Review of electricity market design in Great Britain

26th September 2023

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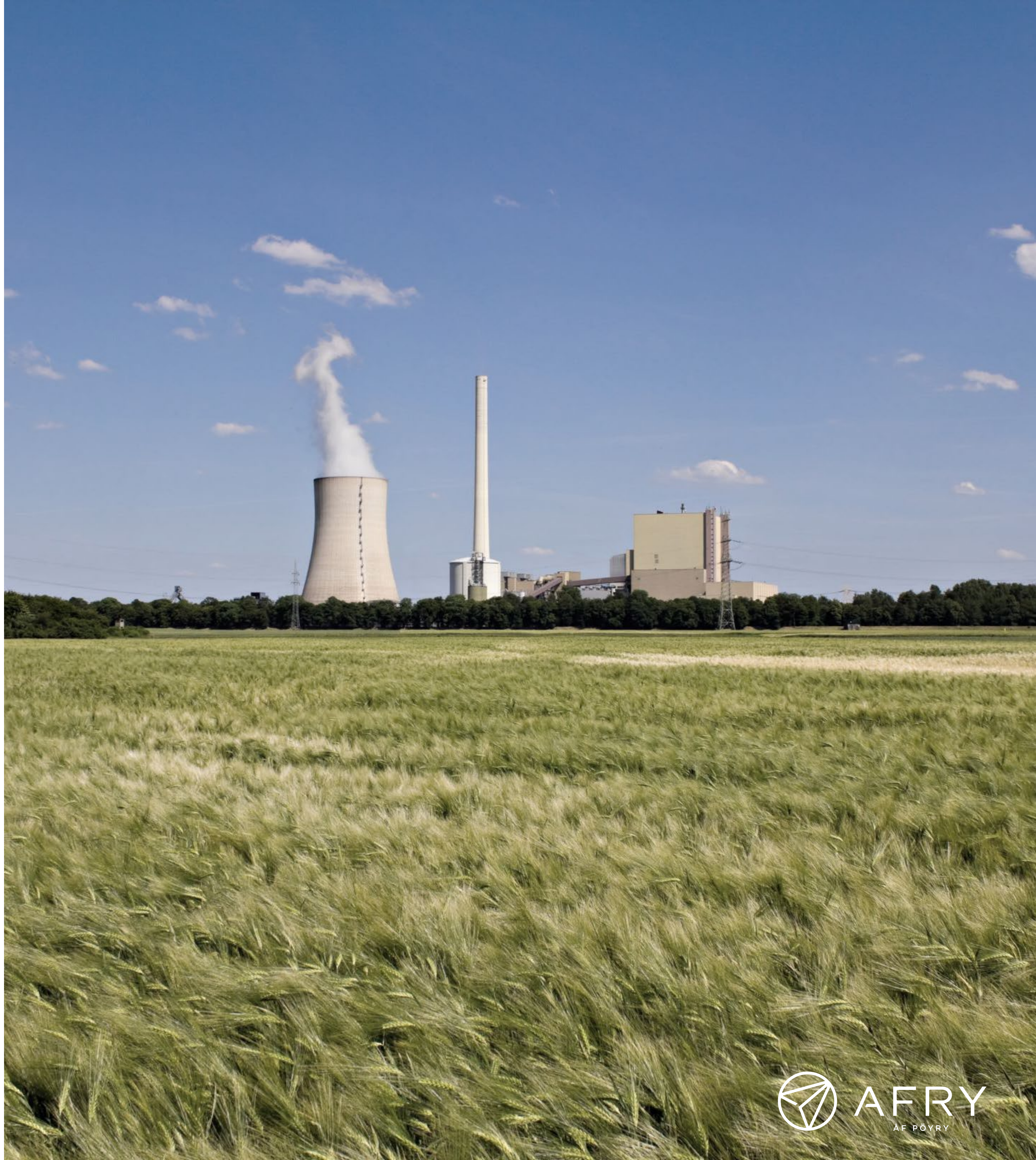
Before we start…

- Please **ask questions** throughout the webinar using the question panel – we'll cover as many as we can at the end.

- The **slide pack and recording** will be available on our website to all attendees as soon as they're available.



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AFRY has completed a multiclient study on options for revising electricity market design in Great Britain

BACKGROUND

- Various public and private entities have questioned whether GB's current market arrangement are fit for net zero by 2050
- In March 2022, National Grid ESO proposed **a centralised, nodal wholesale market design** with co-optimised energy and ancillary services
- During July to October 2022, BEIS (Department for Energy Security and Net Zero) ran a consultation on a **Review of Electricity Market Arrangements (REMA)**, with a very broad scope and a wide range of possible reforms. Responses were published March 2023, and ruled out some options as shown on the right.
- The whole industry senses that that there is a need to **explore alternatives** to such a fundamental re-design, and also to **objectively explore** the challenges and potential downsides
- AFRY completed **Phase 1** of a two-Phase multi-client study examining alternative market designs qualitatively in October 2022.
- **Phase 2,** which has entailed modelling and quantitative evaluation of the revised market designs, has just been completed.
- The study has been financially supported by a range of stakeholders from the GB electricity market. We have also benefited from the participation of representatives from National Grid ESO, National Grid ET, DESNZ and Ofgem as observers in the project meetings

SCOPE OF THE REMA CONSULTATION

Figure 1: A map of the options space highlighting options discounted based on consultation feedback.

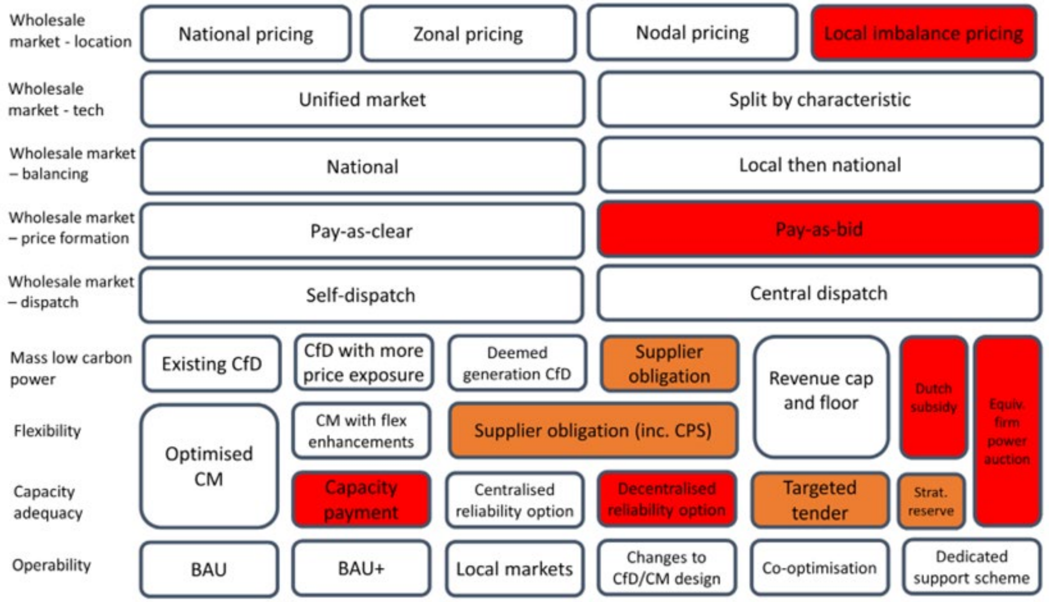


Image source: REMA Consultation Response (2023)

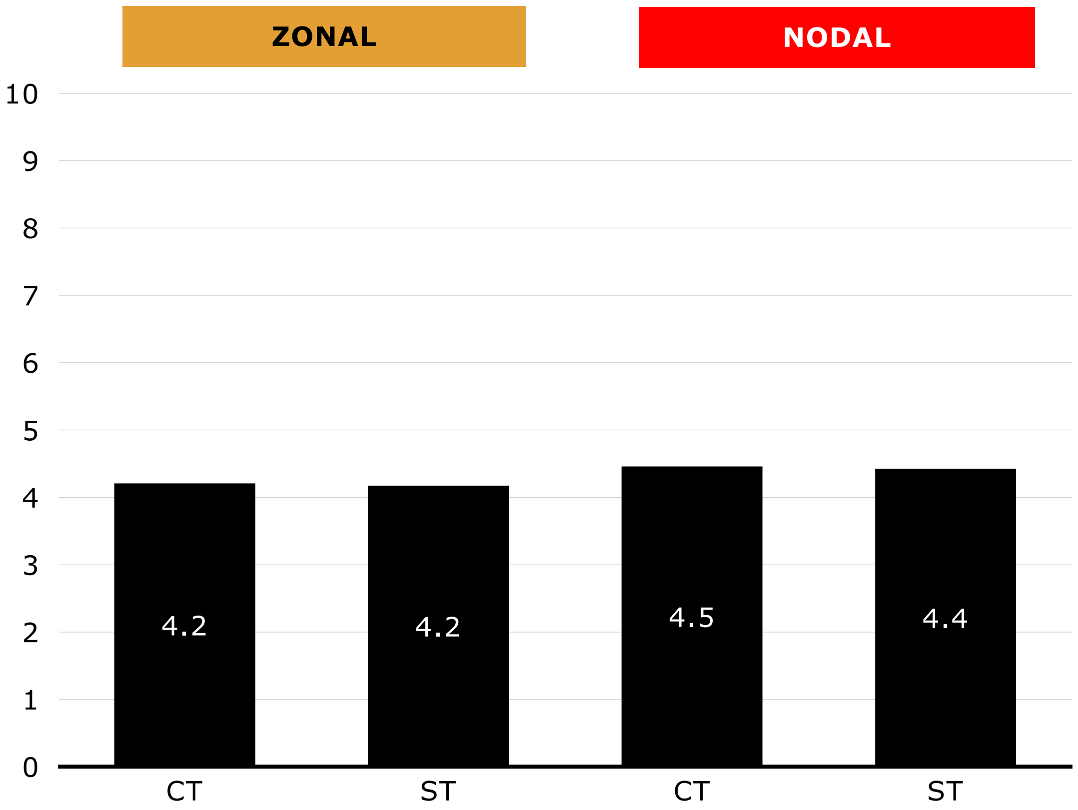
The Phase 2 quantitative analysis has focused on the locational aspects of the current market design debate

- We have modelled three main market design cases - a National BAU baseline, Zonal, and Nodal, reflecting coherent design choices on:
  - Energy market granularity: national, 11 zones or 511 nodes
  - Locational grid charges: national cases only, zero in zonal and nodal cases
  - Market redispatch to respect transmission constraints: zonal for National BAU, nodal for zonal cases with redispatch
  - Renewable support arrangements: BAU CfD arrangements (National BAU case only) or deemed generation CfD arrangements with revised award mechanism based on least-cost of top-up payments (all cases except National BAU)
  - We also modelled an alternative 'National Enhanced' case, and sensitivity cases on delayed network build and cost of capital
- Each case has been modelled against two scenarios, based on the Consumer Transformation (CT) and System Transformation (ST) scenarios from NGESO's Future Energy Scenarios (FES) 2022
  - both achieve a net zero power grid by 2035, but under different decarbonisation pathways
  - we added a requirement to both scenarios to meet the 50GW offshore wind target by 2035
  - capacity expansion is based on exogeneous input assumptions from the FES 2022, with locations based on the Energy Ten Year Statement (ETYS) 2022, plus additional economic capacity built endogenously within the model (subject to constraints)
  - network expansion is based on exogeneous assumptions from the ETYS 2022 and NOA7 until 2030, plus economic assessment of Holistic Network Development plan (HND) options; from 2035 there is endogenous network expansion
- We have used a socio-economic welfare assessment as an all-in way of comparing the benefits or disbenefits of different locational market designs

There is only a small potential economic welfare benefit from changing to a locational energy market, representing about 1% of consumer bills

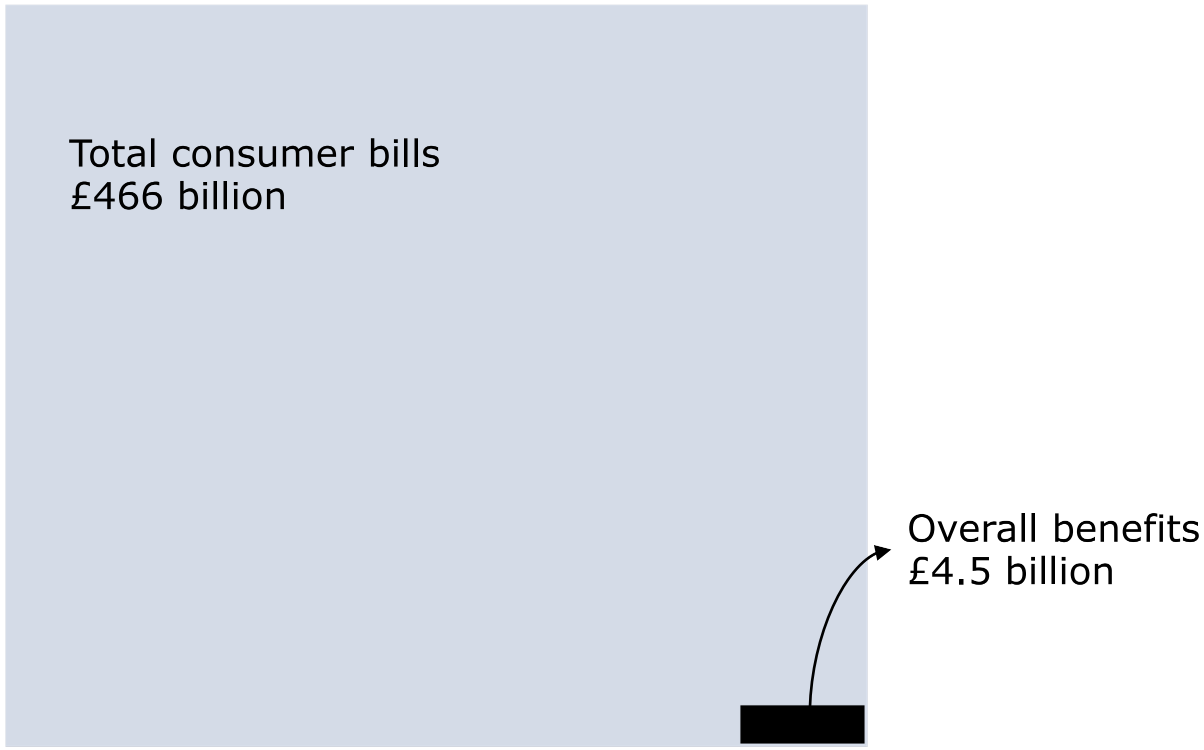
TOTAL ECONOMIC WELFARE BENEFIT, ZONAL AND NODAL CASES VERSUS NATIONAL BAU BY SCENARIO

Net Present Value 2028-50 at 3.5% discount rate (£billion real 2021)



TOTAL ECONOMIC WELFARE BENEFIT COMPARED WITH CONSUMER BILLS

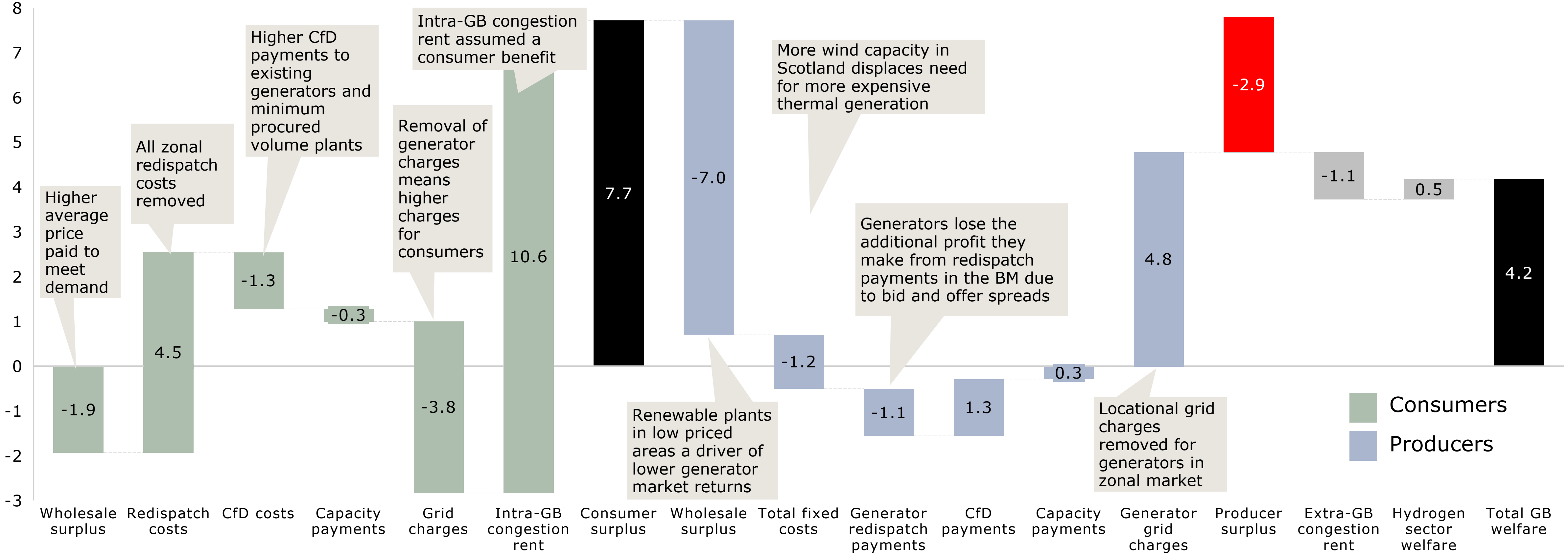
Net Present Value 2028-50 at 3.5% discount rate (£billion real 2021)



The small potential welfare gains from locational markets risk being overshadowed by distributional issues

TOTAL ECONOMIC WELFARE BENEFIT BREAKDOWN, ZONAL VERSUS NATIONAL BAU, SYSTEM TRANSFORMATION

Net Present Value 2028-50 at 3.5% discount rate (£billion real 2021)



Locational markets might not strengthen locational investment signals compared to current national market arrangements

LOCATIONAL SIGNAL STRENGTH BY TECHNOLOGY

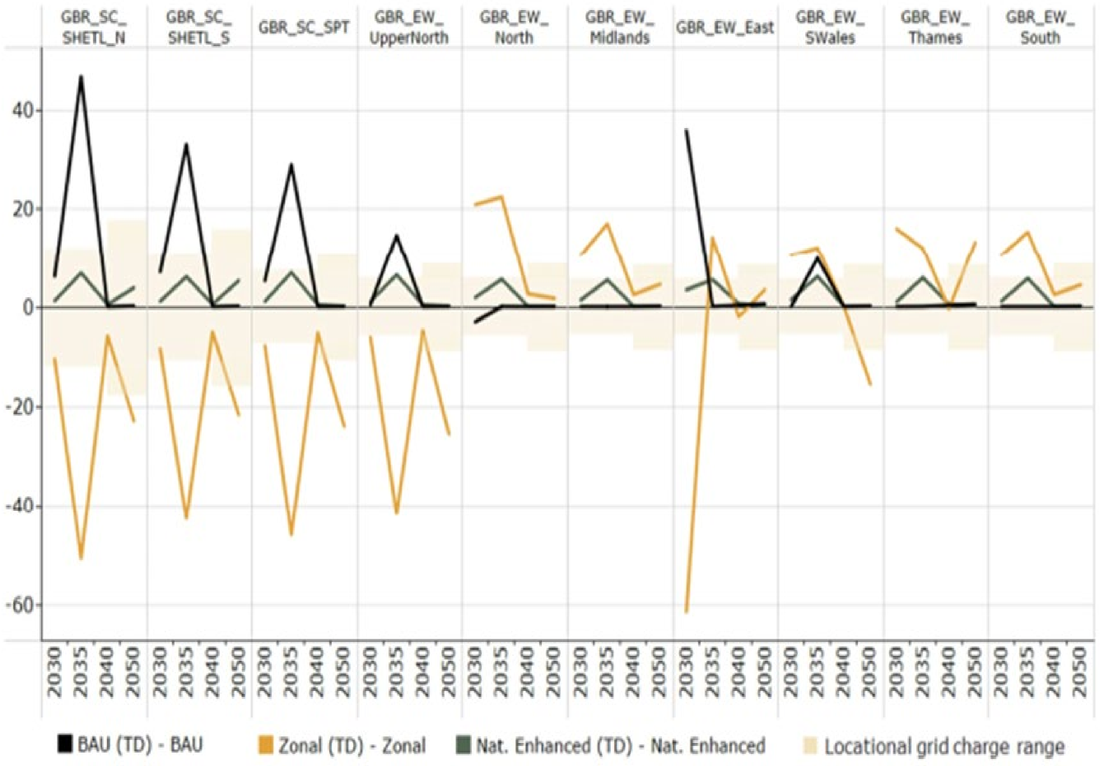
		2030	2035	2040	2050
Onshore wind	Zonal	●●●	●●	●●	●●
	National BAU	●●	●●●	●●●	●●●
Solar PV	Zonal	●	●	●	●
	National BAU	●●●	●●●	●●●	●●●
Offshore wind	Zonal	●●●	●●	●●	●●
	National BAU	●●	●●●	●●●	●●●
Gas CCS	Zonal	●●●	●●	●●	●●
	National BAU	●●●	●●●	●●●	●●●
Batteries	Zonal	●◑	●◑	●◑	●◑
	National BAU	●	●	●	●

- A stronger or sharper locational signal is defined as one that provides larger incentives for generation to locate closer to demand (typically meaning further south)
- Across the modelled cases, we have captured the overall locational signal strength faced by market participants by modelling both locational energy prices (present in the zonal and nodal cases, and absent in the national cases), as well as locational grid charges (absent in the zonal and nodal cases, present in the national cases).
- We have examined a metric based on wholesale energy market gross margins to compare changes in overall locational signal between cases
- We find that for many technologies including onshore wind, offshore wind and gas plants (with CCS), locational signals under a zonal or nodal market design are sharper until 2030 but weaker by 2035
- Longer term, and contrary to conventional wisdom, today’s national market with locational transmission network charging would provide a stronger signal. This reflects our assumption that network congestion will reduce over time as network build is progressed.

Risks to investor confidence are larger in a locational market, with the potential to cause large risks to unhedged generators

IMPACTS OF TRANSMISSION DELAY COMPARED

Energy market plus redispatch gross margins for merchant onshore wind, Consumer Transformation scenario (£/kW, real 2021)

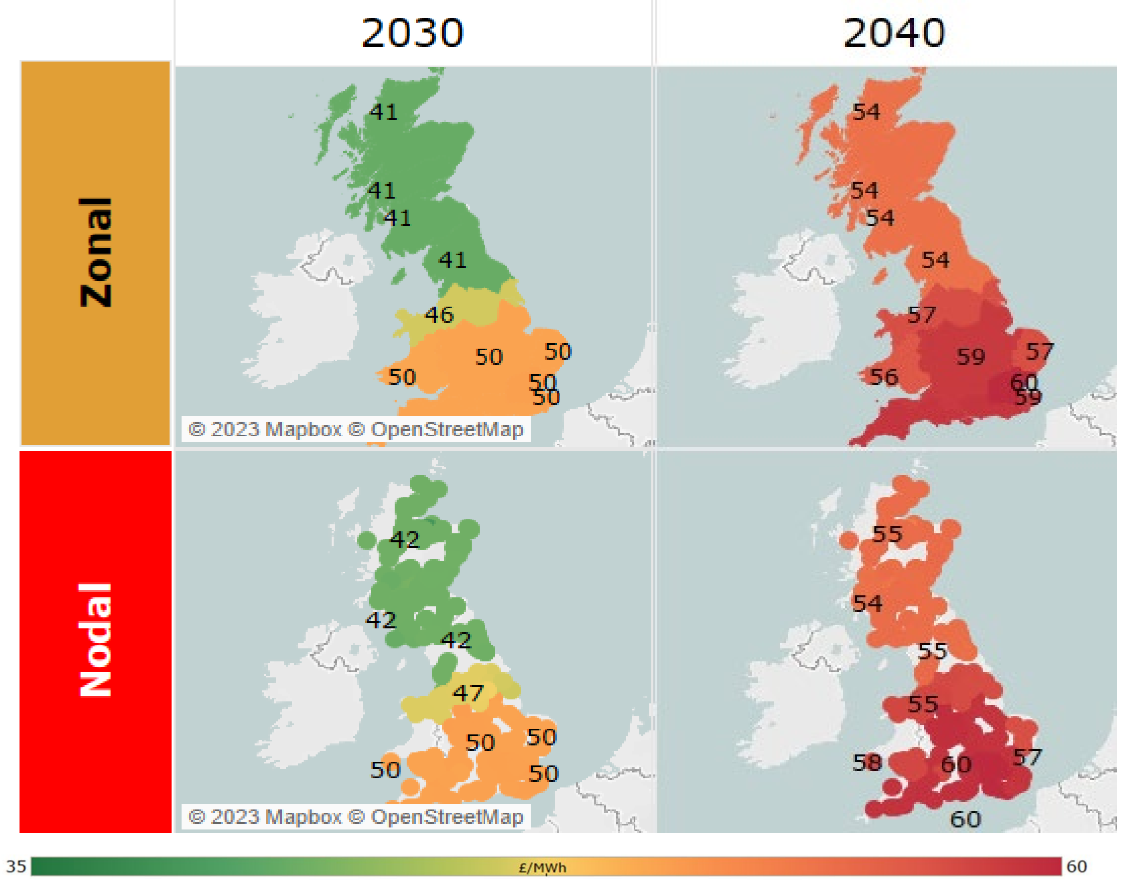


- We have run a sensitivity assuming an unanticipated delay to grid build (based on a 5-year delay to transmission reinforcements post-2030)
- In a zonal market, the impact of delayed grid build is severely negative for generators who end up being held behind an export constraint for longer, with the risk of some generators going out of business because they happen to be in the wrong place
- We find that locational markets have the potential to cause large risks to unhedged generators (including existing generators that are unhedged after any long-term support contract ends)
- Overall, any move to a locational market design would need to be accompanied by mechanisms that limit the risks faced by individual connectees. This is a weakness in locational market designs generally, whether nodal or zonal in nature
- We have not modelled any secondary impacts to overall welfare changes or consequential transfers between consumers and producers that might need to follow in managing such an infrastructure shock

The increased complexity of locational markets may create barriers to entry, and reduce liquidity

WHOLSALE POWER PRICES, CONSUMER TRANSFORMATION

£/MWh, real 2021

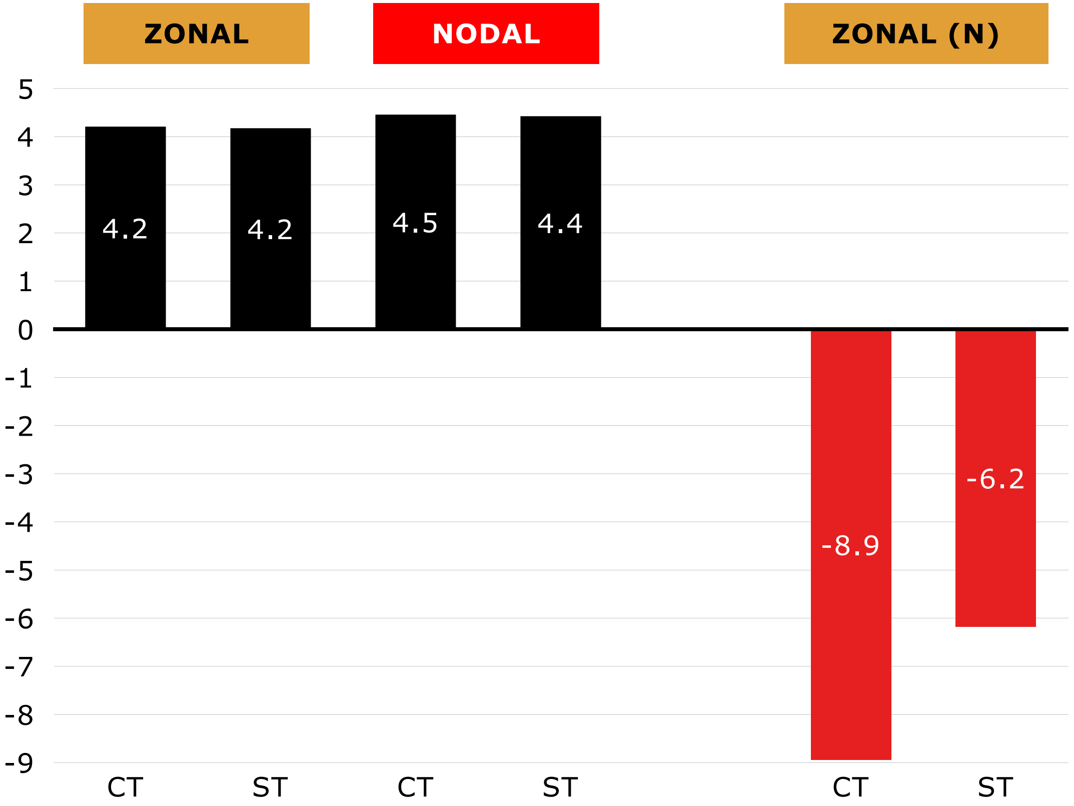


- The complexity of the energy market will increase with the number of locations, creating additional challenges for predictability and decision making
- For smaller or less sophisticated developers, the complexity and cost of working out if a location is a good one in a locational market may be a significant barrier to entry
- Exposure to unforeseen events would increase for generators in a locational market, with an associated cost in time and resources devoted to understanding and managing them
- Market participants face risks and exposure to circumstances outside their control which cannot readily be hedged; at any given location, hedging and risk management options may not be available for the production profile or duration needed to support investment
- Furthermore, the number of active market participants is likely to decrease if the market is segmented into locations. Fewer buyers and sellers could have an adverse impact on market liquidity
- Overall the increased complexity of locational markets may create barriers to entry and reduce liquidity, which would likely reduce the overall economic welfare benefit achievable in practice

The potential economic welfare benefits of changing to locational energy markets disappear if investment risk in generation increases

TOTAL ECONOMIC WELFARE BENEFIT, ZONAL AND NODAL CASES VERSUS NATIONAL BAU BY SCENARIO

Net Present Value 2028-50 at 3.5% discount rate (£billion real 2021)



COMBINATIONS OF HURDLE RATE INCREASES IN THE ZONAL CASE THAT ELIMINATE ALL ECONOMIC WELFARE BENEFIT RELATIVE TO NATIONAL BAU*

CONSUMER TRANSFORMATION	CfD capacity	OCGT capacity	Other non-OCGT capacity
	+0.25%	+0.60%	+1.20%
	+0.50%	+0.04%	+0.08%
	+0.52%	-	-

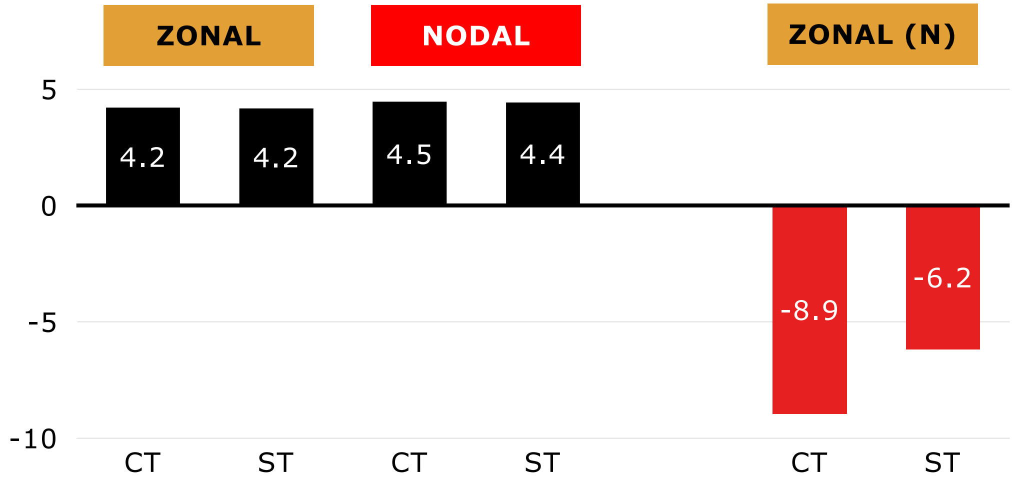
SYSTEM TRANSFORMATION	CfD capacity	OCGT capacity	Other non-OCGT capacity
	+0.25%	+1.00%	+2.00%
	+0.50%	+0.18%	+0.36%
	+0.56%	-	-

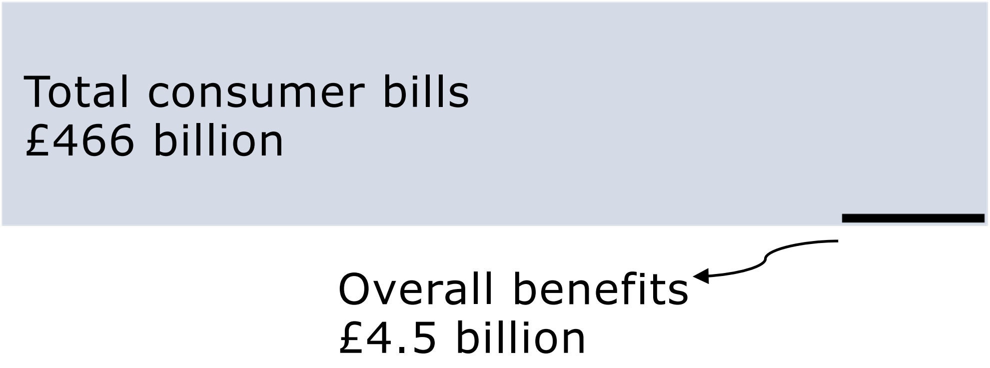
* These increases are over and above the increases that are already present in the Zonal case relative to National BAU. So in the case of the additional +0.52% for CfD capacity in Consumer Transformation, the total hurdle rate increases relative to BAU to eliminate all economic benefit in the Zonal case are: CfD capacity: +0.52%, OCGT capacity +0.5%, other non-OCGT capacity +1%.

Summary of Key Messages

1. Evolutionary change is advised to maintain investment momentum
2. There is only a small economic welfare benefit of changing to a locational energy market
3. Locational markets give better dispatch incentives, particularly for interconnection
4. Locational markets might not strengthen locational investment signals compared to current national market arrangements
5. Risks to investor confidence are larger in a locational market
6. The potential economic welfare benefits of changing to locational energy markets disappear if investment risk in generation increases
7. The increased complexity of locational markets may create barriers to entry
8. With simple changes to locational grid charges, we were able to replicate some but not all of the benefits of locational markets
9. The window for reform to support the transition to a net zero power sector by 2035 is limited

TOTAL ECONOMIC WELFARE BENEFIT BREAKDOWN, ZONAL AND NODAL CASES VERSUS NATIONAL BAU BY SCENARIO





Notes: Zonal (N) = Zonal with +100bps hurdle rate increase for CfD-supported new-build renewable capacity. Consumer Transformation = CT, System Transformation = ST

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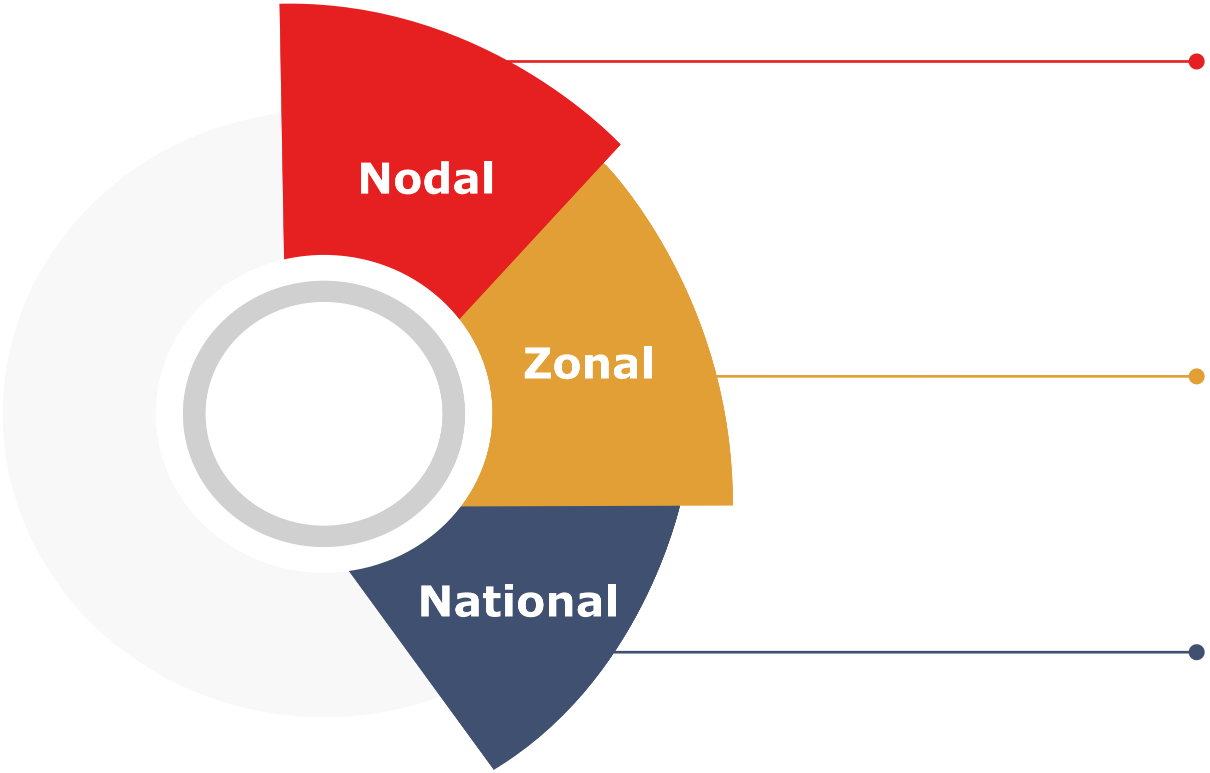
Our recommendations reflect the difficulty of changing market arrangements during a period of required investment, with evolutionary change advised



Nodal pricing should not be progressed further due to difficulties in handling decentralised resources with within-day uncertainties. The feasibility of this approach is uncertain in a decarbonised system reliant on decentralised balancing, and its compatibility with the 2035 investment timeline is questionable.

Further exploration of zonal markets requires risk mitigation planning to address complexities and wealth transfers. Implications on cost of capital and potential delivery challenges necessitate thorough investigation.

Retaining the national market warrants focused efforts to enhance investment and operational incentives, particularly for interconnectors and constrained resources. Improving stability, incentives, and information flows under the current market design is essential.

Other consultancies have carried out socio-economic welfare comparisons of potential locational market designs in Great Britain

HIGH LEVEL POINTS OF COMPARISON BETWEEN AFRY AND FTI

- FTI Consulting has carried out a study for Ofgem, showing higher socio-economic welfare benefits in the FTI locational market cases
- Comparing published numbers directly is subject to several caveats, including:
  - Start and end date (AFRY: 2028-2050 vs FTI: 2025-2040)
  - Money base year (AFRY: real 2021 vs FTI: 2024?)

- Total welfare benefits in FTI cases (System Transformation scenario)*:
  - £13.1 billion for nodal versus national
  - £6.2 billion for zonal versus national
- Benefits in Leading the Way are higher (£7.1 billion to £15.3 billion for zonal cases, £14.4 to £24.0 billion for nodal cases); greater re-siting of renewable capacity in this scenario likely to be a key driver

1 Locational optimisation of the National BAU baseline

We have co-optimised locations of new generation capacity and network reinforcement in the National BAU case (accounting for locational grid charges), resulting in economic capacity locations in National BAU

FTI create a national baseline case by expanding capacity at existing locations up to match the FES 2021 capacities, with no locational optimisation

Effect: Benefits from our locational market cases will be smaller as we compare to a national baseline that is already locationally optimised

2 Locational optimisation of Zonal but not Nodal cases

We use our Zonal capacity locations as the basis for our Nodal case; we have not optimised capacity locations based on nodal prices; FTI assume capacity locations can fully optimise against nodal prices. Also, we model 11 zones in the Zonal case (including East Anglia), whereas FTI have modelled 7, resulting in some network constraints not being captured in the FTI zonal case

Effect: Our Nodal case shows a smaller improvement relative to our Zonal, as more of the benefits are captured in our more granular Zonal case

3 Higher cost of capital assumptions

We have assumed increases in cost of capital for non-CfD supported capacity in our main Zonal and Nodal cases; FTI have assumed none

Effect: Increased costs lower economic benefits in our Zonal and Nodal cases

4 Additional economic network build

We have modelled additional economic build of network from 2035, over and above the NO7 assumptions, unlike FTI

Effect: Our network will tend to be less constrained in the long-term, which reduces the operational efficiency benefits of a locational market relative to a national baseline

*Locational pricing assessment in GB: Final modelling results, p.62. Values are £bn, Present Value 2025-40, Locational case (Zonal or Nodal) – National case, System Transformation

Q&A

Q&A

Why is redispatch modelled per zone in the BAU setup and not at nodal level?

Essentially because for the National and Zonal cases we have co-optimised generation build-out and network build-out at the 11-zone level independently for each case and scenario (National BAU, Zonal, Consumer Transformation, System Transformation), which would result in 4 different grids at the nodal level. Owing to the time and complexity involved in the nodal grid modelling, we elected to create nodal grid representations of the Zonal cases only. Consequently, we have been able to do a nodal redispatch of the Zonal cases, but not a full nodal redispatch of the national cases. The change in welfare going from the Zonal case plus Nodal redispatch to the Nodal case was small (c. an additional £0.3 billion c.f. Zonal total welfare of £4.2 billion), reflecting that an 11-zone energy market captures most of the network constraints causing congestion. We have assumed that for the overall welfare difference of going from national to nodal you can add the £4.2 billion and £0.3 billion – though this is an approximation.

Have you taken retail markets into consideration or is this only a wholesale market perspective? With retail markets, I was referring to competition in the market and hedging possibilities for customers.

All the modelling is based on optimisation of the wholesale energy market (plus redispatch to resolve transmission constraints). Other than noting the importance and commenting qualitatively, we have not modelled any effects related to competition in the retail market or possibilities for consumer hedging. Anecdotally; we have heard that in locational markets without adequate cross-zone hedging products, competition in the retail market can be damaged as the price differences cannot be hedged by retailers without generation in the zones concerned.

Referring to the grid charges; in the zonal/nodal case, would the cost for generators be adjusted based on the congestion (or lack thereof) of the zone/node?

As part of definition of the Zonal and Nodal market design cases, we remove (wider network) locational grid charges for generators (although they could still be subject to a flat non-locational component). The logic of this is that a locational energy market provides a sufficient locational signal to generators, so the need for locational grid charges is removed. As the generator grid charges are non-locational by definition, they would not be adjusted by congestion in the zone or node. However, in aggregate we assume that intra-GB congestion rent within a locational market would be collected by the TSO and used to pay for the costs of the grid, reducing the revenue recovery required from consumers and producers through grid charges.

Q&A

In this presentation of the costs and benefits, are your saying that redispatch costs = socioeconomic costs?

No – it is mostly a transfer between consumers and producers which does not affect overall socio-economic welfare (although the distributional issue of consumers paying and producers gaining has become a more prominent issue for the TSO and policy makers as redispatch volumes have grown in recent years). However, this can include a transfer between producers and consumers in different countries, and welfare is presented from a GB perspective, so that can have an effect on the welfare presented. Redispatch only affects total economic welfare to the extent that additional costs are incurred to get to the final optimal dispatch position via a market + redispatch process (e.g. a zonal market with nodal redispatch), compared to process that does not require redispatch (e.g. a nodal market). The physical constraints that have to be managed are the same under either arrangement, and there are challenges in achieving optimal final dispatch in both cases.

Given the history of grid development in the past 20 years in Europe, are you not overestimating the ability to get grid built?

We have taken grid build-out assumptions from the TSO over the period to 2035, so these reflect TSO views rather than AFRY views. The AFRY view is that the TSO's grid build-out assumptions in the scenarios we have modelled are indeed bullish, although we note that there is now an increased policy and regulatory focus on accelerating grid build. The importance of this issue was the driver for our Transmission Delay sensitivity, in which we have assumed all grid build is delayed (by 5 years after 2030, varying amounts before 2030)

A lot seem to depend on your assumption that grid development catches up with RES development in 2035. If that does not happen, what changes about your conclusion on the feasibility of zonal and nodal pricing?

Our Transmission Delay sensitivity explores this point. An appropriate level of grid build is important for overall economic welfare regardless of market design, whether national, zonal or nodal. Due to improved operational efficiency of locational markets compared with national (e.g. from more efficient interconnector dispatch), locational markets are more resilient in terms of total welfare than national markets under conditions of delayed grid build (the drop in total welfare is somewhat less severe than in the national market). However, the risks and costs of delayed grid build are allocated differently, with most of the welfare reduction falling on producers in the locational transmission delay cases and on consumers in the national delay cases. This is a further dimension of the conclusion that locational markets pose unhedgeable risks to generators, and implementation of a zonal market design must include careful design of robust risk mitigation measures as a pre-condition, alongside an improved evidence base on the impacts on cost of capital (we do not recommend proceeding with nodal given the complexity and limited additional welfare benefit). In summary, with less grid build, both benefits and risks/costs associated with a locational market design would be higher.

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Q&A

Is "deemed output" for CfD safe? Needs to be defensible (customers need to understand they're paying for real energy as opposed to "deemed" energy) and auditable (no CfD if you don't do the maintenance etc).

The deemed output CfD should be seen as a benefit to consumers, improving dispatch and ultimately reducing consumers bills. The leadership that might be required from policy makers and regulators to deliver that message effectively is noted. On audit issues such as plant maintenance, there is no reason why a deemed generation CfD could not have the same conditions as the existing arrangements. Arrangements need to be in place to ensure deemed generation (capability) is accurate in periods where there is curtailment.

Does your model have an inherent high reliance on grid charges to achieve a locational result? How does this lead to grid build-out, given that the TOs can just sit on the high charges and connect limited capacity to a limited network?

In our national market cases, locational grid charges are the primary locational signal (as well as locational transmission losses), and so in that sense, there is a high reliance on grid charges to achieve a modelled locational result. In the locational (Zonal and Nodal cases), locational grid charges are removed so there is no reliance on them in terms of locational outcomes – locational outcomes result primarily from the locational granularity of the energy market. In both the national and locational cases, the reliance or not on locational grid charges is a design assumption for the particular market design case – it is not inherent in the model itself, just one of many model input assumptions. In the national and zonal cases, economic grid-build out in the longer term is influenced by the pattern of generation build, which in turn is influenced by the locational signal in the particular case (either mainly grid charges or mainly energy market granularity), under the assumption that there are suitable incentives on the TSO to build grid when it is economic to do so to relieve congestion. In the long-run we would expect policy makers and regulators to intervene if that was not happening. We explore the effect of sub-optimal, delayed transmission build in our Transmission Delay sensitivity. Note that the TSO cannot act as a pure monopolist, restricting capacity to maximise revenue. If anything, there is an incentive to over-invest (and earn a rate of return on the asset base) although the RIIO incentives have mitigated this. TSO underinvestment is because it is hard (planning, etc) not because they have incentives to underinvest.

Have you taken into account in your assumptions that cost of capital could increase if local or nodal prices were implemented?

Yes – see slide 12.

Have you looked into whether zonal and nodal pricing will free-up more grid capacity - and if so, how much?

Yes – in the National and Zonal cases we have co-optimised the grid build and generation build in the longer term, so the difference in network build can then be seen. See the additional slide at the end of this Q&A section.

Q&A

Do you assume in the Nodal market that the demand for electricity at each node will stay the same over 15-25 years?

No – we assume demand growth at each node occurs, growing in proportion with the overall scenario demand. However, we assume a uniform growth rate in demand at each node (except in the case of the additional demand from electrolysers, which is locationally dependent on electrolyser siting).

For the National BAU scenario, did the transmission grid charges change over time? Were they evaluated to see how much these would increase in the 5-year transmission delay?

For the National BAU case, we modelled internally consistent projections of locational transmission grid charges for 11 zones using National Grid's Transport and Tariff Model, for each modelled year (2030, 2035, 2040 and 2050), each scenario, and by technology. In the National BAU case, the transmission charges do therefore evolve over time to 2050. As the Transmission Delay sensitivity was a sensitivity rather than fully internally consistent scenario, the locational transmission grid charges were not re-evaluated. Note that the recently published ten-year view of TNUoS showed (albeit in a difference FES Scenario) an even more sharp increase in the locational range of TNUoS charges.

If the case for zonal / nodal is so relatively weak, what considerations are you worried might push Government towards it (or something similar)?

Current high levels of redispatch and the corresponding transfers from consumers to producers seem to have taken on a high prominence within the debate as a driver of the need for a locational market. There are also some concerns over bidding behaviour in the balancing market; while most of these issues do not affect total welfare, they are a cost to consumers. We are not convinced that this is such a large or fundamental problem that it requires a move to a locational market, rather than more targeted action. The fundamental focus should be on overall market efficiency and maximising total welfare. We see some evidence that locational markets could provide operational efficiency benefits, but with increased risks to effective investment, so whether an overall welfare gain is achievable in practice is debatable. The split between consumers and producers of any welfare gain (or indeed welfare loss if the reforms are not well implemented) is somewhat arbitrary depending on the priorities of policy makers in managing risks and costs between the two groups, so a focus on one type of cost to one group that may (or may not result) to one group shouldn't be the primary driver of such a large market reform.

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Q&A

Clearly there is a major difference emerging between different analyses - what process of scrutinising/critiquing modelling methodologies and assumptions do we think would aid collective understanding of the issues (bearing in mind the inherent limitations of modelling studies for understanding the dynamic impact on incentives to innovate in technologies and business models)?

Our high-level comparison with the FTI study (see slide 15) hopefully illustrates that the differences in overall socio-economic welfare comparisons are smaller than they might seem at first sight, once comparisons are made on approximately like-for-like basis (e.g. on scenario background, welfare component examined etc), with differences in methodology probably explaining most of the residual variation. There probably is a case for a type of meta-study where the key drivers of differences are documented; policy makers and others could then take a view on which would appear most credible or realistic. However, we believe the conclusions are broadly consistent: in terms of total consumer bills the potential benefits of moving to a locational market are small, and without mitigating measures the cost of capital increases could outweigh any possible benefits. We do take a different view on the possible benefits of nodal markets: we do not believe that investors could fully optimise their siting decisions at a nodal level (effectively based on perfect foresight of the nodal prices).

In your report exec summary, you mentioned the potential benefit of introducing time of use tariffs or network charges for interconnectors. Is this something you've investigated further? Based on what you said earlier, it sounds like you're just recommending further exploration of this

We did not investigate time of use tariffs or network charges for interconnectors within the Phase 2 modelling – these among the items we recommend for further exploration

Have you looked into to what extent the socioeconomic benefits (or other benefits like carbon reductions) accruing to GB are offset by disbenefits to our European neighbours?

Our assessment of economic welfare has been focused on GB, although we have accounted for assumed welfare transfers to and from Europe resulting from changes in interconnector dispatch as part of this assessment (see p.67 – 68 of the Public Summary Report). To the extent generators outside GB would benefit from redispatch in GB, that represents a transfer of welfare out of GB.

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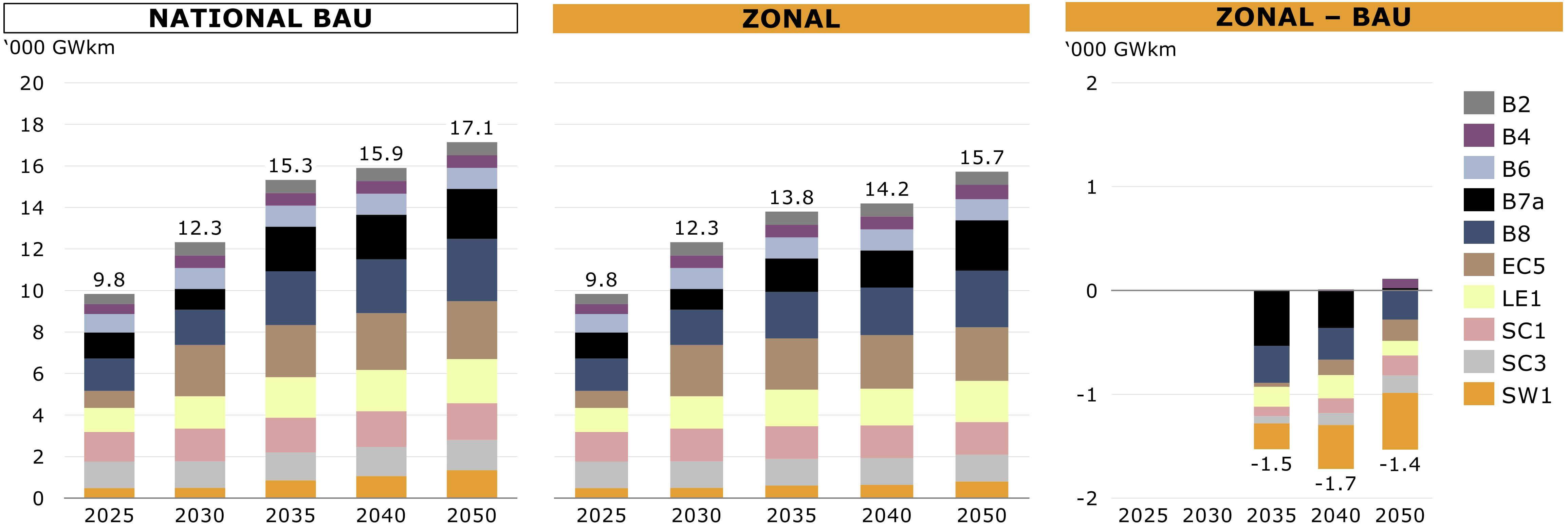
From 2035, all further expansion of the AC grid is based on economic assessment[1]

AC TRANSMISSION CAPABILITY BROKEN DOWN BY BOUNDARY



1. HVDC capacities are not shown/included. Exogeneous HVDC capacity increases between 2030 and 2035 from 8.25 GW to 12.25 GW (based on NO7 HVDC lines scheduled to enter service in 2031). In addition, in 2035, there is a further 2GW increase in HVDC capacity based on economic expansion.

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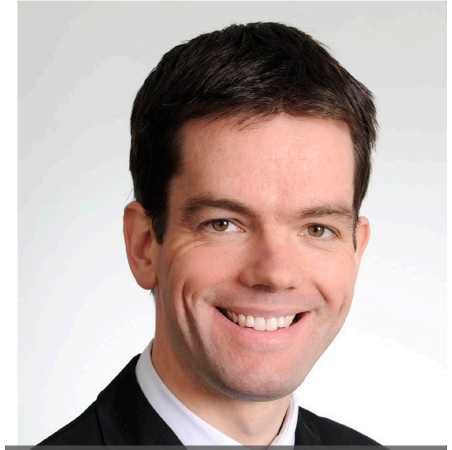

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