System Benefits from Efficient Locational Signals

A study on moving the electricity market to a locational pricing model for the Department of Energy Security and Net Zero

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Executive Summary

Potential reform to introduce locational pricing to GB's wholesale electricity markets is one of the most substantial reform options identified in the Government's Review of Electricity Markets Arrangements (REMA) Programme

The Great Britain electricity system is set to undergo significant change in the coming years as the system evolves to achieve decarbonisation targets whilst meeting significant increases in demand. The Government's REMA consultation set out many potential changes with the aim to ensure that the Great British electricity market is fit for purpose for the future.

The consultation highlighted that there is a need to provide efficient locational signals to minimise system costs. More efficient locational signals could incentivise generation and flexible assets to build in suitable parts of the network, i.e., closer to demand and to operate in ways which can lower system costs. One possible way to achieve more efficient locational signals is by moving to a locational wholesale pricing. Locational pricing is an electricity market design where the wholesale electricity price at separate locations in GB represent the locational value of energy for that location. This compares to the current wholesale market design where a single national electricity price applies across the entirety of the network.

Grant Thornton and LCP Delta were commissioned by Government to assess the impacts of alternative locational investment and operational signals within the electricity system by modelling the market under locational pricing.

In this study for the Department of Energy Security and Net Zero (DESNZ), the impacts on the system and consumer costs in the electricity system are assessed, based on a move from the current *national pricing model (counterfactual)* to a *locational pricing model (factual)*. Using LCP Delta's Locational Dispatch Model, it also considers the impact of stronger locational signals on key electricity system outcomes including wholesale prices, generation mix, emissions, and the interaction of locational pricing with other Government policies. All outputs and conclusions from this study do not represent Government policy nor an expression of preference. The study is intended as evidence for the Government and industry to draw key conclusions on the merits of moving the market to a locational pricing model.

For this analysis, a zonal approach where the country is split into 12 zones which capture the key transmission network boundaries is used. This approach seeks to capture the most important network constraints, without modelling at a spuriously accurate level of detail.

The benefits of moving to locational pricing are subject to various uncertainties around the future make-up of the power sector and how locational pricing is implemented. Many of these are reflected in the analysis undertaken.

The potential benefits of moving to locational pricing are subject to significant uncertainties. In this study the analysis assesses the impact of moving to locational pricing across a range of different scenarios to capture the impact of key uncertainties allowing for an in-depth assessment with all assumptions provided by DESNZ unless stated. These are outlined below:

- Within the current national pricing model, various inefficiencies exist when redispatching the system though locational balancing in the Balancing Mechanism (BM) to resolve locational constraints. Due to uncertainty around the extent of these inefficiencies and whether changes can be made in the current market to remove/limit them, scenarios have been modelled with and without three different redispatch inefficiencies included:
    - A potential inefficiency in the current national pricing system is how interconnectors act with respect to locational constraints. Interconnector behaviour in response to national wholesale prices can exacerbate constraints, and National Grid ESO (NGESO) are limited in their ability to redispatch them in cost effective ways. Interconnectors are redispatched outside the BM to deal with locational constraints and other system needs. This is challenging to model as there is limited transparency on how this is done. Due to this uncertainty, two counterfactual scenarios which vary interconnection's participation in locational balancing have been run where interconnectors either fully participate in locational balancing (i.e., are dispatched efficiently), or do not participate at all. Both counterfactual scenarios are limited as neither accurately represent redispatch of interconnectors under current market arrangements. However, the scenarios are helpful in showing the potential operational benefits of locational pricing.
    - Recent evidence has shown that storage is often 'skipped' in the BM[1], limiting how often it is redispatched. Two scenarios are modelled, one where storage is not restricted in its redispatch actions (assuming improvements to the current market) to resolve locational constraints through the BM, and another where is storage is restricted in its redispatch actions (an approximation of the status quo).
    - Analysis of historic data shows that there is often a disconnect between the prices at which bids/offers in the BM are accepted, and the prices suggested by fundamental modelling. Generators can push offer prices up (or bid prices down), above their short run marginal costs (SRMC), capturing infra marginal rents and potentially leading to additional costs for the consumer. To capture this uncertainty, three bid/offer scenarios are modelled assuming generators bid/offer at cost, bid/offer up to the cost of the marginal unit (core scenario) or bid/offer at cost plus an uplift.
- Assumptions on demand and capacity mix are taken from the DESNZ Net Zero scenarios. These are an illustrative, net zero-consistent electricity demand and generation scenarios for Great Britain but are not a forecast. Most scenarios in the study are based on the DESNZ Net Zero Higher Demand scenario where annual demand levels (excluding electrolysis) reach around 700TWh by 2050. An alternative scenario is tested based on the DESNZ Net Zero Lower demand scenario where demand reaches 525TWh in 2050.
- The level of network reinforcement is a key uncertainty that could have a material impact on results. The network build assumed in most scenarios is based on NGESO's Network Options Assessment 7 (NOA7) refresh, which triples network capacity across key boundaries between now and 2040. Given the uncertainty around whether this can be achieved an alternative scenario where network build is delayed by three years is tested.

[1] Assets being 'skipped' in the BM is not exclusive to storage only. Modelling in this study for 'skipped' assets is limited to storage as this does occur most often for storage assets.

- A key uncertainty is the impact that moving to locational pricing could have on the cost of capital of investing in power plants. Sensitivity testing has been carried out to understand the impact that a higher cost of capital could have on the potential benefits.
- A moving to locational pricing will impact existing policies, in particular the Contracts for Difference (CfD) scheme. The extent to which CfD plants are exposed to locational signals is a key consideration. Two alternative scenarios are considered where the CfD reference price is set on a national basis and where it is set based on the zonal price for each plant. These different approaches vary CfD plants exposure to locational pricing.
- Where plants can locate will impact of moving to locational pricing. Restrictions on where different technologies can locate is applied across all scenarios and are varied for offshore wind to understand the impact additional location restrictions can have.

As with any modelling there are some common assumptions and methodology choices that have been made across all scenarios which affect the conclusions that can be drawn from this study. The most important of these to highlight are:

- The capacity mix of technologies is held constant between the national pricing counterfactual and the locational pricing factual in each scenario. This means that the impact of locational pricing on future technology build-out (capacity mix) are excluded.
- This capacity is relocated based on signals from TNUoS charges and locational balancing payments in the counterfactual, and locational pricing signals in the factual. This ensures a fair comparison across the factual and counterfactual. This relocation is subject to build limits and other restrictions, and load factors of intermittent renewables vary across locations. Costs of technologies do not vary by location due to lack of available data.
- Network build is held constant in the national pricing counterfactuals and locational pricing factuals. This means the potential benefits of reducing network investment from moving to locational pricing are not included. To model this benefit would require an in-depth analysis akin to NG ESO's Network Options Assessment (NOA) which is out of scope for this study.

The study finds that more efficient locational signals from moving to locational pricing leads to some system benefits with larger benefits for consumers, compared to a counterfactual where plants locate based on current market signals from TNUoS.

In scenarios based on DESNZ's Net Zero higher demand scenario and with no assumed impact on cost of capital, moving to locational pricing decreases 2030 to 2050 electricity system costs by £5bn (NPV in 2022 real prices) with redispatch inefficiencies in the national pricing counterfactual removed and £15bn where redispatch inefficiencies are assumed in the national pricing counterfactual. Consumer costs are reduced by £24bn and £59bn for the two scenarios, which results in a £19bn and £44bn producer cost increase. This shows a system benefit from moving to locational pricing with costs transferred from producers to consumers. 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, and operational efficiency, where cost savings are a result of changes in the operation of the market (regardless of plants changing location).

In the scenario where interconnectors can fully participate in locational balancing and other redispatch inefficiencies in the national pricing counterfactual are removed, system costs decrease by £5bn when moving to locational pricing. In this scenario, all system level cost reductions are driven by the investment efficiency due to the movement of plants to locations that are more beneficial to the system. For example, 6GW more solar locating in the highest demand zone and 10GW more offshore wind locating in the most southern zone by 2050. This movement allows for a more efficient dispatch of the fleet such that lower cost plants (mainly renewables) can dispatch more frequently without turning on more expensive gas plants or importing via the interconnectors. This results in more efficient generation from the same fleet with key boundaries on the network becoming less constrained which benefits the system.

In the scenario where redispatch inefficiencies and no interconnector participation in locational balancing are assumed in the national pricing counterfactual, system cost reductions from moving to locational pricing increase from £5bn to £15bn. This £10bn increase is a result of additional operational benefits[2] from interconnectors and storage being used more efficiently. In the national pricing counterfactual, the absence of interconnection and reduced dispatch of storage in locational balancing means constraints need to be solved by the redispatch of other technologies. This results in more expensive domestic generation, such as unabated gas, turning up to resolve constraints which increases generation costs in the counterfactual. However, under locational pricing this is no longer an issue as interconnectors and storage dispatch against the zonal rather than national price (and it is assumed they do so efficiently).

As outlined above, both counterfactual scenarios modelled are limited in that neither accurately represent redispatch of interconnectors under current market arrangements. It is likely that somewhere between the two scenarios is a more accurate representation of interconnector redispatch. Regardless, these scenarios do show that moving to locational pricing could provide operational benefits to the system through more efficient signals to interconnection and storage. However, other ways to achieve at least some of these efficiencies through changes to a national pricing market are likely to be possible and should be explored by Government.

The analysis also shows that moving to locational pricing will see large transfers between producers and consumers (in the low-to-mid tens of £billions), with consumers benefiting greatly. These transfers are higher with redispatch inefficiencies assumed in the counterfactual. Interconnectors not participating in locational balancing, storage limited in its dispatch in locational balancing and generators bidding/offering into the BM with an uplift increase constraint costs in the national pricing counterfactual. As constraint costs no longer directly apply in a locational pricing market (with constraints being factored into wholesale costs instead), this increases the benefits of moving to locational pricing.

Depending on the policy decisions taken this transfer between producers and consumers could create risks for the power sector, which could manifest as increases in CfD strike prices and capacity market clearing prices or requiring additional government policy support to incentivise the technologies that are needed to decarbonise the sector.

[2] It should be noted that plant locations also change in the counterfactual meaning there are some additional investment efficiency savings as well

System cost benefits could be outweighed by increases in cost of capital. Increases in cost of capital of 0.3 to 0.9 percentage points result in a move to locational pricing becoming a net cost to the system.

The cost of capital is the expected compensation required by investors to undertake risky investments. The higher the uncertainty around future cash flows, the higher the risk for an investor. In exchange for taking more risk, an investor will require a higher return leading to a higher Weighted Average Cost of Capital (WACC) for project developers. Introducing a large change to the system such as locational pricing could be seen by investors as an increase in risk resulting in higher levels of WACC, although changes to policy design alongside locational pricing to reduce risk may mitigate some of this impact.

There is significant uncertainty as to whether introducing locational pricing would increase cost of capital for investors, and if so, to what extent. Various other studies have reached different conclusions on the impact that this could have with values ranging from 0 to 3 percentage points (pp). In this study, cost of capital increases of between 0 and 2pp are modelled, where a uniform step change is assumed over time and across all technologies (except Nuclear which is assumed to be unaffected due to having Regulated Asset Base agreements). Testing this range on the analysis shows that a 0.3pp to 0.9pp increase in cost of capital removes all the system benefits in the two scenarios outlined above, while a 1pp increase results in a move to locational pricing becoming a net system cost of £4-12bn and a 2pp increase a net system cost of £23-30bn. This highlights that the impact of moving to locational pricing on investor risk is a key consideration for policy makers when considering a move to a locational pricing model.

A delayed build in transmission networks can increase the benefits of moving to locational pricing as more efficient location drives higher benefits in a more constrained network.

Network reinforcement levels are a vital assumption for assessing the impact of moving to locational pricing. This is because plants moving to more efficient locations that are closer to demand centres to avoid network constraints is one of the key potential benefits of locational pricing. A more constrained network will lead to higher benefits from moving to locational pricing as plants moving location has more of an impact.

The study finds that a delay in network build can increase the benefits of moving to locational pricing with a 3-year delay in the NOA7 refresh network build increasing benefits of moving to locational pricing by 10% (2030-50). In this scenario, the difference in benefits in percentage terms is higher in earlier years where the difference in network build is larger (although in absolute terms it is lower as more of the benefits are in later years). For the 2030-40 evaluation period, the benefits of moving to locational pricing are 26% higher with a 3-year network delay. This highlights that locational pricing will bring more benefits to the system if network reinforcement plans cannot be met. As such the achievable level of network build needs to be considered in any decision made on moving to locational pricing. It is also with noting that who bears the risk of network delays changes. In the counterfactual, it is borne by consumers through constraint costs whereas under locational pricing, the risk is borne by investors.

The interaction between CfDs and locational pricing is vital and exposing CfD plants to locational signals as much as possible could help to bring more benefits to the system. However, these benefits would need to be weighed against potential increases to investor risk.

The interaction of locational pricing with CfDs is a key area of consideration. While we do not want to pre-empt what government policy would be in this area, the analysis does look at two different ways that the CfD could interact with locational pricing. This is done by varying the CfD reference price between two options; a CfD reference price based on the supported plant's zonal wholesale price and a reference price based on an unconstrained national price. This essentially alters their exposure to locational signals – a zonal reference price would avoid any exposure to locational pricing signals (though plant would remain exposed to curtailment risk) when compared to an unconstrained national reference price, which would fully expose plant to locational pricing signals. The interaction with the negative pricing rule also needs to be carefully considered when moving to locational pricing.

The study finds that increasing CfD plants' exposure to locational signals could help deliver the full benefits of moving to locational pricing, although this depends on other impacts from exposing CfD plants to more risk. System benefits are at £5bn (NPV 2030-50) with CfD plants fully exposed to locational signals through a national reference price compared to £3.5bn (NPV 2030-50) in a scenario where the CfD plant have a zonal reference price, a difference of £1.5bn. This suggests that exposing as many plants and technologies as possible is needed to maximise the potential benefits from locational signals – however, this does not include cost of capital impacts, which may be higher with greater exposure to locational signals. Overall, in assessing the case for locational pricing, the Government must consider the interaction with the CfD as this can have a key impact on benefit levels.

Overall moving to locational pricing can provide benefits to the system and to consumers but these benefits will depend on how it is implemented and how investors will react to such a significant change.

Moving to locational pricing could provide a stronger signal to incentivise plants to locate more efficiently for the system than the current version of TNUoS does. This 'investment efficiency' can provide benefits of £5bn in a core scenario. It can also provide an additional operational efficiency system cost saving of up to £10bn in the scenarios tested however the extent of operational efficiency savings does depend on what is assumed in the national pricing counterfactual. The impact on consumers is greater with benefits of £24bn to £59bn but costs for producers increase by £19bn to £36bn. These impacts are higher if there is less network build or if CfD plants are fully exposed to locational signals.

However, the study finds that these benefits will be removed if the cost of capital for investors increases by 0.3 to 0.9 percentage points meaning Government needs to fully consider what the impact will be on investors of such a fundamental change to the market. It also finds that Government should consider if some of these benefits can also be achieved through modifications to the current national pricing model, particularly the operational efficiency benefits which may not be unique to locational pricing.

1. Introduction

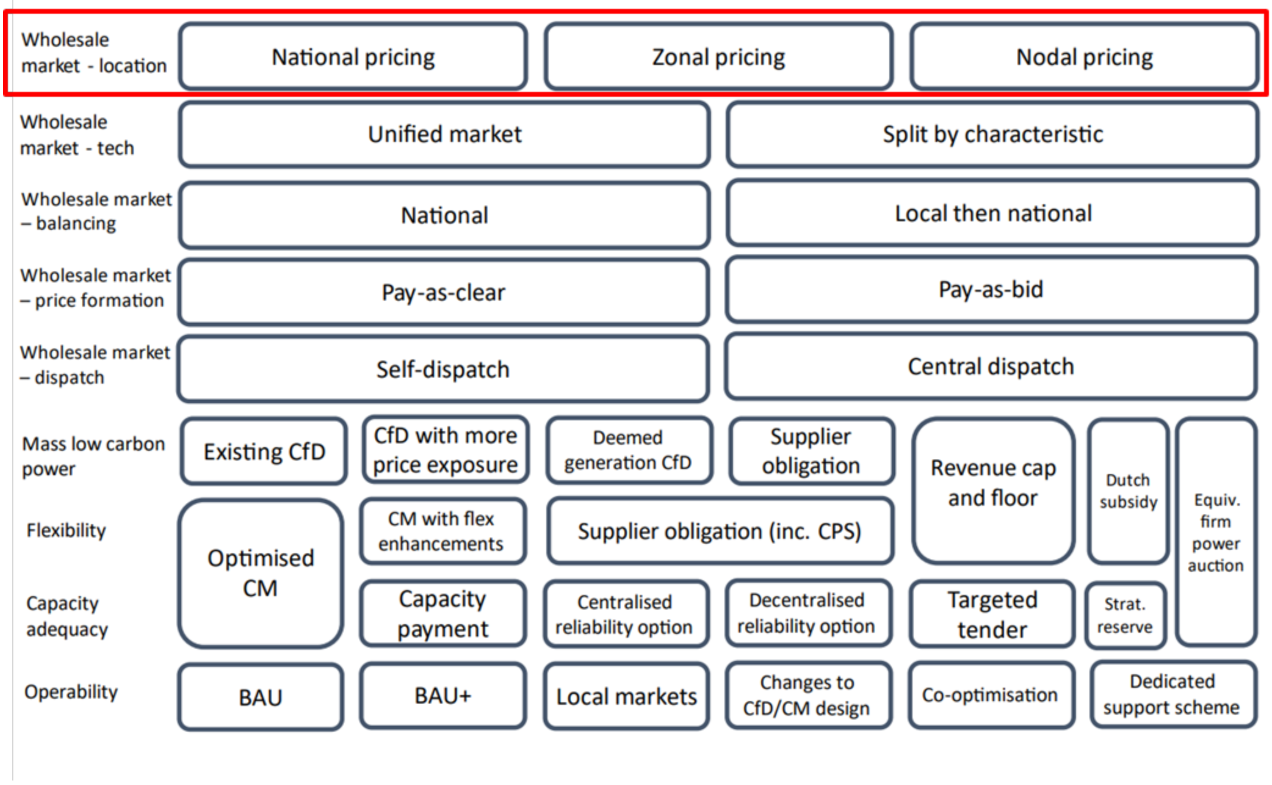
1.1. Background and Context

The Government published its Review of Electricity Market Arrangements (REMA) consultation in July 2022[3] outlining a range of options for reforms to electricity markets. The consultation highlighted **locational pricing** as a possible market reform that could help to deliver a low carbon, low-cost power system.

The aim of the REMA programme is to ensure that the electricity market is fit for purpose for the future, by delivering reform to electricity market arrangements that facilitate the meeting of the full decarbonisation of the electricity system by 2035, subject to security of supply, target whilst being cost-effective for both the system and consumers.

Through the case for change work undertaken by LCP Delta for NGESO and the Government, several key challenges were identified which could act as barriers to achieving a fully decarbonised electricity system. The REMA consultation outlined several potential changes to the system that could help deliver this. One of the most fundamental potential changes to the market is the introduction of locational pricing within the wholesale market, *where granular locational signals are introduced into wholesale electricity prices*.

Figure 1: *Options under consideration in REMA programme (figure taken from REMA consultation document[2]). Wholesale market - location options are the focus of this study*



[3]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1098100/review-electricity-market-arrangements.pdf

The locational case for change highlighted the need to provide efficient locational signals to minimise system costs. Renewable assets are likely to locate where the natural resources are most plentiful and where they can obtain the necessary planning consents, however this is often far away from demand. Efficient locational signals could incentivise generation, flexible assets, and demand to locate in suitable parts of the network, e.g., in areas with spare network capacity, where market prices are most advantageous and to operate in ways which can lower system costs.

DESNZ have commissioned LCP Delta and Grant Thornton to carry out a study to improve understanding of the **value of more efficient locational signals** within the electricity system by reforming the market to a locational pricing model. This will inform market design policy decisions under the Review of Electricity Market Arrangements (REMA). As part of this report, we assess the **possible system and consumer benefits** of moving the GB wholesale market from a national pricing model to a **locational pricing model**.

All outputs and conclusions from this study do not represent Government policy nor an expression of preference. The study is intended as evidence for the Government and industry to draw key conclusions on the merits of moving the market to a locational pricing model. Additionally, while the DESNZ Net Zero scenario data used shows an illustrative, net zero-consistent electricity demand and generation scenario for Great Britain, it is not a forecast.

1.2. Project Overview

The analysis measures the system and consumer cost impacts of moving from a *national pricing model (counterfactual)* to a *locational pricing model (factual)*. It also looks at other impacts from moving to a locational pricing model such as impacts on wholesale prices, generation, emissions, security of supply, and impacts on other policies such as the CfD.

Given uncertainties around the exact shape of the future GB electricity system, the analysis assesses the impact of moving to locational pricing across a range of different scenarios which allows for a more complete assessment against a range of possible future scenarios. These include:

1. Variations in underlying demand and capacity mix (based on a low demand DESNZ scenario and high demand DESNZ scenario).
2. Variations in network investment/build-out levels.
3. Variations in the way CfDs are implemented with locational pricing.
4. Cost of capital impacts.
5. Variation to the national pricing counterfactual where different levels of redispatch inefficiency are assumed. This includes changes to whether interconnectors can be redispatched in locational balancing, limited redispatch of storage in locational balancing and changes to bid/offer prices from generators in the BM.
6. Variations in restrictions on where certain assets can locate.

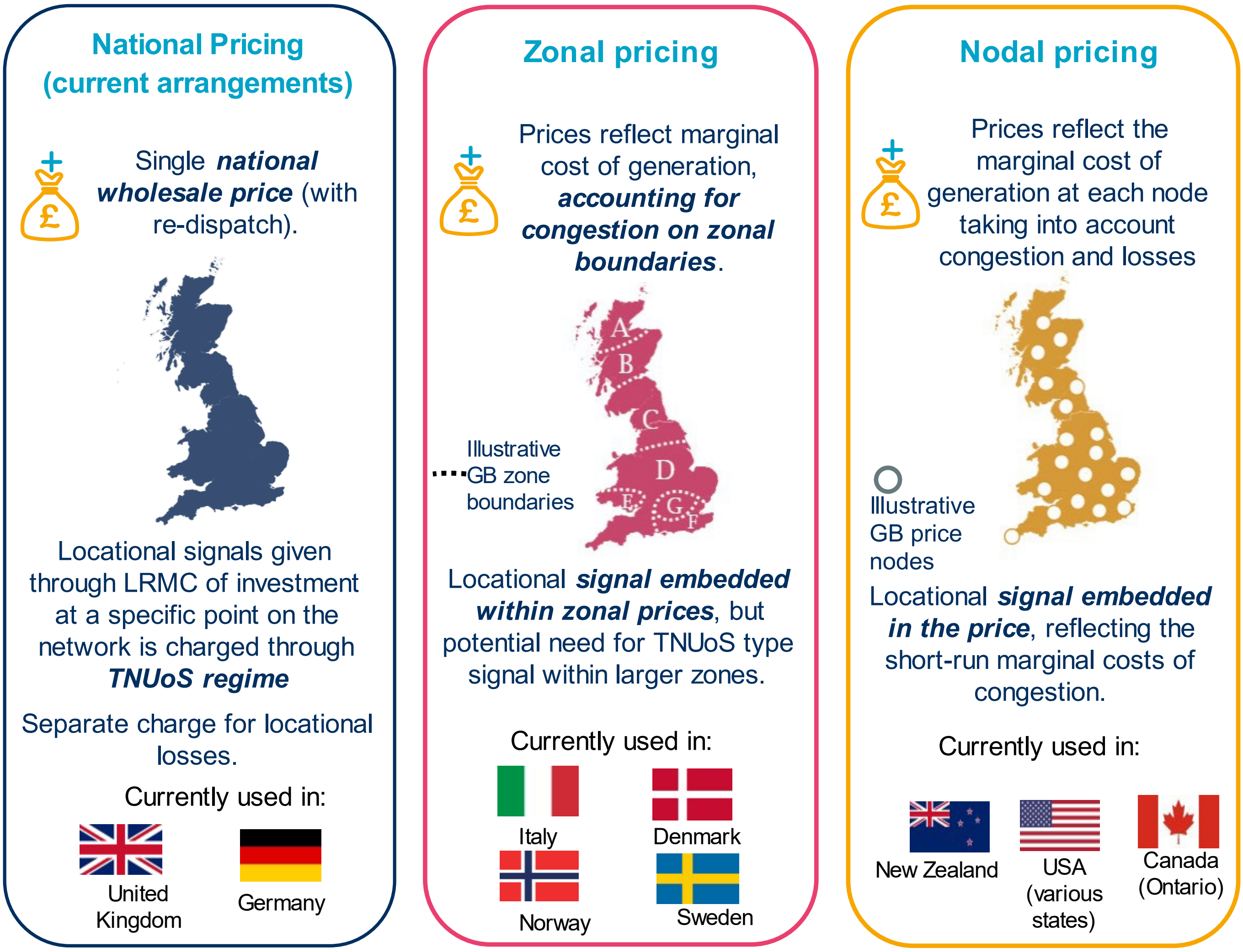
The majority of analysis for this project has been completed between January and July 2023 with all assumptions used in modelling provided during this period.

1.3. Wholesale Market Locational Options

The Great Britain (GB) wholesale market's current design has a single national electricity price, which applies to the entirety of the network[4]. This means all generation and demand receive the same wholesale price, irrespective of their physical location.

Locational pricing is an electricity market design where the wholesale electricity price at separate locations in GB represent the locational value of energy for that location. These can be set at any level of granularity. The two granularities often discussed are **zonal pricing**, for example using zones which reflect areas behind key transmission constraints, and **nodal pricing**, for example using each grid supply point on the transmission system. The figure below provides an overview of these options:

Figure 2: *Wholesale Market illustrative locational pricing options*



[4] There is an adjustment for transmission and distribution losses, which are allocated through the use of transmission loss factors (TLFs) and line loss factors (LLFs). These scale the energy consumed or generated, which effectively means prices are adjusted. However, TLFs in particular are not very granular, and only set on a seasonal basis.

1.4. National Pricing

Under GB's current national pricing structure, the wholesale price of electricity does not vary for different market participants based on their location on the network[5] (though adjustments are made for the average level of transmission losses expected at a zonal level on a seasonal basis). This is because the national wholesale price effectively represents the result of an "unconstrained dispatch" – where network constraints are ignored, and it is assumed that generation from any location on the network can reach demand at any location on the network.

Locational Balancing

To ensure that all electricity generated can reach demand, the system operator, National Grid ESO (NGESO), redispatch assets via turn up and turn down actions in the balancing mechanism. With this redispatch, there are a number of locational considerations that NGESO need to account for to ensure that a stable and secure electricity supply is maintained, statutory resilience requirements are sustained, and that operating requirements of the transmission assets are met.

Current market arrangements require assets registered as Balancing Mechanism units (BMUs) to issue Initial Physical Notifications (IPNs) to be issued for the following day at 10:00GMT the day before delivery, usually for the whole day. These provide NGESO with an early understanding of how each asset will be importing and exporting the following day. Assets are then free to continue to trade their power through the two day-ahead auctions (N2EX and APX) the three intraday auctions, the on-exchange continuous market, or bilaterally. Units can continue to trade their power, changing their Physical Notification (PN) up until gate closure (1-hour prior to the commencement of a given half-hourly settlement period).

At gate closure, NGESO has confirmed positions of each BMU in the market and can then begin redispatching units according to the requirements of the system. At this stage, NGESO can take actions in the Balancing Mechanism (BM) to instruct units to deviate from their Final Physical Notification (FPN). By repositioning units in this way, NGESO ensures that system needs are met.

There are two main types of constraints that NGESO take actions to resolve: thermal constraints and stability constraints. A thermal constraint is where the physical limits of the transmission network are reached, resulting in equipment (such as transmission cables) being overloaded and overheating. To reduce the temperature of the electrical circuit, NGESO reduces the amount of power passing through that part of the network. It does this, by reducing generation on the 'wrong' side of the constraint and increasing generation to make up for that now shortfall of energy (i.e. balancing) on the other side of the constraint. Each part of the network has a maximum amount of energy that can be passed through it, often referred to as boundary capability.

[5] Note that due to decentralised trading arrangements there is no single national price. The majority of electricity is sold over the counter using pay-as-bid contracts, where the price is bilaterally determined by the two parties. There are some auction markets (e.g. day ahead auctions) that use pay-as-clear pricing where all auction participants pay/receive the same price.

The cost of these actions depends on the units being actioned. For example, the transmission network between Scotland and Northern England (known as the B6 boundary) cannot always facilitate the transmission of power from north to south when wind generation is high in Scotland. Therefore, NGESO will take action on Scottish wind generation units, curtailing their output by paying them to turn down. Payments to the wind generation units are typically at the cost of the subsidy that the wind generator will miss out on (some FITs, but mainly RO, or CfD). NGESO will then need to redispatch that energy south of this boundary constraint (in England) by paying another generator to tun-up. Currently, this is typically a gas generator in the south of England. This ensures that the energy demand is met across the country but reduces the power through the problem circuit (B6 boundary in this case) and therefore resolving the network constraint.

System stability constraints typically refer to inertia and voltage requirements. NGESO also typically addresses these through the BM, however, it is starting to manage an increasing proportion of them through stability pathfinders and tenders. Through the BM, NGESO can take actions to bring units onto the system to provide system stability (either inertia to reduce the Rate of Change of Frequency (RoCoF), or voltage and reactive power) in different locations. Actions to resolve stability issues at a locational level are taken less frequently than for thermal constraints, as many thermal plants provide stability services as a by-product of providing active power.

Not all assets participate in the BM to alleviate locational constraints. Interconnectors do not participate directly in the GB balancing mechanism. Under current market arrangements, after gate closure changes to interconnector flows to address GB system concerns primarily relies on “system to system” arrangements with agreement needing to be reached between the NGESO, the interconnected country’s TSO and the interconnector owner. NGESO do sometimes redispatch interconnectors to some extent to change interconnector imports/exports to help resolve constraints (with costs being captured as part of Balancing Service Adjust Data (BSAD)) although there are no clear rules and limited transparency as to how and when this is used. This issue is explored further in 3.7 and chapter 5 of this study.

Locational Investment Signals

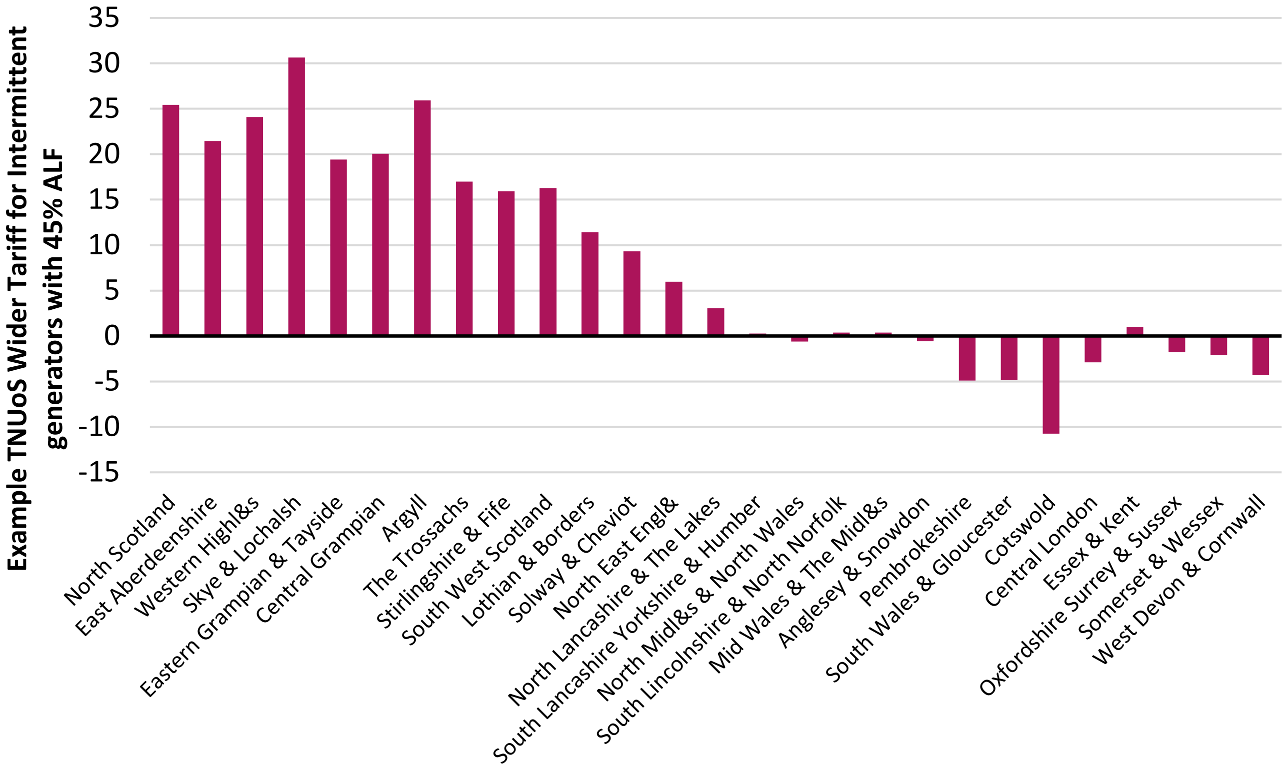
Locational investment signals are primarily given to transmission connected generation assets in two ways; the Balancing Mechanism and Transmissions Use of System Charges (TNUoS) charges.

As outlined above, actions are taken by NGESO through the BM to resolve locational constraints by turning plant up or down. This can result in additional profits for those assets being used to help resolve constraints, such as generating units located nearer demand centres, and can provide an incentive for assets to locate in beneficial parts of the network. However, it does not disincentive generation assets from exacerbating constraints, as these plants will still receive wholesale market revenue, and their BM bids for constraint actions will ensure they at least break even from being turned down to resolve constraints.

TNUoS charges are charged on generators and suppliers to recover allowed revenue for Transmission Network owners for the cost of building and maintaining the transmission network. TNUoS charges vary by location, with TNUoS tariffs split into 27 supply zones and 14 demand zones. The locational element of TNUoS charges is designed to be cost reflective, capturing the estimated additional network investment associated with each asset. In general terms, this means that those generators located further from demand (e.g. North Scotland) pay higher TNUoS charges than those located closer to demand (e.g. London). This provides an investment signal to generation assets to located in zones with lower TNUoS charges. A number of concerns have been raised about TNUoS, including its cost reflectivity and unpredictability. Further work is ongoing by NGESO, Ofgem and an industry Task Force to explore improvements to the methodology[6]. Note that the TNUoS tariff calculation methodology assumes a network that is sized to cover estimated peak flows and does not consider network constraints.

Example wider TNUoS tariff charges for 2023/24 for intermittent generators with a 45% annual load factor are shown below. This shows that intermittent renewables, such as wind, would pay significantly higher TNUoS charges to locate in Scotland and would get paid to locate in parts of Southern England.

Figure 3: *Example wider TNUoS tariff: Intermittent generator in 2023/24 with an Annual Load Factor of 45% as published by NGESO[7]*



6 https://www.ofgem.gov.uk/sites/default/files/2022-05/TNUoS%20Task%20Forces%20May%202022.pdf

7 5YV of TNUoS Tariffs for 2024/25 to 2028/29 (nationalgrideso.com)

1.5. Locational Pricing

In locational pricing markets, electricity is priced based on the marginal cost of meeting demand at that location on the network. This considers any generation at that location and any imports and exports from the network. Each defined area within the market has a separate price. Price differences between areas occur where there are transmission capability limits between areas, resulting in network constraints.

Locational pricing can be implemented under different granularities – these tend to be split into two types, zonal pricing and nodal pricing. Under zonal pricing there is generally a small number of price zones within a single country. For example, Italy currently has seven zones and Sweden has four zones with these reviewed periodically every few years. With a zonal pricing model, some additional redispatch may still be required to resolve network constraints within zones but zones should be chosen such that all major transmission network boundaries are included.

Markets with nodal pricing, can have 1000s of nodes reflecting different offtake and injection points (e.g.: grid supply points) with the price varying at each node. Nodal Pricing has been implemented in several international markets, including parts of the United States, Canada, Australia, and New Zealand. Learnings from these markets can help in understanding how the implementation of locational pricing could operate in practice.

Nodal pricing requires a centralised dispatch model that considers network constraints, removing the need for a re-dispatch where NGESO takes action to alleviate these constraints. This could also mean more efficient procurement of some ancillary services, such as inertia and reactive power, as this could be included within a centralised dispatch.

For example, if there is an excess of wind power relative to demand in Scotland, and the network does not have the capability to transport all of this power to demand further south, some of the available wind power would need to be curtailed. The marginal cost of meeting additional demand in Scotland is now close to zero (and perhaps even negative) – as it can be met by reducing the amount of wind curtailed. However, meeting additional demand in England and Wales may require increasing gas generation, at a much higher price.

Locational pricing would likely lead to the introduction of Financial Transmission Rights (FTRs). This would allow participants in the market to partially hedge their locational benefit and manage their exposure to locational price volatility. FTRs are used in other markets to enable market participants to hedge the locational price spread between their location and the wider market, allowing them to effectively trade forward products at the market price. Given the UK's international investor base, it follows that FTRs are likely to be leveraged in the UK system.

In locational pricing markets, strong locational signals are provided as the cost of resolving network constraints is reflected within the wholesale prices. As a result, plants are incentivised to locate in areas that have a higher average price, thus resolving network constraints in the process.

It should be noted that is likely TNUoS is likely to still exist under a locational pricing model in some form to ensure the networks get the revenue they require under the regulated asset value model. However, the locational element of TNUoS will no longer be needed as this is driven by the variation in wholesale price across location. While we do not want pre-empt policy in this area, is it likely that the TNUoS rate would become flat across the country under a locational pricing model.

1.6. What are the potential impacts of moving to locational pricing?

There are several studies which have looked into the case of moving to locational pricing. Each of these have outlined the potential impacts of moving to locational pricing. This includes studies from Energy Systems Catapult[8] and FTI for Ofgem[9]. A summary of the potential advantages and disadvantages are outlined in the graphic below.

POTENTIAL ADVANTAGES	POTENTIAL DISADVANTAGES
Efficient cost-reflective pricing e.g. not compensating curtailed generation	**Implementation challenges** Transitional uncertainty, may affect transition to Net Zero
Investment signals: generation e.g. locate flexible generation assets near demand centres	**Locational pricing may not be needed to achieve near system optimal dispatch** Changes to balancing could achieve this[10]
Investment signals: demand e.g. locate demand near generation sources	**Limited groups able to respond** Potentially difficult for existing gen, site-specific gen, CfD, and domestic consumers to move
More transparent, granular pricing	**Difficult to forecast and 'bank' signals** Cannibalisation of signal from other flexibility & reinforcements
Avoided network build More efficient siting of generation and demand could mean less network build is required	**Increased cost of capital on investment** If exposed, may increase system and consumer costs (through CfD and CM price increases)
	Market Power High scarcity pricing in constrained regions may have larger impacts on infra-marginal rents

Only a subset of these potential advantages and disadvantages are in scope of this study[10]. The scope is outlined in Chapter 2 with more detail in subsequent sections.

[8] Locational Energy Pricing | Energy Systems Catapult
[9] Assessment of Locational Wholesale Pricing for GB (ofgem.gov.uk)
[10] Additional studies likely to be needed to understand if and how changes to balancing could be made to achieve near optimal system dispatch under a national pricing model.

2. Approach and Methodology

2.1. Project Scope

As outlined in 1.2, this project aims to analyse the impacts of moving to locational pricing in a variety of scenarios. However, with moving to locational pricing being such a significant change to the system, not every possible impact as outlined above can be analysed in detail. The table below show what is and isn't in scope.

***Table 1:** Areas in and out of scope of this project*

In scope	Out of scope
The effect of locational pricing on system and consumer costs.	How locational benefits could be hedged via FTRs
How locational signals could influence the location of future build of generation assets in both the current model (TNUoS) and locational pricing model	The effect of locational pricing on demand portability (with the exception of electrolysers)
The interaction between locational pricing and the CfD regime and the impact this has on cost, including variations in the CfD reference price and impact on strike prices	The effect of locational pricing on future technology build-out (capacity mix) and impact on investment (with exception of cost of capital changes), such as an investment hiatus
The effect of network build and reinforcement timelines on cost benefits.	Impacts of avoided network build
The effect of interconnector participation in locational balancing in the national pricing counterfactual .	The organisational cost of locational pricing implementation and how it could delay investment decisions.
The effect of redispatch inefficiencies for storage in the national pricing counterfactual	Impact of changes in market liquidity and market power
Different approaches to how generators bid/offer in the balancing mechanism	Distribution Use of System (DUoS) charges impact on the location of distribution connected assets in the counterfactual
Assessment of potential impacts from increased cost of capital	Impacts on energy imbalance within the Balancing Mechanism and Ancillary Services (inertia, reserve etc.). It is assumed that there is no significant impact on these services as a result of moving to locational pricing.
Exposure of different technology types to locational pricing	
Restrictions on location for different technologies	

The impacts of those areas in scope will depend on the assumptions used within the modelling. These are discussed in more detail in Chapter 3. Those areas that are out of scope of this study could affect the results and therefore the case for moving to locational pricing in different ways, specifically:

- Demand portability could increase the benefits of moving to locational pricing as demand is able to change location in response to locational prices. For example, some demand could choose to move to Scotland where prices would likely be lower. With the exception of electrolysers, it is very difficult to make assumptions on how demand is able to move location. Additionally, it is also an important policy decision if locational pricing were to be implemented as to how much demand would be exposed to locational pricing.
- Moving to locational pricing could benefit certain technologies more than others causing changes in the future make-up of the system. Changes in capacity mix due to moving to locational pricing could provide additional benefits as technologies that are beneficial to the system could build as a result of enabling locational pricing. This is out of scope for this modelling as the capacity mix in the DESNZ scenarios used for this study are not necessarily optimised for current market signals so optimising capacity mix under a locational pricing model would mean an optimised scenario being compared against an unoptimised scenario.
- The implementation costs of moving to locational pricing are out of scope of this study as these costs are highly uncertain and therefore require a detailed bottom-up study to obtain. High implementation costs would reduce the system benefits of moving to locational pricing.
- Moving to a new more complex wholesale market design has the potential to cause an investment hiatus for low carbon technologies as developers and investors delay decisions on new projects while a new market design is implemented. This would reduce the benefits of moving to locational pricing and could mean more expensive gas generation continuing for longer. This is noted as a key consideration in the REMA consultation which states that ‘the transition to nodal pricing would require careful management, to minimise disruption for market participants and avoid a hiatus in investment’. Quantifying this potential disruption is out of scope of this project due to the uncertainty around this but is a key consideration for Government in considering the case for locational pricing.
- Moving to locational pricing has the potential to provide an additional benefit of reducing the investment required in network build-out. As a result of improved locational signals, plants could locate closer to demand centres meaning there is less need to move electricity from one part of the country to another. This is out of scope of this project as it would require a detailed network optimisation exercise to be undertaken. However, the possible benefits around this should be explored by Government in more detail if possible.

2.2. LCP Delta’s Locational Dispatch Model

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:

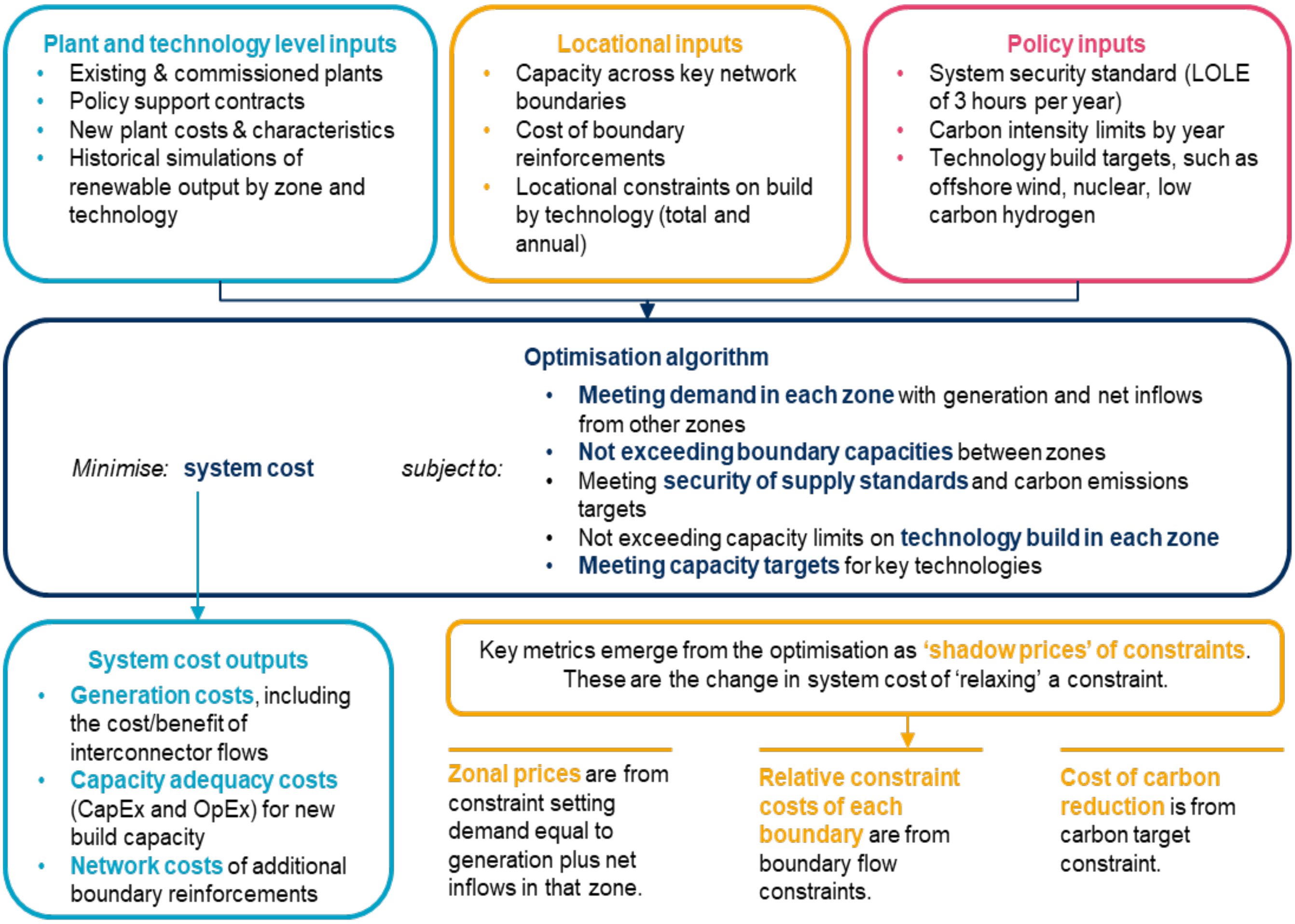
- **Market dispatch.** Simulating the supply and demand in each hour by zone, based on market fundamentals. This determines the operation of each plant on the system, and the wholesale market price(s).
- **Capacity relocation.** Re-allocating new plant to a different zone, based on market incentives 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).

In the following two sections we describe each of these functions in turn.

Market Dispatch

The market dispatch algorithm simulates the supply demand in each hour by zone, using an optimisation algorithm based on market fundamentals. Each year is simulated multiple times with variation in demand, wind and solar levels to simulate uncertainty in these conditions. Results are averaged over all simulations. An overview of the model can be seen below:

Figure 4: *LCP Delta's Locational Dispatch Model Diagram*



The model has different running modes enabling it to simulate both a national pricing model and a locational pricing model. To simulate a national pricing model, the model is first run with no locational constraints assumed to simulate the day-ahead market. A locational redispatch is then run to model what plants would turn-up or turn-down in locational balancing. This simulates what happens under redispatch within our current national pricing market. To simulate a locational pricing model, a third running model is used where a full locational dispatch is simulated with locational constraints accounted for. This accounts for changes in operates to the market such as changes to how interconnectors and storage are dispatched. This is explored in more detail in Chapter 5.

Inputs to the market dispatch model include:

- Information about all current and future "plant"[11] – i.e. generation assets or flexible assets (such as storage and electrolysers) in GB and in any interconnected market.
- Demand projections (including peak and total demand) for GB and interconnected markets.
- Zonal information, including the share of demand in each zone and the maximum flow of power between zone (boundary capacity).
- Interconnector information.
- Intermittency profiles for solar and wind availability, which vary by zone.

Using information about each plant, the model calculates a "bid" in each hour that the plant is willing to sell its energy for. The bid is calculated using fuel costs, variable operating costs, carbon costs, policy adjustments, start costs, and scarcity pricing adjustments. This is the plant's short-run marginal cost (SRMC), factoring in start costs and scarcity pricing.

An optimisation problem is set up for each day of the run period. The optimisation aims to minimise the total bid costs for the day while obeying constraints around plant behaviour, boundary flow capacity and demand to calculate the generation of each plant in each hour.

After the optimisation has completed, the price is calculated in each zone based on the marginal bid in each hour. Where the flow between two zones is below the maximum boundary capacity (i.e. boundary constraint is not "binding"), the prices for the two zones will be the same (based on marginal bid across both zones). However, when boundary constraints are binding, prices will be set based on the marginal bid in each constrained zone.

[11] Future plants are defined as any plant not online at the beginning of the model run. E.g. if the model run starts in 2025 but a plant isn't coming online until 2027 as it was commissioned with a CfD

Example of prices with binding boundary constraints:

Assume that we have 3 zones as shown with flow going in the direction of the arrows. The maximum accepted bid from all generating units within that zone is shown. The price in the zone is set as the maximum of the maximum accepted generating bid and unconstrained flows to/from other zones. The flow from zone 1 to zone 2 at maximum capacity so the price in the two zones is different. In zone 3, the importing boundary flow is the marginal bid so is setting the price.

Finally, the model then calculates and outputs information on the modelled market. This includes, the generation of plants, boundary flows, zonal prices, system costs, consumer costs and other carbon emissions.

Capacity relocation

The capacity relocation process aims to optimise the location of generation plants and other flexible assets (such as storage and electrolysis) to maximise their profits while keeping the total capacity of each technology constant.

As a starting point, the assumptions for the location of new capacity are in line with existing and pipeline build. The process then takes an iterative approach, relocating new build plants to the most profitable zone, subject to restrictions on where certain new build can be located (for example due to planning regulations or seabed leasing). This is calculated for all plant types and technologies simultaneously. More detail on the location restrictions for different technologies used in this study can be found in section 3.

The iterative approach allows cannibalisation impacts to be considered, with the relocation of capacity into a zone typically reducing the margins available in that zone. At a certain point, there are no further profitable relocation decisions available. The process is exactly the same in the locational pricing scenarios as in the counterfactual scenario (representing current market arrangements), just with different factors driving the profitability and the incentives for location.

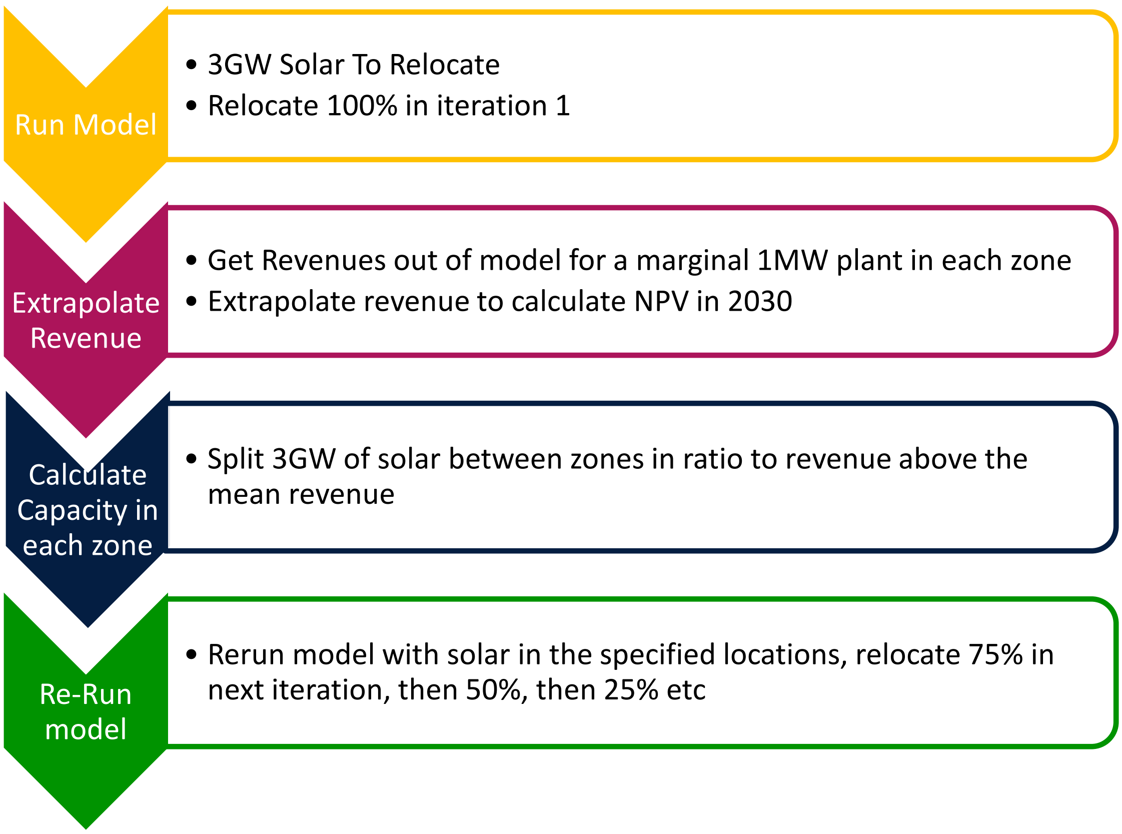
A key factor in all scenarios for determining the optimal locations of many renewable technologies is the availability of natural resources, which varies by zone. For example, Scotland tends to have higher wind load factors, while Southern England has higher solar load factors.

Under current market arrangements (with a national wholesale price), the key locational incentives are Transmission Network Use of System (TNUoS) charges. The model dynamically calculates TNUoS charges (using a simplified version of the transport and tariff model used by NGESO to calculate charges), and the charges are updated after each set of capacity relocations. Capacity will be incentivised to locate away from zones with higher TNUoS charges (such as those currently faced by wind plants in Scotland) and locate in zones with lower TNUoS charges (including the negative charges currently observed in some southern zones).

In addition, under current market arrangements profits made through locational balancing also provide an incentive and are included in the model's profitability calculation. Note that (unlike in a scenario with locational wholesale prices) there is no *disincentive* provided by locational balancing, i.e. locational balancing only presents an upside for plant, as they can still capture the national wholesale price when turned down for locational balancing purposes.

In the locational pricing scenarios, the zonal wholesale market prices are the key incentives. Generating Plants will gain higher profits higher price zones rather than lower price zones so are incentivised to locate there. Demand-side flexibility assets will look to locate in lower price zones to buy their electricity more cheaply while storage will choose to locate in zones with the highest price spreads. A diagram of how the relocation algorithm works in the model is outlined below:

Figure 5: *Diagram to show how capacity is relocated for example technology*



2.3. Modelling Location

Choice of zonal pricing over nodal pricing modelling

When modelling Locational Pricing, a key modelling decision is whether to model individual nodes on the network (nodal approach) or take a zonal approach, where zones are selected to group together similar nodes. For this analysis, **we have taken a zonal approach** to locational signals. This involved splitting the country into zones which capture those transmission boundaries which incur the highest constraint costs. These constraints are those modelled by NGESO in their latest Network Options Assessment (NOA) reports[12].

This approach captures the most important, highest cost network investment decisions and reflects the main causes of redispatch due to locational constraints. In comparison, nodal pricing signals can be volatile and sensitive to small changes in local network investment, or in local generation capacity. This makes detailed nodal modelling very challenging and potentially provides a spurious level of detail given the uncertainty within a number of key assumptions.

This means that modelling locational pricing at a nodal level risks overestimating the benefits of locational signals due to the level of "perfect foresight" assumed within the modelling. Under nodal pricing, if the optimisation assumes investors have perfect foresight of the revenues they will ultimately receive (which is typical in any optimisation modelling) then the system modelled can be unrealistically optimised, and risks exaggerating the benefits of the locational signal.

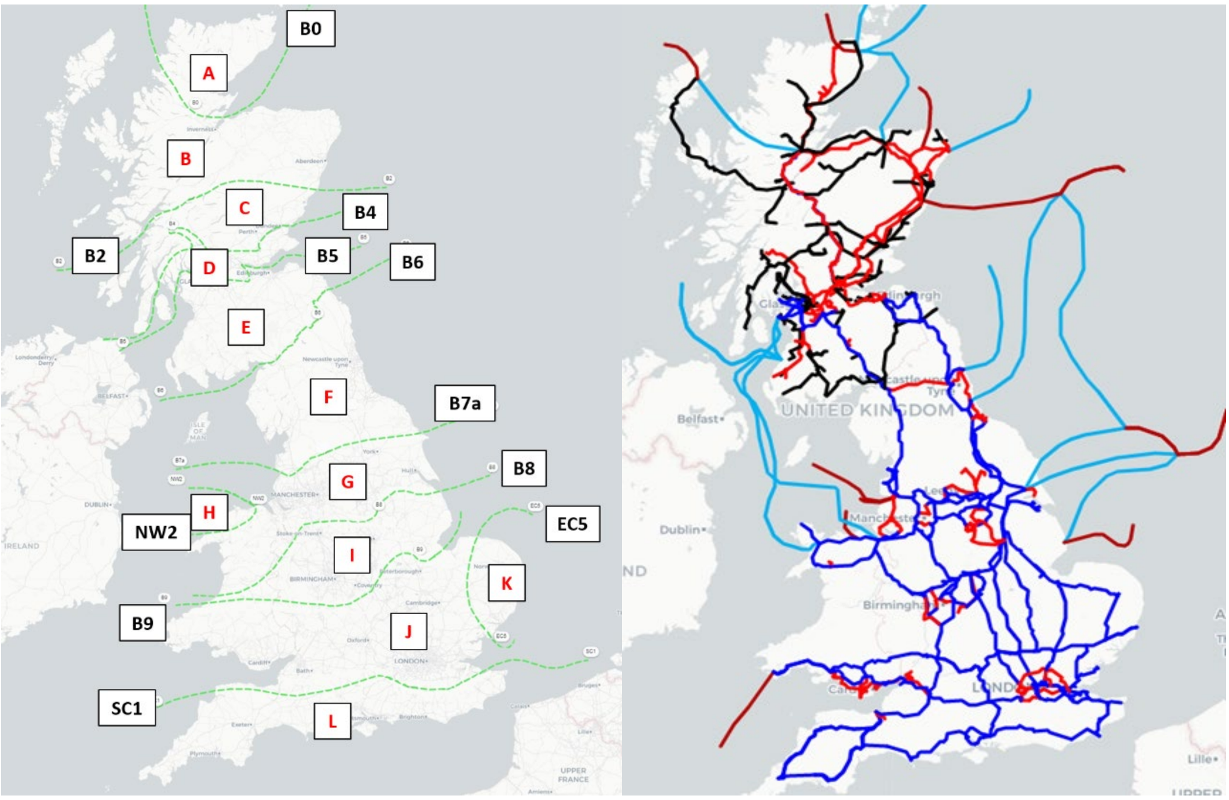
Experience from other markets who have implemented zonal pricing demonstrates that taking a zonal approach captures longer-term fundamental trends (in the UK context, this would cover excess of supply in Scotland) and are less susceptible to unpredictable changes.

Zones

The figure below shows the main transmission lines under the Electricity Ten Year Statement (ETYS)[13] published by NGESO and these are the 12 zones that are used in the modelling undertaken for this study. The zones are designed so that the main transmission lines flow between well-defined zones. The zones are also defined in such a way so that any major transmission line can only flow through or to one zone and not into two distinct zones. This allowed the boundaries as defined to be given appropriate capacities within the model based off real transmission line capacities.

[12] Network Options Assessment (NOA) | ESO (nationalgrideso.com)
[13] Electricity Ten Year Statement (ETYS) | ESO (nationalgrideso.com)

Figure 6: *Map of boundaries and zones (left) used for modelling analysis, boundaries shown in green with boundary names in black, zone names shown in red. Map of main transmission lines in Great Britain (right).*[14]



These 12 zones were chosen based on the data available on boundary capacities as provided by DESNZ. This captures the most important boundary capacities as outlined by NGESO in their Network Options Assessment (NOA) 7 refresh report[15] published by NGESO. This incorporates the offshore network design set out in the Holistic Network Design (HND) in addition to the first NOA7 report. Additional zones were not considered as transmission capacity data was not available in low enough granularity.

2.4. Model Limitations

There are a number of limitations in the modelling conducted, as outlined below. Many of these were considered reasonable given the limited time available and the focus of this project, and we do not expect them to have a significant impact on the overall results and conclusions of the work. However, many of these could be explored through further sensitivity analysis. The modelling and scope limitations are outlined below:

- Demand Side Response (DSR)[16] is not explicitly modelled. Peak demand inputted into the model is post DSR to account for this (taken from DESNZ' own modelling). This means we

[14] Taken/edited from Our Interactive Map | ESO (nationalgrideso.com)
[15] Network Options Assessment 2021/22 Refresh (nationalgrideso.com)
[16] Here DSR refers to consumers shifting their electricity usage to move demand away from peak periods. For example, smart charging of Electric Vehicles or

do not consider the impact changing DSR and the portability of demand could have in easing network constraints.

- The Capacity Mechanism (CM) auction or Contract for Difference (CfD) auctions are not explicitly modelled. Plant capacity is taken as a direct input to the model from DESNZ's own model which does include modelling of these. Strike prices for the CfD and CM clearing prices are assumed to be same as DESNZ own modelling. However, how these might change as a result of moving to locational pricing is considered by an off-model calculation. This accounts for the change in consumer costs by assuming that CM and CfD plants make the same profit in both the national pricing counterfactual and the locational pricing factual.
- Frequency, voltage, or inertia constraints as well as balancing for national energy imbalance reasons within the balancing mechanism are not modelled. Intra-zonal congestion is also not modelled as data has only been provided for the 12 zones modelled. As these will have to be satisfied in both national and zonal models, not including these should make little difference to overall system results. There would still be an associated cost of these in a locational price model with some form of balancing market still required in a zonal market. Alternatively, if locational pricing was implemented within centralised dispatch, then procurement of these services could be streamlined providing an efficiency saving. For this analysis, we effectively assume these costs are the same in national and locational models – we believe this is a reasonable assumption given the capacity mix is assumed to be the same in both, though we recognise there would be some impact.
- Plants are not built endogenously in the model. Total capacity is assumed as fixed input into the model so any potential change in capacity mix due to locational pricing was not considered. Varying both capacity and location of plants simultaneously would be complex, time consuming and require a wide number of assumptions. For the purposes of this project, it was agreed to optimise location rather than capacity. This means that the analysis does not capture how locational pricing might change how much of different technologies builds – for example changing revenues for unabated gas plants may make these less attractive to build in the capacity market by raising their capacity market bid such that another technology builds in its place.
- Plant dispatch is optimised within day in the modelling. This assumes that plants only have up to a day of foresight available. The only exception to this is longer duration electricity storage (LDES) such as pumped storage which does have a longer foresight period. While plants may have further foresight than this in reality, this is still preferable to the model having perfect foresight and a plant's dispatch being fully optimised across a month or a year. This means it is a reasonable approximation of plant behaviour and the overall system would still operate in the way we would expect.
- Storage plants do not bid into the model in the same way as traditional plants, so are not modelled as price-setters. It is assumed that storage plants will act to minimise dispatch costs through charging and discharging provided they earn a sufficient return (specified on input). This is representative of batteries behaviour from a system point of view but does not optimise battery profits at an individual level. This is likely to make little difference to overall results for this project as the battery fleet overall is still operating in the way we would expect.

- Plants are grouped together by technology and zone in the modelling[17], to create a smaller optimisation problem that is quicker to solve. This means that start costs and constraints in terms of minimum up and down times are not fully considered. This could mean that over a short time period (a few hours), some plants come on or offline too quickly – for example if there is a spike in demand or fast drop in wind.
- Demand and Intermittency (weather) inputs are based off historical shapes and patterns. How these shapes will change with the introduction of new technologies and climate change has not been fully considered. This means we are not fully capturing how the shape of the demand will change over time – this could have interactions with where plants relocate but given this is a limitation in the factual and counterfactual this should not have a significant impact on overall results.
- Each interconnected country is modelled as one zone with generation and prices in these countries modelled in the same way as domestic zones. Interconnection between foreign countries and any constraints within a foreign country has not been considered. This could affect how much is imported and exported between GB and connected countries. This impact is expected to be small. Assumptions on foreign countries are outlined and how interconnectors are treated in the national pricing model in terms of locational balancing is covered in 3.7 below.
- Unplanned outages are not stochastically simulated by the model. Availability percentages are used as an estimate for available capacity. This is a common approach taken across power sector models and we do not expect will have a significant impact on the overall results for this project.
- The relocation algorithm works in steps to iterate towards a stable solution which represents a local optimum. Finding the true optimal relocation under each scenario was not feasible given the time constraints of the analysis. Testing with different size steps was completed showing that the step size chosen produced a compromise between stability and model runtime.[18] As both the factual and counterfactual start from the same capacity locations assumption and follow the same iterative steps we believe that this limitation has little impact on conclusions.
- The relocation algorithm does not consider all factors that are important in siting decisions due to a lack of data availability. The responses to the REMA consultation highlights that 'Respondents…cited the importance of alternative factors in the siting decision' such as required infrastructure, land suitability, planning and obtaining grid connections. Where data is available on these elements, these have been used to restrict where plants are able to locate (discussed further in 3.5) but other factors have not been included. For electrolysers in particular, modelling of the hydrogen system is out of scope, so the model assumes the electricity price and curtailment levels in different zones are the drivers of electrolyser location/operation decisions. This means that other factors that would affect location and operation of hydrogen assets are not considered including the location of H2 demand, the

[17] Technologies are grouped based on key characteristics and technology type. For example, offshore wind and onshore wind are separate techs. Gas technologies are grouped into CCGT, OCGT and Reciprocating Engines.
[18] Testing with 50%, 33%, 25% and 10% step sizes completed. 25% and 10% show very little difference in results suggesting going below 10% would not be useful. 10% step size used for modelling.

availability of H2 T&S, variations in the H2 price and availability of resources e.g. water for H2 production. As these factors are not included in the both the national pricing counterfactual and locational pricing factual then the difference this could make on the impact of moving to locational pricing is likely to be limited.

2.5. Assessing Impacts

To assess the system impacts of moving to locational pricing, the analysis measures the system and consumer 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, and incorporated into the Dynamic Dispatch Model for use in Government power sector impact assessments and VfM assessments. System costs represent the costs of building, operating and maintaining the power system and are split into the following components:

- **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 (DESNZ central appraisal price[19]). 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 appraisal price)
- **Capex Costs -** Capital costs include pre-development, construction and infrastructure costs (all £/kW) for building 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.
- **Network Costs** - Cost of maintaining, reinforcing and extending the transmission network, including the costs of managing constraints. Note that distribution network costs are not included as these would need to be modelled separately.
- **Interconnection 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.

[19] Valuation of greenhouse gas emissions: for policy appraisal and evaluation - GOV.UK (www.gov.uk)

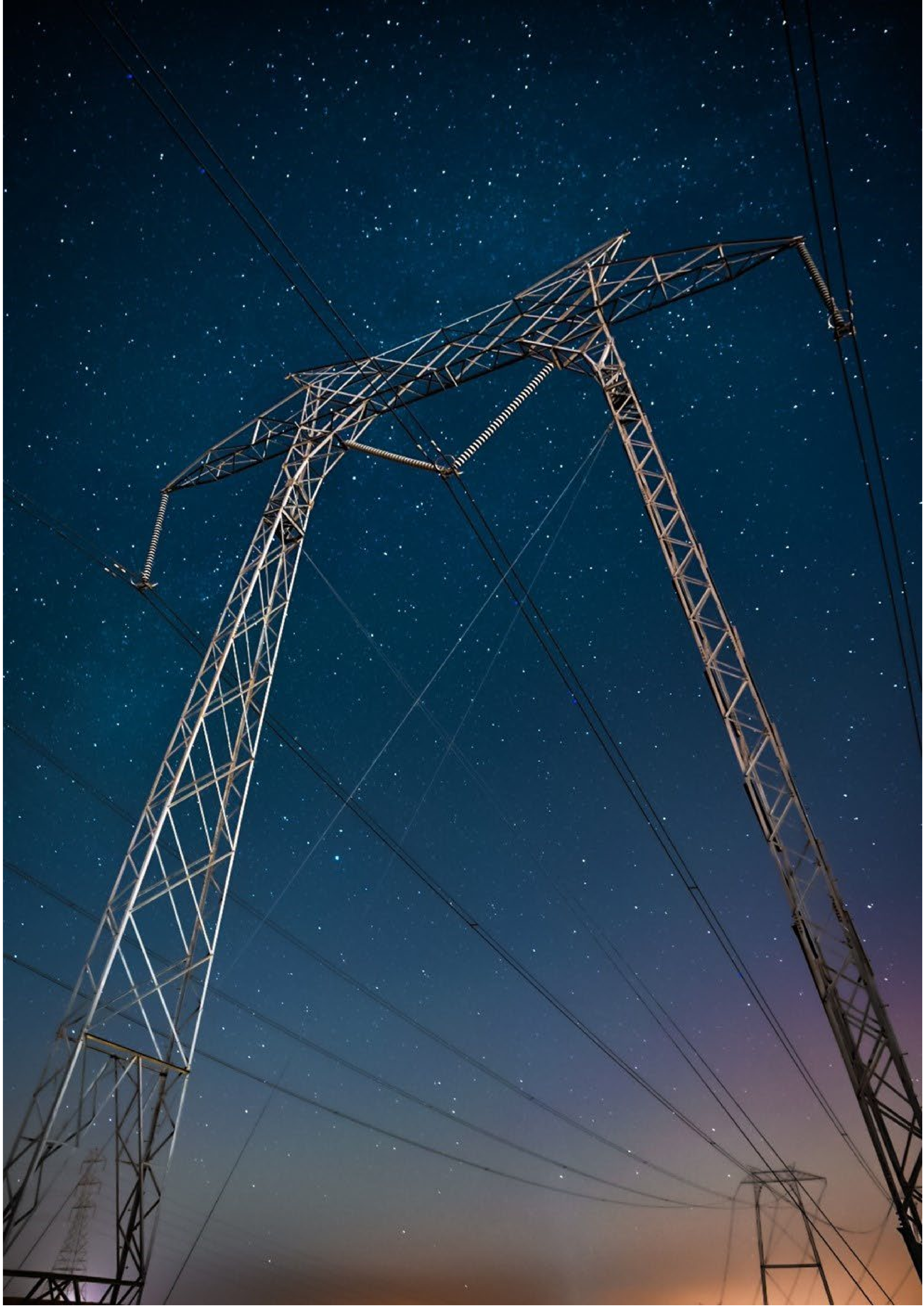
The redistributive impact on consumers and producers is also assessed. The impact on consumer costs[20] is all the costs that are passed on to consumer bills. These are split into the following components:

- **Wholesale costs** – The cost to consumers of paying generators the wholesale price, calculated as wholesale price multiplied by demand in each period.
- **Policy support costs** – The payments made to generators as a result of having policy support contracts such as CfDs and ROCs for both new and existing plants. These are split into two in charts in later sections to represent those that cannot change their strike prices and those that can.
- **Network costs –** The cost of maintaining, reinforcing and extending the transmission network.
- **Constraint Costs –** The payments made to generators as result of being asked to turn-up or turn-down through the balancing mechanism to manage locational constraints. These only appear in the national pricing model.
- **Congestion rents –** This represents the profit that domestic transmission network owners would earn based on the wholesale price differential between two connecting zones. It is assumed that this benefit is passed onto consumers so is a transfer between consumers and producers. These are only present in a locational pricing model.

The impact on producers is also assessed. This represents the costs incurred by producers (inc. interconnectors). The components for this are the same as for the consumer costs. Consumer costs plus producer costs equal overall system costs

All cost impacts presented in the modelling sections below represent a Net Present Value (NPV) of costs from 2030-50. Future costs are discounted at a rate of 3.5% per year as per green book guidance. Costs are presented in real 2022 terms.

[20] Residual balancing costs are also a consumer cost but as noted above, these have not been modelled for this project so are not included



3. Assumptions, Scenarios & Uncertainty

To analyse the system benefits of moving to locational pricing requires many assumptions for both the counterfactual national pricing model and factual locational pricing model. This includes power plant capacities, demand, network build-out, commodity prices, technology prices and policy inputs.

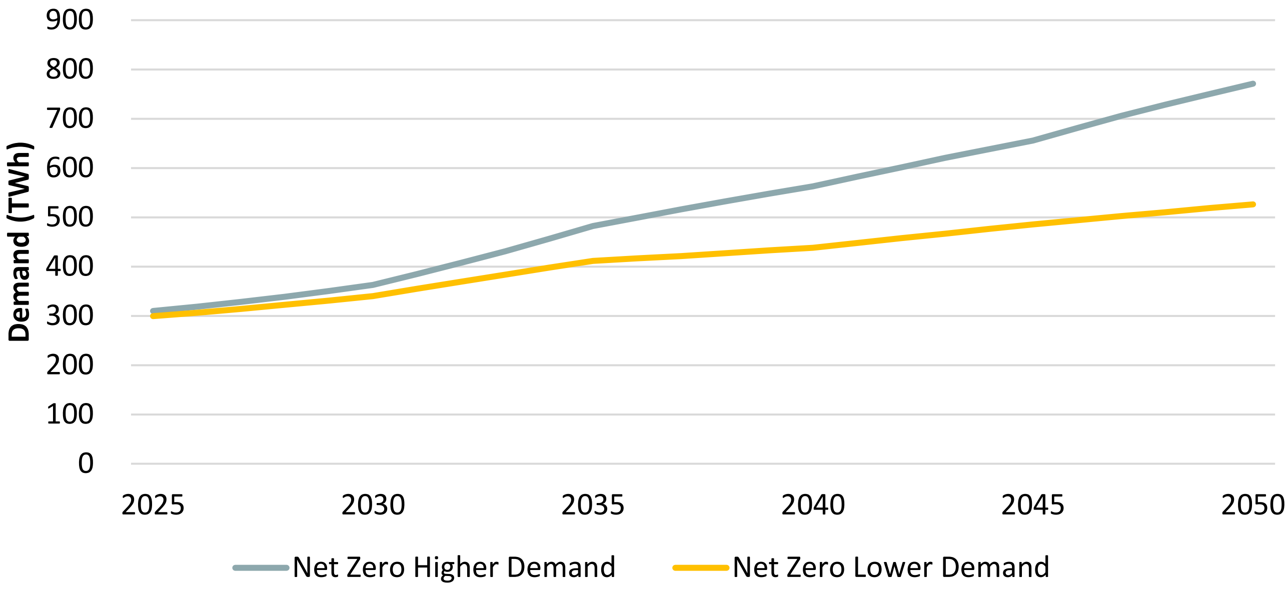
There are many uncertainties regarding both the future make-up of the power sector and how locational pricing could potentially be implemented, that could cause significant changes in the impacts of moving to locational pricing. To be able to fully assess the benefits of moving to locational pricing and for DESNZ to be able to make a fully informed decision, then the impact these uncertainties have on results need to be tested. This has been tested through the modelling of different scenarios where assumptions for key uncertainties are varied.

This section gives an overview of the key inputs for the counterfactual and factual including where the inputs are varied for each of the scenarios to reflect the uncertainty. All assumptions have been provided by DESNZ to LCP Delta for this project unless otherwise stated.

3.1. Future demand and capacity

Electricity demand both in terms of total demand across the year and peak demand for a given hour are important inputs into the model. For this project, two different demand scenarios are modelled using inputs from DESNZ own power sector scenarios from the Dynamic Dispatch Model (DDM); a Net Zero Lower Demand scenario and a Net Zero Higher Demand scenarios.

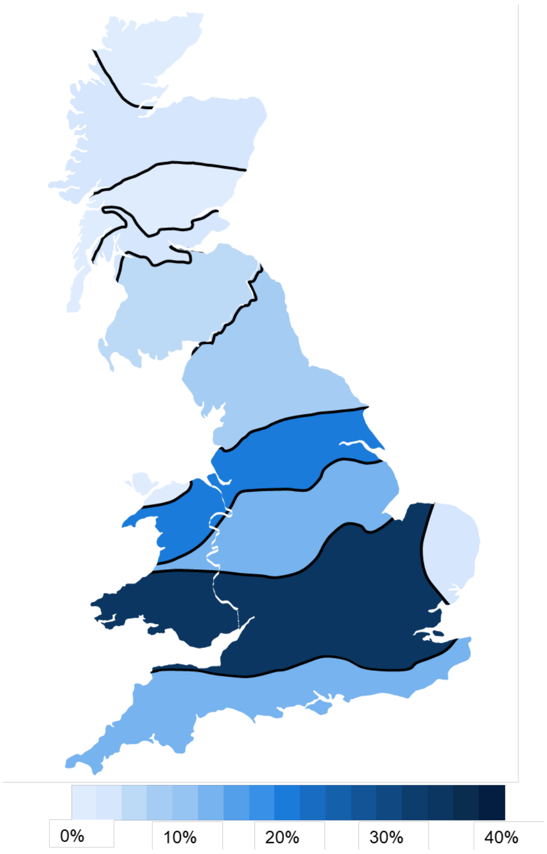
***Figure 7**: GB Electricity demand in DESNZ Scenarios*



Future electricity demand is highly uncertain as it depends on decarbonisation choices in other sectors such as heat, transport and industry, which is why two demand levels are modelled. The higher scenario represents a higher electrification pathway while the lower scenario represents a lower electrification/higher hydrogen pathway which leads to lower electricity demand (although still higher than today's levels). The Net Zero higher demand scenario is the core scenario used for this project as outlined in chapter 4, with most other scenarios based off this. The Net Zero Lower demand scenario is modelled separately with results for this scenario outlined in chapter 7.

The location of demand is also important. With the exception of electrolysers, the portability of demand is out of scope of this project. This is because assumptions on how different consumers are exposed to locational pricing are difficult to obtain and are a key policy decision if locational pricing is to be implemented that we do not pre-empt in this study. For example, exposing households to locational pricing as they will not be able to move to gain a benefit, but some non-domestic consumers may be able to change locaiton to gain a benefit. The percentage split of demand by location assumed in this study is based on the split of demand across zones in the National Grid ESO Future Energy Scenarios (FES) 2022[21] and is the same across all scenarios.

Figure 8: *Demand % by zone used in analysis – taken from FES 2022*



In addition to uncertainty around future demand, the future technology mix on the power system both in terms of scale (reflecting total and peak demand) and mix of technologies is also uncertain and another key input into the model. While it is anticipated that renewables,

[21] [Future Energy Scenarios | ESO (nationalgrideso.com)]

mainly wind and solar, will dominate electricity generation as outlined in the Net Zero Strategy[22] – the extent of this is uncertain. The make-up of the technologies needing to complement renewables such as Nuclear, CCS, Hydrogen, and storage technologies is also uncertain. To capture these uncertainties within the analysis, two technology mix scenarios have been modelled linked to each of the demand scenarios outlined above. The different mixes used are outlined below:

***Figure 9:** Capacity (GW) by Technology - DESNZ Net Zero Higher Demand Scenario*

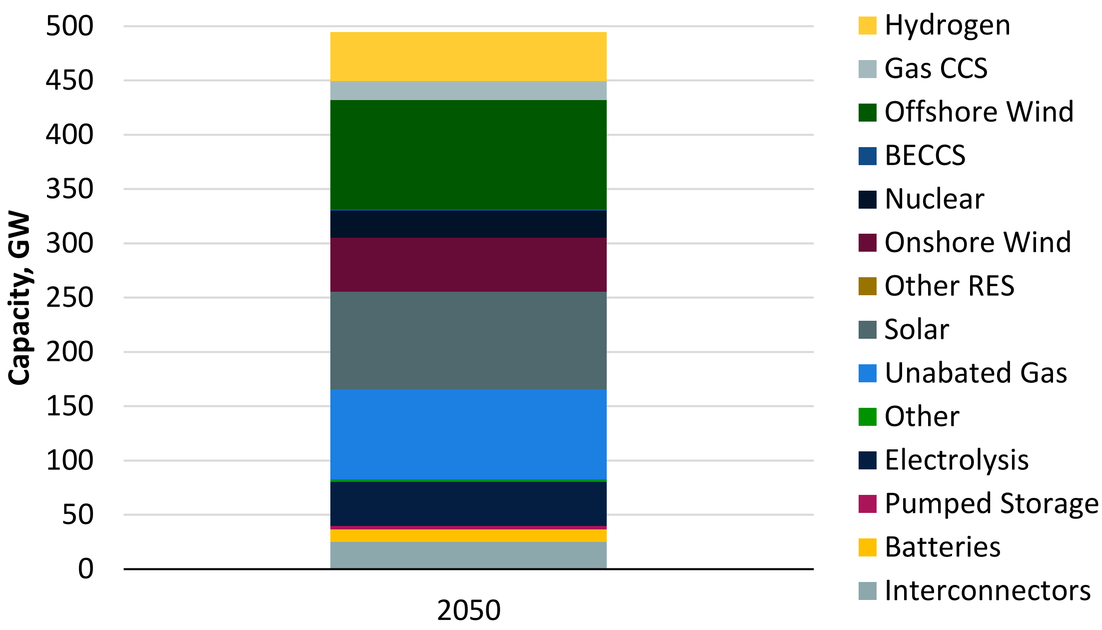
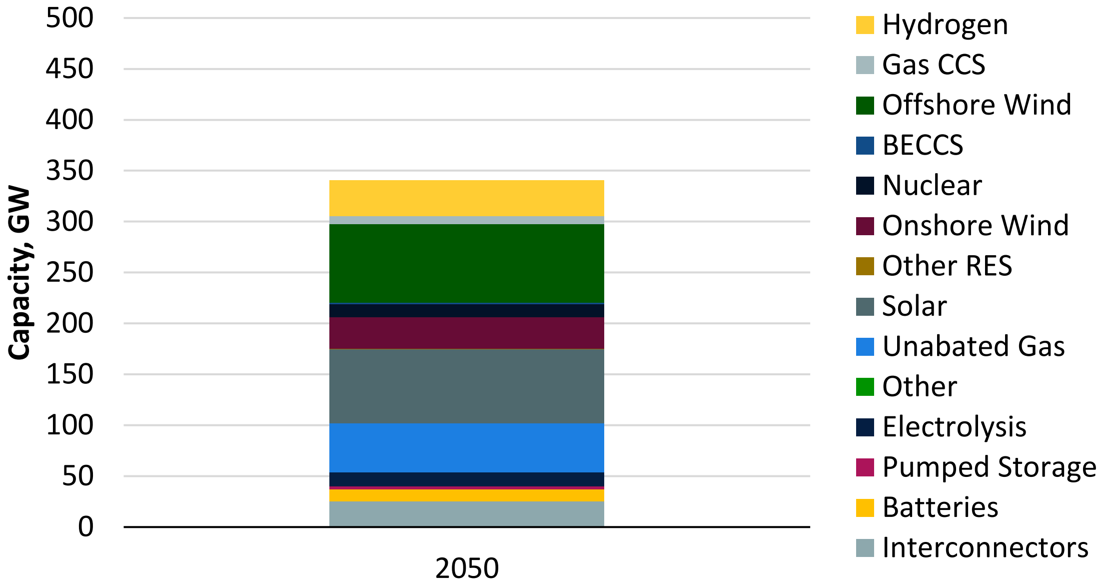


***Figure 10:** Capacity (GW) by Technology - DESNZ Net Zero Lower Demand Scenario*



Changes to demands levels and technology mix would have an impact on the system benefits of moving to a locational pricing model. For example, a higher demand and larger system could see more capacity change location between the national and locational models driving

[22] Net Zero Strategy: Build Back Greener - GOV.UK (www.gov.uk)

higher benefits but could also mean more capex costs that would be affected by changes to cost of capital (discussed further below). Additionally, a technology mix with higher levels of nuclear and/or CCS with less renewables may be less impacted by a move to locational pricing as these technologies are less likely to be able to change location to respond to locational signals.

While it is possible that moving to locational pricing could change the technology mix, this has not been modelled for this project. This is because it is uncertain how locational pricing would change capacity mix given how it will be implemented is still uncertain and because keeping the mix the same in the counterfactual and factual allows for a fairer and more robust comparison from introducing locational pricing. Additionally, there are many drivers of capacity build-out that would need to be included, including how locational pricing interacts with all government policies that need to be defined before this can be modelled in detail.

3.2. Network granularity and build-out

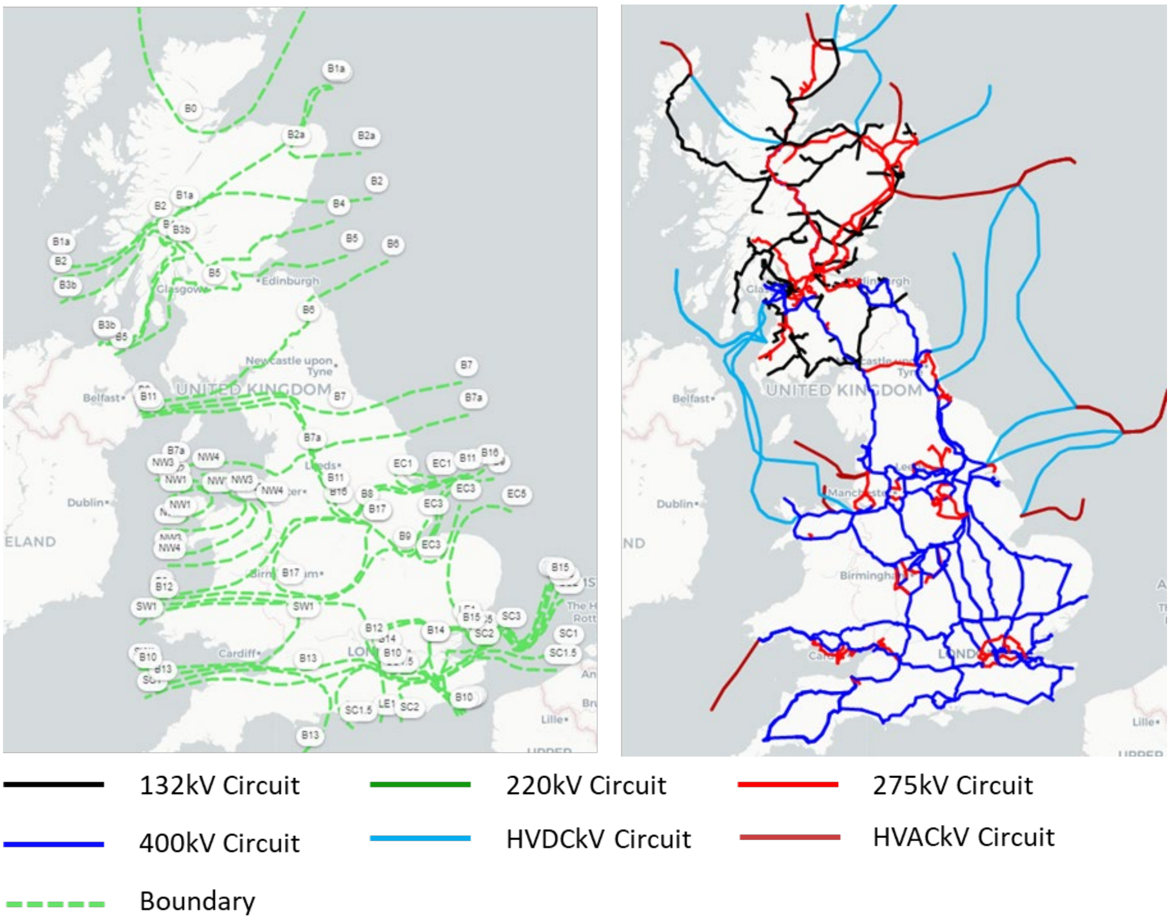
Moving electricity from its point of generation to point of demand is a key challenge of any electricity sector and the GB electricity sector is no different. Generation assets are often located away from demand centres. For example, most wind generation is in Scotland, but south-east England has the highest level of demand. Moving electricity from generation point to demand centres is restricted by the capacity on the transmission network at certain points. For example, the B6 boundary is the key network boundary between Scotland and England and only has a certain amount of capacity (i.e. electricity in MW that can be moved from Scotland to England at any one time).

As a result of these network restrictions, the Transmission System Operator (NGESO in GB) often must step in to turn-down generation in network constrained areas, such as Scotland, and turn-up generation near demand centres, such as south-east England, to ensure network restrictions are not breached and supply meets demand. This is known as locational balancing. This locational balancing can be a substantial cost to the system as generators are paid to turn-up and turn-down through the balancing mechanism. Previous LCP Delta analysis[23] showed that the cost of turning-down wind generation due to locational issues and turning up gas generation cost consumers £800m across 2020-21 and curtailed enough wind generation to supply around 800,000 households.

The maps below show all the transmission network boundaries present in the GB system and the transmissions network lines as projected by NGESO in 2030 from the NOA7 refresh.

[23] Drax-LCP - Renewable curtailment report

Figure 11: *Map of GB boundaries and transmissions network lines in 2030*[24]



The detail in which to model the network and the level of reinforcement are both key assumptions that will affect the impacts of moving to locational pricing. As outlined above in section 2.3, the focus of this project is modelling at a zonal rather than nodal level but there are still choices to make in the granularity and make-up of zones that are modelled. The zones modelled need to be granular such that the benefits of moving to locational pricing can be realised but also realistic based on the data available so not to make spuriously accurate assumptions.

Based on data available from NGESO's Network Options Assessment 7 (NOA 7) and Holistic Network Design (HND)[25] as provided by DESNZ, there was clear data available for 11 boundaries. These form the 12 zones that are modelled for this project as shown in Figure 6 in section 2.3 above. Modelling of alternative zone make-ups were considered, especially as moves to locational pricing could change which boundaries are most constrained. However, it the zones chosen are likely to represent all major constrained boundaries and data available on other zone make-ups was limited.

In addition to choosing the zones to model, network reinforcement levels are a vital assumption for assessing the impact of moving to location pricing. This is because plants moving to more efficient locations is one of the key potential benefits of locational pricing. A more constrained

[24]Our Interactive Map | National Grid ESO
[25] Network Options Assessment 2021/22 Refresh (nationalgrideso.com)

network will likely lead to higher benefits from moving to locational pricing as plants moving location has more of an impact. This is because their generation is more fully utilised in the locational pricing factual and used less in the national pricing counterfactual.

As acknowledged in the Government and Ofgems' Electricity Networks Strategic Framework[26], 'The network needs to be transformed at an unprecedented scale and pace to accommodate decarbonisation and demand growth'. Given the high level of reinforcement needed, there is significant uncertainty as to how much network build-out there will be from now to 2050 and how quickly that build can happen. As a result, 2 different network scenarios have been modelled for this project. These are based on the latest Network Option Assessment[27] (NOA 7) and the Holistic Network Design (HND). These are used in the central scenarios and represent the best current view on the future of future network reinforcement and while it is likely that further reinforcement will be completed beyond this, it is difficult to obtain assumptions on network reinforcement beyond this.

With a 3-fold increase in total network boundary capacity across the boundaries assumed in the NOA 7 + HND scenario and network reinforcement projects often being delayed, the alternative network build scenario assumes a 3-year delay to NOA7 and HND build. Results from the alternative network reinforcement scenario is outlined in section 6.

The size and cost of building the network is assumed to be the same in both the national and locational models. While moving to locational pricing could change the level of network reinforcement as noted in 2.1, in this study it is assumed the level of network reinforcement is unchanged between the national pricing counterfactual and locational pricing factual meaning the network cost from a system viewpoint will be unchanged. How the network costs are paid for between consumers and producers does change when moving to locational pricing because of congestion rents being present in the locational market. As explained in section 2, these rents are profits for domestic transmission network owners which would decrease the need for network costs to be covered by consumers. In this study, this is represented as a transfer between consumers and producers, benefitting consumers. It is unlikely congestion rents would cover all network costs however so TNUoS is likely to still be in present in some form in locational pricing although as noted in 1.5, this will likely become a flat charge across the country given the locational signal is given in a different way. In this study, it is assumed the non-locational element of TNUoS is still present and paid by consumers in the locational pricing model.

3.3. Foreign Market Assumptions

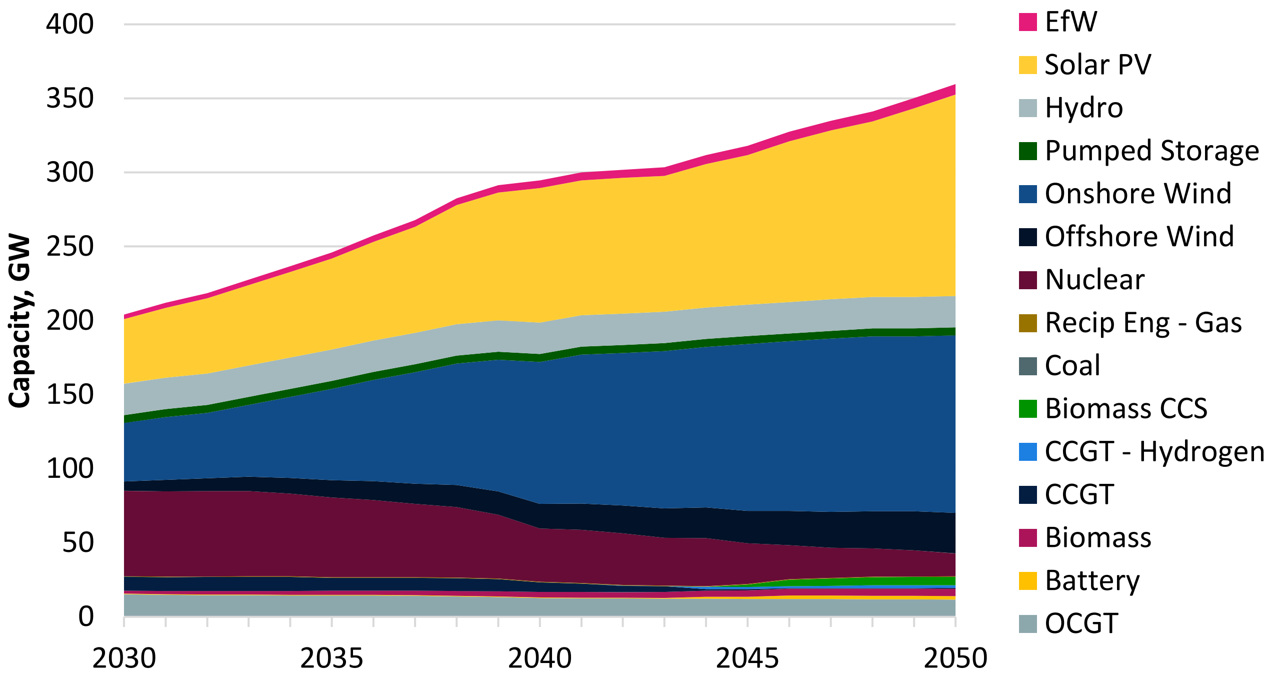
Interconnector capacity deployment is also assumed to be in line with the DESNZ Net Zero Higher demand scenario with total interconnector capacity assumed to increase to over 19GW by 2030. By 2030, GB is connected to 7 markets: Ireland, France, Netherlands, Belgium, Norway, Denmark and Germany. As outlined above, each connected market is modelled as a

[26] Electricity Networks Strategic Framework: Enabling a secure, net zero energy system (publishing.service.gov.uk)
[27] Network Options Assessment (NOA) | National Grid ESO

different zone – this requires the same assumptions, capacity build-out, demand, commodity prices etc. that is needed for the GB market.

As DESNZ do not have assumptions on foreign markets, annual demand and capacity build out[28] is taken from the National Grid ESO Future Energy Scenarios (FES) 2022[29] as published in ES2 of the databook. As an example, the capacity build-out for France is shown below:

Figure 12: *Capacity build out in France 2030-2050 from FES 20222 LW/CT Scenario*



Peak demand for European countries is not included in the FES data so this was calculated using the annual demand and data from ENTSO-E's European Resource Adequacy Assessment (ERAA) 2022[30]. Commodity prices are assumed to be same as GB with foreign market carbon price assumed to equal GB as the Carbon Price Support (CPS) is assumed to be 0 in GB by 2030. Setting CPS to 0 in 2030 is a simplifying assumption and does not reflect current HMT policy but is used to avoid distortions when modelling.

3.4. Technology Costs and Costs of Capital

As the power sector decarbonises and demand increases, large amounts of new build capacity will need to be added to the system. As a result, the future capital costs of new build plants will be a key driver of power system costs in the future. Previous LCP Delta analysis[31] has shown that capital costs (including both construction and financing cost) will make up around half of power system costs from now to 2050 while previous Government analysis has highlighted how changing capital costs assumptions can have large impacts on modelling results[32].

28 Note that some adjustments were made to the foreign market capacity to scale up capacity for some countries to ensure security of supply in all countries where there is no demand that is unserved in any period
29 Future Energy Scenarios | ESO (nationalgrideso.com)
30 ERAA 2022 | ERAA 2022 by ENTSO-E (entsoe.eu)
31 Net Zero without Breaking the Bank | LCP 2021 report for SSE
32 Modelling 2050 – electricity system analysis - GOV.UK (www.gov.uk)

Assumptions around new build technology costs and their characteristics come from the 2020 BEIS Generation Cost report[33] with some updates and additions provided by DESNZ for the purpose of this project.

One of the key assumptions related to capital costs is hurdle rates for each technology or the 'cost of capital'. Hurdle rates are 'defined as the minimum financial return that a project developer would require over a project's lifetime on a pre-tax real basis. This acts as the rate at which both costs and generation revenues are discounted across time'[34]. Moving to locational pricing could affect the hurdle rates of different technologies as the uncertainty and complexity of moving to a locational pricing model could drive project developers to require a higher minimum financial return on their investment. However, this impact could be partially mitigated through changes to government policy. This is explored through the modelling of different cost of capital scenarios and is outlined in more detail in chapter 6.

3.5. Plant location decisions and restrictions

The portability of different assets has been considered as part of this analysis. As outlined in section 1.5, locational pricing is more likely to drive efficient plant location. However, there are a variety of factors that drive where a plant chooses to locate. This includes:

- **Market signals** – as outlined in 2.2, locational signals as a result of moving to locational pricing changes where a plant may locate compared to locational signals from the TNUoS regime in the counterfactual.
- **Load Factor** – for renewable plants, different locations in the country will give different load factors depending on wind and sun levels. Wind plants will have a higher load factor in windier Scotland while solar plants will have a higher load factor in sunnier south-east England. This is captured in the modelling by using different weather data across each of the zones.
- **Cost variation by location** – the technology costs for certain technologies may vary by location. For example, seabed leasing for offshore wind is currently more expensive in England compared to Scotland. This is not captured in the modelling as there is no clear data on these variations available. As this limitation is in both the factual and counterfactual, it will have a limited impact on results. As these factors are not present in the relocation due to TNUoS in counterfactual and relocation due to locational pricing in the factual then if relocation benefits are slightly overestimated due to not fully taking account of cost variation by location then this impact is overestimated in both factual and counterfactual, meaning its impact should to a large extent be accounted for.
- **Topography** – Some technologies need certain topographies to be able to build that would only be available in certain parts of the country. For example, pumped storage plants need specific topographies and available water to build which means they can only build in certain locations such as Scotland and Wales. This is captured in the modelling as certain

[33] BEIS Electricity Generation Costs (2020) - GOV.UK (www.gov.uk)
[34] BEIS Electricity Generation Costs (2020) - GOV.UK (www.gov.uk)

technologies are assumed to only be built in certain locations or restricting how much of a technology can built in a zone, such as maximum levels of offshore wind on the seabed.

- **Planning restrictions** – Planning restrictions may restrict where technologies can be built. This is captured in the modelling by assuming some technologies cannot build in some locations. For example, it is assumed that no new onshore wind can build in England.
- **Government policy** – Current Government policy may dictate where certain technologies build. This is due to various reasons such as safety concerns or connection to infrastructure. This is assumed in the modelling by applying restrictions on where technologies can build. For example, for this modelling project it has been is assumed Nuclear cannot change location as the sites where they can build are restricted while CCS plants can only build within CCS clusters due to the need to connect to the CCS transport and storage network.

The assumptions used regarding restriction on plant locations are outlined in the table below. These are used across all scenarios with the exception of the scenarios in chapter 10. In the scenarios in this chapter, alternative locations restrictions for offshore wind are explored in where more conservative estimates are used for seabed availability meaning less capacity can build in certain zones.

Table 2: *Technology Location Restrictions*

Technology	Exposure to TNUoS signal	Exposure to Locational Pricing Signal	Restrictions on zones
Offshore Wind	Full exposure	Exposed to signal but dependent on CfD arrangements	Limits by zone based on seabed availability
Onshore Wind	Assumed 50% of capacity is exposed to TNUoS signal as 50% is distribution connected	Exposed to signal but some capacity dependent on CfD arrangements	Can only build in Scotland and Wales.
Solar	Assumed to be 100% distribution connected so no exposure	Exposed to signal but some capacity dependent on CfD arrangements	No limits
Other Renewables	Assumed location is dictated by other factors so does not change location, e.g.: resource availability		
Nuclear	Assumed locations are fixed as Nuclear sites across the country are limited		
Gas CCS	Full exposure	Full exposure	Limited based on locations of industrial clusters.[35]
Biomass CCS	Assumed location is dictated by other factors so does not change location, e.g.: location of current biomass plants		
Hydrogen	Full exposure	Full exposure	Limited based on locations of industrial clusters[31]
Electrolysers	Full exposure	Full exposure	Limited based on locations of industrial clusters[31] and max of 50% new build in Scotland
Storage	Full exposure	Full exposure	No limits

[35] This is assumed to be all zones except A and H, and zone L before 2035

3.6. Interaction with the CfD

How locational pricing would interact with other Government policies, such as the Contracts for Difference (CfD) scheme, is a key consideration. While we do not want to pre-empt what Government policy would be in this area, we do need to consider how locational pricing will affect CfD-supported plants in the modelling as this will have a significant impact on system and consumer costs. Within the analysis, the main thing that has been considered is how much exposure a CfD plant would have to locational signals. This has been done by varying the definition of the CfD refence price. This is a key sensitivity and is explored in more detail in chapter 9.

For the core scenarios, it is assumed that CfD plants have full exposure to locational signals from locational pricing, which is achieved by assuming the CfD reference prices are set at a national level. This was chosen to understand the maximum impact locational signals could have on generation.

Moving to locational pricing may also interact with the CfD regime in other ways and may mean that its design may need to be reevaluated by Government if locational pricing were to be implemented. These are out of scope of this study; however, one important area is the impact of CfD negative pricing rules. Currently, when the day-ahead price (i.e. the CfD reference price for intermittent plant) is negative CfD plants contracted from AR4 onwards will not get paid their CfD top-up. This was implemented to avoid perverse incentives in the market and avoid these plant bidding at negative prices. However, these CfD plants will still be incentivised to bid negative in the intraday and balancing market. As shown in previous LCP Delta analysis[36], this creates an inconsistency between the different markets that could lead to inefficiencies.

If the GB market moves to locational pricing and the CfD reference price is based on a national (rather than zonal) price, then the effect of this inconsistency could be amplified, as CfD plants will be incentivised to bid negative in their local zonal market in the same way they would be in the balancing market under current market arrangements (as long as the national reference price remains above zero). This could cause inefficiencies in the market and ultimately increase system costs. For example, negative prices would encourage an inefficient level of storage dispatch (with storage being indirectly subsidised by CfD payments) and of storage investment. As a result, when moving to locational pricing, our modelling assumes that this rule is extended so that the negative pricing rule also applies to the CfD's local zonal price (as well as its national reference price). Additionally, to avoid this being compared to a counterfactual case with no negative pricing rule in locational balancing, the same change is assumed to be made to the current balancing market.

It is likely that moving to locational pricing will also cause changes in CfD strike prices. If CfD plant are fully exposed to locational signals (through a national reference price) then plant in low price zones will receive revenues below their strike price (as they receive wholesale revenues that are lower than their reference price), which will in turn mean they require a higher strike price to achieve the same overall level of return. If CfD plant are not exposed

[36] New CfD rules – the case for further reform | Lane Clark & Peacock LLP (lcp.uk.com)

(through a zonal reference price) then they may still be affected by locational curtailment. Under current market arrangements, CfD plant that are turned down (i.e. curtailed) for locational constraints, lose their support payments, but still “lock-in” wholesale market revenues (and can bid at negative levels to recover their lost support payments, though as discussed above we assume this is prevented in the future). Under locational pricing, these plants would never be dispatched in the first place, so do not receive any revenues. Additionally, higher hurdle rates (due to greater risk exposure) are likely to increase the strike price that a plant will need to receive.

3.7. Participation of interconnectors in locational balancing

A current inefficiency in the system is how interconnectors act with respect to locational constraints. As highlighted in National Grid ESO’S Net Zero Market Reform report[37], ‘Interconnectors and storage are at times incentivised by the current market design to flow in a direction that exacerbates constraints.’ For example, at times of constraint in Scotland & North England, GB may be importing from Norway due to lower prices in Norway compared to GB. This would exacerbate the constraint exporting power further south in GB. In moving to locational pricing, interconnectors would no longer be able to exacerbate constraints in this way as the price would vary by zone and locational balancing is no longer required. In the Norway example, the same circumstance under locational pricing would mean GB would not import from Norway as the price in North England would be lower than Norway due to high levels of wind on the system in that zone. This is highlighted as one of the major benefits of moving to locational pricing in the NGESO Net Zero Market Reform report.

Under current market arrangements, changing interconnector flows to resolve network constraints is limited, as they do not compete directly in the GB BM and GB is not coupled with connected markets. Instead, NGESO must instruct interconnectors outside the BM via trades either pre or post gate closure. Pre gate closure, there are arrangements for intraday auctions in which interconnector flows can change from the day-ahead stage, but these are only available on some interconnectors and timing constraints limit how close to real time flows can be changed. Post gate closure, changing interconnector flows relies on system operator to system operator (SO-SO) arrangements with agreement needed between the NGESO, the interconnected country’s Transmission System Operator (TSO) and the interconnector owner for the trade to go ahead. This is outlined in paragraph 7.5 of Section 4 of the Balancing Settlement Code[38]. These arrangements do allow for flows across interconnectors to be changed, with actions recorded in the Balancing Services Adjustment Data (BSAD), however the process used to arrange these trades is not transparent with NGESO publishing limited information on how this is done. These trades also appear to be used in a limited capacity despite changing interconnector flows appearing to be more cost effective in many circumstances. The trades can also be expensive for consumers with consumers having to pay

[37] download (nationalgrideso.com)
[38] https://bscdocs.elexon.co.uk/bsc/bsc-section-r-collection-and-aggregation-of-meter-data-from-cva-metering-systems

very high prices to change interconnectors compared to the wholesale price in GB and the connected country. For example, on 20th July 2022 interconnectors were paid up to £9,000/MWh to take action to reduce their exports in the southeast of the country to deal with constraint issues in this area.

Modelling how NG ESO currently redispatch interconnectors is extremely challenging as there is limited transparency on how the intraday auctions and SO-SO trades are used to manage network constraints. How often they are used is also likely to change significantly in the future as more interconnectors connect to the system, particularly with several planned interconnectors set to connect in constrained areas such as Scotland and the South of England. Given that one of the key benefits of moving to locational is likely to be more efficiency redispatch of interconnectors and the uncertainty around how interconnectors are resdispatched in the current market, it is prudent to test alternative national pricing counterfactual scenarios where interconnectors participation in locational balancing is varied. As a result, for the modelling undertaken in this study the decision has been taken to run two scenarios around interconnectors participation in locational balancing where interconnectors must be either able to fully participate in the locational balancing, or not at all. These are defined as follows:

- **Interconnectors fully participate in locational balancing** – This means that interconnector flows in the model have full flexibility to be redispatched as needed to deal with locational constraints with no restrictions if they are the most economic option. This is assumed in the core scenario outlined in chapter 4.
- **Interconnectors do not participate in locational balancing** – This means that interconnectors flows scheduled in the day ahead market in the model cannot be changed intraday or in the BM to deal with locational constraint issues. This is assumed in the scenarios outlined in chapter 5.

As outlined above, some locational balancing via the interconnectors does take place under current arrangements meaning the current reality is likely to fall somewhere between the two of these scenarios. However, given the uncertainty around what the level of redispatch that can be assumed, both scenarios are tested to give the full spectrum of outcomes around this key uncertainty. It should also be noted that the core scenario where interconnectors fully participate in locational balancing, this in effect does assume some change to current arrangements in the national pricing counterfactual for interconnectors participation which should be noted in any interpretation of results. This study does not look to assess whether changes to the current system can be made to allow interconnectors to be more effectively redispatched to deal with constraints, although that is not to say such changes are not possible. As a result, this change to the national pricing counterfactual for the interconnectors fully participating in locational balancing scenario does not represent any government policy in this area.

As a result of this assumption, this means that the modelling will only show a limited system cost operational benefit due to the more efficient operation of interconnectors under locational pricing as the same flows are ultimately achieved. There will be a consumer benefit due to reduced interconnector costs that would flow through into system costs as a result of interconnectors no longer being paid to reverse flow, but this will be small compared to interconnectors not participating in locational balancing at all. Given the significant uncertainty and impact that this assumption will likely have, it is prudent to test a scenario whereby interconnectors do not participate in locational balancing in the national pricing counterfactual in order to understand the potential scale of the operational system cost benefits more efficient dispatch of interconnectors if moving to locational pricing. The results from this alternative scenario are outlined in chapter 5.

3.8. Operation of locational constraint actions in balancing

Assets are redispatched in the balancing mechanism to balance supply and demand, as well as managing system needs in real time – including resolving network constraints. Each BMU or balancing unit submits bids and offers to NGESO to change their generation. NGESO needs to balance multiple aspects of the system including but not limited to locational constraints. Generally, the aim is to do this in the lowest cost way possible but by considering all balancing needs. However, it has been observed that some technologies are not always dispatched in the balancing mechanism even when they are lower priced than other actions that are accepted. This is commonly known as assets being 'skipped'.

Storage is commonly a technology that is skipped. This was highlighted in a letter sent to NGESO by the Electricity Storage Network (ESN)[39] outlining analysis which showed the average skip rate for battery storage assets to be 80% in June 2023. We have included this as a sensitivity to analyse the cost of storage assets having limited actions accepted in locational balancing. This is applied by limiting storage action change from the day ahead market to the balancing market by a maximum of 20%. We recognise that this is not a precise replication of the 80% "skip rate" mentioned above, nor is it a forecast of the level of BM acceptance. We expect to see "skip rates" for storage reduce in the future given NGESO are looking at changes around this already so it is unlikely to remain at this level to 2030. However, the 80% assumption is used to understand the upper bound of this issue if no changes are made. More detail on the approach taken is outlined in section 5.3 and results from this alternative scenario are outlined in 5.4.

Additionally, within the current market, there is often a disconnect between where the prices at which bids and offers are accepted, and the prices suggested by fundamental modelling. Generators can push offer prices up (or bid prices down), above their short run marginal costs, to capture infra marginal rents, to reflect scarcity, or for other reasons such as reflecting outage risk. In the core scenarios this has been partly reflected by modelling the BM as a 'pay as clear' market, i.e. equivalent to assuming plant offer up (or bid down) to the marginal unit's cost.

In order to consider market uplifts in bid and offer prices based on historic observations, DESNZ have provided us with historic figures of these average uplifts (using data from 2015-

[39] Electricity-Storage-Network-letter-to-ESO-on-Balancing-Mechanism-dispatch.pdf (regen.co.uk)

2019) and they have been applied within the modelling, assuming a ‘pay as bid’ market. This allows us to consider the effect of these uplifts on consumer costs. More detail on the approach taken and the results from this alternative scenario are outlined in chapter 5.

3.9. Locational Pricing implementation

The timing regarding the introduction of locational pricing and the length of any transitionary period could have a significant impact on results. The earlier locational pricing is introduced, the higher the impact it could have as more plants may be driven to change location. However, announcing its introduction could lead to delays in some investment as developers wait to see the impact of the change before committing to investment in the GB power market.

For the purposes of this analysis, it is assumed that the locational pricing is implemented from 2030. DESNZ view this as suitable modelling assumption to estimate when locational pricing could realistically be introduced. As noted in Chapter 2, the implementation costs of moving to locational pricing are out of scope of this study as these costs are highly uncertain and therefore require a detailed bottom-up study to obtain. However, they should be considered by DESNZ in any decision made on locational pricing,

No impacts from a transitionary period are assumed, with the timing of capacity deployment held steady across the scenarios. It is possible that moving to locational pricing could lead to delays in investment. While this is something that needs to be considered in any decision on locational pricing, it is considered out of scope of this analysis as requires more in-depth research to establish assumptions that can be used in the modelling.

3.10. Scenario summary

The below table outlines the scenarios tested in the analysis:

***Table 3:** Summary of scenarios modelled*

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	ICs in national pricing model	Batteries in national pricing model	BM Uplift	Offshore wind location restriction
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
No ICs in Locational Balancing	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
No ICs and limited storage in locational balancing	DESNZ Net Zero Lower demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Limited participation in locational balancing	Bid up to marginal unit	Lower restriction
Full Operational Impacts	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Limited participation in locational balancing	Bid up to marginal unit + uplift	Lower restriction
DESNZ Net Zero Lower Demand	DESNZ Net Zero Lower demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
Cost of Capital scenarios	DESNZ Net Zero Higher demand	Increased hurdle rates	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
Network build 3-year delay	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND with 3-year delay	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
CfD partially exposed to locational signals	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Partial exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
Higher offshore wind restriction	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Higher restriction

4. Modelling Results – Core scenario

This section outlines the key results from the core scenario, showing the impacts of moving to locational pricing. The key assumptions for this scenario are shown in the table below:

Table 4: *Assumptions used in the core scenario*

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	ICs in national pricing model	Batteries in national pricing model	BM Uplift	Offshore wind location restriction
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generati on Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction

The core scenario used in this study does not necessarily represent DESNZ' preferred or most likely view of how the future system will look. It has been chosen as the core scenario for this analysis as a representative scenario to evaluate the possible impacts of moving to locational pricing and as a starting point for comparison against the different scenarios explored in later chapters. As noted above, all assumptions used have been provided by DESNZ unless otherwise stated.

4.1. System Cost impacts

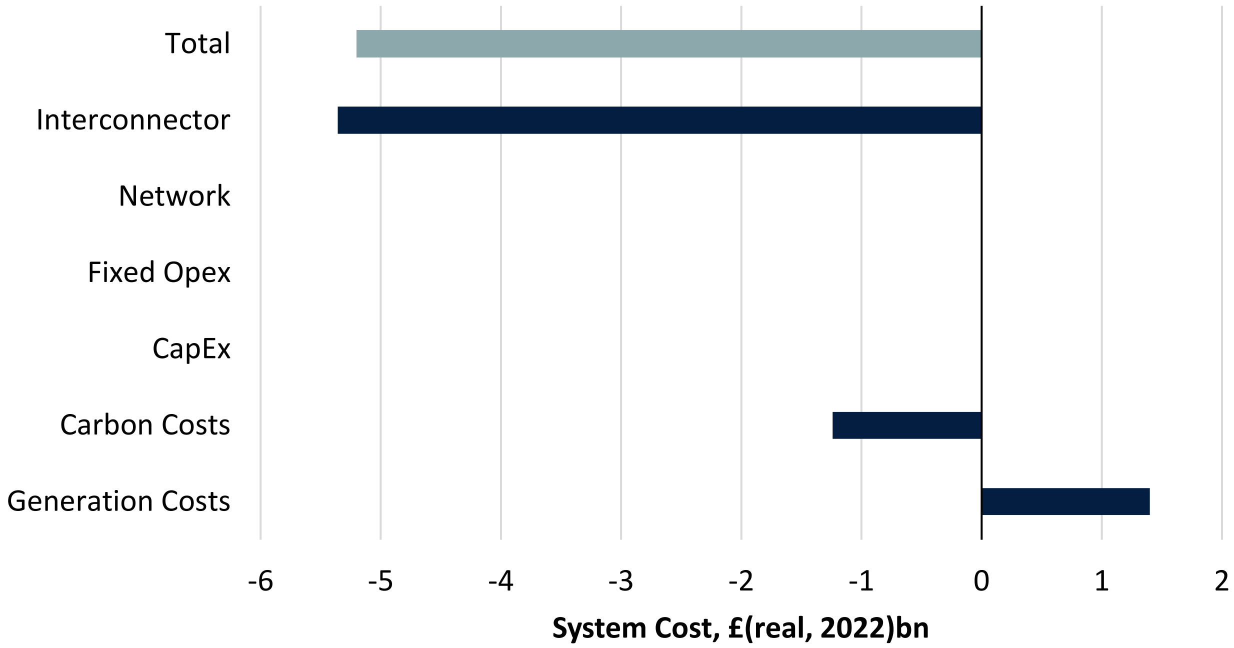
With no assumed impact on cost of capital, system costs of moving to locational pricing reduce by £5.2bn (given as an NPV from 2030-2050). This shows that there is a small benefit from moving to locational pricing. In these scenarios:

- **Generation costs** increase by £1.4bn. A move to locational pricing enables technologies with lower generation costs to generate more regularly to meet demand. Generation from renewables increases slightly overall as more energy is exported to Europe. Additionally, hydrogen generation increases to replace some imports and gas generation. See generation breakdown below for further discussion on this.
- **Carbon costs** decrease by £1.2bn as reductions in gas generation, due to higher renewable and hydrogen generation, leads to decreases in emissions.
- **Interconnector costs** are reduced by £5.4bn due to less imports and more exports via the interconnectors. This is a result of lower cost technologies, mainly renewables, being able to generate more after relocation. This both replaces some imports and allows for higher exports due to prices in higher renewable zones being lower too. Overall, this means GB is able to export more due to lower cost energy.
- **Capex costs** show no impact on from moving to locational pricing in this scenario. This is by design in this scenario and is due to no change in capacity mix between the national pricing counterfactual and locational pricing factual meaning the overall new build of power plants is unchanged so there is no change in capital costs. In this scenario there is no

change in cost of capital assumed as a result of moving to locational pricing which would also affect capital costs. This impact is explored further in the next section.

- **Fixed Opex costs** show no impact as well. No change in fixed costs is expected and is again due to no change in overall capacity mix across the factual and counterfactual.
- **Network costs** show no change as the network build assumed is the same across the factual and counterfactual. The regulated asset value model that provides the allowed revenue to network operators is also assumed to be unchanged when moving to locational pricing. This means that the total amount of allowed revenue for the network built is the same in both the national pricing counterfactual and locational pricing factual.

Figure 13: *Change in System Costs between national and locational Pricing in DESNZ Net Zero higher demand scenario (-ve costs show a system benefit from moving to locational pricing)*



The key driver of the change in system costs is movement of plants to locations that are more beneficial to the system. This 'investment efficiency' means plants locate more efficiently meaning lower cost plants such as renewables can dispatch more frequently without turning on more expensive gas plants and more exports over the interconnectors which reduces interconnector and carbon costs. However, the change in system cost is relatively small at £5.2bn. TNUoS signals provided in the national pricing model also give a locational signal, although this is not as responsive as that from locational pricing.

The modelling results show that there is a very limited benefit from 'operational efficiency'[40] where there is more efficient dispatch of the fleet from moving to locational pricing without relocation of plants. However, this is a function of modelling limitations. Efficient redispatch of the fleet is assumed in the counterfactual, including effectively assuming that changes are

[40] An operational efficiency saving is defined as a cost saving as a result of changes in the operation of the market due to locational pricing. This is effectively a reduction in costs without any capacity being moved due to improved investment signals.

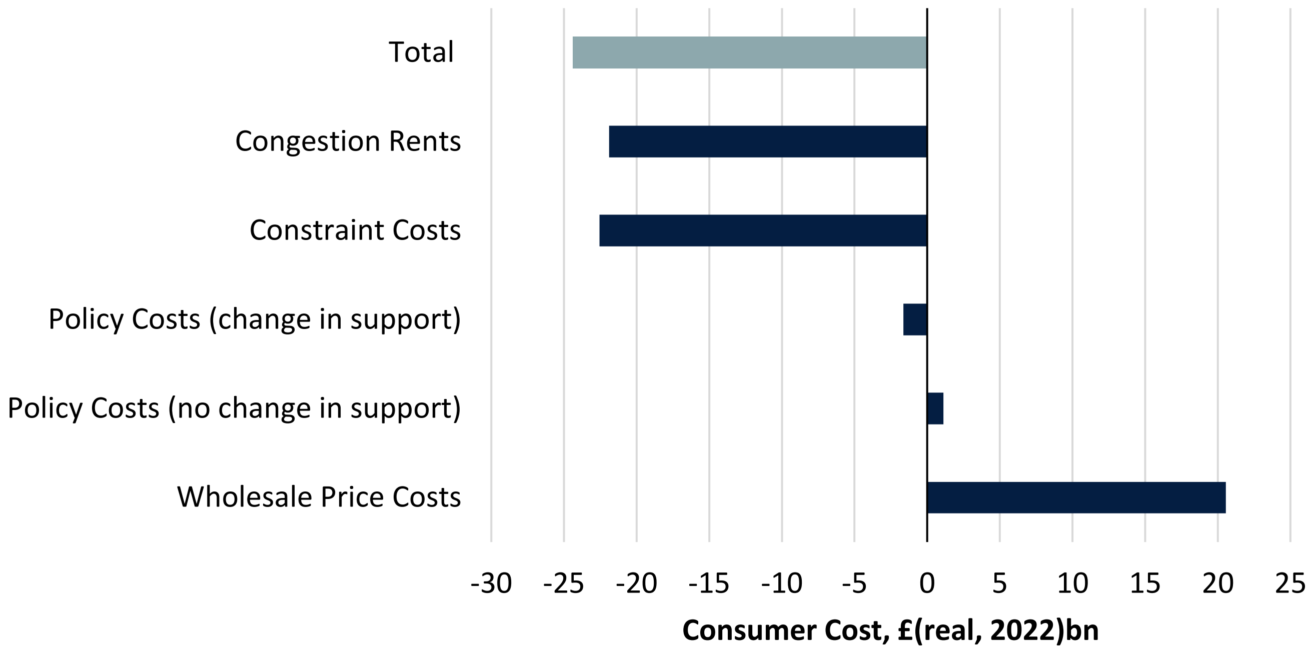
made to the balancing mechanism such that interconnectors can fully participate in locational balancing as outlined in 3.7. The effect of an alternative assumption where interconnectors cannot participate in locational balancing in the national pricing counterfactual is discussed in Chapter 9. It should be noted that demand side response (DSR) is not explicitly modelled in this analysis, so this excludes the effect of DSR on operational efficiency.

4.2. Impacts on Consumers and Producers

The impact of moving to locational pricing varies across consumers and producers. The analysis shows a £24bn benefit for consumers but this means there is an £19bn cost for producers and interconnectors.

Given these figures are much greater than the overall system cost impacts, this shows that moving to locational pricing will see lots of transfer from producers and consumers. While from a system cost perspective, there are no 'operational efficiency' savings, from a consumer perspective moving to locational pricing would result in 'operational efficiency' benefits that would reduce bills for consumers. However, due to this transfer of costs this could create risks within the power sector. This could manifest itself in different ways with some projects no longer being investable as a result, CfD strike prices and capacity market clearing prices increasing, or requiring additional government policy support to get the technologies that are needed for decarbonisation to market.

Figure 14: *Change in Consumer Costs Between National and Zonal Pricing for the DESNZ Net Zero higher demand scenario*



The impacts on consumers are broken down as follows:

- **Constraint costs** decrease by £23bn as these costs are no longer present in a locational pricing model where locational balancing is no longer needed. This is an operational change to the system. For example, wind plants, are no longer paid to turn-down in the balancing market as they are in the counterfactual. Instead, these costs are included within wholesale pricing costs. These costs are effectively being moved elsewhere by increases in strike prices to account for losses in revenue or higher wholesale prices in some zones, but overall do reduce as turn-down payments no longer exist.

- **Policy costs**[41] decrease by £0.5bn. For existing plants and those plants in the pipeline that already have policy contracts, there is no change in support levels (CfD strike prices and CM clearing prices). For these plants costs increase by £1.1bn as CfD support payments increase to offset a drop in market revenues for these plants. This is because they are more likely to be located in lower cost locational price zones and lose revenue that they would have previously earned through turning down in the balancing market. However, for those plants that do not yet have policy contracts and can therefore adapt their CfD strike price or CM bid, the higher market revenues (see higher wholesale price costs) lead to decreases in policy costs of £1.6bn (excluding cost of capital impacts) as plants need to secure less revenue through policy due to higher revenues in the market. These two types of plants offset each other slightly meaning an overall decrease of £0.5bn in policy costs.
- **Wholesale price costs** increase by £21bn as prices increase in the highest demand zones compared to the national run. This is mainly due to constraint costs effectively moving into wholesale prices given these prices now account for constraints. Impact on wholesale prices is explored in more detail in 4.5.
- **Congestion rents** become a feature of the system as a result of moving to locational pricing. As network operators move electricity from a lower cost zone to a more expensive zone within GB, they make revenue on the difference in price between these zones. This is assumed to be passed through to consumer reducing the network cost proportion of bills. In this scenario, congestion rents are £22bn and as these are assumed to be passed onto consumers then these appear as a reduction in consumer costs on the graph above.

An important consideration for moving to locational pricing from a policy perspective is whether consumers themselves are exposed to locational prices. This is important in terms of the distributional impacts on consumers in different parts of the country and whether some demand relocates due to locational pricing (which is out of scope of this modelling).

Depending on how locational pricing is implemented then the benefit on consumers could vary across the country. If consumers are fully exposed, then those in the higher price zones in southern England may pay more for their energy than those in lower price zones in Scotland. There is a policy choice there as to whether the consumer impact would be averaged in some way so that the impact would be the same for everyone. This could also vary by type of

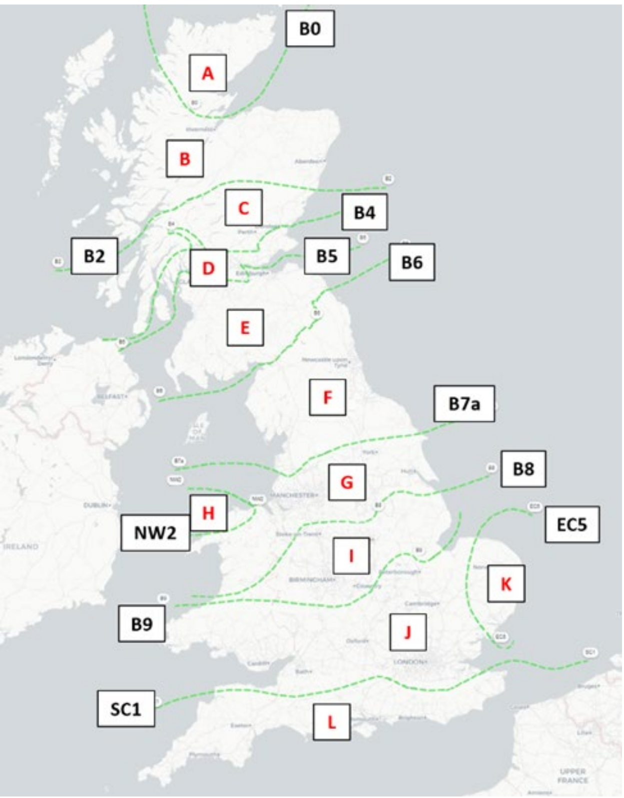
[41] Policy costs are split into two types:
No change in support = changes in policy support payments assuming no change in CfD strike prices or CM clearing prices. This mainly represents changes in CfD support payments due to differences in wholesale revenues and generation levels.
Change in support = estimated impact on policy costs of changing future CfD strike prices and CM clearing prices so that new plant still achieve the same required return.

consumer depending on whether they are exposed demand to locational signals or not. For example, it may be unfair to expose households to locational prices, but it may be beneficial expose certain non-domestic consumers, such as some forms of industrial processes, as some could change location based on energy prices.

4.3. Capacity relocation

Differences in location of capacity are the key driver of system cost difference between the national pricing counterfactual and locational pricing factual. As outlined in section 2, the model optimises location in the counterfactual based on current TNUoS signals and in the factual based on locational pricing signals. The signals from locational pricing are stronger than TNUoS for plant location so plant locations in the factual are better for the system in this scenario compared to the counterfactual. The zones modelled are shown in the map below:

Figure 15: *Map of zones modelled, boundaries shown in green with boundary names in black, zone names shown in red.*



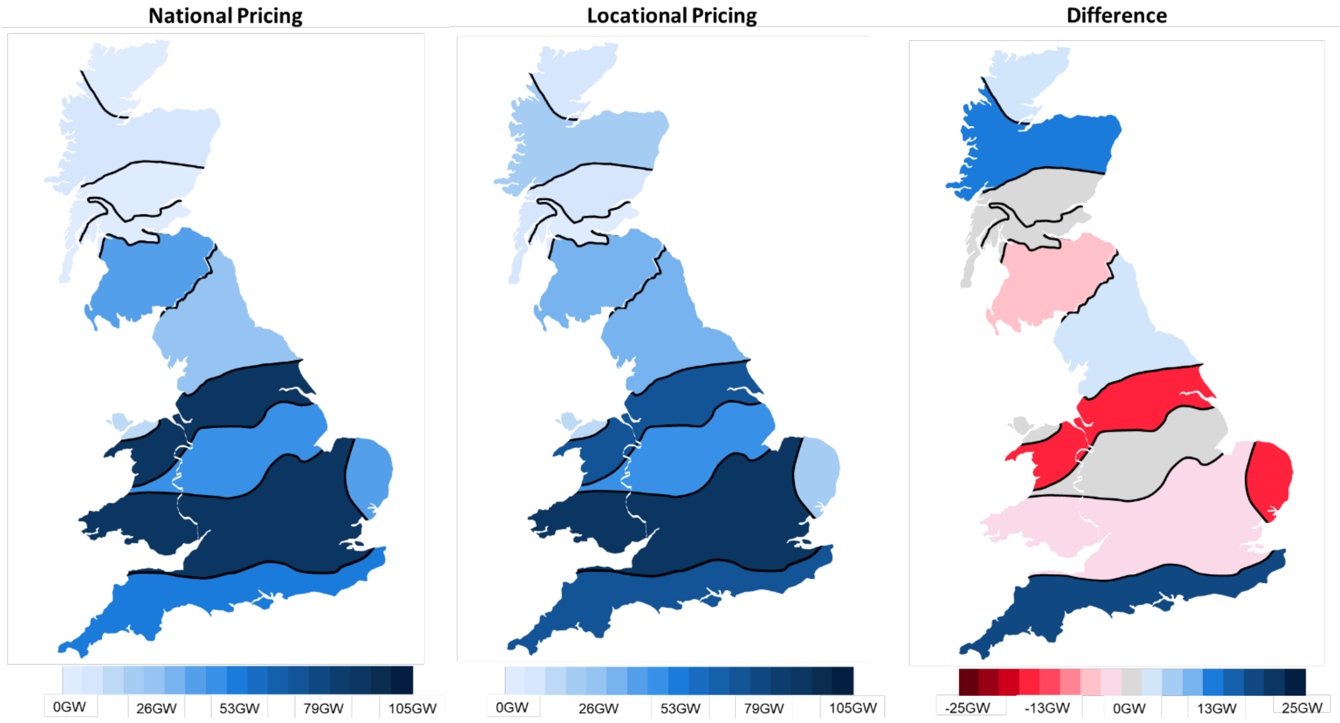
As outlined in 3.4, there are a variety of factors that affect a plant's decision on location in addition to market signals, a subset of which are captured in the modelling. In the counterfactual, it is important that the impact of current locational signals from TNUoS are captured in the modelling to ensure that the locational signal provided by TNUoS influences capacity relocation through the same mechanism as locational pricing signals. While TNUoS does provide a locational signal to plants as network constrained areas have higher TNUoS charges than less constrained areas, it doesn't directly reflect constraint costs and doesn't change as directly and responsively as constraints increase Including plants locating based on TNUoS signals in the counterfactual ensures a fair comparison across the national pricing counterfactual and locational pricing counterfactual and that an unoptimised counterfactual is not being compared to an optimised factual.

The below capacity maps outline the location of different technologies in 2050 for the national pricing counterfactual (with TNUoS) and the locational pricing factual for those technologies that are able to move location (as outlined in 3.4). The final map shows the difference between these to illustrate where capacity is moving when moving to locational pricing.

All Capacity

- The below maps show the movement of all domestic generation capacity in 2050 when moving from national to locational pricing.
- Overall, this shows total capacity in each zone shifts by in most zones with a maximum of 10GW moving in either direction as the system moves to locational pricing. While initially this may indicate a small relocation impact from the increased locational signals locational pricing brings, this is masked as movements of different technologies are offsetting each other and changes within any single technology are more pronounced. For example, offshore wind and solar are generally moving further south but thermal plants such as hydrogen and gas CCS are moving further north so these offset each other.
- Key movements for all capacity are increased capacity in Zone L (Southern England) and Zones A and B (Northern Scotland) and less capacity in Zone K (East Anglia), Zone F (Northern England) and Zone D (middle of Scotland). The reasons for these movements are explored in more detail in the technology maps below.

Figure 16: *Location of all capacity in 2050 with TNUoS or Locational price signals, and difference between scenarios*[42]

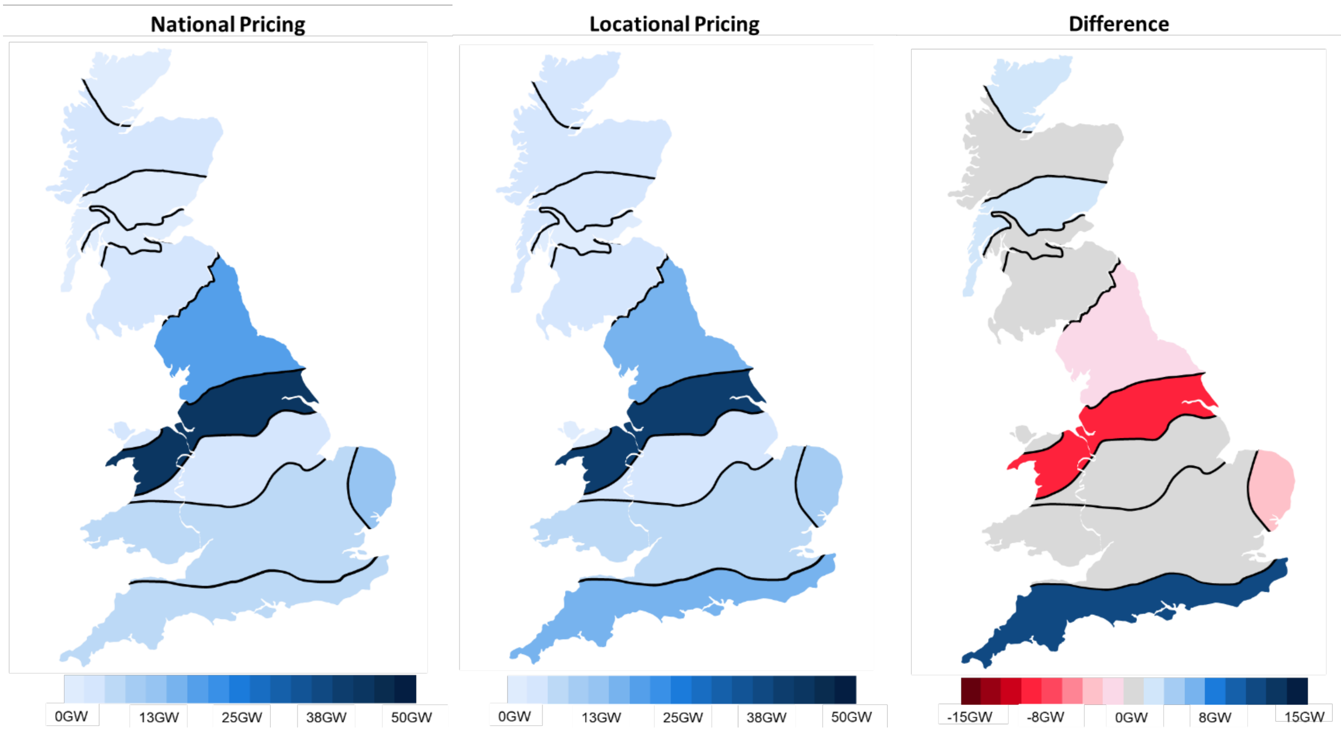


[42] This shows domestic generation capacity only so interconnector and electrolyser capacities are not included.

Offshore Wind

- The location of offshore wind reflects a balance between higher load factors that can be achieved further north and the impacts of locational pricing mean higher locational prices nearer demand centres and no payment for turn-downs due to constraints. Seabed availability does put restrictions on where offshore wind can locate. This is reflected in the modelling with data provided by the Crown Estate giving overall restrictions as to how much offshore wind can build in each zone[43] but it should be noted that this is the most generous interpretation of availability provided by the Crown Estate, only based on seabed depth in certain areas. In this scenario, it is assumed that the CfD is fully exposed to locational pricing in the factual.

Figure 17: *Location of offshore wind capacity in 2050 with TNUoS or Locational price signals, and difference between scenarios.*[44]



- Currently, most existing and planned offshore wind build is located in South Scotland, North England and East Anglia (zones E, F, G and K) showing higher load factors tend to be the bigger drive of these two factors (although planning from seabed leasing rounds is a clear constraint). In the counterfactual this trend continues but less is located in South Scotland (zones D and E) compared to North England (zones F and G) and East Anglia (Zone K) as a result of higher TNUoS charges beyond the B6 boundary.
- Moving to locational pricing sees offshore wind move further south, which is beneficial to the system. While zone G in northern England still has the highest offshore wind capacity, this is 10GW lower in 2050 than in the counterfactual reflecting lower revenues that can be achieved here compared to more southern zones. Capacity also decreases in zones F

[43] The assumptions in restrictions for offshore wind allows for the maximum possible wind capacity by zone taking into account only constraints considered 'hard' within the UK seabed.
[44] Difference is national pricing – locational pricing

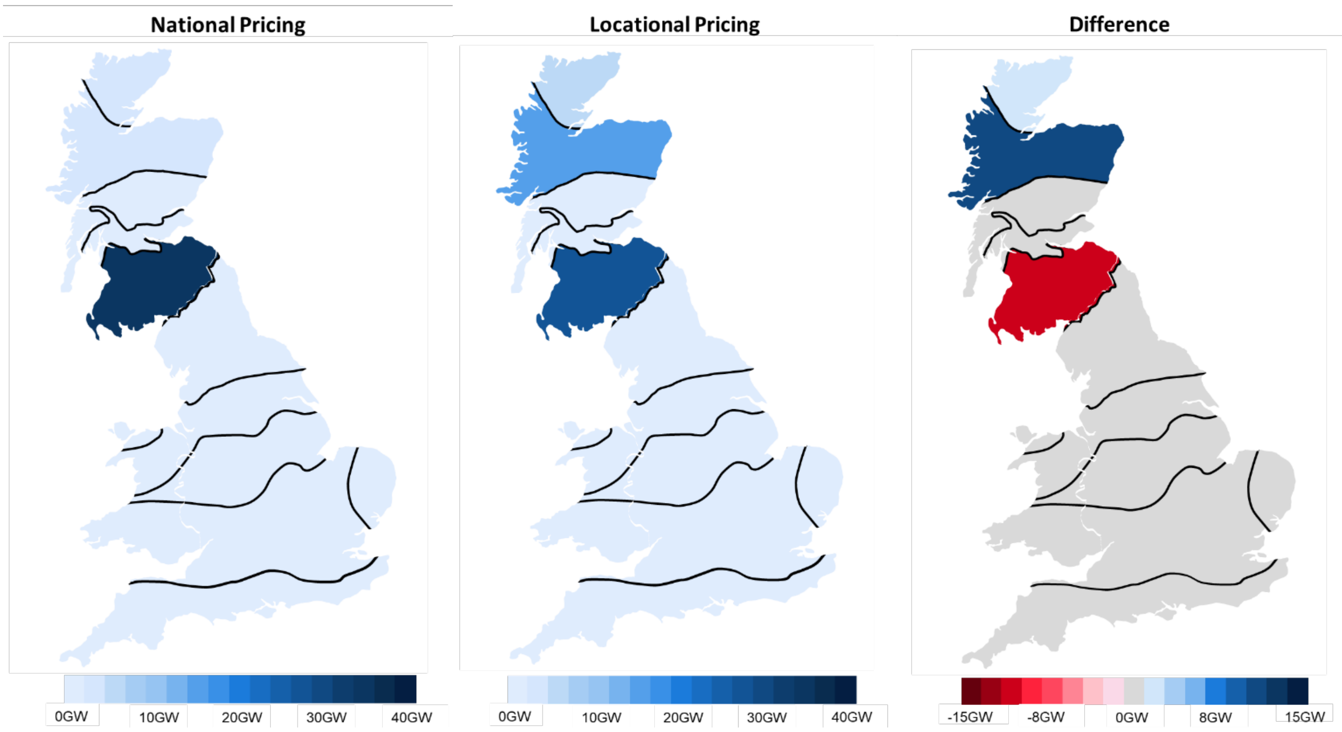
(Northern England) and K (East Anglia). Instead, offshore wind capacity increases in zone L (Southern England), which is more often constrained.

- Higher load factors can be achieved for offshore wind in Scotland, and this is still important in determining where offshore wind locates. Offshore wind capacity actually increases overall in Scotland by 4GW from moving to locational pricing, showing that increased load factors will still be important drive for offshore wind projects going forward. The majority of the increase in Scottish offshore wind capacity is seen from 2040 onwards, showing this is more beneficial with locational prices as boundary constraints are reduced.

Onshore Wind

- Onshore wind new build is restricted to Scotland and Wales in the model to reflect limited deployment that has been seen in England. As there is no zone that is just defined as Wales – onshore wind build is allowed across all zones that contain Wales (G, I and J). Onshore wind build in these zones is restricted to 10% of the total onshore wind capacity in every year across these three zones to reflect a maximum of 10% of total capacity in Wales, as per current onshore wind build.

Figure 18: *Location of onshore wind capacity in 2050 with TNUoS or Locational price signals, and difference between scenarios.*



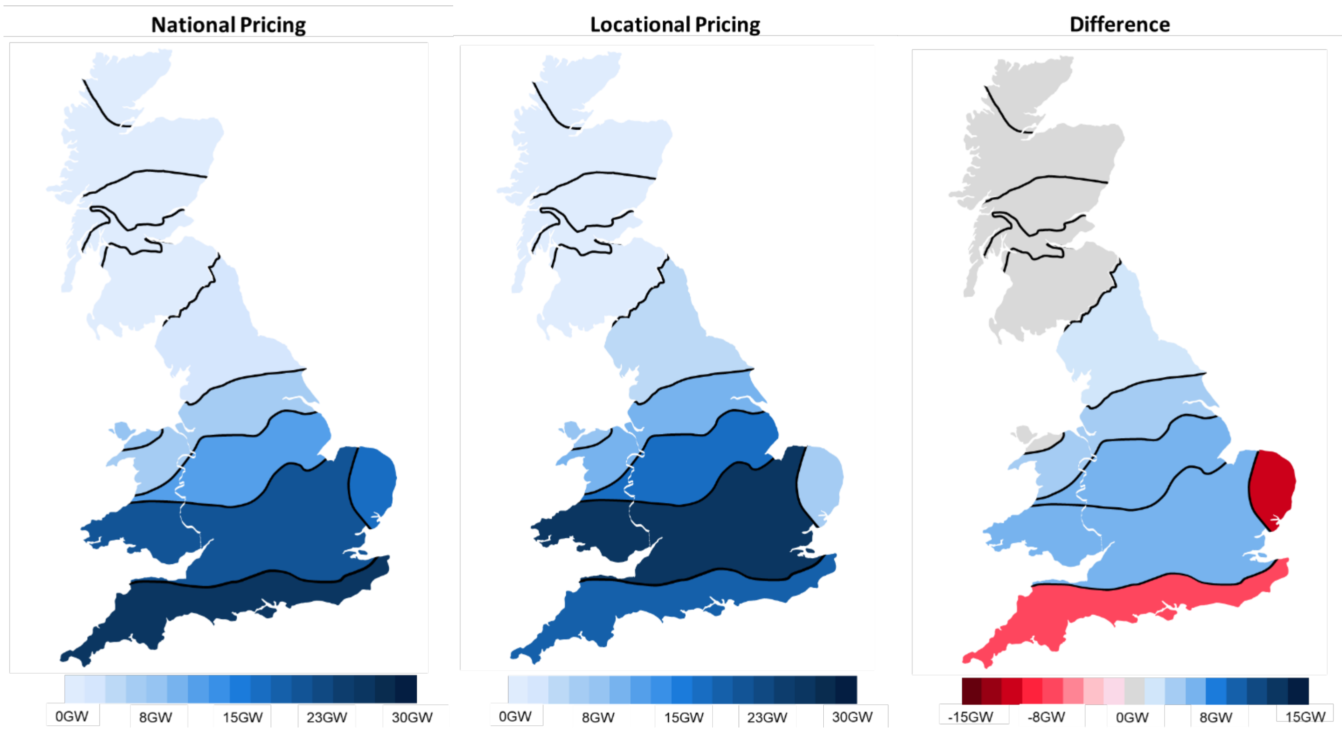
- In the counterfactual, TNUoS signals are not as strong as for other technologies given around 50% is assumed to be distribution connected (so would not pay TNUoS). This results in a weak locational signal for the counterfactual for onshore wind meaning it locates based on where it gets the best load factor. This results in very high levels of onshore wind build in Scottish zones, particularly zone E (Southern Scotland).

- Moving to locational pricing, onshore wind is more distributed across Scotland. From 2040-2050, less than 10% of total capacity is built in Wales. This is due to reduced boundary constraints across the country due to other technologies relocating, allowing onshore wind capacity to take advantage of the higher load factors in the north. By 2050, there is 12GW less onshore wind just north of the Scottish border (zone E), and 13GW more in the most northerly Scottish zones (A and B).

Solar

- Currently solar build is primarily focused on southern England due to the higher load factors that solar can achieve there. In the counterfactual, solar build is not affected by TNUoS charges as it is assumed to be distribution connected. Solar plants locate where they can make the most revenue however, which leads them to primarily locate where load factors are highest – in Southern England and Wales (Zones I, J and L).

Figure 19: *Location of solar capacity in 2050 with TNUoS or Locational price signals, and difference between scenarios.*



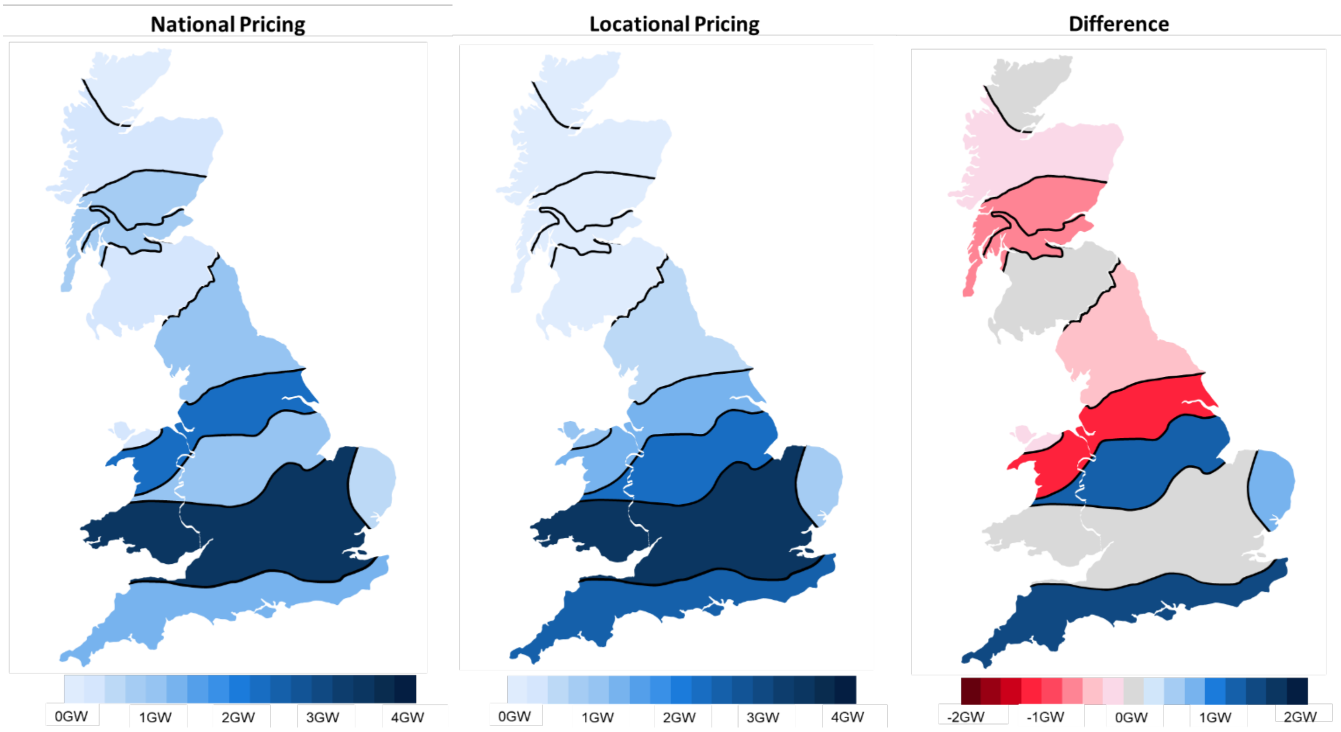
- Moving to locational pricing sees new solar build continue to be focused on the south of Great Britain. All English zones with the exception of L (southern England) and K (East Anglia) see an increase in solar capacity with solar focusing its build towards higher demand areas and locating away from zone L with offshore wind cannibalising revenues in this zone.
- In the counterfactual, new build is predominately in the most southerly zone (L) reflecting the higher load factors that can be achieved there. In contrast, the factual shows highest build in zones I and J (southern England and Wales). This is due to the increased locational

signal in the factual which drives more solar to locate in that zone as it is has the highest demand.

Batteries

- Batteries in the DESNZ Higher Demand scenario are assumed to be a mix of Lithium-ion batteries with durations ranging from 1 to 4 hours. Batteries are incentivised to locate where there is the greatest price spread so that they can charge when prices are low and discharge when prices are high. Batteries are assumed to be mostly distribution connected so in the counterfactual it is assumed they build at the same rate across their current locations. In the counterfactual, the batteries are quite spread across the country. Capacity mostly locates in England with highest capacities in zones J (southern England inc. London) and G (Middle/northern England).

Figure 20: *Location of Battery capacity in 2050 with TNUoS or Locational pricing signals, and difference between scenarios.*



- In the factual, batteries see movement south to the highest demand zones with the highest concentration still around London (zone J) but increases seen in zones I, K and L in the south of England. Moving to locational pricing significantly reduces price volatility in northern England and Scotland as prices are often set by renewables. The zones with the highest price spreads are those with higher demand and less renewables in southern England so batteries choose to locate there. Lower battery capacity behind network constraints could pose problems for renewable generators located in those zones as there is limited storage to help reduce their curtailment although other flexibility assets such as electrolysers and interconnectors can also help reduce curtailment.
- Depending on the rate of network build and the locations of constraints, the system benefit of locating batteries in each zone will vary. For example, Zone J is often import constrained

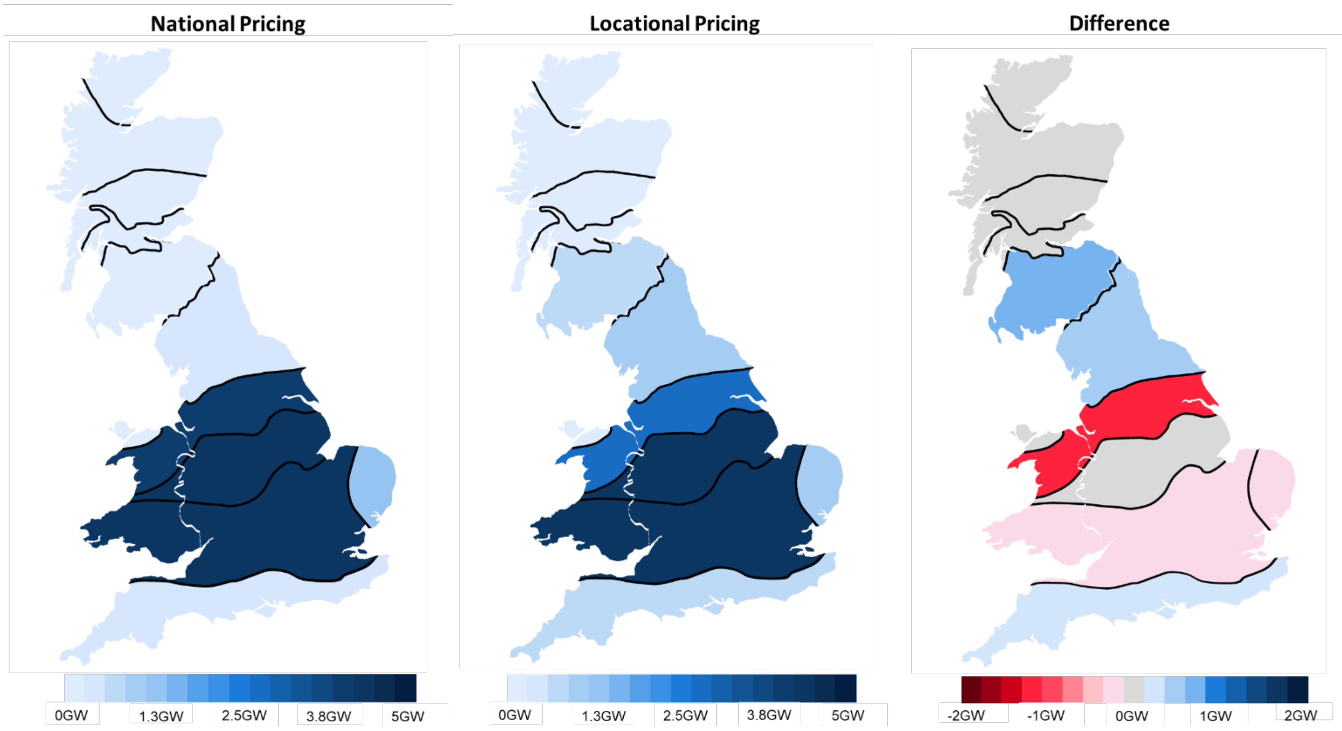
– that is, boundary constraints limit import to that zone. Having batteries in Zone J would be helpful when Zone J is import constrained, as the batteries could discharge to provide extra generation in Zone J at these times and charge up when the boundaries are not constrained. In Zone J, there is an adequate balance of constrained and unconstrained periods to provide battery storage with many of these opportunities.

- Equally, may be less valuable in other zones. For example, Zone A is often export constrained due to wind generation, low demand and insufficient boundary capacity. Adding a battery in Zone A would allow the battery to charge on that excess wind generation. However, there are few opportunities for the battery to discharge when the boundary is not constrained. This limits the opportunities for battery storage in these zones.

Gas CCS

- As a price setter due to their high SRMC, gas CCS plants will look to locate where they can generate most often. However, they are restricted in their location based on the availability of CCS pipelines. As a result, it is assumed gas CCS plants can only locate within industrial clusters. This is assumed to be all zones except A and H, and zone L before 2035.

Figure 21: *Location of Gas CCS capacity in 2050 with TNUoS or Locational price signals, and difference between scenarios.*



- In the counterfactual, gas CCS capacity is concentrated around high demand zones in Southern England where both TNUoS charges are lower, and they are more likely to be turned-up in locational balancing.
- Locational pricing does not see significant changes to where Gas CCS is located with the highest concentration of capacity still in the south. However, capacity does become slightly

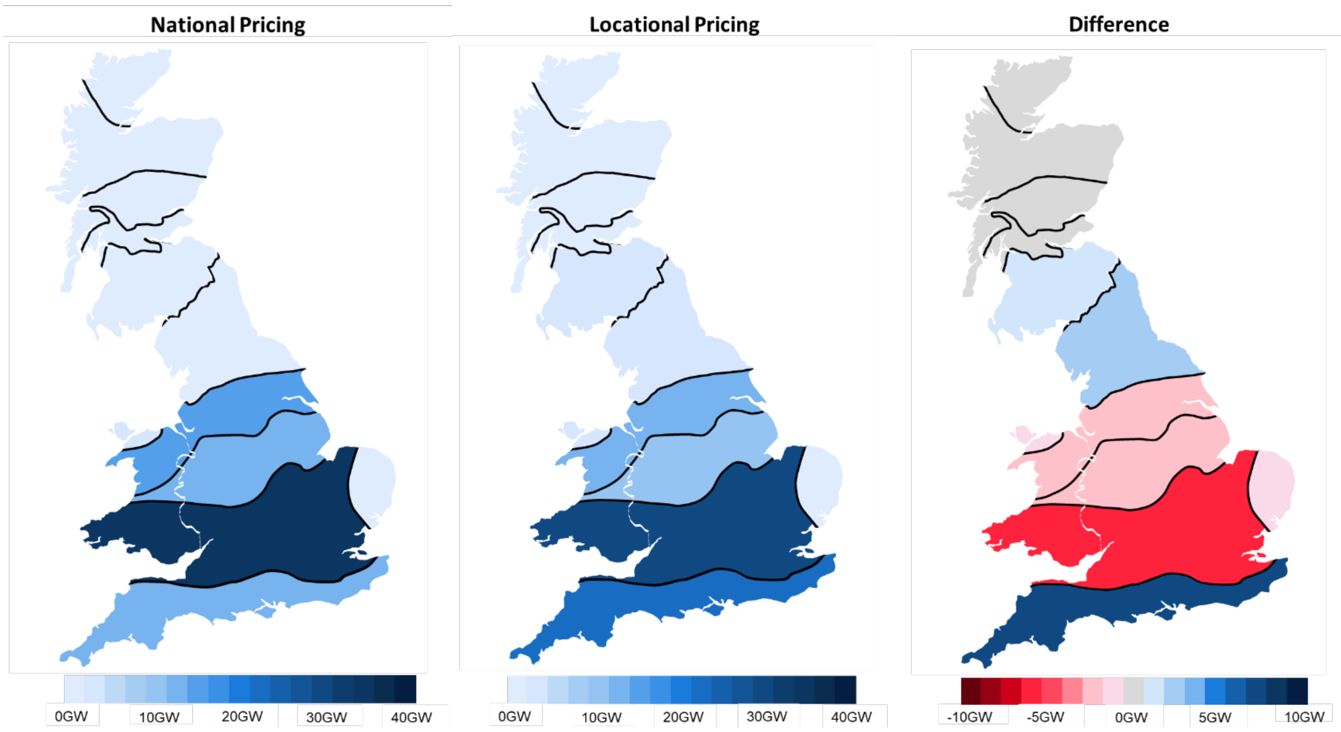
more evenly distributed across all zones. This is due to the locational pricing signal becoming more cannibalised in the high demand zones as gas CCS, hydrogen, storage and unabated gas compete in these zones. This combined with lower renewables in northern zones in the locational price model sees some capacity to relocate further north.

- Overall, moving to locational pricing helps to spread Gas CCS more evenly across the country to help reduce constraints and reduce competition.

Unabated gas

- The high amounts of unabated gas capacity on the system by 2050 in the DESNZ scenarios (83GW in the Net Zero higher demand scenario) have very low load factors due to the high amounts of renewables and other low carbon capacity on the system. As a result, unbated gas plants will look to locate where they can generate as regularly as possible and set the price at a high level.

Figure 22: *Location of unabated gas capacity in 2050 with TNUoS or Locational price signals, and difference between scenarios.*



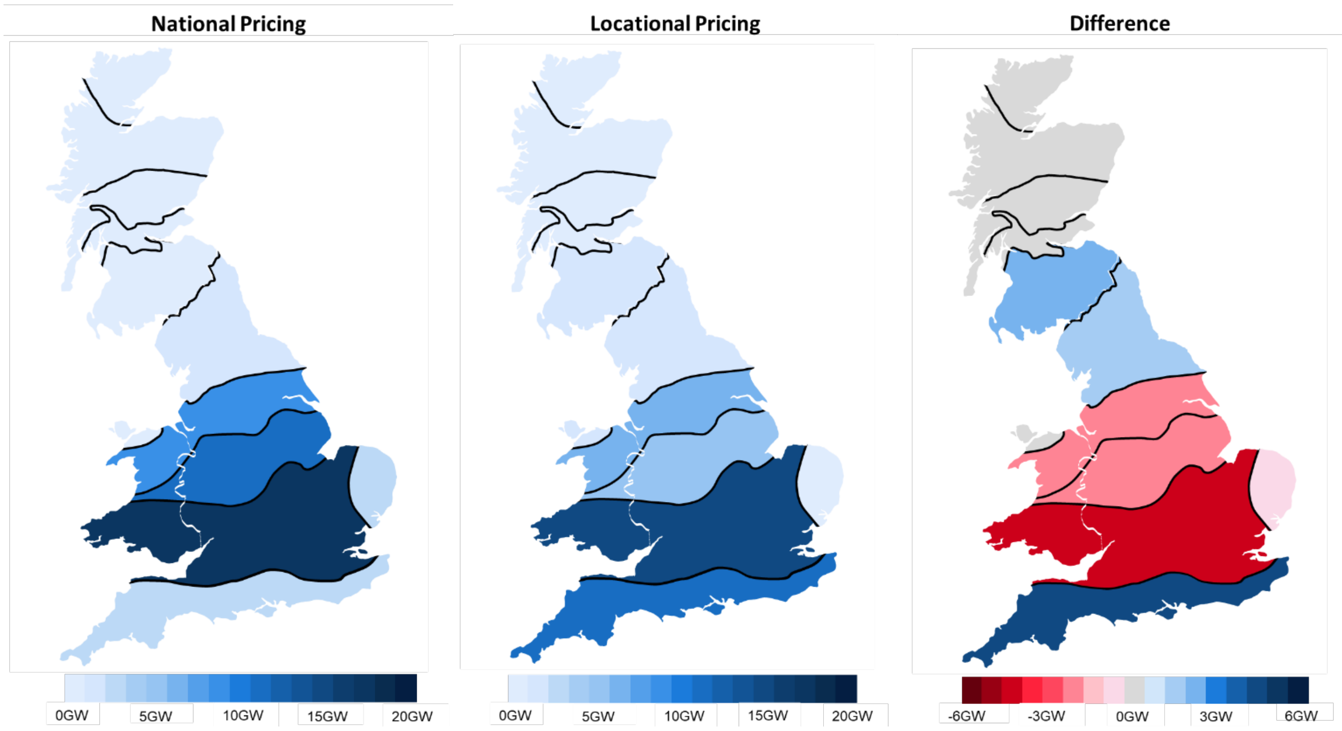
- The counterfactual, with TNUoS charges as locational signals, sees unabated gas capacity concentrated around high demand zones. This reflects where many unabated gas plants are currently located.
- The locational pricing factual also has the highest concentration of capacity in the south, but with additional capacity more evenly distributed across all zones. The differences in relocation are due to the locational pricing signal being cannibalised as more gas generators choose to locate in zones with higher prices, causing the price to fall. In particular more gas capacity locates in Zone L (southern England). In contrast, the TNUoS charges are less responsive to the move in generation and so do not increase to the same extent that the zonal price decreases.

- From a system operation perspective in a locational pricing model, it's helpful to have gas plants located close to demand so that demand can be met at times of system stress. However, having gas located more evenly can also be helpful to meet constraints caused by other factors such as low wind days and allows more flexibility on the system.

Hydrogen Power plants

- For this study, hydrogen power plants refer to Combined Cycle Hydrogen Turbine (CCHT) plants to produce hydrogen with the price of hydrogen burned in the plants set based on the price of blue hydrogen as provided by DESNZ. As an electricity price setter due to their high SRMC, hydrogen power plants will look to locate where they can generate most often. However, like gas CCS plants, it is assumed that they can only locate within industrial clusters. This is assumed to be all zones except A (north Scotland) and H (north Wales), and zone L (southern England) before 2035.

Figure 23: *Location of hydrogen capacity in 2050 with TNUoS or Locational price signals, and difference between scenarios*



- In both the national pricing counterfactual and locational pricing factual, there is no new build of hydrogen in Scottish zones. Instead, under both models, the highest levels of capacity is located in zone J (London/southern England). National pricing causes high levels of hydrogen build to be concentrated around this centre of demand due to lower TNUoS levels and more opportunities to turn-up in locational due to constraints not allowing energy to be transferred to this part of country.
- Moving to locational pricing sees more hydrogen capacity distributed more evenly across the English zones. While zone J still has the highest capacity, this is 4GW lower than in the national pricing scenario, and 6GW more capacity locates in Zone L (southern England). This is because there is more renewable and other generation in this scenario due to

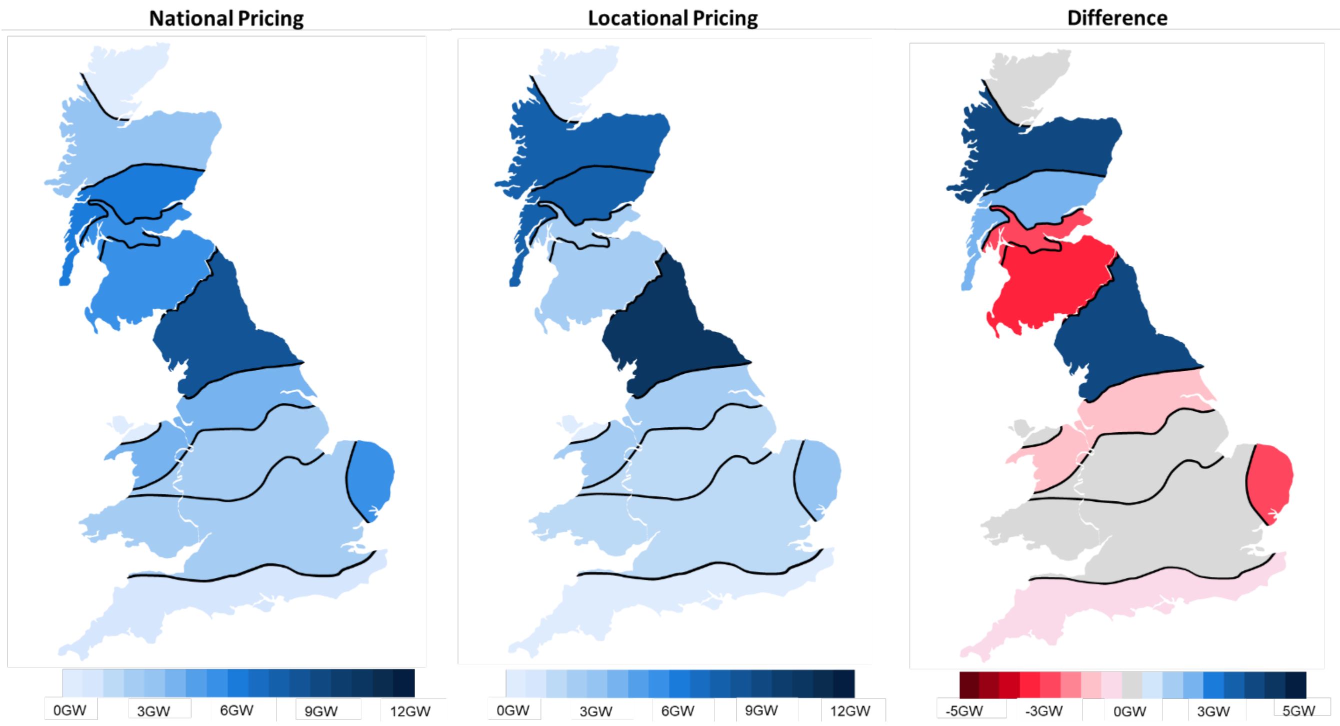
reduced constraints, and so the hydrogen capacity distributes more evenly where it will generate the most, without cannibalising the locational signal as this reduces the zone price. Zone L is also the highest price zone so more hydrogen locates there to obtain the higher locational price in this zone.

- As for unabated gas, from a system operation perspective it's helpful to have hydrogen plants located close to demand so that demand can be met at times of system stress. However, hydrogen located more evenly can also be helpful to meet constraints caused by other factors such as low wind days and allows more flexibility on the system.

Electrolysers

- Electrolysers are a source of demand within the power sector where electricity is used to produce green hydrogen, primarily from renewables that would otherwise be curtailed. Electrolysers are the only demand source that are able to change location in response in locational signals within this analysis. Similar to gas CCS and hydrogen, they are only allowed to relocate to industrial cluster zones assumed to be all zones except A and H, and zone L before 2035. Electrolysers are also restricted so that maximum of 50% of capacity can be built in Scotland.

Figure 24: *Location of Electrolyser capacity in 2050 with National or Locational price signals, and difference between scenarios.*



- Electrolysers only produce hydrogen when the wholesale electricity price is low, and so in a locational model the electrolysers locate in the north in zones that more frequently have lower prices. With a national price for electricity, the primary incentive for an electrolyser to locate somewhere is where they can use renewable generation that would otherwise be curtailed, which will account for renewables being curtailed due to network constraints. For example, when there is high wind in Scotland, there is likely to be a low national cost and so the electrolysers will produce hydrogen if they can access energy. In Scotland there is likely to be no boundary constraints to provide energy to an electrolyser, but in south England there may be more network constraints and electrolyser action would result in higher prices with generators in the south of England being turned on.

- In both cases, this incentivises electrolysers to locate further north with most capacity locating in the north of Great Britain and the highest concentration in the middle zones of Scotland. In the locational pricing model, the maximum of 50% capacity in Scotland is hit in all years.

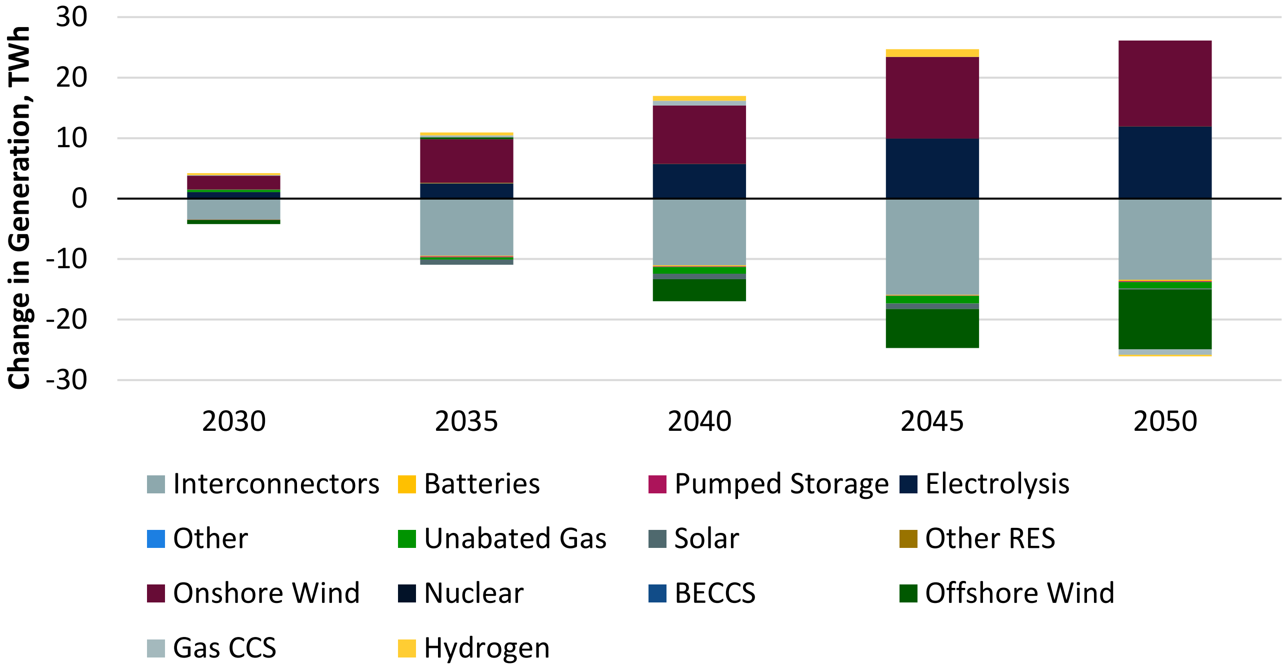
4.4. Generation and Emissions

Changes in capacity location due to locational pricing drive changes in generation which in turn drive reduction in emissions. This also drives the reduction seen in carbon costs within system costs.

Generation

The below graph shows the changes in generation for the DESNZ Net Zero higher demand scenario between the national pricing counterfactual and the locational pricing factual.

Figure 25: *Generation change by technology between national pricing counterfactual and locational pricing factual*



The key differences in generation are:

- Net imports via the interconnectors are lower in the locational pricing model compared to the national model. This is due to more renewables located in the zones where these were previously generating meaning, they can replace imports and increase exports. This drives changes in interconnectors costs.

- Batteries and pumped storage are used more often as the changing locations of batteries[45] and renewable assets mean that they can be used more efficiently for the system and can capture higher price spreads in certain zones. This partially drives the small increase in generation costs.
- Unabated gas and gas CCS generation decreases as increased battery usage and higher generation from renewables displaces this. For unabated gas, this is also slightly displaced by hydrogen. This drives changes in emissions and therefore carbon costs.
- Hydrogen generation increases as hydrogen moves to areas where it can displace unabated gas and some imports. This partially drives the small increase in generation costs.
- Generation from renewables overall increases as they are located more efficiently so can generate more regularly when the system needs them. However, this is mainly due to high increases in onshore wind generation as there is less overall capacity (from other technology types except onshore wind) in Scotland and boundaries being less constrained in a locational pricing model (explored further below) means onshore wind generation in Scotland can increase. Offshore wind generation decreases slightly overall which appears to mainly be due to less electrolyser use although does increase in southern zones. These overall increase in renewable generation drive the small increases in generation costs.
- Electrolyser production decreases from moving to locational pricing (this is represented as an increase in the above chart as electrolysis is effectively negative generation). This is as a result of more efficient dispatch so less excess energy for electrolysers to use and slightly higher prices across zones meaning electricity is not as cheap in certain periods for the electrolysers to run.
- Nuclear and Biomass CCS see no change in their generation. This is because they do not change locations and their operation is unaffected by moving to locational pricing.
- All generation changes are driven by changes in capacity location. As noted previously it is assumed that interconnectors can participate in locational balancing in the counterfactual which means there are limited operational efficiency gains as a result of moving to locational pricing.

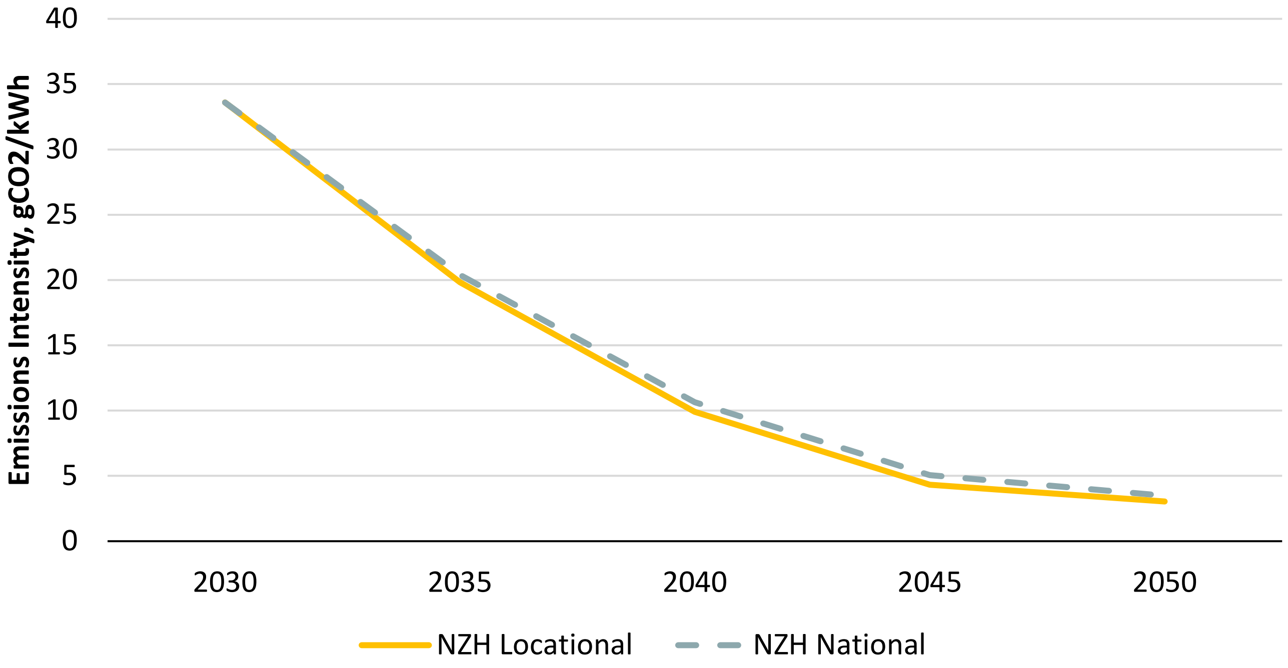
Emissions

The below chart shows the corresponding change in emissions because of the changes in generation. Carbon emissions are similar in both scenarios, although overall slightly lower in the factual. This is due to reduced generation from gas CCS plants and unabated gas.

[45] Pumped storage does not relocate as there is assumed to be no new pumped storage capacity in the DESNZ scenarios so the 2.9GW of pumped storage stays fixed through the modelled period

This shows that moving to locational pricing could have a positive impact on reaching emissions targets. Although the effect would highly depend on what the capacity mix of the system.

Figure 26: *Emissions intensity for counterfactual and factual for the DESNZ Net Zero higher demand scenario*



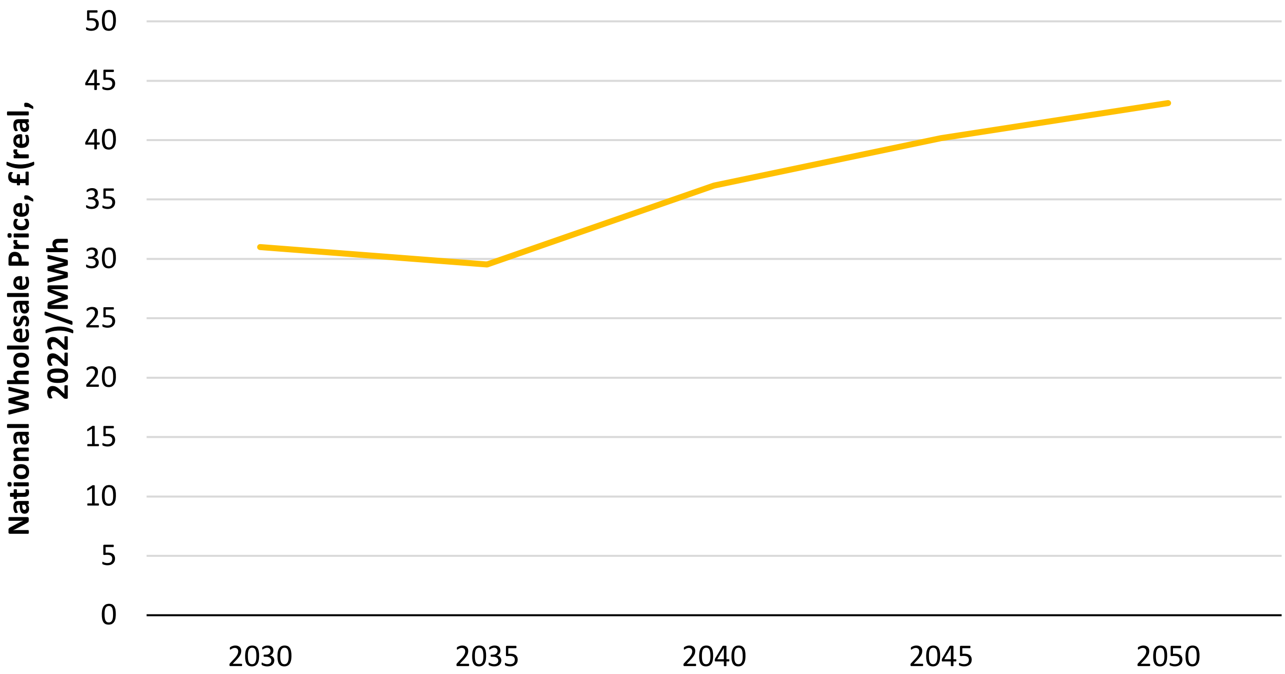
4.5. Price Outcomes

Prices in the national pricing counterfactual decrease from current levels to around £30/MWh by 2030 as gas prices (as provided by DESNZ) return to more 'normal' levels and renewable penetration increases. Prices stay relatively constant between 2030 and 2035[46]. While renewable penetration increases meaning renewables set the price more often, carbon prices and hydrogen prices also increase. Therefore, when gas and hydrogen (both foreign and domestic) are setting the price then they do so at a more expensive level.

Slight rises in price are then seen from 2035-2050 as renewables penetration increase more slowly than in earlier years in the DESNZ scenarios. This is a function of the inputs and assumptions used in the modelling. This means that while the proportion of time renewables set the price does not change significantly, the carbon price rises and the propensity for hydrogen generation to set the price increases, causing increases in average wholesale prices.

[46] Note that only every 5 years are modelled from 2030 to 2050

Figure 27: *Demand weighted Wholesale price in the national pricing counterfactual for DESNZ Net Zero Higher scenario*



In the locational factual, each zone follows a similar pattern in terms of the general trend but the differences in prices between zones vary depending on the type of capacity located there. The prices in each zone can be seen in the graph and maps below:

Figure 28: *Zonal prices in the locational pricing factual for DESNZ Net Zero Higher scenario*

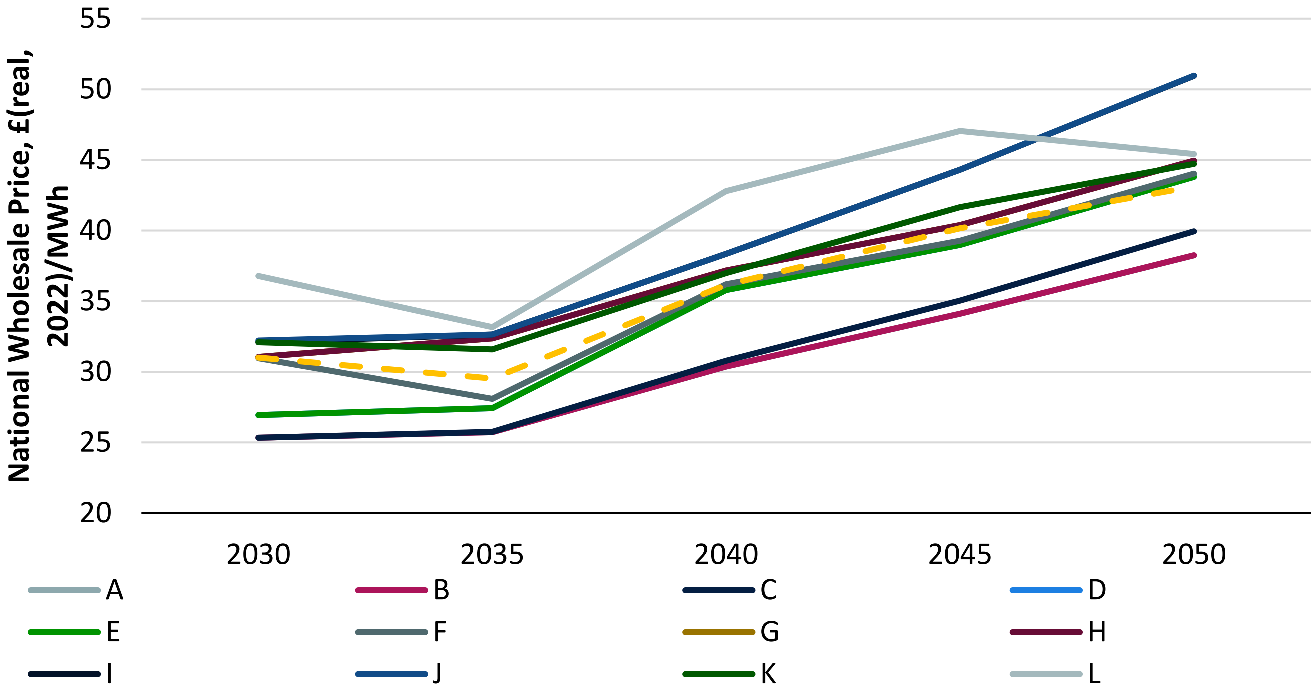
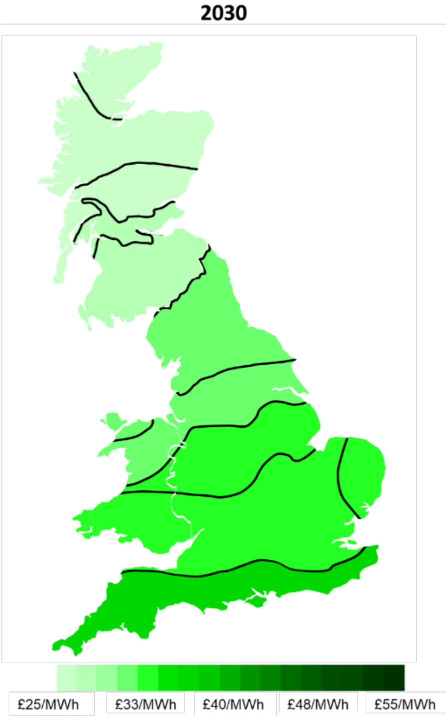
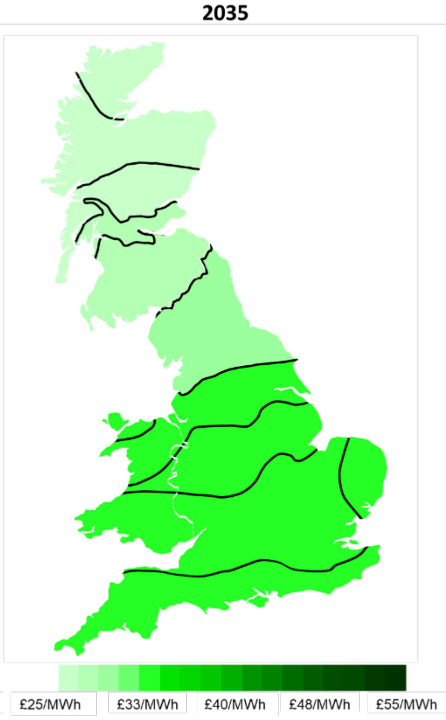


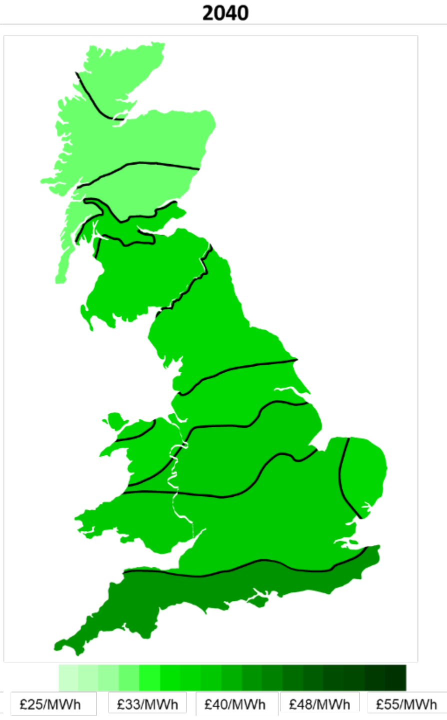
Figure 29: *Zonal price maps in the locational pricing factual for DESNZ Net Zero Higher scenario in £(2022)/MWh*



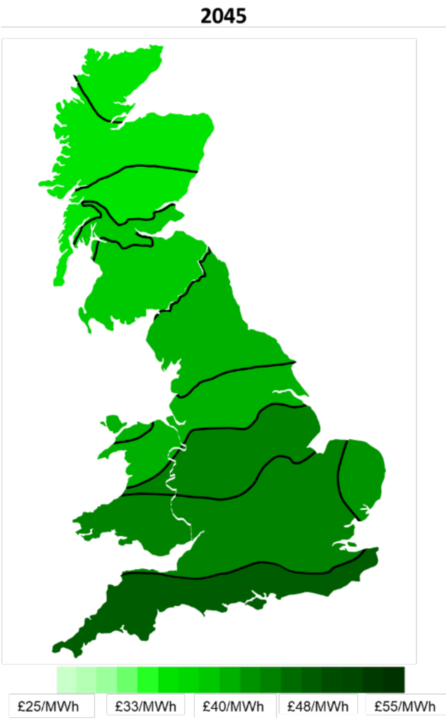
National price: £31/MWh
Locational Price: £25-37/MWh



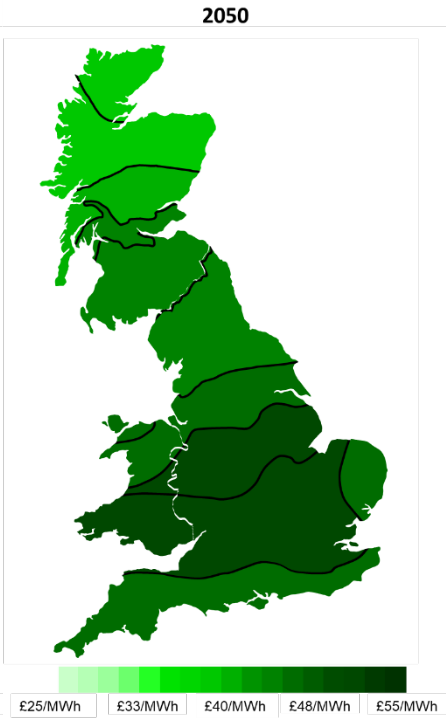
National price: £30/MWh
Locational Price: £26-33/MWh



National price: £36/MWh
Locational Price: £30-43/MWh



National price: £40/MWh
Locational Price: £34-47/MWh



National price: £43/MWh
Locational Price: £38-51/MWh

Zones A, B and C in North Scotland have the cheapest price as significant levels of wind are located there and demand is relatively low. This means that wind sets the price often here, however as these zones are not constrained that often then it is more common for the prices in other zones to set prices here.

The zones in South and Central England such as zone J, I and L, with high demand relative to their generation have higher prices than zones with excess generation, such as Northern Scotland. This is due to the constraints across the boundaries of the zones preventing sufficient power being transferred between zones, requiring more expensive generation to be used in zones with high demand relative to generation. Prices vary by up to £13/MWh across zones – for example in 2050 zone B has the lowest price at £38/MWh compared to £51/MWh in zone I. This range stays relatively consistent over time with the range in prices at £12/MWh in 2030 and £13/MWh in 2050.

On average, demand weighted wholesale prices are slightly higher in the locational pricing factual than the national counterfactual. Prices in high demand zones show price increases compared to a national pricing counterfactual. This is because more expensive plants are needed to meet demand once boundary constraints are considered. This leads to increased consumer costs from wholesale pricing, as consumers have to pay more for their energy usage in some zones. Within consumer costs, this is partially due to constraint costs being moved into wholesale price costs but as constraint costs are removed and this decrease is higher than increases in wholesale price costs then this results in an overall benefit for consumers.

Given the disparity across zones, it will be important for policy makers to consider whether end users in different zones should pay different prices for their energy. As outlined above, we assume demand (with the exception of electrolysers) will not be able to relocate in response to locational signals in the same way as generation should be able to.

4.6. Boundary Constraints

In the locational pricing model, when a boundary between two zones is not constrained (i.e. not at full capacity), the price between the two zones is the same. While the prices shown above for locational pricing do have variation across zones, this range may not be as significant as some may expect with prices in all years for all zones above £25/MWh on average and no zone close to £0/MWh on average. This is dictated by how often boundaries are constrained. Those constrained more often tend to have a different price to other zones while those constrained less often tend to have prices similar to other zones.

The impact of this can be seen by observing how often different boundaries are constrained. As expected, the national scenario is more constrained overall compared to the locational scenario. This is due to the location of capacity in the country with capacity located more efficiently in the locational scenario.

Figure 30: *The percentage of time boundaries are constrained in the National Pricing counterfactual NZH scenario.*[47]

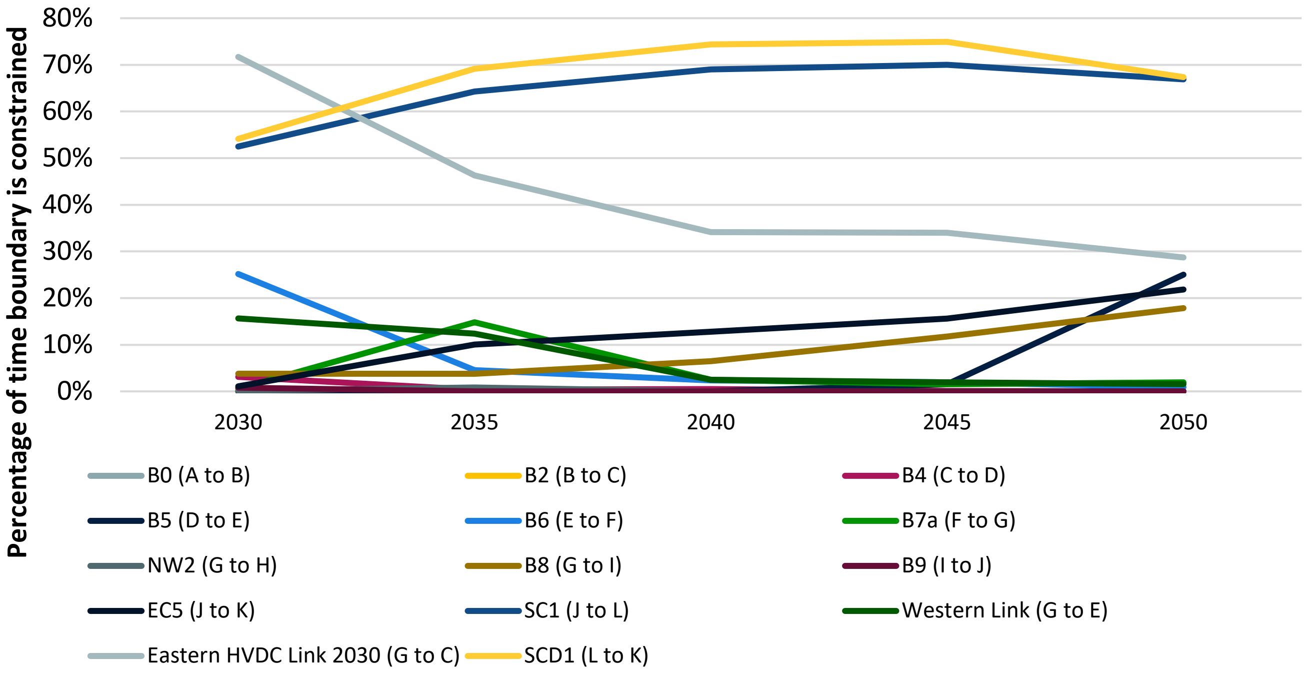
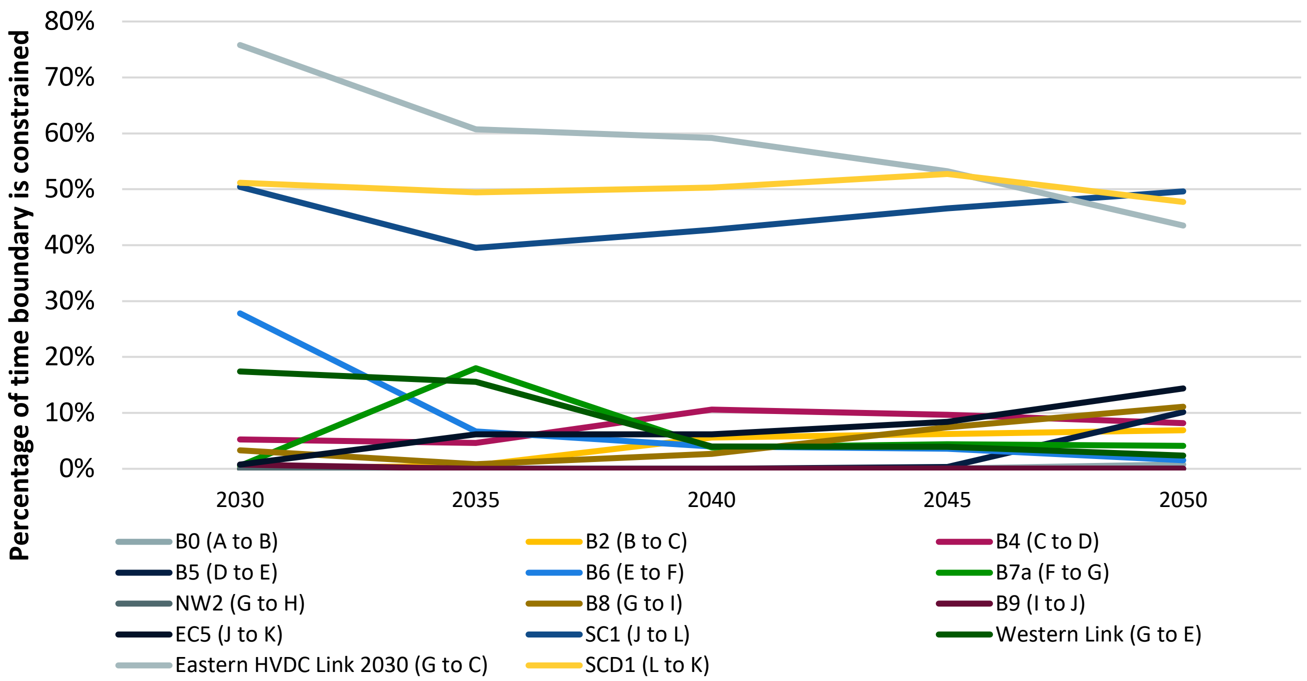


Figure 31: *The percentage of time boundaries are constrained in the Locational Pricing factual NZH scenario.*



In both the factual and counterfactual, the boundaries to/from zone L (southern England) are most constrained. This is mainly due to relatively little capacity currently being located in this

[47] For map of zones see 3.2

zone and it being one of the highest demand zones. This is very strongly impacted by interconnector actions as a lot of interconnectors are connected to zone L. Boundaries to and from zones across the B6 boundary are also sometimes constrained in both scenarios due to where the renewables are located.

Boundary constraints are highest in 2030. 2030 has the lowest boundary capacity to demand ratio so this is expected. Boundary capacity doesn't change after 2040 but demand continues to increase. This causes the percentage constrained percentages to start to creep up again after 2040 for most boundaries.

It should be noted that the model's optimisation engine will more commonly choose to push flow across one boundary than across multiple boundaries to transfer flow between the same two zones in order to minimise losses across the network. This means that HVDCs[48] are more constrained than the same route through other boundaries. Along with increases in network capacity, this is one of the reasons as to why the B6 boundary in particular is constrained less often over time.

[48] HVDCs are high voltage direct current long cables usually put under the sea. These are normally large links to move electricity over large instances In the modelling we assume that there are two large HVDCs from zones G to C and zones G to E. There are less energy losses flowing energy across 1 long HVDC than through multiple high and low voltage cables. This is reflected within the modelling.

5. Operational Efficiency Benefits of Locational Pricing

This section outlines the key results in relation to the operational efficiency benefits of moving to a locational pricing model. An operational efficiency saving is defined as a cost saving because of changes in the operation of the market when moving to locational pricing. This represents any additional reduction in costs without any capacity being moved due to improved investment signals. The key assumptions for this scenario are shown in the table below:

Table 5: *Assumptions used in the operational efficiency scenarios*

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	ICs in national pricing model	Batteries in national pricing model	BM Uplift	Offshore wind location restriction
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
No ICs in Locational Balancing	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
No ICs and limited storage in locational balancing	DESNZ Net Zero Lower demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Limited participation in locational balancing	Bid up to marginal unit	Lower restriction
Full Operation al Impacts	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Limited participation in locational balancing	Bid up to marginal unit + uplift	Lower restriction

This chapter outlines the impacts of three key areas where inefficiencies exist in the current redispatch of assets due to locational constraints under the national pricing model; participation of interconnectors in locational balancing, dispatch of storage in locational balancing and uplift of bids/offers in the balancing mechanism above the Short Run Marginal Cost for some assets. An overview of each of these areas is provided in turn along with modelling results.

This section outlines the cost impacts of moving to locational pricing under the core DESNZ scenarios against different national pricing counterfactuals with each operational impact added. All assumptions used in this section are provided by DESNZ unless otherwise stated.

It is important to note that operational efficiency benefits are not necessarily unique to locational pricing. It is possible that changes could be made to the current national pricing model to achieve some of the same benefits. However, further research is needed to understand the extent to which benefits could be achieved under a reformed national market.

5.1. Interconnectors' participation in locational balancing

As outlined in section 3.7, a current inefficiency in the system is how interconnectors act with respect to locational constraints. Under current market arrangements, interconnector participation in balancing 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, NGESO must instruct interconnectors outside the BM via trades.

The results in section 4's counterfactual assume that interconnectors can efficiently participate in locational balancing. However, this is not realistic under current market arrangements with the SO-SO trades currently used not able to fully redispatch interconnectors in the most economical way. Given uncertainty as to how much interconnectors can participate in locational balancing, it is prudent to test an alternative scenario whereby interconnectors are not able to participate in locational balancing in the national pricing counterfactual. This removes the interconnectors' ability to act within locational balancing meaning that constraints are resolved by turning up or down other technologies instead. For example, more expensive domestic generation, such as unabated gas, may be turned up to manage constraints instead of interconnectors utilising cheaper foreign generation. The results from this scenario allow us to understand the potential maximum operational benefits of more efficient interconnector dispatch under locational pricing.

From a generation perspective, if interconnectors can participate in locational balancing in a national pricing counterfactual, if CfD negative pricing rules are applied consistently, and if there is no change in the location of capacity then there will be very little difference between what ultimately generates in a national pricing model and a locational pricing model. If all plants bid based on a short run marginal cost[49], then there should be no operational difference between the two – this is assumed in the modelling and if the three above criteria are applied then we would see no changes in generation or system costs. However, consumer costs would still change as locational pricing transfers costs between consumers and producers by reducing BM redispatch.

The results of this section show the impact on system costs when comparing a locational pricing factual (where interconnectors fully participate) compared to a national pricing counterfactual where interconnectors cannot participate in locational balancing. This is for the following two scenarios:

[49] This could also include a small uplift to reflect scarcity. In the current market, assets do often increase their bids/offers to reflect scarcity and perception of the need for their services by including an uplift in their bid. However, this could also apply in locational wholesale markets as well. This scarcity uplift is not modelled in detail as it is extremely hard to predict as it depends on numerous factors.

Table 6: *Scenarios covered in 5.2*

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	Interconnectors in counterfactual
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing
No participation of Interconnectors in Locational Balancing	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing

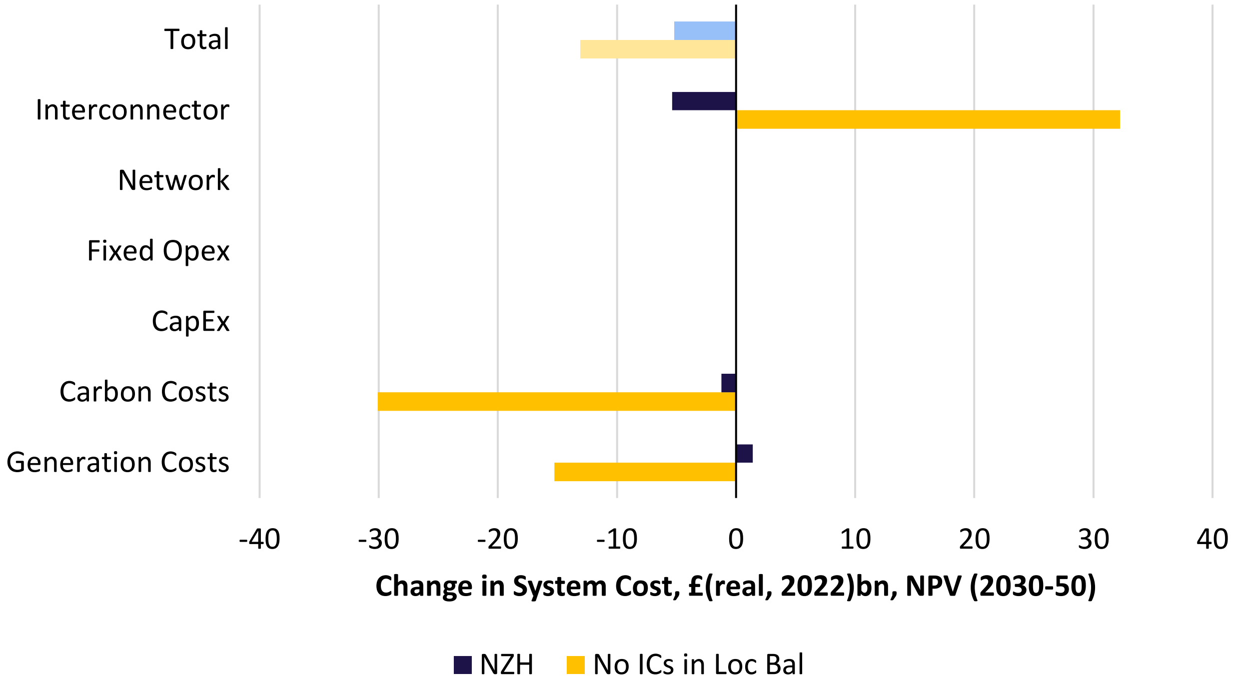
5.2. No interconnectors in Locational Balancing Counterfactual Modelling Results

In this scenario, the impact of moving to locational pricing is larger compared to the results outlined in section 4. This is due to interconnectors being used more efficiently in the locational pricing factual resulting in operational efficiency savings from moving to locational pricing[50]. Overall, this sees the system benefits increase from £5.2bn in a scenario where interconnectors can participate in locational balancing in the national pricing counterfactual to £13.1bn in a scenario where interconnectors cannot participate in locational balancing in the counterfactual.

In terms of distributional impacts, consumer benefits also increase from £24.4bn in a scenario where interconnectors can participate in locational balancing in the counterfactual to £49.4bn where interconnectors cannot participate in locational balancing in the counterfactual. However, this leads to larger adverse effect on producers, with the cost to producers of moving to locational pricing increasing from £19.2bn where interconnectors can participate in locational balancing in the counterfactual to £36.3bn where interconnectors cannot participate in locational balancing in the counterfactual.

[50] An operational efficiency saving is defined as a cost saving as a result of changes in the operation of the market due to locational pricing. This is effectively a reduction in costs without any capacity being moved due to improved investment signals

***Figure 32:** Change in System Costs for NZH scenario and No ICs in locational balancing scenario.*



This is a significant increase compared to the Net Zero higher demand core scenario outlined in section 4 and shows that enabling a move to locational pricing from current arrangements (where interconnectors cannot participate in locational balancing) would bring operational benefits to the system.

The key changes in system costs from moving to locational pricing compared to a national pricing counterfactual where interconnectors cannot participate in locational balancing are:

- **Interconnector costs** – There are greater net exports via the interconnectors in the no interconnectors in locational balancing counterfactual compared to the core (NZH) counterfactual, as interconnectors are only responding to national prices. This leads to interconnectors exacerbating locational constraints as they are unable to reduce exports or switch to importing to solve locational signals. As a result, net imports increase when we move to locational pricing against a no interconnectors in locational balancing counterfactual causing interconnector costs to increase. In comparison net imports decrease in the core scenario when moving to locational pricing leading to interconnector costs decreasing.
- **Generation costs** – these decrease when moving to locational pricing with a no interconnectors in locational balancing scenario as lower cost imports and renewables replace gas, gas CCS and hydrogen generation. In comparison in the core scenario, net imports decrease while lower cost hydrogen generation and renewables increase leading to a slight increase in generation costs.
- **Carbon costs** – these decrease across both scenarios as unabated gas generation decrease but this decrease is larger in the no interconnectors in locational balancing scenario as gas is more often used to resolve locational constraints in the counterfactual.

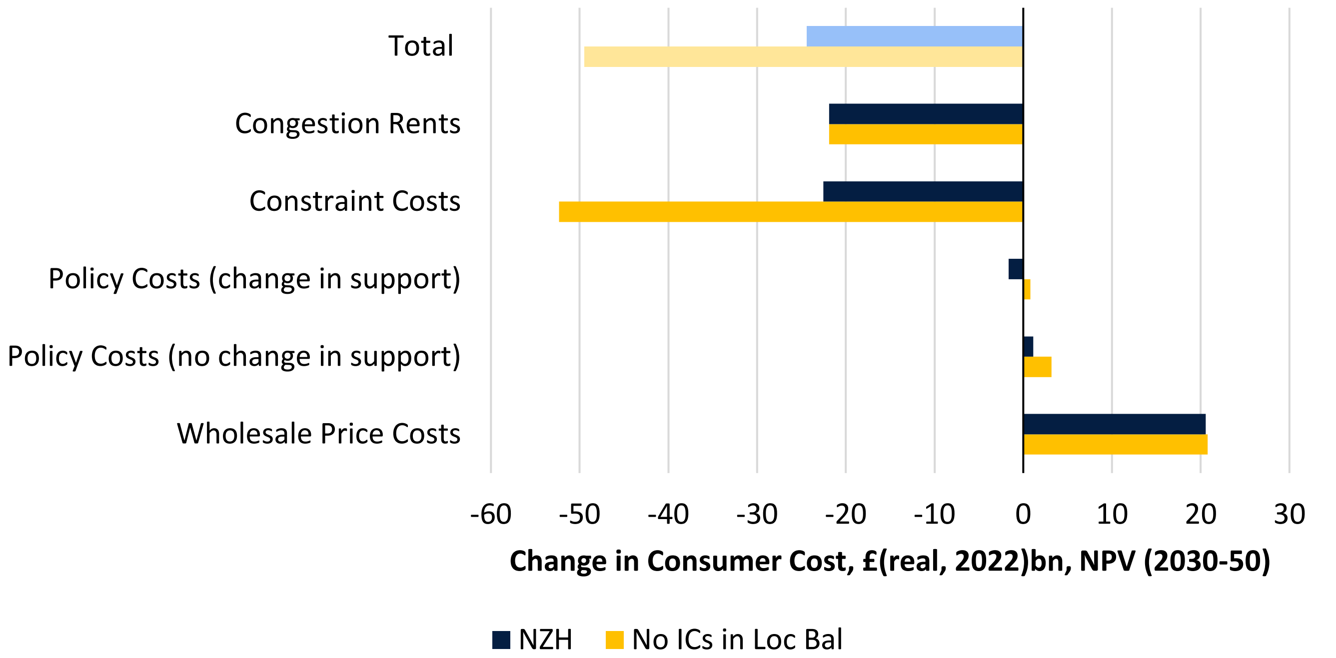
The primary reason for such a big increase in system cost savings in the no interconnectors in locational balancing scenario is due to the 'operational efficiency' benefits from moving to locational pricing. This is because in the counterfactual, interconnectors significantly exacerbate constraints in many circumstances and as they cannot change their position from the day ahead market, higher cost thermal assets such as unabated gas need to be turned up more regularly in locational balancing.

It should be noted that under current arrangements interconnectors do participate in locational balancing through the operation of Balancing actions (as outlined in 1.4). This was not modelled due to lack of available data and clear rules on how these balancing actions are used by NGESO. This means that the benefits of moving to locational pricing compared to a scenario where interconnectors do not participate in locational balancing will likely be higher. This is explored in more detail in the next chapter.

Consumer benefits from moving to locational pricing also increase in a scenario where interconnectors cannot participate in locational balancing in the counterfactual. Consumer benefits increase from £24.4bn in a scenario where interconnectors can participate in locational balancing in the counterfactual to £49.4bn where interconnectors cannot participate in locational balancing in the counterfactual. However, this leads to larger adverse effect on producers, with the cost to producers of moving to locational pricing increasing from £19.2bn where interconnectors can participate in locational balancing in the counterfactual to £36.3bn where interconnectors cannot participate in locational balancing in the counterfactual.

The only significant difference between the change in consumer costs for these two scenarios is in constraint costs with savings significantly higher in the scenario where interconnectors cannot participate in locational balancing in the counterfactual. All other costs show relatively little change. Congestion rents are the same across the two scenarios as the factual (where locational pricing is implemented) is the same for both of these scenarios with the change to how interconnectors participate in locational balancing only applying to the counterfactual. This is shown in the graph below:

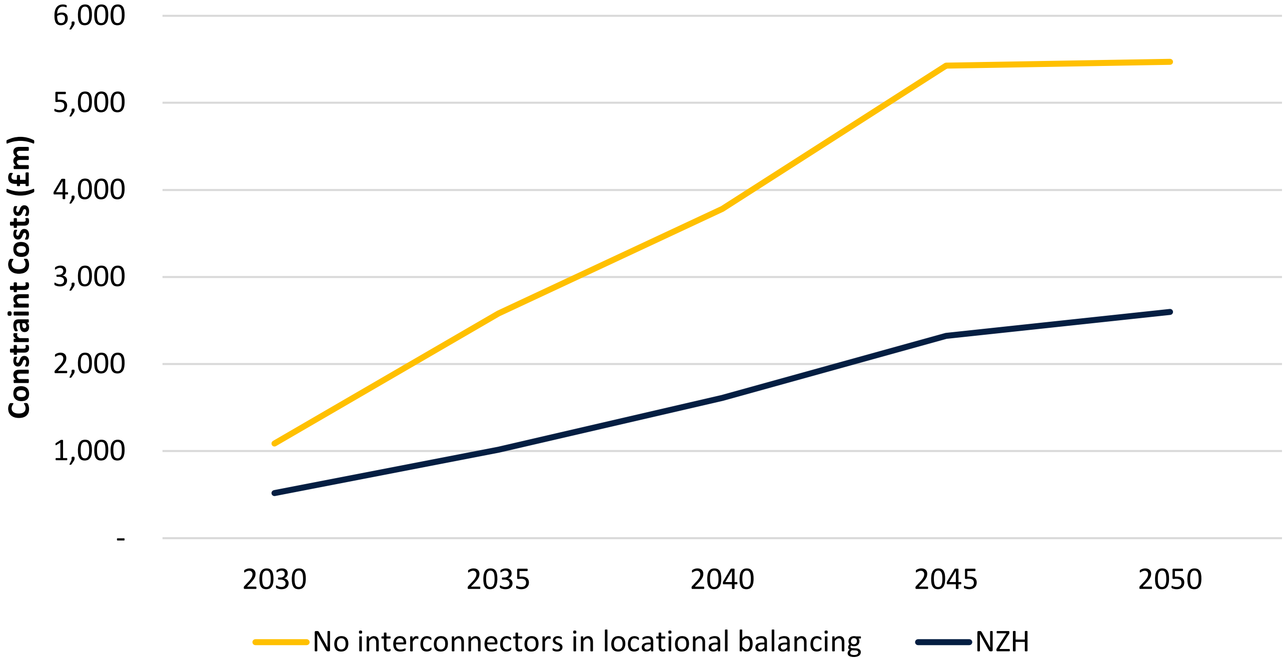
Figure 33: *Change in Consumer Costs for NZH scenario and No iCs in locational balancing scenario.*



Comparing constraint costs across the two counterfactuals illustrates why system cost savings are higher in the scenario without interconnectors in locational balancing. As the graph below shows, constraint costs are significantly higher with no interconnectors participating in locational balancing compared to 100% participation in locational balancing. Constraint costs in the counterfactual are calculated based on the amount of generation that is constrained and the prices that generation is turned up and down at. In both scenarios, constraint costs increase over time as boundaries are constrained more regularly. This is due to the rate of demand and capacity (particularly in constrained areas) increasing faster than the rate of network build.

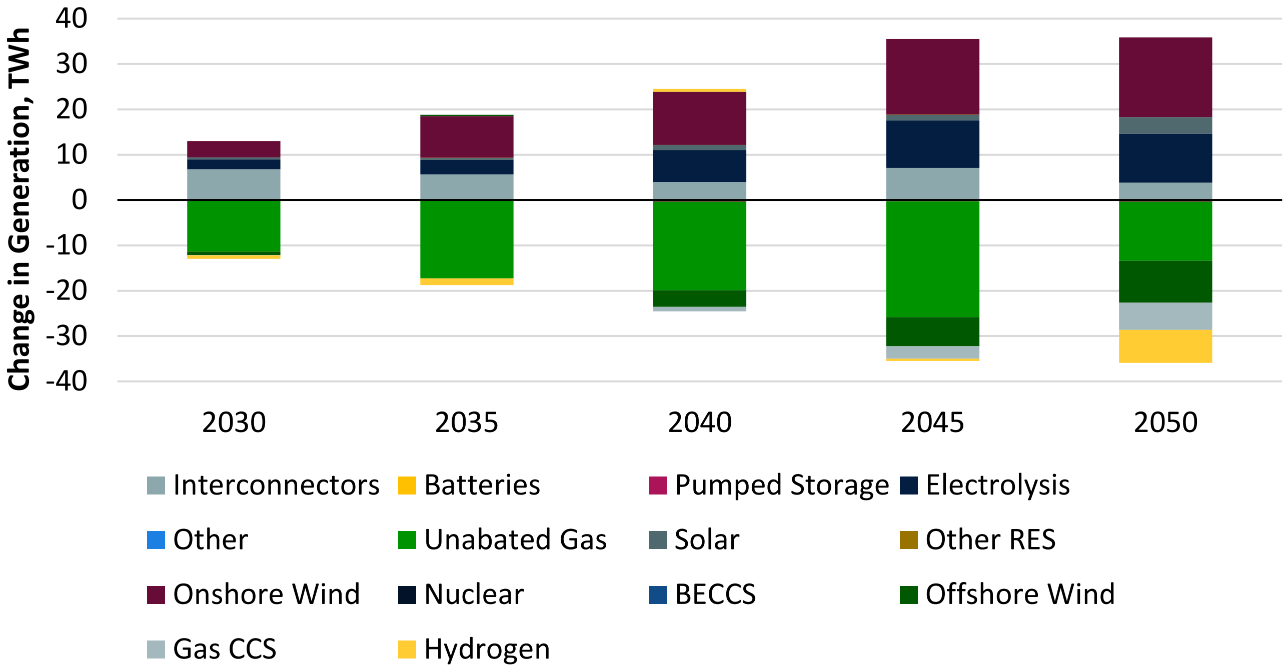
As can be seen below, the constraint costs are significantly higher in the no interconnectors in locational balancing counterfactual as interconnectors significantly exacerbate constraints in many circumstances and higher cost thermal assets such as unabated gas need to be turned up more regularly in locational balancing. As a result, moving to locational pricing has more of an impact as interconnectors help rather than hinder constraints.

Figure 34: *Constraint Costs in National pricing counterfactual for core scenario (NZH) and the no interconnectors in locational balancing scenario*



The higher impact of moving to locational pricing with the no interconnectors in locational balancing counterfactual can be illustrated by looking at the changes in generation as a result of moving to locational pricing. This is outlined in the graph below which shows the changes in generation between a national pricing counterfactual where interconnectors cannot participate in locational balancing and a locational pricing factual.

Figure 35: *Generation change by technology between national pricing counterfactual where interconnectors cannot participate in locational balancing and locational pricing factual.*



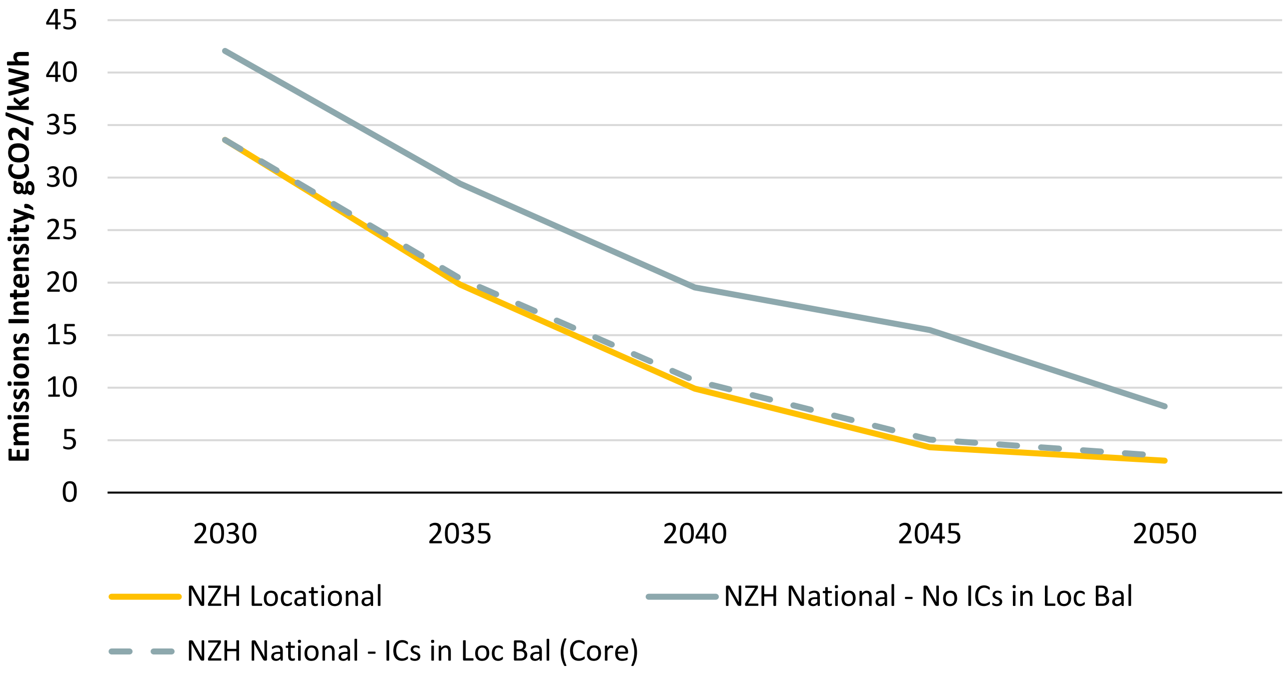
The key changes in generation are:

- Net imports via the interconnectors increasing by up to 7TWh per year as interconnectors can act more effectively to ease constraints.
- Decreases in unabated gas, gas CCS and hydrogen generation as these no longer need to be turned up as often to manage locational constraints. This reduces generation costs and carbon costs significantly.
- Increases in solar and onshore wind generation. This is primarily due to the relocation of these plants to more effective locations in the same way as the core scenarios.

The change in generation leads to corresponding changes in emissions. With no interconnectors participating in locational balancing in the counterfactual, moving to locational pricing has a significant impact on emissions. Emissions intensity drops by 10gCO2/kWh in 2025 and 2040 and 5gCO2/kWh in 2050.

This decrease comes from unabated gas generation being used significantly less across all years with renewables and imports via the interconnectors being used more in its place. In comparison, emissions reduction as a result of moving to locational pricing are quite small in the core scenario where interconnectors do participate in locational balancing 1gCO2/kWh decrease in emissions in any 1 year. This shows that any emissions impacts from moving to locational pricing is more likely to come from operational efficiency changes as opposed to investment efficiency changes.

Figure 36: *Emissions intensity for counterfactual with and without interconnectors participating in locational balancing and factual for the DESNZ Net Zero higher demand scenario*



Overall, these results shows that if interconnectors cannot fully participate in locational balancing in the current market, then the benefits of moving to locational pricing are increased, both in terms of costs and emissions.

5.3. Storage Dispatch in Locational Balancing

As outlined in 1.4, the Balancing Mechanism is the GB system operator's primary tool for redispatching assets to balance supply and demand, as well as managing system needs in real time. It becomes active post-gate closure (1hr before the start of each settlement period). Assets that participate in the BM (known as BM Units or BMUs) submit Bid Offer Pairs for each settlement period (up to five). Each pair consists of the prices that the BMU is willing to incrementally increase (offer) or decrease (bid) their power output (or consumption) for a certain tranche of volume.

If the BM were a simple energy market with infinitely flexible units, Bids and Offers would be accepted in merit order – taking the most cost-effective action first. However, the BM solves a multitude of energy and system needs – one of which is locational constraints, meaning that at times certain BMUs will be 'out of merit' where their bid/offer does not get accepted despite them bidding/offering at a price that would see them in merit if the BM were a simple energy market. This is often referred to as these assets being 'skipped'.

The NGESO has historically separated the types of skips into two distinct buckets of explained and unexplained skips:

- **Explained Skip**: An explained skip is when a Bid/Offer that is in economic merit order is 'skipped over' by the ESO for a more expensive action, but for legitimate reasoning. This can be because of system need and the skipped unit not being able to meet that need. Some out of merit acceptances are unavoidable in the BM as currently designed. For example, due to locational constraints, system stability and unit-level constraints. Second, some are necessary for operational reasons and are not preventable under current Electricity National Control Centre (ENCC) and wider industry practices. This includes reasons such as time constraints for decisions, legacy processes and inaccuracy of participant data.
- **Unexplained Skip:** An unexplained skip is when a Bid/Offer that is in economic merit order is "skipped over" by the NGESO for a more expensive action, and no valid reason can be assigned. This could be due to control room error or because of legacy systems and infrastructure.

While any asset can be skipped, this has been highlighted as a specific issue for battery storage assets in recent months due to the number of skips that occur for these assets. This was highlighted in the letter sent to NGESO by the Electricity Storage Network (ESN) outlining analysis which estimated that the average skip rate for battery storage assets was 80% in June 2023 with an estimated annualised cost to the consumer of £150m.

NGESO is currently undertaking work to better understand and address this issue in the current market (which LCP Delta is supporting). As a result, it is expected that the “skip rate” is unlikely to remain at such high levels in 2030. However, if current issues were to persist, this could have an impact on the costs involved in resolving locational constraints in the BM, with storage penetration increasing and network constraints become more prevalent in the future. A move to locational pricing could reduce the extent of this issue as locational constraints would be factored into the wholesale market removing the need for plant to be redispatched for locational reasons through the BM.

To capture the potential impact of this within the modelling, an additional scenario has been modelled where the level that storage is redispatched to resolve locational constraints in the BM is limited in the national pricing counterfactual. This is applied within the model by limiting the amount that storage plants are able to change the charge they hold after the wholesale market in locational balancing.

For the scenarios outlined in the next section, it is assumed that storage assets’ charge and discharge actions in the BM for resolving locational constraints only represent a maximum of 20% of their maximum capacity in any given hour (MW input/output). In other words, Bids and Offers for storage are only ever accepted up to a maximum of 20% of their MW capacity within any given hour in the BM for resolving locational constraints. This assumption was provided by DESNZ and came from the letter sent to NGESO by the Electricity Storage Network (ESN)[51]. We recognise that this is not a precise replication of the 80% ‘skip rate’ referenced above from the ESN analysis, but it allows us to test the impact of lower levels of BM acceptance for storage assets. It does not represent a forecast of the level of acceptances for storage in the BM and is likely to represent an overestimate of the possible impacts.

It should be noted that this assumption is not applied in the core scenario as it is assumed that NGESO makes changes to the current market before 2030 to reduce battery skips.

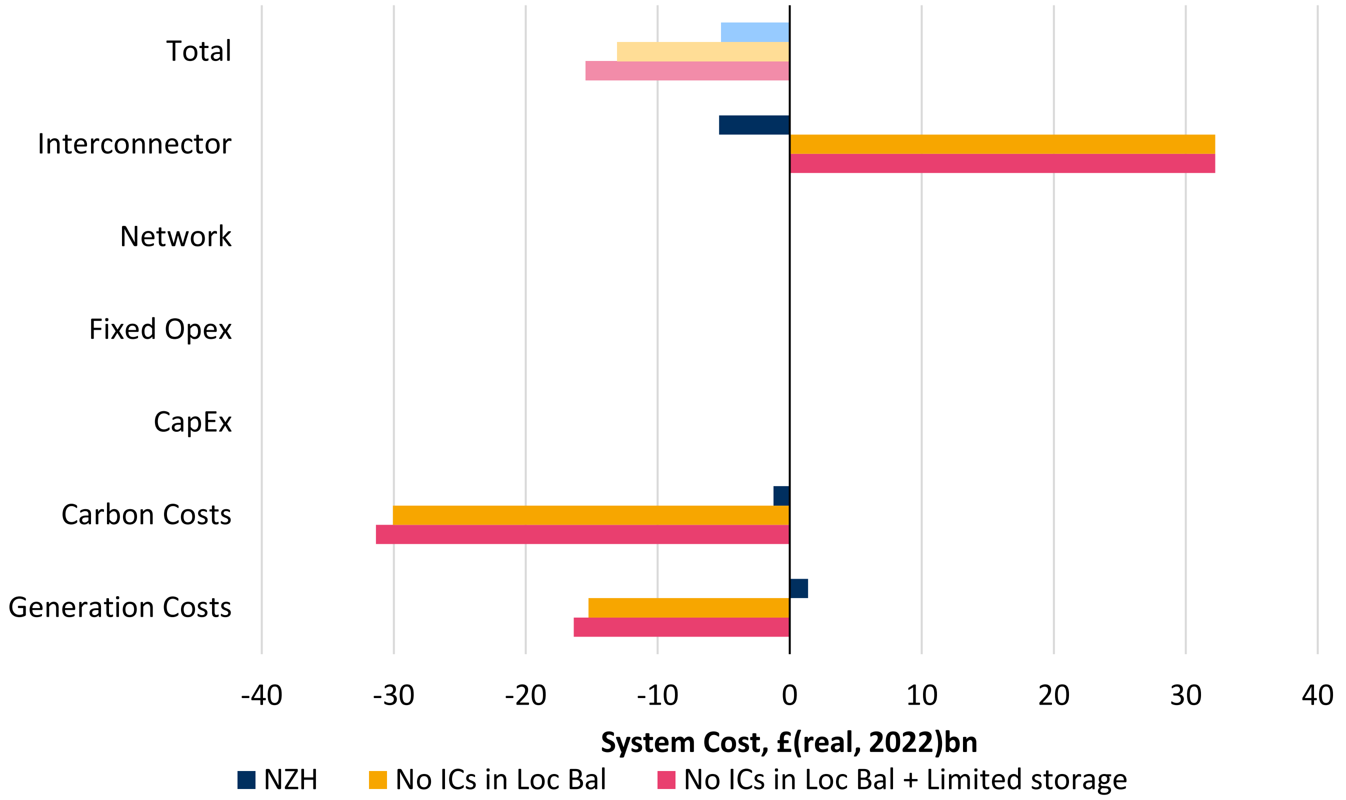
5.4. Limited Storage Dispatch in Locational Balancing Counterfactual Modelling Results

In this scenario, the system impact of moving to locational pricing is larger compared to the results outlined in 5.2. The limited storage dispatch in locational balancing in the national pricing counterfactual as described above is applied in addition to the no interconnectors participating in locational balancing. Overall, this sees the system benefits increase from £13.1bn in a scenario where interconnectors cannot participate in locational balancing in the national pricing counterfactual to £15.5bn in a scenario where interconnectors cannot participate in locational balancing and storage is not redispatched efficiently in the counterfactual. This is an additional benefit of £2.4bn. This is due to both storage and interconnectors being used more efficiently in the locational pricing factual compared to the

[51] Electricity-Storage-Network-letter-to-ESO-on-Balancing-Mechanism-dispatch.pdf (regen.co.uk)

national pricing counterfactual. This results in a higher operational efficiency saving from moving to locational pricing.

Figure 37: *System cost difference between NZH and no interconnectors in locational balancing and storage not redispatched efficiently*



This is a significant increase compared to the Net Zero higher demand core scenario outlined in section 4 and shows that enabling a move to locational pricing from a scenario where both interconnectors and storage are limited in terms of how they are dispatched in locational balancing would bring operational benefits to the system. It also highlights that if current market arrangements can ensure that both interconnectors and storage are dispatched more efficiently to resolve locational constraints then this could also bring significant benefits.

These results show that from a system perspective, limited participation of interconnectors in locational balancing is more significant than inefficient redispatch of storage. This is likely a result of interconnectors being more likely than storage to exacerbate constraints when they cannot act to respond to constraints, with interconnectors representing a larger overall share of energy market volumes (as are not duration limited), and the assumption that interconnectors would not participate at all in the counterfactual, whereas storage dispatch is just limited.

Key changes in system costs as a result of limited storage dispatch in locational balancing are:

- **Generation costs** – these decrease by slightly more than in the no interconnectors in locational balancing scenario. This is because the counterfactual with limited storage dispatch in locational balancing counterfactual has higher levels of unabated gas, gas CCS and hydrogen generation to resolve constraints.

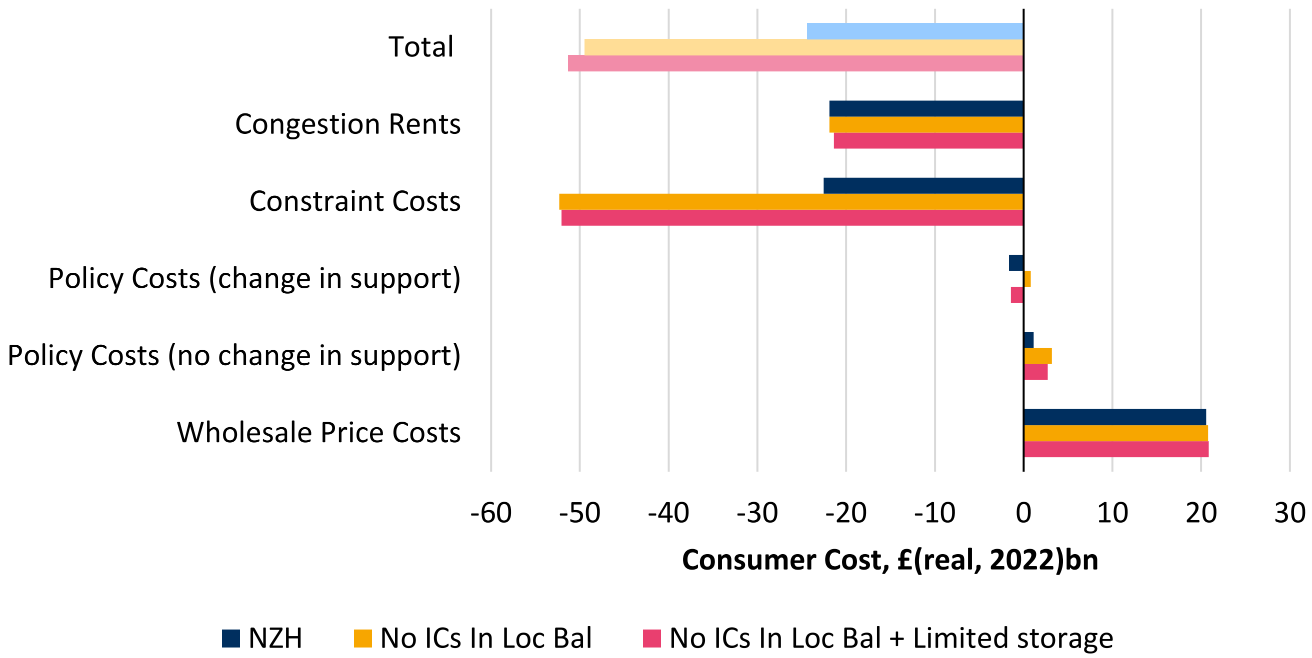
- **Carbon costs** – these also decrease by slightly more in this scenario compared to the no interconnectors in locational balancing scenario as gas is more often used to resolve locational constraints in the counterfactual (where storage dispatch is limited).

Overall, this leads to an increase in the benefits of moving to locational pricing of around £2.4bn (from £13.1bn to £15.5bn) due to increased 'operational efficiency' benefits. This is because in the counterfactual, storage dispatch to resolve locational constraints in the BM is limited, meaning higher cost thermal assets such as unabated gas need to be turned up more regularly in locational balancing.

It should be noted that assumptions for this scenario are uncertain and the sensitivity tested here is intended to provide an upper bound of this impact under DESNZ assumptions for capacity deployment. The system cost impact is also smaller if the limited storage dispatch assumption was applied to the core scenario only (i.e.: with interconnectors fully participating in locational balancing), with an additional benefit of £1bn from moving to locational pricing. This shows that the impact of the different operational efficiency sensitivities tested in this chapter are scenario dependent and the order in which they are applied matters, in terms of quantifying the impact of each one.

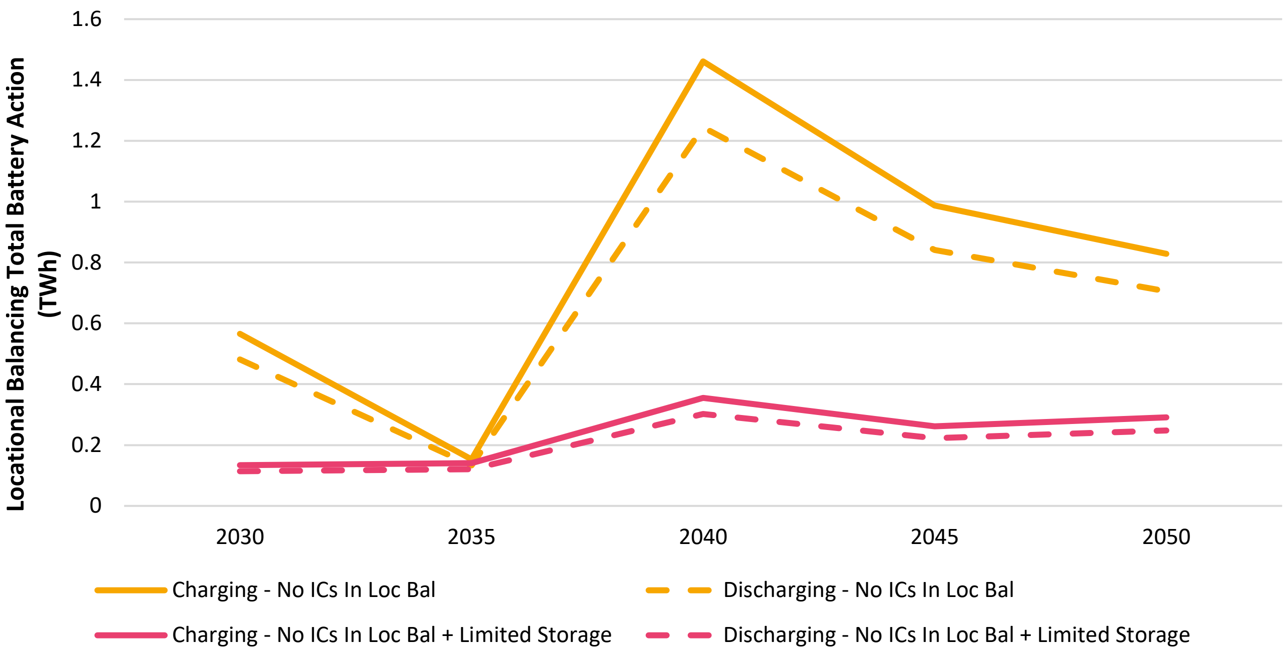
Consumer benefits from moving to locational pricing also increase in a scenario where interconnectors cannot participate in locational balancing and storage is not redispatched efficiently in the counterfactual. Consumer benefits increase from £49.4bn in a scenario where interconnectors cannot participate in locational balancing in the counterfactual to £51.4bn in a scenario where storage is also not redispatched efficiently in the counterfactual. This is an increase of £2bn. Only minor changes are observed across cost types with minor changes across constraint costs and policy costs contributing to the £2bn change as shown below:

Figure 38: *Consumer Cost Difference between NZH and no interconnectors in locational balancing with limited storage*



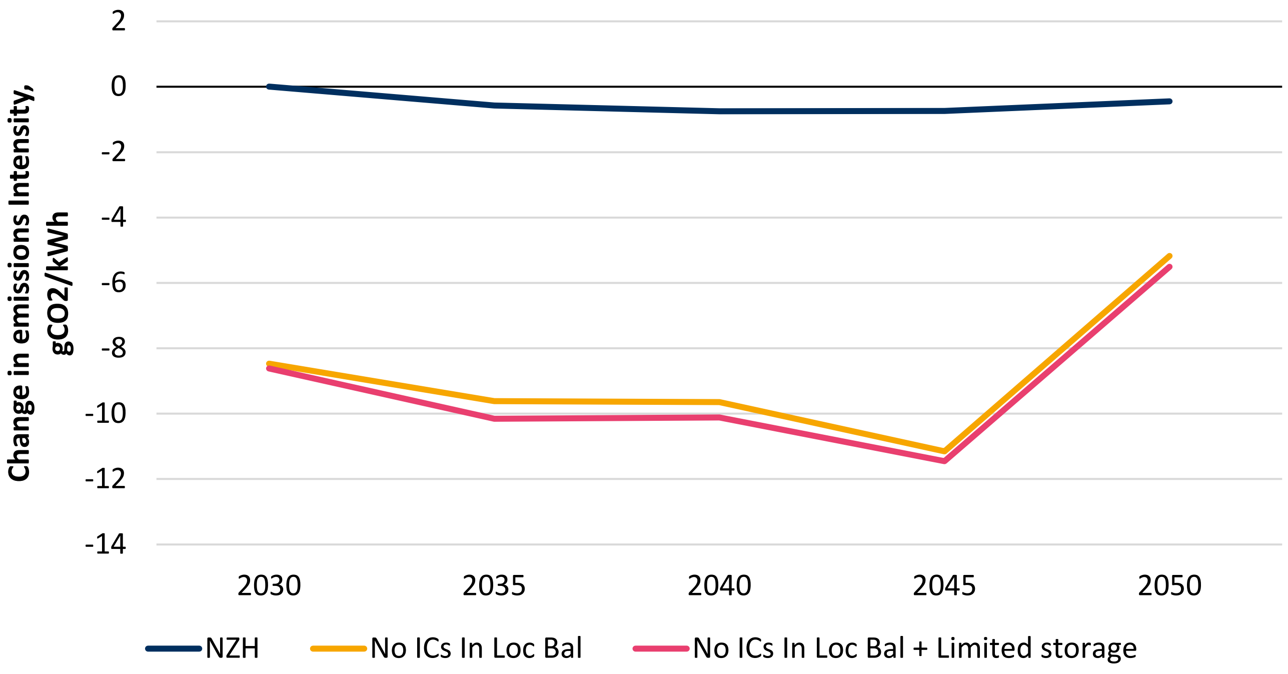
The change in system cost benefits is due to reduced storage actions within locational balancing in the national pricing counterfactual. As can be seen in the chart below, the charging and discharging actions within locational balancing are significantly reduced as a result of the storage only being able to change its charging actions by a maximum of 20% between wholesale and locational balancing. These reduced actions require other generators, mainly gas, to increase their actions in locational balancing.

Figure 39: *Total locational balancing storage actions with and without limited storage*



This reduction in storage use and increase in gas use in locational balancing also increases emissions in the counterfactual. This means that moving to locational pricing leads to unabated gas generation being used significantly less across all years with renewable and imports via the interconnectors being used more in its place. In comparison to the no interconnectors participating in locational balancing scenario, emissions reduction from moving to locational pricing is slightly higher compared to a counterfactual where interconnectors cannot participate in locational balancing and storage is not redispatched efficiently. In comparison to the core scenario where interconnectors fully participate and storage dispatch is unconstrained in locational balancing, there is a maximum of 1gCO2/kWh decrease in emissions in any single year. This again shows that any emissions impacts from moving to locational pricing is more likely to come from operational efficiency changes as opposed to investment efficiency changes.

Figure 40: *Change in carbon emissions from moving to locational pricing under NZH scenario, and with no interconnectors in locational balancing and limited storage dispatch in locational balancing*



5.5. Alternative bid and offer assumptions in the Balancing Mechanism

Within the current market, there is often a disconnect between the prices at which bids and offers in the BM are accepted, and the prices suggested by fundamental modelling. Generators can push offer prices up (or bid prices down), above their short run marginal costs, to capture infra marginal rents, to reflect scarcity, or for other reasons such as reflecting outage risk or additional maintenance costs associated with frequent cycling.

The balancing mechanism is a 'pay as bid' market meaning that generators are paid the based on the of the Bid/Offer price they submit. Typically, under market fundamentals we would expect participants in a pay as bid market to bid up to the cost of the marginal provider – essentially resulting in the same outcome as a pay as clear market. In the core scenario (outlined in chapter 4), we have modelled the BM as a 'pay as clear' market, based on these fundamentals. However, for a number of reasons, this may not be the outcome we would expect in the BM, which is not a single homogenous market, as all participants do not have perfect information, some participants have market power and bidding for locational constraint purposes is regulated.

To explore the impact of this assumption, an alternative approach has been used where generators bid/offer at their SRMC plus an uplift based on historic data (provided by DESNZ). This reflects how generators have historically bid/offered within the balancing market. Note given the exceptional circumstances across 2021-22 due to the energy crisis and the Covid pandemic across 2020/21, only data from 2015-2019 has been used for this calculation. The uplifts calculated vary by technology and are outlined below:

Table 7: *BM Uplift values used in modelling*

Technology	Bid Uplift (£/MWh)	Offer Uplift (£/MWh)
CCGT	-10	30
OCGT and Gas Recip	-16	44
Hydrogen*	-10	30
Gas CCS*	-10	30
Biomass (including BECCS)	-15	21
Wind and other renewables	0	0

Given there are no hydrogen or gas CCS plants on the system at present, it is assumed that the uplift for these plants is the same as CCGTs. Wind and other renewables are assumed to have no bid or offer uplifts. In the data, some bid uplifts were observed but these have not applied in the modelling as we assume in this report that all bids/offers are floored at 0 for supported plant.

Note that in addition to plant's uplifting their bids/offers to capture infra marginal rents in a pay as bid market, some of the uplift may be due to costs that are not captured in our modelling. For example, the risk of tripping due to starting up at short notice, which exposes the plant to potential cashout penalties.

The above values are applied as uplifts to the turn-up (offers) and turn-down (bids) prices for locational balancing within the model. It is assumed that the uplift would not affect which plants dispatch, as plants would not change their bid/offer in such way that they would no longer be accepted. This means that the generation mix and therefore the system costs will not change in the national pricing counterfactual with the BM uplift added. As a result, the main impact of the change is on consumer costs through higher constraint costs due to increased prices in locational balancing. The results from this sensitivity are outlined in the next section.

It is worth also noting that the Transmission Constraint Licencing Condition (TCLC) prohibits generators from obtaining excessive benefit through the BM during constrained periods. It is therefore prudent to test an additional sensitivity whereby all generators bid/offer at cost rather than bid/offer with an uplift or bid/offer at the cost of the marginal unit (as in the core scenarios). The results from this sensitivity are outlined in the next section.

5.6. Alternative BM Bid/Offer assumptions in Counterfactual Modelling Results

In these scenarios, the system impact of moving to locational pricing is unchanged compared to the results outlined in 5.4. As system cost is the cost of operating the system, these costs are not directly affected by changes to market prices if there is no change in which plants are generating (or their underlying costs). As outlined above, we have assumed that plant dispatch doesn't change with changes to bid/offer assumptions with the cheapest plants still dispatched first meaning there are no changes to system cost.

Where the alternative bid/offer assumption changes do have an impact is in terms of consumer cost. As outlined above, under the BM uplift approach bids and offers by generators in the BM (for the national pricing counterfactual) are different to the core scenario where generators bid up to the marginal unit. The modelling results show that overall this means higher offers (and lower bids), with increases in plant revenues and profits. This increases the costs of the BM as the price generators are being paid for their offers increases (and the amount they pay for their bids decreases). This represents a benefit to producers (generators) which is passed from consumers to producers in the form of constraint costs. The result is that this sees the consumer benefits of moving to locational pricing increase compared to the core scenarios where it is assumed plants bid up to the marginal unit in the counterfactual.

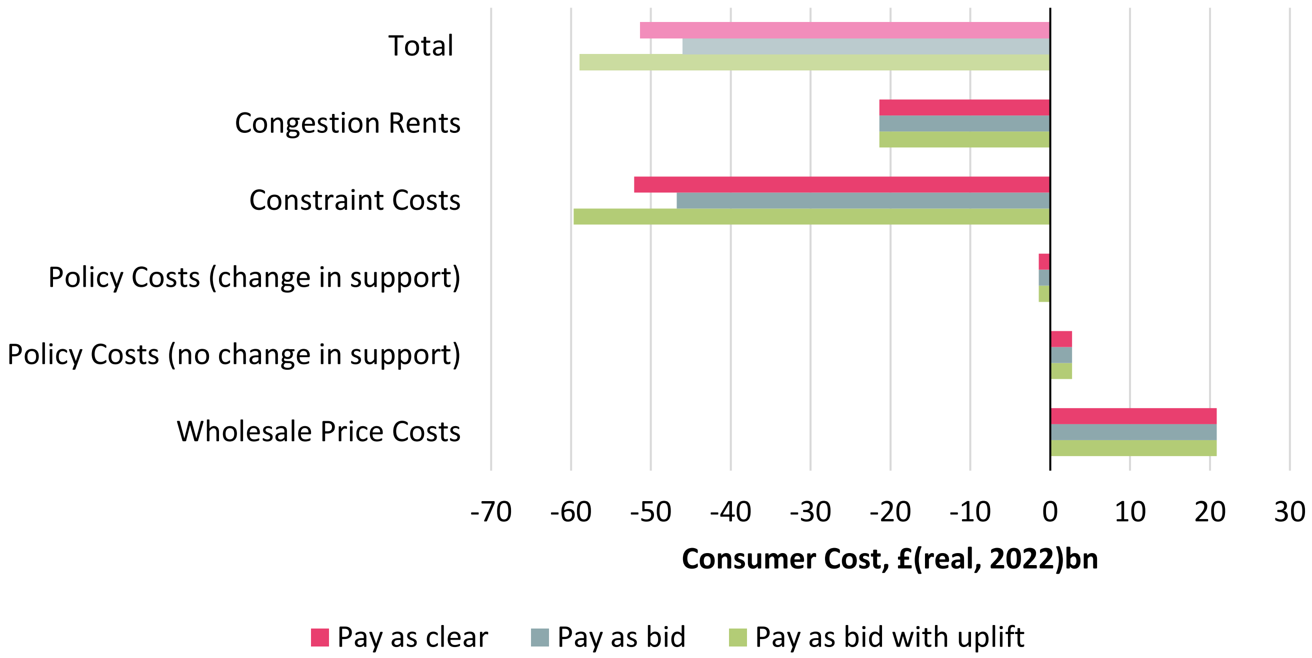
Note that we assume no change in the locational pricing factual scenario, as we continue to assume that this operates as a pay as clear market where the price is set by the marginal unit relevant to each zone, and that all units bid at cost.

Alternatively, as outlined in section 5.5 above, a strict interpretation of TCLC would be that all generators bid/offer into the BM at their SRMC when resolving locational constraints. If this was the case, then this would reduce the cost of bids/offers compared to both the scenario outlined above and the core scenario (where generators bid/offer up to the marginal unit in the BM). This would reduce costs for locational balancing compared to the core scenario with constraint cost decreasing due to lower offers (& higher bids) from generators. Again, as constraint costs are removed when moving to locational pricing this sees the consumer benefits of moving to locational pricing decrease compared to the core scenarios where it is assumed plants bid/offer up to the marginal unit.

The chart below shows the effects the different bidding sensitivities have on the total consumer cost benefit in a scenario where interconnectors do not participate and storage dispatch is limited in locational balancing.

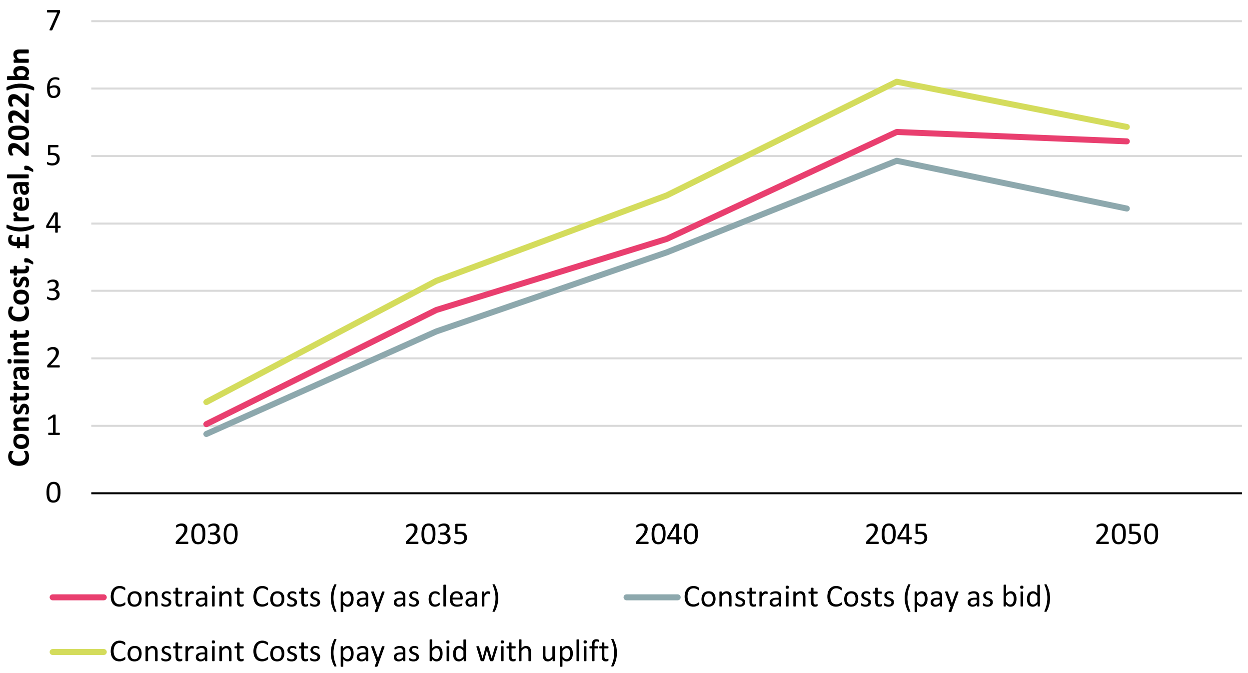
Assuming that the plants get paid at their bid/offer price and that they bid/offer at cost, gives the smallest consumer cost saving at £46bn. Assuming that plants bid/offer up to the marginal unit (same as result outlined in 5.5) increases this consumer cost saving to £51bn as balancing actions become more expensive. However, assuming that plants get paid at their bid/offer price and their bid/offer price includes an uplift on their costs (using historical data), the consumer cost saving increases to £59bn.

Figure 41: *Consumer cost under different bidding scenarios with no ICs in Locational Balancing and limited storage*



The chart below shows the total constraint costs under the different alternative bid and offer assumptions. All the bidding types show a similar constraint cost pattern across the years as balancing generation doesn't change between the three scenarios. This highlights that the constraint cost in the current market is sensitive to the bid and offer strategy that generators employ.

Figure 42: *Constraint Cost across all the bidding scenarios under the no interconnectors in locational balancing with limited storage*



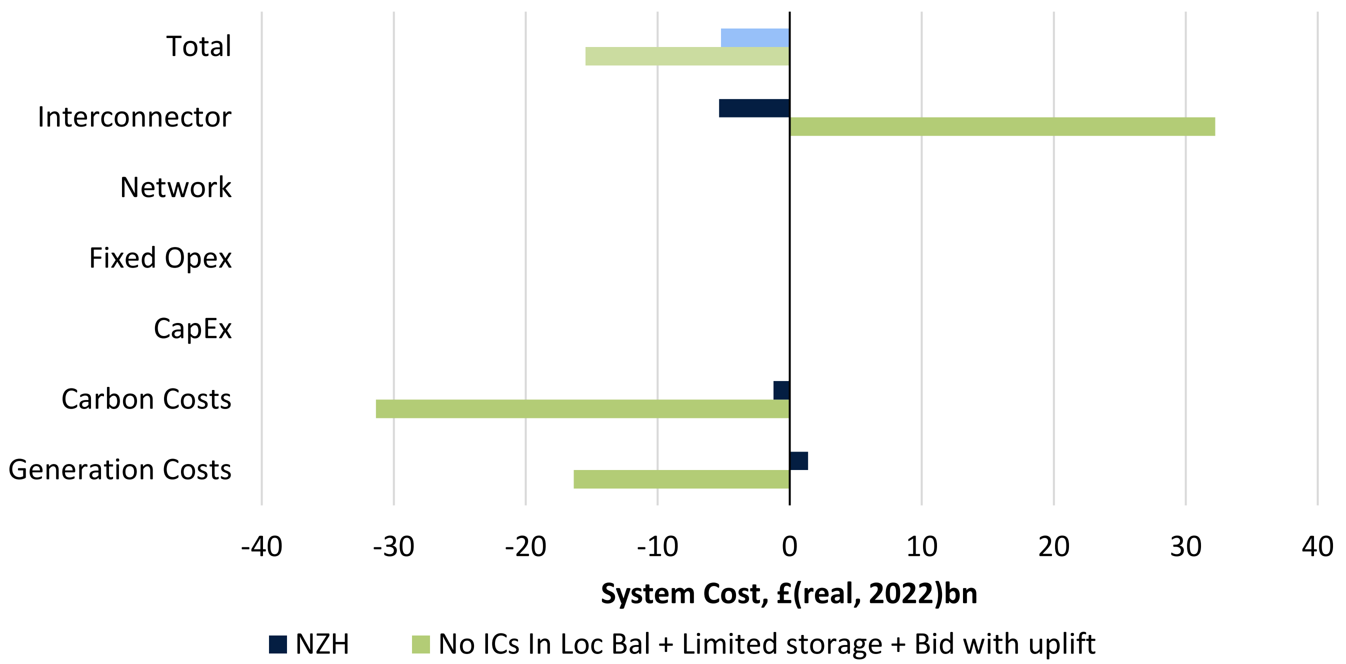
5.7. Operational Efficiency Benefits of Locational Pricing Summary

The sections above outline the additional benefits of moving to locational pricing with alternative assumptions for the counterfactual where locational balancing under current market arrangements is assumed to be less efficient compared to the core scenario. Each of the changes builds upon the previous change. First, it is assumed that interconnectors do not participate in locational balancing, then storageis assumed to not dispatch efficiently and finally alternative bid/offer pricing assumptions are applied where generators bid/offer into the BM at cost plus an uplift. Together these 3 areas allow us to form an understanding of the possible operational efficiency benefits of moving to locational pricing. This represents additional reductions in system and/or consumer costs without any capacity being moved due to improved investment signals.

These 3 areas combined increases the system cost benefit of locational marginal pricing from £5bn to £15bn in the NZH scenario. This equates to an extra £10bn system saving in moving to locational pricing as outlined in the chart below.

The majority of this saving comes from the assumption that interconnectors cannot participate in locational balancing. Under these assumptions the change in generation costs decrease due to the fact that more expensive generation in needed in locational balancing instead of using interconnection. Assuming that storage assets are also not redisaptched efficiently, further decreases the change in generation costs as again more expensive generation is needed in locational balancing instead of using storage.

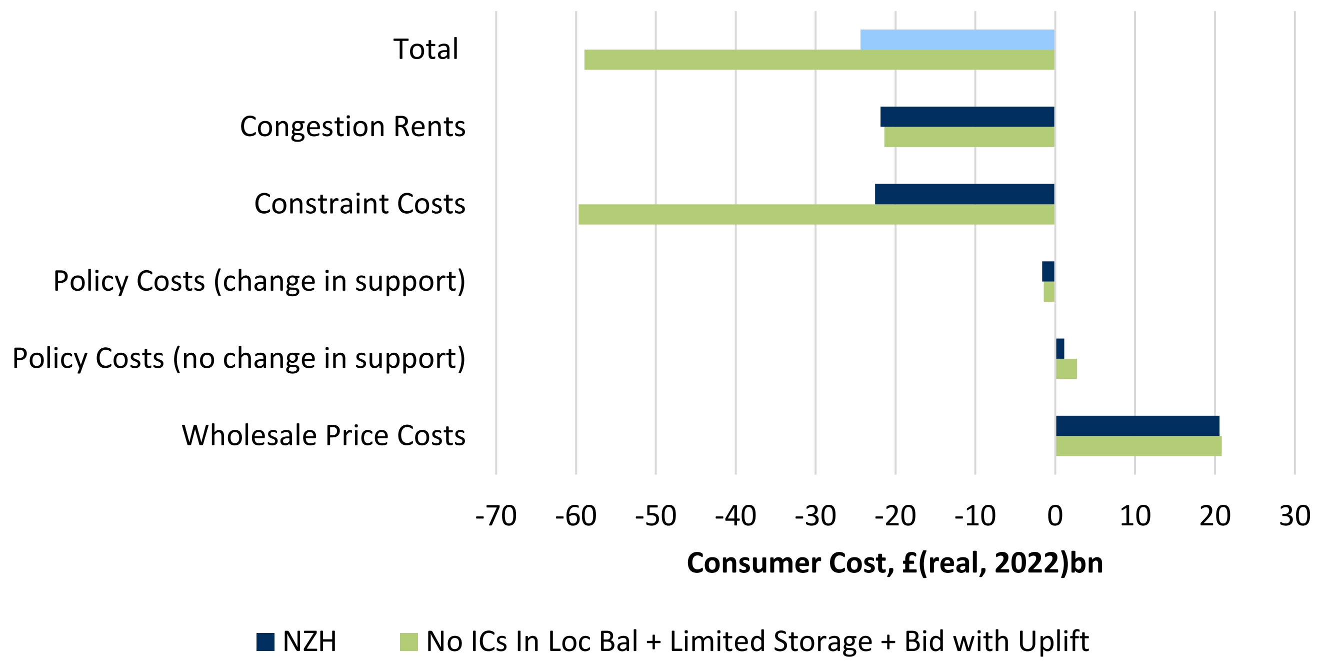
Figure 43: *Overall system cost change of moving to locational pricing in core scenario (NZH) and redispatch inefficiency scenario*



Applying all three operational efficiency benefits increases the consumer cost benefit from £24bn to £59bn. This equates to a £35bn additional consumer cost saving from moving to locational pricing.

Almost all of this saving comes from the increases in constraint costs in the counterfactual scenario. Assuming interconnectors do not participate in locational balancing, means that more expensive domestic generation is required to locationally balance the system hence the constraint costs increase. Furthermore, restricting how much storage is dispatched in locational balancing, also means that more expensive generation is needed instead. Finally, assuming that all plants bid/offer with an uplift in locational balancing on top of their costs (based on historic observed data) means that constraint costs further increase.

Figure 44: *Overall consumer cost change of moving to locational pricing in core scenario (NZH) and redispatch inefficiency scenario*



6. Cost of Capital

6.1. Why is cost of capital important?

The cost of capital is broadly the expected compensation required by investors to undertake risky investments. Risk is defined as the uncertainty around expected future cash flows that results from making these investments. A commonly used measure for an investor's required return is the Weighted Average Cost of Capital (WACC), which is a weighted average of the equity investor's risk (cost of equity, or CoE) and the lender's risk (cost of debt, or CoD).

Broadly speaking, the higher the uncertainty around future cash flows, the higher is the risk for an investor. The investor requires a higher return in exchange for taking more risk, and this translates to a higher WACC.

In the regulated parts of the utilities sector (which includes energy along with water and telecoms), WACC is important for several reasons. First, in an economically efficient system, if non-diversifiable risk increases, the compensation to investors should increase. This is ultimately paid for by the consumer, usually through higher energy tariffs.[52] Some investors may accept higher risk with lower returns. They will either withdraw capital and reinvest in industries or countries where they can expect to receive an appropriate risk-adjusted return, or they will underinvest in new UK energy assets. Such behaviour leads to the long-run degradation of the energy system and high future infrastructure costs.

In general, it is important both to correctly calculate WACC to ensure the integrity of the energy system, as well as to analyse the effect any potential policy change to WACC may have on the costs borne by consumers.

6.2. Cost of Capital impacts

Because investors must be compensated for higher risk, any increases in non-diversifiable risk caused by the adoption of locational marginal pricing (LMP) could partially offset any savings due to improvements in system costs. Several studies have attempted to quantify any potential changes to WACC due to an introduction of LMP. At one end, one piece of research which compared and contrasted the expected cash flows under the current TNUoS regime and the potential LMP regime, concluded that risk, as measured by the expected changes in the volatility of cash flows, is likely to increase if LMP is implemented. The study suggests an increase in WACC of potentially as high as 2%-3%.[53] A study by University of Strathclyde cites the same range of 2%-3%, but suggests that other support packages such as CfDs can reduce this range.[54] However, a workshop in 2022 delivered for Ofgem was more circumspect,

[52] If the Government subsidises tariffs, consumers pay through a combination of higher energy tariffs and future taxes.
[53] 14 October 2022, Frontier Economics, 'Locational marginal pricing – implications for cost of capital'.
[54]https://strathprints.strath.ac.uk/83869/31/Gill_etal_2023_Exploring_market_change_in_the_GB_electricity_system_MAIN_REPORT.pdf

highlighting the lack of evidence, uncertainty around the effect of CfDs, and the ultimate correlation between returns and fossil fuel prices.[55] They tested a sensitivity within their analysis which assumed a 0.5 percentage point change in WACC for some technology types but the core scenarios assumed no change in WACC. At the other extreme, some industry studies find no causal evidence of an increase in WACC.[56]

Ultimately, evolution in policy design, particularly for hedging tools such as CfDs and Financial Transmission Rights (FTRs), may offset some of the increased risk, thereby decreasing WACC from otherwise high levels. The ability to hedge using these tools depends greatly on the liquidity and maturity of these markets, and if generators can easily find counterparties to hedge specific types of risk. There are also suggestions that some exposure to short-term price volatility creates incentives to improve cost efficiencies.[57] In addition, the argument can be made that at least some locational risks are diversifiable, although for a UK energy investor there is an undiversifiable element correlated with government policy.

In any event, these trade-offs must be carefully considered, because continued increases in WACC will create a threshold where LMP makes the economics of the system worse off as a whole, i.e., increases in WACC outweigh the savings made in system costs.

Our estimates use previous research regarding WACC and locational pricing to inform our scenario testing analysis. We consider five WACC scenarios in our modelling:

1. No change in WACC
2. WACC – breakeven level (the increase in WACC such that the system benefits of locational pricing are negated)
3. WACC + 1%;
4. WACC + 1.5%;
5. WACC + 2%.

We held constant all other modelling assumptions: demand and capacity, network build, CfD, and interconnectors and ultimately present the savings in system costs net of increased capital costs. These levels have been chosen to encompass both the 0.0% to 0.5% range used by FTI and the lower bound of 1.8% in the Frontier study[58]. All estimates are applied as a uniform increase in WACC for all technologies from 2030 to 2050 to reflect the higher risk for investors due to the additional complexities of a locational pricing system. This change is applied to all technologies with the exception of Nuclear which is assumed to be unaffected as its Regulated Asset Base (RAB) means moving to locational pricing will not change its revenues.

We report this range rather than the higher Frontier range of 2%-3% for several reasons. First, at these higher levels, costs due to the higher WACC dwarf any potential savings due to system costs and do not help identify the acceptable risk threshold. Second, Frontier also assume pure nodal pricing with no grandfathering, which makes it difficult to accurately compare with the structure under consideration here which could include some level of

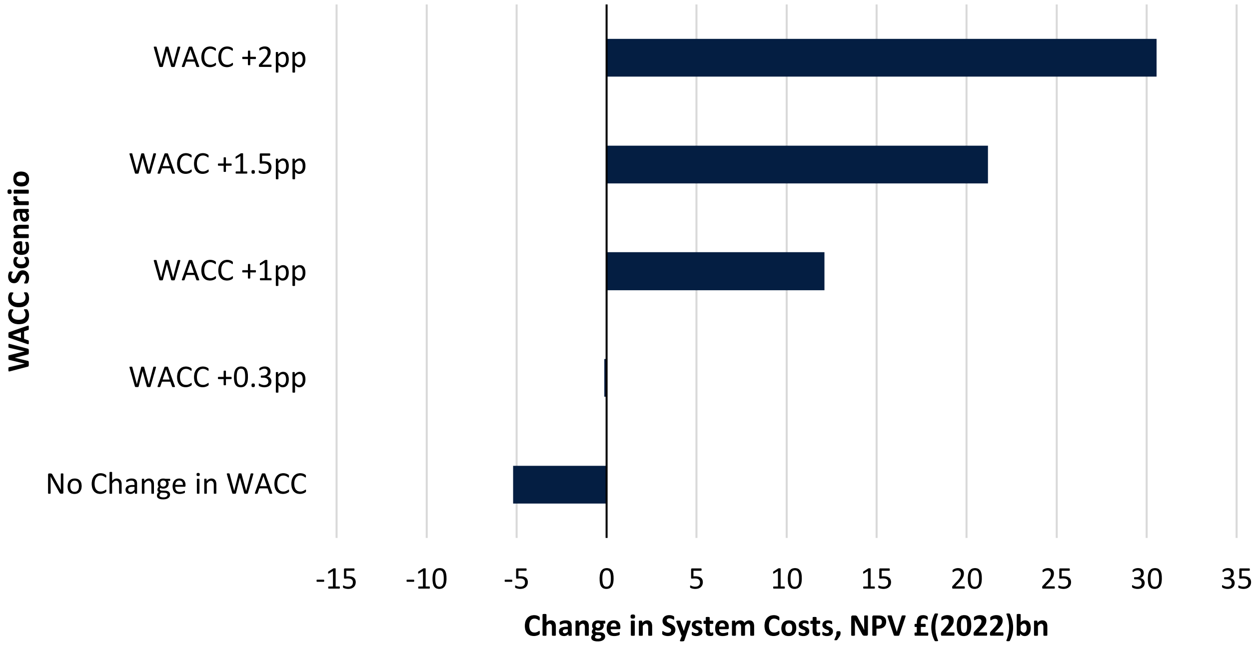
[55] 20 October 2022, FTI, 'Updated Modelling Results', pp 55-56.
[56] https://es.catapult.org.uk/report/rema-international-learnings-on-investment-support-for-clean-electricity/
[57] https://ukerc.ac.uk/publications/zero-carbon-electricity/
[58] 14 October 2022, Frontier Economics, 'Locational marginal pricing – implications for cost of capital', pp 25.

grandfathering. An assessment of grandfathering costs is out of scope of this study. Third, a report by Europe Economics finds that DESNZ WACC rates across technologies have been falling in recent years, applying overall downward pressure to baseline WACCs.[59] Therefore, the range used is both consistent with prior research and also allows us to identify the threshold at which increases in WACC become unacceptably large.

6.3. Cost of Capital Modelling Results

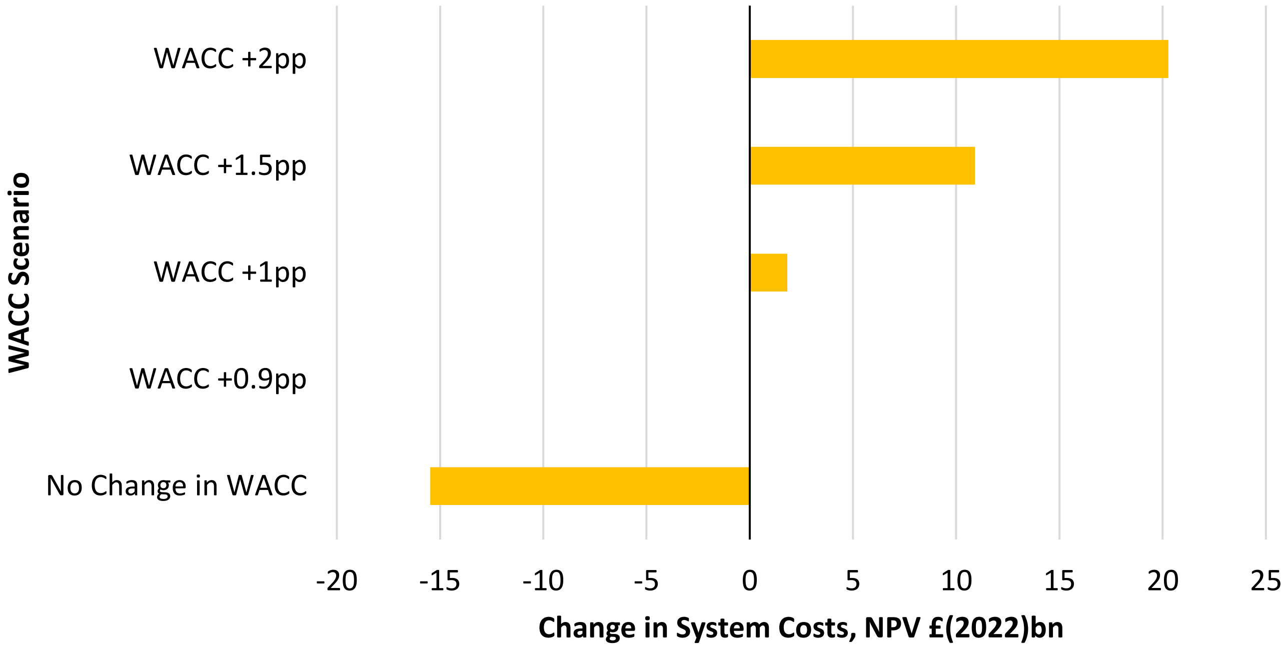
We report the modelled net system cost savings from the move to LMP in Figures 37 and 38 below. The cost of capital impacts has been calculated for the two scenarios outlined in chapters 4 and 5; the core scenario and the no participation of interconnectors in locational balancing scenario. The charts show the system cost changes from moving to locational pricing with various uniform increases in cost of capital across the entire modelled period in the two scenarios. Each bar represents a different change in WACC with the 4 WACC scenarios outlined above plus the breakeven points for both scenarios.

Figure 45: *WACC scenario analysis for core scenario showing system cost changes from moving to locational pricing with various WACC percentage point increases applied uniformly across modelled period. Compared to the core counterfactual with redispatch efficiencies removed.*



[59] November 2018, Europe Economics, 'Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies' p 5.

***Figure 46:** WACC scenario analysis for full operational impacts scenario showing system cost changes from moving to locational pricing with various WACC percentage point increases applied uniformly across modelled period. Compared to the core counterfactual with redispatch efficiencies included.*



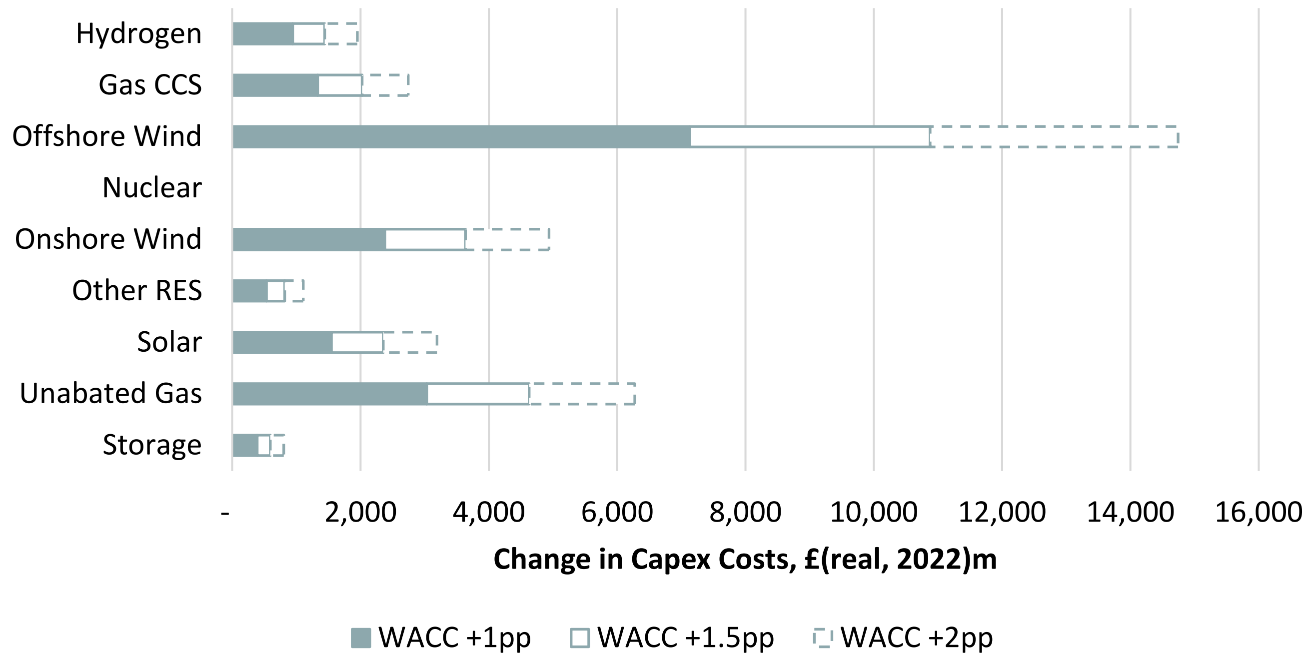
This analysis shows a lower breakeven point for the "core scenario" with just a 0.3 percentage point increase in WACC across all technologies (except Nuclear) resulting in all system level benefits from moving to locational pricing being negated. After crossing this threshold, the increase in investor risk more than offsets the benchmark £5.2bn savings in system costs created by locational pricing's adoption.

The breakeven point is higher in the "full operational impacts" scenario as the system cost benefits without any changes in cost of capital are higher due to the additional operational benefits. In this scenario, there is a 0.9 percentage point increase in WACC across all technologies (except Nuclear) resulting in all system level benefits from moving to locational pricing being negated.

Our results suggest that the value of locational pricing is highly sensitive to small uniform changes in WACC where just a 1 percentage point uniform increase resulting in a move to locational pricing costs the system £2-12bn. In addition, the threshold at the lower end of estimates in existing research quantifying the expected changes in risk due to LMP. This evidence suggests that perceived changes in investor risk need to be considered carefully and managed.

The chart below shows the change in capex costs by technology across the WACC scenarios outlined above. Changes in WACC have a disproportionate impact on highly capital-intensive assets and those with the largest capacity. This is why offshore wind shows the biggest increase with over 100GW assumed to be built by 2050, followed by unabated gas which has over 80GW capacity by 2050. This assumes a uniform increase all technologies, but this will likely vary by technology as discussed in more detail below. Note the impact is the same in the two scenarios shown above as the capacity build out is the same in both scenarios.

Figure 47: *Changes in Capex Costs (NPV) in the DESNZ Net Zero higher scenario for various levels of WACC percentage point increase.*



6.4. Impact of variable WACC for differing technologies

As noted above, small changes in WACC significantly affect the feasibility of LMP, because capital costs (incorporating the cost of finance) begin to dwarf cost savings as risk increases. It is therefore important to note that the assumptions around the cost of capital scenarios are, by necessity, non-complex. For the benchmark WACC for each type of technology, we use the DESNZ hurdle rates from the 2020 generation cost report[60] with some adjustments[61]. We then adjust all the WACCs for each individual technology by the same percentage point amount. The underlying assumption is that the absolute change in risk is the same for all technologies in each scenario.

It is likely that risk does not increase in lockstep for each type of technology for several reasons. First, the underlying betas[62] are different for each technology. Therefore, even a linear change in overall risk level for all technologies will likely result in different changes to WACC for each individual technology. Secondly, LMP may affect different technologies in different ways. For example, LMP may change levels of risk in the offshore wind industry in different ways relative to the solar industry.

[60] BEIS Electricity Generation Costs (2020) - GOV.UK (www.gov.uk)
[61] Some adjustments to hurdle rates and capex costs were provided by DESNZ for this project
[62] The beta is defined as the degree of volatility of a security with regard to the market as a whole.

Such changes are likely to be most significant where there are restrictions on location of a particular asset class. Offshore wind is likely to be exposed to a reduced number of possible grid connection points, compared to solar or gas turbines. Hence, such technologies are likely to be more vulnerable to a change to their WACC as a result of a shift to LMP. In addition, as noted elsewhere in this report, the future of the CfD regime, treatment of interconnection within the wholesale market and other factors will also affect the expected distribution of cash flows and therefore, the relative risk between technologies.

7. Lower Electricity Demand

As outlined in 3.1, two different demand and capacity scenarios have been modelled. This section outlines results for the Net Zero.

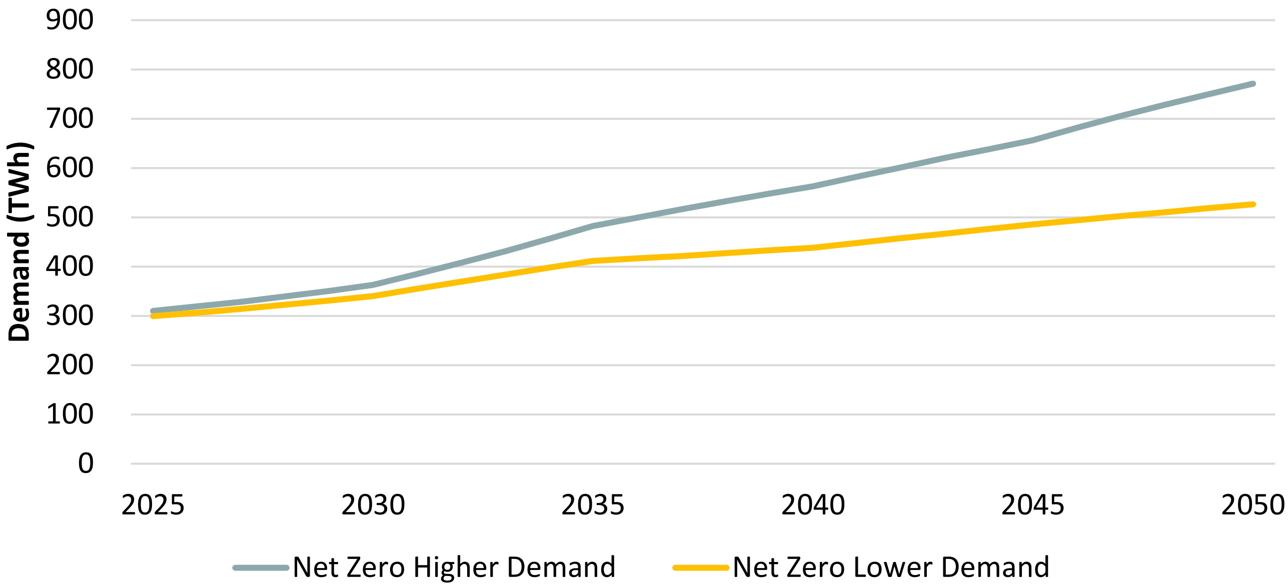
Table 8: *Assumptions used in the alternative demand and capacity scenarios outlined in this chapter*

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	ICs in national pricing model	Batteries in national pricing model	BM Uplift	Offshore wind location restriction
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
DESNZ Net Zero Lower Demand	DESNZ Net Zero Lower demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction

7.1. Why is demand and capacity mix important?

As outlined in section 3.1, there is significant uncertainty around future electricity demand given it depends on decarbonisation choices within other sectors. This is illustrated in DESNZ through two demand scenarios: Net Zero Lower Demand (NZL) and Net Zero Higher Demand (NZH) scenario as shown in the chart below.

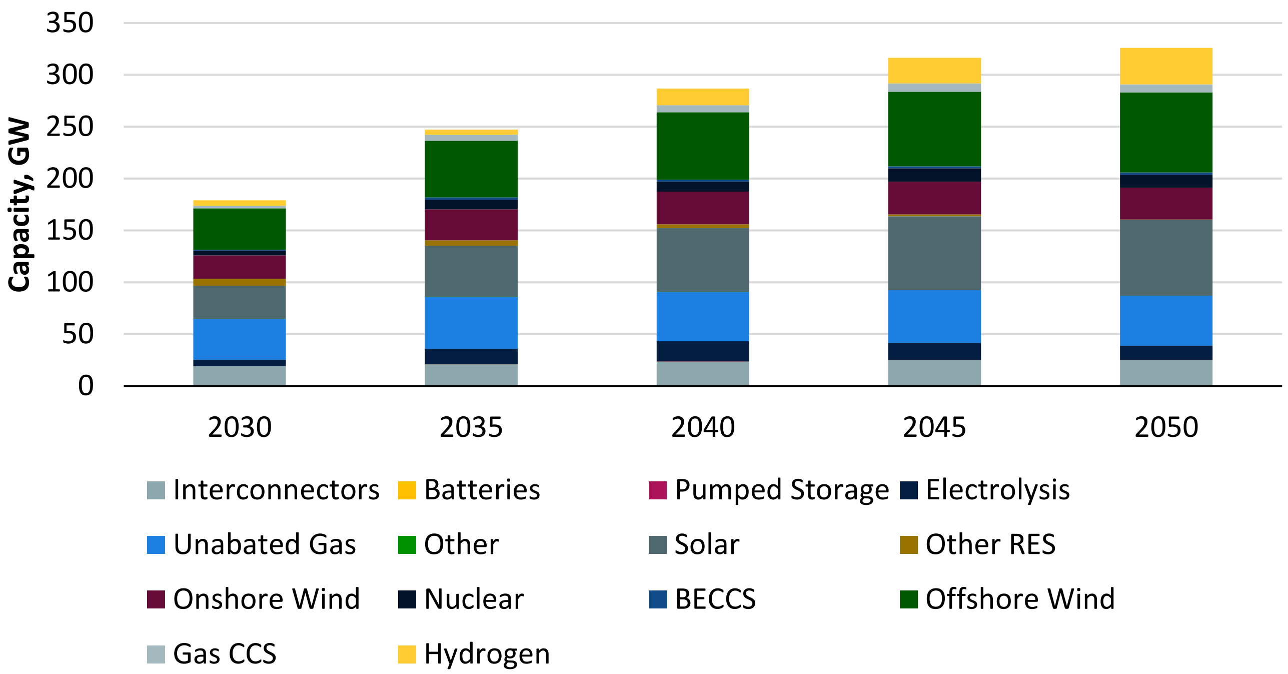
Figure 48: *GB Electricity demand in DESNZ Scenarios*



The DESNZ NZL scenario models a lower demand scenario with less capacity to meet this demand. Most importantly, the boundary capacity assumptions have not changed between the NZL and NZH scenarios as defined in assumptions provided by DESNZ. This means that there will be less constraints between zones as we have less demand overall but the same capacity to move generation around the country. A lower demand scenario would likely mean that network capacity would also change in response to this as such a high level of network build is unlikely to be optimal in this case.

The price between two zones can only be different when the boundary between them is constrained. If boundaries are constrained less often, then the price spread across the zones is smaller. Therefore, the impact of locational pricing is less effective in reducing system costs in a lower demand scenario. The capacity mix used in the NZL scenario is shown below:

Figure 49: *Net Zero Lower Demand locational capacity graph by technology and year*

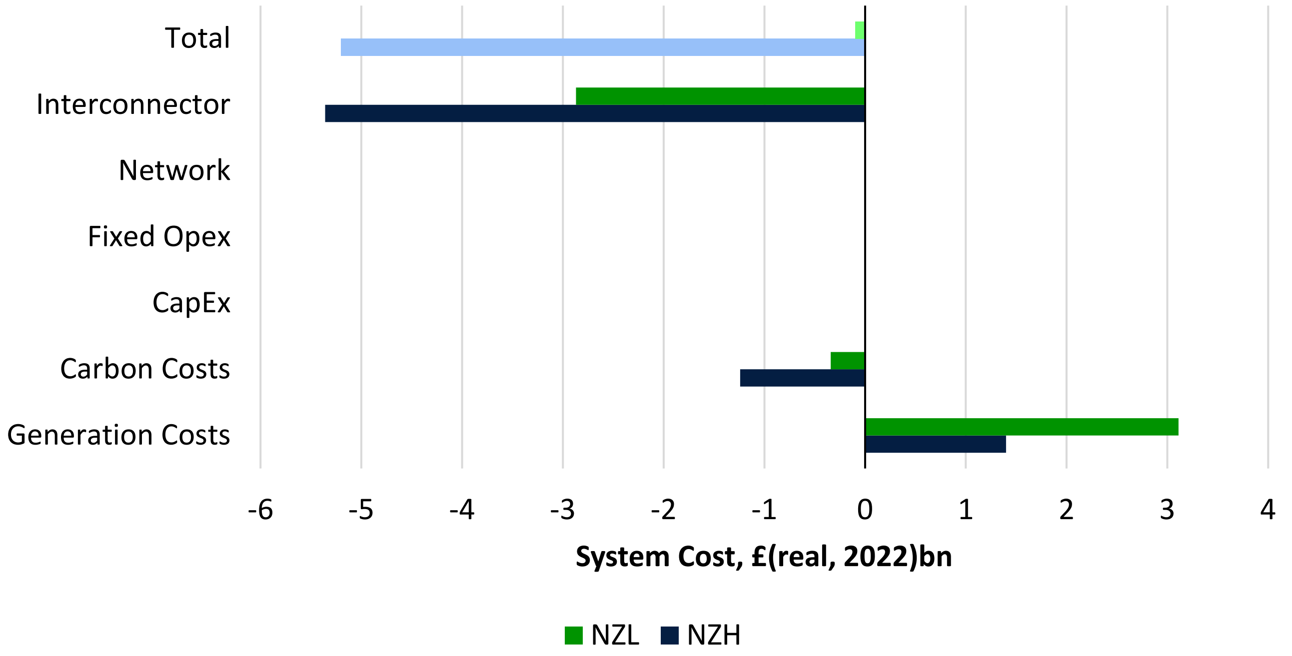


7.2. Lower Electricity Demand Modelling Results

The total system benefit for the NZL scenario of just £0.1bn (given as an NPV from 2030-2050). This is significantly less than the £5.2bn than in the NZH scenario. In terms of distributional impacts, there are still benefits to consumers with these costs reducing by £14.1bn, a £10bn reduction compared to the NZH scenario. As these consumer benefits are nearly all transfers in the NZL scenario then producer costs increase by £14bn, compared to a £19.1bn increase in the NZH scenario.

This shows that with less demand on the system but the same boundary capacity, the benefit of moving to locational pricing is significantly reduced. However, it should be noted that in reality, we would expect planned boundary capacity upgrades to be adjusted in a lower demand world as it is unlikely to be cost optimal from a network perspective to increase boundary capacities by 3x in this scenario.

Figure 50: *The system cost breakdown for the NZL scenario*

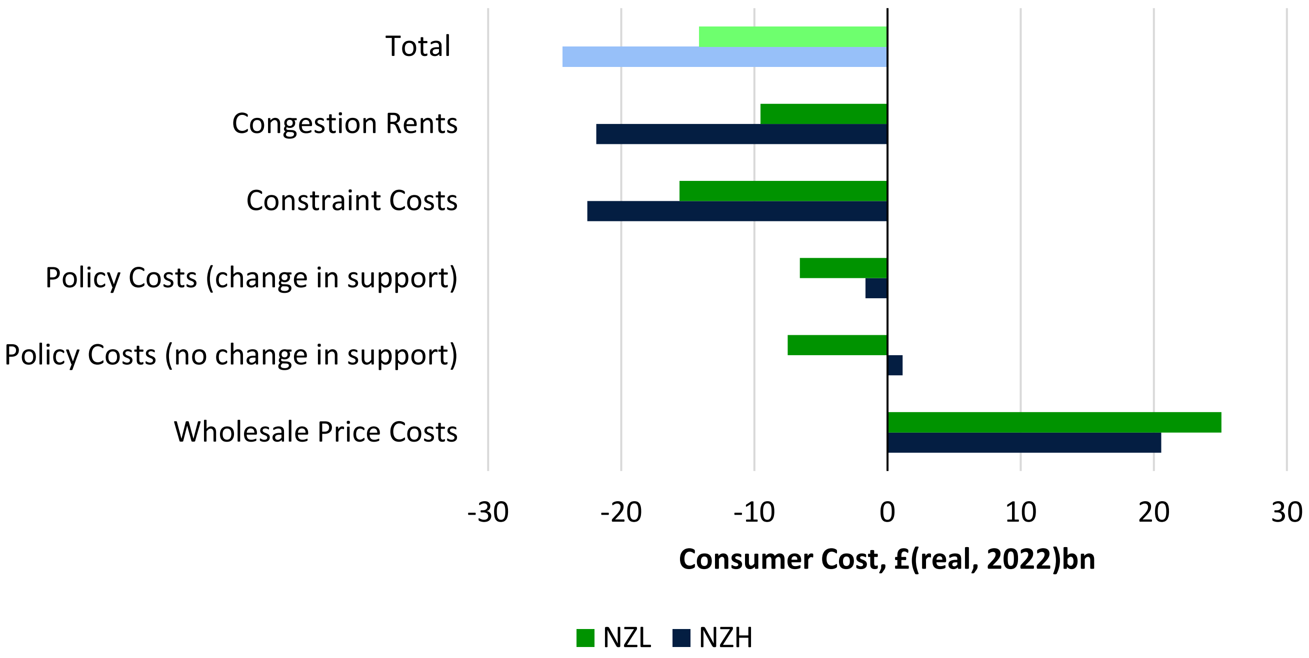


When comparing the NZH and NZL scenarios, the same costs reduce across both scenarios. However, the benefits of moving to locational pricing are smaller in the NZL. This is a result of the overall size of the system being smaller, with lower demand and lower overall capacity, meaning there are less plants that can be moved in this scenario so less impact movement of plants can have on costs. The boundary capacities also remain constant between the two scenarios, so boundaries are less constrained in the NZL scenario as there is just less overall demand on the system. The reasons for system cost changes are slightly different to the NZH scenario as outlined in 4.1:

- **Generation costs** increase by £3.1bn. While generation from expensive unabated gas plants does decrease in this scenario, generation from hydrogen and gas CCS plants increases leading to an overall increase in generation costs. This is as a result of renewables generation decreasing compared to the national pricing counterfactual. Reasons for this are explored in more detail below.
- **Carbon costs** decrease by £0.3bn as reductions in gas generation, due to increases in gas CCS and hydrogen generation, leads to decreases in emissions.
- **Interconnector costs** are reduced by £2.8bn due to less imports and a slight increase in exports via the interconnectors. Hydrogen and gas CCS generation are replacing some imports while exports also increase across some interconnectors as the wholesale price is lower in northern and Scottish zones.

For consumer costs, as with system costs then benefits are significantly reduced but moving to locational pricing still sees a benefit of £14.1bn in the NZL scenario compared to £24.4bn in the NZH scenario. As there are very limited system benefits in the NZL scenario, all these benefits are transfers between consumers and producers. Producer costs increase by £14bn, compared to a £19.1bn increase in the NZH scenario.

Figure 51: *Change in Consumer Costs between National and Zonal Pricing for the DESNZ Net Zero higher and lower demand scenario*



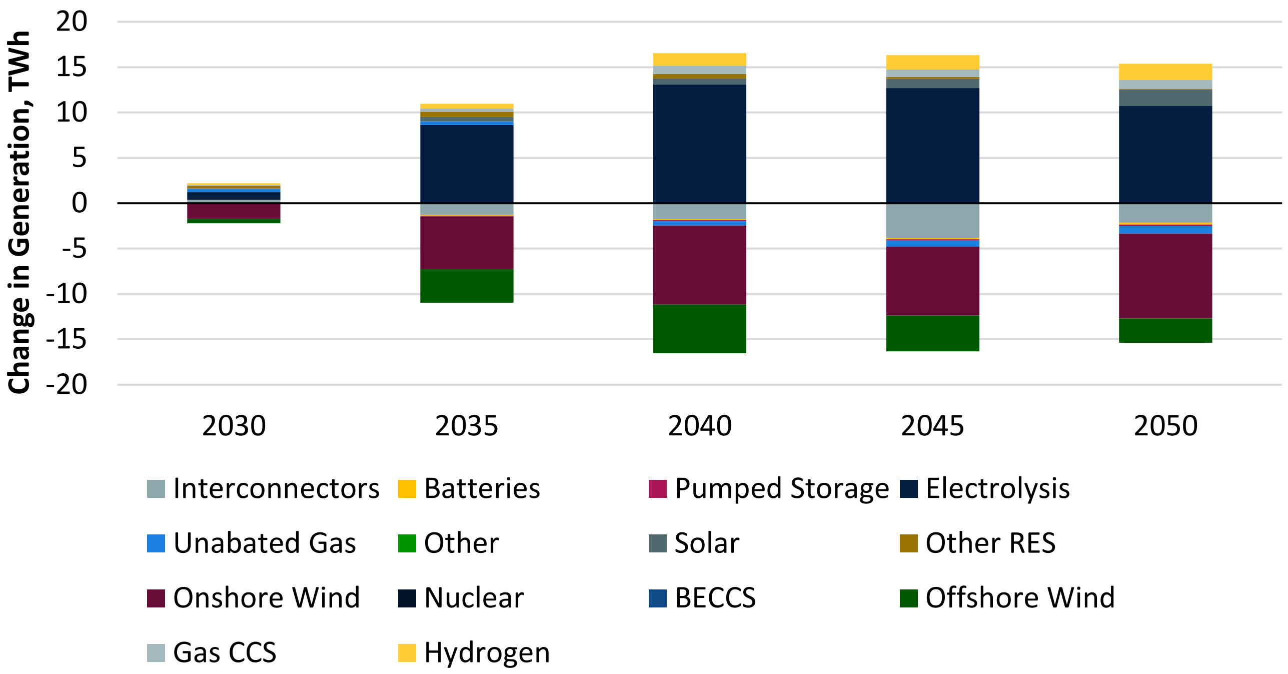
As with system costs, when comparing the NZH and NZL scenarios, the same costs change in similar ways across both scenarios from moving to locational pricing with the benefits of smaller in the NZL scenario. Key changes in costs are:

- **Constraint costs** decrease by £15.6bn in the NZL scenario compared to £23bn in the NZH scenario. The reason for decreases is due to these costs are no longer present in a locational pricing model where locational balancing is no longer needed with a portion of these costs effectively moved to wholesale prices instead. The reduction in constraint costs is lower in the NZL scenario as the system is smaller compared to the NZH scenario but with the same network build-out resulting in boundaries being constrained less often
- **Wholesale price costs** increase by £25bn in the NZL scenario compared to £21bn in the NZH scenario as a result of moving to locational prices. Increases are mainly due to constraint costs effectively moving into wholesale prices given these prices now account for constraints. Prices are higher in the NZL scenario as there is less variation in price across zones as boundaries are less often constrained meaning prices are comparatively higher in the NZL scenario compared to the NZH scenario in some zones. This is explored further below.
- **Congestion rents** reduce by £9.5bn in the NZL scenario compared to £22bn in the NZH scenario from moving to locational pricing. This decrease is primarily due to boundaries being less constrained in the NZL scenario due to a smaller system with the same size network as the NZH scenario.

- **Policy costs** decrease by £14.1bn in the NZL scenario compared to £0.5bn in the NZH scenario from moving to locational pricing. This larger decrease is mainly due to increase in wholesale prices from moving to locational pricing reducing CfD top-up payments to a greater extent in the NZL scenario.

One of the key system cost differences between the NZH and NZL is the higher increase in generation costs in the NZL as a result of moving to locational pricing and this increase no longer being offset by the decrease in interconnector costs. And therefore, resulting in almost no system benefit from moving to locational pricing. While we would expect all cost changes to be smaller in a lower demand scenario, the higher change in generation costs is surprising. What drives this is changes in generation between the locational pricing factual and national pricing counterfactual.

Figure 52: *Generation change by technology for the NZL scenario between national pricing counterfactual and locational pricing factual*



The key changes in generation are:

- Renewable generation from offshore wind and onshore wind decreases when moving to locational pricing. Due to boundaries being constrained less often compared to the NZH, then the price is higher in northern England and Scottish zones which means a lower proportion of wind is being used in electrolysis and is being exported from these zones compared to the NZH. Less generation in these zones could drive the wind to relocate to higher price zones further south to capture more revenue, however it does not do that as prices are quite consistent across the country due to less boundary constraints meaning the wind would make similar revenue even if located further south.
- Gas CCS and hydrogen generation increases in this scenario when moving to locational pricing as more of this technology is locating in the higher demand southern zones. With

more wind locating north compared to the counterfactual then generation from these assets increases.

- Use of electrolysis decreases (shown an increase in above chart as it is demand) as higher wholesale prices in many zones mean it is no longer profitable for electrolysers to be used.
- Interconnector exports decrease slightly in the north but increase elsewhere as higher prices mean less renewables are used in electrolysis, so some renewables are being exported instead.

One of the key consumer cost differences can be seen in wholesale prices where the change in wholesale costs as a result of moving to locational pricing are actually higher in the NZL scenario compared to the NZH scenario. The wholesale prices differences across zones can be seen in the chart and maps below. As noted above, compared to the NZH the price range is a lot narrower and prices in Scottish zones (A to E) are higher because of boundaries being constrained less often and therefore prices being consistent across zones. Prices in all zones in the locational pricing factual are actually higher than the national price in the counterfactual with Zone L (southern England) having the highest prices in all years except 2050. This is a result of constraint costs being moved into wholesale pricing and the boundaries not being constrained very often meaning prices are consistent across zones. This is a key driver in changes in renewable generation and less use of electrolysis outlined above.

Figure 53: *Zonal prices in the locational pricing factual for DESNZ Net Zero Higher scenario*

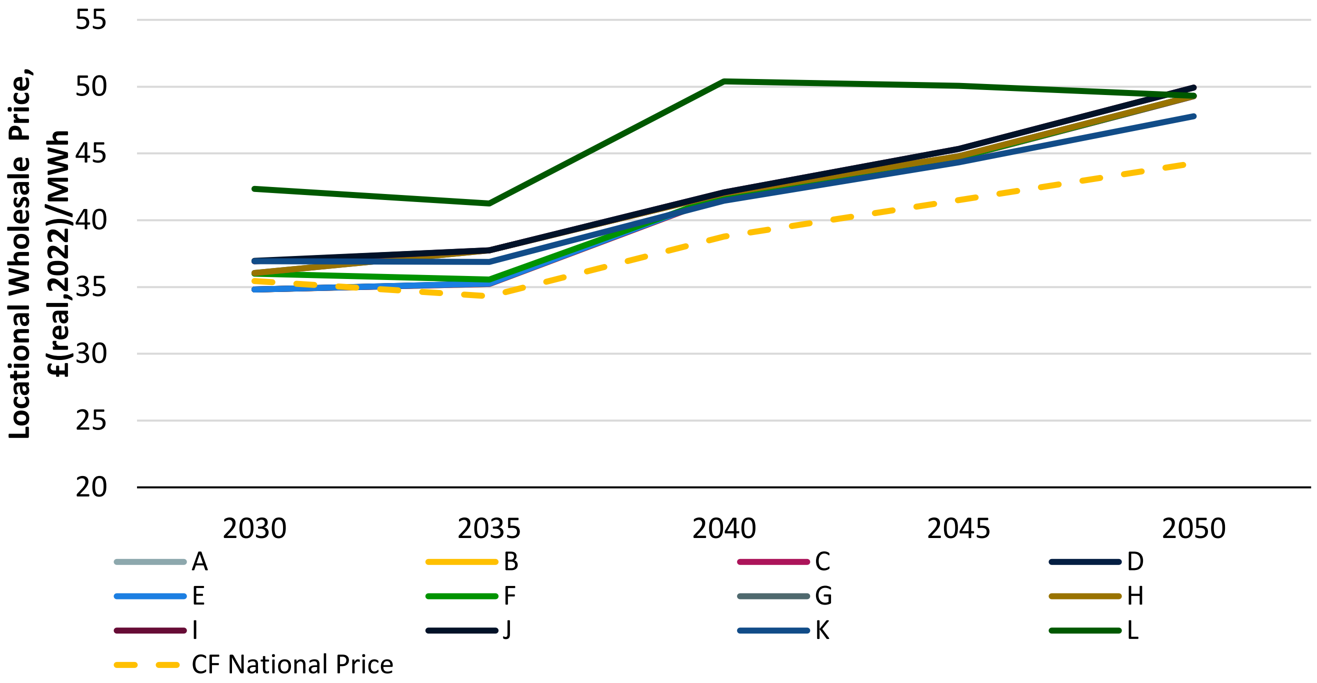
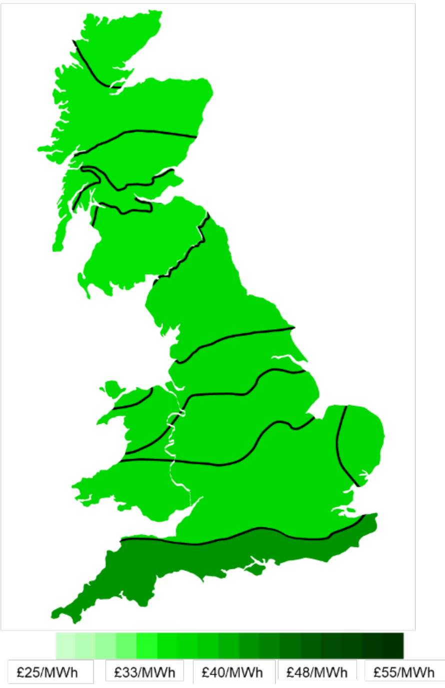


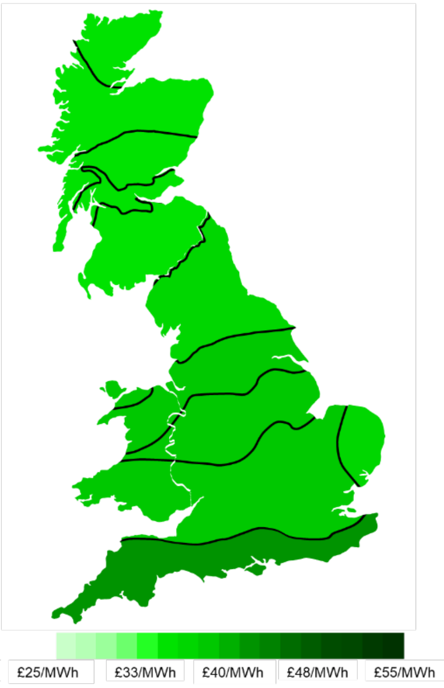
Figure 54: *Zonal price maps in the locational pricing factual for DESNZ Net Zero Lower Demand scenario in £(2022)/MWh*

2030



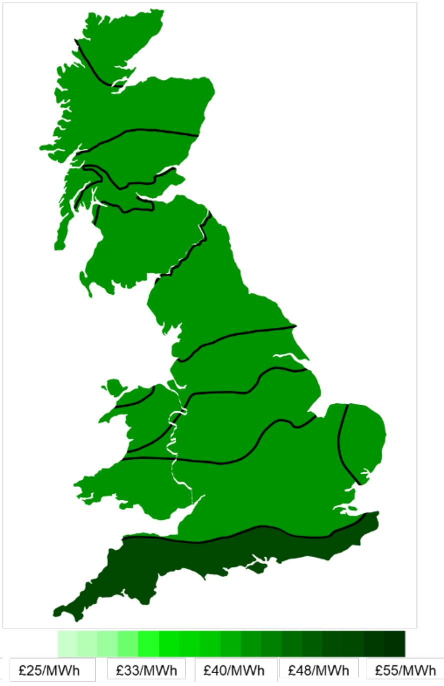
National price: £36/MWh
Locational Price: £35-42/MWh

2035



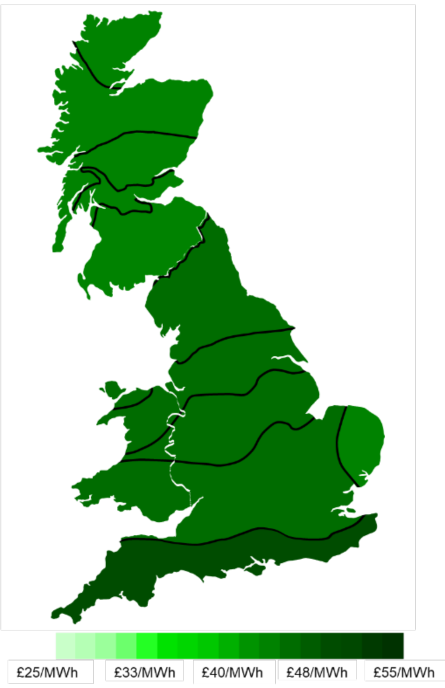
National price: £34/MWh
Locational Price: £35-41/MWh

2040



National price: £39/MWh
Locational Price: £41-50/MWh

2045



National price: £41/MWh
Locational Price: £44-50/MWh

2050

National price: £45/MWh
Locational Price: £47-50/MWh

Boundary constraints are the key driver of these generation changes and prices being similar across zones. The boundary capacities between the NZH and NZL scenarios remain the same. However, as demand has decreased, there is a lot less energy needed in each zone. This has reduced the amount of time that boundaries are constrained and led to a smaller range in prices across zones.

By 2050, boundaries are constrained on average 5% less of the time between NZH and NZL in the locational pricing counterfactual. And comparing across the national pricing and locational pricing factual, there is no significant change in how often boundaries are constrained with only zone L (southern England) seeing any real change in how often it is constrained. This highlights that this scenario is likely to have too much network build in northern locations and in reality, less network would need to be built in northern locations to meet this level of demand and capacity. Additional reinforcement is still needed around zone L, even with reduced demand, due to the amount of interconnector capacity connected there. The network build is non-optimal in this scenario.

Figure 55: *Percentage of time boundaries are constrained in national pricing counterfactual for Net Zero Lower Demand Scenario*

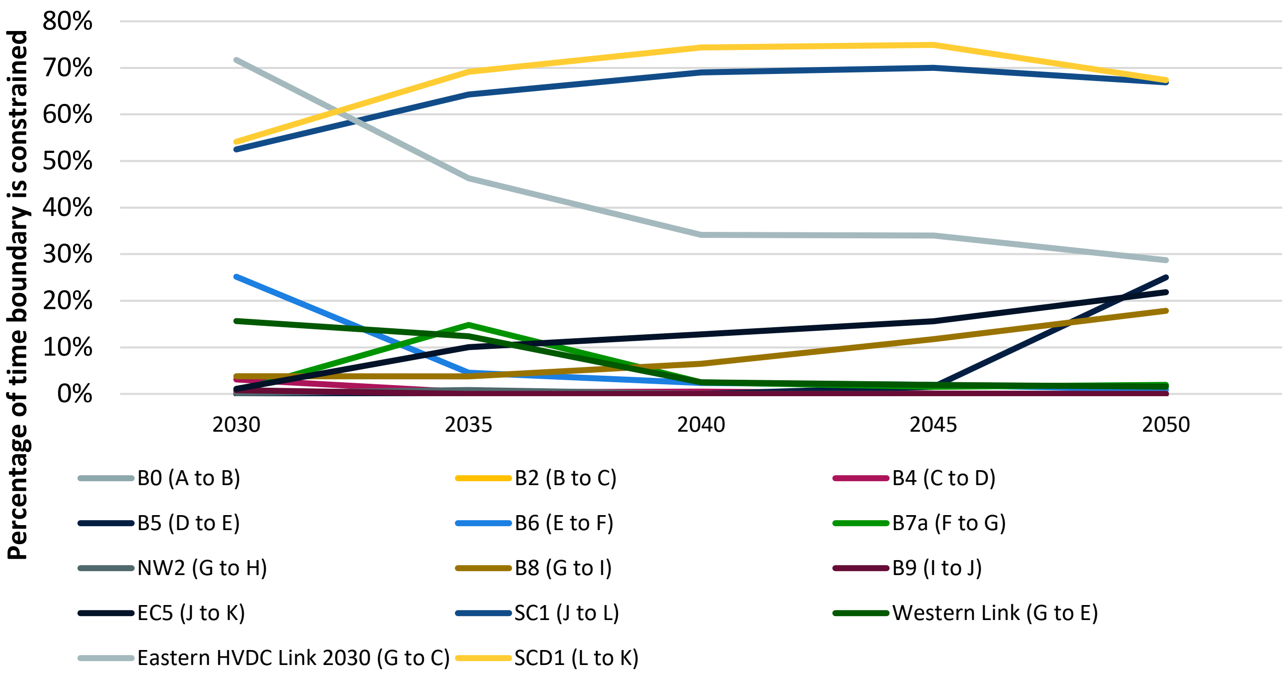
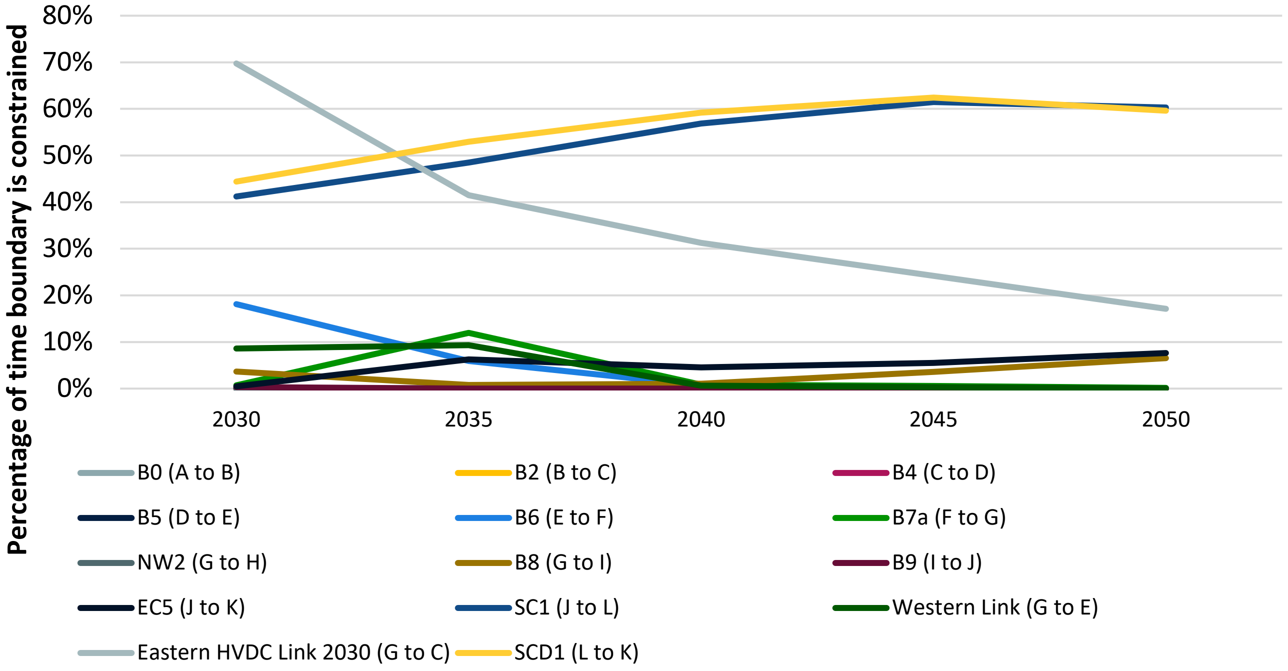


Figure 56: *Percentage of time boundaries are constrained in locational pricing counterfactual for Net Zero Lower Demand Scenario*



8. Changing Network Build

This section outlines the key results from the alternative network build scenarios, showing the impacts of moving to locational pricing in these scenarios. The key assumptions for this scenario are shown in the table below:

Table 9: *Assumptions used in the network build scenarios outlined in this chapter.*

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	ICs in national pricing model	Batteries in national pricing model	BM Uplift	Offshore wind location restriction
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
Network build 3-year delay	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND with 3-year delay	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction

8.1. Why is network build important for locational pricing?

As outlined in section 3.2, network reinforcement levels are a vital assumption for assessing the impact of moving to location pricing. At present, the existing network restricts the extent of transfer of cheap, renewable energy from the north to high demand areas in the south when wind output is high, as the network does not have the capability to transfer the large volume of energy. This causes increased prices both from wind curtailment due to network constraints, and from turning on more expensive generation nearer the source of demand.

Network build assumptions significantly affect where capacity locates, as network build can alleviate network constraints and so reduce locational generation restrictions. Plants moving to more efficient locations that are closer to demand centres to avoid network constraints is one of the key potential benefits of locational pricing. A more constrained network will lead to higher benefits from moving to locational pricing as plants moving location has more of an impact. This is because their generation is more utilised in the factual and used less in the counterfactual.

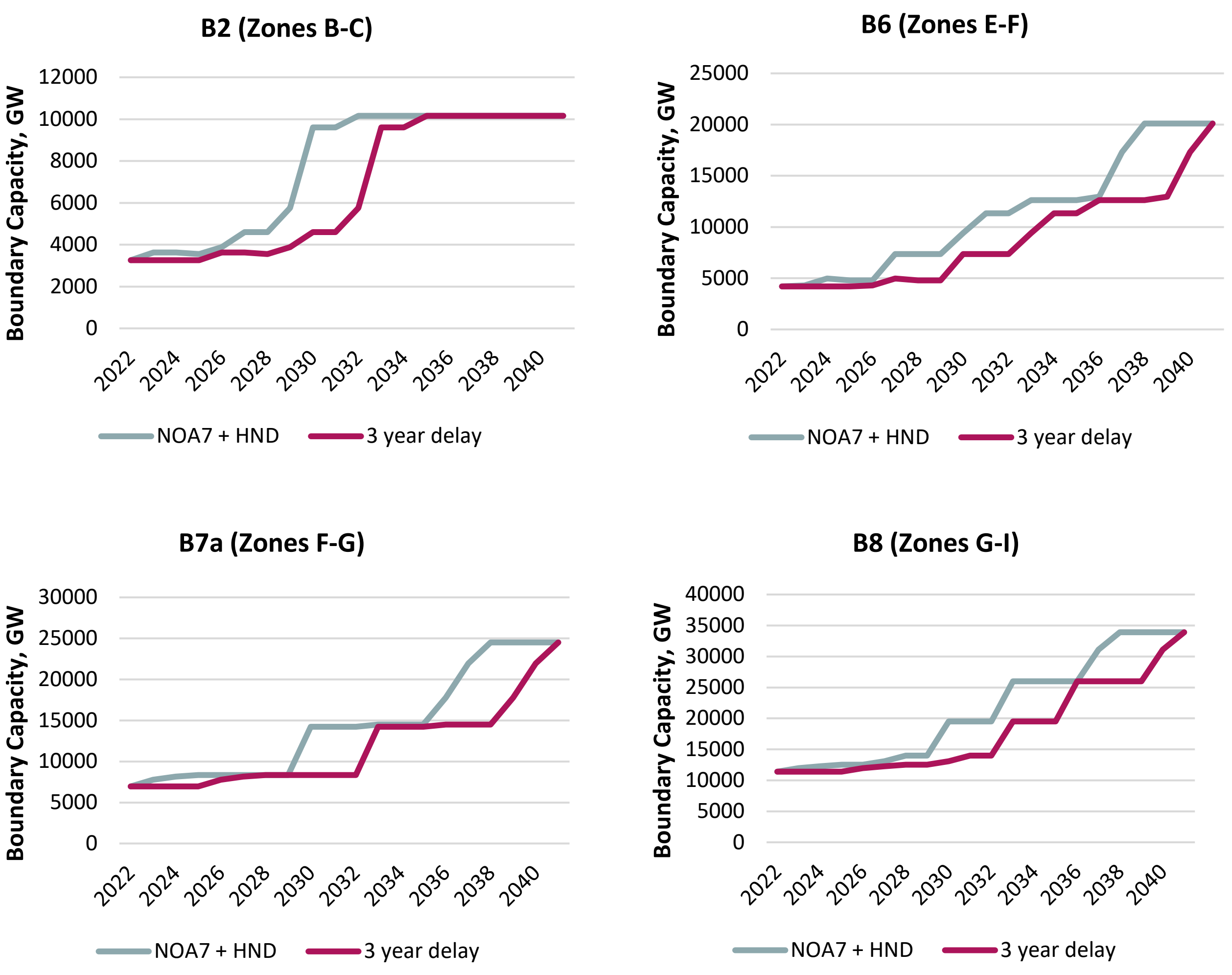
It should be noted that one of the often-mooted potential benefits of moving to locational pricing would be the need to build less network as a result. This is due to generators locating closer to demand reducing the need for electricity to be transported across the country. To model this benefit would require an in-depth study similar to the NOA so this is considered out of scope for this analysis.

8.2. Alternative network scenarios

Assumed future network build is outlined in the NOA7 and HND documents published by NGESO. These outline how the capacity of major boundaries modelled in this project will be upgraded in the coming years. This only contains upgrades to 2040 which means in the modelling we have assumed no further network upgrades from 2040 to 2050 due to lack of available assumptions. There is significant risk associated with this network build out however, with the build assumed to be at an unprecedented scale that has not previously been seen in GB. Given these risks, an alternative network capacity scenario has been tested to understand the impact that a slower network build could have on the system benefits for locational pricing.

One alternative network build scenario is tested with assumptions provided by DESNZ: a 3-year delay from the NOA7 and HND in addition to the core scenario. The below charts show the differences between the different network build scenarios for some of the key boundaries.

Figure 57: *Projected capability at selected boundaries based on different NOA7 scenarios. Boundary capability shown to 2041 in line with NOA7 data.*[63]



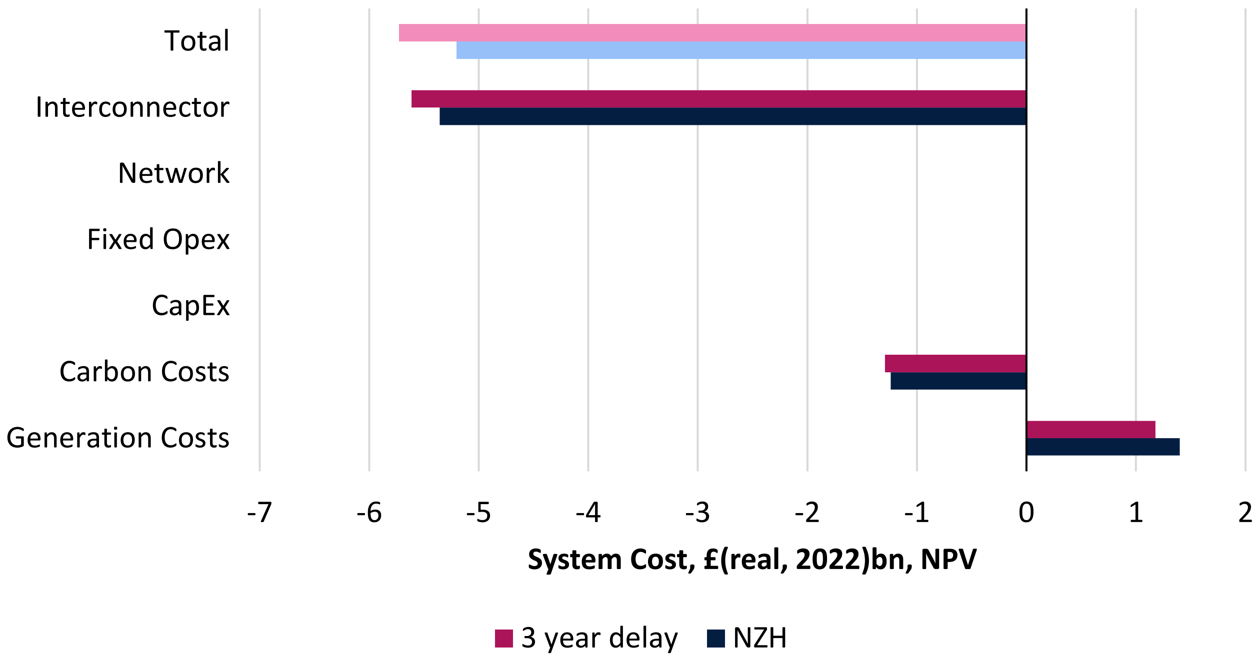
[63] Note that boundary capacities are flatlined from 2040

As can be seen above, across many of the key boundaries network capacity is assumed to significantly increase in the coming years even with a 3-year delay. The 2030s in particular see a significantly faster build rate compared to the 2020s with total network capacity 3 times larger by 2040 compared to 2022. A 3-year delay does not reduce network build that much with the boundary capacity assumptions in 2040, 2045 and 2050 the same across these years in the core and 3-year delay scenarios. The capacity locations are assumed to be the same as the core scenario as it is assumed that investors would not have had sight of these delays and are still locating based on an on-time network build-out.

8.3. Alternative network scenarios Modelling Results

The delayed network build scenario shows higher system benefits of moving to locational pricing. With NOA7 and HND build, moving to locational pricing shows a benefit of £5.2bn, but this increases to £5.7bn with a 3-year delay in network build, an increase of 10%. A similar trend is observed in distributional impacts. Consumer benefits of moving to locational pricing increase from £24.4bn in the core (NZH) scenario to £27.2bn in the 3-year network delay scenario, a change of 14%. This leads to the producer surplus from moving to locational pricing increasing from a cost to producers of £19.2bn in the core scenario to £21.5bn. a change of 12%.

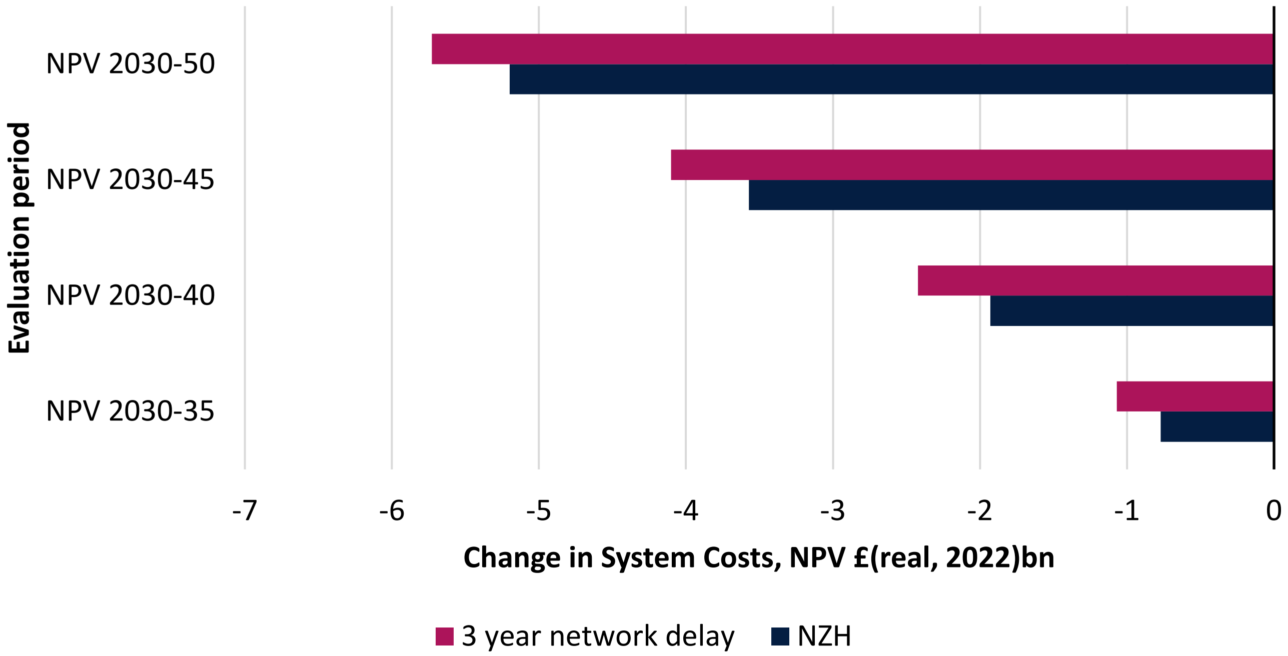
Figure 58: *Change in system costs (NPV 2030-50) between national and zonal pricing with a 3-year delay from NOA7 network build and the core scenario (NZH)*



The biggest change across the scenarios can be seen in generation and interconnector costs. The network delay scenario causes a larger discrepancy in generation costs because the location of capacity becomes more important as the network becomes more constrained. As zonal pricing provides a more reflective locational signal than TNUoS does in the national model, more capacity is located in zones closer to demand where the zonal price is higher. This results in less network constraints and lower generation costs, but also in lower carbon costs as the changes in generation result in less emissions.

As noted above, a 3-year delay in networks only sees significant differences in network build in 2030 and 2035 with a small change in 2040. Network build is then the same in the 3-year delay scenario for 2045 and 2050. Because of this it is useful to look at breakdown of the differences in the system cost change of moving to locational pricing for different evaluations periods. This can be seen in the graph below:

Figure 59: *Change in system costs between national and zonal pricing with a 3-year delay from NOA7 network build and the core scenario (NZH) for different evaluation periods*

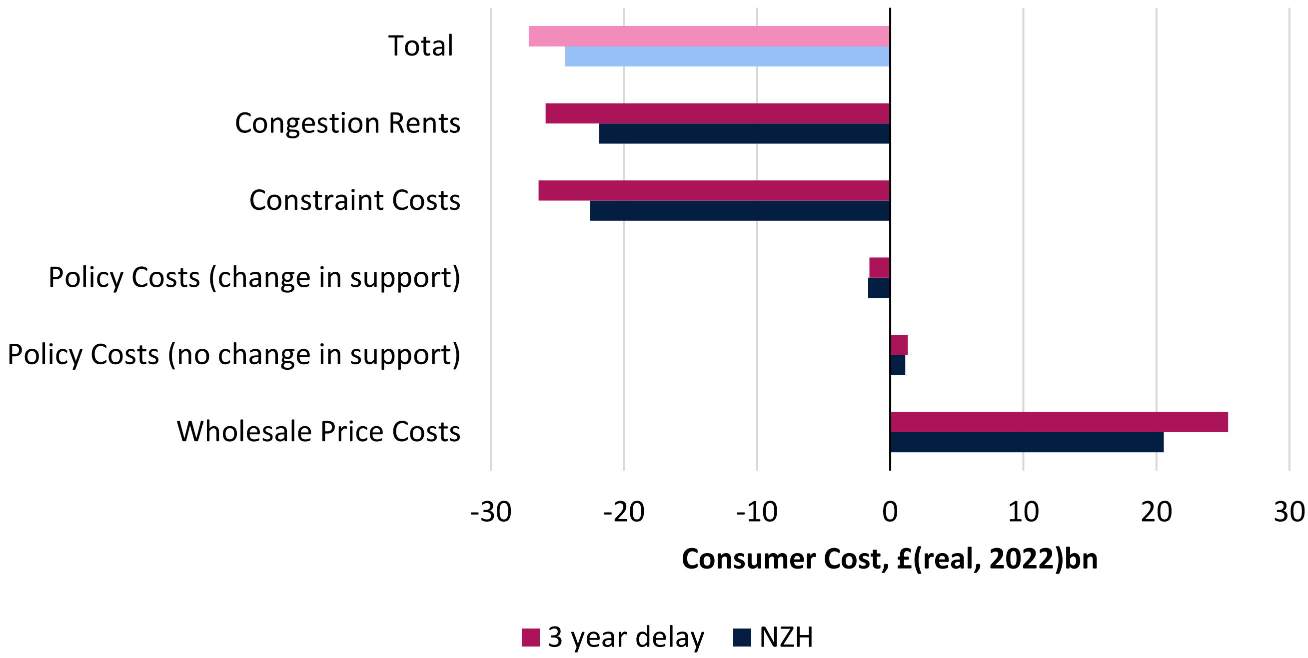


As can be seen above, moving to locational pricing has larger system impacts in 2030-2035 and 2030-2040 periods with a 3-year network delay. In 2030-35 evaluation periods, the system benefits are 39% (£0.3bn) higher and in the 2030-40 evaluation period, benefits are 26% higher (£0.5bn). This highlight moving to locational pricing could make more difference if the network was significantly smaller.

In terms of the distributional impacts, a similar trend is observed to system costs. Consumer benefits of moving to locational pricing increase from £24.4bn in the core (NZH) scenario to £27.2bn in the 3-year network delay scenario, a change of 14%. This leads to the producer surplus from moving to locational pricing increasing from a cost to producers of £19.2bn in the core scenario to £21.5bn. a change of 12%.

Key differences between the two scenarios are increases in congestion rents and constraint cost benefits as a result of the network being more constrained in the counterfactual and thus moving to locational pricing able to reduce these costs by a higher amount. Conversely the impact on wholesale price costs increase as more constraints on the system lead to higher prices in some areas increasing these costs.

Figure 60: *Change in Consumer Costs between National and Zonal Pricing for the DESNZ Net Zero higher scenario and 3-year network delay scenario*

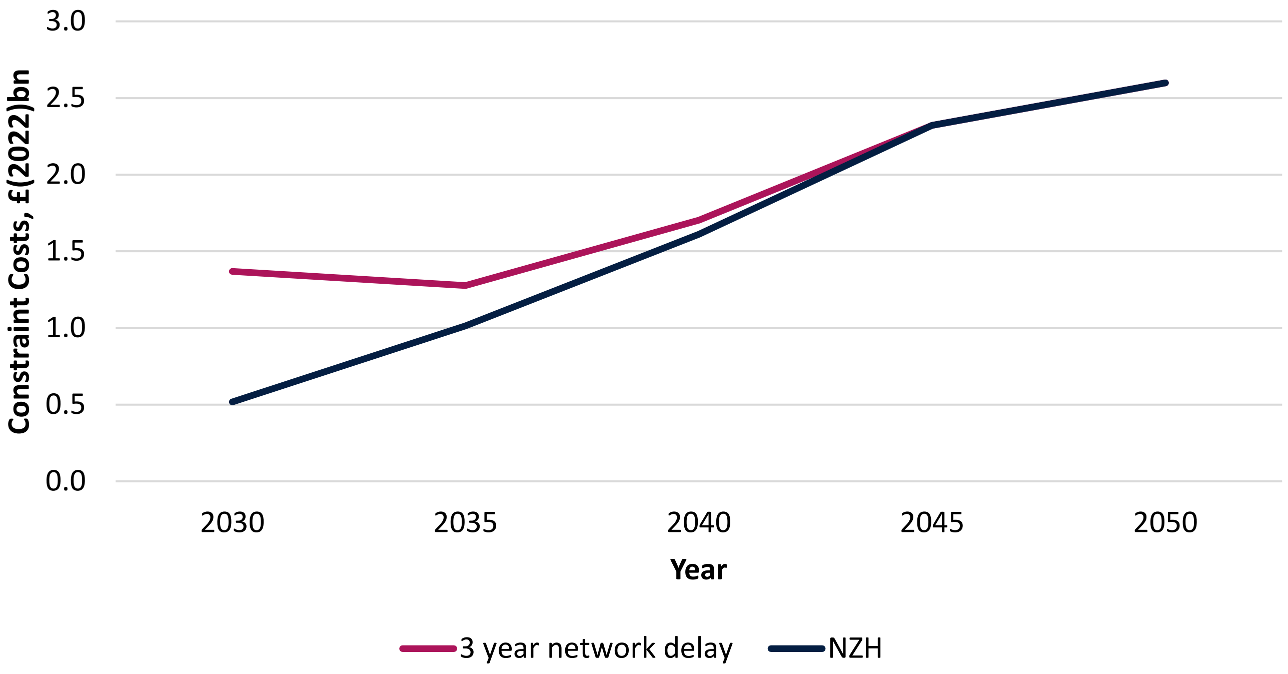


Less network build-out sees the differences between the amount boundaries are constrained in the national pricing counterfactual and locational pricing factual change. In general, a smaller network shows less flows across boundaries and more constraints. This increases the constraint costs in the counterfactual meaning that moving to locational pricing makes more of a difference.

This can be seen in the chart below comparing constraint costs in the national pricing counterfactual across the two network scenarios modelled. Constraint costs in the counterfactual are made up of two parts, the amount of generation that is constrained and the price that generation is turned down out. Constraint costs tend to increase over time as boundaries are constrained more regularly in the modelling. This is due to the rate of demand and capacity (particularly in constrained areas) increasing at a faster than the rate of network build in the DESNZ Net Zero Higher Demand scenario.

Constraint costs are higher in the network delay scenario as there is less boundary capacity on the system but the same amount of demand. This has the largest impact in 2030 with constraint costs being nearly 3x higher given that the NOA7r + HND build assumes a large increase in build in 2030 in the core scenario, which is not there in the 3-year network delay scenario (as shown in the graphs in 7.2). By 2035, the difference in network build is smaller between the two scenarios which results in constraint costs being 27% higher. This declines to just 6% in 2040 as there is little difference in network build across the two scenarios at this point. The constraint costs converge in 2045 as the network is the same across the two scenarios.

***Figure 61:** Constraint Costs in the national pricing counterfactual in the NZH and three-year network delay scenario*



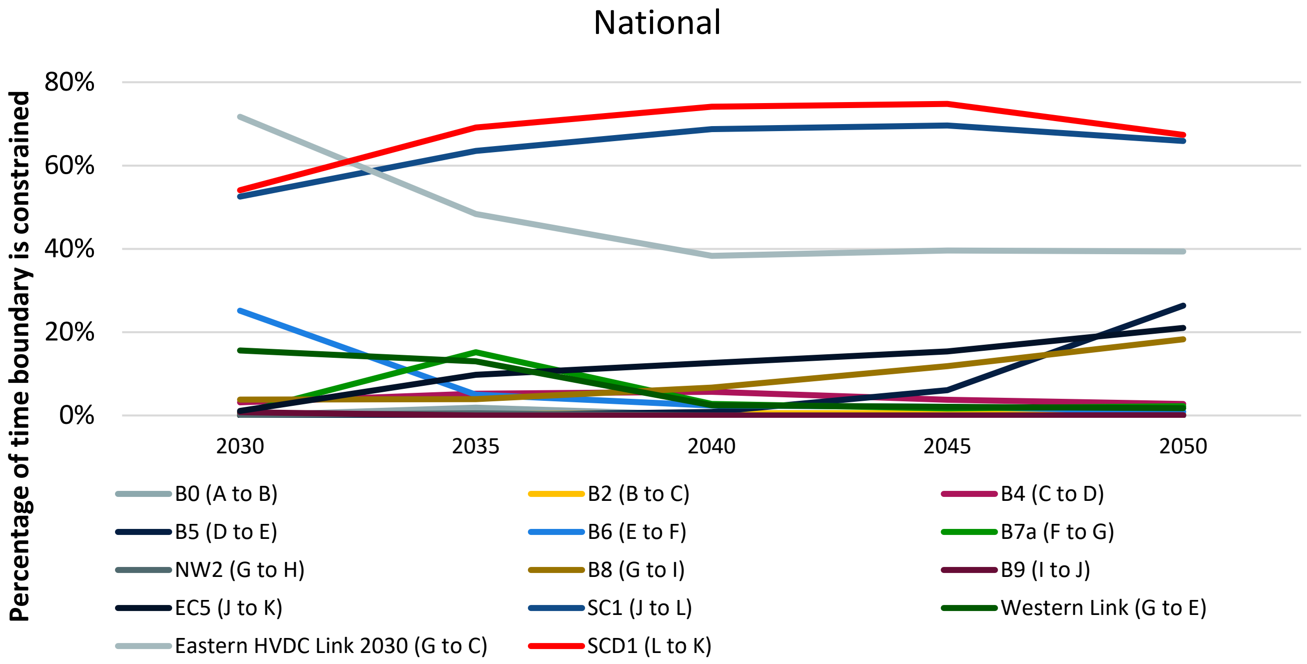
This differences across scenarios can also be illustrated by looking at the percentage of time each boundary is constrained across the different scenarios. In general, boundaries are more constrained in a national world, particularly from 2040 onwards. This is largely due to increased capacity locating in the north, far away from the majority of demand in the south. This increased boundary constraints results in increased congestion rents, and higher levels of curtailment.

The charts below show the percentage of time boundaries are constrained. The national diagrams show the percentage of time boundaries are constrained[64] after locational balancing. The three-year delay scenario is constrained more often in the national pricing counterfactual, especially in earlier years reflecting the higher constraint costs shown above. However, when the system moves to a locational pricing model, how often boundaries are constrained is similar across the core scenario and network delay scenario. This shows why moving to locational pricing makes more of a difference in the network delay scenario.

It should be noted that the additional HVDC links are not online by 2030 in the three-year delay scenario. This explains why benefits of moving to locational pricing increase in this scenario. However, this change is not that significant as boundary capacity is not too different in certain years. In particular, the boundary constraints are exactly the same in 2045 and 2050 as the network assumptions are flatlined after 2040 in the core scenario and from 2043 in the network delay scenario.[65]

[64] Constrained in this context means that boundary is at maximum capacity
[65] Note that only every 5 years are modelled.

Figure 62: *The percentage of time that each boundary is constrained in the locational pricing factual and national pricing counterfactual (after locational balancing) NZH scenario*



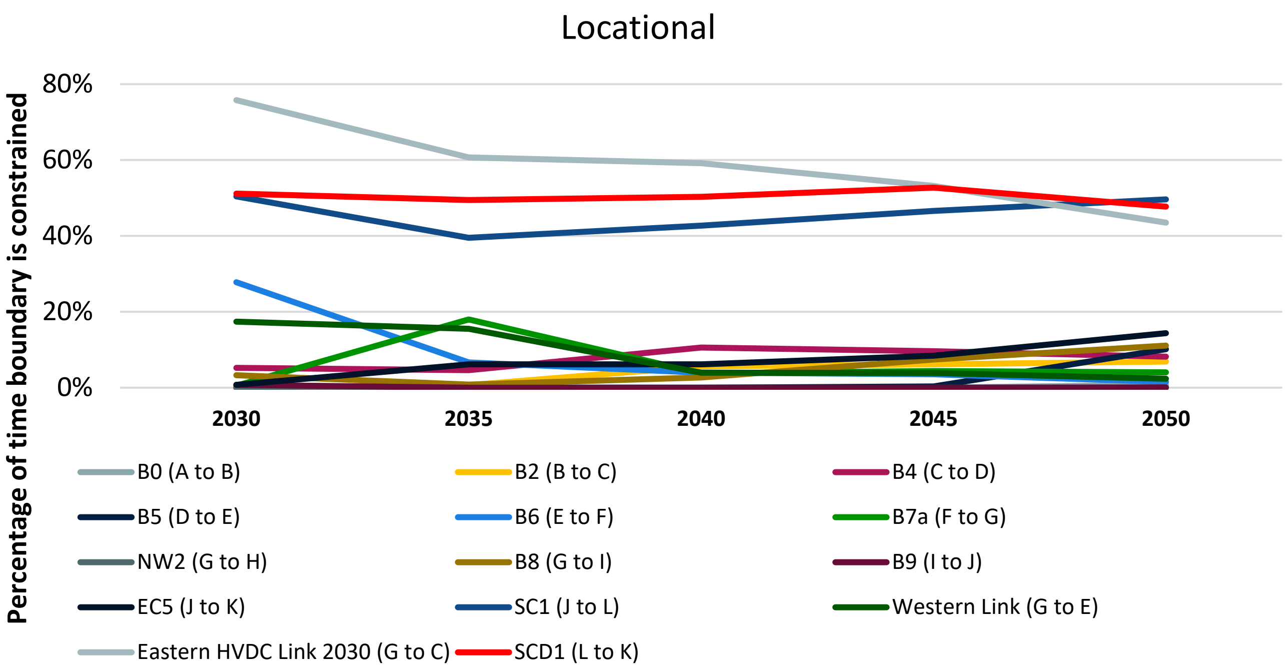
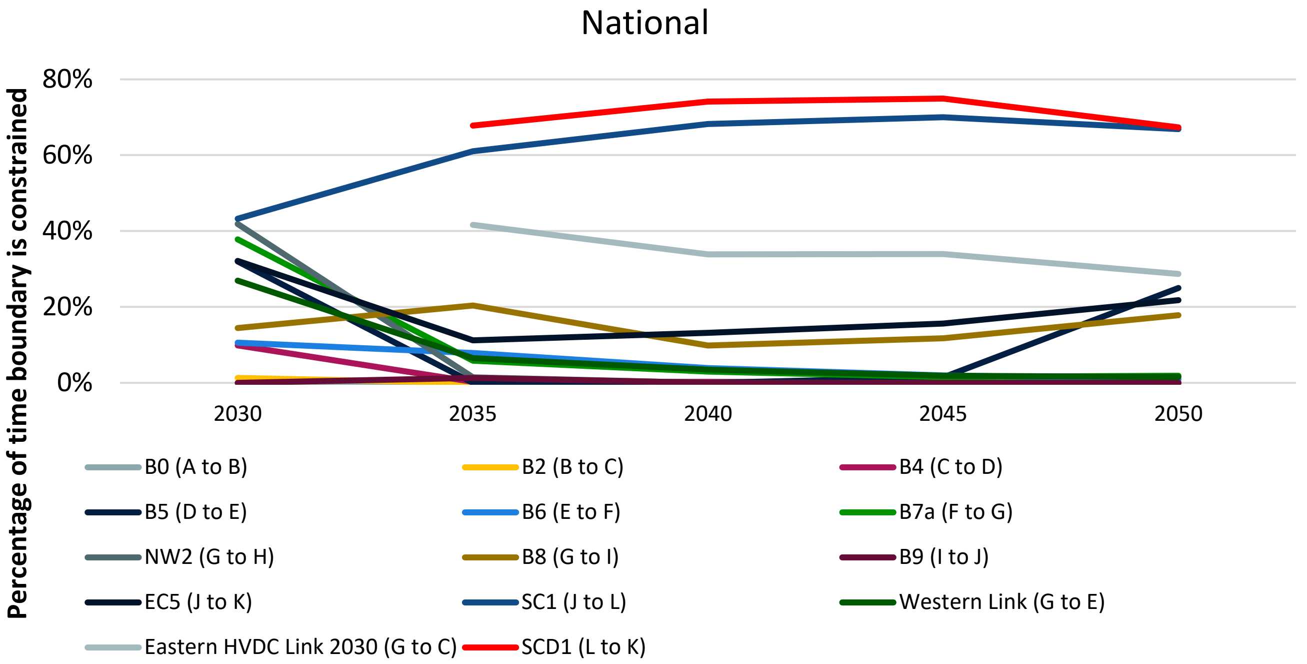
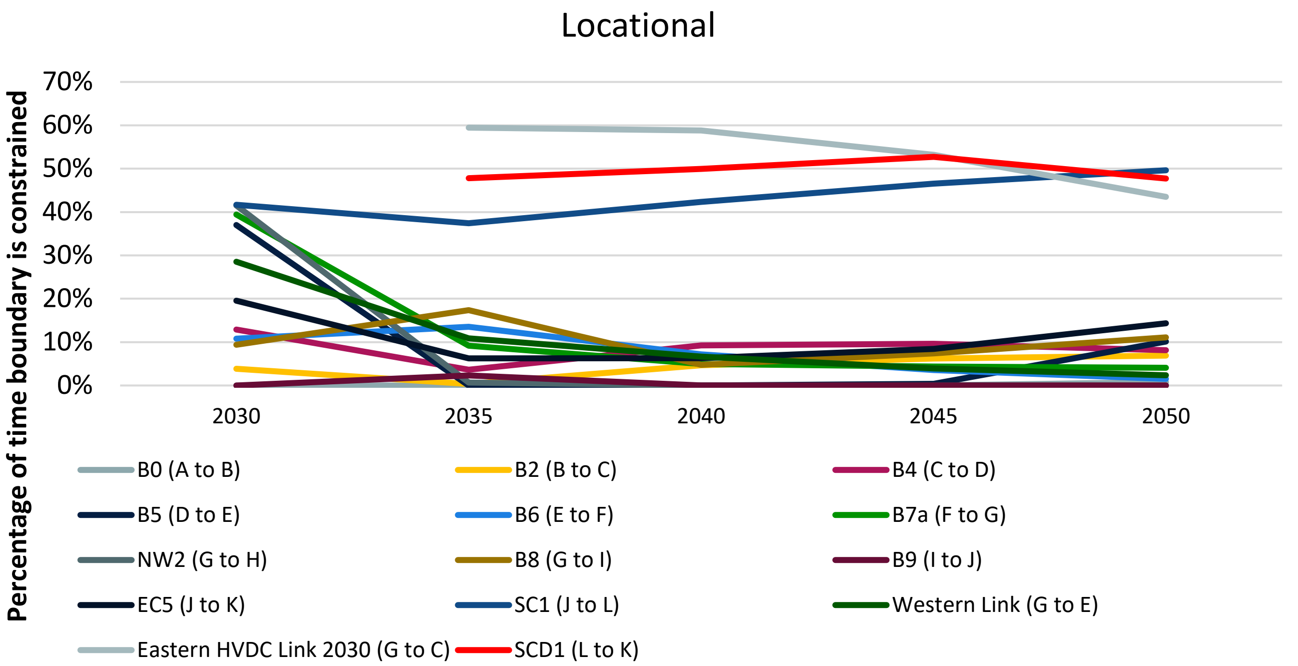


Figure 63: *The percentage of time that each boundary is constrained in the locational pricing factual for the 3-year network delay scenario*[66].





[66] Note that in the 3 year network delay scenario, the Eastern HVDC and SCD1 boundaries do not have a value in 2030 as they only come online after this point

9. Locational Pricing and the Contracts for Difference Scheme

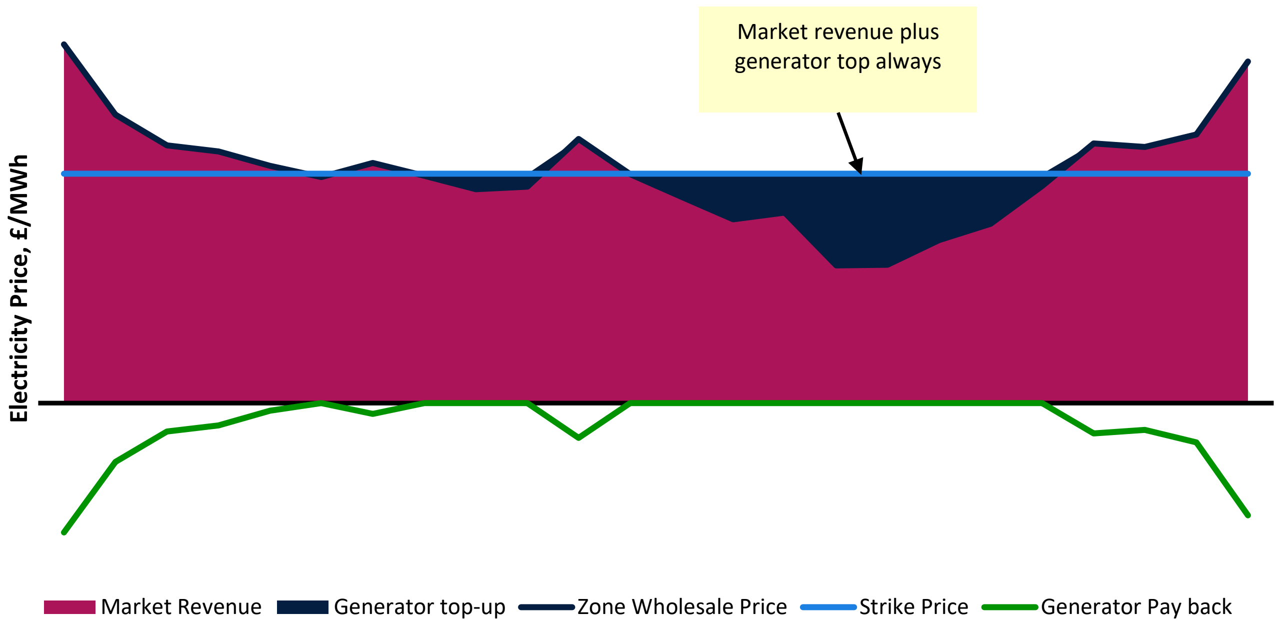
This section outlines the modelling conducted to assess the impact of moving to locational pricing with alternative options for how the Contracts for Difference (CfD) scheme interacts with locational pricing.

9.1. Options for Locational Pricing and the CfD

The interaction of locational pricing with CfDs is a key area of consideration. While we do not want to pre-empt what government policy would be in this area and a detailed consideration of the interactions is out of scope for this project (for example changes to pot structure), we do need to consider how locational pricing will affect CfDs in the modelling. This will have a material impact on system and consumer costs. Within the analysis, our main point of consideration is how much exposure CfD supported plants would have to locational signals. This gives us two different options for the modelling**:**

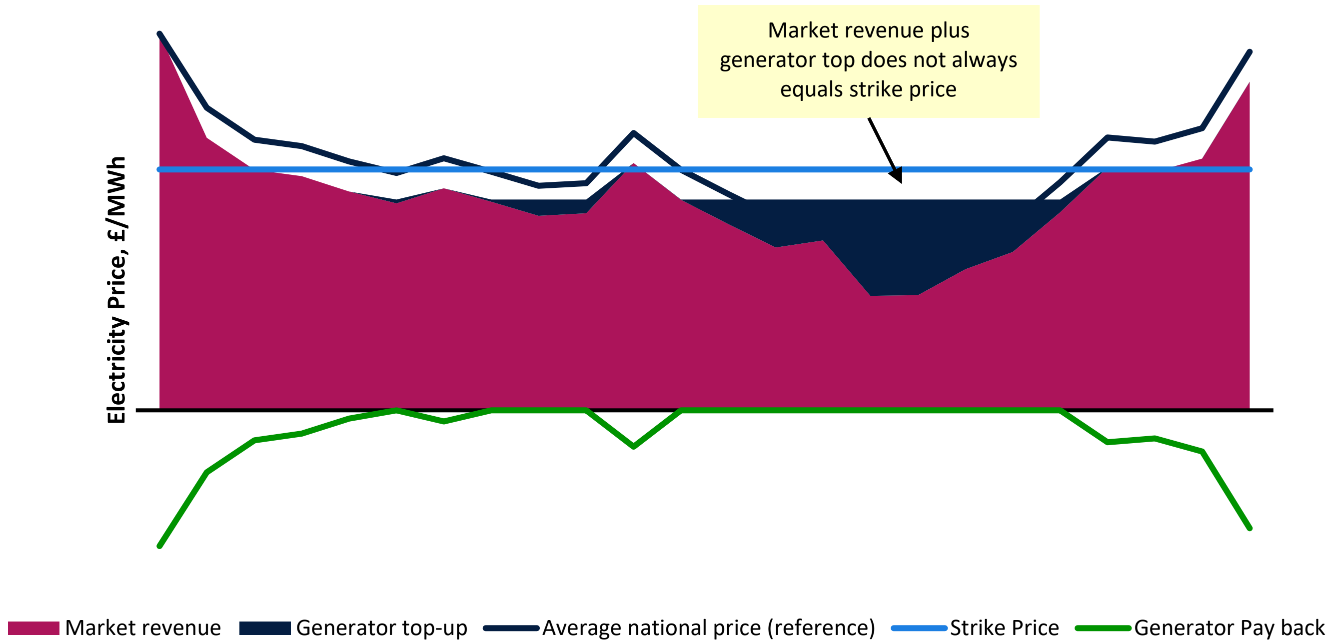
- **CfD plants have no exposure to locational pricing signals** – this would replicate the current model for CfDs with the reference price = zonal price (i.e. the price the CfD plant is paid in the wholesale market). This would mean that the CfD top up above this point always ensures CfD plants receive their strike price, regardless of which zone they are located. Locational exposure is limited to the risks associated with curtailment ("volume risk"), with plants no longer achieving revenues when they are curtailed for locational reasons, as they are no longer able to achieve wholesale revenues in these periods or be compensated through the balancing mechanism. This is shown in the illustration below.

Figure 64: *CfD and locational pricing example - less exposure to locational signals*



- **CfD plants have full exposure to locational signals** – the reference price = same for all plant irrespective of location, e.g. the national price with no constraints, or the average of all zonal prices. This would mean that in zones where the zonal wholesale price is less than the national reference price, top-ups to market revenue would not be enough for CfD plants to obtain the strike price. Whereas in other zones, with a higher price, some CfD plants would receive a top-up that takes their revenues above the strike price, meaning plants have an incentive to relocate. This is show in the illustration below.

***Figure 65:** CfD and locational pricing example - full exposure to locational signals*



The advantage of the second option over the first is that CfD plants are more likely to locate in areas which are for beneficial to the system. However, this approach comes with some risk as the CfD plants are more exposed to market prices. This could undermine a fundamental principle of the CfD regime, which is to protect these plants from price risk, and therefore potentially increase cost of capital for CfD plants and reduce overall investability in renewable forms of generation.

Within both options outlined above, the change in CfD policy is applied eqaully to both exsiting and new plants. For the second option in particular, this could mean that existing plant CfD top-ups reduce without the ability to change where they locate. How to treat existing CfD plants is another a key decision that DESNZ must take if moving to locational pricing.

Additionally, as discussed in section 0 the negative pricing rule would likely need to change in option 2. Rather than plants no longer receiving their top up payments if the reference price (national price) goes negative, they would no longer recivce a top-up if the national or zonal price goes negative. Otherwise the system is likely to end up with CfD plant still bidding negative into the wholesale market, resulting in negative prices in many zones in many periods.

Negative prices (that are driven by policy support payments rather than physical constraints) represent a distortion to the system, and will lead to the inefficient dispatch and deployment of demand-side flexibility, including storage. In our modelling, we have assumed that future CfD plant will not be incentivised to bid below zero in the locational pricing scenario or in locational balancing in the national pricing scenario.

These risks highlight that any implementation of CfD in a locational pricing market would need careful considered to avoid undermining the principles of the CfD regime and avoid causing unintended consequences in the wider market.

9.2. Modelling results – different CfD options

The two scenarios modelled with different CfD options are outlined in the table below. The core scenario outlined in section 4 already contains option 2 above where the CfD is fully exposed to locational pricing.

Table 10: *Assumptions used in the two CfD scenarios*

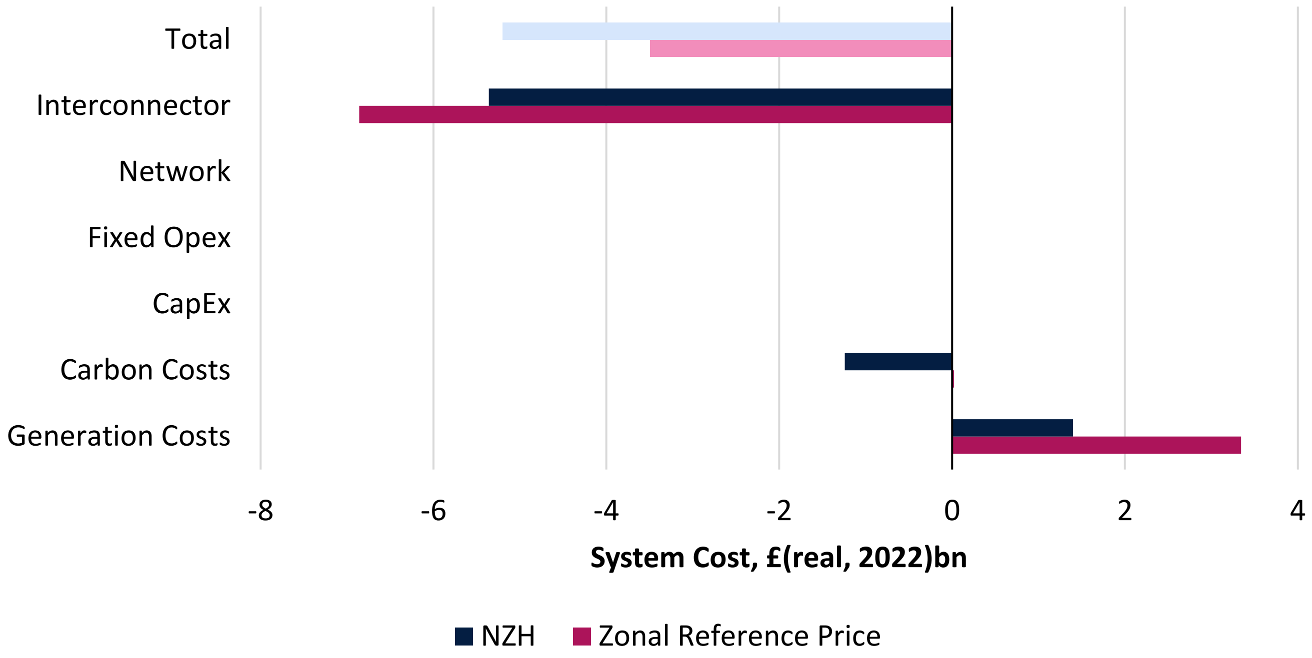
Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	ICs in national pricing model	Batteries in national pricing model	BM Uplift	Offshore wind location restriction
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
CfD partially exposed to locational signals	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Partial exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction

Overall, results show that partially exposing CfD plants to locational signals through a zonal CfD reference price result in lower system benefits compared to fully exposing CfD plants to locational through a national reference price. System benefits reduce from £5.2bn with a national CfD reference price to £3.5bn with a zonal CfD reference price, a reduction of 33%. In terms of distribution impacts, consumer costs do not change significantly with the consumer benefit at £24.4bn with a national CfD reference price and £23.7bn with a zonal CfD reference price. However, this means that the cost to producers increases in a zonal CfD reference price scenario with costs to producers of £20.2bn compared to £19.2bn in a national CfD reference price scenario, an increase of £1bn.

Cost Impacts

The system costs results show that the CfD being fully exposed to locational signals results in a higher system benefit from moving to locational pricing. Around 70% of the benefit is still retained with CfD partially exposed to locational signals with benefits in the zonal reference price scenario reducing to £3.5bn. This is as a result of CfD plants moving to more efficient locations in a national pricing scenario resulting in more efficient generation location for the system so a bigger system cost saving. It should be noted that no impact is assumed on cost of capital in either scenario shown here.

Figure 66: *Change in system costs between national pricing and locational pricing with a national and zonal reference price.*



The primary difference between the two CfD scenario results is a larger generation cost increase in the zonal reference pricing scenario, and this increase no longer being outweighed by the reduction in interconnector cost. This is despite the reduction in interconnector costs being greater in the zonal reference price scenario due to increased exports to Norway. The key driver of this is fewer renewable generators locating near demand zones as the zonal reference price drives them to locate wherever their generation will be highest, which is not necessarily beneficial for the system. For example, more wind locating in Scotland increases their generation, but this causes a higher proportion of wind generation to be exported abroad.

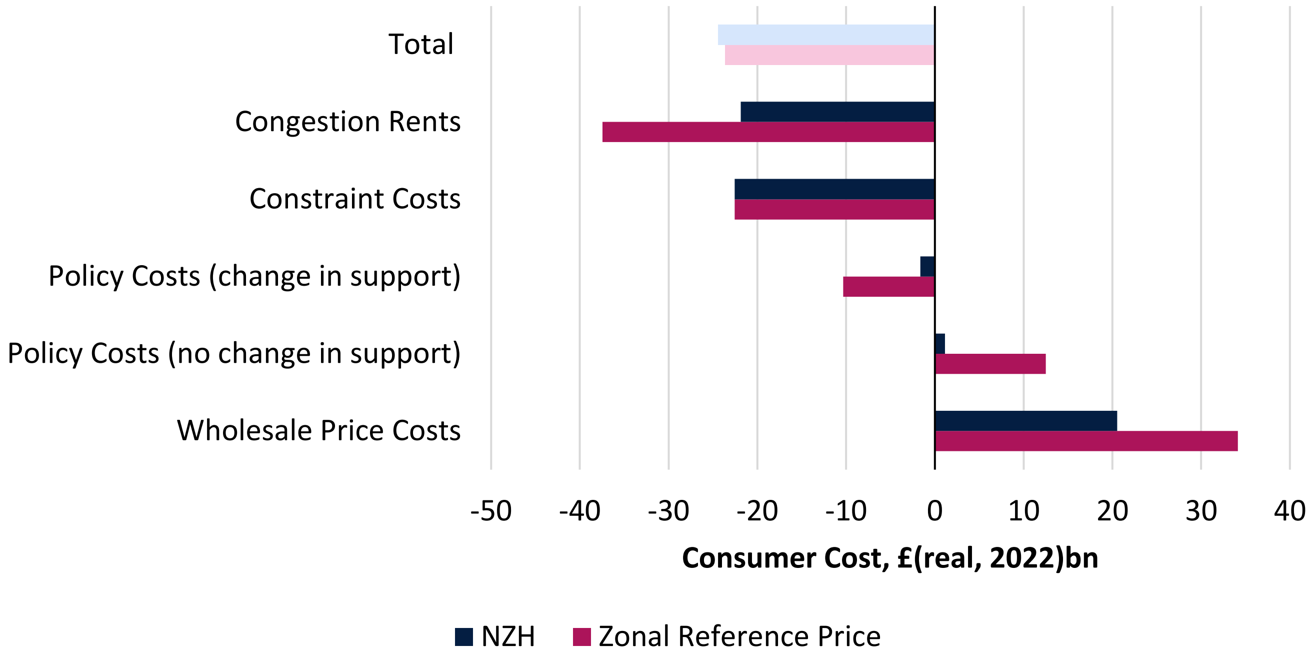
Where these plants are fully exposed to locational signals (national reference price), they locate in places that are more beneficial to the system. The zonal reference price encourages plants to locate where they will generate most in order to maximise their revenue as there is no risk, they will not get paid their full strike price. Therefore, the only driver of movement in this scenario is these plants no longer being able to receive turn down payments in locational balancing, however as this is now taken into account in wholesale prices instead then this is not likely to be a significant diver.

Wind in particular is driven to locate further north compared to the national pricing counterfactual where load factors are higher, and they can also export to electrolysers. This in turn causes more gas CCS and hydrogen generation in southerly zones, increasing generation costs. It also causes more overall domestic generation with more electricity being used to produce hydrogen via electrolysis also causing generation costs to increase. It should be noted here that more hydrogen production via electrolysis could be a benefit for other sectors outside of power which is not captured in these costs.

There is still a £23.7 benefit to consumers of moving to locational pricing with a zonal CfD reference price, only a slight decrease on the £24.4bn benefit with a national reference price. Compared to the national CfD reference price scenario, a move to locational pricing with a zonal CfD price results in more significant congestion rent benefits due to more disparity in prices across zone, but this leads to higher increases in wholesale costs due to higher prices in southern zones with more thermal generation. Policy costs also increase as top-up payments are higher as a result of more renewables locating in lower price zones. Constraint costs are unchanged between the two scenarios as constraint costs only apply in the counterfactual[67]

With consumer costs not changing significantly between the two CfD reference price scenarios but the system cost impacts being lower in the zonal CfD reference price scenario, this means that the costs to producers is higher in the zonal CfD reference price where costs increase by £1bn to £20.2bn. While producers would benefit from the larger increase in wholesale price costs in this scenario, the increased congestion rent benefit for consumers leads to higher costs for producers given this is a transfer between the two.

Figure 67: *Change in consumer costs between national pricing and zonal pricing with a national or zonal reference price.*



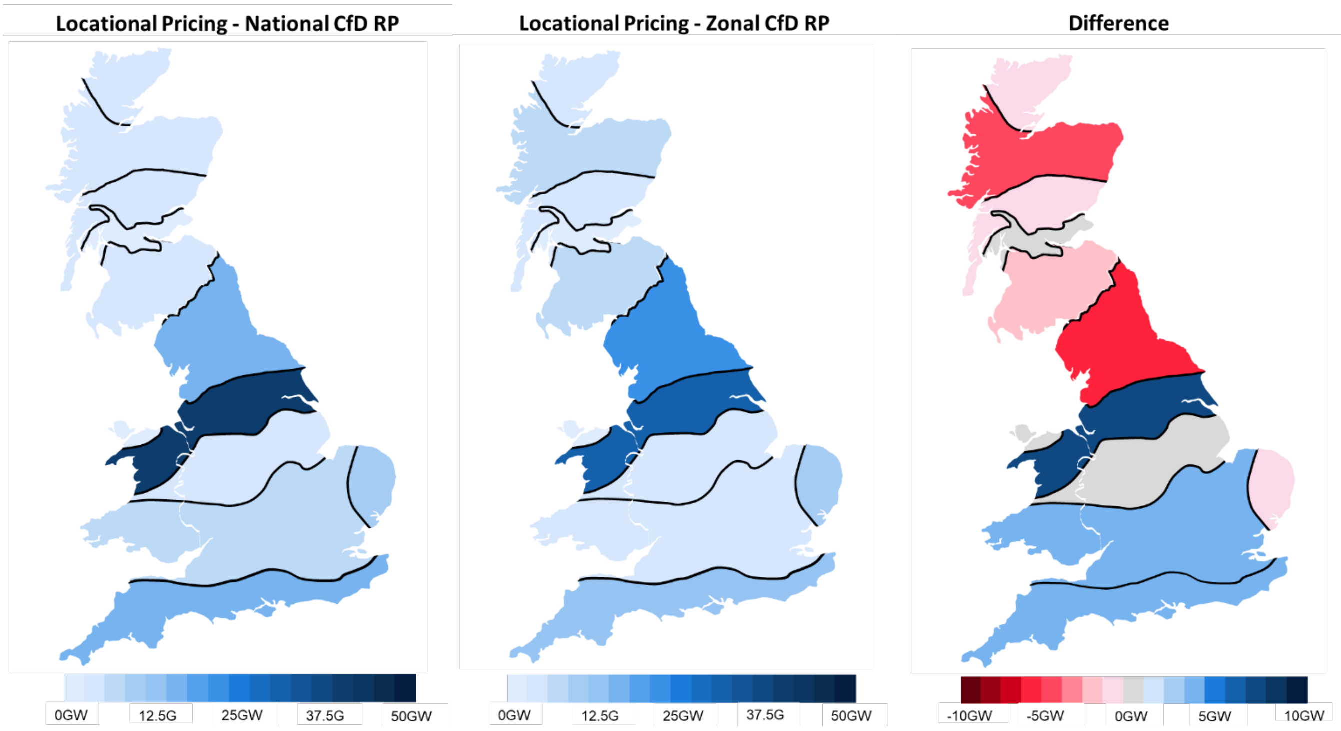
[67] There are no constraint costs in the factual scenarios where locational pricing is implemented as there is no intra-zone congestion costs due to a lack of available network data for boundary capacities beyond the 12 zones modelled

The below outlines relocation changes across the CfD scenarios for renewable technologies and the resulting changes in generation for the zonal reference price scenario.

Offshore Wind Capacity location

- As seen in section 4.3, most existing and planned offshore wind build is located in South Scotland, North England and East Anglia (zones E, F, G and K[68]) as these areas show showing higher load factors and TNUoS charges are lower than in North Scotland. In the national wholesale pricing counterfactual this trend continues but less is located in South Scotland as a result of higher TNUoS charges beyond the B6 boundary.
- Moving to locational pricing where CfD plants are partially exposed to locational signals sees this wind choose to locate in zones where its load factor is highest. This is because it will receive its full strike price whenever it generates although is still partially exposed to locational signals as it is no longer compensating for turning down. Offshore wind capacity increases in parts of north Scotland, where load factors are higher. The partial exposure to locational pricing does see some increases in the south of England as these plants do need to account for how often they generate given they are no longer compensated for being turned down due to locational constraints.
- Moving to locational price where CfD plants are fully exposed to locational signals sees a different affect, with less capacity in North Scotland. Capacity in zone G (middle/northern England) is 10.1GW lower in 2050 than the counterfactual, with a more capacity moving to the south of the country, particularly zone L.

Figure 68: *Location of offshore wind capacity in 2050 in locational pricing factual with a national or zonal reference price. RP = reference price. Difference is National RP – Zonal RP*

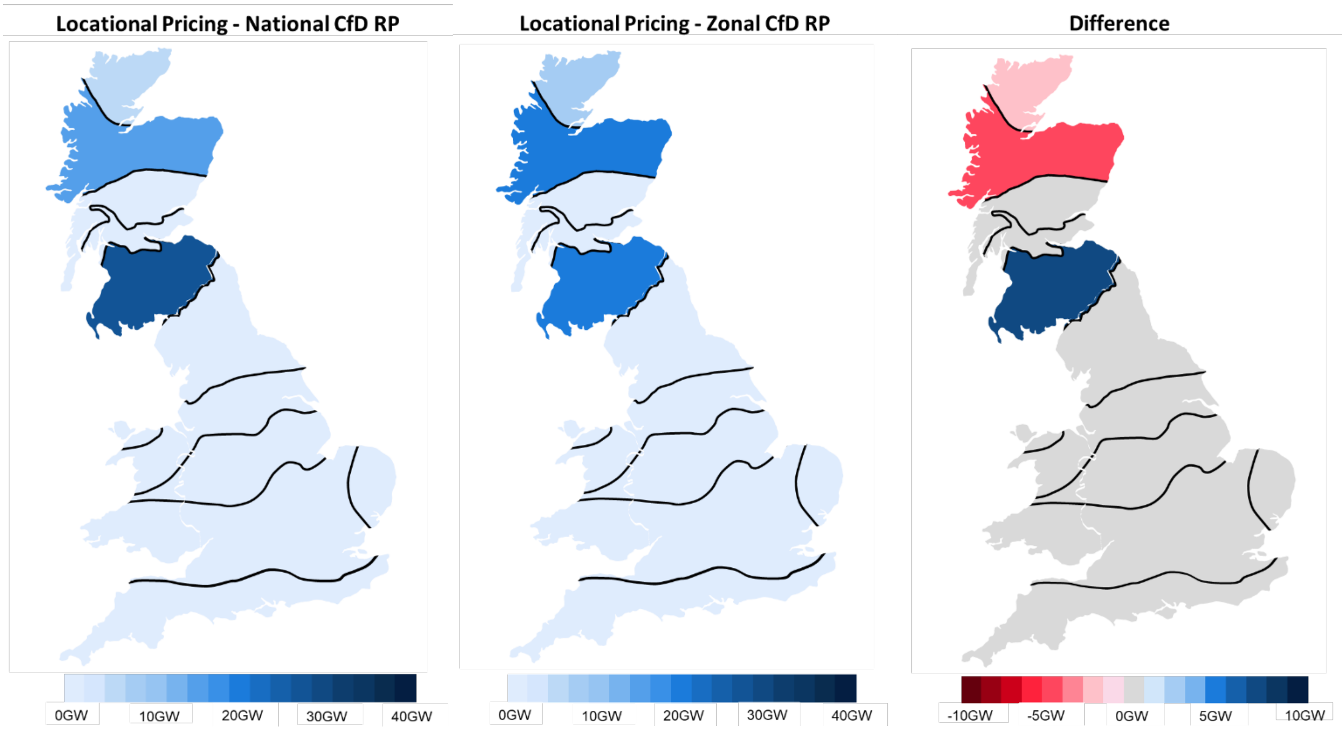


[68] See figure 8 for map of zones

Onshore Wind Capacity location

- As outlined in section 4.3, in the counterfactual, TNUoS signals are not as strong for onshore wind as for other technologies given around 50% is assumed to be distribution connected (so would not pay TNUoS). This results in a weaker locational signal for the counterfactual for onshore wind meaning it locates based on where it can generate the most. Onshore wind is restricted in where it can move, a maximum of 10% of new build capacity can be built in Wales and new build cannot build in England. This results in 10% of capacity building in Wales, and most of Scottish capacity locating in zone E, close to the B6 border to avoid other Scottish constraints.
- Moving to locational pricing where CfD plants are partially exposed to locational signals sees onshore wind locate more evenly across Scotland, balancing where it can gain the highest load factors and reducing constraints. This reflects the overall reduction in constraints in Scotland, allowing more build further north. Limited onshore wind locates in Wales with the 10% threshold not hit in most years.
- Moving to locational pricing where CfD plants are fully exposed to locational signals sees onshore wind locate based on a combination of locational signals and higher load factors. In this scenario onshore wind also locates more evenly across Scotland but with a slightly more southern focus compared to the zonal CfD reference price scenario with more locating in zone E (southern Scotland) where the majority of capacity is located across all scenarios. Compared to the counterfactual however, more capacity is located further north in Scotland (almost 12GW more in zone B than counterfactual). This reflects the locational signal, driving capacity to locate in zones with higher prices.

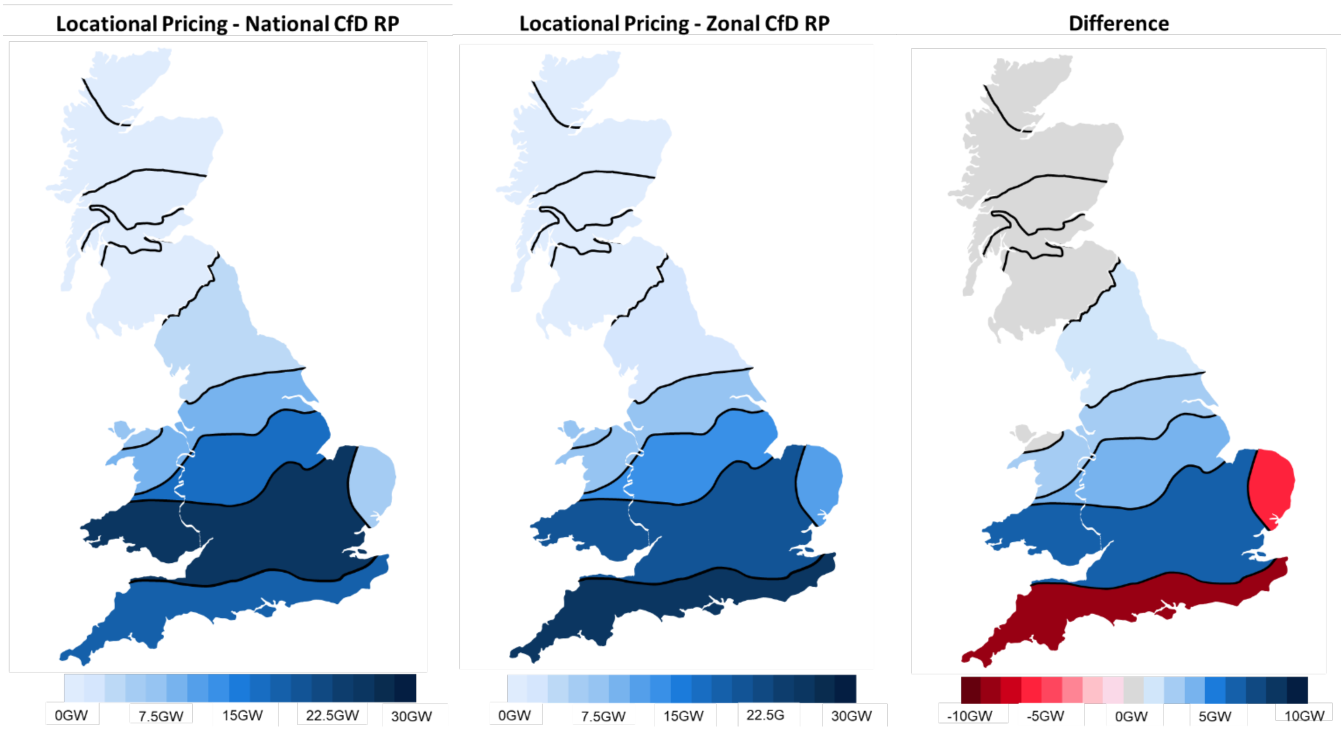
Figure 69: *Location of onshore wind capacity in 2050 in locational pricing factual with a national or zonal reference price. RP = reference price. Difference is National RP – Zonal RP*



Solar Capacity location

- As outlined in 4.3, currently solar build is primarily focused in southern England due to the higher load factors that solar can achieve there. Solar is predominantly distribution connected and so does not pay TNUoS charges. As a result, in the counterfactual it locates where it can generate the most, and so make the most revenue. This results in the majority of solar building in the most southerly zone (L), reflecting the higher load factors that can be achieved there.
- Moving to locational pricing where CfD plants are partially exposed to locational signals sees new solar build continue to be focused in the south of the country. The zone with the highest capacity remains Zone L. This is because with a zonal reference price, the locational incentive is to avoid constraints and maximise load factors. Compared to national pricing with the current CfD, a zonal reference price sees 5GW less build in zone K (East Anglia), and slightly increased solar capacities is zones F-I (middle/south of England and Wales) and L (southern England).
- Locational pricing where CfD plants are fully exposed to locational signals again sees new solar build focused in the south of England, but with a stronger signal to locate by demand. The zone with the highest capacity moves from zone L to zone J due to increased locational signal in the factual driving more solar to locate closer to demand. Overall solar capacity is more evenly distributed across the country in this scenario, because of the cannibalisation of the locational signal and zonal price as more solar builds in that zone.

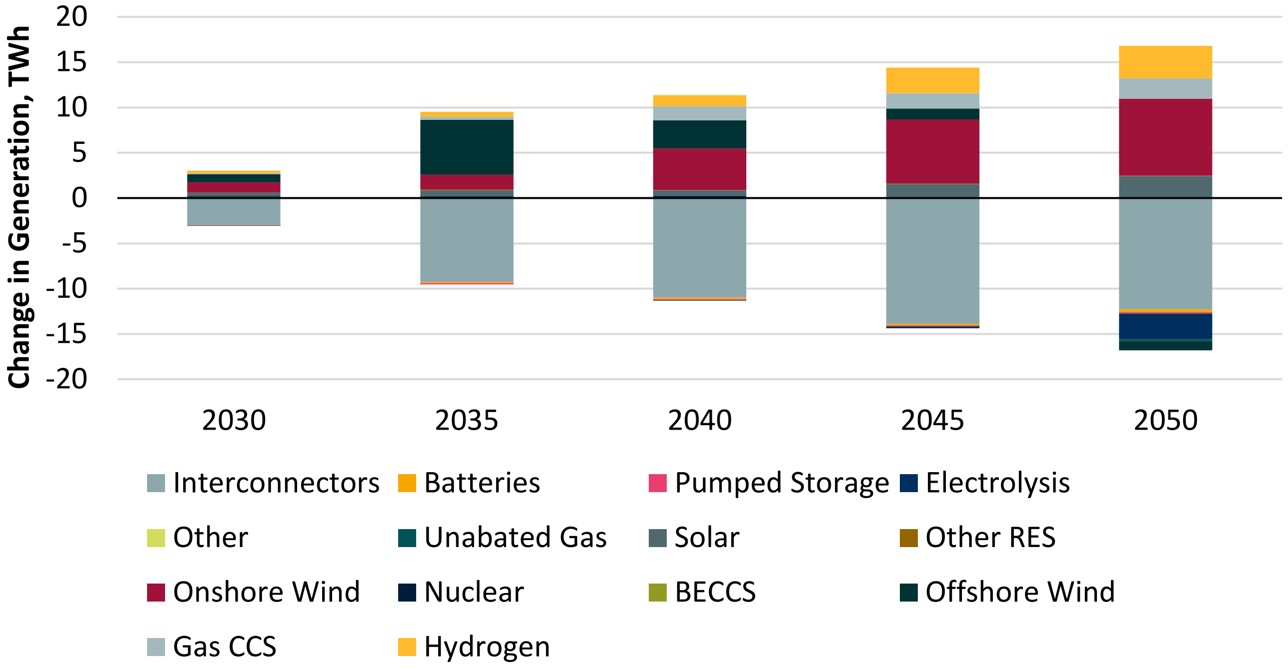
Figure 70: *Location of solar capacity in 2050 in locational pricing factual with a national or zonal reference price. RP = reference price. Difference is National RP – Zonal RP.*



Generation

Generation changes as a result of moving to locational pricing with a zonal CfD reference price can be seen below.

Figure 71: *Generation change by technology between national pricing counterfactual and locational pricing with zonal CfD reference price factual.*



Compared to the national pricing counterfactual, a locational pricing with a zonal CfD reference price factual sees the following changes to generation:

- Overall renewable generation increases for all CfD technologies (solar, onshore wind and offshore wind). This is as a result of more renewable generation locating in higher load factor zones – in the south for solar and in the north for wind.
- This causes electrolysis production to increase (shown as decrease on graph as electrolysis is modelled as a negative generation) and an increase in interconnector exports. This results in overall domestic generation in GB increasing.
- Generation from gas CCS, hydrogen and unabated gas increases. This is because a zonal reference price encourages CfD plants to locate where they can generate the most. This is in high wind areas, namely Northern Scotland. However, due to locational constraints, we need more thermal generation in southern zones to make up for the deficit during periods of high demand.

10. Offshore Wind Alternative Location Restrictions

This section outlines the modelling conducted to assess the impacts of moving to locational pricing with alternative restrictions for where offshore wind is able to locate and differing capex cost assumptions across different zones.

10.1. Why are Offshore Wind locations important?

As outlined in section 3.5, the portability of different assets is a key consideration in the context of locational pricing. One of the key potential benefits of locational pricing is that it can drive more efficient plant locations, however the extent to which power plants are able to relocate is a key assumption that will directly affect the benefits of moving to locational pricing.

Offshore wind is likely to be a key technology in the future system. Under the DESNZ Net Zero higher demand scenario capacity increases to 100GW by 2050 from 15GW today. Given such high-capacity levels, where offshore wind farms can locate, and any restrictions on this, can change the benefits of moving to locational pricing. To test the impact of this, an alternative scenario is tested where offshore wind is more restricted in where it can locate. This alternative scenario uses more conservative projections of seabed availability meaning less capacity can be built in certain zones. The restrictions on offshore wind by zone used in the core scenario and the low seabed availability scenario are shown in the table below:

Table 11: *Offshore wind maximum new build capacity per zone for core scenario and additional restriction scenario*

Zone	Core Offshore Wind New Build Limit (GW)	Restricted Offshore Wind New Build Limit (GW)
A	366	1.5
B	435	14.5
C	9	0
D	3	0
E	33	11.5
F	141	48
G	81	1.5
H	2.1	0
I	3	0
J	6	0
K	12	0
L	240	21.5

Both scenarios were provided by DESNZ and are derived from the Future Offshore Winds (FOWS) project commissioned by DESNZ, The Crown Estate and Crown Estate Scotland[69]. The higher level used in the core scenario uses the FOWS 2 scenario while the FOWS 10 as the lower limit for seabed availability. The distinction between these scenarios is in the interpretation of 'hard constraints' where certain marine users are prioritised, and their areas are deemed ‘immovable’ and unavailable for offshore wind. The results from this scenario are outlined below.

10.2. Alternative Offshore Wind Restriction Scenarios Modelling Results

The two scenarios modelled with different seabed availability for offshore wind are outlined in the table below. The core scenario outlined in section 4 already contains the higher seabed availability level.

Table 12: *Assumptions used in the scenarios outlined in this chapter.*

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	ICs in national pricing model	Batteries in national pricing model	BM Uplift	Offshore wind location restriction
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction
Higher offshore wind restriction	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Higher restriction

Overall, results show that with additional restrictions on where offshore wind can locate, the system benefits of moving to locational pricing slightly increase by £1.5bn compared to the core scenarios with a lower restriction on where offshore wind can locate. This is due to the locational pricing signal incentivising more movement of other generation types in response to the more restrictive offshore wind locations. However, consumer benefits decrease slightly by £0.8bn. This is due to the higher constraints from the more restricted offshore wind causing wholesale prices to rise by more when moving to locational pricing which reduces the consumer benefit.

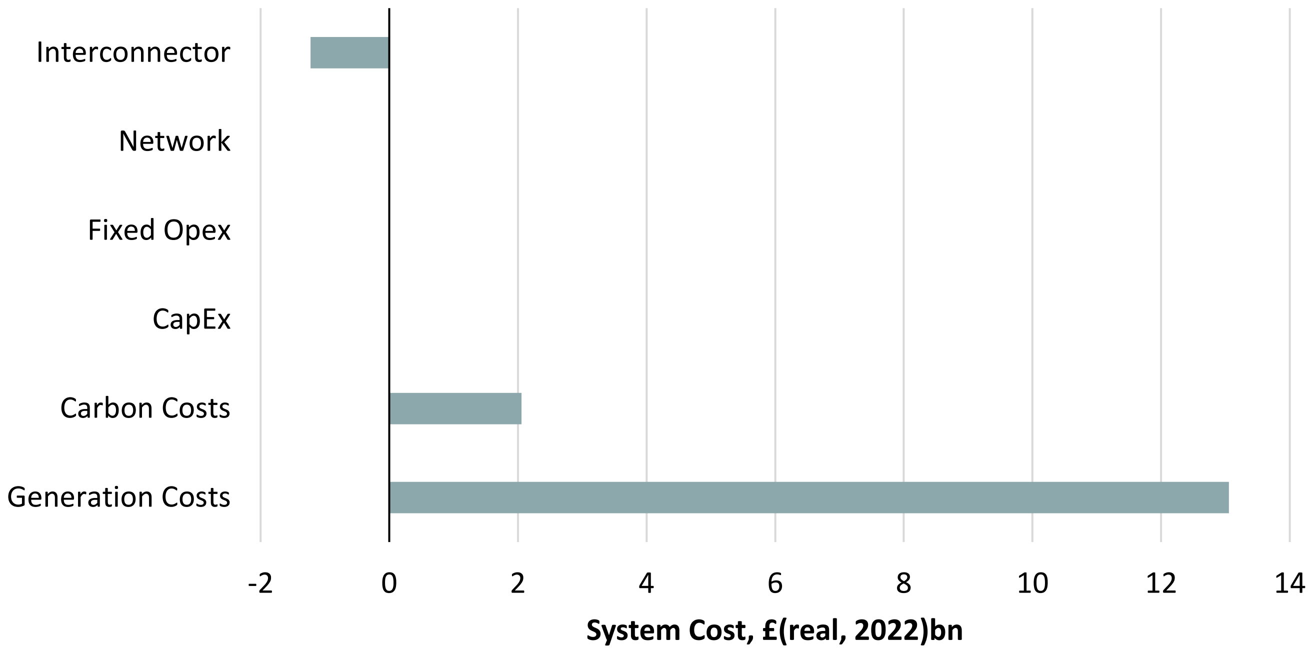
Cost Impacts

Assuming additional restrictions on where offshore wind can locate increases system costs in the national pricing counterfactual. This is driven by offshore wind being in less optimal locations for the system meaning additional generation from thermal assets such as unabated gas, gas CCS and hydrogen is needed. This drives up both generation and carbon costs compared to the national pricing counterfactual in the core scenario meaning total system

[69] FOWS (futureoffshorewindscenarios.co.uk)

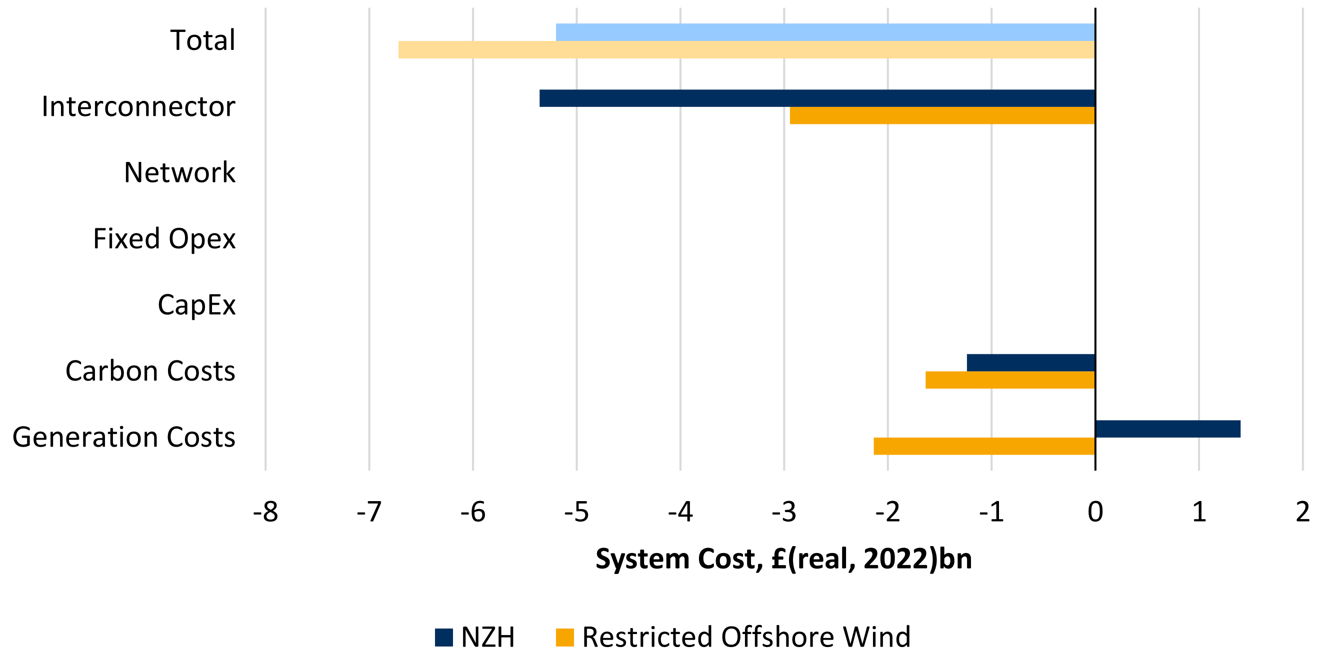
costs are £14bn higher in the national pricing counterfactual with additional restrictions on offshore wind.

Figure 72: *Change in system costs between additional restrictions on offshore wind location scenario compared to the core scenarios, both in the national pricing counterfactual*



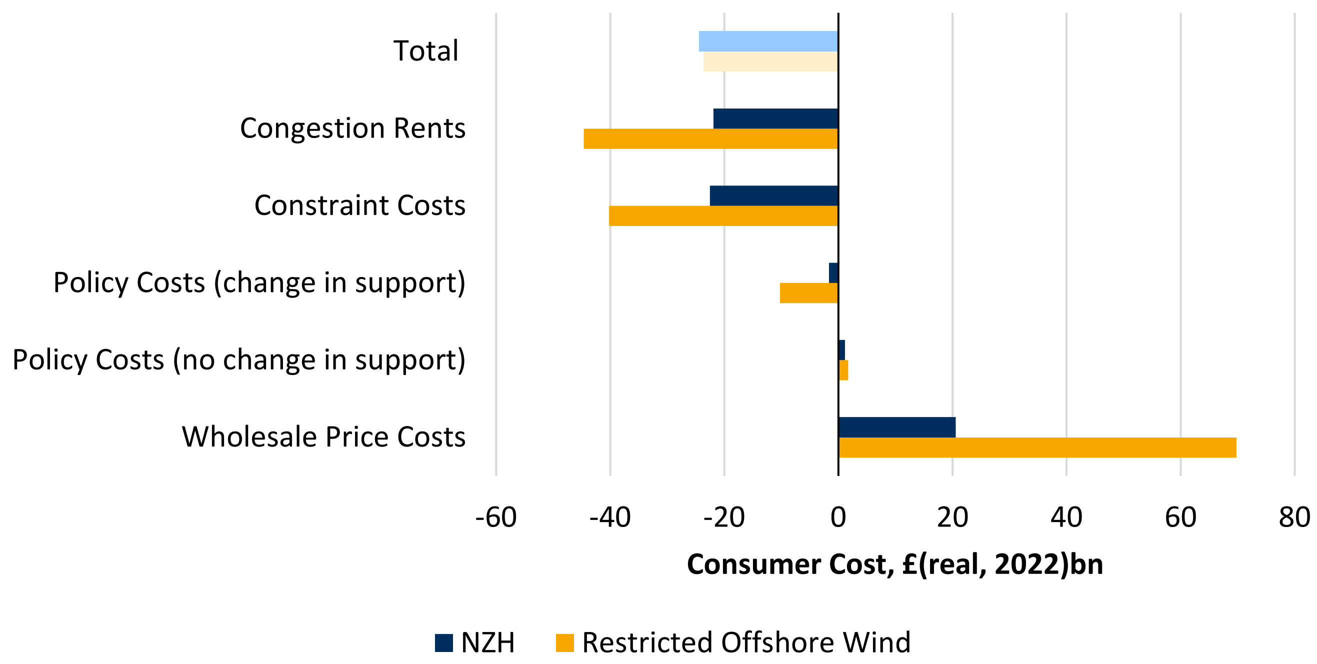
Looking at the impact of the move to locational pricing, the additional restrictions on offshore wind locations result in a higher system benefit from moving to locational pricing. Benefits of moving to locational pricing increase to £6.7bn (NPV 2030-50) compared to £5.2bn in the core scenario with lower restrictions on offshore wind locations (as outlined in chapter 4). This change in benefits compared to the core scenario is driven by the more efficient locational signal under locational pricing having a bigger impact on the locations of technologies other than offshore wind. This in turn means moving to locational pricing reduces the generation from higher cost thermal assets (unabated gas, gas CCS and hydrogen) by a greater amount than in the core scenario causing a larger decrease in generation and carbon costs.

Figure 73: *System cost impacts of moving to locational pricing under the NZH and higher restricted offshore wind scenarios*



Unlike the system benefits, the consumer benefits from moving to locational pricing decrease under the restricted offshore wind scenario. Consumer benefits decrease from £24.4bn in the core (NZH) scenario to £23.6bn in the higher restriction offshore wind scenario, a decrease of £0.8bn as shown in the chart below.

Figure 74: *Consumer cost in NZH and restricted offshore wind scenarios*



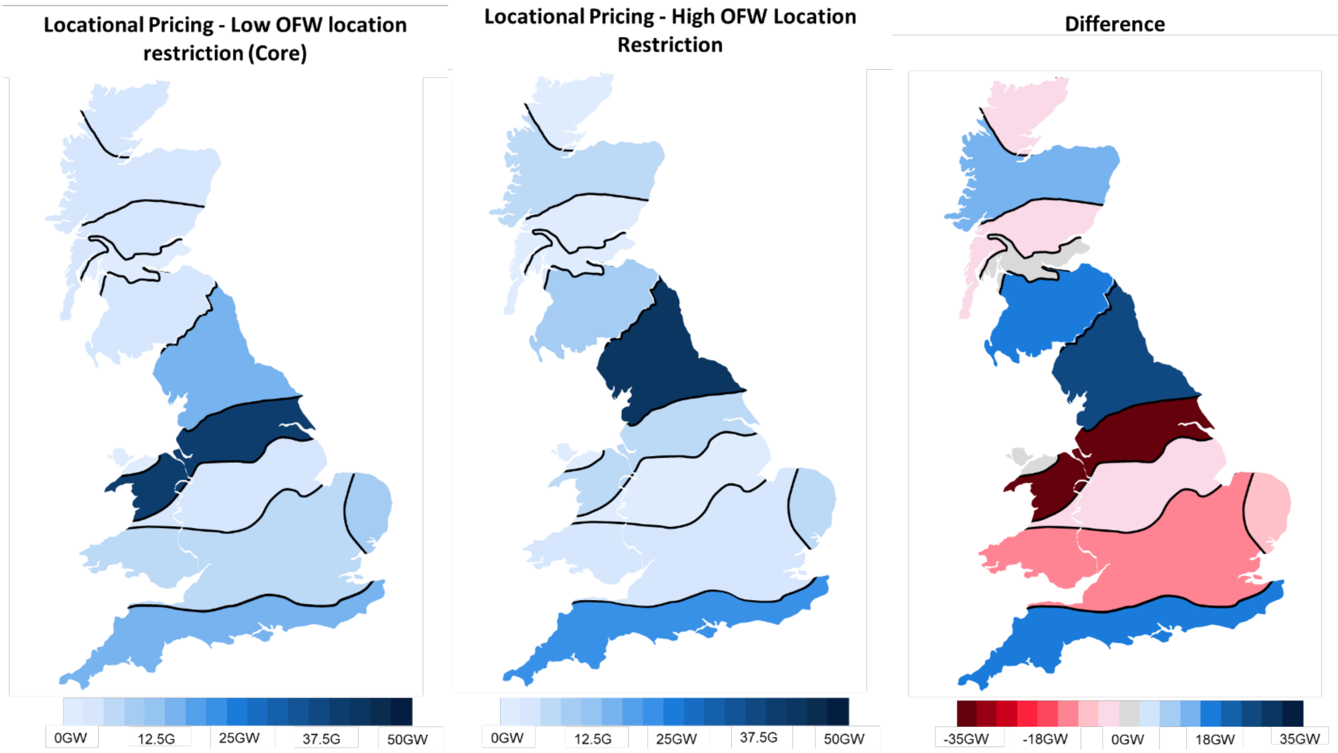
A key difference between the two scenarios is a larger decrease in constraint costs when moving to locational pricing as a result of the network being more constrained in the national pricing counterfactual. Similarly, congestion rents provide a larger benefit as the system is more constrained in the locational pricing factual with additional offshore wind location restrictions compared to the core scenario. However, these additional benefits are more than offset by increases in wholesale price costs as more constraints on the system (with restricted offshore wind) lead to higher prices under locational pricing as the constraints are reflected in the wholesale price.

Offshore Wind Capacity Location

Comparing the location of offshore wind in the locational pricing factual across the two different scenarios shows the difference that the additional location restrictions on offshore wind has.

With the additional restrictions, the offshore wind capacity is more concentrated in certain zones, particularly in the north of England (zone F), south of England (zone L) and south Scotland (zone E). This leads to less offshore wind capacity in the middle of England where demand is high (zones G to J). This results in more usage of thermal generators, like unabated gas, gas CCS and hydrogen, and higher levels of wind curtailment, when wind is more restricted in both the national price counterfactual and locational pricing factual.

Figure 75: *Location of offshore wind capacity in 2050 in locational pricing factual with different levels of offshore wind location restrictions*



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