Locational Marginal Pricing in Great Britain

Public Report

September 2023

Foreword

I'm delighted to introduce a major new report from Aurora Energy Research on locational marginal pricing (LMP), a key aspect of the UK Government's Review of Electricity Market Arrangements (REMA).

On the face of it, our system is changing to one dominated by renewables and flexibility, meaning value is increasingly specific to particular times and places; yet much about our market design fails to reflect this. A Wholesale Market that does not reflect the physics of a Net Zero power system surely cannot be sustainable. LMP systems have been found to operate successfully in multiple countries which Aurora analyses: from zonal systems in Australia, Europe and Japan, to nodal systems in the US. But the devil is in the detail. Whether LMP lowers or raises costs depends greatly on the rest of the system design and investment; to put it bluntly, we cannot expect sharper market signals to influence investment decisions if the rest of the system is so centrally planned that investors have no room for manoeuvre over where to place an asset. Even where theoretically beneficial, poor implementation could risk the investment needed in networks, flexibility and renewables.

Our study looks at the potential benefits of different forms of LMP compared to the current system. But we hope to add to the debate by looking more broadly at how LMP interacts as part of a wider market and system design, including both network investment and the new hydrogen economy, and how the benefits or costs of LMP change in different contexts.

Aurora has brought our best-in-class analytic capabilities and international experience modelling nodal and zonal markets together with a fantastic group of clients—representing the full spectrum of investment geographically and technologically, who have challenged and improved our work throughout. We are hugely grateful for their support. However, this report is independent and represents Aurora's perspective, not the corporate nor policy position of any of our clients.

Dan Monzani
Managing Director, UK and Ireland
Aurora Energy Research

Study participants

This study was conducted for a group of public sector observers and private sector clients interested in exploring the implications of locational marginal pricing on the GB energy market through modelled results of both zonal and nodal market designs. Our findings and policy conclusions are based on our own independent analysis and do not necessarily reflect the views of the participating clients.

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About Aurora Energy Research

Aurora was founded in 2013 by University of Oxford professors and economists who saw the need for a deeper focus on quality analysis. With decades of experience at the highest levels of academia and energy policy, Aurora combines unmatched experience across energy, environmental and financial markets with cutting-edge technical skills like no other energy analytics provider.

Aurora's data-driven analytics on European and global energy markets provide valuable intelligence on the global energy transformation through forecasts, reports, forums and bespoke consultancy services.

By focusing on delivering the best quality analysis available, we have built a reputation for service that is:

- **Independent –** we are not afraid to challenge the 'norm' by looking at the energy markets objectively.
- **Transparent –** all our analyses undergo further refining through a detailed consultation process across our private and public sector clients.
- **Accurate –** we drill right down to the requisite level of detail and ensure results are internally consistent. In power market analysis, this means half hour granularity with complete internal consistency across energy, capacity, balancing and other markets.
- **Credible –** trusted by our clients, our results have proven bankability.

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Aurora provides market leading forecasts & data-driven intelligence for the global energy transition

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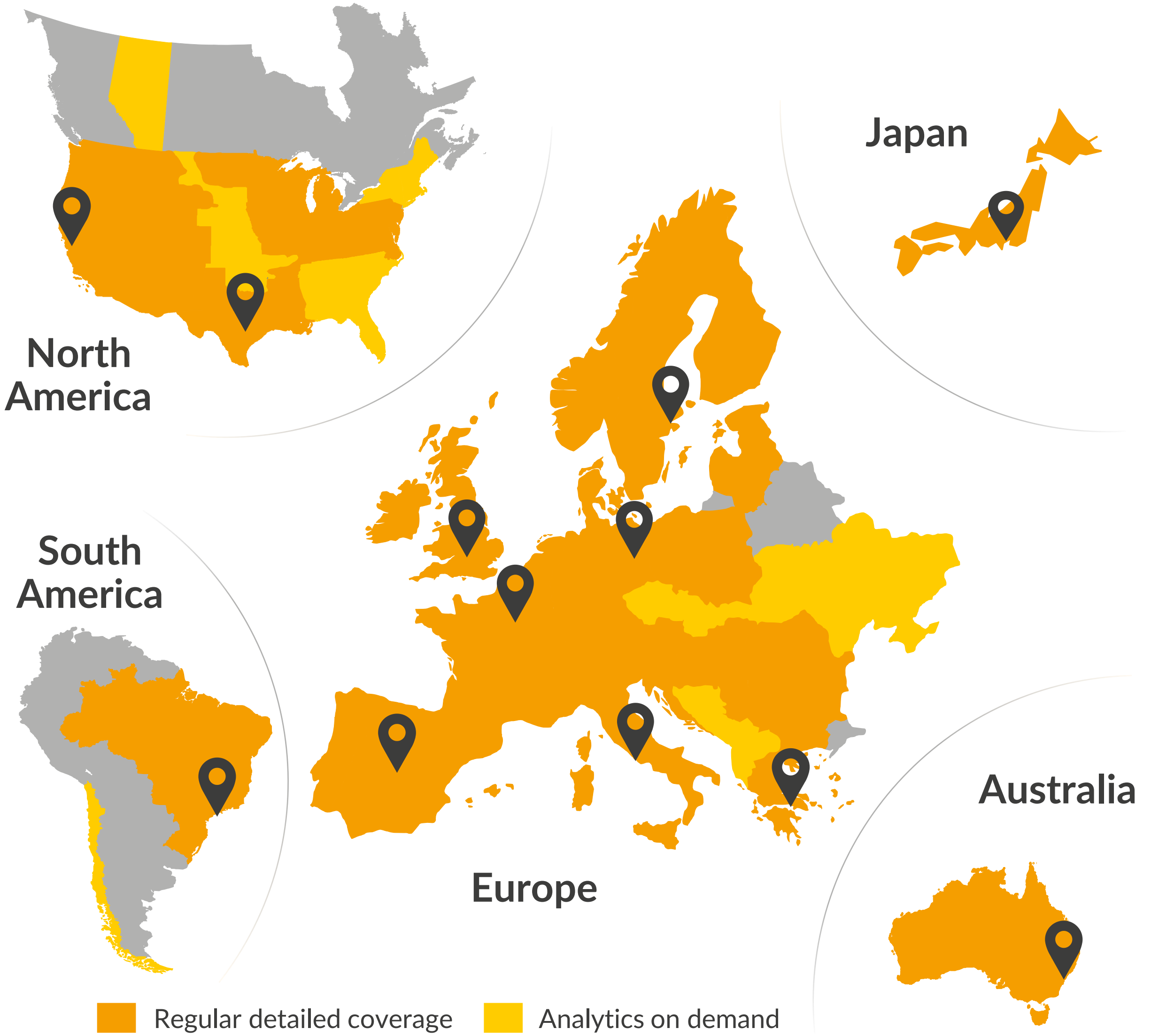

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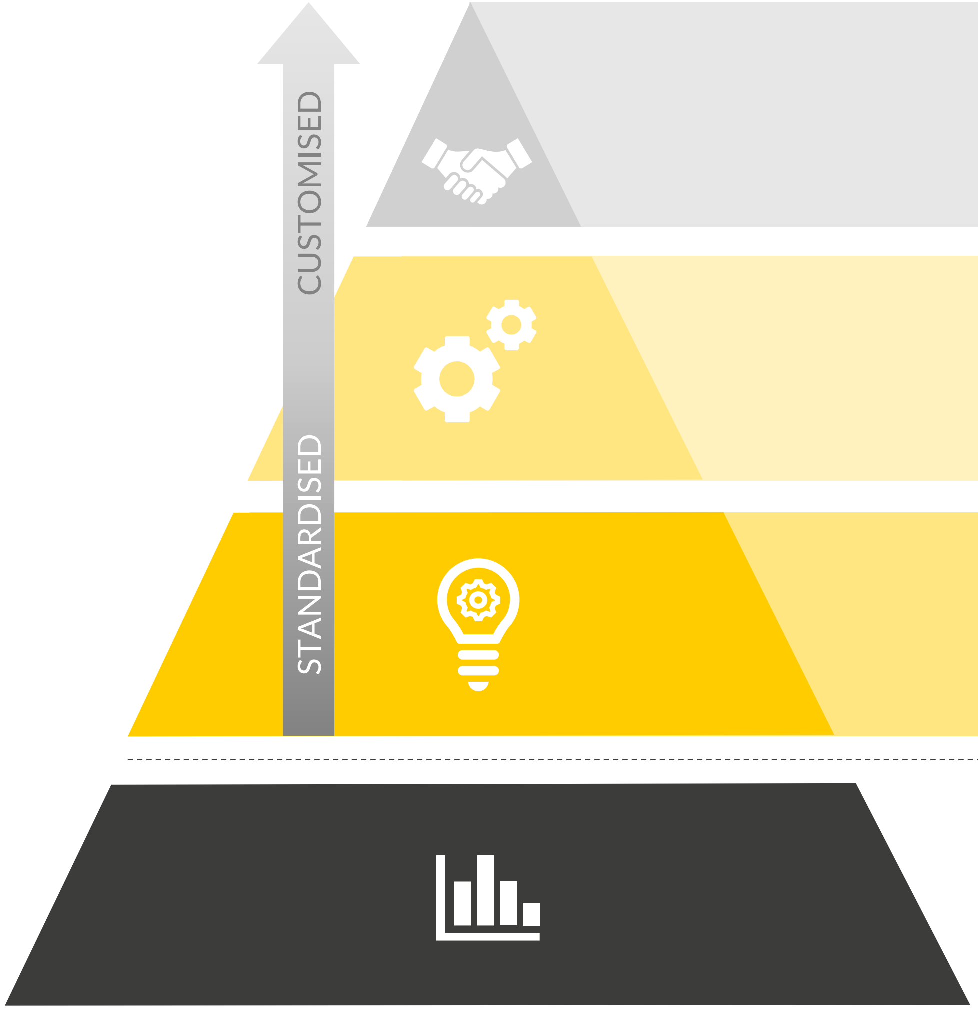

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Source: Aurora Energy Research

Agenda

Unlike Great Britain, several other countries have Wholesale Markets based on zonal or nodal locational marginal pricing (LMP)

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- The UK Government's **Review of Energy Market Arrangements (REMA)** consultation, published 18th July 2022, included an option to introduce location-based Wholesale electricity prices to incentivise power assets to deploy closer to centres of high electricity demand and reduce network costs associated with sub-optimal locations of assets
- Proponents of LMP in GB argue it **would produce a more efficient system** as a result of 1) better located generation and demand investments and/or 2) more efficient dispatch of assets
- Some advocates suggest LMP as **an alternative to network build**—claiming the locational signals would be sufficient to drive optimal placing of generation, storage, and demand to reduce the need for more wires

The impetus for LMP in REMA is for integrating a tremendous amount of renewables against an increasingly limited network (i.e., Net Zero by 2035). As such, the majority of our analysis is centred on Aurora Net Zero. However, for comprehensiveness, we have examined LMP briefly under a scenario where Net Zero isn't achieved until 2050 (Aurora Central)

Theoretical benefits of LMP for the Energy Trilemma

Decarbonisation: Enables the efficient siting of generation assets on the system by effectively enveloping TNUoS, TLM, Wholesale Market, Balancing Mechanism (i.e., system actions due to locational constraints) into a single, adequate market signal

Affordability: Would effectively eliminate the need for two-stage market settlement (except for intrazonal congestion under zonal LMP), leading to lower overall costs to consumers

Security of Supply: Would give network, power and storage developers sharper signals to build in a manner to reduce constraints on the GB network. This would in turn reduce the overbuild on the system and reduce the Capacity Market costs

Source(s): Aurora Energy Research

Critics argue that the theoretical benefits may be overstated once real-world siting constraints and costs are considered

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Effectiveness of LMP is measured in its ability to transmit differentiated locational signals to market participants while reducing the overall cost to the consumer

There are several factors that might limit the effectiveness of LMP signals

- Offshore wind farms may not always be situated near demand or unconstrained grid connections due to The Crown Estate and Crown Estate Scotland seabed leasing, which consider a range of factors including other seabed uses and grid connection availability
- There are certain locational aspects from a resource and workforce availability perspective which provide a strong incentive for siting
- Hedging mechanisms and financial transmission rights (FTRs) allow generators to protect themselves from loss of revenue driven by congestion on the grid
- Grandfathering CfD and CM contracts may shield asset operators from the desired locational signal

LMP might contribute to higher costs and missing Net Zero by 2035

- The energy cost on the system is supplemented by additional risks and costs that can be difficult to quantify beforehand (particularly for nodal LMP): Increase to cost of capital due to increased volatility and uncertainty, central dispatch management costs, realistic start date of LMP implementation which may reduces its impact for near-term goals, and other transition costs
- The path towards decarbonisation by 2035 depends on continued investment into low-carbon generation. Stalling on project investments due to market uncertainty or a vacuum on financial and legal services for managing the transition to LMP may lead to this target being missed

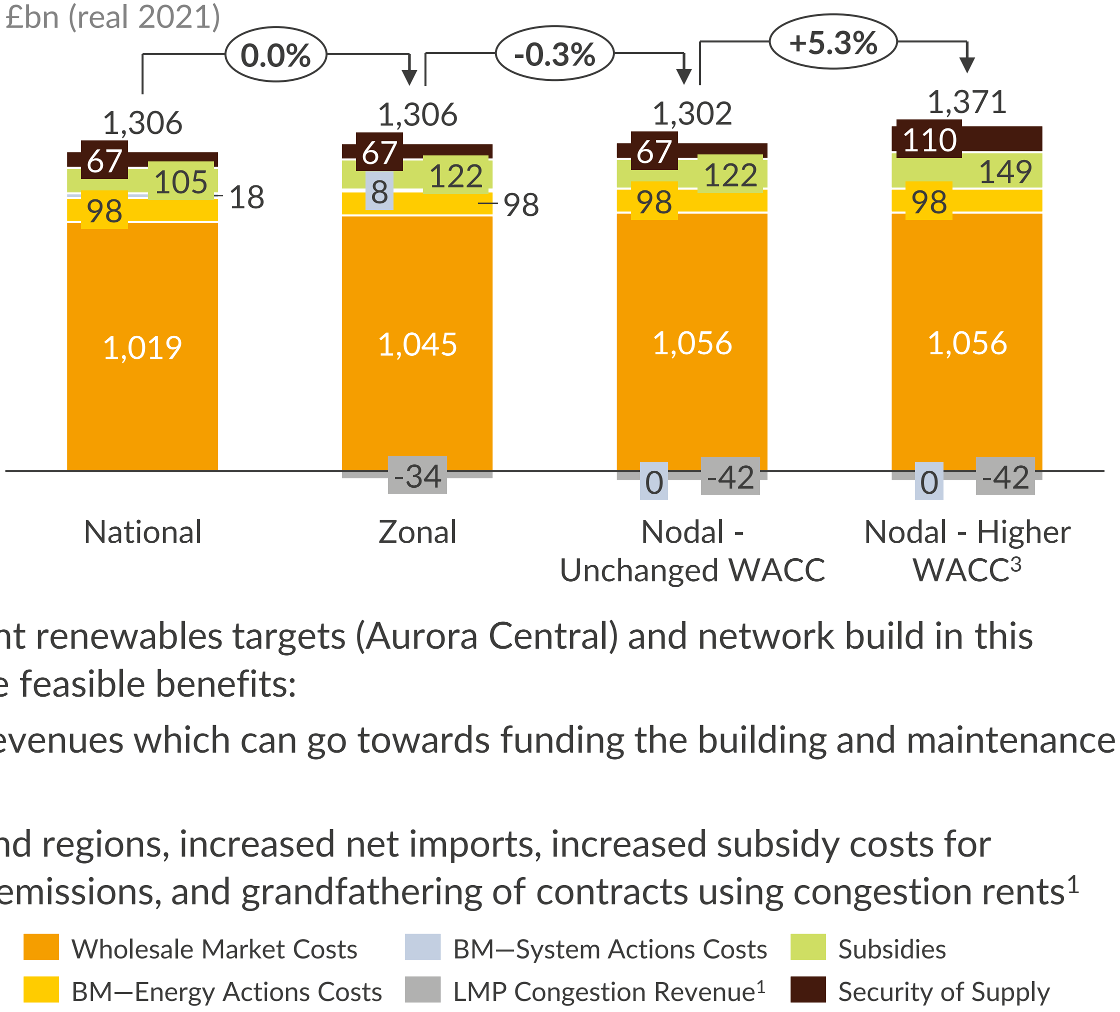
Source(s): Aurora Energy Research

Aurora finds, in a scenario where Net Zero by 2035 isn't achieved, a switch to LMP would likely result in increased costs to the consumer with little benefit

Central

- In a scenario where Net Zero Power isn't achieved until c. 2050 (Aurora Central), with full planned network build-out, **we model there would be negligible impact to the cost to consumers**
- **There would be additional costs in this scenario above the current national pricing system (not quantified in this report), due to:**
  - Potential delays to investments due to uncertainty during implementation, especially for nodal pricing combined with central dispatch;
  - Potential increases in the cost of capital (WACC) from reduced cashflows, volatility in cashflows, and market uncertainty; and
  - Different designs of the CfD scheme and Capacity Market could increase costs

Cost to the Consumer[2], Aurora Central, 2025–2060
£bn (real 2021)



- We have not evaluated a scenario where we under-deliver both Government renewables targets (Aurora Central) and network build in this study, since this is wholly contrary to the aims for REMA, but there could be feasible benefits:
  - Some benefit from LMP may occur in the form of increased congestion revenues which can go towards funding the building and maintenance of the network in lieu of TNUoS
  - Albeit this would likely be concurrent with increased prices in high-demand regions, increased net imports, increased subsidy costs for Scottish renewables, further curtailment of renewables leading to higher emissions, and grandfathering of contracts using congestion rents[1]

1) In practice, some of the congestion rent presented here could be distributed back to producers to grandfather previous arrangements to maintain security of supply 2) LMP results are likely higher than modelled due to real, unmodelled factors such as WACC increase, transition costs, congestion rent 'leakage', etc. 3) Aurora has not explicitly modelled this scenario. It is estimated based on the cost of capital increase impacts explore against Nodal for Net Zero.

Source(s): Aurora Energy Research

Consideration of constraints between 7 zones results in reduced RES generation in low-price zones and increased imports

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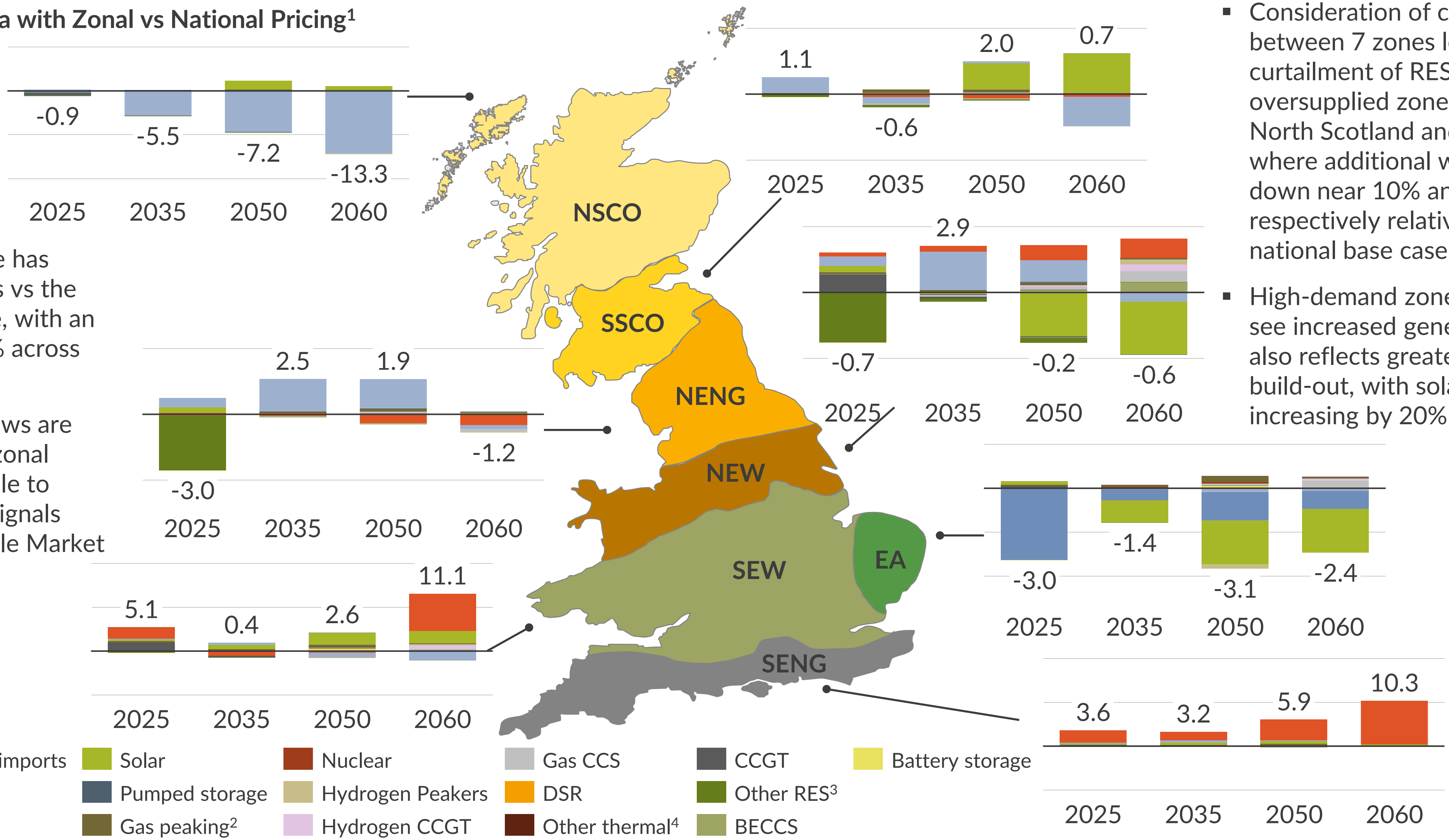
Central

Net Generation Delta with Zonal vs National Pricing[1]
TWh



- Zonal Central case has higher net imports vs the national base case, with an average rise of 5% across the forecast
- Interconnector flows are higher under the zonal where they are able to respond to price signals from the Wholesale Market

- Consideration of constraints between 7 zones leads to greater curtailment of RES in oversupplied zones such as North Scotland and East Anglia, where additional wind turns down near 10% and 30% respectively relative to the national base case
- High-demand zones such as SEW see increased generation which also reflects greater capacity build-out, with solar generation increasing by 20% by 2060

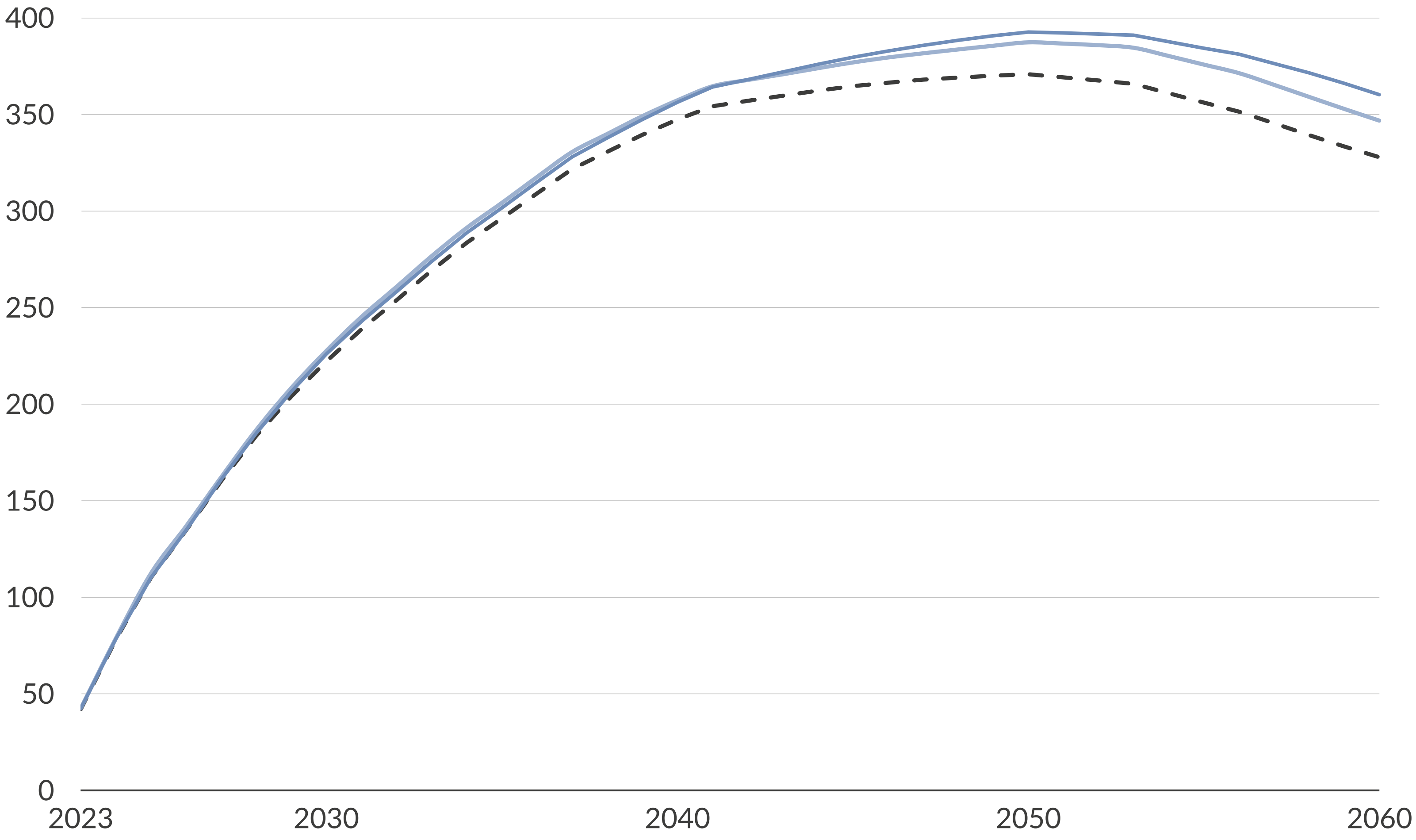
1) Generation deltas in the zonal vs national model reflect changes in endogenous capacity build-out and interconnector imports. Plus the consideration of interzonal constraints between 7 zones in Wholesale dispatch vs 3 zone locational balancing in Aurora's national model. 2) Gas peaking includes OCGT and reciprocating engines. 3) Other RES includes biomass, EfW, hydro, and marine: 4) Other thermal includes embedded CHP.
Source(s): Aurora Energy Research

LMP under the Central scenario leads to a 5–10% increase in emissions over the forecast due to an increase in peakers and imports

Central

Cumulative Emissions

$MtCO_{2,eq}$



- Both the national and zonal models achieve net zero emissions around 2050 under the Central scenario
- Less policy support for decarbonisation delivers a system with fewer renewables and a slower move towards Net Zero
- Higher deployment of peakers in LMP and imports push up emissions 5–10% on average across the forecast

Source(s): Aurora Energy Research

In achieving Net Zero by 2035, there is limited potential for impacting build locations of generation assets on the system solely through price signals

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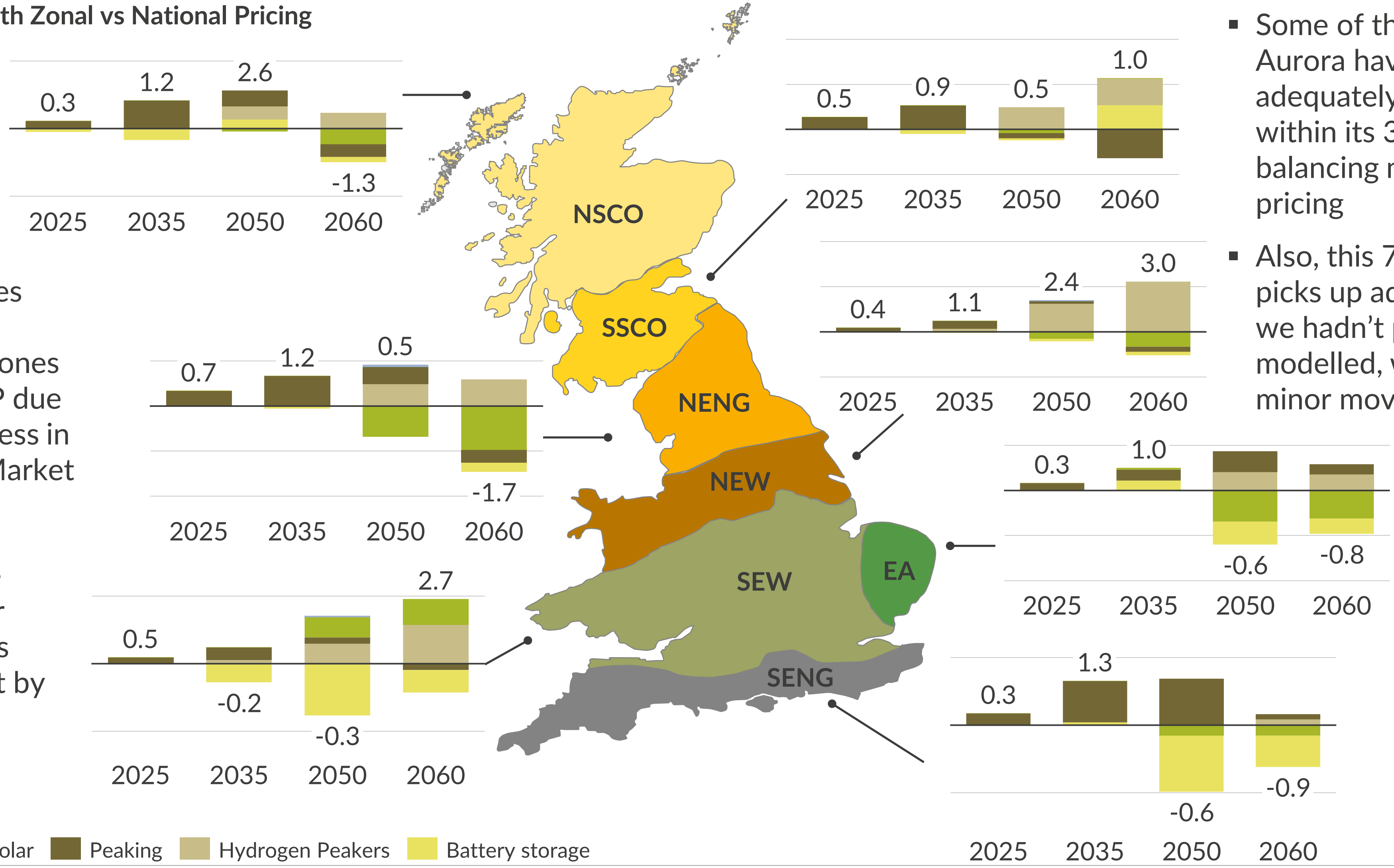
Net Zero

Net Capacity Delta with Zonal vs National Pricing
GW



- Peaking capacities grow by 28% on average across zones under zonal LMP due to greater tightness in the Wholesale Market
- Loss of arbitrage opportunities for batteries reduces battery build-out by 12% on average
- Some of this result is due to Aurora having already adequately sited generation within its 3-zone locational balancing model with National pricing
- Also, this 7-zone modelling picks up additional congestion we hadn't previously modelled, which can create minor movements

Source(s): Aurora Energy Research

Consideration of constraints between 7 zones results in reduced RES generation in low price zones and increased imports

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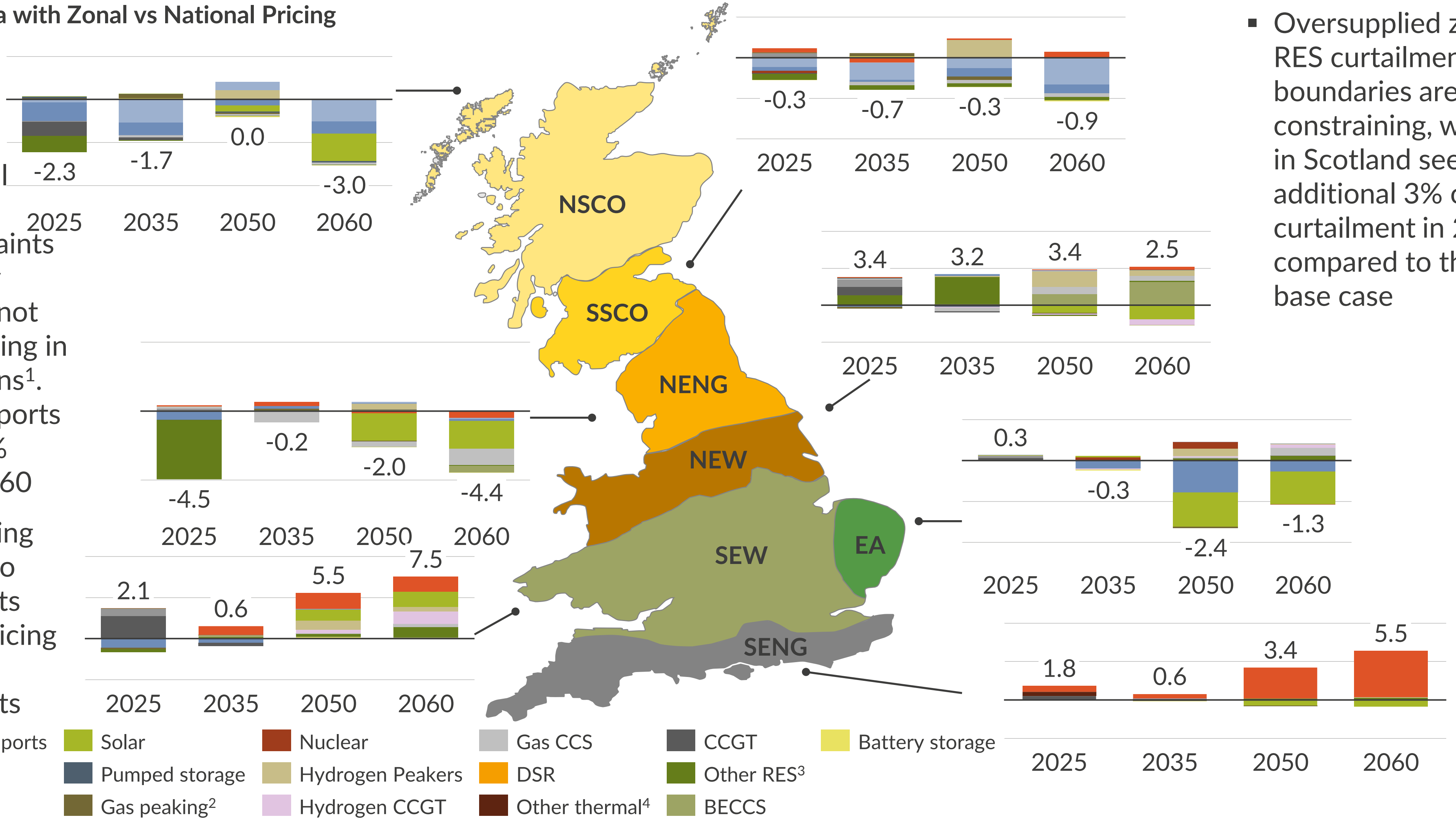
Net Zero

Net Generation Delta with Zonal vs National Pricing
TWh



- Moving to a zonal model allows interzonal constraints to be resolved by interconnectors, not previously partaking in BM System actions[1]. This drives up imports on average by 5% between 2025 – 60
- BM reform allowing interconnectors to resolve constraints under national pricing could lead to comparable results

- Oversupplied zones see RES curtailment when boundaries are constraining, with wind in Scotland seeing an additional 3% of curtailment in 2035 compared to the national base case

1) Current Schedule 7a trades are not considered in National BM system actions. 2) Gas peaking includes OCGT and reciprocating engines. 3) Other RES includes biomass, EfW, hydro, and marine: 4) Other thermal includes embedded CHP.

Source(s): Aurora Energy Research

Under Net Zero by 2035, system build keeps emissions from the different models tracking each other very closely

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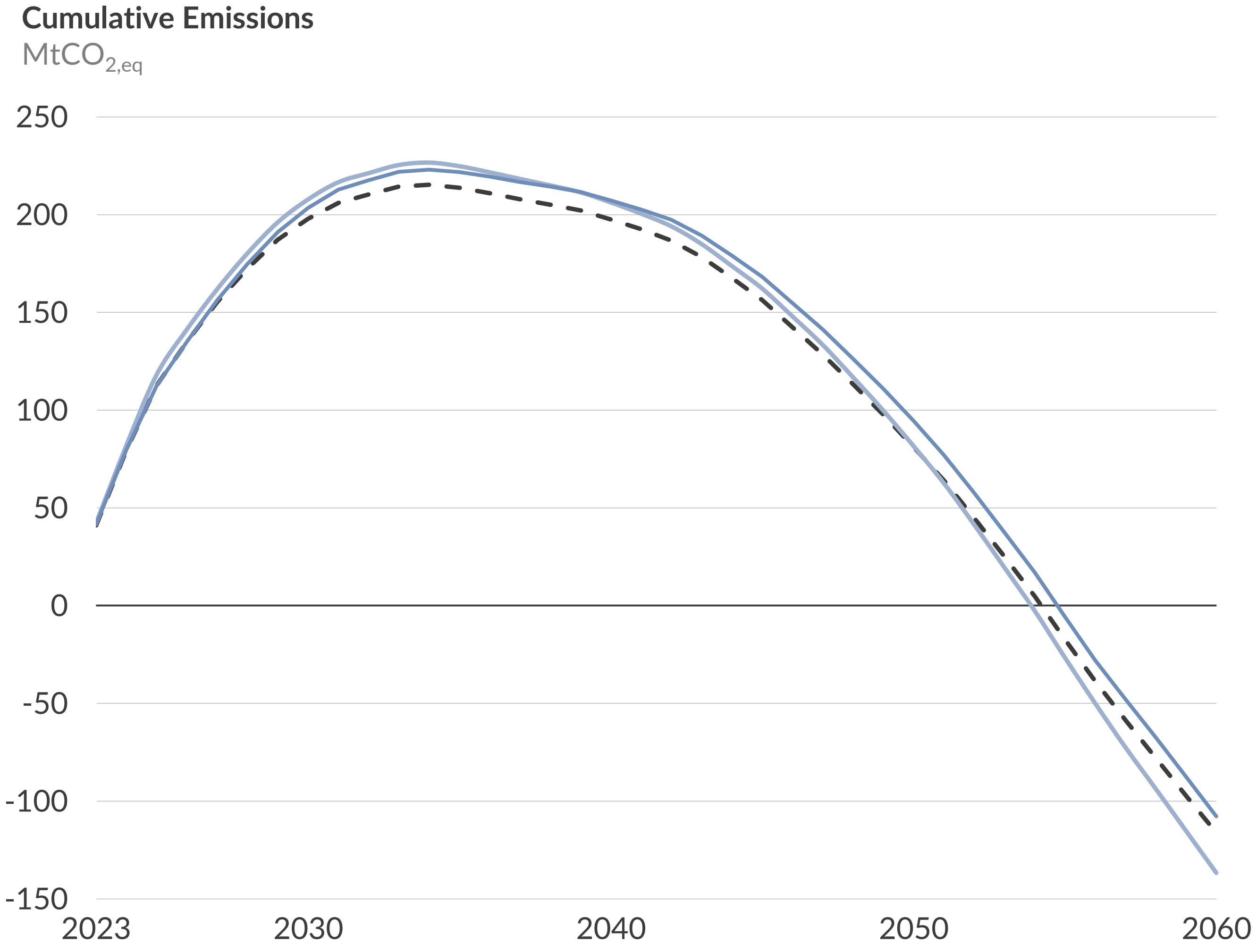
Net Zero



- Both the national and zonal models achieve net zero emissions by 2035, with parity in total emissions between the two models achieved in 2050
- Emissions in the zonal model are higher in earlier years owing to boundary constraints requiring an increased dispatch of thermal technologies in undersupplied southern zones
- As endogenous capacity responds to integrated locational signals in the Wholesale price towards the middle and end of the forecast, emissions fall faster than the national model, achieving lower emissions by 2060 both annually and cumulatively

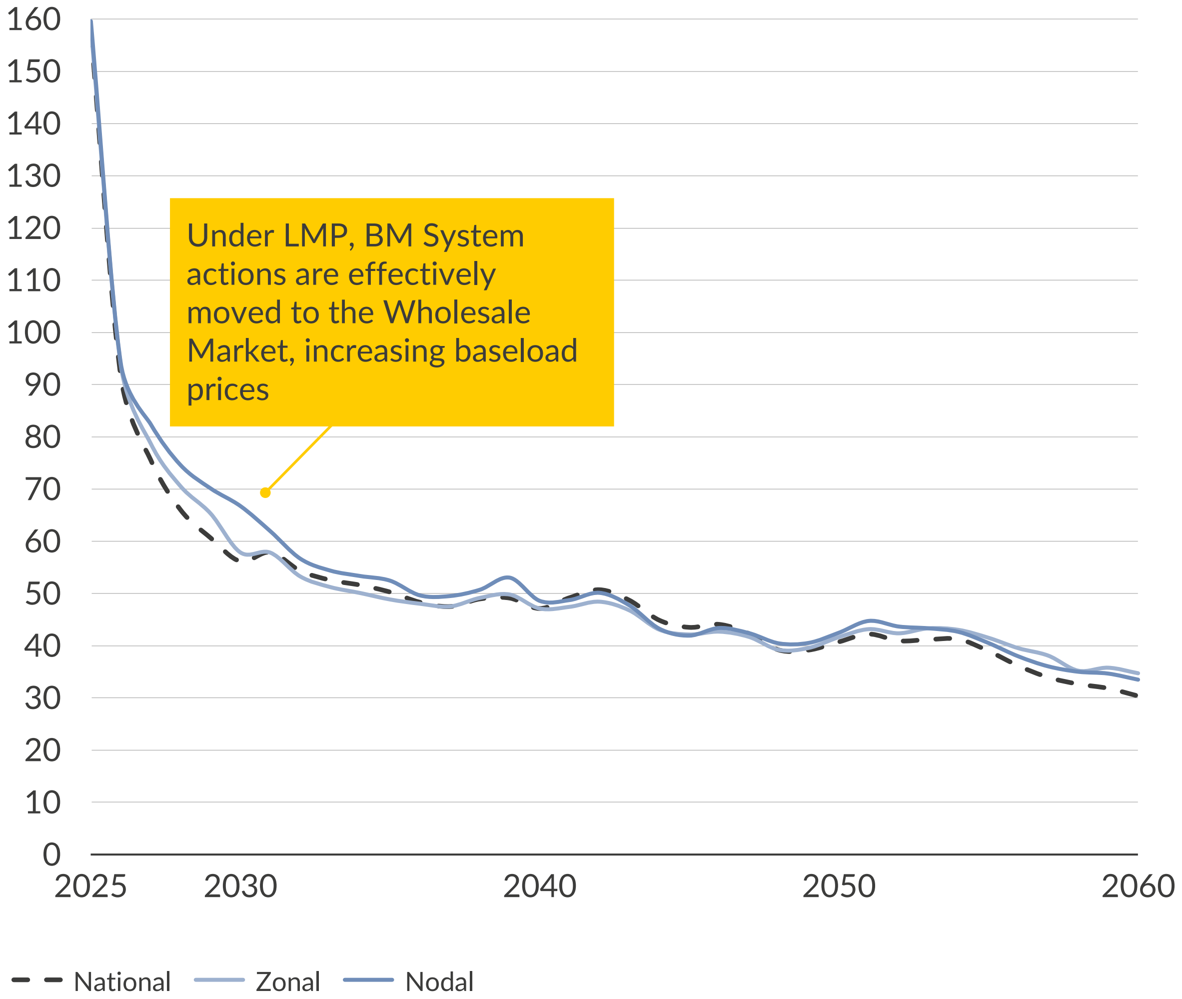
Source(s): Aurora Energy Research

LMP could marginally increase Wholesale prices, particularly in the short term, as network constraints are no longer resolved in the Balancing Mechanism

Net Zero

Baseload Wholesale Electricity Price — Demand-Weighted Average

£/MWh (real 2021)



- In theory, LMP systems ought to be more efficient overall in part because costs are redistributed into the Wholesale Market reducing potentially inefficient redispatch costs[1]
- Aurora's study finds that introducing LMP systems would have significant compositional effects—notably a transfer of value from Balancing Market redispatch due to system constraints to the Wholesale Market
- In spite of sustained grid build-out, intrazonal congestion in our nodal model inflates wholesale prices, whilst boundary upgrades in the zonal model reduce congestion to the extent that, on average, prices resemble those in the national case towards the end of the forecast

1) See for example, Hirth, Lion and Schlecht, Ingmar, Market-Based Redispatch in Zonal Electricity Markets (November 19, 2018). USAEE Working Paper No. 18-369, Available at SSRN: https://ssrn.com/abstract=3286798

Source(s): Aurora Energy Research

LMP offers potential consumer cost savings, but real outcomes hinge on WACCs, transition uncertainty, and volatility

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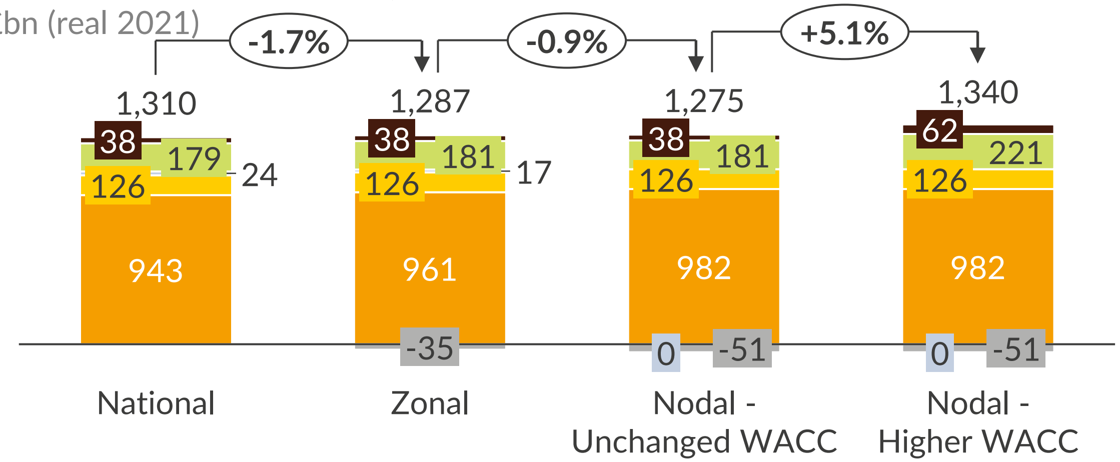
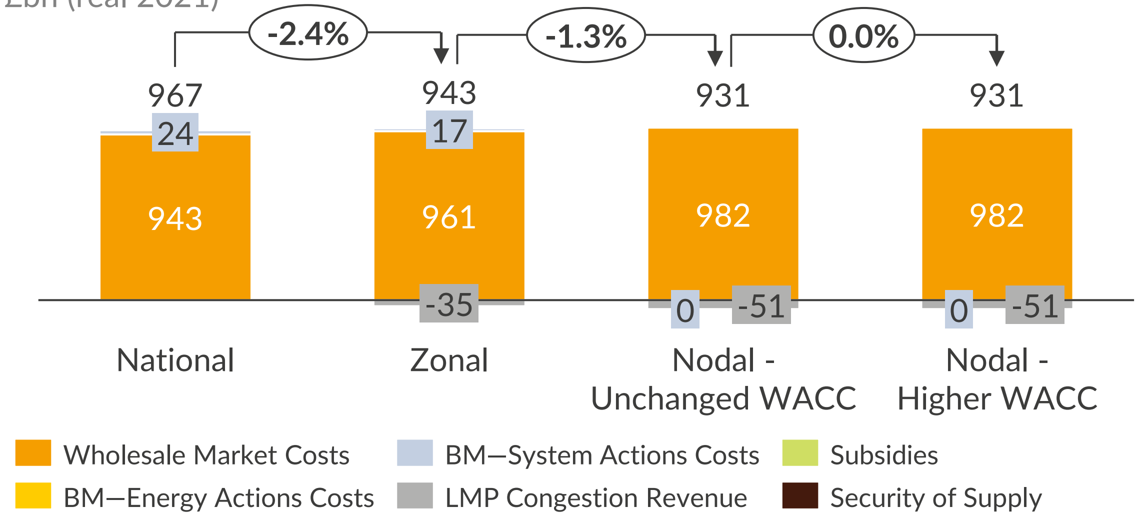
Net Zero

- Switching to **zonal LMP** in a Net Zero power system with fully planned network build-out could **reduce costs to the consumer by £23bn (1.7%)** for 2025–2060, largely due to increased dispatch cost efficiency[1]
- With **nodal LMP**, changes in consumer costs could **range from a decrease of £35bn (2.6%) to an increase of £30bn (2.5%)**, hinging on the WACC of new-build capacity
  - Our study analyses various WACCs under nodal LMP, including scenarios of unchanged WACC and a 3 percentage-point rise across the entire forecast—a probable risk particularly with nodal LMP due to its volatility
  - In both cases, cost reductions are primarily from improved dispatch cost efficiency, offset in the latter scenario by increased security of supply and subsidy costs
- These results are subject to unquantified factors, such as transition uncertainty and potential volatility, which could influence the cost of capital and investment pace over the transition, or necessitate mitigation measures like financial transmission rights

Total Cost to the Consumer[2], 2025–2060
£bn (real 2021)



Dispatch Related Costs to the Consumer, 2025–2060
£bn (real 2021)



1) Measured as Wholesale Market Costs + BM—System Action Costs + LMP Congestion Revenue. These results are sensitive to the assumption on how Congestion Revenue is eventually redistributed. 2) LMP results are likely higher than modelled due to real, unmodelled factors such as WACC increase, transition costs, congestion rent 'leakage', etc.

Source(s): Aurora Energy Research, Frontier Economics "Locational marginal pricing – implications for cost of capital" 14 October 2022

Under Net Zero, a switch to LMP by 2045 could result in decreased total system costs—sooner is only better if there is minimal impact on WACC

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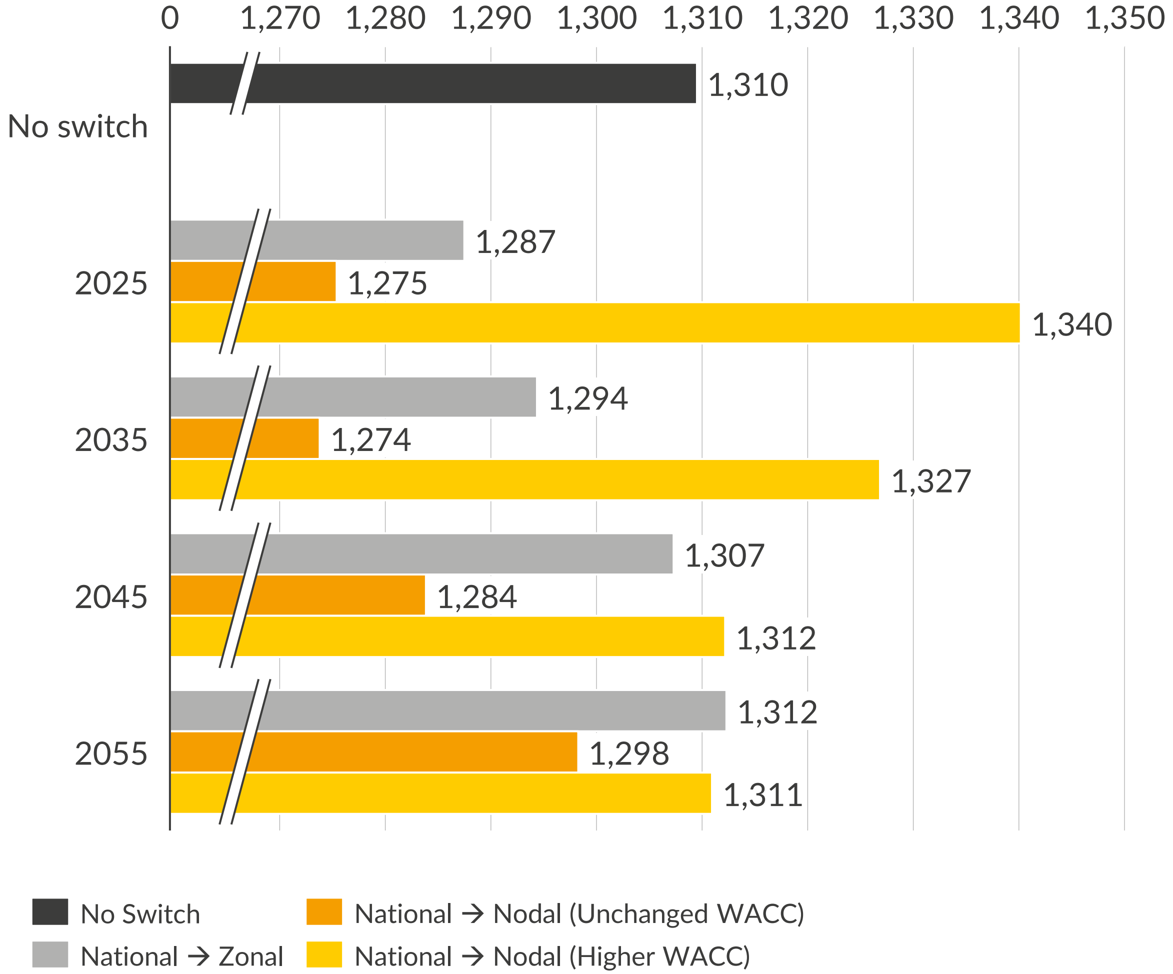
Net Zero

- We have examined the impact on total cost to the consumer by the year a switch to LMP would be implemented
  - Implementation ahead of grid build out transfers more benefit from Scottish generators to consumers
  - But, especially in a nodal system, WACC for new investment could increase which is particularly expensive for early action
- This analysis assumes a seamless transition from the current National Pricing system to LMP (i.e., no investment hiatus or policy costs to grandfather investment expectations)
  - We added our national estimation for cost to the consumer before the LMP switch year with that from LMP after the switch year
  - In reality, there is a path dependency to capacity and grid build that may change these results
- We find, LMP in a Net Zero power system with fully planned network build-out, that it is economically efficient to switch to zonal LMP by 2045 and anytime for nodal LMP *provided implementation can avoid any foreseen impact to WACC*

Total Cost to the Consumer[1], 2025–2060 (by LMP switch year)
£bn (real 2021)



1) LMP results are likely higher than modelled due to real, unmodelled factors such as WACC increase, transition costs, congestion rent 'leakage', etc.

Source(s): Aurora Energy Research

Flexible assets (gas, BESS) gain from LMP in a Net Zero scenario. Renewables would be negatively impacted due to increased curtailment cost exposure

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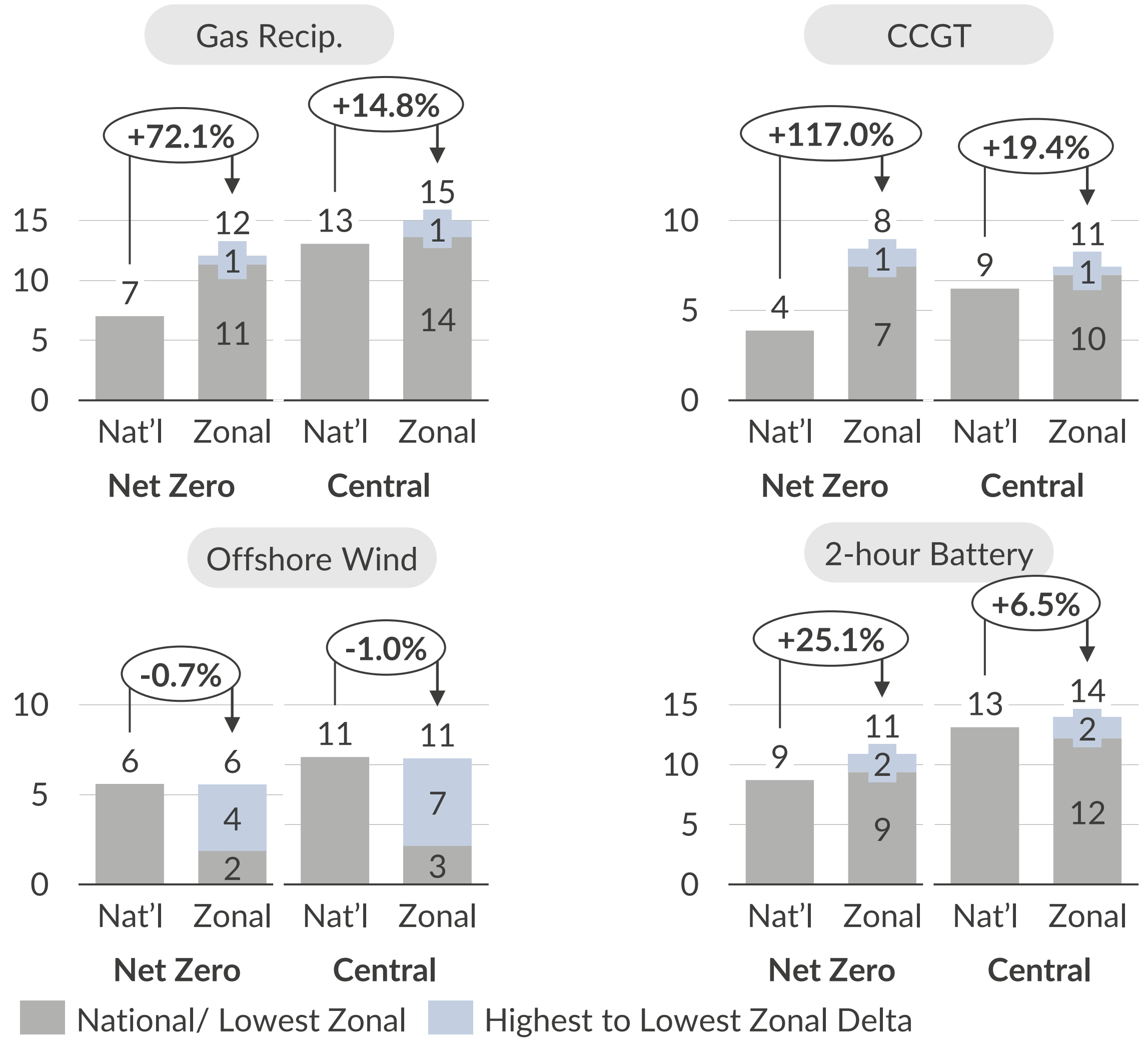
Net Zero

- Assets that have high Capacity Market de-rating factors (i.e., Gas Recips and CCGTs) are largely protected from a switch to LMP
- Battery economics are very exposed to the market scenarios, benefitting from high volatility and spreads under Net Zero, while dropping below the national gross margins in Central results where the higher Wholesale spreads are offset by a loss of arbitrage opportunities from the Balancing Mechanism
- RES assets are most differentiated across zones, negatively impacted by zonal constraints driving more curtailment of these assets. RES assets in the southern, high-demand zones (except for East Anglia) are relatively better off due to lower curtailment
- An optimal switch to LMP would be in the late 2020s or early 2030s to mitigate impact on portfolio IRRs[1]

Average IRR (2025–2030 Entry Year)
%



Note: National IRRs are a simple average of National High and Low. These IRRs are reflect merchant business case plus capacity market (i.e., notwithstanding subsidisation)

Source(s): Aurora Energy Research

The impact of LMP is highly sensitive to other system parameters, particularly…

The Pace of the Transition:

- We test slower renewable build, especially offshore wind (in Aurora Central market scenario where Net Zero by 2035 is not achieved)
- We test slower network build in our sensitivity analysis

How strongly location is fixed via planning versus having flexibility to respond to market signals:

- We test higher market-responsiveness for new demand in our sensitivity analysis on hydrogen electrolyers
- We do not test highly market-responsive new offshore wind since this requires overbuilding offshore networks to provide a market-based choice of locations in a given timeframe to an extent not feasible in the near term without major planning changes coupled with a more merchant CfD system

Source(s): Aurora Energy Research

LMP mitigates the cost to the consumer impact of delays and shortfall of network build

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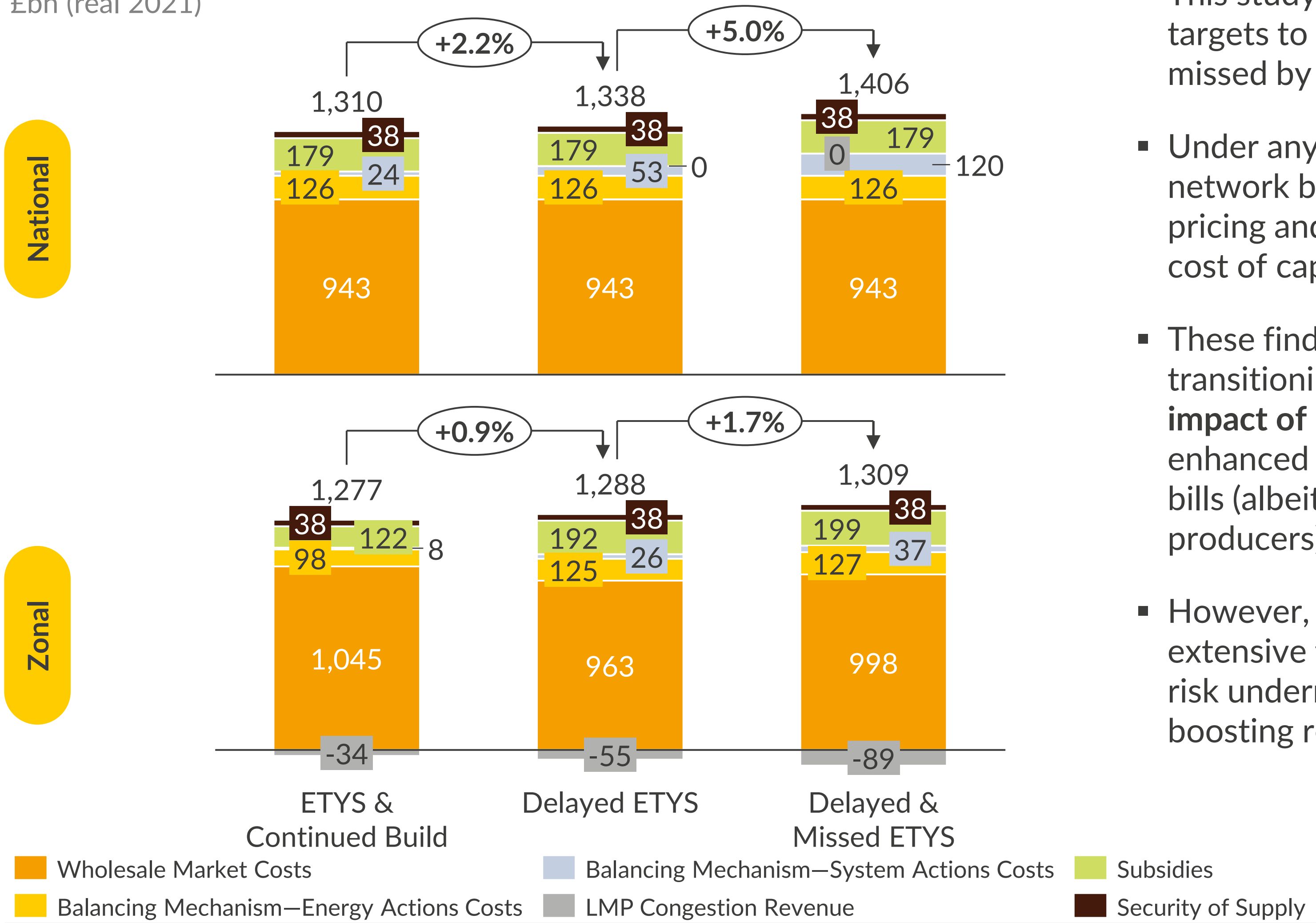
Net Zero

Total Cost to the Consumer[2], 2025–2060
£bn (real 2021)



- This study compared the impact of meeting ETYS network build targets to scenarios where ETYS is 1) delayed or 2) delayed and missed by 33%
- Under any Net Zero system, deferring or reducing expected network build raises consumer costs—£96bn (7.2%) under national pricing and £32bn (2.6%) under zonal LMP, excluding potential cost of capital impacts
- These findings underscore the need for grid build out, even when transitioning to LMP. Although, **LMP mitigates the consumer cost impact of network build delays and shortfalls**, primarily through enhanced congestion revenue which could help lower consumer bills (albeit some of this value could be transferred back to producers)[1]
- However, the study reveals no evidence that LMP can substitute extensive transmission system reinforcement. Grid build shortfalls risk undermining decarbonisation and security of supply goals by boosting renewables curtailment and imports

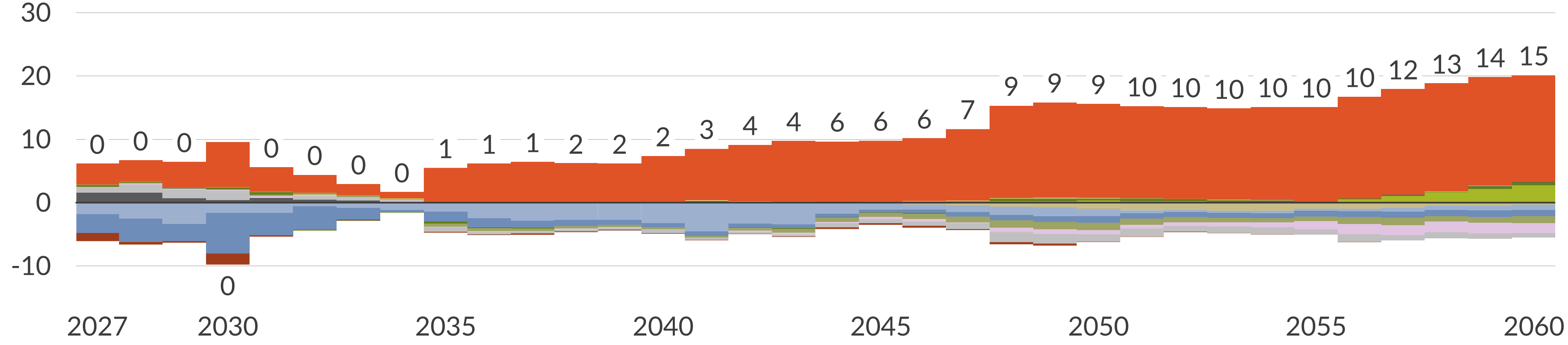
1) Congestion revenue can be redistributed in a variety of ways: paying for grid reinforcement in lieu of TNUoS, reducing environmental and policy costs that end-consumers pay, paying for Financial Transmission Rights to strategically important generation assets 2) 1) LMP results are likely higher than modelled due to real, unmodelled factors such as WACC increase, transition costs, congestion rent 'leakage', etc.
Source(s): Aurora Energy Research

However, reduced transmission capacity could lead to significant increases in RES curtailment and imports

Net Zero

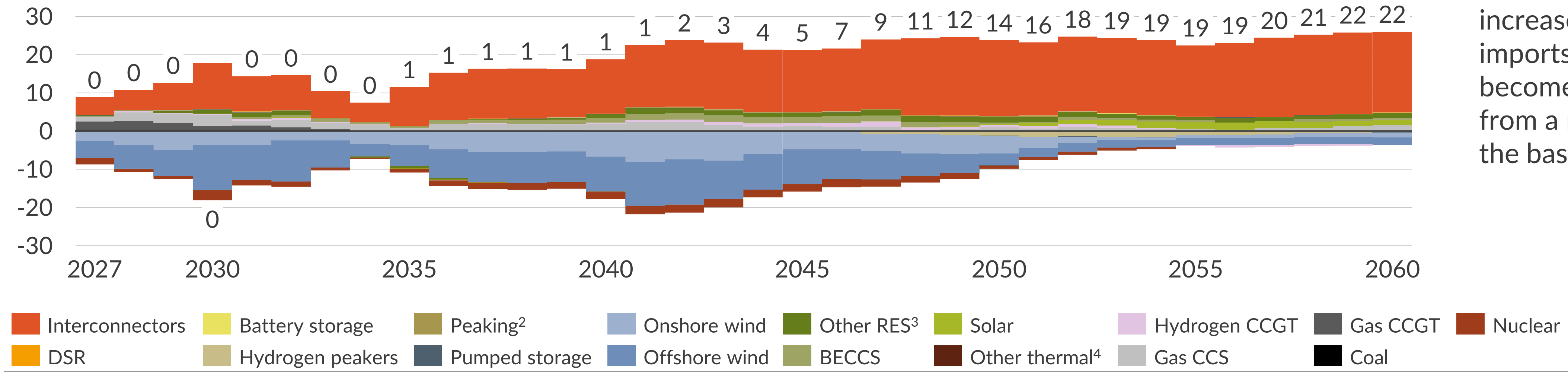
Generation Delta for Delayed ETYS vs Zonal Net Zero[1]

TWh



Generation Delta for Delayed & Missed ETYS vs Zonal Net Zero[1]

TWh



- Changes to net endogenous capacity built under the two transmission line sensitivities remain below 1% relative to the total capacity under the zonal Net Zero base case
- With more restricted capacity build in the years up to 2035, there is more curtailment of wind assets and an increased reliance on imports, moving GB to become a net importer from a net exporter in the base case

1) Generation including net interconnector flows. 2) Peaking includes OCGT and reciprocating engines. 3) Other RES includes biomass, EfW, hydro, and marine: 4) Other thermal includes embedded CHP.

Source(s): Aurora Energy Research

The system benefits of LMP vary according to other uncertainties and could also be assessed as a strategy to manage the transition

Net Zero

LMP interacts with other changes in the system with uncertain future impacts. Policymakers and investors need to make decisions within this uncertainty

- The transition to Net Zero includes many uncertainties which interact in complex ways
- Two important dimensions affecting both system designers and investors are:
  i. Uncertainty over the speed at which the network can be reinforced and expanded, including planning, build and supply chain constraints which exist even after receiving regulatory approval to invest
  ii. The uncertain impact on WACCs from exposing RES to stronger market signals, including through locational marginal pricing
- Both of these uncertainties can be partially influenced ex-ante. However, to some extent, the outcomes are not fully knowable by policy-makers in advance and decisions on LMP will need to be taken whilst still uncertain about the pace of network build and the potential changes in WACCs in a more market responsive design
- By mapping these two dimensions together we can view the net impact of zonal pricing on whole cost to the consumer depending how these uncertain outcomes crystallise in practice
- The uncertainty matrix on the right illustrates the net impact during the first decade of zonal LMP (starting in 2030). Beyond 2040, there would be additional net benefits in both low network scenarios
- This illustrates benefits to LMP in a world with limited WACC impact (even stronger under low network build), modest regrets in a low network/high WACC impact scenario and significant costs in a high network/high WACC impact scenario

Uncertainty Matrix: Net Benefit of Zonal LMP vs National Pricing by Different Scenarios, Total Cost to the Consumer, Net Zero, 2030–2040, £bn

Network build delayed? (Delayed & missed ETYS grid by 33% sensitivity) / **WACC for new RES increases?** (By 3%)	No	Yes
No	£8bn	est. £-20bn[1]
Yes	£26bn	est. £-2bn[2]

All network delay scenarios are worse for consumers (see page 19), zonal LMP helps mitigate losses versus the low network counterfactual, especially if combined with relocated demand (see page 21). LMP in lieu of full network build is is not an optimal outcome.

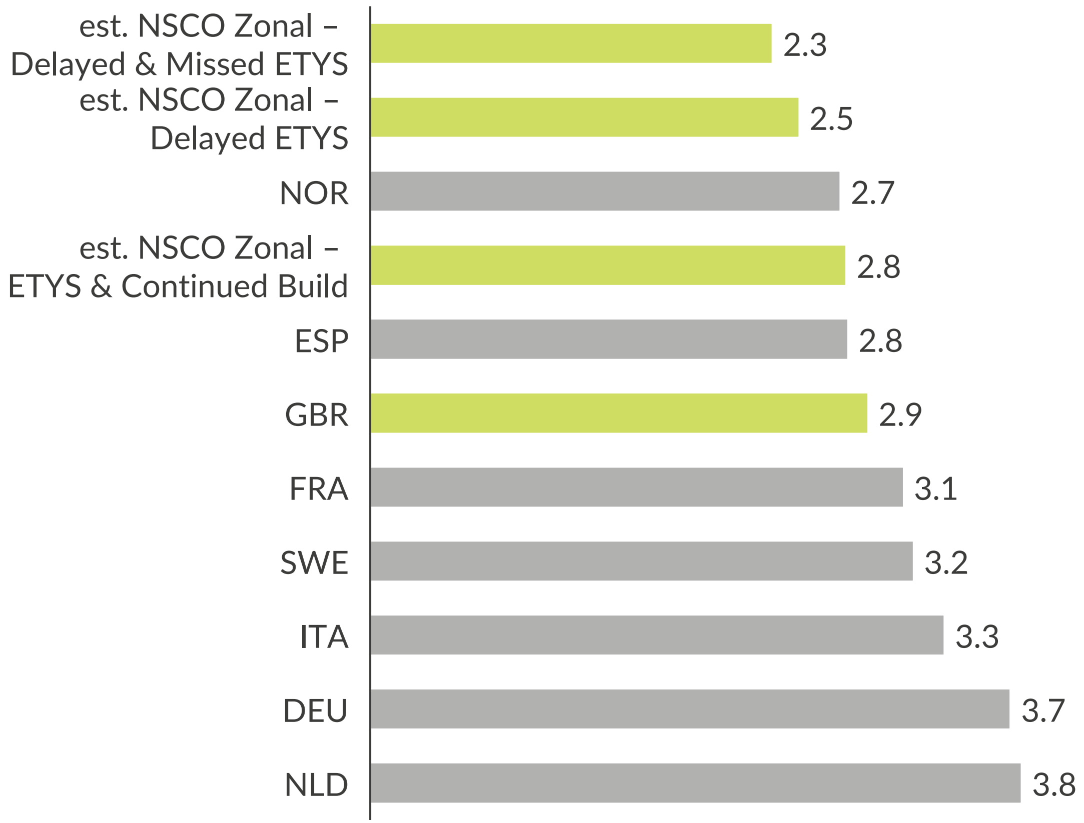
1) We examined an increase to WACCs plausible given the higher volatility in a nodal system; a more modest impact may apply to a switch to Zonal LMP. 2) The confluence of delayed network build and increased WACCs weren't explored in the study, but we would generally expect this average of both factors based on the direction of travel for their individual sensitivities.

Source(s): Aurora Energy Research

With a more constrained GB grid, LMP could position northern Scotland more competitively for hydrogen generation in Europe

Central

LCOH in 2035 for Co-Located, Grid-Connected Electrolysers, Aurora Central Scenario, National Pricing (unless otherwise stated)
EUR/kg H_2[1] (real 2022)



- Significant growth in European green hydrogen production is expected by 2035, with increased trade and locational flexibility
- Rising hydrogen electrolyser demand across the 2030s could be met with low-cost production in northern Scotland, where persistent boundary congestion results in low electricity prices
- Under LMP and/or mechanisms[2], especially in scenarios with network underbuild, the **low wholesale electricity costs in northern Scotland could cut the levelized cost of hydrogen (LCOH) 3–20%**
- Europe's most competitive hydrogen production locations. While unlikely to influence early investments (which will likely be made close to demand), it could be a strategic consideration for significant European hydrogen trade
- However, to reap these benefits, hydrogen production would need to shift to these areas and the substantial transport costs, not considered in this analysis would need to be addressed

1) Comparison provides sizing estimate only, achieved LCOH by country will differ based on the business case. Zonal LCOH assumed a grid connected asset rather than island set-up. In estimation, we have applied differences in modelled Net Zero scenarios to Central scenario results for comparability (Central was used due to data availability). 2) Balancing Mechanism reform for instance
Source(s): Aurora Energy Research

We don't rule out that sharper locational signals could be delivered through alternative mechanisms such as reformed TNUoS

AURORA

Net Zero

Change to Wider TNUoS Tariff to Have Comparable Locational Signal as Zonal LMP, 2025–2060 average[1,2], £/kW/year

Aurora LMP Zone	Current TNUoS Zone	CCGT (CC)	CCGT w/ CCS (CLC)	Offshore Wind (Int.)	Onshore Wind (Int.)	Solar PV (Int.)	Gas Recip. (CC)	H_2 Peaker (CLC)	1-hour Battery (CC)	2-hour Battery (CC)	4-hour Battery (CC)
NSCO	1–7	-17.2	-38.7	-40.7	11.5	-32.0	-22.6	-61.6	-16.7	-31.8	-33.3
SSCO	8–11	-10.4	-16.4	16.1	14.1	-11.2	-17.2	-37.5	-11.3	-19.0	-19.6
NENG	12–15	-6.8	0.1	17.9	41.2	5.9	-15.7	-21.5	-8.3	-11.9	-12.8
NEW	15–17, 19	-7.9	2.2	12.7	41.8	10.1	-16.4	-18.8	-10.3	-11.2	-12.1
SEW	18–23	2.4	16.2	30.9	30.9	19.5	-6.1	-4.0	-0.0	-1.1	-2.0
EA	18	-19.5	10.1	42.8	57.4	8.8	-25.5	-11.2	-19.2	-23.8	-24.6
SENG	24–27	9.3	12.4	10.0	12.9	7.0	0.7	-5.2	6.8	5.0	5.3

Decreased tariff | Decreased tariff but still a cost | Increased tariff | Increased tariff but still a benefit

- **Changes to TNUoS could provide much of the same locational investment incentive** to generation and demand as LMP—though more simply and less costly than LMP implementation
- Albeit a similar dispatch signal would not be delivered except for the fact that assets are incentivised to site closer to demand
- Aurora has calculated the average level Wider TNUoS tariffs would need to be to reflect the economic outcomes for assets under zonal LMP—suggesting the optimal economic, locational incentivisation on the system
- **Most technologies except renewables, would face reduced Wider Tariffs** across most regions in order to achieve a comparable impact from LMP under Net Zero
- In practice, **this would require completely changing TNUoS** from simply recovering transmission network costs to sending a deliberate LMP-like investment signal

1) In this instance, negative change in TNUoS represents a reduced cost (possibly even becoming a benefit: solid green), whereas a positive change in TNUoS represents an increased cost (but could still be a benefit: shaded red). 2) CCGT, Recip, and Batteries are classed as Conventional Carbon generators; CCGT + CCS and H_2 Peaker as Conventional Low Carbon; and Offshore Wind, Onshore Wind and Solar PV as Intermittent per TNUoS calculations. See the XI. Appendix | Aurora's Modelling Assumptions – Wider TNUoS Tariffs for Aurora's assumptions on TNUoS, Source(s): Aurora Energy Research, NGESO

Agenda

This multi-client study aims to understand how GB electricity markets would look under locational marginal pricing (LMP)

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The UK Government's **Review of Energy Market Arrangements (REMA)** consultation, published 18th July 2022, included an option to introduce location-based Wholesale electricity prices to incentivise power assets to deploy closer to electricity demand and reduce network costs associated with sub-optimal locations of assets.[1]

Responses to the REMA consultation highlight industry interest with consideration required for:

- **Cost-benefit analysis of nodal and zonal pricing mechanisms**
- How locational pricing works in transmitting investment signals as opposed to operational signals
- **Responsiveness of different technologies to locational signals**
- Implementation time for a new market design
- Implications of **demand exposure to locational signal** and potential consumer impact
- How locational pricing **may induce a transfer of economic welfare from producers to consumers**
- Alternative means of addressing congestion, such as
  - **Reform of Transmission Network Use of System (TNUoS) charges to send improved locational signals**
  - **Accelerating build-out of transmission infrastructure** and the relative value for money of such an investment and the implementation of a centralised dispatch system

Dimensions explored in this study

Nodal pricing

Market clearing prices and dispatch settled at each node

Nodes = Some segment of GB's transmission substations

Expected benefits:

Location-specific signal for siting additional supply and demand

Allows for specific costing of congestion across transmission lines

Expected challenges:

Nodal volatility driving inefficient investment signals

Zonal pricing

Market clearing prices and dispatch settle at defined market zones

Zones = some combination of GB's nodes

Expected benefits:

Likely results in larger pooling of supply and demand, resulting in more competitive mini-markets

Expected challenges:

Consumers may face varying power prices depending on their location, driving regional divides

1) Linked to this option was also a reform to move from marginal pricing to pay-as-bid pricing, a reform to separate markets for intermittent and firm, to reduce price volatility and cannibalisation, and other reforms to change the design of the Balancing Mechanism, settlement periods and gate closure. All of which are not the focus of this study.

Source(s): Aurora Energy Research, National Grid ESO, BEIS (Now DESNZ)

Locational pricing components include incremental costs not otherwise captured in national Wholesale prices

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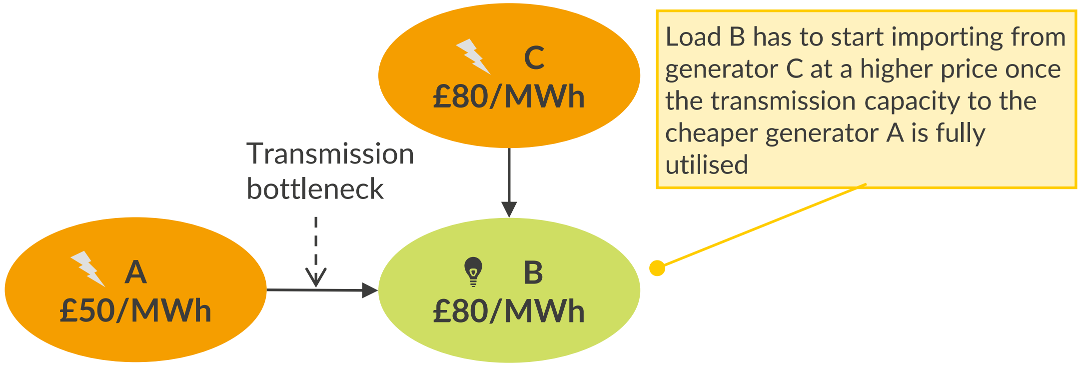
Components of Locational Pricing:

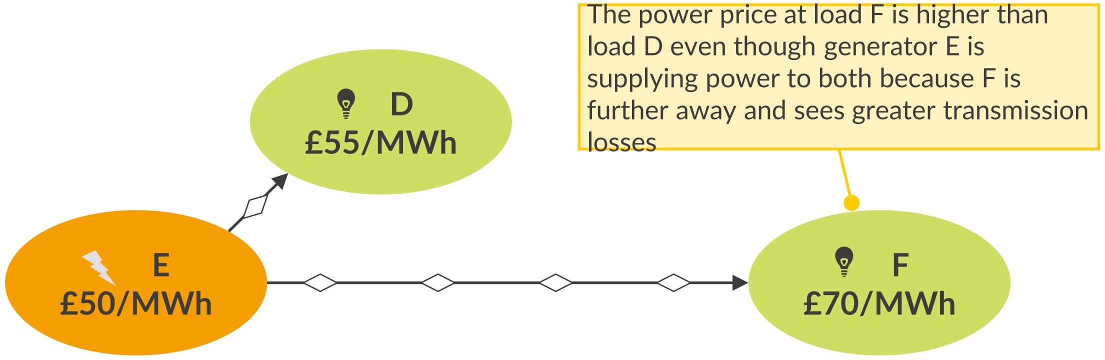
Present in the current national system

Locational Price = Marginal cost of generation + Uplift + (A) Marginal cost of transmission congestion + (B) Marginal cost of transmission losses[1]

A Cost of providing an additional unit of energy at a particular location after accounting for grid constraints is factored in

B Transmission losses are factored into the cost of electricity at a particular location





- Generation behind constraints receives a lower price than generation ahead of constraints
- Encourages new generation (and potentially demand) to locate in areas that minimise transmission losses

- Demand separated from generation by grid constraints pays more to reflect the cost of more expensive generation closer to the demand
- Encourages new investments to select locations that reduce grid congestion, significantly reducing the need for system actions

Generator Load Flow of power Losses

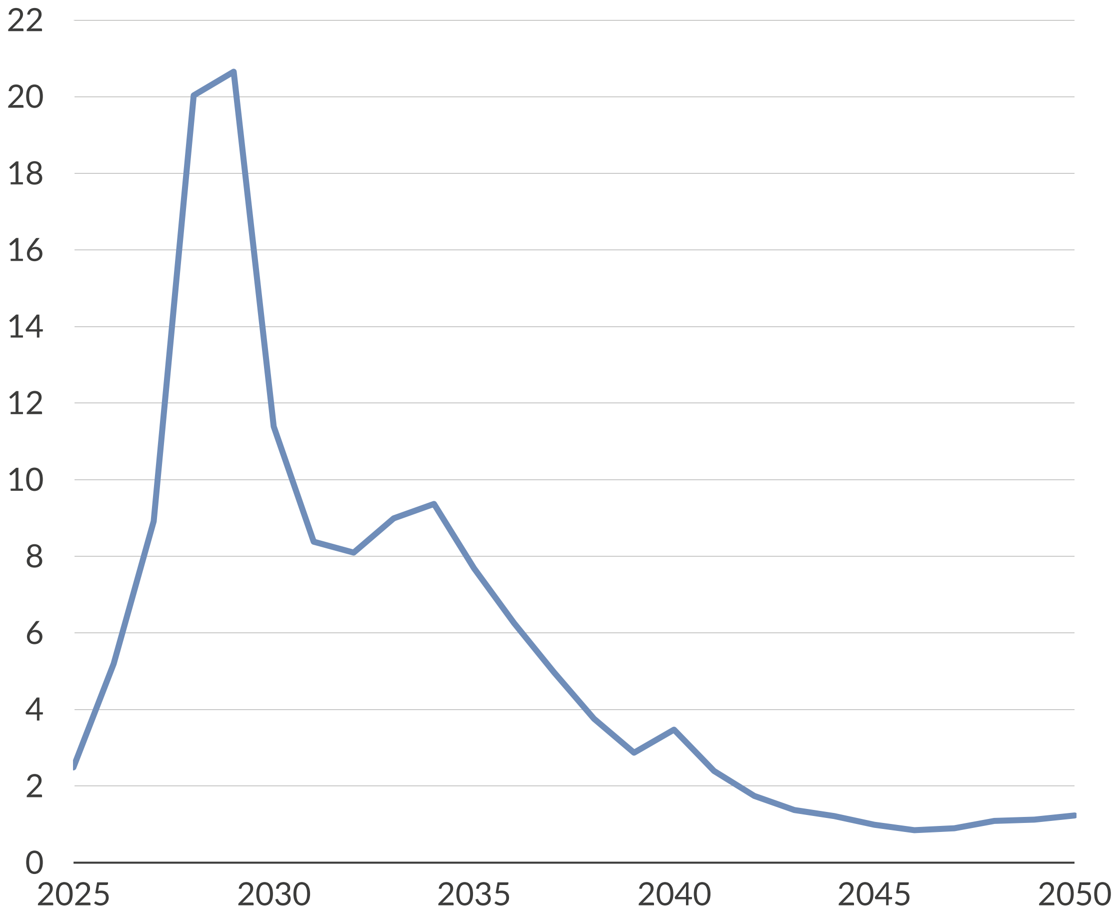
1) Aurora's models do not consider transmission losses explicitly; we apply an inflation to demand to account for average losses on the system.

Source(s): Aurora Energy Research, National Grid, Elexon

In a theoretical world, LMP incentivises the optimal placement of generation near high-demand centres, reducing system curtailment

Curtailment of RES Assets, National Pricing—Aurora Central

TWh



LMP Theoretical Benefit to Decarbonisation

LMP in theory enables the efficient siting of generation assets on the system by effectively enveloping TNUoS, TLM, Wholesale Market, Balancing Mechanism (i.e., system actions due to locational constraints) into a single, adequate market signal.

- Drastically higher deployment of low-carbon and supporting technologies will be required to achieve the country’s Net Zero Power by 2035 target. Further, these technologies will need to be enabled to operate in a manner that leads to lower emissions on the system.
- What is being currently observed, and is projected to grow considerably into the future, is low-carbon generation assets being sited far from high-demand centres. Without a corresponding level of transmission capability and/or storage, these low-carbon resources will grow increasingly underutilised—leading to inefficient spending of scarce capital and subsidisation.
- The current system uses Transmission Use of System Charges (TNUoS) and Transmission Loss Multipliers (TLM) to encourage siting assets near demand centres, aiming to lower transmission costs and improve asset utilisation.
- In theory, LMP could envelop TNUoS, TLM, Wholesale Market and the locational re-balancing through the Balancing Mechanism into a single, efficient market signal that incentivises the efficient siting of generation as well as new demand, storage and transmission investment.

Source(s): Aurora Energy Research

For LMP to be successful, it should reduce overbuild and deliver lower system cost

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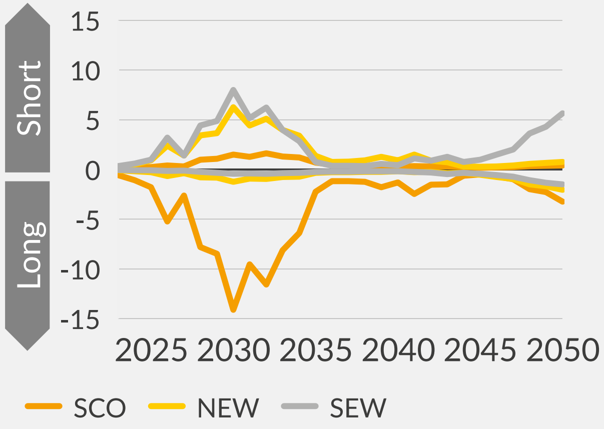
LMP Theoretical Benefit to Affordability

LMP in theory would effectively eliminate the need for two-stage market settlement (except for intrazonal congestion under zonal LMP), leading to lower overall costs for consumers.

- The GB electricity system is solved in a two-stage process. The first stage is the fairly transparent Wholesale Market that ignores the physics of the electricity grid, allowing for all generators to bid to meet the aggregated supply on the system. The second stage, among other functions, involves the grid operator accounting for previously ignored physics through the less transparent, less free-market Balancing Mechanism.
- As more and more generators are sited further away from demand centres—and there isn't enough transmission capability nor storage to deliver this power—an increasing amount of the electricity delivered will be finally settled through the Balancing Mechanism; which presents an additional level of costs that will be borne by end-consumers.

Volume of BM System Actions due to locational constraints
TWh

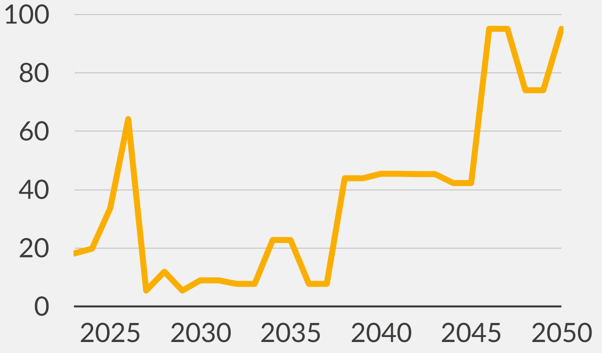


LMP Theoretical Benefit to Security of Supply

LMP in theory would give network developers and power and storage developers sharper signals to build in a manner to reduce constraints on the GB network. This would in turn reduce the overbuild on the system and reduce the Capacity Market costs.

- Locational signals ensure flexible generation is sited near high and peak demand centres, thus delivering a system less constrained by transmission congestion on the grid. With more efficient placement, the overbuild requirements across the country are diminished and there is an expectation that costs of maintaining GB Security of Supply are reduced.

Capacity Market price forecast
£/kW



Source(s): Aurora Energy Research

Critics argue that the theoretical benefits may be overstated once real-world siting constraints and costs are considered

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Effectiveness of LMP is measured in its ability to transmit differentiated locational signals to market participants while reducing the overall cost to the consumer

There are several factors that might limit the effectiveness of LMP signals

- Offshore wind farms may not always be situated near demand or unconstrained grid connections due to The Crown Estate and Crown Estate Scotland seabed leasing, which consider a range of factors including other seabed uses and grid connection availability
- There are certain locational aspects from a resource and workforce availability perspective which provide a strong incentive for siting
- Hedging mechanisms and financial transmission rights (FTRs) allow generators to protect themselves from loss of revenue driven by congestion on the grid
- Grandfathering CfD and CM contracts may shield asset operators from the desired locational signal

LMP might contribute to higher costs and missing Net Zero by 2035

- The energy cost on the system is supplemented by additional risks and costs that can be difficult to quantify beforehand (particularly for nodal LMP): Increase to cost of capital due to increased volatility and uncertainty, central dispatch management costs, realistic start date of LMP implementation which may reduces its impact for near-term goals, and other transition costs
- The path towards decarbonisation by 2035 depends on continued investment into low-carbon generation. Stalling on project investments due to market uncertainty or a vacuum on financial and legal services for managing the transition to LMP may lead to this target being missed

Source(s): Aurora Energy Research

Locational Marginal Pricing can raise the cost of capital due to increased risks and revenue unpredictability

Considering the probable cost of capital increase, particularly under nodal LMP as evidenced by Frontier Economics, Aurora has analysed the cost to the consumer of a 3 percentage-point increase in WACC under Net Zero. The results of this scenario can be found in VI. Cost to the Consumer | Impact of Cost of Capital Increase

Revenue Volatility: The introduction of LMP can lead to more unpredictable revenues for electricity generators. This happens where prices in an LMP system change significantly based on supply and demand conditions at different locations and times. This unpredictability can make investments seem riskier, which could lead to a higher cost of capital. It is more likely in small, illiquid zones or in a nodal system.

No Compensation for Curtailment: In an LMP system, generators might not get paid when they're curtailed due to transmission constraints. This lack of compensation can increase risk for investors, leading to a higher required return on investment

Network Development Risks: The earnings of generators can be significantly influenced by the pace of network and local load development. Any delays or unexpected changes can impact returns, adding another layer of risk for investors

Transition Period Uncertainty: The process of transitioning to an LMP system can create a period of uncertainty, which can increase the risk for investors, leading to a higher cost of capital (or policy costs to grandfather prior investment cases)

Evidence from Other Markets: Experiences from other markets (i.e., LMP transition in Australia) that have explored transitioning to LMP suggest that such a transition can lead to an increase in the cost of capital. This is often due to increased revenue volatility

Source(s): Frontier Economics "Assessing Locational Marginal Pricing in GB" October 14 October 2022. Frontier Economics "Locational marginal pricing – implications for cost of capital" 14 October 2022

Agenda

Aurora's national GB model uses an iterative process to reach an optimal market solution based on the specified scenario inputs

AURORA

Nat'l / Zonal Models

4 Integrated Models

Hydrogen (AER-HY)

Carbon (AER-ETS)

Power markets (AER-ES)

Global Commodities & Gas (AER-GLO/GAS)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows based on price differences between regions[2]

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model. 2) Other regions that have interconnectors to GB are modelled to determine relative price differences between regions and therefore interconnector flows. These additional regions are modelled with capacities fixed exogenously based on the latest Aurora forecast results for the region.

Source(s): Aurora Energy Research

The nodal model uses three key input categories that drive nodal outcomes

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Nodal Model

Key Network modelling input parameters

Network

i. Network changes
ii. Transmission constraints
iii. Interconnectors

Load flow

Load

i. Residential, commercial and industrial demand
ii. Demand Side Response
iii. Electrolyser demand

Generation

i. Thermal assets
ii. Renewables buildout
iii. Battery storage
iv. Flexible technologies

Source(s): Aurora Energy Research

Aurora's nodal model required the development of a GB Network Model to produce nodal price forecasts and congestion analysis

AURORA

Nodal Model

Step 1: Model the Wholesale and ancillary markets

Step 2: Model the network flows

Wholesale Market assumptions
- Technology, commodity, demand, policy assumptions etc.

GB Power Market Model
- Simultaneously models Wholesale and ancillary service markets
  - Half-hourly granularity
  - Iterative modelling
- Capacity build / exit / mothballing
  - IRR / NPV driven
- Detailed technology assessments

Continuous iteration until an equilibrium is reached

Market level outputs
- Total load
- Generation mix and economic capacity expansion – IRR / NPV driven endogenous build-out is taken from our GB Power Market Model
- Economic plant retirements

GB Network Model
- Clears least cost dispatch under transmission constraints

Network level outputs
- Asset level generation
- Nodal price outcomes
- Transmission line flows
- Congestion revenue

Input parameters

Network
- NGESO 2022 Electricity Ten Year Statement (ETYS) Network
- NGESO 2022 ETYS transmission line upgrades
- Future network build-out based on NGESO ETYS until 2031
- Beyond ETYS network build-out is iterated upon using network model congestion revenue based algorithm

Generation
- Locational generator placement based on CM & CfD results, Aurora's expected build-out and National Grid Future Energy Scenarios
- Interconnector flows based on GB Market Level Model outputs

Load
- Aurora GB demand forecast distributed across nodes using Elexon GSP flows and embedded generation

In-house model | Input | Output

Source(s): Aurora Energy Research, National Grid ESO

Available publications and registers guide the distribution of national capacity across zonal and nodal models

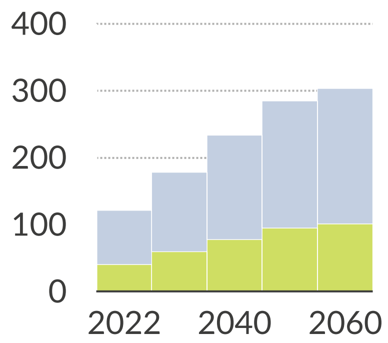
AURORA

Capacity is allocated across Aurora's nodal model and attributed to nodes mapped from NG ESO ETYS publications on an iterative basis using publicly-available registers of GB capacity distribution supplemented by Aurora's own assumptions.

1 Aurora capacity as of October 2022 is allocated across GB nodes

- Nodal locations of subsidised assets are taken from the subsidy registers[1,2]
- Location of non-subsidy existing and future transmission capacity is supplemented from the TEC Register[3]
- Remaining capacity is split according to FES Leading the Way (LtW) proportions
- Zonal capacities are aggregated within zones based on the nodal distribution within the zone

2 Modelling



- Exogenous capacity [4] is brought onto the nodes for technology classes supported by policy and the TEC register
- Endogenous capacity is allowed to build within any zone based on perceived merchant economics at the node and constrained by build limits

3 Output

- Total capacity changes across the time horizon based on the optimal model solve, with endogenous capacity built according to the NPV of each technology and the capacity caps in place at each node
- Nodal and zonal capacities will reflect initial proportions, adjusted according to exogenously determined build and any endogenous capacity

1) Subsidy registers include the LCCC CfD Register and Capacity Market Register. 2) This approach reinforces some elements of current siting logic. 3) NG ESO Transmission Entry Capacity (TEC) Register contains a list of projects that hold contracts for TEC. This includes existing and future connection projects directly connected to the National Electricity Transmission System (NETS), or make use of it. 4) Representative capacity only.

Source(s): Aurora Energy Research,

In our modelling, onshore renewables, peaking plants and storage may build endogenously based on modelled plant economics

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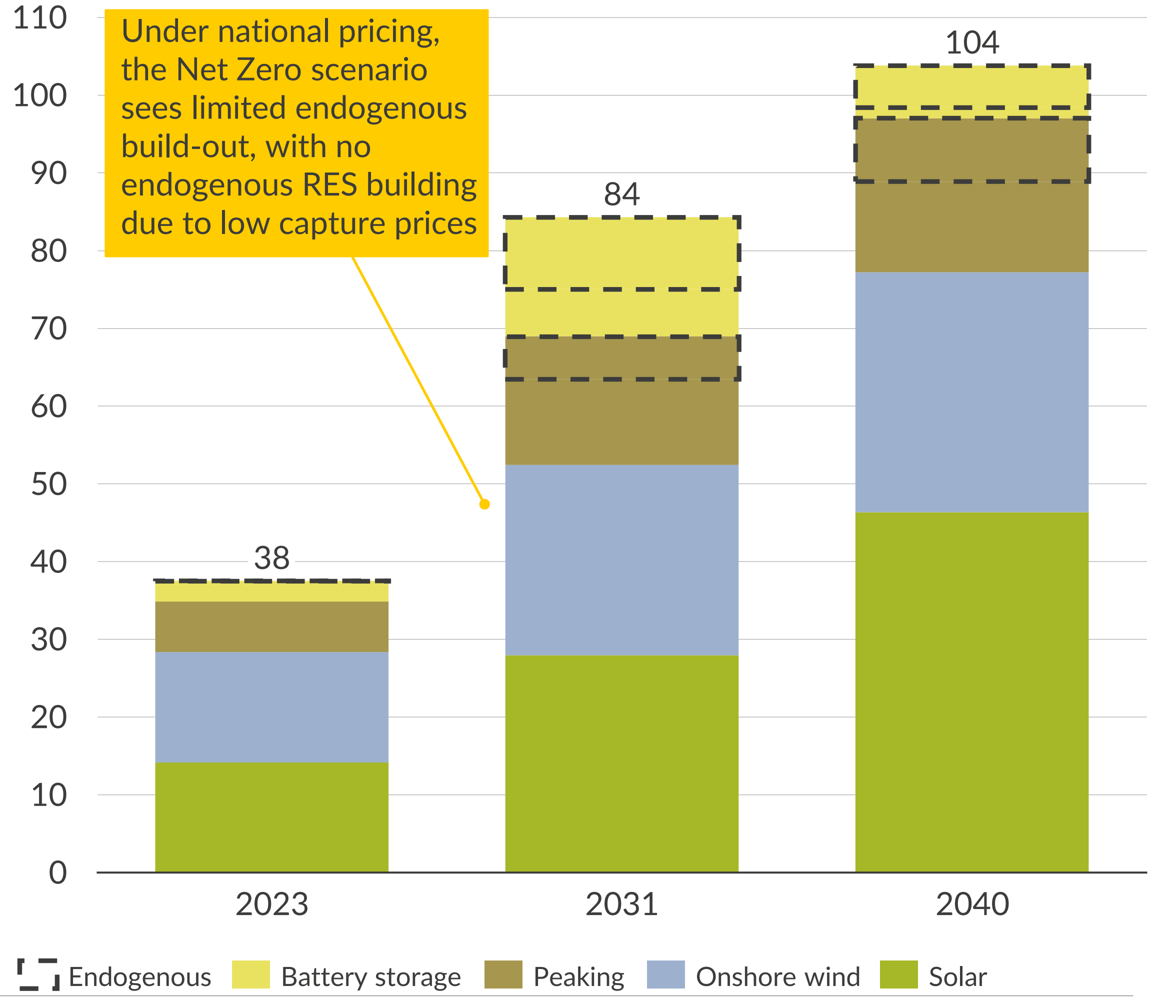
	Technology class	Relevant support schemes	Build type – Aurora LMP Models: Exogenous	Build type – Aurora LMP Models: Endogenous
Conventional	Nuclear	Contracts for Difference (CfD)	✓	
Conventional	CCGTs	Capacity Market (CM)	✓	
Conventional	Emerging technologies	Hydrogen price support, DPA[4]	✓	
Renewables	Biomass and other renewables	CfD, Renewables Obligation (RO)	✓	
Renewables	Offshore wind	CfD, RO	✓	
Renewables	Onshore wind	CM, CfD, RO	✓	✓
Renewables	Solar PV	CM, CfD, RO	✓	✓
Flexible	Peaking plants	CM	✓	✓
Flexible	Storage	CM	✓	✓
Flexible	Interconnectors	CM	✓	

Installed Net Zero[1] Exogenous and Endogenous[2] Capacity
GW

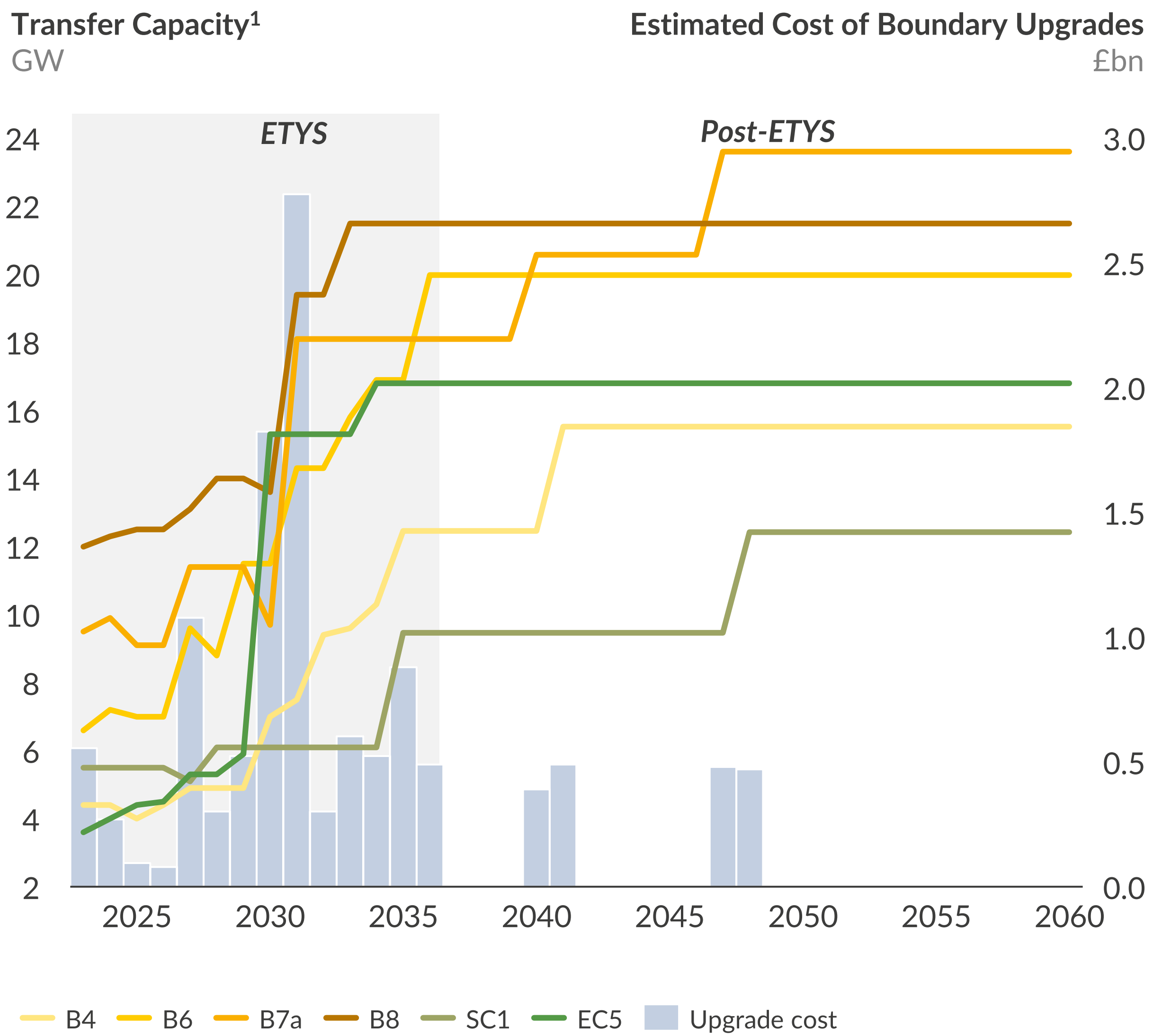


1) Net Zero has a higher proportion of exogenously defined capacity than that in the Central scenario. This is driven by the policy commitments required to ensure commitment to Net Zero. 2) Only merchant assets build endogenously within the model.

Source(s): Aurora Energy Research

Build-out of the zonal transmission network is completed using a cost-based methodology following implementation of ETYS upgrades

Zonal Pricing



Our zonal model uses a congestion-weighted approach to upgrade boundaries post-ETYS

- The base assumption for the forecast is that all upgrades committed to under ETYS are implemented according to the anticipated timelines
- Beyond the completion of ETYS boundary upgrades, we assume a level of maintained momentum in grid build and so include further upgrades
- The zonal model upgrade methodology assumes a fixed price per MW of transmission boundary upgrade[2]
- Boundaries are upgraded based on their contribution to congestion revenue, which is calculated as:

Congestion revenue = Price delta between zones × Power flow across zonal boundaries

- The available budget for boundary upgrades in a given year is set by the total congestion revenue across all boundaries in the previous year[3]
- In order to be upgraded, a boundary's congestion revenue must exceed a minimum threshold, reflecting more realistic upgrade decisions

1) In the Aurora Net Zero zonal scenario. 2) The nodal model uses an algorithmic approach, based on a comparable concept, but is able to alter the cost and size of upgrades dependent on the line voltage. 3) This is a simplification used for modelling purposes as in reality investment decisions are likely to be made and start earlier in the timeframe, although would be based on forecast budget availability.

Source(s): Aurora Energy Research

Our nodal model uses a congestion-cost weighted approach to upgrade lines post-ETYS

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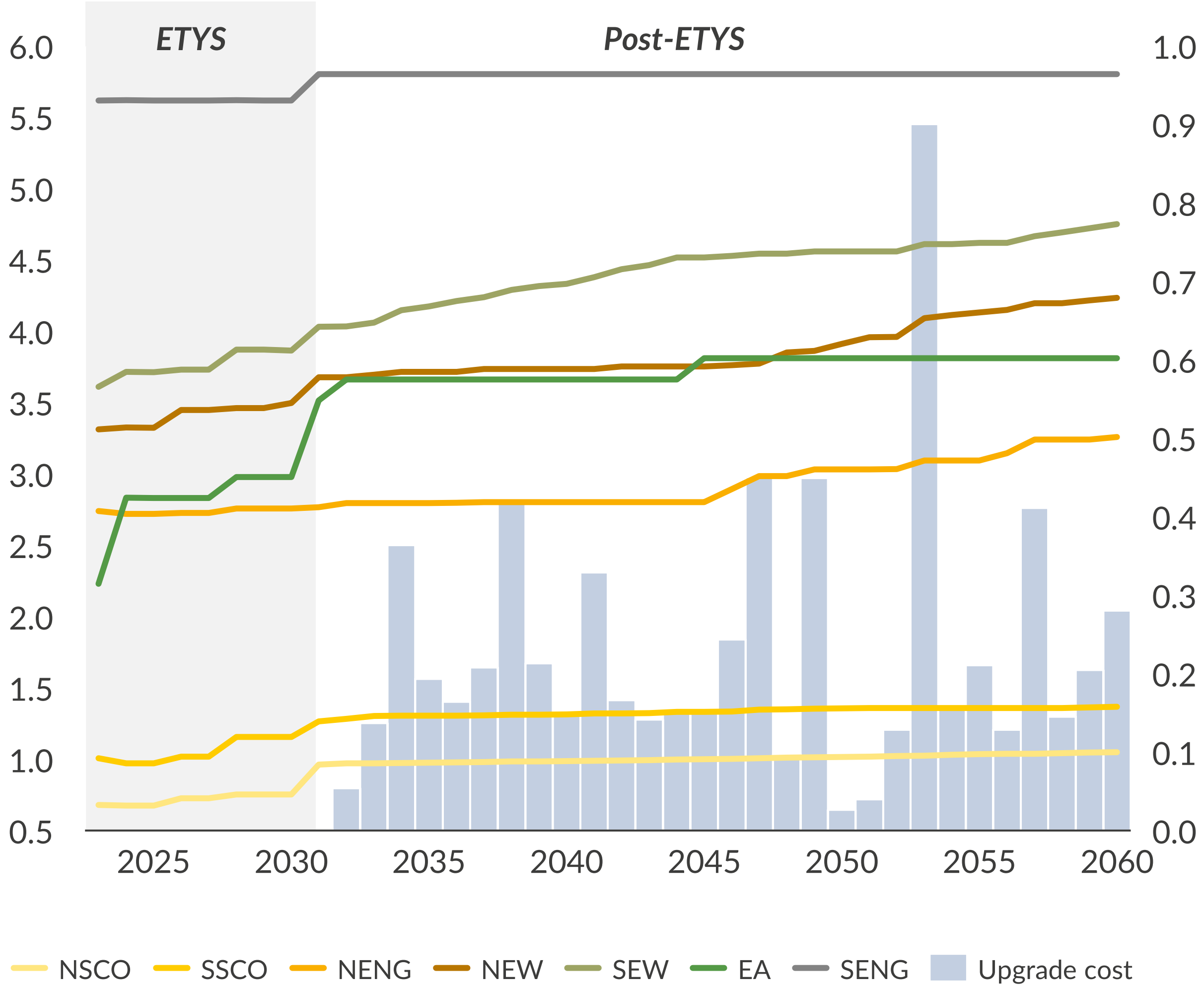
Nodal Pricing

Average Nodal Connected Line Capacity[1]
GW

Estimated Cost of Line Upgrades[2]
£bn



Our nodal model uses a congestion-cost weighted approach to upgrade lines post-ETYS

- Similarly, to the zonal model, the nodal model includes line upgrades beyond ETYS
- Lines are upgraded each year with a budget for each line proportional to the total cost of congestion incurred on that line in the previous year
- The congestion revenue is calculated in a similar way to the zonal model:

Congestion revenue = Line's marginal congestion cost × Power flow across constraining lines

- The yearly budget is spent in order from the line which will decrease the overall cost of congestion the most until the budget is spent or upgrades are no longer reaching the threshold
- We assume minimum and maximum bounds for line capacity increases to decisions to reflect more realistic upgrade decisions:

Voltage (kV)	Min Upgrade (MW)	Max Upgrade (MW)	Overhead Line cost (£/MW/km)	Underground Line Cost (£/MW/km)
33	30	50	1,750	13,000
132	150	300	1,550	11,450
220	250	400	1,350	10,000
275	600	1500	1,250	9,250
400	1500	4000	1,000	7,300

1) In the Aurora Net Zero nodal scenario. 2) As determined by the upgrade algorithm for Net Zero, includes only the cost of thermal upgrading of lines and is not the total transmission CAPEX.

Source(s): Aurora Energy Research

Agenda

Alongside the base Net Zero zonal and nodal results, this study reviews a range of sensitivities and scenarios to highlight competing drivers

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	Scenario/ Sensitivity	Description	Included in costs to consumer?
Scenarios	**Aurora Net Zero**	▪ Aurora's view for the evolution of the GB power market until 2060 complementing published policy and Aurora's own assumptions on how this would be achieved with a mix of renewables and low-carbon baseload technologies. Power sector carbon intensity reaches -26 gCO_2/kWh by 2060 under the following assumptions: – Aurora's internally-consistent outlook for technological developments and commodity prices for a global two-degree outlook – Expected policy support for technologies required to achieve economic-wide carbon-neutrality by 2050	✓
Scenarios	**Aurora Central**	▪ Aurora's best view of the evolution of the GB power market until 2060, our Central forecast results in a power sector carbon intensity of -9 gCO_2/kWh under the following considerations: – Aurora's internally-consistent Central outlook for technological developments (e.g., Capex) and modelled commodity prices – Incorporating currently stated policies, alongside a conservative view of future policy objectives (including potential subsidies) and market developments that have been informed through discussions with key stakeholders (including policy makers, developers and financial institutions)	✓
Sensitivities	**Low Transmission line upgrades**	▪ Two low transmission line upgrade cases reflect realistic deviations from the baseline assumptions on future upgrades ▪ The first assumes a build-out of ETYS only but with a delay and second considers the implications of falling short of ETYS targets	✓
Sensitivities	**Alternative demand**	▪ Electrolysers are expected to make up 39 GW of green hydrogen supply by 2050 under Aurora's Net Zero scenario, and are perceived as demand source most able to respond to locational pricing signals ▪ This alternative demand scenario places electrolysers proportionally to offshore and onshore wind development in GB, rather than the current approach based on current project pipelines	✓

Source(s): Aurora Energy Research,

Key Takeaways – Cost to the consumer of national, zonal and nodal markets

AURORA

1. Over 2025–2060, LMP systems result in 1.7–2.6% cheaper total cost to the consumer under Net Zero compared to the status quo, however these savings are likely eroded by real, unmodelled factors. There is virtually no benefit in a scenario where Net Zero is not achieved

2. Looking at a narrower set of years, 2030–2040, a switch to zonal LMP results in 1–2% reduction in cost to the consumer across Central and Net Zero, however these savings are likely eroded by real, unmodelled factors. There is no benefit from a switch to nodal LMP

3. Under Net Zero, a switch to LMP by 2045 could result in 0.2–2% cheaper cost to the consumer than the Status Quo, with a sooner change resulting in even lower costs. However, these savings are likely eroded by real, unmodelled factors

4. It is probable that a switch to LMP could increase cost of capital—due to increased uncertainty risks. A 3pp point increase in cost of capital could raise total cost to the consumer for a switch to LMP c.5%, thus making LMP ultimately more expensive than the Status Quo

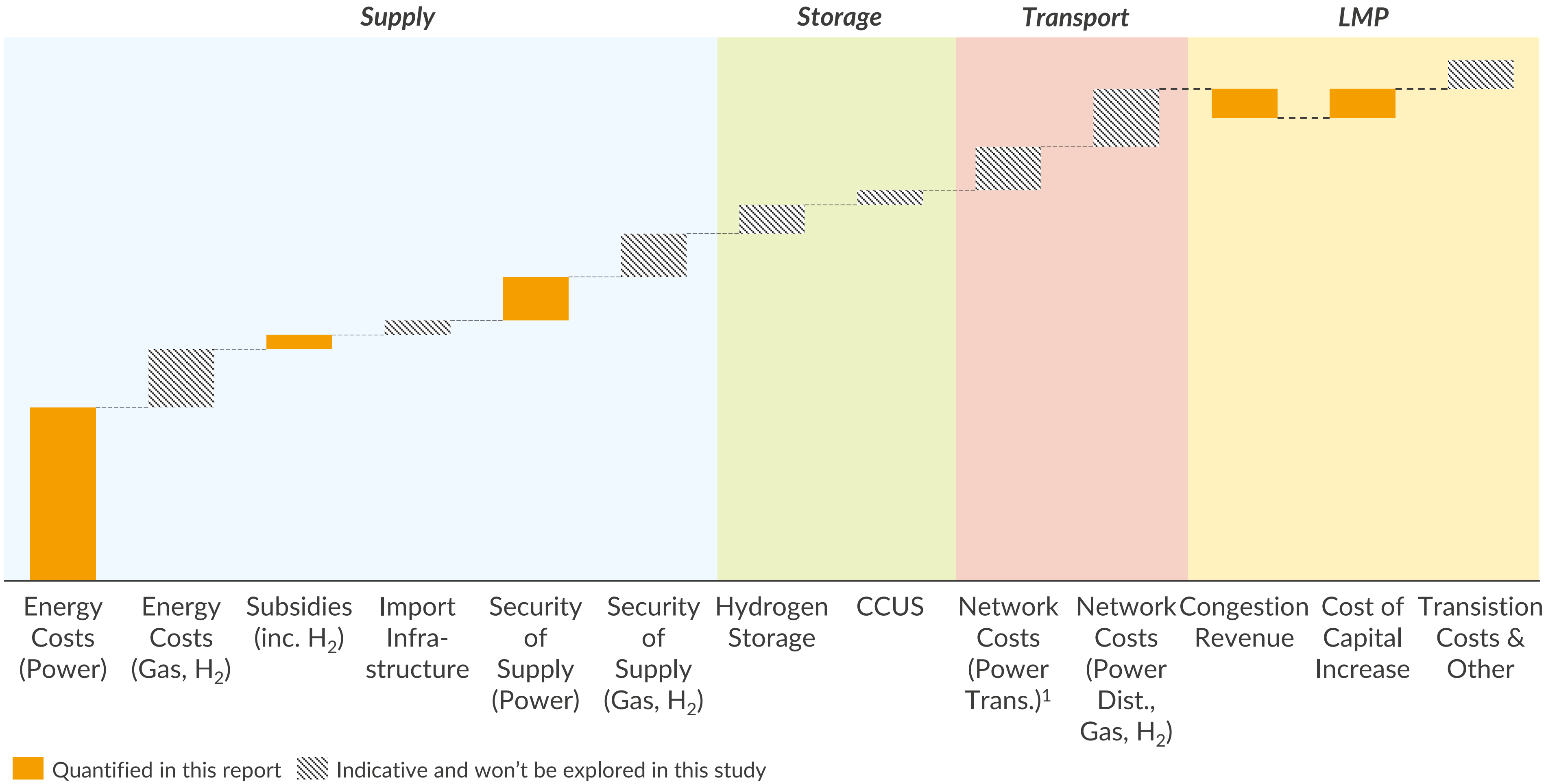
5. These results are sensitive to a multitude of factors from what's included, the methodologies employed, and additional risks and uncertainties (e.g., CfD reference prices, Financial Transmission Rights, Transition Costs, Central Dispatch management costs, etc.)

Source(s): Aurora Energy Research

A change to LMP will affect several components of the cost to the consumer of the energy system in Great Britain

The costs explored in this section are those that end up on retail power bills: not total capital employed in the building and maintenance of the power system.

Illustrative Diagram of Cost to the Consumer Components



- We evaluated the cost to the consumer totals across 2025–60 for each of the models considering the most relevant components
- In the following pages we:
  - Roughly examine the impact of the year of switching to LMP on total cost to the consumer
  - Examine the impact of a cost of capital increase on LMP from increased perceived risk

1) Relative network costs for the low grid build sensitivities are estimated later in the report however they are excluded from this section in order to focus on comparisons between the key outputs of Aurora's modelling.

Source(s): Aurora Energy Research

Aurora has taken a whole system approach to determine the trade-offs associated with each of the market pricing models (1/2)

AURORA

The method we used to calculate consumer costs differs in some aspects from the method our models use to solve for various markets. This was necessary to make a fair comparison between our models. However, this method cannot be easily incorporated into the national pricing model results in other contexts.

Component	National	Zonal	Nodal
Wholesale Cost	▪ The total cost to the grid of purchasing power, defined as the product of national demand and national price for each settlement period	▪ Defined similarly as the product of zonal demand and zonal price for each settlement period and zone	▪ Defined similarly as the product of nodal demand and nodal price for each settlement period and node
BM Energy Cost	▪ Energy actions are assumed to be resolved at the national level across all models, with no locational price differences, with the cost calculated by multiplying accepted bid/offer prices by the national imbalance volume		
BM System Cost	▪ **Note: This is not the BMS as calculated in our three-zone model** ▪ To better compare the cost of system actions between models, the nodal model is utilised across all three, enabling the capture of all constraints in all models ▪ Volumes of system actions are determined by the difference in plant dispatch between the nodal model with line constraints and without ▪ Bids/offers are approximated by the SRMC of the plant, accounting for technology and subsidy	▪ Interzonal system actions are assumed to be eliminated by a switch to LMP, though intrazonal system actions are retained in local congestion ▪ Interzonal system actions volumes are calculated by the difference in imports/exports between zones ▪ Bids/offers are approximated by average SRMCs accepted in the national determination of BM system costs ▪ The product is subtracted from the national figure to arrive at intrazonal BM system costs	▪ No BM cost to the consumer as all constraints are resolved in Wholesale dispatch

Source(s): Aurora Energy Research

Aurora has taken a whole system approach to determine the trade-offs associated with each of the market pricing models (2/2)

AURORA

The method we used to calculate consumer costs differs in some aspects from the method our models use to solve for various markets. This was necessary to make a fair comparison between our models. However, this method cannot be easily incorporated into the national pricing model results in other contexts.

Component	National	Zonal	Nodal
Subsidy Cost	▪ CfD costs use the national Wholesale price as the reference price, coupled with contracted national strike prices for existing assets ▪ Strike prices for assumed future CfD capacity are calculated in order to result in assets having an NPV of zero ▪ Assumed subsidies for other exogenous capacity are such that their NPV is zero	▪ As for the national model but assuming zonal reference prices for CfD costs	▪ Zonal subsidy costs are used as a proxy for nodal subsidy costs
Security of Supply Cost	▪ The cost of the Capacity Market, where a national Capacity Market is assumed for all models. The precise figures presented for this component were held the same as National Pricing due to a modelling limitation, however, we wouldn't expect significantly different results due to the mobility of price clearing technologies (e.g., gas peakers would be built in high-price zones first due to lower 'missing money' problem). ▪ This is the cost of providing the necessary payments to enable plants to deploy or remain operational) to ensure total generation on the system is sufficient to meet security of supply standards (< 3 hours Loss of Load Expectation (LOLE) per year)		
Congestion Revenue	▪ N/A	▪ The cost recovered by the grid through the purchase of power in low-cost locations and the selling of power in high-cost locations ▪ This is a negative cost which can be the spent by the grid in reducing consumer bills such as through energy rebates or through the reinforcement of the transmission network	

Source(s): Aurora Energy Research

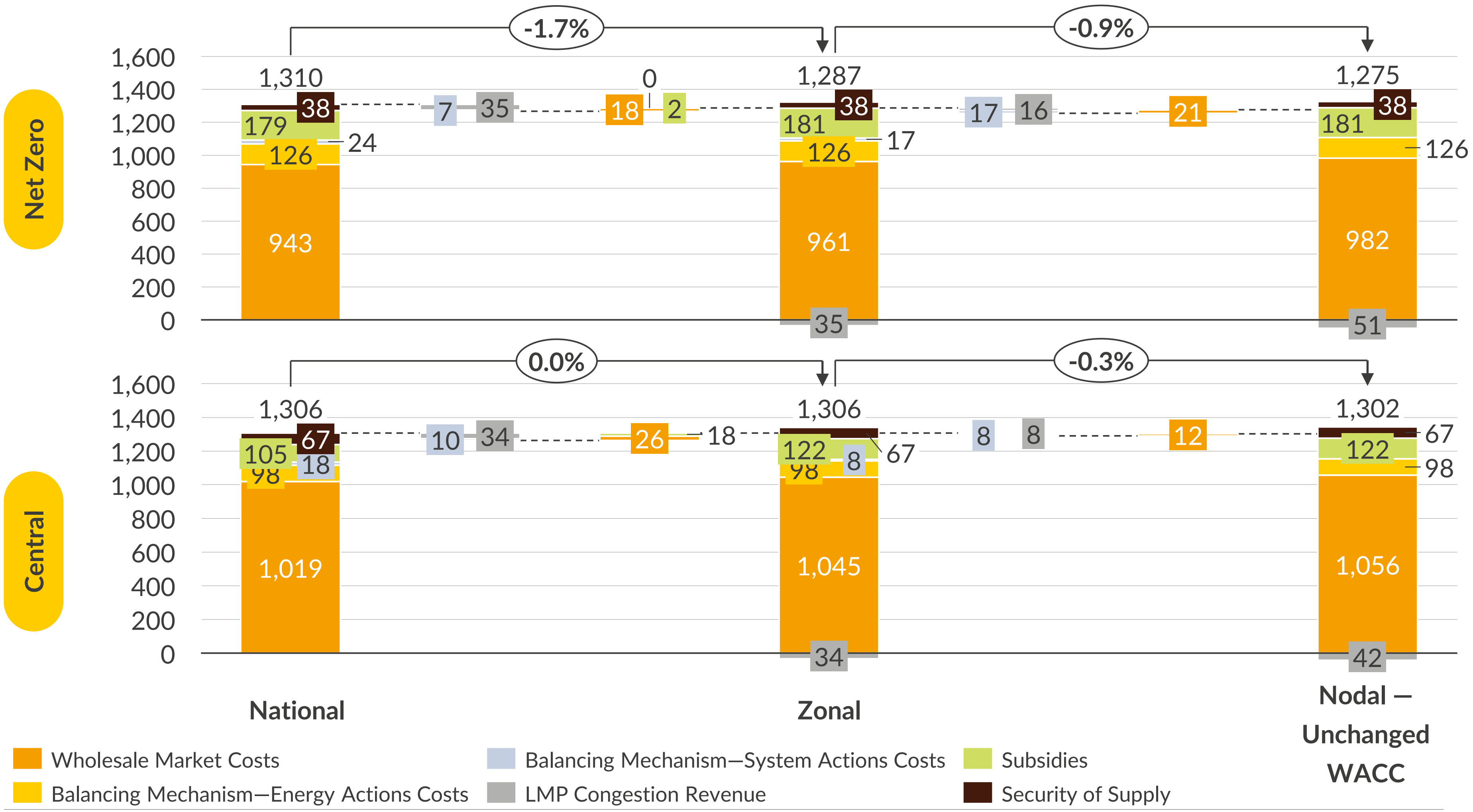
Certain costs have been only been partially or not wholly considered, with the focus of the study on the market model results

Component	Risk
Subsidy Cost	This study has assumed that, under LMP, CfD assets would be topped up based on a zonal reference price, effectively shielding them from zonal price differences across the country. Should the top-up instead be based on a national reference price, CfD revenue would vary by zone, potentially creating additional risk in low-price zones such as North Scotland. This would also likely reduce the total CfD cost.
Implementation/ Transition Cost	A transition to LMP would require a change to the systems and capabilities of both NGESO and market players, creating an implementation cost, the quantification of which is beyond the scope of this study. This cost may be higher under nodal vs zonal pricing due to the extent of changes required to market mechanics relative to the current national system.
Management Cost	A transition to LMP—especially alongside Centralised Dispatch—may create additional ESO administrative costs, the quantification of which is beyond the scope of this study.
Impact on Policy Implementation	A transition to LMP may delay the implementation of policies required to meet Net Zero targets or increase security of supply due to increased market uncertainty and the need for reform, potentially slowing the deployment of new low-carbon technologies. This could place upward pressure on Wholesale prices not captured in this study.
Security of supply	This study assumes the Capacity Market operates on a national basis, whereas a switch to a zonal Capacity Market could increase or decrease costs, depending largely on the transmission capacity between zones and zonal system composition.

Source(s): Aurora Energy Research

While LMP results in higher Wholesale costs, loss of costly BM system actions and congestion revenue produces lower overall energy costs

Total Cost to the Consumer[1], 2025–2060
£bn (real 2021)



1) LMP results are likely higher than modelled due to real, unmodelled factors such as WACC increase, transition costs, congestion rent ‘leakage’, etc.

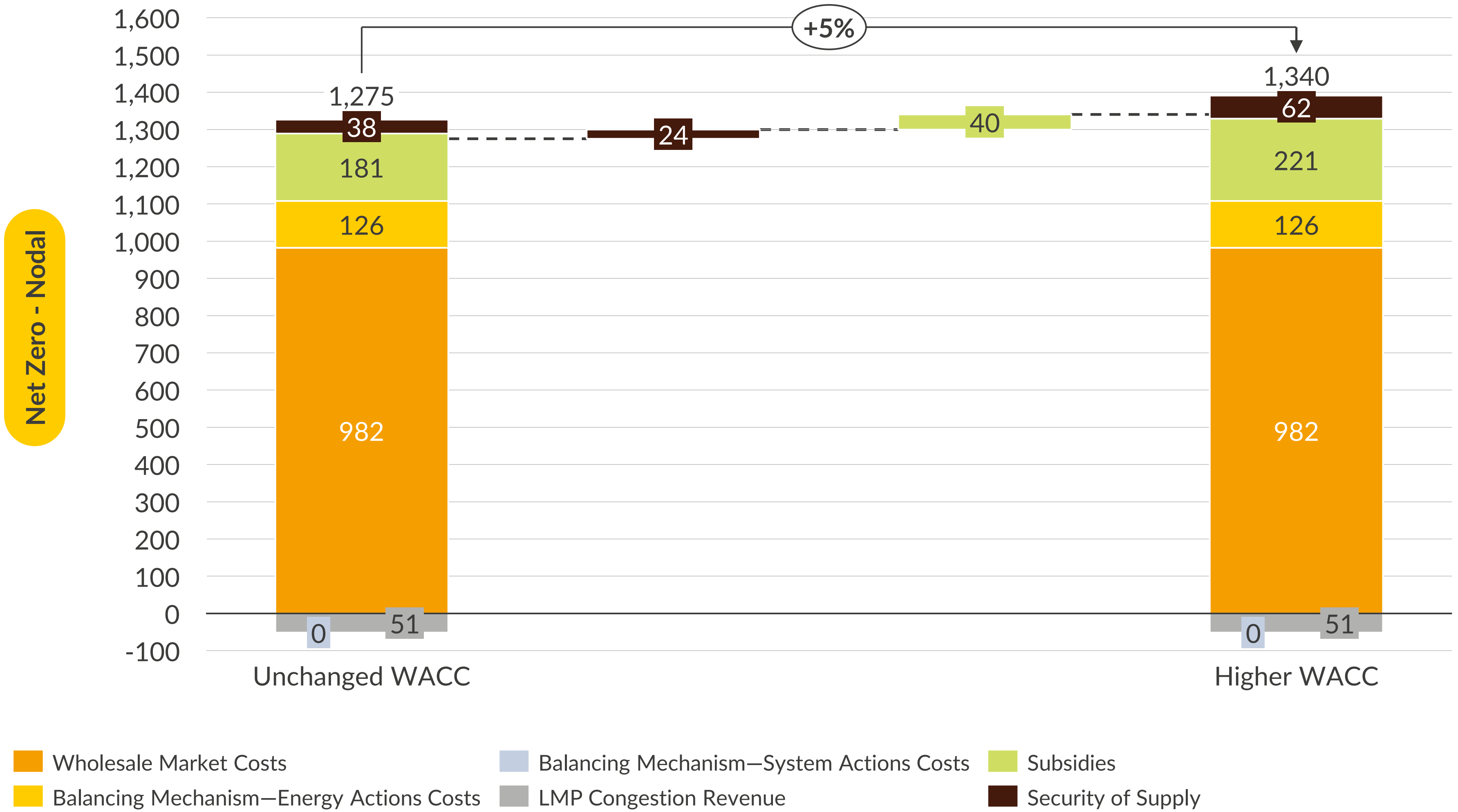
Source(s): Aurora Energy Research

- Wholesale Market costs increase across national to zonal to nodal models for both Net Zero and Central results, driven by the transfer of BM system costs to the consumer into Wholesale price at increasing granularity
- Net Zero includes a higher build-out of renewables than Central, leading to a system with more RES assets setting the price and therefore a lower overall Wholesale cost than in Central
- Congestion revenue from grid rents—highest in the more granular nodal market—offsets higher subsidy costs driven by lower zonal reference prices
- **Note: costs under LMP likely higher due to real, unmodelled factors such as WACC increases and transition costs**

A 3pp increase in the cost of capital for assets supported by subsidies and the CM could result in 5% higher overall system costs

AURORA

Total Cost to the Consumer[2], 2025–2060
£bn (real 2021)



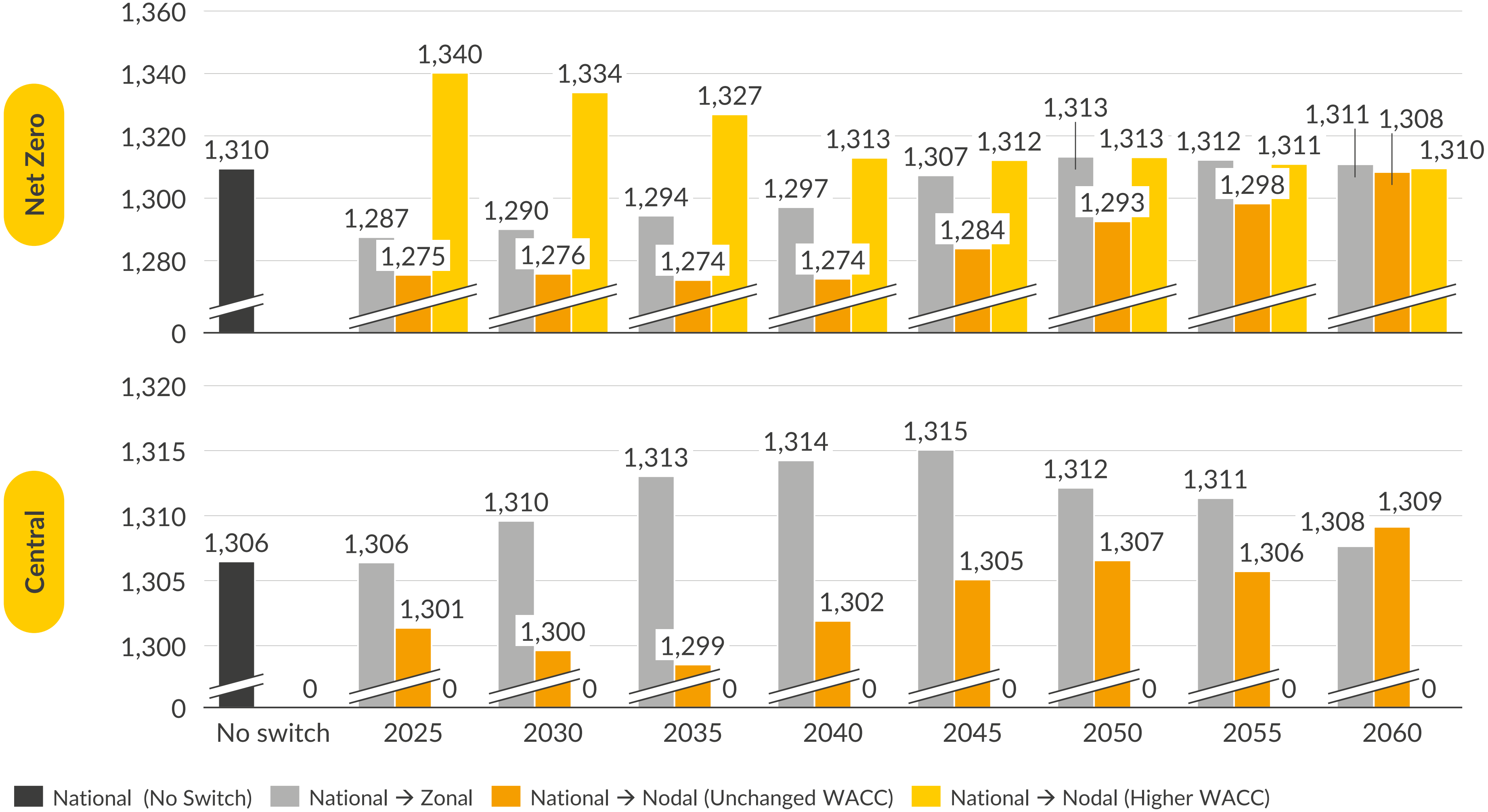
- This sensitivity considers a flat 3pp increase[1] in the weighted average cost of capital (WACC) for all subsidised plants,
  - effectively reflecting higher strike prices for CfD assets,
  - plus greater implicit subsidy requirement for other technologies required to support a Net Zero system
- Capacity Market discount rates are also increased, resulting in higher overall costs from higher bid prices into the Capacity Market auctions
- This increase to the cost of capital is assumed to be constant across the lifetime of the project, therefore represents a more extreme downside risk

1) This increase to the project discount rate does not represent an Aurora forecast to potential growth of discount rates and is used for sizing the order of magnitude of the impact only. Frontier Economics estimation. 2) LMP results are likely higher than modelled due to real, unmodelled factors such as WACC increase, transition costs, congestion rent 'leakage', etc.
Source(s): Aurora Energy Research, Frontier Economics "Locational marginal pricing – implications for cost of capital" 14 October 2022

AURORA

Under Net Zero, a switch to LMP by 2045 could result in decreased total system costs—the sooner the better

Total Cost to the Consumer[1], 2025–2060 (by LMP switch year)
£bn (real 2021)



1) LMP results are likely higher than modelled due to real, unmodelled factors such as WACC increase, transition costs, congestion rent 'leakage', etc.

Source(s): Aurora Energy Research

- We have examined the impact on total cost to the consumer by the year a switch to LMP would be implemented
- We added our national estimation for cost to the consumer before the LMP switch year with that from LMP after the switch year. In reality, there is a path dependency to capacity and grid build that may change these results
- We find, assuming Net Zero is achieved, that it is economically efficient to switch to zonal LMP by 2045 and anytime for nodal LMP, if there is WACCs don't increase—sooner the better
- These results are less straight forward if we don't achieve Net Zero
  - There is no optimal time to switch to zonal LMP, and
  - Nodal LMP is most effective with a switch by 2045 (with 2035 being optimal, though marginally better)

Key Takeaways – The impact of a switch to LMP on asset margins and portfolio IRRs

AURORA

1. Gross margins for assets focus on changes to Wholesale and Balancing Mechanism margins, highlighting where the Capacity Market is required to ensure continued profitability for peaking and baseload technologies

2. Overall capture prices and full-load hours for baseload and peaking technologies under zonal LMP remain either in line with national or fall under Net Zero, reflecting fewer high price periods relative to national

3. Battery economics are very exposed to the market scenarios, benefitting from high volatility and spreads under Net Zero, while dropping below the national gross margins in Central results where the higher Wholesale spreads are offset by a loss of arbitrage opportunities from the Balancing Mechanism

4. RES assets are most differentiated across zones, negatively impacted by zonal constraints driving more curtailment of the assets, while the bottom Wholesale prices during high intermittent generation phases do not diverge substantially from national

5. An optimal switch to LMP would be in the late 2020s or early 2030s to mitigate impact on portfolio IRRs[1]; albeit the analysis presented here reflects a very high-level assessment and doesn’t specifics for the full range technologies on the system

1) Portfolio IRRs assume a seamless switch between systems with no impact on operational expenditure.

Source(s): Aurora Energy Research

Aurora has examined the impact of switching to an LMP system on a portfolio reflective of GB current supply and forward-looking supply

AURORA

Portfolio	Technology Diversity	Locational Diversity	Techs	Capacity Allocation (% of 2GW portfolio)							
				NSCO	SSCO	NENG	NEW	SEW	EA	SENG	Total
Legacy (2023 technology mix)[1]	Low	Low	CCGT	1.5%	0.1%	0.2%	11.0%	22.0%	0.5%	2.8%	**38.1%**
			CCGT w/ CCS								**0.0%**
			Offshore Wind	2.7%		2.3%	3.2%	3.2%	3.3%	1.1%	**15.8%**
			Onshore Wind	5.5%	6.9%	1.2%	1.4%	2.4%	0.1%	0.6%	**18.1%**
			Solar PV	0.2%	0.4%	0.9%	2.3%	9.2%	0.9%	4.1%	**18.0%**
			Gas Recip		0.2%	0.5%	2.5%	2.6%	0.2%	1.2%	**7.2%**
			H_2 Peaker								**0.0%**
			1-hour Battery		0.1%	0.1%	0.6%	0.5%	0.2%	0.2%	**1.7%**
			2-hour Battery	0.1%	0.1%		0.2%	0.5%		0.2%	**1.1%**
			4-hour Battery								**0.0%**
			Total	**10.0%**	**7.8%**	**5.2%**	**21.2%**	**40.4%**	**5.2%**	**10.2%**	
Net Zero (2030 technology mix)[1]	High	High	CCGT	0.8%	0.0%	0.1%	3.0%	6.2%	0.3%	1.2%	**11.6%**
			CCGT w/ CCS			2.1%	2.8%				**4.9%**
			Offshore Wind	5.2%	3.7%	2.3%	4.8%	3.9%	8.3%	0.6%	**28.8%**
			Onshore Wind	6.4%	6.6%	0.8%	0.9%	1.9%		0.6%	**17.2%**
			Solar PV	0.3%	0.3%	0.8%	2.3%	10.2%	0.8%	3.8%	**18.5%**
			Gas Recip	1.5%	1.0%	1.3%	2.3%	2.4%	0.6%	3.0%	**12.1%**
			H_2 Peaker				1.0%	0.1%			**1.1%**
			1-hour Battery		0.2%	0.1%	0.4%	0.7%	0.1%	0.2%	**1.7%**
			2-hour Battery	0.1%	0.3%	0.3%	0.5%	1.1%		0.2%	**2.5%**
			4-hour Battery		0.1%				0.7%	0.5%	**1.3%**
			Total	**14.3%**	**12.2%**	**7.8%**	**18.0%**	**26.5%**	**10.8%**	**10.1%**	

1) The legacy portfolio is made up of a mix of technologies reflecting the GB market composition in 2023, while the Net Zero portfolio is forward looking, building in a broader mix of newer technologies with a wider zonal distribution. The technologies examined follow Aurora's standard market assumptions and regional renewables load factors and only reflect the GB system at a high-level

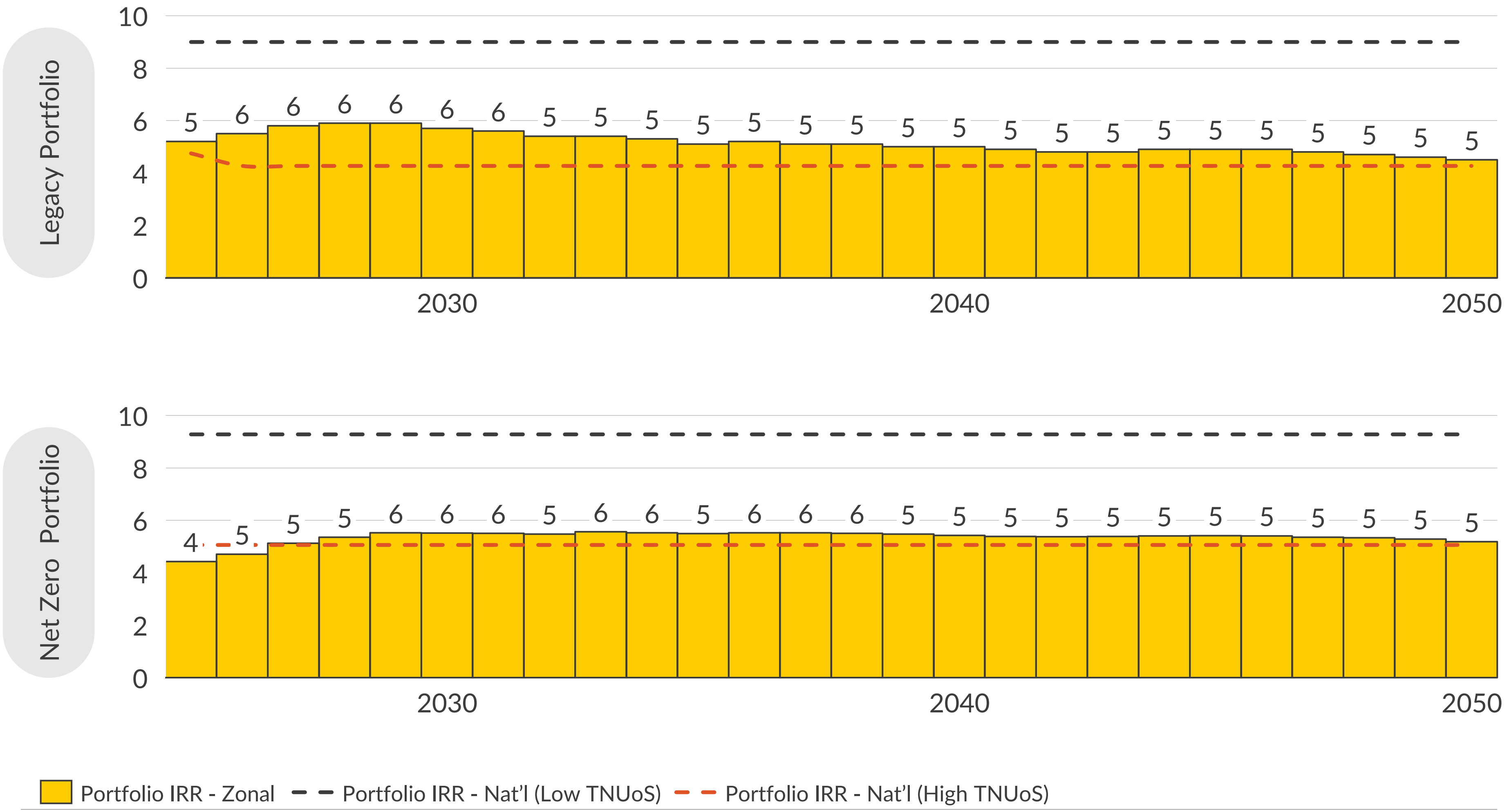
Source(s): Aurora Energy Research

Portfolio IRRs improve with a switch to LMP in the late ’20s, resulting in a comparable IRR to a portfolio in a high-TNUoS zone under national

AURORA

IRR by LMP Switch Year

%



- Varied portfolio compositions produce net similar results over time, with a forward-looking technology mix in the Net Zero portfolio not showing benefits until the late 2020s
- Under the current TNUoS methodology, targeting low-TNUoS zones provides an optimal result in all cases
- Note: The technologies examined follow Aurora’s standard market assumptions and regional renewables load factors and only reflect the GB system at a high-level

Source(s): Aurora Energy Research

Key Takeaways – LMP under a Net Zero scenario

AURORA

1. Under a Net Zero scenario, we assume assets have little opportunity to respond to locational signals, with large proportions of RES, CCS and hydrogen peakers forced onto the GB network through subsidy support

2. Including balancing system actions into the Wholesale price pushes LMP baseload prices above national, with costs to the consumer increasing proportionally more from this increase than is saved from the reduction in balancing system costs

3. In a nodal model, persistence for the top 90th percentile prices remains low, while the top 75th percentile show a stronger trend in maintaining higher value

4. Zonal prices don't capture the same level of polarization of prices driven by intrazonal congestion in the nodal model, e.g. in Scotland

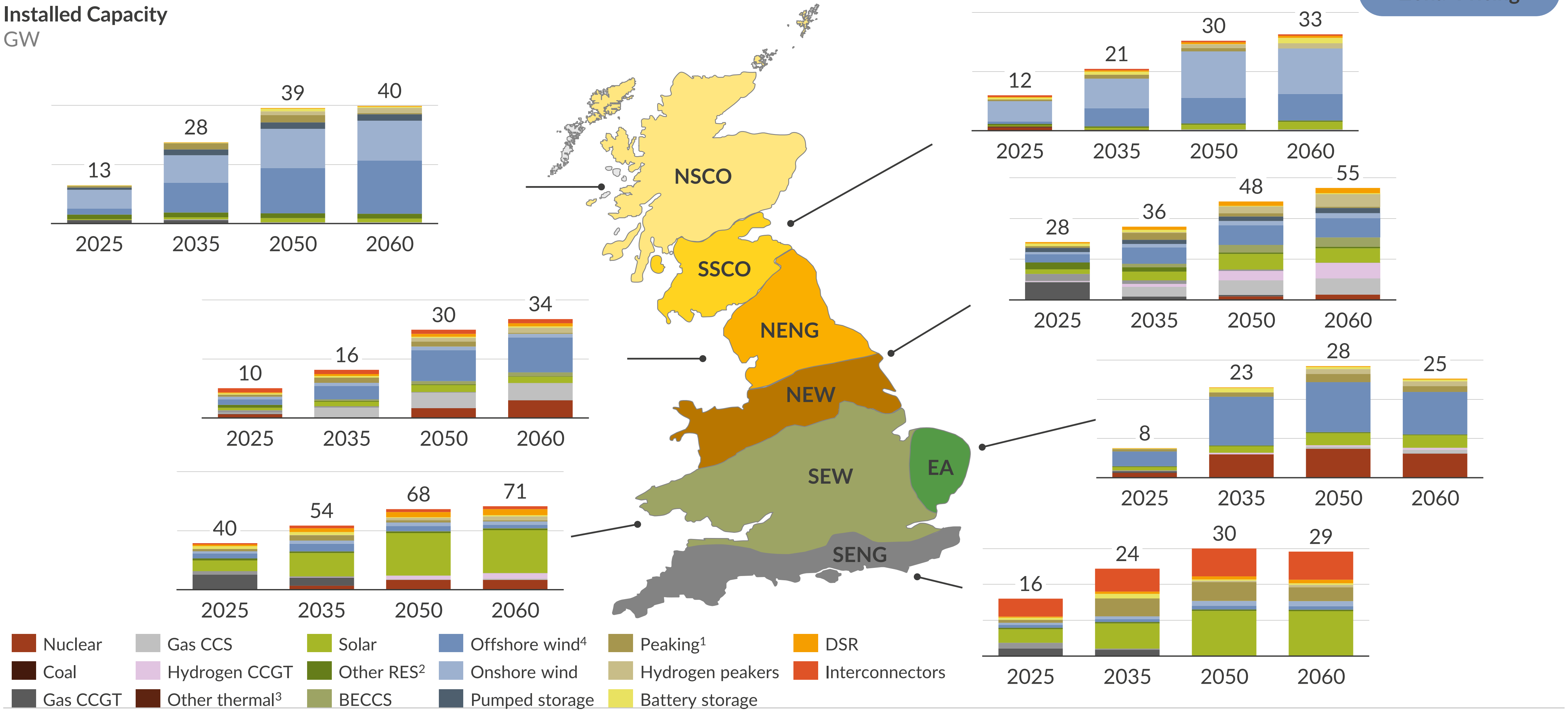
5. Nodal modelling provides more targeted line upgrade requirements than a zonal model which does not capture intrazonal congestion

Source(s): Aurora Energy Research

Zonal capacity is split across the seven zones with most of the wind being placed in Scotland and East Anglia

AURORA

Zonal Pricing

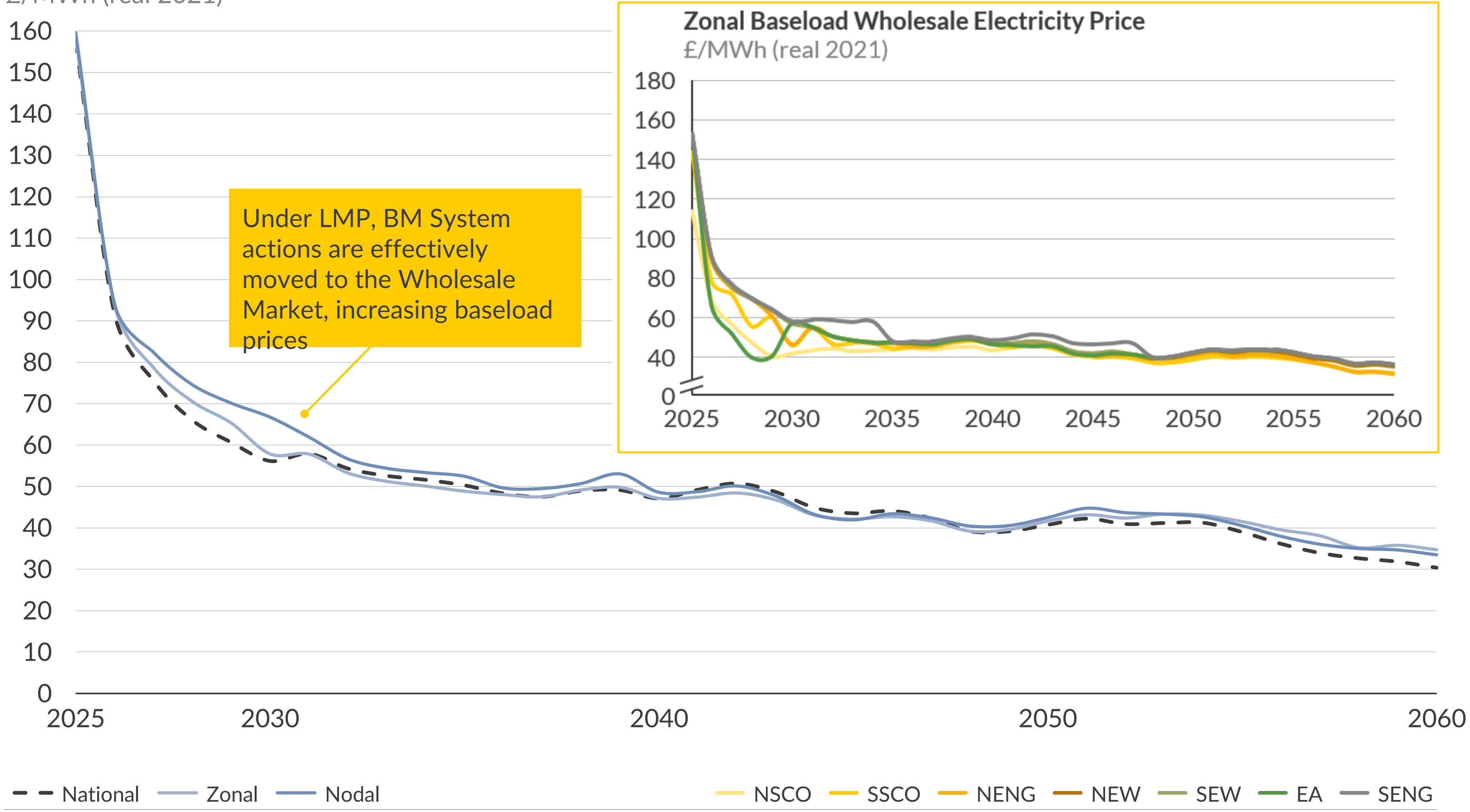


1) Peaking includes OCGT and reciprocating engines. 2) Other RES includes biomass, EfW, hydro, and marine: 3) Other thermal includes embedded CHP. 4) Locations for offshore wind will continue to be determined by The Crown Estate and Crown Estate Scotland and may not occur as modelled.

Source(s): Aurora Energy Research

AURORA

LMP increases baseload prices as network constraints are now considered in Wholesale dispatch, particularly in the short term



Source(s): Aurora Energy Research

Increasing locational granularity increases baseload prices

- In general, we see that the nodal model has the highest baseload prices, followed by zonal then national which track each other more closely. The increase in Wholesale prices is driven by the cost of BM System actions now being incorporated into Wholesale Market prices
- Intrazonal congestion in the nodal model inflates prices despite line upgrades, whilst boundary upgrades in the zonal model reduce congestion to the extent that, on average, prices resemble those in the national case towards the end of the forecast
- Zonal boundary upgrades similarly lead to zones coupling in prices towards the end of the forecast, with SSCO, NSCO and NENG forming a single price zone by 2060, with a similar effect applying to SENG and EA

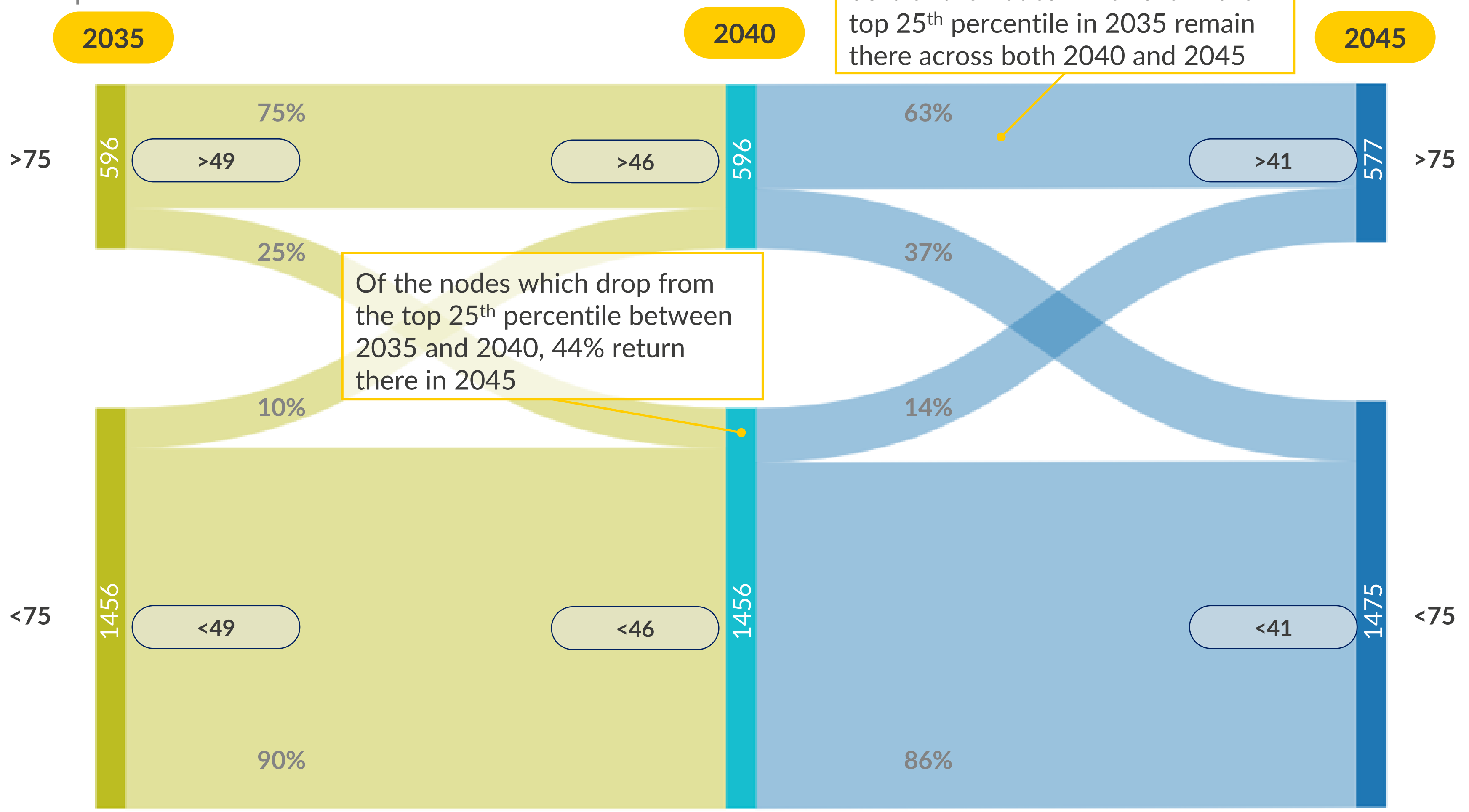
AURORA

The upper price percentiles of nodes see greater persistence owing to demand placement being more stable than generation placement

Nodal Pricing

Average Nodal Price Percentiles

Nodal percentile count



- The distribution of baseload demand is incremental and geographically consistent over the forecast, thus nodes with the highest share are consistently in the upper percentiles of node prices owing to systemic north-south congestion in the network
- Despite systemic congestion, instances of locally congested lines in the forecast can change the price order, leading to the departure of southern nodes from this top quartile
- Generating capacity meanwhile is placed on nodes sporadically and in larger increments, meaning potentially large and infrequent increases in congestion which can skew a nodes place in the price order

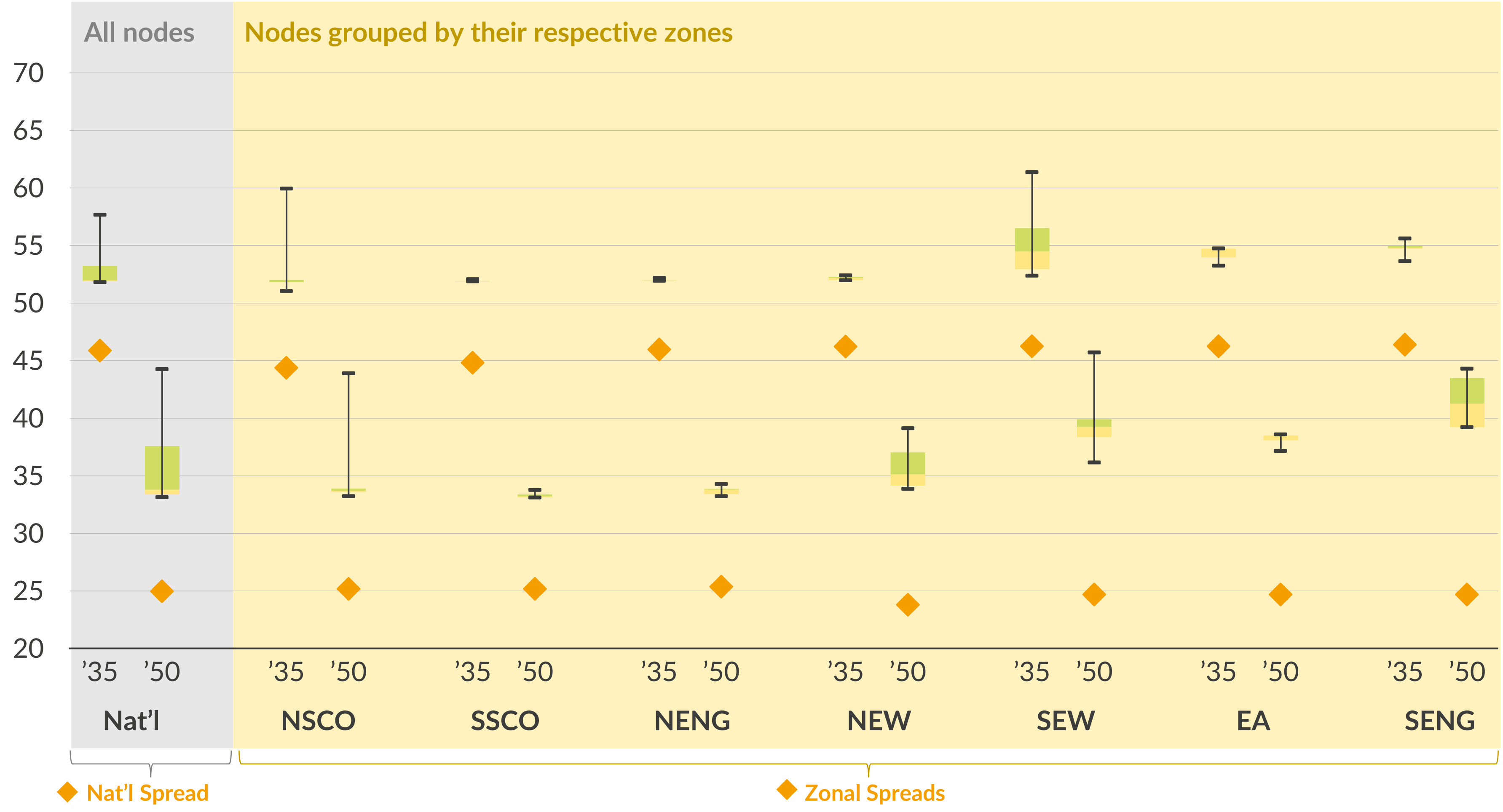
Percentile in £/MWh

Source(s): Aurora Energy Research

Nodal spreads trend higher than their zonal equivalent, which are closer to national, with spreads across all models dropping over time

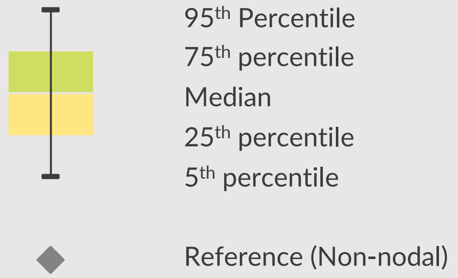
AURORA

Distribution of Nodal Average Daily 2-hour Wholesale Spreads
£/MWh (real 2021)



- Average 2-hour spreads across all models come down over time
- In a nodal system, higher volatility leads to consistently higher 2-hour price spreads than under the zonal system
- Regions more exposed to supply and demand imbalances coupled with increased intermitted generation have higher variation in nodal spreads, while zonal spreads are lower in southern zones than Scotland after resolution of system congestion

Legend for reading nodal distribution



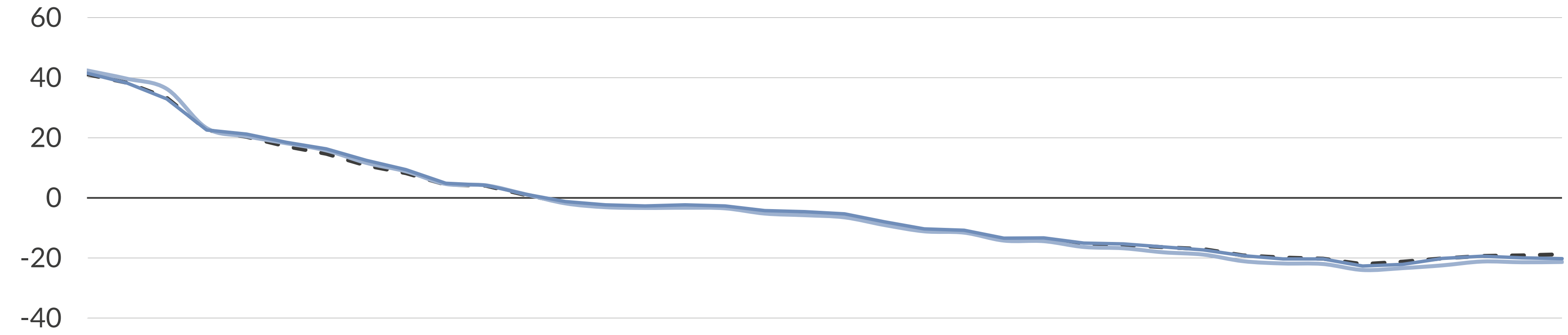
Source(s): Aurora Energy Research

Under Net Zero, system build keeps emissions from the different models tracking each other very closely

AURORA

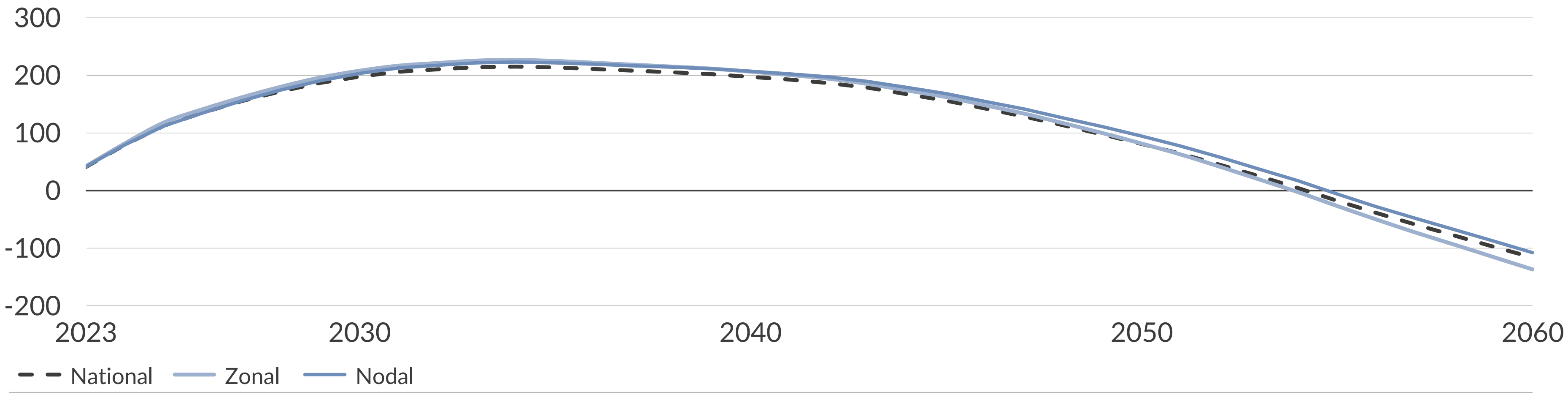
Emissions

$MtCO_{2,eq}$/year



Cumulative Emissions

$MtCO_{2,eq}$



…with some gains realised later in the forecast

- Both the national and zonal models achieve net zero emissions by 2035, with parity in total emissions between the two models achieved in 2050
- Emissions in the zonal model are higher in earlier years owing to boundary constraints requiring an increased dispatch of thermal technologies in undersupplied southern zones
- As endogenous capacity responds to integrated locational signals in the Wholesale price towards the middle and end of the forecast, emissions fall faster than the national model, achieving lower emissions by 2060 both annually and cumulatively

Source(s): Aurora Energy Research

Key Takeaways – LMP market results without Net Zero policy support

AURORA

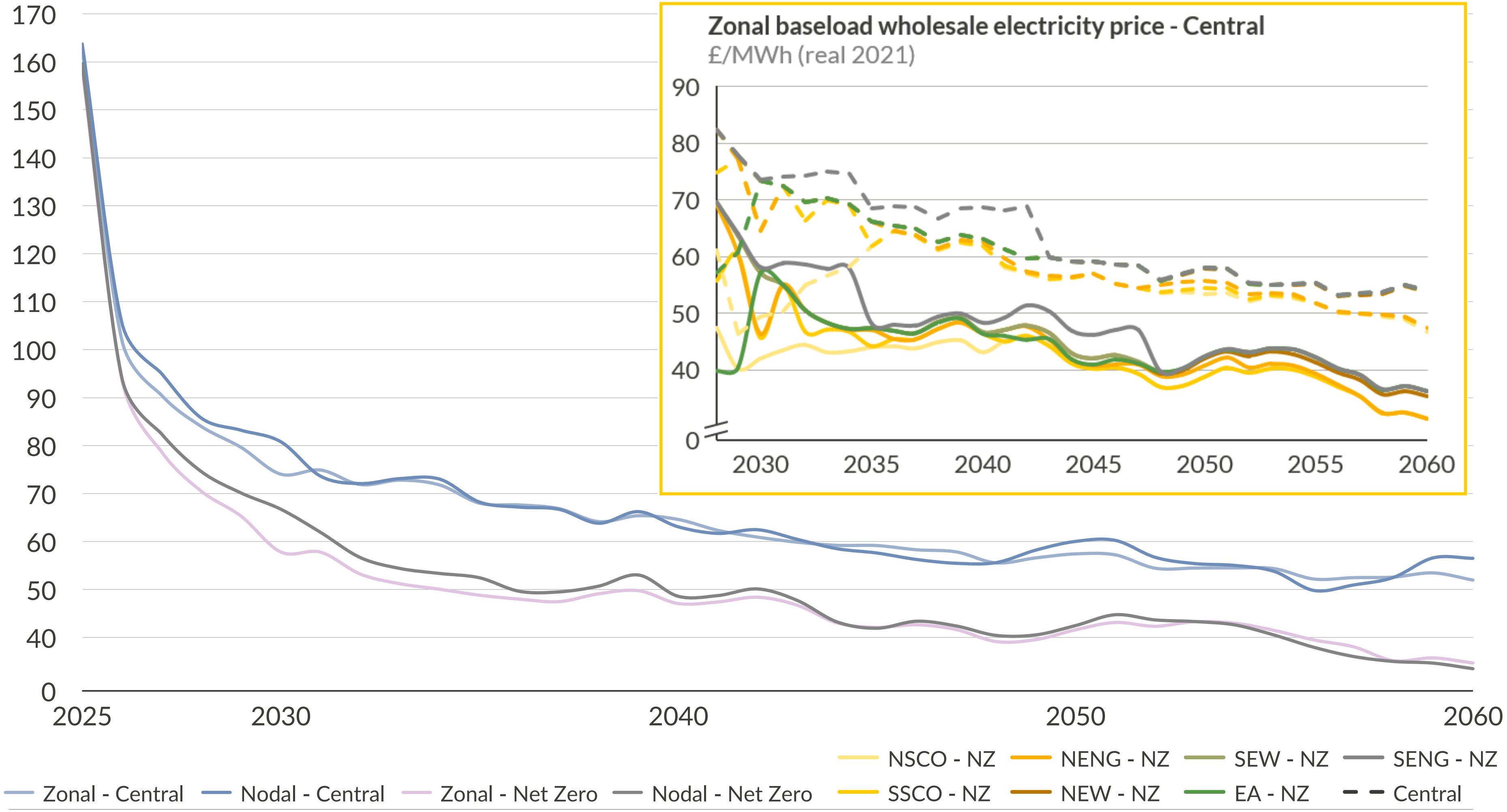
1. LMP baseload prices respond to a Central market scenario in a similar manner to our national model, reflecting higher prices where fewer RES technologies have penetrated the market, and little differentiation in zonal price trends
2. Bottom price percentiles in the zonal model diverge more from the national than under Net Zero results, with lower electrolyser demand disproportionately impacting northern zones
3. For storage assets, a Central scenario produces 2-hour spreads in both nodal and zonal models which trend above national average spreads
4. Nodal modelling produces more uniform price formation relative to Net Zero, with a 3- or 2-zone split forming in the later years
5. Less intermittent capacity drives more stability in prices and therefore more nodal persistence

Source(s): Aurora Energy Research

Between 2030 and 2060, Central baseload prices on average trend ~34% higher than Net Zero, driven by lower build-out of renewables

AURORA

Baseload Wholesale Electricity Price – Demand Weighted Average
£/MWh (real 2021)



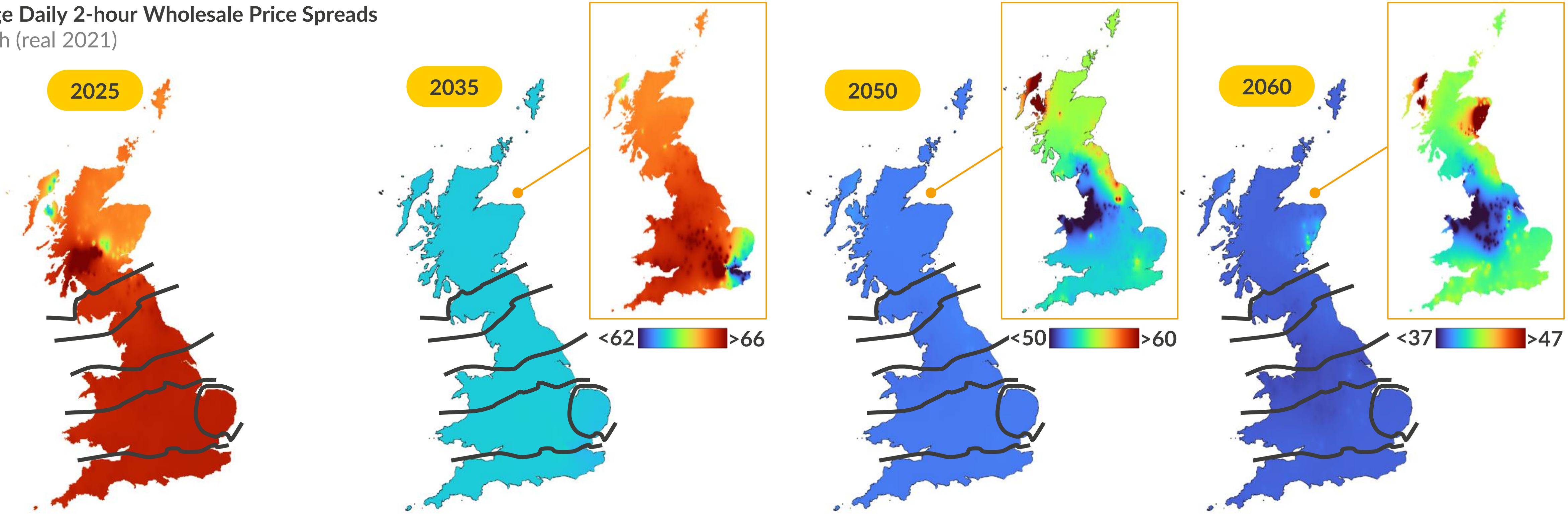
- Relative to Net Zero, Aurora Central sees elevated baseload prices in both the zonal and nodal models, reflecting reduced build-out of low marginal cost, low-carbon generation in the form of hydrogen CCGTs, CCGT+CCS and renewables
- Relative price differences between the 7 zones are similar in the Central and Net Zero zonal scenarios, reflecting the same ETYS line upgrades up to 2034. Prices in SENG, EA and SEW couple earlier in Central, reflecting lower congestion
- Nodal prices are generally higher than zonal prices due to the consideration of intrazonal congestion in Wholesale dispatch

Source(s): Aurora Energy Research

2h price spreads decrease on average over time, with some persistence of higher spreads in Scotland

Nodal Pricing

Average Daily 2-hour Wholesale Price Spreads
£/MWh (real 2021)



- 2-hour price spreads fall across the timeline from 2025 – 2060, primarily reflecting a reduction in top prices, which are increasingly set by lower-SRMC plant due to a fall in gas prices in the short term and build-out of low-carbon peaking technologies in the long term
- We see geographic variability in spreads across the country, with 2060 showing marked congestion in Scotland which leads to high spreads
- Lower electrolyser build-out compared to Net Zero aggravates local congestion issues in Scotland on lines which, in Net Zero, are upgraded within the forecast horizon, namely in the Isle of Lewis and Aberdeenshire
- Our Central line upgrade algorithm with a longer forecast horizon would see these lines upgrade too with an increased budget from congestion revenue late in the forecast

<25 >170

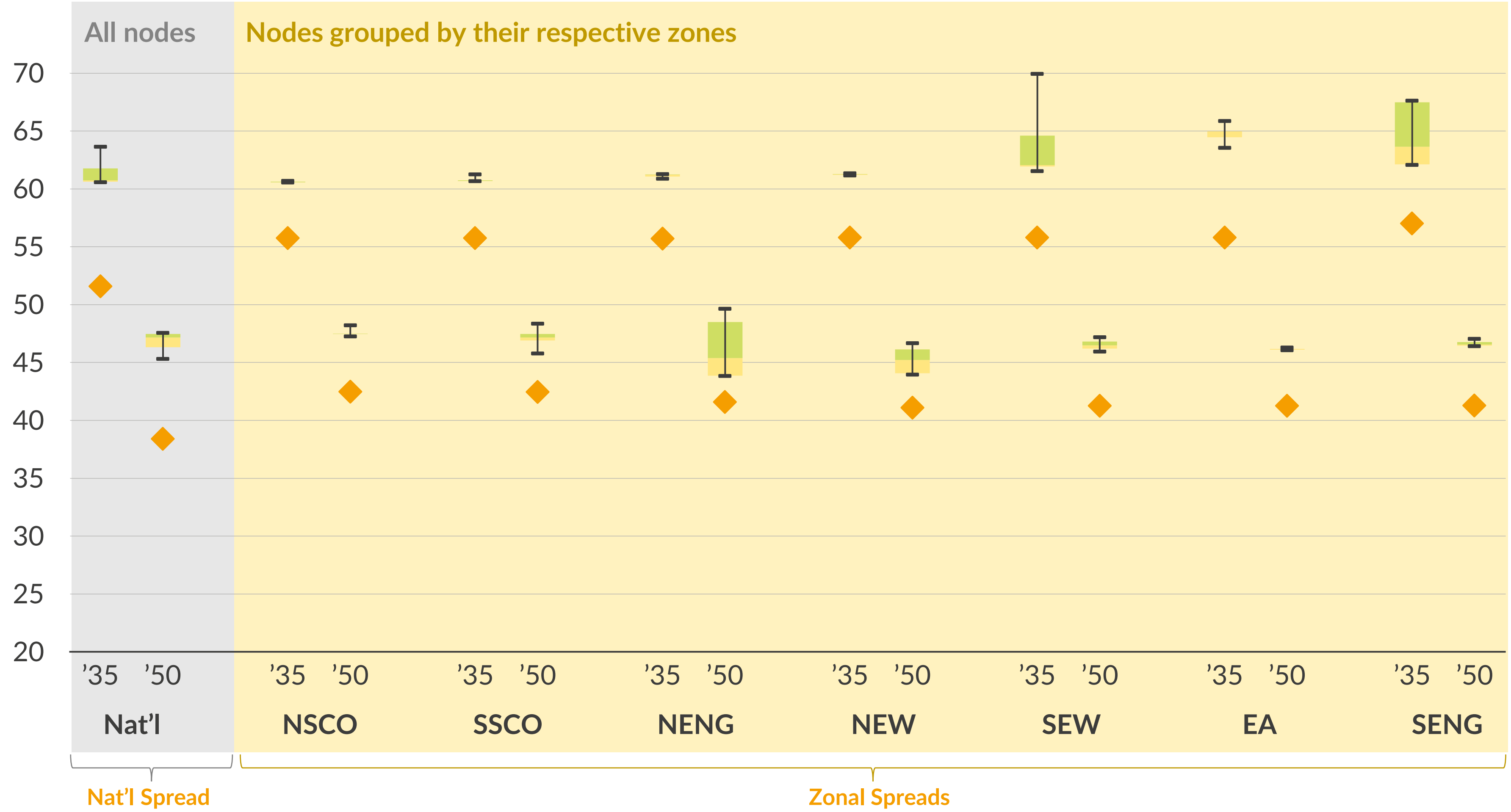
Source(s): Aurora Energy Research

Nodal price spreads continue to trend higher than national and zonal spreads, while falling over time

AURORA

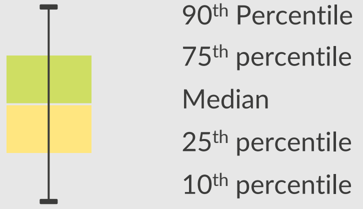
Nodal Pricing

Distribution of Nodal Average 2h Wholesale Spreads
£/MWh (real 2021)



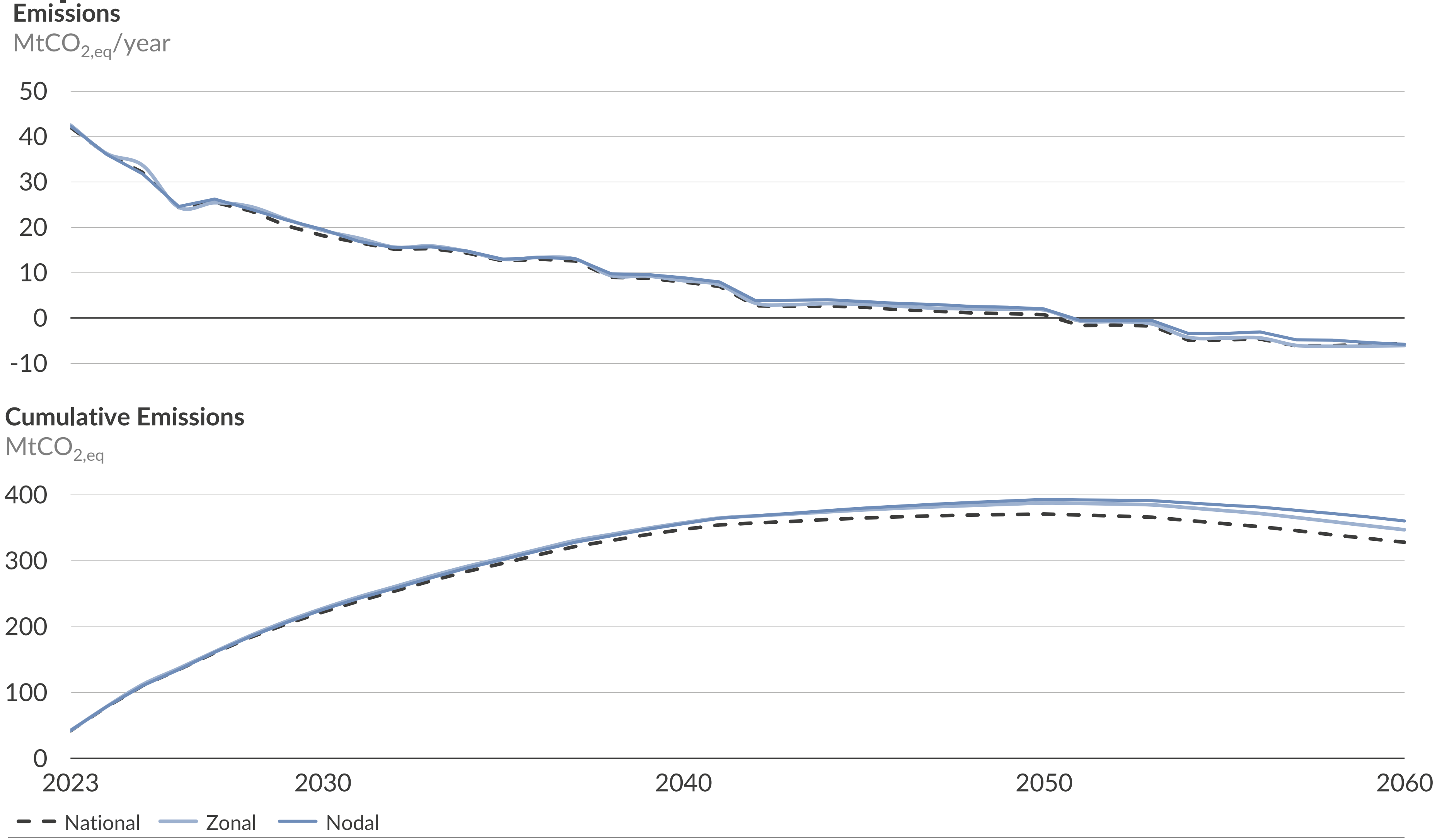
- Greater exposure to local supply/demand imbalances coupled with increased intermittent generation in the forecast leads to upwards overall pressure on nodal price spreads compared to national case
- Spreads trend in line with baseload prices for the nodal model, above both national and zonal spreads
- High volatility of spreads in the later time bands are driven by exposure to local congestion

Legend for reading nodal distribution



Source(s): Aurora Energy Research

LMP under the Central scenario leads to a 5–10% increase in emissions over the forecast due to an increase in peakers and imports



- Both the national and zonal models achieve net zero emissions around 2050 under the Central scenario
- Less policy support for decarbonisation delivers a system with fewer renewables and a slower move towards Net Zero
- Higher deployment of peakers in LMP and imports push up emissions 5–10% on average across the forecast

Source(s): Aurora Energy Research

Key Takeaways – Sensitivity of zonal results to different grid build and alternative demand placement

AURORA

1. A failure to meet ETYS line upgrade commitments would drive up zonal price divergences, increasing opportunities for spatial arbitrage for assets targeting exposure to top price and higher spreads

2. While lower grid build increases overall cost to the consumer in both national and zonal systems, zonal modelling shows that some of this cost increase could be offset by the collection of grid rents allowing targeted redistribution of these revenues back into the market

3. Benefits from placing electrolysers proportional to wind generation to benefit from lower production costs are offset by reduced grid rents and are less material in a well built-out network

4. Lower level of grid development could make Scotland one of the cheapest locations to produce hydrogen in Europe

5. A TNUoS Reform could deliver locational signals aligned with the impact of zonal pricing, and we find that this would lead to higher tariffs for renewable generators

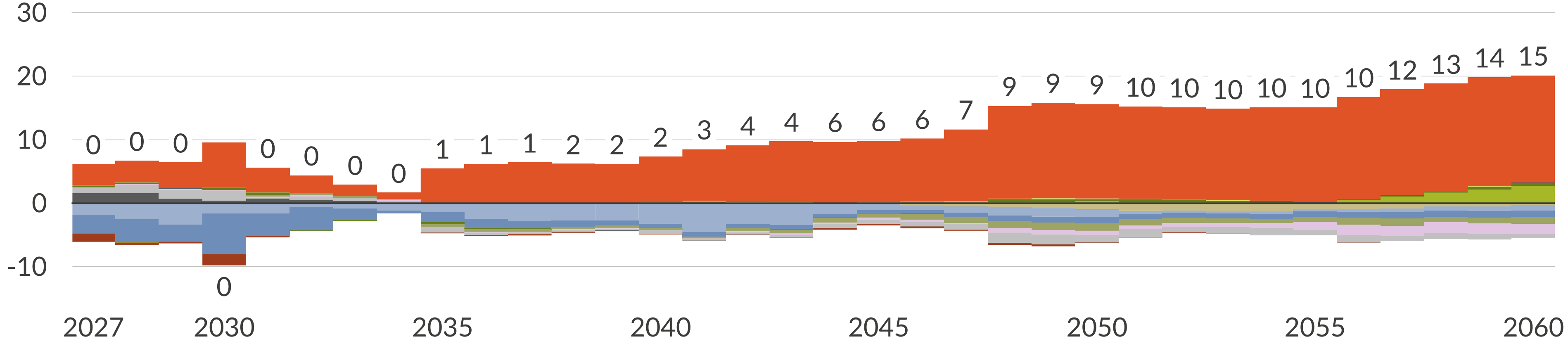
Source(s): Aurora Energy Research

With delayed and lower total transmission capacity built in the model, dispatch switches to less wind generation and increased imports

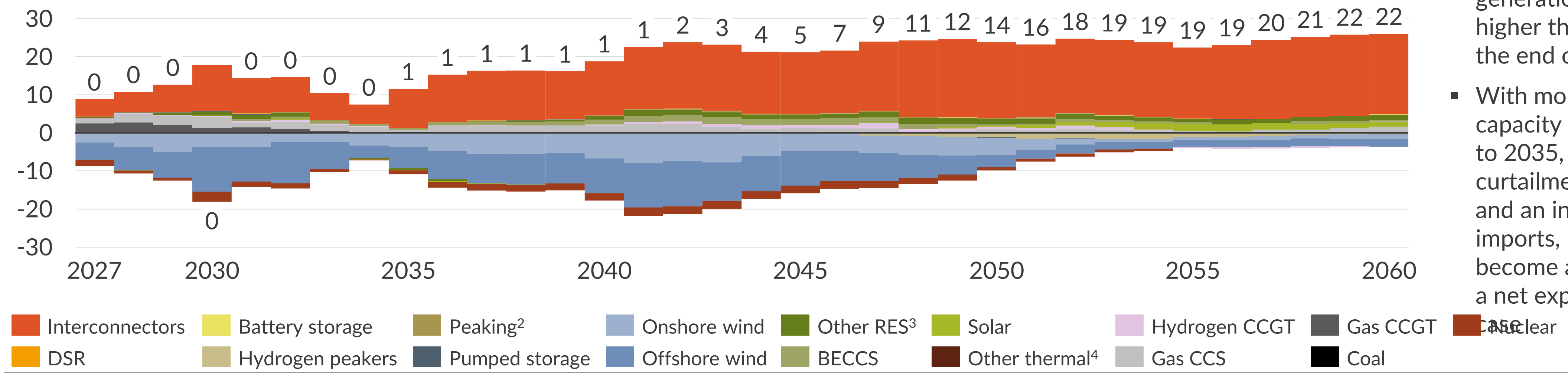
AURORA

Zonal Pricing

Generation Delta for Low Grid Build 1 vs Zonal Net Zero[1]



Generation Delta for Low Grid Build 2 vs Zonal Net Zero[1]



- Changes to net endogenous capacity built under the two transmission line sensitivities remain below 1% relative to the total capacity under the zonal Net Zero base case
- Generation changes under the first low sensitivity, delayed ETYS, ranges from around 1% to 4% change from the base case
- While under lower upgrade assumptions for sensitivity 2, delayed & missed ETYS, generation reaches 6% higher than the base case by the end of the time horizon
- With more restricted capacity build in the years up to 2035, there is more curtailment of wind assets and an increased reliance on imports, moving GB to become a net importer from a net exporter in the base case

1) Generation including net interconnector flows. 2) Peaking includes OCGT and reciprocating engines. 3) Other RES includes biomass, EfW, hydro, and marine: 4) Other thermal includes embedded CHP.

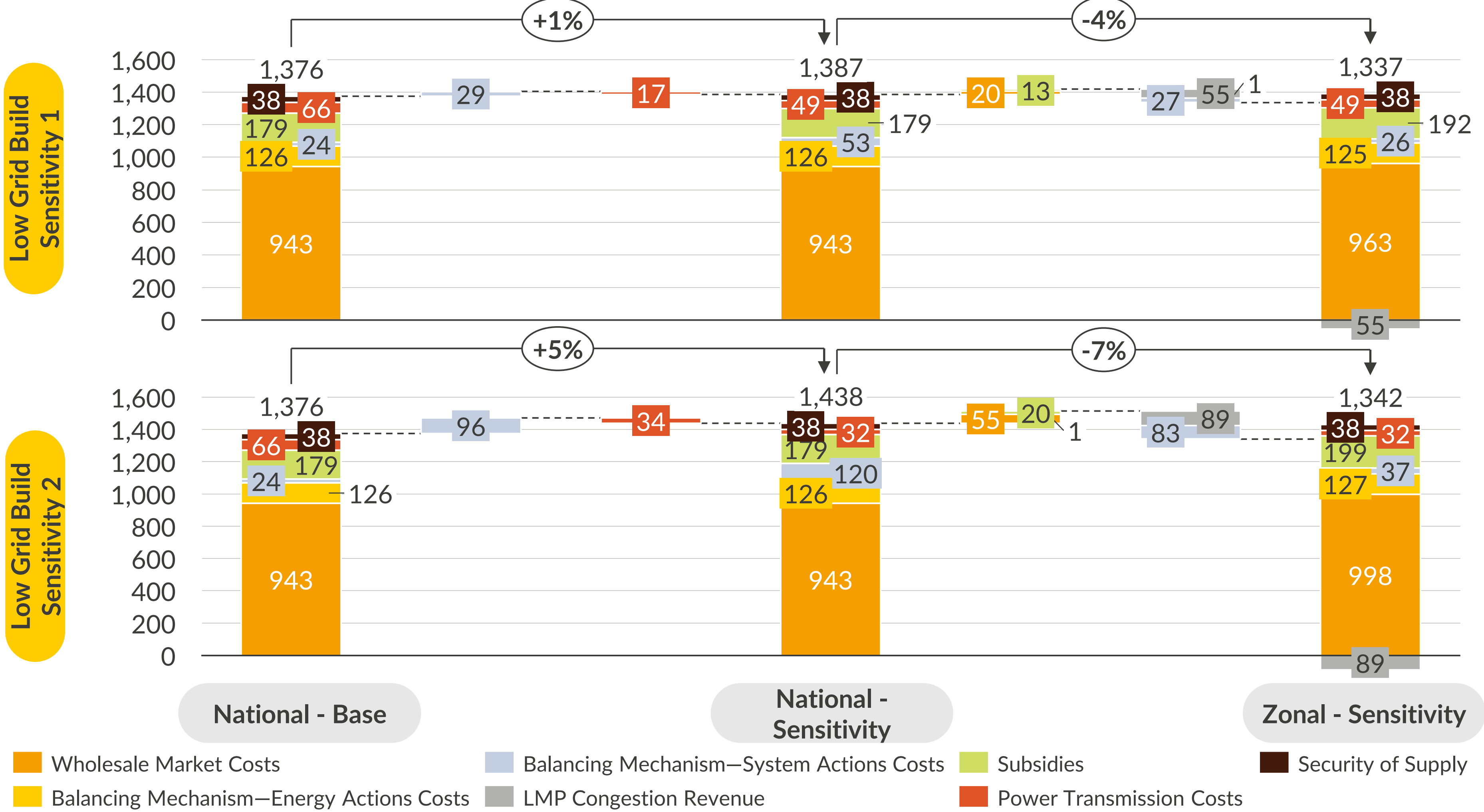
Source(s): Aurora Energy Research

AURORA

Zonal Pricing

While each model shows increased cost to the consumer in a low upgrade sensitivity, zonal grid rents provide a targeted offset to this

Total Cost to the Consumer, 2025–2060
£bn (real 2021)



- Reduced grid build leads to higher BM system actions costs within both the national and zonal models
- Wholesale Market costs increase between a national and zonal market, driven by the transfer of BM system costs into the Wholesale price
- Subsidy costs also increase, required to offset curtailment of RES assets
- Zonal LMP handles delayed grid build better than the national model, with grid rents offsetting other cost increases, and providing a more targeted approach to grid management
- The benefits of grid rents will only be perceived by consumers where these are reinvested back into grid development or go towards reducing consumer bills

Source(s): Aurora Energy Research

The impact of reduced transmission grid build is amplified in a zonal market relative to a national market

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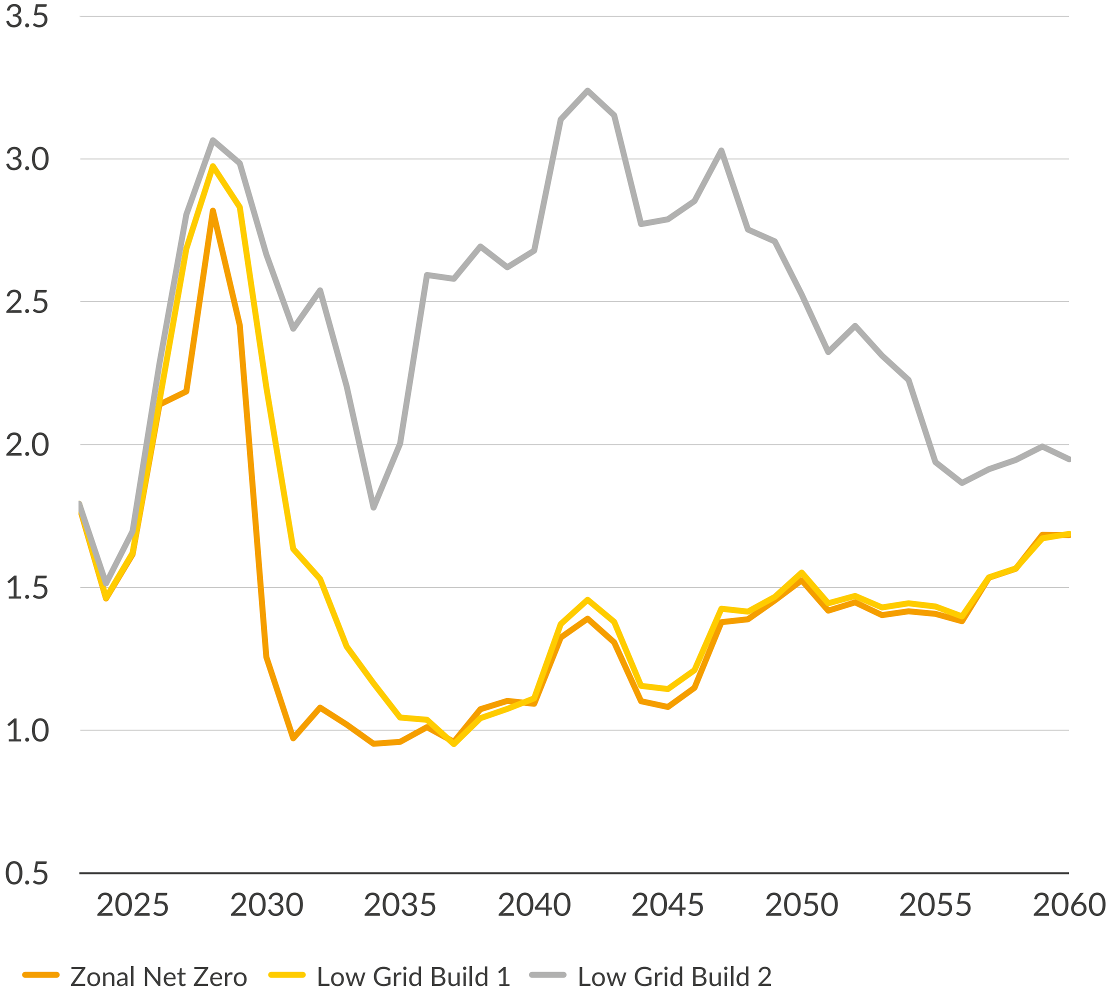
Zonal Pricing

Congestion Revenue for Zonal Net Zero vs Low Grid Build Sensitivities
£bn



- Under LMP, a reduced grid build sends stronger locational investment signals, due to zonal price differentials, volatility and price spreads, with mismatched demand and supply requiring higher capacity built on the system
- In contrast, in a national market, locational signals are delivered through TNUoS or system actions in the BM, with the latter reflecting congestion constraints
- A single market mechanism may deliver a clearer signal for asset build. This is likely to lead to a change in the technology mix on the market, and therefore eventually to a change in both technologies contributing towards dispatch – and therefore emissions – and overall system costs
- Sustained congestion across boundaries under zonal LMP generates congestion rent for the grid operator, which offsets increases in overall cost to the consumer and highlights the optimal boundary upgrade requirements

Source(s): Aurora Energy Research

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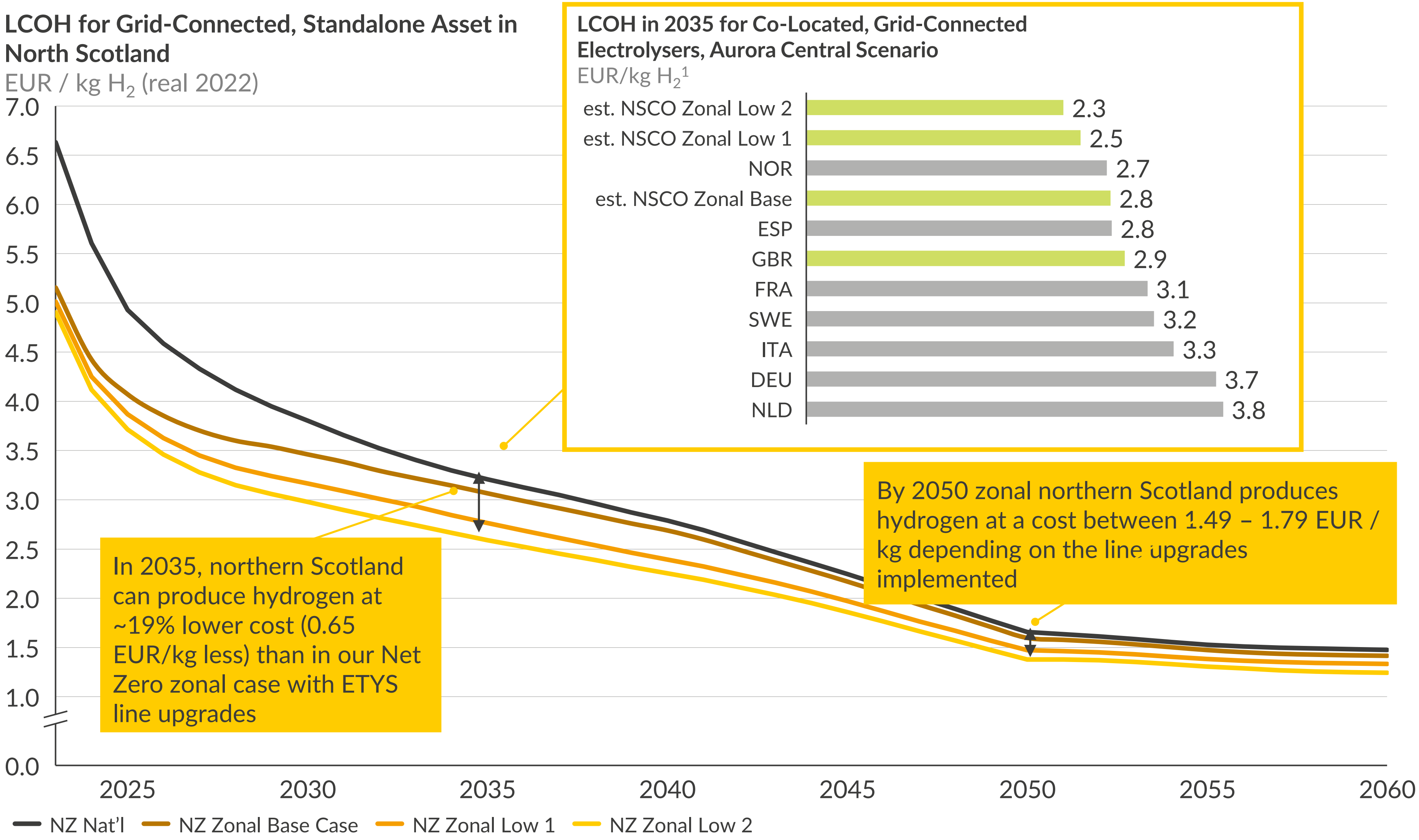
With a more constrained GB grid, LMP could position northern Scotland more competitively for hydrogen generation in Europe

LCOH for Grid-Connected, Standalone Asset in North Scotland

EUR / kg H_2 (real 2022)



- Aurora expects significant growth in European green hydrogen production by 2035. Whilst early projects are often located close to demand, we ultimately expect European hydrogen trade and therefore greater locational optionality
- With hydrogen electrolyser demand growing across the 2030s, this demand can be met with cheap hydrogen production in the north of Scotland, where sustained boundary congestions maintains low electricity prices for grid connected electrolysers
- Low Wholesale electricity costs in northern Scotland could reduce the levelized cost of hydrogen (LCOH) of a grid connected, co-located PEM electrolyser by around 0.30–0.50 EUR/kg H_2
- A reduction in cost of this magnitude could make Scotland one of the most competitive locations for hydrogen production across Europe

1) Comparison provides sizing estimate only, achieved LCOH by country will differ based on the business case. Zonal LCOH assumed a grid connected asset rather than island set-up.

Source(s): Aurora Energy Research

Concentration of demand is moved around GB by placing electrolysers in zones with most wind generation and lowest prices

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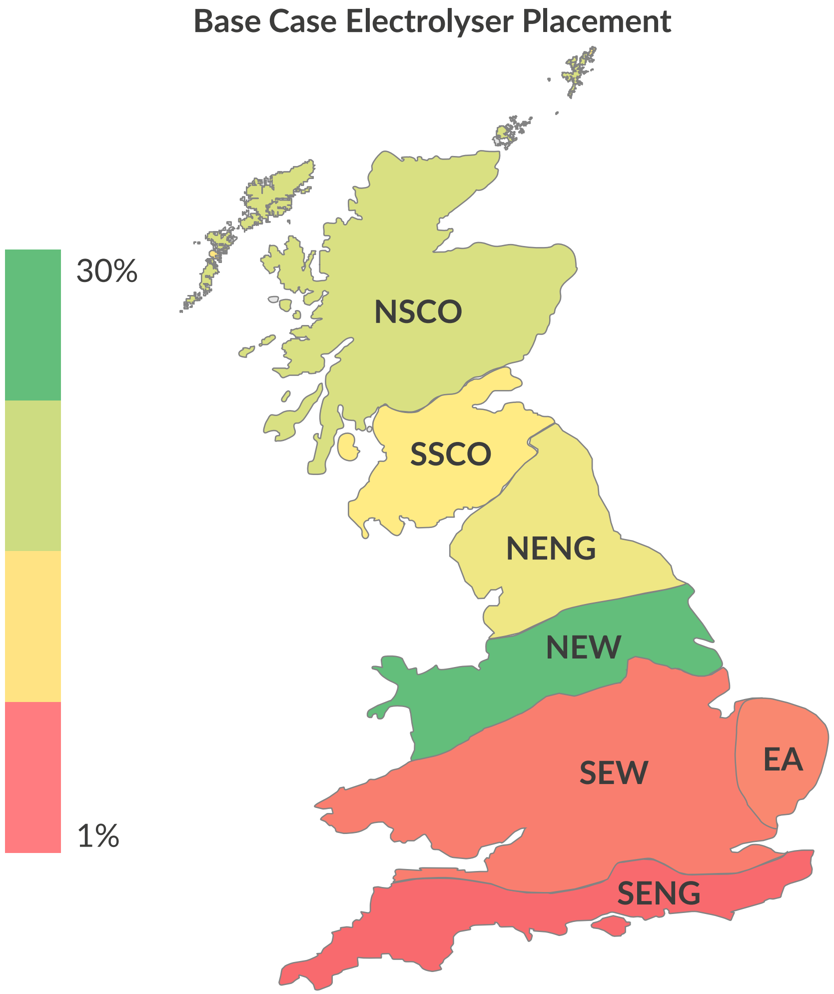
Average Percentage of Total Electrolyser Demand by Zone

%



- Under the base case, electrolyser capacities are distributed across zones based on a combination of Aurora's view on the project pipeline, stated policy, and build-out of renewables. This results in most electrolyser demand in North England and Wales
- Under the alternative placement, electrolyser build-out is directly correlated with the build-out of onshore and offshore wind, reflecting the likely co-location of green hydrogen production and RES generation. This concentrates electrolyser demand in Scotland and East Anglia, taking advantage of low prices in these zones
- In practice, siting this quantity of electrolysers in Northern Scotland and trucking/piping hydrogen is a difficult solution and the respective costs would need to be weighed against the benefits to the business case and the system

Source(s): Aurora Energy Research

In the short term, higher wind generation is driven by electrolysers capturing spill while zonal boundaries remain constrained

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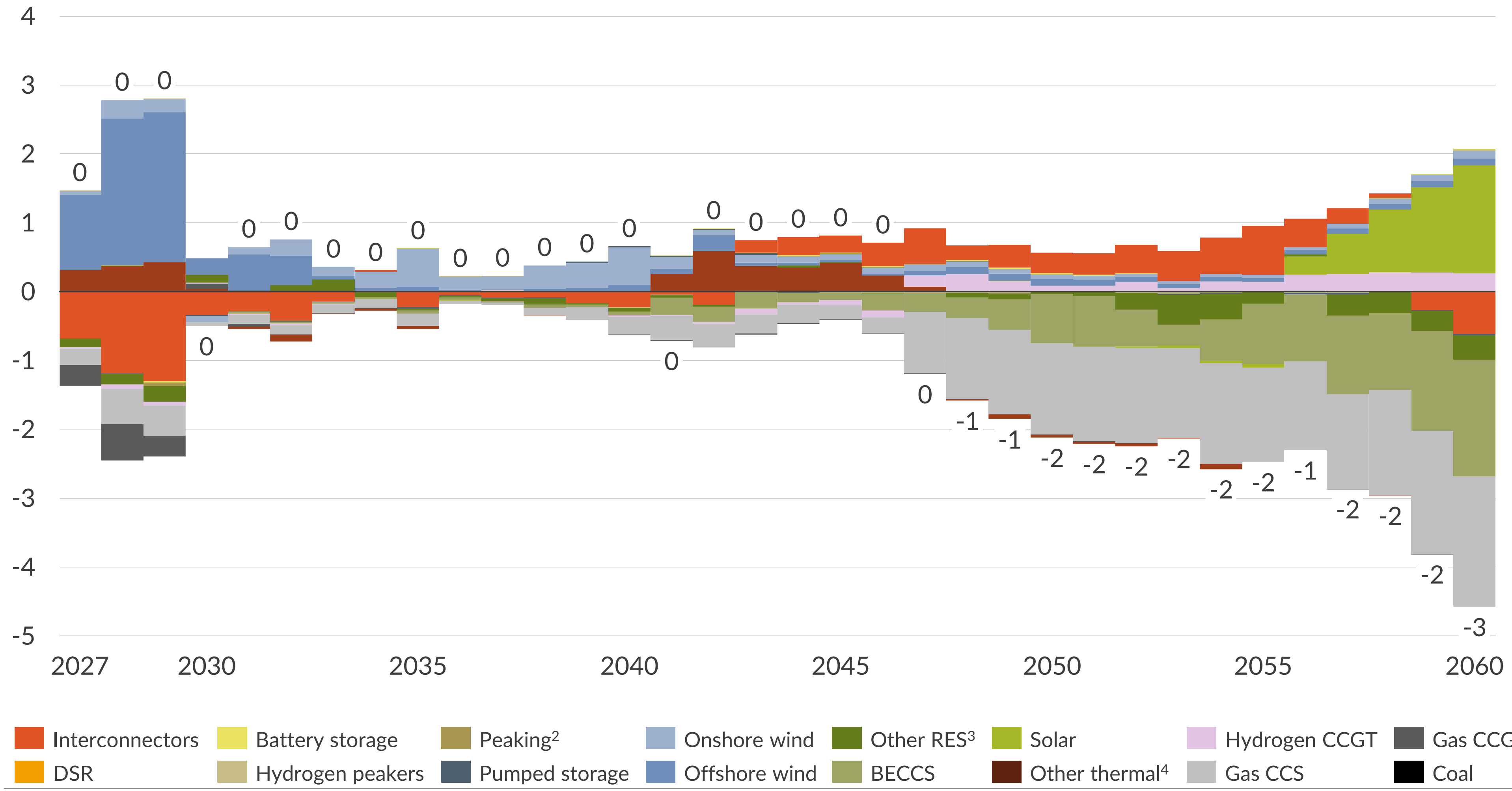
Zonal Pricing

Generation Delta in Alternative Demand Sensitivity vs Zonal Net Zero [1]
TWh



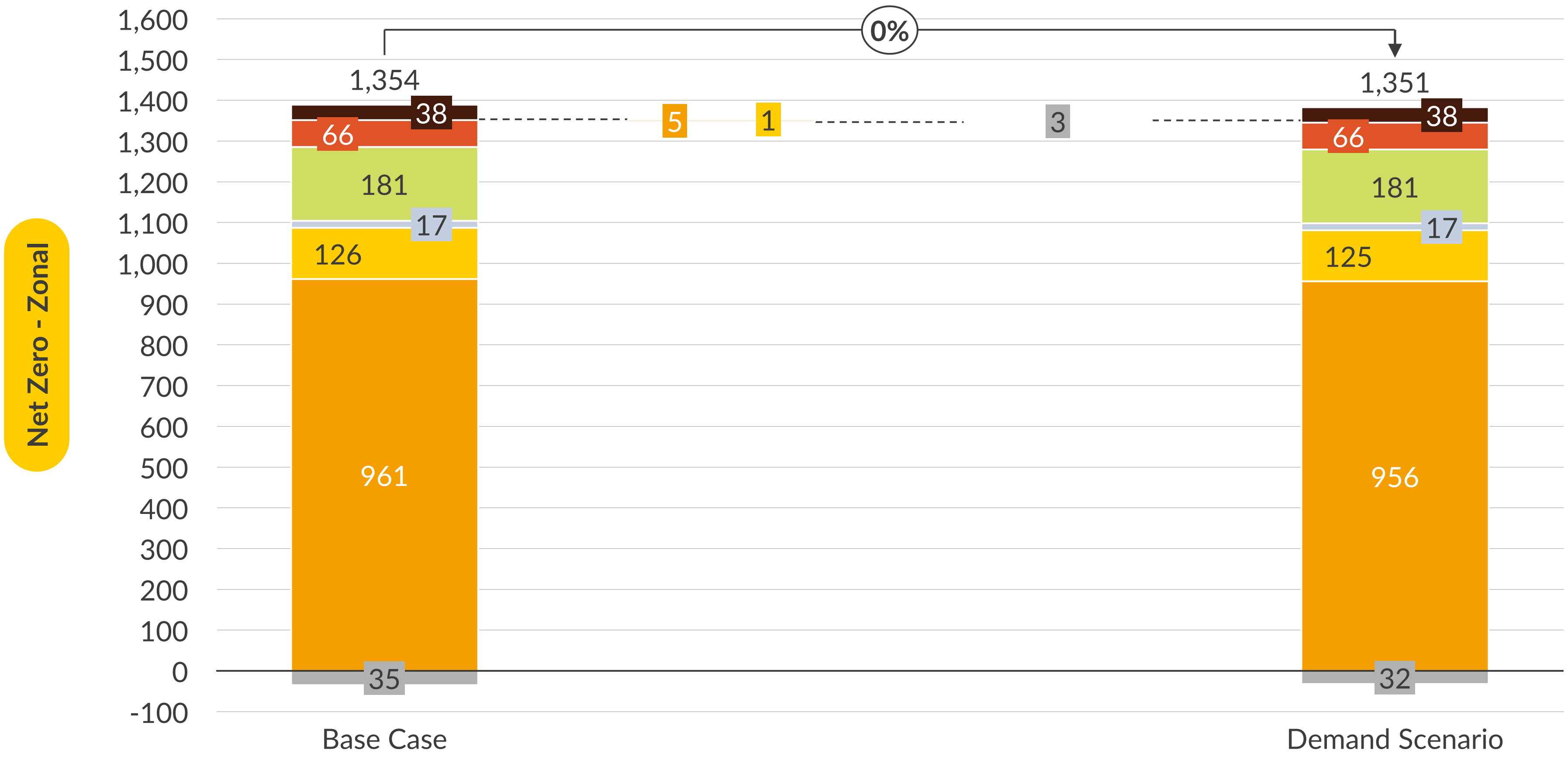
- Increased electrolyser demand in zones with large amounts of offshore wind (North Scotland and East Anglia) acts to reduce curtailment of off- and onshore wind in the 2020s and 2030s relative to the base case
- In the long term, the effect of moving demand is reduced since boundary upgrades relieve congestion and reduce curtailment in the base case
- We see slightly less generation from BECCS and CCGT+CCS in North England post-2045 since reduced electrolyser capacity reduces total demand in these zones

1) Generation including net interconnector flows. 2) Peaking includes OCGT and reciprocating engines. 3) Other RES includes biomass, EfW, hydro, and marine: 4) Other thermal includes embedded CHP.

Source(s): Aurora Energy Research

Power sector benefits to optimised electrolyser placement are offset by reduced grid rents, and less impactful on a well built-out network

Total Cost to the Consumer, 2025–2060
£bn (real 2021)



- Cheaper prices in the short term (up to early 2030s), push down Wholesale costs marginally
- However, looking at the full timeframe of 2025 - 2060, sustained grid build-out and reduced grid rents reduce the net benefit as generation circulates across the network unconstrained
- The benefits in this sensitivity accrue outside power in the form of lower hydrogen costs
- In an LMP world with less transmission grid built across GB, it could be assumed that the cost of hydrogen production is reduced even further than that observed under the sensitivity assessment of zonal modelling to line upgrades, as electrolysers are optimally placed to benefit from the low electricity costs in northern Scotland

Source(s): Aurora Energy Research

A TNUoS reform could change locational signals to be more aligned with the impact of zonal pricing mechanisms

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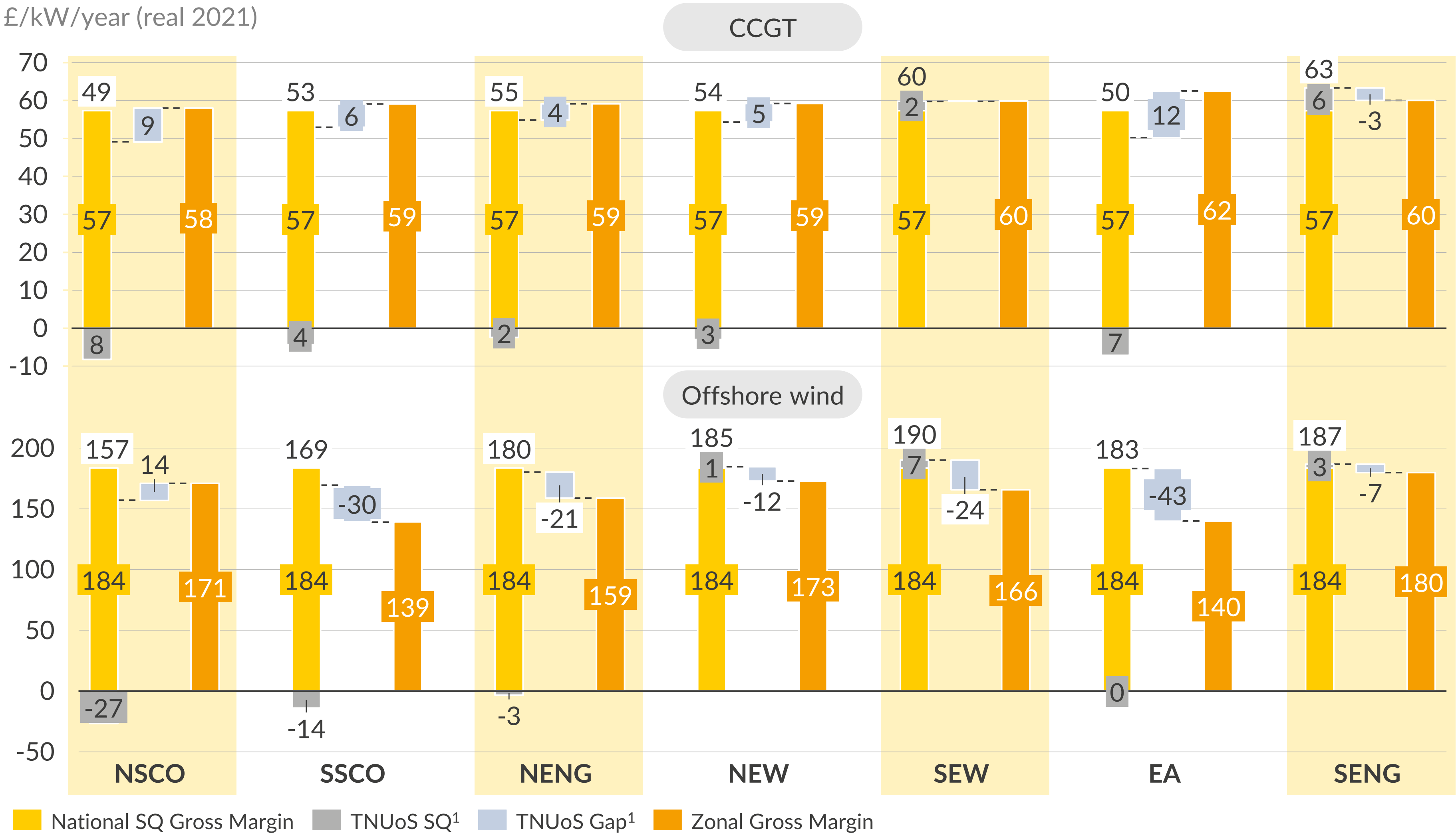
Net Zero

Average Gross Margins for Select Technologies (2025–2060)
£/kW/year (real 2021)



1) In this instance, positive TNUoS represents a benefit (i.e., negative charge), and negative TNUoS represents a cost (i.e., positive charge).

Source(s): Aurora Energy Research

- This case explores what level of TNUoS reform is necessary under Net Zero National (Status Quo) to achieve similar profitability for assets as is accomplished by Zonal Locational Marginal Pricing
- To do so, we've compared assets gross margin stacks under National Net Zero with TNUoS included to the gross margins estimated under Zonal LMP for Net Zero. The difference between these two values suggest the increment of TNUoS wider charges that should be added to/removed from assets
- In practice, **this would require completely reforming TNUoS** to no longer reflect costs for the transmission network to assets, but purely to capture an LMP-like investment signal

On average over 2025–2060, renewables stand to face higher Wider TNUoS tariffs to provide a comparable investment signal as Zonal LMP

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Net Zero

Wider TNUoS Tariff to Have Comparable Locational Signal as Zonal LMP, 2025–2060 Average (Delta to Original)[1,2], £/kW/year

Aurora LMP Zone	Current TNUoS Zone	CCGT (CC)	CCGT w/ CCS (CLC)	Offshore Wind (Int.)	Onshore Wind (Int.)	Solar PV (Int.)	Gas Recip. (CC)	H_2 Peaker (CLC)	1-hour Battery (CC)	2-hour Battery (CC)	4-hour Battery (CC)
NSCO	1–7	-8.9 (-17.2)	-13.3 (-38.7)	-14.0 (-40.7)	36.4 (11.5)	-10.3 (-32.0)	-17.4 (-22.6)	-37.5 (-61.6)	-10.5 (-16.7)	-20.9 (-31.8)	-22.5 (-33.3)
SSCO	8–11	-6.1 (-10.4)	-3.3 (-16.4)	30.3 (16.1)	27.0 (14.1)	-0.8 (-11.2)	-14.4 (-17.2)	-25.5 (-37.5)	-8.0 (-11.3)	-13.3 (-19.0)	-14.0 (-19.6)
NENG	12–15	-4.3 (-6.8)	4.7 (0.1)	21.4 (17.9)	43.9 (41.2)	7.2 (5.9)	-13.7 (-15.7)	-17.5 (-21.5)	-6.1 (-8.3)	-9.1 (-11.9)	-9.9 (-12.8)
NEW	15–17, 19	-4.9 (-7.9)	5.1 (2.2)	11.7 (12.7)	40.6 (41.8)	8.3 (10.1)	-13.4 (-16.4)	-16.2 (-18.8)	-7.4 (-10.3)	-8.2 (-11.2)	-9.1 (-12.1)
SEW	18–23	-0.1 (2.4)	11.5 (16.2)	24.4 (30.9)	24.4 (30.9)	13.0 (19.5)	-8.4 (-6.1)	-8.8 (-4.0)	-2.3 (-0.0)	-3.8 (-1.1)	-4.7 (-2.0)
EA	18	-12.4 (-19.5)	9.5 (10.1)	43.3 (42.8)	57.2 (57.4)	7.3 (8.8)	-18.4 (-25.5)	-12.4 (-11.2)	-12.1 (-19.2)	-16.5 (-23.8)	-17.3 (-24.6)
SENG	24–27	3.3 (9.3)	8.0 (12.4)	6.9 (10.0)	10.1 (12.9)	4.7 (7.0)	-5.0 (0.7)	-9.3 (-5.2)	1.0 (6.8)	-1.3 (5.0)	-1.0 (5.3)

Decreased tariff | Decreased tariff but still a cost | Increased tariff | Increased tariff but still a benefit

- Most technologies except renewables, would face reduced Wider Tariffs across most regions in order to achieve a comparable impact to LMP under Net Zero
- A standout case is Southern England (SENG), which is a continually constrained zone in our modelling. The needed TNUoS reform provides negative charges (benefit) for flexible technologies (Gas recip., H_2 Peaker, and 2–4-hour batteries)
- **It should be noted that this is based on a particular scenario using Aurora Net Zero and assumes sufficient grid built-out throughout the forecast**
  – which results in some counterintuitive propositions such as offshore wind in Northern Scotland receiving TNUoS as a benefit under a potential reform—due to these assets having a sufficient route-to-market (low curtailment) coupled with high load factors
  – these results could change significantly depending on assumptions of network development and the pathways to decarbonisation

1) In this instance, negative TNUoS charge represents a benefit and a positive TNUoS charge represents a cost . 2) CCGT, Recip, and Batteries are classed as Conventional Carbon generators; CCGT + CCS and H_2 Peaker as Conventional Low Carbon; and Offshore Wind, Onshore Wind and Solar PV as Intermittent per TNUoS calculations. See the XI. Appendix | Aurora's Modelling Assumptions – Wider TNUoS Tariffs for Aurora's assumptions on TNUoS

Source(s): Aurora Energy Research, NGESO

Agenda

The effectiveness of LMP as a mechanism aimed at reducing costs and supporting decarbonisation will depend on complementary policies (1/2)

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Effectiveness of LMP is measured in its ability to transmit differentiated locational signals to market participants while reducing the overall system cost

REMA – range of reforms to market arrangements working towards alleviating the energy trilemma objectives

- Supply (constrained siting decisions) and demand (electrolysers, smart demand) is not as mobile as required for LMP mechanics to have an effect
- Timing of the implementation of new market mechanics would be too slow to capture pricing benefits
- Lack of clarity on distinctions between zonal and nodal specificities leading to a lack of clarity on which mechanism would benefit the GB market

LMP Results

- Electrolyser placement near high wind generation sites could position Scotland competitively for hydrogen production in Europe, while shielding RES through subsidy support or siting constraints is likely to lead to minimal differentiation of system composition from LMP
- Optimal timing for a switch to LMP from a cost to the consumer perspective would be in the late '20s, early '30s, however reality of implementation within this timeframe is questionable
- A nodal system achieves more targeted revenue from system constraints and so has a better ability to reduce cost to the consumer than zonal, providing this revenue is reinvested into the system

Net Zero – Decarbonisation of energy by 2035

- Changing investment signals could lead to a delay in the decarbonisation of the electricity sector

LMP Results

- Aurora modelling assumes a limited ability for investment to respond to LMP signals and change course from current build direction
- Responsiveness of LMP therefore stays in line with national, with emissions entirely dependent on how much RES, CCS and hydrogen is forced onto the system through policy support (contrast of Central to Net Zero scenarios)
- Neither nodal nor zonal appears to translate market signals into faster decarbonisation benefits than a national market

Source(s): Aurora Energy Research

The effectiveness of LMP as a mechanism aimed at reducing costs and supporting decarbonisation will depend on complementary policies (2/2)

AURORA

Effectiveness of LMP is measured in its ability to transmit differentiated locational signals to market participants while reducing the overall system cost

ETYS (incl. HND, ASTI, and eventual Centralised Strategic Network Plan – grid development required to support Net Zero

- Grid development processes/initiatives take results from The Crown Estate and Crown Estate Scotland decision-making on seabed leasing into account, , which consider a range of factors including other seabed uses and grid connection availability
- Increasing energy demand on an already constrained GB grid risks losing the potential LMP benefits

LMP Results

- Sustained grid build-out in line with ETYS 22, HND and beyond, move GB towards price equilibrium towards the late 2030s
- Reduced grid build-out leads to price polarisations across the country even as average price goes down, supported by deployment of RES assets, with southern zones increasingly dependent on potentially costly imports and northern zones shielded from high interzonal demand pushing down bottom percentile prices
- Higher volatility and spreads on a low grid build system provide opportunities for market participants seeking exposure to spreads, while potentially driving away market investors seeking out higher levels of stability

Other market reforms – BM or TNUoS Reforms

- The BM does not currently allow all asset types to participate equally and transparently in resolving constraints
- TNUoS signals have not historically changed location decisions for offshore wind generation

LMP Results

- Switching to LMP allows cost to the consumer from the BM to be resolved by all asset types under the Wholesale Market, which could be alternatively achieved through reform to the BM
- Zonal prices under LMP are a product of grid build, remaining more polarised in a system with less transmission capacity and therefore providing a stronger signal for optimal location of generation. This signal is most effective in a market where generators are unconstrained on siting decisions (e.g., seabed leasing, grid connections)

Source(s): Aurora Energy Research

Details and disclaimer

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Locational Marginal Pricing in Great Britain

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