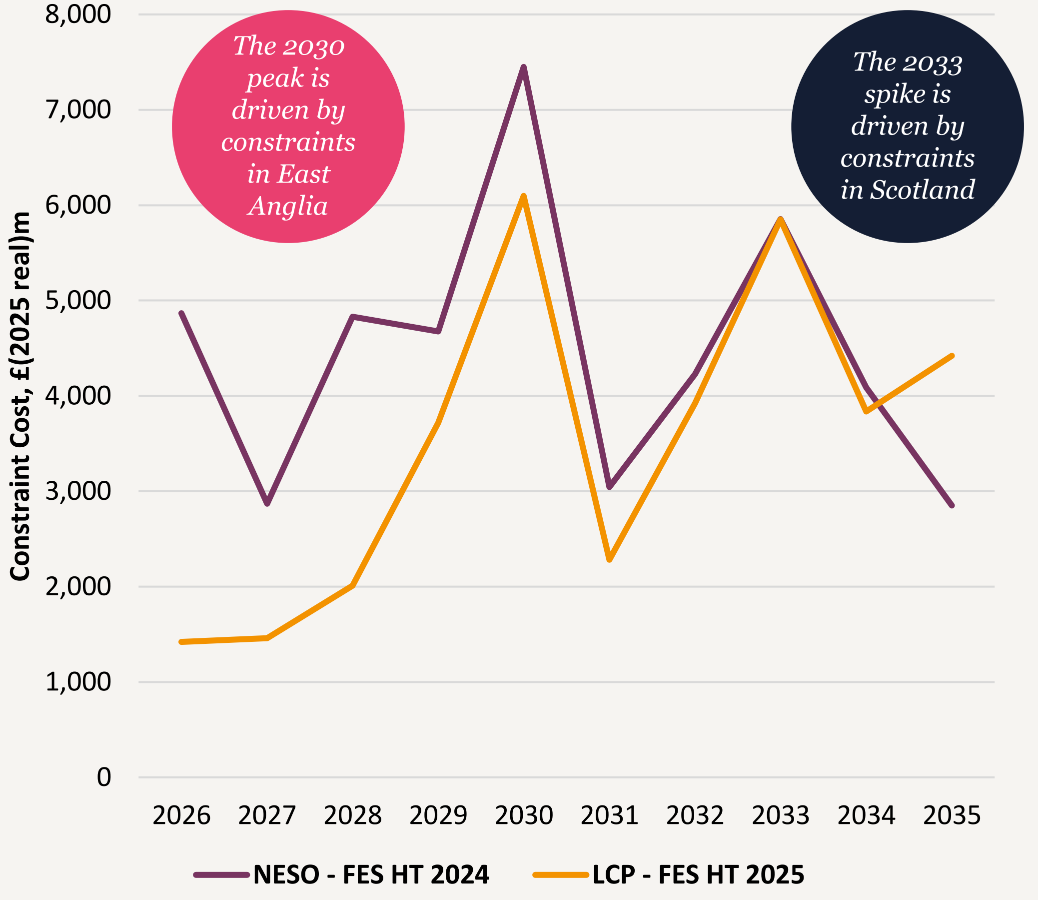
Modelling was first undertaken under NESO's Holistic Transition (HT) scenario, which aligns with meeting Clean Power 2030. This scenario has been chosen as it is the primary scenario that NESO use in network planning and in the 2025 Annual Balancing report.

In LCP modelling, the scenario has been updated to FES25 assumptions compared to FES24 assumptions used in the latest NESO projections. FES25 has less renewable build in this scenario in the years to 2030 as well as slightly lower commodity prices. Comparing LCP modelled constraint costs to 2035 with the latest NESO projections for HT shows:

- From 2025 to 2028 LCP modelling shows significantly lower constraint costs. This is consistent with the actual constraint costs in 2025 being significantly lower than those projected by NESO. Differences will be driven by the lower renewable capacity in FES25, but this is unlikely to explain the whole difference.
- Constraint costs rise sharply in 2030, as significant offshore wind capacity comes online in East Anglia (Zone K), constraining the EC5 boundary. The 2030 cost in LCP modelling is £6.1bn compared to £7.4bn in NESO figures. The subsequent sharp drop in 2031 is due to network reinforcements on the EC5 boundary.
- Another spike occurs in 2033 due to increased constraints in North Scotland with NESO and LCP numbers being similar at £5.9bn constraint costs. This is driven by constraints in Scotland.
- Costs reduce in 2034 when large HVDCs connecting North Scotland to England are expected to come online. In 2035, LCP modelling sees constraint costs increase, while NESO figures see continued reductions despite increased generation capacity and limited boundary upgrades in both FES24 and FES25.

Updating from FES24 to FES25 is likely to explain most of the difference but there could be other differences in assumptions including on capacity locations, boundary availability and redispatch of interconnectors. As NESO does not publish its assumptions on these key areas, it is difficult to identify to what extent these lead to differences in the projections.

Constraint Costs under the FES Holistic Transition Scenario: LCP vs. NESO modelling



Boundary Constraints in 2030

The constraint cost peak in 2030 in FES HT is driven by more offshore wind in East Anglia ahead of network upgrades

The FES25 Holistic Transition scenario assumes a high buildout of offshore wind reaching 47GW by 2030. A lot of the assumed build is in East Anglia which drives significant constraints in this area. This is a key change from the network constraints on the system today, which are almost entirely in Scotland.

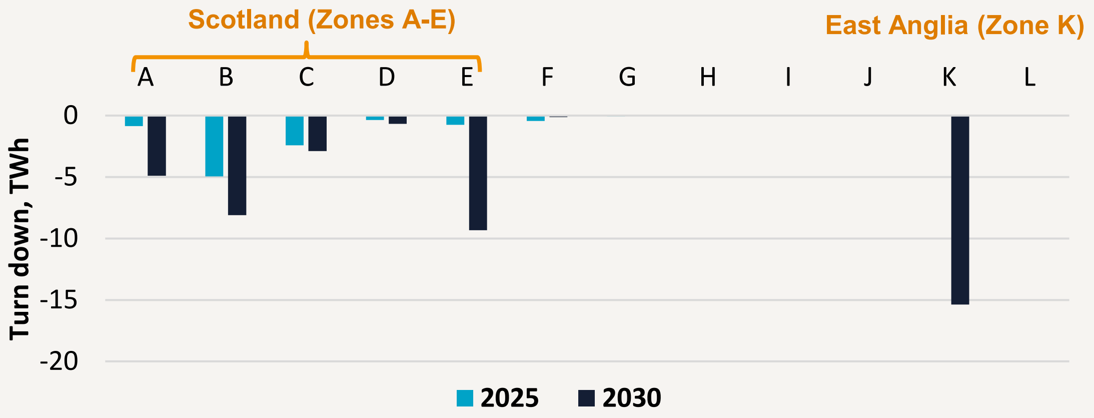
The chart on the top right shows the modelled renewable turn-down in 2025 and 2030 by zone. Total turn-down volume increases from 10TWh to 41TWh. This is driven by turn-downs in Scotland continuing to rise and East Anglia (Zone K) experiencing 15TWh of turn-down.

The EC5 boundary currently faces almost no constraints, however by 2030 our modelling shows it will be constrained in 52% of periods. In comparison, Scottish boundaries see a more modest increase with B4 rising from 40% to 57% and B6 rising from 31% to 51%.

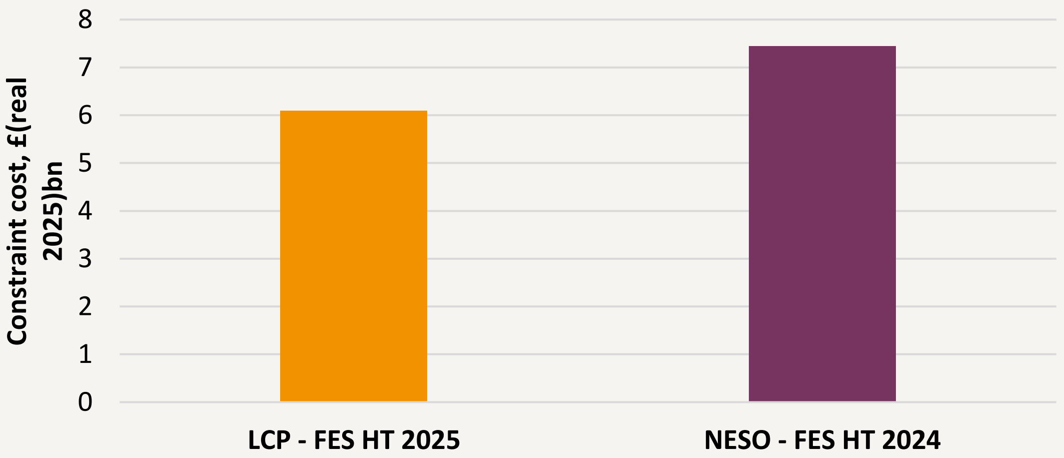
Key network upgrades in East Anglia, designed to reinforce the EC5, are expected to come online in 2031, including the Norwich to Tilbury project and Sea Link (SCD1). Once the EC5 upgrades come online in 2031, turn-down in Zone K decreases to 1TWh with the EC5 boundary constrained in just 22%. This is a key driver of the decrease in constraint costs from 2030 to 2031.

LCP modelling of the FES25 Holistic Transition scenario shows a constraint cost of £6.1bn in 2030, lower than NESO's projection of £7.4bn. This combined with the significant decrease in 2031 as East Anglia network capacity is improved suggests that NESO sees a higher level of constraint in East Anglia in 2030 compared to LCP modelling. One possible explanation for the difference is the reduction in the total Offshore Wind capacity in 2030 from 53.7GW in FES24 to 46.5GW in FES25, some of which is likely to be in East Anglia. There are likely other drivers but without more detail on NESO modelling, it is difficult to identify these with certainty.

Constraint volumes of renewable generation in LCP modelling of FES HT 2030



Constraint cost in 2030 under LCP Modelling and NESO modelling



The impact of constraints on consumer costs

Only a portion of the total constraint costs is an additional cost to consumers

The cost of balancing the system is ultimately passed onto consumers through Balancing Services Use of System (BSUoS) charges. In 2024/25 BSUoS charges contributed to ~3.4% of electricity bills for an average domestic consumer which works out to be about ~£3 a month on a typical domestic electricity bill[1].

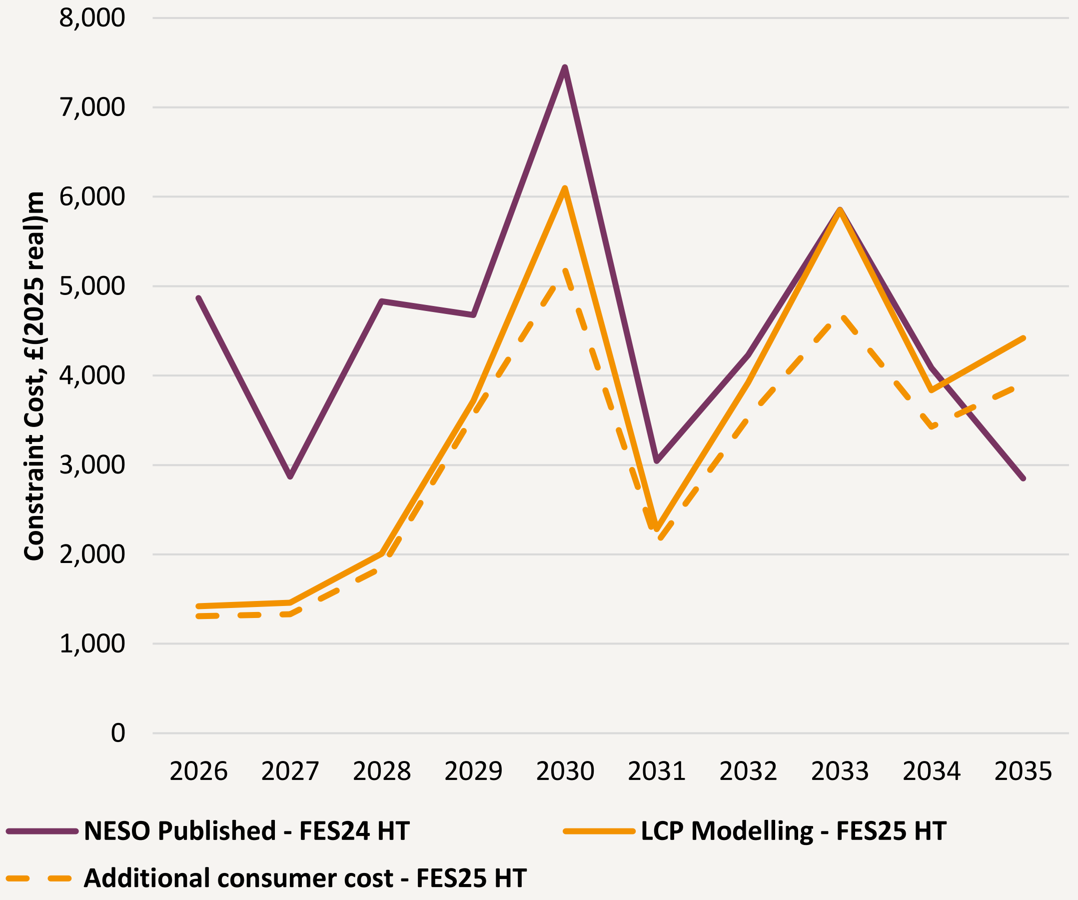
However, not all elements of constraint costs are an additional cost to the consumer. This is because the subsidy opportunity cost element of constraint costs does not increase consumer costs, if these renewable generators had not been turned down, the consumers would still have to pay the cost of the subsidy. In effect, this means the cost to the consumers is being transferred from policy payments to BSUoS without impacting the overall cost.

Subsidy opportunity cost makes up a large portion of total constraint costs. The dashed lines on the chart shows the true additional cost of constraints to consumers with the subsidy opportunity cost removed under FES Holistic Transition scenario. This shows:

- In 2030, the additional cost of constraints to consumers is £5.2bn, £1bn lower than the constraint costs including the subsidy opportunity cost.
- This continues across the 2030s. In 2033, the additional cost of constraints to consumers is £1.1bn lower in FES HT with the subsidy opportunity cost removed.

This highlights that when looking at the additional impact of constraints on consumers, the subsidy opportunity cost should be removed.

Constraint Costs under the FES Holistic Transition Scenario and with subsidy costs removed



[1] 2025 Annual Balancing Costs Report

LCP Central Scenario

LCP Central Scenario has a slower renewables build aligned to the recent AR7 results

To understand the sensitivity of constraint costs to key assumptions, an alternative scenario is modelled. The LCP Central Scenario represents LCP Delta's independent view of the current trajectory of the GB power sector to 2035. Renewable capacity build is more in line with recent trends and consistent with the results from CfD AR7 (although it is assumed renewable capacity increases with future CfD auctions).

This means that, although significant decarbonisation is assumed and the scenario is consistent with meeting Net Zero in 2050, it does not reach the capacity required to meet Clean Power 2030. For example, the FES HT scenario assumes 47GW in 2030 and 86GW in 2035 compared to 36GW and 52GW in the LCP Central.

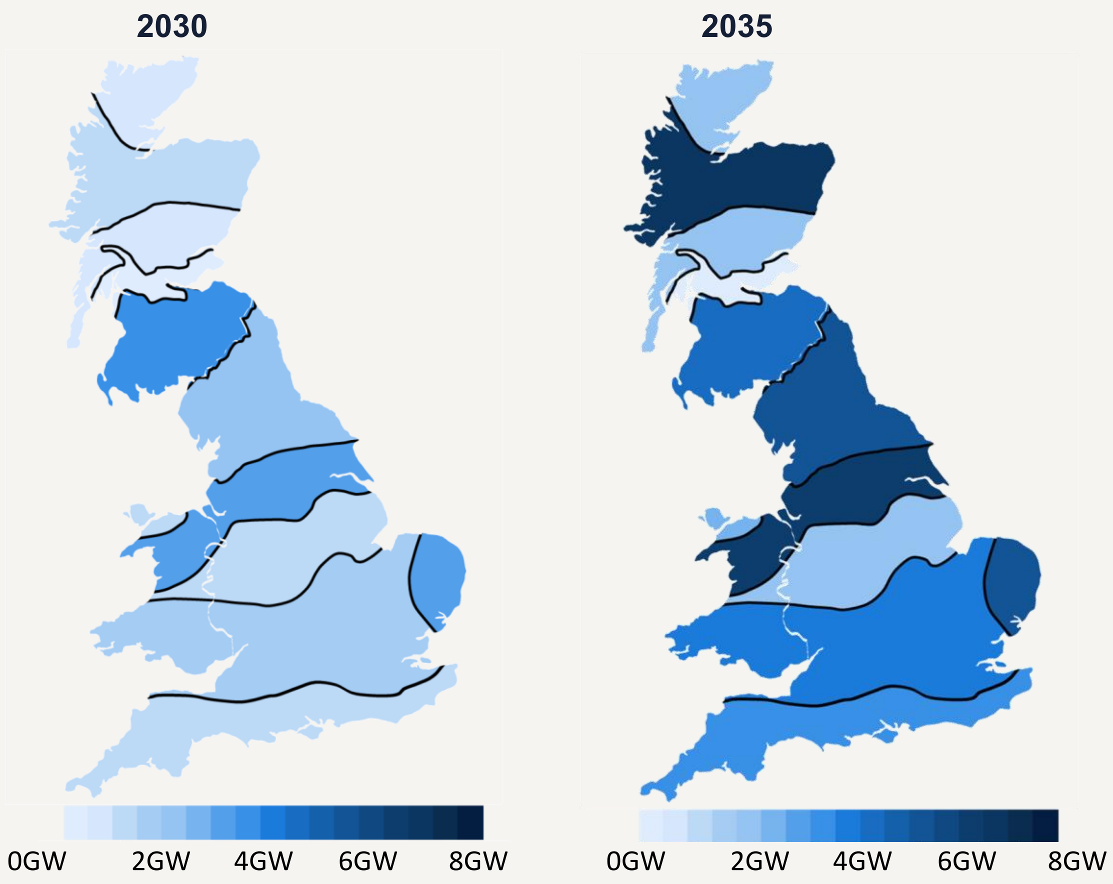
The chart on the right shows the difference in offshore and onshore wind capacity by zone between the two scenarios. In 2030, the majority of the difference in capacity is in England and Wales. By 2035, there is significant difference across the entire country. The differences in deployment will drive differences in constraint costs.

To reflect lower generation capacity under LCP Central scenario, the boundary capacity is also adjusted. This assumes that if renewable build is known to be slower than in the HT scenario (which is used in network planning) then longer-term plans will likely be adjusted to delay or not build certain network upgrades as these are no longer economical. This assumes:

- There are no changes until 2030, as most of these projects are already underway and have confirmed funding as part of RIIO-T3.
- Post 2030, there are delays to several key boundary upgrades. For example, the Eastern Greenlink 3 and 4 offshore connections that connect Scotland to England and the offshore Sea-Link (SCD1) connection between East Anglia and Kent.

The full capacity mix under both scenarios and further details of the LCP Central Scenario is provided in the appendix.

Difference in Total Wind Capacity between FES25 HT and LCP Central



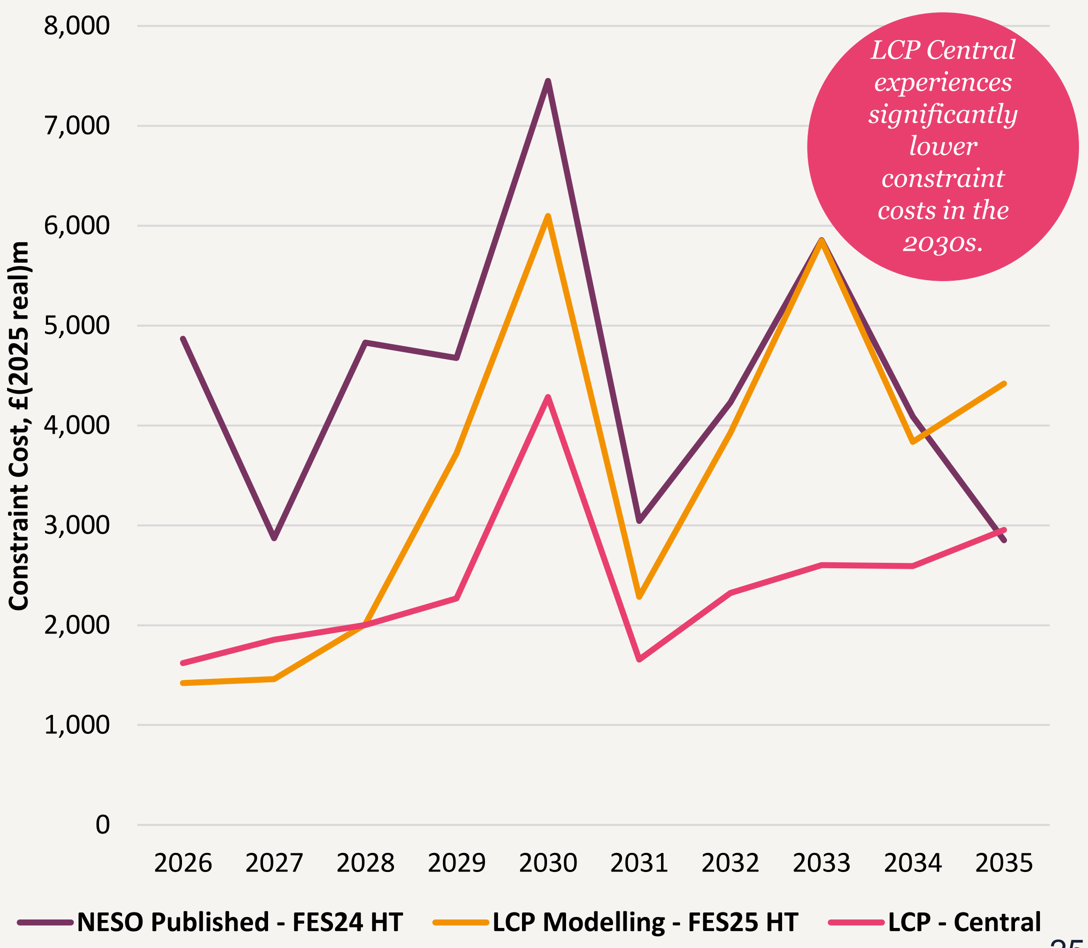
Constraints under the LCP Central Scenario

Constraint costs under the LCP Scenario are higher in the short term but avoid the large peaks seen in later years

The slower deployment of renewable capacity under LCP Central allows boundary upgrades to keep pace with generation growth, in contrast to FES HT where there is insufficient network to accommodate the generation capacity. LCP Central experiences significantly lower constraint costs in the 2030s, even with delays in network reinforcements.

- From 2026 to 2028, constraint costs increase steadily and are higher in LCP Central than the FES HT scenario due to:
  - Slightly higher onshore wind capacity under LCP Central.
  - Lower storage capacity under LCP central leading to higher curtailment.
  - More gas use at the day ahead stage, meaning that more expensive peakers are turned up to deal with constraints.
- Until 2030, wind capacity in Scotland is similar across both scenarios reflecting known build-out, so Scottish boundaries are similarly constrained. Differences in 2029 and 2030 are driven mainly by constraints in the English boundaries, particularly the EC5 boundary.
- After 2030, FES HT sees a large buildout of offshore wind capacity in North Scotland. Lower renewable capacity in LCP Central reduces constraints in Scotland and avoids the spike in constraint cost in 2033 seen in FES HT.
- While lower levels of wind capacity leads to lower constraint costs, this must be weighed against the decarbonisation ambition and system benefits of deploying additional wind in the FES HT scenario.

Constraint Costs under the FES Holistic Transition and LCP Central Scenario



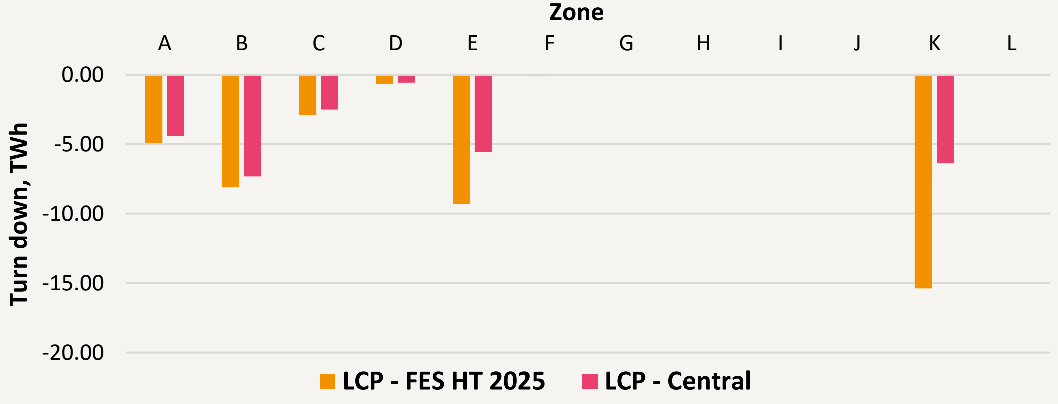
Constraints under the LCP Central Scenario

The EC5 and Scottish boundaries experience less constraints under the LCP Central scenario

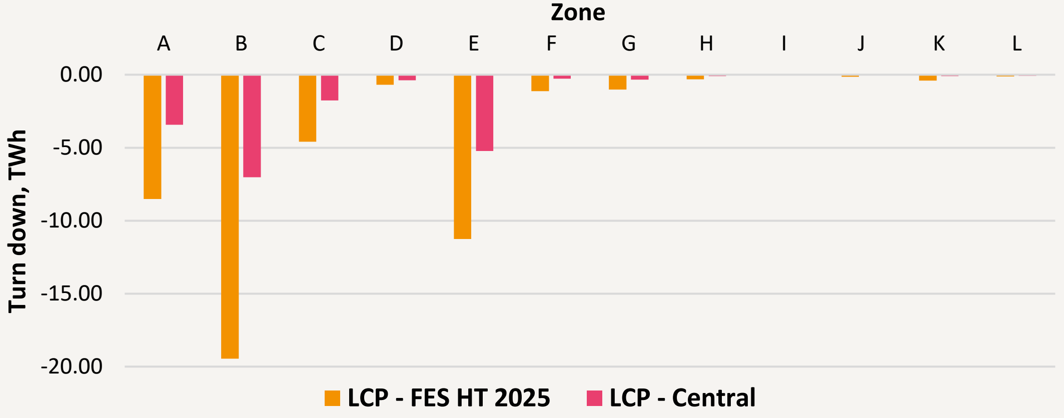
Comparing the constraint volumes by zone in 2030 and 2033 under LCP Central and FES Holistic Transition highlights the differences between which boundaries drive constraints in each scenario:

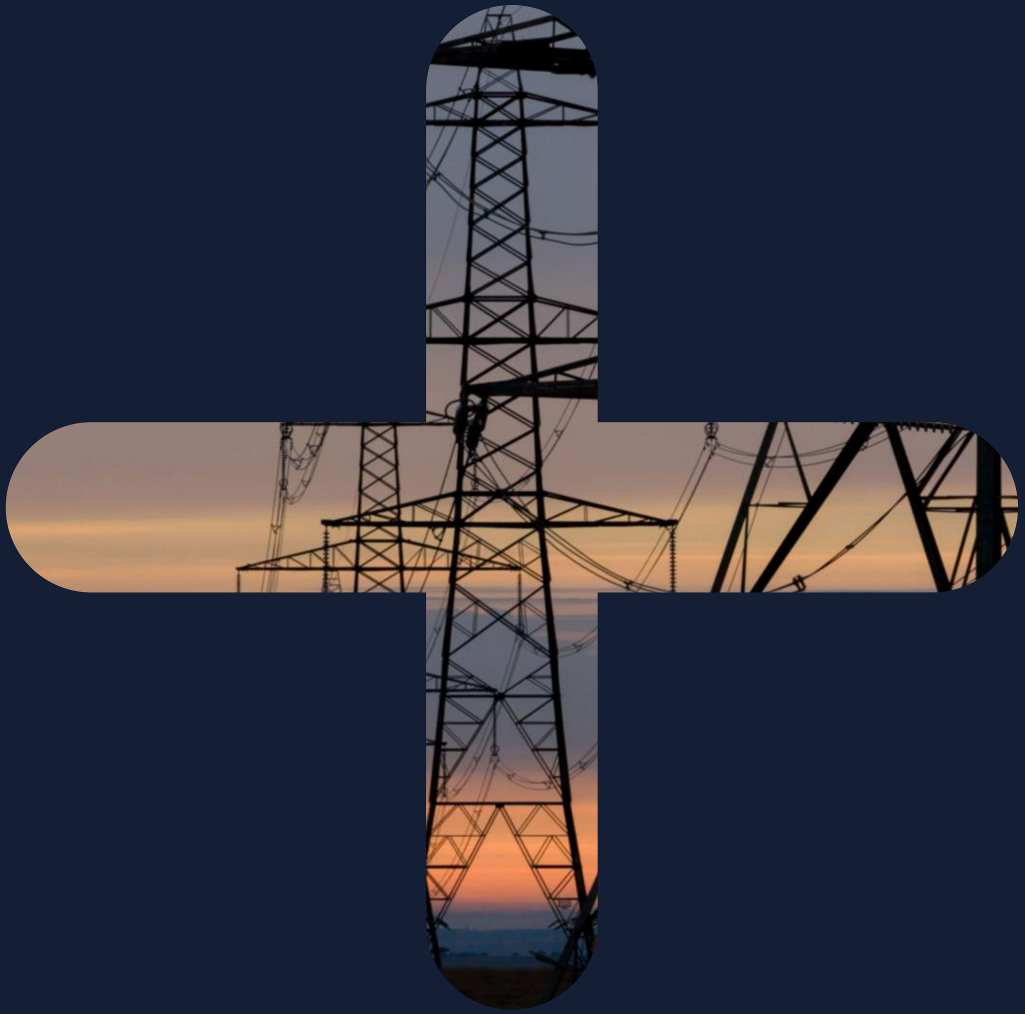
- In 2030, the Scottish boundaries (B0-6) experience heavy constraints under both scenarios. The B6 and the Northen English boundaries (B7a and B8) experience greater constraints under the FES HT Scenario. This is due to higher onshore wind capacity in South Scotland and offshore wind capacity in North England under the FES HT scenario.
- Due to the constraints on the English boundaries, generation north of these boundaries are turned down. As a results, the volume of constraints in Scotland is higher under FES HT compared to LCP Central.
- Under both scenarios, East Anglia faces significant constraints in 2030. This is because a large amount of offshore wind capacity comes online in East Anglia during 2029 and 2030, before network upgrades are completed. This mismatch leads to high levels of constraint at the EC5 in 2030. The constraint volumes under FES HT is significantly higher than under LCP Central.
- The LCP Central has lower levels of offshore wind capacity in East Anglia than FES HT and therefore experience lower constraints volumes in Zone K.
- By 2033, constraints across all boundaries are significantly higher under the FES HT scenario, particularly in Scotland and Northern England. This is due to the higher level of renewable capacity in the early 2030s under FES HT compared to LCP Central.

2030 - Constraint volumes of renewable generation under the FES Holistic Transition and LCP Central Scenarios



2033 - Constraint volumes of renewable generation under the FES Holistic Transition and LCP Central Scenarios





Measures to Reduce Constraint Costs

RNP measures to reduce constraint costs

We have modelled the impact of various RNP measures to manage constraints and to reduce constraint costs

The Summer 2025 REMA update from DESNZ outlined various measures that were under consideration as part of the RNP Delivery Plan. To understand the impact that some of the shorter-term measures could have on reducing constraint costs, 5 measures have been modelled under both baseline scenarios; FES Holistic Transition and LCP Central. These measures have been measured individually to see their possible impact and measures 1 to 4 to see the overall impact:

Network

1. **Accelerated network capacity upgrades in East Anglia** – In line with the analysis that NESO has undertaken in the 2025 Annual Balancing Report, the impact of bringing forward key network projects is modelled. Specifically, this looks at bringing forward two key projects in East Anglia from 2031 to 2030.
2. **Improvements to existing network carrying capacity** – There are measures that could be implemented to increase the network availability including dynamic line rating, boundary flow smoothing, improvements to network outage management and greater use of intertrips. This will essentially allow the network to operate at closer to 100% of the boundary capacity.

System Balancing

3. **Greater participation of smaller assets in the BM** – many smaller, embedded assets do not currently participate in the Balancing Mechanism. This measure increases the pool of providers able to offer lower cost turn up and turn down actions to include smaller flexible assets.
4. **Forward contracting of flexible capacity outside of BM** – Forward contracting through a Constraints Management Market allowing NESO to secure flexibility volumes ahead of real time. This could allow for the cost of redispatch actions to be decreased as bids/offers are secured ahead of time for a lower price.

Interconnector

5. **Improvements to interconnector redispatch** – The way in which interconnector flows are currently traded leads to inefficiencies in interconnector redispatch that ultimately means interconnectors are often exacerbating constraints on the system. This measure looks at improvements to how interconnector flows are redispatched and how to reduce them exacerbating constraint costs.

These measures will involve some practical implementation challenges and associated financial costs, which should be further analysed. However, it is likely that the overall benefits of each measures would outweigh their associated implementation costs.

Measures to reduce constraint costs

Measure 1: Network – Accelerated network upgrades in East Anglia

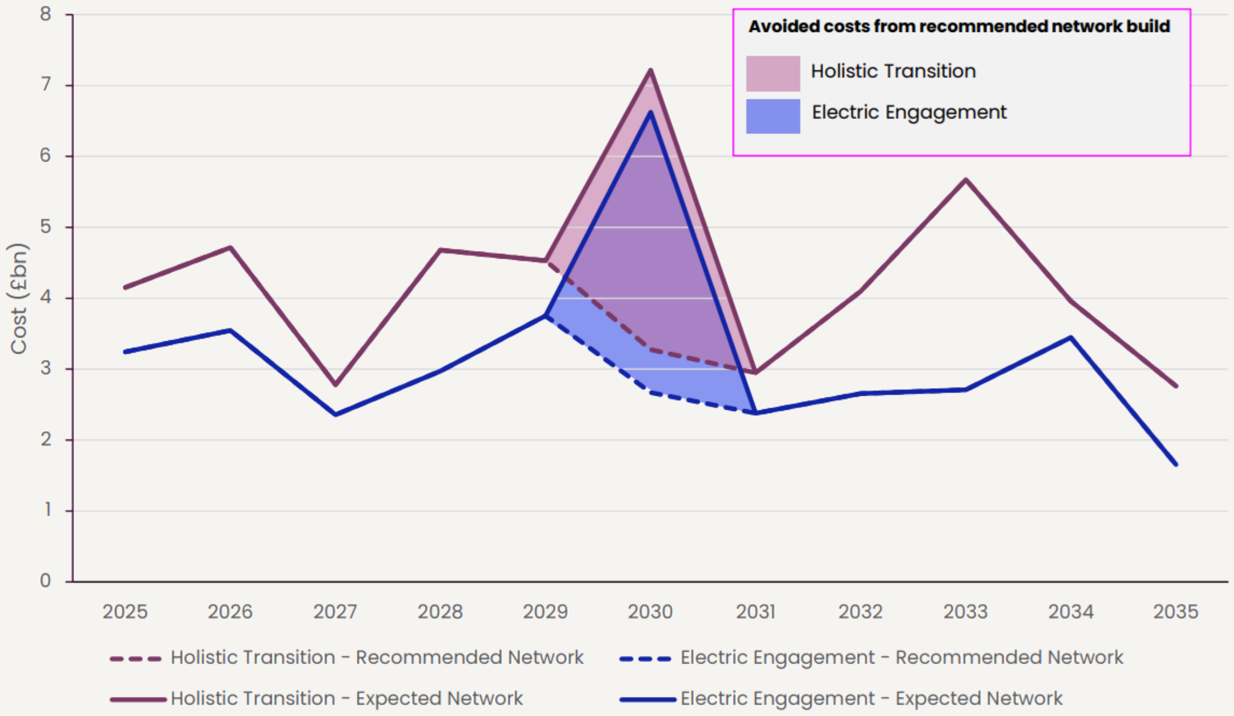
In the 2025 Annual Balancing Report, NESO identified network projects to bring forward to 2030 that delivers a network which supports Clean Power 2030. This was published as the ‘recommended network’ that is needed to reach the CP2030 target compared to the ‘expected network’ published in the Beyond 2030 report in 2024. NESO is still exploring the extent to which these network upgrades can be bought forward.

The recommended network includes three projects identified as critical to delivering a network which supports the clean power pathways, but at present have delivery dates in 2031. These projects are Norwich to Tilbury (AENC and ATNC) and Sea-Link (SCD1). These all reduce constraints in East Anglia (behind the EC5 constraint) and increases the EC5 boundary capability from 5,900MW to 13,500MW in 2030 in the FES Holistic Transition scenario. In LCP Central, this increases the 2030 boundary capability from 5,900MW to 11,500MW[1].

NESO analysis shows that the delivery of these projects in 2031, which is after significant deployment of offshore wind in East Anglia, is a key driver for the 2030 spike in constraint costs. NESO is actively exploring ways to secure earlier delivery of these network upgrades. NESO modelling shows that this could lead to savings of £3.9bn in 2030 in the FES24 Holistic Transition scenario.

For this measure, we have undertaken the same analysis assuming that these projects are brought forward by one year to 2030. It should be noted that there is likely to be an associated cost of bringing these projects so these will need to be weighed against the fall in the constraint costs in any decision to accelerate this network upgrade.

NESO Thermal constraint projections under recommended and expected network



[1] This difference is due to later deployment of the offshore SCD1 Sea-Link connection between East Anglia and Kent under LCP Central

Measures to reduce constraint costs

Measure 1: Network – Accelerated network upgrades in East Anglia

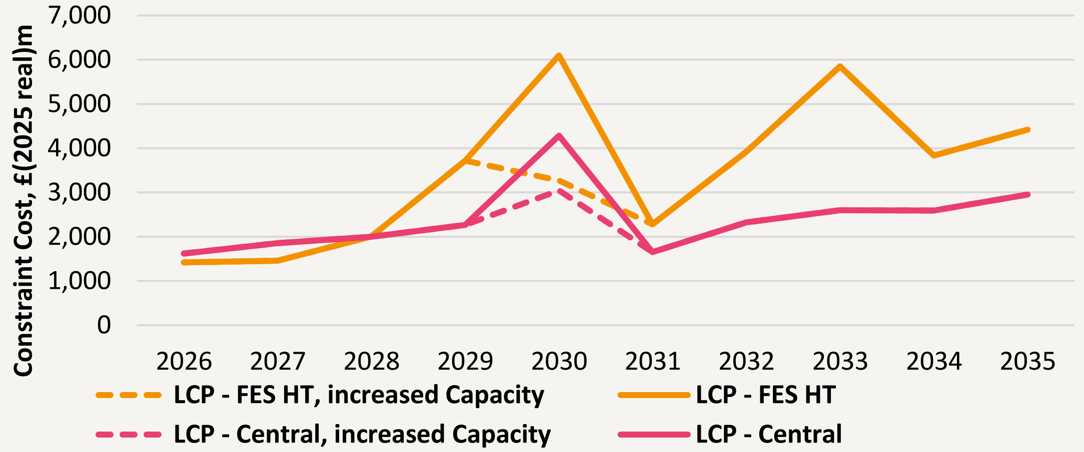
This measure replicates NESO modelling of bringing forward network improvements in East Anglia which increases the EC5 boundary capability.

Including this additional network in 2030 reduces constraint costs from £6.1bn in the FES HT counterfactual to £3.3bn, a reduction of £2.8bn. This is a lower reduction than seen in equivalent NESO modelling which shows a reduction of £3.9bn. Part of this is likely to be driven by higher renewable capacity in East Anglia in FES24 compared to FES25 but without seeing more detail on NESO's modelling, it's hard to say in detail what causes the difference.

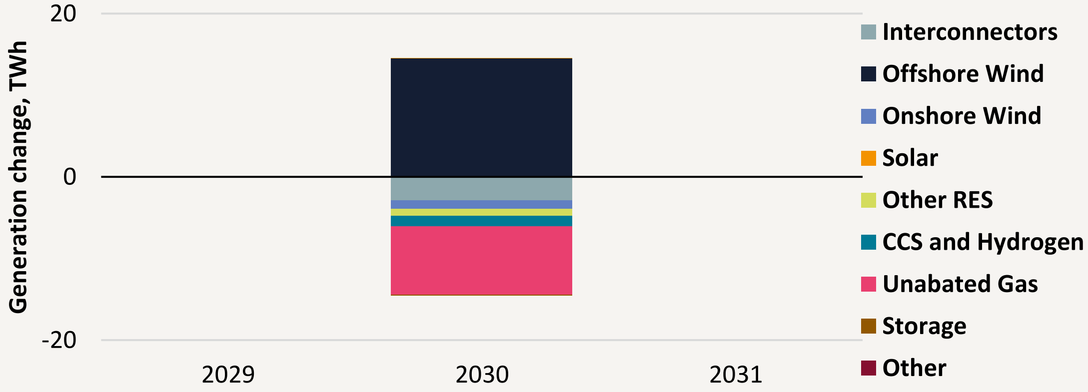
Under LCP Central scenario, there is a smaller reduction of £1.3bn due to less constraints across the EC5 boundary. While still a large impact, it is smaller than under FES HT as constraints in East Anglia are lower in the LCP Central baseline due to lower wind capacity in this area.

The change in constraint costs is driven by reducing the EC5 boundary constraint from 55% to 13% in the HT scenario and 43% to 1% in the LCP Central scenario. The higher network capacity reduces offshore wind curtailment in the East Anglia increasing overall offshore wind generation by 14TWh in the HT Scenario. This leads to 8TWh less gas needing to be turned up as well as reductions in CCS gas and interconnector imports. This would also reduce 2030 emissions on the system by 19%, making the government's Clean Power 2030 target more achievable.

Modelled Constraint Costs under accelerated East Anglia grid upgrades



Modelled change in generation in 2030 under FES Holistic Transition from accelerated East Anglia grid upgrades



Measures to reduce constraint costs

Measure 2: Network – Improvements to existing network carrying capacity

Within the baseline scenarios, it is assumed that the carrying capacity on the network varies across the year as a result of general maintenance on the network and is based on historical data of network availability, excluding 2025.

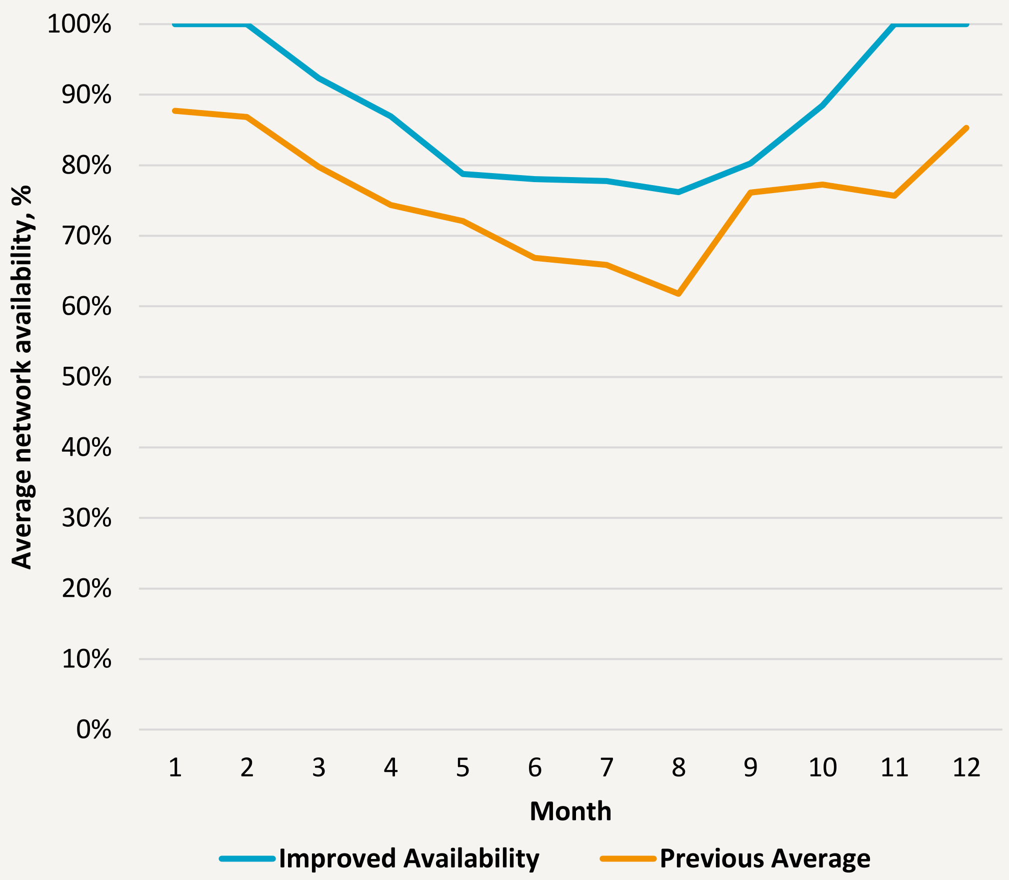
To model this measure, the average transmission boundary availability has been increased relative to historical values to reflect the potential deployment of operability measures identified by NESO, including dynamic line ratings, expanded intertrip schemes, better outage planning and more flexible application of Security and Quality of Supply Standards (SQSS) limits[1].

It is difficult to quantify how much difference each of these measures will make to network carrying capacity individually. As such we have taken a simplified approach and assumed improvements based on the carrying capacity of the current best performing boundaries. There may be characteristics on certain network boundaries (e.g.: lower voltage networks in Scotland) that mean reaching the same performance as the best performing boundary is challenging. However, given the low performance of the network in 2025, it is vital that this is explored in more detail by NESO/DESNZ.

Network carrying capacity is assumed to improve to 100% in the winter months, when demand and constraints are highest. Improvements in network carrying capacity are also assumed in other months, but do not reach 100% as ongoing maintenance of the system will still be required during these months. On average network capacity changes to:

- Spring/Autumn from 76% to 88%
- Summer from 65% to 77%
- Winter 87% to 100%.

Improvement to network carrying capacity



[1] This approach is consistent with evidence from Operational Transparency Reports showing increased utilisation of existing assets without compromising system security

Measures to reduce constraint costs

Measure 2: Network – Improvements to existing network carrying capacity

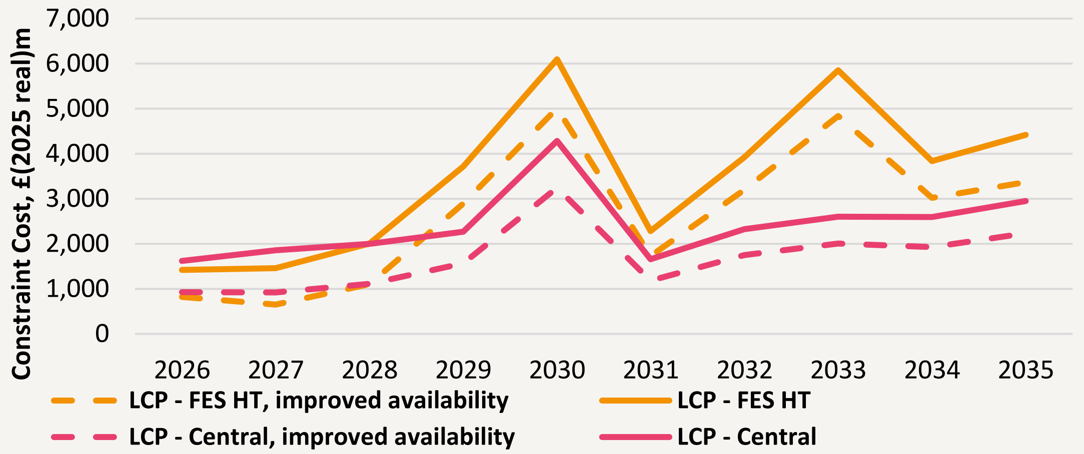
The improvements to network carrying capacity result in a significant reduction in constraint costs in all years, under both scenarios. Savings are highest in years with the greatest constraints. In 2030, savings reach £1.1bn under the FES Holistic Transition scenario and £1.1bn under LCP Central.

The higher level of network carrying capacity results in less curtailment of renewable generation in key regions (mostly Scotland). This increases renewable generation and decreases gas generation, driving the reduction in constraint costs. Under the FES HT scenario, in any year there is at least 3TWh of additional renewable generation and 2.5TWh less unabated gas generation. In 2030, unabated gas generation is reduced by 4.8TWh which reduces carbon emissions by 11%.

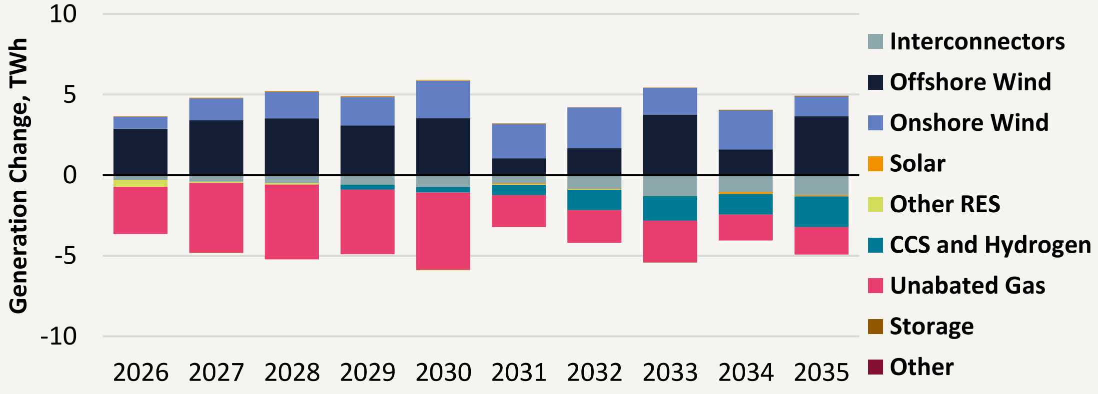
Overall, this highlights the key role that improvements to network carrying capacity can play in reducing constraints on the system and reforms to improve network availability should be a key focus for NESO and DESNZ.

It may be the case that the network carrying capacity improvements we have assumed may not be possible for all boundaries, however any improvements which are achieved will lead to a reduction in constraint cost.

Modelled Constraint Costs under improved network carrying capacity



Modelled change in generation under FES Holistic Transition from improved network carrying capacity



Measures to reduce constraint costs

Measure 3: System Balancing – Increased participation of smaller assets in the BM

Competition within the BM can be strengthened by the growing participation of smaller flexible assets, increasing the pool of providers able to offer lower cost turn up and turn down actions. This broader participation helps reduce constraint costs by increasing competition within the BM, leading to lower cost bids/offers being accepted.

This measure was proposed by DESNZ in their REMA Summer Update (2025) and the recent Call for input published by NESO outlines options to lower the mandatory BM participation threshold to 10MW or 1MW. There could also be other methods to improve this by providing incentives for greater participation.

The participation of smaller assets in the BM is modelled in the following way:

- **Baseline:** We assume that only assets with BMU IDs participate in the balancing mechanism. This is calculated using historic analysis of assets with BMU IDs, compared to current capacity levels to calculate a % participation by technology type.
- **Greater participation:** We increase the % participation across key generation (including behind the meter and V2G) technologies above 1MW to the levels shown in the table on the right-ahand side. This could represent lowering the threshold to 1MW but in reality, many of these assets don't actively participate.
- **Full participation:** We also model the potential benefit of full participation of the selected technologies for assets above 1MW. This shows the potential size of the prize in terms of participation of smaller assets should all those above 1MW actively participate if the threshold is lowered.

Changes in participation across key technologies

Technology*	Baseline	Greater	Full
Biomass	80%	90%	100%
Demand Side Response (incl.V2G)	0%	50%	100%
Onshore Wind	64%	82%	100%
Solar	4%	52%	100%
Peakers	81%	91%	100%
OCGT	65%	83%	100%
Electrolysis	For electrolysers, we have increased their balancing participation dynamically, all capacity to 2030 is unable to participate, and that new build capacity can participate in the following way: • **Greater participation:** Half new build capacity from 2030 can participate. • **Full participation:** All new build capacity from 2030 can participate.		

* Other technologies are either able to participate fully in the BM, or do not participate at all (for example, CHP plants or Energy from Waste), for these technologies their participation is unchanged from the baseline.

Measures to reduce constraint costs

Measure 3a: System Balancing – Greater participation of smaller assets in the BM

Allowing greater participation of smaller assets in the BM increases the competition and sees more flexible assets compete in the BM. This version of the measures assumes that there is greater participation around all smaller assets by 50%.

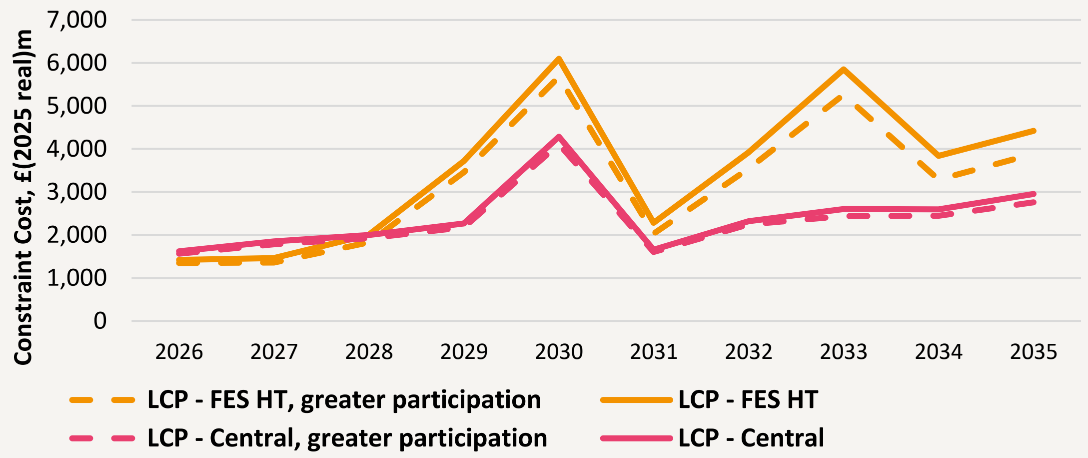
This leads to a reduction in constraint costs of 12% in 2035 in the FES Holistic Transition scenario, over £0.5bn, and by 7% in 2035 under LCP Central, a reduction of £0.2bn. The impact increases over time as the amount of smaller assets, particularly demand side assets (demand side response and electrolysis), on the system increases.

Ultimately this leads to increased generation from renewables, up almost 4TWh from onshore wind, offshore wind and other renewables which replace thermal generation and interconnection in the HT scenario across certain years. This is a result of demand being moved which reduces constraints on the system.

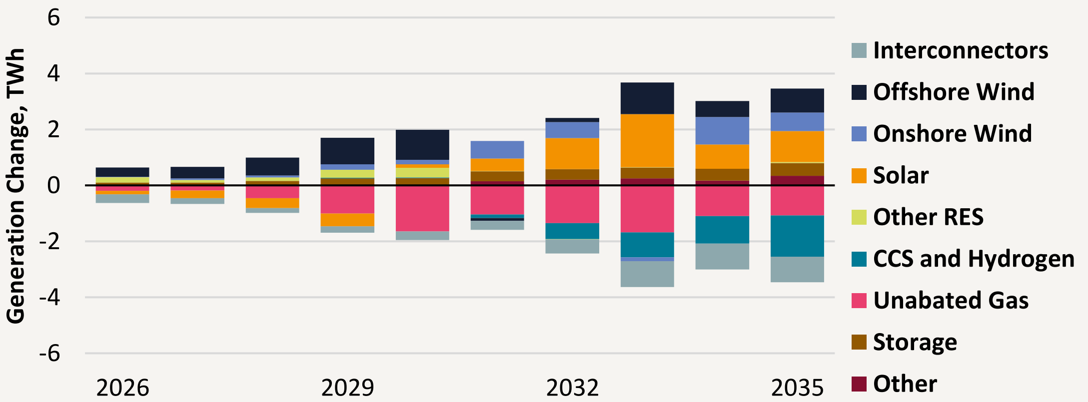
The participation of smaller assets also reduces the cost of some turn-ups as smaller assets are often cheaper to turn-up than unabated gas. Under the FES HT scenario, in 2030, unabated gas generation is reduced by 1.6TWh reducing carbon emissions by ~11%.

Overall, this shows that reducing the mandatory threshold of BM participation to 1MW is something DESNZ and NESO should consider.

Modelled Constraint Costs under greater participation of smaller assets in the BM



Modelled change in generation under FES Holistic Transition from greater participation of smaller assets in the BM



Measures to reduce constraint costs

Measure 3b: System Balancing – Full participation of smaller assets in the BM

This version of the measure increases the participation of smaller assets, so the entire fleet (above 1MW) is participating in the BM. This therefore represents the entire potential reduction in constraint costs through full participation of smaller assets.

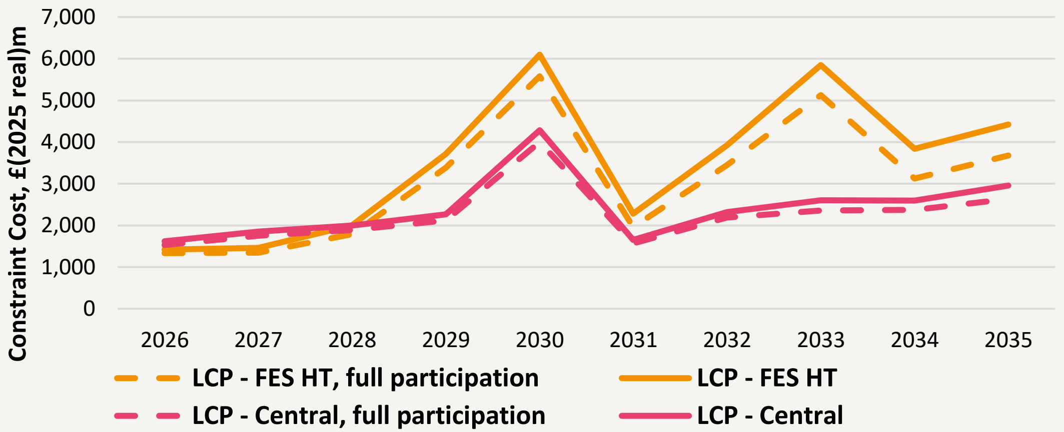
With 100% of smaller assets competing in the BM, this reduces constraint costs by 17% in 2035 under FES Holistic Transition, over £0.7bn, and by 11% in 2035 under LCP Central, a reduction of £0.3bn. This effectively represents the overall size of the prize in terms of participation of smaller assets.

Again, the participation of smaller assets sees increased generation from renewables, over 4.5TWh more which replaces thermal generation and interconnection in the HT scenario across certain years. In 2030, unabated gas generation is reduced by 2.2TWh reducing carbon emissions by ~15%.

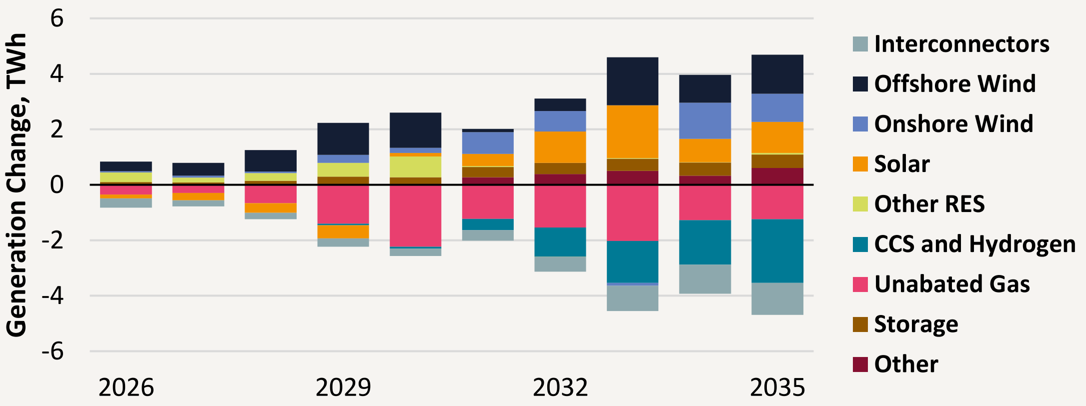
Despite the further increase in the amount of smaller assets competing in the BM, the reduction in constraint costs is only slightly higher under full participation increasing from 12% to 17% under FES HT and 7% to 11% under LCP Central.

This highlights that while allowing all smaller assets to participate in the BM will bring benefits, the largest benefit comes from the first 50% of smaller assets and therefore NESO and DESNZ may wish to focus on facilitating their participation as a priority.

Modelled Constraint Costs under full participation of smaller assets in the BM



Modelled change in generation under FES Holistic Transition from full participation of smaller assets in the BM



Measures to reduce constraint costs

Measure 4: System Balancing – Forward Contracting of Capacity outside of the BM

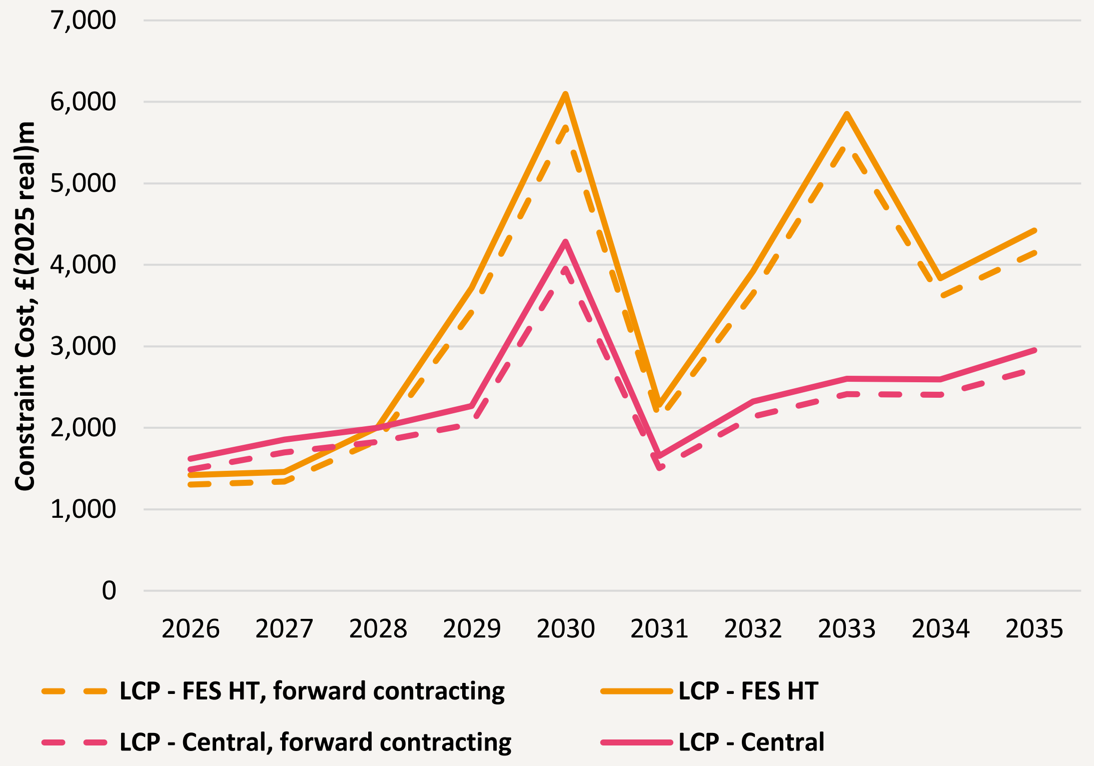
Forward contracting through a Constraints Management Market could allow NESO to secure flexibility volumes ahead of real time, enabling more competitive pricing by avoiding the need to purchase actions at short notice in the Balancing Mechanism. This is likely to work in a similar way to the current Balancing Reserve market.

Procuring capacity at the day-ahead stage, or further in advance provides greater certainty for participants, supporting more efficient bidding behaviour and lowering bid and offer premiums relative to the status quo. This advanced procurement reduces the overall cost of managing constraints and can also encourage new flexibility providers to enter the market by providing longer term revenue certainty.

In line with the second report of NESO's Constraint Collaboration Project, we propose a reduction in the average bid and offer premia by 16% in England and Wales, and by 8.7% in Scotland.

The result of this forward contracting is that we see a constant reduction in constraint costs of 7-9% per year, by as much as £0.4bn in 2030 in the FES Holistic Transition scenario and £0.3bn in the LCP Central scenario. This reflects the potential saving that could result from avoiding the need to purchase actions at short notice in the Balancing Mechanism.

Modelled Constraint Costs under forward contracting of capacity



Major savings from measures in combination

Measures 1-4 in combination could save £3.8bn in constraint costs in 2030 under FES Holistic Transition

The measures outlined in previous slides can be combined to assess the overall impact on reducing constraint costs*. While there is some offsetting across the measures, together the measures have a significant impact on reducing constraint costs:

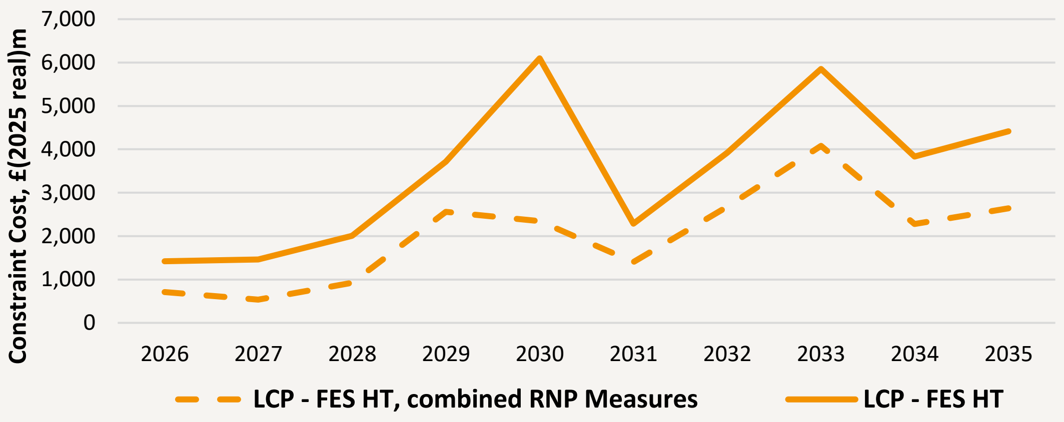
- Under the FES Holistic Transition scenario, there are no years prior to 2032 which have a constraint cost over £3bn. The peak value under FES HT now occurs in 2033 at £4.1bn. In most years the reduction in constraints is £1-2bn with a greater impact of £3.8bn in 2030 due to the improvements in the network in that year. Constraint costs only grow by 44% from 2025 to 2035, less than demand growth of 58% over the same period.
- Under LCP Central there are no years where the constraint cost exceeds £2.2bn with the peak cost remaining in 2030 at £2.2bn. In most years, the reduction in costs due to the measures is around £1bn with a greater impact of £2.1bn in 2030 due to the improvements to the network in that year.

The combination of these measures results in increased generation from renewables and less use of gas.

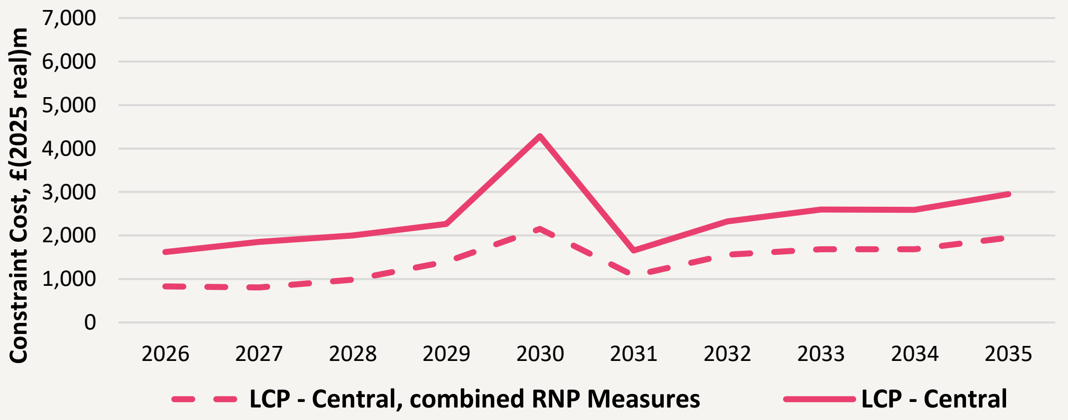
- Under FES HT in 2030, unabated gas generation is reduced by 12.6TWh (33%) reducing carbon emissions by 4.4MTCO$_2$ (29%). This also increases the % of generation from low carbon sources from 91% to 96% making the CP2030 target achievable.
- Under LCP Central in 2030, unabated gas generation is reduced by 7.1TWh (17%) and emissions by 2.4MTCO$_2$ (15%). The % of generation from low carbon sources increases by 3pp bringing the CP2030 target closer under the current trajectory and achieving it in the early 2030s.

*For participation of smaller assets, we have assumed greater participation (3a), but not full participation (3b).

Modelled Constraint Costs under FES Holistic Transition – All measures



Modelled Constraint Costs under LCP Central – All measures



Measures to reduce constraint costs

Measure 5: Other – Improved interconnector redispatch

Under the current market arrangements, there are various factors which limit redispatch of interconnector flows and therefore lead to inefficiencies on the system and higher constraint costs. These range from timing of countertrading and auction arrangements to the risk premiums that are often applied when bidding to change interconnector flows. These are summarised opposite.

In the latest REMA update, DESNZ highlighted that they were exploring ways to improve ways to better align interconnector flows with constraints. This includes options to change flows at the day-ahead stage (e.g. through improved use of Net Transfer Capacity) and improved redispatch arrangements (e.g. more options for trading interconnector flows pre and post gate closure). DESNZ also highlighted that they would 'need to work bilaterally with European partners' on this issue.

Given the uncertainty around the different options for improving interconnector redispatch, to model this measure we have assumed that interconnector redispatch is improved such that interconnectors can fully redispatch their flows in the market. While this scenario may represent the best possible outcome, as the complex nature of interconnector trading makes full redispatch unlikely, it helps to illustrate the potential benefits of improved interconnector redispatch on constraint costs. Given the uncertainty, this measure is assessed separately to others.

Reasons for inefficient redispatch of interconnectors under current market arrangements

Auction Arrangements

Intraday auction arrangements are not available on all interconnectors which restricts NESO's ability to countertrade to redispatch interconnector flows.

Timing of countertrading

The timing of intraday auctions means that NESO is having to make decisions on interconnector countertrading 12 hours before the relevant period and at least 2 hours before delivery.

Risk Premium

Risk premiums applied to price of trades to change in interconnector flows may lead to higher prices than NESO is willing to accept pricing these trades (which in theory should be cheaper) out of the market.

SO-SO Trade Arrangements

There is a limited availability of System Operator to System Operator (SO-SO) trade arrangements post gate closure across interconnectors with arrangements currently only available for Denmark and Ireland.

Obligation on SO-SO Trades

There is no obligation for interconnected SOs to accept a request to trade, even if a price has been posted. This means that NESO may prefer a higher priced offer from a domestic asset to an uncertain lower priced trade on an interconnector.

Pricing of SO-SO trades

The pricing of post gate closure SO-SO trades are not transparent and may not be reflective of real-time market conditions in each hour. SOs can set prices ahead of gate closure meaning efficient options may be "priced out" of the GB market.

Measures to reduce constraint costs

Measure 5: Other – Improved interconnector redispatch

The limitations on redispatch of interconnector flows means that interconnectors can exacerbate constraints. This is a common occurrence in the market, where interconnectors are exacerbating constraints through excessive exports or imports.

Example of interconnector flows exacerbating constraints

The map on the right shows a period of excessive exports over interconnectors on 20 June 2024 20.30-21.00.

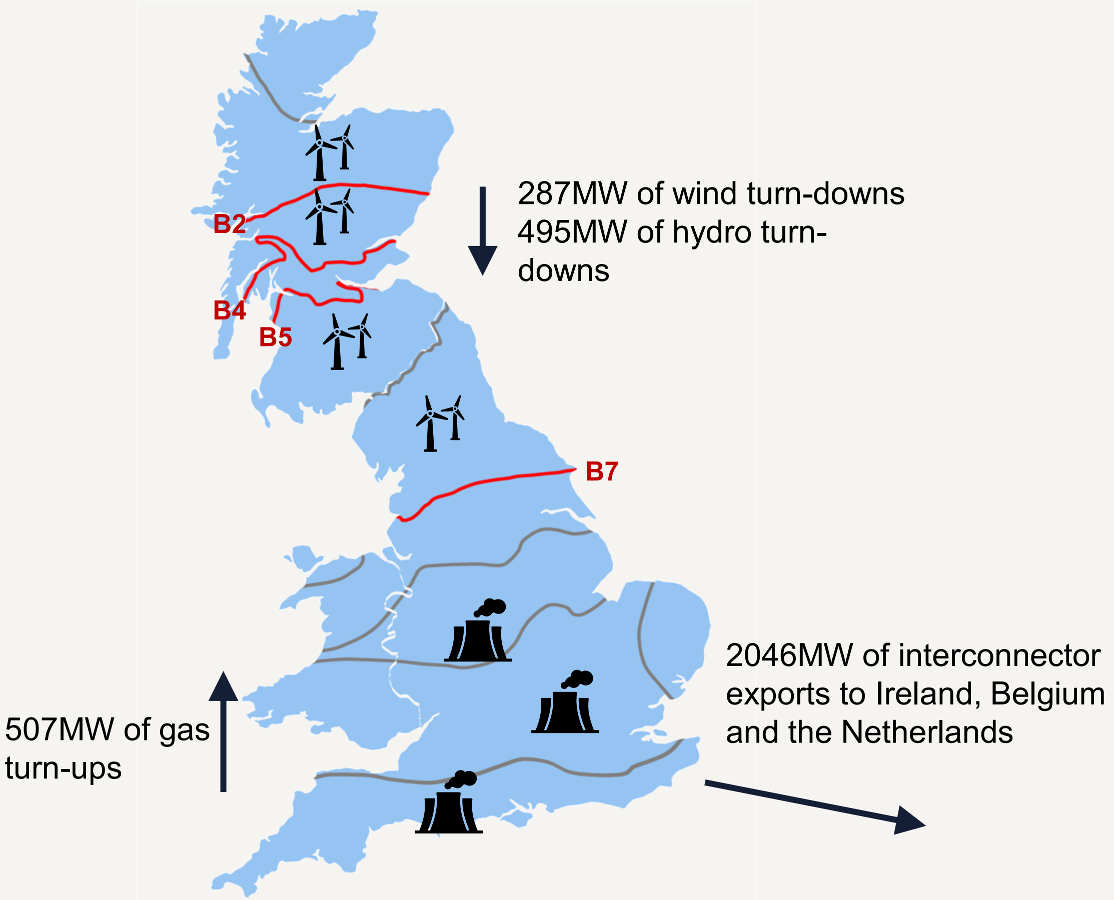
In this example, the B2, B4 and B5 boundaries in North Scotland were all constrained and the B7 in North England was also constrained. This required hydro-pumped storage and wind to be turned-down in Scotland, and gas generation needed to be turned up to meet English demand.

However, at the same time interconnectors below the B7 boundary were net exporting to Belgium, the Netherlands and Ireland. If these exports were reduced or switched to imports, then this would have reduced the need for gas turn-ups in the south saving on both costs and emissions in GB.

Overall, this leads to an inefficiency in the market as relatively expensive gas is being turned up, when decreasing interconnector exports would be a cheaper option if their flows could be redispatched based on prevailing market prices.

A more detailed example showing how this impacts constraints across the day can be seen in the Appendix.

Example of excessive exports – 20th June 2024 20.30-21.00



Measures to reduce constraint costs

Measure 5: Other – Improved interconnector redispatch

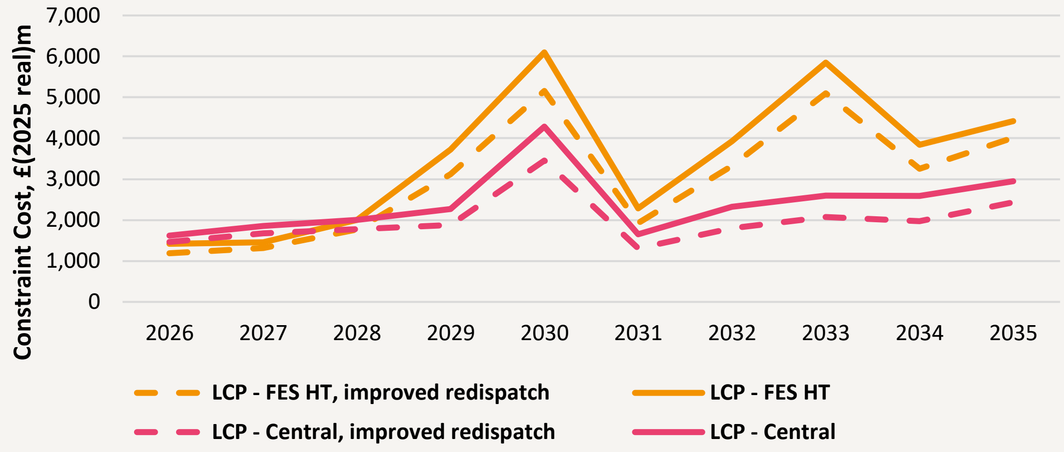
The ability to fully redispatch interconnectors flows improves the ability of NESO to adjust the flow from their day ahead (DA) wholesale market schedules to help manage constraints.

This has a significant impact on constraint costs reducing them by 9% -16% across the years modelled. Savings increase from 2029 onwards as more interconnectors come online. The impact is larger in years with higher constraint costs, with a reduction of £1.0bn in 2030 under FES Holistic Transition and £0.8bn under LCP Central.

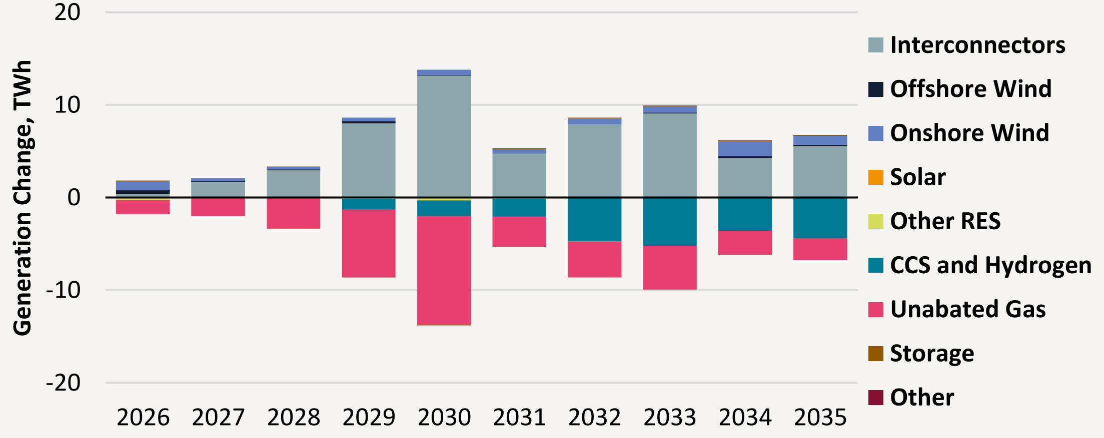
The decrease in constraint costs is due to more effectively using interconnectors for redispatch and preventing them from exacerbating constraints. This leads to higher interconnector imports (or reductions in exports) replacing unabated gas turn-ups and increased renewable generation as interconnectors reduce import into (or increase export out of) constrained regions. In 2030, unabated gas generation is reduced by 11.7TWh and carbon emissions are reduced by over 27%.

While improving redispatch of interconnector flow is unlikely to result in interconnectors flowing 100% efficiently as assumed here, partial improvements would still lead to significant reductions in constraint costs. Additionally, with the FES HT scenario assuming additional interconnector deployment post 2035, savings are likely to persist post 2035 as interconnector capacity continues to increase.

Modelled Constraint Costs under improved IC redispatch



Modelled change in generation under FES HT from improved IC redispatch



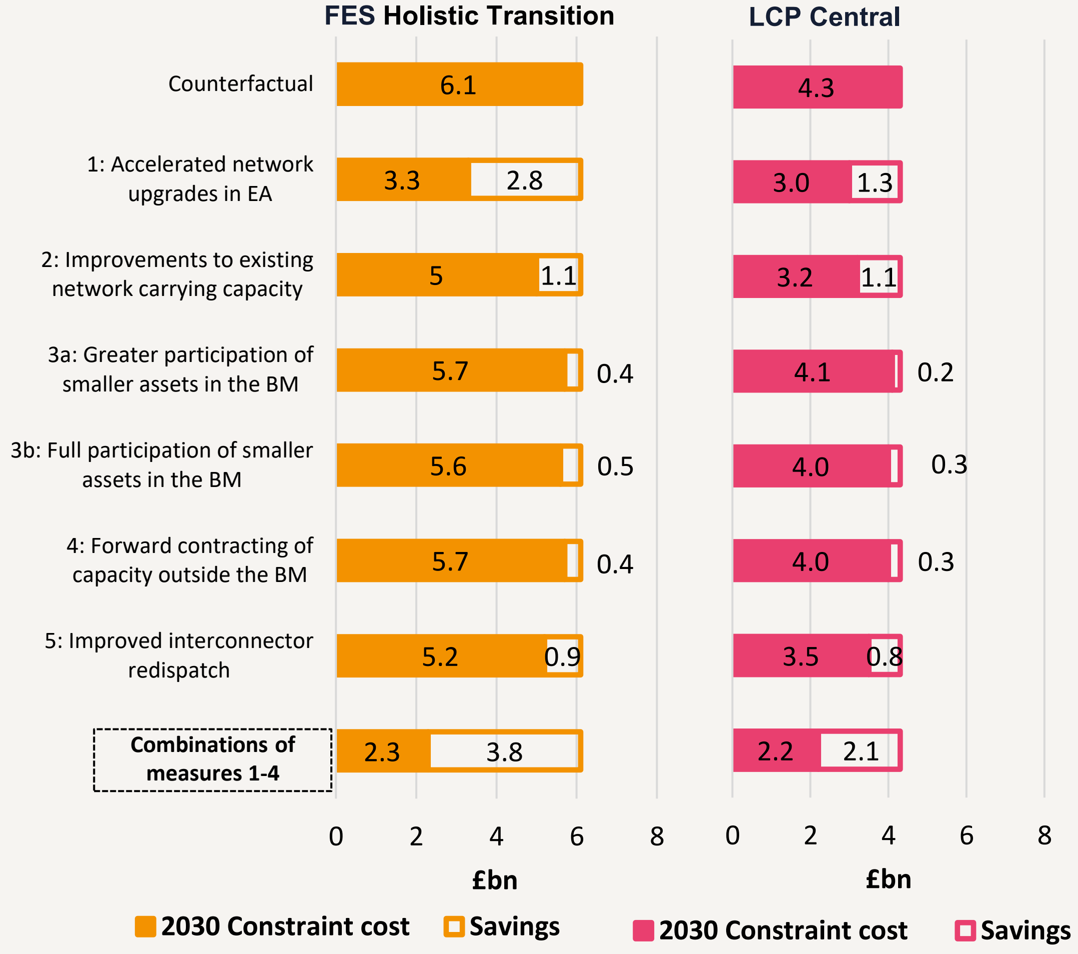
Summary of measures to reduce constraint costs

All measures assessed have a significant impact on reducing constraint costs

All the measures modelled result in reduced constraints costs over the 2026-35 periods. Some of the measures modelled may show the maximum savings which can be achieved, but even partial implementation would still deliver meaningful cost reductions. Looking across the measures:

- Bringing forward the East Anglia network upgrades leads to the largest single-year reduction in constraint cost of £2.8bn in 2030 the FES HT scenario and £1.3bn in the LCP Central scenario. This also results in a 22/11% reduction in gas use and 19/8% reduction in emissions.
- Network availability improvements led to the greatest savings over the whole modelled period (excluding 2030 network upgrades in EA). Constraint costs reduce by £1.1bn savings just in 2030 alone under both the FES HT and LCP Central scenarios while gas use reduces by 13/12% and emissions decrease by 11/9%.
- Increased participation of smaller assets in the BM reduces constraint costs by up to £0.5bn under FES HT and £0.3bn in LCP Central. However, incremental improvements should be prioritised as the benefit is driven by the first 50% to participate provide 70%-80% of the benefit.
- Combining measures reduces 2030 constraints cost to similar levels of £2.2-2.3bn in both scenarios, down from £6.1bn in FES HT and £4.3bn in LCP Central. This also reduces gas use by 33/17% (12.6/7.1TWh) and emissions by 29/15% (4.4/2.4MTCO_2). This highlights how the different measures can work together to reduce constraints.
- Improved interconnector redispatch is considered independently of the other measures bit this could reduce 2030 constraint costs by £0.9bn in FES HT and £0.8bn in LCP Central. It also reduces gas use by 31/20% and emissions by 27/17%. While it is unlikely the whole benefit could be realised, even partial improvements could have a significant impact.

Reduction in 2030 constraint costs relative to counterfactual



LCPDelta

Recommendations for NESO

While NESO have improved transparency on constraints, further improvements would allow for increased industry engagement on the issue

For this report we have used the public information published by NESO including historical data on constraint volumes, constraint costs and actual boundary limits as well as information on future projections from FES publications, NESO balancing report, boundary availability assumptions and ETYS publications. In addition, we have received replies to our queries directly from NESO. We welcome the improvements in transparency and data on constraints from NESO in recent years, but we believe further changes are needed. Below, we have set out how NESO could improve its published data and provide greater transparency on both historical data and future constraint projections. We would welcome any discussions with NESO on these recommendations.

Improvements to historical data

1. **Improvements in data quality** – Some datasets contain what look like errors, such as boundary limits spiking to 10GW in the DA constraint flows and limits dataset. There also appears to be some discrepancies between data published in NESO reports and in NESO data – for example, availability data in Operational Transparency forum slides compared to constraint flow and limits data.
2. **Additional data –** Key statistics such as how often boundaries are constrained and the network availability compared to max capacity can be calculated from NESO data. However, it would be helpful if these were reported in the data by default.
3. **Clearer explanation of data sources** – NESO publish a range of valuable data sources, however some lack sufficient documentation and it is not always clear what is included in the data. For example, it is unclear whether reported constraint costs reflect only accepted bids and offer costs or all associated system actions.
4. **Ensure consistent labelling** – boundary names used in the constraint flow and limits data is different from the names used in the ETYS making it difficult to understand. In addition, a single boundary sometimes has multiple names.
5. **Expand boundaries coverage** – Not all boundaries are included in the constraint flow and limits dataset, such as the EC5 despite this being a key boundary.
6. **Real time data on constraint costs –** Constraint cost data is currently published at a daily level. A more granular dataset at a half-hourly/hourly level that is published close to real-time would allow for more detailed analysis on drivers of constraints as well as increase visibility for market participants.
7. **Breakdown of constraint costs –** A more detailed breakdown of the constraint cost by turn-down/turn-up, by technology type and location would increase understanding of what is driving constraints.

Improvements to future projection publications

1. **Publish key assumptions -** the results of constraints modelling can be highly sensitive to the assumptions used. Therefore, it is essential NESO publishes their assumptions used for the modelling in the NESO Balancing Report, particularly as the detailed FES publications does not include any constraints modelling. Specifically, NESO should clarify their assumptions on:
    - Location of generation capacities
    - The boundaries included in their modelling and when in the year upgrades are completed
    - The availability assumptions applied to these boundaries
    - How interconnector redispatch is modelled
2. **Transparency on modelling methodology** - more information should be provided on the methodology used to calculate constraint costs, including how bids and offers have been determined.
3. **Explain key drivers** – it would be useful for the Balancing Report to include more detail on the key drivers of constraint costs. While NESO notes that East Anglia is a major contributor to the spike in 2030, there is little information on the factors driving constraints in other years.
4. **Optimal level of constraints –** it would be useful if NESO could highlight what they consider to be an optimal level of constraint costs vs investment in networks. This would help to improve public debate on this topic by suggesting a realistic target range for the level of constraints costs.

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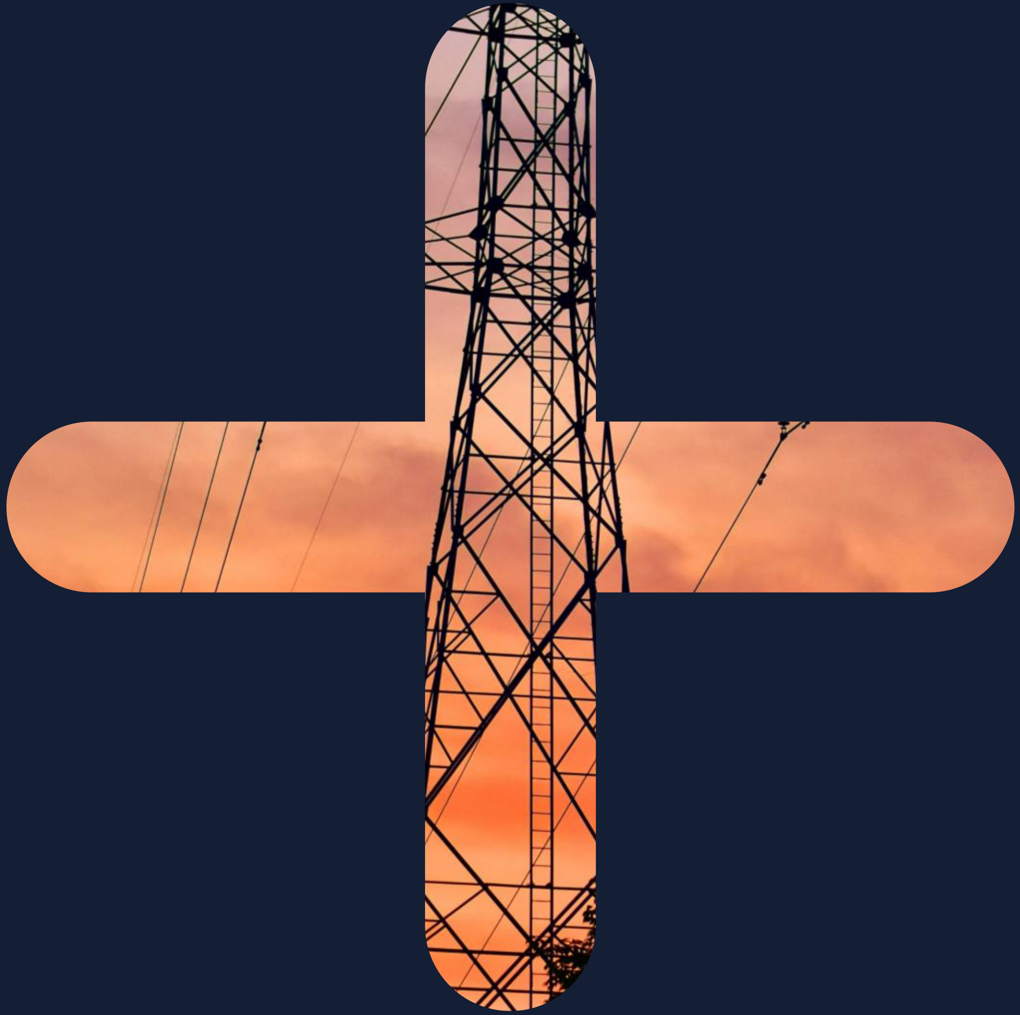


Appendix 1

Modelling Approach and additional results

LCP Delta's Pan-European Model

Detailed multizone power market model simulates GB and markets across Europe with detailed modelling of network constraints

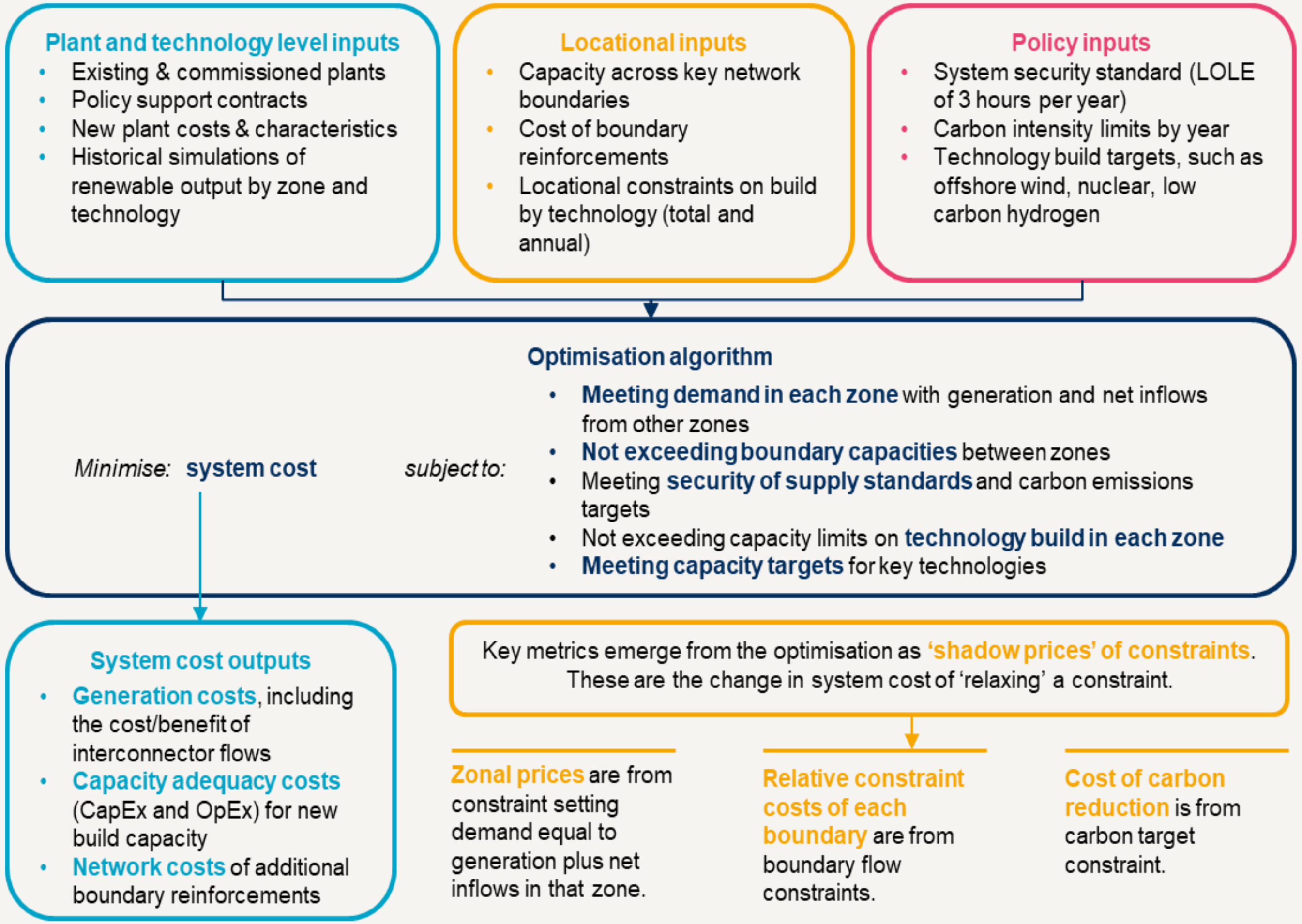
LCP Delta's Locational Dispatch Model (LDM) is a stochastic optimisation-based model designed to simulate the GB power sector and European sector.

It has been developed specifically to model network constraints within GB and connections to Europe*. The model works by simulating generation and demand every hour on a long-term basis. The model has been used in various studies to look at the impacts of network constraints and other changes to the system, including analysing the impacts of moving to zonal pricing in our report for DESNZ.

The model simulates the supply and demand in each hour across the country, based on market fundamentals. This determines the operation of each plant on the system, and the wholesale market price(s).

The model then simulates the supply and demand in each hour in each zone to determine the redispatch that needs to happen in order to meet locational constraints,

LCP Delta's Locational Dispatch Model Diagram



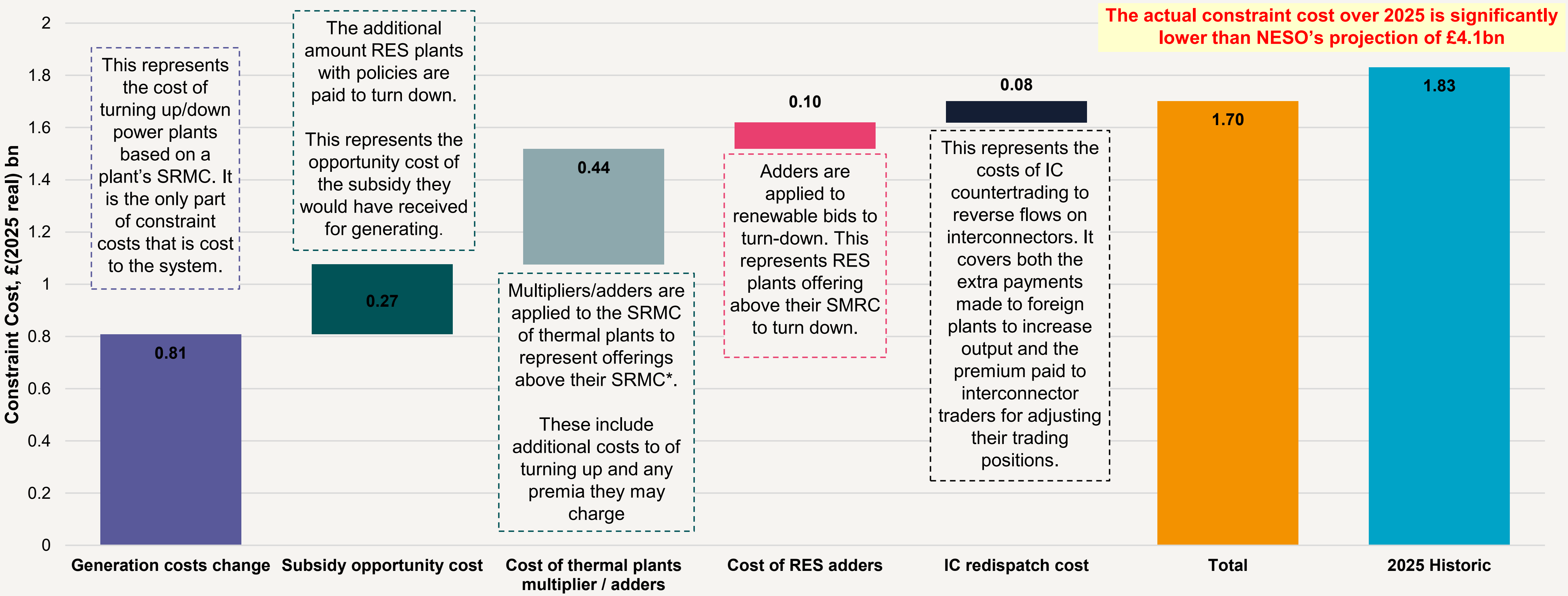
*Second order countries (i.e.: countries connected to GB interconnected countries) are not modelled in detail, but the interconnector flows within Europe are captured within the modelling

Modelling 2025 Constraint Costs

The modelled constraint costs are slightly lower than the actual constraint costs over 2025

To calculate the constraint costs, we followed the same approach as NESO. Historical analysis shows that plants charge a premium above their SRMC to turn up or down in the BM. Following NESO's methodology, we have captured this in our calculation of the constraint cost via using bid/offer multipliers and adders. NESO has not published the multipliers and adders used to calculate their modelled constraint costs since 2017, so these have been calculated from 2025 data.

Breakdown of constraint costs under NESO methodology



*This method is consistent with NESO as described in [Interconnector Cap and Floor – Note 2 template for Interconnector chapter]

Approach to Modelling Economic Curtailment

As more wind and other renewables are added to the system, the number of periods where there is more renewable (plus nuclear) generation than demand on the system will increase. During these periods, some renewables will not be able to generate or be ‘out of merit’. As a result, some of the potential generation from these plants will be unused. This is known as economic curtailment.

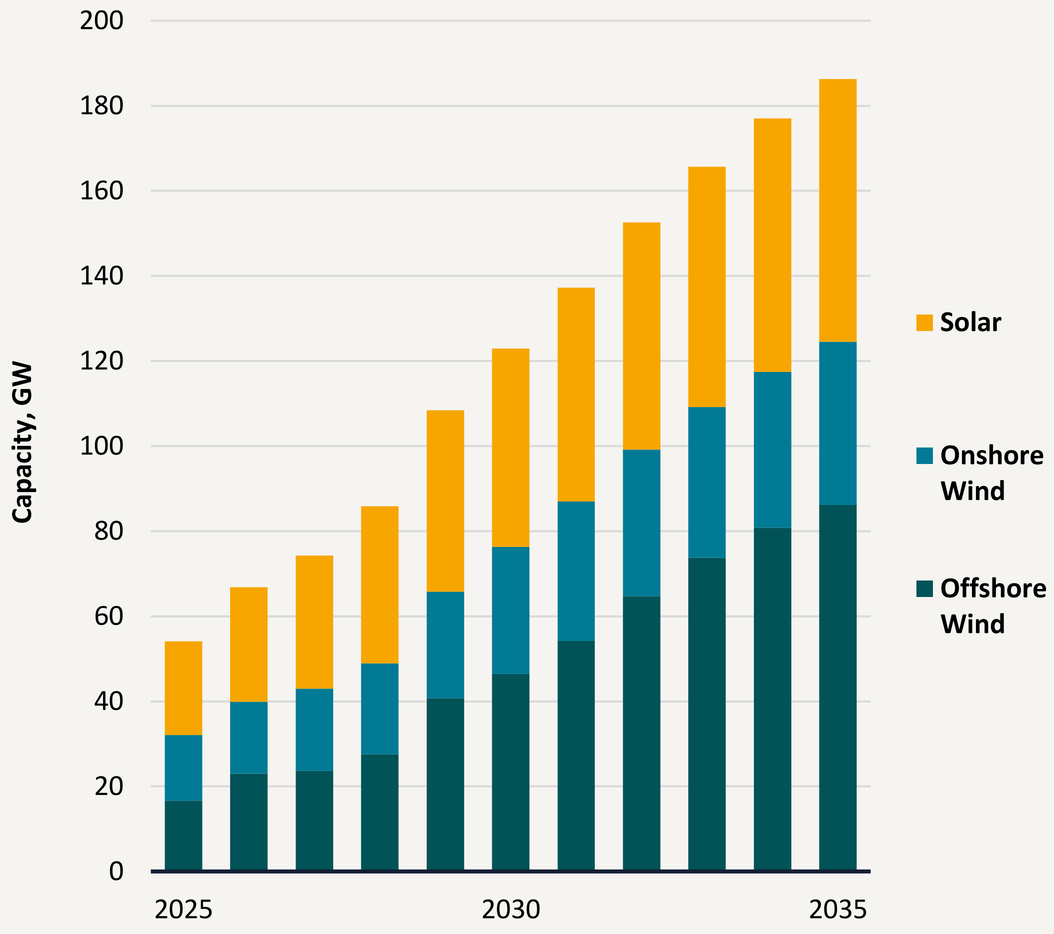
Currently, there is very little economic curtailment of renewable generation. As renewable capacity increases curtailment is expected to become more prevalent, particularly under the FES HT scenario due to its fast deployment of renewable capacity.

Which plants are chosen to generate in the day-ahead and intraday markets, and which are plants curtailed will have a material impact on constraints. For example, if a plant is behind a constrained boundary generates then they will have to be turned down and add to the constraint costs.

In our modelling, we have taken the following approach:

- We have assumed a range of CfD strike prices future wind plants can have based on historic auctions. No regional differentiation in strike prices (e.g. Scotland) is assumed
- Plants with AR4+ contracts all bid in at £0 and are dispatched in wholesale markets based on strike-price merit order. Plants with a higher strike price are curtailed later.

FES HT Renewable Capacity



Modelling Interconnector redispatch

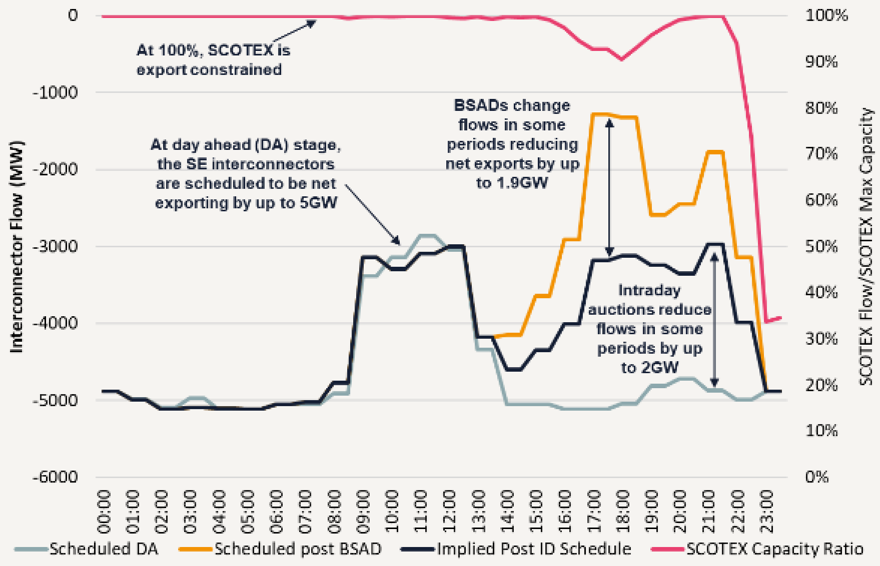
Detailed example of redispatch inefficiency

Under current market arrangements, interconnector redispatch to resolve constraints on the network is limited. While arrangements to redispatch interconnectors do exist, these are done outside of the BM meaning NESO is restricted in its ability to redispatch interconnectors within BM timescales. This means that interconnectors can exacerbate constraints, with limited opportunities to adjust the flow from their day ahead (DA) wholesale market schedules.

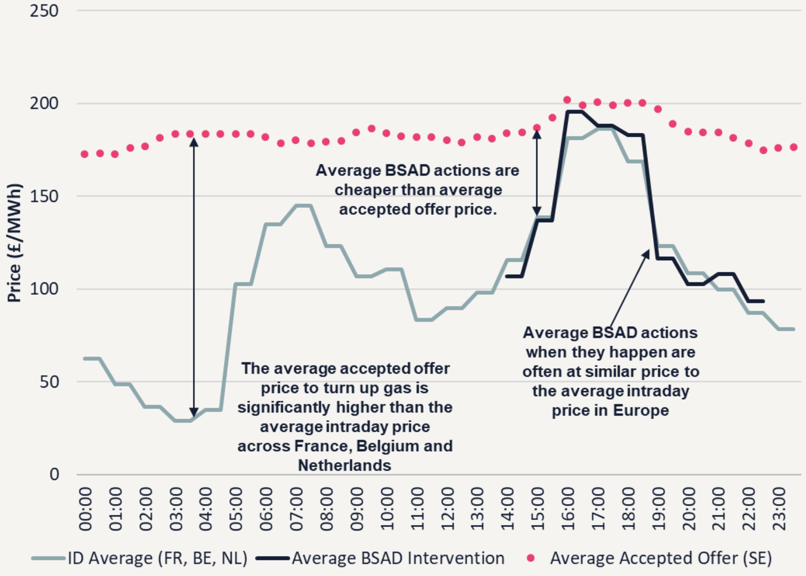
This is a common occurrence in the market as shown in the charts below for the 10th November 2022. In this example, the B6 (SCOTEX) boundary is constrained meaning Scottish wind generation cannot be transported to demand centres England. This means other generation needs to be turned up to meet English demand. At the same time, interconnectors in the South-East are net exporting to France, Belgium and Netherlands. At the DA stage, their scheduled net export is around 5GW overnight, dropping to 3GW in the morning.

Redispatch of interconnector flows is recorded through the Balancing Services Adjustment Data (BSAD). Redispatch does change interconnector flows slightly during the later afternoon and evening. However, interconnectors are still net exporting across the whole day despite the B6 being constrained meaning more generation in the south of England (mostly unabated gas) needs to be turned up to ensure supply meets demand. This is despite the average intraday price (which redispatch actions normally follow) in the connected European markets being significantly lower than accepted offers for unabated gas. Overall, this leads to an inefficiency in the market as relatively expensive gas is being turned up, when decreasing interconnector exports would be a cheaper option if their flows could be redispatched based on prevailing market prices.

Net IC Flow (FR, BE, NL) and SCOTEX Flow as a Proportion of its Max Capacity on 10/11/2022



Intraday, BSAD Intervention, and Accepted Bid and Offer Prices on 10/11/2022



Modelling Interconnector redispatch improvements

To model how interconnectors are currently redispatched in the market, we will use 3 levers within the model:

1. **Flow limit % -** this restricts how much interconnectors can change their flow from their day-ahead position. The maximum this value can be is 200% which represents an interconnector moving from full export to full import. So, for a 1GW interconnector, a 25% flow limit means they can change their flow by up to 500MW. Whether the flow changes and by how much is still dictated by prices in GB and connected markets – the flow limit is just the maximum possible change from the interconnectors wholesale position.
2. **Minimum spread** – this represents the minimum level of profit that interconnectors have to make in order to redispatch their flows. This aligns with what was observed in historical data where a risk premium is added onto countertrading bids. So, if the minimum spread is £21/MWh and the interconnector needs to increase imports/reduce exports then the trader needs to see a minimum £21/MWh differential between GB and connected markets to undertake the trade.

Together these assumptions aim to replicate how interconnectors redispatch in the current market. Specifically:

- Only a small amount of their flows can be redispatched using countertrading in line with observed data. This represents the limitations and uncertainties that are placed on NESO when countertrading on interconnectors.
- The minimum spread replicates the risk premium that tends to be applied to bids when countertrading.

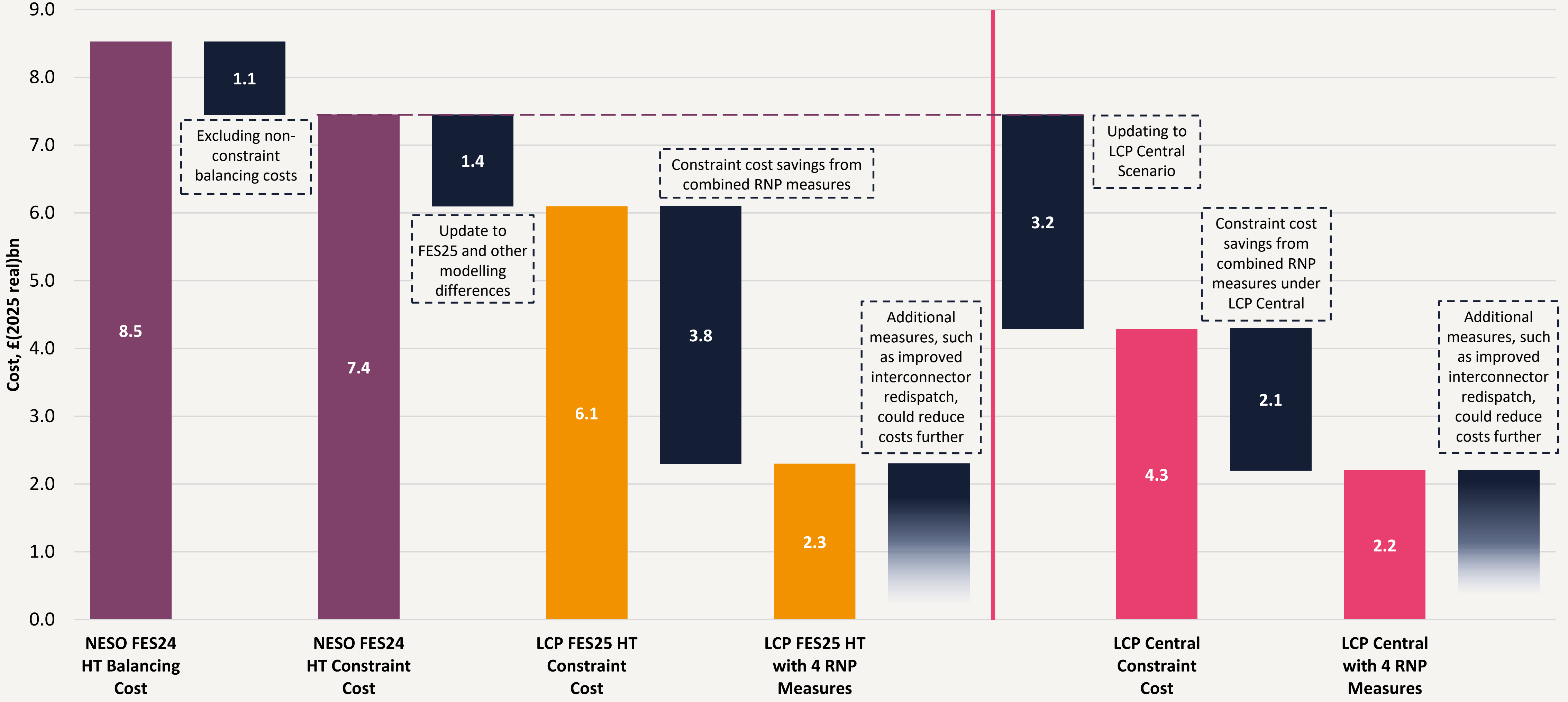
To simulate improved interconnector redispatch, we modify the flow limit assumption across all interconnectors to assume that interconnectors can fully redispatch their flows. It is assumed the minimum spread remains as there is still some risk associated with trading interconnectors as there is little evidence on how this would change and this is also reflective of how other assets bid into the BM.

Summary of inputs for modelling interconnector redispatch inefficiency in counterfactual

Region	Counterfactual		Improvement	
	Flow limit %	Minimum Spread (£/MWh)	Flow limit %	Minimum Spread (£/MWh)
Belgium	33%	21	200%	21
Denmark	22%	21	200%	21
France	45%	21	200%	21
Germany	22%	21	200%	21
Ireland	0%	0	200%	21
Netherlands	30%	21	200%	21
Norway	0%	0	200%	21

Constraint costs in 2030

Summary of 2030 constrained costs from our modelled scenarios



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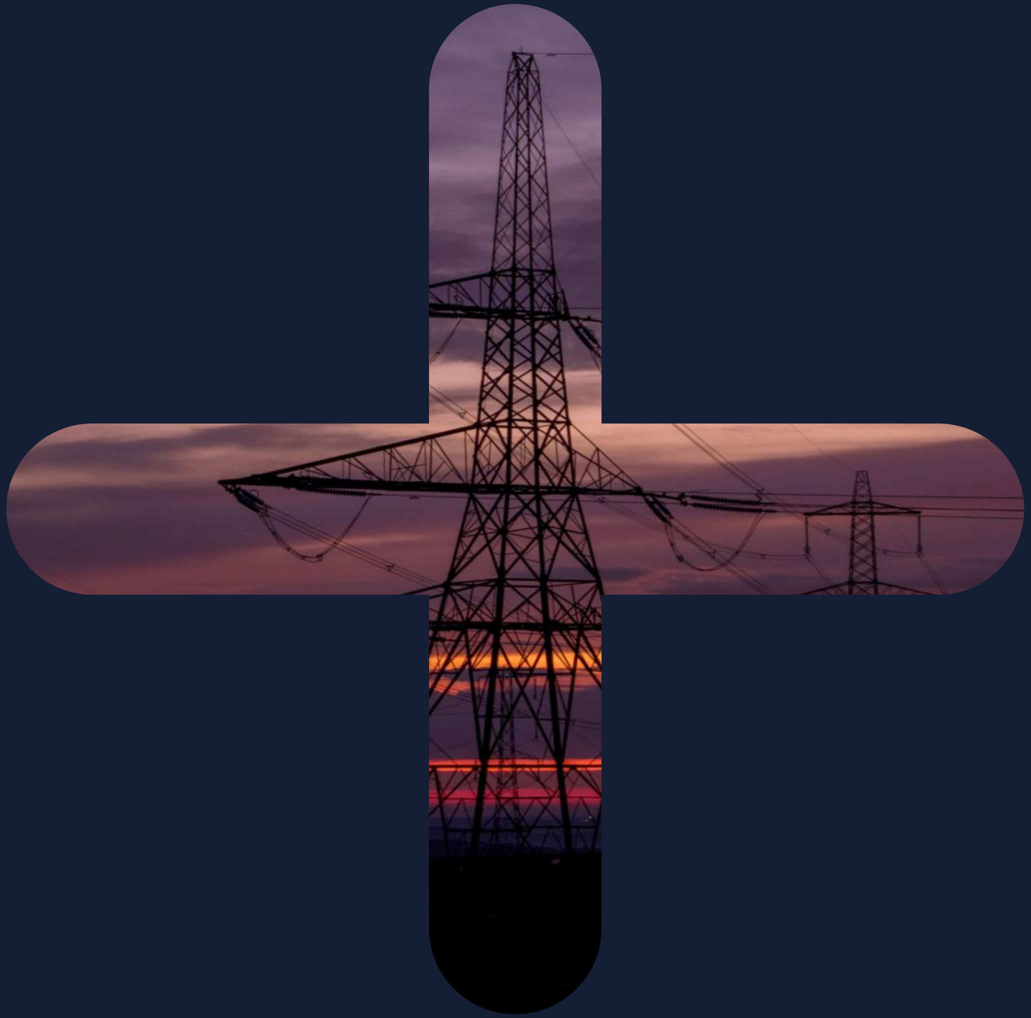


Appendix 2

Scenario Assumptions

Assumptions summary – Holistic Transition

Most of the assumptions for the FES HT are taken from NESO FES publications but FES does not publish all assumptions in the detailed required, so some is taken from other sources.

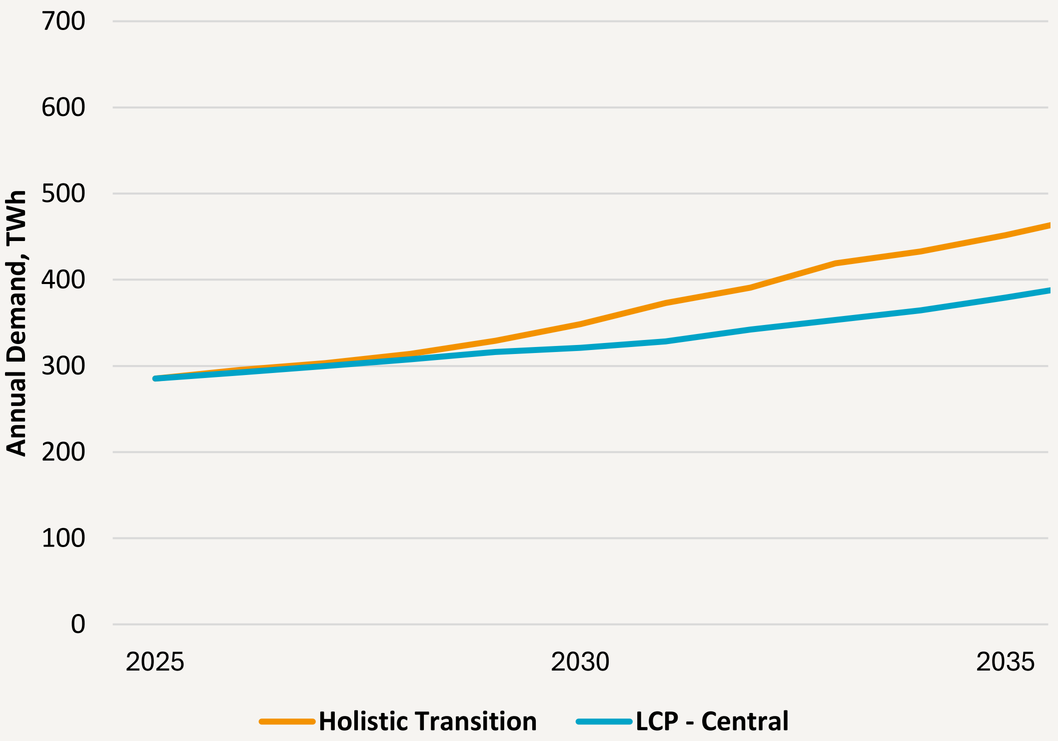
Assumption name	Description	Source	Comments
Demand	Annual demand and peak demand in GB	FES 2025 Databook – total generation	Total generation in FES (inc. net imports and storage charging) does not equal total reported demand. To align better with FES generation, total generation has been used as the demand input
Capacity Mix	Capacity build out across all technologies in GB – renewables, nuclear, gas, gas ccs, hydrogen, storage etc.	FES 2025 Databook	Capacities taken directly from FES. Minor adjustments made to total firm capacity to add some peaking plants to ensure security of supply standard is met in all years
Interconnectors	Interconnector online dates, countries to connected and size	FES 2025 databook & NESO interconnector register	FES only publishes total interconnector capacity not the projects or countries connected to. NESO interconnection register is used to estimate which projects come online when to align to total FES capacity.
Storage	Storage capacity, projects and duration including LDES projects	FES 2025 Databook	FES publishes total GW and GWh of storage broken down by technology but does not publish how many a full breakdown of storage capacity breakdown. LCP have made assumptions on split of projects to align to overall storage GW and GWh.
Europe Capacity Mix	Capacity build out across all technologies in connected countries – renewables, nuclear, gas, gas ccs, hydrogen, storage etc.	FES 2025 Databook	FES 2025 published data with some minor adjustments to ensure security of supply in connected countries
Europe Demand	Annual demand and peak demand in Europe	FES 2025 Databook	FES 2025 for total demand. Peak demand not in FES so scaled from 2024 levels based on change in total demand.
Commodity Prices	Gas, coal, carbon and hydrogen prices in GB and Europe	FES 2025 Databook	Prices as published
Carbon appraisal price	Carbon appraisal price to value unpriced carbon externality	DESNZ Valuation of greenhouse gas emissions	DESNZ central appraisal price
GB Zones	Zones and boundaries being modelled for constraint analysis in GB	LCP/NESO	12 zones in line with previous LCP zonal analysis capturing the key transmission contraints
Network build-out	GB network build required	NESO Electricity Ten Year statement	Beyond 2030 network as published by NESO
Capacity and demand locations	Location splits of each technology and demand by GB zone	FES/LCP	FES 2025 published detailed locations of distribution connected assets. Transmission connected assets are only published at a high-level so assumptions taken from other sources and LCP internal knowledge on some locations
Renewable load factors	Potential load factors for renewables over time	FES/LCP	FES publish generation and curtailment (pre constraints) so potential load factors over time are aligned with this. Load factors of individual projects are aligned with actuals where possible.
Technology costs and characteristics	Capital and operation costs of each technology and key characteristics of those technologies	DESNZ generation cost report	Published costs from DESNZ generation costs report (with renewables additions published in CfD auctions for AR6 and AR7)

Demand

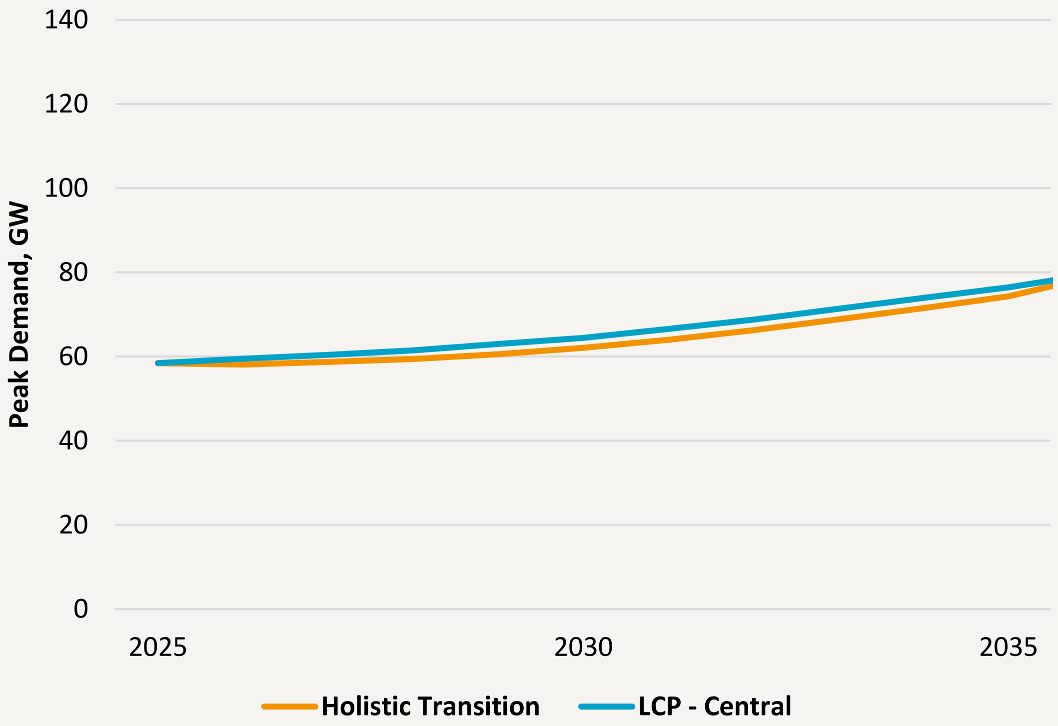
Total and peak demand

- The LCP Central scenario assumes a comparatively low level of total annual demand growth through to 2035 versus the Holistic Transition scenario, with a more conservative assumption for the pace of electrification in the near-term.
- Peak demand growth is very similar in Holistic Transition compared to LCP Central with both scenarios showing peak demand of around 75GW in 2035.

Total annual electricity demand projections



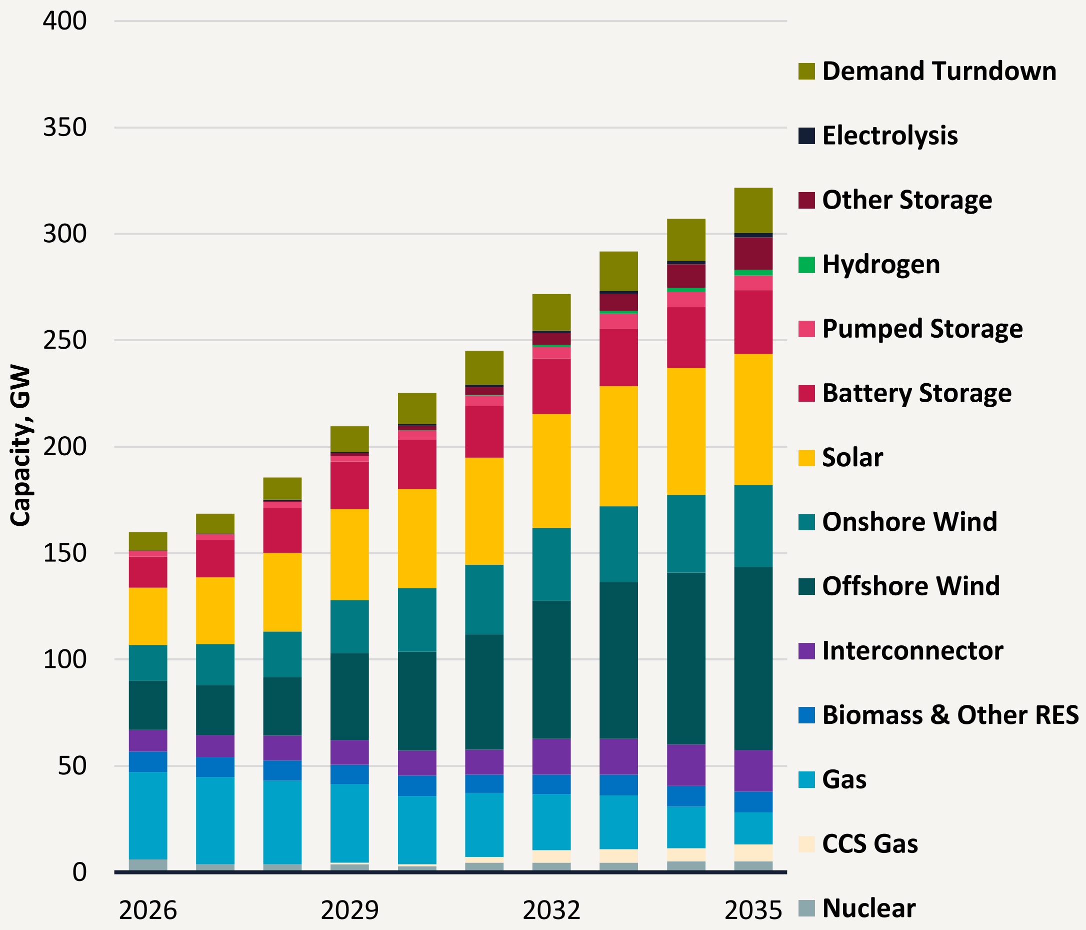
Peak electricity demand projections



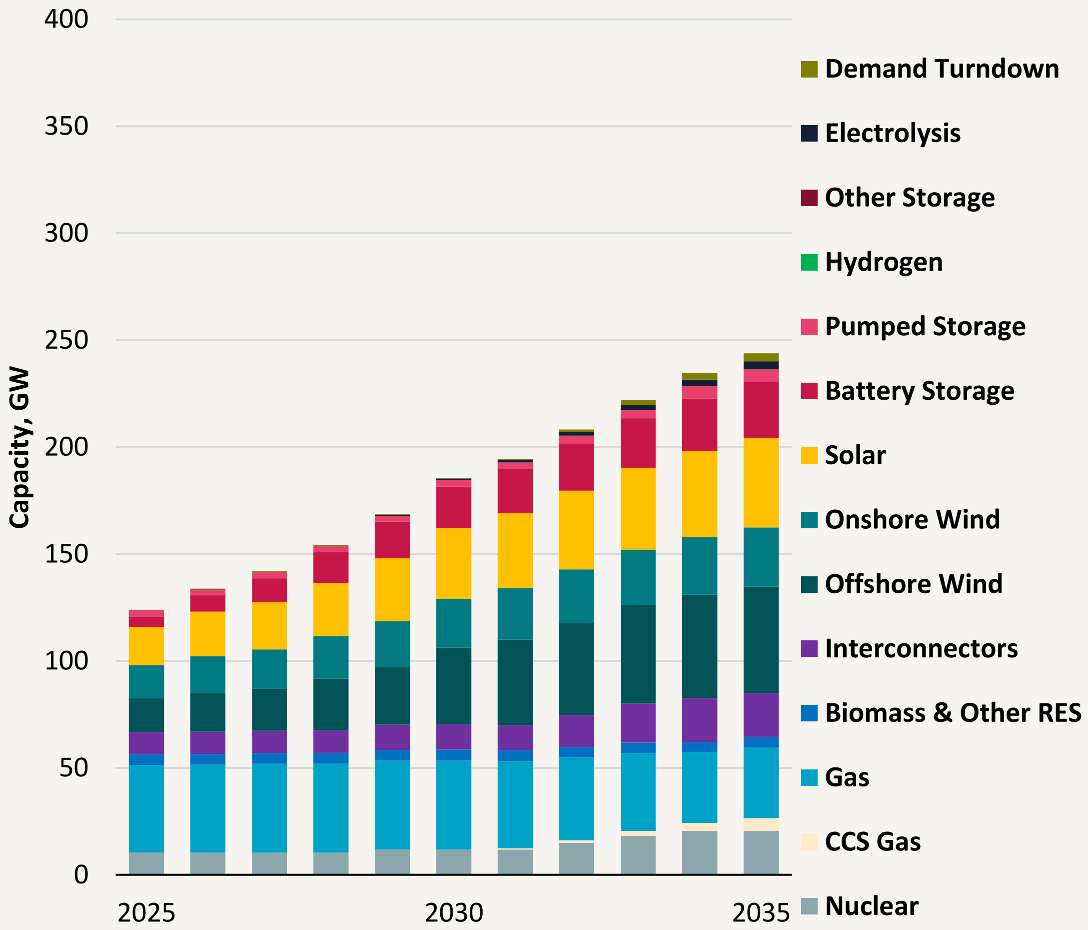
Scenario Overview

Capacity Mix

Capacity Mix – Holistic Transition



Capacity Mix – Central

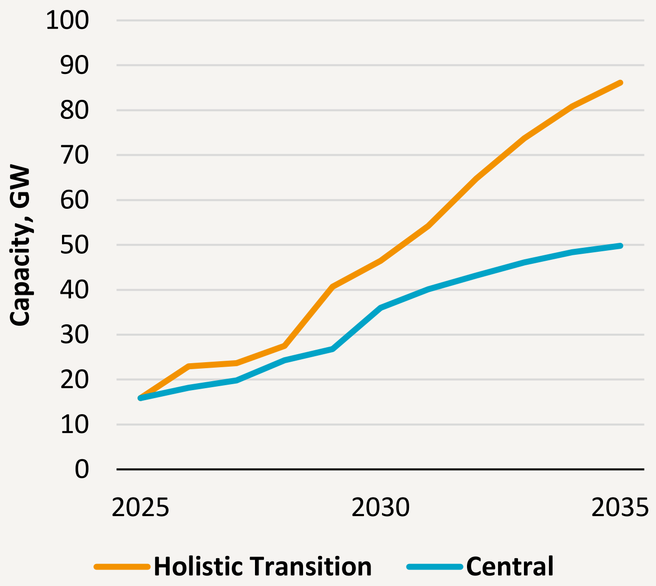


Assumptions

Renewable Capacity – NESO Holistic Transition vs Central / AR7

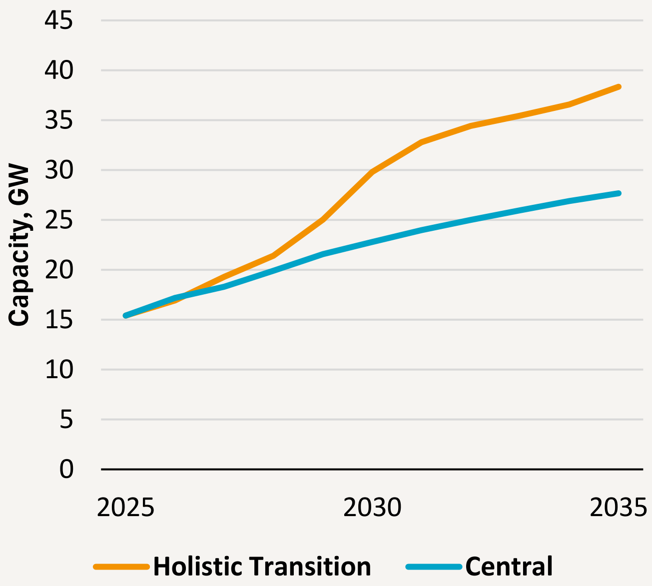
Offshore Wind

- In the **Holistic Transition** scenario Offshore wind capacity grows rapidly from 16GW in 2025 to 86GW in 2035.
- In **Central**, we assume a more gradual buildout, growing from 16GW in 2025 to 50GW in 2035.



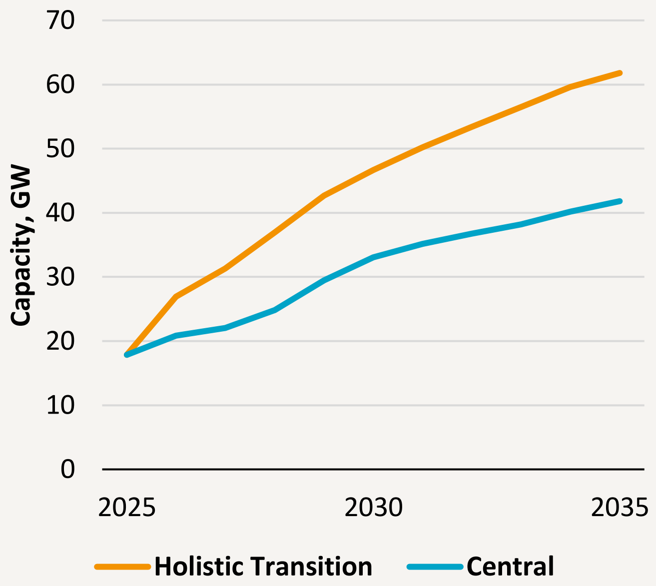
Onshore wind

- In the **Holistic Transition** scenario Onshore wind capacity grows from 15GW in 2025 to 38GW in 2035.
- In **Central**, we assume a slower rollout, with Onshore wind capacity growing from 15GW in 2025 to 28GW in 2035.



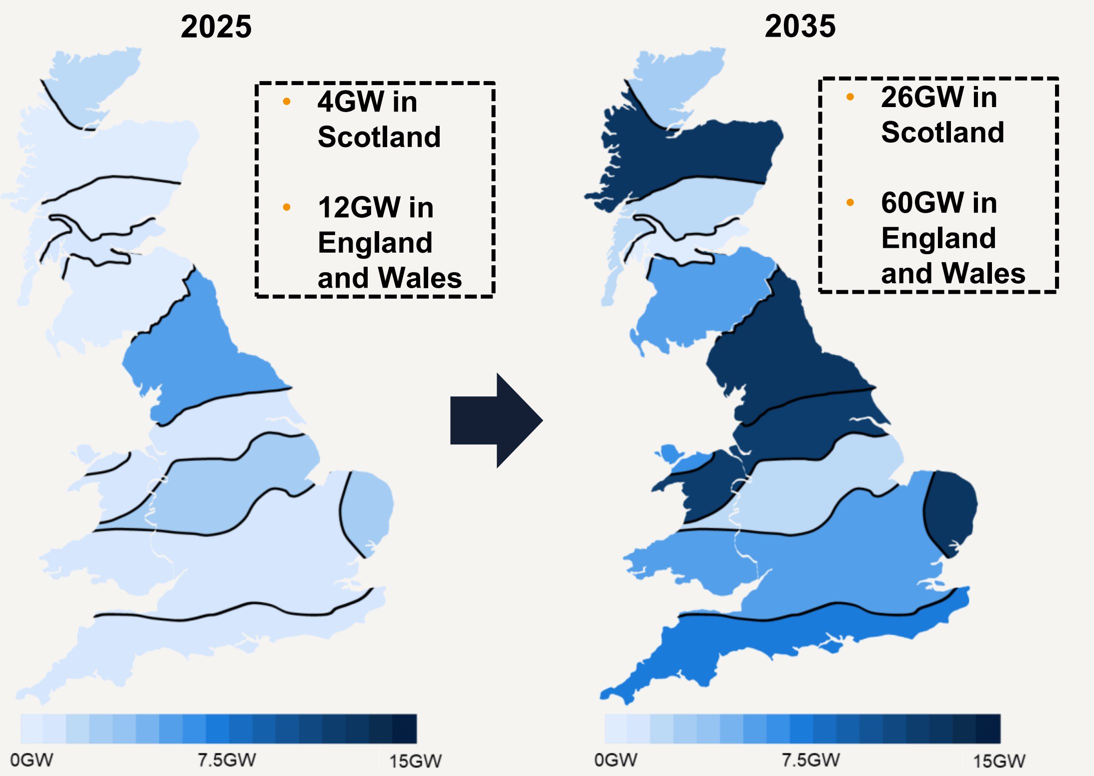
Solar

- In the **Holistic Transition** scenario Onshore wind capacity grows from 18GW in 2025 to 62GW in 2035.
- In **Central**, we again assume a slower rollout of Solar capacity compared to HT, growing from 18GW in 2025 to 42GW in 2035.

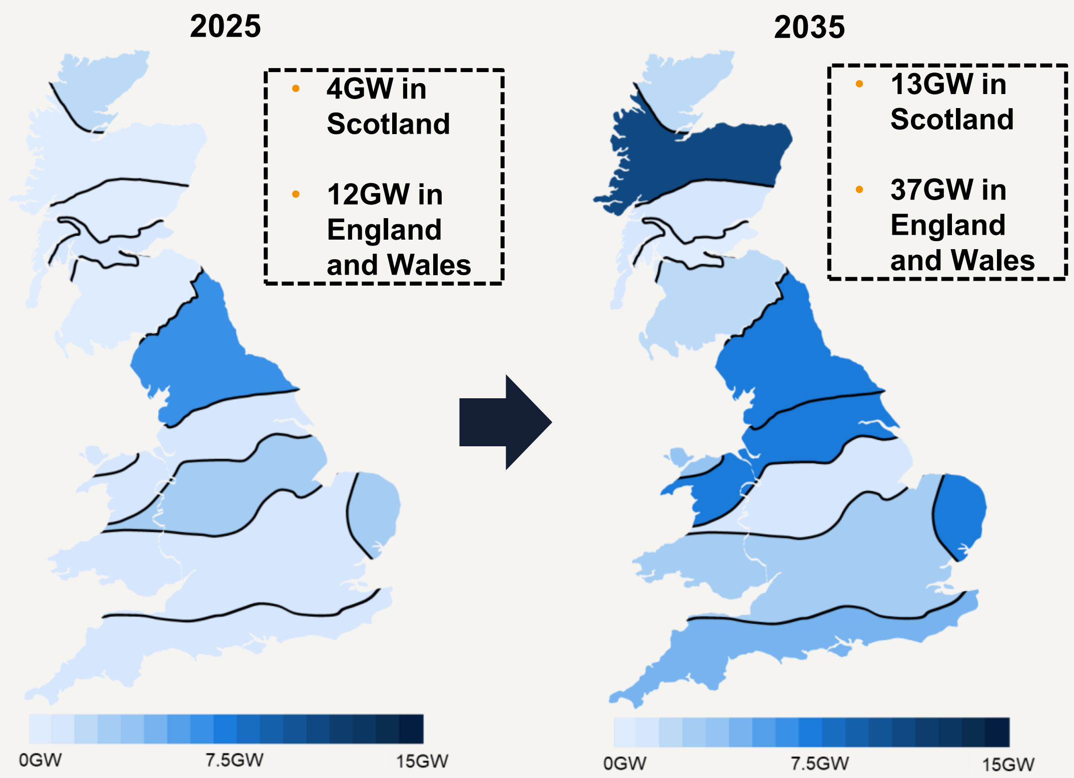


Offshore wind location

NESO Holistic Transition



LCP Central

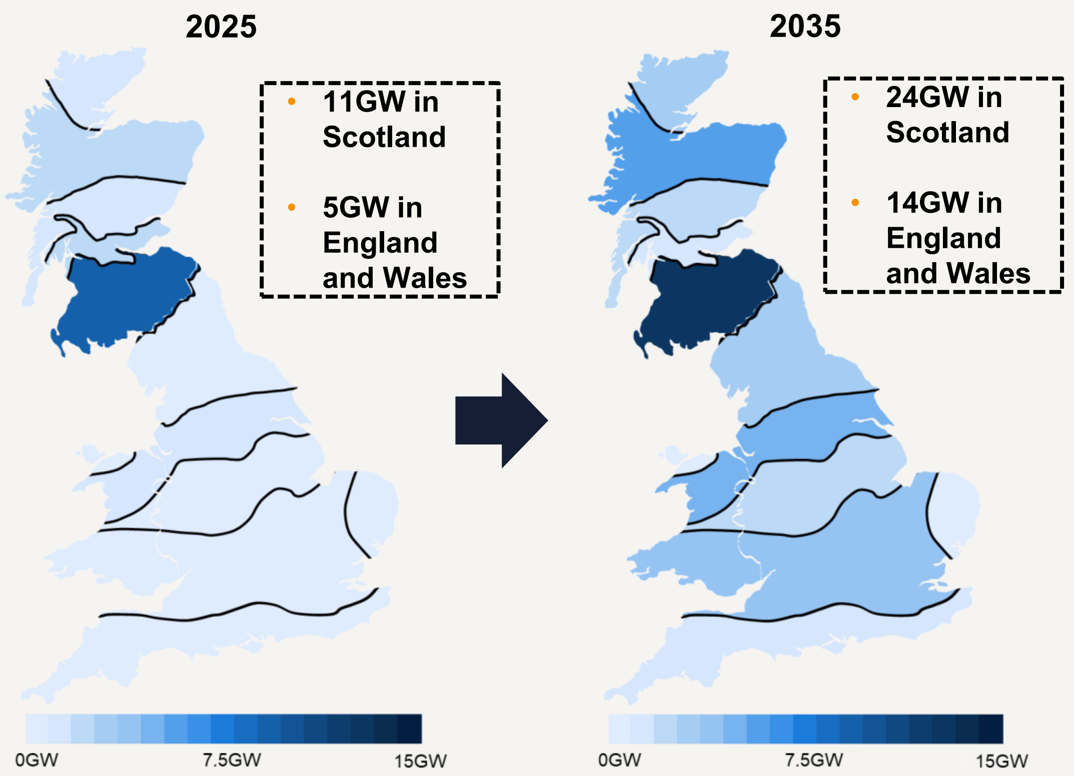


Throughout the modelling period, we see rapid growth in offshore wind capacity within the both scenarios;

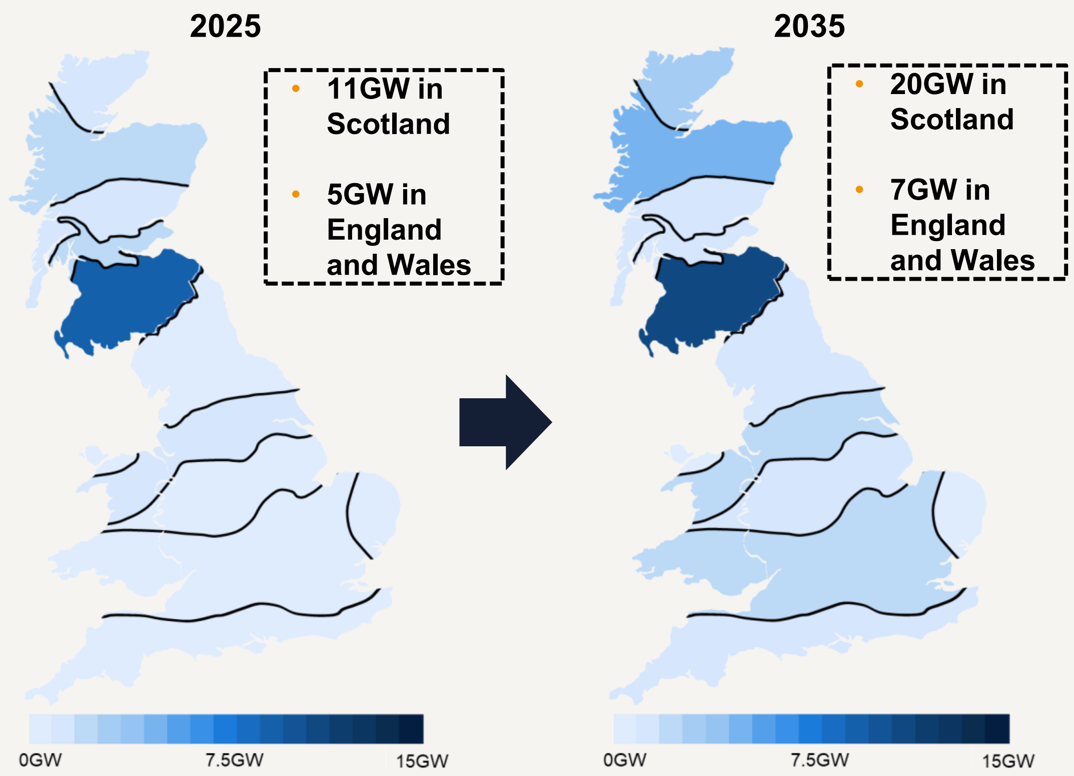
- In the HT scenario we see offshore wind capacity grow from 16GW in 2025 to 86GW in 2035. The areas that see the largest growth in capacity are Scottish and Northern English zones, as well as East Anglia.
- In the LCP Central scenario, we see offshore wind capacity grow from 16GW in 2025 to 50GW in 2035. The areas that see the largest growth in capacity are again the Scottish and Northern English zones, as well as East Anglia.

Onshore wind location

NESO Holistic Transition



LCP Central

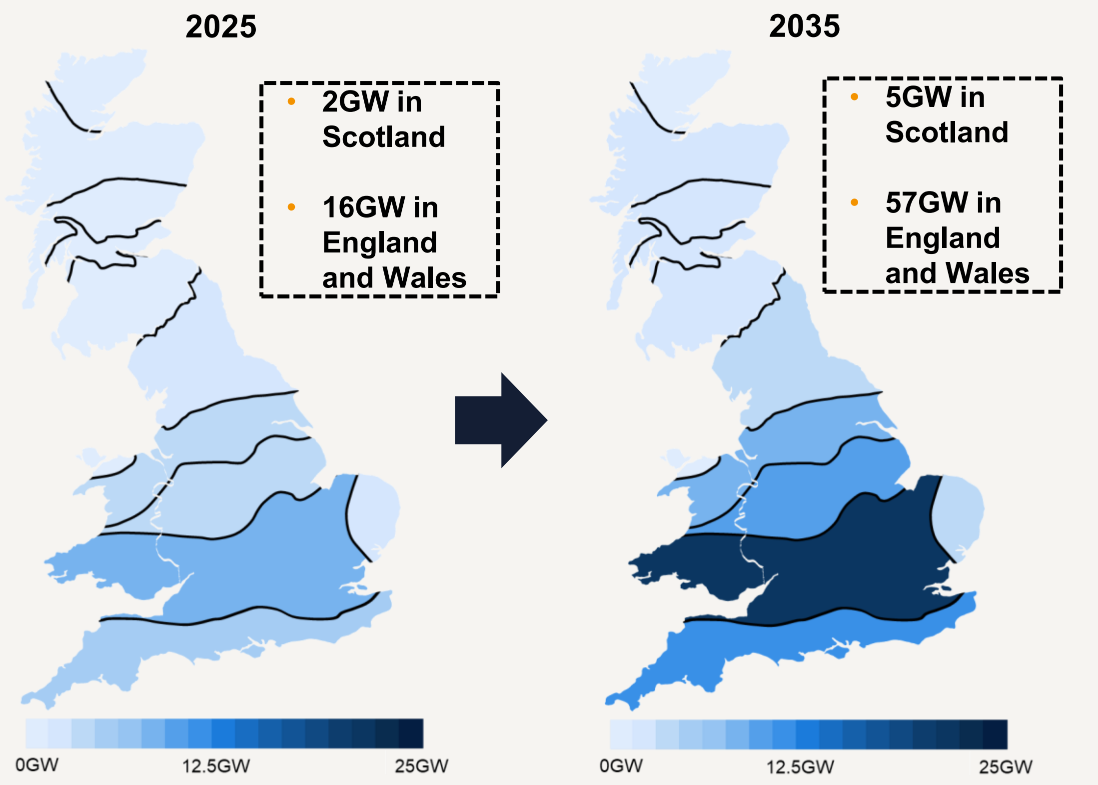


Throughout the modelling period, we see rapid growth in Onshore wind capacity within the both scenarios;

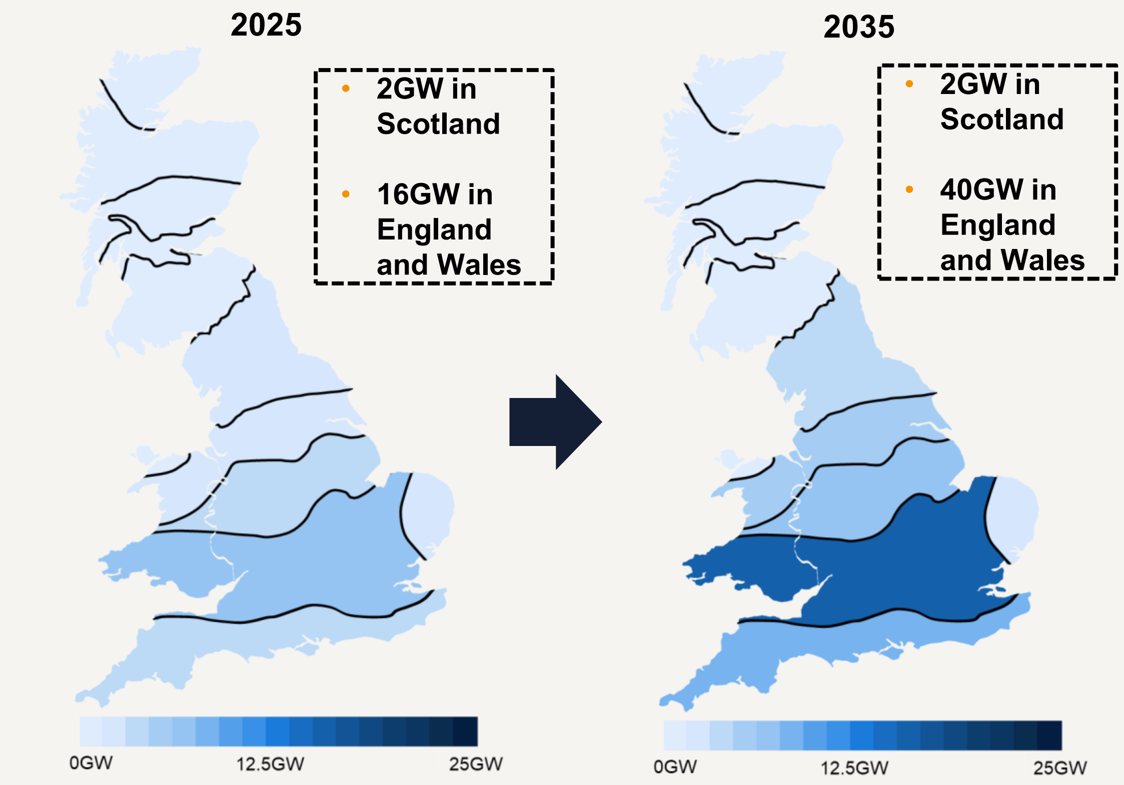
- In the HT scenario we see 15GW in 2025, growing to 38GW in 2035. Onshore wind capacity locations evolve from being mainly in Scotland in 2025 to being more evenly spread across the country by 2035.
- In the LCP Central scenario, Onshore wind capacity grows from 15GW in 2025 to 28GW in 2035, we see Onshore wind build-out mainly in Scotland throughout the modelling period, with less of a spread than in Holistic Transition.

Solar PV location

NESO Holistic Transition



LCP Central



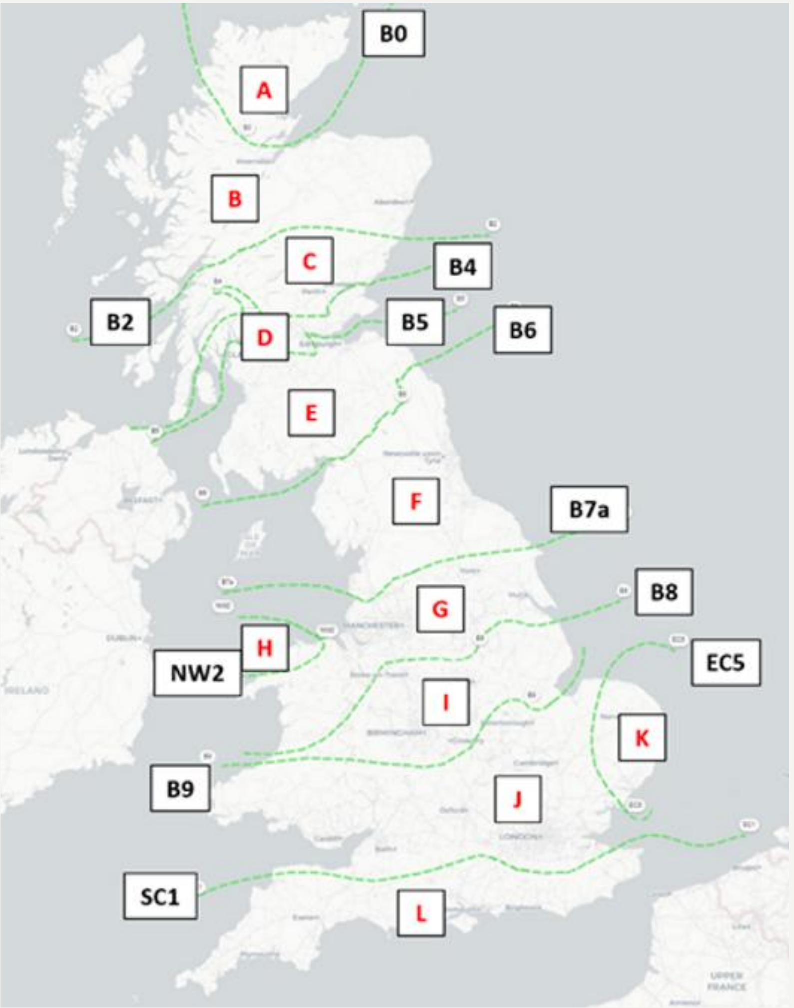
Throughout the modelling period, we see rapid growth in Solar PV capacity within the both scenarios:

- In the HT scenario, we see Solar capacity increasing from 18GW in 2025 to 62GW in 2035. The location of this capacity is mainly in England and Wales, with very little build-out in Scotland.
- In the LCP Central scenario, we see a lower Solar capacity build-out, from 18GW in 2025 to 42GW in 2035. The location of this capacity is again mainly in England and Wales, with very little build-out in Scotland

Network assumptions

Assumptions on boundary capacity (in MW) across the key boundaries under NESO HT

Boundary Capacity (MW)	2025	2030	2035
B0	1,800	4,700	4,600
B2	3,500	6,000	12,000
B4	4,000	7,300	12,000
B5	4,300	8,300	11,700
B6	7,000	10,200	16,800
B7a	10,600	13,500	19,700
B8	12,500	16,400	23,400
B9	12,900	15,300	19,300
EC5	4,300	5,900	14,200
NW2	1,400	7,000	7,000
SC1	8,700	11,200	11,200



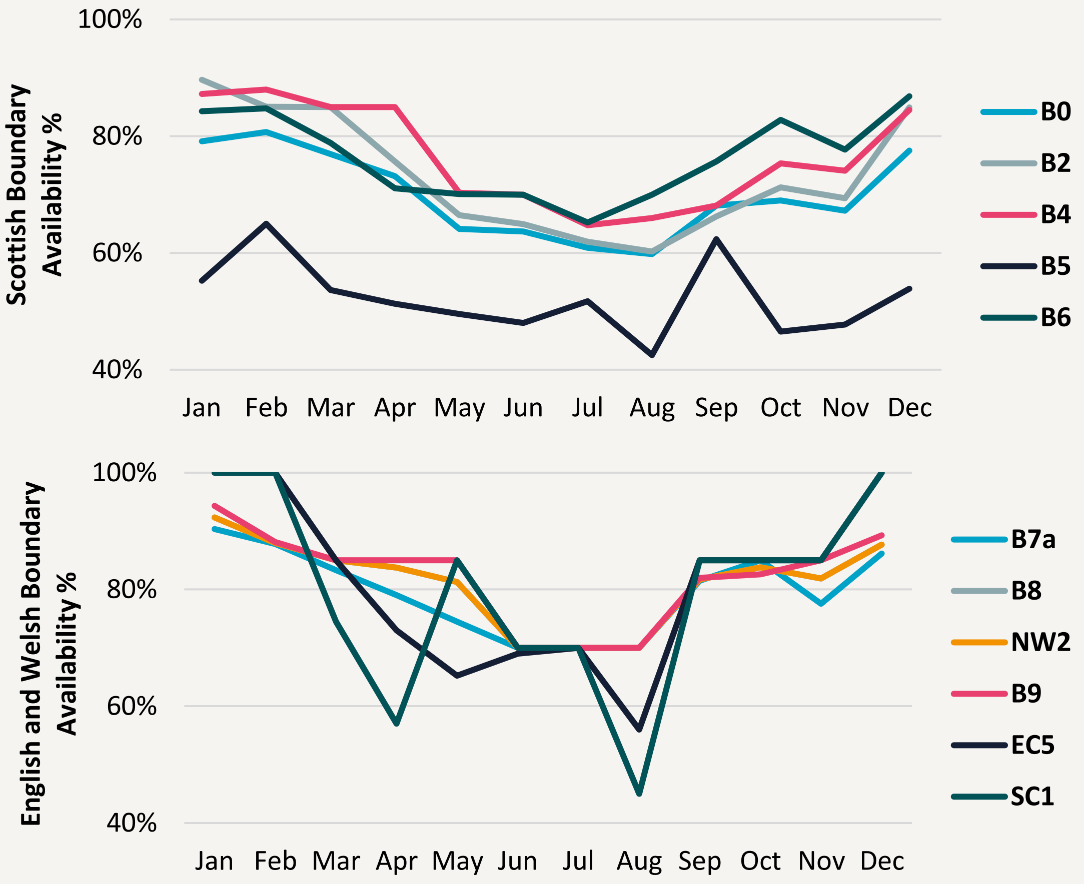
All HVDC cables are accounted for within the boundary capacities

Boundary availability assumption

The boundary availability used has been derived from NESO published data and historical availability

- NESO has published their seasonal boundary capacity scaling in the Annex 2 of the tCSNP Refresh methodology where specific capacities are not provided by transmission operators.
- However, it is not clear how NESO has applied these in their modelling, as it implies that boundaries are at 100% availability during winter, contrary to what we see in the historical data.
- We have derived our boundary availability assumption as the minimum of the NESO published data and historic availability.
- The historic boundary availability is calculated from data published by NESO in the:
  - Day Ahead Constraint Flows and Limits (2019 – 2025 data)
  - NESO Operational Transparency Forum (2025 data)
- NESO does not publish data for the B0, B8 and NW2 boundaries within the two publications. Where information is not available, we have used the average availability for Scotland and for England and Wales.
- We have not included reduced availability from major upgrades as it is assumed this is already included in published NESO capacities. Due to this, we have excluded 2025 data to calculate the availability where possible.

Boundary availability for each of the 11 boundaries modelled



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