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Zonal Pricing in Great Britain

Assessing the impacts of the 'Beyond 2030' network plans

Report for sse

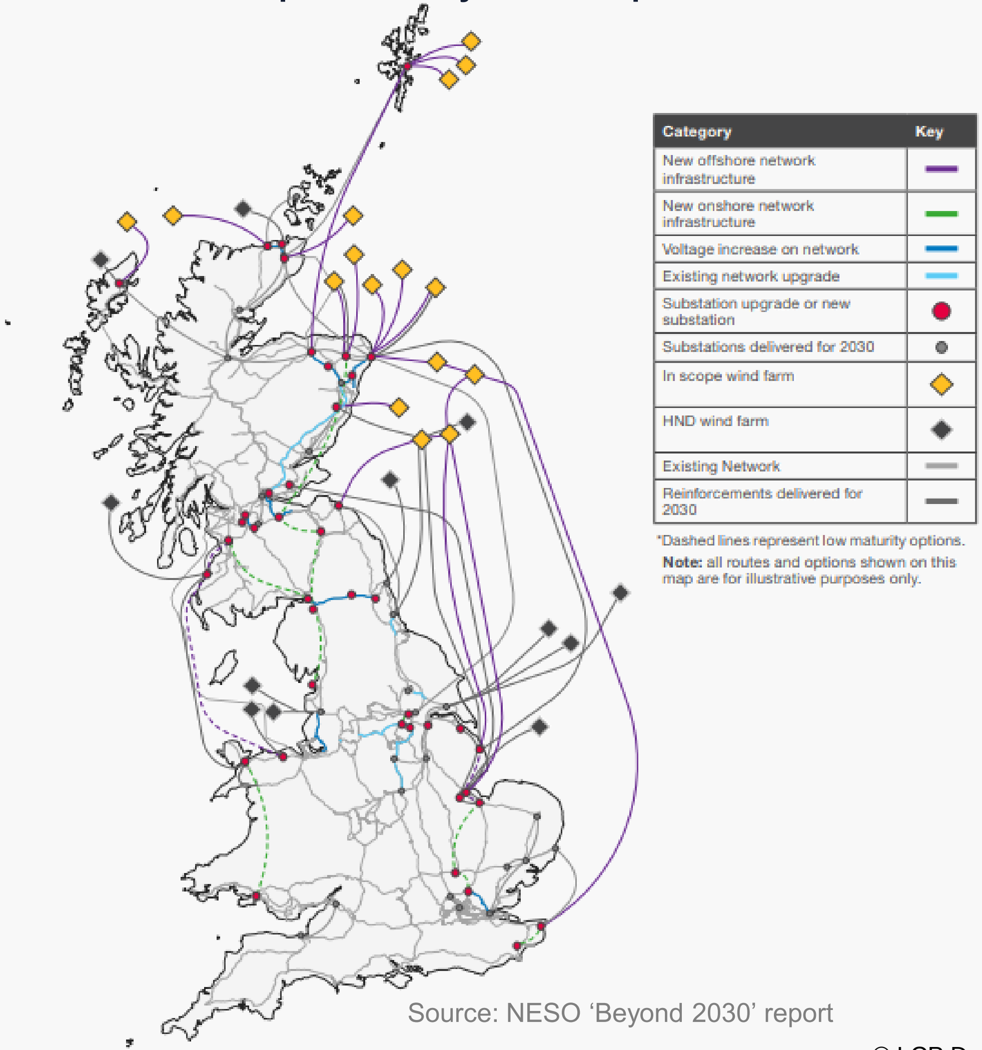
OCTOBER 2024

Introduction

SSE have commissioned LCP Delta to analyse the impacts of moving to zonal pricing under NESO's latest 'Beyond 2030' network plans from Spring 2024 by updating the previous analysis completed for DESNZ in 2023

- LCP Delta's previous analysis for the Department for Energy Security and Net Zero (DESNZ) on the impacts of zonal pricing, completed in Autumn 2023, was based on the National Energy System Operator's (NESO), now outdated, **'NOA7 refresh'** network plans from Summer 2022.
- Since the completion of that analysis, in Spring 2024 the NESO released updated network build-out plans in their **'Beyond 2030'** report. These plans recommend an additional £58bn of investment in electricity networks, increasing network capacity in many areas beyond those outlined in the 'NOA7 refresh' plans, as well as facilitating the connection of more offshore wind in Scotland.
- Recent announcements have shown that DESNZ, Ofgem and the NESO are moving towards **strategic planning of GB's energy infrastructure** where the location of future assets and the associated network to connect them are planned years in advance of delivery. This is emphasised by announcements on the longer-term role of the **Strategic Spatial Energy Plan (SSEP) and Centralised Strategic Network Plan (CSNP)**, and the upcoming **Clean Power Plan for 2030** to deliver on the UK's Clean Power Mission.
- The previous DESNZ analysis also did not consider strategic energy infrastructure planning decisions in detail. Therefore, taking the updated network plans and considering a more strategically planned energy system, SSE have commissioned LCP Delta to provide analysis on how the impacts of moving to zonal pricing change with these updates factored in.
- The previous analysis for DESNZ is used as a starting point with assumptions aligning as closely as possible to ensure consistency.

Additional network plans in 'Beyond 2030' publication



Source: NESO 'Beyond 2030' report

Executive Summary

Key findings from the analysis and implications for the upcoming Clean Power Plan for 2030

The system benefits of zonal pricing are significantly reduced under the 'Beyond 2030' network plans, with no system benefits if redispatch reforms are delivered.

The 2030-2050 modelled benefits of zonal pricing decrease under NESO's 'Beyond 2030' network plans compared to the now outdated 'NOA7 Refresh' network plans. Benefits decrease from £5-15bn under 'NOA7 Refresh' to £0-11bn under the 'Beyond 2030' network combined with offshore wind locations being determined by seabed leasing.

With greater levels of network reinforcement, and the Government's commitment to strategic planning, asset locations are increasingly being pre-determined.

Introducing reforms to allow better redispatch of interconnectors under national pricing eliminates the modelled system benefits of zonal pricing and could be delivered in advance of 2030.

Even delivering partial redispatch of just 25% of interconnector capacity would reduce the modelled system benefits of zonal pricing by 80% (£8bn), from £11bn to £3bn.

With demand growth and the level of interconnection connecting into the region, the SC1 boundary in the South of England becomes one of the most constrained areas of the GB network. Additional reinforcements to increase the SC1 boundary capacity reduces the system benefits of zonal pricing by £2.3bn if interconnector redispatch cannot be delivered (and £0.5bn if it can).

The case for zonal pricing is very sensitive to the impact on investment, even if interconnector reforms cannot be delivered, a modest increase in the cost of capital eliminates the purported benefits.

The analysis shows that an increase in the cost of capital of only 0.6 percentage points (pp) wipes out purported benefits of zonal pricing of £11bn, down from 0.9pp under the previous analysis for DESNZ. This falls again to 0.4pp if the SC1 boundary capacity is upgraded.

Greater impacts on the cost of capital result in a move to zonal pricing becoming a net system cost. A 1pp increase in the cost of capital means a move to zonal pricing results in a net system cost of £8-19bn.

Recommendations for the Clean Power Plan

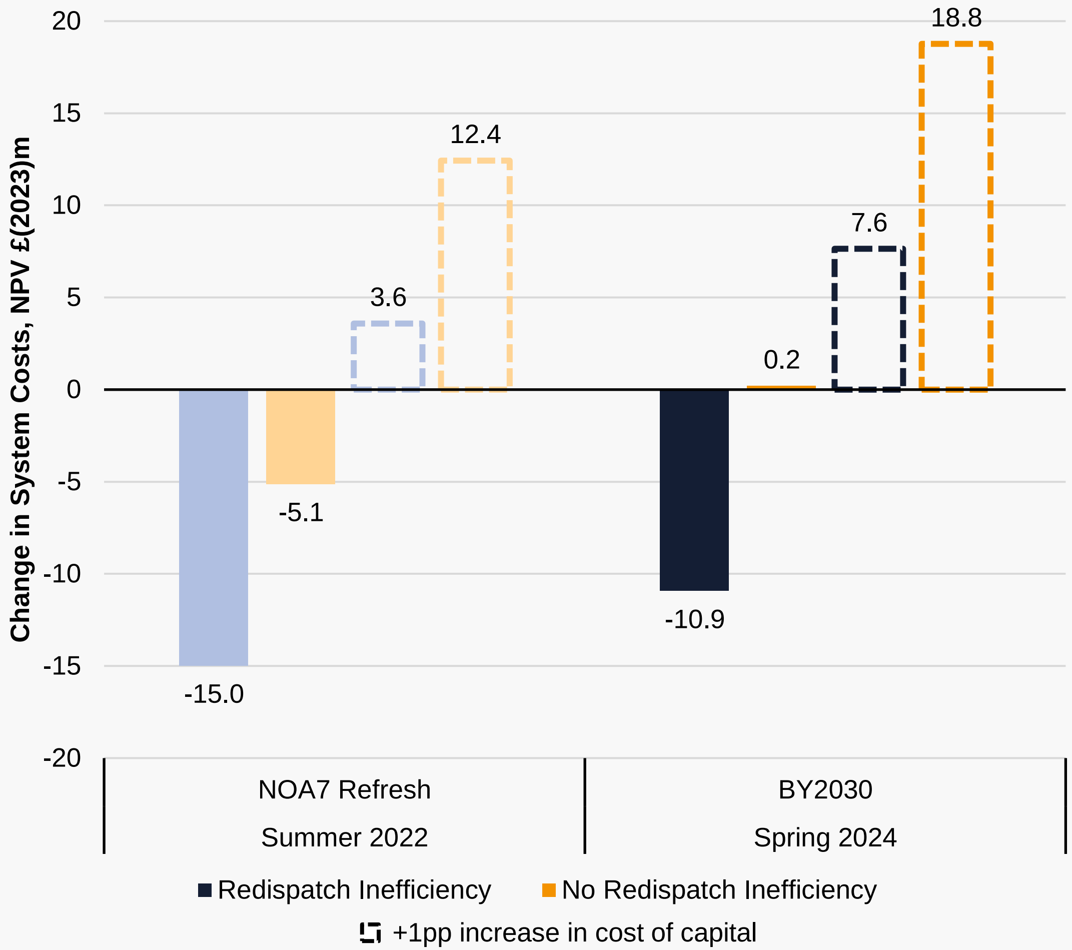
1. **Implement reforms to improve interconnector redispatch under national pricing.** The ability for interconnectors to deal with constraints is a fundamental driver of the case for zonal pricing. Making incremental reforms to allow better redispatch of interconnectors under national pricing could be delivered in advance of 2030, bringing consumer and system benefits and reducing reliance on unabated gas for balancing the system.
2. **Improvements to the network in the South of England.** Grid constraints between England and Scotland are reduced by the 'Beyond 2030' network plans, but structural constraints in other parts of the system continue (e.g. SC1 boundary). Reinforcement in these areas could have benefits in any scenario, with additional value if incremental interconnector reforms cannot be delivered.
3. **Any zonal decision needs to consider latest strategic energy infrastructure plans.** Given the change in zonal pricing impacts from the 'Beyond 2030' network plans, a review of the case for zonal pricing by DESNZ will be required, including any upcoming generation and network plans in the Clean Power Plan for 2030.

Key findings – Impact of latest grid plans

Increased network capacity and the ability to connect more offshore wind in Scotland under the 'Beyond 2030' plans from Spring 2024 significantly reduce the benefits of moving to zonal pricing

- LCP Delta's previous analysis for DESNZ assessed the impacts of zonal pricing under now outdated network plans (the 'NOA7 refresh', from summer 2022) and had limited consideration of strategic infrastructure planning, such as offshore wind seabed leasing.
- Including the 'Beyond 2030' network plans from Spring 2024, along with fixing offshore wind locations based on seabed leasing, leads to a **significant reduction in the modelled system benefits of moving to zonal pricing to £0-11bn.** This is compared to the £5-15bn under the 'NOA7 Refresh' plans from Summer 2022.
- **The modelled system benefits of moving to zonal pricing are eliminated if interconnector redispatch reforms can be delivered to allow interconnectors to fully redispatch their capacity.** This is shown in the "No Redispatch Inefficiency" scenario in the report, where interconnectors can fully redispatch their flows under the current national pricing arrangement.
- **When considering the potential impact on investments, zonal pricing becomes a £8-19bn cost to the system**' with only a 1pp uniform increase in the cost of capital for all technologies (except Nuclear).
- **Increased network capacity reduces the system benefits of moving to zonal pricing.** With DESNZ commissioning the NESO to provide recommendations on a plan for Clean Power 2030, including on network build-out, any plans to upgrade the network further is likely to reduce the system benefits further.

Change in modelled system costs from moving to zonal pricing under Summer 2022 grid plans and 'Beyond 2030' network plans

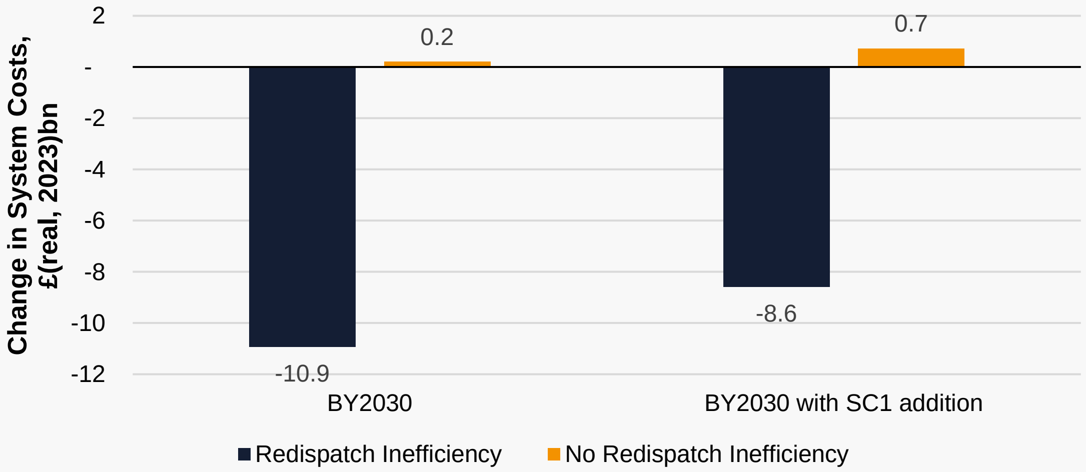


Key findings – Impact of interconnectors

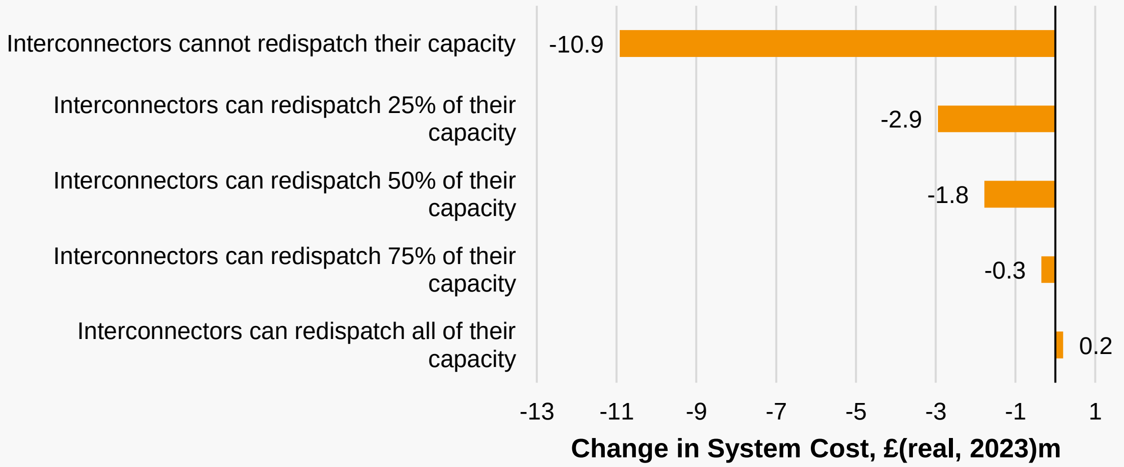
The operational efficiency benefits of moving to zonal pricing are driven by more efficient use of interconnectors to deal with constraints in Southern England. Changes to the current national pricing system could achieve a similar outcome.

- **Structural constraints between England and Scotland are reduced under the 'Beyond 2030' plans. However, the SC1 network boundary in the South of England becomes more constrained in the future** should internal reinforcement not be forthcoming, with high levels of demand growth assumed and significant additional levels of interconnection connecting into the region.
- The NESO's 'Beyond 2030' network plans include a significant increase in the SC1 boundary capacity compared to the 'NOA7 Refresh' plans, however, it is unclear from NESO data what is causing this increase.
- **Including this increase in SC1 boundary capacity reduces the benefits of moving to zonal pricing by £2.3bn** in the redispatch inefficiency scenario (where interconnectors cannot redispatch under national pricing).
- **Interconnectors can add significantly to constraint costs** under current market arrangements and system operator practice, as the current ability to redispatch them in response to system constraints is limited.
- **Introducing reforms to allow interconnectors to redispatch their capacity under national pricing can deliver significant system benefits** and is likely able to be delivered more quickly than implementing zonal pricing.
- **Reforming the national market to enable the redispatch of just a small proportion of interconnector capacity reduces the system benefits of zonal pricing by £8bn.** Sensitivity testing shows that under a national pricing scenario where interconnectors can redispatch 25%, 50% or 75% of their capacity, benefits reduce from £10.9bn to £2.9bn, £1.8bn and £0.3bn respectively.

System cost changes of moving to zonal pricing under 'Beyond 2030' network plans and with increased SC1 boundary capacity



System cost changes of moving to zonal pricing with different levels of interconnector redispatch in national pricing counterfactual



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Introduction

Background on zonal pricing, the 'Beyond 2030' network plans, and strategic energy infrastructure planning

Background

The Government’s second REMA consultation left zonal pricing on the table as a reform option for the GB market

- The Government’s **Review of Electricity Market Arrangements (REMA)** programme, which started in July 2022, is considering a range of reforms to the GB system to ensure the market is fit for purpose for the future.
- The Department for Energy Security and Net Zero (DESNZ) published its second REMA consultation in March 2024. This narrowed down the options for electricity market reform from the first consultation.
- One of the key issues that **REMA is looking to address is reforms to reduce locational constraints on the network**. Zonal pricing remains an option that DESNZ is considering alongside reforms to the current national market to deal with this issue.
- For the second REMA consultation, **LCP Delta was commissioned by DESNZ along with Grant Thornton to independently assess the impacts of moving the market to zonal pricing**.
- However, given it was undertaken during Autumn 2023, **this analysis used the, now outdated, Network Options Assessment 7 Refresh** (‘NOA7 Refresh’) assumptions for network reinforcement and did not consider strategic energy infrastructure planning decisions in detail.
- The report was published alongside the consultation with the findings informing DESNZ’s position. The full report can be found here and a summary of key findings can be seen in the Annex.

National Pricing

Single ***national wholesale price*** with re-dispatch in the balancing mechanism to resolve constraint issues.

Locational signals given through LRMC of investment at a specific point on the network charged through ***TNUoS regime***

Separate charge for locational losses.

Currently used in:

GB

Germany

Zonal pricing

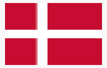
Prices reflect marginal cost of generation, ***accounting for congestion on zonal boundaries***.

Illustrative GB zone boundaries

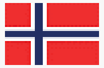
Locational ***signal embedded within zonal prices***, but potential need for TNUoS type signal within larger zones.

Currently used in:

Italy



Denmark



Norway

The move to strategic network planning

Future network plans have evolved since the completion of LCP Delta's analysis for DESNZ with the publication of the 'Beyond 2030' network plan and will likely change again with the publication of CSNPs every 3 years from 2027.

- Prior to 2022, the then Electricity System Operator (ESO) published an annual Network Options Assessment (NOA) outlining their recommendations for which onshore reinforcement projects should receive investment for the next financial year. The last of these was the 2021 7th Network Options Assessment (NOA7).
- The **'NOA7 refresh'** in Summer 2022 took the first step towards strategic network planning in GB by updating the NOA7 plans to include recommendations on an integrated network design to connect offshore wind farms (in line with the UK's offshore wind target at the time of 40GW by 2030) to the GB network in addition to plans for onshore infrastructure in NOA7. These plans are now known as the first transitional Centralised Strategic Network Plan (tCSNP1).
- Following the recent energy crisis, and the UK's offshore wind target of 50GW by 2030, grid plans were expanded further in Spring 2024 as the ESO published the **'Beyond 2030'** plans. This is known as tCSNP2 and has increased network capability and connects more offshore wind up to 2030 and beyond.
- A fuller **Centralised Strategic Network plan (CSNP)** is planned for 2026 which aims to build on tCSNPs. This plan is to be updated every 3 years covering both onshore and offshore networks. This will be informed by a wider Strategic Spatial Energy Plan (SSEP) covering other energy vectors, discussed in the next slide.
- With the new Government's Clean Power Mission, the now National Energy System Operator (NESO) is undertaking a **Clean Power Plan** exercise to consider the system needs to deliver a clean power system by 2030, potentially including further upgrades to grid capacity.

Pre 2022: Yearly Network Options Assessment

2022: NOA7 Refresh

The 'NOA7 Refresh' published in 2022 combines the NOA7 and HND to provide a full plan for onshore and offshore networks

2024: 'Beyond 2030'

The 'Beyond 2030' report builds on the 'NOA7 Refresh' providing a set of network recommendations throughout the 2030s

2024: Clean Power 2030

NESO's Clean Power 2030 recommendations will outline changes needed to network plans for the Clean Power Mission

2026: CSNP

A full Centralised Strategic Network Plan (CSNP) covering the transmission network is due in 2026 alongside a new Strategic Spatial Energy Plan (SSEP)

Post 2027: Annual updates to CSNP with new version every 3 years

A plan for a strategic plan

The Strategic Spatial Energy Plan is likely to dictate the location of future projects on the GB electricity system

- In response to the Network Commissioner's report in November 2023, DESNZ published the Transmission Acceleration Plan. This included the announcement of plans to develop a **Strategic Spatial Energy Plan (SSEP).**

- The SSEP aims to 'bridge the gap between government policy and infrastructure development plans' across GB and 'will support the government in tandem with energy markets to determine the optimal location of energy infrastructure'.

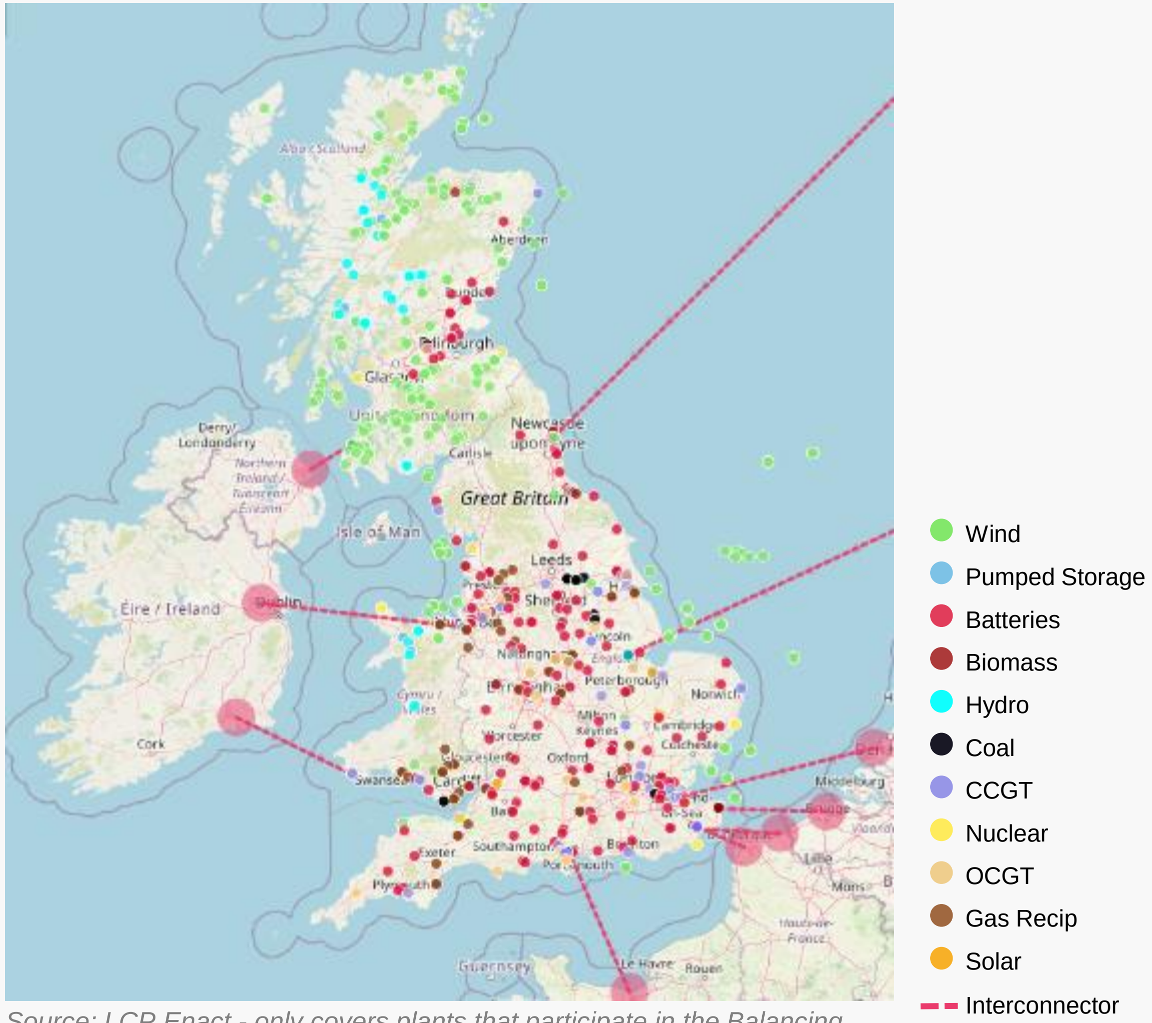
- The UK, Scottish, and Welsh energy ministers have now jointly **commissioned the NESO to produce the first SSEP for GB in 2026**. The first iteration will focus on electricity generation and storage, including hydrogen assets – mapping the potential locations, quantities, and types.

- The SSEP will be used to plan the future energy system with its outputs feeding directly into future strategic network planning, the CSNP, which will set out the required network to deliver on the requirements identified in the SSEP.

- The commitment to **strategic planning of the GB energy system will therefore impact the benefits case of moving to zonal pricing** as the location of projects and infrastructure will be dictated based on these decisions as opposed to the locational signals from zonal pricing.

- This impact can already be seen for offshore wind through results from seabed leasing rounds.

Map of current GB Power Plants



Source: LCP Enact - only covers plants that participate in the Balancing Mechanism

The UK's Clean Power Mission for 2030

The NESO has been asked by the Government to provide practical advice on how to achieve clean power by 2030

- The new Government has ambitions to accelerate grid decarbonisation and achieve a 'clean power' system by 2030 with increased capacity ambitions for many technologies.
- To achieve this, the Government has formally commissioned the NESO 'to provide practical advice on achieving clean power by 2030' consisting 'of a range of pathways that enable a decarbonised power system for Great Britain by 2030'.
- This includes an overview of what is needed to reach clean power by 2030 and an assessment of costs and benefits, opportunities and challenges, and risks.
- Within this, the Government has asked for advice on what the key requirements are for the transmission network and to consider a spatial element 'focusing on those locations that offer opportunities for rapid infrastructure development'. Any accelerated or expanded grid plans have not been accounted for this in this modelling.
- As a result, this could mean further transmission network upgrades are brought forward or locations of other infrastructure determined to facilitate the clean power target being reached.
- This will likely have an impact on the case for zonal pricing as increased network in 2030 could reduce the benefits of moving to zonal pricing.

	Previous government key commitments	New government key commitments*
CO_2 Decarbonisation	**Fully decarbonise the power sector,** subject to security of supply, by 2035	A Clean GB power system by 2030
Offshore Wind	Ambition to deliver up to **50GW of offshore wind by 2030**, with up to 5GW from floating offshore wind by 2030.	Quadruple offshore wind with an ambition of 55 GW by 2030" "Pioneer floating offshore wind, by fast-tracking at least 5 GW
Onshore Wind	Develop partnerships for onshore wind projects for supportive communities. Planning regulations still limited	"More than double our onshore wind capacity to 35 GW"
Solar	Ambition for a **fivefold increase in solar capacity by 2035** to reach 70GW of ground and rooftop capacity together.	"More than triple solar power to 50 GW" by 2030
Hydrogen	**2030 low carbon hydrogen production target of 10GW**, with electrolysers contributing at least 50% (5GW) of this.	"Double the government's target on green hydrogen [from electrolysis], with 10 GW of production" by 2030

*Taken from Labour Manifesto

Approach

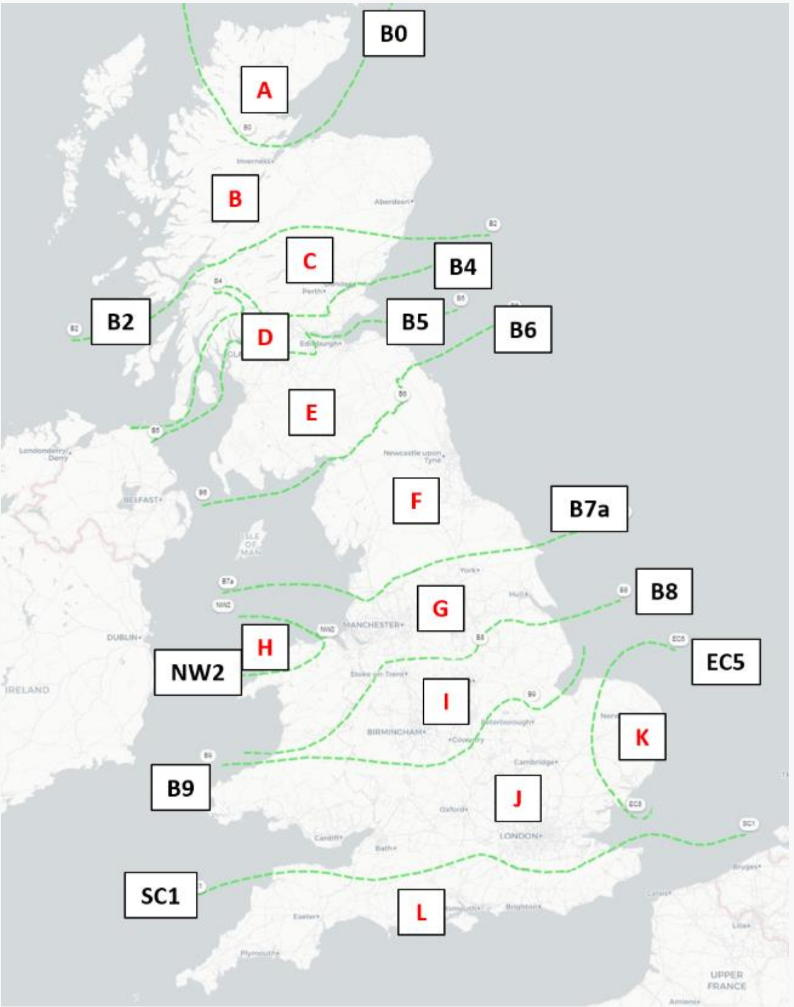
Modelling approach, assumptions, scenarios, and sensitivities

Modelling Approach and assumptions

The modelling aims to use the same methodology and similar assumptions to LCP Delta’s study for DESNZ

- The modelling approach used in this report aims to replicate the approach and assumptions used in the analysis for DESNZ as closely as possible.
- The analysis utilises LCP Delta’s Locational Dispatch Model (LDM) which enables detailed modelling of locational constraints on the network.
- 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 the NESO publications – Electricity Ten Year Statement (ETYS) and ‘Beyond 2030’ report.
- Market assumptions (Demand, Capacity and Commodity Prices) use published versions of DESNZ data where available. Where data is not published, LCP Delta have either used our own internal assumptions or interpreted from available DESNZ data. More detail on approach and assumptions used in the modelling can be found in the Annex.
- There are two stages to this analysis, building on the previous analysis for DESNZ:
  - **Previous analysis: ‘NOA7 Refresh’ network plans** – Impacts of zonal pricing assessed under, now outdated, 'NOA7 Refresh' network build-out (using ETYS 2023 assumptions). This aims to provide a baseline by replicating as closely as possible the analysis completed for DESNZ.
  - **‘Beyond 2030’ network plans** – Impacts of zonal pricing assessed under ‘Beyond 2030’ network plans and considering a more strategically planned energy system. This includes both the additional network reinforcement and reinforcements from these plans as well as fixed offshore wind locations that align with this increased network based on seabed leasing round results.
  - **Sensitivity Analysis** – Assessing the impacts of zonal pricing under ‘Beyond 2030’ network plans under various sensitivities. The scenarios and sensitivities are outlined in more detail in the next slide.

Locational Pricing Zones

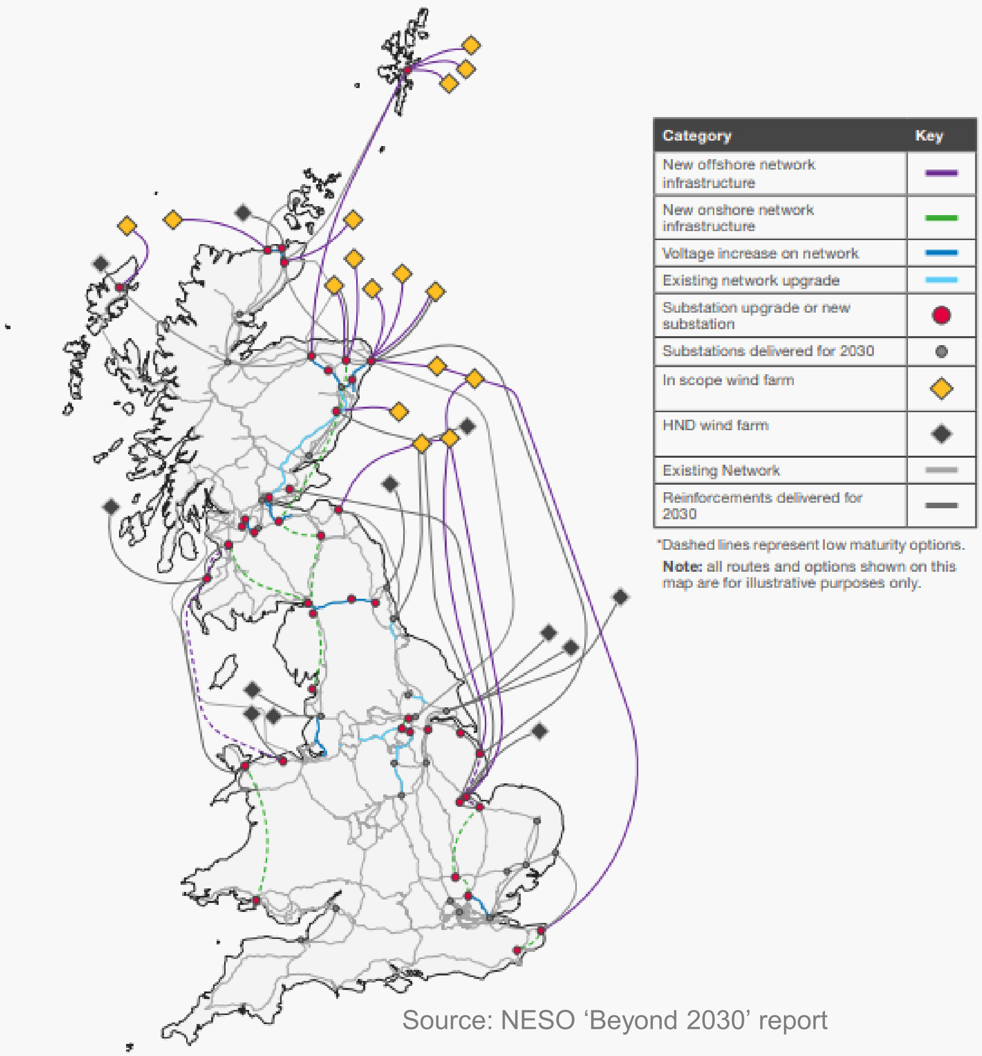


The upgraded 'Beyond 2030' network plans

The NESO has published updated network plans to further increase network capacity up to 2030 and beyond

- In March 2024, the NESO published updated plans for new and upgraded network infrastructure to be built post-2030 in its 'Beyond 2030' report. This is in addition to previous plans as published in the 'NOA7 refresh'.
- The plan recommends an additional £58bn of direct investment in electricity networks facilitating the connection of an additional 21GW of offshore wind in Scotland and other additional low carbon generators across the country.
- This will increase capacity on several key network boundaries across the country while also providing additional offshore links from Scotland to England.
- The increased network capacity in the 'Beyond 2030' plans relative to the 'NOA7 Refresh' significantly impacts the case for moving to zonal pricing. This was highlighted in LCP Delta's previous analysis which showed changes to network capacity will impact the system benefits of zonal pricing.
- This is because a larger network will reduce the need for improved locational signals as electricity can be more easily transported across various parts of the network to demand centres.
- The modelling results in the next section used the 'Beyond 2030' boundary capacities as published by the NESO. This is an update of previous data published as part of the Electricity Ten Year Statement (ETYS) reflecting the boundary capacities from the 'NOA7 Refresh' which were used by LCP Delta in the analysis for DESNZ.
- A more detailed overview of the 'Beyond 2030' capacities and how these compare to the 'NOA7 Refresh' can be found in the annex.

'Beyond 2030' Network Plans



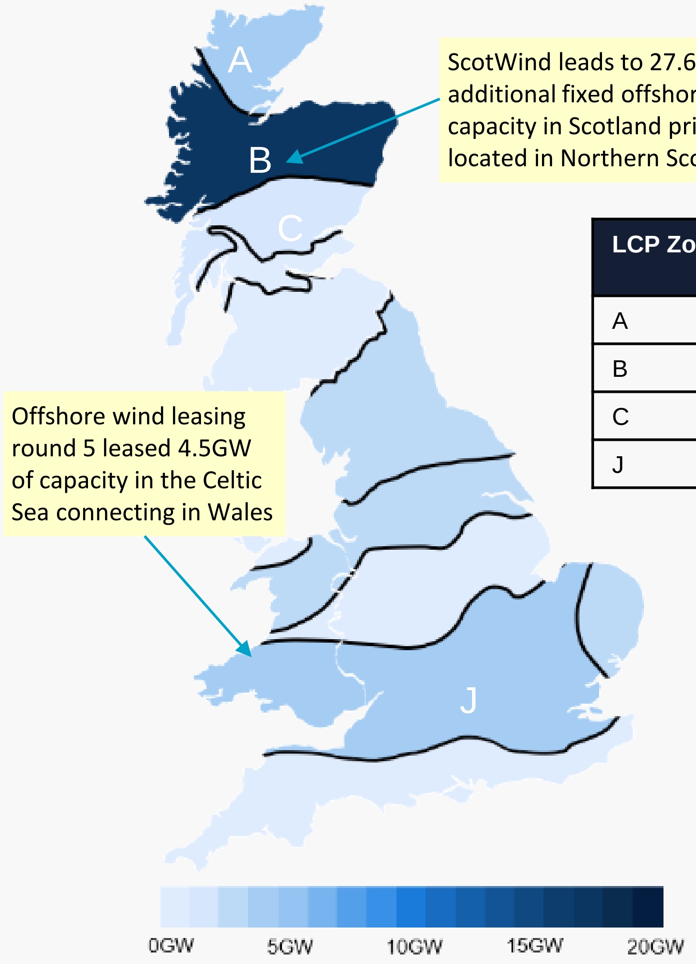
Source: NESO 'Beyond 2030' report

Strategic Infrastructure Planning - Offshore wind locations

Strategic infrastructure planning is already in progress with seabed leasing rounds in Scotland, England and Wales determining the location of some future offshore wind capacity

- Seabed leasing by the Crown Estate and Crown Estate Scotland has already leased 32GW of seabed for new offshore wind projects. This reflects strategic infrastructure planning decisions that were not factored into the analysis previously completed for DESNZ.
- The 20 projects from the ScotWind leasing round account for 27.6GW, located in Scotland. The Offshore Wind Leasing Round 5 also accounts for 4.5GW of additional offshore wind capacity in the Celtic sea.
- Leasing seabed is one of the major obstacles for a new offshore wind project and is a strong indicator of where new projects are likely to be located.
- The 'Beyond 2030' network plans have also factored in these new offshore wind projects, particularly in Scotland where the plans facilitate the connection of 21GW of additional offshore wind projects.
- Together these two factors are likely to mean that the locational signals set by TNUoS or zonal pricing would have a limited impact on where these offshore wind projects will locate.
- As a result, the analysis outlined in future sections looks at scenarios where 32.1GW of additional offshore wind is fixed in its location based on seabed leasing round results. This is higher in earlier years as it is assumed the next offshore wind plants are built in these areas.

Fixed offshore wind capacity locations based on seabed leasing rounds to date



LCP Zone	Offshore wind capacity fixed (GW)
A	4.3
B	22.5
C	0.8
J	4.5

Scenarios and Sensitivities

Various scenarios and sensitivities were tested to give a fuller understanding of potential impacts

- Across all scenarios and sensitivities modelled, the modelling compares the system costs for a zonal pricing factual with a national pricing counterfactual across the period 2030-2050. All changes in assumptions are applied to both the counterfactual and factual (unless otherwise stated).
- There is significant uncertainty around how interconnectors (and to a lesser extent storage) in the current national market are redispatched to deal with constraints and whether this could be changed under reforms to the national market. Given this uncertainty, each locational pricing factual is compared against two national pricing counterfactuals where interconnector redispatch is varied. These scenarios are:

National Pricing scenario	Description
Redispatch inefficiency	In this scenario, interconnectors are not able to be redispatched to deal with constraints, with their flows fixed at the day ahead stage.
No redispatch inefficiency	In this scenario, interconnectors can be fully redispatched to deal with constraints and essentially participate in locational balancing.

- Given the uncertainty around the makeup of the future system and potential reforms to the national pricing counterfactual, it is prudent to test different sensitivities to give a fuller understanding of the potential impacts of moving to zonal pricing under the 'Beyond 2030' plans. The additional sensitivities tested are outlined in the table below:

Sensitivity Name	Description
1. Interconnector reforms in a national market	Whether interconnectors can be redispatched to deal with constraints in a national pricing market has a significant impact on the case for moving to zonal pricing. Previous analysis has tested interconnectors being able to fully redispatch or not redispatch at all. These sensitivities look at levels between these two extremes, with interconnectors able to redispatch 25%, 50% and 75% of their flows.
2. Addressing Southern (SC1) Constraint	LCP Delta's previous analysis showed the SC1 boundary becomes heavily constrained in future, particularly under the national pricing counterfactual. This sensitivity increases the boundary capacity on SC1 to test the impact of increased network capacity in this area.
3. 3-year network acceleration	A 'what-if' scenario to test the impacts of accelerated investments and upgrades in network infrastructure where all upgrades are brought forward by 3-years.
4. Alternative demand and capacity mix	An alternative market background scenario with lower demand based on the DESNZ Net Zero Lower Demand scenario.

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Recap: Zonal pricing under NOA7 Refresh Plans

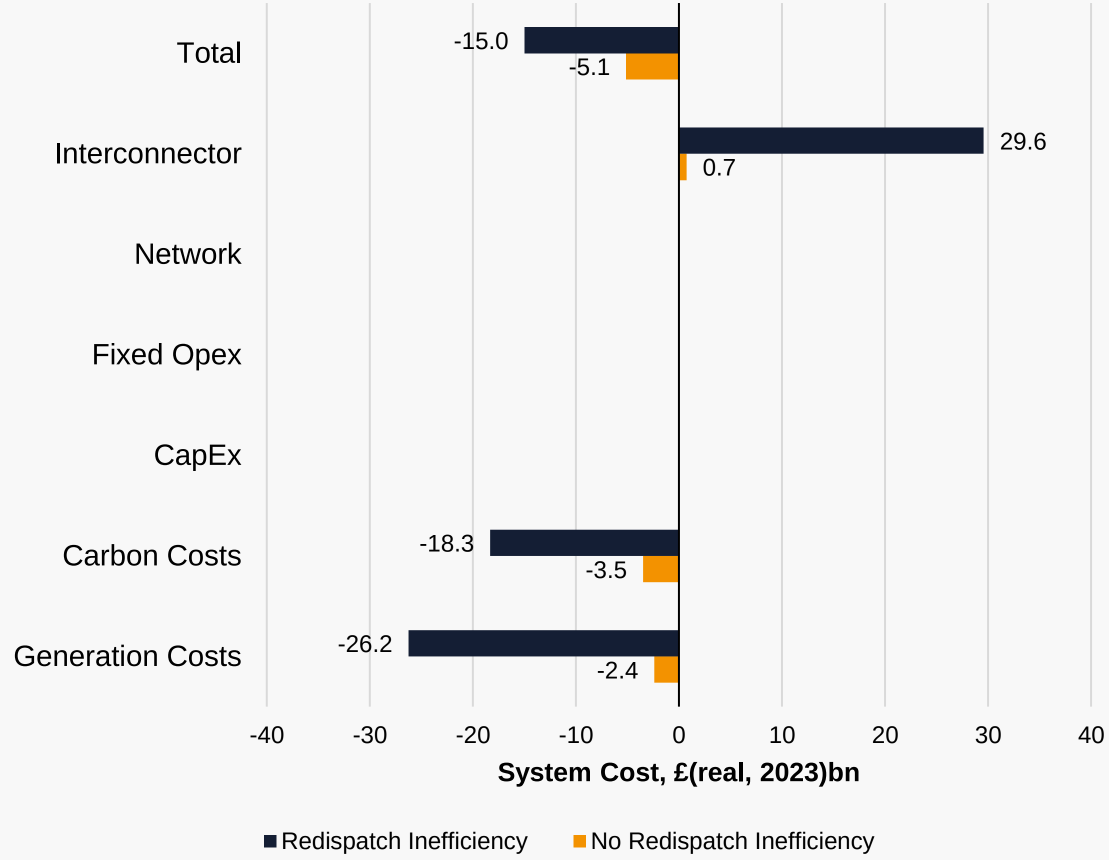
Replicating the analysis completed for DESNZ

Impacts of zonal pricing under 'NOA7 Refresh' network plans

Replicating analysis from the previous study for DESNZ using outdated grid plans from 2022 showed that with no assumed impact on cost of capital, moving to zonal pricing brings benefits of £5-15bn

- The first stage of this analysis aims to provide a baseline by replicating as closely as possible the analysis completed in the previous study for DESNZ, based on the now outdated 'NOA7 Refresh' network plans.
- Based on DESNZ's Net Zero higher demand scenario and with no assumed impact on cost of capital, **moving to zonal pricing decreases 2030 to 2050 electricity system costs by £5-15bn** (NPV in 2023 real prices).
- System benefits of moving to zonal pricing are £5bn with no redispatch inefficiencies and £15bn where redispatch inefficiencies are assumed, in the national pricing counterfactual.
- The drivers of these benefits are split into two types:
    - **Investment efficiency**, where more efficient locational signals cause plants to locate in areas more beneficial to the system. For example, more renewables locating closer to demand centres.
    - **Operational efficiency**, where cost savings are a result of changes in the operation of the market (regardless of plants changing location). This is primarily due to more efficient operation of interconnectors under zonal pricing due to restrictions on how they can redispatch their flows in the current national market. These benefits are only present in the "Redispatch inefficiency" scenario.
- The analysis is conducted using LCP Delta's Locational Dispatch model. For more information on how the model works, please see the annex

Overall system cost change of moving to zonal pricing in core scenario and redispatch inefficiency scenario

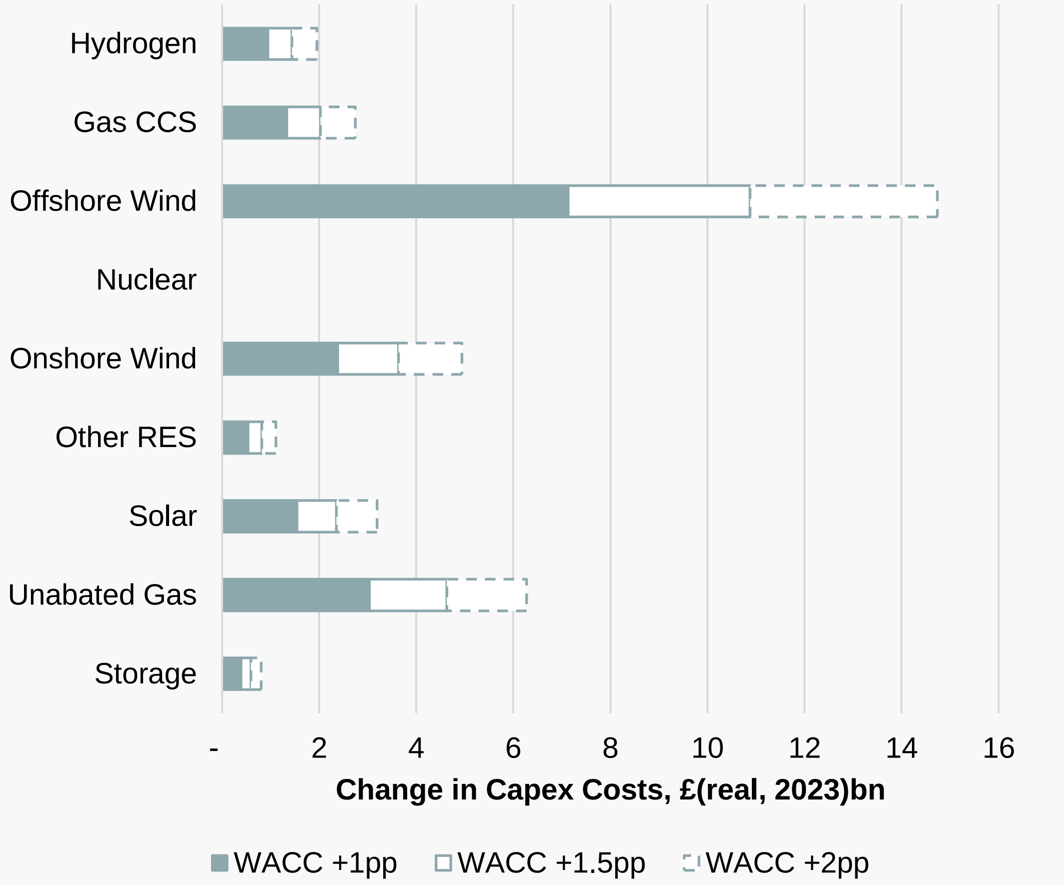


Cost of capital impacts under 'NOA7 refresh' network plans

The system benefits of moving to zonal pricing in the 2022 grid plans were wiped out by a cost of capital increase of 0.3 to 0.9 percentage points

- The cost of capital is the expected return required by investors to undertake risky investments. The higher the uncertainty around future cash flows, the higher the risk for an investor, and therefore the higher the cost of capital.
- The complexity and uncertainty around the introduction of zonal pricing could mean that investors see GB power investments as riskier leading them to require a higher WACC (weighted average cost of capital).
- In particular, Contracts for Difference (CfD) supported generation would be exposed to significantly increased uncertainty in its cashflows if CfD reference prices are based on a national price (which we assume in this modelling). This would be somewhat offset by the reduction in uncertainty associated with TNUoS charges, which would be removed under zonal pricing.
- There is uncertainty on the exact extent of the impact of introducing zonal pricing on the cost of capital for investors. As such, a range of impacts have been tested.
- The analysis shows that the system cost benefits would be outweighed by modest increases in the cost of capital. Uniform increases of 0.3 to 0.9 pp in cost of capital for all technologies (excluding Nuclear) results in a move to zonal pricing becoming a net cost to the system.
- A 1pp increase results in a move to zonal pricing becoming a net system cost of £4-13.5bn and a 2pp increase a net system cost of £23-33bn.

Changes in Capex Costs (NPV) in the DESNZ Net Zero higher demand scenario for various levels of WACC percentage point increase.



Zonal pricing under 'Beyond 2030' plans

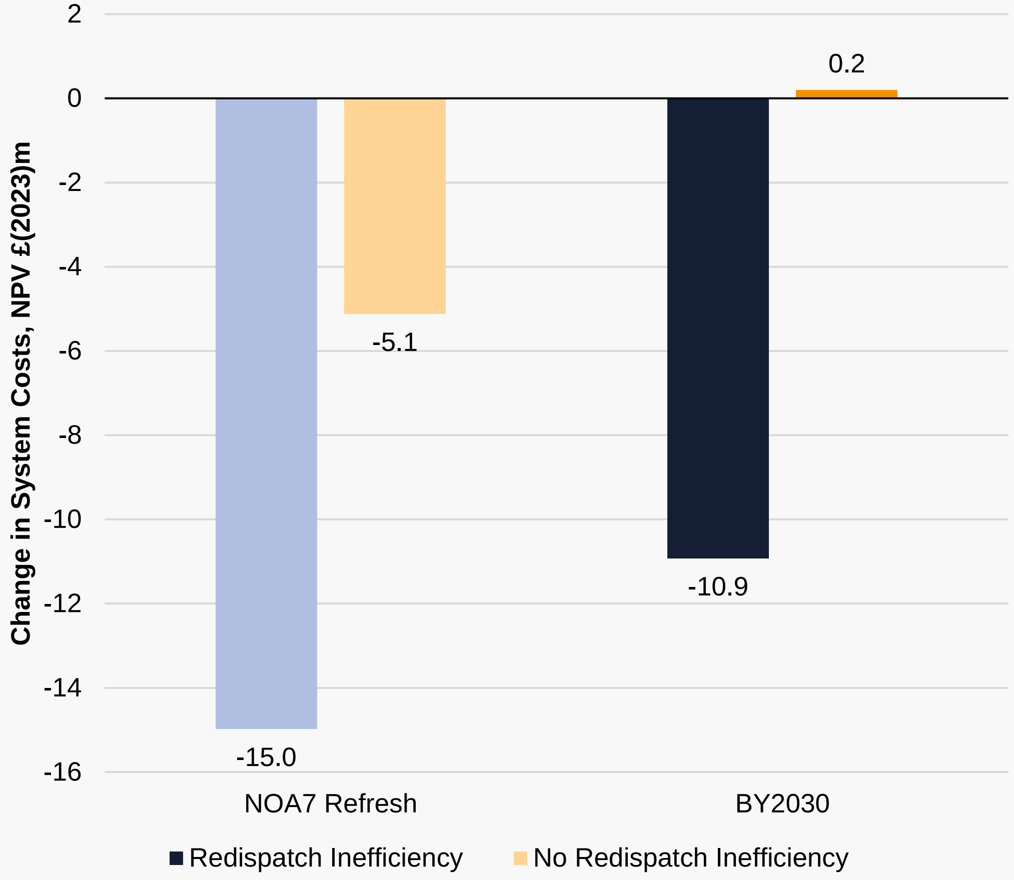
Impacts of moving to zonal pricing under 'Beyond 2030' network plans and Strategic Energy Infrastructure planning

System cost impact of 'Beyond 2030' network plans

Increased network capacity under the 'Beyond 2030' plans and fixing offshore wind locations based on seabed leasing significantly reduces the benefits of moving to zonal pricing

- This section outlines the modelling results of moving the GB market to a zonal pricing approach under the 'Beyond 2030' network plans.
- LCP Delta's previous analysis for DESNZ outlined in the previous section assessed the impacts of zonal pricing under now outdated network plans and had limited consideration of strategic infrastructure planning, such as offshore wind seabed leasing.
- Including the 'Beyond 2030' network plans, along with fixing offshore wind locations based on seabed leasing, **leads to a significant reduction in the modelled benefits of moving to zonal pricing to £0-11bn across 2030-2050.** This is compared to the £5-15bn previously reported in the DESNZ study using 'NOA7 Refresh' network plans.
- **The benefits of moving to zonal pricing are eliminated and instead become a net system cost of £0.2bn** under the no redispatch inefficiency scenario. This is a result of the additional network facilitating the flow of renewable energy (e.g. from North to South) reducing the need for locational signals beyond TNUoS.
- **When considering the impact a move to zonal pricing could have on investment, an increase of only 0pp to 0.6pp to the cost of capital for all technologies (excluding Nuclear) wipes out the modelled system benefits of zonal pricing.** This is compared to the 0.3pp to 0.9pp previously reported.
- **If the cost of capital increases by only 1pp, then zonal pricing becomes a £8-19bn cost to the system.** This is compared to £2-12bn previously reported.

Overall system cost change of moving to zonal pricing across all scenarios tested

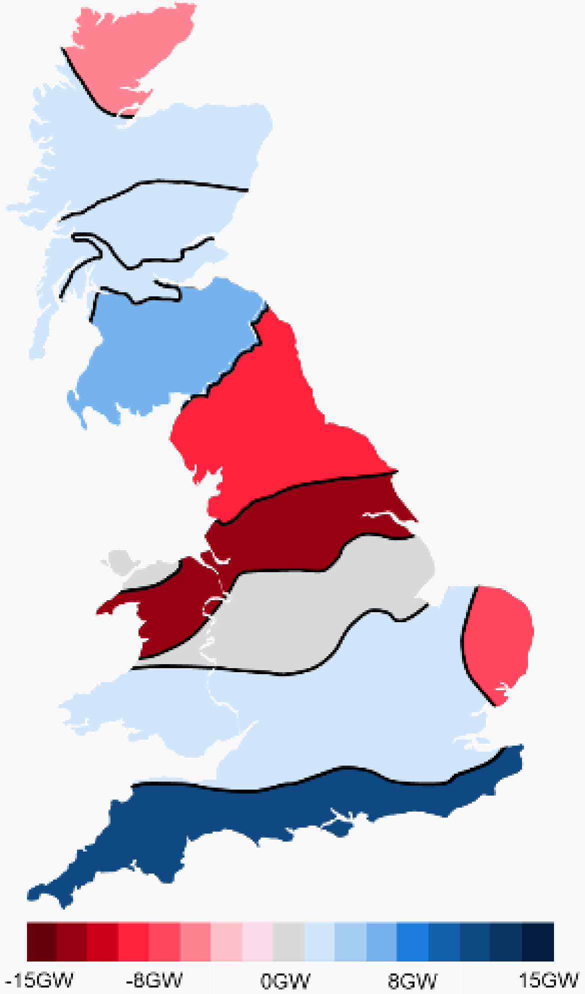


Offshore wind locations

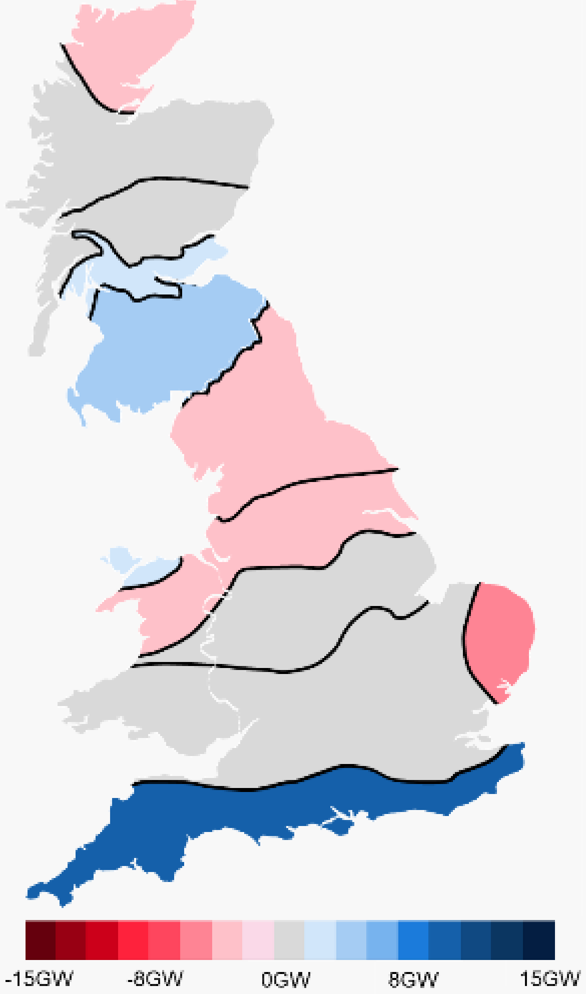
The fixed locations mean zonal pricing only has a small impact on the movement of offshore wind

- In the modelling, **plants locate based on the locational signals** provided under the current national market and under zonal pricing.
- **Restrictions are applied on where plants can locate** in line with assumptions used in the previous analysis DESNZ. In addition, the move to a more strategically planned system leads to more offshore wind locations being fixed based on results from seabed leasing rounds (as outlined in slide 14).
- Under the 'NOA7 refresh' network plans with limited offshore wind restrictions, **offshore wind capacity moves away from the north of Scotland, the north of England and East Anglia** to locate in the south of the country under zonal pricing.
- Under the 'Beyond 2030' network plans, applying a strategic planning approach by fixing offshore wind locations based on existing seabed leasing, similar movements are seen, however the differences are much smaller.
- **With more offshore wind locations fixed, and higher levels of network reinforcement, zonal pricing has less of an impact on offshore wind locations.**

'NOA7 refresh' with limited offshore wind restrictions – Difference in offshore wind capacity by location



'Beyond 2030' with fixed offshore wind locations – Difference in offshore wind capacity by location



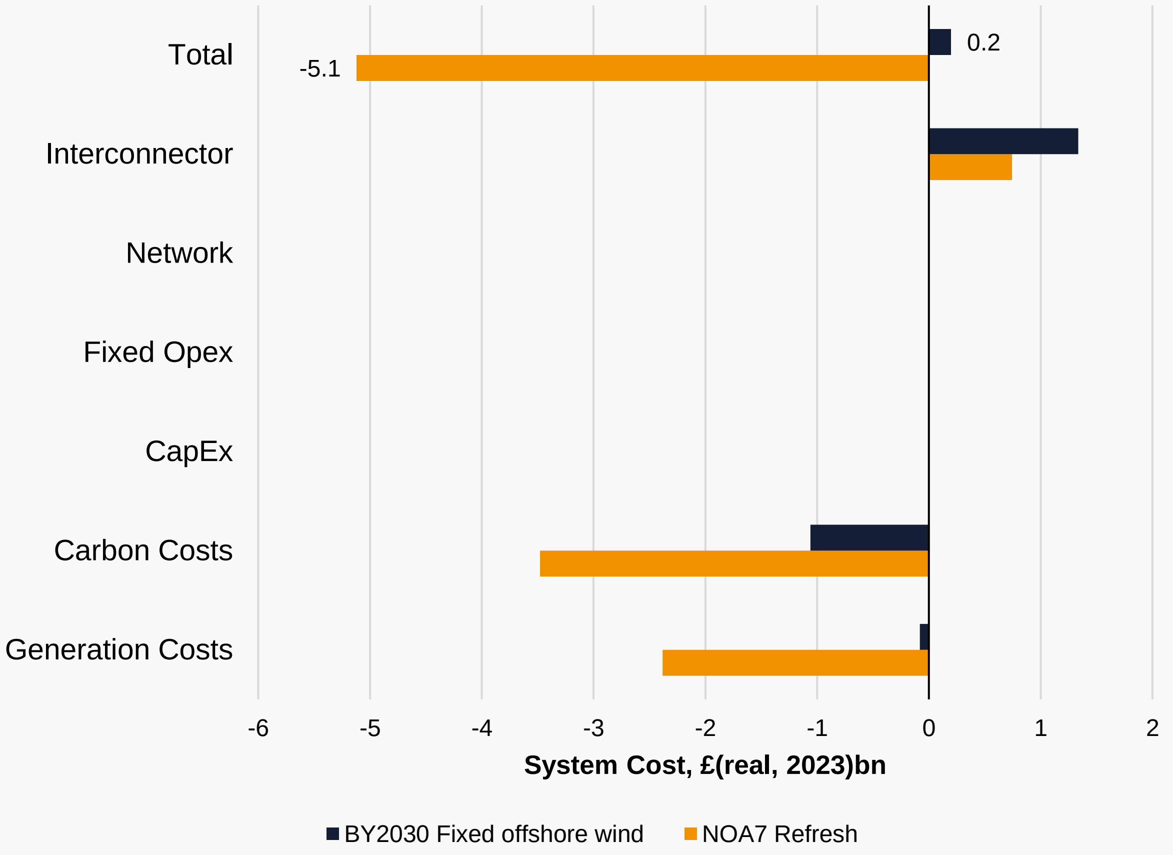
System cost impact under 'No Redispatch Inefficiency' scenario

Fixing offshore wind locations under 'Beyond 2030' network plans eliminates the benefits of zonal pricing

- **Moving to zonal pricing increases electricity system costs by £0.2bn over the period 2030 to 2050 in the 'No Redispatch Inefficiency' scenario***, with offshore wind locations fixed by seabed leasing (NPV in 2023 real prices).
- **The benefits of a move to zonal pricing are therefore eliminated in this scenario** when compared to the £5.1bn benefit previously reported in the DESNZ study using now outdated network plans.
- While the model suggests some offshore wind does relocate further south under zonal pricing, the impact is significantly reduced compared to the previously modelled 'NOA7 Refresh' scenario.
- This is a result of the increased network capacity (particularly in Scotland) reducing the occurrence of constraints in the national pricing counterfactual meaning curtailment of renewables is much lower.
- The benefits of relocating capacity are significantly reduced as many of the network problems have been addressed due to the higher network capacity, meaning there is a limited reduction in generation and carbon costs – reducing the benefits case for zonal pricing.
- The increase in interconnector costs now outweighs the reduction in generation and carbon costs leading to an overall cost increase from moving to zonal pricing.

** where interconnection is able to be redispatched to resolve locational constraints in the national pricing counterfactual*

Overall system cost change of moving to zonal pricing in the 'No Redispatch Inefficiency' scenario with 'NOA7 Refresh' network and 'Beyond 2030' plans with fixed offshore wind locations

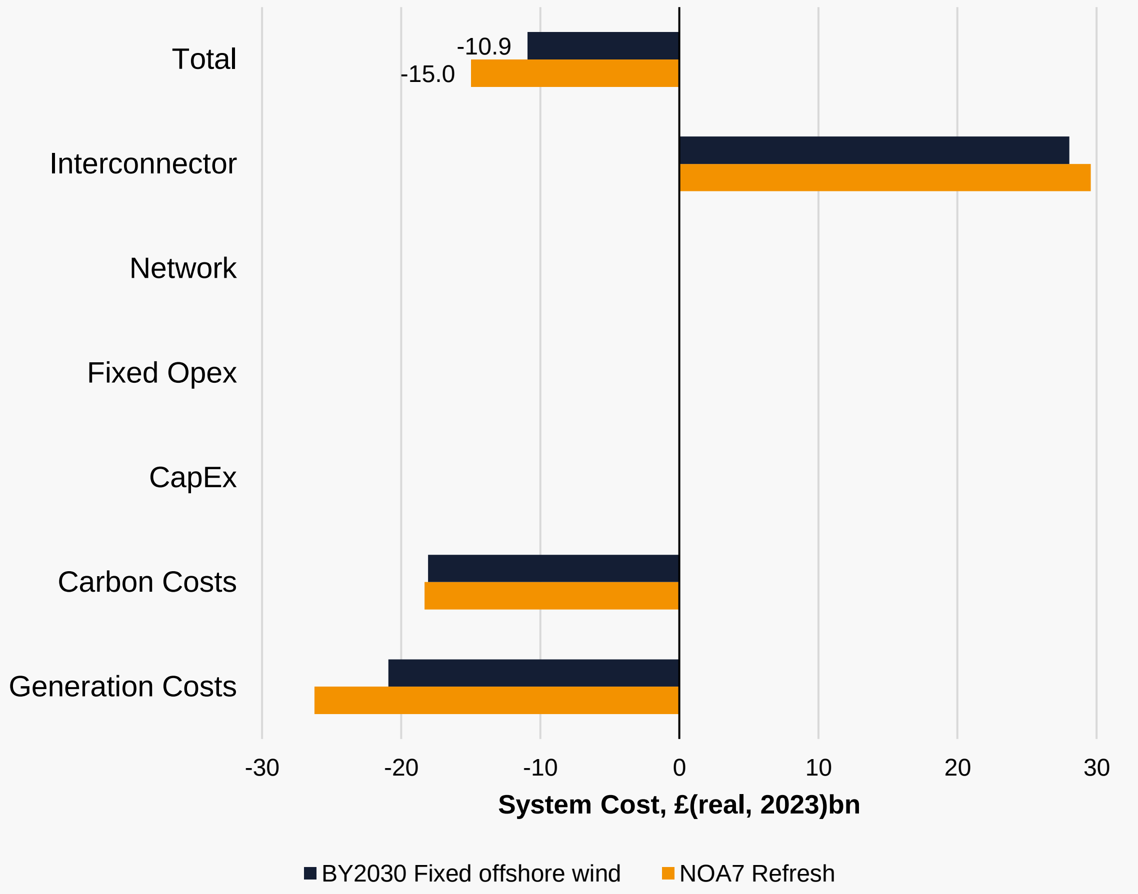


System cost impact under ‘Redispatch Inefficiency’ scenario

Fixing offshore wind locations under ‘Beyond 2030’ network plans reduces the benefits of zonal pricing

- **The benefits of moving to zonal pricing decrease by £4bn, to £11bn in the period 2030 to 2050 in the ‘Redispatch Inefficiency’ scenario***, with offshore wind locations fixed by seabed leasing (NPV in 2023 real prices).
- The increased network capacity, particularly in Scotland, reduces the occurrence of constraints in the national pricing counterfactual meaning curtailment of renewables is lower than under the previously modelled 'NOA7 Refresh' network plans.
- However, with redispatch inefficiencies of interconnectors, the modelling shows high levels of constraints in the South of England where a number of interconnectors are connected into.
- When moving to zonal pricing, the benefits of relocation are still high as many of the network problems remain despite the higher network capacity meaning there is a limited reduction in generation and carbon costs when comparing to the equivalent NOA7 scenario.
- The increase in interconnector costs is not enough to outweigh the large generation and carbon costs caused by more unabated gas generation in England, we therefore find that moving to zonal pricing represents a benefit of £11bn when interconnectors are unable to be redispatched.

Overall system cost change of moving to zonal pricing in the ‘Redispatch Inefficiency’ scenario (NZH) under ‘Beyond 2030’ plans with fixed offshore wind locations



** where interconnection is not able to be redispatched to resolve locational constraints in the national pricing counterfactual*

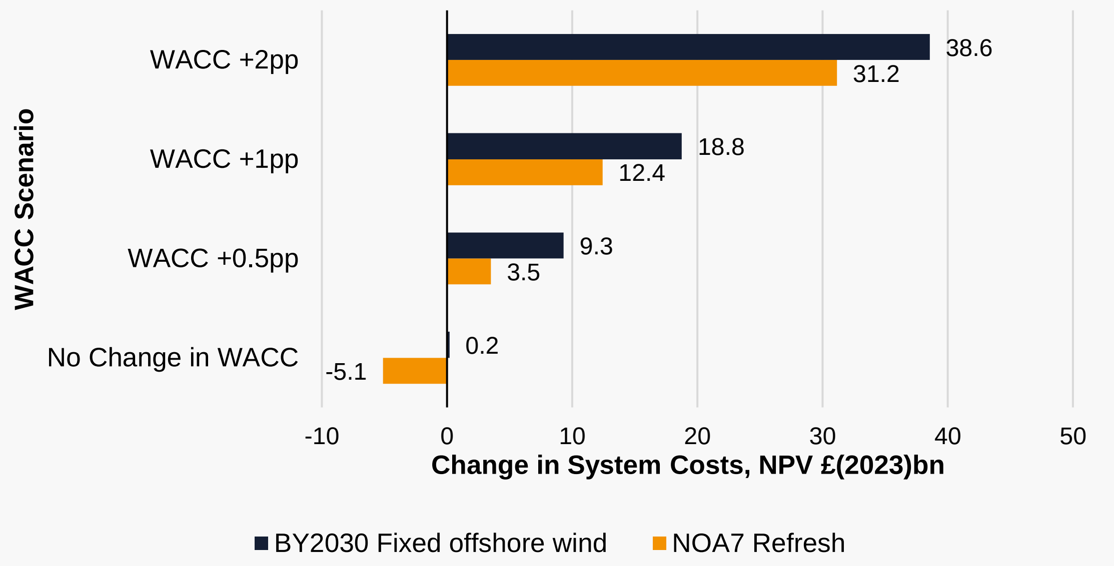
Cost of capital impacts

Changes in cost of capital between 0 and 0.6 percentage points wipe out the benefits of moving to zonal pricing

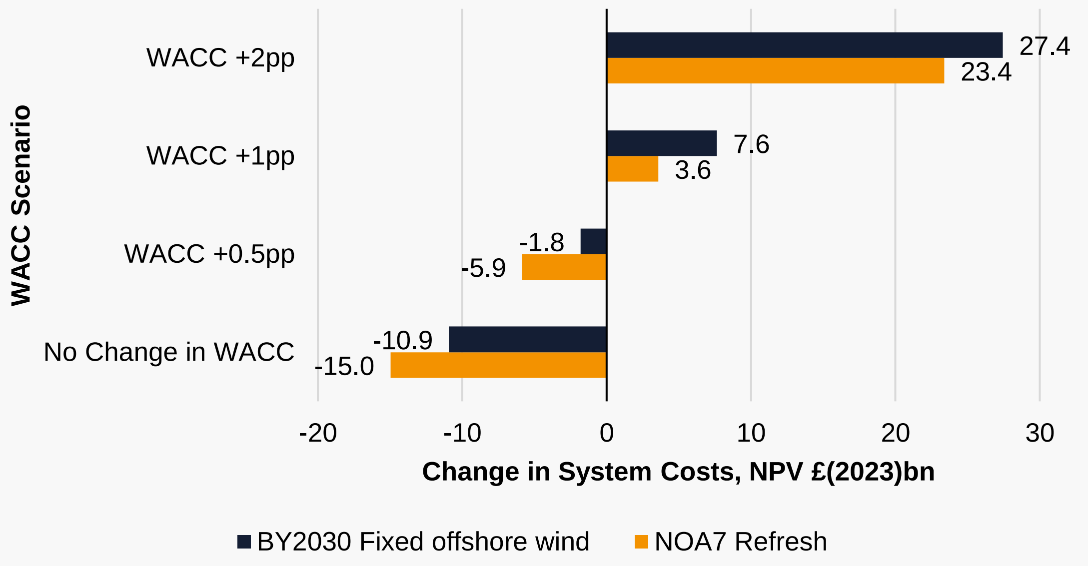
- With no system benefit of moving to zonal pricing under the no redispatch inefficiency scenario with 'Beyond 2030' network plans, any change in cost of capital will lead to zonal pricing become a cost to the system. This compares to a 0.3pp increase in the previously modelled 'NOA7 Refresh' scenario.
- **Zonal pricing becomes a £19bn cost to the system** if the cost of capital increases by only 1pp.

- Under the redispatch inefficiency scenario, the system benefit of moving to zonal pricing is £11bn with no impact on cost of capital. This means a 0.6pp increase in cost of capital wipes out the benefits of zonal pricing compared to 0.8pp in the equivalent NOA7 scenario.
- **Zonal pricing becomes a £8bn cost to the system** if the cost of capital increases by only 1pp.

Changes in system benefits for different levels of cost of capital scenarios under No Redispatch Inefficiency scenario



Changes in system benefits for different levels of cost of capital scenarios under Redispatch Inefficiency scenario



Sensitivity Analysis

Modelling of sensitivities to assess the impact of zonal pricing under different assumptions

Sensitivity analysis

Various sensitivities were tested to give a fuller understanding of potential impacts

- Given the uncertainty around the makeup of the future system and potential reforms to the national pricing counterfactual, it is prudent to test different sensitivities to give a fuller understanding of the potential impacts of moving to zonal pricing under the 'Beyond 2030' network plans. The additional sensitivities tested are outlined the table below:

Sensitivity Name	Description
1. Interconnector reforms in a national market	LCP Delta's previous analysis highlighted that assumptions around the extent to which interconnectors can be redispatched to deal with constraints in the current national pricing market can have a significant impact on the case for moving to zonal pricing. Previous scenarios have only tested interconnectors being able to fully redispatch or not redispatch at all. These sensitivities look at levels in between these two extremes, with interconnectors able to redispatch 25%, 50% and 75% of their flows.
2. Addressing Southern (SC1) Constraint to address interconnector issues	LCP Delta's previous analysis for DESNZ showed that the SC1 constraint becomes heavily constrained in future, particularly under the national pricing counterfactual. This sensitivity increases the boundary capacity on SC1, based on NESO data, to understand the impact of increased network upgrades in this area.
3. 3-year network acceleration	A 'what-if' scenario to test the impacts of accelerated investments and upgrades in network infrastructure where all upgrades are brought forward by 3-years.
4. Alternative demand and capacity mix	An alternative market background scenario with lower demand based on the DESNZ Net Zero Lower Demand scenario.

- All changes to assumptions are made to the 'Beyond 2030' scenario presented in the previous section.

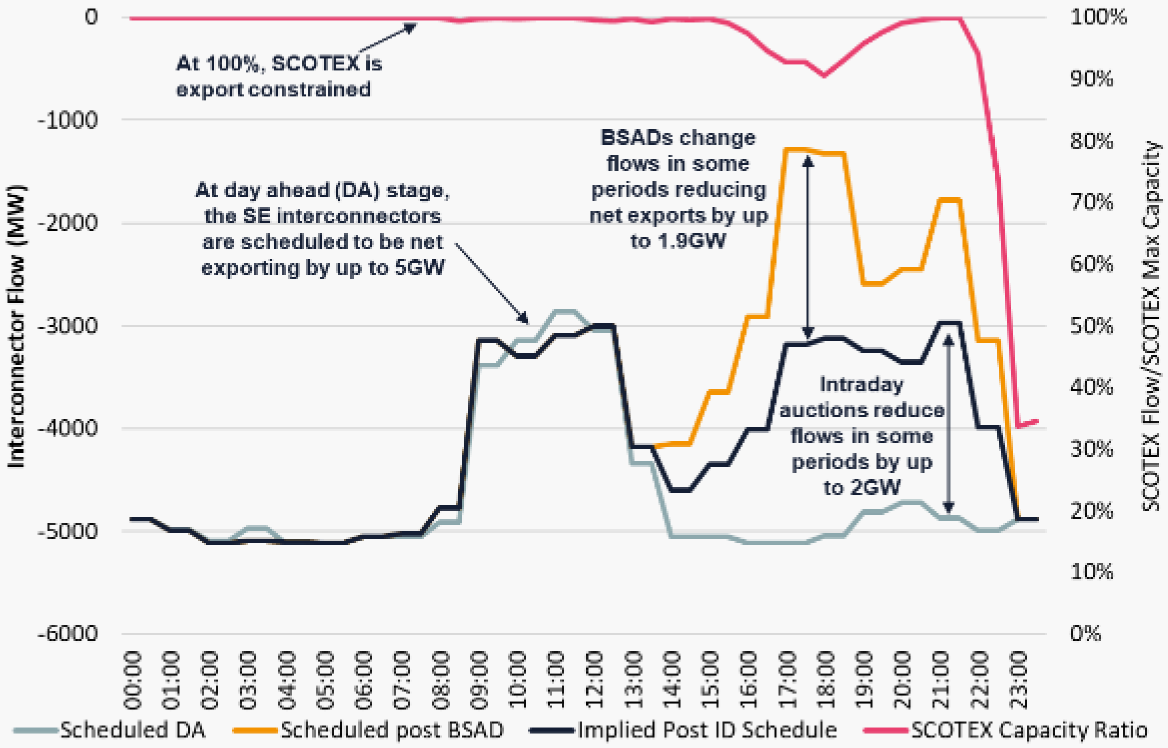
Sensitivity 1 - Interconnector redispatch reforms

Under current market arrangements, interconnectors can often exacerbate constraints

- **Under current market arrangements, interconnector redispatch to resolve constraints is limited**, as they do not compete directly in the GB BM and GB is not coupled with all connected markets. Instead, interconnector flows are adjusted outside the BM.
- This means that **interconnectors can exacerbate constraints**, with limited opportunities to adjust the flow from their day ahead (DA) wholesale market schedules.
- This is common occurrence in the market as shown by the example day in the chart opposite for the 10th November 2022.
- In this example, the SCOTEX boundary (B6) is export constrained meaning wind generation scheduled in the DA market in Scotland cannot be transported to meet demand in England. This means other generation needs to be turned up to meet demand in England.
- At the same time, interconnectors in the Southeast are net exporting to France, Belgium and Netherlands. At the DA stage, these are scheduled to net export at around 5GW overnight with a drop to 3GW in the morning.
- During intraday auctions and then through Balancing Service Adjustment Data (BSAD) actions (actions taken by ESO outside the BM), interconnector flows are changed 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.

[Continued on next slide]

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

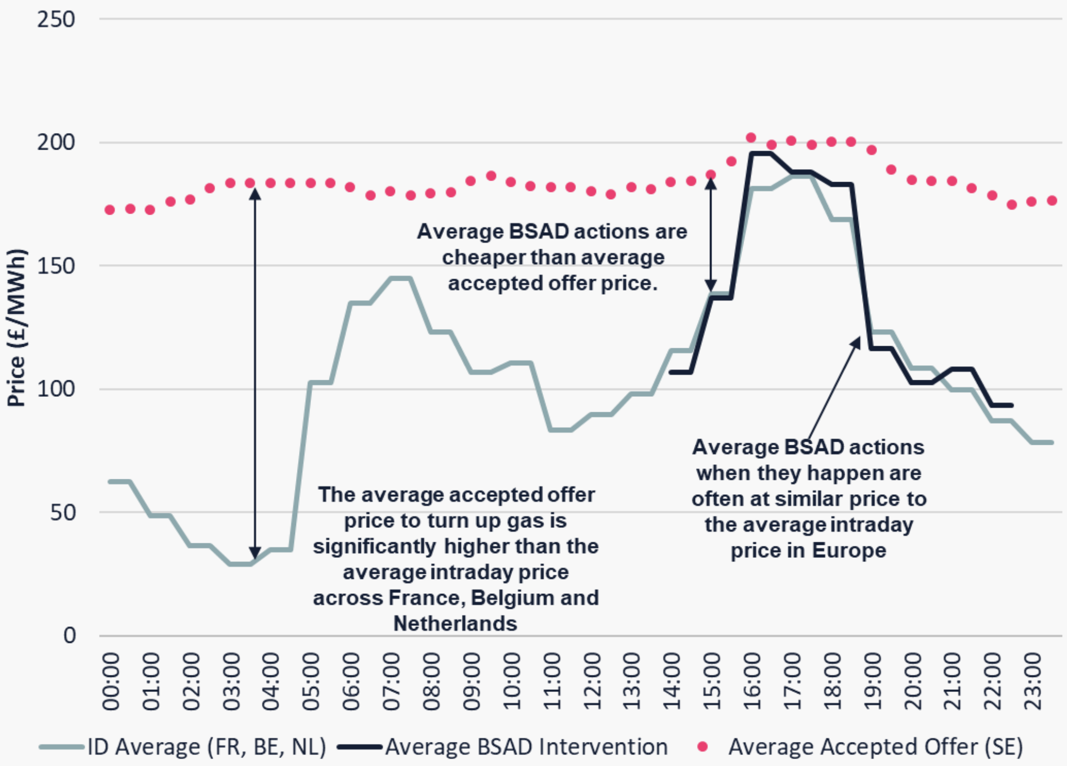


Sensitivity 1 - Interconnector redispatch reforms

Under current market arrangements, interconnectors can often exacerbate constraints

- While interconnector flows are adjusted during some periods, this adjustment is limited, and interconnectors are still exporting across the whole day meaning gas is turned up in all periods across the day at a premium price.
- This is despite the **average intraday price in the connected European markets being significantly lower than the price gas in the Southeast is turned up for**, as shown on the chart opposite.
- Overall, this leads to an **inefficiency in the market as more expensive gas is being turned up than there needs to be**, if interconnectors were able to change their flows in redispatch. This ultimately increases costs to the system and consumer.
- On this example day, the actual cost of turning up gas (and a small amount of changes to interconnectors within day) totalled £13.1m across the day**. If interconnector flows could be redispatched more effectively to avoid turning up gas on this day, this could have reduced costs across the day by £4.7m.**

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



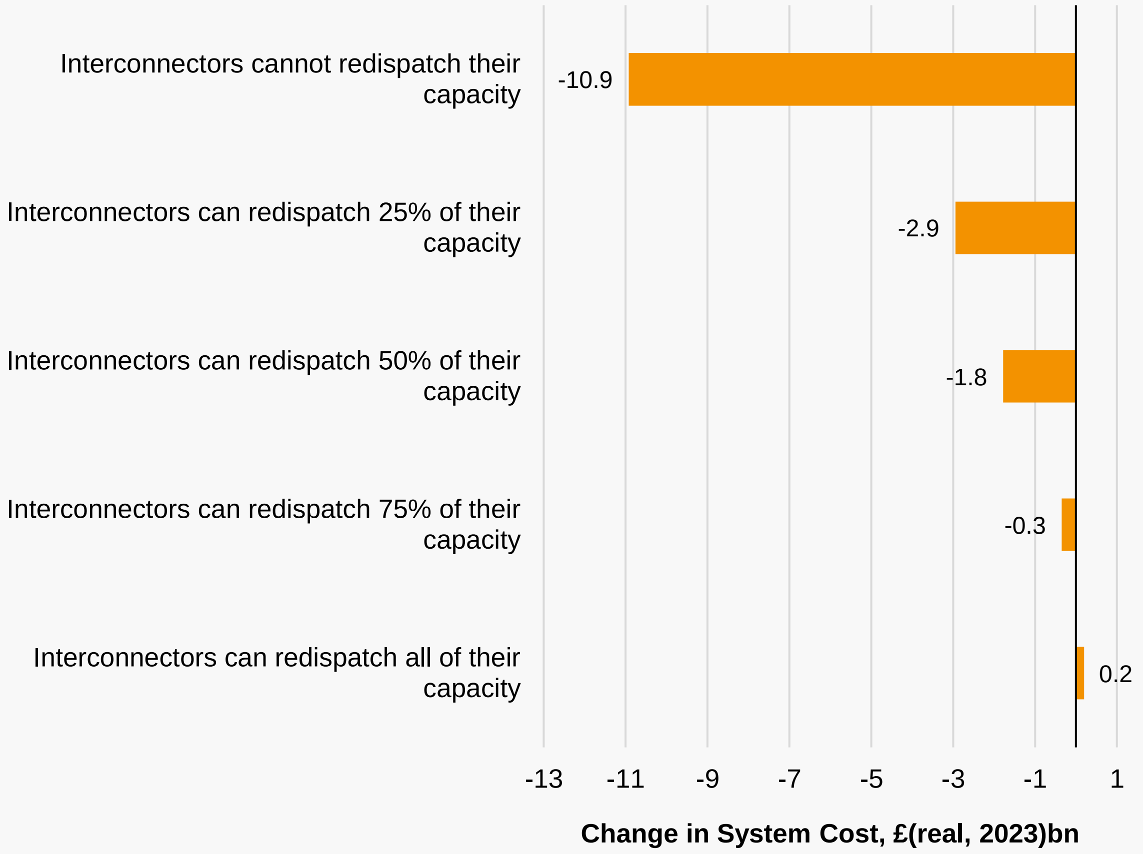
Source: LCP Enact

Sensitivity 1 - Interconnector redispatch reforms

Reforms to allow even a small proportion of interconnector capacity to be redispatched to deal with constraints can significantly reduce the benefits of moving to zonal pricing

- **Under zonal pricing, interconnectors would no longer exacerbate constraint issues** as interconnectors would respond to zonal prices in the DA market.
- The two national counterfactual scenarios in the previous section show a £0bn benefit in a scenario where interconnectors can fully redispatch their flows (no redispatch inefficiency scenario) and an £11bn benefit where interconnectors cannot redispatch their flows at all (redispatch inefficiency scenario).
- To **test the impact of interconnectors being partially redispatched**, 3 additional sensitivities have been modelled where interconnectors can redispatch 25%, 50% and 75% of their capacity.
- Under a national pricing scenario where **interconnectors can redispatch 25%, 50% or 75% of their capacity, benefits reduce to £2.9bn, £1.8bn and £0.3bn respectively.**
- This shows that **reforms to allow redispatch of just 25% of interconnector capacity reduces the benefits of moving to zonal pricing by 80% to £2.9bn from £10.9bn**. This highlights that even moderate reform to allow more efficient redispatch of interconnectors can bring significant benefits to the system.
- This is something that should be **assessed in more detail by DESNZ when considering alternatives to zonal pricing**.

Changes in system benefits for different levels of interconnector redispatch under national pricing counterfactual

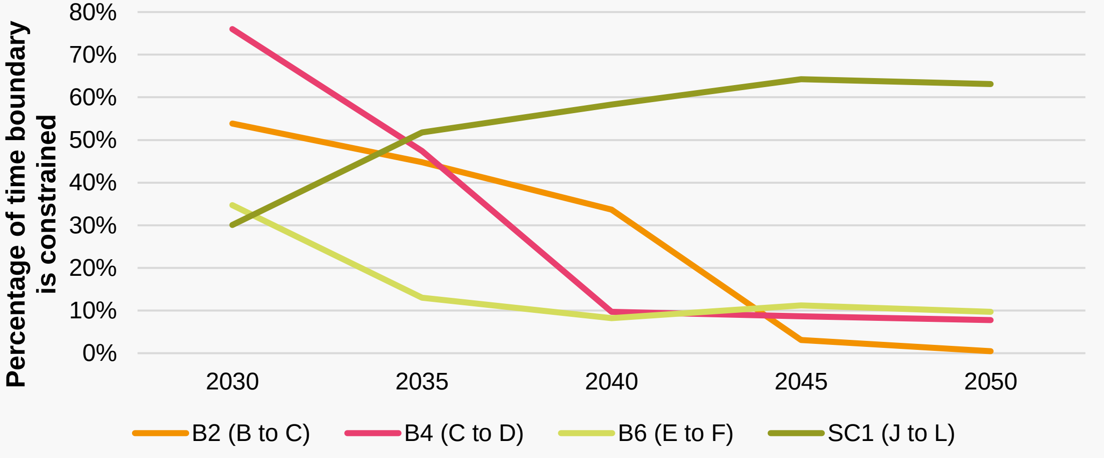


Sensitivity 2 - Increases to SC1 boundary capacity

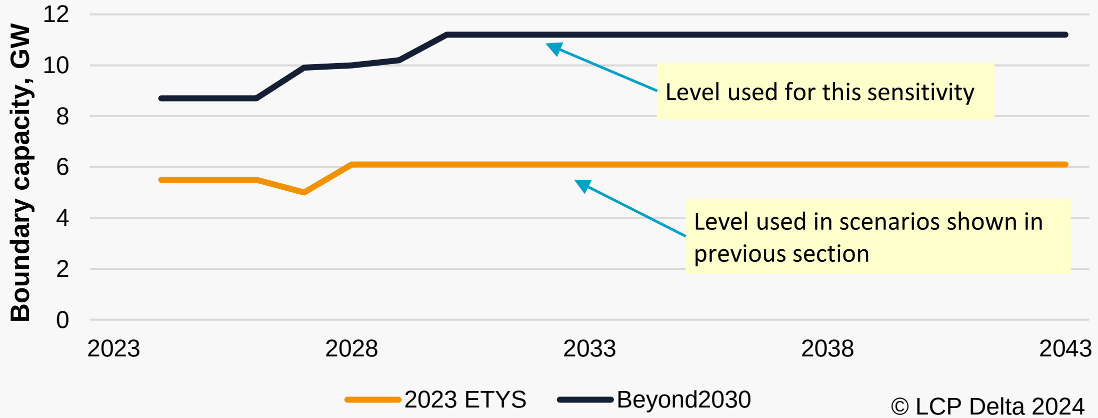
Our analysis shows that SC1 is likely to be a boundary with a high level of constraint in future, particularly without efficient redispatch of Interconnection

- Under **the 'Beyond 2030' plans the structural congestion between England and Scotland is significantly reduced** (assuming assets locate based on locational signals).
- However, with high levels of demand and significant levels of interconnection connecting in the region, **the SC1 boundary in the south of England is likely to become more constrained** in future.
- Under the 'Beyond 2030' national pricing scenario, the SC1 boundary is constrained over 60% of the time in the 2040s.
- This means that **increases in the SC1 boundary capacity could have a significant impact on the benefits of moving to zonal pricing**.
- The 'Beyond 2030' network plans published by ESO include a significant increase in the SC1 boundary capacity compared to the 'NOA7 refresh', however it is unclear from the report what is causing this increase.
- As such this increase was not included in the core scenarios in the previous section and is included as a sensitivity here instead.
- This shows the SC1 boundary capacity increasing by 5GW from 2030 compared to the 2023 ETYS publication.

Key constraints under 'Beyond 2030' plans with fixed offshore wind locations in national pricing counterfactual



SC1 boundary capacity under 2023 ETYS and 'Beyond 2030' network plans

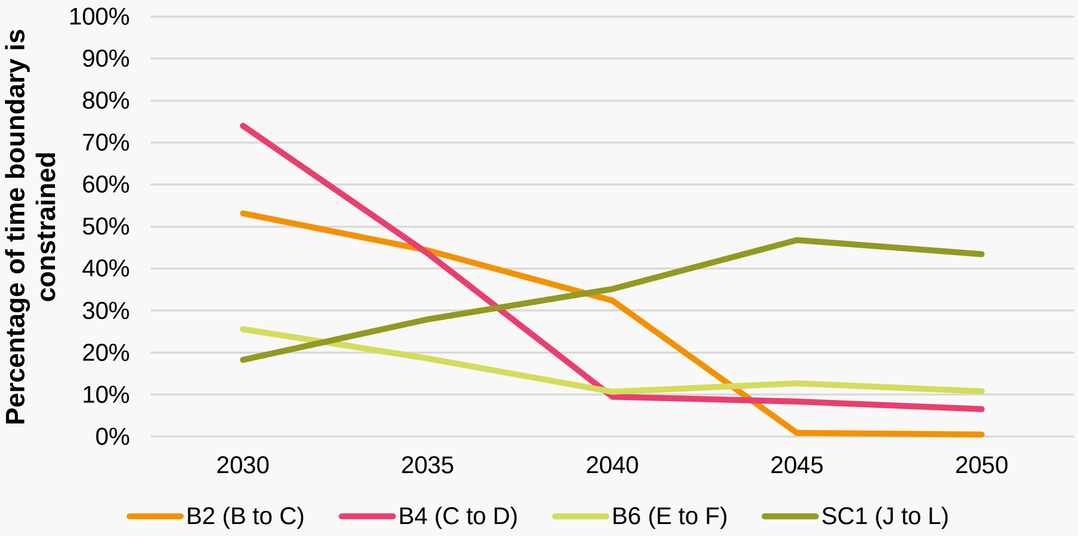


Sensitivity 2 - Increases to SC1 boundary capacity

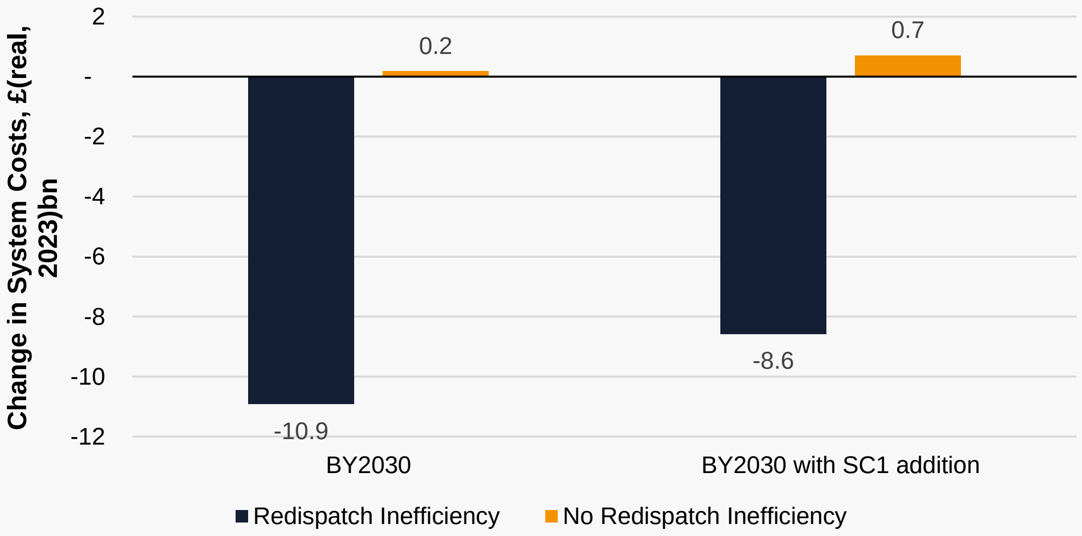
Increases to the SC1 boundary capacity in line with 'Beyond 2030' publication reduces benefits of moving to zonal pricing by £2.3bn in the redispatch inefficiency scenario

- **Increasing capacity on the SC1 boundary leads to the system being less constrained** in the national pricing counterfactual.
- Under this scenario, more generation is able to be exported into the south of England meaning that interconnectors do not exacerbate constraints as much as they were previously.
- In the redispatch inefficiency scenario (where interconnectors cannot redispatch under national pricing), **additional reinforcement to the SC1 boundary reduces the benefits of moving to zonal pricing by £2.3bn, from £10.9bn to £8.6bn.**
- Under the no redispatch inefficiency scenario, changes to the SC1 boundary have a limited impact with a move to zonal pricing increasing costs by £0.7bn compared to £0.2bn before the change.

Key constraints under the SC1 boundary capacity scenario in national pricing counterfactual



System cost changes between counterfactuals under the SC1 boundary scenario

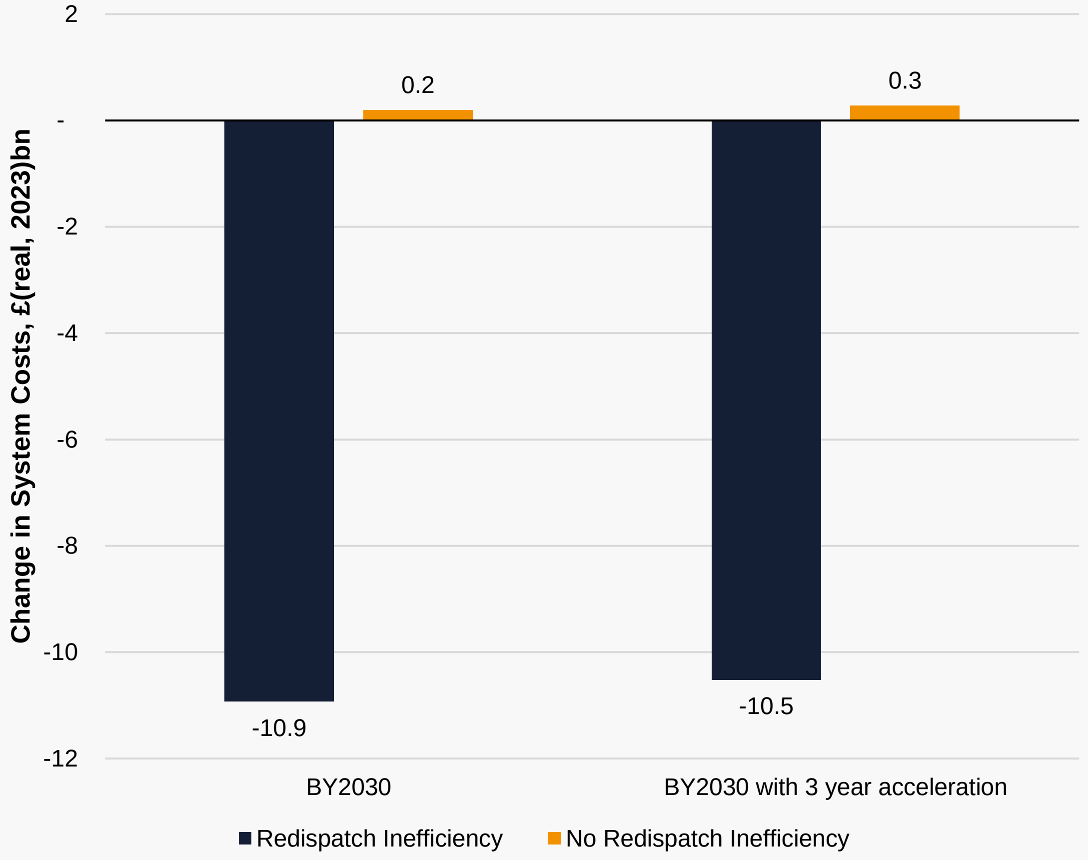


Sensitivity 3 - Network acceleration

Accelerating network build-out by 3 years reduces the benefits of moving to zonal pricing although the impacts are small

- **Accelerating the network build-out by 3 years leads to the system being less constrained**, particularly in the national pricing counterfactual.
- In the redispatch inefficiency scenario (where interconnectors cannot redispatch under national pricing), **accelerated network build-out reduces the benefits of moving to zonal pricing by £0.4bn**, from £10.9bn to £10.5bn.
- Under this scenario, more generation is able to be exported into the south of England earlier than in the core 'Beyond 2030' scenario meaning that interconnectors do not exacerbate constraints to the same degree.
- Under the no redispatch inefficiency scenario, accelerating network build out has a limited impact with a move to zonal pricing increasing costs by £0.3bn compared to £0.2bn before the change.

System cost changes between counterfactuals under the 3-year Network Acceleration scenario

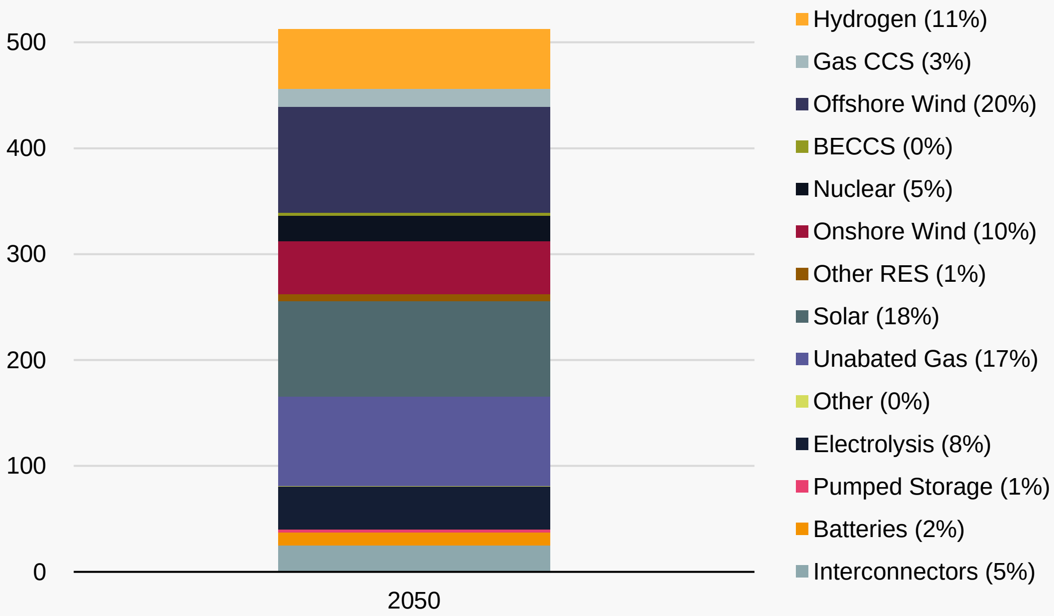


Sensitivity 4 - Alternative demand and capacity mix

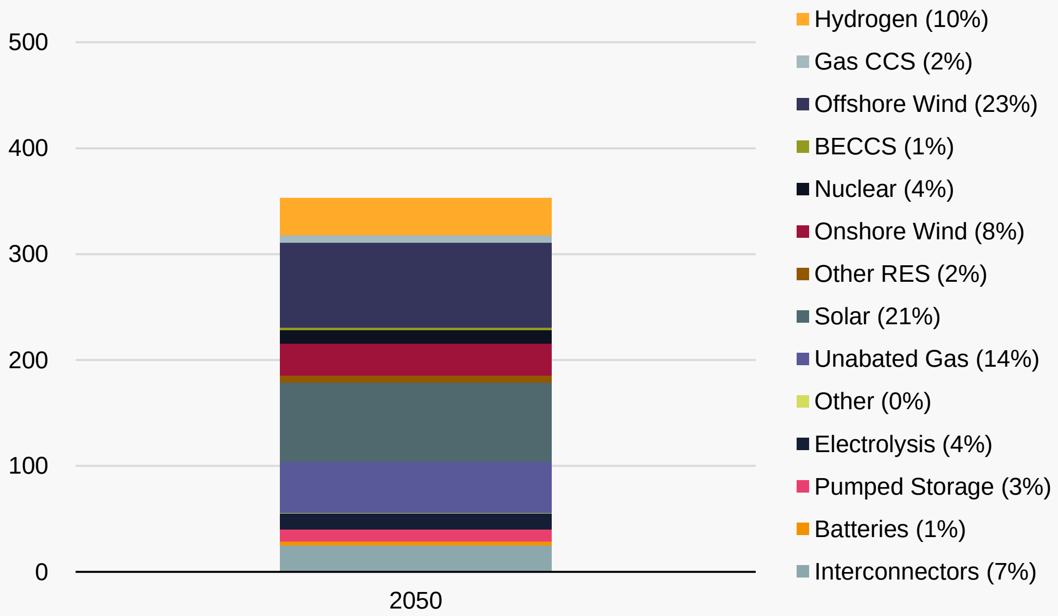
The makeup of the future system is highly uncertain, so an alternative demand and capacity mix based on DESNZ’s Net Zero Lower Demand scenario has been tested

- The results shown in previous slides all use a market background scenario based on DESNZ’ Net Zero Higher Demand scenario. This scenario assumes a high level of demand reaching 775TWh by 2050.
- Given the uncertainty around the future demand for the electricity system and what the capacity mix would look like, it is **prudent to test an alternative demand and capacity mix to understand the impact this could have on results**.
- As was done in the study completed for DESNZ, **an alternative demand and capacity mix is tested based on DESNZ’ Net Zero lower demand scenario**. This scenario assumes a lower level of electrification from other sectors with demand reaching 536TWh by 2050.
- This also results in a different capacity mix with significantly lower total capacity mix as well as a different mix of technologies as shown in the charts below.

2050 Capacity mix under DESNZ NZH scenario



2050 Capacity mix under DESNZ NZL scenario

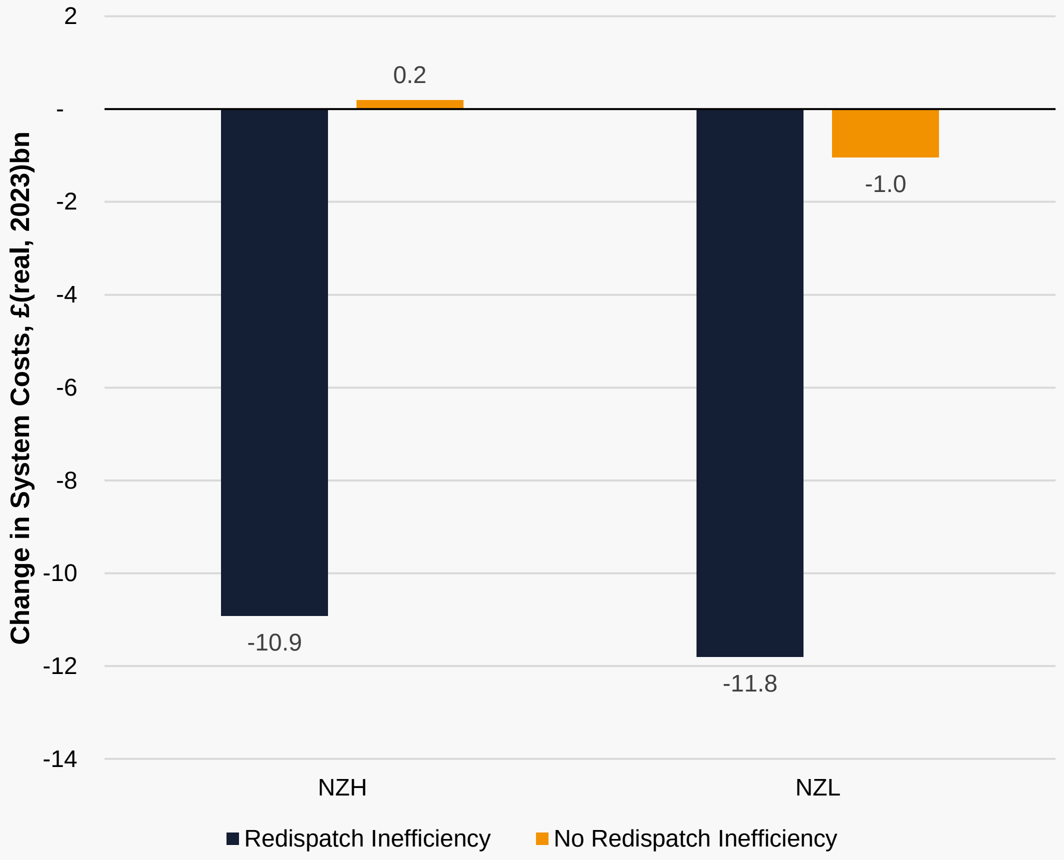


Sensitivity 4 - Alternative demand and capacity mix

A move to zonal pricing under DESNZ Net Zero lower demand scenario sees a limited change in the benefits of moving to zonal pricing.

- Under the DESNZ Net Zero lower demand scenario we see that the **effect of moving to zonal pricing shows a similar level of benefits to the core scenario**.
- Under this scenario we see a small impact in the no redispatch inefficiency where the impact of moving to zonal pricing changes from being a cost of £0.2bn, to being a benefit of £1bn.
- Similarly, in the redispatch inefficiency scenario, the benefits of moving to zonal pricing increase by £0.9bn, from just under £11bn to £11.8bn.
- Overall, **this shows relatively little difference in the overall findings with a different demand and capacity mix**.

System cost change of moving to zonal pricing under the DESNZ Net Zero lower demand and Net Zero Higher demand (core) scenario with 'Beyond 2030' network



Annex

Recap of LCP Delta's Locational pricing Study for DESNZ

Our study assessing the impacts of moving to locational pricing under the 2022 grid plans was published alongside the REMA Consultation

- LCP Delta and Grant Thornton were commissioned by Government to independently assess the impacts of alternative locational investment and operational signals within the electricity system by modelling the market under locational pricing.
- The impacts on the system and consumer costs in the electricity system were assessed, based on a move from the current national pricing model (counterfactual) to a locational pricing model (factual).
- The assessment was completed under a number of different scenarios that looked at some of the key uncertainties including impact on investment, network delays and interaction with other government policies
- Overall, the analysis showed a £5-15bn system cost benefit of moving to locational pricing, however the impacts vary based on key variables such as reforms to the national market, impacts on cost of capital and future network build-out.
- The findings from the study informed DESNZ's position on locational pricing in the second REMA consultation.
- The full report can be found here.

Moving to locational pricing can bring benefits to the GB energy system

Analysis shows that moving GB to a zonal pricing model can brining system benefits of £5-15bn under the DESNZ Net Zero Higher Demand Scenario.

Benefits are partially driven by generators locating closer to demand centres

The more efficient locational signal that locational pricing provides compared to existing TNUoS arrangements leads to capacity locating in areas more beneficial to the system.

Assumptions on redispatch in the national pricing counterfactual are key

Analysis shows system benefits are reduced from £15bn to £5bn with a more efficient redispatch of Interconnection assumed in a national pricing model.

Increases to cost of capital could wipe out the system benefits

If locational pricing leads to increases of 0.3 to 0.9 pp in the cost of capital for all technologies (exc Nuclear), system benefits are reduced to zero.

Locational pricing leads to a transfer of costs from consumers to producers

Analysis shows that a move to locational pricing could benefit consumers by £24-59bn, but this results in producer costs increasing by £19-36bn.

Delays to assumed network build could increase the system benefits

Analysis shows that if there is a 3-year delay to the planned network build, this would increase the benefits of moving to locational pricing by 10%.

LCP Delta's Locational Dispatch Model

Our Locational Dispatch Model allows for detailed modelling of network constraints

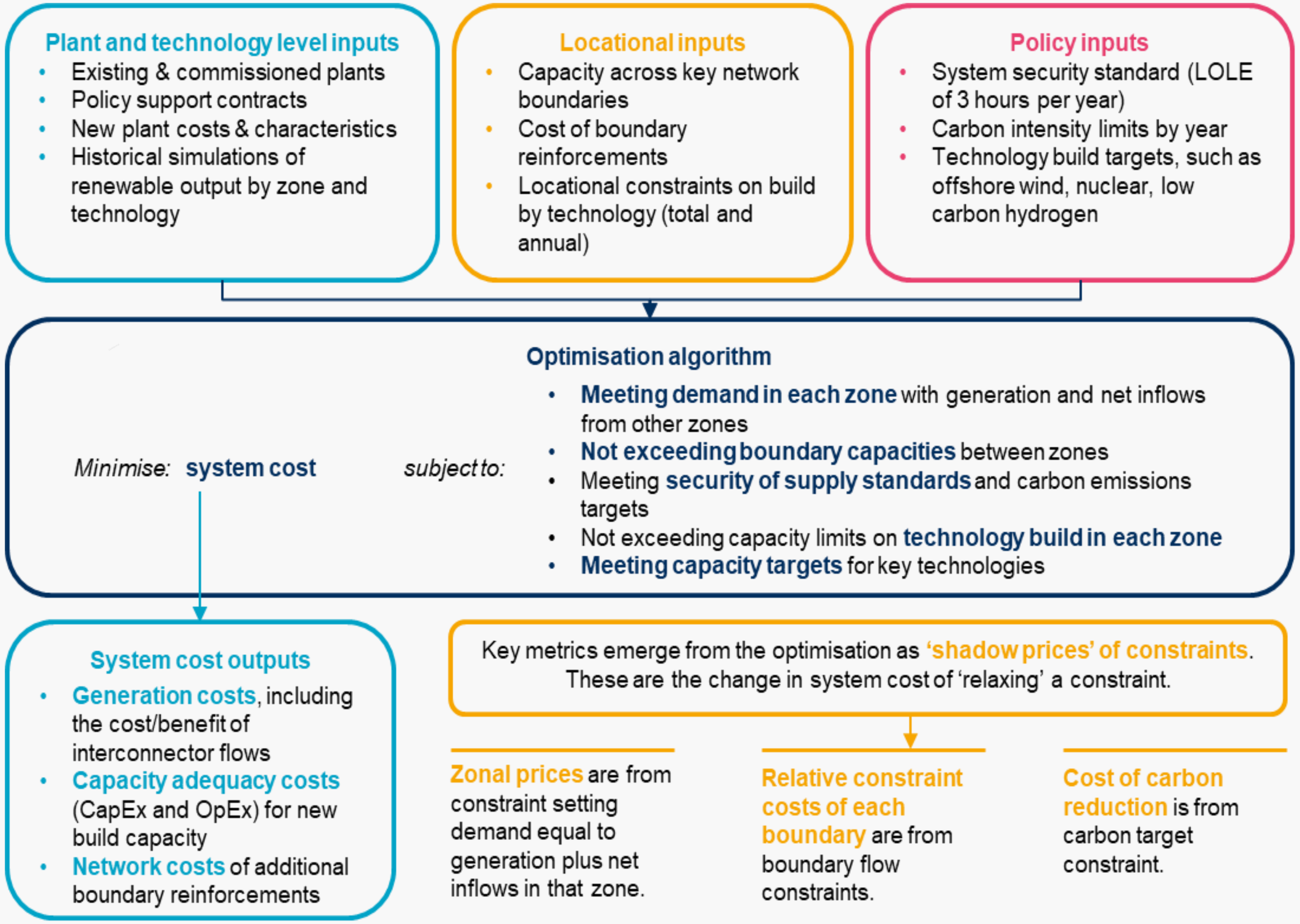
LCP Delta's Locational Dispatch Model (LDM) is a stochastic optimisation-based model designed to simulate the GB power sector with locational pricing. It has been developed specifically to model network constraints and understand the benefits of changing locational signals. The model works by simulating generation and demand every hour on a long-term basis.

There are two main functions to the model:

- **Market dispatch:** Simulating the supply and demand in each hour by zone, based on market fundamentals. This determines the operation of each plant on the system, and the wholesale market price(s).

- **Capacity relocation:** Re-allocating new plant to a different zone, based on market incentives and subject to zonal capacity restrictions (these can vary by technology). These incentives include wholesale prices (zonal or national), TNUoS (transmission network use of system) charges, policy support levels and generation availability (e.g. wind and solar available output vary by zone).

LCP Delta's Locational Dispatch Model Diagram



System Cost Framework

LCP Delta's system cost framework is used to assess the impact of moving to zonal pricing

- To assess the system impacts of moving to zonal pricing, the analysis measures the system costs of moving from a national pricing counterfactual to a locational pricing factual.
- This approach aligns with Government value for money (VfM) guidance as set out in the Green Book.
- The approach to system costs uses the framework for Whole System Costs that was developed in 2015 between LCP, Frontier Economics and UK Government.
- This approach is used by the Government for power sector impact assessments and VfM assessments.
- System costs represent the costs of building, operating and maintaining the power system for both consumers and producers. They are broken down into various components as shown in the graphic opposite.

LCP Delta system cost framework

Generation costs

- Fuel and variable operating costs (VOM) costs of plants associated with meeting electricity demand hour to hour, i.e. wholesale market dispatch

Carbon costs

- Carbon costs based on carbon emissions priced at social cost of carbon.
- The carbon cost can be split into two parts, carbon costs at the market price (carbon price plants pay) and unpriced carbon costs (additional carbon costs valued at DESNZ carbon appraisal price)

Capex Costs

- Capital costs include pre-development, construction and infrastructure costs (all £/kW) for building new plants.
- For system cost, this is cost of financing these investments, so are spread over the economic lifetime of the plant based on the assumed hurdle rate for the technology.

Fixed Opex Costs

- Fixed operating costs of plants, any operating costs that do not vary with output, and represented in £/kW terms.

Interconnector costs

- Costs associated with building, maintain and operating interconnectors.
- Costs are a 50:50 split between imports priced at the domestic market price and exports are priced at the foreign market price. Costs are proportioned to the markets owning each interconnector.

Network costs

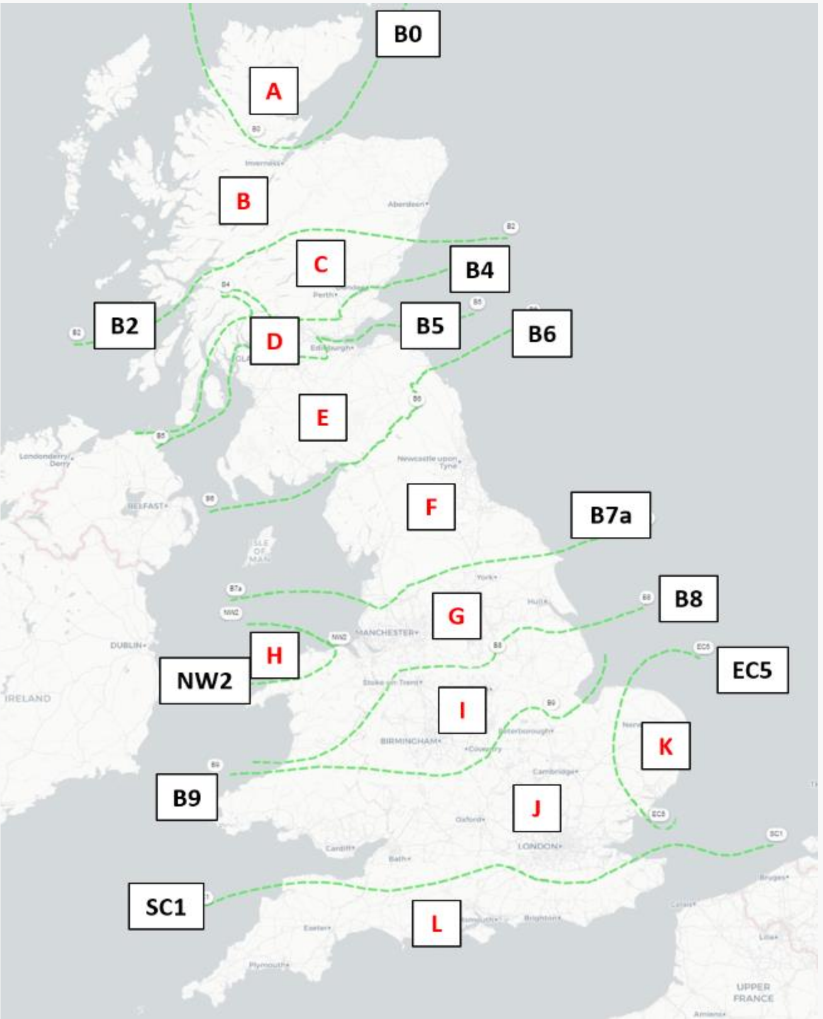
- Cost of maintaining, reinforcing and extending the transmission network

Key Input assumptions

The analysis replicates the assumptions used in LCP Delta's study with DESNZ as closely as possible

- Key assumptions used in the modelling are as close as possible to the Government's own Net Zero Higher Demand scenario used in the previous DESNZ study.
- This ensures consistency between this analysis and the previous analysis LCP Delta completed for DESNZ.
- This includes inputs on demand, capacity mix and commodity prices. Where these have not been published by DESNZ in detail, LCP Delta have made assumptions based on available data. For example, DESNZ publish a detailed breakdown of their assumed capacity mix for 2050 only, so some assumptions have been made on capacity mix for intervening years.
- Assumptions on zonal pricing specifically such as zonal breakdown and restrictions on capacity movement are taken directly from LCP Delta's report for DESNZ. For example, the country is split into 12 zones which capture the key transmission network boundaries is used.

Zones used in LCP Delta Zonal Pricing Study

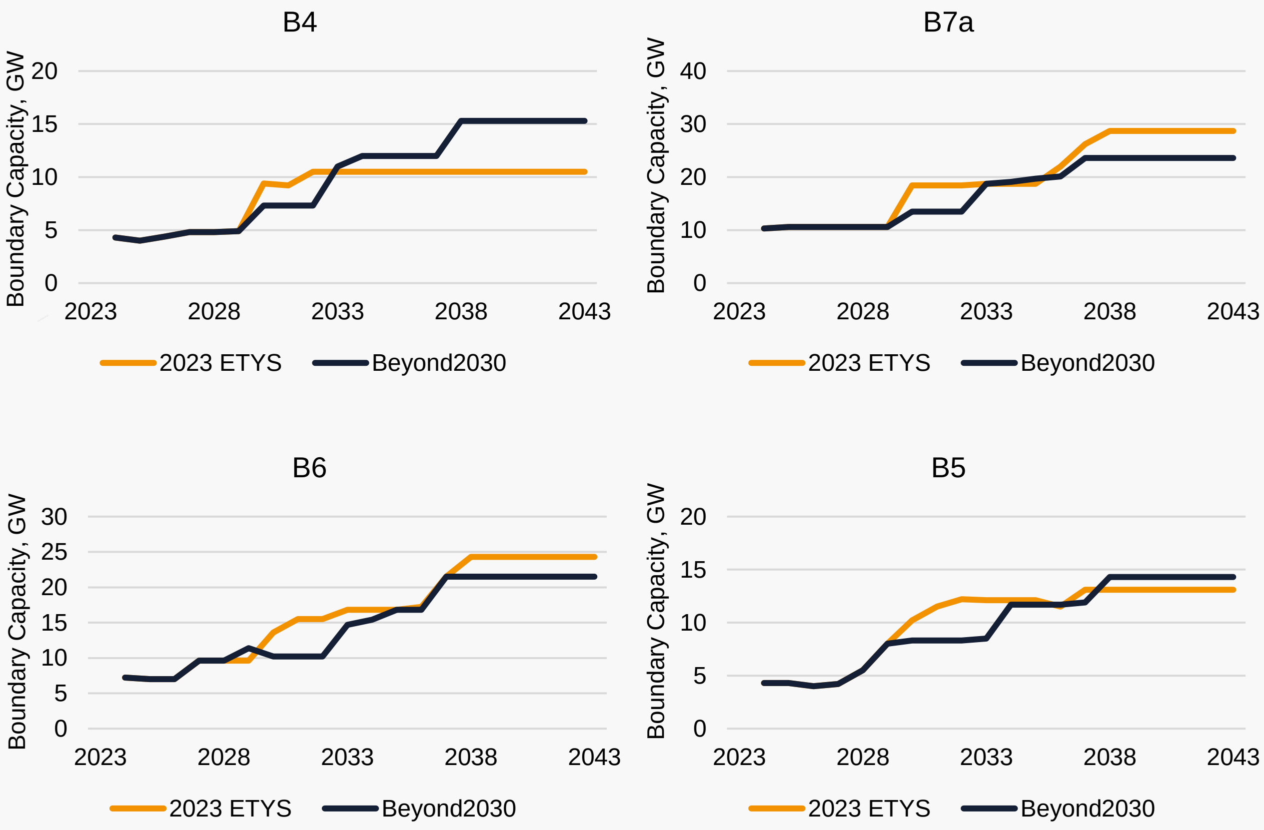


‘Beyond 2030’ network plans

Our analysis of the ‘Beyond 2030’ boundary capacities highlights some inconsistencies in the data published by the NESO between new plans and those published previously

- As part of the NESO’s publication of ‘Beyond 2030’, updated boundary capacities were published for key boundaries across the country. This is an update of previous data published as part of the Electricity Ten Year Statement (ETYS) reflecting the boundary capacities from NOA7. This was the data used by LCP in the study for government.
- Comparing these two datasets showed some inconsistences with ‘Beyond 2030’ capacities on some boundaries often being less than in NOA7 despite the ‘Beyond 2030’ plans, by definition, being plans to increase network infrastructure. **Some examples of are shown in the graphs opposite.**
- From analysis completed by LCP, it is not clear why this happens in the data published by ESO with no detail published on why some boundary capacities have changed significantly. This creates difficulty in determining assumptions to use on future network capacity for ‘Beyond 2030’ modelling for assessing the impacts of moving to zonal pricing.
- To test the impact of increased network capacity (as per the intention of ‘Beyond 2030’) and ensure consistency with previous modelling, NOA7 boundary capacities (as published in ETYS) have been used for the NOA7 network plans while **the greater of NOA7 and ‘Beyond 2030’ have been used for the 'Beyond 2030’ plans.**
- The 'Beyond 2030’ plans also include additional HVDC links running from Scottish wind farms which are included as additional network boundaries between zones. Full assumptions on boundary capacities used in the modelling are outlined in the annex.

Boundary capacities published by NESO for NOA7 (ETYS) and ‘Beyond 2030’



Source: NESO

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