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Assessment of locational wholesale electricity market design options in GB

FTI Consulting | Energy Systems Catapult

Key findings

Locational electricity wholesale prices are a well-established feature of electricity markets and have been widely adopted in OECD countries.

In this report, we set out our findings from our detailed quantitative assessment of the costs and benefits of Great Britain introducing wholesale electricity prices that vary by location. This report has been undertaken for Ofgem, and has benefitted from consultation with industry, policymakers and academics in Britain and globally.

We find that relative to the current market design, locational wholesale electricity prices could lead to:

£13bn to £24bn of societal benefits

in GB between 2025 and 2040 in a nodal market design, and £6bn to £15bn in a zonal market design

£28bn to £51bn of consumer benefits

in GB between 2025 and 2040 in a nodal market design, and £15bn to £31bn in a zonal market design

Consumers in each GB region benefitting

although the size of benefits differs across GB due to variation in wholesale electricity prices between different regions

Improved utilisation of flexibility assets

in dispatch, meaning lower spend on managing constraints and potential significant savings in transmission investment

65 to 100 $MtCO_2$ of reduced emissions

in GB between 2025 and 2040 in a nodal market design, equivalent to £12bn to £18bn of additional benefits

Significant changes to asset revenues

leading to “winners and losers” among different stakeholders; policymakers may wish to consider transitional or mitigation measures

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Executive summary

1. Driven by concerns over climate change, nearly all countries across the globe are seeking to reduce the emissions of carbon dioxide and other harmful gases into the atmosphere, albeit to widely varying degrees. The UK is at the forefront of this ambition, aiming to "*end its contribution to global warming*" and "*bring all greenhouse gas emissions to net zero by 2050*".[1]

2. This will require decarbonisation across all sectors of the UK economy and radical changes in the way energy is produced and consumed. Notably, many sectors of the economy that have historically relied upon fossil fuels, for example transport and domestic heating, will need different sources of energy. These sources will most likely be directly or indirectly from the electricity sector, which means significant generation will be required from non-carbon emitting sources to meet greater volumes of electricity demand than has historically been the case.

3. The electricity sector in Great Britain ("GB") has already made significant steps in the decarbonisation of electricity production – for example the share of electricity produced from zero-carbon sources, predominantly wind and solar, has doubled since 2010. This has led to a considerable decrease in carbon emissions, displacing some fossil-fuelled thermal generators which have been the historically dominant sources of electricity generation.

4. However, solar and wind generation are, by nature, more intermittent and unpredictable – making the electricity system more challenging to operate. A further complication is that renewables generation often tends to be more decentralised, in that the new sources of generation are often sited in locations that have favourable wind and solar conditions but are relatively distant from the demand centres that they serve.

5. An additional issue is that relative to most other commodity markets, electricity has atypical physical characteristics which complicate how electricity markets function. For example, overall production and consumption must balance almost exactly across the system on a second-by-second basis, and that the transportation of electricity from generators to consumers is governed by physical limits that make the electricity networks susceptible to bottlenecks. As a result, electricity markets, unlike markets for most other commodities, need to be designed and operated by a central authority to ensure that the physical characteristics are respected while, at the same time, allowing market participants to compete in a wholesale electricity market.

6. The first wholesale electricity markets around the globe were designed in the 1980s and 1990s – as policymakers, initially in the US and UK, sought to drive greater efficiency from the sector relative to the typically vertically integrated and, in the GB case, monopoly state-owned industry structures that had existed for most of the post-war period. The initial electricity market – the "Pool" - went live in 1990 but was superseded by the so-called New Electricity Trading Arrangements ("NETA") that were developed in the late 1990s and went live in May 2001.

7. Since then, there have been many modifications to the market design, for instance, the geographic expansion of the market footprint in 2005 to include Scotland as well as England & Wales. However, the overarching key features have remained broadly unchanged. This has led many stakeholders to suggest that the current market design is increasingly out of date and may not be

[1] See the BEIS press release announcing the filing of Net Zero emissions law, 27 June 2019 (link).

well suited to the continued decarbonisation needed to achieve Net Zero. DESNZ has identified a strong case for change to the current arrangements in its ongoing Review of Electricity Market Arrangements ("REMA").[2]

8. As part of REMA, one reform option identified by DESNZ is the extent to which the wholesale electricity market design in GB should include a price that varies by location. The current design incorporates a single national price that varies for each 30-minute settlement period – reflecting prevailing national demand and supply conditions in that half hour. However, wholesale electricity markets can also be designed so that prices vary by location as well as by time period to reflect local (rather than national) demand and supply conditions for each settlement period.[3]

9. A fundamental advantage of greater locational granularity in wholesale electricity markets is that the wholesale prices can better reflect the physical constraints of the local electricity system – and in particular the potential bottlenecks on the transmission network. In the absence of locational pricing, the national price does not take into account any physical network constraints. Instead, the system operator ("SO") – which is the central entity in all systems that has ultimate responsibility for ensuring that demand for electricity is met – needs to intervene to alleviate bottlenecks that may arise. In the GB market this is increasingly costly – reaching c.£2bn in 2022, up from less than £200m in 2010, and this cost is borne by GB consumers.[4] Moreover, the Electricity System Operator ("ESO") forecasts that these costs are likely to increase at a "*dramatic and accelerating rate*" in the coming years.[5] However, there may also be additional costs with more granular locational pricing too: for example, implementation costs will need to be incurred and some stakeholders suggest that greater locational pricing is more risky and could potentially increase the cost of financing the new investments needed to achieve Net Zero.

10. Ofgem is undertaking an assessment of locational pricing to provide insight into the potential impacts to support the Government's decision-making. As part of this assessment, Ofgem has engaged FTI Consulting ("FTI"), supported by Energy Systems Catapult ("ESC"), to perform a quantitative assessment of the costs and benefits of introducing locational pricing into the wholesale electricity market in GB. This report presents our assumptions, analyses performed, and key findings.

11. In the remainder of this Executive Summary, we briefly outline the approach we have adopted to perform this assessment followed by a summary of the 12 key findings of our work.

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2 Indeed, 80% of respondents to DESNZ's ongoing Review of Electricity Market Arrangements agreed with the statement that "*the current market design is not fit for purpose*". See the summary of responses to the REMA consultation (link).

3 Many electricity markets across the globe operate in this way already. For example, some markets, including Norway, Sweden and Italy have adopted so-called zonal pricing, in which wholesale electricity prices can vary between pre-defined geographical footprints. Other jurisdictions, such as New Zealand, Singapore and many US markets, have adopted nodal pricing, in which prices are set at each major injection and offtake point (or node) of the transmission grid. In these markets, wholesale electricity prices are set at hundreds or even thousands of different nodes in each settlement period.

4 This figure can be calculated based on the Monthly Balancing Services Summary as published by the ESO (link).

5 See the ESO's publication on the Net Zero Market Reform Phase 3 Conclusions (link).

A. Approach

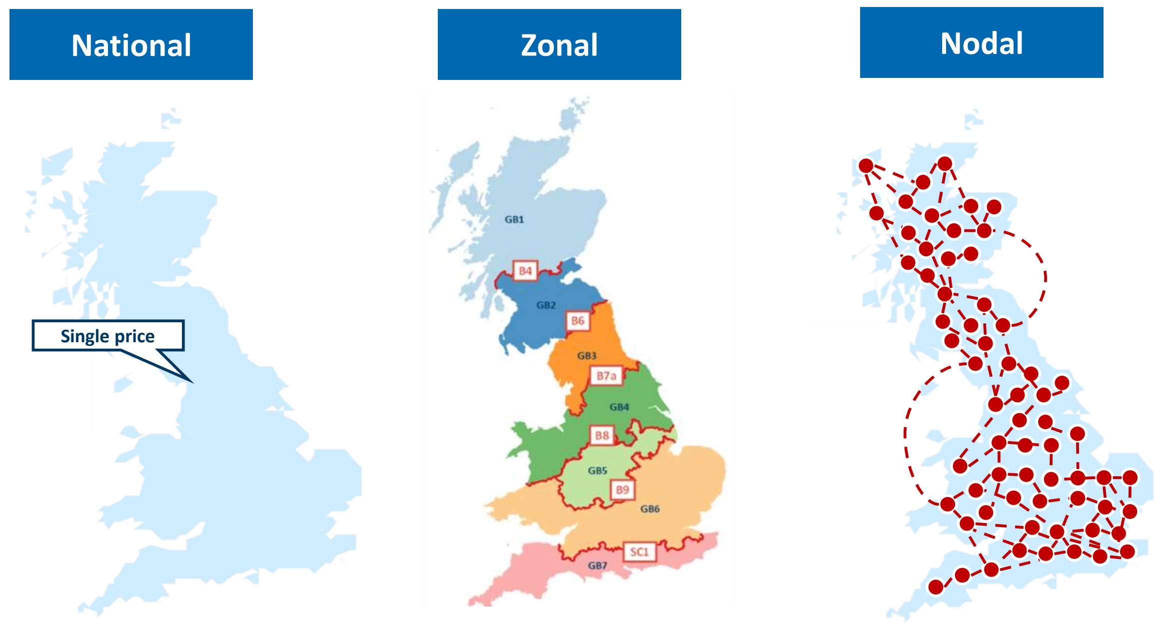
12. We have assessed quantitatively the likely benefits and costs of changing the locational granularity of the GB wholesale electricity market. To do this, we have modelled the GB energy system using an industry standard electricity market modelling platform, which allows us to forecast the likely evolution of wholesale electricity prices under different locational market designs using transparent and industry-validated assumptions on the possible evolution of the energy system.

13. We have augmented our pre-existing model of European energy markets by developing a detailed representation of the GB electricity system allowing us to model wholesale electricity price based on supply, demand and transmission capacity dynamics. Our GB model was then integrated with our pan-EU model to allow for a detailed representation of cross-border electricity trading in our assessment of locational pricing. This has allowed us to forecast wholesale prices paid to generators by consumers under a range of different locational market designs for GB.

14. Our assessment has focused on three different levels of locational granularity in the wholesale market. These are:

- a base case representing the status quo of a **national pricing marke**t;
- a **zonal pricing market design** where GB is split into seven distinct price zones with the boundaries of the zones reflecting the expected incidence of bottlenecks on the transmission system; and
- a **nodal pricing market design** in which prices are determined at all of the c.850 nodes. This is illustrated, schematically, below in Figure ES-1.

Figure ES-1: Illustrative schematic depicting the three different market designs assessed in our work



Source: FTI analysis

15. We keep all other input variables, such as the future evolution of generation mix and demand, constant across the three market designs in order to isolate the impact of more locationally granular prices on both consumers and society as a whole.

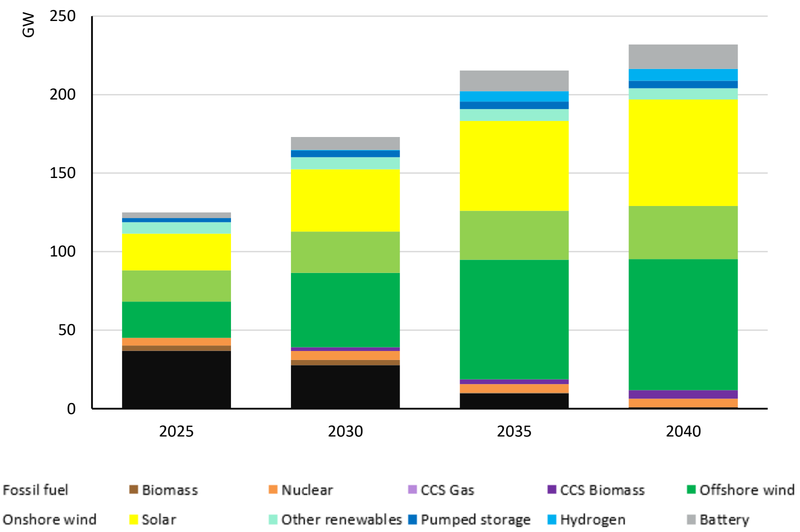
16. From the outset of our work, we were aware that changes to the locational granularity of the wholesale market design would have the potential to impact different cohorts of stakeholders either positively or negatively. As such, we anticipated that this study would receive a high degree of stakeholder scrutiny. We have therefore sought to be as transparent as possible in our approach to assessing the costs and benefits and have engaged extensively with stakeholders across the industry throughout our assessment.

17. For example, we held three industry wide stakeholder workshops where our methodology and assessment were explained and feedback was provided by stakeholders, which allowed us to refine our approach and analysis. We have also held a large number of smaller stakeholder meetings, discussed our approach with ESO and validated our approach to forming assumptions with Ofgem. Our aim has been to allow as much scrutiny as reasonably possible of our methodology, our assumptions, and our overall approach, in order to provide reassurance to Ofgem and stakeholders regarding the robustness of our findings and our analytical neutrality.

18. Another key element to our approach has been to draw upon well-established third-party sources of information and of assumptions wherever possible. In particular, we have adopted many of the input assumptions developed by the ESO from the Future Energy Scenarios ("FES"). These scenarios portray four different versions of how the GB electricity system may evolve, in terms of likely change in the demand for electricity in GB and the sources of generation to meet that demand.

19. For example, the FES Leading the Way scenario envisages a future electricity system that relies on offshore wind generation and solar generation to meet the majority of our electricity needs by 2040. This is illustrated below in Figure ES-2.

Figure ES-2: Installed GB electricity capacity under the Leading the Way scenario

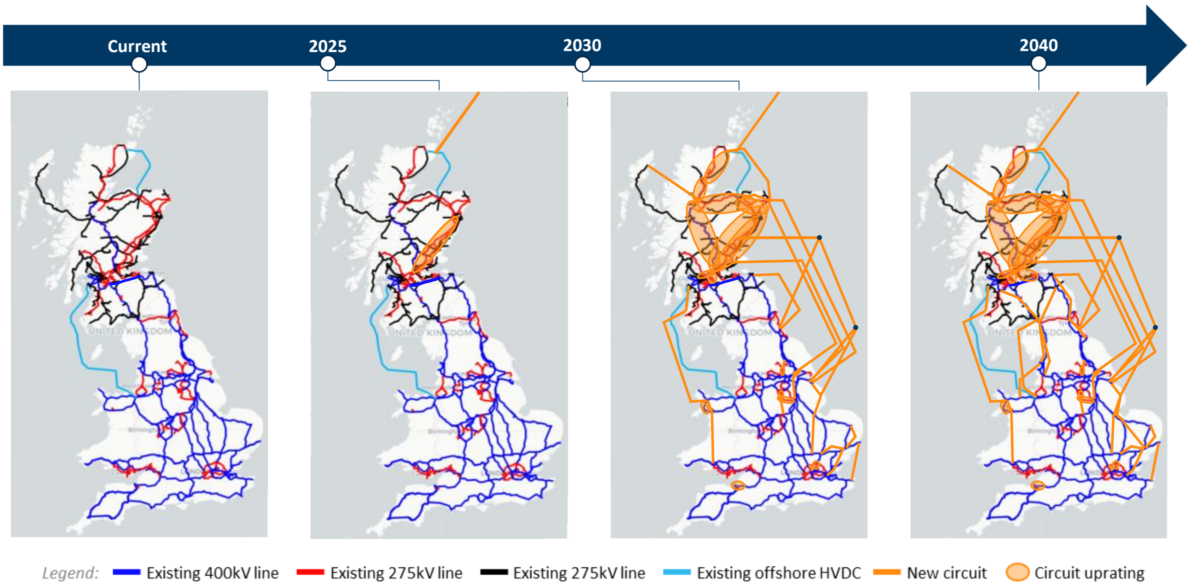


Source: FES 21

20. As Figure ES-2 above shows, under this scenario, in 2025 GB is expected to have c.37GW of thermal generation which, by 2035, will have fallen to 10GW. At the same time, offshore wind generation is expected to increase by 260% from 23GW in 2025 to 83GW in 2040. After consultation with stakeholders this scenario, Leading the Way, was chosen as one of our scenarios for the quantitative assessment. We also assessed the likely impact of locational prices if the GB electricity system evolved differently under the alternative FES scenario termed System Transformation, which forecasts greater reliance on nuclear generation and less offshore wind generation.

21. Similarly, we use the ESO's assumptions in order to model the evolution of the transmission grid, as depicted for the Network Options Assessment 7 ("NOA7") scenario in Figure ES-3 below.

Figure ES-3: Evolution of the GB transmission grid over the modelling period



Source: ETYS and NOA7.
Note: *we have fixed the build-out of the transmission network across the different wholesale electricity market designs*

22. As Figure ES-3 illustrates, under NOA7, transmission capacity increases until 2041,[6] which is the forecast horizon for ESO. This impacted how we approached our overall assessment, as we were unable to forecast locational prices past 2040 due to the lack of underlying assumptions regarding the evolution of the transmission grid. Therefore, after consultation with industry and in agreement with Ofgem, our assessment only considers the impact of moving to locational prices until 2040.[7]

6 We have fixed the transmission network build assumptions across locational market designs assessed in order to prevent distortion of our results due to varying levels of transmission between scenarios.

7 In our assessment, we assume that a locational pricing regime is implemented on 1 January 2025. This allows us to capture a 16-year time period based on the expected evolution of the transmission grid to 2040.

23. In addition to NOA7, the ESO released an additional network development plan following the start of this engagement, known as the Holistic Network Design ("HND"). This plan envisages an acceleration of transmission investment relative to the NOA7 plan, which is likely to impact the evolution of locational prices under the different FES scenarios. As such, in consultation with stakeholders and in agreement with Ofgem, we also assessed the impact of locational pricing using the evolution of transmission under HND as well.

24. Therefore, we assessed the impact of greater locational pricing to 2040 under three different scenarios: the Leading the Way scenario with the original NOA7 transmission plan ("LtW (NOA7)"), the Leading the Way Scenario with the faster roll out of transmission as per the HND ("LtW (HND)") and the System Transformation scenario ("SysTr (NOA7)").

25. For the scenarios agreed upon with Ofgem, we calculated in our market model how prices would be expected to evolve and for each different locational market design (i.e., for national, zonal and nodal). In turn, this allowed us to assess the expected consumer welfare and total GB socioeconomic welfare from transitioning to locational pricing.

26. Although our electricity market modelling was the focus of our work, we also evaluated a number of other factors that could impact the overall assessment of costs and benefits of locational pricing. Specifically, we assessed:

- the likely level of **implementation costs** that would be incurred both centrally and by market participants in any change to the design of the wholesale market;
- the potential impact on the **cost of capital** that participants incur in financing assets; and
- the potential impact on **market liquidity.**

B. Summary of key findings

27. In this section, we set out the 12 key findings from our assessment.

Key finding 1: The costs of transmission congestion are likely to continue to increase significantly under the current GB market design

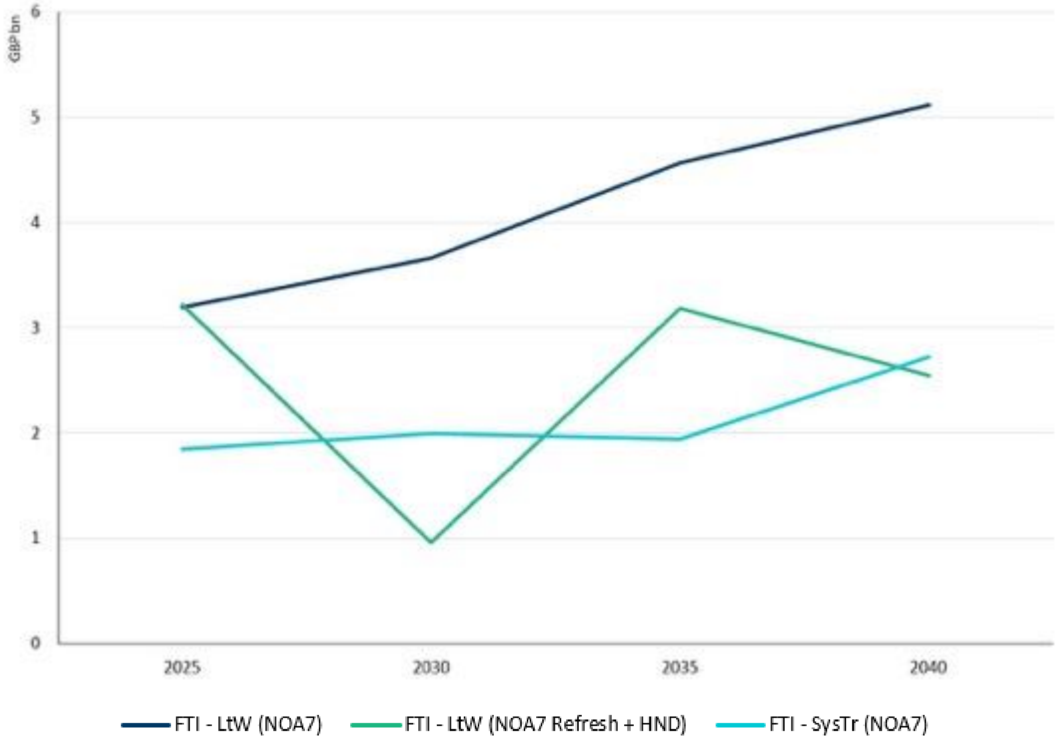
28. Since the liberalisation of the GB electricity sector, a key objective of the wholesale market was to facilitate trading between market participants to encourage competition in the generation of electricity. To achieve this, a major market design decision was that generators and consumers of electricity could trade with each other, forming a single price in each period regardless of each party's geographical location in the GB system. An impact of this market design feature is that market outcomes are often inconsistent with the capabilities of the transmission system – in that the volume of electricity intended to be generated in one locality cannot actually be conveyed to another region where electricity is demanded because of limited transmission capacity.

29. Under the current GB market design, this is resolved by the ESO intervening in the market – typically by instructing specific generators at particular locations to increase output and others, sited elsewhere, to curtail production. This ensures that, in practice, demand and supply balance in a manner that is consistent with the physical realities of the transmission network. The participants that are instructed to either increase or decrease production (or, for the demand side, to change consumption) receive compensation from the ESO. The costs of this – known as transmission constraint management costs – are recovered from all consumers.

30. Historically, these constraint management costs have been relatively low (for example in the period 2009/10 to 2014/15 the costs of congestion were on average c.£220mn per annum). However, in recent years congestion costs have increased markedly – reaching c.£1,960mn in 2022. One of the drivers of the increased cost is the roll out of renewables generation, which is often sited at geographically distant points on the GB network that are far from the centres of demand. Given the expected magnitude and rate of increase in renewables generation as GB transitions to Net Zero, the ESO anticipates that this trend in constraint management costs will continue.[8]

31. Our findings support this view. Our estimates of future constraint management costs under a national pricing design are broadly in line with the ESO's assessment, as illustrated below in Figure ES-4.

Figure ES-4: Constraint costs for all three scenarios under a national market design, £bn



Source: FTI analysis

32. As Figure ES-4 indicates, we anticipate that under the LtW (NOA7) scenario, constraint costs would increase significantly over the forecast horizon as greater volumes of renewables generation connect to the grid, and would reach c.£5bn per annum by 2040. This represents a 14-fold increase to the annual average congestion cost in the period 2010 to 2020. Additional transmission, as represented by the LtW (HND) scenario, has the impact of significantly reducing the volume of generation that needs to be curtailed, consequently reducing the cost of constraint management in the 2025 to 2030 period. However, from 2030, congestion costs begin to rise again under this scenario as well – reaching c.£3bn per annum in 2035.

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[8] See the ESO's publication on the Net Zero Market Reform Phase 3 Conclusions (link).

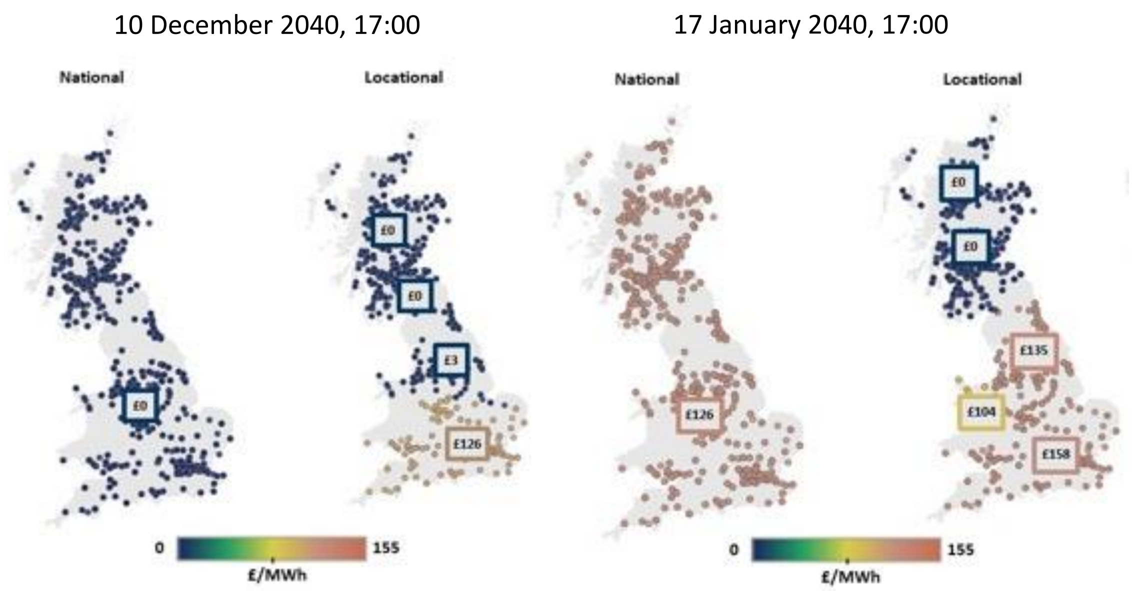
33. Under SysTr (NOA7), which has greater volumes of nuclear generation that is located in the southern part of the country, congestion costs are lower at c.£2bn per annum throughout the forecast period.

34. As noted previously, these costs are borne by the ESO but are subsequently recovered from all consumers. We forecast this cost would constitute between 11% and 14% of the overall cost of electricity to consumers, including CfD payments, for the LtW (NOA7) scenario under the national market design. Similarly, under the cost constitutes between 4% and 11% of the overall cost of electricity to consumers under LtW (HND) and 6% and 10% of the overall cost of electricity to consumers under SysTr (NOA7).[9]

Key finding 2: Under a more granular locational wholesale market, we find that prices in GB would vary markedly across the country and would be significantly lower in the north.

35. In contrast to a national market design, a locational wholesale electricity market takes account of the capabilities of the transmission network when wholesale prices are determined. It does this either as an approximation, in the case of a zonal market design, or exactly, in the case of a nodal market design. We modelled prices under the national, zonal, and nodal market designs for each of the scenarios for each hour of a modelled year. The figure below illustrates the outcome for two modelled hours – the 10 December 2040 at 17:00 and 17 January 2040 at 17:00 – for the LtW (NOA7) scenario.

Figure ES-5: Example prices under LtW (NOA7) for a national and locational market designs, 10 December 2040 17:00 and 17 January 2040 at 17:00



Source: FTI analysis

36. In the first modelled hour illustrated on the left pane, high wind conditions in Scotland and the north of England mean that, under a national market design, the market would clear at c.£0 per MWh. However, under a locational market (we show a nodal market, but zonal has a similar trend),

9 We have cross-checked our estimates and they are broadly in line with the forecast constraint costs published by the ESO.

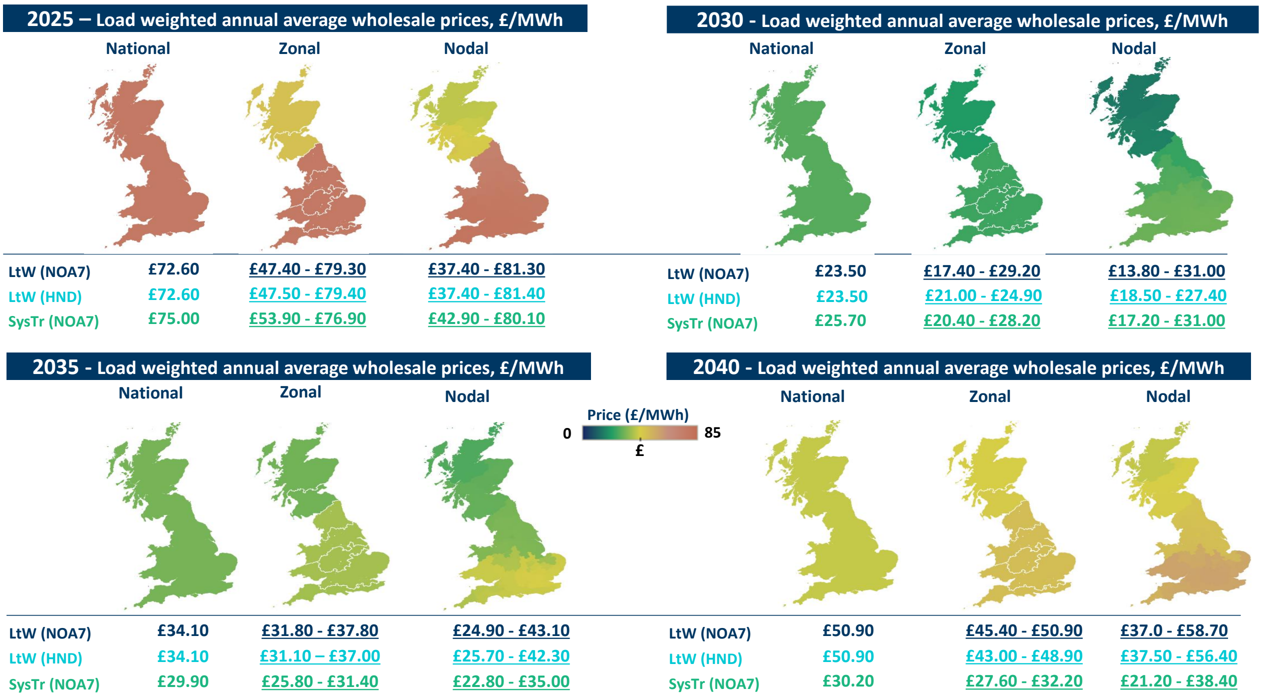
the price is significantly higher in the south – in this case around £126 per MWh for this particular hour, while still very low in the north – roughly around £0 per MWh in Scotland and £3 per MWh in northern England. The reason for the price differential between the north and the south of the country is that there is a transmission bottleneck on the system that means some low-cost generation sited in the north cannot serve the demand situated in the south. Instead, southern demand has to be met by higher cost generation sited in that region which, in turn, sets the price for that locality.

37. Under the national market the same transmission bottleneck exists, but as discussed above, the ESO intervenes in the market to resolve the congestion – in this case by instructing generating plant in the south to increase production and those in the north to curtail output. In so doing it would incur congestion costs for that hour that are borne by consumers.

38. The right pane shows a similar effect for a different hour. The main difference in this hour is that the national market would clear at a high price but, under a locational market, prices would be low in the north of the country due to the high wind conditions in that region.

39. The above two hours are representative of the general trend observed in locational markets in GB of lower wholesale prices in the north and higher prices in the south. Nonetheless, there are many hours when prices would be broadly the same under any market design – either generally low (if there is lot of renewables production spread across the country) or generally high (if there is limited renewables output). We show below in Figure ES-6 the dispersion of annual average prices across the system which is the average for each of our modelled years for all hours of that year.

Figure ES-6: Annual average load-weighted prices for LtW (NOA7), SysTr (NOA7) and LtW (HND) under all three market designs, 2025 to 2040



Source: FTI analysis
Note: The illustrations above depict the prices observed under the LtW (NOA7) scenario.

40. This significant fall in annual average price under both scenarios in the 2025 to 2030 period is a result of large volumes of renewable generation coming online and also an assumed fall in the gas price.[10] While renewables generation is assumed to continue to be rolled out at pace over the period, thereby exerting downward pressure on prices, the demand for electricity increases, as new sectors are electrified, thereby exerting upward pressure on prices.

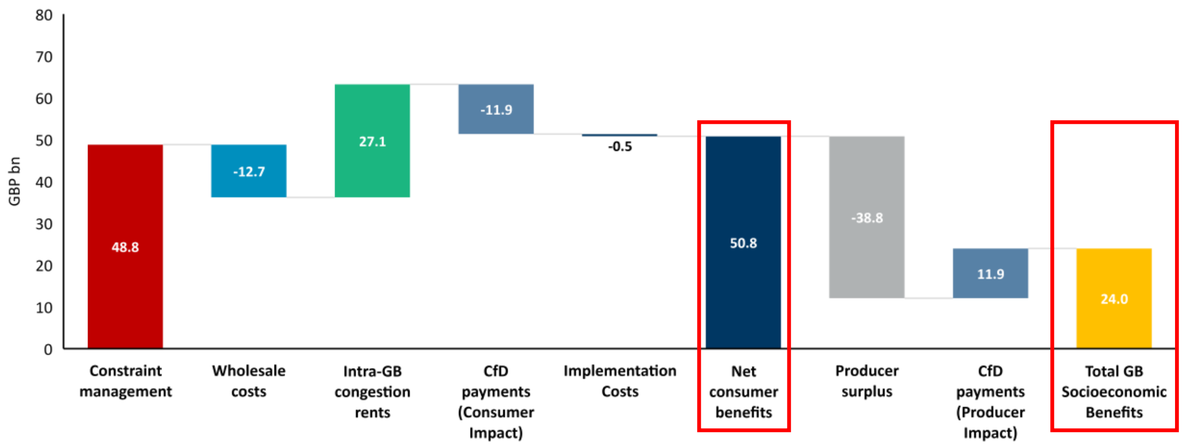
41. For both scenarios, under a zonal or nodal market design, wholesale prices in the north of GB are expected to be lower than under a national market design, while the south of GB sees an increase in wholesale prices. As we would expect, there is a wider range of prices under a nodal market design relative to a zonal market design.

42. The spread in prices is smaller under System Transformation as prices in Scotland are higher due to less offshore wind rollout, while prices in the south of GB are lower due to a greater reliance on nuclear generation. Lower overall demand in this scenario also means that prices tend to be lower relative to the Leading the Way scenarios.

Key finding 3: The overall expected net benefit to GB consumers of a transition to nodal pricing varies between £28bn and £51bn over the 16-year modelling period depending on the scenario. When evaluated on a socioeconomic basis, the expected net benefits of a transition to nodal pricing are between £13bn and £24bn. Zonal pricing would result in consumer and socioeconomic benefits at approximately half of the level of nodal pricing.

43. The prices we forecast for each market design, our forecasts of congestion costs and our assumptions on implementation costs allow us to calculate an overall measure of the benefits of transitioning to a zonal or nodal market relative to the status quo national market design for each scenario. Figure ES-7 below illustrates the breakdown in costs and benefits in the case of the transition to nodal pricing under the LtW NOA7 scenario.

Figure ES-7: Overall Cost Benefit Assessment for a nodal market design relative to a national market design (2025-2040) – LtW (NOA7)



Source: FTI analysis
Note: The values presented above are the Net Present Value of the relevant costs and benefits over the 16-year modelling period.

[10] Our assumptions on commodity pricing are detailed (further) in Appendix 1.

44. Figure ES-7 shows that the largest benefit to consumers of a transition to nodal pricing is the **reduction in constraint management costs** as represented by the red column. Under a national market design, these constraint management costs incurred by the ESO would be recovered from consumers. However, under a nodal market design, bottlenecks in the transmission system directly impact the level of the wholesale price – with those areas that experience surplus energy behind a transmission constraint, known as export constrained areas, having lower wholesale prices. By contrast, those areas of the network where there is a shortfall in generation – import-constrained areas – tend to experience higher wholesale prices. We illustrated this effect earlier in this summary – as set out in Figure ES-5. One impact of this is that there is, in a nodal market, no requirement for the ESO to intervene to resolve congestion – rather it is resolved by the market itself.[11] Hence, under a nodal market there is no congestion cost to be incurred by the ESO and therefore no congestion costs to be recovered from consumers. As such, for the LtW (NOA7) scenario, we estimate this would generate benefits of c.£49bn over the modelling period.

45. Under a zonal market, bottlenecks in transmission between zones are resolved by movements in the wholesale price, but, within a price zone, congestion that arises will still need to be resolved by interventions from the ESO, with cost recovered from consumers (as per the national design).

46. A transition to a locational market would, by design, **change the wholesale prices** paid by consumers, with different consumers potentially facing different prices in any given settlement period. Under the LtW (NOA7) scenario, the reduction in the wholesale price in the north of GB is more than offset by an increase in the wholesale costs paid by consumers in the south – resulting in a net increase of c.£13bn across the generality of consumers (represented by the light blue column in Figure ES-7 above). The main driver of this result is that some of the costs that were previously incurred by the ESO in managing constraints are, by virtue of the market design, transferred into the wholesale price – meaning prices tend to rise in import-constrained parts of the system.

47. A further feature of locational wholesale markets are **congestion rents**, which are an outcome of the settlement process. Congestion rents arise because the electricity that is generated in an export constrained area is paid a comparatively low price yet some of this electricity is conveyed across the transmission network (albeit at volumes limited by the capacity of the network) and then paid for by consumers at the prevailing comparatively higher price in that part of the network. This creates the congestion rent surplus. Under the LtW (NOA7) scenario we estimate that congestion rent would be c.£27bn (represented by the green column in Figure ES-7 over the forecast period.

48. For the purposes of this assessment, we have assumed that this benefit is passed back to consumers. This is commonplace in most locational markets of the world and occurs either directly, as a result of the settlement process, or indirectly through receipts from the auction of rights to the surplus. In the latter case, the rights are often termed Financial Transmission Rights and are used by market participants and traders to hedge the price risk between two locations.

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[11] We note that under all market designs modelled, there may be instances where the SO is required to intervene to account for unexpected changes in supply and demand, as well as unexpected outages of the transmission lines, in real-time. This occurs under national, zonal and nodal pricing regimes, and we have not sought to model any impact on the costs that arise from such interventions.

49. A further potential use of the congestion revenues would be to fund compensation payments to generators that are expected to lose out under a transition to locational pricing. We have not sought to evaluate this as it is a decision for policymakers, but note that as it is simply a transfer, any use of congestion rents for this purpose would most likely result in a negative impact on consumers but an equal and offsetting positive impact on generators. Therefore, the total GB socioeconomic benefits would be unchanged.

50. A change in wholesale prices would also have an impact on the overall **support payments** made to generators under the Contract for Differences ("CfD") mechanism. As the CfD payment amount is calculated as the difference between the prevailing wholesale price and the agreed strike price for the CfD contract, it follows that a move to locational prices will result in higher CfD support payments to generators in regions where wholesale prices are lower than under a national market design and vice versa for regions that have higher wholesale prices. Our market modelling confirms this, as we find that generators located in the north of England and Scotland receive higher support payments (as wholesale prices fall in that region) while the opposite is true for generators receiving support payments in the south of the country. For example, Hinkley Point C located in the south of the country receives £1bn less in support payments over the forecast period under a nodal market as a result of an increase of c.£1bn in wholesale revenues. Overall, the plant's revenues do not change over the forecast period, as it continues to receive revenue in line with the agreed strike prices.

51. As the turquoise column indicates, the overall impact is an additional cost to consumers of c.£12bn as the additional support payments to generators sited in the north are greater than the reduced support payments to generators located in the south.

52. **Implementation costs** are, in relative terms, low. Our assessment involved reviews of precedent from other markets that have transitioned to locational pricing, as well as discussions with systems vendors and the ESO. We believe a conservative estimate of £500m is appropriate, which we assume is all recovered from consumers. This might be incurred directly, in the case of the central system costs incurred by the ESO and other central agencies (such as Elexon), or indirectly if we assume that all participant costs incurred in changing systems and contracts are eventually passed on to consumers.

53. As the dark blue column indicates, this yields an **overall expected consumer benefit of c.£51bn** for the modelling period 2025 to 2040 under a LtW (NOA7) scenario. While policymakers employ different approaches to evaluating the costs and benefits of a particular reform, we note that a conventional socioeconomic approach would also need to consider the impact on producers.

54. In this regard, one impact of nodal pricing would be to reduce the aggregate revenues earned by generators. In this scenario, we estimate the reduction in **producer surplus**, that is the change in generator revenues, to be c.£39bn over the forecast period.

55. There are two main components of this effect. First, under a national pricing regime, generators are compensated by the ESO for their actions to resolve transmission constraints through the Balancing Mechanism. Under a nodal market design no compensation is paid (as the market itself, not the ESO, resolves the constraint). Second, the changes in wholesale prices by location results in changes in the amount paid to generators. For generators sited in export-constrained parts of the network, prices will be lower in that region relative to under a national market design. These generators would receive lower infra-marginal rents, that is the difference between the price received by the generator and the production costs incurred. Conversely, generators sited in import-constrained parts of the network could receive higher revenues in the wholesale market.

56. The reduction in wholesale revenues to generators is offset to some extent by increases in **CfD payments** – as the turquoise bar indicates in Figure ES-7 above. In the LtW (NOA7) scenario this represents the c.£12bn additional CfD payments from consumers to generators, as discussed above (which is why it is an equal and offsetting amount in Figure ES-7 above).

57. Overall, we find that a transition to nodal pricing from national pricing would deliver **socioeconomic benefits of c.£24bn** over the forecast period.

58. We have undertaken the analysis described above for each of the three scenarios and assessed the impact of transitioning to zonal or nodal pricing relative to maintaining the status quo national market design. We present our conclusions in Table ES-1 below, presenting both the consumer benefits and socioeconomic benefits for each permutation.

Table ES-1: Expected impact of locational market design options relative to national market design (GBP bn), 2025-2040

Scenario	Zonal		Nodal	
	Consumer benefit	Socioeconomic welfare	Consumer benefit	Socioeconomic welfare
LtW (NOA7)	30.7	15.3	50.8	24.0
SysTr (NOA7)	15.2	6.2	28.0	13.1
LtW (HND)	18.7	7.1	34.2	14.4

Source: FTI analysis

59. As Table ES-1 indicates, in broad terms a transition to zonal pricing would deliver about half of the benefits of a transition to nodal pricing under all three scenarios - whether the overall benefit is assessed on a consumer only or broader socioeconomic perspective. Furthermore, socioeconomic benefits tend to be between 40% and 50% of the benefits to consumers.

60. When comparing the level of benefits between scenarios, we find that the addition of more transmission reduces the overall benefits of transitioning to locationally granular pricing by between 40% to 50% depending on which measure of benefit is used, as determined by comparing the LtW (HND) scenario to the LtW (NOA7) scenario. This result is directionally unsurprising as greater volumes of transmission mean the system is less constrained. It is though important to note that we have not factored the additional cost of the transmission assets that are deployed in the LtW (HND) scenario relative to LtW (NOA7) into our assessment in Table ES-1 above. We return to this topic later in this summary.

61. Finally, the benefits of moving to more locationally granular wholesale prices under the SysTr (NOA7) scenario are roughly half of those observed under the LtW (NOA7) scenario. Again, this result is directionally as expected given that, under this scenario, more nuclear generation is deployed in the southern half of the country which serves to alleviate some of the congestion in the transmission network.

62. Overall, the benefits to consumers from transitioning to zonal pricing reduces the wholesale cost of electricity by between 5% and 12% depending on the scenario and whether or not we include CfD payments in the cost of electricity. Were nodal pricing to be adopted, the overall expected wholesale cost paid by consumers would fall by between 9% and 20% depending on the scenario and the inclusion of CfDs in the cost of electricity, as shown below in Table ES-2. By way of comparison, we note that the NETA market reform was expected by Ofgem to reduce wholesale prices by 10%.[12]

Table ES-2: Consumer benefit relative to the wholesale cost of electricity, 2025-2040

Scenario	Zonal		Nodal	
	Consumer benefit relative to cost of electricity	Consumer benefit relative to cost of electricity (incl. CfDs)	Consumer benefit relative to cost of electricity	Consumer benefit relative to cost of electricity (incl. CfDs)
LtW (NOA7)	12%	8%	20%	14%
LtW (HND)	8%	5%	15%	10%
SysTr (NOA7)	8%	5%	15%	9%

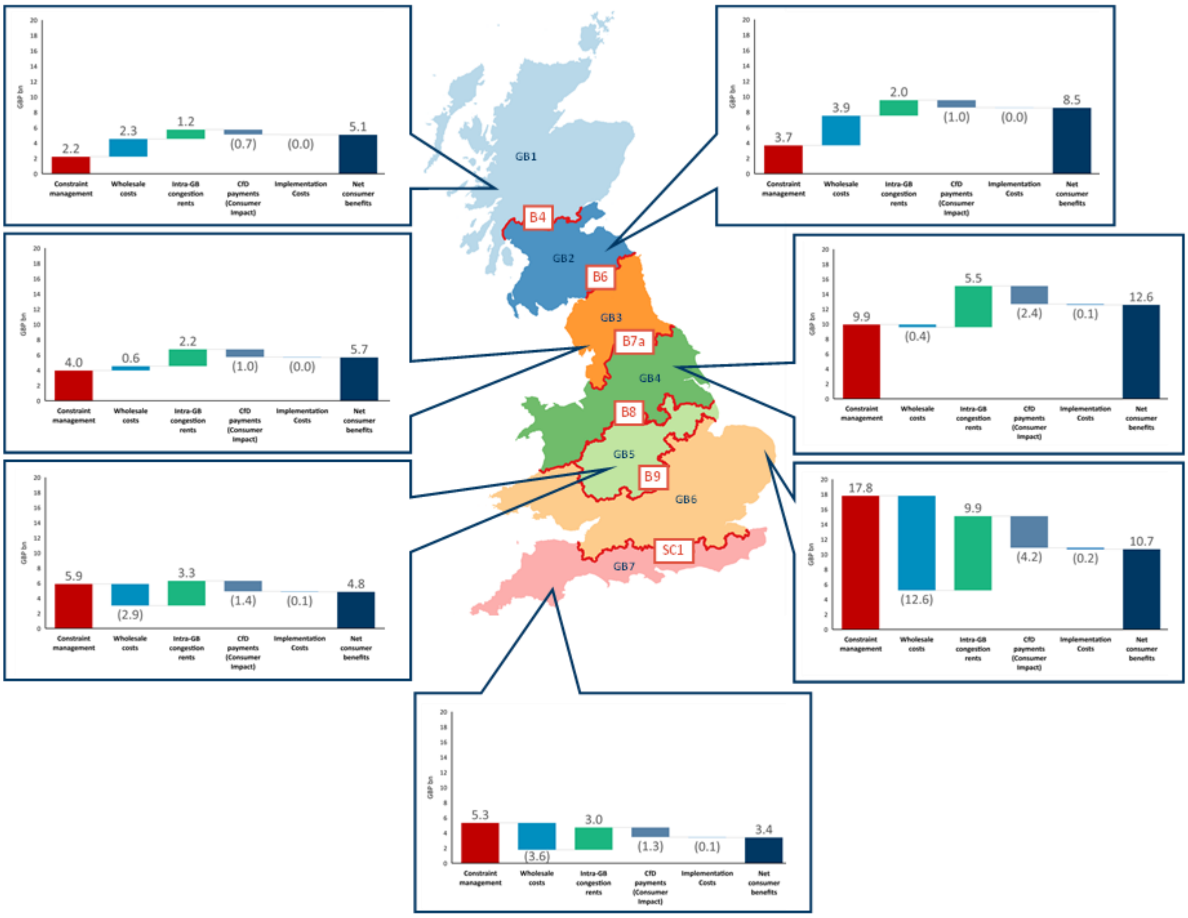
Source: FTI analysis

Key finding 4: We find that all consumers in all regions of the country benefit from a move to locational wholesale pricing, under all three modelled scenarios. However, the magnitude of benefits varies across the country as consumers in the north benefit more than those in the south.

63. We are able to disaggregate our benefits assessment presented above on a regional basis. This is set out below in Figure ES-8 for a transition to nodal pricing under the LtW (NOA7) scenario. For ease of exposition, we have aggregated the nodes present into seven zones – a convention we adopt extensively in this report when illustrating the impact of nodal pricing.

[12] See page 88 of Ofgem's Review of the first year of NETA, 2002 (link).

Figure ES-8: Regional distribution of consumer benefits from transitioning to a nodal market design – LtW (NOA7)



Source: FTI analysis

64. As Figure ES-8 illustrates, most of the cost and benefits are borne proportionally across all regions – in that the reduction in congestion costs, the benefit of intra-GB congestion rents, CfD costs and implementation costs are all assumed to be allocated to each region on a per MWh basis. However, the fact that there are different wholesale prices in different parts of the country means that the impact of transitioning to locational pricing will vary by region.

65. Given that, under locational pricing, prices fall in the north of the country, changes in the wholesale price constitute a benefit to consumers – as indicated by the light blue column having a positive impact on consumer benefits in the northern regions of the country. For instance, consumers in the northernmost region, GB1, have a wholesale benefit of £2.3bn in addition to benefits of reduced constraint payments.

66. By contrast, consumers in the south face higher wholesale prices under a nodal market design than under a national market design, resulting in a negative impact as a result of wholesale prices changes (as indicated by the light blue bar being a negative benefit in the southern regions of the country). However, the negative impact of wholesale prices is, for all regions, more than offset by the positive benefit of reduced constraint management payments (i.e., the red columns indicating congestion cost savings are always greater in magnitude than the offsetting negative light blue columns indicating wholesale cost increases).

67. We find that the trend described above – i.e., that all consumers in all regions benefit in the transition to locationally granular pricing, albeit in different proportions – is found for all three scenarios and for both zonal and nodal pricing.

Key finding 5: Several stakeholders have argued that moving to locational pricing would lead to greater investor risk and uncertainty which would increase their cost of capital. We have found limited evidence that this would, in practice, be a material cost. In addition, we have found no evidence of reduced liquidity as a result of locational pricing.

68. The changing patterns of wholesale prices under locational market designs could affect the level of uncertainty faced by market participants. For instance, our modelling suggests that locational pricing would have limited effects on average price volatility, but would increase the level of price volatility over time in some locations (while reducing it in others). Depending on the form of support mechanisms such as CfDs, there could also be increases in volatility of revenues for generators in certain locations.

69. However, standard finance theory suggests that it is crucial to consider whether any such increases in volatility can be diversified. Significant effects on cost of capital are only likely if investors are unable to manage their portfolio to take account of the increased volatility of one asset. Our review of experience in other jurisdictions identified little direct evidence on the impact of locational pricing on the cost of capital – indeed, it might be expected that investors would be better able to manage risks under locational pricing, for instance by investing in a portfolio of assets around GB. In addition, we would expect there to be several mechanisms available to help investors to manage risks in practice, including CfDs.

70. In our central analysis, we therefore assume no change in investors' cost of capital as a result of locational pricing. We have, however, modelled a variant scenario in which higher capital costs reduce the benefits of nodal pricing by around £7.5bn under the LtW (NOA7) scenario, and by around £5.5bn under the SysTr (NOA7) scenario.

71. We have analysed liquidity of wholesale markets in GB and in selected markets with locational pricing, and found that, if anything, there appears to be greater liquidity in markets with locational pricing relative to markets with national pricing. We do not see any reasons to expect liquidity to change significantly as a result of locational pricing, though liquidity might concentrate in practice at trading hubs, as happens in several North American markets.

Key finding 6: Historical precedent from other jurisdictions indicates that market participants may incur implementation costs of c.£0.5bn in the transition to locational pricing. We have found no evidence of an investment hiatus during the transition

72. Implementing a form of more granular locational pricing in GB would require many parties to invest in new operational functions and systems to carry out the activities required under a zonal or nodal market. This may include new computing and software systems, updated energy procurement, hedging and billing processes, and staff training and recruitment, among other cost elements.

73. CBAs carried out in other jurisdictions provide a relatively wide range of cost estimates across each category, with varying proportions of SO and market participant costs. Apart from ERCOT's 2008 CBA which estimated costs of £560m, all implementation cost estimates were below £300m in 2022 values. Based on historical assessments, and input from market participants, we have estimated implementation costs of £0.5bn in the transitioning to locational pricing.

74. In our assessment of other jurisdictions that have transitioned to nodal pricing, we have not observed any material impact on the rate of generation investment. For example, during the transition in the Texas market between 2006 and 2010, installed generation capacity increased from 71.8GW to 84.2GW, even without a capacity mechanism. Rather, other policy instruments could be more material drivers of investment decisions. For example, we might expect that the maintenance of the CfD regime and the capacity market would serve to maintain a reasonable degree of investor confidence. Moreover, as we described above, wholesale prices in some regions are likely to increase relative to a national regime. So, to the extent that there was a slowdown in the rate of investment, we might expect it to be focused in areas where prices are expected to be low, with potentially increased roll out of new assets in regions where prices are expected to be high.

Key finding 7: A transition to locational pricing leads to a faster reduction in emissions over the modelling period. Using DESNZ assumptions on the societal cost of carbon emissions indicates further socioeconomic benefits as a result of reduced emissions.

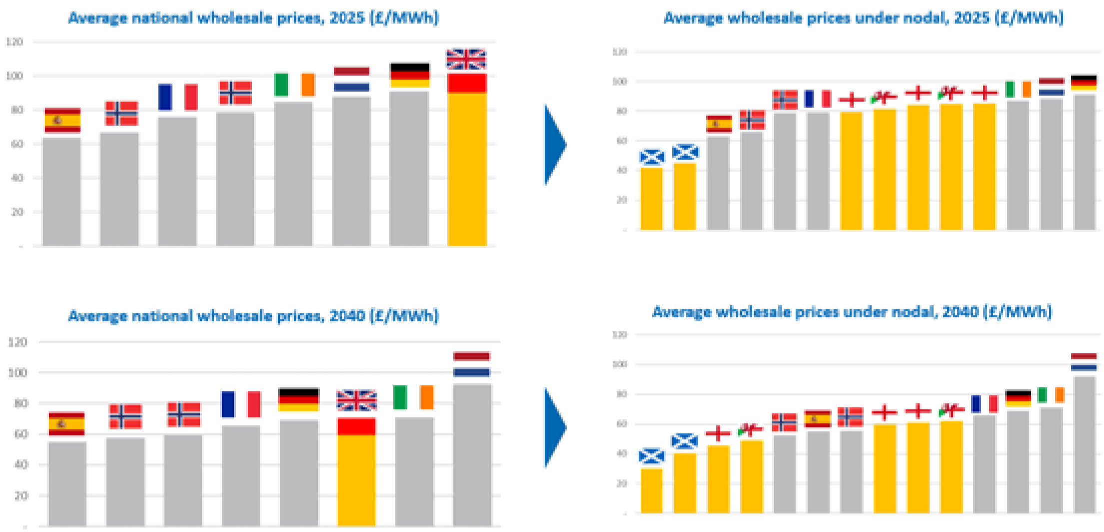
75. Reflecting Net Zero objectives, emissions fall to zero under all market designs by 2040. However, we find that emissions fall faster under a GB market with locational pricing. A transition to a nodal market would result in between 65 and 100 million tonnes of carbon dioxide equivalent ("MtCO2e") reduction in the period to 2040. This is because a market with greater locational granularity results in less renewables curtailment and better use of interconnectors, which displaces some thermal generation.

76. While we capture this benefit in the modelling presented above, the value we place on the reduced carbon emissions is based on market prices. For policy evaluation purposes, DESNZ adopts a different approach for evaluating carbon emissions which is intended to reflect the full societal cost of carbon emissions and is significantly higher than the value we have used in our modelling. Therefore, evaluating carbon emissions on the basis of DESNZ's carbon value leads to a higher estimate of the benefits of locational pricing – with additional benefits of between c.£12bn and c.£18bn over the modelling period a transition to a nodal market.

Key finding 8: We find that under a locational pricing regime, wholesale electricity prices fall significantly in the northern regions of GB. This effect is particularly pronounced under a nodal pricing regime, where, under the LtW (NOA7) scenario, annual average wholesale prices in Scotland would be the lowest in Western Europe.

77. As discussed earlier, our analysis shows a significant reduction in wholesale electricity prices in the north of Britain. When benchmarked against European countries we find that annual average prices in Scotland would likely fall to the lowest in Europe as shown in Figure ES-9 below.

Figure ES-9: Annual average prices for GB and other OECD countries, £ per MWh, LtW (NOA7)



Source: FTI analysis.
Note: This assessment does not include the impact of renewable support mechanisms in any country, which would also impact the overall prices faced by consumers.
Red portions of the GB wholesale price indicate the congestion cost component. We are unable to calculate the corresponding cost recovery of constraint management costs for the European nations shown, as this can be done via a variety of mechanisms and consists of different components.

78. Intuitively, this result is unsurprising – Scotland has some of the best conditions for wind generation in Europe and, under the FES scenarios, a very significant roll-out of zero marginal cost renewables generation in Scotland is anticipated. Combined with the limitations on transmission build and relatively low demand (peak demand in Scotland is assumed to be 9GW with generation capacity between 60GW and 65GW in 2040), this means that prices would be significantly lower under locational pricing. We observe a similar trend, albeit to differing extents, under the other scenarios assessed in our work.

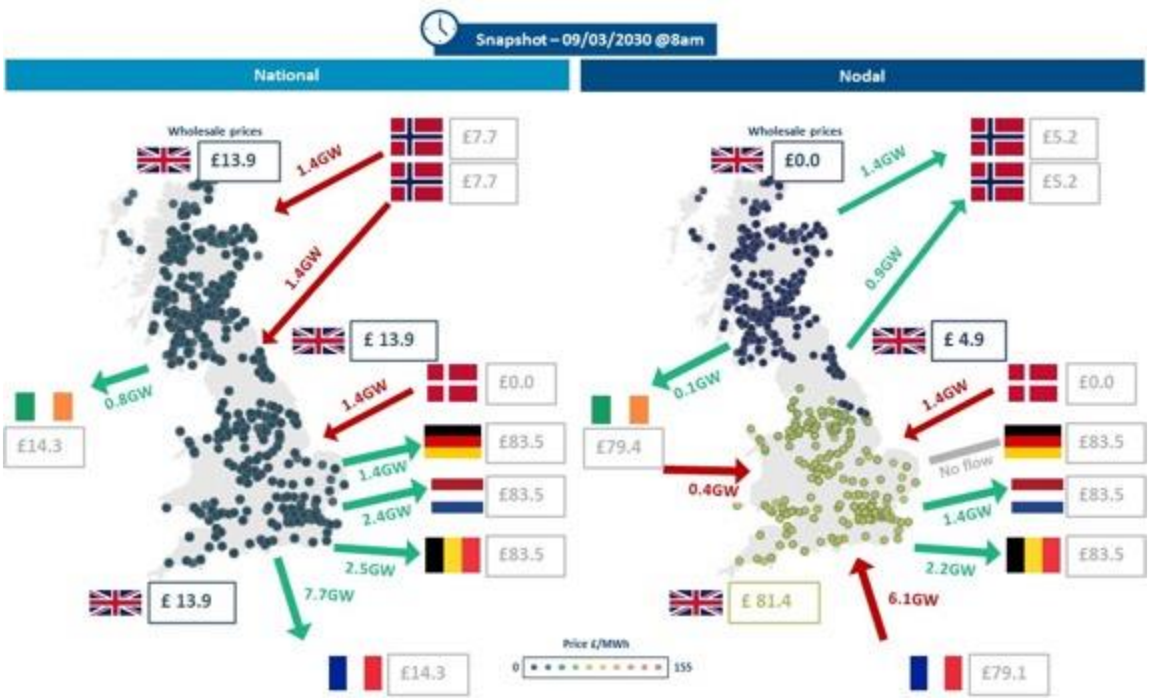
79. This points to a further benefit in locational pricing that we have not sought to capture quantitatively in this analysis but may be material: the possibility of large users of electricity choosing to site in Scotland and northern England to capture the low prices of electricity in those regions. For example, industrial users may find that the benefits of lower electricity costs justify siting in these areas (even if other costs are higher). This may apply within GB – in that some large consumers that would have sited in the south would now site in the north. Equally, it could also trigger inward investment into GB – in that users may choose to site in Scotland relative to siting in other countries.

80. Under a locational pricing regime, a direct benefit to the electricity system of demand siting closer to generation would be to reduce the need for electricity transmission – for the simple reason that greater volumes of electricity would be consumed close to where it is generated. As we have not sought to evaluate this benefit, we believe this may represent one element of our assessment where there are additional potential benefits. Furthermore, there are potential implications for wider government policies – significantly lower electricity prices in the north of Britain which induce large industrial consumers to site in the area would seem likely to have knock-on beneficial impacts to the wider regional economy.

Key finding 9: Flows on interconnectors to other European countries change significantly with more locationally granular wholesale prices in the GB market. Flows to and from Norway and France are particularly impacted which, in turn, impact wholesale prices in those countries.

81. The direction of flow on interconnectors between GB and European countries is determined by prices – with electricity in low priced areas flowing to higher priced regions. A move to locational pricing in GB would therefore have the effect of, for some time periods at least, changing the scheduled direction of flow on interconnectors. Figure ES-10 below illustrates this effect for 9 March 2030 at 08:00 in both the national market design and the nodal market design in the LtW (NOA7) scenario (a zonal market has a similar impact).

Figure ES-10: Interconnector flows between GB and other European countries, LtW (NOA7)

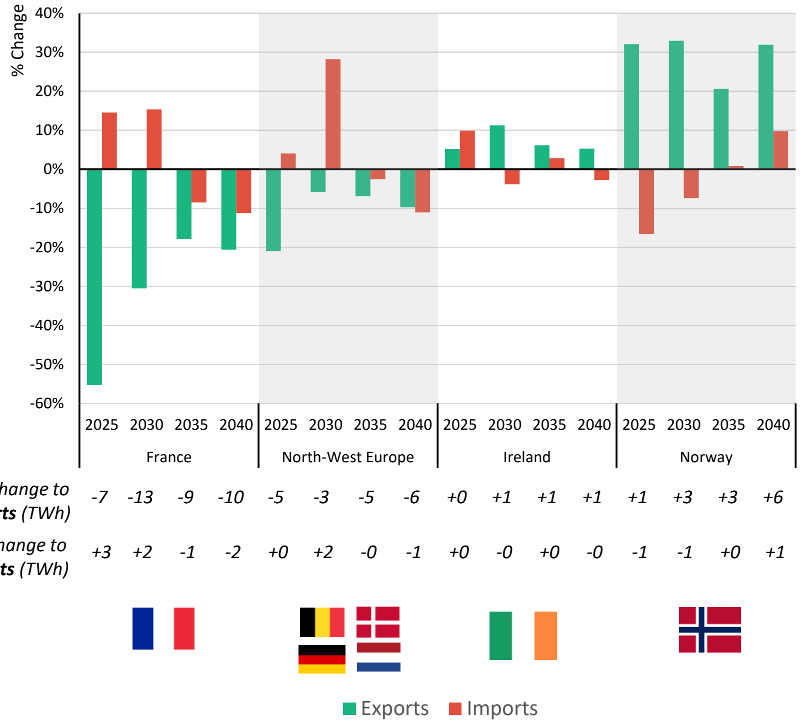


Source: FTI analysis

82. As Figure ES-10 shows, in this hour, under a national price regime, the clearing price would be £13.9 per MWh in GB. Given the prevailing prices for each country in that hour (as indicated by the grey numbers), the model forecasts flows from Norway and Demark into GB, and flows from GB out to France, Germany, Belgium, the Netherlands and Ireland. However, for the same hour under a nodal pricing regime, the bottlenecks in the GB transmission system are reflected in the prevailing locational wholesale prices – with prices in Scotland at £0 per MWh, around £4.9 per MWh in northern England, and around £81.4 per MWh in the south. This impacts on the flows on the interconnectors – there is a now a 2.3GW flow *from* northern GB to Norway (rather than a 2.8GW flow *to* northern Britain from Norway under a national pricing market) – implying an overall change of 5.1W in flows between Norway and northern GB for this hour. The opposite effect is observed with scheduled flows to France in this sample hour – scheduled exports *from* GB *to* France of 7.7GW under a national pricing regime are instead, under a nodal regime, imports *to* GB *from* France of 6.1GW – implying an overall change in net scheduled flow to France of 13.8GW.

83. Over the course of a year, we find that there are significant changes in both imports and exports of electricity. We show this below in Figure ES-11.

Figure ES-11: Net change in imports and exports between GB and European countries, LtW (NOA7)



	France 2025	France 2030	France 2035	France 2040	North-West Europe 2025	North-West Europe 2030	North-West Europe 2035	North-West Europe 2040	Ireland 2025	Ireland 2030	Ireland 2035	Ireland 2040	Norway 2025	Norway 2030	Norway 2035	Norway 2040
*Net change to **exports** (TWh)*	*-7*	*-13*	*-9*	*-10*	*-5*	*-3*	*-5*	*-6*	*+0*	*+1*	*+1*	*+1*	*+1*	*+3*	*+3*	*+6*
*Net change to **imports** (TWh)*	*+3*	*+2*	*-1*	*-2*	*+0*	*+2*	*-0*	*-1*	*+0*	*-0*	*+0*	*-0*	*-1*	*-1*	*+0*	*+1*

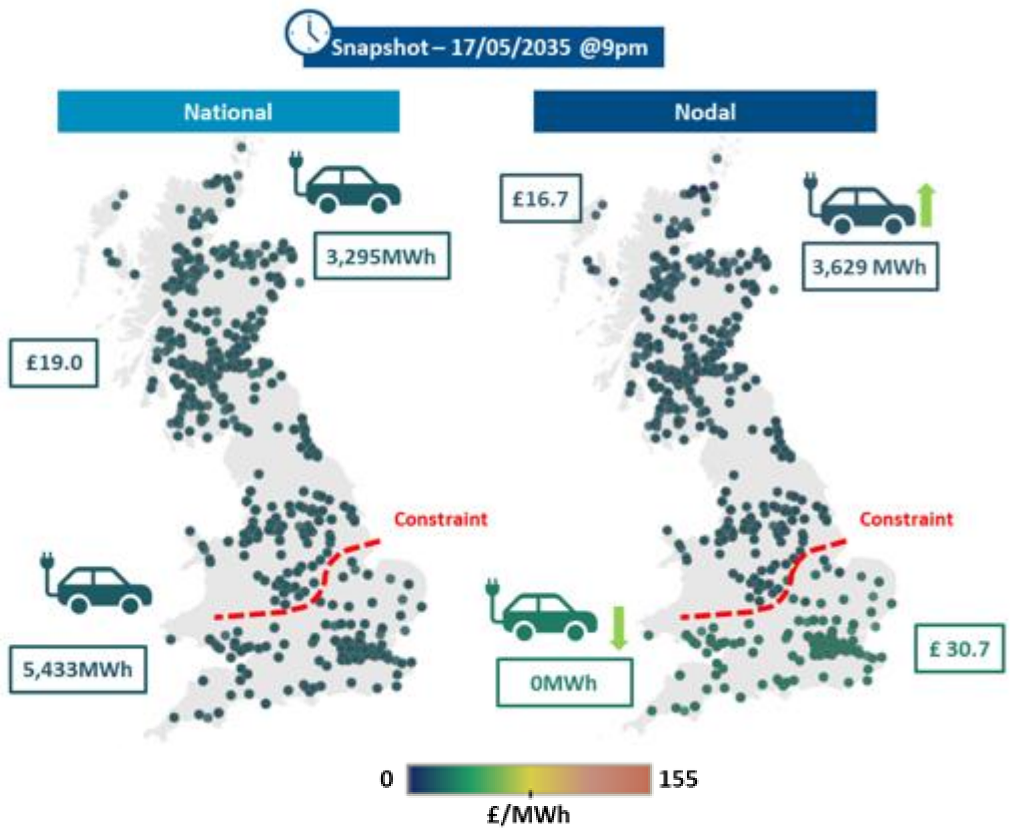
Source: FTI analysis

84. As Figure ES-11 illustrates, the most significant impacts are on flows to and from France – with between a 20% to 50% reduction in exports from GB over the forecast period – and to and from Norway – with exports to Norway from northern Britain increasing by between 20% and 30%.

Key finding 10: Locational prices can significantly alter the charging profiles of electric vehicles, and thus in turn help alleviate transmission bottlenecks.

85. All of the scenarios we model envisage large scale electrification of the transportation sector and, in particular, the rapid adoption of Electric Vehicles ("EVs"). The charging of EVs is forecast to constitute a major proportion of electricity demand and also offer the possibility of providing flexibility to the grid. Such flexibility can result from charging only when electricity is relatively plentiful, and also from using the car's battery to discharge energy back onto the network at times of relative scarcity. Figure ES-12 below illustrates how EV charging would vary for a particular hour in 2035 in both the national and nodal market designs under the LtW scenario.

Figure ES-12: EV charging profiles under national and nodal market designs, LtW (NOA7)



Source: FTI analysis

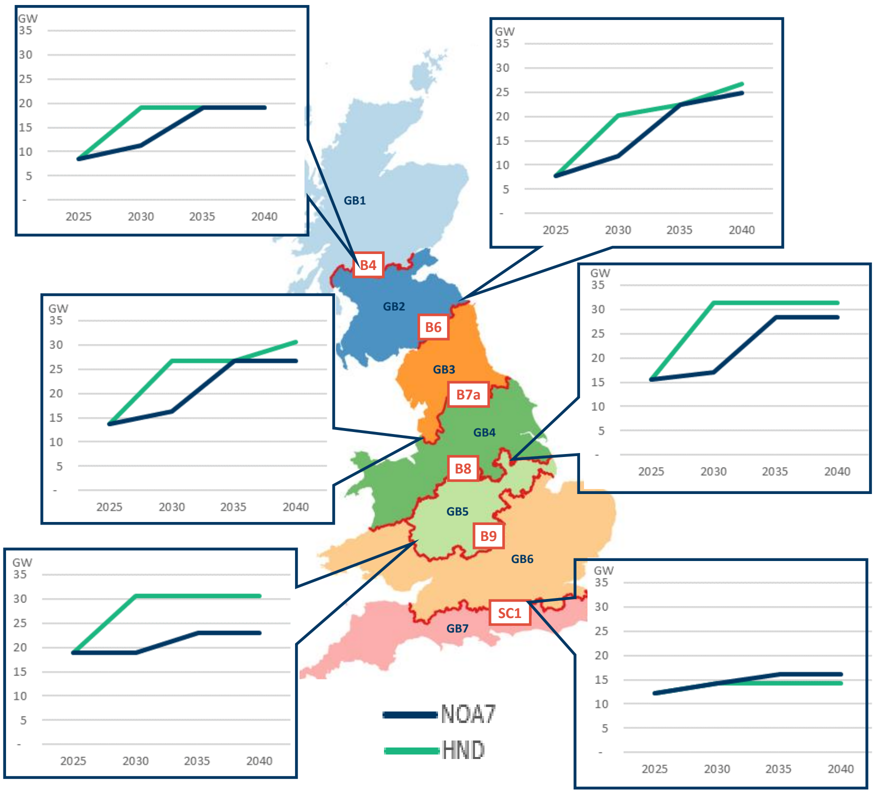
86. As Figure ES-12 illustrates, a transition to a nodal price regime would lead to higher prices in this particular hour in the south of Britain. This leads EVs to cease charging in this hour – in expectation of lower prices later in the evening – which serves to alleviate the transmission congestion on the network. By contrast, under a national price market design, the lower price means the EV fleet in the south of Britain would continue charging – thus exacerbating the transmission congestion. We find that overall, for modelled year 2035, there is a difference in when EV's are charging between a national and nodal market in c.28% of hours,[13] indicating that locational pricing can have a significant impact on flexible sources of demand.

[13] This calculation fixes the amount of generation capacity in each node so that the figure will only reflect changes to wholesale electricity market conditions and not capacity. There might be other factors not related to wholesale prices that cause EVs to operate differently (e.g., extended periods of £0 prices), but we do not consider them to be material.

Key finding 11: Greater locational granularity in wholesale markets has the potential to reduce the need for transmission investment relative to a national pricing regime. This is mainly due to improved siting decisions of participants and better use of two-way assets such as interconnectors that, everything else equal, reduce the need for incremental transmission.

87. As we noted earlier in this summary, the LtW scenario modelled has two different underlying transmission scenarios. Our initial scenario uses the NOA7 transmission development plan, whilst the second uses an updated HND transmission development plan. Although we model the two transmission grids on a nodal basis, the main differences are represented below in Figure ES-13.

Figure ES-13: Transmission capacity at main congestion boundaries, NOA7 and HND



Source: ETYS and NOA7, FTI analysis

88. As Figure ES-13 illustrates, the HND transmission plan envisages a greater and faster roll out of transmission relative to the NOA7 transmission plan, particularly in 2030. Given the underlying generation backgrounds were the same for both transmission plans, we could therefore evaluate the benefits of the HND transmission upgrade relative to NOA7 under both a national and nodal market design.

89. Under a national pricing regime, we found that the benefits of the enhancement would, under the current ESO methodology, be evaluated at c.£28bn over the 16-year modelling period (undiscounted). This represents the difference between the two forecasts of constraints costs under the different transmission plans, as shown above in Figure ES-13. By contrast, under a nodal regime, the same set of transmission enhancements have a benefit of £3bn.

90. The drivers of the difference in benefits are a consequence of the operation of locational markets. First, in investment timescales, locational pricing encourages potential changes in market participants' siting decisions – with generation encouraged to consider siting nearer centres of demand (where prices tend to be higher).[14] Either case would, everything else equal, reduce the need for additional transmission and therefore the benefits of a given transmission enhancement.

91. Second, in operational timescales, two-way assets – and in particular interconnectors – can frequently exacerbate constraints in a national market design. As we illustrated above in Figure ES-11, the wholesale market national price may encourage imports from Norway into GB and exports from GB to France at times of system constraints – thereby, in practice, worsening congestion. In a locational wholesale market, the transmission constraints are reflected in the wholesale prices, meaning that imports into and exports from GB can only work with the transmission system rather than against it. In essence, locational pricing, and in particular nodal pricing, allows the wholesale market to optimise the use of all the flexible generation and demand assets of the system in a way that national pricing simply cannot. Given this greater effectiveness in usage of the current asset base across the entire value chain, a given incremental transmission asset can only be relatively less beneficial under a locational pricing regime than under a national market design.

92. A third driver of the difference in benefits of transmission enhancements relates to a technicality associated with Balancing Mechanism bids and offers and how these are then used to evaluate transmission benefits under a national regime, but not under a nodal market design.

93. Given the substantial expected cost of the transmission upgrade under current plans, locational pricing may therefore generate additional material benefits to those identified earlier in this summary by optimising the transmission network in line with a locational pricing regime.

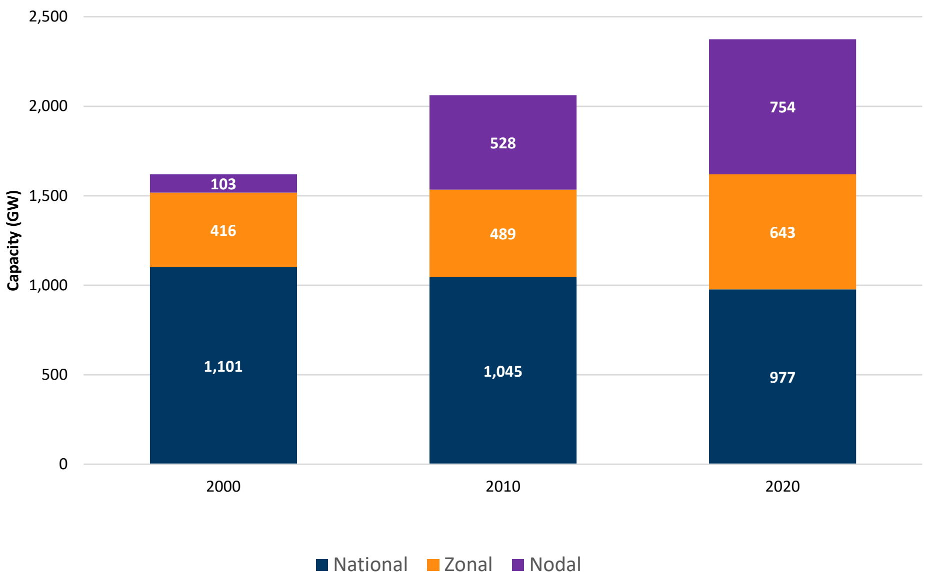
94. We should emphasise that this conclusion on transmission investment does not suggest that upgrades to the GB transmission system are no longer required under locational pricing. Instead, our findings show that, a locational pricing regime can be complementary to transmission planning and investment, reducing the requirements for additional transmission.

Key finding 12: Globally, zonal and nodal electricity market designs have become increasingly prevalent over the last 20 years.

95. As part of our work, we reviewed the historical and current electricity market designs for other Organisation for Economic Co-operation and Development ("OECD") countries. Our findings are summarised below in Figure ES-14, which illustrates the installed capacity by market design in each of the liberalised electricity markets in the OECD.

[14] Larger demand users could also be incentivised to site nearer larger, and more remote, generation (where prices tend to be lower). This effect is not modelled.

Figure ES-14: Installed capacity by market design in OECD countries



Source: International Renewable Energy Agency ("IRENA"), CAISO, NYISO, ERCOT, Ministry of Business, Innovation and Employment, New Zealand ("MBIE NZ"), Potomac Economics, IESO, Digest of UK Energy Statistics ("DUKES"), Federal Energy Regulatory Commission ("FERC"), SPP, ISO-NE.

96. At the turn of the century, national pricing was the most common design. GB, much of Europe and many parts of the US operated on this basis. Some markets operated on a zonal basis, but only two – New Zealand and the New York market (NYISO) – operated on a nodal basis. Since then, zonal and nodal markets have significantly increased in number so that, by 2020, the share of installed capacity operating in locational market designs is now significantly greater than the share of markets that operate under a national market design.

97. A main driver of this trend is that some markets that originally adopted national or zonal pricing have increased the locational granularity of their markets by switching to either zonal or nodal pricing. Sweden, for example, adopted zonal pricing and in the US, the markets of Texas and California switched from zonal pricing to nodal pricing. This trend is continuing, for example with Ontario's transition to nodal pricing and the expansion of the geographical reach of CAISO's wholesale electricity market dispatch systems via the Western Energy Imbalance Market.

98. A secondary driver is that some markets that were not liberalised at the turn of the century immediately adopted a locational market design. For instance, the market of the mid-west part of the US, MISO, liberalised its market in 2005 and immediately adopted nodal pricing.

99. Locationally granular markets feature a wide range of generation mixes, for instance, among nodal pricing markets:

- New Zealand features a mix of hydro generation in the South Island and thermal, geothermal, and renewable generation in the North Island;
- Singapore features predominantly thermal generation;
- the vast geographic footprint of the northeast US power market (PJM market) includes many sources of generation, with nuclear and thermal generation in the majority;

- the Texas market (ERCOT) and the Southwest Power Pool (SPP) have high proportions of wind generation; and
- California (CAISO) has recently observed significant roll-out of solar and battery storage.

C. Conclusions and final thoughts

100. The UK has set itself the ambitious goal of achieving net zero carbon emissions across the economy by 2050 – including plans for electricity sector emissions to hit net zero by 2035. The scale of ambition raises formidable technical and economic challenges which will likely increase in complexity as more sectors in the economy decarbonise. It is against this backdrop that we have conducted this study to assess the costs and benefits of different designs for the way in which electricity wholesale prices are determined.

101. Ultimately, prices provide signals that convey information to producers and consumers of a product. When a product is plentiful – in that the supply of the product is abundant – a low price signals that more of the product can be consumed at relatively low cost and that the incremental value of additional production is low. By contrast, when a product is scarce, price is used to ration its availability to those that value it the most and to encourage other producers to deliver more of the product. In this respect, electricity prices are intended to be no different to the prices of products in other markets – they signal when, and where, the product is relatively scarce and relatively plentiful.

102. As we evolve towards Net Zero, the intermittent nature of renewables generation will likely result in our electricity system rapidly and frequently switching from periods of abundant supplies of electricity to periods of relative scarcity. We have shown in this study that within GB, these fluctuations will frequently also be regional in nature – in particular, the north of GB will likely have more periods of relatively abundant supplies of electricity whereas the south of GB will have more periods of relative scarcity. The current design of our electricity market seems ill-equipped to manage these fluctuations, as wholesale prices do not reflect locational imbalances in demand and supply.

103. In our study, we have found that changing the GB electricity market to locational wholesale pricing would be expected to increase both societal welfare and consumer benefits in GB under all scenarios – with consumers benefiting in all regions of GB. These benefits are significantly more pronounced in scenarios with a nodal market design than in a zonal market design. Conversely, we have found that maintaining the status quo would likely impose very significant additional costs on consumers, and could delay the decarbonisation of the power sector.

104. There would inevitably be challenges in transitioning to locational wholesale pricing in GB. However, our review of international experience suggests that such challenges can be overcome with costs that are small relative to the potential benefits. The experience of other countries should provide confidence that locational pricing could play a significant role in facilitating the more efficient functioning of a decarbonised electricity market in GB.

105. We trust that our assessment will be informative to policymakers, industry and consumers – and hope that our findings can contribute to delivering Net Zero ambitions on behalf of consumers and citizens in the UK.

1. Introduction

1.1. In order to achieve very challenging decarbonisation objectives, electricity sectors across the globe are undergoing rapid and fundamental change. Increasing proportions of electricity are generated by non-carbon emitting resources such as wind and solar power. Compared to the large carbon-emitting power stations that prevailed in most of the developed world until recently – such as those fuelled by oil, coal and gas – the output from these new renewables resources is more intermittent and unpredictable. It also tends to be more decentralised, in that the new sources of generation are often sited in locations that have favourable wind and solar resources but are relatively distant from the demand centres that they serve.

1.2. Alongside increased decarbonisation of generation, demand for electricity is set to grow significantly as other sectors switch away from carbon intensive fuels. For example, the increasing adoption of heat pumps ("HPs") for heating homes and electric vehicles (“EVs”) for transport will significantly increase the use of electricity in the economy. Finally, new technologies have the potential to alter radically the way in which electricity is consumed. Notably, the era of digitalisation offers the possibility of much more sophisticated consumer demand management, while technological developments allow for greater potential to store electricity.

1.3. The United Kingdom is one of the world leaders in the decarbonisation of the electricity sector. The share of electricity produced by zero-carbon resources has more than doubled since 2010,[15] while emissions from the power sector have fallen by more than 75% over the last three decades.[16] Moreover, the Government has committed to “*end its contribution to global warming*”, introducing legislation that creates a legal requirement to "*bring all greenhouse gas emissions to net zero by 2050*" and, more recently, committing to decarbonise the electricity system by 2035.[17]

1.4. While the ways in which we produce and consume electricity are undergoing radical transformation, the way in which producers trade electricity with consumers has remained relatively unchanged in Great Britain (“GB”) since 2001. The wholesale electricity market is designed to enable producers of electricity to compete with each other to sell electricity to consumers (both large industrial consumer and retailers that serve domestic and small business consumers). Known as the New Electricity Trading Arrangements ("NETA"), the current GB wholesale electricity market arrangements were developed in the late 1990s, going live in March 2001.[18]

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[15] National Grid, ‘Energy Explained’, accessed 24 February 2023 (link). According to National Grid, Zero-carbon sources provided 48.5% of electricity used in 2022, up from c.20% in 2010.

[16] BEIS (2021), ‘2020 UK greenhouse gas emissions, provisional figures’ (link).

[17] BEIS (2019), ‘UK becomes first major economy to pass Net Zero emissions law’ (link). HM Government (2021), British Energy Security Strategy (link). Note, the 2035 decarbonisation targets are subject to ensuring security of supply in the GB energy system.

[18] NETA replaced the previous market arrangements known as the "Pool", introduced at the time of privatisation in 1990.

1.5. The original NETA design (and its predecessor) only applied to the electricity markets of England and Wales; Scotland sat outside of this market, with its prices administered to match those in England and Wales. Following its perceived success,[19] NETA was extended to Scotland in 2005, creating a single GB electricity market, operating under the British Electricity Trading and Transmission Arrangements ("BETTA").

1.6. While there have been many market design modifications since 2005, the overarching key features of the NETA market have remained broadly the same. However, in light of the fundamental changes in the production and consumption of electricity, many stakeholders consider that the current wholesale market arrangements appear increasingly outdated.[20] Without reform, there are concerns that the costs of achieving Net Zero may be materially higher than they need to be, to the detriment of consumers and citizens.

1.7. In this context, an area of considerable debate has been the extent to which the design of the wholesale electricity market in GB should include a price that varies by location. Currently, the NETA design incorporates a single national price that varies for each 30-minute settlement period – reflecting prevailing national demand and supply conditions in that half hour. However, in many other electricity markets across the globe, wholesale prices vary by location as well as by time period. In these electricity markets, wholesale prices reflect local (rather than national) demand and supply conditions of the electricity system for each settlement period.

1.8. The issue of location in wholesale electricity prices has received further prominence since March 2022 as the National Grid Electricity System Operator ("ESO") completed a 15-month programme titled Net Zero Market Reforms. This programme explored how GB electricity markets may need to evolve to support a carbon-free electricity system by 2035 and to enable whole-economy decarbonisation at an acceptable cost to consumers by 2050. The third phase of the work identified a number of significant problems with the operation of the current electricity market that were "*arising because the wholesale market price is missing a key component: dynamic real-time locational signals*".[21]

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[19] Ofgem (2002), 'Leaflet for British Electricity Trading and Transmission Arrangements' (link).

[20] For example, see ES Catapult (link), Institute For Global Change (link), Policy Exchange (link), UCL (link) and Oxford Energy (link). The recent summary of responses to REMA (published March 2023, link) showed that 80% of respondents agreed with DESNZ that the "*current market arrangements are not fit for purpose*".

[21] The four issues identified by the ESO were that there was "*dramatic and accelerating*" increase in transmission constraint management costs despite significant transmission investments; increasingly challenging balancing of the network, with growing levels of inefficient dispatch; market signals leading to two-way assets (such as interconnectors and storage) sometimes exacerbating transmission constraints; and insufficient signals from the current market design to fully unlock sources of flexibility required to facilitate Net Zero – see National Grid ESO (2022), 'Net Zero Market Reform, Phase 3 Conclusions' (link).

1.9. Furthermore, the Department for Energy Security and Net Zero ("DESNZ", previously the Department for Business, Energy & Industrial Strategy or "BEIS") announced a Review of Electricity Market Arrangements ("REMA") in April 2022, which seeks to examine potential options to reform the GB electricity market design to ensure it is "*fit for the purpose of maintaining energy security and affordability for consumers as the electricity sector decarbonises*".[22] This consultation opened in July 2022 and put forward the Government's objectives for electricity market design, as well as an initial assessment of reform options. One of the reforms under consideration is the potential introduction of more granular locational signals in the electricity wholesale market.

1.10. In parallel, Ofgem is undertaking a Locational Pricing Assessment, which, as its central question, examines whether introducing locational granularity into the wholesale electricity market would enable a fully-flexible, low-carbon, low-cost system.[23] Ofgem is assessing potential alternative wholesale market arrangements that vary according to the granularity of the locational price of electricity.

1.11. It is in this context that Ofgem has engaged FTI Consulting ("FTI"), supported by Energy Systems Catapult ("ESC"), to perform an assessment of the costs and benefits of introducing locational pricing into the wholesale electricity market in GB. This report is our independent assessment of the expected costs and benefits, informed by substantial stakeholder engagement and in-depth modelling of future electricity market developments.

A. Purpose and objectives of this report

1.12. We have assessed the expected costs and benefits of changing the design of the electricity market in GB by comparing a market with a single national wholesale price of electricity to one in which the wholesale price of electricity can vary by location, depending on local demand and supply conditions, as well as the available transmission capacity. In contrast to many other studies on the net benefits of locational pricing,[24] we have carried out a quantitative assessment of the benefits and the costs under a range of different possible scenarios. This allows us to estimate the economic impact on consumers of different market design options. We also estimate the impact on producers and the ESO to derive an overall economic assessment of the costs and benefits to society in GB as a whole.

1.13. Introducing wholesale electricity prices that vary by location means that generators at different locations would likely be paid different prices for electricity. It also means that, under some market design options, consumers in different parts of the country could pay different prices for electricity. Therefore, the impacts on different groups of generators and consumers could vary, and we have also assessed the expected regional effects of different locational market design options.

1.14. Finally, we have considered some possible transitional measures that may accommodate the shift from the current market design to a locational market design, and assessed how these might affect the overall expected costs and benefits.

[22] BEIS (2022), 'Review of Electricity Market Arrangements – Consultation Document' (link).

[23] Ofgem (2022), 'Locational Pricing Assessment' (link). This assessment arose from the Full Chain Flexibility Strategic Change Programme.

[24] For instance, the UK Energy Research Centre's report on 'Exploring the implications of locational marginal pricing of electricity' as published on 4 October 2022 (link).

1.15. The findings in this report are intended to provide Ofgem, and in turn the Government, with an objective and well-evidenced economic assessment of the effects of locational pricing.

B. Process

1.16. In December 2021, Ofgem published an Invitation To Tender to undertake a technical assessment of introducing locational pricing.[25] FTI, supported by ESC, submitted a proposal and, after being shortlisted and interviewed by Ofgem, were selected to undertake the assessment in March 2022. The FTI team[26] comprises UK, Europe and US experts with broad-based and in-depth global experience in both the design of electricity markets and modelling of these markets.[27] The ESC team members bring additional insights on the socioeconomic landscape of the GB electricity sector.[28]

1.17. We were aware from the outset of our assessment – not least from our experience from other electricity markets that have transitioned to locational wholesale prices[29] – that any change to the design of the GB market has the potential to affect different stakeholders positively or negatively. In this context, it is understandable that any assessment is likely to be critically examined and subject to a high degree of stakeholder scrutiny.

1.18. We have therefore sought to be as transparent as possible in our approach and have engaged extensively with stakeholders across the industry throughout our assessment. Our aim has been to allow as much scrutiny as reasonably possible of our methodology, our assumptions and our overall approach to provide reassurance to Ofgem and stakeholders of the robustness of our findings and of our analytical neutrality. To this end, we have:

- used an industry standard modelling tool, Plexos, to quantitatively assess different possible designs of the GB electricity market;
- sought, wherever possible, to use third-party publicly-available information as inputs into our modelling. In particular, we have used widely-accepted, industry-standard data produced by ESO and the European Network of Transmission System Operators for Electricity ("ENTSO-E") for potential scenarios of the evolution of electricity generation, demand and transmission components of the electricity sector over the forecast period. Furthermore, we have sought advice from industry stakeholders as to which scenarios are most appropriate to use in our modelling;

25 Ofgem (2021) 'Design Options for Nodal Pricing in GB: A Technical Assessment: Contract Reference Number 2021–153'

26 The FTI experts involved in the report include Jason Mann (link), Joe Perkins (link), Martina Lindovska (link), William Hogan (link), Scott Harvey (link), Susan Pope, Mitch DeRubis and Fabien Roques (link).

27 Previous work includes: 'Resource Adequacy Mechanisms in the National Electricity Market' (2020) (link); 'Essential System Services in the National Electricity Market' (2020) (link).

28 The Energy Systems Catapult experts involved were Guy Newey (link), Ben Shafran and George Day.

29 Members of the FTI team have been involved in the transition to more granular locational market designs in several energy markets in North America including Ontario (IESO), California (CAISO) and Texas (ERCOT).

- conducted five industry-wide workshops[30] attended by a total of over 500 industry stakeholders with the aim of seeking feedback on our approach, data sources, and emerging results;
- held bilateral discussions with a wide range of GB industry participants, including investors in windfarms and battery storage, as well as other market participants who provide demand flexibility;
- supported Ofgem in publishing a Frequently Asked Questions document responding to queries on our modelling assumptions and methodology;
- presented our initial findings to the Europe-wide industry group, the European Federation of Energy Traders;
- held meetings with senior executives of US-based power exchanges to understand the impact on liquidity of trading in locational electricity markets;
- engaged extensively with ESO to clarify details of the proposed enhancements to the transmission network over the modelling period, which included meetings with senior management and control room personnel;
- discussed several specific issues with academic experts on electricity markets in the UK, Europe, Australia, and US;
- met DESNZ frequently to discuss our approach, assumptions and emerging results; and
- discussed our emerging findings and approach regularly with the Ofgem working team, as well as periodically with senior Ofgem staff.

1.19. Our hope is that all stakeholders that have engaged with us are aware of the methodology we have used and the assumptions we have adopted and, as far as is reasonably possible given the polarised nature of views on the issue, are assured by the robustness and analytical objectivity of our approach.

C. Restrictions

1.20. This report has been prepared solely for the benefit of Ofgem for use for the purpose described in this introduction.

1.21. FTI accepts no liability or duty of care to any person other than Ofgem for the content of the report and disclaims all responsibility for the consequences of any person other than Ofgem acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

D. Limitations to the scope of our work

1.22. This report contains information obtained or derived from a variety of sources. FTI has not sought to establish the reliability of those sources or verified the information provided.

[30] Our first workshop in May 2022 discussed our proposed modelling approach and key assumptions (link); our second workshop in August 2022 provided an initial overview of our emerging assessment results (link); and our third workshop in October 2022 set out an updated view of our assessment (link). In June 2023, we conducted two further workshops in London and Glasgow to present a summary of our findings to stakeholders.

1.23. No representation or warranty of any kind (whether express or implied) is given by FTI to any person (except to Ofgem under the relevant terms of our engagement) as to the accuracy or completeness of this report.

1.24. This report is based on information available to FTI at the time of writing the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

E. Structure of this report

1.25. This report is divided into eleven further chapters. These are:

- Background and context:
  - **Chapter 2** describes the background of locational wholesale electricity market design.
  - **Chapter 3** explores market design in practice, covering the experiences in GB and in other developed countries.
- Assessment approach and methodology:
  - **Chapter 4** sets out our overall approach and methodology for the assessment of potential design options for locational wholesale markets.
  - **Chapter 5** details our power market model and the assumptions underlying it.
- Modelling outputs and assessment results:
  - **Chapter 6** sets out the capacity and generation outputs from our assessment.
  - **Chapter 7** sets out the pricing and financial outputs from our assessment.
  - **Chapter 8** describes our assessment of the wider system impacts of locational wholesale market pricing changes.
  - **Chapter 9** consolidates our modelling results into a Cost Benefit Assessment ("CBA") of the expected impacts on consumers and GB as a whole.
  - **Chapter 10** sets out our indicative assessment of the benefits of incremental transmission.
  - **Chapter 11** sets out the results of our sensitivity analysis.
- Conclusions of our analysis and final remarks, which is set out in **Chapter 12**.

1.26. Additionally, this report includes the following supporting appendices:

- **Appendix 1** provides further detail on our modelling assumptions.
- **Appendix 2** sets out our modelling results for the System Transformation scenario.
- **Appendix 3** sets out our modelling results for the Leading the Way (HND) scenario.
- **Appendix 4** sets out further detail on our assessment on the impact on cost of capital.
- **Appendix 5** sets out a glossary to the report.

2. Background: locational options for electricity market design

2.1. From the 1980s, policymakers in numerous jurisdictions across the globe wished to reduce the role of the state in many sectors of the economy, believing that privately-owned businesses were more likely to be efficient and deliver better service to voters than state-owned monopoly businesses. This led to a wave of privatisations and liberalisations, in which GB was at the forefront – successively privatising its telecoms, gas, water and electricity sectors between 1984 and 1991.[31]

2.2. In the electricity sector, GB policymakers were concerned that the state-owned Central Electricity Generating Board ("CEGB"), that owned and operated all the electricity generators and the transmission network in England & Wales, was inefficient in both its planning and development of the sector and its operation.[32] As well as harnessing the perceived efficiency benefits of private ownership, policymakers were keen to introduce competition into the sector. This was in contrast to the earlier privatisation of the gas sector, which transferred the vertically-integrated gas company, British Gas, directly into private ownership while retaining its monopoly status. Competition in the electricity sector would reward and therefore incentivise efficient production of electricity – ultimately to the benefit of consumers through lower electricity prices.

2.3. While the transmission and distribution networks that conveyed electricity from power stations to end-users were considered to be natural monopolies that could not be opened to competition, electricity generation was judged to be potentially competitive. The proliferation of electricity generators adopting different technologies of varied vintages (typically coal and oil-fired thermal generation, nuclear, hydro and pumped storage) afforded policymakers the opportunity to develop competition in the generation of electricity.[33]

2.4. Therefore, the CEGB was divided into National Grid Company ("NGC"), the owner and operator of the transmission network, which was subject to monopoly regulation, and two non-nuclear privately-owned electricity generating companies each owning a portfolio of power stations (PowerGen and National Power). To bring about competition between the generating companies, a wholesale electricity market was developed. Known as the Pool and operated by the now separated NGC, it provided the platform for generators to compete.[34]

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31 Armstrong, Cowan and Vickers (1994), 'Regulatory Reform: Economic Analysis and British Experience', MIT Press (link). The government sometimes retained a significant stake in these sectors beyond 1991; for instance, it sold its minority stakes in non-nuclear electricity generators in 1995.

32 Armstrong, Cowan and Vickers (1994), 'Regulatory Reform: Economic Analysis and British Experience', MIT Press (link).

33 See National Grid's brief on the 'History of Electricity in Britain' (link).

34 BEIS (2020), 'GB Implementation Plan', Description of the GB electricity market, p.9 (link).

2.5. Some parts of the US adopted a similar approach. While US electricity producers were often privately owned, they were mostly vertically-integrated monopoly providers of electricity. Unlike GB, policymakers typically chose not to separate (or unbundle) the transmission business from the generating companies. Instead, to introduce competition between generators, policymakers separated out the system operator part of the electricity companies into an independent entity. The Independent System Operators ("ISOs"), as they were termed, were responsible for operating (but not owning) the transmission system and ensuring that all generators in their region had non-discriminatory access to the network through the operation of a wholesale electricity market.

2.6. It is the details of how these wholesale markets for electricity work – the design of the market – and how they allow electricity to be traded between producers, consumers and storage providers that is the subject of this study. This background chapter considers, in turn:

- the main variants in wholesale market design – particularly with respect to location (**Section A**); and
- the expected effects, from a theoretical perspective, of different locational market designs on different electricity market participants (**Section B**).

A. Wholesale electricity market variants

2.7. At the outset, we make the observation that regardless of the commercial, market, institutional and regulatory arrangements in place in an electricity sector, the physical operation of electricity systems, consisting of potentially thousands of generators, tens of thousands of kilometres of transmission and distribution cables as well as millions of consumers, is ultimately governed by the laws of physics.

2.8. Two physical constraints are particularly relevant in this context:

- **Law 1:** First, the supply and demand of electricity must balance on a second-by-second basis at all locations on the power grid. Any deviation between demand and supply results in fluctuations away from the nominal system frequency (in GB and in Europe this is 50Hz, in some other countries it is 60Hz). The safe tolerance around the central frequency is very narrow (+/- 1% is the allowed tolerance in GB). Deviations beyond these thresholds run the risk of the entire system blacking out.
- **Law 2:** Second, in Alternating Current ("AC") systems, electrical current is distributed over all possible pathways in inverse proportion to their impedance. An implication of this is that a power station injecting power onto a meshed standard AC transmission system cannot "direct" the current to a particular location – rather the electricity flows so that impedance is equalised across all possible lines.

2.9. These are laws of physics akin to gravity. They cannot be overridden by political or social preferences and the operation of the electricity sector ultimately must be consistent with them. While several different wholesale market design approaches have been developed across the globe, the laws of physics mean that there is one common theme across all market designs (and all market structures either liberalised or non-liberalised) – the need for a system operator ("SO").

2.10. The need to balance on a second-by-second basis across the entire network (Law 1), taking into account the way that electricity flows around the system (Law 2) means that, in practice, a central entity is required to co-ordinate the output (or dispatch, as it is most commonly termed) of all controllable plants on the system at the moment of delivery (known as real-time).[35] Moreover, the SO also has to prepare additional back-up resources (known as reserves) so that output can come online immediately if there are unexpected changes in generation (e.g. due to breakdowns or fluctuations in renewables output), outages of transmission cables, or unexpected changes in demand. Increasingly, the SO may also have a role in encouraging demand-side flexibility, which can play a similar role in enabling the system to respond to unexpected events.[36]

2.11. Ahead of dispatch, electricity systems need to plan for real-time by identifying the combination of controllable plants and demand-side flexibility that will enable supply of electricity to meet the demand in the forthcoming period. This is known as scheduling. In the context of this study, we discuss, first, the approach to developing the schedule and, second, the approach to pricing within an electricity market.

Scheduling

2.12. The scheduling of generation can either be centralised, in which case the SO is responsible for organising the intended running profiles of plants for the forthcoming real-time period, or self-scheduled, in which case the owners and operators of power plants make decisions on their intended operating profiles.[37]

- **Centralised scheduling** allows the SO to schedule the intended running profile of plants ahead of real-time – typically at the day-ahead stage – on the basis of offers (and usually other technical information) submitted by generators.[38] The SO uses this information to develop an operationally feasible running profile of the plants on the system that takes account of the need to balance supply and demand (Law 1), the physical limitations of the transmission network (Law 2), and the physical operating parameters of the resources.
- In **self-scheduling** markets, individual market participants inform the SO of the intended running profile of their power plant (or consumption of their customers) in the coming period at a point in time ahead of real time. In GB, this point is known as gate closure. After gate closure, the SO takes control of the system, which might involve adjusting the output of some plants away from its intended operating profile to ensure compliance with the physical realities of the system. The SO has a range of tools to make these adjustments to participants' intended running profiles – notably, in the GB context, the Balancing Mechanism ("BM") and bilateral contracts with market participants (known as ancillary services).

2.13. We briefly discuss each approach in turn.

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[35] We define controllable (or dispatchable) plant as a generating resource that can respond with relative short notice to changes in market conditions or instructions from the SO. This can include, for instance, storage providers and interconnectors.

[36] The ESO launched a demand flexibility service in winter 2022/23 – see National Grid's brief on the ESO's Demand Flexibility Service (link).

[37] We describe these different approaches as centralised or self-scheduling. They are often described as "central dispatch" or "self-dispatch", but this terminology can be misleading as dispatch is in practice centralised for all controllable plants in all markets. Rather it is the scheduling of plants ahead of real time that is either centrally or self-scheduled depending on the design of the market.

[38] Other technical information may include start-up costs and ties, minimum load costs and levels, incremental energy offers, and ramp rates among others.

Centralised scheduling

2.14. While the SO may release advance warning of certain system stress conditions or may choose to defer transmission or generator outages, the role of the SO in determining the schedule typically begins at the day-ahead stage.[39] At the day-ahead stage, the SO typically operates a "day-ahead market" and receives offers and technical information from market participants, allowing it to develop an operationally feasible schedule that sets out the intended running profile of all the plants on the system for the following day (including storage and demand-side response).

2.15. While this schedule is designed to select the lowest-cost resource profile to meet demand, the SO cannot always select the lowest-priced offers. Rather, the SO has to consider a large number of other factors in choosing which offers to select and therefore which plant to schedule to run. These include incremental energy offers of power plants (particularly thermal generators),[40] system stability requirements, and the finite capacity of the transmission network (i.e., the need to respect Law 2 above). Where there are transmission constraints – meaning that there is insufficient local demand to consume the output of local power plants, and insufficient transmission capacity to convey that output to other parts of the system – the SO will often choose offers from relatively costly plant in areas that are not impacted by transmission constraints, in order to meet the geographical pattern of demand. The term for this scheduling is security-constrained economic dispatch, which is used in the day-ahead stage as well as in real time.

Self-scheduling

2.16. In self-scheduling markets, the design of the wholesale market plays a key role in incentivising market participants to schedule the intended operation of plant in line with the overall intended consumption of market participants. One of the pioneering self-scheduling markets was the NETA design in England & Wales, which went live in 2001, and was extended to include Scotland in 2005. Similar market designs have been adopted throughout Europe and form the basis of the current EU Target Model.[41]

2.17. Under self-scheduling, market participants are incentivised to balance production and consumption over a set time period known as a balancing period. In the GB market, the current duration of the balancing period is 30 minutes.[42] Market participants are charged an imbalance price if the metered output or consumption in a given 30-minute period is less than or greater than the participant's contracted volumes for that period.[43] The imbalance price therefore effectively acts as a penalty for a failure to contract accurately ahead of gate closure, and it is ideally set to encourage market participants to ensure that the contracted volumes are equivalent to the anticipated

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39 For instance, based on information about which plants are likely to be available to generate and which transmission lines are likely to be available to convey electricity – rather than, say, being scheduled for outages to allow for maintenance.

40 In the case of storage, the SO would take account of round-trip efficiency (losses) and operation and maintenance costs in scheduling the resources.

41 European Commission (2017), 'Establishing a Guideline on Electricity Balancing' (link).

42 The EU normally requires 15-minute balancing periods, under its 2017 guideline on electricity balancing (link).

43 The imbalance price has evolved over time, and GB currently has a single imbalance price across the country faced by all market participants, whether long (over-generating / under-consuming) or short (under-generating / over-consuming). Until 2015, there were two separate imbalance prices, with a higher price paid by market participants who were short than those who were long. This provided particularly strong incentives to avoid the imbalance price.

metered output or offtake of the market participant.[44] This means that electricity consumers and their suppliers are incentivised to contract to buy electricity from generators ahead of real-time in a way that best matches their expected consumption in a future period. Generators, for their part, are incentivised to honour the contracts by producing in line with the contracted volumes due to the same incentive to avoid the imbalance price.

2.18. This approach is somewhat consistent with respecting Physical Law 1, in that there are incentives on individual participants that encourage the aggregate balancing of supply and demand every 30 minutes.[45] However, Physical Law 2 is entirely ignored in the current GB wholesale electricity market. This has the potential advantage that market participants do not need to consider their respective locations when contracting with each other. However, it has the disadvantage that when participants notify the SO of their intended running profiles at gate closure, there is a risk that, due to the finite capacity of the transmission network, the output from generators that is contracted for delivery will not, in aggregate, be able to be conveyed to the demand on the system. Where there are transmission constraints, therefore, the market-determined schedule is highly likely to be operationally infeasible in the sense that the notified intended running patterns of power plant will not actually be able to meet system demand.

2.19. As a result, the SO makes adjustments to the nominated running profiles after gate closure to ensure that Physical Law 2 is respected in real time. To do so, it contracts with market participants in the BM (and potentially other contractual tools) in a process often termed redispatch, to either increase or decrease intended output (or consumption) from the notified output (or consumption) profiles submitted at gate closure. The costs of these trades by the SO are recovered through a charge across all electricity consumers.[46]

44 The design of an imbalance price can highly challenging and contentious as can produce distortionary incentives for market participants to keep the system balanced in each location. Some of these issues are raised in this paper Chaves-Avila et al. (2013) 'The interplay between imbalance pricing mechanisms and network congestions – Analysis of the German electricity market' (link).

45 This is obviously some way from the second-by-second balance needed to respect Physical Law 1 fully, which is partly why the SO takes control of dispatch after gate closure to "fine tune" intended running profiles.

46 The Balancing Services Use of System ("BSUoS") charges.

Box 2-1: The origins of the New Electricity Trading Arrangements

NETA were based on arrangements developed for the GB gas market earlier in the 1990s. The physical properties of the gas system approximate those of the electricity system in that there is a need to balance injections of gas onto the network with offtakes of gas (as per Physical Law 1) and gas tends to flow around the gas network from areas of high pressure to low pressure to equalise pressure across the system (as per Physical Law 2).

However, the similarities between the two systems are only very approximate. Notably, there is a very significant tolerance in the need to balance gas injections and offtakes, with no requirement for second-by-second balancing. For example, the gas national transmission system ("NTS") can operate at pressures between 40 bar and 90 bar.[47] The electricity sector equivalent – frequency – has a tolerance of +/- 1%.

Furthermore, while gas does flow around the system to equalise pressure (akin to Law 2 of the electricity system), it does so very slowly – at about 30 mph.[48] Combined with high tolerances, this means that, in contrast to the electricity system, there can be material variations in pressure in different parts of the system at the same point in time. Furthermore, compressors and valves can be used to "direct" gas in certain directions, albeit at a fuel cost for operating the compressors.

Pricing

2.20. A further fundamental market design decision is the extent of locational granularity of prices across an area. There are three broad options that electricity markets have adopted:

- **Nodal pricing** (also known as locational marginal pricing or "LMPs"): each node on the transmission system (typically defined as each injection point, offtake point and transmission line intersection at transmission substations) can face a different price. Examples of markets with nodal pricing are New Zealand, Singapore and many all organised markets in the US (such as CAISO,[49] ERCOT, Southwest Power Pool ("SPP"), New York ISO ("NYISO"), ISO-NE and PJM).
- **National (or uniform) pricing:** there is one electricity price across the whole of the electricity market. Examples of markets with national pricing include GB, Germany, France, Spain as well as Pennsylvania-New Jersey-Maryland ("PJM") and the Independent System Operator New England ("ISO-NE") before transitioning to a nodal market.
- **Zonal pricing:** The market is divided into several different pricing zones. Within a zone, electricity prices are identical, but they can differ between zones. Examples of markets with zonal pricing include Australia (in the National Energy Market, "NEM"), Italy, Norway and Sweden. US markets such as the California Independent System Operator ("CAISO") and the Electric Reliability Council of Texas ("ERCOT") also had zonal pricing before transitioning to a nodal market.

2.21. We discuss these in more detail below.

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47 National Grid GSO (2018), 'Operational Overview' (link).

48 The actual flow rate varies and is a function of a number of factors such as upstream and downstream pressures, friction of pipelines, and gas flow temperature. The panhandle equation is used to calculate flow rate (detailed in link).

49 The geographical reach of CAISO's wholesale electricity market dispatch systems has expanded (and is continuing to do so) into neighbouring regions, collectively known as the Western Energy Imbalance Market (link).

Nodal pricing

2.22. Under nodal pricing, there are individual electricity prices for each major injection or offtake point on the system. The price at each node reflects the cost of meeting an incremental unit of demand at that specific node in that specific balancing period.[50]

2.23. Since the cost of meeting an incremental unit of demand at a point on the system is dependent on the capacity of the transmission system and thermal losses, as well as the cost of generation, the price at each node varies by location. Prices will usually be low in areas with large surplus of relatively low-cost generation and limited demand, and high in areas with higher demand and limited low-cost generation.[51] The extent of price differences will depend in particular on whether there are transmission constraints – if the transmission network is built extensively relative to generation and demand, regional price differences will usually be low, driven primarily by technical losses in transmitting energy across the country.[52] If there are significant transmission constraints, there will also be significant price differences, reflecting the physical impossibility of conveying electricity from areas with surplus generation to those with high demand.

2.24. Typically, nodal prices are set initially in a day-ahead market which is used to derive the centrally-determined schedule. With nodal pricing, supply and demand are cleared with reference to transmission and other security constraints to produce an initial schedule. The intended running profiles of generators are in line with expected demand on the system (Law 1) and the intended running profiles of generators also respect the transmission network's anticipated capability (Law 2).[53]

2.25. The prices set in the day-ahead markets that determine the schedule are financially firm contracts and settled on that basis. After the schedule is set, the SO refines it in the run up to real-time in light of improved information as to the actual likely level of demand and updates to generator availability and transmission capability.

[50] The duration of balancing periods in many nodal markets has reduced over time. Many now operate 5-minute balancing periods.

[51] Low demand areas with high levels of renewables can also experience high prices if there is limited flexible resources with ramping capability.

[52] Losses arise as a result of thermal impedance, meaning that some of the electricity generated at a node is dissipated or lost as heat as it is conveyed along a transmission line.

[53] The schedule can also be developed in a way that builds in contingencies in case of unexpected outages in generation and transmission or unexpected fluctuations in generation and demand. It also allows for the "co-optimisation" of ancillary services so that providers of such services deliver in a way that is consistent with their intended outputs in the energy market.

2.26. A final set of nodal prices is therefore set in real-time. These prices reflect actual observed demand and the actual generation used to meet that demand given the capability of the transmission network at that time. The real-time nodal prices are used to settle deviations between the volumes determined in the day-ahead market and the metered volumes for each participant at each node. Hence, a participant that is short (i.e., has under-generated or over-consumed relative to its day-ahead contract volume) at that node pays the real-time nodal price for the volume of the deviation. Conversely, those participants that are long (i.e., have over-generated or under-consumed) are paid the real-time nodal price. Critically, this reconciliation between metered and contracted positions is calculated for each node and each node is settled at the price specific to that node.

National pricing

2.27. National pricing is the current pricing approach in GB. There is a single wholesale electricity price across the entire geographic footprint of the market.

2.28. In a national pricing market such as GB, the wholesale market operates through participant-to-participant trading either as bilateral trading or through exchanges. The wholesale price is therefore presented as the clearing prices by the marginal plant in auctions (typically day-ahead auctions) conducted by power exchanges. Market participants are not required to submit any financial information of these trades to the ESO; instead, they are required to submit their physical notifications to the ESO up to gate closure. As noted above, the incentives inherent to the national market design are intended to encourage participants to align their physical notifications to their respective contractual positions.

2.29. After gate closure, the SO relies on the BM – which is a locational market in which the SO is counterparty to all trades. Market participants can bid in the prices specific to each unit and location that they will accept to be constrained-off (for their generation to be turned down, or demand increased) and offer the prices that they will accept to be constrained-on (for their generation to be increased, or demand reduced). The SO then chooses the combination of bids and offers that it determines will minimise system costs, taking into account the locational constraints on the system, as well as other factors such as the need to procure ancillary services.

2.30. The BM is "pay-as-bid", meaning that successful bidders receive the amount that they bid at (as opposed to a pay-as-clear pricing market).

2.31. As well as the setting of prices within the BM, other important choices in the post-gate closure process include questions such as whether to maintain a strategic reserve (and how to call upon it if so), how much information to gather from market participants, and which market participants are able to participate.[54]

[54] Previous work for Ofgem has found limited participation in the BM by providers of Demand Side Response, for instance – CRA (2017), 'Assessment of the economic value of demand-side participation in the Balancing Mechanism and an evaluation of options to improve access' (link).

Zonal pricing

2.32. Under a zonal price structure, the market is divided into several different price zones. Each node within a zone has the same price, but prices can differ between zones. As with nodal pricing, the extent of price differentials will depend in particular on the balance of supply and demand across different zones, and the capability of the transmission system between the price zones. The number of zones could in principle be large (up to the number of nodes on the transmission system), but in practice countries that have adopted zonal pricing typically operate fewer than ten zones.

2.33. Zonal pricing markets can combined with a self-scheduling design, as is the case in the NordPool system across Denmark, Finland, Norway, Sweden and the Baltic countries. Self-scheduling such as the NordPool system typically occurs within the zone. In these markets, there are two broad approaches to allocating transmission capacity – market participants could either book cross-zonal transmission capacity or be subjected to a market-coupling algorithm that incorporates the value of transmission capacity into the zonal spot price.[55]

2.34. Alternatively, zonal price markets can be integrated with a centralised-scheduling design, operating a security-constrained economic dispatch which determines dispatch outcomes considering the technical feasibility of generation units and transmission lines. Prices, and the related balancing payments, are then calculated on a zonal basis, and subsequently settled in the settlement process.

2.35. While zonal markets introduce stronger locational signals than national pricing, they can face some additional issues, particularly when combined with self-scheduling. This includes difficulties in determining the zones, and in altering zonal boundaries as both the transmission network and patterns of generation and demand evolve over time.[56] Moreover, there will usually remain some need for the SO to carry out redispatch within zones to reflect intra-zonal transmission constraints.[57]

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[55] An explanation on different approaches to allocating transmission capacity can be found in NordPool Group's brief on 'Explicit and implicit capacity auction' (link). The NordPool system allocates transmission capacity using implicit auctions, see NordPool Group's brief on 'Capacities' (link).

[56] See, for instance, Eickle and Schittekatte (2022), 'A critical assessment of arguments against nodal electricity prices in the European debate' (link).

[57] Significant redispatch costs can arise even in a zonal market. For example, Italy has one of the highest redispatch costs in Europe despite having seven zones (€1.47bn in 2020). See Table 1 in ACER's Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 – Electricity Wholesale Markets Volume (link).

Box 2-2: Self-scheduling in nodal markets

While one of the key features of nodal markets is the use of a centralised-scheduling system to facilitate efficient scheduling, commitment and dispatch across all of the nodes in the market, most nodal market designs (such as in the US) allow market participants to choose to both self-commit and self-schedule resources as an option.

In these designs, market participants choose, at a day-ahead stage, and again in real-time, whether to self-commit and/or self-schedule their resources. Resources that self-commit in the day-ahead market will have financially-binding schedules like other resources, covering the self-committed and/or self-scheduled output. The SO then optimises the schedules for individual resources, while taking the minimum load schedules of self-committed units and self-schedules as a fixed input in the optimisation. The resulting hourly schedules represent binding financial commitments to market participants and all "in merit" plants are paid the clearing price (the nodal price) derived from the SO clearing algorithm. A key difference from the self-scheduling in GB markets is that these commitments are specific to each node at the day-ahead stage and settled at the day-ahead nodal price.

Any deviations from self-scheduled volumes would be exposed to the real-time price and may be subject to deviation charges.

Resources that do not self-commit in the day-ahead market can choose to self-commit their resources in real-time, selling their output at real-time nodal prices. Equally resources may choose (or need) to recommit in real time relative to their day-ahead commitments – in this case the deviation between day-ahead volumes and real-time volumes are settled at the real-time nodal price.

The ability to self-schedule also allows for the possibility of market participants entering in ex ante physical contracts similar to the GB market. In this case, matched physical contract volumes are nominated into the settlement process (for both production and consumption) and only deviations between the metered volumes and the contract volumes are settled at the real-time nodal price. A key difference to the GB regime, however, is that the matched physical contract volumes are settled at a specific location. To the extent that the seller and consumer are at different locations, the seller is responsible for paying the difference in the nodal prices between its supply source and the trading point and the consumer is responsible for paying the difference in the nodal prices between the trading point and the location of its load.

However, it is important to note that sellers do not have to self-schedule their resource to cover such a "physical contract." They could allow their resource to be economically dispatched by the system operator and cover their bilateral contract by purchasing power from the grid when the LMP price is lower than their incremental cost. Because all contracts are ultimately financial in LMP markets, much forward contracting in LMP markets is structured as contracts for differences settling at trading hubs. Structuring forward contracts to settle at a trading hub allows the parties to the contract to trade around their contractual position on commodity exchanges to cover plant outages, changes in load obligations and other factors.

Typically, "must run" generators (i.e. those with low cost output and an inability to follow dispatch instructions) such as nuclear plants would choose to self-commit and self-schedule their output in the day-ahead market, while thermal units with long start up times may self-commit their minimum load block to ensure that they are online but allow the SO to dispatch them economically based on their offer prices. Other types of resources, such as run of river hydro, may self-schedule their output in real-time based on real-time river flows.

B. Theoretical impacts of different market design approaches

2.36. In this section, we briefly consider some of the potential impacts of differing locational pricing approaches. We consider in the following sub-sections:

- the short-term impact in terms of financial flows to market participants and overall incidence of costs to consumers;
- the longer-term impact on market participants; and
- other potential impacts that arise under locational pricing.

2.37. In each sub-section we cover both quantifiable and qualitative impacts. These are theoretical impacts designed to illustrate how different approaches could affect different groups. We also briefly outline the approach we have adopted in this study for assessing the quantifiable impacts that is the focus of this report. Our modelling work, described in later chapters, provides an in-depth assessment of the expected impacts of locational pricing in the GB context.

Short-run impacts

2.38. We might expect limited effects of locational pricing on overall efficiency in the short run (i.e., when assuming a fixed capital mix across different market designs). This is because, as emphasised above, ultimately all systems need to be centrally dispatched. With the same patterns of demand and generation capacity, we might expect the market and SO to optimise the system similarly across different market structures.[58] However, financial flows will be different, resulting in changes to the distribution of costs and benefits among and between generators, storage providers and consumers.

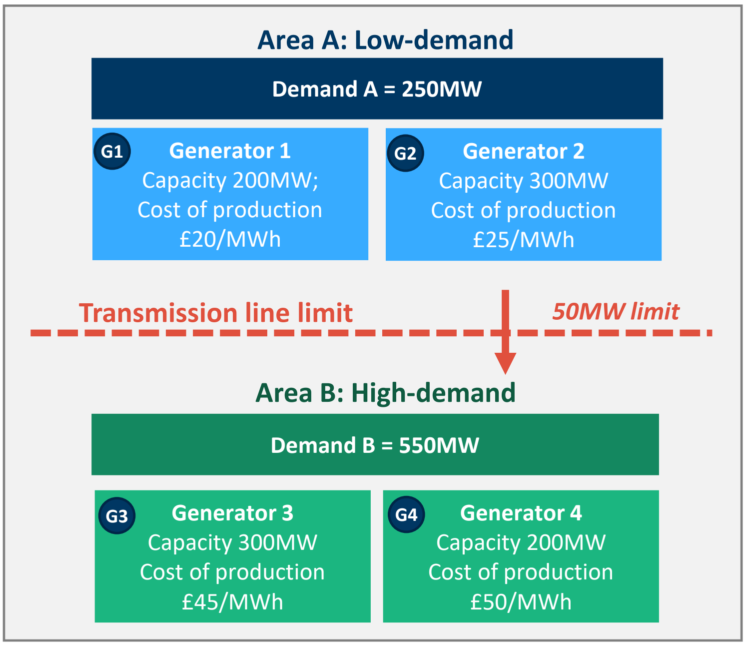
2.39. First, we use a simple two-node example to explain how the financial flows vary between market designs. In this setting, there is no difference between zonal and nodal pricing, so we only consider the difference between any form of locational pricing and wholly national pricing. We then discuss how efficiency of dispatch could in practice change across different market designs.

Differences in financial flows in different market designs

2.40. Figure 2-1 shows a simple two node (or zone) electricity system, with generation and demand at both nodes.

[58] We discuss this assumption later in this sub-section.

Figure 2-1: Simple two node worked example



Source: Stylised example, FTI analysis

2.41. For the purpose of this stylised example, we consider only a one one-hour period. The set-up of the worked example involves the following assumptions:

- **System demand** is assumed to be 800MW, with 250MW in Area A and 550MW in Area B.
- The four **generators** have different incremental costs of generating.
  - Generators at Node A are relatively low cost (costs are £20 per MWh for Generator 1 and £25 per MWh for Generator 2); while
  - those at Node B are relatively high cost (costs are £45 per MWh for Generator 3 and £50 for Generator 4).
- The **transmission system** can convey a maximum of 50MW between Node A and Node B.
- We assume that there are no transmission losses, perfect foresight (so that there are no unexpected generator or transmission outages and no changes in the expected level of demand), and that each generator bids at its marginal cost and has no technical limits on its operation.[59]

Worked example: national price market outcome

2.42. With national pricing, the 800MW of demand can be met by the lowest-cost Generators 1, 2 and 3, with Generator 3 setting the market price of £45 per MWh. This is the price paid by the 800MW of demand and received by all three generating units. Therefore, Generators 1, 2 and 3 earn £9,000, £13,500 and £13,500 respectively,[60] and the demand side pays £36,000.

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59 Such as costs of ramping up or down generation.
60 200MW*£45 = £9,000 and £300MW*£45 = £13,500.

2.43. At gate closure, the generating units notify the SO of their intended generation profiles, and consumers or their suppliers would also submit their intended consumption profiles (totalling 250MW and 550MW in Area A and Area B respectively).

2.44. At this stage, the SO assesses the schedule against the actual physical capability of the system. In this case it finds the intended schedule is not consistent with the physical reality – generators at Node A wish to generate 500MW in aggregate. But only 250MW is demanded at Node A and only 50MW can be transported away to Node B. Therefore, there is a 200MW excess of generation at Node A. The opposite is true at Node B – 300MW is committed to be generated (by Generator 3) and 50MW can be imported, yet 550MW is demanded.

2.45. This is the transmission constraint that SO needs to intervene in the market to resolve. It does so through the BM. By assumption, Generator 4 will be prepared to submit an offer into the BM expressing a willingness to generate – that is, to sell to the SO – at £50 per MWh for up to 300MW.[61]

2.46. As Generators 1, 2 and 3 intend to operate at full capacity, they cannot, in this period, offer to sell further electricity to the SO in the BM. They can, however, bid to reduce their output. The generators in this example incur a cost in generating. For example, Generator 2 will incur a cost of £25 per MWh in meeting its contractual volume of 300MW, for which it will receive the market price of £45 per MWh. It will therefore be prepared to pay up to £25 per MWh for not being required to meet its commitment to (knowing that it will receive £45 per MWh from the wholesale market in any case).

2.47. Therefore, in this example, at the time of gate closure, Generators 1, 2 and 3 submit bids to *reduce* their generation in the BM at their prevailing marginal costs – of £20 per MWh, £25 per MWh and £45 per MWh respectively. Given this structure of bids and offers into the BM, the SO can ensure that the overall output of the generating units reflects the physical realities of the network. To do this, it buys an incremental 200MW from Generator 4 at £50 per MWh. This ensures that demand in Area B will, in aggregate, be met with 300MW and 200MW being generated by Generators 3 and 4 respectively, and 50MW being conveyed across the transmission line from Area A.

2.48. In Area A, the SO must reduce the output of one of the generators by 200MW to ensure system balance in that part of the system. It therefore chooses the most favourable bid, which is the highest-priced bid to reduce generation – in this case from Generator 2 – of £25 per MWh. The SO therefore accepts £25 per MWh from Generator 2 for it to reduce its generation by 200MW, meaning that Generator 2 pays £5,000 to the SO.

61 In principle, demand response providers could also offer to reduce their demand; we ignore this in this example.

2.49. These transactions by the SO have now ensured that the finalised schedule respects the physical laws of the system. Generators 1, 2, 3 and 4 will generate 200MW, 100MW, 300MW and 200MW respectively to meet the demand of 800MW in that period. Overall, the following financial flows have occurred:

- Generator 1 receives £9,000 from the contract market and generates 200MW to meet that commitment (and incurs a cost of £4,000 in so doing).
- Generator 2 receives £13,500 for 300MW in the contract market but buys back 200MW from the SO in the BM at a cost of £5,000. It therefore receives a net amount of £8,500. In real time it generates 100MW (and incurs a cost of £2,500).
- Generator 3 receives £13,500 for 300MW in the contract market and generates 300MW to meet that commitment. It incurs a cost £13,500 in so doing – it is the "marginal" generator in the national market this period that sets the market-clearing price.
- Generator 4 receives £10,000 for 200MW in the BM (and generates 200MW at a cost of £10,000).
- The SO pays out £10,000 and receives £5,000 – implying a net cost of £5,000.
- Demand pays out £36,000 in the contract market. However, it also must fund the SO costs of £5,000, so that the overall cost to consumers for the 800MW of electricity demanded is £41,000.

2.50. A point worth emphasising here is that the cost incurred in resolving the transmission constraint is always a cost in that the SO must "buy high and sell low". That is, the SO buys at a high price from a generator that is located in a high-demand location but is too high-cost to be competitive in the national market. It sells back at a low price to a generator that was competitive in the national market but is located in a part of the network where there is insufficient demand and insufficient transmission to allow its output to be consumed. This is the cost of the transmission constraint that is then recovered from consumers.

Worked example: locational price market outcome

2.51. Under locational pricing, the market is designed in such a way that the physical laws of the system are (in broad terms) respected. Assuming as before that market participants submit their bids in line with their marginal costs, the SO can optimise which bids to select to meet the demand (of 800MW) given the configuration of the transmission network. The lowest cost outcome is to select 200MW, 100MW, 300MW and 200MW respectively from Generators 1, 2, 3 and 4.

2.52. The price is set at each location to reflect the incremental cost of meeting a unit of demand at each node on the system. At Node A, were demand to increase from 250MW to 251MW, Generator 2 would need to increase output from 150MW to 151MW at a cost of £25 per MWh. Therefore, the price at Node A, in this example, is £25 per MWh. At Node B, were demand to increase by one unit to 501MW, Generator 4 would need to increase output from 200MW to 201MW. Note in this example that Generator 2, although it is less costly and has available capacity, cannot serve the demand at Node B as the transmission line is already operating at full capacity.

2.53. These prices – of £25 per MWh and £50 per MWh for Nodes A and B respectively – are used to clear the day-ahead market. Hence Generators 1 and 2 are paid £25 per MWh for their output of 200MW and 150MW respectively and demand at Node A pays £25 per MWh. In Node B, Generators 3 and 4 are paid £50 per MWh for their output of 300MW and 150MW respectively and demand pays £50 per MWh.

2.54. In this simple setting, there is no need for the SO to make any further refinements to the schedule in the run up to real time and hence each generator proceeds to generate in line with the day-ahead schedule.

2.55. The financial flows under this market design are somewhat different from those in the national market:

- Generator 1 receives £5,000 for 200MW;
- Generator 2 receives £2,500 for 100MW;
- Generator 3 receives £15,000 for 300MW;
- Generator 4 receives £10,000 for 200MW; and
- in aggregate, therefore, the four generators receive £32,500.

2.56. In contrast to the national pricing regime under a more granular locational market, demand pays for its consumption at the prevailing price at each node. In this case, therefore, demand at Node A pays £25 per MWh for 250MW, totalling £6,250, while demand at Node B pays £50 per MWh for 550MW, totalling £27,500. The total payment by demand is therefore £33,750.

2.57. Note that, in aggregate, the amount paid out by demand is £1,250 greater than the amount paid to generators. This arises because 50MW of the output that is generated at Node A is paid the nodal price of £25 per MWh but is conveyed to Node B on the transmission line where the nodal price paid by demand is £50 per MWh. In most locational markets, this surplus is passed back to consumers so that in this example consumers would in aggregate pay £32,500.[62]

Worked example: comparison of financial flows between national and locational markets

2.58. Table 2-1 below compares the financial flows and outputs under each market design.

[62] This surplus is the genesis of many hedging instruments used in locational markets. Often referred to as FTRs, market participants can acquire a right to the financial surplus generated by the price spread of two nodes in the settlement process. This creates the potential for a market participant to hedge the price risk at the node it is located to the extent that the volume of transmission is available. In the context of the stylised example, if Generator A were to acquire the FTR for 50MW of the spread between Node A and Node B, this effectively means it can sell 50MW of its output at Node A for £25 and receive a further £25 for the spread between Node A and Node B. Effectively, therefore, Generator A receives the Node B price of £50 per MWh for that 50MW of output. It acts as a hedge in the sense that, were the price to fall in Node A or increase in Node B then the price spread would widen. For example, should demand drop to 100MW in Node A (rather than 250MW), the nodal price would fall to £20 (as only 150MW of Generator 1 output is required to meet the 100MW of demand and the 50MW that can be conveyed to Node B). However, the spread between the nodal prices would widen to £30 so that Generator A still, in effect, receives £50 per MWh for 50MW of its output (£20 per MWh from selling into the power market at its node and £30 for the value of the FTR). While a number of allocation approaches are conceivable, in many markets the rights to the surplus are auctioned to market participants with the auction receipts passed back to consumers. Given our highly stylised assumptions regarding perfect foresight, we assume that the auction for 50MW of transmission rights between A and B would clear at the value of the congestion rent that arises in settlement (£1,250). Hence, the £1,250 in this example is still received by consumers.

Table 2-1: Financial flows and outputs in our illustrative worked example

	National market		Locational market		Percentage change in revenues
	Output / consumption (MW)	Revenues/ payments	Output / consumption (MW)	Revenues / payments	
Generator 1	200MW	£9,000	200MW	£5,000	-44%
Generator 2	100MW	£8,500	100MW	£2,500	-71%
Generator 3	300MW	£13,500	300MW	£15,000	+11%
Generator 4	200MW	£10,000	200MW	£10,000	0%
Total revenues	***800MW***	***£41,000***	***800MW***	***£32,500***	***-21%***
Demand A	250MW	£12,813	250MW	£5,859	-54%
Demand B	550MW	£28,187	550MW	£26,641	-5%
Total payments	***800MW***	***£41,000***	***800MW***	***£32,500***	***-21%***

Source: FTI analysis

2.59. As Table 2-1 indicates, the outputs by each generator are the same in this stylised example. There is no difference in the efficiency of dispatch as the least-cost plant is used to meet demand given the transmission constraints. However, the financial flows are very different. Generators in the export-constrained part of the system receive lower revenues under locational pricing. This is because, first, the wholesale price received is lower and, second, those generators that were constrained off are no longer compensated. Hence, in our example, Generator 2's revenues fall by 71% under locational pricing relative to national pricing. By contrast, generators in the import-constrained part of the system under a locational market now receive a clearing price set by the generator that was previously called by the SO in the BM. Hence, in this case, Generator 3's revenues increase by 11% under locational pricing. Generator 4, as the marginal plant on the system, receives the same – it is either called in the BM (in the national market design) or sets the clearing price in the locational market design. Overall, the amount paid to generators is lower.[63]

2.60. There is also a change in the payments by demand – in this example, the amount paid by demand in Node A falls by 54% as it can now access the less costly generation in its location without needing to pay the national price, and it does not need to pay for constraint management. Demand in Node B pays a higher nodal price (up from £45 per MWh to £50 per MWh), but in this example also pays less because it no longer needs to pay its portion of the constraint management cost charge *and* it receives congestion rent revenues.[64]

[63] This might be expected to be typically the case, because inframarginal rents will typically be lower as a result of a closer match between local demand and supply. However, it need not always be so. For instance, if Generator 4's cost was £79 per MWh or higher, the total amount received by generators would rise – the reduction in the amount paid by consumers in node A would be outweighed by an increase in node B.

[64] Note that congestion costs, constraint management costs and congestion rents have different meanings. We have adopted the following convention in this report. Congestion costs refer to the additional cost on the electricity system arising from insufficient transmission capacity between two points on the system restricting flows from lower cost supply to meet demand. Constraint management costs refer to the specific costs incurred by the SO in the BM to address these constraints. Congestion rents refer the financial surplus from revenue collected from demand less payments to generators driven by price differentials between two points on the system.

2.61. In general, we would expect financial flows between the two market designs to change as in this stylised example. Generators sited in export-constrained parts of the system will (by design) always receive lower revenues in a locational market design than under a national pricing regime, while those sited in import-constrained parts of the network will always receive either higher or the same revenues.

2.62. The demand-side effects are more nuanced. Demand in the export-constrained part of the network will (by design) always pay less in a locational market (as it can now pay the low local price rather than the national price). Demand in the import-constrained part of the network could either pay less, the same, or more. In our stylised example, it pays less because the increase in wholesale prices in its area (from £45 per MWh to £50 per MWh) is more than offset by a decrease in constraint management costs and the incremental revenue passed back to it in congestion rents.[65]

2.63. Overall, transitioning to locational pricing will change the direction of payment flows to generators. Generators in export-constrained areas receive lower payments, generators in import-constrained areas receive the same or higher payments. We can also say definitively that demand in export-constrained parts of the network will pay less. There is no directional certainty, however, on changes in payments by demand in the import-constrained parts of the network. Whether it is higher, lower or the same, will depend on the prevailing marginal costs of generation in that part of the network and the extent of transmission constraints.

Our approach to assessing financial flows

2.64. This is a very simple example to illustrate potential changes in financial flows. In our modelling, we assess expected financial flows in the context of the GB market under the three different market designs, based on a wide range of assumptions about factors such as the costs of different technologies, the configuration of the transmission network and the evolution of fuel prices. These assumptions are discussed further in Chapter 4.

Practical considerations

2.65. In our simple example, while the payment flows are different, the amount generated by each unit is the same – hence the overall cost (for instance, the fuel costs incurred by generators) of meeting demand in the different market designs is identical. This is an abstraction from reality; in practice, where there are more than two zones or nodes, we would usually expect dispatch, and therefore generation, to differ between market designs with locational pricing and those without. This is because a system with locational pricing can optimise dispatch simultaneously across all locations. In general, locational pricing should therefore enable more efficient dispatch, that is the least cost set of resources is utilised, than systems with national prices only.

2.66. Moreover, our example included the assumptions of perfect foresight and of no technical limitations on the output of generating units. This meant that in the national market example, it was possible for the SO to use the BM to balance the system efficiently in that it could call on a generator in the export-constrained part of the system (Generator 4) to increase output after being notified at gate closure of the intended outputs of each unit on the system, and it could also turn down Generator 2.

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65 Total payments by demand in node B would rise if Generator 4's cost was £54.99 per MWh or higher.

2.67. In practice, relaxing those assumptions potentially presents a challenge for the SO. In the period of one hour between gate closure and commencement of real time, it must resolve the infeasible aggregate schedule notified by individual participants by operating in the BM so that the final generator schedule is compliant with the technical limitations of the network.

2.68. This short time duration raises the possibility that the SO might not be able to draw on the most efficient plant, relative to a situation in which it was aware of intended running profile further ahead of time. For example, suppose that Generator 4, due to its technical characteristics, needs six hours' notice ahead of commencing operation and that there is now, a fifth generator located in the import-constrained part of the network (Generator 5) that could respond in the one-hour timescale albeit with a higher marginal cost of, say, £100 per MWh. In this case, the SO would not be able to call on Generator 4 to operate, but would instead need to take the offer of Generator 5, incurring higher costs in doing so. Had the SO been aware of the intended outputs of the generators earlier (in this case 6 hours earlier) it may have been able to call upon the lower-cost but slower-responding Generator 4.

2.69. By contrast, in a locational market, it might be expected that the day-ahead market would be broadly compliant with the constraints imposed by the transmission system. In our stylised example, Generator 4 would have been scheduled at the day-ahead stage, ensuring that it had sufficient time to prepare to meet its requirements in real time.

2.70. National market designs have developed a number of mitigations to try to resolve this issue – for example, participants need to provide an earlier indication of their intended outputs to the SO (termed Initial Physical Notifications) that are periodically updated as gate closure approaches. However, these are not financially binding so there are no financial implications of changing intended running profiles ahead of gate closure. Similarly, the SO has a range of tools that it can deploy ahead of gate closure, such as start-up contracts, which allow it to contract with plants located in import-constrained regions that need more than one hour's notice but are unlikely to be economic to operate in the national market.

Our approach to assessing potential differences in dispatch

2.71. In our in-depth modelling work, we analyse the impact on changes to dispatch outcomes as a result of the ability to optimise across all nodes or zones in the system. This is compared to the national pricing market system which determines a single uniform price at every location, and then alters dispatch to reach a feasible schedule. This therefore captures some of the expected change in efficiency of dispatch under locational pricing.

2.72. In practice in nodal markets, balancing in real-time is based on security-constrained economic dispatch, unlike in a national or zonal market.[66] Forward commitments in nodal markets are based on a combination of security-constrained economic dispatch in the day-ahead market and in intra-day scheduling. In addition, the elimination of constrained-off payments would be expected to eliminate any incentive for market participants to commit unnecessary resources in order to increase their constrained-off payments.

[66] Security-constrained economic dispatch ("SCED") refers to the dispatch algorithm (or mathematical model) that determines optimal dispatch outcomes whilst considering the operational limits of both generation and transmission facilities. See Federal Energy Regulatory Commission (2006), 'Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations' (link).

2.73. However, our assessment does not capture the full effects of locational pricing on dispatch as we do not assess all of the potential impacts of centralised scheduling relative to self-scheduling. For instance, this means we do not take account of the potential benefits such as:

- improved dispatch resulting from the SO having broader and deeper information about plant capabilities, meaning that, for instance, it can better optimise across the wholesale market and the market for ancillary services;
- the potential benefits of centralised scheduling within an hour;
- the ability to co-optimise energy and reserves more easily than in a self-scheduling market; and
- improved dispatch resulting from the SO's role in scheduling with financial unit-specific commitments at the day-ahead stage (versus gate closure one hour before real-time).

2.74. Conversely, there could be scenarios with more efficient dispatch under a self-scheduled market design than a centrally-scheduled design. For instance, if the SO lacks the depth of information held by market participants, it may be unable to forecast variations in load or intermittent resource output as well as market participants in making its scheduling decisions. As another example, difficulties in incentivising the SO could mean that it does not make optimal use of the information it receives, suggesting that dispatch could be more efficient when it has a more limited role.[67] Such potential effects of central scheduling are also not included in our assessment.

Longer-run impacts

2.75. As well as short-term effects, locational pricing may have impacts on the electricity market in the long run. These could arise as the differences in financial flows set out above may induce differences in where on the electricity system market participants choose to locate and, potentially also, closure decisions. This might apply to both generators and to demand. We discuss each in turn and then also briefly consider the impact on transmission investment.

Generation siting decisions

2.76. Under a locational market design, the wholesale market provides locational signals and therefore offers the potential to affect siting decisions, based upon expected wholesale prices at a given location over the lifetime of the asset. For instance, investors in a generation plant might invest in areas where they expect future prices to be high.

2.77. Of course, expected energy prices will not be the only factor driving siting decisions. For example, a wind generator may prefer to site in an import-constrained area that is less windy but has a higher expected price than an export-constrained area of the network with high wind resource but an expected lower price. Furthermore, planning restrictions may significantly limit the range of sites available in any case, so locating in a high-priced area may, in practice, be more difficult.[68]

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67 Such considerations were important drivers of the NETA reforms. See Ofgem/DTI (1999), 'The New Electricity Trading Arrangements' (link).

68 A study on the 2011 Swedish electricity market splitting reform shows evidence of wind investors responding to a locational wholesale price signal. In the case of Sweden, the study shows greater investments in higher price zones. See Lundin (2021), 'Geographic Price Granularity and Investments in Wind Power: Evidence from a Swedish Electricity Market Spitting Reform' (link).

2.78. Under national pricing, the wholesale market, by design, has no impact on siting decisions. This is because the same price is received for a marginal unit of output from a generator regardless of its location. Furthermore, by virtue of the operation of the BM, generators also receive compensation for not generating if the physical realities of the transmission system prevent them from doing so.

2.79. As a result, under national pricing, investment in new generation capacity can increase rather than reduce consumer costs. For instance, in our stylised example, suppose that a new generator enters in Node A with a marginal cost of £30 per MWh and a capacity of 100MW. The cost of this generator is below the national price of £45, so it is scheduled to generate at gate closure. But it cannot generate in practice, given transmission constraints. It bids not to generate in the BM, and pays £3,000 (£30 per MW*100) not to do so. There is no change to the actual pattern of generation and demand, but consumer costs increase by £1,500 (the £4,500 paid to the new generator in the wholesale market minus the £3,000 received from it in the BM).

2.80. Overall, therefore, under national pricing, the wholesale market does not influence siting decisions of market participants. This runs the risk of encouraging generators to site in areas of the network that are not beneficial to the energy system as a whole, because the transmission system limits the extent to which they can produce. This could increase costs to consumers as the SO needs to take a greater volume of actions (and therefore incur greater cost) in the BM.

Storage siting decisions

2.81. Storage providers, such as battery owners, earn revenues in the wholesale electricity market primarily through variability in prices; they rely on buying electricity when prices are low, and selling it when prices are high. In addition, they can earn revenues from some ancillary services (such as Short Term Operating Reserves and Black Start) as well as through the BM.

2.82. This means that a key consideration in the siting decisions of storage providers under locational pricing is the extent of expected price volatility.[69] Storage providers could expect to earn higher revenues where expected price volatility is high and so, to the extent that they are able to move their plant, might be expected to locate in such areas. By locating in areas with high price volatility, storage providers should reduce such volatility over time, with potential system benefits as a result.

2.83. Under national pricing, the wholesale price does not provide any locational signals for storage providers. This means that, as with generators, storage providers have limited consideration for the locational constraints on the system when choosing where to locate. In some circumstances, this means that additional storage assets fail to mitigate constraints on the network and could make them even worse, as we discuss further in Box 6-1.

[69] Pumped hydro storage facilities face similar considerations to battery storage; however, their siting decisions are limited to geographical resources.

Demand siting decisions

2.84. The same logic that applies to generators applies to the siting decisions of the demand side too, due to different locational wholesale prices faced by consumers. In a locational market, a new consumer could choose to site in a part of the network with lower prices (at Node A in our example) and therefore access the lower cost generation available there. Conversely, it could choose to site in the import-constrained area, albeit facing the high price of that electricity. That is to say, it too will need to trade off the benefits of being in a low-priced area (that is perhaps less conveniently sited) with a high priced area (that perhaps is more convenient).[70]

2.85. Of course, this siting decision is unaffected in the national market as demand pays the same price wherever it locates which is the wholesale price plus the uplift charge needed to recover the costs of constraint management. In the context of our stylised example, the impact of 100MW of new demand siting in Node B would be to increase the clearing price to £50 per MWh and therefore increase both the payments by all consumers (regardless of location) and the revenues to generators. If it were to site at Node A, then the price would also increase to £50 but, importantly, the cost of constraint management would reduce (as now Generator 2 has less volume that needs to be constrained).

2.86. In practical terms, many demand-side consumers (notably domestic consumers) will consider a whole range of other factors in their siting decisions (and the cost of electricity is unlikely to be a major determinant).[71] But this might not be true of all demand; there is potentially a cohort of large energy-intensive consumers that may be attracted by differentials in wholesale prices and choose where to site on the basis of the expected difference between prices in each area.[72]

Transmission development decisions

2.87. While nodal pricing regimes offer the theoretical potential of merchant investment in transmission, in which private investments in transmission assets that connect two nodes earn the congestion rents created by the new transmission asset, it is generally agreed that market failures make this, in practice, unlikely to be viable except in unique conditions.[73] For this reason, regardless of whether the market has a national or a locational pricing regime, investment in transmission tends to remain the duty of a monopoly transmission operator as the sole provider of transmission assets over a defined geographical footprint, and in which the amount of revenue it can recover from consumers is restricted by regulation.[74]

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70 A study of the manufacturing industry in the US shows energy-intensive industries concentrating in areas with lower electricity prices. See Kahn, Mansur (2013), 'Do local energy prices and regulation affect the geographic concentration of employment?' (link).

71 For example, the cost of electricity may have a negligible impact on deciding where to build new residential buildings across GB.

72 Iceland's low electricity prices are seen as a key reason for its strengths in industries such as aluminium smelting and data centres. Fraunhofer (2020), 'Electricity costs of energy intensive industries in Iceland' (link).

73 Joskow and Tirole (2005), 'Merchant transmission investment' (link).

74 We note that there have been some attempts to introduce competition into the transmission sector in recent years. See, for example, Ofgem (2016) 'Quick Guide to the CATO Regime' (link), or National Grid ESO (2021) 'Early Competition Plan' (link).

2.88. The difference in market design has the potential to influence the business case for new transmission investment. This is because the way in which the economic benefits of an investment in transmission assets manifest differ. In a national market design, the benefit to consumers of an upgrade to the transmission network will result in reduction in constraint management costs that are incurred by the SO (and ultimately funded by consumers).

2.89. With locational prices, the incremental transmission will have two types of impact on consumers. These are:

- First, incremental transmission will change wholesale prices at nodes or zones on the system. Typically, prices in export-constrained parts of the system will rise while those in import-constrained parts of the network will reduce.
- Second, the amount of congestion rent will change, albeit the direction of change will depend on each individual case. This is because the volume of congestion rent will increase (as there is a greater volume of flows across the transmission line) but the price spread between the two nodes will likely narrow, leading to congestion rent with lower prices. Hence congestion rents could either increase or decrease.

2.90. It will also impact producers – those in export constrained parts of the network will be able to produce greater volumes and at higher prices. Conversely, those in import-constrained regions will experience price reductions and, likely, reduced output as a result of the additional electricity conveyed on the incremental transmission lines.

2.91. In a nodal or zonal market there is the additional possibility that participants opt to site in a different location as a result of changes in wholesale prices that occur as result of the transmission investment. This effect would also need to be taken into account in an evaluation. There would be no such change in siting decisions in a national wholesale market as result of transmission investment.[75]

2.92. Overall, therefore, the methodology for assessing the economic merits of new transmission will vary depending on which market design is in place: [76]

- For national market designs, an economic assessment of a transmission investment would evaluate the expected reductions in constraint management costs that would otherwise be incurred by the SO in the BM – the costs of which would ultimately be recovered from consumers – and compare these to the costs of the proposed investment.[77]

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[75] Two caveats, albeit at a conceptual level, are warranted to this. First, it is theoretically conceivable that some generators that would have opted to site in an import-constrained area of the network in anticipation of earning revenues through constrained-on payments in the BM would be deterred as a result of new transmission investment. Second, it is also theoretically conceivable that transmission charges may be adjusted to account for the impact on participants of the new transmission investment and so influence siting decisions (see our discussion of TNUoS transmission charges below).

[76] We should note that an economic needs case may not be the only factor motivating incremental transmission investment. TSOs often cite the reliability benefits arising from increased transmission and incremental transmission investment is often justified on account of meeting wider public policy objectives (such as connecting renewables generation).

[77] See, for example, National Grid ESO (2020), Network Options Assessment Methodology (link), that describes the approach that ESO take to assessing the benefits of network reinforcements.

- For locational market designs, the costs of new transmission investments (between nodes in a nodal market and between zones in a zonal market) would be evaluated against the resulting socioeconomic benefits, which would be the aggregate of three components:
  - First, the changes in wholesale prices paid by consumers (noting that some consumers at some location would see prices rise and some fall) – this is the change in the consumer surplus that arises because of the increased transmission;
  - Second the change in the wholesale revenues received by producers (again noting some experience higher revenues and some lower) - this is the change in the producer surplus; and
  - Third, the aggregate change in the congestion rent earned by virtue of the changes in the price differentials and volumes that are conveyed between nodes (or zones).[78]

Locational signals in national pricing markets

2.93. While national-pricing markets lack locational signals in their wholesale prices, they can include locational signals through other mechanisms, including:

- transmission charges;
- decision-making on connections; and
- BM payments.

2.94. In GB, the transmission network use of system charge (“TNUoS”) is set to proxy the “long run marginal cost” of transmission. This means that tariffs are higher for generators in areas of the network that tend to be distant from main centres of load (and therefore more likely to be behind transmission constraints) and lower (or even negative) for generators that are sited close to load (and therefore are determined to use less of the network). The same is true for charges levied on demand; they are lower in areas of the network close to generation and higher in areas that are distant from generation. In turn, this is intended to influence siting decisions of new entrant participants.

2.95. Relative to locational wholesale pricing, there may be some potential benefits of providing locational signals through transmission charges such as TNUoS. In particular, because the price is fixed on an annual basis, there is predictability of charges to participants (and new entrants), potentially making siting decisions more straightforward and therefore lowering the risk to new entrants. Against this, however, locational transmission charges are unable to reflect the short-run costs that market participants cause, since the charge is set on an annual basis and does not reflect the actual conditions of the network and flows. This means that there will inevitably be some inefficiencies to siting decisions. Moreover, the evolving nature of the GB energy system means that the optimal transmission charge is likely to change significantly over time. This can be problematic where decision making is lengthy, for instance in the determination of the administered TNUoS charge, and subject to rent-seeking behaviour by affected stakeholders.

[78] This assessment process could be, in many ways, similar to the approach adopted currently by Ofgem and the EU for assessing the socioeconomic value of interconnectors – i.e., transmission assets that connect two price zones. See, for example, FTI Consulting and Compass Lexecon (2022) ‘NeuConnect socio-economic welfare impact’ (link).

2.96. Second, the approach to obtaining a connection to the network can influence siting decisions. One approach is simply to restrict access to the network for those generators that wish to connect in export-constrained parts of the network, or conversely to restrict access to the network for demand in import-constrained parts of the network. Additionally, connection charges can potentially be used to influence siting decisions by reflecting the cost of network reinforcement associated with the new entrant (so-called deep connection charging). In principle, such connection charges can therefore influence siting decisions so that generation and demand is encouraged to locate where it imposes limited costs on the system. However, such fine-tuning by administrative fiat is difficult in practice.

2.97. Third, the BM can provide at least some locational signals. Generators may have an incentive to locate in import-constrained areas if they expect to be paid to generate at a price above the national price. To the extent that they are able to offer to generate at a price above their marginal cost in the BM, this could make investment in import-constrained areas more attractive than in export-constrained areas.[79] Equally, it is conceivable that some large consumers could choose to site in export-constrained regions of the network and bid to buy electricity in the BM below the prevailing national wholesale market price.

Our approach

2.98. In our modelling work, as we discuss further in Chapter 4, we allow for locational pricing to have some limited impact on the siting decisions of generators and storage providers, while reflecting likely real-world constraints on the extent to which capacity could move in practice.

2.99. We adopt a conservative approach to demand portability, and do not allow for locational pricing to have any effect on the location of demand.

2.100. We do not explicitly model transmission network and connection charges, but in practice, current expectations about the impacts of charging on the location of demand and generation are accounted for in the Future Energy Scenarios ("FES") that lie at the core of our modelling. Although TNUoS charges are not explicitly modelled as part of the FES process, these are assumed to implicitly influence developers' investment decisions and are therefore implicitly considered in the siting of future generation when individual connection locations taken into account.

Other potential impacts

2.101. Having considered the potential different outcomes from the structure of locational pricing in the short and long term, in this section we consider some wider potential impacts of a move to locational pricing in the GB context. In turn, we briefly discuss:[80]

- trading liquidity;
- cost of capital;
- the exercise of market power; and
- interactions with other policies.

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79 We note that some investors may find it challenging to rely on BM revenues for financing given their limited tradability and the potential for regulatory interventions.

80 Eicke and Schittekatte (2022) 'Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European Debate' (link).

Liquidity

2.102. One potential argument in favour of national markets over locational markets is that national pricing allows significant volumes of electricity to be traded between market participants. This is because buyers and sellers of electricity can trade in electricity markets unfettered by the physical realities of the transmission network. Larger volumes of trading between a greater number of market participants can aid price discovery, provide greater confidence to all market participants in the prices they are trading at, and reduce the volatility of prices to the benefit of consumers. Moreover, higher liquidity could reduce uncertainty and risk, and thus stimulate investment.[81]

2.103. By contrast, locational markets are often perceived to lead to reduced liquidity relative to national markets as trading between market participants must be in keeping with the physical realities of the transmission network. By design, this must limit the number of buyers and sellers and the volume of trading relative to a national market that does not constrain trading. In turn, this potentially increases the volatility of prices and the risk to market participants. Returning to our earlier example, a generator sited at Node A can under national pricing sell to a market with an aggregate demand of 800MW, but in a locational market the market available to it is only 300MW in size.

2.104. However, this is misleading since the higher potential volume of trades may not in reality be deliverable. In our example, a liquid forward market might trade on the basis of a market size of 800MW, but in practice, only 300MW of demand can access the output of a generator sited at Node A. Hence, as we discussed earlier, the SO will need to unwind many trades in a national market after gate closure, with an associated cost to consumers.

2.105. A related argument is that the complexity of locational pricing markets could reduce liquidity. We believe that this is something of a misconception regarding nodal pricing. Over the last 20 years, there have been significant developments to make trading in nodal markets easier, such as the creation of trading hubs to allow market participants to trade at a hub price (the weighted average price for a predefined set of nodes on an electricity system).[82] A large number of buyers and sellers can trade at the hub and in so doing increase market liquidity.[83]

2.106. We discuss the potential impacts of locational pricing on liquidity in nodal markets in greater detail in Section 8C.

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81 Ofgem / DTI (1999), 'The New Electricity Trading Arrangements', p.11 (link).

82 Mathiesen (2011), 'Mapping of selected markets with nodal pricing or similar systems Australia, New Zealand and North American power markets', p.37 (link).

83 This does, however, leave a market participant exposed to the difference between the hub price and nodal price. Typically, variation between the nodal price and the hub price is relatively low, since the nodes selected for a hub tend to be in close proximity with few if any transmission constraints. Market participants can hedge this risk through FTRs. We note concerns about how far forward these contracts might be available – evidence from the US shows relatively low demand from market participants for contracts further than five years out.

Cost of capital

2.107. A further concern raised by several stakeholders regarding locational pricing is that locational markets may be riskier for investors – particularly those in generation assets. This could be as a result of greater uncertainty about future prices at a particular location, or because of uncertainty about whether generation will be dispatched. Moreover, some stakeholders have raised concerns about increased uncertainty during the transition to a new market design.

2.108. On this basis, some stakeholders have argued that increased uncertainty could lead investors to demand a higher return on new investments, increasing the cost of financing new assets. This would likely need to be recovered from consumers, for instance through higher wholesale prices or through the higher cost of policy support mechanisms, thus reducing the benefits to consumers (or increasing the costs) of locational pricing. Whether there is an impact on the cost of capital might though depend on whether investors are able to diversify any increased risk through a portfolio of other investments. In the canonical Capital Asset Pricing Model ("CAPM") used by many regulators around the world, including Ofgem, risks that are diversifiable typically do not result in any increase in investors' cost of capital.

2.109. We discuss potential impacts of locational pricing on the cost of capital of investment in greater detail in Section 8B and Appendix 4.

Market power

2.110. Third, different market designs could in principle affect the ability of market participants to exercise market power. For instance, it could be argued that because a national market has a larger number of market participants than any individual zonal or nodal market, it is less likely that any individual market participant will be able to exercise market power.

2.111. However, we consider that this argument is somewhat specious. Market power under either market design is a locational phenomenon that is driven by the physics of the network rather the design of the market. The design of the market simply changes how market power can manifest itself:

- In a locational market, a market participant that has a limited number of competitors could potentially exert market power through its bidding in the wholesale market. For generators, this would most likely be in import-constrained areas, while for consumers it would most likely be in export-constrained areas.
- In a national market, a market participant can potentially exert market power through the BM. For instance, in import-constrained parts of the network, the SO will often have a limited number of market participants to choose between if it needs to increase generation or reduce demand. Market participants can therefore exert market power by making high offers to increase their generation.[84]

[84] Ofgem has recently expressed concerns about BM bidding in its call for input on possible options for reform – see Ofgem's 2022 'Call for Input on options to address high balancing costs' (link).

2.112. In both market designs, regulators have developed mechanisms to try to limit the exercise of market power:

- In more granular locational markets, in particular nodal markets, measures include:[85]
  - Ex-ante measures to assess whether generators are potentially "pivotal" (used in CAISO, ERCOT and PJM) or other tests for the exercise of market power such as the "conduct and impact test" used in SPP, Midcontinent Independent System Operator ("MISO"), NYISO and ISO-NE). In these cases, bids into the market have restrictions placed upon them under certain market conditions.
  - Ex-post measures based on analysis of the conduct and impact of market participant behaviour.
- In national markets, measures include:
  - Specific restrictions on bidding behaviour to prevent abuse of a pivotal position. In GB, these include the Transmission Constraint Licence Condition, which limits the ability of participants in export-constrained areas to earn excess profits.[86]
  - Market monitoring to identify potentially problematic behaviour, with enforcement tools including the Regulation on Energy Market Integrity and Transparency ("REMIT")[87] and general competition powers.

2.113. Based on the evidence from international case studies available to us, we do not expect to see significant differences in the exercise of market power across market designs. We therefore do not explicitly incorporate market power in our assessment of locational pricing. However, as we discuss in Chapter 5, our modelling of BM pricing could in practice include some element of market power.

Interactions with other policies

2.114. A move to locational pricing would have many interactions with other policies. It is beyond the scope of our work to analyse these in detail, let alone to recommend how those policies might change if locational pricing were to be implemented. But we highlight here some areas where interactions might be most relevant:

- **Support for low-carbon generation**, for instance through Contracts for Difference ("CfDs"). Current CfDs do not incorporate locational signals, and strike prices are based on the national wholesale price. This means that, if left unchanged, CfD holders would have limited incentive to change their siting decisions under a locational pricing regime (such incentives would only apply at the end of the typically 15 year CfD contracts). However, there are several options for altering the design of CfDs so that they do include locational signals, for instance by basing strike prices on the node at which a generator is based and allocating CfDs to minimise the expected level of support payments.[88]

85 Graf et al. (2021), 'Market power mitigation mechanisms for wholesale electricity markets: status quo and challenges' (link).
86 Ofgem (2017), 'Transmission Constraint Licence Condition Guidance' (link).
87 See Ofgem's material regarding 'REMIT and Wholesale Market Integrity' (link).
88 Alternatively, reference prices could be linked to the trading-hub, so they are exposed to locational risk.

- **Transmission charging:** under a locational pricing wholesale market, there is less need to configure transmission charges to send locational signals to influence siting decisions explicitly (locational transmission charges would potentially still be required within zones in a zonal market but not in a nodal market). Hence, for the main non-locational part of transmission charges, recovering the costs of the existing grid can be relatively simplistic (a flat rate per MWh charge, for example). How charges are levied to fund the cost of new investment in transmission is more nuanced and there has been considerable research on the topic in recent years. Known as the "beneficiary pays" principle, Box 2-3 below provides a brief summary of the latest thinking on transmission planning and charging in some LMP markets – notably New Zealand.
- **Distribution network charging** (or locational pricing): locational pricing at the transmission level has often been seen as a prerequisite for locational pricing at the distribution level (or perhaps for stronger locational signals in distribution network charging). Distributional locational pricing would however be significantly more complicated than transmission-level locational pricing, and has not yet been implemented in any other jurisdictions.

Box 2-3: Transmission planning and charging in nodal markets

Transmission planning and delivery of investments

In locational market designs, price signals can potentially support the planning and delivery of transmission investment. For example, a large price differential between two zones or nodes would be some measure of the value of a transmission asset that connects the two points. In theory, this could lead to more market-based transmission investments and potentially even investment on a merchant basis.

While perhaps intuitively attractive, it is generally agreed by academics that such an approach would lead to inefficient investment in transmission.[89] The principal arguments against merchant transmission investments financed by congestion rents relate to two specific market failures in transmission. First, the fact that transmission investment is typically "lumpy" and, as such, exhibits very large economics of scale (in that doubling size does not double cost); and second, it also exhibits large economies of scope in that a given transmission investment serves many parties and at many locations. The latter effect means that the congestion rent earned is only likely to be a proportion of the overall socioeconomic benefit of a given transmission investment.

As such, transmission investments continue to require regulatory planning, centralised co-ordination and a cost recovery mechanism – even in a more granular locational pricing market.

Transmission charging in nodal markets

Given that congestion rent is only a proportion of the overall benefit of a given transmission investment, it follows that an additional revenue recovery mechanism is likely to be required to fund the overall costs of the transmission grid.[90] This is invariably a transmission charge that is

[89] See, for example, Joskow and Tirole (2005), 'Merchant Transmission Investment' (link).

[90] This is discussed in Rivier et al. (2013), 'Electricity Transmission', p.279 (link). Although in an optimally developed grid revenues would recover 100% of total transmission costs, this holds only under ideal grid investment conditions. In reality, such recovery is not achieved due to factors such as the discrete nature of transmission investment, discrepancies between static and dynamic expansion plans, and unavoidable planning errors. This means that the fraction of network costs recovered by network revenues is typically around 20%.

levied on grid users. Given that locational signals are sent through the wholesale price, there is potentially less need to send locational signals through a transmission charge (as per the TNUoS style charging methodology in GB). However, as noted earlier, transmission investment between nodes or zones impact the level of prices at those locations, implying that some market participants on the network are likely to benefit more than others from a given investment. For example, transmission enhancements that allow greater volumes of electricity to flow from export constrained parts of the system are likely to increase prices in that region and therefore benefit generators in that part of the network.

This issue has led to the so-called "beneficiary-pays" principle being incorporated into the transmission charging regime in some nodal markets and indeed for some transmission upgrades within the EU electricity market.[91] For example, in New Zealand, the Electricity Authority has recently implemented a new regime of transmission charges which apply the principle that *"charges for a grid investment should allocate the cost of the investment between users and over time in proportion to the benefits that grid users are expected to get from the investment".*[92] This therefore implies there may be some limited need for locationally varying transmission charges even in a nodal pricing market.

2.115. In our modelling work, we have not assumed radical changes in policy direction beyond policies already announced by Ofgem or DESNZ. However, as we discuss further in Section 5D, we have had to make several assumptions on future CfDs given the growing magnitude of CfD-backed generation to allow locational pricing to influence siting decisions to an extent. For example, in locational market designs, we assume that awards for future CfDs for generators take account of the expected path of locational wholesale prices in different areas.

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91 In the EU, cross-border cost allocation ("CBCA") arrangements guide the cost allocation process for transmission investments between Member States. In some cases, ACER will decide on how costs will be allocated, placing the cost burden on entities that are responsible for the area that the project is sited in (reflecting the beneficiaries-pay principle). However, in cases where the asset is not physically located in a particular region, but the region is a net beneficiary of the asset by more than 10%, the region may still be allocated some of the investment costs. See ACER (2015) 'Decision of the Agency for the Cooperation of Energy Regulators No 02/2015' (link) and Energy Community (2016) 'Explanatory Notes on the Implementation of EU Regulation 347/2013 – MC Decision 2015/09' (link). This may be the case for example where a neighbouring region could benefit from an intra-state investment in transmission capacity.

92 Hogan (2018), 'Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal' (link) and Hogan (2018), 'A Primer on Transmission Benefits and Cost Allocation' (link).

3. Market design in practice: the GB experience and global trends

3.1. In the previous chapter, we explained that two key differences between market designs are how different electricity markets schedule resources to meet demand ahead of real-time dispatch and the extent of locational variation of wholesale electricity prices. Markets can be self-scheduled or centrally-scheduled, and can have national, zonal or nodal prices – with the current GB market design as an example of a self-scheduled national pricing market. We discussed, from a theoretical perspective, how these differences could have both short-run and long-run impacts on the efficiency of operation and the payment flows between and among consumers, generators and storage providers.

3.2. In this chapter, we now consider the experience of market design in practice. We divide our considerations into two parts:

- First, given it is the subject of this report, we discuss the development of the GB wholesale electricity market (**Section A**).
- Second, we briefly discuss global trends in electricity market design since 2000 (**Section B**).

A. The GB wholesale electricity market

3.3. As we noted in Chapter 2, the NETA market design, which went live in England & Wales in 2001, was pioneering in implementing a self-scheduling market. Seen as radical at the time, we consider in this sub-section:

- First, the experience of NETA since 2001 and whether it has functioned as initially intended – particularly with regard to the subjects that are the focus of this report.
- Second, important recent policy developments relevant to locational pricing.

Experience of NETA since inception

3.4. The overarching aim of NETA, cited at the time, was to put "*in place market-based trading arrangements more in line with those being adopted in other competitive commodity and energy markets*".[93] As described in Chapter 2, it did this by creating a set of incentives to encourage ex-ante contracting in forward markets between consumers and generators, who would be subject to imbalance payments if they did not consume or generate in line with their contractual volumes.

3.5. This regime was expected to lead to substantial benefits relative to the existing pool design, including "*lower prices from more efficient and more competitive trading; greater choice of markets; more scope for demand management; sharper incentives to manage risks; transparency from simple bids; forward price curves to facilitate new entry; avoidance of discrimination against fuel sources by acknowledging the value of flexible plants in a competitive market; more liquid contracts markets; scope for greater co-ordination and consistency with gas; and more flexible and*

93 Office of Electricity Regulation (1998), 'Review of Electricity Trading Arrangements Framework Document' (link).

effective governance".[94] Estimates prior to NETA implementation expected wholesale prices to decrease by c.10% as a result of the change in the design of the market regime.[95]

3.6. Central to this was the idea that the aggregate schedule of planned generation, as created by the interaction of market participants, would ensure that the system was roughly balanced in each (half-hour) settlement period against which contracted and metered volumes are measured. Of course, this does not imply that demand and supply are balanced on a second-by-second basis, so the SO was expected to fine-tune the intended outputs to ensure the system remained secure.

3.7. Additionally, the SO would reduce or increase generating output (or demand) to meet unexpected shortfalls or surpluses (for instance, due to generator outages or unexpected changes in demand). The costs of these interventions would be recovered from parties deviating from their contractual volumes through the imbalance pricing regime as part of the settlement process (in line with the so-called "polluter pays" principle).

3.8. Under NETA it was, by design, not necessary for market participants to consider the physical realities of the transmission network when contracting and scheduling their intended production and consumption. To the extent that the transmission network capacity was, in reality, insufficient to convey the aggregate scheduled generation to the intended consumers, the SO would intervene by increasing and decreasing the output of some generators in specific locations of the network to ensure overall system balance was achieved in real time. Unlike the polluter pays imbalance charge, the cost of interventions to resolve transmission constraints was recovered from all market participants through a charge levied on all generators and consumers connected to the transmission system.

3.9. When NETA was established, it was hoped that, for any given half hour, market participants' intended generation and consumption would roughly equal out across the geographical footprint of the market, meaning that the cost incurred by the SO in resolving transmission constraints would be relatively low. Furthermore, policymakers believed that they could resolve any problems by adjusting the market design and the arrangements for access to the transmission network after NETA go-live.[96, 97]

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94 Office of Electricity Regulation (1998), 'Review of Electricity Trading Arrangements: Working Paper on Trading Inside and Outside the Pool' (link).

95 Office of Electricity Regulation (1998), 'Review of Electricity Trading Arrangements: Working Paper on Trading Inside and Outside the Pool' (link).

96 See, for example, Ofgem (2001), 'Transmission Access and Losses under NETA' (link) – published some 2 months after NETA go-live. The consultation document describes some of the issues associated with firm transmission access that might lead to short- and long-run inefficiencies. It explains how a new regime of auctioning transmission access rights, that are "*capable of reflecting effectively the underlying physical characteristics of the transmission network; and…. the temporal and spatial nature of transmission constraints*", was an "*efficient means*" of achieving its aims of non-discriminatory access to the network. It goes on to note that should the reforms of transmission access be implemented then "*it may be appropriate to reduce or remove the locational differentiation in TNUoS charges and to move to a per MWh charging arrangement for all generation and demand*".

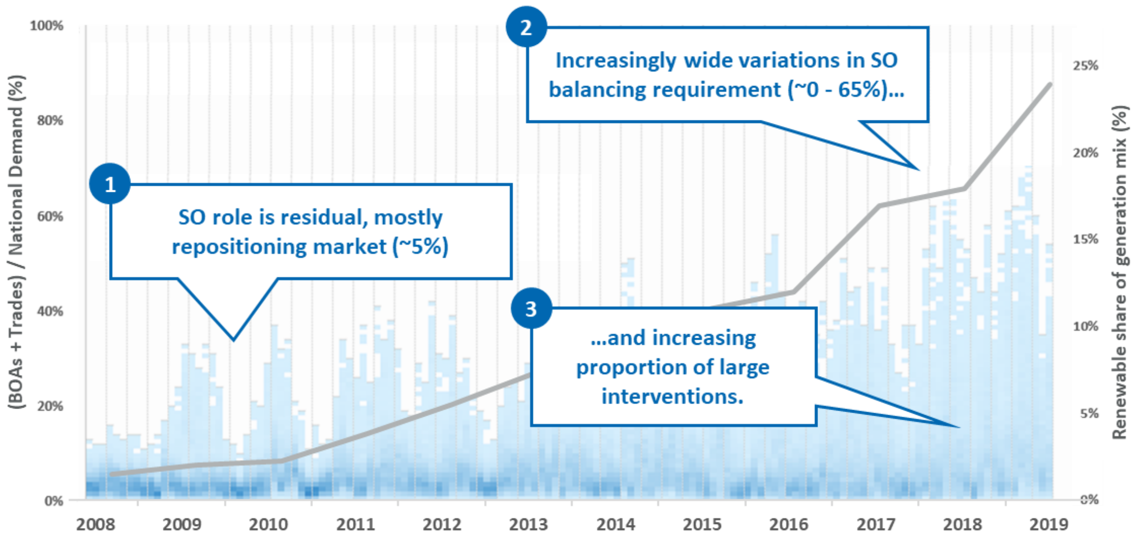
97 Again, as with the design of the NETA electricity market itself, the parallel was the GB gas market. During the early period of operation of the gas market, significant transmission bottlenecks on the NTS meant that some entry terminals access to the network needed to be restricted (notably at the St Fergus entry terminal in the summer of 1998). This led to the introduction of entry capacity auctions that effectively price rationed the availability of access to the gas transmission network. See Ofgem (1999), 'St Fergus and Bacton investigation: a progress report' (link).

3.10. Overall, therefore, the role of the SO was intended to be that of a *residual balancer,* in that it was only expected to carry out a relatively small volume of trades compared to the large volume of electricity traded between market participants in a competitive electricity market.

3.11. In the initial phase of its operation, the NETA market design appeared to perform as policymakers hoped, in that the SO did indeed play only a residual role in balancing the system and the cost of resolving transmission constraints was relatively low. For example, in 2008, after some seven years of operation, the SO needed to intervene in the market for volume equivalent to only about 5% of demand and constraint management costs were c.£150m per annum.[98]

3.12. However, this picture has changed dramatically in the last decade as the share of renewable generation in GB has increased. The SO now has a very material, and apparently non-residual, role in balancing the system. Notably, as indicated in Figure 3-1 below, the SO now takes balancing actions that regularly exceed 50% of GB demand.

Figure 3-1: SO balancing as proportion of national demand vs renewable share of generation



Source: ESO Net Zero Market Reform, Phase 3 Conclusions, March 2022 (link).

3.13. In Figure 3-1 above, the blue pixels represent the left-axis, that is the proportion of the SO balancing activities relative to total demand.[99] A darker shade of blue relates to a higher frequency of actions of a given size. The grey line represents the right-axis, that is the proportion of renewable generation in the GB energy system. The figure illustrates that, contrary to the aims of NETA, over the last decade the SO has had to play an increasingly large role to ensure the system remains balanced in real time.

3.14. Mirroring this rise in interventions by the SO has been a ten-fold increase in the cost of resolving transmission constraints between 2010 and 2022 – as illustrated in Figure 3-2.

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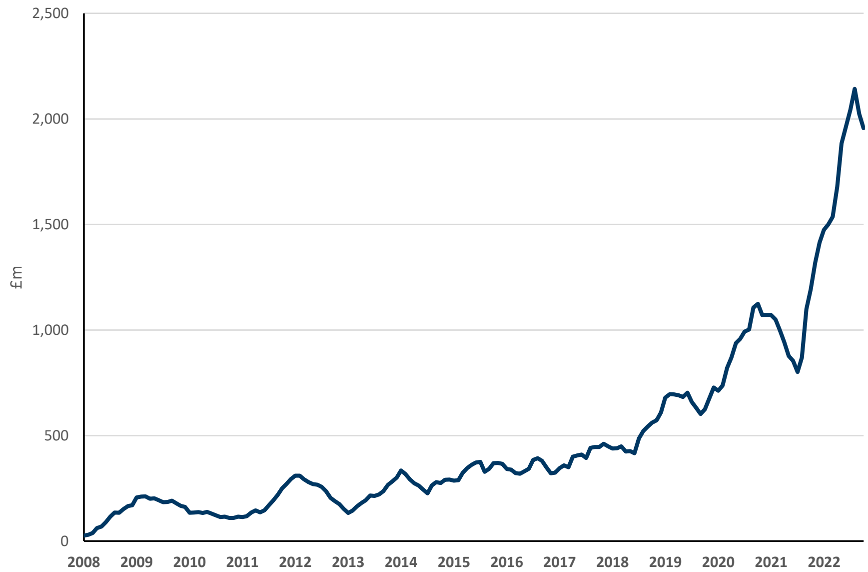
98 Derived from Figure 3-1 and Figure 3-2 below.

99 Balancing activities include Bids and Offers, trades and instructions issued by the ESO's Electricity National Control Centre ("ENCC") to keep the system in balance.

Figure 3-2: GB historical constraint management costs (12-month rolling average, £m)[100]



Source: ESO's Monthly Balancing Services Summary reports; FTI analysis[101]

3.15. There are many potential drivers of the increase in the volume of SO interventions and consequently the constraint management costs, with no definitive view on the relative importance of each particular factor. However, four key drivers of the trend towards greater SO intervention are:

- increasing volumes of renewable generation;
- expansion of the NETA market design footprint to include Scotland in 2005;
- implementation of the Connect and Manage policy for access to the transmission network in 2010; and
- a material shortfall in transmission network capacity in the 2010s relative to policymakers' ambitions.

3.16. We briefly discuss these factors in the following sub-sections.

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[100] These costs represent an increase in both volume of trades as well as on prices as more expensive units need to be redispatched. Additionally, in 2022, prices were also elevated due to the Russia-Ukraine crisis.

[101] To address the incentive to place higher bids, the Transmission Constraint Licence Condition was introduced in 2012 with the intention of reducing the costs of resolving congestion.

Increase in renewables generation

3.17. Increasing consensus on the implications of climate change, expressed through international commitments such as the Kyoto protocol, has resulted in rapid decarbonisation becoming a public and policy priority. This priority was crystalised in 2008, when the Climate Change Act was introduced, introducing legally-binding decarbonisation targets to cut greenhouse-gas emissions across the economy.[102] This was accompanied by energy-sector specific targets, such as the 2009 EU Renewable Energy directive, which established a target for 20% of energy to come from renewable sources by 2020.[103]

3.18. As well as highlighting the increase in SO interventions, Figure 3-1 above also shows that the share of renewables in GB transmission-connected generation grew from 2% in 2008 to over 20% in 2019. Combined with the shift of thermal generation from coal-fired to gas-fired power stations, this had a transformational impact on GB's carbon emissions, with greenhouse gas emissions from energy supply falling by half between 2010 and 2018.[104]

3.19. Most renewables generation comes from wind and solar plants, which have inherently more intermittent and unpredictable output than conventional sources of generation. In the context of the GB market design, this means that, everything else held equal, we would expect there to be more interventions by the SO near to real time, for instance due to changing weather conditions outside the control of either generators or the SO itself.

Expansion of NETA market to include Scotland in 2005

3.20. The expansion of the NETA market geographic footprint to include Scotland in 2005 is likely to have increased the extent and cost of SO interventions. This, by design, allowed a greater number of market participants dispersed over a much wider geographic area to trade with each other at a single price. Therefore, despite there being relatively limited transmission between Scotland and England at the time, market participants across England, Scotland and Wales could trade with each other entirely unfettered by the physical realities of the network.

3.21. Everything else being equal, this change would be expected to raise the potential for greater volumes of congestion and greater costs of constraint management.

Connect and Manage policy in 2010

3.22. A further potential driver of the increase in constraint management costs was the implementation of the Connect and Manage policy in 2010. Policymakers were concerned that the pace of roll-out of renewables generation was being delayed by the access arrangements to the transmission network that, at the time, operated a queuing system on a "first-come, first served" basis. In practice, this meant that in some parts of the country access to the network was highly limited and dependent on the construction of new transmission assets before new generation could connect to the transmission network.

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102 UK Government (2008) 'Climate Change Act' (link).

103 European Commission (2009) 'Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC' (link).

104 Ofgem (2019) 'State of the Energy Market 2019', Figure 5.7 (link).

3.23. By contrast, the Connect and Manage policy implemented a new connection approach in which generators received a fixed connection date and were entitled to use the system from that date. Enabling work is considered a pre-condition for generators to connect, whilst wider works are not required – generators are able to connect regardless of whether the transmission network had, by that time, actually been reinforced to support the connecting generation.[105] While this change might have accelerated the growth of renewables generation, it ran the risk that transmission network build would not keep pace, leading to more transmission network constraints and increased SO interventions.

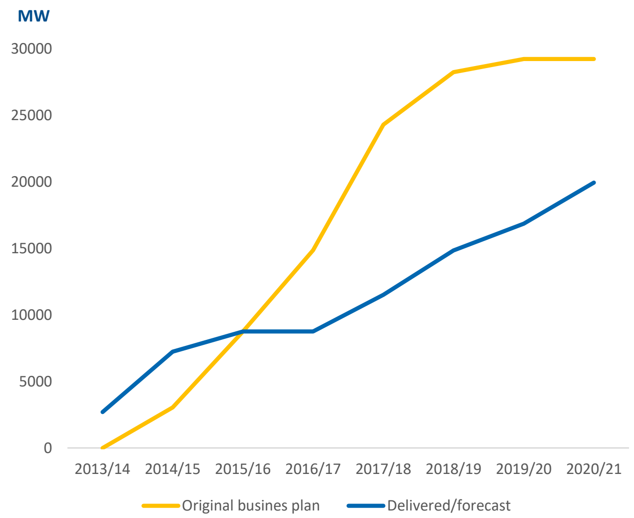
3.24. The impact assessment that accompanied the policy decision recognised that the policy would lead to an increase in constraint management costs that would be socialised across all consumers.[106] Forecasts undertaken for the Department of Energy and Climate Change ("DECC", the precursor organisation to DESNZ) expected that constraint management costs would total c.£1bn in Net Present Value ("NPV") terms over the 10-year period between 2010 and 2020, of which about 20% (c.£200m) was attributed to the Connect and Manage policy. In practice, this was a very significant underestimate of the overall constraint management costs incurred in the period – constraint management costs were around £3bn between 2010 and 2020 in NPV terms.[107] That is, the cost of constraint management, ultimately recovered from consumers, was around three times higher than expected by the forecasts that informed the policy decision to implement Connect and Manage.[108] Indeed to the extent that a large proportion of the £2bn additional constraint management costs can be attributed to renewables generation that was able to connect the network as a result of the Connect and Manage policy, it follows that policymakers may have underestimated the cost to consumers of the policy by up to a factor of ten.

Lower than expected levels of new transmission network capacity delivered in 2010s

3.25. While the roll out of renewables generation has been relatively rapid, it has arguably been more challenging to deliver new investments in transmission network capacity. Figure 3-3 illustrates planned and actual roll-out of boundary reinforcement projects over the price control period 2013 to 2021.

105 See Ofgem's guidance on the Connect and Manage regime (link).
106 See DECC's Impact Assessment on 'Proposals for improving Grid Access' (link).
107 Calculated using 2009 prices (using the GDP price deflator) and in 2010 PV terms based on a discount rate of 3.5%.
108 Forecasts undertaken in 2009 by consultants for Ofgem were less sanguine; see Frontier Economics' report on the 'Assessment of the potential impact on consumers of connect and manage access proposals' (link). These forecasts were dismissed by DECC on page 12, on the grounds that the assumptions of relatively low network investment and relatively high amounts of wind generation connecting in Scotland were "very unlikely".

Figure 3-3: Comparison of cumulative planned vs actual delivery of boundary reinforcement projects in GB over RIIO-1 price control



Sources: Ofgem – RIIO1 Performance summary documents; TOs Annual Performance Reports; FTI analysis.

3.26. The actual delivery of new transmission investment lagged by 32% relative to plans set out at the beginning of the period. While we have not studied the reasons for this shortfall, factors frequently mentioned include difficulties in planning, consenting and construction of assets, in particular technological challenges of incorporating new offshore transmission assets into the existing network.

3.27. Clearly, under-delivery of transmission network capacity relative to expectation (and relative to the roll-out of generation in export-constrained areas of the network) would be expected to increase constraint management costs, other things equal.

Emerging issues and developments

3.28. In addition to the above, several recent developments provide important context when considering the case for and against greater locational pricing.

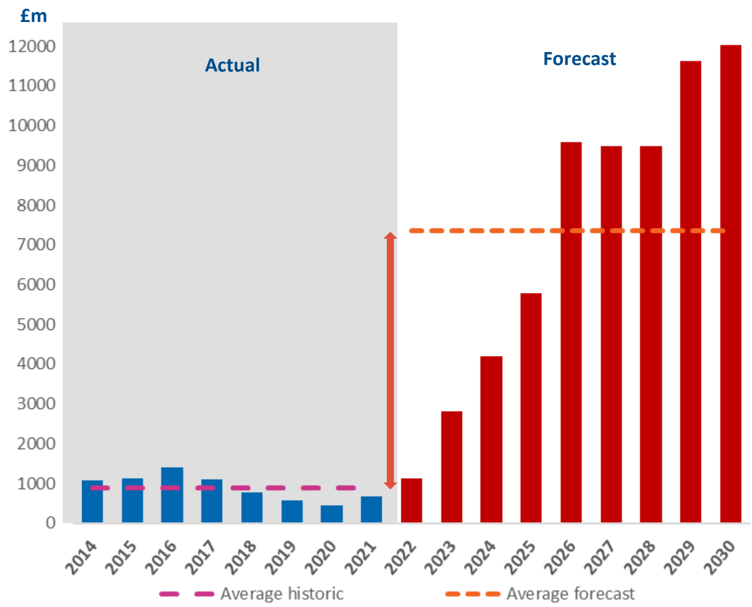
3.29. In 2020, the government announced that it would phase out the sale of new petrol and diesel cars by 2030.[109] While EVs still represent a minority of new cars, their numbers have risen rapidly in recent years, and there are now around a million Ultra Low Emission Vehicles on the road in the UK.[110] EV charging is likely to represent a rapidly increasing proportion of total electricity demand in coming years. This creates potential costs, including the risk of increasing transmission constraints because of a geographical mismatch between demand and supply. But it also increases the opportunities for greater flexibility of demand, for instance through flexible charging and Vehicle-to-Grid ("V2G") technologies that provide energy from vehicles to the grid.

[109] Just prior to publication of this report, the GB government adjusted the date of this phase out to 2035.
[110] House of Commons Library (2023), 'Electrical Vehicles and Infrastructure' (link).

3.30. In April 2022, the flagship UK Government energy policy (British Energy Security Strategy, or "BESS") articulated a plan for a rapid acceleration in UK's decarbonisation strategy. This plan included, among other elements, a significantly more ambitious deployment of offshore wind across GB than previously envisaged, reaching 50GW by 2030. This ambition posed a potential concern as to how such a large volume of offshore wind would in practice be delivered to consumers.

3.31. As a result, in July 2022, the ESO announced its plans for the Holistic Network Design ("HND") for transmission network development.[111] This set out an ambitious vision for how the transmission network (both offshore and onshore) would need to evolve in the coming years to accommodate the increased volume of offshore wind in GB. Critically, the HND has sought to consider simultaneously how offshore wind farms could be connected to the GB transmission network and how the power could be transported to where it would be consumed. The ESO also published the NOA 2021/22 Refresh, which sought to take into account the HND policy and to articulate the implications for GB transmission network investments. In total more than £53.7 billion worth of new grid infrastructure will be required to meet the government 2030 offshore wind target.[112] Figure 3-4 shows the scale of the expected increase in transmission network spend planned to deliver HND in coming years. The annual rate of investment in transmission will need to increase eight-fold from 2022 for the rest of this decade relative to the spend in the previous decade if the HND target is to be met.

Figure 3-4: Comparison of average annual expenditure to deliver HND reinforcements (including NOA7)



Sources: Ofgem-RIIO Performance report; RIIO T2 PCFM; ESO-Pathway to 2030 Holistic Network Design and NOA Refresh; FTI analysis.

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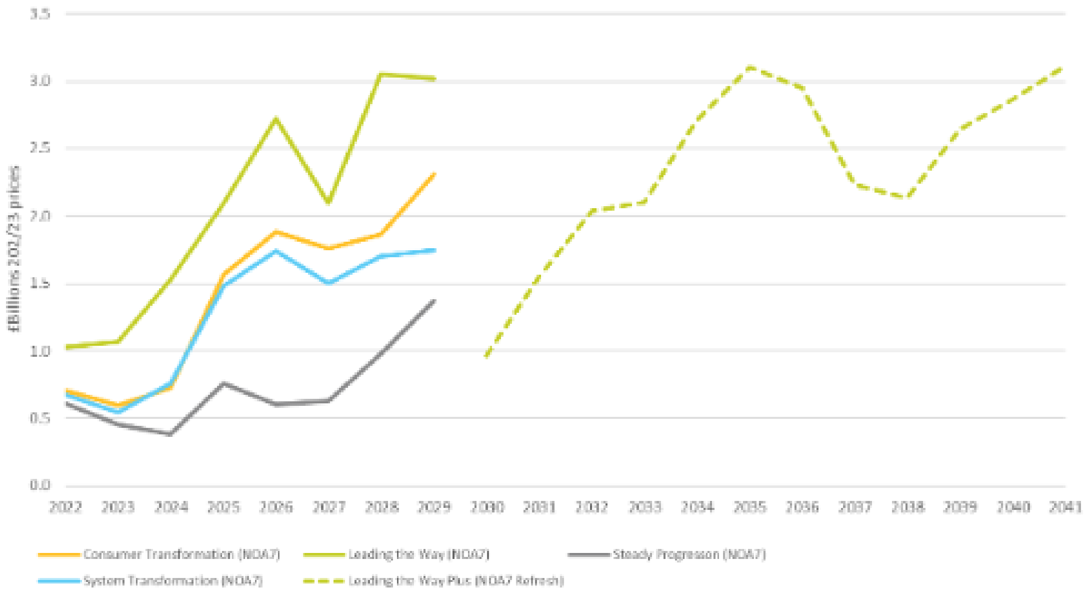
[111] National Grid ESO (2022), 'Pathway to 2030 – A holistic network design to support offshore wind deployment for Net Zero' (link).

[112] The total investment required is made up of £32 billion for the recommended offshore design and £21.7 billion for the onshore design – see ESO's Pathway to 2030 Holistic Network Design summary report, page 22 (link).

3.32. The ESO has projected that constraint management costs are expected to continue to rise over the coming decade. In August 2022, it forecast that constraint management costs could reach up to £3bn per year by 2030, as highlighted in Figure 3-5 below.[113]

Figure 3-5: ESO's Modelled constraint management costs in GB



Source: ESO (2022) Modelled Constraint Costs – August 2022 (link)

3.33. Even with the very significant volumes of additional transmission build-out under the HND plan, the ESO expects annual constraint management costs to reach £3bn, albeit at a later date in the mid-2030s. Constraint management costs are not expected to return to the levels observed at the beginning of this decade (let alone to the levels observed only five or 10 years ago).

3.34. Recent GB experience makes it clear that the balance between new transmission network capacity and new generation capacity is a key driver of constraint management costs; in the 2010s, the lag in the delivery of transmission network capacity relative to generation was an important driver in the increase in constraint management costs. To the extent that future network capacity is rolled out more slowly than generation capacity, as has been the case historically, constraint management costs might be higher than currently anticipated. Conversely, if future network capacity is rolled out more quickly than generation capacity, constraint management costs could be lower than expected. With growth in electricity demand as well as in new generation and transmission network capacity expected to be significantly greater in this decade than in the 2010s, the stakes are even higher than previously. A lag in transmission network roll-out could cause constraint management costs to escalate to levels that are considerably higher than currently forecast by ESO.

113 National Grid ESO, 'Modelled Constraint Costs for NOA in 2020/21' (link).

B. Evolution of market design in other liberalised energy markets

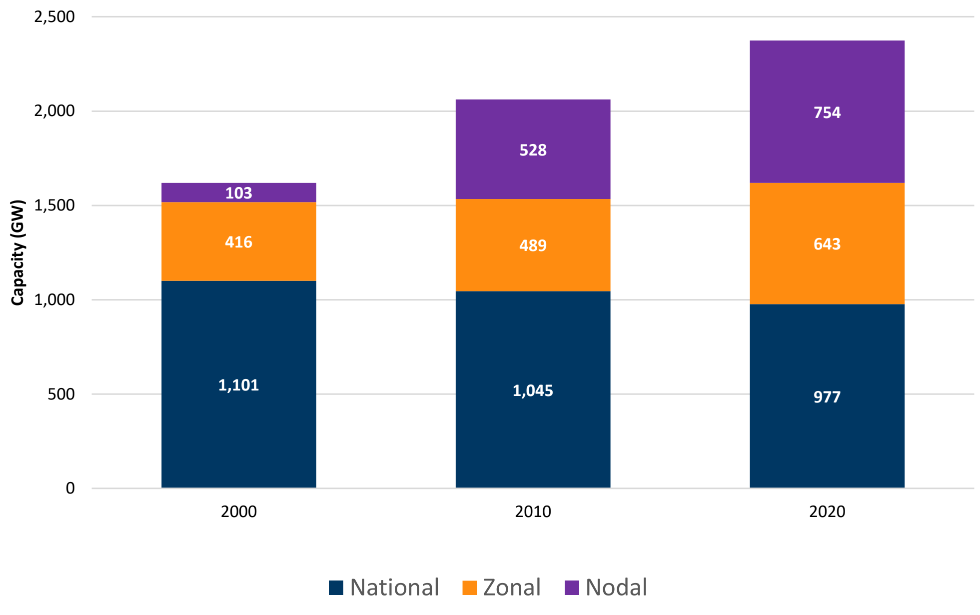
3.35. In this section, we provide a brief overview of how and whether comparator electricity markets reflect locational factors in their wholesale market pricing. This is intended to provide the global context for the GB market.

3.36. We have limited our survey to Organisation for Economic Cooperation and Development ("OECD") member countries (as of 2000) except Iceland and categorised for each country:

- the volume of installed capacity in each country from 2000 to 2020 at five-year intervals;
- whether the market could be considered to have a liberalised electricity sector; and
- for each liberalised market, whether the market design incorporates national, zonal or nodal pricing.

3.37. Figure 3-6 summarises the evolution of installed generation capacity in the liberalised OECD markets and the split of those markets between national, zonal and nodal market designs. In 2000, about 68% of the installed capacity of liberalised electricity markets in the OECD operated under national pricing. This was mainly the nascent liberalised markets of Europe as well as some regions of the US. Zonal pricing existed in a small number of regions, such as Australia,[114] Norway and Japan. Nodal markets were at the time relatively unusual – operating only in New Zealand as well as PJM and NYISO in the US.

Figure 3-6: Evolution of installed capacity under market design options across the OECD countries with liberalised electricity markets

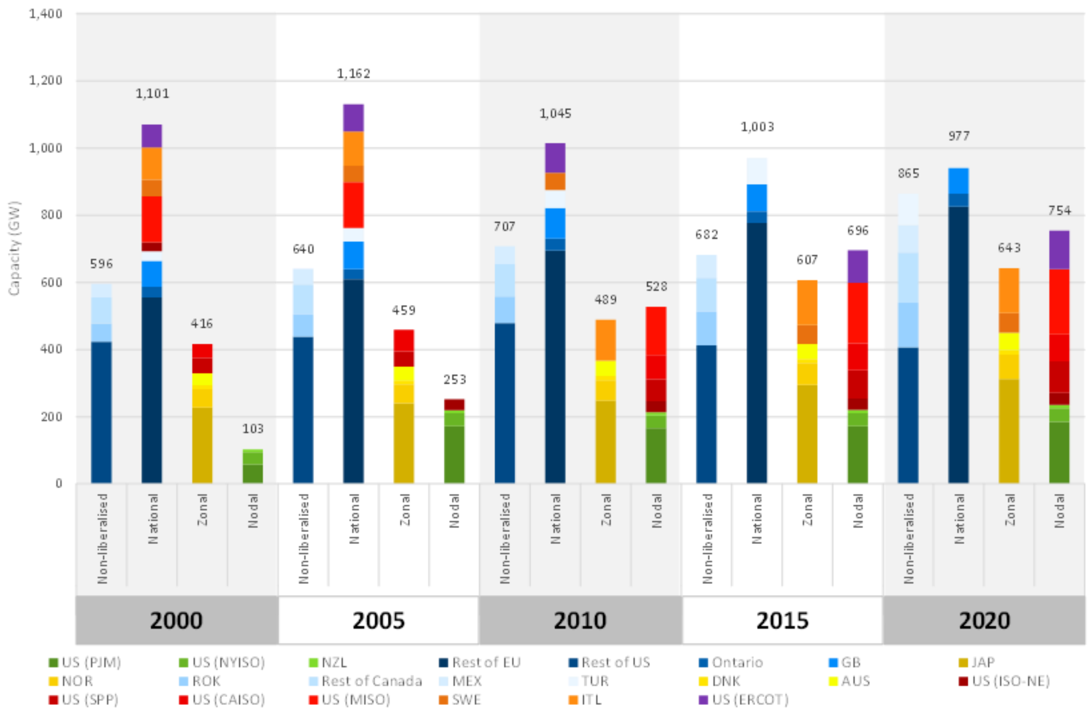


Source: International Renewable Energy Agency ("IRENA"), CAISO, NYISO, ERCOT, Ministry of Business, Innovation and Employment, New Zealand ("MBIE NZ"), Potomac Economics, IESO, Digest of UK Energy Statistics ("DUKES"), Federal Energy Regulatory Commission ("FERC"), SPP, ISO-NE.

[114] We include the National Electricity Market of the Eastern states (of Tasmania, Queensland, New South Wales, Victoria, South Australia and ACT) for Australia and therefore exclude Western Australia and Northern Territories from the data shown here.

3.38. Figure 3-7 provides the underlying data for each OECD country, showing the extent to which each country can be classified as either non-liberalised or having a national, zonal or nodal market design.[115] Most of the remaining markets with national pricing are in Europe.

Figure 3-7: Share of market design options across the OECD countries



Source: IRENA, CAISO, NYISO, ERCOT, MBIE NZ, Potomac Economics, IESO, DUKES, FERC, SPP, ISO-NE
Note: Chart includes OECD member countries (as of 2000) except Iceland. [116,117]

3.39. By 2020, the proportion of installed capacity in national-price markets had fallen to 41%, with 32% of capacity in markets with nodal pricing, and 27% with zonal pricing. There are several drivers of this trend, including:

- Many regions in the US, for example the markets of California and Texas, transitioned from zonal to nodal market designs as a result of perceived shortcomings in earlier market designs.
- Some national markets transitioned to zonal markets. For example, Sweden adopted a four-zone market in 2010 and the Germany-Austria bidding zone was split in 2018 (not reflected in the diagram above).

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115 Some electricity market classified as non-liberalised may have some elements of wholesale electricity competition (e.g., through independent power producers) and/or are in the early stages of liberalisation.
116 This chart has been limited by the data provided to us. Some capacity figures, particularly in the US, are based on net capacity values instead of gross capacity (and averaged across summer and winter). This would slightly understate the comparable capacity for nodal markets shown in this chart.
117 The Rest of Canada excludes Ontario and Alberta. The Rest of US excludes the ISOs. A portion of this capacity may be part of electricity markets that are not strictly non-liberalised (for example, some regions around, and including, CAISO are part of the Western EIM which dispatches resources across an integrated system on a nodal basis).

3.40. As such, the increase in capacities between nodal, zonal and national pricing markets reflects changes in locational market design in addition to increases in capacity investment profiles within each market.

3.41. Overall, across liberalised OECD electricity markets, there has been a trend towards greater locational granularity being incorporated into wholesale electricity markets over the last 20 years. Notably, instances of liberalised markets where the level of locational granularity of their wholesale electricity prices has reduced are extremely rare.[118]

3.42. A main driver of this trend is that some markets that originally adopted national or zonal markets have increased the locational granularity of their markets by switching to either zonal or nodal markets. Sweden, for example, adopted zonal pricing and in the US, the markets of Texas and California switched from zonal pricing to nodal pricing.

3.43. A secondary driver is that some markets that were not liberalised at the turn of the century immediately adopted a locational market design. For instance, the market of the mid-west part of the US, MISO, liberalised its market in 2005 and immediately adopted nodal pricing.

3.44. We also observed that growth in generation capacity – frequently of renewables generation - has occurred under all market designs and there appears to have been no change in the rate of growth during any transition to a more granular locational market.

3.45. Locationally granular markets feature a wide range of generation mixes, for instance, among nodal pricing markets:

- New Zealand features a mix of hydro generation in the South Island and thermal, geothermal, and renewable generation in the North Island;
- Singapore features predominantly thermal generation;
- the vast geographic footprint of the northeast US power market (PJM market) includes many sources of generation, with nuclear and thermal generation in the majority;
- the Texas market (ERCOT) and the Southwest Power Pool (SPP) have high proportions of wind generation; and
- California (CAISO) has recently observed significant roll-out of solar and battery storage.

[118] We are aware of only two instances – the expansion NETA to include Scotland in 2005, and the merging of the generation only Snowy price region with price regions of NSW and Victoria in the NEM (Australia) in 2008.

4. Assessment approach and methodology

4.1. As described in Chapter 2, the locational granularity of wholesale electricity markets has a wide range of potential impacts on the way in which the electricity market functions, in both operational and investment timescales, and ultimately has a significant impact on the costs paid by consumers. Following this, we set out the historical experience of the GB national market design and described some of the perceived challenges and opportunities that arise as a result of the transition to Net Zero in Chapter 3.

4.2. In this chapter, we set out an overview of the approach and methodology that we have taken to evaluate the potential impacts of greater locational granularity of pricing in the GB wholesale market. We have undertaken this assessment with an awareness of the need for it to be critically examined and subject to a high degree of stakeholder scrutiny.

4.3. As such, our assessment approach and methodology, as set out below, follows from an extensive stakeholder engagement across the industry. We have sought to develop an approach that is as transparent as possible, in order to support a neutral and robust assessment. This chapter therefore outlines:

- our overall approach and the key modelling principles that underpin our assessment (**Section A**);
- an overview of the key impacts of locational market designs that we have captured in our assessment (**Section B**); and
- our approach for evaluating the overall consumer impact and net socioeconomic impact (**Section C**).

A. Overall approach and key principles

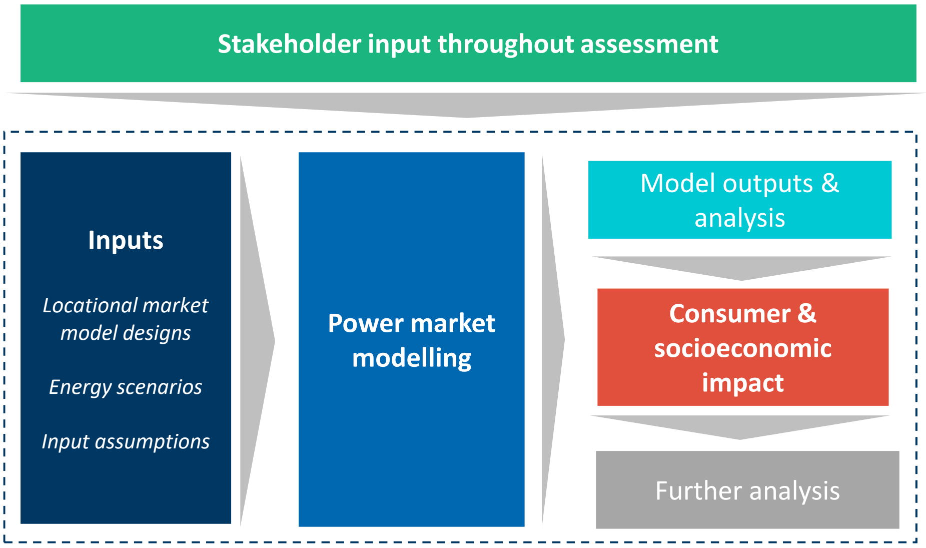
4.4. Given the broad scope of our assessment, we introduce our approach with the following sub-sections:

- Our overall approach at a high-level.
- The key principles underpinning our assessment.

Overall high-level approach

4.5. The assessment presented in this report is based on a detailed quantitative and qualitative assessment performed across 12 months in 2022 and 2023. It draws on a wide range of information sources, including Ofgem, DESNZ, ESO, industry stakeholders and academics, as well as FTI experts. A high-level schematic of our overall approach is set out in Figure 4-1 below.

Figure 4-1: Summary of our overall approach



Source: FTI analysis

4.6. As indicated in Figure 4-1 above, our approach starts with the development of input assumptions for the modelling and analysis. These inputs are drawn from a range of publicly available sources, confidential information provided by the ESO, and stakeholder feedback collected across the assessment. Where possible, inputs have been derived from external, credible third-party sources, with additional modelling assumptions tested through multiple rounds of stakeholder engagement.

4.7. These inputs have fed into the power market modelling as well as the multiple strands of quantitative and qualitative analysis that assess the broader impacts of more granular locational pricing. Where possible, we have sought to interrogate our results via international precedent.

4.8. This analysis forms the overall results for the CBA, which captures both the consumer impact and the wider socioeconomic impact, which accounts for both the consumer and producer impact. From these results, we explore the regional impact of different locational wholesale market design options, conduct a sensitivity analysis and consider potential transition and mitigation measures.

4.9. The results of our CBA show the impact of more granular locational pricing *relative to the counterfactual*, i.e., relative to the current GB market design with a national GB-wide wholesale price.[119] We have not sought to augment the existing GB market design with hypothetical future policies as part of the core assessment.

4.10. Across the modelling period, we have modelled outcomes for each market design under two distinct Net Zero-compliant scenarios, based on the Leading the Way and System Transformation scenarios as set out in the ESO's FES 2021 publication, in order to present a range of outcomes for GB.

Key principles of our assessment approach

4.11. Given the importance and first-of-a-kind nature of our assessment approach, we have sought to follow several key principles when making specific methodology choices:

[119] We explain our use of the counterfactual in more detail in Section 5D.

- **Transparency** on our sources of information where possible. For example:
  - External, credible, third-party public sources of information have been used where available including the FES, the Electricity Ten Year Statement ("ETYS"), NOA and ENTSO-E's TYNDP and ERAA assessments.
  - Where public sources of information were unavailable, we have needed to use confidential sources of information provided to us by the ESO. In particular, we rely on a dataset regarding the location of existing and future generation assets, as well as project specific data on new transmission projects that have been provided to us by the ESO under a non-disclosure agreement ("NDA").
  - Where additional modelling assumptions needed to be made, or a methodology developed, by FTI, we have recorded these in the report. Where possible, they have also been tested through multiple rounds of stakeholder engagement.
- **Simplicity** in our approach where possible. For example:
  - We have avoided undertaking any quantitative analysis that may be perceived as reliant on policy decisions regarding the extent of demand-side exposure, for example we have not considered the potential benefits of more granular locational pricing from demand re-siting or greater investments in energy-intensive industries.
  - We rely on the use of least-cost economic dispatch to simulate real-time outcomes of the power market model (i.e., without reflecting any market power in the wholesale market or balancing mechanism).
  - We do not apply explicit additional weighting to any individual factors in the CBA results, for example prioritising consumer outcomes over wider system impacts.
- **Clarity** in presenting our analysis and findings. For example:
  - We distinguish efficiency gains/losses from welfare transfers among cohorts of stakeholders. In doing so, we set out parties who may benefit or be disadvantaged from more granular locational pricing, and the potential degree of change.
  - On the impacts that are not quantifiable, we have also endeavoured to be clear on the qualitative impact on consumers.
- **Robustness** in our approach to ensure our findings are meaningful and reliable for stakeholders. For example:
  - We model three scenarios and treat each scenario equally. One of these scenarios – Leading the Way (HND) – covers an acceleration and increase in the capacity of the GB transmission network based on the ESO's NOA Refresh publication. All three scenarios serve as the "base case" in our assessment, and we do not consider either scenario more or less indicative of the costs and benefits of transitioning to locational marginal pricing.
  - We assess the distributional impact of the CBA results and conduct two further sensitivities to test specific hypotheses and policies.

4.12. The following sections provide further detail on key aspects of the assessment approach.

B. Assessing the impacts of wholesale electricity market design on consumers

4.13. Our analysis has considered a wide range of impacts that a transition from the current GB market design towards more granular locational wholesale pricing would have.[120] The key impacts considered in our analysis are summarised in Figure 4-2 below and described in more detail in the following sub-sections.

Figure 4-2: Impacts of a transition to more granular locational pricing

Source: FTI analysis

4.14. The overall impact of transitioning to a more granular locational market design can be grouped into four key categories, aligned with the descriptions set out in Section 2B:

- The **short-run impacts** of more granular locational pricing on the operation of the wholesale market and BM, affecting price and generation outcomes in each market.
- The **long-run impacts** of more granular locational pricing on both supply-side and demand-side market participants, as discussed in Section 2B.
- The impact on **key policy mechanisms** that are linked directly to the wholesale electricity price, namely CfDs and interconnector Cap and Floor ("C&F") agreements.
- The **wider system impact** that a transition to more granular locational pricing might have, including implementation costs and the impact on investor cost of capital.

4.15. We discuss each in turn in the following sub-sections.

Short-run impacts

4.16. In our analysis, we have modelled outcomes in both the wholesale market and BM (where appropriate) for each market design in order to capture some of the short-run effects set out in Chapter 2. A change in the total cost of serving electricity demand across the two markets forms a core part of the consumer impact in our assessment. This has four effects as set out in Figure 4-3 below.

[120] In our assessment, we assume that a locational pricing regime is implemented on 1 January 2025. This allows us to capture a 16-year time period based on the expected evolution of the transmission grid to 2040.

Figure 4-3: Short-run impacts

Type	Effect	Quantified
Short-run operational impacts	**Changes in wholesale prices** (lower in export-constrained areas and higher in import-constrained areas)	✓
	Reduced cost of congestion to be borne by consumers	✓
	Improved signals across all resource types including **flexibility resources**	✓
	Surplus revenues from congestion rent and losses	✓
	Cost changes from centralised scheduling	

Source: FTI analysis

Changes to wholesale electricity prices

4.17. First, we have evaluated the change in hourly **wholesale electricity prices** resulting from the level of locational granularity captured by the relevant wholesale market. In the national market, this is a single price for the whole of GB, calculated assuming no transmission constraints on the GB network (with the cost of transmission constraints addressed in the BM). For the zonal market, the wholesale price reflects transmission constraints between zones, but not the additional constraints within each zone. For the nodal market, the settled wholesale electricity price at each node reflects all transmission constraints and associated losses across the transmission network. As such, more granular locational pricing would be expected to:

- increase wholesale electricity prices in areas that are import-constrained (i.e., where demand, combined with maximum import capacity from neighbouring areas, exceeds available low-cost supply); and
- reduce wholesale electricity prices in areas that are export-constrained (i.e., where low-cost supply, combined with maximum export capacity into neighbouring areas, exceeds local demand).

Reduced cost of constraint management

4.18. Second, we have estimated the impact of each market design on the **costs of resolving transmission network constraints**. As described in Chapter 2, under the current GB market design, the ESO is required to adjust generating resources after gate closure for each settlement period in response to intra-GB transmission constraints. The cost of these (necessary) interventions is recovered through a charge across all electricity consumers.

4.19. Under a zonal market design, an increased proportion of intra-GB transmission constraints would be accounted for in the ex-ante wholesale market settlement, reducing the required volume (and associated cost) of SO interventions. Under a nodal market design, all transmission constraints would, by design, already be accounted for in the wholesale market, removing the need for additional SO interventions.[121]

4.20. As highlighted above, for each locational market design and scenario, we have modelled the expected volume and associated cost of the redispatch actions that the ESO is required to take in the BM to resolve intra-GB transmission constraints. Further detail on the methodology and assumptions of our modelling of the BM can be found in Section 5D and Appendix 1.

Improved signals across all resource types

4.21. Third, our modelling has captured the effect of improved operational signals from wholesale prices across all resource types under the different market designs.

4.22. This is particularly relevant for both flexible consumer demand and two-way assets such as storage and interconnectors. Under the current national market design, two-way assets can often be exposed to wholesale price signals that may (from a system perspective) induce the assets to exacerbate, rather than alleviate, constraints in parts of the transmission network.

4.23. For example, under the current national market design, an interconnector in an export-constrained region of GB (i.e., where available low-cost generation exceeds local demand and export capacity), may receive a price signal in the wholesale market to import additional power to the region, exacerbating the existing local oversupply. This would, in turn, increase the required volume and associated cost of ESO interventions in the BM, with the ESO required to either direct the interconnector to reverse its flows or constrain off more domestic generation than would otherwise have been necessary.[122]

4.24. However, under a zonal or nodal market, more granular locational prices could provide price signals to the interconnector in the wholesale market to instead export power, providing additional export capacity for the export-constrained region at potentially lower cost.

4.25. Captured within our modelling is also, therefore, the impact of improved signalling on wholesale market dispatch. By virtue of this, the overall cost of serving electricity demand in GB is also potentially reduced. Revenues earned by interconnectors vary for each market design option, driven by changes in the GB wholesale market price at the landing site of each interconnector – which we calculate as part of our overall assessment.

[121] We note that under all market designs modelled, there may be instances where the SO is required to intervene to account for unexpected changes in supply and demand, as well as unexpected outages of the transmission lines, in real-time. This occurs under national, zonal and nodal pricing regimes, and we have not sought to model any impact on the costs that arise from such interventions.

[122] Historically, the ESO has tended to opt to constrain domestic generation on or off in the BM, rather than contract with interconnectors to reverse flow direction. Directing interconnectors to reverse flows post-gate closure requires a bilateral trade between the ESO and the relevant SO in the connected market, which, in response, will need to alter generation in its own market. While bilateral SO to SO trades have been employed very infrequently across 2022, these have typically attracted a much higher cost than the redispatch of domestic generation. Furthermore, we note that the outcome of current discussions among policymakers relating to the allowed ramping rate of interconnectors could further limit the ability of interconnectors to flexibly respond in the BM.

4.26. To isolate the specific contribution of improved dispatch efficiency to the benefits of more granular locational pricing, we have also conducted a "Dispatch-only" sensitivity. This is described further in Section 11A.

Surplus revenues from intra-GB transmission congestion rents

4.27. Fourth, as set out in Chapter 2, a more locationally granular wholesale market can generate **financial surpluses** linked to the price spread between two nodes in the settlement process. This surplus is driven by the difference between the price paid by consumers at an importing node, and the price received by the relevant generators at an exporting node. This surplus comprises two components – intra-GB congestion rent and a loss residual. The latter arises because the nodal price at the importing node includes a marginal loss factor element to account for the loss of power when transporting between the two nodes.

4.28. We describe the congestion rent that is earned as a result of the difference in locational wholesale prices between nodes earlier in Chapter 2 and calculate the potential value of the congestion rent earned under both the zonal market and nodal market design. In line with many markets globally, we assume for the purposes of the assessment that this surplus is returned to consumers. We note however that policymakers could in practice choose to redistribute some (or indeed all) of the surplus rents to other stakeholders should they so choose. We consider this issue further in our discussion of transitional measures in Chapter 9.

Efficiency gains from centralised scheduling

4.29. Fifth, as described in Chapter 2, a move to a centralised scheduling market design might deliver greater efficiency gains. This could be achieved in the following ways:

- First, balancing in real time (and commitments in the day-ahead market) is based on a security-constrained economic dispatch, unlike in a national or zonal market. Similarly, forward commitments in nodal markets are based on a combination of security-constrained economic dispatch in the day-ahead market and intra-day scheduling. This may lead to different dispatch outcomes than would otherwise occur in a self-scheduling market, all else equal.[123]
- Second, the SO, as the centralised operator, would receive a greater set of information at an earlier stage (typically day-ahead) which is likely to be more reliable (given the financial incentives of market participants to do so). This information could potentially be used to produce more efficient dispatch outcomes.
- Third, centralised scheduling might offer a lower barrier and more level-playing field for smaller assets and new entrants in wholesale markets. These participants could simply submit their offers into the market without the need for bilateral contracting.
- Fourth, centralised scheduling offers greater opportunities to co-optimise energy and reserves more efficiently.

123 This is because the security-constrained economic dispatch algorithm optimises dispatch outcomes across all nodes simultaneously with respect to transmission constraints, which may *mathematically* produce different outcomes versus the two stage self-scheduling approach where dispatch is determined on an unconstrained basis, followed by corrective balancing actions.

4.30. As we also noted in Chapter 2, arguments have previously been advanced in favour of greater efficiency in self-scheduling relative to central scheduling. These principally relate to the view that individual participants may have more reliable information about the way in which the assets they own can perform than can be conveyed to the SO in the format needed for the SO's optimisation. This in turn may allow more optimal use of the assets under self-scheduling relative to central scheduling.

4.31. Given these uncertainties and conflicting views, we have not sought to model these effects in deriving our overall assessment of the costs and benefits of greater locational pricing in the wholesale market.

Long-run impacts

4.32. An increase in the locational granularity of wholesale prices could also generate longer-term impacts as shown in Figure 4-4 below.

Figure 4-4: Long-run impacts

Type	Effect	Quantified
Long-run investment impacts	Greater price signals to incentivise **generation and storage to site** at more efficient locations	✓
	Stronger and more accurate price signals to incentivise **demand to site** at more efficient locations	
	Improved signals for **transmission development** (due to transparent wholesale prices between different nodes)	✓

Source: FTI analysis
Note: The orange tick represents additional analysis that is not included in our welfare quantification but is presented in Chapter 10.

Incentivising improved siting of generation and storage

4.33. As described in Chapter 2, under the current market design, all generators dispatched in a given hour receive a single national wholesale electricity price in each trading period, regardless of their location on the network. The single wholesale price provides a general approximation of the marginal cost of meeting national demand, but regularly fails to reflect the marginal cost of electricity at that particular location.

4.34. In this sense, under the current market design, generators do not receive a price signal from the wholesale market to site in areas that would most benefit the system, and siting decisions are largely taken on the basis of (i) private costs to the generator (including TNUoS); and (ii) forecast climate conditions in the area (in the case of renewable generators).[124] Importantly, in our modelling of the current market design, the capacity and location of all generators is fixed to that set out in the relevant FES 21 scenario, provided by the ESO for this assessment in a confidential dataset.

[124] As described in Chapter 2, under the current GB market design, locational TNUoS charges provide a level of locational investment signal. TNUoS assumptions are implicitly embedded in the locational siting of generation in the FES datasets confidentially provided to us by the ESO, which we have agreed, through the stakeholder engagement process, to rely on in our modelling of the current market design.

4.35. However, under a nodal market design (and to a lesser extent, under a zonal design), localised wholesale prices reveal the marginal cost of meeting demand at that location in each time period. In hours where there is a high volume of excess generation in an export-constrained region, the wholesale power price will fall. In areas that require additional generation in these hours, power prices will stay higher. The electricity price reflects the demand for, and value of, electricity in a given hour in each location.

4.36. Generators are incentivised to consider the benefits of siting either closer to demand sources, or in areas with spare transmission capacity. In this sense, locational price signals can help incentivise generation to site in more optimal locations from a system perspective, by “internalising” the cost of transmission constraints to some extent. This effect is compounded for storage assets, given their participation as both a buyer and a seller of power in different periods on the wholesale market.

4.37. As a result, in our modelling of the zonal and nodal markets, we allow a limited proportion of new-build generation assets (that are not currently in development), and all grid-connected storage assets, to site in different locations in response to wholesale price signals, relative to the location set out in FES. We recognise that broader “real world” limitations will inevitably apply to the siting decisions of generator and storage assets, in particular constraining the total amount of capacity that can be built in specific areas. Additionally, we assume that all projects in development do not site in different locations than as set out in FES 21. We therefore place a number of technology-specific constraints on asset re-siting decisions, as detailed further in Section 5D.

4.38. The effect of this re-siting is captured by a change in the wholesale and balancing costs of meeting demand in specific regions, as well as by the impact on curtailment of renewable generation, which is covered in Section 6D. We also perform a “Dispatch-only” modelling sensitivity in order to assess the benefits of nodal pricing without the re-siting of generation and storage assets, which is discussed further in Chapter 11.

Incentivising improved siting of demand

4.39. The incremental cost of accommodating new sources of large-scale electricity demand, such as electrolysers or data centres, varies greatly at different points on the network, depending on the availability of spare generation capacity and transmission capacity to meet additional demand. Under the current market design, these large consumers will face the same wholesale price at any location, despite the variation in the marginal cost of meeting demand at different points on the grid.

4.40. As mentioned in Chapter 2, a key hypothesised benefit of nodal market design is that locational pricing, by design, reveals in all time periods the marginal cost of meeting demand at that location. The nodal price accounts for the impact of the physical constraints of the transmission network in meeting demand at each point in time.

4.41. In effect, locational pricing can potentially provide improved economic signals to electricity consumers, by aligning the private and system costs of a new consumer siting at a particular point on the network. New consumers will be exposed to the additional marginal costs that their siting decision places on the local network at their connected node, resulting in two key effects.

- First, new consumers may be encouraged to site in export-constrained areas, where the marginal cost of serving additional demand is relatively low. In export-constrained areas, with regular periods where local generation exceeds available demand, low average wholesale prices would be attractive to new sources of demand, while additional demand in these areas could help to reduce curtailment of local generation.
- Second, new consumers that continue to site in import-constrained areas, where the cost of meeting current demand is already very high, will face a greater cost for doing so. By "internalising" a proportion of the marginal cost of meeting additional demand in a region, locational pricing can better allocate costs to those responsible for them.

4.42. We note that the converse is also true – higher prices in some parts of the network may encourage some consumers to exit from a given location, thereby reducing demand in that part of the network.

4.43. After discussions with stakeholders and in agreement with Ofgem, in our modelling, we have not sought to capture this hypothesised benefit of locational pricing. The reason for this is that it is more difficult for us to make informed assumptions on the price sensitivity of demand, relative to that of generation and storage in which we have detailed cost assumptions that have been verified by the ESO and other third parties. We therefore fix the size and location of all demand sources across the three modelled market arrangements to that forecast by the ESO in the relevant FES scenario. By maintaining this consistency across the market arrangements, we are able to better capture the impacts of locational pricing on the efficiency of both short-term dispatch and long-term generator siting. However, we would expect some further benefits from demand re-siting under locational pricing, beyond those captured in our core CBA results.

Incentivising more efficient transmission investment

4.44. As raised in Chapter 2, a further hypothesised impact of locational wholesale pricing is that it can improve the efficiency of future transmission investment, affecting the optimal size and shape of the transmission network. It can do so in two key ways:

- First, by encouraging new generation capacity, storage and large consumers to site in a way that takes into account persistent bottlenecks on the transmission network, locational pricing can encourage a more efficient use of the existing transmission network, thereby reducing the need for incremental transmission investments.
- Second, the financial surpluses earned via intra-GB congestion rents may potentially serve to highlight specific transmission boundaries where there is a large discrepancy between the demand for and availability of transmission capacity. As a result, locational pricing may potentially provide improved signals to support more efficient transmission network planning.

4.45. However, we have not sought to explicitly capture the impact of locational pricing on the development of the transmission network as part of our core assessment. Instead, we have relied on external data sources, thereby assuming the same transmission build-out profiles over the period 2025 to 2040 across each locational market model, to provide a better comparison of the locational effects of different market designs on dispatch and generator siting. This approach is aligned with feedback from several stakeholders. As such, in our modelling, all transmission capacities, including expected commissioning and upgrade dates, are derived from and aligned to ESO forecasts. The forecast topology of the network varies between the three modelled scenarios, but, within each modelled scenario, the network topology is consistent for each of the modelled market designs.

4.46. We also noted in Chapter 2 that the introduction of locational pricing could potentially change the way in which the merits of transmission enhancements are assessed. Under a national market, the business case for a transmission investment is likely to involve an assessment of the costs of the project relative to the benefit of reduced constraint management costs. By contrast, under a nodal pricing market the business case for a transmission enhancement will, most likely, assess the costs of the asset relative to the changes in wholesale prices on the system and the change in congestion rent.[125]

4.47. We set out, in Chapter 10, our assessment of the impact on the need for transmission investment.

Key policy interactions

4.48. Government has previously sought to limit the exposure of certain assets to fluctuations in wholesale prices. The aim of these policies is to reduce the cost of financing new assets by de-risking their revenue streams (which are particularly dependent on prevailing wholesale prices) in order to encourage their development. The cost of these schemes is ultimately borne by consumers.

4.49. In particular, two such policies as shown in Figure 4-5 are:[126]

- CfDs, which provide a degree of price stability to low-carbon generators; and
- the Cap and Floor regime, which supports the construction of interconnectors between GB and other electricity markets.

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125 Two of our modelled scenarios differ predominantly in their assumptions on the volume of transmission capacity. This therefore affords us the opportunity to compare how the business cases for the same set of transmission assets would be evaluated under both a national market design and a more locational market design. This is discussed further in Section 5D.

126 Other policies that might have an interaction with the wholesale market includes the Capacity Market, RAB funding models, Dispatchable Power Agreement, Renewables Obligation (as it tapers off) among others. We have only quantified the impact of locational wholesale electricity pricing on the CfD regime due to the potential sizable impact on consumers relative to other policy mechanisms.

Figure 4-5: Key policy interactions

Type	Effect	Quantified
Policy interactions	Changes to **CFD payments**	✓
	Impact on **Cap and Floor agreements**	

Source: FTI analysis

4.50. As the support provided by these policy mechanisms is linked to wholesale electricity prices, more granular locational prices could impact the future cost of the policies. We set out our approach to assessing these impacts below.

Contracts for Differences

4.51. CfDs were introduced to accelerate the development of new low-carbon generation capacity, aiming to ensure that developers could be confident they would receive the revenue needed to cover their investment costs. CfDs provide developers with a fixed price per unit of output, known as a strike price, and have predominantly been determined via a competitive auction ahead of construction. Their design means they protect developers from the volatility and level of wholesale prices.

4.52. When the prevailing wholesale price is lower than the agreed strike price, CfD generators are compensated for the shortfall by support payments from consumers. When the wholesale price exceeds the strike price, CfD generators redistribute excess revenues earned on the wholesale market back to consumers.

4.53. As a result, a change in market design could impact the support costs borne by consumers for both existing and future CfD generators, by impacting hourly wholesale prices.

4.54. The size of the impact on support costs depends on the following assumptions, which may be different for existing and new CfD contracts based on the:

- approach to CfD generators in the wholesale electricity market;
- duration of CfD contracts;
- definition of the strike price;
- definition of the reference price (i.e., how it relates to the locational wholesale price); and
- forecast generation volume.

4.55. In our analysis, we assume that CfD generators participate in the wholesale electricity market by bidding at a price of zero in all hours and are prioritised in dispatch ahead of merchant renewables. This separates the analysis into two parts – the modelled generation outcomes of CfD generators and the calculation of CfD support payments under the assumed terms of the contracts. We explain the rationale behind our bidding approach and assumptions in Chapter 5.

4.56. To calculate CfD support payments, we assume that all existing CfD contracts continue to expiry, such that relevant generators continue to receive their agreed CfD support for the remainder of the contract period for their actual output. Under more granular locational market designs, we assume that these CfD generators would maintain their strike price, and the reference price would be based on the relevant zonal or nodal price where they are located. However, CfD generators would now receive lower constrained-off payments in the BM (or none, in the case of a nodal market design).[127]

4.57. Similarly, new CfD generators built across our modelling period receive an assumed strike price for all non-curtailed generation across a 16-year period. As above, CfD support payments are calculated relative to the hourly wholesale price at the connected node. Further detail on our CfD-related assumptions can be found in Section 5D.

4.58. In our CBA results, CfD support payments are considered a direct transfer between consumers and producers. As a result, we present the impact of CfD payments in both the consumer and producer sections of our net results. We continue the assumption that the cost of CfD support payments is spread across all GB consumers, rather than targeted to specific consumer cohorts.

Cap and Floor agreements for interconnectors

4.59. Ofgem's C&F regime provides interconnectors with a similar, albeit looser, protection from wholesale price variability. With revenues primarily earned from the differences in hourly wholesale prices between two connected countries, interconnector earnings can substantially vary from one year to the next dependent on broader power market dynamics, increasing the risk taken on by investors.

4.60. Under the C&F, each interconnector is set a maximum and minimum allowed set of revenues to be earned across a given period – the "cap" and "floor" respectively.[128] Annual revenues earned by the interconnector are periodically compared to the cap and floor levels and, similar to CfDs, support payments are made from consumers to the asset owner in the event of a shortfall. Where annual revenues exceed the cap, the asset owner redistributes the surplus back to consumers.

4.61. With annual revenues closely linked to the GB wholesale price, a change in wholesale market design can potentially impact both the annual revenues accruing to the asset owner and, in turn, the net support costs transferred between producers and consumers.

4.62. We have not sought to augment our analysis with an assessment of the impact of locational pricing on the expected C&F support payments of each interconnector. The details of existing arrangements are commercially sensitive, and cap and floor levels are yet to be agreed for many of the interconnectors that are captured in our modelling but are currently under development. Additionally, there is considerable uncertainty around the regime design for future multi-purpose interconnectors.

[127] If policymakers decide to compensate existing generators for the loss in constrained-off payments, this will be represented by a one-to-one transfer from consumer benefits to producer benefits. The socioeconomic benefit will remain the same. We discuss this further in Chapter 9D.

[128] C&F arrangements vary by interconnector, with some assets set a maximum and minimum annual revenue, and some assets seeing revenues bound across a 5-year period.

4.63. In our results, the impact of a move to locational wholesale pricing varies across interconnector assets, as detailed further in Section 6F. In our assessment of producer surplus, we include the net impact of each market design on the overall revenues of interconnector asset owners.

Wider system impacts

4.64. An extensive change in market design may affect certain areas of the wider GB energy system. In the following sub-sections, we discuss the elements shown in Figure 4-6 below.

Figure 4-6: Wider system impacts

Type	Effect	Quantified
Wider system impacts	**ESO system implementation costs**	✓
	Market participant implementation costs	✓
	Changing **risk profiles** of market participants including **financing cost**	

Source: FTI analysis

ESO and market participant implementation costs

4.65. Transitioning to a zonal or nodal market would inevitably mean that **implementation costs** would need to be incurred by market participants and the ESO, both in terms of IT systems and software investments that parties would need to make, as well as the effort spent on training staff and developing new processes.

4.66. In particular, some stakeholders have argued that the costs from introducing more granular locational pricing could include:

- the complexity of transitioning legacy contracts to the new arrangements;
- costs incurred by parties in forecasting more volatile prices (both for energy and for transmission capacity); and/or
- updating the arrangements for other market design elements (such as CfDs).

4.67. We have estimated implementation costs based on both a review of experiences in other jurisdictions and discussions with stakeholders. Although the costs will initially be borne by the ESO or market participants, we expect they will ultimately be recovered from consumers, and as a result we include this estimate of implementation costs in the consumer impact section of our CBA.

4.68. Further detail on our assessment of implementation costs can be found in Section 8A.

Cost of capital

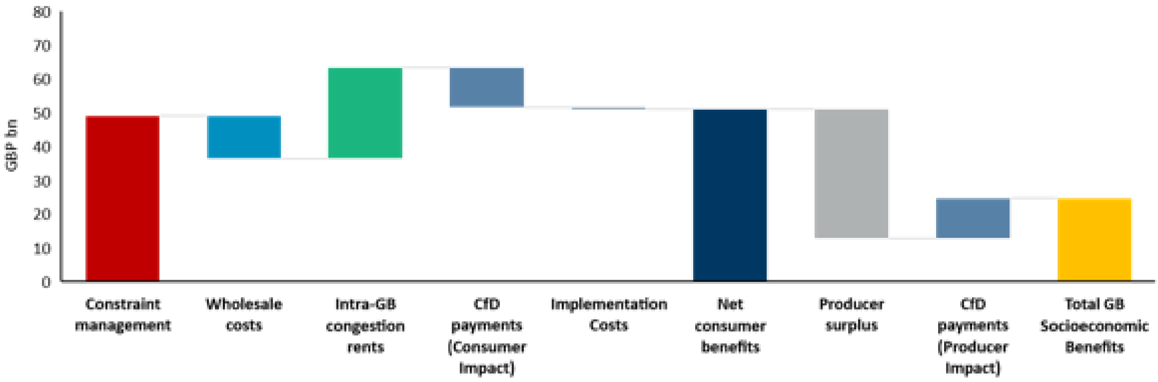
4.69. As highlighted in Chapter 2, some stakeholders have raised the issue that a move to zonal or nodal pricing would increase the risk and uncertainty faced by investors, particularly those in generation assets. It is suggested that this may arise due to, for example, greater volatility of wholesale prices under a nodal design, driving greater forecasting complexity of wholesale prices and volumes at different locations. The argument follows that this could lead to investors demanding a higher return on investments due to the greater uncertainty associated with the revenues generated by their asset, increasing the cost of financing new assets.

4.70. In Section 8B of this report, we consider in detail the available evidence on the impact of locational pricing on the cost of capital.

C. Overall consumer and socioeconomic impact

4.71. As described in the previous sub-sections, we have sought to quantify a broad range of impacts of a change in wholesale market design as part of our core CBA assessment. As set out in Figure 4-7 below, these have been grouped into consumer impacts and producer impacts, with the net total providing total GB socioeconomic benefits.

Figure 4-7: Illustrative consumer and socioeconomic impact, NPV of benefits between 2025-2040



Source: Illustrative example, FTI analysis

4.72. The overall impact on consumers from more granular locational pricing is composed of the following effects:

- A reduction in the **costs of resolving transmission network constraints**, by reducing the volume and associated cost of required interventions by the ESO in the BM.
- Changes in **wholesale prices**, resulting from the increased incorporation of the physical constraints of the transmission network in the wholesale price settlement.
- The creation of **intra-GB transmission congestion rents**, arising from price differentials between two locations on the GB network. In our core assessment, these are assumed to be entirely redistributed back to consumers.
- Changes to the cost of **CfD payments** borne by consumers, due to changes in the wholesale electricity price received by CfD generators.
- The **implementation costs** of transitioning to a new locational market design. This includes both the costs incurred by the ESO as well as market participants (both of which are assumed to then be recovered from consumers at the start of the modelling period).

4.73. The sum of the five impacts above provides an estimate of the net consumer benefits of locational pricing. To arrive at the net impact for GB, these must be adjusted to account for additional impacts on producers. In our assessment, we quantify:

- The change in **producer surplus**, that is the **change in revenues minus the change in associated costs of generation**. Our assessment of producer surplus captures the change in producer surplus on both the wholesale market and BM, as well as 50% of the change in congestion rents earned by GB interconnector owners.

- Changes to the **CfD payments** received by generators due to changes in wholesale prices at connected nodes.

4.74. As noted, we do not include in our assessment any potential changes in the need for transmission capacity that might arise as a result of a transition to a more granular locational wholesale market. However, we do provide an assessment of the differences in the benefits case for a given set of transmission enhancements when assessed under a national and nodal market design as an indicator of the likely difference in need for transmission.

4.75. As the quantitative assessment above reflects the aggregate impact, we have also conducted analysis that assesses the **distributional impact** on consumers located around GB. This is set out in Section 9B.

4.76. We have assumed that the transition from a national market design to a nodal or zonal market design occurs instantly from the start of the modelling period. Therefore, we have not quantified any transitional or mitigation measures beyond the baseline approach discussed above. This implies the following assumptions:

- As described above, generators with existing CfD contracts are shielded from the effects of locational prices – we assume that support payments would continue over the 15-year term according to the awarded strike price and modelled reference price. However, CfD generators will now be exposed to constraint risk, in that they will no longer receive constrained-off payments in the BM. Beyond the term of the CfD contract, generators will then be exposed to full merchant risk.
- No other cohorts of market participants or consumers will be shielded from the impacts of more granular locational prices. Hence, all non-CfD generators would now be exposed to constraint risk.[129]
- We do not consider the impact of other generation contracts such as ancillary service contracts or Capacity Market contracts.

4.77. We discuss in Section 9D a range of policy options for transitional and mitigation measures that could be introduced when implementing locational pricing, including their potential impact, which can be assessed on top of the baseline results. Quantified impacts have been summed across the modelling period and discounted to a present value, as set out further in Section 9A.

[129] We discuss our treatment of future CfD contracts in Appendix 1.

5. Power market model and assumptions

5.1. As discussed in Chapter 4, a key part of our assessment approach and methodology was to develop the main input assumptions for our modelling and analysis. In doing so, we have relied on well-established and credible third-party sources where possible, in consultation with stakeholders and in agreement with Ofgem.[130] The input assumptions feed into our power market modelling and multiple strands of quantitative and qualitative analysis covering the broad impact of more granular locational pricing.

5.2. The development of the inputs is therefore based on credible third-party sources where reasonably possible. In particular, we have relied on:

- ESO datasets on transmission and generation assets;
- publicly available information (notably FES 2021 and the Ten-Year Network Development Plan ("TYNDP") 2022);[131] and
- bilateral engagements with ESO (ETYS, NOA, FES teams) and DESNZ.

5.3. This chapter sets out the setup of our power market model and the assumptions used to guide the quantitative analysis of the impacts discussed in Chapter 4. The following sections provide further detail on:

- our overarching power market modelling tool (**Section A**);
- the geographical set-up of our power market model and its configuration for each market design (**Section B**);
- an overview of the scenarios and sensitivities assessed (**Section C**);
- our key inputs and modelling assumptions (**Section D**); and
- the modelling runs undertaken, and the key outputs produced (**Section E**).

5.4. A more detailed description of our input assumptions can be found in Appendix 1.

A. Power market modelling tool

5.5. To perform our cost-benefit analysis on the impact of implementing locational pricing in GB, we have used an in-house power market model, developed using the Plexos software platform.[132] This platform is a dispatch optimisation software on which we have built a detailed representation of the wholesale market supply and demand fundamentals of the European electricity market, including GB. The Plexos platform is widely recognised and utilised by European regulators, Transmission System Operators ("TSOs") and their advisors. It is also widely used internationally, including in Australia and the US. We have previously deployed the Plexos software on national, zonal and nodal locational pricing engagements in GB, Europe, Australia, Asia and parts of the US.

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130 This includes three stakeholder workshops (link) and Ofgem's Call for Input request (link).
131 For more information on the TYNDP, see the ENTSO-G website (link).
132 This software was developed and licensed by Energy Exemplar (link).

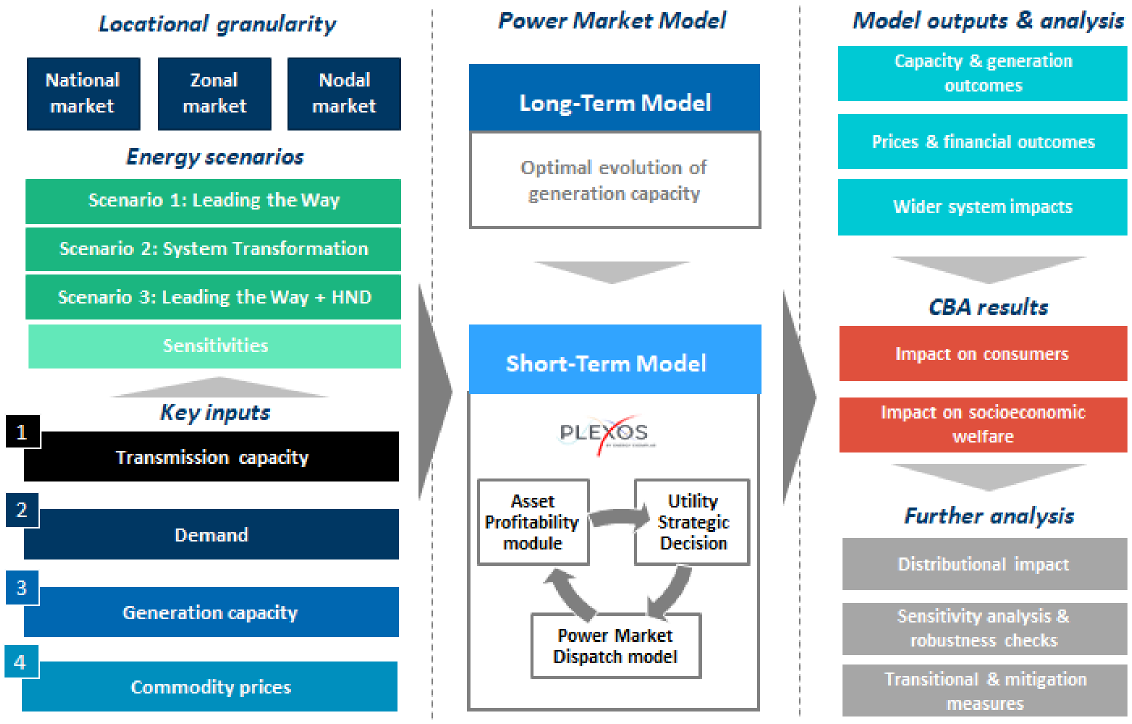
5.6. The overall objective of a power market modelling tool is to determine the least-cost development and dispatch of generation and demand-side resources to meet demand at all times and locations. Plexos considers, among other factors, the technical characteristics and limitations of both the network and of each generating unit across all locations modelled, in order to forecast the least-cost generation profile and associated clearing price in each hour at each location on the system.

5.7. To determine the least-cost dispatch, the Plexos model optimises across two modelling phases. These are:

- First, we run a long-term expansion model (the "long-term model") which determines the optimal evolution of generation capacity to meet demand at least-cost. This optimises the investment decisions of new generation and storage assets and key input assumptions such as local climate profiles and transmission build.
- Second, we run a short-term dispatch model (the "short-term model") which takes the capacities from the long-term model as an input and determines the least-cost generation dispatch on an hourly basis, based on a defined set of network and generation constraints. The short-term model also estimates transmission flows (including across interconnectors), generation costs, wholesale prices and flexible demand profiles, among other factors.

5.8. A simplified overview of the how our power market modelling fits into the overall assessment is summarised in Figure 5-1 below.

Figure 5-1: Overview of our power market modelling approach



Source: FTI analysis

5.9. As shown in Figure 5-1 above, our power market modelling approach covers three key steps. These are:

- setting up the market model designs, which requires defining the:
  - locational granularity that we model;
  - modelling scenarios and sensitivities; and
  - key input and modelling assumptions.
- running the Plexos software platform for the modelling runs required; and
- generating the modelled outputs, before analysing the impact of locational prices on consumer and socioeconomic welfare.

5.10. The use of any power market modelling tool necessarily has to take account of trade-offs – particularly between modelling detail and practicality (in terms of data need and computational requirements). In particular, we note that:

- The long-term model is a cost-based model and does not implicitly consider the financial viability of generating units, rather it focuses on meeting demand at least-cost to the system.
- The use of Plexos to optimise the build-out and dispatch of generation capacity implicitly assumes a degree of "perfect foresight",[133] that is the model has a complete view of some inputs, for example climate profiles at different locations.
- The computational requirements of modelling the complexities of the GB and European network have been intensive. As such, the long-term capacity expansion model necessitates a trade-off between the number of years that capacity siting is optimised across, and the granularity of load profiles used within each year. Based on this trade-off and discussions with stakeholders, we model a full set of outcomes for an entire year, every five years, between 2025 and 2040 (i.e., 2025, 2030, 2035, and 2040).
- We have assumed that generators prioritise longer-term price signals to inform re-siting decisions, with reduced visibility of intra-day market dynamics. Following stakeholder feedback, one exception is for batteries where we have assumed that they prioritise the granularity of load profiles as they typically have much shorter asset lives and place greater value on intra-day price volatility. Further detail on our capacity expansion modelling can be found in Section 5D and Appendix 1.
- The short-term model dispatches generators using a short-run marginal cost ("SRMC") pricing algorithm. Under this methodology, generators bid at a function of their SRMC and start-up costs and will be dispatched if the wholesale price is greater or equal to their bid. SRMC pricing assumes perfect competition between generators, and therefore does not account for bidding strategies that generators may employ to exploit market power in specific hours.

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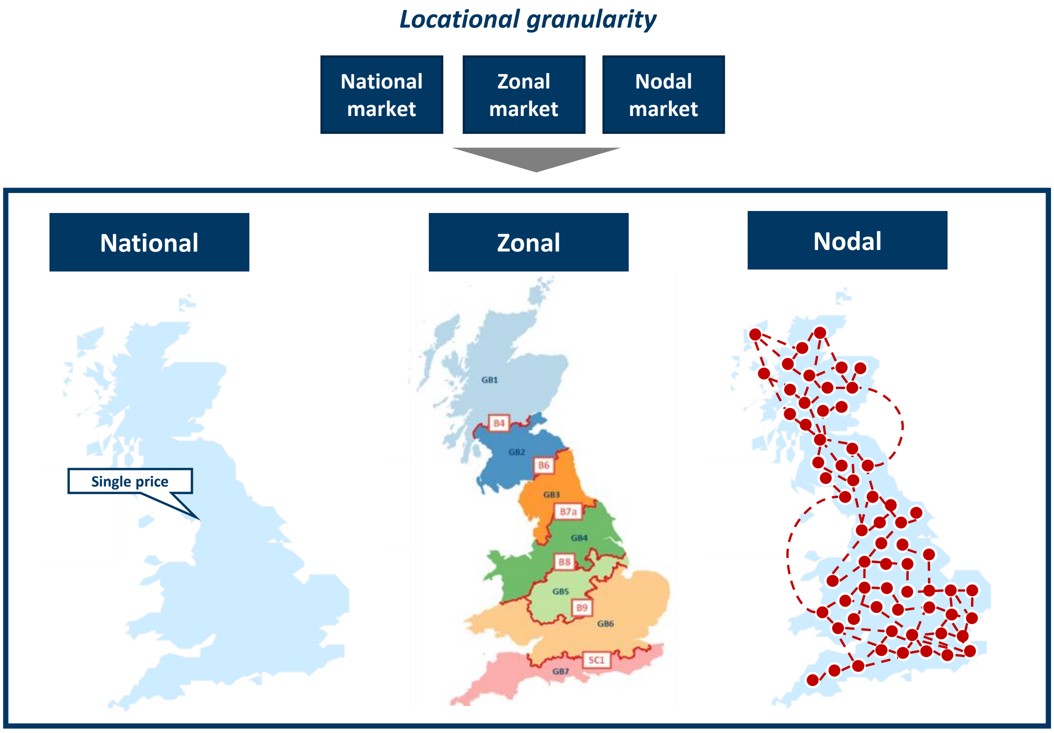
[133] Our assumption of perfect foresight is limited in our model. The modelling tool aggregates hours into "blocks" which are then optimised in steps. This means that the optimisation of the capacity of scarce resources, e.g., hydro, biomass or hydrogen, would be aggregated into weeks or months, which means that the modelling tool would only have a perfect foresight of this aggregated data.

5.11. Nevertheless, we do not consider these limitations to be material on our assessment as they have been well established in other assessments – particularly over long timescales. Additionally, our design of the geographical set-up of the model, as well as the set of scenarios used, provide a meaningful representation of the future GB energy market. We discuss this below.

B. Geographical set-up of our power market model

5.12. As indicated earlier, we have developed a power market model that provides a detailed representation of the GB wholesale electricity market and balancing mechanism, for each of the three locational market designs we have assessed. Figure 5-2 below provides an illustration of the modelled market arrangements.

Figure 5-2: Geographical set-up of our three locational market models



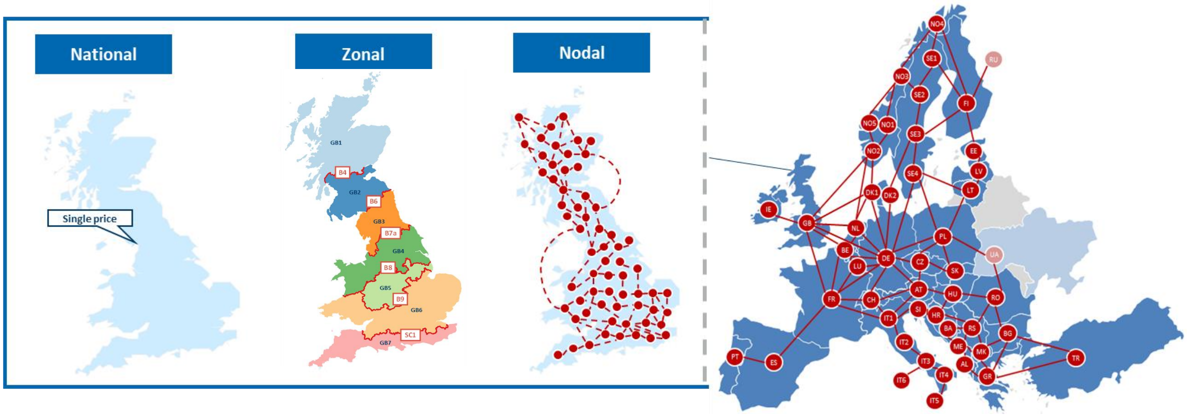
Source: FTI analysis

5.13. As shown in Figure 5-2, we have constructed three separate locational wholesale model designs with increasing levels of granularity. These are:

- a **national market model design** with a single national wholesale price;
- a **zonal market model design** with the GB electricity system divided into seven zones with individual zonal wholesale prices and outcomes; and
- a **nodal market model design** with a GB electricity system divided into c.850 nodes with individual nodal wholesale prices and outcomes.

5.14. These locational model designs have been integrated with our pan-European market model to ensure that modelling outcomes capture the dynamic impact of interconnector flows between GB and Europe under each market design. A high-level schematic is set out below in Figure 5-3.

Figure 5-3: High-level schematics of our overall geographical model set-up



Source: FTI analysis

5.15. As Figure 5-3 indicates, our GB power market models are integrated into our pan-European model, which is a detailed representation of the power markets in 49 countries.

5.16. On the development of the three locational market model designs, two key questions had to be considered. These were:

- what constitutes the **status quo** under the national market model design to form the baseline counterfactual of the assessment; and
- the **level of granularity** for the zonal and nodal market model designs (i.e., the number of zones or nodes).

Baseline counterfactual

5.17. To undertake an assessment of the costs and benefits of changing the market design in GB, we needed to design a counterfactual against which market design changes would be assessed. This involved decisions on whether to include further policy reforms to the current GB market design as the counterfactual. If further policy reforms were included in the counterfactual, then we would have had to make further assumptions on which policy reforms to include, as well as the detailed design of them.

5.18. In consultation with stakeholders and in agreement with Ofgem, we have used the **current status quo GB market design without further assumed policy reforms** (i.e., the "national" model) as the counterfactual. Our analysis of the two more granular locational wholesale electricity market design options: "zonal" and "nodal" is compared against this baseline counterfactual.

5.19. Therefore, we have assumed that under the status quo, the national market model design as it currently stands would continue across the modelling period. This means that outcomes of the zonal and nodal markets are assessed relative to the outcomes in the national market, assuming no further augmentation of the existing market design with additional policies.

5.20. We have also assumed that all existing policy mechanisms and regulatory arrangements under the current market design continue across the modelling period. This includes the current designs of the CfD regime, Capacity Market and BM. Furthermore, while we are aware of potential reforms to the TNUoS regime, we have assumed that the current regime continues.

5.21. This reliance on the status quo market design as the baseline counterfactual represents standard practice in CBAs of this type and enables a clean comparison between the different options. Recognising the broad range of potential future pathways for the GB power system, even under the existing market design, we have sought to assess the impact of locational pricing across a range of scenarios and sensitivity cases. We consider all three scenarios modelled (LtW (NOA7), LtW (HND) and SysTr (NOA7) as baseline counterfactuals, and therefore treat the cost and benefit assessments from the three scenarios equally.

Level of granularity for the locational market model designs

5.22. There was a range in the degree of locational granularity that we could model. Table 5-1 below sets out the range that we considered for the nodal market design.

Table 5-1: Nodal market model design options

Nodal options	Number of nodes	Advantages	Disadvantages
1. Grid Supply Points (“GSPs”) only *(i.e., only interface points between the transmission and distribution networks)*	350+	▪ Based on the number of GSPs which are well defined and well understood within the industry ▪ Likely to be sufficient to capture majority of the transmission constraints	▪ Does not fully align with transmission network topology ▪ Calculation of the losses will deviate from actual observed values
2. Transmission substations	c.850	▪ Better reflects generation location (e.g., includes generation-only nodes) ▪ More accurate representation/calculation of the overall network losses	▪ More computationally challenging than option above
3. All nodes identified in **ESO’s PowerFactory model**	1,800+	▪ Representation of the ESO network model as used for system planning (and not necessarily for market modelling)	▪ A large number of nodes are defined historically and may not be relevant as it does not represent the actual system configuration
Include all the **distribution-level nodes**	10,000+	▪ More accurate representation of the combined transmission and distribution network	▪ ESO has no visibility over distribution level nodes ▪ No evidence of a “needs case” to introduce dynamic locational price signals at the distribution level ▪ No international precedent for distribution nodal pricing

Source: FTI assessment based on discussions with stakeholders and agreement with Ofgem.
Note: Transmission substations include any point on the transmission network where two or more circuits connect (e.g., transmission-distribution, transmission-generator and transmission-transmission interfaces) and are at or above 275kV in England and Wales or at or above 132kV in Scotland.

5.23. The options shown in the table above were presented and discussed with industry stakeholders,[134] and building from the feedback provided, we define the nodes based on transmission substations (i.e., Option 2). Relative to using only GSP points, this increases the complexity and associated computational challenges of our model but does allow us to better reflect the network topology while capturing transmission constraints.

5.24. Similarly, the locational granularity of a zonal market model design also needed to be determined. In this regard we considered, first, the number of zones that should be defined and second whether the zones should be redefined over the modelling period. We set out the advantages and disadvantages on the first issue in Table 5-2 below.

Table 5-2: Zonal market model design options

Zonal options	Number of zones	Advantages	Disadvantages
1. Pre-BETTA split	2	▪ Splits along a boundary with the most significant constraint management costs ▪ Might address stakeholder concerns regarding liquidity	▪ It would ignore many of the key transmission boundaries, especially in later years, when this boundary is reinforced by many projects
2. Main constraint zones *(as forecast by ESO)*	7	▪ Based on the set of most significant constraint boundaries ▪ Defined by the ESO providing objectivity	▪ The forecast only runs up to 2031 and hence might not be reflective of boundaries in the mid to late 2030s
3. Network Options Assessment (“NOA”) & Electricity Ten Year Statement (“ETYS”) zones *(as currently identified)*	20	▪ Boundaries developed based on Security and Quality of Supply Standard (“SQSS”) requirements ▪ Identifies additional, less critical, network bottlenecks	▪ Some boundary zones overlap or represent the subset of larger constraint boundary ▪ Highly fragmented
4. AFRY’s BID3 model zones	40+	▪ Consistent with the approach used in FES market modelling (may vary over time depending on generation fleet)	▪ Zones are not fixed and vary for different technologies ▪ Zones do not reflect constraint boundaries

Source: FTI assessment based on discussions with stakeholders and agreement with Ofgem.
Note: For NOA & ETYS zones, NOA defines 18 active constraint zones in the latest NOA7 assessment while the ETYS defines 23 zones. AFRY’s BID3’s model zones are based on the ESO’s long-term market and network constraint modelling.

5.25. Given the advantages and disadvantages for each zonal market model design option highlighted above, we agreed with Ofgem (following consultation with stakeholders) that the seven-zone option was an appropriate configuration, as it sufficiently covers the most constrained boundaries and reflects a more realistic zonal market compared with other jurisdictions.[134]

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[134] Options for locational granularity of zonal market design were discussed with industry and stakeholder feedback following the first workshop organised by Ofgem (link).

5.26. We have not sought to redefine the zones across our modelling period. It is possible to identify the optimal zones in each year modelled, to reflect the changes to the boundary constraints over time. However, we were advised by Ofgem that it may be prudent to keep zonal boundaries fixed over time. We recognise that this may also not be reflective of realistic policy choices should a zonal market be implemented.

C. Scenarios and sensitivities

5.27. With the level of locational granularity determined for each modelled market design, the second step to our power market modelling approach required selecting and defining a set of scenarios and sensitivities to account for future uncertainties. For this modelling assessment, we have defined scenarios and sensitivities in the following way:

- Energy scenarios refer to the **set of supply, demand and transmission input assumptions** that reflect different views on the future evolution of the GB energy market.
- Sensitivities refer to **amendments to specific assumptions** within a scenario to test a hypothesis, for example, to account for a policy design choice, or to isolate a specific impact of locational pricing.

5.28. In agreement with Ofgem and in consultation with stakeholders, we model several scenarios and sensitivities, which we discuss in turn in the following sub-sections.

Scenarios

5.29. For the scenarios that we adopt in our modelling, we considered a number of approaches with Ofgem and industry stakeholders. Options included whether to adopt the ESO's FES forecasts, create our own scenario (in consultation with stakeholders), use another third party's forecast, or a combination of these approaches.

5.30. Rather than adopt scenarios that could potentially be considered to favour one view over others, we concluded with Ofgem and in consultation with stakeholders that it would be most appropriate to incorporate the FES scenarios. Using the ESO's FES scenarios was generally agreed to provide a number of advantages: the pre-defined scenarios are well-understood by industry, cover a wide range of potentially evolutions of the GB energy system, and have themselves been subject to extensive stakeholder engagement during their development.

5.31. Furthermore, the FES datasets (provided by the ESO for this assessment) include the ESO's view of the size and location of every generator location specified at the locational granularity of the transmission substation out to 2050. This is therefore in line with our agreed approach to model nodal market to a locational granularity of c.850 nodes. The assumptions are developed in line with the ESO's view of future transmission requirements and the capability of GB's transmission network that underpin our modelled network topology. As a result, the FES scenarios provide internally consistent assumptions across generator locations and transmission capacities that remove the need to diverge from the ESO's transmission network forecasts for our modelling.[135]

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[135] As described in Chapter 2, under the current GB market design, locational TNUoS charges provide a level of locational investment signal. TNUoS assumptions are implicitly embedded in the locational siting of generation in the FES datasets confidentially provided to us by the ESO, which we have agreed, through the stakeholder engagement process, to rely on in our modelling of the current market design.

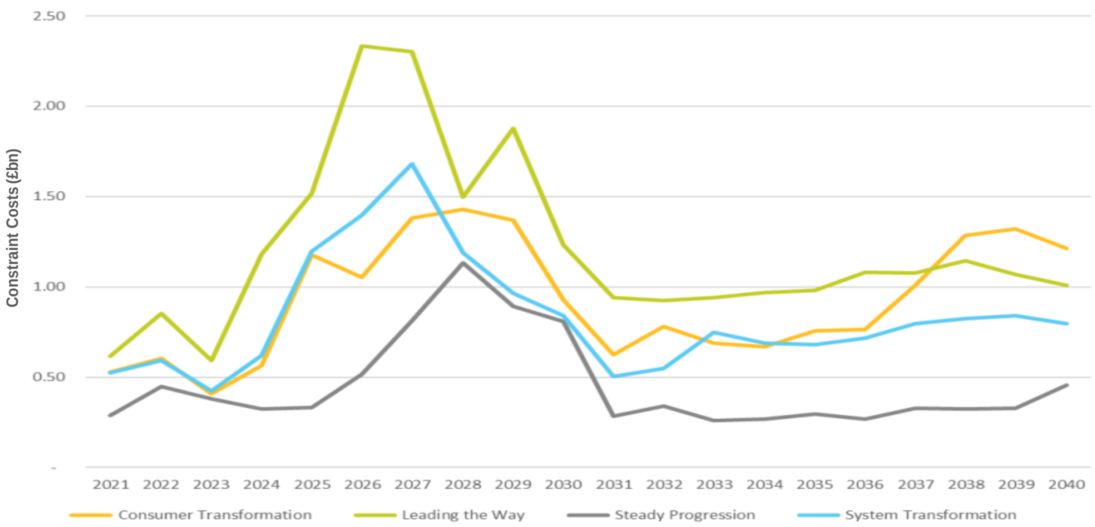
5.32. We understand that the forecast location of individual generators on the network is subject to significant future uncertainty, and concur with stakeholders that the change in location of generators impacts the estimated benefits of locational pricing.

5.33. As such, all three scenarios have been constructed on the basis of external publicly available information, in combination with confidential information on the network topology received from the ESO. Each of these scenarios reflects a combination of assumptions on total electricity demand, the generation mix and volume to meet that demand, GB and EU cross-border transmission capacity, and internal GB transmission network capacity.

5.34. Our scenarios are based on FES 21, as this was the latest published version of FES at the outset of this project. While FES 22 was available from July 2022, we would not have been able to use those scenarios as the detailed underlying network datasets required for the nodal modelling (e.g., ETYS and NOA7) were only available for FES 21 at the time of undertaking the work.

5.35. To select the appropriate FES 21 scenarios to model, we chose two scenarios that covered a reasonably wide range of the evolution of potential outcomes in the GB energy system. The ESO's forecast constraint management costs in FES 21 as shown in Figure 5-4 below:

Figure 5-4: ESO forecast constraint management costs in FES 21



Source: FES 21

5.36. As shown in the Figure 5-4 above, FES 21 is made up of four key scenarios – Leading the Way ("LtW"), Consumer Transformation ("CT"), System Transformation ("SysTr"), and Steady Progression ("SP"). We note that unlike the other three scenarios, the SP scenario is not compliant with Net Zero, and hence we have excluded this from our assessment.

5.37. Among the other three scenarios, the LtW scenario corresponds to the most constrained GB energy system while the SysTr scenario corresponds to the least constrained GB energy system. As such, following consultation with stakeholders, we have used the LtW scenario as the "upper bound" scenario in terms of the likely extent of system constraints and the SysTr scenario as the "lower bound" for our assessment.

5.38. After the selection of the two scenarios with Ofgem and stakeholders early on in our assessment, the ESO subsequently published a new HND Pathway and NOA refresh in July 2022 which represents that ESO's view of the extensive additional transmission investment required to help deliver the Government's ambition for 50GW of connected offshore wind capacity by 2030. Following discussions with Ofgem and stakeholders, we then combined the portfolio of additional transmission projects identified in the HND programme and NOA7 refresh with the network and generation assumptions in the LtW scenario, forming a new "LtW (HND)" scenario, representing a future where an ambitious level of transmission build is successfully delivered with no delays.

5.39. This scenario aims to assess how the cost and benefits of locational pricing change in a world where the extensive portfolio of HND transmission projects is delivered by 2030. We provide further detail on the transmission network topology that underpins each of our scenarios in Section 5D.

5.40. Therefore, in our assessment, we have a total of three scenarios:

- The Leading the Way scenario based on NOA7 transmission build assumptions (which we refer to in the remainder of the report as "**LtW (NOA7)**").
- The System Transformation scenario based on NOA7 transmission build assumptions (**"SysTr (NOA7)"**).
- The Leading the Way scenario based on NOA7 Refresh transmission build assumptions, incorporating the HND programme ("**LtW (HND)"**)

Sensitivities

5.41. In addition to the three energy scenarios outlined above, we conduct two sensitivity analyses to test the impact of specific hypotheses or policy options raised by Ofgem and stakeholders.[136] These sensitivities are:

- a **dispatch-only sensitivity** to test the benefits of more granular locational pricing while controlling for the benefits of re-siting generation;[137] and
- a **load shielding sensitivity** to test the benefits of more granular locational pricing while shielding consumers from these locational prices.

[136] We initially considered a long list of potential sensitivities but have prioritised these two sensitivities given the importance to stakeholders and policymakers. Other potential sensitivities include demand portability, allowing total capacity to flex by locational market designs, generation sensitivities (amending nuclear or interconnector capacity build profiles), transmission sensitivities (optimising the level of incremental transmission build), and alternative scenarios (e.g., using DESNZ assumptions).

[137] This sensitivity assumes that locational signals are delivered perfectly through other mechanism such as central planning under the national pricing model, and therefore generators are sited identically under both the national and nodal market designs. This allows us to assess the benefits of price variation across GB, while removing the benefits caused specifically by the more efficient siting of generators.

5.42. The **dispatch-only sensitivity** isolates the impact of more granular locational pricing on the efficiency of dispatch, by excluding the potential benefits of generator and storage re-siting decisions. The purpose of this sensitivity is to test whether locational pricing would lead to more efficient dispatch outcomes. This was conducted on the basis that several stakeholders believed that the efficient re-siting of generators and storage could be centrally planned perfectly and/or delivered via other policies or mechanisms such as through TNUoS reforms – therefore negating the need for (and potentially benefit of) locational signals in the wholesale market that influence siting decisions.

5.43. We test this sensitivity by modelling outcomes under each market design using an identical capacity profile, using the capacity siting decisions as specified in the nodal long-term model. This sensitivity assumes that the size and location of all generation as well as the transmission capacity is identical across each of the locational market designs, optimised assuming that generator and storage siting investments can be made based on (the modelled) perfect locational investment signals.

5.44. A **load shielding** sensitivity tests the impact of "shielding" consumers from the locational price at their connected node, instead exposing all consumers to a single average national wholesale price in each hour, while retaining locational pricing for generators, storage and electrolysers. The purpose of this sensitivity is to test how the estimated system benefits of nodal pricing change when flexible consumer load, provided for example through smart charging of EVs and HPs, is unable to optimise consumption around the local price at the connected node.

5.45. We test this sensitivity by applying the modelled demand profiles (including flexible assets) optimised based on a single price in the national market model to the nodal market model. We then compare wholesale market outcomes under "shielded" market model to outcomes in our standard nodal market model, to assess the impact of the imperfect load profiles on in a nodal market design.

5.46. Our assessment for both these sensitivities is set out in Chapter 11.

D. Key inputs and modelling assumptions

5.47. To calibrate our power market model to align with the three energy scenarios for each market design arrangement, we developed a series of input assumptions in coordination with stakeholders, focused on the four key areas set out in Figure 5-5 below. These areas are (1) transmission capacity, (2) demand, (3), generation capacity, and (4) commodity prices. Additionally, we also set out our assumptions for our assessment of the BM and CfDs.

Figure 5-5: Categories of key input and assumptions

1	**Transmission capacity**	Define transmission capacity (and associated parameters) between each zone / node and across the country over time
2	**Demand**	Define the evolution of demand levels for each node, their hourly profiles and flexibility assumptions by type
3	**Generation capacity**	Develop generation capacity (including storage) build-out profiles
4	**Commodity prices**	Define commodity price assumptions
5	**Balancing mechanism**	Define BM assumptions
6	**Contracts-for-Difference**	Define CfD assumptions

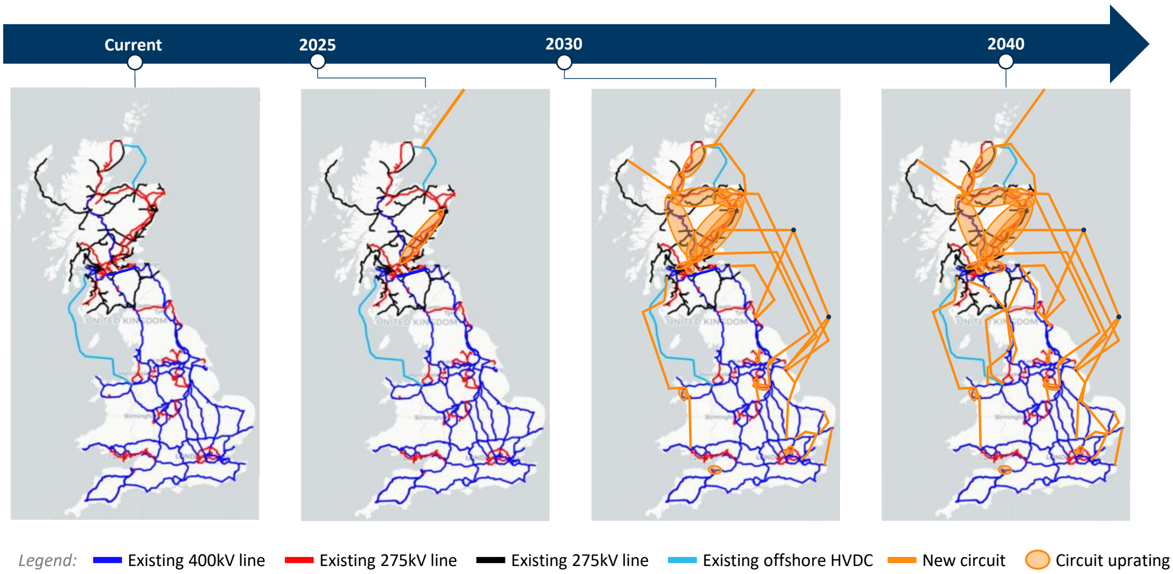
Source: FTI analysis

5.48. We summarise each of these in turn in the following sub-sections, with a more detailed discussion of our input assumptions set out in Appendix 1.

Transmission capacity inputs

5.49. Assessing the impact of different locational market design outcomes requires an accurate definition and evolution of the GB transmission network topology across the modelling period. Figure 5-6 below provides an illustrative example of our transmission assumptions.

Figure 5-6: High-level map of future transmission build



Source: FTI analysis
Note: The diagram above is only illustrative based on information provided by the ESO's HND documents.

5.50. As indicated in the illustrative diagram above, we have defined three detailed representations of the transmission network according to the three scenarios in each of the modelled years. These representations are based on the following:

- the LtW (NOA7) and SysTr (NOA7) scenarios follow the relevant transmission build-out information set out in NOA7;[138]
- the LtW (HND) scenario follows the transmission build-out information set out in NOA7 Refresh.[139]

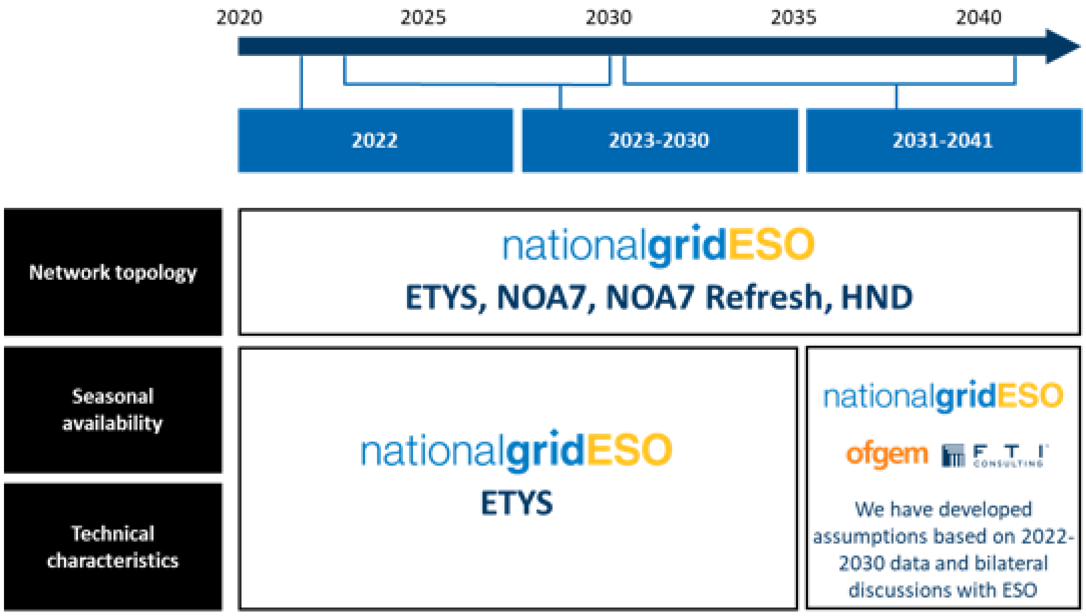
5.51. To define the network topology as set out above, the following inputs were used:

- the transmission capacity between each pair of nodes in the nodal market design and each pair of zones in the zonal market design across the country in each year;
- the seasonal thermal rating of each transmission line;
- technical characteristics of circuits and transformers to compute losses; and
- relevant additional security of supply constraints related to the use of specific assets.

5.52. We set out our data sources for the inputs required in Figure 5-7 below:

[138] National Grid ESO, 'Network Options Assessment 2021/22' (link).
[139] National Grid ESO, 'Network Options Assessment Refresh 2022' (link).

Figure 5-7: Sources for our transmission input assumptions



Source: FTI analysis based on discussions with stakeholders and agreement with Ofgem

5.53. As shown in Figure 5-7 above, we have relied on the ETYS 2021 as a starting point between 2022 and 2030 which includes detailed information of the transmission network parameters such as connectivity and impedances that allow detailed modelling of the transmission network including network losses.[140] From 2030, we then augment the information provided in ETYS with individual projects identified by NOA7 (as well as information provided through the HND and NOA7 refresh plans in our LtW (HND) scenario).[141] These input assumptions have been validated directly with the ESO's relevant network planning teams over several bilateral discussions.

140 National Grid ESO (2022), 'ETYS – Appendix B – System technical data' (link).

141 Circuit characteristic (e.g., seasonal ratings and impedances) for the reinforcement proposed by NOA are based on standard parameters for transmission assets based on type (e.g., OHL, Cable, Transformer) length, and nominal capacity.

Box 5-1: Holistic Network Design

The ESO developed the HND as part of DESNZ's offshore transmission network review ("OTNR"). It seeks to deliver the coordinated onshore and offshore transmission network required to support the connection of 50GW of offshore wind by 2030 in GB, as well as Net Zero by 2050 for GB and by 2045 for Scotland.

Development of the HND has been guided by the terms of reference set out by the OTNR.[142] It includes the four objectives of minimising the whole system cost (Objective 1), while meeting network planning and operational standards (Objective 2) as well as appropriately balancing local community, environmental (Objective 3) and economic impacts (Objective 4) to ensure clean, affordable and reliable energy to the consumer.

The requirement to consider coordinated offshore and onshore development against a broad range of objectives represents a key departure from the standard network development process under the NOA. Reinforcement proposed under NOA7 only considers the optimal level of onshore reinforcement against the FES 21, focusing on cost only and without considering offshore networks. Therefore, compared with the transmission plan developed under the NOA process, HND and NOA refresh plans include changes in onshore network developments to complement new coordinated offshore network requirements.

Building from the information provided by the ESO, and supplemented by further detailed discussions with them, we identified transmission projects that are either new or have an accelerated delivery in HND relative to NOA7. In total, there are more than 3000km of new circuits with up to 63GW of additional capacity across 25 projects which would require expenditure greater than the NOA7 estimate, as a result of both new projects and from the acceleration of projects identified through the earlier NOA7 process.

5.54. In order to account for the additional redundancy that is built into the network through the obligation to meet the Security and Quality of Supply Standard requirements and to accommodate flows under both planned and unplanned circuit outages, we have adjusted the circuit capacity uniformly across the network by the Locational Onshore Security Factor, as discussed in Appendix 1. The calculation of the Security Factor is regularly performed by the ESO as part of the TNUoS wider tariffs under the methodology scrutinised by the industry and approved by Ofgem.[143]

5.55. One main limitation to the transmission assumptions is that the ESO's NOA7 modelling ends in 2041. This meant that to be able to model outcomes beyond 2041, we would either have to assume no change in transmission build-out, or assume a transmission build-out profile using either exogenous assumptions or endogenous calculations of an assumed transmission roll out in the 2040s. Both of these approaches would be deficient, in that they would risk a high degree of spurious accuracy. Therefore, in consultation with stakeholders, we have limited the modelling period to 2040 to ensure that modelled outcomes remain grounded in the key principles outlined in Section 4A.

[142] UK Government, 'Offshore transmission network review', last updated July 2022 (link).
[143] National Grid ESO (2020), 'Guidance on TNUOS Locational Onshore Security Factor Calculation' (link).

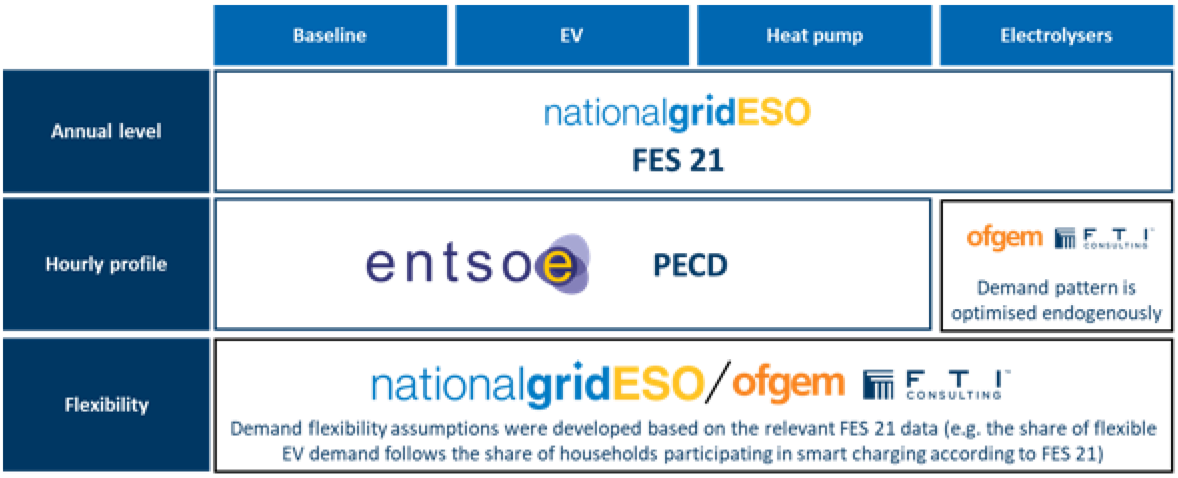
Demand inputs

5.56. To model dispatch outcomes, the following demand inputs are required:

- The annual demand by node, year and demand type.
- The hourly demand profiles by demand type.
- Flexibility assumptions (i.e., price responsiveness) by demand type.

5.57. We set out our data sources for the demand inputs in Figure 5-8 below according to each demand type, which we have split into four categories.

Figure 5-8: Sources for our demand input assumptions



Source: FTI assessment based on discussions with stakeholders and agreement with Ofgem. Note: Baseline demand refers to all consumer demand (including domestic, commercial and industrial), except for the low-carbon technologies, which are modelled separately (EV, HPs, electrolysers).

5.58. As indicated in Figure 5-8, we rely primarily on the ESO's assumptions as provided by FES 21 or directly under an NDA for the annual demand levels and the level of flexibility associated with each kind of demand. We have also used publicly available hourly demand profile data from ENTSO-E, published as part of Pan-European Climate Database ("PECD").[144] Demand profiles of electrolysers require no exogeneous assumptions, as these are optimised endogenously in our model.

5.59. In order to accurately represent demand, we split consumer demand into four main components – baseline demand, EVs, HPs and electrolysers. For each of these components, in each scenario we define the following parameters:

- **Total annual demand** (at each node) is defined in FES 21.
- **Demand profile** is based on the PECD. These profiles are optimised by the model, using flexibility assumptions developed in FES 21 which are presented in Table 5-3 below.

[144] The PECD is published by ENTSO-E and is the basis of the TYNDP modelling.

Table 5-3: Flexibility assumptions for different demand types

Demand type	Flexibility assumption
Baseline demand	▪ There are two tiers of demand shedding from baseline demand included in the model, which are activated at very high price levels ▪ Maximum capacity from demand shedding and price levels are based on FES 21 and discussions with ESO
EVs	▪ Some proportion of EVs optimise demand across the day to minimise cost, consuming at times when power is lowest cost (the share of these EVs is as specified in FES 21) ▪ Some proportion of EVs can provide generation to the electricity grid (the share of these EVs is as specified in FES 21) ▪ Other EVs follow a fixed hourly demand profile peaking late at night
HPs	▪ Some proportion of HPs optimise demand within each day to minimise cost, consuming when power is least cost (the share of these HPs is as specified FES 21) ▪ Other HPs follow a fixed hourly demand profile
Electrolysers	▪ Electrolyser capacity and total annual consumption is fixed to FES 21 ▪ Demand profile is optimised within the year in the model

Source: FES 21; FTI assessment based on discussions with stakeholders and agreement with Ofgem

5.60. To ensure our assumptions are transparent and accepted, we have clarified them with Ofgem and the ESO, and discussed them with stakeholders in workshops.

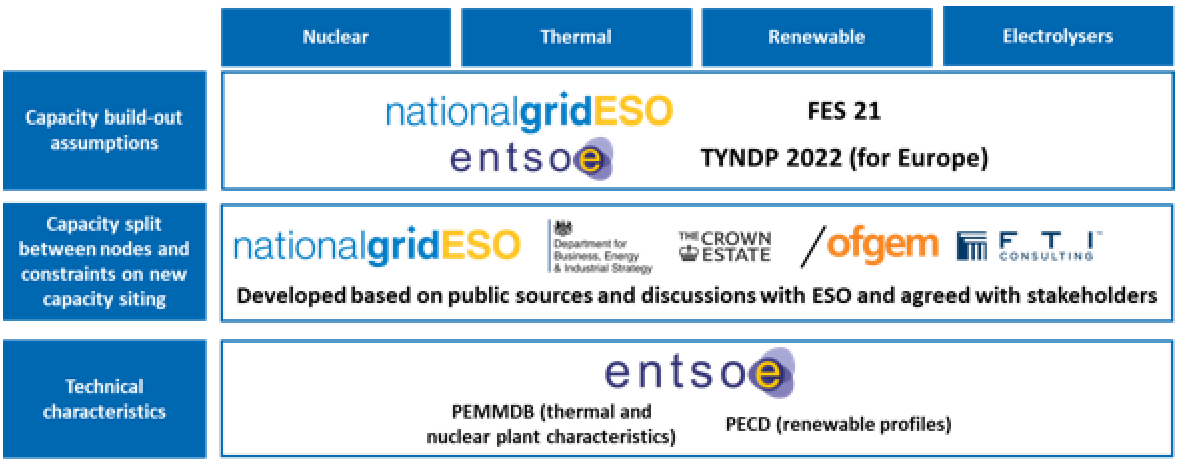
Generation capacity

5.61. The following generation capacity inputs are required in our modelling assessment:

- The total generation capacity per technology used across each scenario.
- The generation capacity per technology at each specific location used across each scenario.
- The constraints around siting decisions (reflecting technological and geographical constraints).
- The technical characteristics of generators.

5.62. We set out our key sources in Figure 5-9 below.

Figure 5-9: Sources for generation capacity input assumptions



Source: FTI analysis based on discussions with stakeholders and agreement with Ofgem

5.63. As observed in the figure above, we rely on several sources to the capacity assumptions required.

5.64. On the generation capacity build out assumptions, we use the following assumptions following discussions with stakeholders:

- For the national market models, we rely on the total generation capacity and the generation capacity at each location as defined in FES 21.
- For the zonal and nodal market models, we rely on the total generation capacity as defined in FES 21 but some new capacity can be sited at different locations in response to locational price signals, when it is economic to do so.

5.65. The ability of new capacity to site in different locations under the zonal and nodal market models is subject to assumptions of real world technological and geographical constraints. These constraints were developed based on several sources, including DESNZ's Carbon Capture, Utilisation and Storage ("CCUS") cluster roadmap and Crown Estate lease information. Additionally, we assume that all projects in development do not site in different locations than as set out in FES 21.

5.66. This means that in our assessment, we make the conservative assumption that locational prices do not affect the overall capacity mix, and instead only affect the locations of a limited set of new generation capacity.

5.67. The constraints to siting decisions of new generators that were used are set out in Table 5-4 below.

Table 5-4: Responsiveness to locational wholesale electricity price signals in siting decisions

Technology	Ability to relocate in response to locational wholesale electricity price signals
Nuclear	Do not respond (fixed as per FES 21 in terms of timing and in terms of location)
Fossil fuel	
Biomass	
Biomass (Carbon Capture and Storage, "CCS")	Location optimised across the clusters and nodes corresponding to each cluster identified based on the government strategy
Hydrogen-fuelled generation	Location optimised across nodes with hydrogen production capacity in FES 21 and/or as within hydrogen clusters
Offshore wind	Does respond, limited by historic CfD Allocation Round results and Seabed lease availability
Onshore wind	Does respond, limited by: ▪ New onshore wind in England is fixed to FES 21, i.e., a limited increase; and ▪ New onshore wind in Scotland and Wales can locate on any node within Scotland and Wales with onshore wind capacity in FES 21 ▪ Maximum additional capacity per node in Scotland and Wales set at twice that of FES 21 forecast
Solar	Does respond, limited by maximum additional capacity per node set at twice that of FES 21 forecast
Battery storage	▪ Does respond, new capacity can locate on any node with battery capacity in FES 21 ▪ New capacity at every 5 years at each node is limited to 400MW (this corresponds to the largest increase identified in FES)
Hydro and Pumped Storage	Do not respond
Interconnectors	Do not respond – capacity and landing point location as per FES 21

Source: FTI assessment based on discussions with stakeholders and agreement with Ofgem.
Note: In conjunction with these limits, we assume all projects in development (mostly prior to 2030) site as per FES 21.

5.68. For offshore wind as indicated in Table 5-4, we have carried out an additional crosscheck to ensure that:

- all committed projects (i.e., under construction or awarded under a CfD contract) are built; and
- offshore wind capacity in each sea area does not exceed the current seabed leases in the area or the capacity set out in the FES 21 until 2030. Increases up to 2040 are limited to twice the currently leased amount or by FES 21, whichever is higher.

5.69. For the technical characteristics across all generator types, we have sought information provided by public sources as far as available:

- For technical characteristics regarding thermal plants, we have relied on the ENTSO-E's Pan-European Market Modelling Database ("PEMMDB").
- For renewable generators' availability profiles, we have relied on the PECD. These profiles are based on the 2013 climate year, in line with ESO's choice of climate year used for the FES and NOA. The PECD includes climate data for 5 different onshore GB regions and 13 offshore regions. We have assigned each node to one of the 5 onshore regions.

5.70. The assumptions adopted allow direct comparison across the three locational market model designs under consideration. However, they are also potentially conservative, as more granular locational pricing could trigger a change in the generation capacity mix rather than assuming it is held constant. Restricting most new builds to locations with prior new build is arguably also conservative, as it limits the optimisation of siting. We discuss the siting decisions under the different market designs in further detail in Appendix 1.

Commodity prices

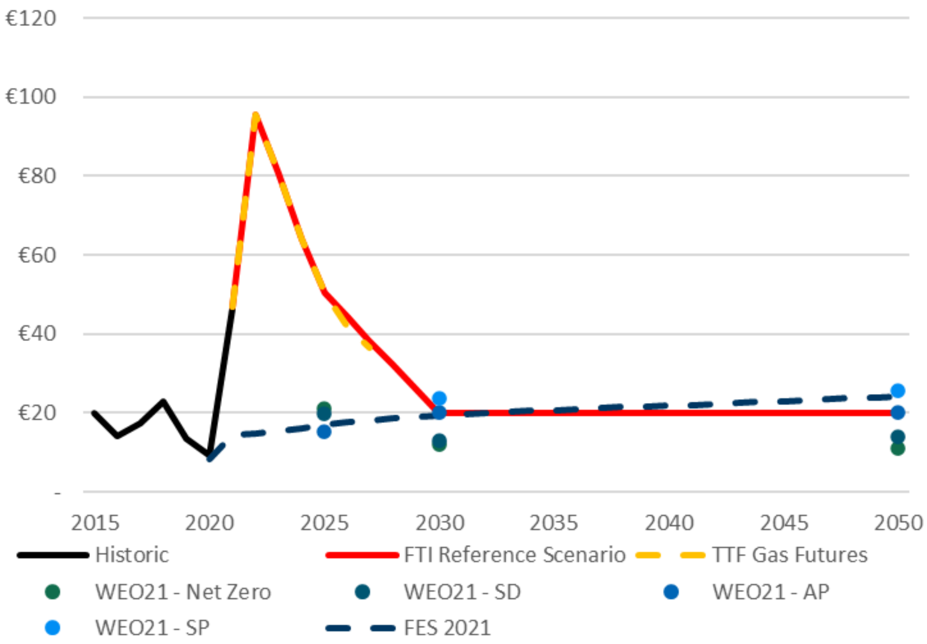
5.71. Commodity price forecasts (mainly carbon and gas) are the main determinant of the short-run marginal costs ("SRMCs") of thermal power generators, and thus, in turn, a primary driver of wholesale electricity prices.[145]

5.72. For these assumptions, we have relied on the future curves and long-term benchmarks to reflect recent market development. The choice of futures and long-term benchmarks were based on TYNDP, which uses the same set of benchmarks.

5.73. Our gas price forecast below is based a combination of these sources as set out in Figure 5-10 below.

[145] Other relevant commodities include coal, oil, and biomass. We have used the same approach, relying on future curves and long-term benchmarks to form our set of assumptions.

Figure 5-10: Gas price forecast – € per MWh



Source: WEO; TTF; TYNDP; FES; Bloomberg; FTI analysis.
Note: The prices in the figure above are in real terms, as 2022 Euros.

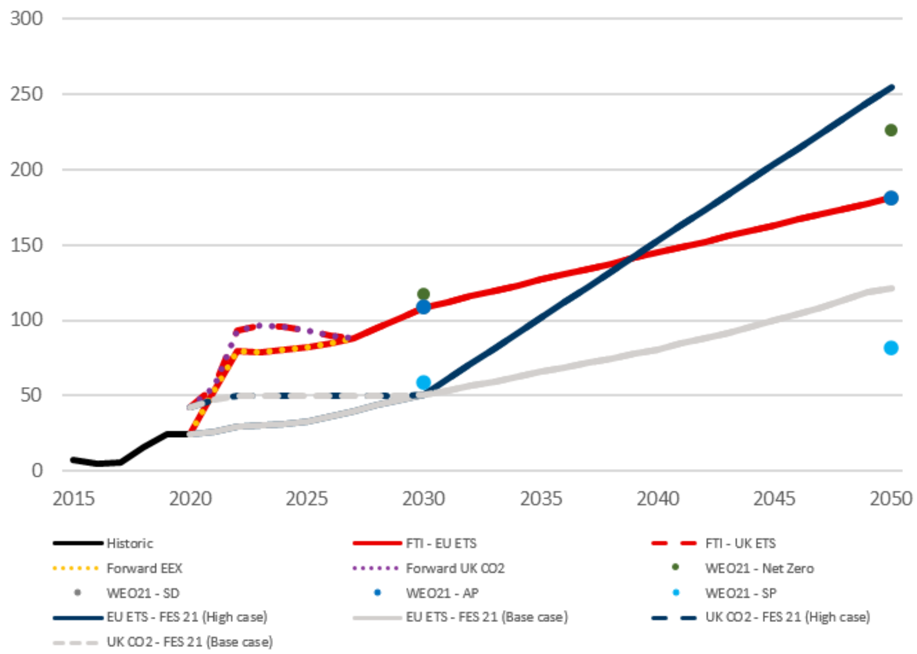
5.74. As shown in Figure 5-10, the gas price forecast follows the forward curves up to 2025 and World Economic Outlook ("WEO") long-term forecasts from 2030.[146]

5.75. Similarly, our carbon price assumptions are based on a mix of future curves and long-term benchmarks from the WEO. This includes an adjustment for the Carbon Price Floor in the UK, leading to higher carbon prices in the UK compared to Continental Europe, until the late 2020s, when the two are assumed to converge. [147] This can be seen in Figure 5-11 below.

[146] The forecast gas prices rely on 2021 and early 2022 data sources. This has been tested with stakeholders and agreed with Ofgem.

[147] While we have considered the market impact from forecasted carbon prices, we have not considered the policy-administered carbon values which are intended to reflect the full societal cost of carbon. This is explored further in Section 9C.

Figure 5-11: Carbon price forecast – € per tCO2



Sources: WEO; TYNDP; FES; Bloomberg; FTI analysis.
Note: The prices in the figure above are in real terms, as 2022 Euros.

BM assumptions

5.76. To model constraint management costs that arise in national and zonal market designs,[148] we have also assessed BM outcomes, noting the particular challenges in doing so. This is due to the unique features of the BM, including that the SO:

- has to balance on a locational basis;
- trades with market participants on a pay-as-bid basis; and
- is the only counterparty.

5.77. Given these features, we have agreed the following approach and assumptions with stakeholders. This involves the following:

- We undertake two model runs per scenario – an unconstrained model run assuming no constraints on the network, and a constrained model run (also referred to as the "redispatch" model run) accounting for the physical reality of the transmission network. This provides the congestion volumes.

[148] As set out in Section 2, a nodal market model design does not require a BM to manage constraints as the value of constraints are included in the nodal price. We note that under all market designs modelled, there may be instances where the SO is required to intervene to account for unexpected changes in supply and demand, as well as unexpected outages of the transmission lines, in real-time. This occurs under national, zonal and nodal pricing regimes, and we have not sought to model any impact on the costs that arise from such interventions.

- In the constrained run, we fix demand and generation from technologies and demand types that are not assumed to take part in the BM.
- We then apply the assumed BM bid and offer prices to the differences in generation between the two model runs to calculate the constraint management costs.

5.78. The estimated BM bid and offer prices have been developed using historical behaviour in the BM as well as forecasts of fuel and carbon costs across different technology types. This is set out in Table 5-5 below. We refined our assumptions over time based on discussions with stakeholders, particularly Ofgem and the ESO. We discuss our approach in more detail in Appendix 1.

Table 5-5: Assumed BM bid and offer prices

Technology	Cost to ESO Bid	Cost to ESO Offer
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost
Biomass	- Fuel cost	Offer Uplift + Fuel cost
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)
ROCs renewables	ROCs[1]	(theoretical only so no price assumed)
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)
Merchant renewables	£0	Offer Uplift
Batteries	- Price Paid	Price Received + Offer Uplift
Other Storage Technology	- Marginal Value	Marginal Value
Hydrogen generation H_2	- Marginal Value	Marginal Value
Interconnector	Cost of reversing flow €130 / €100[2]	Cost of reversing flow €130 / €100[2]

Source: FTI assessment based on discussions with stakeholders and agreement with Ofgem.
Note: We assume the following technologies do not participate in the BM – Demand Side Response ("DSR"), nuclear, hydro (run-of-river) and small-scale thermal.[149]
[1]*The number of Renewable Obligation Certificates ("ROCs") will depend on technology. For simplicity, we assumed 1.9 ROCs for offshore wind and 0.99 ROCs for onshore wind which is the average per technology from DESNZ (link).*
[2]*The cost of reversing flow of €130 assumed in 2025 and €100 in all other modelled years, as discussed in greater detail in Appendix 1A.*

[149] We assume that CCS gas generators participate in the BM in the same way as fossil fuel generators (but with different carbon costs). There are no CCS gas generators in the Leading the Way scenario in the modelling period.

5.79. The offer uplift included for some technologies is based primarily on historical experience and can be substantial. For instance, we assume a multiplier offer uplift for fossil fuel generators.[150] This offer uplift may reflect a range of factors, including start-up costs, the pay-as-bid nature of the BM (meaning that we would typically expect offers to generate to be in excess of marginal cost – sometimes to reflect the locational marginal value of electricity in that part of the network) and effective market power of plant in a situation where there may be limited alternatives.

5.80. To the extent that market power is one factor, our approach could in principle overestimate the consumer benefits of locational pricing, as we do not assume any market power in our wholesale market modelling.

5.81. A further assumption relates to the assumed participation of interconnectors in the BM. Historically, interconnector participation has been very low reflecting the inherent complications of SOs trading with each other in the BM close to real time. We have therefore assumed a relatively high cost of reversing interconnector flows in line with our discussions with ESO.

CfD assumptions

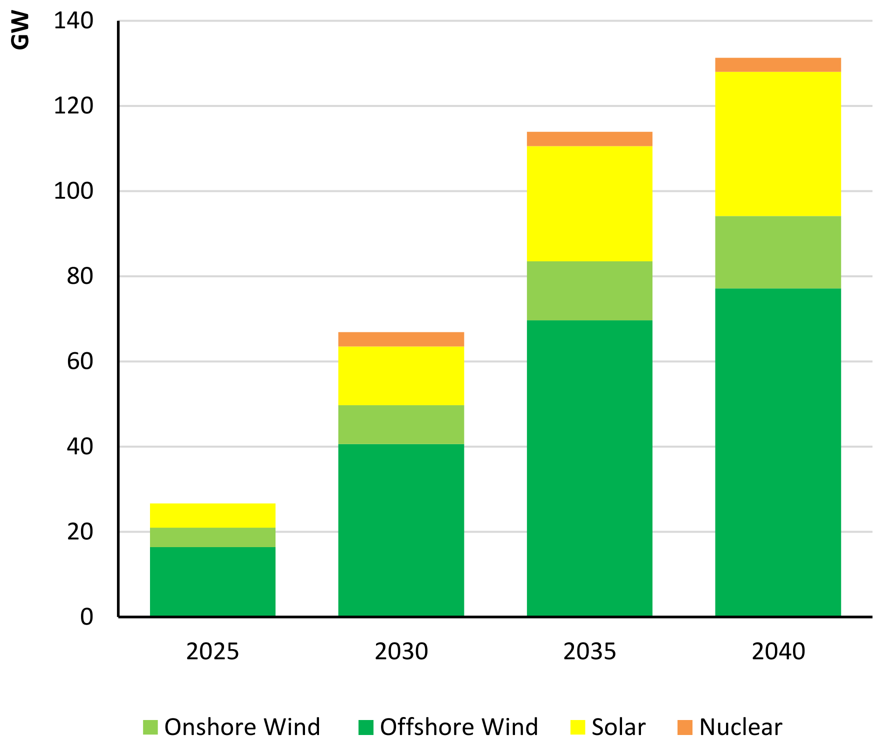
5.82. We also estimated how costs could change as a result in changes in CfD payments under locational pricing. Our approach to assessing this is based on:

- a profile of the evolution of CfD generator capacity over the modelling period; and
- assumptions on the future CfD regime design.

5.83. Our projected capacity of CfD generators is set out by technology in Figure 5-12 below.

[150] Our approach mimics the approach adopted by the ESO, National Grid ESO (2017), 'Long-term market and network constraint modelling', p.15 (link). As stated in their report, the ESO applied an offer multiplier of 1.63 to gas generators in 2017. We discuss the basis of our offer multiplier in greater detail in Appendix 1A.

Figure 5-12: Projected capacity of CfD generators under LtW



Sources: FES 21; DESNZ Generation Cost Report 2020; FTI analysis.

5.84. As shown in Figure 5-12, we assume that CfD contracts would be available, in part or fully, across four technologies. Following a discussion with stakeholders, we assume that the following projects are included:

- existing projects with CfD contracts;
- all proposed offshore wind projects awarded CfDs in Auction Rounds 1 to 4;
- Hinkley Point C;
- all future offshore wind projects;
- 50% of future solar projects; and
- 50% of future onshore wind projects.

5.85. We have assumed that 50% of future solar and onshore wind projects (beyond existing auction rounds) will be awarded CfD contracts as a balanced assumption to represent an increasing number of awards in recent CfD auctions, as well as the increasing potential for more merchant investments. We note that amending this assumption would have no net impact on our assessment of the overall change in socioeconomic welfare arising as a result of a change to locational pricing. This is because it would reflect a pure transfer between producers and consumers. For example, a lower proportion of future onshore wind and solar projects with CfD contracts will increase consumer benefits and decrease producer surplus by the same amount.[151] Additionally, all other technology types are excluded due to immateriality or uncertainty.

5.86. Our constrained model estimates a generation profile for each project included in the list above, allowing us to estimate the cost of CfD support payments on consumers via the following equation:

$$CfD\ support\ payments = \sum_{all\ hours} (Strike\ price - reference\ price) * Generation\ volume$$

5.87. Our assumptions for calculating the CfD support payments are set out in Table 5-6 below.

Table 5-6: Assumptions for calculating CfD support payments

	National market	Zonal market	Nodal market
Strike price	Strike prices for future contracts are based on DESNZ's levelised cost of electricity ("LCOE") estimates as stated in the Generation Cost Report 2020.[152] ▪ We take an arithmetic average across the LCOEs by technology type. ▪ We assume the same LCOE across all locations. In practice, this might differ based on capacity factors and constraint risks.		
Reference price[153]	National price	Zonal price[154]	Nodal price[155]
Generation volume	Constrained model output (i.e., redispatch model run)[156]		Actual output

Source: FTI analysis

[151] Changing the proportion of onshore wind and solar projects with CfD contracts would also affect our constraint cost estimate. This is because CfD generators are assumed to place higher bids in the BM than generators without CfDs, which would in turn result in greater constrained-off payments in the national market than in the zonal or nodal markets. As a result, an increase to our assumption on the proportion of renewable projects with CfD contracts would theoretically have both a negative impact on consumer benefits in the transition to a locational market (as greater CfD support payments are required) and a positive impact (as consumers incur lower constraint costs).

[152] BEIS (2020), 'Electricity Generation Costs' (link).

[153] The specific design of CfDs, and their implications for investors and consumers, have been discussed with stakeholders at a high level. We have also discussed alternative variants to the CfD regime which introduce locational elements.

[154] The zonal reference price could be defined in a number of alternative ways (e.g., national price with an allocation of a price hedging contract to zones). For simplicity we have assumed that the reference price would be based on the individual zonal price.

[155] The nodal reference price could be defined in a number of alternative ways (e.g., the trading hub price or a national price with an allocation of FTRs to nodes). For simplicity we have assumed that the reference price would be based on the individual nodal price.

[156] This represents actual output. As per our discussion in Chapter 4, CfD generators will be exposed to greater constraint risks in a zonal or nodal market design.

5.88. On the basis of our assumptions, as the reference prices above are linked to the wholesale electricity price, the assumed bidding strategy of CfD generators may have an impact on the CfD support payment calculations. In our power market model, CfD generators bid at their SRMC, irrespective of their CfD contract. This reflects a simplified modelling approach which avoids making assumptions on generator behaviour (and thereby avoids inadvertently assuming a level of market power or distortionary behaviour due to policy quirks). We would not expect a more complicated model of bidding behaviour to have a material impact on our assessment.

E. Modelling runs and key outputs

5.89. Bringing together the approach and set of inputs above, our modelling assessment covers three locational market design models, three scenarios and two sensitivities, for an assessment period between 2025 and 2040, inclusive. Due to computing limitations, we model a full year every five years between the period forming four data points.[157]

5.90. The inputs in our model, and consequently the outputs of the model, are all in 2022 prices. Any input assumptions based on other price years have been deflated or inflated accordingly for the purposes of our assessment.

5.91. To capture the value of more granular locational pricing more accurately, we interpolate the expected benefits and costs for the years between the years modelled (i.e., between 2025, 2030, 2035 and 2040). These interpolated benefits and costs are discounted back to 2024, under the assumption that 2025 would serve as the first year of implementation. We use a discount rate of 3.5% as stipulated in the Green Book.[158]

5.92. Our outputs reflect hourly outputs for each modelled year. These outputs include the following:[159]

- **Capacity and generation ("physical") outcomes** covering capacity, generation, curtailment, emissions and interconnector flows.
- **Pricing and financial outcomes** covering wholesale prices and cost to consumers, constraint management cost, intra-GB congestion rent, impact on the cost of CfD and producer impact.

5.93. Given the assumptions used in our own model, we set out our modelling and assessment results in Chapters 6 and 7 below.

[157] Note, a full year in our model is made up of 52 weeks (i.e., 364 days or 8736 hours).

[158] See the House of Lord's library focus on the Governments 'Green Book' (link).

[159] Specifically, the power market model produces capacity, prices and generation profiles. These profiles were then "processed" and analysed by FTI to form more meaningful financial outcomes including the wholesale price impact, constraint management cost, intra-GB congestion rent, impact on the cost of CfDs and producer impact.

6. Capacity and generation outcomes

6.1. In Chapters 4 and 5, we outlined the methodology and assumptions used to calibrate our power market model and our assessment of the consumer and socioeconomic benefits for each wholesale market design. In this chapter, we describe the key capacity and generation outcomes forecast by our modelling under each market design, namely:

- the optimal siting of GB generation and storage capacity under the zonal and nodal wholesale market designs, subject to technology-specific constraints;
- the least-cost generation mix in the wholesale market for each market design, respecting the relevant transmission constraints both between GB and connected electricity markets, and within GB (for the zonal and nodal models); and
- the necessary volume and cost of ESO redispatch actions in the BM, for both the current and zonal market designs.

6.2. As discussed above, we have forecast electricity market outcomes for each market design under three distinct scenarios in order to assess the impact of locational electricity pricing across a credible range of pathways. These three scenarios are: LtW (NOA7), LtW (HND), and SysTr (NOA7).

6.3. As a result, we have a large volume of analysis to present, both of the "gross outcomes" for each market design in each scenario, and the "comparative outcome" of moving from the national market design to a locational market design. We consider all three scenarios modelled in our assessment as "base counterfactuals". We have assessed all three scenarios equally and do not place a greater weighting on any of them, however, for ease of exposition, we present a full picture of outcomes under the LtW (NOA7) scenario in the main body of our report.[160] At the end of this chapter, we summarise the key results of our other two scenarios, with a full presentation of results in the other two scenarios set out in Appendices 2 and 3.

6.4. The remainder of this chapter describes the main capacity and generation outcomes under the LtW (NOA7) scenario for each market design, namely the:

- capacity mix and its different locations under the three modelled market arrangements (**Section A**);
- generation mix in the wholesale market and the BM (**Section B**);
- constrained-on and off generation in the BM (**Section C**);
- curtailment of wind generation (**Section D**);
- emissions associated with the generation mix (**Section E**); and
- interconnector flows in the wholesale market (**Section F**).

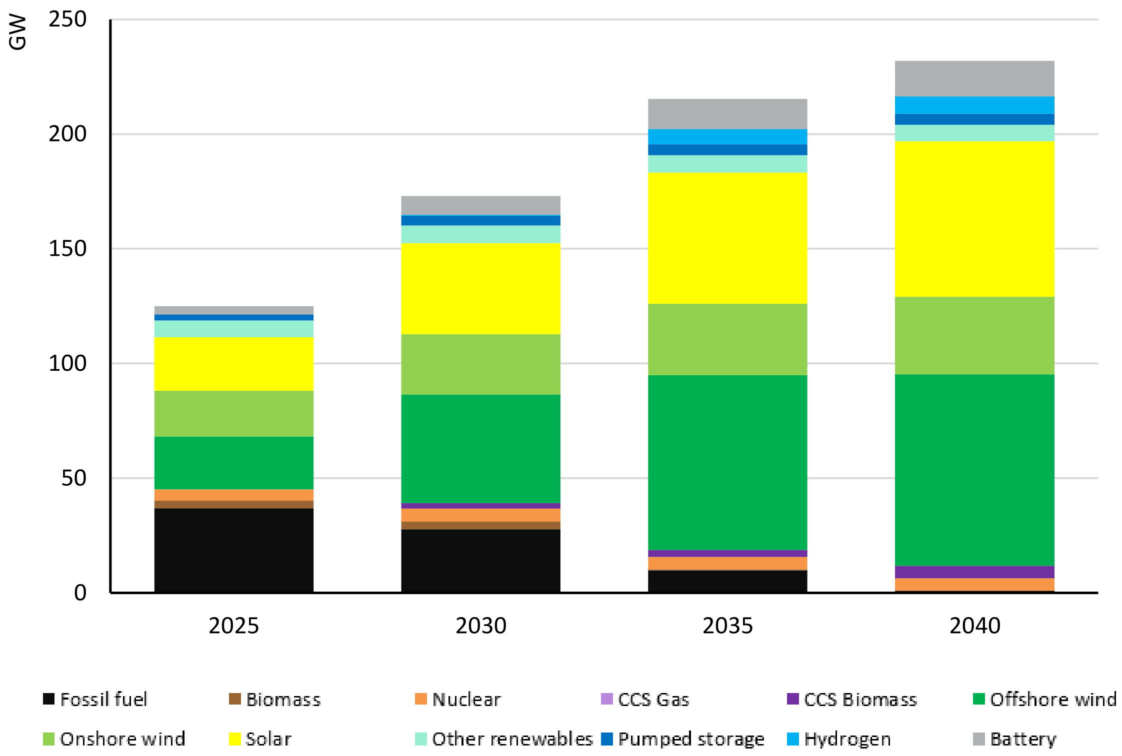
6.5. We then summarise the key results of the LtW (HND) and SysTr (NOA7) scenarios in **Section G**.

[160] The LtW (NOA7) scenario is the first scenario we modelled in our assessment, with the initial results presented in the August 2022 stakeholder workshop.

A. Capacity

6.6. As described in Chapters 4 and 5, in our modelling, the total installed capacity of each technology in each year is fixed across all market designs as set out in the relevant FES 21 scenario. In our modelling of the zonal and nodal market designs, the total capacity of each technology remains unchanged. However, a proportion of new-build capacity is allowed to site differently, relative to the ESO's FES 21 assumptions, in response to price signals from the wholesale market, subject to the technology-specific constraints set out in Section 5D.

Figure 6-1: Installed capacity – LtW



Source: ESO, FES 21, LtW.
Note: We present interconnectors separately to focus on generation and storage resources only for certain charts before a fuller treatment of the impacts on interconnectors.

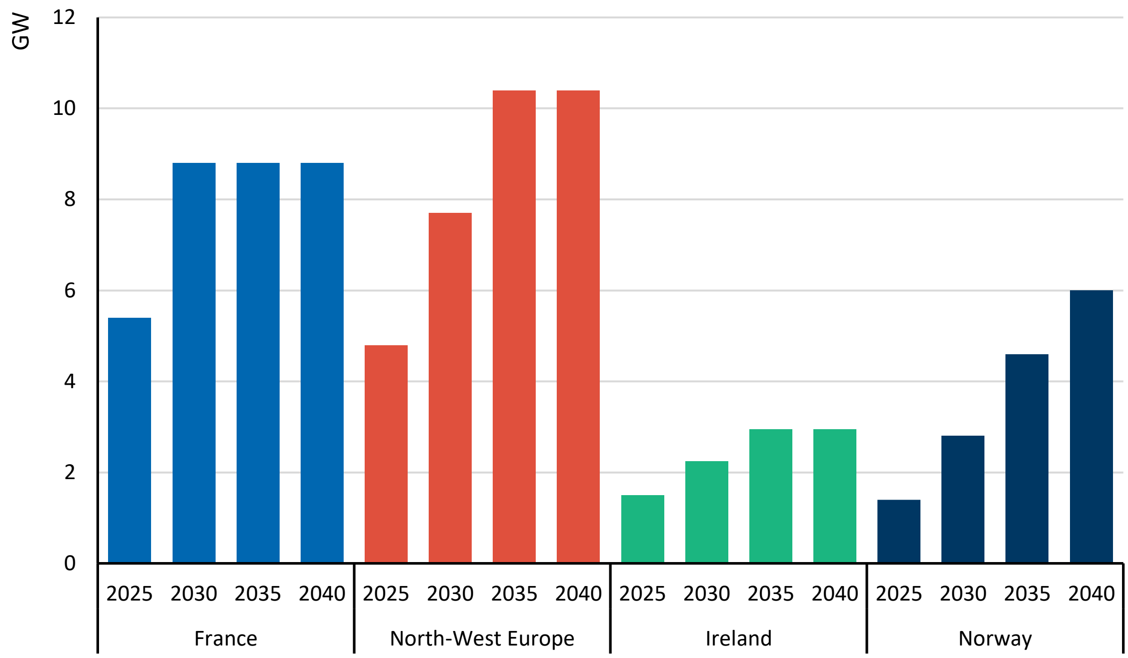
6.7. Figure 6-1 above shows the aggregate GB installed capacity under LtW. This is the ESO's most ambitious scenario in terms of decarbonisation and includes:

- an early phase-out of the existing fossil fuel generation fleet and no new additions beyond 2025;
- a rapid deployment of intermittent renewables, especially offshore wind, which reaches 47GW in 2030 and 83GW in 2040;
- an early adoption of new generation technologies, such as Small Modular Reactors ("SMR") and hydrogen;
- the introduction of carbon negative generation technologies, such as CCS Biomass; and

- flexibility provided by a high level of storage capacity (including compressed air and liquid air storage), augmented by increased interconnection between GB and other electricity markets as well as an extensive uptake of load-shifting and V2G generation by highly engaged consumers.

6.8. Figure 6-2 below shows the evolution of interconnection capacity under the LtW scenario. An over 15GW increase is forecast between 2025 and 2040, which makes interconnectors one of the main sources of flexibility on the GB system.

Figure 6-2: Interconnector capacity by region – LtW (NOA7)



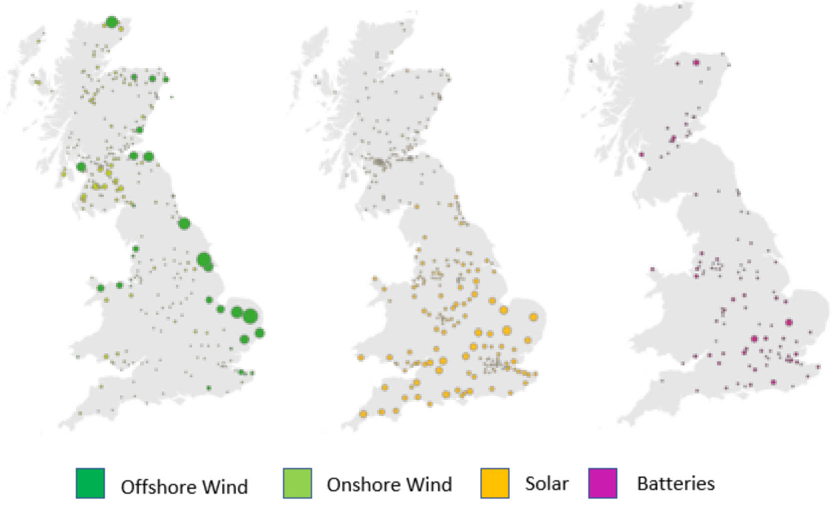
Source: FES 21
Note: North-West Europe includes Belgium, Denmark, Germany and the Netherlands.

6.9. Interconnection capacity between GB and other European countries is assumed to increase rapidly in the first half of the modelling period under the LtW (NOA7) scenario. Total interconnection capacity is forecast to increase to c.22GW by 2030 from the current c.8.5GW, predominantly due to the installation of new cables to France and North-West Europe. Interconnection capacity further increases to c.28GW by 2040, following new links to North-West Europe and Norway. In the remainder of this subsection, we discuss capacity across all three market designs, in turn, over the modelling period.

National

6.10. As highlighted throughout this report, the siting of existing and new generators under the national market (i.e., the current market design) is fixed in each year to the relevant FES scenario, based on a detailed confidential dataset provided by the ESO. This dataset includes nodal-level data on the expected size and location of generation capacity across GB in each year out to 2050, which we have incorporated into our power market model. As an example, Figure 6-3 below shows the expected location of wind, solar and storage capacity in the LtW dataset, and by extension our modelling of the national scenario, in 2030.

Figure 6-3 Installed capacity by node under a national market design (2030) – LtW (NOA7)

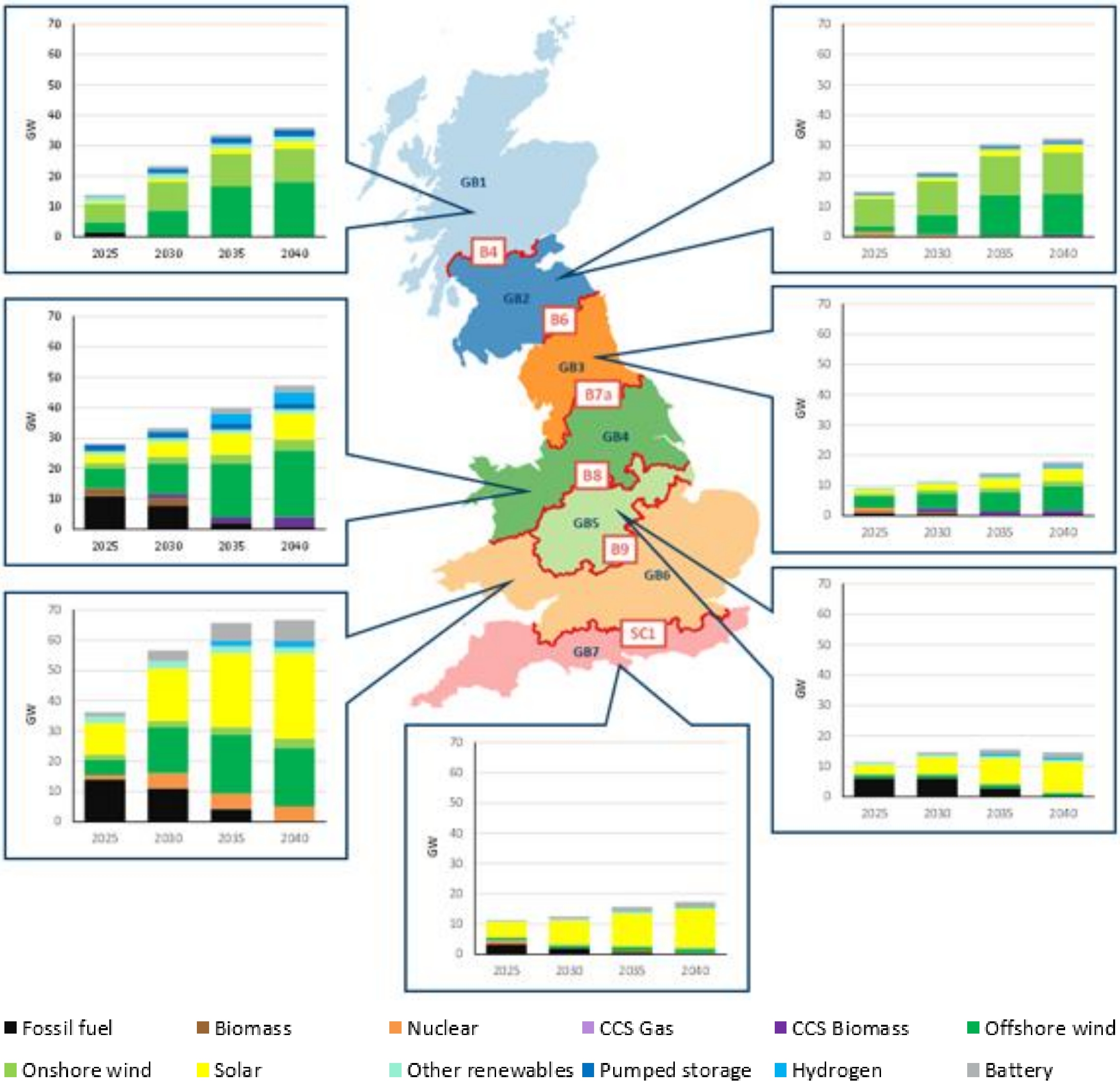


Source: National Grid ESO, FES 2021, LtW.
Note: The size of dots represents the amount of installed capacity at each location, but dot size is not directly comparable across technologies.

6.11. For ease of presentation, in the remainder of this chapter we present installed capacities by technology at an aggregated zonal level. However, in our underlying modelling and analysis, all capacities are specified to the nodal level. Similarly, when presenting the re-siting of capacities between modelled market designs, we do so at an aggregated zonal level.

6.12. For example, Figure 6-4 below shows the aggerated version of the generation capacity per technology and zone for each modelled year under the status quo national market.

Figure 6-4: Installed capacity grouped by zone under a national market design – LtW (NOA7)



Source: National Grid ESO, FES 2021, LtW.

6.13. As seen in Figure 6-4 above, under LtW (NOA7) the majority of fossil fuel generation capacity is retired across all zones by 2035, with almost all unabated capacity removed by 2040. This significantly reduces the dispatchable generation capacity in the zones that include the largest demand centres (GB4, GB5 and GB6 in Figure 6-4).

6.14. Offshore wind is deployed in all suitable areas throughout the modelling period, including the North Sea (GB6, GB4, GB3 and GB2), Irish Sea (GB4 and GB3), Celtic Sea (GB6), and the waters around northern and western Scotland (GB1 and GB2).

6.15. Under the LtW (NOA7) scenario as determined by ESO, the combined offshore and onshore wind capacity in Scotland (GB1 and GB2) increases eight-fold compared to 2021 levels, reaching 35GW in 2030 and 56GW in 2040.[161]

[161] Total installed wind capacity in Scotland in 2021 is 7,066MW according to DUKES 2022.

6.16. Solar capacity increases significantly in England, where climate conditions are generally more favourable for solar generators (GB3 to GB7).

6.17. Older nuclear plants, namely Dungeness B, Heysham 2 and Torness 2 are assumed to retire by 2030, reducing nuclear capacity in GB2, GB3 and GB7. However, this is offset by the commissioning of Hinkley Point C in the same year in GB6.

6.18. In the FES dataset provided by ESO, the majority of grid-connected storage is forecast to be installed near large demand centres, with the vast majority installed in the GB6 region.

Zonal

6.19. As mentioned previously, in our modelling of the zonal market design, the total capacity of each technology in each year remains fixed to that set out in FES 2021. However, we allow some new-build generation capacity, and all grid-connected storage assets, to site in different zones in response to prevailing wholesale market price signals and subject to the technology specific constraints outlined in Section 5D.

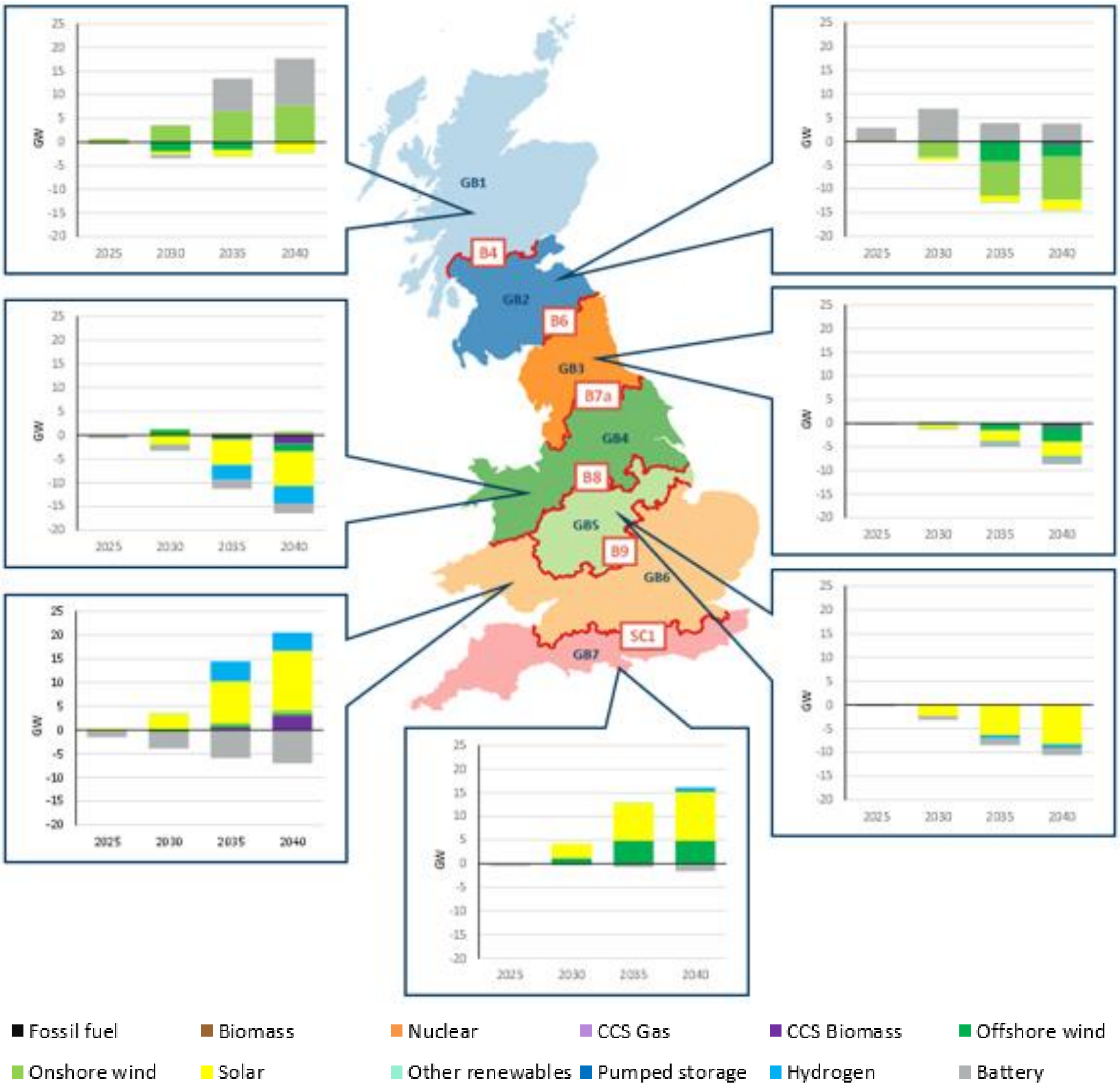
6.20. The siting of new generation capacity across zones are not optimised *within zones* as we assume that there is no locational wholesale price signal within the zone; instead, these are allocated in proportion to the distribution of forecasted capacity by technology across the nodes over time within each zone, set out in the relevant FES scenario.[162, 163]

6.21. The change in capacity in each zone as a result of moving from the current wholesale market design to a zonal model can be seen in Figure 6-5 below.

[162] For example, suppose a hypothetical zone contains three nodes, with onshore wind capacity of 5GW, 3GW and 2GW at Node 1, Node 2 and Node 3 respectively in the FES dataset. If the zonal capacity expansion model seeks to locate an additional 3GW of new onshore wind capacity into the zone, 1.5GW would be allocated to Node 1, 0.9GW to Node 2, and 0.6GW to Node 3. The re-siting method for site specific technologies, such as CCS or offshore wind follows a different approach, which is described in detail in Appendix 1.

[163] Conceivably, under a zonal pricing regime it might be possible to send a locational intra-zonal signal through the transmission charge for each zone and hence potentially influence siting decisions within a zone. We have not incorporated this feature explicitly. However, given the existing FES roll out incorporates a locational signal that varies by location across the system, our “pro-rating” approach of allocating changes in zonal generation capacity by node (albeit subject to technology specific siting constraints) might reasonably apportion a hypothetical “zonal” TNUoS charge.

Figure 6-5: Change in location of generation capacity between a zonal and national market design – LtW (NOA7)



Source: FTI analysis

6.22. Under a zonal market design, a proportion of solar capacity is expected to relocate to the southern zones (GB6 and GB7) in order to benefit from both the improved local climate conditions (increasing annual capacity factors) and the higher average wholesale prices in the zones south of the B9 boundary (relative to the average zonal prices further north).

6.23. We also forecast a relocation of onshore wind capacity away from the south of Scotland (GB2) relative to the FES forecast. Hourly wholesale prices are broadly equal between GB1 and GB2 in the latter years of the modelling period and, as a result, c.5GW of new onshore wind capacity sites in GB1 rather than GB2 (as expected under FES 21) to benefit from higher average capacity factors with minimal impact to the average price received (the capture price).[164] Approximately 2GW of new onshore wind capacity also locates in Wales to benefit from higher average zonal prices in GB4 and GB6 relative to GB2, but this is limited by our assumed build limits and local network constraints.

6.24. Our zonal modelling forecasts that some new offshore wind capacity would not locate in the northern zones (GB2 to GB4) but rather in the Celtic Sea (GB7). Capacity factors in the Celtic Sea are comparable to other high-wind potential areas[165] and re-siting to the Celtic Sea allows offshore wind farms to benefit from both higher capture prices and reduced transmission constraints relative to zones further north. As discussed in Section 5D, we place specific limits on the amount of new offshore wind capacity that can be sited at each offshore areas based on the seabed leases awarded and the planned capacity in FES 21 in each area.

6.25. Combined offshore and onshore wind capacity in Scotland is still expected to reach c.52GW by 2040 in the zonal model, constituting a less than 10% decrease under zonal market arrangements compared to that set out in FES 21 for the current market design.

6.26. A key finding of our zonal capacity expansion modelling is that an extensive proportion of grid-scale batteries opt to site away from demand centres in southern GB and site in Scotland (GB1 and GB2) instead. As detailed further in Box 6-1, Scottish zones see much higher price volatility between hours, with wholesale prices regularly dropping close to zero in windy periods. Price volatility between hours is relatively more limited in England and Wales.

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164 According to the PECD, new onshore wind farms in northern Scotland can have a c.41.8% annual capacity factor compared to c.40.4% in southern Scotland, based on the 2013 climate year.

165 According to the PECD, new offshore wind farms around the north-east Scotland can have a c.53.1% annual capacity factor compared to c.52.2% in the Celtic Sea, based on the 2013 climate year.

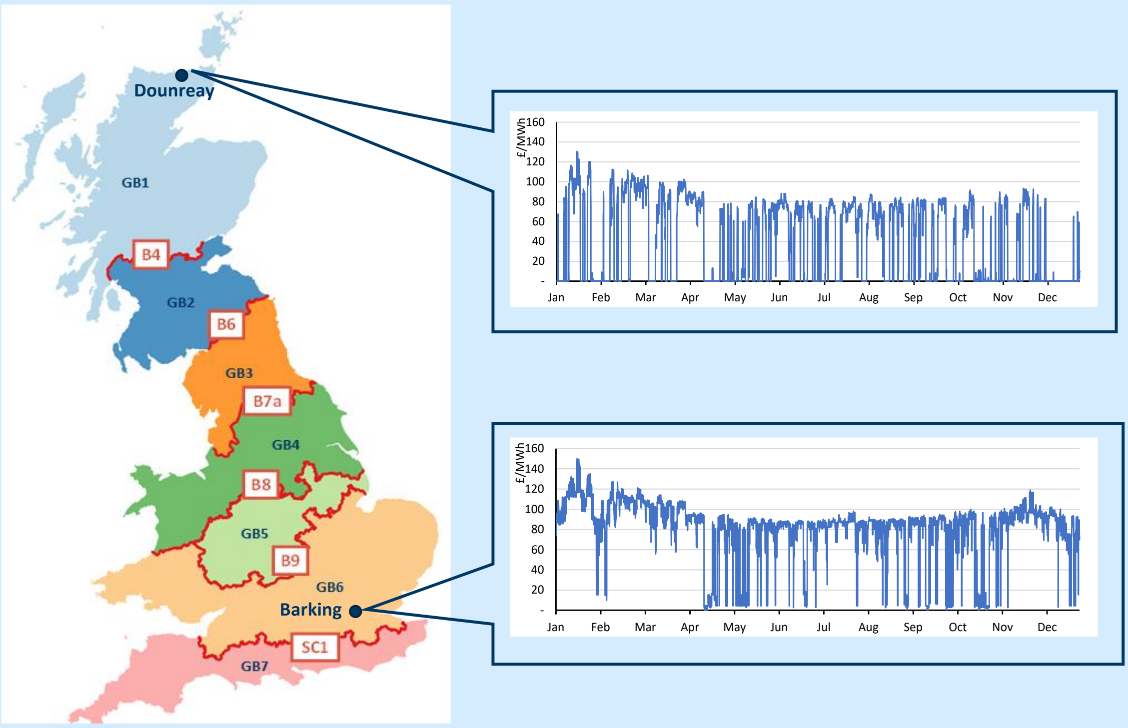
Box 6-1: Battery siting under nodal and zonal market arrangements

Batteries earn revenues in the wholesale market by buying electricity when prices are low due to high renewable generation or low demand, and selling this power when prices are high due to low renewable generation or high demand. This usually means charging overnight and discharging during the afternoon peaks when prices are higher.

As a result, batteries locate in areas which experience higher price differentials in the short-term. This traditionally happens at locations either around demand centres or in areas with high intermittent renewable capacity. GB includes both areas with high demand, such as London or the Midlands, and areas with high intermittent renewable capacity, such as Scotland, Wales or East Anglia. To understand why batteries choose to locate at one of these areas rather than the others, we need to compare the hourly price patterns at each of these areas.

In Figure 6-6 below, we present the hourly prices in 2025 under the LtW (NOA7) scenario at a node within the largest demand centre in GB, London (Barking) and at a node with high wind capacity in the northernmost part of Scotland (Dounreay). The comparison of these two nodes provides an explanation regarding why a large proportion of the grid-connected batteries tend to site in Scotland in our modelling.

Figure 6-6: Hourly price profiles at selected nodes in 2025 – LtW (NOA7)



Source: FTI analysis

Prices at Barking are higher in the afternoon peaks than the prices at Dounreay, allowing batteries to sell at a higher price. However, the difference between the Barking and Dounreay high prices is below £10 per MWh on most days. At the same time, prices in Dounreay decrease to £0 per MWh more often than at Barking due to high installed wind capacity in the area, allowing batteries to often charge up for zero cost. Overall, this creates a higher spread for batteries on most days in Dounreay, making them more commercially attractive than batteries sited at Barking. A higher standard deviation at Dounreay (c.£40.3 per MWh) compared to Barking (c.£29.8 per MWh) also illustrates this point.

The spread remains higher in Dounreay throughout the whole modelling period, as the new renewable capacity is deployed at a high pace in Scotland and remains high enough that prices frequently fall to £0 per MWh. At the same time price spikes in the south of the country are also limited by other forms of flexibility that are embedded with the LtW (NOA7) scenario – specifically the FES assumptions on interconnectors and demand side response. Both of these are centred around the south of the country and high demand areas and affect these areas more.

Under the LtW (NOA7) scenario, most of the flexibility on the system is not provided by grid connected batteries, but rather by thermal generation in the early years and by the demand side and interconnectors in the later years. Since these are located mostly in England and Wales (and in line with our assumptions set out earlier do not re-locate in response to zonal or nodal wholesale prices), the higher price volatility observed in Scotland makes it more commercially attractive for battery siting. The imbalance between price volatility in Scotland and in England and Wales remains even after most grid-connected storage is built in Scotland. If the assumptions in FES 21 regarding the ability of interconnectors to respond flexibly to prices and the extent of demand side response (particularly V2G) were overly optimistic, then we would anticipate higher price volatility in the south also – which would in turn impact battery siting decisions.

However, on the basis of the assumptions in the LtW (NOA7) scenario, the siting of batteries is also more efficient from a system perspective as, in their absence, more wind generation would be curtailed. Furthermore, being in an export-constrained location does not prevent batteries from generating at high priced hours when wind is low, as most of the constraints between Scotland and England are caused by wind generation.

Nodal

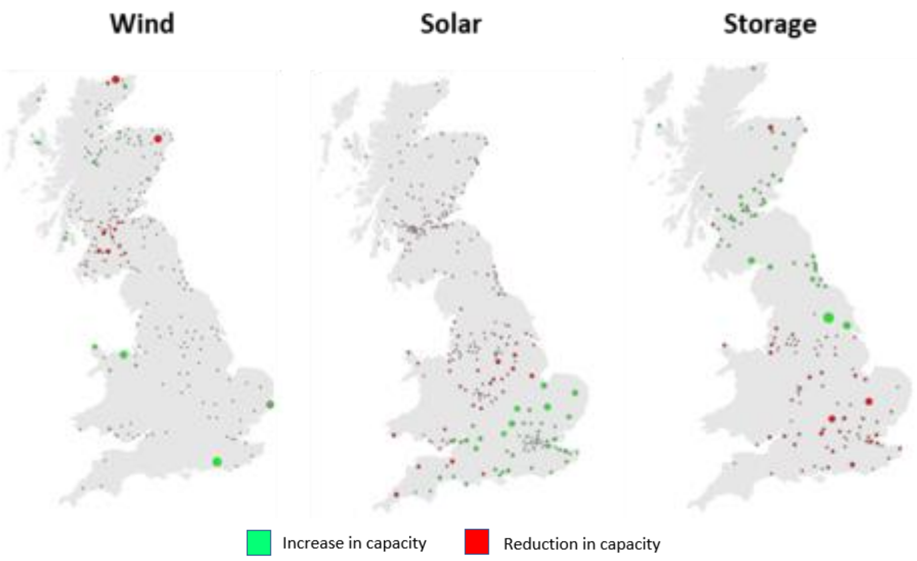
6.27. As explained above, in our modelling of the nodal market design, the total capacity of each technology in each year remains fixed to that set out in the relevant FES 21 scenario. However, as with the zonal model, we allow some new-build generation capacity (that are not in development) and all grid-connected storage assets to site in different locations, but this time across nodes in response to prevailing wholesale market price signals at each node.

6.28. Importantly, for the nodal market design, our capacity expansion model is used both to assess the amount of capacity of each technology type that seeks to site at a different node rather than the node envisaged in FES 21, and to allocate the capacity to the optimal nodes on the system, subject to the technology-specific constraints detailed in Chapter 5.

6.29. An example of this relocation of capacity between nodes, relative to that envisaged in FES 21, is provided in Figure 6-7 below, which highlights how the capacity of wind, solar and battery capacity changes in the LtW (NOA7) scenario in 2030 when moving from the current market design to a nodal model.

6.30. As mentioned above, for presentational purposes we aggregate capacity impacts to the zonal level for the remainder of this sub-section. However, our underlying modelling results include the re-siting of capacity at the nodal level.

Figure 6-7: Change in installed capacity under nodal market design (2030) – LtW (NOA7)

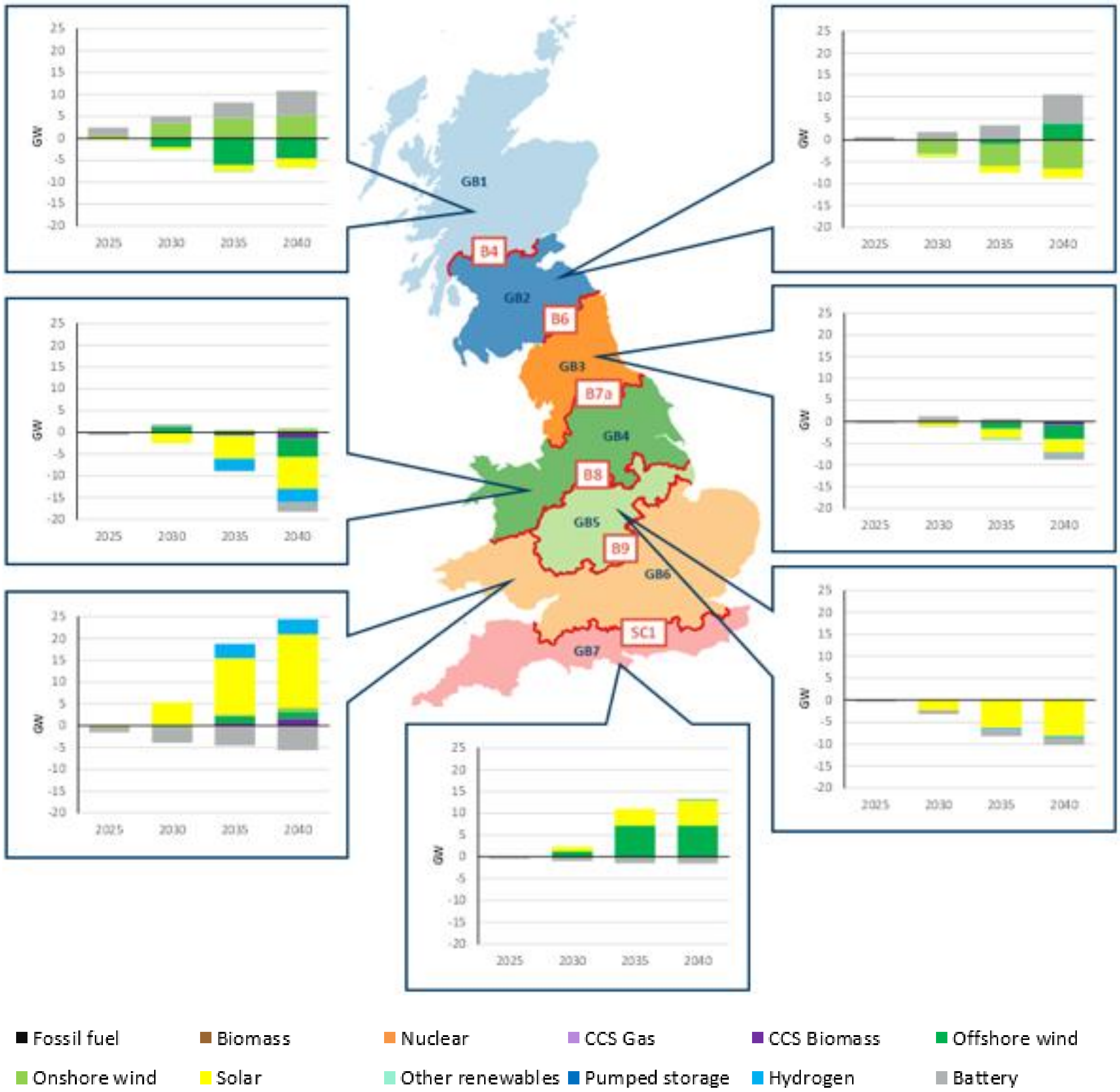


Source: FTI analysis
Note: The size of dots represents the change in installed capacity at each location, but dot size is not directly comparable across technologies.

6.31. The 2030 example in Figure 6-7 shows more onshore wind farms being located in northern Scotland and Wales compared to the national model. More new onshore wind farms are built in northern Scotland, as the capacity factors are higher in this area and the prices in the two Scottish regions are broadly similar in most hours. As a result, wind farms in northern Scotland benefit from higher volume of generation and are not penalised by lower capture prices relative to the South of Scotland. No onshore wind is relocated from Scotland to England due to our assumption that English onshore wind is fixed to FES 21, even though this re-siting would be economically attractive. The extent of re-siting from Scotland to Wales is limited by the assumed capacity limit placed on each node and by local network constraints, whilst keep capacity between market designs constant on a technology basis.

6.32. Solar generation capacity increases are centred around the southeast of GB and storage capacity increases are mainly in Scotland, in line with the zonal results. Figure 6-8 below shows an aggregated version of Figure 6-7 for all technologies per zone in all modelled year under a nodal market.

Figure 6-8: Change in location of installed capacity between a nodal and national market design – LtW (NOA7)



Source: FTI analysis

6.33. The optimal capacity evolution forecast by our nodal model, shown in Figure 6-8, is in line with the evolution under the zonal market design. Attracted by higher nodal prices and the better climatic condition assumptions as per the PECD, more than 20GW of new solar generation capacity is forecast to site in GB6 and GB7 rather than in other zones by 2040, while c.6GW of onshore wind does not site in southern Scotland, but rather in to northern Scotland and Wales instead.

6.34. Offshore wind projects connecting at the northern shores of Scotland lead to increased stress on boundaries within GB1 (B0, B1a and B2). This stress is taken into consideration for new offshore wind projects under nodal pricing and, as a result, we see a delayed offshore wind build-out in northern Scotland (which is c.4.6GW lower compared to the status quo build-out). Most of this capacity (c.3.5GW) is located in southern Scotland instead, where connection sites on the southern sites of these boundaries are available. This relocation is not observed in the zonal modelling, as these intra-zonal transmission boundaries are not considered for siting decisions.

6.35. Similarly to the results seen in the zonal sub-section, most new grid-connected batteries are expected to be built in Scotland. However, more of these new batteries are built in southern Scotland relative to the results of the zonal re-siting, following relatively lower build-out of wind in GB1 under nodal markets compared to zonal.

6.36. Combined offshore and onshore wind capacity in Scotland is still within 10% of that set out in FES 21 in 2040 and is forecast to increase more than seven-fold compared to the 2021 level. This compares to an eight-fold increase under the ESO's LtW scenario in FES 21.

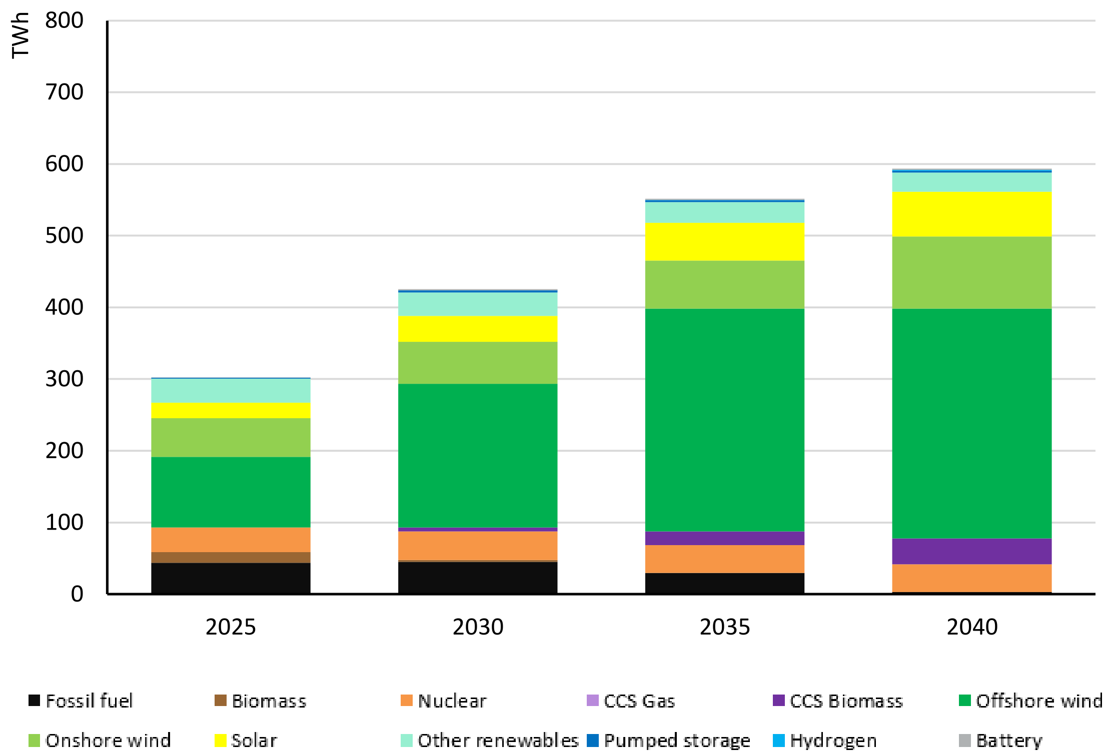
B. Generation

6.37. In this section we compare the dispatched generation mix under each market arrangement. For the national and zonal markets, this includes the effect of generation being constrained on and off by the ESO in the BM to ensure that dispatch is compatible with transmission constraints on the GB transmission network.

National

6.38. The generation mix post-BM[166] under the status quo national market is presented in Figure 6-9 below.

Figure 6-9: Generation by technology under a national market design – LtW (NOA7)



Source: FTI analysis

Note: There are no CCS gas generators in the Leading the Way scenario in the modelling period.

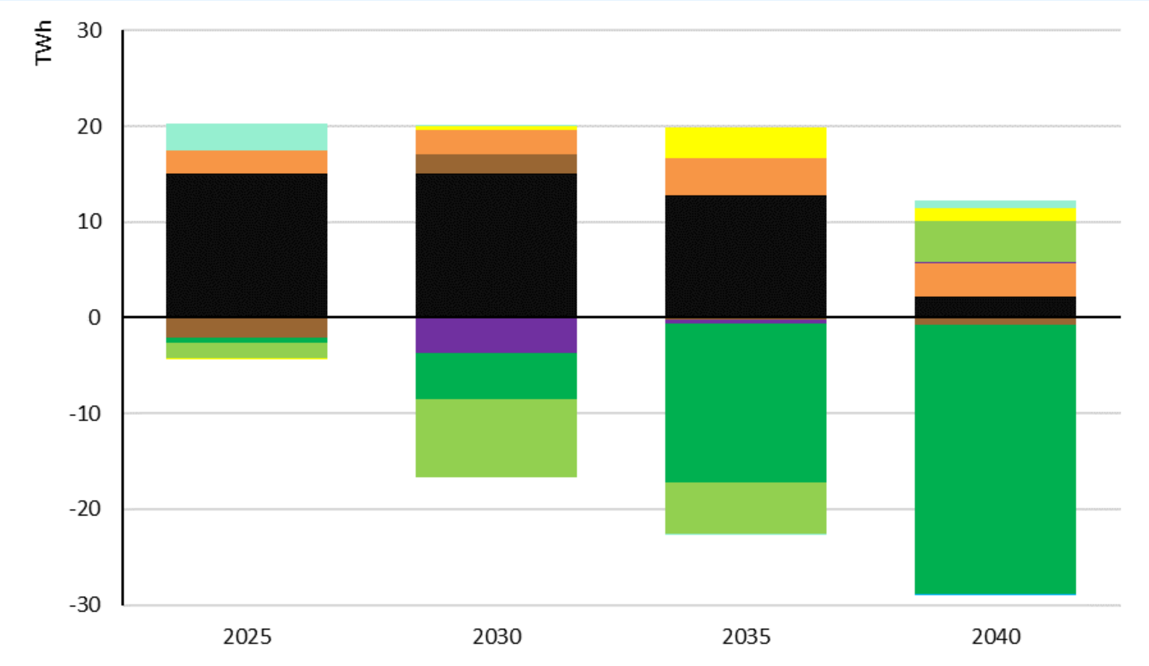
[166] The term 'post-BM' represents the generation profile after the SO has accounted for constraints, i.e., it excludes generation that was constrained off and includes any generation that was constrained on.

6.39. The generation mix under all market arrangements, shown in Figure 6-9 for a national pricing market, follows the evolution of the capacity mix. The share of generation from fossil fuels decreases in line with the retirement of gas plants. The shortfall created by this phase-out, as well as the steadily increasing demand for electricity driven by the electrification of transport, heating, and industrial processes, is met by increased generation from intermittent renewables, CCS Biomass and nuclear plants.

Box 6-2: Generation mix compared to FES 21 under LtW

To validate our modelling assumptions, we have crosschecked the generation mix of our model to the data presented in FES 21. Figure 6-10 below provides the differences between the FES 21 LtW generation mix and the pre-redispatch generation mix of our LtW (NOA7) scenario.

Figure 6-10: Difference in generation mix under FES 21 and FTI modelling



Source: FES 21 and FTI analysis
Note: Chart shows FES 21 outcomes less FTI modelled outcomes.

As shown on Figure 6-10, there are two main differences between in the FTI modelling compared to FES 21. Firstly, fossil fuel generation makes up a larger proportion of the total generation in our modelling compared to the FES modelling. In 2025, 9% of the total generation is from fossil fuels in our modelling compared to 5% in FES 21. While both sets of modelling predict that the contribution of fossil fuel generation falls below 1% during the modelling period, the FES 21 modelling reaches this level in 2035, but it is only reached in 2040 in our modelling (and remains at 3% in 2035). Secondly, we forecast lower wind generation relative to FES 21. The difference increases with the level of installed wind capacity reaches the highest level in 2040. In this year, we predict c.24TWh less generation, which corresponds to c.5% of the total wind generation in FES 21.

The increased fossil fuel generation in 2025 and 2030 is, we believe, due to different underlying commodity price assumptions. FES 21 relies on commodity prices from early to mid-2021, while the FTI modelling uses commodity prices from April 2022. As a result, some of the effects of the Ukraine crisis are reflected in our commodity price forecasts, but not in FES 21. These effects were relatively higher on Continental Europe, where reliance on gas from pipelines originating from Russia was higher. As a result, generators using gas in GB are likely to be more competitive than those in connected countries (such as Germany), leading to an increase in domestic generation for export.

Lower wind generation and, in turn, increased fossil fuel generation from 2030 onwards is a consequence of different underlying wind capacity profiles. As we describe in Appendix 1, we were not able to rely on the renewable capacity and demand profiles used in the FES 21 modelling and instead we used hourly profiles published by ENTSO-E. While we have adjusted these hourly profiles to have the same annual capacity factor as the ones used in the FES 21 modelling, the hourly profile of the two are likely to be different. As a result, overall wind curtailment differs in the two modelling analyses, which in turn leads to knock on impacts on output from other generation technologies as well.

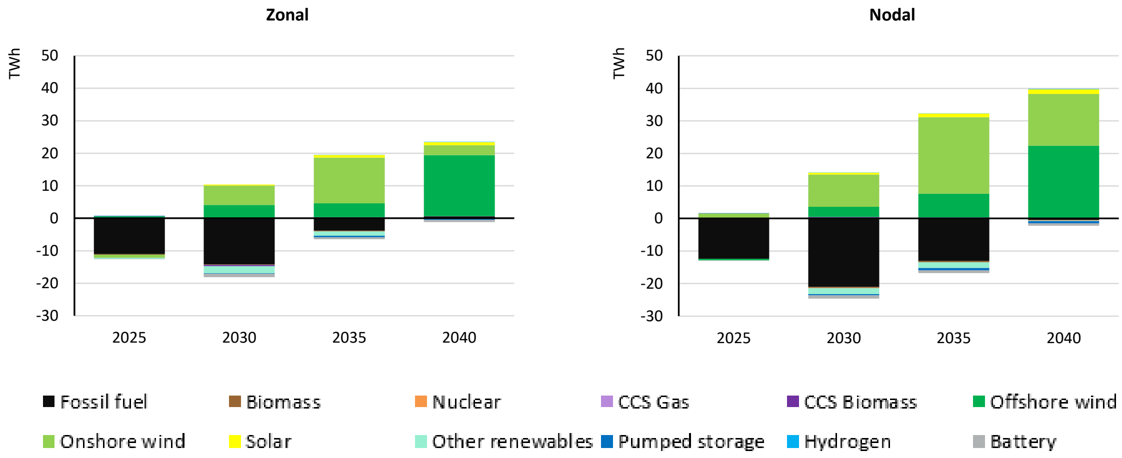
6.40. The transition away from fossil fuel generators relies on increased flexibility from alternative sources. By 2040, under LtW (NOA7):

- residential and industrial **demand side flexibility** becomes the largest source of flexibility, while V2G, smart charging, flexible heating systems and direct DSR participation in the wholesale market are predicted to provide up 59GW of flexibility;
- **interconnector** capacity between GB and other electricity markets reaches 28GW;
- generation capacity from grid-connected and behind-the-meter **storage assets** increases to 28GW; and
- 24GW of **electrolyser** capacity is connected to the grid to utilise surplus renewable generation.

Zonal and nodal

6.41. Figure 6-11 below shows the expected change in generation mix when moving from the current market design to a zonal or nodal model. The chart on the left compares the post-redispatch generation mix in the national model with the equivalent generation mix in a zonal market. The chart on the right compares the post-redispatch generation mix in the national model with that of the wholesale market in the nodal model. The nodal model, by design, does not require additional intervention by the ESO to balance the system.

Figure 6-11: Changes in the generation mix under a zonal and nodal market design relative to the post-redispatch national generation mix – LtW (NOA7)



Source: FTI analysis

6.42. Figure 6-11 shows that moving to a zonal or nodal market could reduce the amount of power sourced from fossil fuel generators in all years before their eventual phasing out in 2040, as well as increase the generation from offshore and onshore windfarms. This is made possible by:

- A better siting of intermittent renewable generators under zonal and nodal markets relative to that assumed in FES 21. By incentivising generators to re-locate away from the most constrained transmission boundaries, a greater proportion of wind generation is able to reach end-users under a zonal or nodal market design, rather than being constrained off. This in turn reduces the amount of flexible generation required from fossil fuel generators.
- A more efficient use of two-way assets such as interconnectors and storage:
  - As detailed in Box 6-3 below, under the current market design, wholesale electricity price signals can cause two-way assets to exacerbate power shortages in import-constrained areas in some hours.[167]
  - Under a zonal or nodal market design, locational wholesale price signals instead enable two-way assets to schedule flows in a more "system-optimal" way, helping to alleviate constraints in both export-constrained and import-constrained nodes across the year. In our modelling, this results in a reduction in fossil fuel generation being constrained on in the BM.
- Storage assets siting on the generation dominated side of transmission boundaries reduces the curtailment of wind generations, as storage assets could use this energy to charge up. Once wind generation on the system decreases and fossil fuel generators are required to meet

[167] In our modelling the ESO first prioritises the redispatch of domestic generation, with scheduled interconnector flows reversed in the BM as a last resort. However, in the later years of the modelling period, interconnectors form a key remaining component of flexible electricity supply, with the flexibility provided by fossil fuel generation largely retired by 2035. As a result, the reversal of scheduled interconnector flows forms a key component of ESO interventions in the BM in our modelling in 2035 and 2040.

demand, the storage asset would be able to generate, as the boundaries are unlikely to be constrained in these hours and would replace generation from fossil fuel generators.

- Similar to interconnectors, demand can be optimised on both sides of the boundary to alleviate stress on the boundary and in turn decrease wind curtailment and fossil fuel generation at the same time.

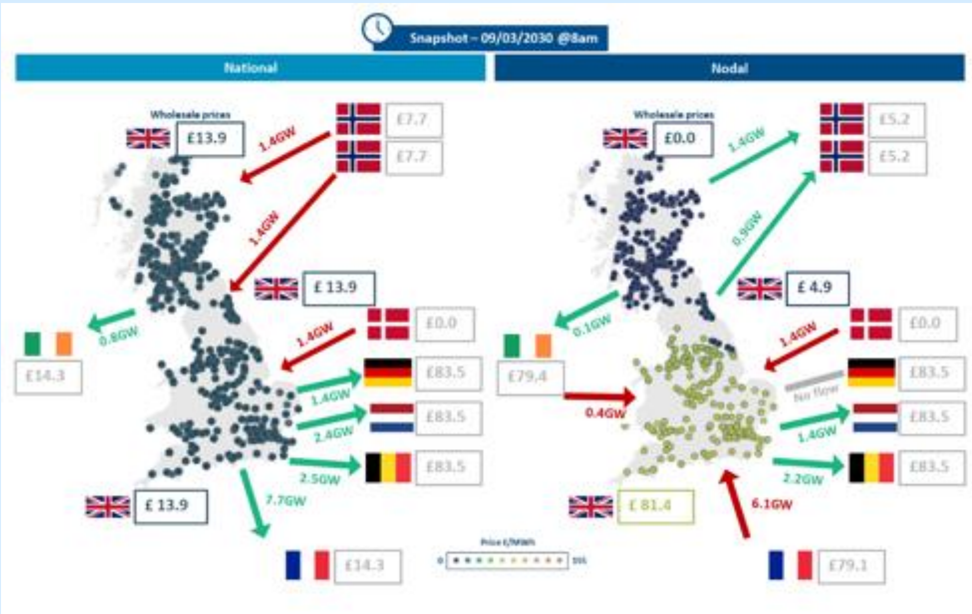
Box 6-3: Worked example of two-way asset flows under national and nodal wholesale pricing

Figure 6-12 below illustrates the prevailing wholesale price at each GB node in a particular hour of our modelling – in this case 8am 9 March 2030 – under both the national and nodal wholesale market designs. It highlights the net interconnector flows to each connected country and the prevailing wholesale market price in each market.

Under the national model, a single wholesale price applies to all GB nodes, clearing at a price of £13.9 per MWh. While it is a relatively windy hour, renewable generation is not sufficient to meet total GB demand in the wholesale market, requiring some imports and generation from biomass. Under the prevailing wholesale price, GB is scheduled to import relatively cheaper power from Norway and Denmark and exports to other connected countries. GB exports set the price in both France and Ireland.

However, in this hour ESO redispatch interventions of £1.5m are required. Scotland is export-constrained, requiring surplus wind generation to be curtailed, while additional Combined Cycle Gas Turbine ("CCGT") generation must be constrained on in the import-constrained south of GB to make up for this shortfall. Thus, in the wholesale market, interconnectors are scheduled to import additional power from an export-constrained region (from Norway) and export power from import-constrained regions in the south of GB. Interconnectors to Belgium, Netherlands and Germany are flowing at maximum capacity, while 7.7GW of interconnector capacity to France out of the total 8.8GW is also utilised to export power. These scheduled flows exacerbate local network constraints.

Figure 6-12: Indicative snapshot of Interconnector flows under National and Nodal market designs



Source: FTI analysis

However, with nodal pricing, the wholesale market implicitly accounts for transmission constraints in the initial price settlement. As a result, prices in the export-constrained Scotland fall to £0.0 per MWh, reflecting the very low marginal value of energy in an hour where surplus wind generation is being curtailed, while in northern England prices fall to £4.9 per MWh. Accordingly, GB-Norway interconnectors and some of the GB-Ireland interconnectors instead export power from GB, therefore increasing exports from the northern GB export-constrained region.

At the same time, the wholesale price in the south of GB is higher under the nodal market than it would have been under the national market, as CCGTs are scheduled to generate rather than being constrained on. The higher prices also lead to different scheduling for interconnectors in these areas. France becomes a net exporter of 6.1GW electricity to GB, while exports to north-western European countries decrease to 3.6GW from 6.3GW.

The effect on scheduled interconnector flows to Ireland is mixed, as some of these connect in Scotland where prices decrease, while some of them connect in southern Wales, where prices are higher than they were under the status quo market arrangements.

It is also worth noting that because of the change in scheduled interconnector flows, prices also change in the neighbouring countries. For this hour, the prices in Norway decrease by c.£2.5 per MWh, as Norway can consume wind generation from the north of GB that is otherwise curtailed, rather than consume its own reservoir-based hydro resource and export to GB. Given the huge potential of storage of the Norwegian system, this arguably would seem to allow a significantly better use of the Norwegian hydro system by the predominantly renewables GB system than under the national pricing regime.

The net position of scheduled France-GB flows changes by nearly 14GW as a result of nodal pricing. Such a large swing requires gas generation to be turned on in France, leading to a wholesale price increase of over £60 per MWh in this hour. Under a national pricing regime, scheduled imports from GB were setting the price in France. However, the low-cost electricity scheduled to export to France from GB that occurs under the national market design cannot, in reality, be delivered because of network constraints on the GB transmission system. Instead, in the BM, the ESO constrains on gas plants in the south of GB to allow exports to be delivered to France. Notably, the cost of this ESO intervention is recovered from GB consumers. We observe a similar situation in Ireland, where a much smaller swing is sufficient to require gas generation to be turned on, due to the smaller size of the Irish market.

6.43. Overall, moving to a zonal or nodal market design leads to a change in the total volume of GB generation, with effects varying across our modelling period. In the earlier years of our modelling, total GB generation falls, with improved price signals to interconnectors enabling imports from neighbouring countries to displace some fossil fuel generation. In later years, because of more efficient dispatch and some generation siting in different places, total GB generation increases under a zonal or nodal market design, driven by increased interconnector exports from export-constrained nodes in GB, enabling GB to export additional wind generation that would otherwise be curtailed under the current market design.

6.44. In addition to this, more efficient use of demand side response allows for reduced curtailment under both zonal and nodal market designs, thus resulting in an increase in total GB generation in locationally granular market designs relative to a national market design. We demonstrate this via the worked example in Box 6-4 below.

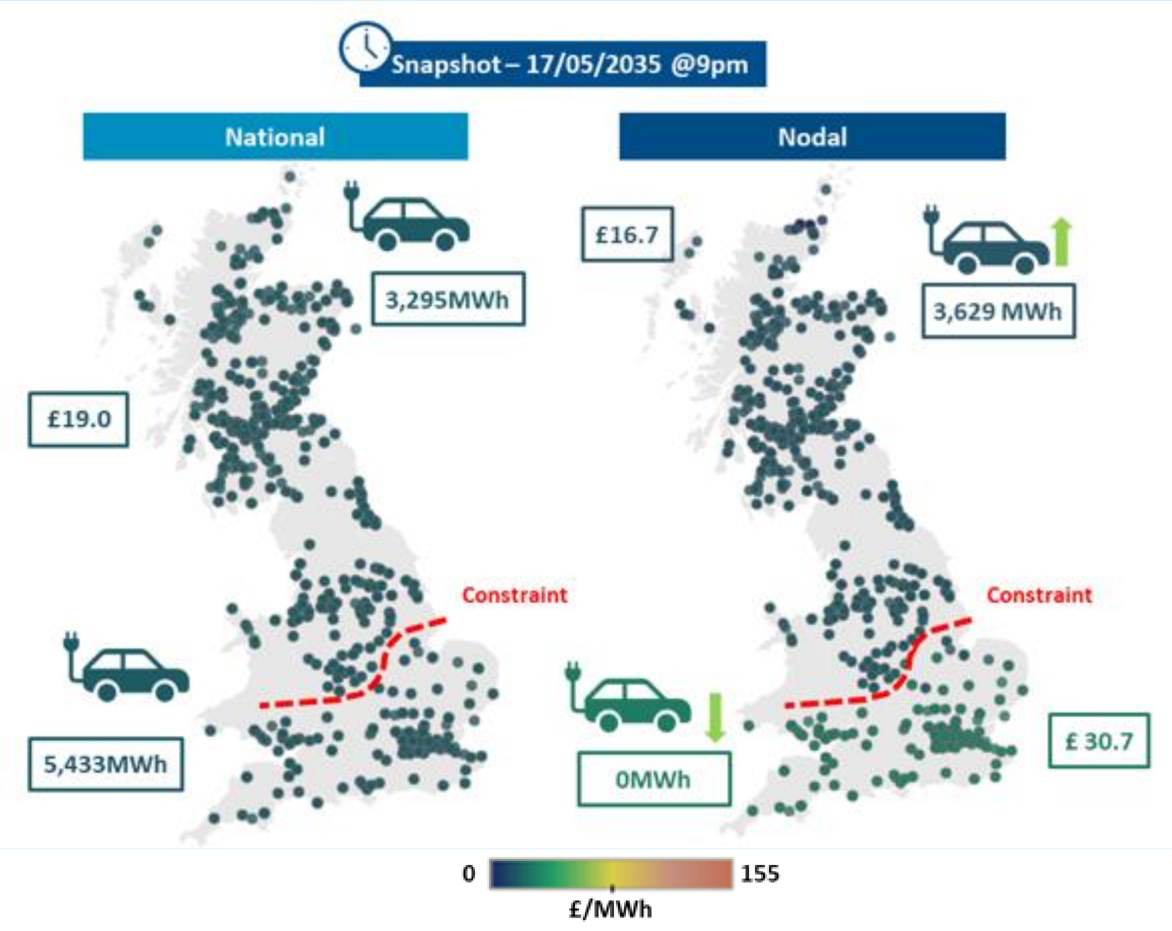
Box 6-4: Worked example of demand side response under national and nodal wholesale pricing

Figure 6-13 below shows the prevailing wholesale price at each GB node in a particular hour of our modelling (17 May 2035 at 21:00) under both the national and nodal wholesale market designs, with the consumption of smart charging EVs also highlighted.

Under the national model, a single wholesale price applies to all GB nodes, clearing at a price of £19.0 per MWh. Demand is met by mostly renewable generation, complemented with imports from Norway and generation from batteries. Smart EV charging decisions are made based on this national wholesale price, and total consumption from EVs is a function of the number of EVs in each region rather than locational price signals. As a result, electricity consumption by smart charging EVs is similarly high on the southern and northern side of the boundary due to the total number of EVs in each area.

However, the scheduling under the status quo wholesale market is not feasible due to transmission constraints, and additional CCGT generation on the southern side of the transmission constraint must be constrained on to meet demand, at a cost to consumers. Conversely, there is insufficient demand north of the transmission constraint, so wind generation is constrained off in the BM.

Figure 6-13: Indicative snapshot of EV behaviour under National and Nodal market designs



Source: FTI analysis

However, with nodal pricing, the wholesale market implicitly accounts for transmission constraints in the initial price settlement. Prices north of the constraint are slightly lower than what they were under the national market, at c.£16.70 per MWh, reflecting the low marginal cost of electricity. This causes the demand from EVs in the north of GB to be higher than it was under the national market.

Conversely, prices on the southern side of the constrained transmission boundary increase, as the import and generation that was previously dispatched through the BM is now paid through the wholesale market. In response to the higher price, smart EV charging is completely shifted to a different hour, when the same transmission constraint is not present on the system.

C. Congestion impact

6.45. As described in Chapter 4, the current market design requires interventions by the ESO to redispatch the system in response to transmission constraints on the GB network. This would also be required under a zonal market design albeit to a lesser extent as locational wholesale price signals would be expected to reduce the volume and associated cost of intervention required of the ESO.

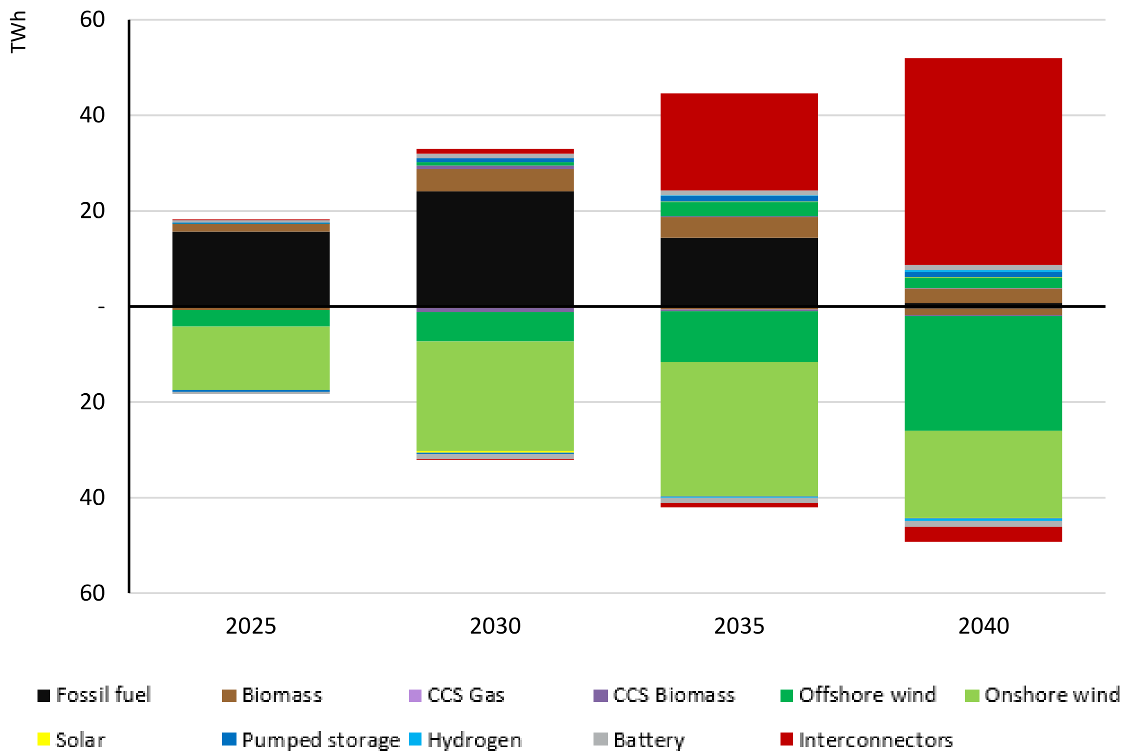
6.46. Following extensive discussions with both the ESO and industry stakeholders, we have developed a ”redispatch” model to estimate the volume of generation that would be constrained on or off by the ESO under both the national and zonal market arrangements. The underlying assumptions for our redispatch model are discussed further in Section 5D and Appendix 1.

6.47. In this section, we present our forecasts of the volume of generation expected to be redispatched by the ESO under a national and zonal market design, broken down by technology.

National

6.48. The figure below shows the evolution of constrained-on and -off generation under the status quo national market. Positive values represent constrained-on generation, and negative values represent constrained-off generation.

Figure 6-14: Constrained generation under a national market design – LtW (NOA7)



Source: FTI analysis

6.49. As shown in Figure 6-14 above, under the national market, increasing quantities of onshore and offshore wind generation are forecast to be constrained off across the modelling period. Constrained-off generation increases from c.17GWh in 2025 to c.42GWh by 2040. This takes place despite significant investments in the transmission network due to a combination of factors, as described in Section 6B above, such as that price signals in the wholesale market frequently result in two-way assets being used inefficiently from a system perspective.

6.50. This requires the ESO to constrain on additional output from alternative generators via redispatch interventions, primarily provided by fossil fuel generation between 2025-2035. In the final years of the modelling period, interconnectors form a significant proportion of remaining flexible capacity on the system and are utilised extensively for redispatch actions.[168]

6.51. We have discussed our approach with ESO regarding the modelling of the BM and validated our findings that interconnectors become the main asset to be constrained on as gas generation is phased-out.

Zonal

6.52. A zonal market would, by design, be expected to see lower constrained volumes than the current market design, driven by two key factors, as discussed in Chapter 2 and Box 6-3 above.

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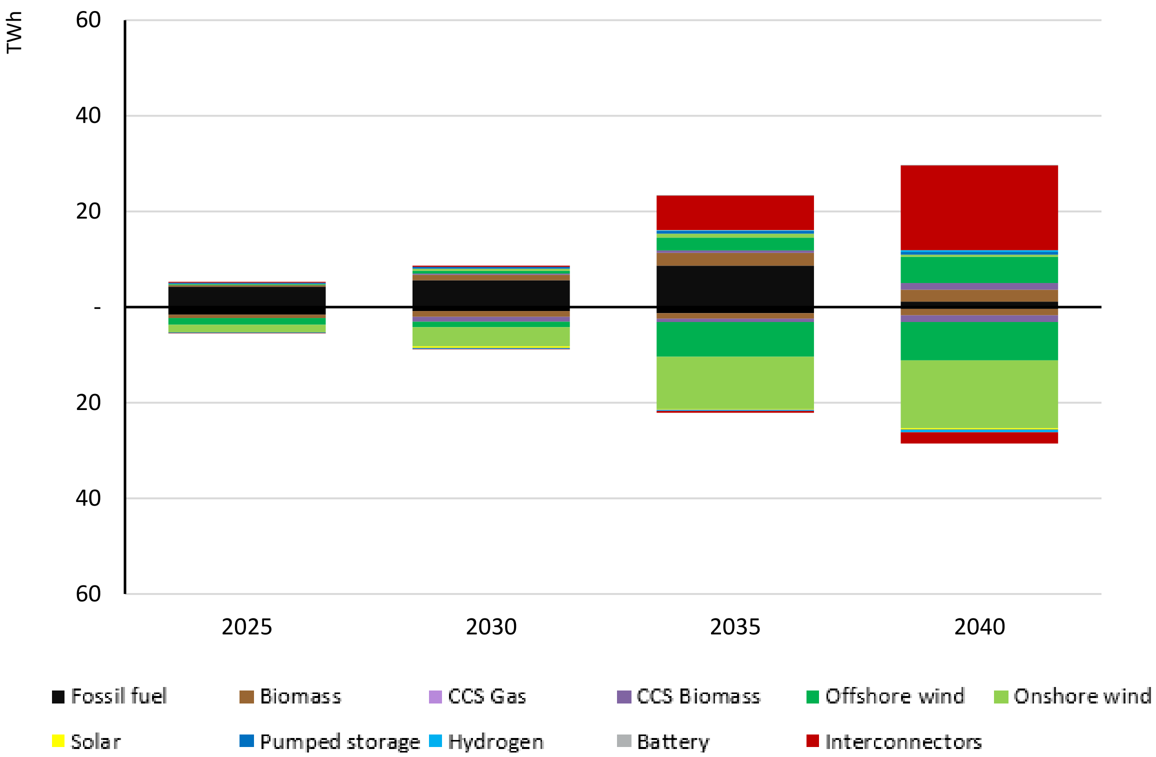
[168] In discussions with the ESO, we have compared the forecast volume of participation by interconnectors on the BM in our modelling with the ESO's own internal forecasts. Our results are closely aligned on both the current and future volume of participation by interconnectors.

6.53. First, in the short-term, by accounting for some of the key physical constraints of the transmission network in the initial wholesale price settlement, a zonal market will reflect some of the physical capabilities of the transmission network to market participants, particularly two-way assets, to operate in a "system-optimal" way, reducing the volume of ESO interventions required for redispatch.

6.54. Second, in the long-term, zonal wholesale prices that better reflect the marginal value of electricity in a particular area could encourage new generators to site in areas which are more able to export additional power to demand centres, reducing congestion on the transmission network over the longer run.

6.55. The impact of both these factors is highlighted in Figure 6-15 below, with forecast constrained volumes and a zonal market design roughly half of those forecast under the current market design. As above, positive values represent constrained-on generation, and negative values represent constrained-off generation.

Figure 6-15: Constrained generation under a zonal market design – LtW (NOA7)



Source: FTI analysis

6.56. Similar to the national model, under a zonal market design, the requirement for ESO redispatch interventions increases across the modelling period, with offshore and onshore wind generation increasingly constrained off as transmission boundaries become more congested. However, the volume of wind generation that is constrained off remains significantly below that forecast for the national model.

6.57. The technology mix of constrained-on generation follows a similar profile to that forecast for the current market design, albeit at lower volume levels. Until 2035, the majority of redispatch flexibility is provided by fossil fuel generation. With fossil fuel capacity retiring across the 2030s, driven by both rising carbon prices and policy direction, an increasing proportion of redispatch flexibility is performed by interconnectors.

6.58. A key result of the forecast constrained volumes of the zonal market design is that, while the selected zonal boundaries appear to eliminate the majority of required redispatch actions in the early modelling years, increasing constrained volumes in the 2030s suggest that new intra-zonal boundaries emerge on the system over time. As noted in previous chapters, under a zonal market design, re-zoning would likely need to be considered at regular intervals, to ensure that the zonal wholesale market continued to reflect the physical network over time.

Box 6-5: Effect of the BM on interconnector imports and exports

As we describe in Section 5D and Appendix 1, interconnectors can participate in the BM, but a price is associated with changing flows on interconnectors. This assumption is based on historic data, which shows that gas generators are more likely to be used for balancing than interconnectors.

Figure 6-16 below shows how interconnector flows change, as a result of redispatch, under the previously described assumptions on the BM. This data is grouped by the connecting countries to show how different group of interconnectors behave differently on the BM.

Figure 6-16: Interconnector flows in the BM

Source: FTI analysis

There are essentially no changes in flows in 2025 and only limited changes in 2030, as there is enough fossil fuel capacity (c.37GW in 2025 and c.27GW in 2030) in the GB system to provide the necessary amount of constrained-on generation in each hour. As a result, interconnectors rarely need to have their flows changed by the SO in the BM.

However, constrained-off volumes across technologies keep rising in the 2030s under all scenarios, due to the increase in installed wind capacity in the north of GB, which consequently increase the need for constrained-on generation in the south. This increase coincides with the phase-out of fossil fuel generation (c.10GW in 2035 and c.1GW in 2040), requiring interconnectors to provide increasing amount of constrained-on generation. Interconnectors provide this flexibility by reducing exports to France and North-West Europe and increasing imports from the same countries.

These interconnectors are scheduled to flow the "wrong-way" because the national market is not able to observe transmission constraints on the GB grid ahead of gate closure. For instance, in hours where GB has a relatively low electricity price, interconnectors are sometimes scheduled to export to countries where the price is set by higher cost units. However, once transmission constraints are accounted for, there may not be sufficient transmission capacity to cover the total demand in the south of GB and the scheduled export. Therefore, either export has to be reduced (or even switched to import) or other higher SRMC units have to be turned on in GB as well. We return to this issue in Chapter 10.

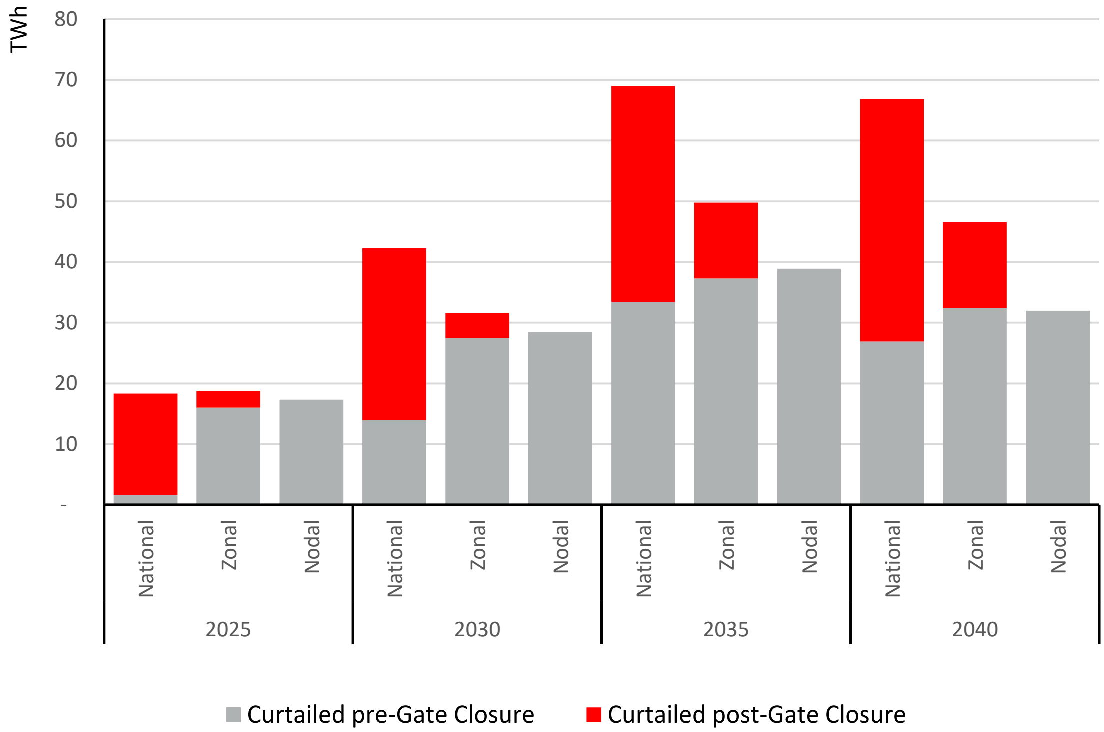
D. Curtailment

6.59. Under the status quo national market, wind generation can be curtailed pre- and post-gate closure. Pre-gate closure curtailment takes place if there is more renewable generation across GB than demand and export capacity combined. Post-gate closure curtailment happens in hours when there is insufficient transmission capacity on the GB transmission grid to convey the wind generation to consumers and, instead, balancing actions are required. As part of this balancing action, wind generation is constrained off while flexible generation at the other side of the transmission boundary is constrained on.

6.60. Pre-gate closure curtailment is expected to increase under zonal and nodal market arrangements, as more of the transmission constraints are taken into account at the scheduling stage. However, post-gate closure curtailment is expected to decrease under locational pricing, as there is a reduced need for redispatch under zonal markets and no need at all under nodal markets. This reduction is expected to outweigh the increase in pre-gate closure curtailment, as demand flexibility and two-way assets scheduling will be optimised while considering renewable generation and transmission constraints at the same time.

6.61. In Figure 6-17 below, we present both pre- and post-gate closure curtailment across all modelled market arrangements.

Figure 6-17: Wind curtailment – LtW (NOA7)



Source: FTI analysis

6.62. For the reasons described in Section 6B and 6C, locational pricing allows better utilisation of intermittent renewable generation, especially wind generation, and reduces their curtailment, as illustrated in Figure 6-17.

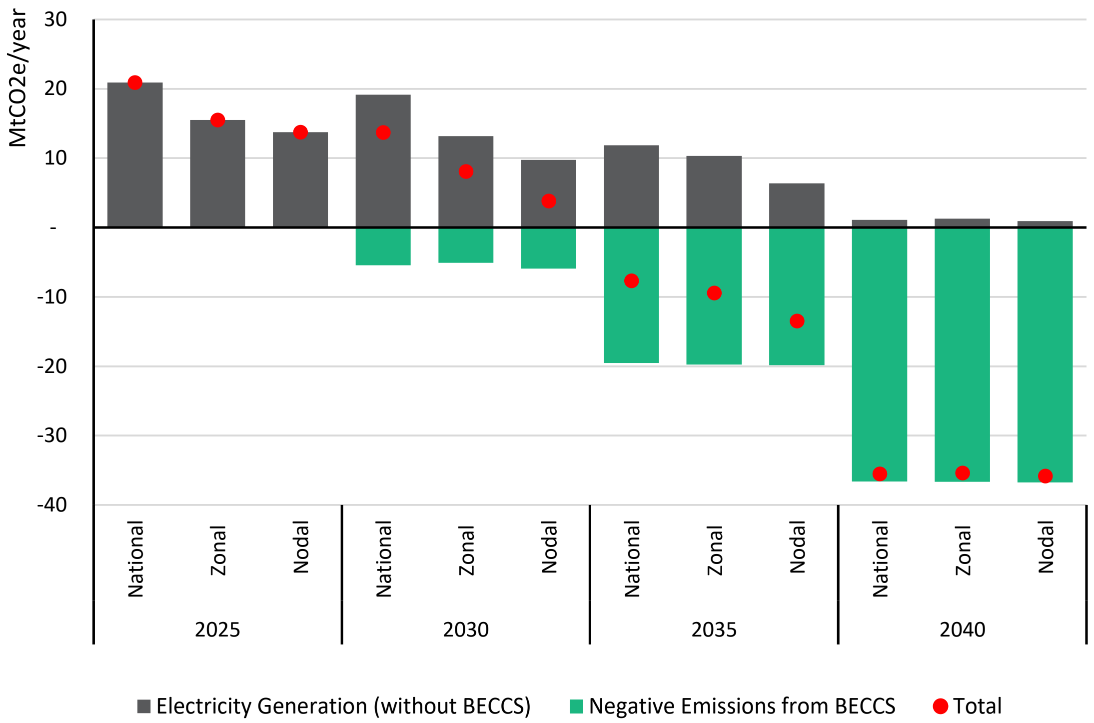
6.63. Specifically, under national pricing, about 18TWh of wind generation are expected to be curtailed off in 2025, with the figure expected to rise to almost 70TWh by 2035.

6.64. Over the modelling period, moving to nodal markets reduces wind curtailment by c.327TWh or 40%, while zonal markets lead to a c.209TWh or 26% reduction, indicating that under more locationally granular pricing, the GB market is able to utilise the same quantity of wind generation with a lower number of wind turbines (and therefore lower investment).

E. Emissions

6.65. Figure 6-18 below compares the level of emissions for each of the market designs in each modelling year.

Figure 6-18: Emissions from electricity generation – LtW (NOA7)



Source: FTI analysis
Note: Emissions from waste plants are excluded, as these are not currently part of the UK emissions trading scheme.

6.66. As shown in Figure 6-18, all market arrangements reach the same emissions levels by 2040, representing an average reduction of 52.3 MtCO2e from 2025 levels. This reduction is a result of the fossil fuel generation fleet being phased-out and the negative emissions from Bioenergy with Carbon Capture and Storage (“BECCS"), which is limited by the available biomass supply.

6.67. However, nodal and zonal markets reduce emissions in all other modelled years relative to the status quo national market. This is predominantly because generation from fossil fuel plants is replaced by more efficient utilisation of renewable generation and interconnector imports, as described in Section 6C.

6.68. The faster reduction in emissions would allow the UK to reach its Net Zero targets earlier or to create extra headroom for other industries, where emission reduction may be more challenging.

F. Interconnector flows

6.69. Electricity interconnectors are cross-border transmission links that allow electricity to flow between two connected electricity markets. They enable resources to be shared across wider geographic footprints, with excess supply from one region contributing to meeting demand in another. This is likely to become increasingly valuable as renewable penetration grows, with interconnectors helping low-carbon electricity to be shared efficiently across multiple regions.

6.70. Interconnector flows are optimised on an hourly basis in our model based on the prevailing price at the two connected nodes, and depend on both the intermittency of renewable generation (arising from weather patterns) and structural differences in power systems (such as the availability of hydro in Norway and nuclear in France). However, for ease of exposition, we will present annual imports and exports and mainly refer to annual prices in the connected countries and nodes, as these allow us to highlight the most important trends.

6.71. This section first outlines forecast annual interconnector flows under the current wholesale market design, before highlighting the percentage change in flows under zonal and nodal pricing. Importantly, this section focuses on wholesale market outcomes. The redispatch of interconnector flows to alleviate transmission constraints (and associated cost) is discussed in further detail in Box 6-5.

6.72. For the purposes of this summary analysis, interconnector imports and exports have been aggregated into four broad regions, to highlight overall trends while preserving the commercial anonymity of individual assets. However, our core modelling and results assess the full impact on each interconnector individually.

6.73. In the charts below, "exports" refers to interconnector flows from GB to connected electricity markets, while "imports" refers to flows into GB from connected markets.

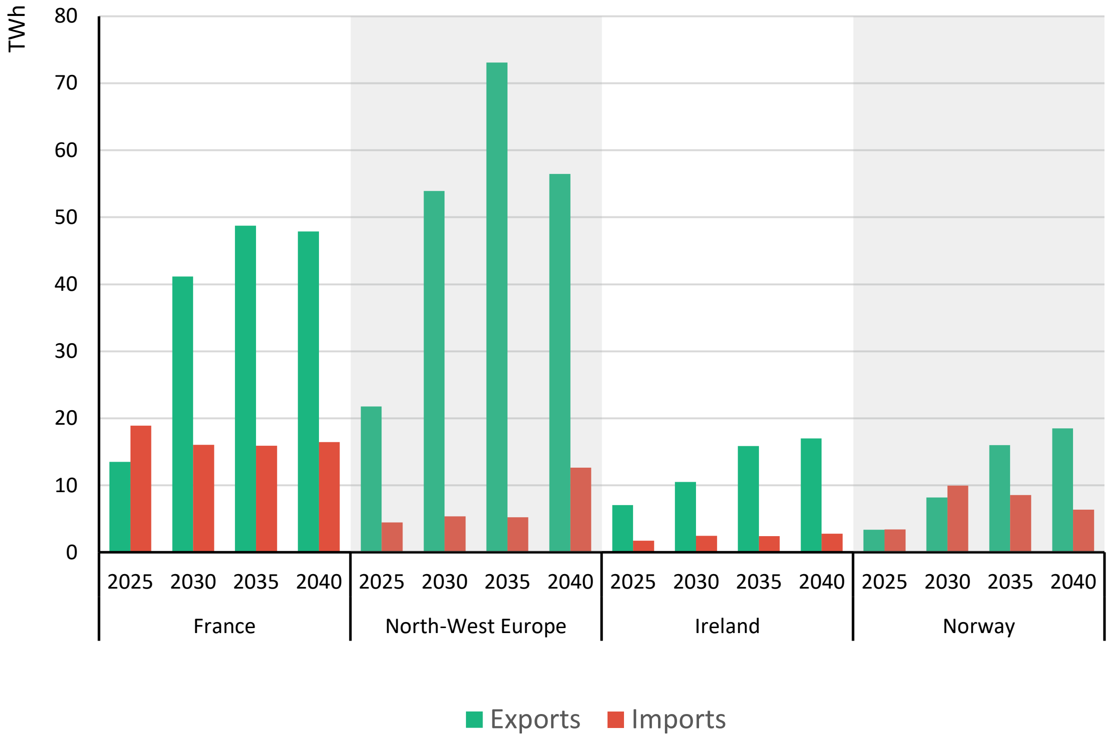
National

6.74. As discussed above, interconnectors enable the trading of power between connected electricity markets, with power exported from the lower-priced to the higher-priced region.

6.75. Under the current market design, the wholesale electricity price is the same at all points on the GB network. As a result, for the national model, the difference in the balance of scheduled flows between GB and connected markets is driven by the differences in the national wholesale price of the connected market.

6.76. Figure 6-19 below shows the modelled annual interconnector flows scheduled between GB and connected electricity markets under the current wholesale market design.

Figure 6-19: Interconnector imports and exports scheduled under a national market design, grouped by region – LtW (NOA7)



Source: FTI analysis

6.77. As highlighted in Figure 6-19 above, under the LtW (NOA7) scenario, GB is generally a significant net exporter of electricity to France, North-West Europe, and Ireland across the 2025-2040 modelling period.[169] This is driven by the rapid deployment of renewable generation capacity in GB, which outpaces that in the connected markets, causing GB wholesale prices to regularly fall below those in connected markets.

6.78. However, in 2025 when the renewable deployment is in its earlier stage, GB is still a net importer from France. In this year, high gas prices have a relatively greater impact on GB wholesale prices, given the greater reliance of the GB system on gas generation. French prices are less dependent on gas prices due to the extensive nuclear deployment.

6.79. Annual net interconnector flows between GB and Norway are more balanced, driven by lower electricity prices in Norway compared to other connected markets. Overall GB is a net importer from Norway in 2025 and 2030 by a small margin, while in later years, the extensive deployment of GB renewable capacity in LtW (NOA7) leads to GB becoming a net exporter.

[169] FES 21 predicts GB to be a net exporter of 71.6 TWh in 2030 and 110.8 TWh in 2035 under the LtW (NOA7) scenario.

6.80. However, as discussed above, the current market design regularly fails to reflect the value of electricity at specific points on the network, thereby raising the risk that the price signal provided to a particular interconnector at a given landing point is either too high or too low. In many cases, the single national wholesale price is lower for import-constrained areas and higher for export-constrained areas than it would be under a locational wholesale market. As a result, redispatch of interconnector flows is required in the later years of our modelling. The impact of this is discussed further in Box 6-5.

Zonal

6.81. Under a zonal market design, locationally granular pricing differentiates the price across GB and interconnectors receive price signals which incorporate the effects of the major GB transmission constraints. When prices fall in certain areas of GB under a zonal market model, the lower cost of electricity leads to higher net flows out of these zones. Conversely, in areas of GB where zonal prices rise relative to the national model, interconnectors receive price signals to increase imports and decrease exports, in response to scarce electricity.

6.82. Figure 6-20 below compares interconnector flows under the zonal model to those under the current market design.

Figure 6-20: Percentage change in interconnector import and export volumes scheduled as a result of switching from a national to a zonal market design, grouped by region – LtW (NOA7)

Source: FTI analysis

6.83. As shown in Figure 6-20 above, exports from the south of GB decrease due to an increase in the prices in those zones under a zonal market model, to better reflect the higher marginal value of electricity in those zones. Under a national market model, prices in the south are lower than the marginal value and often send the wrong signals to interconnectors. This results in excessive exports to France and North-West Europe in 2025 and 2030, while the resulting congestion is typically managed by constraining on fossil fuel generation, as explained in Box 6-5 in Section 6C. The more accurate price signals under zonal pricing relative to a national pricing model result in interconnectors reducing exports and increasing imports to GB from France and North-West Europe in the wholesale market in 2025 and 2030.

6.84. In 2035 and 2040, imports into GB from France and North-West Europe fall, due to the siting of additional offshore wind to GB7 and solar resources to more southerly parts of GB, as shown in Figure 6-5 in Section 6A, as well as improved use of demand flexibility in GB. While zonal pricing sends better signals to two-way assets, the increased prevalence of intermittent renewable generation decreases the zonal price in the south of GB in some hours relative to the national market model, leading to an increase in net exports.

6.85. The landing points of interconnectors to Ireland are located across multiple zones within GB, so zonal pricing has different effects on imports relative to the national model, depending on the specific interconnector in question. The reduction in imports from Ireland of c.20% in 2030 is the result of an interconnector connected to one of the Scotland price zones, where the zonal price falls on average relative to the national model. When placed in the context of total imports from Ireland in 2030, this change is small in absolute terms relative to imports from other regions.

6.86. Exports to Ireland remain largely unchanged, suggesting that the pricing signals driving exports under a national market model still exist under a zonal market model.

6.87. In 2025, the only GB-Norway interconnector, which is online lands in the northern England, leading to increased imports under zonal as the prices increase in this region. From 2030, in line with the FES 21 scenario, additional interconnector capacity landing in Scotland comes online. In response to the extensive deployment of renewable generation, zonal prices decrease in Scotland relative to a national pricing market and consequently, exports to Norway increase in a zonal market by c.20% and 5% in 2030 and 2035 respectively, relative to a national market design.

Nodal

6.88. Under a nodal market design, locationally granular pricing provides price signals which even more accurately reflect the different cost of electricity and transmission constraints at locations across GB. Although there are some trends which are common across a zonal and a nodal market, some changes in imports and exports are different under each of the two locationally granular market design choices. Zonal pricing still provides imperfect wholesale market signals to two-way assets, notably when there are transmission constraints within zones.

6.89. Figure 6-21 below compares interconnector flows under the nodal model relative to the current market design, showing the percentage change in flows to the four aggregated regions.

Figure 6-21: Percentage change in interconnector import and export volumes as a result of switching from a national to a nodal market design, grouped by region – LtW (NOA7)

Source: FTI analysis

6.90. Figure 6-21 above shows an increase in imports to GB from France and North-West Europe, as well as a significant reduction in exports to France and North-West Europe, in 2025 and 2030 under a nodal market model. Nodal prices increase relative to national prices in southern England, resulting in higher net flows into GB. While this effect is also present under a zonal market, it is more pronounced under a nodal market design, as all of the transmission constraints and intra-GB losses are taken into account. Combined, these lead to higher prices in the south of GB. Relative to a national pricing market, this therefore markedly reduces exports to France – particularly in 2025 and 2030. For the same reason, imports to GB increase in the earlier years of our modelling period.

6.91. By 2035 and 2040, imports from France and North-West Europe fall under a nodal market model (as they do under a zonal market model) relative to a national market. Again, this is due to increased re-siting of generation to the southern zones, as well as improved demand optimisation under the nodal model compared to the status quo national model.

6.92. Additionally in 2035 and 2040, exports to France and North-West Europe fall relative to the status quo market design, a result which is not seen under a move to zonal pricing. As shown in Box 6-5, under a national market model, interconnectors provide constrained-on generation by reducing exports to France and North-West Europe in 2035 and 2040, to alleviate transmission constraints. This still happens under a zonal market, but to a lesser extent resulting in a larger decrease under nodal markets.

6.93. Interconnectors to Ireland land at nodes which vary across GB geographically. The price effects on imports and exports vary depending on the interconnector in question, leaving aggregate flows relatively unchanged (as per our zonal pricing outcome).

6.94. There is a large increase in exports to Norway across the entire modelling period under a nodal market model, which is not observed under zonal markets. This is the consequence of the landing point of two of the interconnectors that are assumed to connect GB and Norway. Both connect on the northern side of their relevant zones and cause intra-zonal congestion. Nodal prices are able to account for this congestion by allowing surplus wind generation, that would otherwise be constrained off, to be exported under both the national and zonal market designs.

G. Overview of other scenarios

6.95. In this section we highlight a set of capacity and generation outcomes, similar to those represented above for LtW (NOA7), from the SysTr (NOA7) and LtW (HND) scenarios. The full detailed outcomes for these scenarios can be found in Appendix 2 and Appendix 3, respectively.

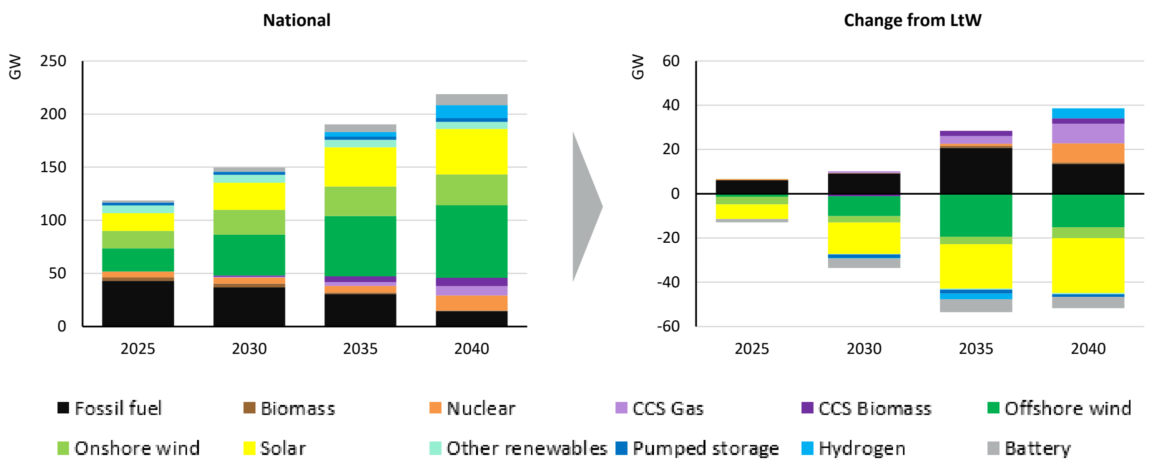
System Transformation

6.96. Our second scenario for our modelling assessment, SysTr (NOA7), represents a slower transition to Net Zero than LtW (NOA7), brought about by supply-side flexibility as well as increased hydrogen production and utilisation.

Capacity

6.97. Figure 6-22 below shows both the installed capacity under the SysTr (NOA7) scenario and the relative change from the LtW (NOA7) scenario.

Figure 6-22: Installed capacity under a national market design – SysTr (NOA7)



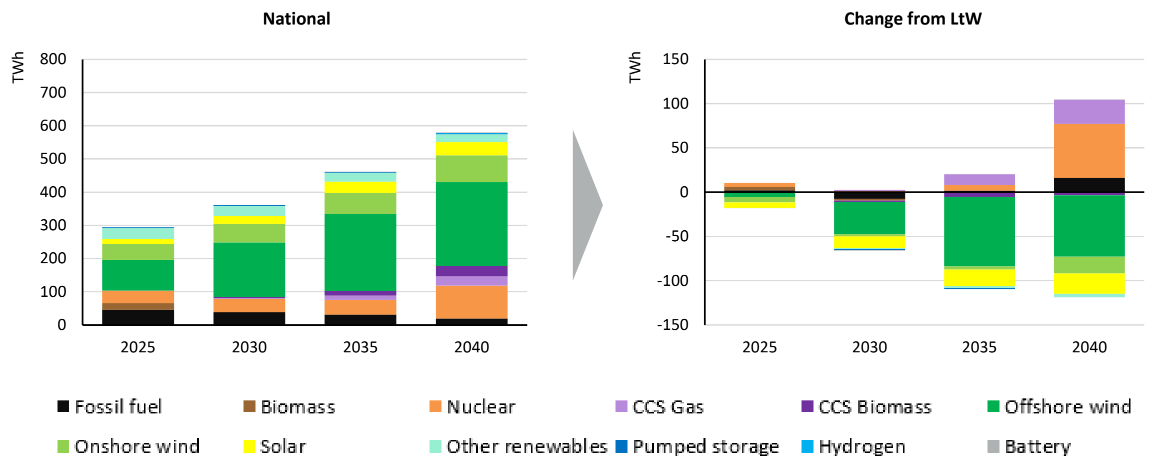
Source: FTI analysis

6.98. As can be seen in the figure above, relative to LtW (NOA7), the SysTr (NOA7) scenario has significantly lower offshore wind and solar capacity, in lieu of more fossil fuel plants throughout the modelling period, as well as greater nuclear and CCS gas capacity in the latter years.

Generation

6.99. Figure 6-23 sets out the differences in generation profiles between the SysTr (NOA7) and LtW (NOA7) scenarios.

Figure 6-23: Generation under a national market design – SysTr (NOA7)



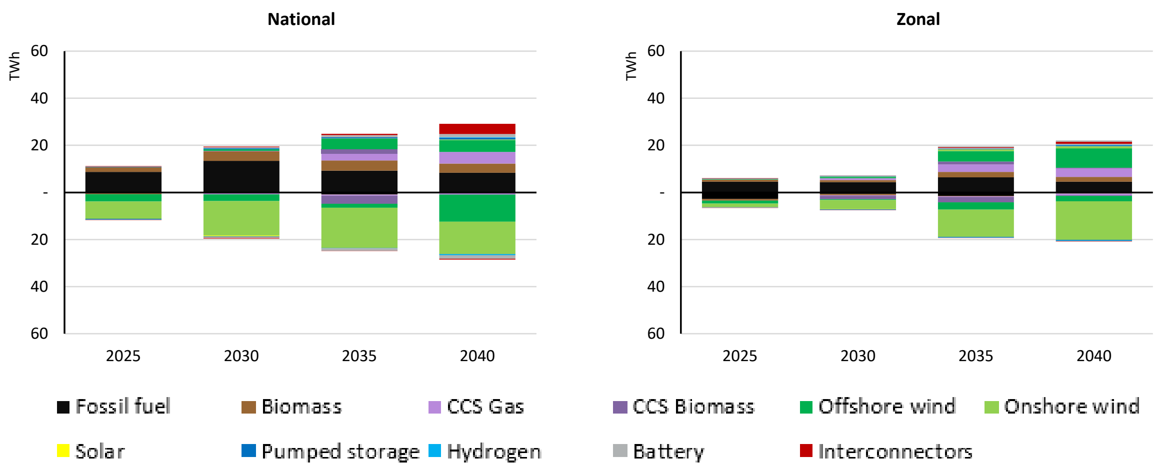
Source: FES 21

6.100. As shown in Figure 6-23 above, SysTr (NOA7) envisages less wind and solar output than LtW (NOA7), driven by lower demand requirements. However, increased demand in the latter years (due to delayed electrification of transport and heating) is met by additional nuclear and CCS gas output.[170]

Congestion impact

6.101. The congestion impact for national and zonal market models can be found in Figure 6-24 below.

Figure 6-24: Constrained volume under a national and zonal market design – SysTr (NOA7)



Source: FTI analysis

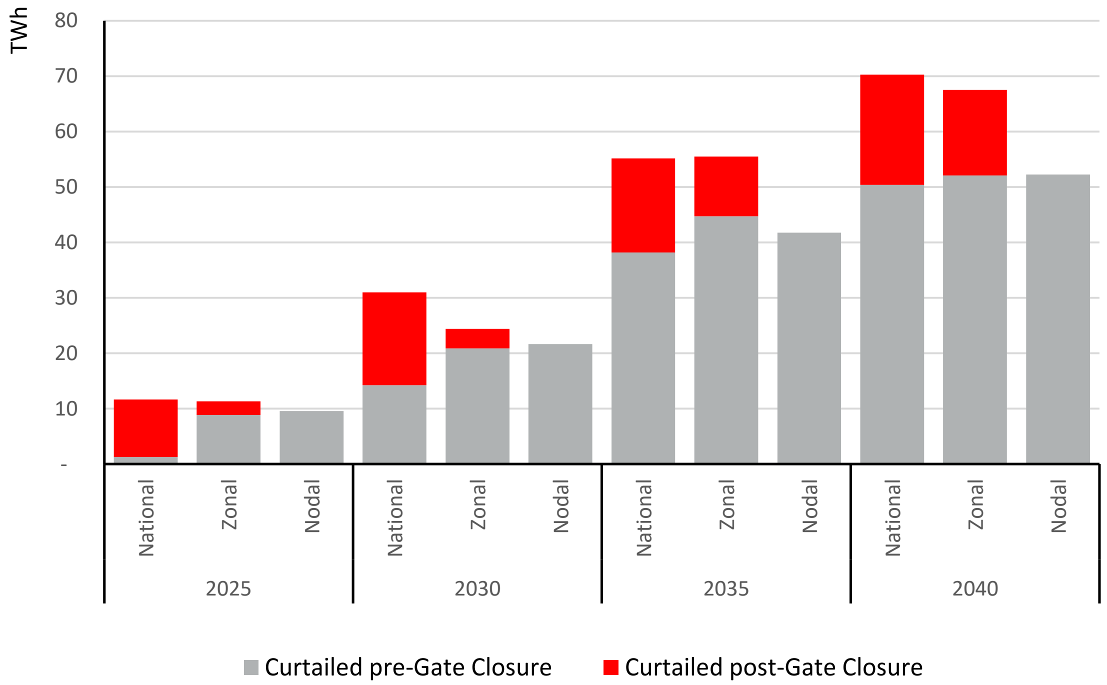
[170] The difference in nuclear generation under SysTr and LtW is greater in our modelling (c.61TWh) compared to FES 21 (c.48TWh). This is driven by different assumptions regarding the bidding behaviour of new nuclear plants. We have assumed that new nuclear plants (including SMRs) would bid similarly to legacy ones and would provide baseline generation, while FES treats these in a more flexible way. Since, SysTr includes higher nuclear capacity, this leads to a greater difference under this scenario.

6.102. Similar to LtW (NOA7), congestion volumes are expected to increase in both the national and zonal market designs. Congestion volumes in the zonal market are relatively small in the first decade, but then expand significantly, indicating the shift of larger boundary constraints from across zones to within zones.

Curtailment

6.103. Figure 6-25 shows the wind curtailment across the three market designs under the SysTr (NOA7) scenario.

Figure 6-25: Wind curtailment – SysTr (NOA7)



Source: FTI analysis

6.104. As shown Figure 6-25 above, more granular locational market designs result in lower overall curtailment of wind. As indicated above, the overall levels of wind curtailment between the national and zonal market designs are broadly similar indicating the shift in constraints to within zones.

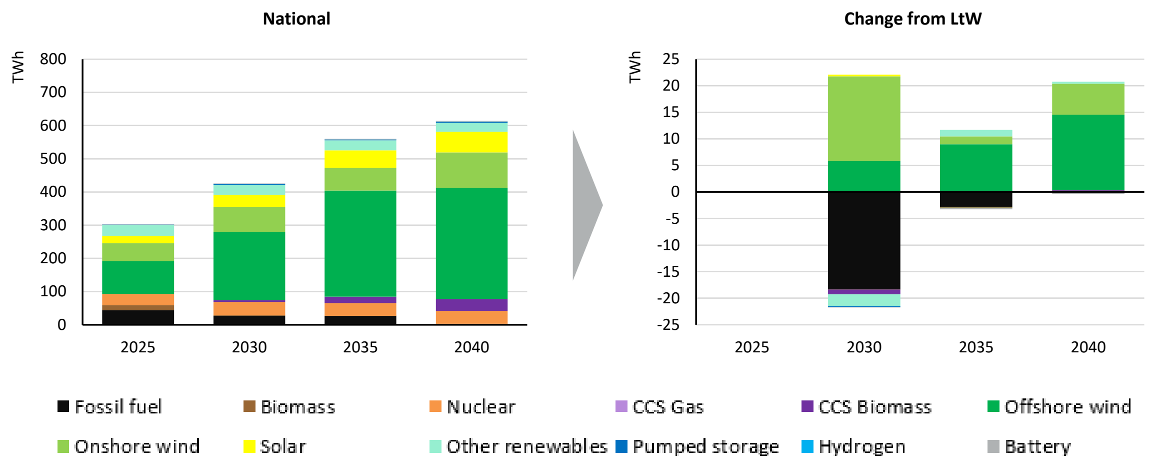
Leading the Way (HND)

6.105. LtW (HND) installed capacity is the same as LtW (NOA7) across the whole of GB, as the two scenarios differ only by the transmission capacity modelled.

Generation

6.106. Figure 6-26 below shows the generation profile under the LtW (HND) scenario, and the changes from the LtW (NOA7) scenario.

Figure 6-26: Generation under a national market design – LtW (HND)



Source: FES 21

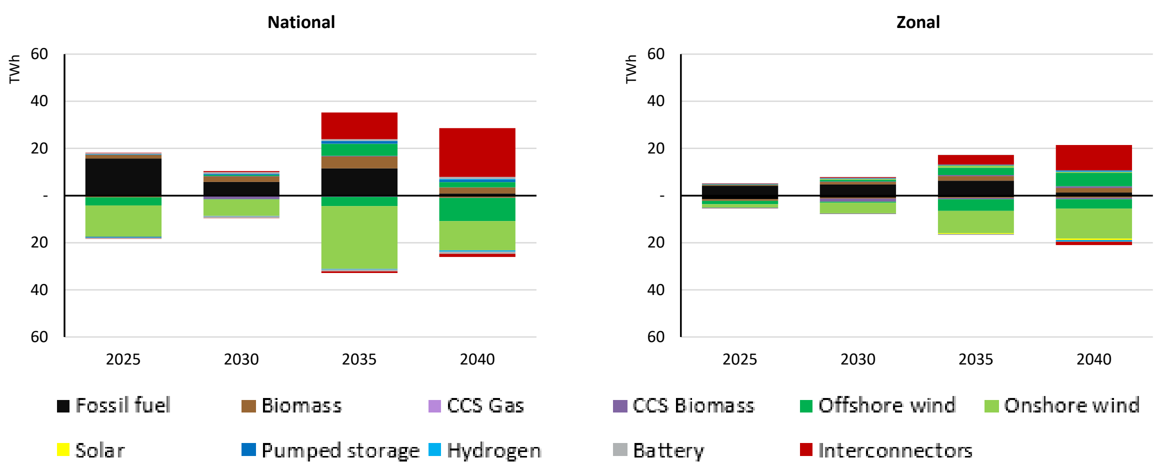
6.107. As shown in Figure 6-26 above, the LtW (HND) scenario consists of greater wind generation and less fossil fuel generation that LtW (NOA7) in 2030. This is due to the additional transmission capacity that primarily comes online in the period between 2025 and 2030, which allows a greater proportion of demand across GB to be met by wind generation, and consequently a reduced need to constrain on CCGT generation.

6.108. As fossil fuels are phased out, additional transmission capacity allows wind generation to be exported to France and Western Europe, rather than be constrained off as in LtW (NOA7). This explains the greater levels of total generation in 2035 and 2040, relative to LtW (NOA7), despite the demand profile remaining fixed across the two scenarios.

Congestion impact

6.109. The congestion impact for a national and zonal market model can be found in Figure 6-27 below.

Figure 6-27: Constrained volume under a national and zonal market design – LtW (HND)



Source: FTI analysis

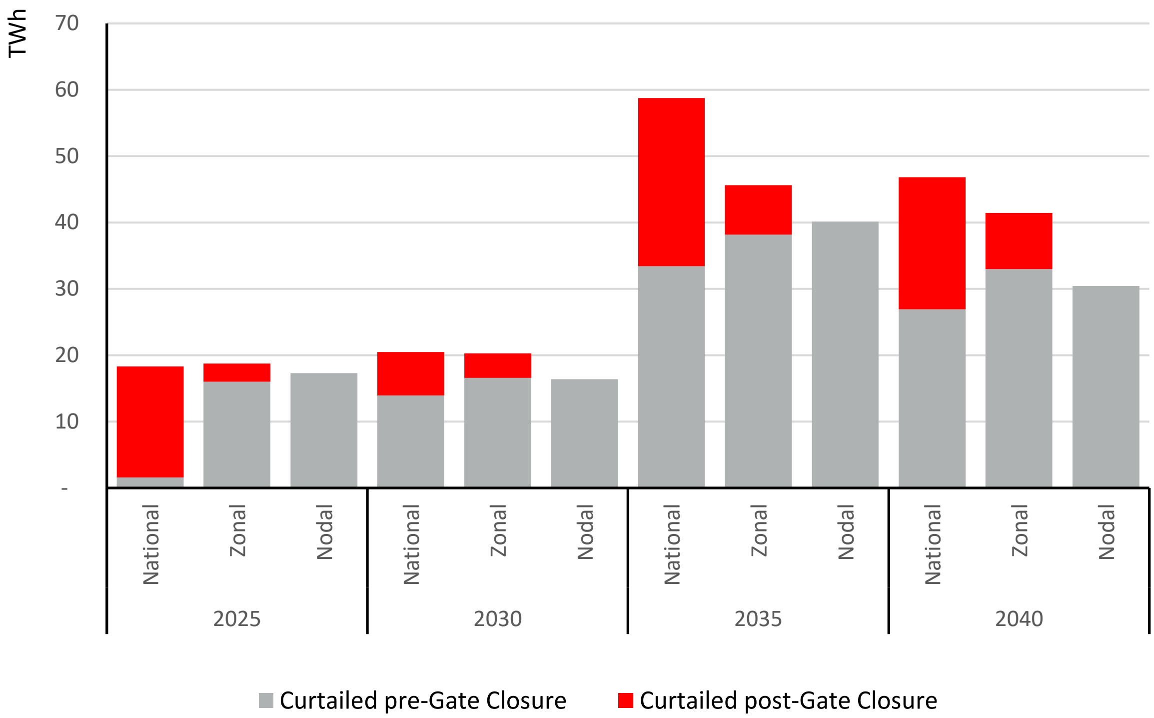
6.110. Compared to LtW (NOA7), constrained volumes under a national market reduce from 2030 due to the additional transmission capacity which comes online in LtW (HND). As fossil fuels are phased out, interconnectors are required to resolve transmission constraints, but due to increased transmission capacity in LtW (HND), these volumes are lower than under the LtW (NOA7) scenario.

6.111. Zonal constrained volumes under LtW (HND) mirror the trend observed under LtW (NOA7). There is a slight reduction in volumes from 2030 onwards under LtW (HND), due to additional transmission capacity, but this effect is smaller than under a national market model as transmission constraints are already partially reflected in zonal wholesale prices.

Curtailment

6.112. Figure 6-28 shows the wind curtailment across the three market designs under the LtW (HND) scenario.

Figure 6-28: Wind curtailment – LtW (HND)



Source: FTI analysis

6.113. As is the case under LtW (NOA7), more locationally granular pricing reduces overall curtailment of wind generation. Due to the increase in transmission capacity under LtW (HND), there is less wind curtailment in the BM under both national and zonal market designs from 2030 onwards.

7. Pricing and financial outcomes

7.1. In the previous chapter, we set out the key physical outcomes forecasted for each market design under the LtW (NOA7) scenario, with a focus on how the location and output of generation capacity develops across the modelled period, concluding with a brief comparison of key results with the other two modelled scenarios.

7.2. Building on this physical overview of the electricity system, we outline in this chapter the resulting electricity prices and financial flows between consumers and producers under each set of market arrangement.

7.3. Similar to the previous chapter, for presentational purposes we present here the full set of results for the LtW (NOA7) scenario, before highlighting key differences between scenarios at the end of the chapter. The full set of results for the LtW (HND) and SysTr (NOA7) scenarios are provided in Appendices 2 and 3.

7.4. In the remainder of this chapter, we explore the following impacts for each market design:

- change in wholesale electricity prices and cost faced by GB consumers (**Section A**);
- reduction in the cost of constraint management (**Section B**);
- changes in CfD payments from consumers (**Section C**);
- total electricity cost for GB consumers and the impact of intra-GB congestion rents (**Section D**); and
- producer impact, including producer surplus in the wholesale market and BM, as well as changes in CfD payments to producers (**Section E**).

A. Wholesale electricity prices and cost

7.5. Wholesale electricity prices in zonal and nodal markets will, by design, be different from those forecast for the national market, as the impact of transmission boundary limitations and network losses are considered in the formulation of locationally granular prices. The extent of this difference will depend on the level of congestion and degree of losses observed on the system in each hour.

7.6. A key output of our power market modelling is the estimated wholesale price at every node on the GB transmission network for every hour across the modelled period. Under the national model, the price is identical across all nodes within GB, reflecting the single national wholesale price of the current market design. For the zonal model, wholesale prices regularly vary <u>between</u> the modelled zones, driven by inter-zonal transmission constraints, but are always identical at all nodes <u>within</u> each zone. Under the nodal model, the wholesale price varies at every node.

7.7. We provide details of price outcomes from our modelling in the two following subsections:

- First, we present analysis of how prices vary across different locational market design options.
- Second, we provide details of average annual prices under each market design.

Price formulation under each market design option

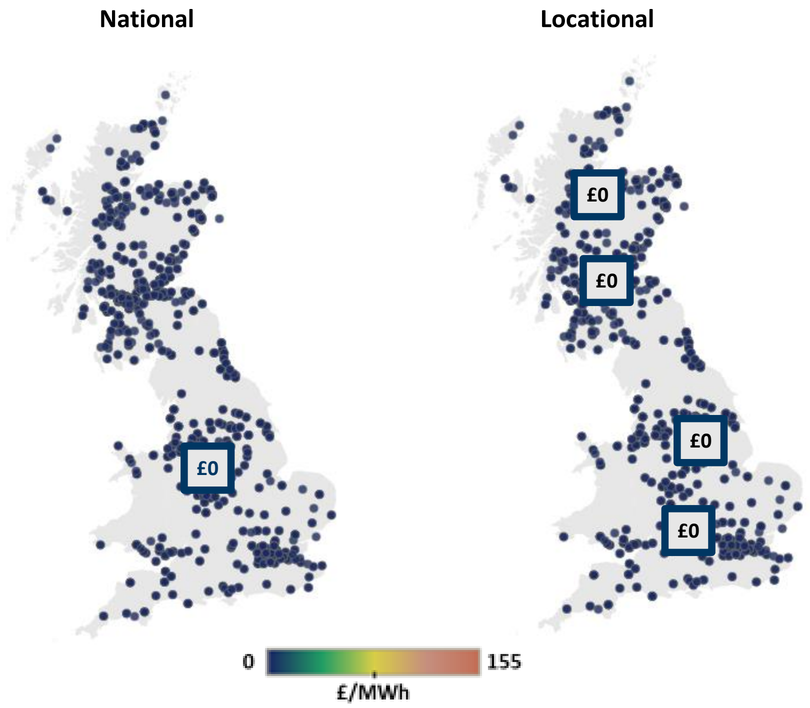
7.8. In this subsection, we explain how prices under each market design differ. The example below shows our results for a nodal market relative to a national market design. Very similar, albeit less pronounced, effects can be observed in a zonal market design.

Example hours

7.9. We highlight, in particular, the impact of wind generation on price formation, by illustrating how prices are formed under a range of different wind output patterns.

7.10. Figure 7-1 below shows the wholesale electricity prices under the national and locational market designs from our modelling at midday on 29 September 2040.

Figure 7-1: Example of a very high wind hour across GB (29 September 2040 – 12:00)

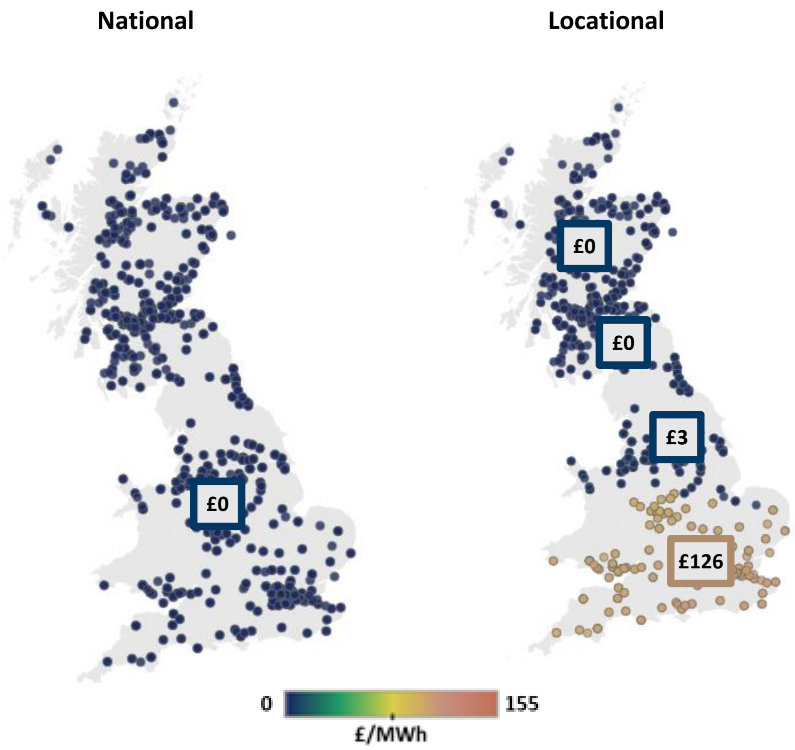


Source: FTI analysis

7.11. As shown in Figure 7-1 above, the high wind output *across* GB relative to demand at each location is sufficiently high enough to cause wholesale electricity prices to be set at zero in both a national and a nodal market.

7.12. In contrast, we show the wholesale electricity prices for a specific hour (17:00 on 10 December 2040) where wind output is high in Scotland and northern England in Figure 7-2 below.

Figure 7-2: Example of a very high wind hour in Scotland and northern England (10 December 2040 – 17:00)



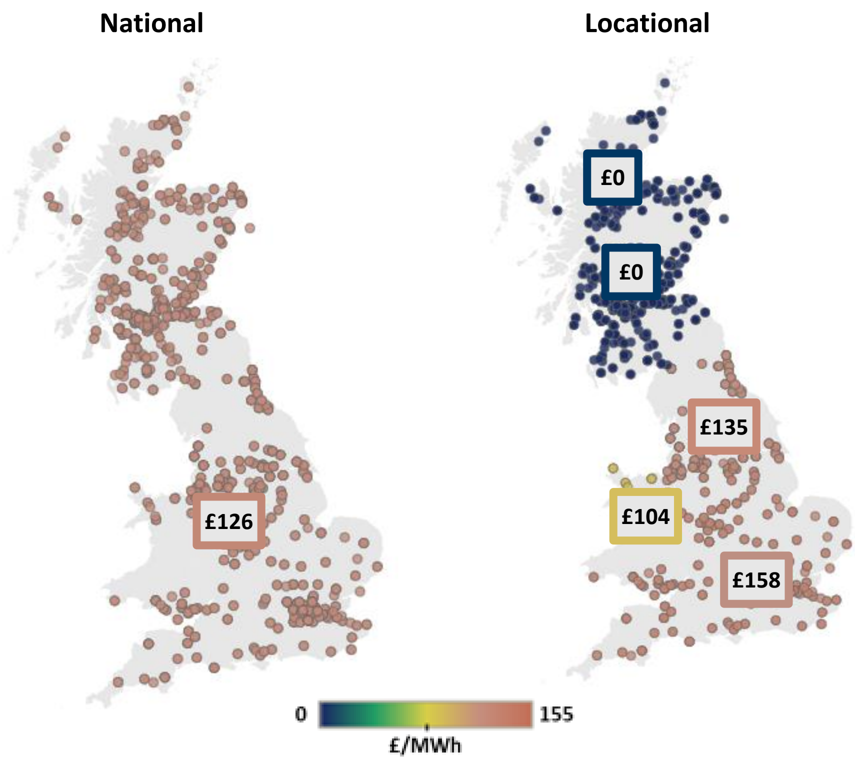
Source: FTI analysis

7.13. For the example hour shown in Figure 7-2 above, wind generation in Scotland and northern England is particularly high. Under the national model, wind generation in Scotland is high enough to set the national price to zero, as the scheduling process does not take into account any transmission network constraints. However, there is, in reality, insufficient transmission capacity between southern England and northern England to convey all of the wind energy to the southern part of the country. As a result, balancing action is required to turn down some wind farms in the north of GB and turn on some generation in southern England – this is reflected in the cost of the BM instead of the wholesale electricity market.

7.14. However, in our nodal model, the impact of transmission constraints at particular points of the network can clearly be observed, causing a decoupling of wholesale prices between specific regions. Hence even though the same constraint is binding, wholesale electricity prices in southern England in a locational pricing market are higher compared to the national market.

7.15. Figure 7-3 below shows a selected hour where wind output in Scotland and northern England is high but not sufficiently high to clear the national market as the marginal plant.

Figure 7-3: Example of a moderately high wind hour in Scotland and northern England (17 January 2040 – 17:00)



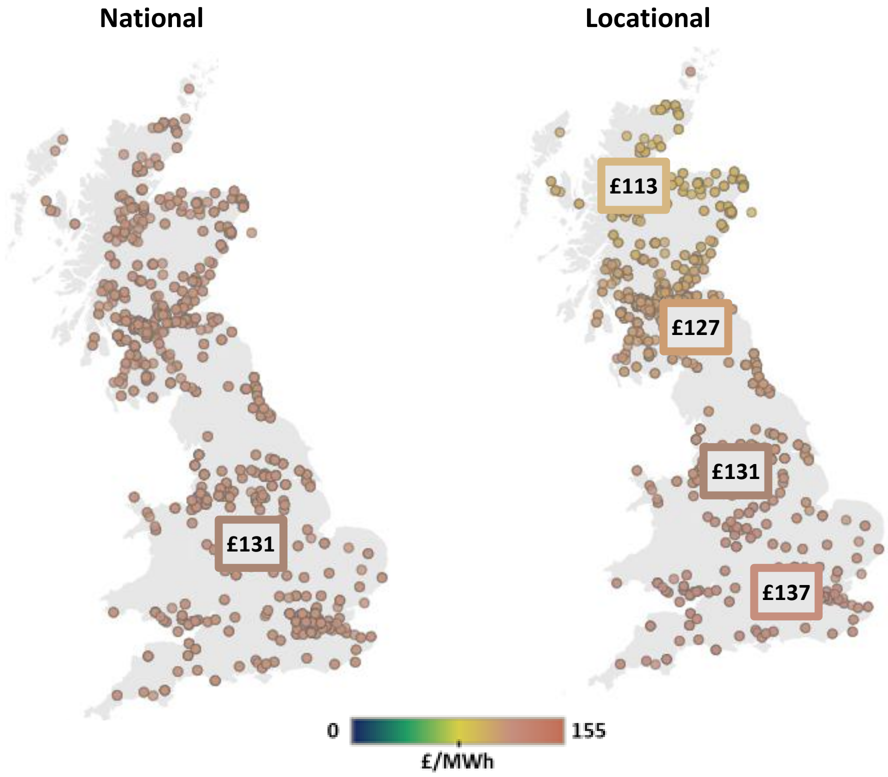
Source: FTI analysis

7.16. In the selected hour shown in Figure 7-3, while wind generation is also high in Scotland and northern England, it is not high enough to set the national price. Instead, the national price in this hour is set by a gas plant, causing all demand to pay this price. However, surplus wind generation (i.e., net of local demand) is higher than the capacity of the key transmission boundary leading to constraints binding between Scotland and GB. In this hour, Scotland is "export-constrained", and wind generators will need to be constrained off by the ESO in redispatch. Similarly, the ESO will require to constrain on additional generators in "import-constrained" areas to meet local demand.

7.17. In the nodal market, the price in Scotland decreases to £0 per MWh, while the price in northern England and northern Wales is also lower compared to the national market. Prices here are set by imports and storage assets. However, the locational price in southern England is c.10% higher than the corresponding national price, as some generation and import are paid through the wholesale market, rather than through the BM, as in the national market.

7.18. In Figure 7-4 below, we show an example of wholesale electricity prices in a specific hour (08:00 on 27 February 2025) when there is low wind across GB.

Figure 7-4: Example of a low wind hour in Scotland and northern England (27 February 2025 – 08:00)



Source: FTI analysis

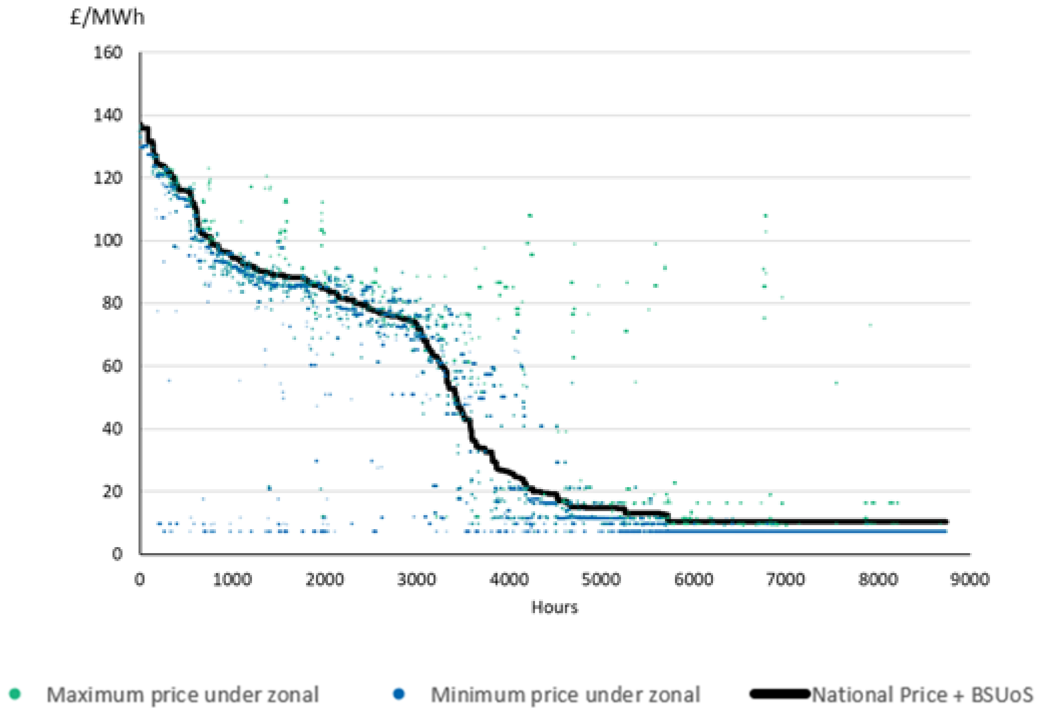
7.19. In the example shown in Figure 7-4 above, wind generation is low and gas generation is setting the price across all of GB, both under the national and the nodal market. Differences between the prices still occur, even as no transmission constraint is binding, because losses are taken into account on the wholesale market.

Price dispersion

7.20. Figure 7-5 and Figure 7-6 below show price variation under a national pricing regime and either a zonal or nodal pricing regime. The price duration curves (shown in black) represent prices modelled under the national pricing regime, with an uplift for the Balancing Services Use of System ("BSUoS") charge.[171] We plot the price in each hour of the modelling period under the national pricing regime, as well as the highest (in green) and lowest (in blue) observed price in the corresponding hour for the zonal market design (in Figure 7-5)[172] and nodal market design (in Figure 7-6).

[171] For the purposes of the charts below, National BSUoS have been added to each data point on an equal basis.
[172] For the purposes of the charts below, Zonal BSUoS have been added to each data point on an equal basis.

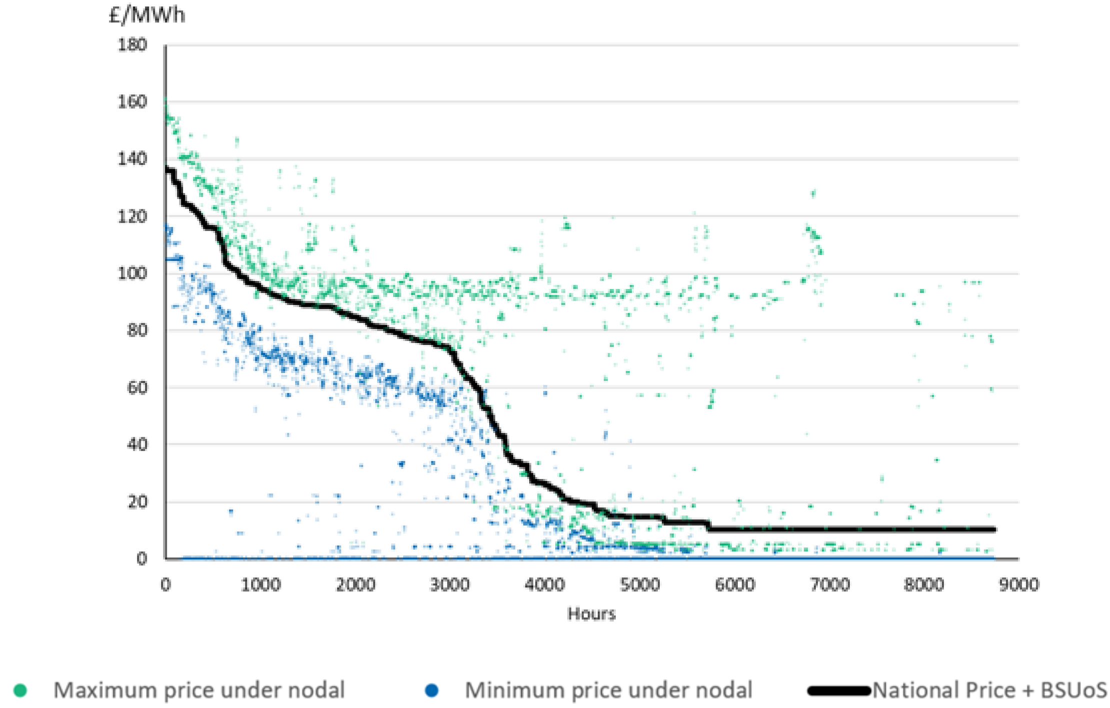
Figure 7-5: Price duration curves comparing national prices to minimum and maximum prices under zonal pricing (2035) – LtW (NOA7)



Source: FTI analysis
Note: This chart ranks the prices observed over the modelling period under the national market design. We compare this to the lowest and highest price observed under the zonal market design for the same hour.

7.21. Figure 7-6 shows as expected the spread of prices is greater under nodal than under both zonal and national market design.

Figure 7-6: Price duration curves comparing national prices to minimum and maximum prices (for each hour, across nodes) under nodal pricing (2035) – LtW (NOA7)



Source: FTI analysis
Note: This chart ranks the prices observed over the modelling period under the national market design. We compare this to the lowest and highest price observed under the nodal market design for the same hour.

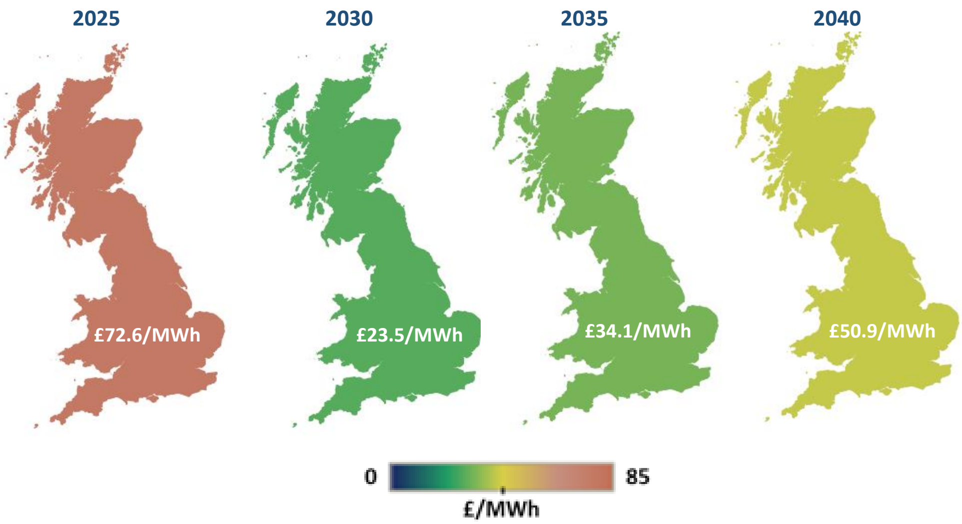
7.22. As Figure 7-6 illustrates, the spread of prices under a nodal market design is considerable. Even under relatively high-priced hours under a national pricing regime, the blue dots on the X-axis indicate that, for the same hour, there would be a significant number of occasions when the price is zero in some parts of the country if the market was designed on a nodal basis, as price reflects the effects of network constraints and energy oversupply. Conversely, when the price is low (i.e., zero plus the BSUoS uplift) under a national pricing regime there are still many nodes on the system where the price would be significantly higher (as indicated by green dots in the top right of the figure) were the regime to operate as a nodal market.

Annual averages

7.23. The previous subsection highlighted how hourly prices are affected by locational pricing. In this subsection we aggregate the hourly prices calculated for each of our four modelled years and for each market design into annual average prices, to provide an indication of longer-term price trends under each market design option.

7.24. Figure 7-7 below shows how prices in our national price scenario evolve over the timeline of modelling period.

Figure 7-7: Wholesale market price under a national market design – LtW (NOA7)



Source: FTI analysis
Note: For the purposes of comparing wholesale prices between the different market arrangements and between the different nodes and zones, we use time-weighted annual average prices.[173]

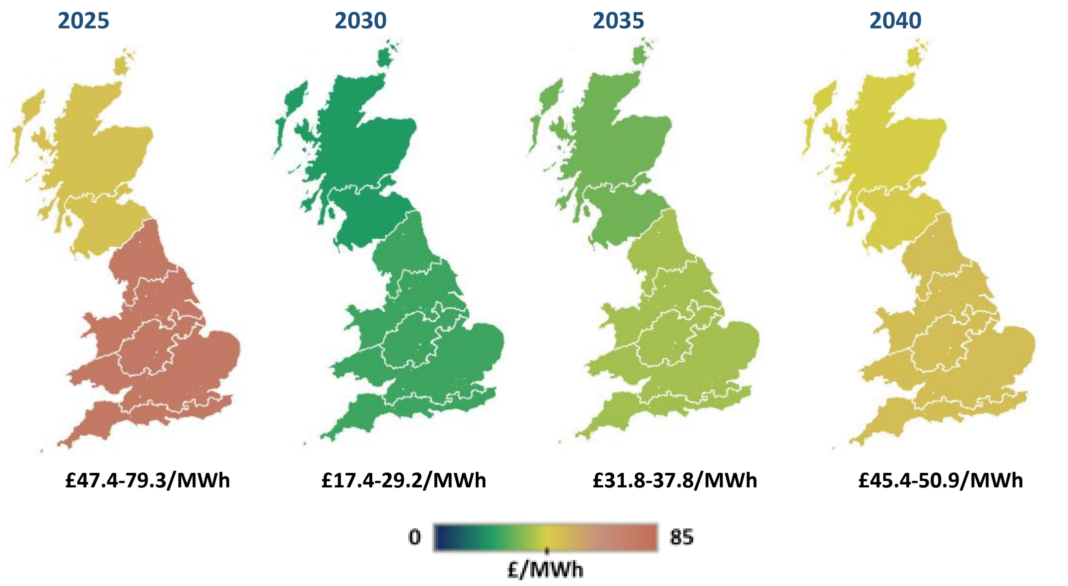
7.25. As illustrated in Figure 7-7, the wholesale electricity price in the national market is £72.6 per MWh in 2025 and falls to £23.5 per MWh in 2030. This significant fall in annual average price is a result of large volumes of renewable generation coming online in the 2025 to 2030 period, as well as an assumed fall in the gas price (as detailed in Chapters 5 and 6). From 2035 onwards the wholesale price is expected to increase, to an average of £34.1 per MWh in 2035 and £50.9 per MWh in 2040. While renewables generation is assumed to continue to be rolled out at pace over the period – thereby exerting downward pressure on prices - the demand for electricity increases, as new sectors are electrified, thereby exerting upward pressure on prices. In addition to this, the assumed increase in carbon prices provides further upward pressure on electricity prices in the 2030s. We also note that the wholesale prices do not include the cost of CfDs which, as we will show later in this chapter, are increasingly material as the system evolves.

Zonal prices

7.26. The evolution of wholesale prices under zonal market arrangements follows a similar trend to that under a national market. Prices decrease sharply between 2025 and 2030, while a steady increase can be observed from 2030 onwards. This is illustrated in Figure 7-8 below.

[173] This is in contrast to other results, where we present annual load-weighted averages. However, load-weighted averages are affected by the mix of demand mix at the given area and would not provide a like-for-like comparison. For example, two nodes with the same price in each hour could have different load-weighted averages, if one has a higher share of electrolyser demand compared to the other.

Figure 7-8: Annual average wholesale market price under a zonal market design – LtW (NOA7)



Source: FTI analysis

7.27. As illustrated in Figure 7-8, average annual zonal prices in both northern Scotland (GB1) and southern Scotland (GB2) are expected to be lower throughout the whole modelling period than the national price shown in Figure 7-7. From 2025 to 2035, the prices of the two Scottish zones are expected to be coupled in most hours, while price differences between the two zones become more prevalent in 2040, as wind capacity in GB1 increases.

7.28. The reduction compared to the national price is the highest in 2025 and 2030, when the Scottish price is £47.4 per MWh and £17.4 per MWh respectively. Scottish prices increase to £31.8 per MWh in 2035 and begin to converge to prices in the other zones, as many of the new large-scale transmission projects come online and the re-siting of generation to more southern zones starts to take effect. However, a difference remains between the prices even in 2040, when the price in GB1 and GB2 are £45.4 per MWh and £47.2 per MWh respectively.

7.29. The opposite effect is forecast for zones in England and Wales (GB3 to GB7), where, as a result of zonal pricing, more of the fossil fuel generation is paid through the wholesale market rather than the BM. English and Welsh zones are frequently price coupled in most hours from 2025 to 2030 and have an average price of £79.3 per MWh and £29.2 per MWh respectively.

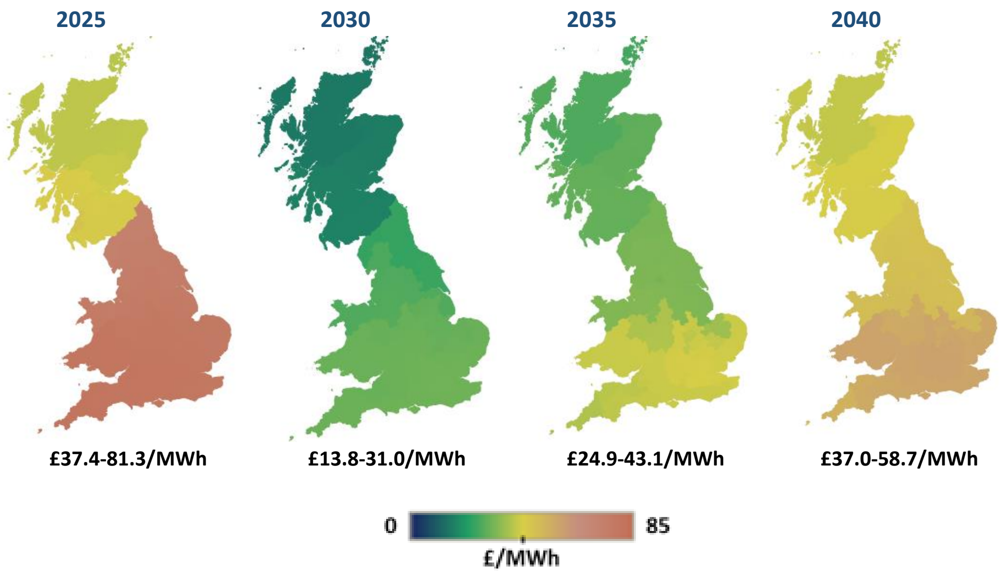
7.30. In 2035, the prices in the two southern zones (GB6 and GB7) are expected to reach £37.8 per MWh, while the price in GB3-GB5 is lower at £36.6 per MWh. In 2040, prices in the English zones are coupled in most hours, with averages ranging between £50.2 to £50.9 per MWh.

7.31. Limited price differentials between the zones within England and Wales and within Scotland are explained by the re-siting of capacity (see Section 6A) which reduces these differences.

Nodal prices

7.32. Figure 7-9 below sets out our forecasts of nodal prices in the 2025 to 2040 period.

Figure 7-9: Annual average wholesale market price under a nodal market design – LtW (NOA7)



Source: FTI analysis

7.33. As illustrated in Figure 7-9, nodal wholesale prices show similar evolution to zonal prices, with Scottish nodes expected to have a lower price compared to national and zonal pricing, while nodes in other areas see an increase in wholesale prices.

7.34. However, as we would expect, there is a wider range of prices in each year and they decouple more often, as all transmission boundaries and losses on all lines are considered in the determination of the wholesale market price.

7.35. Annual average prices for Scotland in 2025 range from £37.4 per MWh in Shetland to £45.3 per MWh in the south of Scotland, around the English border. By 2030, annual average prices decrease, as a result of renewable roll-out and decreased gas prices. Prices near Thurso and Dounreay become the lowest in GB due to the expected installation of offshore wind farms in the area – with an annual average price of £13.8 per MWh. The highest priced areas in Scotland are near the English border and have a price of £17.7 per MWh. In line with the national and zonal market designs, prices increase after 2030 and range between £24.9 to £29.9 per MWh in 2035 and £37.0 to £47.0 per MWh in 2040. The lowest priced GB nodes remain in the Thurso-Dounreay area, while the Edinburgh area becomes the highest cost in Scotland, but prices are still lower compared to the national market.

7.36. Annual prices in England and Wales range between £73.6 per MWh and £81.3 per MWh in 2025. Prices decrease in 2030 to between £23.7 per MWh and £31.0 per MWh, while the price increases again in the second half of the modelling period, ranging from £32.0 to £43.1 per MWh in 2035 and £47.1 to £58.7 per MWh in 2040.

7.37. The lower priced areas outside of Scotland are in northern England, close to the Scottish border, while the highest priced areas are around London.

7.38. Figure 7-9 also shows that in 2025 and 2030, B6 is expected to be the main transmission boundary, but by 2040 new boundaries emerge on the system, even after some capacity sites away from the congested areas relative to FES 21. The main new boundaries are across the Midlands, northern England and within Scotland.

B. Constraint management cost

7.39. As described in Chapter 2, there is a need for a BM to resolve congestion under both the national and zonal pricing regimes, as their wholesale markets do not take into consideration all transmission boundaries on the GB system. Constraining generators on and off in the BM requires payments from the SO, which are ultimately funded by consumers. We analyse these costs in this sub-section.

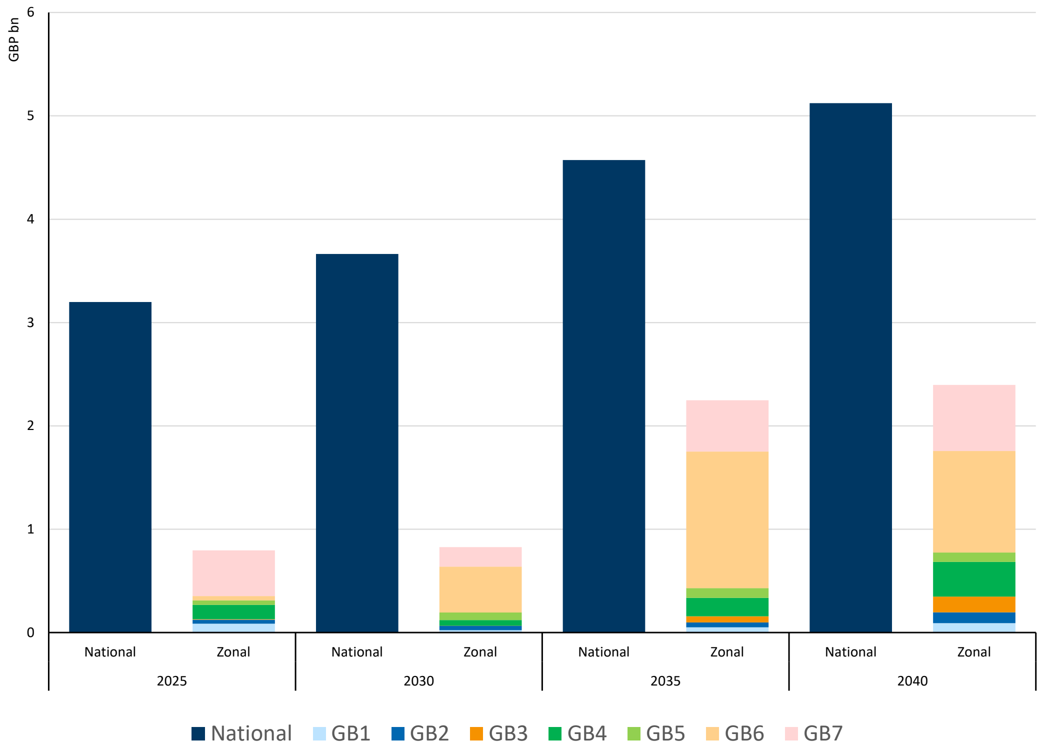
National and zonal constraint management cost estimates

7.40. Constraint management costs will be the highest under the national market arrangement, since no transmission boundaries are considered by the market determined schedule ahead of gate closure. Zonal constraint management costs would be expected to be lower compared to national, as several of the main transmission boundaries are taken into account at the scheduling stage. However, some constraint management costs will inevitably remain, as there would remain transmission constraints within each zone that would need to be resolved through SO intervention. Under nodal markets, the market accounts for all transmission constraints when setting the nodal wholesale price and there are therefore no constraint management costs incurred by the SO.[174]

7.41. Figure 7-10 below sets out our forecast for constraint management costs for the LtW (NOA7) scenario under both national and zonal market designs.

[174] We note that under all market designs modelled, there may be instances where the SO is required to intervene to account for unexpected changes in supply and demand, as well as unexpected outages of the transmission lines, in real-time. This occurs under national, zonal and nodal pricing regimes, and we have not sought to model any impact on the costs that arise from such interventions.

Figure 7-10: Constraint management costs – LtW (NOA7)



Source: FTI analysis

7.42. Constraint management costs follow the congestion volumes described in Section 6C. Costs under the status quo national market increase steadily in all modelled years, while zonal constraint management costs start to increase in 2035, as there is an increase in intra-zonal transmission constraints not reflected in the wholesale market.

7.43. Constraint management costs under the national market increase steadily from c.£3bn to more than £5bn in 2040, as the volume of constrained generation increases, as illustrated in Figure 7-10. Most of this cost is made up by constrained-on payments to fossil fuel generators between 2025 and 2035, while constrained-on payments to interconnectors becomes the largest contributor by 2040. Wind farms with CfDs also receive constrained-off payments to compensate for their lost subsidies in hours when they are constrained due to lack of transmission.

7.44. The 2025 and 2030 estimates for this scenario have also been published by ESO and show similar levels of congestion to our estimates (see comparison in Figure 7-11 below).

7.45. Constraint management costs under a zonal market design remain under £1bn in 2025 and 2030, as most of the congestion on the system is captured by the zone boundaries. However, as the system evolves, new boundaries emerge, as we can see in Figure 7-9. As there would be no locational wholesale signals within zones, this would lead to potential increased intra-zonal congestion, with constraint management costs increasing to over £2bn per year. The increase in intra-zonal constraint management costs we observe in our modelling suggests that, over time, there might be a case for reconfiguring the zones to take account of increasing bottlenecks in some parts of the transmission system.[175]

7.46. The main contributors to constraint management costs are similar under the zonal markets, with fossil fuel plants receiving most of the payments in earlier years and interconnectors receiving the majority in 2040.

Cross-check against ESO estimates

7.47. We have cross-checked our constraint management cost estimates for the status quo national model under all scenarios against those published by ESO in August 2022, which they have undertaken as part of the NOA7 Refresh plan (incorporating HND). Figure 7-11 below presents this comparison.

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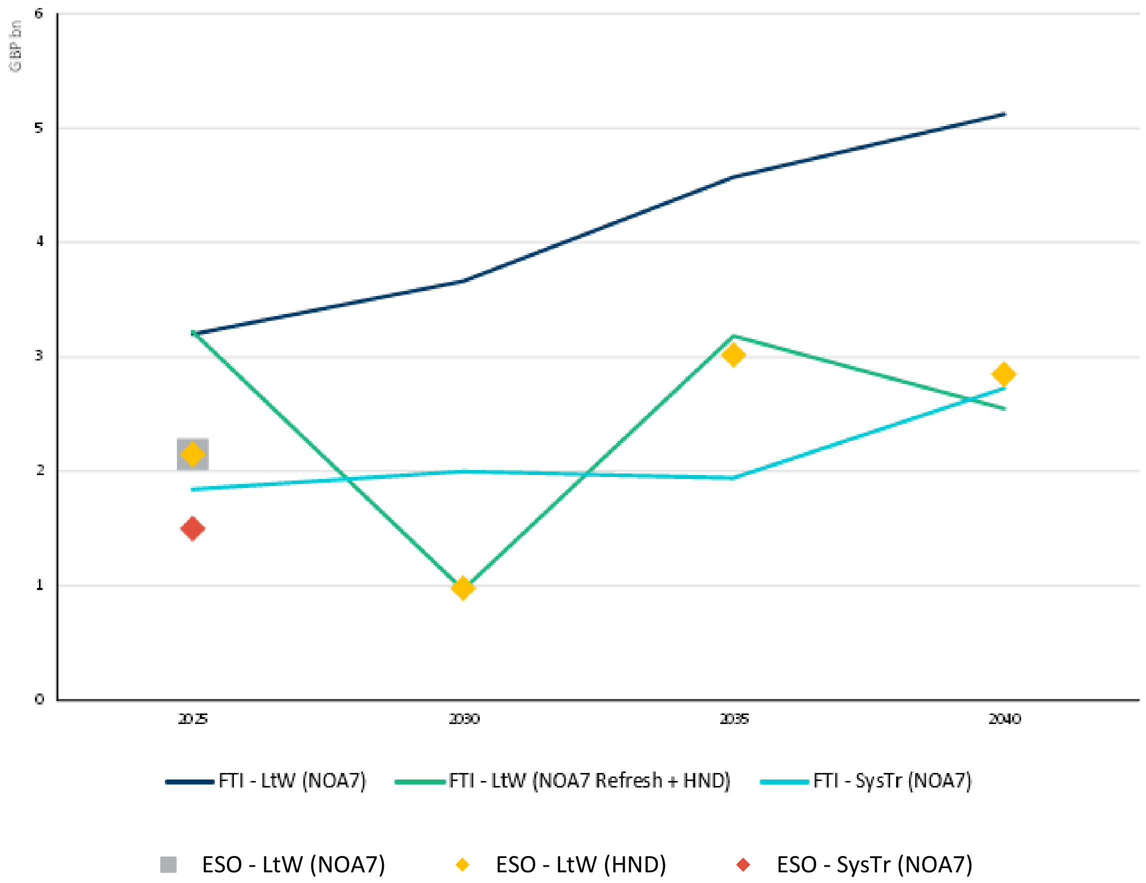
[175] We note that this might present some challenges from stakeholders – inevitably there would be winners and losers in any rezoning process.

Figure 7-11: Comparison of FTI and ESO constraint management cost estimates under a national market design



Source: FTI analysis and ESO, NOA 2021/22 Refresh – August 2022
Note: ESO has published estimates for the four FES scenarios with NOA7 reinforcements from 2023 to 2029, and for the Leading the Way scenario with NOA7 refresh reinforcements (including HND) for 2030 to 2041. NOA7 refresh only differs from NOA7 from 2030 onwards.

7.48. The solid blue line in Figure 7-11 is our forecast of constraint management costs under the LtW (NOA7) scenario that is also presented above in Figure 7-10 above. The green and turquoise lines represent our forecasts of constraint management costs under the LtW (HND) scenario and the SysTr (NOA7) scenario (that are also set out in Appendices 2 and 3).

7.49. These forecasts are directionally as we would expect, i.e., the LtW (HND) forecast for constraint costs is lower than the forecast for LtW (NOA7) as we include the effects of a greater volume of transmission in the LtW (HND) scenario from 2030 onwards. SysTr (NOA7) has a greater volume of generation sited in the south of GB which, all else held equal, would be expected to lower constraint cost forecasts relative to LtW (NOA7).

7.50. As Figure 7-11 illustrates, the ESO forecast of constraint management costs under the status quo national market are, over the forecast period, broadly in line with our own estimates of constraint management costs.

7.51. The slight exception is 2025, when our forecasts deviate somewhat – there is a difference of c.30% under the LtW (NOA7) scenario and c.15% under the SysTr (NOA7) scenario. However, the ESO's estimates of constraint management costs on the GB system between 2030 and 2040 for LtW (HND) are very similar to our forecast. Given the complexities of modelling the BM, the fact that our own independent forecasts are reasonably close to those of the ESO provides a degree of comfort that our methodology and approach is a sufficiently robust estimate of the evolution of constraint management costs for the scenarios that we have modelled.

C. CfD support payments

7.52. As discussed in Section 4B, the financial flows between consumers and producers for CfD support payments are fundamentally linked to the prevailing wholesale price in each hour. Where a change to zonal or nodal pricing leads to a change in hourly wholesale prices, the financial flows between consumers and producers will also change.[176] In this section, we assess the extent to which a move towards locational pricing changes the CfD support payments under a zonal or nodal market design.

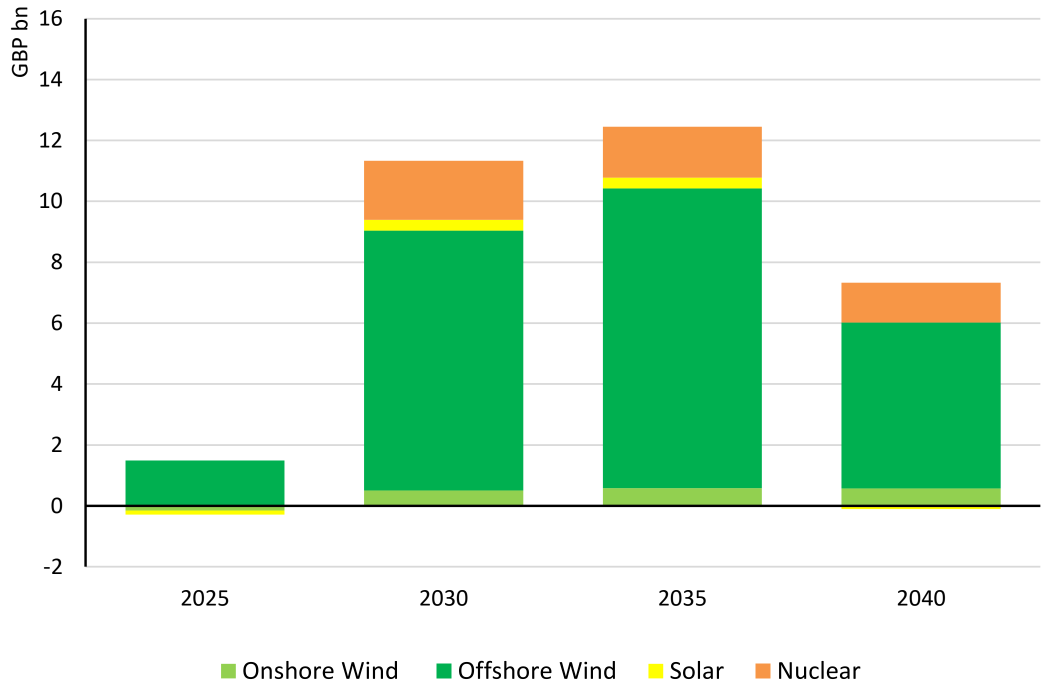
7.53. In general, the direction of change of CfD support payment depends on the location of each generator. Generators sited in export-constrained regions with abundant renewable generation, for example wind farms in Scotland, will generally receive a lower wholesale price under zonal or nodal pricing, and will be compensated with higher CfD support payments as a result. For generators in import-constrained regions, for example solar generators located close to demand centres in the south of GB, the wholesale price received will generally be higher under locational pricing, and as a result support payments from consumers to producers would be expected to fall.

National

7.54. Figure 7-12 below shows the net expected CfD support payments between consumers and producers under the current market design, for each year of our modelling results for the LtW (NOA7) scenario. A positive value indicates a net payment from consumers to producers.

[176] In our analysis, we assume that under a zonal or nodal market design, all existing CfD contracts would be "grandfathered", with generators compensated relative to the local wholesale price in the connected zone or node.

Figure 7-12: CfD support payments under a national market design – LtW (NOA7)



Source: FTI analysis

7.55. Figure 7-12 above highlights that, under the current market design, CfD support payments result in very significant payment from consumers to producers in the LtW (NOA7) scenario, particularly across the 2030s. This is mainly due to accelerated deployment of renewable generation capacity, which outstrips growth in electricity demand and regularly leads to extended periods of very low wholesale prices.

7.56. Indeed, CfD support payments are noticeably higher in 2030 than in 2025, due to a significant reduction in average wholesale prices in 2030, which is a result of a large decline in commodity prices and the acceleration of renewable generation capacity outlined above.

7.57. Additionally, Figure 7-12 demonstrates that the vast majority of CfD support payments are expected to be paid to offshore wind generators, which form a significant proportion of overall capacity with CfD agreements in place. CfD contracts awarded to offshore wind generators typically have the highest strike prices across intermittent renewable generators, reflecting the assets' higher assumed LCOE.

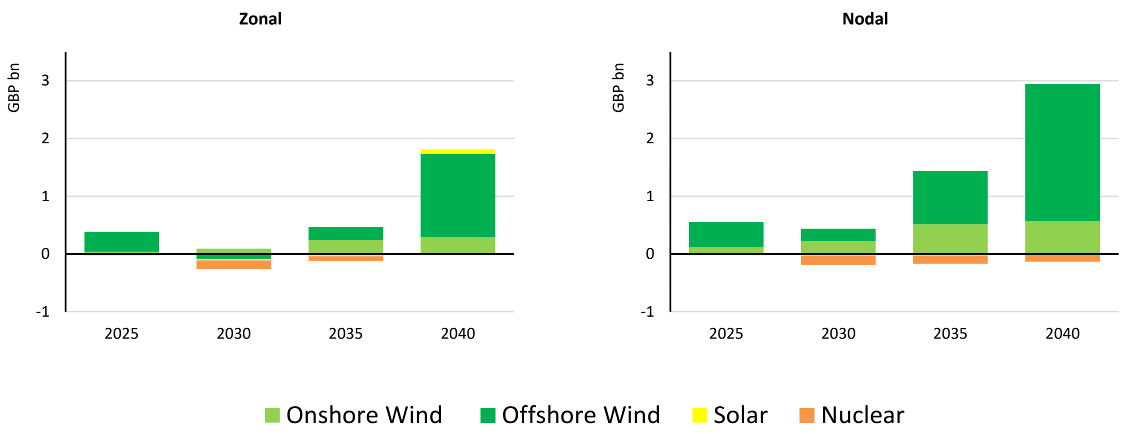
7.58. Onshore wind and solar generators receive relatively lower support payments, with the difference driven by two key factors. First, these assets generally have CfD agreements with lower strike prices, reflecting their relatively lower assumed LCOE. Second, solar and onshore wind generators typically have higher average wholesale capture prices across the year. This is particularly relevant for solar generators, which benefit from the increased consumer demand, and therefore higher wholesale prices, during daylight hours.

7.59. Nuclear generation is expected to start receiving CfD support payments from 2030 with the commissioning of the first unit at Hinkley Point C, with payments amounting to over £1bn per year from 2030 to 2040. The scale of this payment is driven by the wide disparity between the generally low forecast average wholesale prices under LtW (NOA7) and Hinkley Point C's relatively high strike price of £106.12 per MWh.

Zonal and nodal

7.60. Figure 7-13 illustrates the change in CfD payments that would arise under a zonal or nodal market relative to a national market design.

Figure 7-13: Changes in CfD support payments under a zonal and nodal market design relative to a national market design – LtW (NOA7)



Source: FTI analysis

7.61. As shown in Figure 7-13, CfD support payments to both offshore and onshore wind farms increase under nodal and zonal market arrangements. This is caused by lower wholesale prices in renewable dominated areas, which in turn reduces capture prices in the wholesale market and therefore increases the size of the CfD support payment required.

7.62. Under zonal markets, CfD support payments to solar generators increase only marginally in 2040 and slightly decrease in other years. Similarly, CfD support payments to solar generators decrease for all years under a nodal pricing regime. This is because most of the solar capacity is located in the south of GB, where the wholesale prices increase relative to under a national pricing regime. This effect is reinforced by the re-siting, which, under locational pricing regimes, moves even more solar capacity to these zones, where wholesale prices are the highest.

7.63. Similarly, the support payments to Hinkley Point C decrease, as the wholesale price increases at Hinkley Point C's zone and node under locational pricing.

D. Total wholesale electricity cost

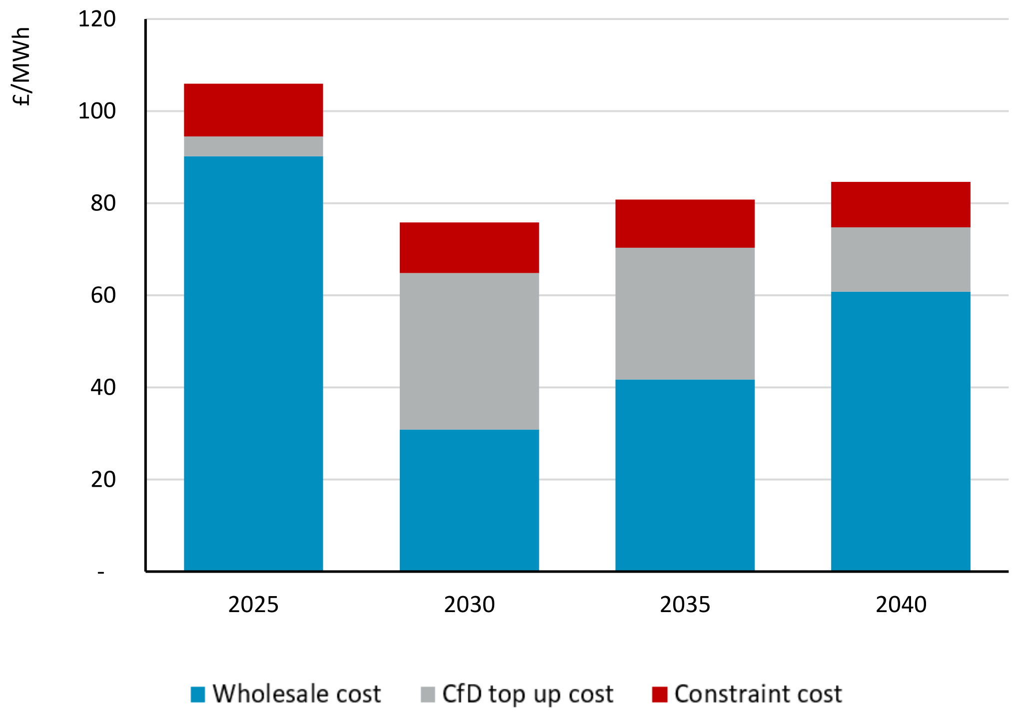
7.64. The modelled variable cost of the electricity generated on the system can be calculated by adding up wholesale costs, constraint management costs and CfD support payments. This metric can allow us to understand how much consumers are paying for wholesale electricity under different market arrangements.

7.65. As sectors of the economy (such as transport) are increasingly electrified through the modelling period, the total demand and, in turn, the total cost of supplying demand, increases. For ease of comparison between the years, we therefore present the costs of electricity on a per unit basis.

National

7.66. Figure 7-14 sets out the total variable cost of wholesale electricity under a national market in the LtW (NOA7) scenario. The calculation of cost of electricity below is based on load-weighted prices as opposed to the time-weighted prices presented in previous sections.

Figure 7-14: Total variable cost of wholesale electricity under a national market design – LtW (NOA7)



Source: FTI analysis

7.67. Figure 7-14 shows that under the national market arrangements in 2025, wholesale costs are the main component of variable costs. However, from 2030 onwards, wholesale prices decrease and the share of generation with CfD contracts increases. As a consequence, CfD support payments become the largest part of electricity costs in 2030.

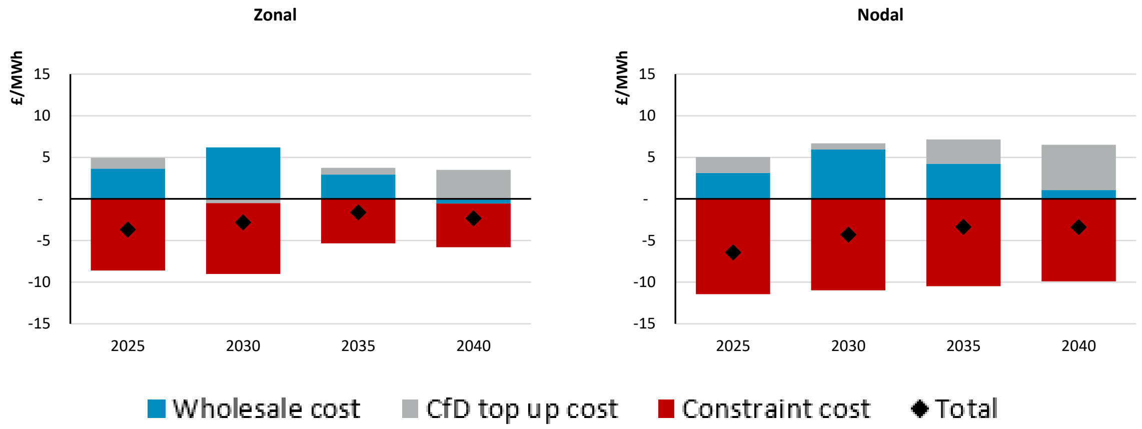
7.68. However, the share of CfD support payments, as a function of total costs, decreases in 2035 and 2040, as the average wholesale price increases due to the reasons discussed in Section 7A.

7.69. Constraint management costs make up more than 10% of the variable costs in each modelled year.

Zonal and nodal

7.70. All of the components of the total electricity costs change under zonal and nodal market arrangements, as we have described in the previous sections of this chapter. The total change in the components can be seen in Figure 7-15 below.

Figure 7-15: Changes in the total variable costs of wholesale electricity under a zonal and nodal market design – LtW (NOA7)



Source: FTI analysis

7.71. As can be seen in Figure 7-15, locational pricing leads to a decrease in the constraint management cost element of the total variable prices, as the transmission constraints are taken into account pre-gate closure and the need for balancing action post-gate closure is removed (or reduced in the case of zonal markets).

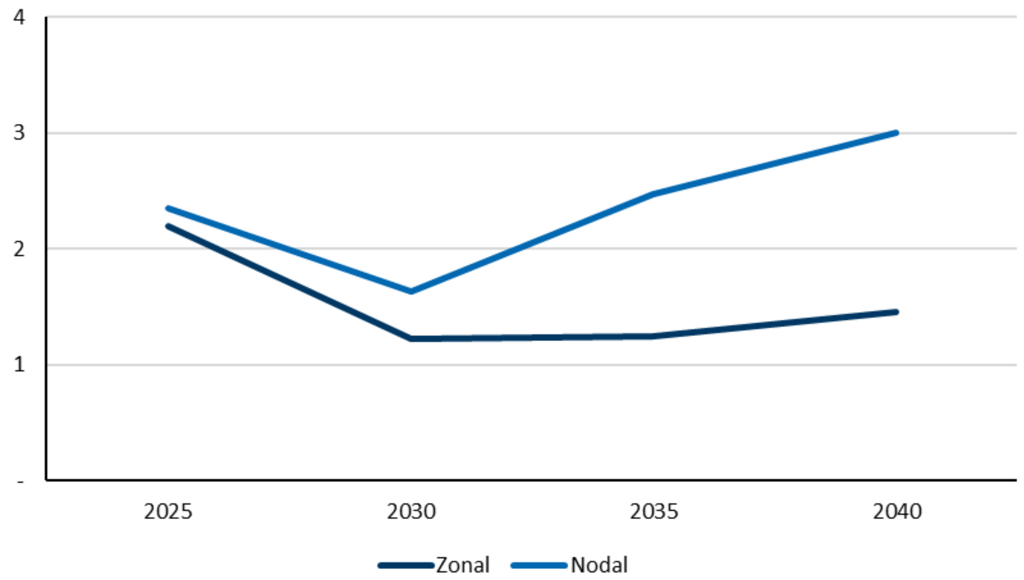
7.72. Wholesale costs increase under locational pricing, as some of the generators, which are paid through the BM in the status quo, would receive payments through the wholesale market. However, this is not sufficient to outweigh the benefits that arise due to the reduction in constraint management costs under nodal and zonal pricing regimes.

7.73. CfD costs are also expected to be higher under locational pricing for the reasons discussed in Section 7C.

7.74. Total variable costs are lower for consumers in each modelled year under a nodal market, even before we account for intra-GB congestion rents (as set out in the next section). Under a zonal market, total variable costs are expected to be lower for consumers in 2025, but are similar to the status quo in 2035 and 2040 due to higher constraint management costs.

7.75. Differences in prices between connected nodes and zones lead to the creation of congestion rents within GB. For the purposes of our assessment, we have assumed that this benefit is accrued to consumers. Figure 7-16 below sets out our estimates of congestion rents.

Figure 7-16: Intra-GB congestion rents – LtW (NOA7), GBP bn



Source: FTI analysis

7.76. As illustrated in Figure 7-16, intra-GB congestion rents under nodal and zonal are similar in 2025 (£2.3bn and £2.2bn respectively), as nodal prices decouple at zonal boundaries most of the time.

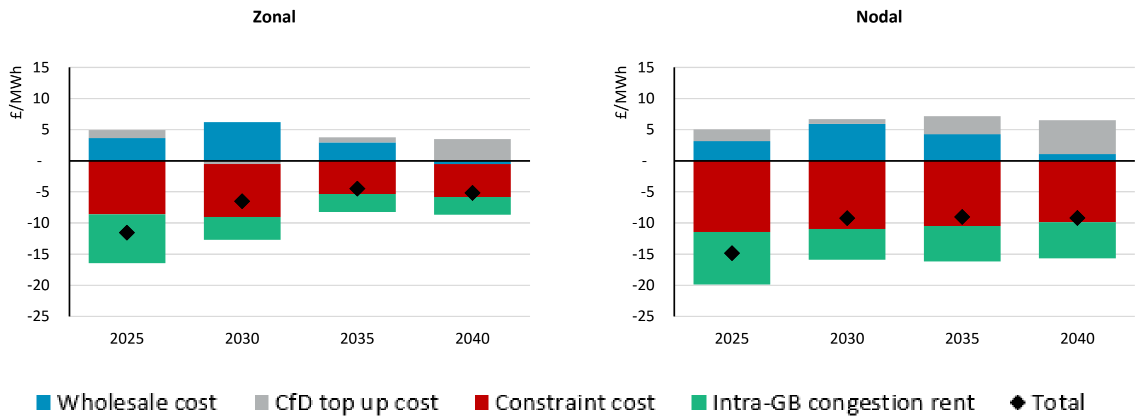
7.77. Congestion rents decrease to £1.6bn and £1.2bn by 2030, as the price difference between the different areas of GB decrease, as shown earlier in this chapter in Figure 7-8 and Figure 7-9. The difference between nodal and zonal congestion rents also starts to increase, as adjacent nodes within the same zone have different prices more often.

7.78. Congestion rents under the nodal market increase to £2.5bn in 2030 and £3.0bn in 2040, as the price differences between regions start to increase, as described in Section 7A.

7.79. Zonal congestion rents show only a marginal increase to £1.3bn in 2035 and £1.5bn in 2040. While congestion on the system increases similarly to the nodal market, this is not captured by the zonal boundaries, as most of the new congestion occurs within zones as shown by increasing constraint management costs under the zonal market and in Figure 7-10.

7.80. Once intra-GB congestion rents are considered, the reduction in costs for consumers under locational pricing is even greater, as shown in Figure 7-17 below.

Figure 7-17: Change in total variable costs of electricity under a zonal and nodal market design, including intra-GB congestion rents – LtW (NOA7)



Source: FTI analysis

7.81. Deducting intra-GB congestion rents from the variable cost of electricity leaves consumers better-off in every modelled year under both zonal and nodal market arrangements. Including intra-GB congestion rents leads to an average cost reduction of c.8% for consumers in a zonal market and c.12% for consumers in a nodal market.

Other scenarios

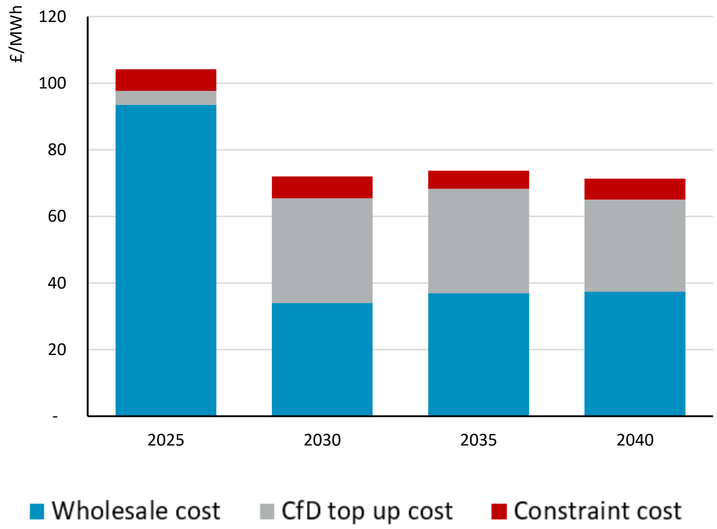
7.82. The directional change in the components of electricity costs set out in the previous section are the same across all scenarios, albeit to differing extents. For instance, the size of the changes in constraint management costs and wholesale costs differ due to the varying levels of congestion under the national market across the different scenarios. Similarly, the impact on CfD support payments will also differ due to the differing generation mix across scenarios, which results in a varied impact on wholesale prices.

7.83. We set out our findings for the SysTr (NOA7) and LtW (HND) scenarios below.

System Transformation

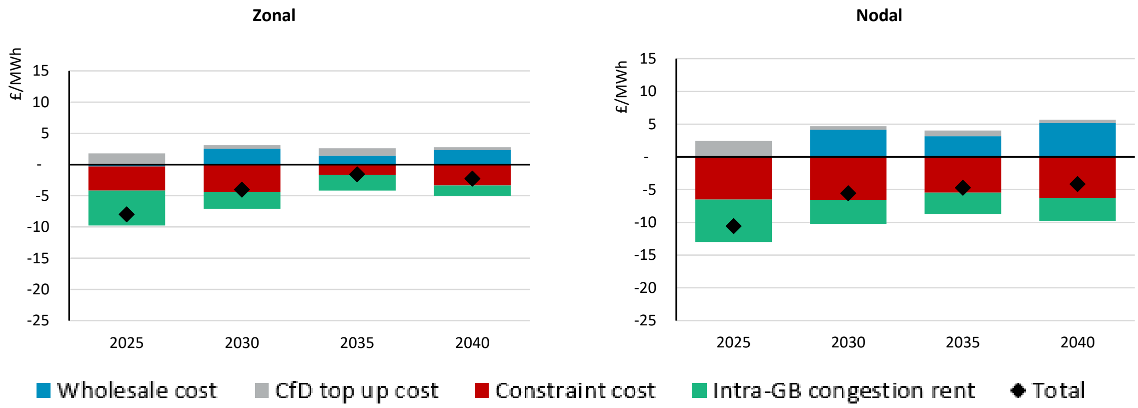
7.84. Figure 7-18 below sets out the total variable cost of electricity under a national market in the SysTr (NOA7) scenario, followed by the change in total costs under locational pricing in Figure 7-19.

Figure 7-18: Total variable cost of electricity under a national market design – SysTr (NOA7)



Source: FTI analysis

Figure 7-19: Change in total variable costs of electricity under a zonal and nodal market design, including intra-GB congestion rents – SysTr (NOA7)



Source: FTI analysis

7.85. Under a national market for SysTr (NOA7), wholesale cost makes up the majority for the variable total electricity cost across the modelled period. The CfDs support payments make up a significant proportion of the total variable costs after 2030, due to the expected increase in generators with CfD contracts. Constraint management costs make up c.8% of total annual cost per MWh across the modelled period.

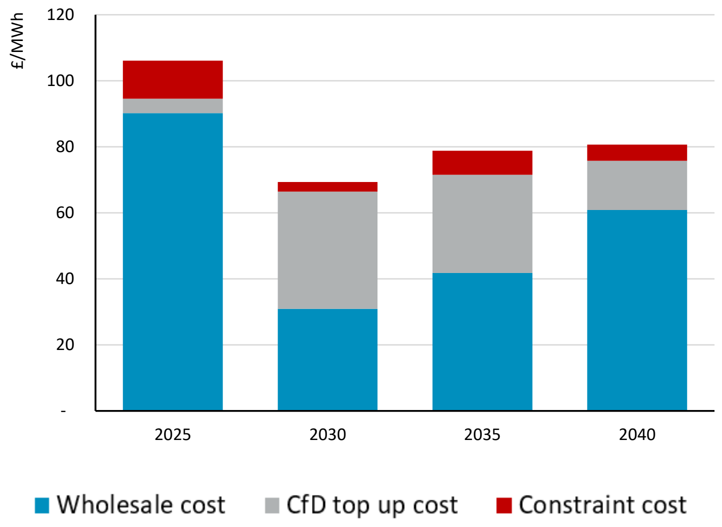
7.86. As shown in Figure 7-19, under SysTr (NOA7), a move to locational pricing reduces the total variable cost of electricity under both the zonal and nodal pricing regimes. Under nodal markets, the total variable cost of electricity is expected to decrease in all modelled years, even before taking into account intra-GB congestion rents.

7.87. Constraint management costs are reduced under locational pricing, however, some of this reduction is offset by increasing wholesale costs, as a larger volume of generation is renumerated in the wholesale market. CfD payments also increase under locational pricing because payments to northern generators increase by a greater amount than the reduction in payments to southern generators.

LtW (HND)

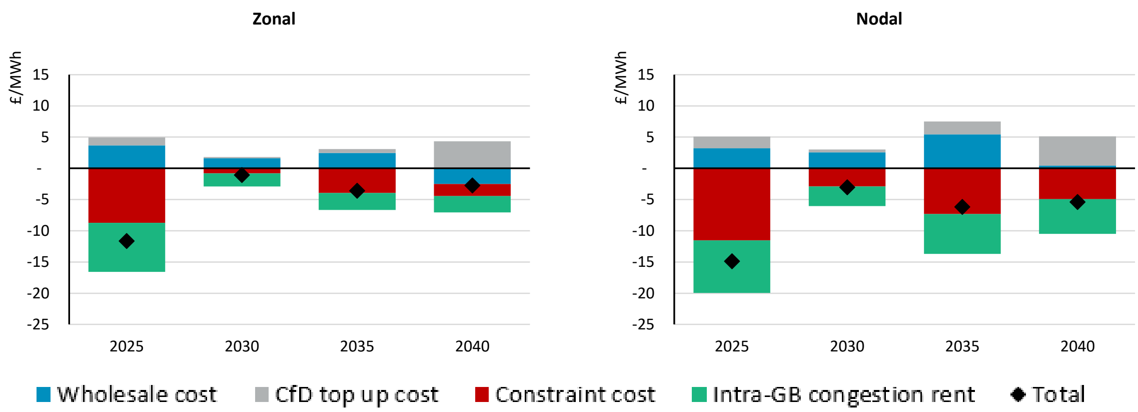
7.88. Figure 7-20 below sets out the total variable cost of electricity under a national market in the LtW (HND) scenario, followed by the change in total costs under locational pricing in Figure 7-21.

Figure 7-20: Total variable cost of electricity under a national market design – LtW (HND)



Source: FTI analysis

Figure 7-21: Change in total variable costs of electricity under a zonal and nodal market design, including intra-GB congestion rents – LtW (HND)



Source: FTI analysis

7.89. The direction of change for each component under LtW (HND) is similar to that observed in our results for the other two scenarios, as can be seen in Figure 7-21.

7.90. Under both nodal and zonal markets, consumers pay significantly less for electricity in 2025, as the benefit of reduced constraint management costs far outweighs the increased costs from other components.

7.91. Consumers are forecast to pay less for electricity in all years under both zonal and nodal market arrangements once intra-GB congestion rents are accounted for. This reduction in costs is smallest in 2030 when new transmission reinforcements are assumed to come online. This transmission reinforcement reduces the cost of constraint management under a national market, decreasing the benefit of more locationally granular pricing on electricity costs.

E. Producer impact

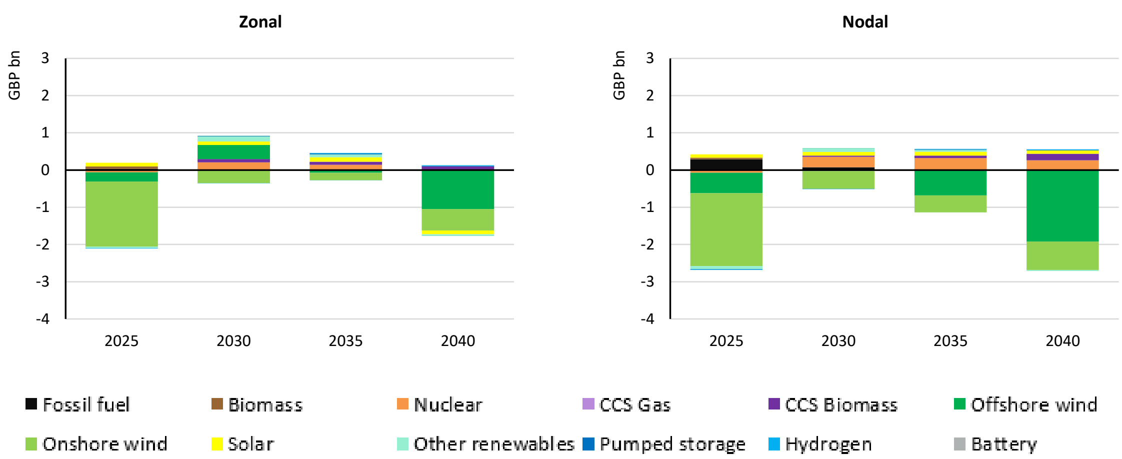
7.92. Moving to nodal or zonal prices impacts producers in several ways. First, changes to wholesale prices mean that generators receive different payments through the wholesale market depending on their location. Second, the reduction or removal of constraint management costs under a zonal or nodal market, respectively, impacts the level of revenues earned in the BM. Third, CfD generators will receive different levels of compensation as a direct consequence of different wholesale prices. We set out the effect of locational pricing on each of these components and in aggregate below.

Wholesale market

7.93. Generators will receive different revenues through the wholesale market under locational pricing regimes. For instance, generators located in southern zones, where prices increase under locational pricing, will see higher revenues from the wholesale market, while generators in the north will likely see a reduction in their wholesale market revenues due to the converse effect. The chart below shows the impact of these changes on the producer surplus for each technology under zonal and nodal market arrangements, relative to under a national market design.

7.94. The effect of changing wholesale prices on generators before any subsidies is presented in Figure 7-22 below.

Figure 7-22: Change in producer surplus on the wholesale market under a zonal and nodal market design – LtW (NOA7)



Source: FTI analysis

7.95. The effect on producers follows the changes in wholesale prices described in Section 7A. Wind generators, that make-up most of the capacity in the areas where the wholesale prices decrease, are expected to recover lower revenues from the wholesale market. However, most of these generators are protected through CfDs and are therefore shielded from the effect of reduced capture prices for the duration of their CfD contracts.

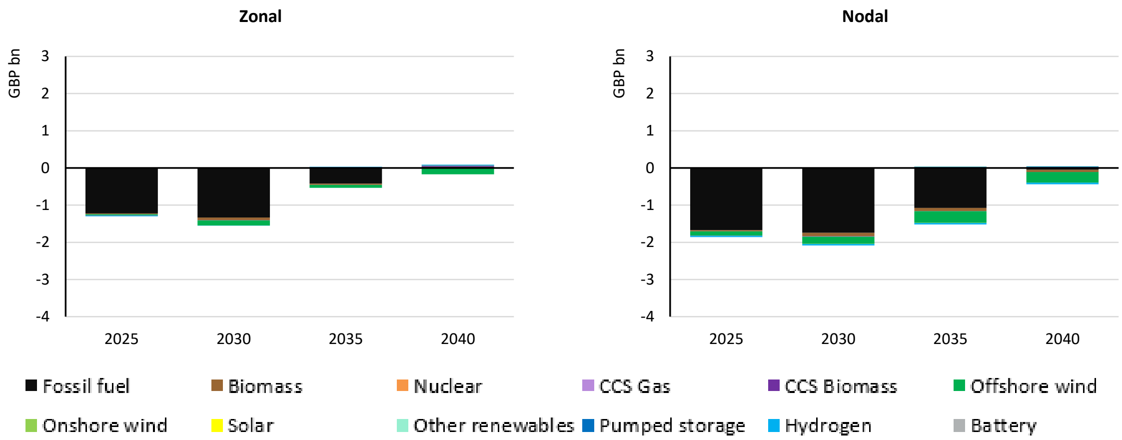
7.96. Technologies which are located predominantly in areas with increased wholesale prices, such as nuclear, solar and fossil fuels in the early years, see an increase in their surplus from the wholesale market.

Balancing mechanism

7.97. BM revenues decrease under locational pricing, albeit to differing extents. Under the zonal pricing regime, the volume of energy dispatched through the BM decreases due to zonal boundaries accounting for most major transmission constraints. Under the nodal pricing regime, wholesale prices account for transmission constraints therefore removing the need for balancing actions.[177] Figure 7-23 below shows these changes for each technology in each modelled year under zonal and nodal market arrangements.

7.98. For the purposes of the producer surplus calculation, we assume that the entire uplift for the BM offers is the result of the pay-as-bid clearing and is captured by producers as a surplus. In practice, some of this uplift reflects actual costs borne by generators, such as start-up costs. This conservative assumption potentially overestimates the negative effect on producers and therefore underestimates total GB socioeconomic benefits from transitioning to locational pricing.

Figure 7-23: Change in producer surplus from the BM under a zonal and nodal market design – LtW (NOA7)



Source: FTI analysis

7.99. Changes in producer surplus through the BM primarily affect fossil fuel generators, as they are the main beneficiaries of the BM, as shown in Figure 7-23. Offshore windfarms also experience a reduction in revenues as they no longer receive constrained-off payments via the BM.

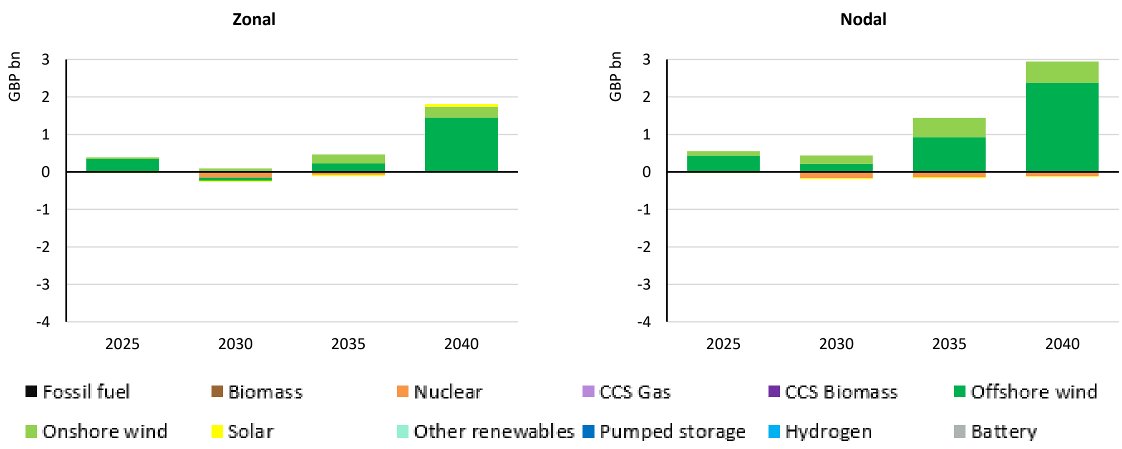
[177] As explained in Chapter 4, there may be instances where the SO is required to intervene to account for unexpected changes in supply, demand and outages in transmission lines in real-time. This occurs in all market designs and we have not sought to model this impact.

CfD support payments

7.100. CfD support payments change under locational pricing, as the wholesale electricity price received by generators is different relative to under a national pricing regime. The direction of the change depends on the location of the generator, as CfD contract holders receive less (more) revenue if the wholesale electricity price at their node or zone increases (decreases). The chart below shows these changes for each technology in each modelled year under zonal and nodal market arrangements, relative to under a national pricing regime.

7.101. The effect of different CfD support payments on generators under the different market arrangements is presented in Figure 7-24 below.

Figure 7-24: Change in CfD support payments under a zonal and nodal market design – LtW (NOA7)



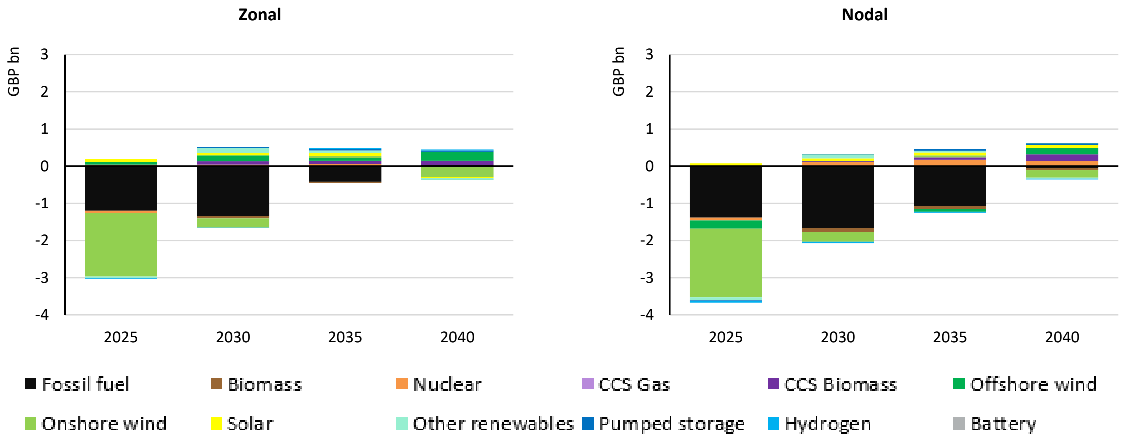
Source: FTI analysis

7.102. Change in CfD revenues mirrors the changes in wholesale revenues for technologies with CfD contracts, as shown in Figure 7-24. Wind generators see an increase in support payments to compensate them for the reduced revenues in the wholesale market, while nuclear generators are expected to receive lower support payments, as their capture prices increase.

Overall impact on generators

7.103. The overall impact on generators is made up of changes in wholesale revenues, BM revenues and CfD support payments. The overall impact for each technology in each year is shown in Figure 7-25 below.

Figure 7-25: Change in total producer surplus of generators under a zonal and nodal market design – LtW (NOA7)



Source: FTI analysis

7.104. The most significant impact is on fossil fuel generators, that experience a reduction in their producer surplus from 2025 to 2035 before they are gradually phased-out. This follows the results presented in Section 6B, which showed a significant reduction in fossil fuel generation.

7.105. Non-CfD onshore wind generators also see a significant decrease in their producer surplus in 2025. Most of these are onshore wind farms with ROCs, who benefit from high capture prices and inframarginal rents in 2025, due to the high gas prices. Under a nodal model, these wind farms are still expected to receive on average c.£42 per MWh on the wholesale market along with their ROCs payment as a top-up, leading to an average revenue of over £90 per MWh.[178]

7.106. These estimates are based on commodity price estimates from early 2022. Given increased commodity price estimates since the Russian invasion of Ukraine, it is likely that locational pricing would transfer even more inframarginal rents from wind farms with ROCs to consumers.

7.107. Some of these inframarginal rents are already covered by the Government's recently rolled out Electricity Generator Levy.[179] As policy decisions such as this were not included in our assessment, the impact on producers of transitioning to greater locational granularity in wholesale prices may be overestimated, as they may be required to return more of their revenues to consumers under the status quo national market.

7.108. Other technologies are impacted less, as they are protected through CfDs or benefit from higher wholesale prices.

Other scenarios

7.109. The directional impact on producer surplus is similar under the other two scenarios. However, the magnitude of the changes is different, as the level of congestion and change in wholesale prices differs across the scenarios.

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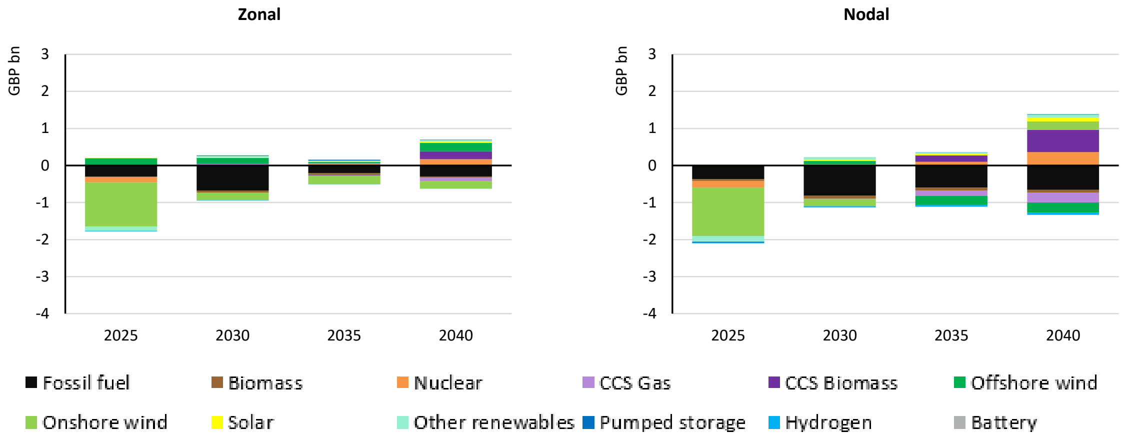
[178] Assuming payment per ROCs remains similar to the 2021/22 levels, when the buyout price was £50.8 per ROC. Ofgem (2021), 'Renewables Obligation (RO) Buy-out Price, Mutualisation Threshold and Mutualisation Ceilings for 2021-22' (link).

[179] 45% of exceptional receipts over £75 per MWh is set to be returned by electricity generators covered by the Act. HMRC (2022), 'Electricity Generator Levy on exceptional electricity generation receipts' (link).

7.110. The overall effect on generators under the SysTr (NOA7) scenario is shown below in Figure 7-26.

Figure 7-26: Change in total producer surplus of generators under a zonal and nodal market design – SysTr (NOA7)



Source: FTI analysis

7.111. The direction of the impact on producers is similar to under LtW (NOA7), with any differences due to the differing generation mix, annual demand level and transmission build-out between the scenarios.

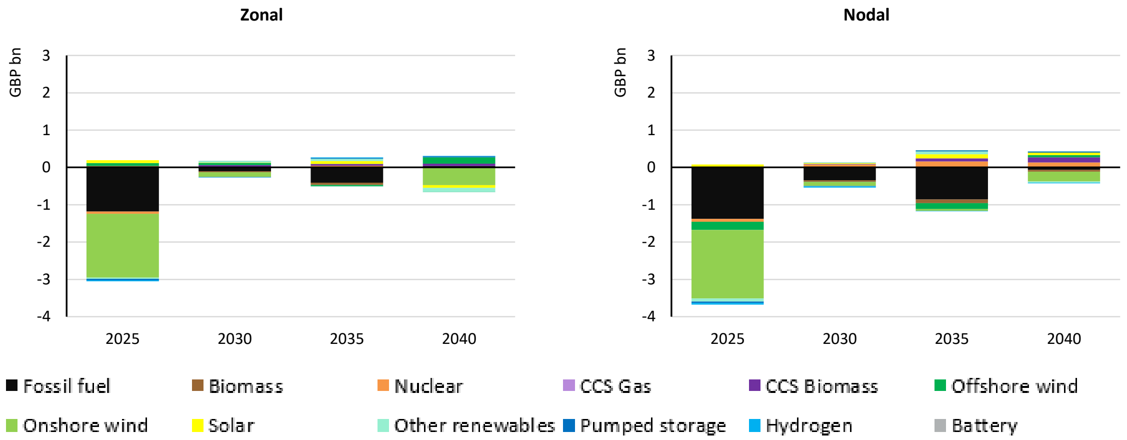
7.112. The surplus of fossil fuel generators decreases by a smaller margin, as the congestion on the system is lower under the national market and therefore fossil fuel generators receive lower revenues in the BM.

7.113. Nuclear generators also earn higher revenues under both zonal and nodal markets compared to the status quo national market. This is a consequence of new SMRs that are expected to be installed in the 2030s across England in zones and nodes where the wholesale price is expected to increase. In practice, these generators may be under some form of revenue stabilisation mechanism (e.g., CfDs) and this extra surplus may therefore be returned to consumers.

7.114. CCS gas generators are also expected to earn lower revenues in 2035 and 2040 under locational pricing, as they lose the surplus they were previously earning on the BM. Similar to SMRs, it is possible that they may also be under a revenue stabilisation mechanism and some of this loss may be compensated for by consumers.

7.115. The overall effect on generators under the LtW (HND) scenario is shown below in Figure 7-27.

Figure 7-27: Change in total producer surplus of generators under a zonal and nodal market design – LtW (HND)



Source: FTI analysis

7.116. Changes under the LtW (HND) scenario are very similar to the changes under the LtW (NOA7) scenario, as the generation and demand assumptions are identical.

7.117. The main difference is that fossil fuel generators are impacted to a lesser extent, as these generators are constrained on less frequently under a national market design, due to the reduced congestion caused by the enhanced transmission build-out in this scenario relative to in LtW (NOA7).

8. Assessment of wider system impacts

8.1. As discussed in Chapter 4, a transition to locational wholesale electricity prices may have wider impacts on the GB energy system beyond direct effects on wholesale electricity markets.

8.2. In this chapter, we consider three areas which could affect the aggregate costs and benefits of different options. These are:

- the implementation costs of transitioning to more granular locational pricing **(Section A)**;
- the potential impact of locational pricing on the cost of capital to market participants **(Section B)**; and
- the potential impact of locational pricing on wholesale electricity market liquidity **(Section C)**.

8.3. In each area, we discuss some key theoretical and empirical insights, based on our research and engagement with stakeholders throughout the assessment process.

8.4. We discuss implementation costs and potential cost of capital impacts in further detail in Appendices 4 and 5 respectively.

A. Implementation costs

8.5. Implementing more granular locational pricing in GB would require many parties to invest in new operational functions and systems to carry out the activities required under a zonal or nodal market.[180] This may include new computing and software systems, updated energy procurement, hedging and billing processes, and staff training and recruitment, among other cost elements.

8.6. These investments can be grouped into two categories:

- **ESO implementation costs**, which are one-off costs to the SO to enhance processes and procure the IT and software systems to operate in a zonal or nodal market; and
- **Market participant costs**, which are one-off costs to update the systems and capabilities of market participants to operate in a zonal or nodal market. These may be particularly difficult to estimate because the cost implications of moving to locational pricing can differ greatly across companies depending on their specific characteristics and requirements.

8.7. In our assessment, we focus primarily on the expected implementation cost of transitioning to a nodal market, and less on a zonal market. We would reasonably expect transitioning to a zonal market to be less costly and complex than moving to a nodal market, so the figures presented here are likely to over-estimate the costs involved in moving to zonal pricing.

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[180] We have not assessed the ongoing costs to the ESO and market participates for any of the market designs. Under a locational market design, there could be additional ongoing costs from, for instance, running a centralised-scheduling system or forecasting locational prices. Conversely, there would likely be reduced ongoing costs from the greatly reduced need to run and participate in a BM.

8.8. To determine an indicative range for these costs, we have considered data gathered from three groups of sources:

- implementation costs incurred or estimated in **cost-benefit analyses in other jurisdictions** that have considered or implemented locational pricing;
- **direct conversations** with system vendors and market participants; and
- **discussions with the ESO** to understand the steps required for implementation.

8.9. We discuss each in turn.

Cost-benefit analyses in other jurisdictions

8.10. Many jurisdictions that have considered or implemented locational pricing have published CBAs. Where possible, we have used these to identify a range of implementation costs. The case studies we considered are set out in Table 8-1.

Table 8-1: International case studies

Jurisdiction	Year of CBA	Market context
CAISO	2008	Transitioned from zonal pricing to nodal pricing as part of its Market Redesign and Technology Upgrade (“MRTU”) programme in 2009[181]
ERCOT	2004, 2008	Transitioned from zonal pricing to nodal pricing in 2010[182]
SPP	2009	Introduced nodal pricing under its Energy Imbalance Market (“EIS”) in 2007, and Financial Transmission Rights in 2014 as part of its “Integrated Market” reforms[183]
Ontario’s Independent Electricity System Operator (“IESO”)	2013, 2017, 2019	Planning to implement nodal pricing for generators in 2023 as part of its Market Renewal Program (“MRP”)[184]
Australian Energy Market Commission (“AEMC”)	2019-2020	Considered moving to nodal pricing as part of its Coordination of Generation and Transmission Investment (“COGATI”) review in Australia’s NEM[185]

Source: FTI analysis

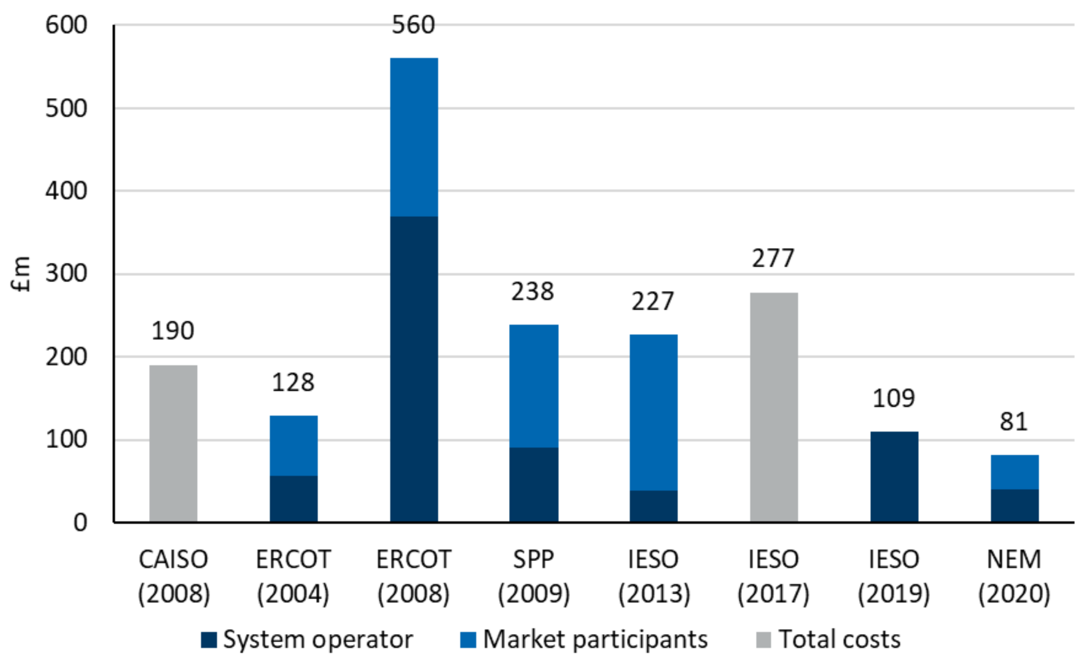
181 Wolak (2011), ‘Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets’, p.247 (link).
182 Electricity Utility Commission (2011), ‘Texas Nodal Market Implementation’ (link).
183 NERA (2020), ‘Costs and Benefits of Access Reform’, p.28 (link).
184 IESO (2019) ‘MRP Energy Stream Business Case’, p.9, 24-26 (link).
185 The inaugural review was completed in 2018. The second COGATI review began in February 2019. See AEMC (2020) ‘Coordination of generation and transmission investment implementation – access and charging’ (link).

8.11. Where data is available, we have broken the cost estimates down into SO costs and market participant costs. Our approach involves the following steps:

- Market participant costs have been adjusted based on the relative installed capacities of the jurisdiction (in the year the CBA was conducted) and in GB in 2021.
- SO implementation costs have not been adjusted for differences in installed capacities between the jurisdiction and GB. This implicitly assumes that SO costs are not proportional to the size of the electricity market in each jurisdiction.
- Implementation costs have not been adjusted for differences in the level of reform required in each energy market relative to GB.
- All costs have been converted from the local currency to GBP based on the average exchange rate for the year the CBA was conducted. All costs have subsequently been converted to 2022 prices.[186]

8.12. We summarise our findings in Figure 8-1.

Figure 8-1: Summary of implementation costs from international case studies (£m, 2022 prices)



Source: CAISO, ERCOT, SPP, IESO, Hard Software.
Notes: 2019 IESO and ERCOT CBAs were conducted mid-implementation of nodal pricing. CAISO conducted an ex-post assessment of benefits as part of the wider Western Energy Imbalance Market but did not assess ex-post costs.[187]

8.13. As displayed above, CBAs carried out in other jurisdictions provide a relatively wide range of cost estimates across each category, with varying proportions of SO and market participant costs. Apart from ERCOT's 2008 CBA, all implementation cost estimates were below £300m in 2022 values.

[186] All costs deflated using the CPIH annual rate data as published by the Office for National Statistics (link).
[187] See the Western Energy Imbalance Market, 'Benefits' (link).

8.14. Notably, ERCOT's 2008 CBA, which was conducted mid-implementation, highlighted significant unexpected cost overruns, primarily due to issues around integrating different systems in different regions. These issues were not experienced in other jurisdictions and may be unlikely to occur in GB due to the national role of the ESO.

8.15. In our assessment of other jurisdictions that have transitioned to nodal pricing, we have not observed any material impact on generation investment, often deemed as an "investment hiatus". As such, we assume that no investment hiatus in our assessment, i.e., we assume that generation investment responds to locational pricing as soon as it is implemented (subject to the re-siting limits discussed in Section 5D).[188] Furthermore, we note that a number of mechanisms, such as CfDs and the capacity mechanism, serve to reduce uncertainty for investors. Finally, we note that prices in some areas of the country are likely to increase in a transition to locational pricing which may encourage investment in these more favourable locations (e.g., import-constrained areas) albeit with the corollary that there would be potentially reduced investment in other parts of the network that are more likely to experience lower prices (i.e., in export-constrained parts of the system).

Interviews with system vendors and market participants

8.16. Second, we interviewed system vendors and market participants to understand their experiences and expectations of the costs of moving to locational pricing.

8.17. We have interviewed two **system vendors**, Hitachi and Siemens, with global experience in implementing IT systems for SOs. Both vendors explained:

- the essential elements required for the transition to a nodal market design including the network models, bidding engines, and systems for the day-ahead and real-time markets;
- how the system requirements required for a nodal market design could be integrated into the SO's existing systems; and
- the roadmap to implementing the necessary changes.

8.18. Additionally, both vendors highlighted that their bespoke solutions in principle are not novel systems and have already been in place in many jurisdictions for many years.

8.19. While the amount of information we can set out in this report is limited due to commercial sensitivities, a high-level conservative estimate of the total implementation cost of a standard system could be between £40m and £60m.

8.20. We issued a request for information from **market participants**, following our first workshop held on 26 May 2022. While we have had several conversations with market participants on the scale of challenges and investments required, we have not received sufficient data to conduct a reliable analysis. Nevertheless, we have not noted any unique challenges that might differ from the experiences of market participants in other jurisdictions.

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[188] Arguably, an investment hiatus issue may also be present in the status quo market design. For example, ongoing uncertainties around TNUoS reform or the BM may deter investments. Additionally, a potentially greater need for further transmission investment to resolve constraints may lead to longer connection queues, and in turn, hinder timely investments.

Discussions with the ESO

8.21. We have had several discussions with the ESO on practical considerations for the implementation of alternative market design solutions, which included discussion with ESO experts at the Electricity National Control Centre ("ENCC"). At this meeting we exchanged views on how existing nodal markets operate in other countries and requested NGESO provide a view on the difference between these markets and the GB market.

8.22. The ESO indicated that it was not in a position to provide an estimate of costs as the scope of changes to the system required had yet to be determined. However, it described six key areas that would require considerable change – data exchange, metering, optimisation process (for the day-ahead market, ancillary services and network configuration), settlement processes, real-time processes, and automation processes to maintain system frequency.

8.23. Each of these six areas would require consultation with industry and suppliers, resourcing and training, as well as implementing additional system capabilities (whether adding to existing IT systems or implementing new ones).

Impact on our assessment

8.24. We do not have sufficient information to make a fully-costed estimate of the expected implementation costs of locational pricing. However, based on our analysis of experience elsewhere and our discussions with the ESO, vendors and market participants, we have assumed that implementation costs would be c.£500m.

8.25. This estimate appears relatively conservative compared to CBAs from other jurisdictions, in that it is in line with ERCOT's 2008 CBA and considerably above all other CBAs. Several stakeholders have posited that implementation costs in GB would be much higher than the costs implemented by US ISOs, as these ISOs already had centralised scheduling in place. This is only the case for three ISOs that had fully centralised scheduling and dispatch market designs prior to nodal implementation – PJM, NYISO and ISO-NE. CAISO and ERCOT, which had a form of centralised zonal market designs and dispatch software, but were based heavily on bilateral contracting among market participants, required completely new systems throughout because their existing software was wholly inadequate. Furthermore, unlike the other ISOs, MISO and SPP were comprised of separate utilities with no centralised dispatch or coordination across the future ISO footprint – they even had to build control rooms when they began operation of LMP markets.

8.26. We have also assumed, conservatively, that the ESO would not incur further costs to manage the system under the status quo national market (that would not be needed under locational pricing). Given the large, expected increase in balancing actions by the ESO under national pricing, it is likely that system management costs will increase significantly in the future, and that some of these costs would not be incurred under locational pricing.

8.27. For simplicity, although we recognise that the cost of transitioning to a zonal market is likely to be lower than to a nodal market, we have also assumed an implementation cost of £500m in our assessment of zonal pricing. Transitioning to a zonal market would also require significant changes in the areas identified above, for instance in the design and implementation of a new balancing mechanism.

8.28. Overall, we note that implementation costs are materially lower than all of the other costs and benefits identified in this study.[189]

B. Cost of capital

8.29. Several stakeholders have argued that moving to more granular locational pricing would lead to greater investor risk and uncertainty. For instance, this could arise due to greater forecasting complexity, increased variability in locational prices and difficulties in predicting how locational prices will be affected by future transmission capacity. In turn, stakeholders argue that this could lead to investors increasing their *risk premia* to compensate them for bearing more risk, resulting in an increase in the cost of capital and thus in the total cost of investment in generation, particularly for renewables such as wind and solar. As a consequence, stakeholders consider that the higher cost to investors could ultimately be passed to consumers in some manner, for example through the capacity market auction clearing prices, CfD auction strike prices or wholesale electricity prices (if participants are assumed to be able to bid in excess of their SRMC).

8.30. We carried out three workstreams to help understand how and whether moving to zonal or nodal pricing would affect the cost of capital for market participants:

- A high-level **assessment of the risks** faced by market participants due to locational pricing, and their expected relationship with the cost of capital.
- Review of evidence received from **stakeholders** on the potential impact to the cost of capital.
- **International evidence** on the experience in other jurisdictions when transitioning to more granular locational pricing.

8.31. Based on our assessment, we carried out a sensitivity analysis to understand the impacts of a change to the cost of capital on the expected net benefits or costs of locational pricing.

8.32. We discuss each area in turn.

Assessment of the risks faced by market participants

8.33. In this sub-section, we consider:

- how transitioning to more granular locational pricing might change the various risks faced by market participants; and
- how these changes to risks might affect investors' cost of capital.

Change in risk faced by market participants due to locational pricing

8.34. Under locational pricing, market participants could face the following changes in risk:

- Risks related to **price variability and uncertain dispatch**. In particular, how the variability of prices received in locational markets compares to that of prices received in the wholesale market and the BM under the current market design.

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[189] By way of context, our assumed implementation costs of £500m are equivalent to 54 days of the overall expected net benefit to consumers (across the entire modelling period) of a transition to nodal pricing under the LtW scenario.

- Risks related to **network charging and build**. In particular, how network capacity changes might affect the variability of prices under different market designs, and how TNUoS charges might vary under different market designs.
- **Regulatory risks** due to potential future changes in market design.
- **Transition risks** relating to uncertainties around the process for changing market design.

8.35. With regards to the **wholesale market**, our modelling suggests that intertemporal (hour-by-hour) volatility is often higher under locational pricing than in national pricing, but this is not always the case. For instance, in 2035 in the LtW (NOA7) scenario, the average volatility of nodal prices and zonal prices is 0.84 and 0.87 respectively while the average volatility of the national price is 0.81.[190] However, in 2040, the volatility of nodal prices is 0.70, while the average volatility of the national price is 0.71.

8.36. Additionally, wholesale price volatility can differ considerably by location in locational market designs. For instance, in 2035, under nodal pricing, the volatility across the different nodes has a range between 0.77 and 1.10.[191]

8.37. The extent of this effect is driven by several factors, including:

- Variability of demand at a zone or node, both from predictable seasonal changes and unexpected demand shocks.
- Variability of supply at a zone or node, driven by the amount and type of generation in the area.

8.38. With regards to the **BM**, the size and absolute volatility of BM revenues would likely be lower in a market with locational pricing. Market participants would participate more in the wholesale electricity market (in lieu of the BM) on a more straightforward pay-as-clear approach, where locational prices are likely to be less volatile and more transparent.[192] This effect might be more pronounced for flexibility providers with access to more transparent revenue streams reflective of real-time locational scarcity conditions on the network.

8.39. The removal of generators' firm access rights to the transmission system means that they would not automatically be compensated if they are behind a constraint and do not generate; this is sometimes referred to as **dispatch or volume risk**. It means that generators could face uncertainty about whether they will be scheduled and what their place will be in the merit order (for instance, if several renewable generators behind a constraint all bid in at zero).

[190] We calculate volatility using the standard deviation of the log of hourly prices to normalise the non-normal distribution of prices. Average volatility is based on the mean volatility across all nodes or zones.

[191] Similarly, under zonal pricing, volatility across the different zones range between 0.84 and 0.9 in 2035. In locational markets, this risk can typically be hedged to some extent using FTRs or an equivalent financial derivative product.

[192] In a nodal market, imbalances would still occur; a settlement approach is still required where the nodal real-time price would be applied to the locational imbalance volume.

8.40. In practice, investors have some tools available to them to help manage changes in price volatility under locational pricing, including:

- **Policy support mechanisms**, which can mitigate price risk (such as CfDs), dispatch risk or both (such as C&F to an extent). For example, CfD holders are guaranteed the strike price if they generate and hence are shielded from variations in the reference price. CfDs issued on a "deemed generation" basis, which pay out based on a generating unit's potential to generate, would reduce or eliminate both pricing and dispatch risk, but may give weaker locational signals.[193]
- **FTRs**, which can help market participants to hedge their price risk. As discussed in Section 2, FTRs are (typically tradeable) financial instruments that entitle the holder to the right to congestion rents between two nodes.

8.41. On **transmission network risk**, greater locational pricing could be expected to reduce (or remove in the case of nodal pricing) the locational signal within the TNUoS tariff as the signal would be incorporated directly into the wholesale price. For instance, if the TNUoS charge were simplified into a flat tariff, this would reduce TNUoS-related risk to investors as well as operational leverage.[194]

8.42. On the other hand, moving to locational pricing could introduce some additional risks for market participants through network build plans.[195] Changes to the profile of these assets would affect the level of congestion in a particular zone or node, in turn affecting locational prices. While this provides the incentives to market participants to consider the expected value of the electricity they produce to the system as whole, some effects on prices faced by market participants may be affected by factors outside their control (note that this affects the revenue potential of generators but may not affect short-term price volatility). In existing locational-price systems, such risks can be partly mitigated through the purchase of FTRs.[196]

8.43. We expect there to be some degree of **regulatory risk** in GB's electricity market regardless of market design, as the structure of the market is not fixed and may be altered in the future. Notwithstanding this, we might expect some reduction in regulatory risk under nodal pricing. This is because nodal price systems incorporate automatic changes in locational signals through the local balance of supply and demand, and so typically require little or no intervention to ensure that supply and demand are balanced at reasonable cost.

8.44. National-price markets may also be more subject to risks that, for instance, the rules of the BM or, given its administered nature, the structure of network charging will change. Zonal price systems are likely to be intermediate in terms of regulatory risk because they introduce risks around the redrawing of zonal boundaries.

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[193] There would be important choices about the design of CfDs in a locational-price system. See for example Gill, MacIver and Bell (2023), 'Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing' (link).

[194] As described in Chapter 2, in a locational market design, transmission upgrades could be funded through a beneficiary-pays approach more easily, which may introduce some regional variation in transmission charges.

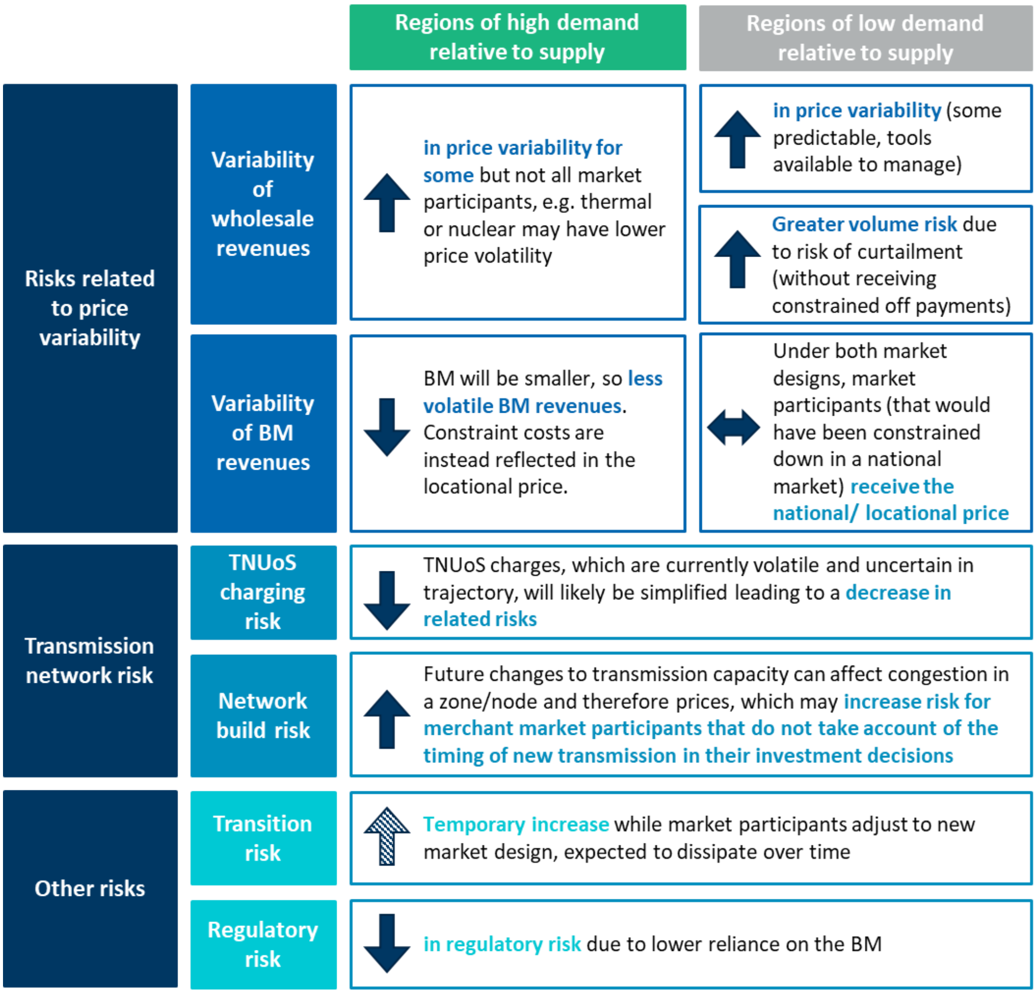
[195] There would be a similar impact from the build plans of other generation or demand assets.

[196] The extent of this risk would depend on the precise design of FTRs and their allocation process. Transmission planning reports such as NOA would also provide a level of foresight to investors.

8.45. **Transition risk** may increase somewhat during a switchover to locational pricing due to uncertainties around the details of the new market design and how it will function, as well as the need to adapt to new market features and conditions. The extent of transition risk will depend on factors such as the clarity and consistency of communication by government, regulator and the SO. Transition risk is particularly relevant for market participants that do not have a regulatory support mechanism such as a CfD. We would expect any transition risk to be temporary and to fall over time.

8.46. Figure 8-2 below summarises our assessment of the change in risks faced by generators from a move to locational pricing. Consumers could be expected to face qualitatively similar changes in risk profiles albeit in the other direction due to the transfer of risk between the two cohorts. The figure shows that there are several different ways in which risks could change as a result of a move to locational pricing, often moving in different directions.

Figure 8-2: Summary of the impact of changes in risk faced by market generators



Source: FTI analysis

8.47. We have not assessed how locational prices might be expected to change revenue risk for storage providers or interconnectors in any detail. These market participants are in a somewhat different situation from consumers and generators, since their revenues tend to be more impacted by the level of volatility of prices.

Impact of changes in risk on the cost of capital

8.48. In this sub-section, we consider how any changes in risk as a result of locational pricing could affect investors' cost of capital, defined as the minimum expected rate of return on capital investment.[197] This minimum expected return is related to the degree of risk associated with the asset and its cash flows; intuitively, higher riskiness might be expected to result in a higher minimum expected rate of return.

8.49. An asset's cost of equity is typically estimated by reference to the CAPM.[198] The CAPM expresses the expected rate of return for a risky asset as:

$$r = r_f + \beta \times (TMR - r_f)$$

where:

r *is the expected rate of return for the risky asset;*

r_f *is the rate of return that an investor would expect to earn on a riskless asset;*

β *is a factor ("beta") specific to the asset, which is a measure of the sensitivity of the asset returns to the volatility of the market returns; and*

TMR *is a measure of the return that equity investors expect from holding the market portfolio.*

8.50. Note that, as an implication of the CAPM, investors are only compensated for bearing systematic risk, which cannot be diversified by holding a basket of securities. Market indices are thought to represent this systematic risk.

8.51. Assets are often financed by a mix of equity and debt. In such cases, the cost of capital will reflect the different costs of equity and debt financing and is calculated as the weighted average cost of capital ("WACC"):

$$WACC = (1 - T) \times D \times r_D + (1 - D) \times r_E$$

where D is the level of gearing (i.e., the extent to which the asset is financed by debt); r_D and r_E are the opportunity cost of debt and equity; and T is an appropriate tax rate.

8.52. The **cost of debt** reflects the cost of raising a company's debt capital. In broad terms, the cost of debt can be assessed as the risk-free rate plus a spread reflecting the company's credit risk. In the GB energy market, the cost of debt for generators is particularly influenced by regulatory support mechanisms such as CfDs for wind and solar generation, and a RAB-based mechanism for new nuclear. For instance, CfDs provide price certainty for generators for the first 15 years of operation, enabling confidence about the level of returns they will earn per MWh of electricity generated. Similarly, C&F arrangements are typically designed so that the Floor payments can cover the investor's cost of debt.[199]

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[197] Ofgem (2011) 'Glossary of terms: RIIO-T1 and GD1 review', p.3 (link).

[198] While it is occasionally criticised, the CAPM approach remains the standard benchmark for regulatory decision-making. See, e.g., the Competition Market Authority's Final Determination on Cost of Equity (link), paragraph 5.12.

[199] See Ofgem's 2021 Interconnector Cap and Floor Regime Handbook (link).

8.53. Since we would expect regulatory support mechanisms to continue under alternative locational market designs, we expect limited change in price risk for market participants that are supported by such mechanisms.[200]

8.54. **Beta** measures the covariance of the returns on an investment with the market return.[201] It assumes that investors hold a diversified portfolio and is a measure of each stock's systematic risk (that is, risk that cannot be diversified away). It is affected by structural changes that change the correlation between the returns on the investment and the market – all else equal, an increase in correlation will lead to an increase in beta. The impact of locational pricing on beta is unclear – it would not have an impact if locational pricing does not increase the non-diversifiable risk. However, even if it does, the direction of impact is unclear – beta could fall if returns become less correlated with fossil fuel prices but could increase if electricity prices become more correlated with aggregate demand.[202]

8.55. **Gearing** refers to the proportion of a firm's capital that is funded by debt and is a measure of a company's financial leverage. We have not identified any reasons to expect locational pricing to alter the level of gearing materially in either direction.

8.56. Our assessment of the relationship between risks faced by market participants and the cost of capital suggests that locational pricing could alter the cost of capital, for instance by changing the correlation between returns on investment in the electricity market and general market returns, or by changing price risk for market participants not covered by regulatory support mechanisms. However, our assessment of risks provides qualitative evidence that the overall risk could move in either direction. This provides an indicative suggestion that the magnitude in either direction could be limited, because of the range of potentially countervailing factors that we have identified.

Evidence received from stakeholders

8.57. We received some evidence on cost of capital impacts from stakeholders, specifically several submissions via Ofgem, as well as multiple claims of potential impacts at our stakeholder workshops. Investors in generation assets have informed us that they would expect some increase in their risk and cost of capital from locational pricing; for instance, one wind investor has highlighted that they would expect an approximately 50 basis point increase in their cost of capital as a result of nodal pricing. In contrast, battery developers have suggested that locational pricing may lead to a decrease in their cost of capital.

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[200] Notably, CfD generators located behind constraints could see a change in volume risk depending on the rules for support payments for when wholesale electricity prices are negative. Currently, CfD generators do not receive support payments only if the wholesale electricity price is negative for six hours or more.

[201] Ofgem (2011) 'Glossary of terms: RIIO-T1 and GD1 review', p.5 (link).

[202] Additionally, with greater locational pricing, investors may be able to diversify locational risk through a portfolio of assets in different locations.

8.58. One challenge with the discussions on the impact on cost of capital with stakeholders is the potential conflation of *non-diversifiable risk* impact versus the overall revenue impact, or the overall change in risk profiles. As such, although many generators would face an increase in risk or a decrease in revenues relative to the status quo, we have been unable to place evidential weight to some of the claims raised as they do not necessarily translate to a higher required cost of capital.[203] Instead, we consider that only changes to the beta parameter are affected by changes in non-diversifiable risk.

8.59. The main quantitative evidence that we received was an October 2022 report by Frontier Economics, commissioned by RWE, SSE and Greencoat Capital. We discuss this report in Box 8-1.

Box 8-1: Frontier Economics' Locational Marginal Pricing – Implications for Cost of Capital report[204]

The report by Frontier Economics ("Frontier") discussed the conceptual differences in investor risks that could arise under the current market design compared to locational pricing. The report also examined quantitatively how the volatility of the locational signal may differ by market design.

Frontier argued that a regime with LMPs might be expected to increase the risks faced by investors around the volatility of their earnings, because of factors such as uncertainty over whether generators will be curtailed and uncertainty over the level and location of spare network capacity. Its quantitative modelling compared riskiness of returns under a proxy for LMPs and the current GB network charging regime and estimated consequent changes to the Sharpe ratio (a measure of the returns to an asset relative to its variance). Frontier concluded that the expected return demanded by investors could increase by 2 to 3 percentage points, while noting several caveats that could increase or decrease this estimated range.

A cost of capital increase of such magnitude would have a material impact on the expected costs and benefits of locational pricing. However, we have identified several important shortcomings in Frontier's approach which mean that we judge it to be insufficiently robust to incorporate in our overall cost-benefit analysis. These include:

(1) Frontier does not relate its arguments about changes in risk to the benchmark CAPM framework for assessing the cost of capital. Within this framework, used by regulators globally (including Ofgem and other GB regulatory authorities), it is key to consider whether risks are diversifiable. Diversifiable risks would not generally be expected to increase required returns. Most or all of the price risks identified by Frontier appear likely to be diversifiable, for instance by investing in a range of generation assets across the country. This suggests that there should be little or no increase in cost of capital resulting from the changes in risk it identifies.

(2) Frontier's assessment of the spread of return on equity attempts to estimate the change in risk for an investor that is <u>equally likely to invest at any single node</u> on the system. This does not answer the actual question that an investor faces, which is how volatile prices are likely to be at the particular node or nodes they expect to invest in, and nor does it take into account investors' ability to hedge risks by investing in multiple projects at different locations.

[203] Similarly, we consider that generator investor surveys have limited value given the preference of some market participants for the status quo.
[204] Frontier Economics (2022) 'Locational marginal pricing – implications for cost of capital' (link).

(3) Frontier does not take into account the impact of those features of energy markets that could mitigate and manage exposure to risks, including CfDs and FTRs. These could enable investors to lock in prices for a significant period at the point of financial close.

(4) Frontier's report does not include any sensitivity analysis or robustness checks, meaning that it is difficult to be confident that its results would be replicated in different plausible specifications.

8.60. Unfortunately, we have received limited quantitative evidence on cost of capital impacts from stakeholders other than from investors in generators and battery storage.

International evidence

8.61. Our review of experience in other jurisdictions identified little direct evidence on the impact of locational pricing on the cost of capital, in particular from previous CBAs.

8.62. The case studies of countries that have adopted locational wholesale pricing, discussed in Appendix 4, do not suggest strong effects of locational pricing on either the pace or cost of renewables investment. Jurisdictions both with and without locational pricing have seen rapid increases in the capacity of renewable generators in recent years. Instead, factors other than market design, particularly the geographical characteristics of a region and the nature of policy incentives, appear to be more important drivers of investment in generation capacity.

8.63. However, we are not aware of any robust tests on the effects of locational pricing on the cost of capital. Moreover, differences in the institutional and policy frameworks across countries mean that there is little direct read-across to likely effects in GB.

Impact on our assessment

8.64. Taking into consideration the three assessment areas, we conclude that both the magnitude and direction of any effect of locational pricing on the cost of capital for market participants are unclear. Moreover, there are several tools that could help investors mitigate the effects from more granular locational pricing.

8.65. In our central quantitative assessment, we have therefore assumed **no change to the cost of capital** of market participants as a result of a move to locational pricing.

Sensitivity analysis

8.66. While our base case assessment assumes no change to the cost of capital, we have tested two sensitivities to assess how an increase in the cost of capital could affect results:

- First, a **plausible uplift sensitivity,** which considers an increase to the WACC based on a plausible set of assumptions for each technology.
- Second, an **extreme WACC sensitivity** which considers what the uniform uplift to the WACC would need to be to negate the expected benefits of locational pricing, when applied to only technologies that are merchant or have CfDs.[205] This approach does not account for differences in risk exposure that might arise from locations, technology type or regulatory support mechanisms.

8.67. We describe these sensitivities in detail in Appendix 4.

[205] These technologies include wind, biomass and solar generators.

8.68. The results of these analyses are that:

- Under the LtW (NOA7) scenario, the plausible uplift sensitivity would reduce the expected net consumer benefits of nodal pricing by £7.5bn between 2025 and 2040.
- Under the same scenario, the extreme WACC sensitivity for LtW (NOA7) finds that an 341bps increase in the WACC would be required to negate the expected consumer benefits of nodal pricing, while an 206bps increase in the WACC would be required to negate the expected consumer benefits of zonal pricing.

C. Market liquidity

8.69. Market liquidity is an important feature of electricity wholesale markets. These markets are considered *liquid* if:

- a significant number of market participants are able to sell and buy products in large quantities quickly; and
- that these trades would not significantly affect prices and/or incur significant transaction costs.

8.70. Some stakeholders have expressed concerns that market liquidity will be lower under more granular locational pricing. These concerns are based on the premise that, in a national market, market participants are able to trade without due consideration of the transmission network, meaning larger volumes of trading can occur relative to in a zonal or nodal market.[206] This creates the perception that zonal and nodal markets will be "thinner" with fewer trading counterparties at each area resulting in less efficient trading and/or higher costs of hedging.

8.71. In response to stakeholders' perception that national market designs are liquid, we highlight a considerable proportion of trades in the national market design do not reflect the physical realities of the network. This means that some liquidity in these markets is illusory – that trades are being made on an unconstrained commodity that may or may not be realised. As such, the effect of many of these trades would either be unwound or counter-traded in the BM. In effect, the illusory nature of liquidity in national markets becomes greater as the proportion of SO balancing actions increases.

8.72. Moreover, one further deficiency of national market designs is the lack of liquid forward markets for generating resources in import-constrained areas, who may seek to contract their outputs at the (higher) BM price.

8.73. To address liquidity concerns in nodal markets, we discuss two points:

- A qualitative description of why market liquidity has not been an issue in nodal markets in the US.
- A quantitative analysis comparing market liquidity in PJM and GB.

[206] Discussed previously in Chapter 2.

Features of nodal markets in the US that supports market liquidity

8.74. One of the key features of nodal markets in the US is the use and centrality of defined "trading hubs". Trading hubs are market exchanges which represent a group of nodes. Market participants buy and sell electricity products through these trading hubs to hedge against the uncertainty of future prices.[207]

8.75. The use of these standard products at each trading hub means that these markets are typically very liquid. Furthermore, trading hubs are used for both bilateral trading and for a wide variety of exchange-traded products. Unlike the GB national self-scheduling market design, the wide spread of exchange-traded products negates the need to find a counterparty and allows all market participants easier access.

8.76. We note that when entering into forward contracts at liquid trading hubs, market participants would still be exposed to the price differences between the relevant individual node and the trading hub. This risk is typically hedged using FTR instruments which are both allocated and sold through auctions and re-traded in balance-of-period auctions coordinated by most US ISOs (e.g., PJM, MISO, NYISO and ISO-NE).[208] As such, throughout our research on international case studies, and from our discussions with US energy experts, we have not observed any critical issues concerning liquidity around these markets.

8.77. Therefore, we consider that the organisation of nodal markets around trading hubs (and complementary use of FTRs) allays concerns regarding market liquidity. To this end, we have also not observed any liquidity issues present in trading hub-based nodal markets. Additionally, we note anecdotally the following:

- PJM accommodates over 20 trading hubs with over 12,000 nodes and is widely considered as one of the most liquid energy markets globally.[209]
- The CBA for Australia's move to LMPs noted that "the introduction of LMP will not lead to a deterioration of contract market liquidity".[210]

Analysis of market liquidity between PJM and GB

8.78. We have also attempted to show quantitatively that trading hubs have comparable liquidity as in GB exchanges. We analyse forward trading volumes across two comparable electricity future exchanges:

- UK baseload and peakload electricity futures; and
- PJM Western Hub Real-Time off-peak and peak futures.[211]

[207] Products are typically differentiated depending on whether they are day-ahead or real-time products, as well as peak or off-peak.
[208] This is discussed further in Box 9-2 and Section 9D.
[209] Climate Policy Initiative (2011), 'International Experiences of Nodal Pricing Implementation' p.5 (link) and the PJM's description of their LMP model (link).
[210] NERA (2020), 'Costs and Benefits of Access Reform', p.101 (link).
[211] Intercontinental Exchange, 'Market Reports - ICE End of Day Futures' (link).

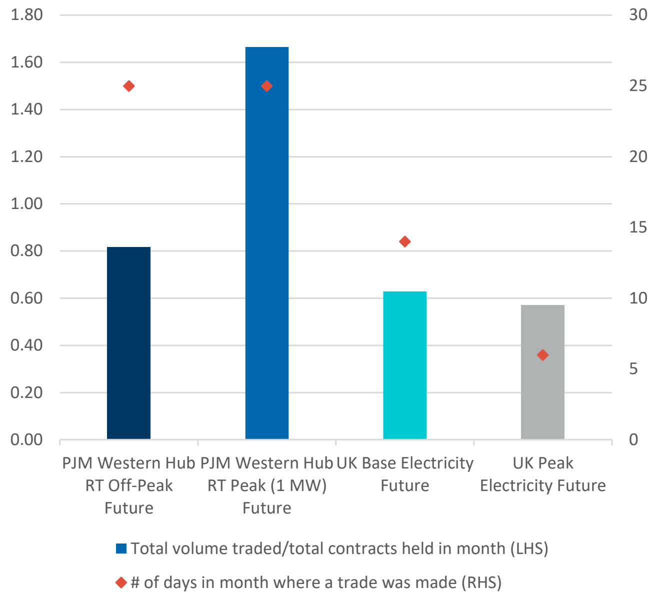
8.79. We note that an analysis of forward trading on exchanges does not include trades made within vertically-integrated entities nor does it account for bilateral contracts. Hence the results understate the level of forward trading and hedging. Nevertheless, despite its limitations, such an analysis might be useful to identify whether market liquidity might be present in the selected exchanges.

8.80. Furthermore, we note that there is no universal measure of liquidity in energy markets making such an analysis challenging. As such, we utilise the following metrics given the data available:

- Metric #1: The total number of trades made in a month as a proportion of the total available stock (defined as open interest). This measures the *relative trading volume* of the market adjusting for the contract market size.
- Metric #2: the number of days in that month where trade was made. This measures the *frequency* of trades occurring in the market.

8.81. We observe trades made in October 2022 for contracted delivery in December 2022 on the ICE exchange. Our results are shown in Figure 8-3 below.

Figure 8-3: Assessment of liquidity between PJM and GB



Source: The ICE (product codes are OPJ, PMI, UBL and UPL); FTI analysis.
Note: Each product has slightly different contract definitions (size, pricing and relevant hours)

8.82. As shown above, the evidence we found is that nodal markets have at least comparable, if not greater, liquidity relative to GB power markets based on our assessment of electricity futures.[212] Adjusting for the contract market size, PJM is shown to be more liquid than in GB, particularly for its peak period product (shown on the left side of the figure). Additionally, the PJM's Western Hub had more days in the month where a trade was made (shown on the right side of the figure).

[212] This is subject to the limitations highlighted above, such as that over-the-counter trades in both PJM and GB are not included.

8.83. While this illustrative analysis cannot be concluded due to the limitations highlighted above (i.e., does not include both trades in bilateral contracts and within vertically-integrated entities, as well as data limitations based on information available from the ICE), it indicates that a liquidity issue seems unlikely to occur in nodal market exchanges.

Impact on our assessment

8.84. Overall, we have found no evidence that a transition to a nodal market with trading hubs would reduce liquidity compared with a national self-dispatch market design – indeed, on the basis of the evidence we have observed, it may well increase it. As such, we have not made any adjustments to our overall locational assessment for the perceived impact on market liquidity.

9. Overall Cost Benefit Assessment results and impact on consumers

9.1. As described in the previous chapters, the overall impact on consumers from more granular locational pricing is composed of a range of different factors. These are:

- a reduction in the cost of transmission network constraint management, as transmission constraints between two areas would be incorporated into the respective locational wholesale price;
- changes in wholesale prices resulting from greater granularity of power prices being formed across GB;
- the creation of intra-GB congestion rent arising from the price differentials between two locations which represents a surplus for consumers;
- changes to the cost of CfD payments (borne by consumers) due to changes in wholesale prices; and
- the implementation cost of transitioning to a new locational market design.

9.2. The sum of the five impacts above provide an estimate of the net consumer benefits of locational pricing. In conjunction, total GB socioeconomic welfare is composed of the same impacts above in addition to the following:

- The change in producer surplus (that is the reduction in profits or rent to generation resources).
- Changes to the revenues from CfD payments (received by generators) due to changes in wholesale prices.

9.3. This chapter consolidates our assessment of each of the areas above to set out the overall impact on GB consumers as well as on GB socioeconomic welfare (**Section A**).

9.4. Additionally, we also consider the regional impact of locational pricing to reflect the fact that benefits and cost of locational pricing would not necessarily be spread equally across GB (**Section B**).

9.5. Based on our assessments, we then explore the impact of locational pricing on the socioeconomic impact of reduced carbon emissions (**Section C**).

9.6. Lastly, we explore a range of transitional and mitigation measures that policymakers could use to support the transition to locational pricing, and discuss how these measures may affect the overall impact on consumers (**Section D**).

A. Overall impact on consumers and socioeconomic welfare

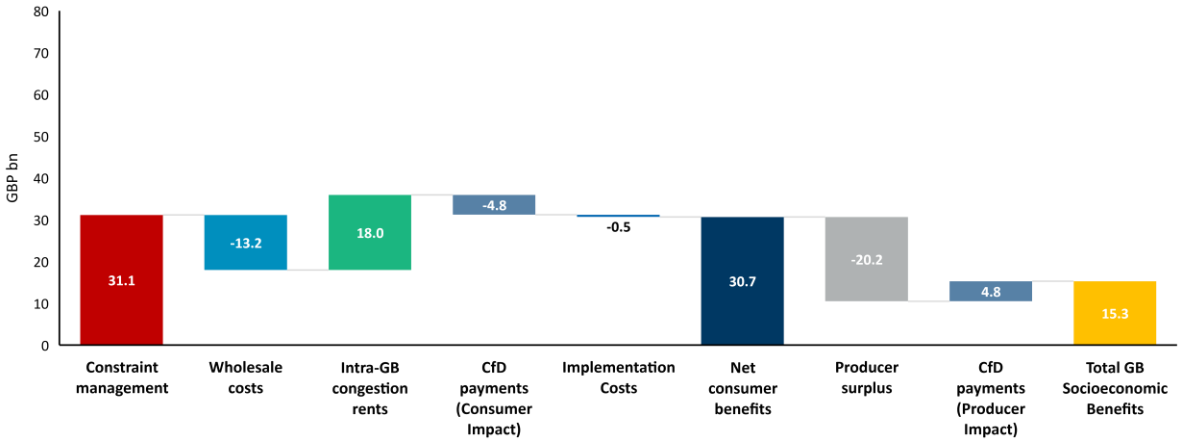
9.7. Below, we set out the overall impact on consumers and socioeconomic welfare for each of the three scenarios – LtW (NOA7), LtW (HND), and SysTr (NOA7). Further details of our outputs can be found in Chapters 6 and 7 for the LtW (NOA7) scenario, Appendix 2 for the SysTr (NOA7) scenario and Appendix 3 for the LtW (HND) scenario. While we have used the LtW (NOA7) scenario to present our findings initially, all three scenarios are considered to be equal and we note that this study only covers two out of four of the FES scenarios.

9.8. These results are based on a 2025 to 2040 modelling period (inclusive) and are in present value terms (2022 figures).

Overall CBA impact – LtW (NOA7)

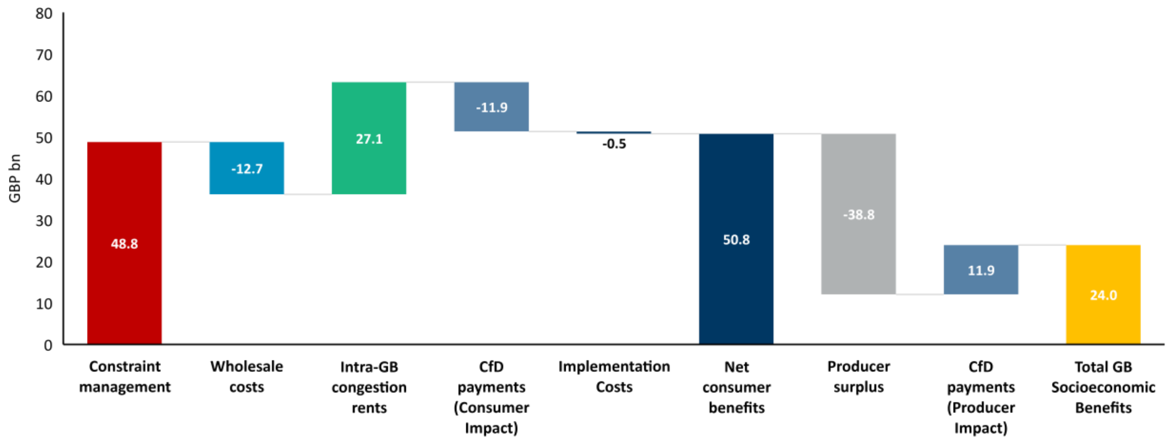
9.9. Figure 9-1 and Figure 9-2 below show the breakdown of consumers benefits and socioeconomic welfare for both the zonal and nodal market designs in the LtW scenario.

Figure 9-1: Overall Cost Benefit Assessment for a zonal market design relative to a national market design (2025-2040) – LtW (NOA7)



Source: FTI analysis

Figure 9-2: Overall Cost Benefit Assessment for a nodal market design relative to a national market design (2025-2040) – LtW (NOA7)



Source: FTI analysis

9.10. As shown in the figures above, our analysis suggests that, under the LtW (NOA7) scenario, a zonal market produces a net consumer benefit of £31bn and socioeconomic benefits of £15bn in the period 2025 to 2040. Our assessment of a transition to a nodal market produces a higher net consumer benefit of £51bn and socioeconomic benefits of £24bn.

9.11. In both sets of results, the overall consumer benefits are derived primarily from the reduction in constraint management costs, followed by the gain of intra-GB congestion rent. These benefits are partially offset by higher wholesale costs at some locations (as the costs of transmission constraints are reflected in locational wholesale prices)[213] and larger CfD support payments under either the zonal or nodal pricing regimes.

9.12. This assessment relies on several key assumptions and limitations which could affect our estimates of consumer benefits and socioeconomic welfare.[214] We set these out in Table 9-1 below.

Table 9-1: Key assumptions which could affect the overall CBA

Key assumptions	Likely impact on results if assumption relaxed
Fixed transmission build: Based on ETYS, NOA7 and information provided by ESO. Does not vary across market designs. We set out in Chapter 10 an assessment of why less transmission is likely to be required in locational markets due to improved locational and operational price signals for market participants.	↑
Fixed capacity mix: Overall generation capacity and technology mix is fixed to FES 21. Allowing the capacity mix across technologies to change between national and locational market designs could increase consumer and socioeconomic benefits and reduce the costs of achieving Net Zero.	↑
No demand re-siting and inward investment: We have fixed the location of demand across each market design assessed. Locational market designs could incentivise demand to site in different locations and/or attract further investments by energy-intensive companies which could lead to further benefits beyond those assessed.	↑
Operational benefits: Our modelling does not account for operational benefits from centralised scheduling as well as other potential benefits from using a security-constrained economic dispatch. For example, we do not consider the impact of the ability to co-optimise energy and reserves more effectively in a nodal market.	↑
Consumer exposure to locational prices: We assumed all consumers are fully exposed to locational pricing. Shielding consumers (or specific consumer types) from locational prices would reduce the estimated benefits.	↓
Further policy support for existing generation: Compensating the investments of some cohorts of existing generation for reduced revenues would lead to a reduction in consumer benefits (offset by higher producer revenues). This would not lead to changes to socioeconomic welfare unless interventions distort market incentives.	↑↓

[213] Under LtW (NOA7), the NPV of wholesale costs in a zonal market is higher than in a nodal market. This is because for a significant amount of the early modelled period, wholesale costs are higher under zonal than under nodal (and the discounting process used to calculate NPV gives greater weighting to the earlier years).

[214] A more detailed discussion on our approach and assumptions are discussed in Sections 4 and 5.

Key assumptions	Likely impact on results if assumption relaxed
FTRs confer full congestion rent benefits to consumers: We assume that all FTRs are auctioned at efficient prices (i.e., with perfect foresight). Any differences between FTR auction revenues and congestion rent collected in the settlement processes would affect consumer benefits (in the form of a direct transfer with FTR holders). There would be no change in socioeconomic welfare unless there is an inefficient risk transfer.	↑↓
No change in cost of capital: We assumed no change in cost of capital due to lack of evidence, but an increase would reduce the estimated benefits, and a decrease would increase the estimated benefits.	↑↓
New generation capacity re-siting assumptions: Assumptions on technology siting were developed in discussion with stakeholders. Any changes to these assumptions could impact the overall benefits in either direction.	↑↓
No other reforms assumed: Our status quo assessment is based on the current market structure and policy landscape. Further changes (e.g., network charging, Capacity Market reforms) could change the overall benefits.	↑↓
Choice and design of zones: Our seven-zone model is based on the six most constrained boundaries which is fixed in the modelling period. Alternative zonal boundaries would change the benefits of our zonal pricing assessment, while periodic rezoning, if assumed in our assessment, would be expected to increase the benefits.	↑↓
Modelling year: Delaying the start of the modelling period, while keeping the length of the modelling period the same, could lead to multiple effects in either direction. Overall, the net benefits are uncertain as they would depend on the energy system beyond 2040 – and in particular whether the benefits in later years would exceed the foregone benefits in early years.	↑↓

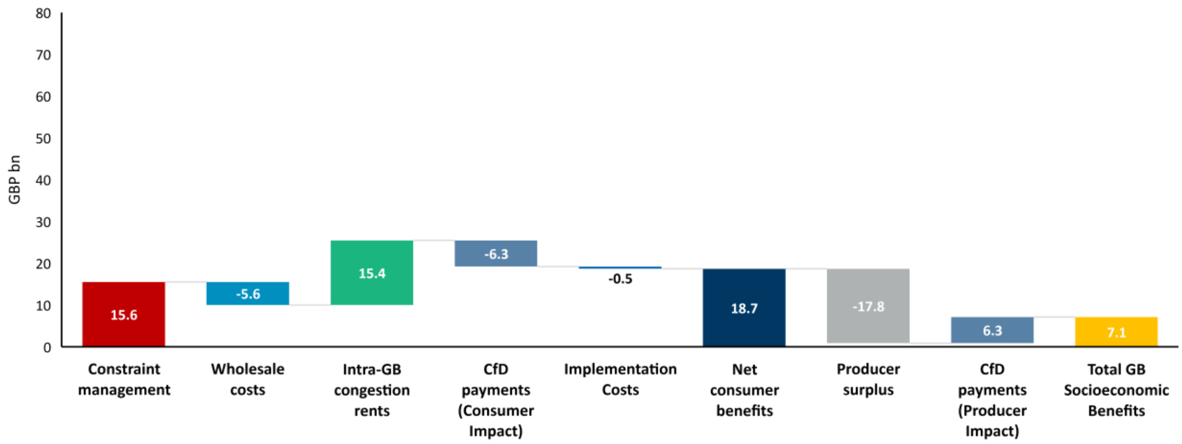
Source: FTI analysis

9.13. Overall, we expect that these results are a conservative estimate given our assumptions. These assumptions are also applied to our assessment for the other scenarios, which we set out below.

Overall CBA impact – LtW (HND)

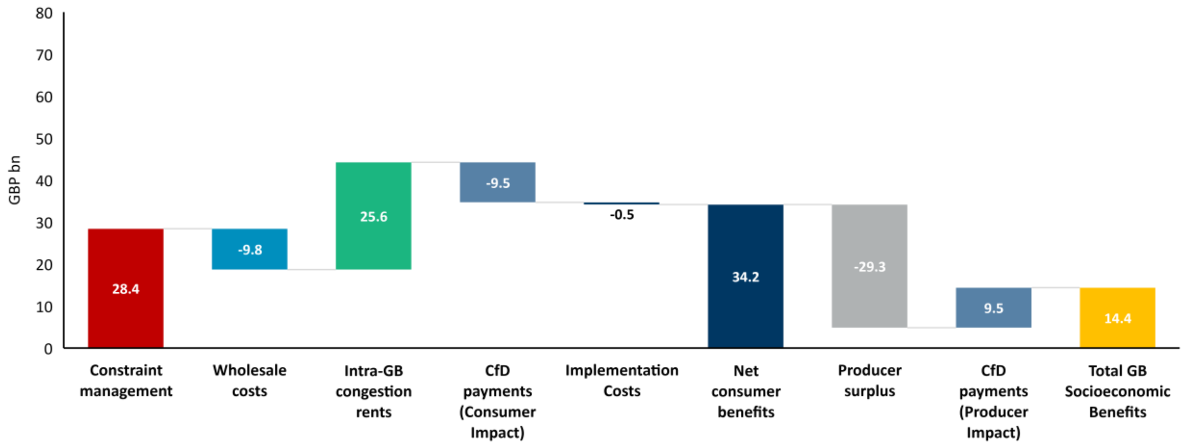
9.14. Figure 9-3 and Figure 9-4 below show the breakdown of consumers benefits and socioeconomic welfare for both the zonal and nodal market designs in the LtW (HND) scenario.

Figure 9-3: Overall Cost Benefit Assessment for a zonal market design relative to a national market design (2025-2040) – LtW (HND)



Source: FTI analysis

Figure 9-4: Overall Cost Benefit Assessment for a nodal market design relative to a national market design (2025-2040) – LtW (HND)



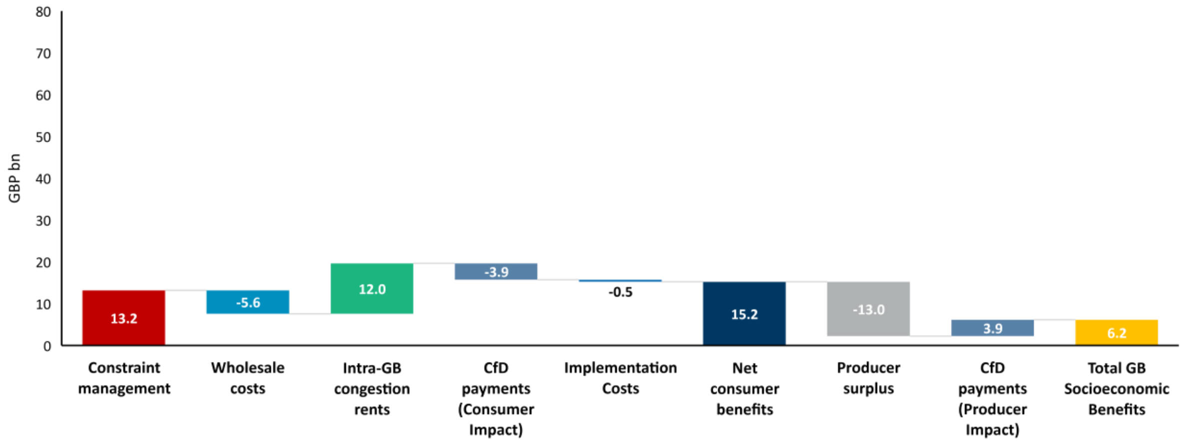
Source: FTI analysis

9.15. As shown in the figures above, under the LtW (HND) scenario, a zonal market produces a net consumer benefit of £19bn and socioeconomic benefits of £7bn. Similar to the LtW (NOA7) scenario, a nodal market produces a higher net consumer benefit of £34bn and socioeconomic benefits of £14bn than the zonal market. It is worth emphasising that our assessment does not take account of the incremental costs of the transmission build out associated with the LtW (HND) scenario relative to LtW (NOA7). This caveat should be born in mind when comparing the results between the two scenarios.

Overall CBA impact – SysTr (NOA7)

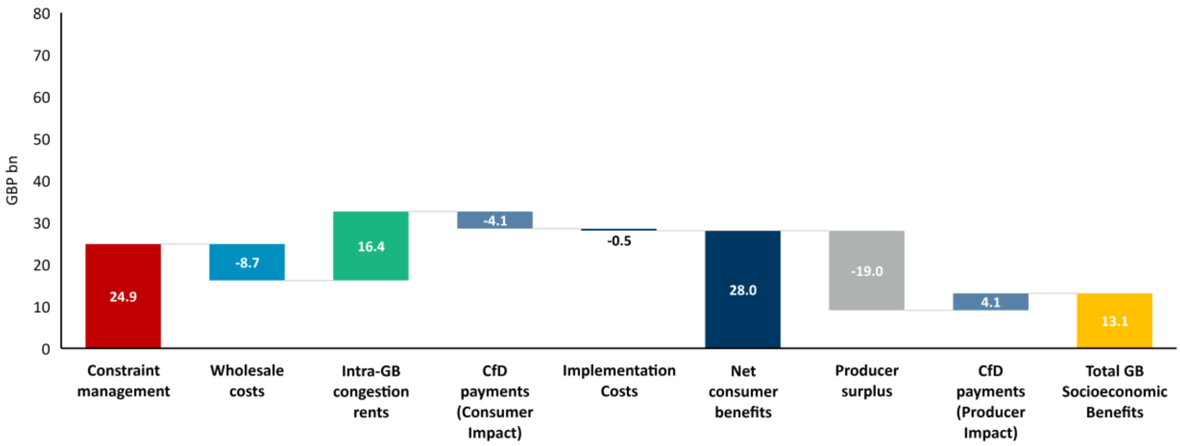
9.16. Figure 9-5 and Figure 9-6 below show the breakdown of consumers benefits and socioeconomic welfare for both the zonal and nodal market designs in the SysTr (NOA7) scenario.

Figure 9-5: Overall Cost Benefit Assessment for a zonal market design relative to a national market design (2025-2040) – SysTr (NOA7)



Source: FTI analysis

Figure 9-6: Overall Cost Benefit Assessment for a nodal market design relative to a national market design (2025-2040) – SysTr (NOA7)



Source: FTI analysis

9.17. As shown in the figures above, our analysis shows that a zonal market produces a net consumer benefit of £15bn and socioeconomic benefits of £6bn. Additionally, our assessment of a transition to a nodal market produces a higher net consumer benefit of £28bn and socioeconomic benefits of £13bn.

Overall CBA impact across all three scenarios

9.18. Table 9-2 below sets out the CBA impact for each of the locational market design options relative to the national market design across the three scenarios.

Table 9-2: CBA impact of locational market design options relative to national market design (GBP bn), 2025-2040

Scenario	Zonal		Nodal	
	Consumer benefit	Socioeconomic welfare	Consumer benefit	Socioeconomic welfare
LtW (NOA7)	30.7	15.3	50.8	24.0
LtW (HND)	18.7	7.1	34.2	14.4
SysTr (NOA7)	15.2	6.2	28.0	13.1

Source: FTI analysis

9.19. As shown in the table above, a nodal market produces higher net consumer benefits and net socioeconomic welfare benefit than the zonal market in each of the three scenarios modelled. Notably, however, we do not consider the incremental cost of transmission in the different scenarios, i.e., we do not consider the cost of HND.

9.20. We have also assessed the size of the modelled consumer benefits relative to the modelled wholesale cost of electricity and constraint management costs. This provides an indication of the potential future bill impact of transitioning to more granular locational market designs based on our assessment. Table 9-3 below sets out the relative size.

Table 9-3: Size of modelled consumer benefits compared to wholesale component of the cost of electricity (for the National LtW (NOA7) scenario)

Item	2025 *GBPm*	2030 *GBPm*	2035 *GBPm*	2040 *GBPm*	Total (2025-2040) *GBPm*
Electricity wholesale cost	21,978	8,976	15,836	27,420	272,254
Constraint management costs	3,199	3,663	4,573	5,123	66,143
Total wholesale component of the cost of electricity	**25,176**	**12,639**	**20,409**	**32,543**	**338,397**
CfD costs	1,205	11,332	12,450	7,220	144,186
Total wholesale component of the cost of electricity (+ CfDs)	**26,382**	**23,971**	**32,859**	**39,763**	**482,582**
Consumer benefit from a nodal market	4,586	3,465	4,387	5,178	68,551
Nodal consumer benefit relative to cost of electricity	**18%**	**27%**	**21%**	**16%**	**20%**
Nodal consumer benefit relative to cost of electricity + CfDs	**17%**	**14%**	**13%**	**13%**	**14%**

Source: FTI analysis
Note: Costs and benefit values stated above are not discounted, i.e., are in real terms. The total value for each item represents the total costs and benefits over the modelling period, with interpolation between the modelled years.

9.21. As shown in the table above, the overall consumer benefits from transitioning to a nodal market represents approximately 20% of the modelled cost of the wholesale component of consumer electricity bills in the national market (or 14% if the cost of CfDs is included). This reflects the increasing wholesale cost from 2030.

9.22. Overall, the benefits to consumers from transitioning to locational pricing reduces the wholesale cost of electricity by 5% to 20% depending on the scenario and locational granularity of the prices, as shown below in Table 9-4.

Table 9-4: Consumer benefit relative to the cost of electricity, 2025-2040

Scenario	Zonal		Nodal	
	Consumer benefit relative to cost of electricity	Consumer benefit relative to cost of electricity (incl. CfDs)	Consumer benefit relative to cost of electricity	Consumer benefit relative to cost of electricity (incl. CfDs)
LtW (NOA7)	12%	8%	20%	14%
LtW (HND)	8%	5%	15%	10%
SysTr (NOA7)	8%	5%	15%	9%

Source: FTI analysis

9.23. This represents a material reduction in the wholesale market component of the energy bills for consumers.[215] By way of comparison, we note that the NETA market reform was expected by Ofgem to reduce wholesale prices by 10%.[216]

9.24. While the aggregate impact on consumer and socioeconomic welfare is clearly positive for each locational market design and scenario, consumers in different locations may be impacted differently. We consider the regional impact on consumers in each location below.

B. Regional impact of locational pricing

9.25. In this section we consider how the impact of changing to a more granular locational pricing regime may vary between regions. We explore two outcomes:

- the impact of locational pricing on GB consumers in different locations; and
- a comparison of GB wholesale prices in each region to other countries in Western Europe.

The regional impact of locational pricing on GB consumers

9.26. As discussed above, the overall consumer benefits are derived from changes in constraint management, intra-GB congestion rent, wholesale costs and CfD support payments.

9.27. Each of these components can be disaggregated into the seven designated zones across GB to estimate the benefits to consumers in different parts of GB. This is done by either:

- calculating the wholesale costs for each specific zone, which is a function of the wholesale price for the relevant zone; and

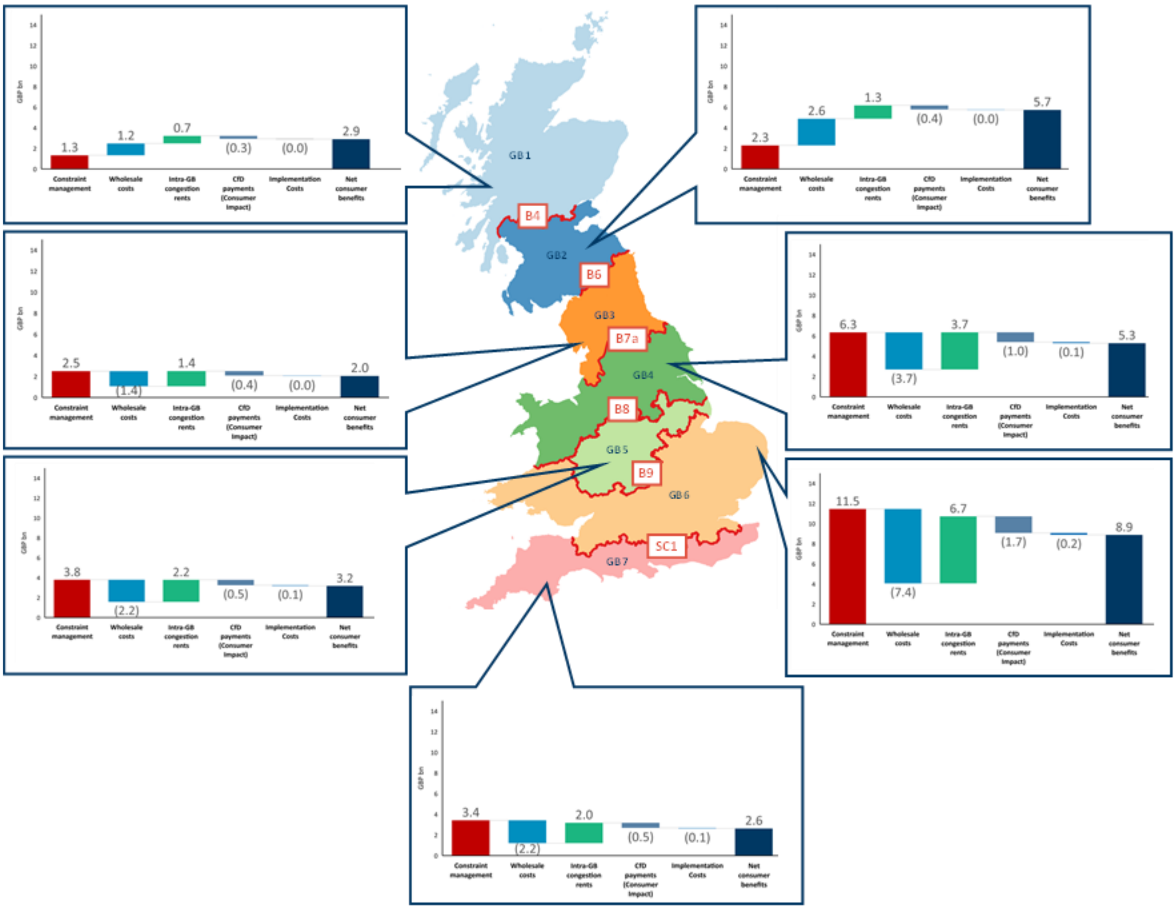
[215] As emphasised elsewhere, the LtW (HND) assessment shown above does not include the incremental cost of transmission. Hence, any comparison between the LtW (NOA7) and LtW (HND) scenarios need to note that, everything else held equal, consumers would bear higher transmission costs under the LtW (HND) scenario.

[216] See page 88 of Ofgem's Review of the first year of NETA, 2002 (link).

- smearing the benefits or costs of components on the basis of the consumer load present in each zone for each year modelled. This approach is used to disaggregate constraint management benefits, intra-GB congestion rents, CfD support payments and implementation costs.

9.28. We show the regional distribution of benefits (and costs) borne by consumers as a consequence of transitioning to a zonal pricing regime in Figure 9-7 below. This is a disaggregation of the benefits shown in Figure 9-1.

Figure 9-7: Regional distribution of consumer benefits from transitioning to a zonal market design – LtW (NOA7)



Source: FTI analysis

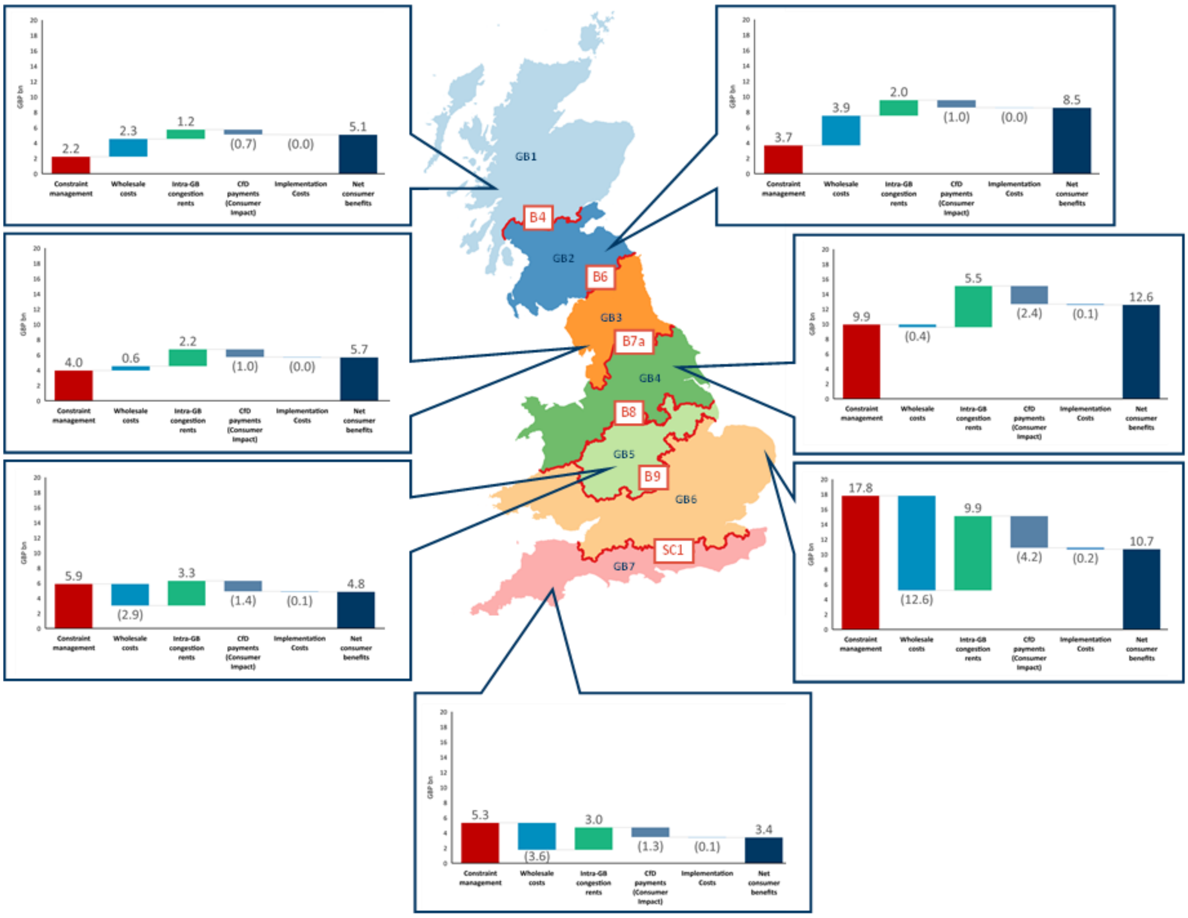
9.29. As shown in Figure 9-7 above, consumers across all seven zones benefit from transitioning to zonal pricing. The extent to which they benefit varies as a result of the wholesale price and consumer load across the respective zones.

9.30. All seven zones benefit from the reduction in the cost of constraint management, with zones consisting of a greater proportion of consumers across GB (i.e., GB4 and GB6 specifically) benefiting to a greater extent from the reduction in constraint management costs in a zonal pricing regime, in comparison to under a national pricing regime. Conversely, zonal pricing results in an increase in CfD support payments across all zones in GB.

9.31. Separately, wholesale prices in the northern zones (GB1, GB2 and GB3) are lower under the zonal pricing regime in comparison to under the national pricing regime, resulting in lower costs to consumers and therefore an increase in benefits realised by consumers in those zones. In contrast, the southern zones have higher wholesale prices relative to the national pricing regime resulting in greater costs and therefore a reduction in the benefits realised by transitioning to zonal pricing.

9.32. We conduct an identical assessment of the distribution of benefits (and costs) borne by consumers as a consequence of transitioning to a nodal pricing regime in Figure 9-8 below (which for presentational purposes is aggregated into the relevant zone the node is located in). This is a disaggregation of the benefits presented in Figure 9-2.

Figure 9-8: Regional distribution of consumer benefits from transitioning to a nodal market design – LtW (NOA7)



Source: FTI analysis

9.33. As shown in Figure 9-8 above, consumers across all regions benefit from transitioning to nodal pricing, but to a greater extent than from transitioning to a zonal pricing regime. Similar to the assessment early in this section, the extent to which they benefit varies as a result of the wholesale price and consumer load across the respective zones.

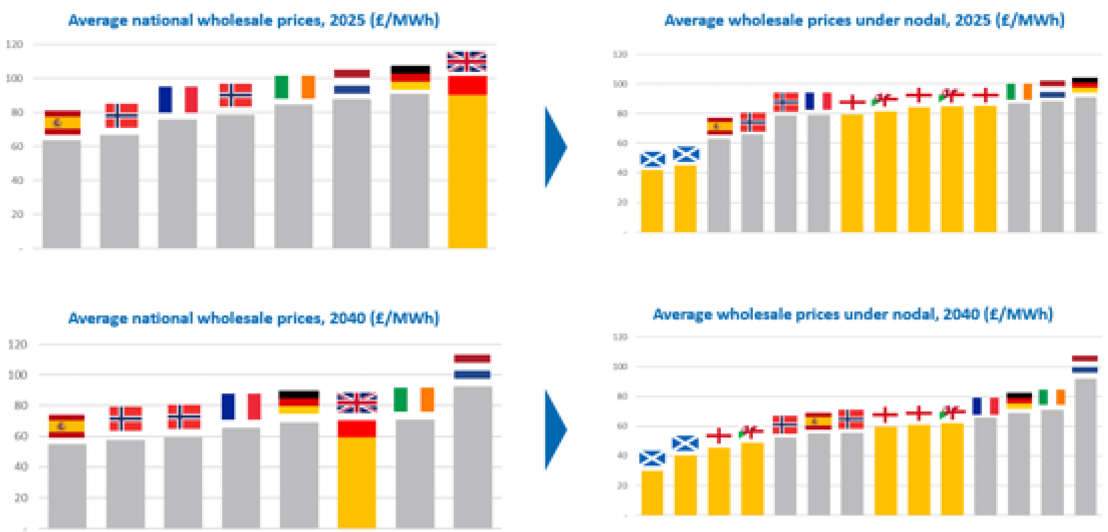
9.34. We observe the same trend above replicated for transitioning to the zonal or nodal market design under both the LtW (HND) and SysTr (NOA7) scenarios, with the magnitude of benefits realised in different zones differing on the basis of generation mix, price changes and consumer load across the different scenarios. We discuss this in greater detail in Appendix 2 and Appendix 3.

Comparison of wholesale prices in each GB zone versus other countries

9.35. Based on the information above, we also compare the wholesale electricity prices in GB with the rest of Western Europe, under both a national and nodal market in GB. This is set out in Figure 9-9 below, demonstrating the impact that nodal pricing would have on the relative wholesale price of electricity across GB when benchmarked to other jurisdictions.

9.36. We have calculated wholesale prices for European countries using our pan-European electricity market model, as described in Section 5. The use of consistent inputs for calculations relating to both GB and European countries, such as underlying commodity prices, means that comparisons are on a like-for-like basis to some extent.

Figure 9-9: Comparison of wholesale prices in GB and Western Europe under a national and nodal market design, 2025 and 2040 – LtW (NOA7)



Source: FTI analysis
Note: This assessment does not include the impact of renewable support mechanisms in any country, which would also impact the overall prices faced by consumers. Red portions of the GB wholesale price indicate the BSUoS component. We are unable to calculate the corresponding cost recovery of constraint management costs for the European nations shown, as this can be done via a variety of mechanisms and consists of different components.

9.37. As shown on the left panels in Figure 9-9 above, under a national pricing regime, GB has one of the highest wholesale electricity market prices in Western Europe throughout the modelling period.

9.38. Conversely, under a nodal pricing regime, Scottish wholesale electricity prices in 2025 would become the lowest in Western Europe, whilst prices across other GB zones would also be lower than in other jurisdictions. More efficient siting and dispatch decisions under the nodal market would also lead to a larger decrease in wholesale electricity by 2040 relative to the national pricing regime, resulting in northern England and northern Wales wholesale electricity prices also becoming amongst the lowest in Western Europe.

9.39. This also indicates that there may be additional benefits from nodal pricing, such as internal investment changes via demand re-siting, where large consumer behaviour may adapt in response to the price differentials across GB.

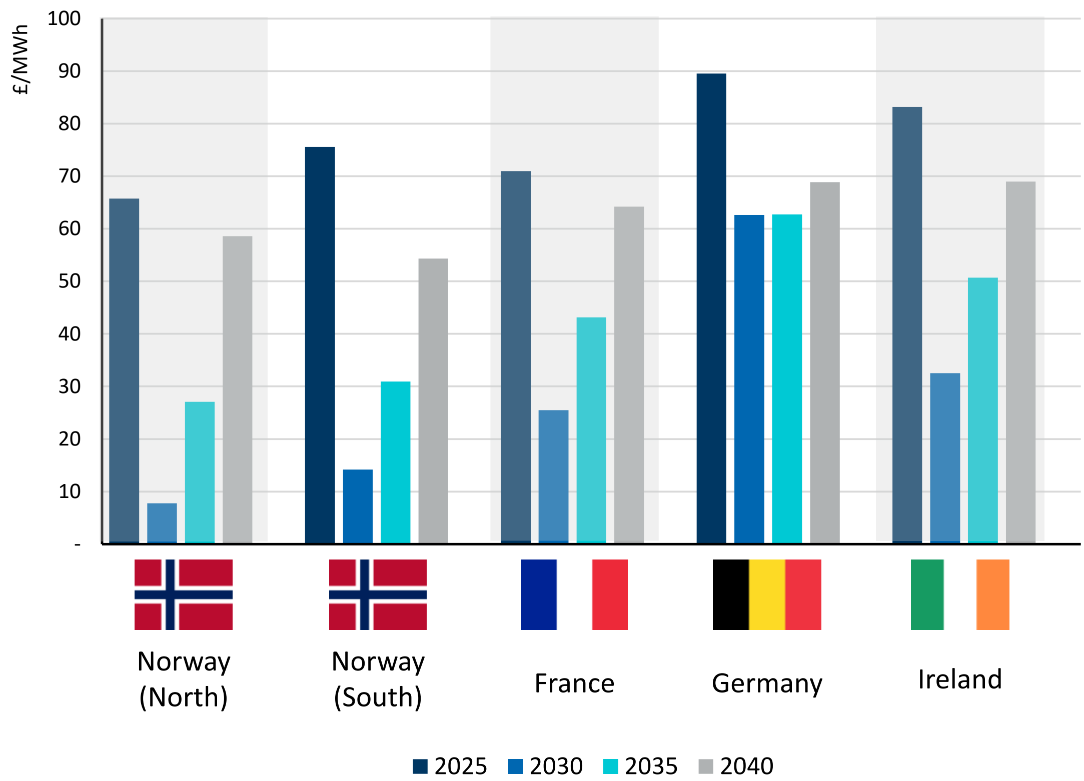
9.40. Collectively, this distributional analysis indicates that consumers across all zones in GB stand to benefit from lower wholesale prices when transitioning to more locationally granular pricing. The benefits derived from decreases in constraint management costs and intra-GB congestion rents significantly exceed the increases in wholesale prices or CfD payments.

Impact on prices in neighbouring countries

9.41. As described in Chapter 5, we have integrated our nodal GB model with our pan-EU model, which covers all countries that are part of the ENTSO-E.[217] This allowed us to model wholesale prices in each European country.

9.42. Figure 9-10 below provides the average annual wholesale prices in some of the countries connected to GB.

Figure 9-10: Average wholesale prices in selected European countries – LtW (NOA7)



Source: FTI analysis

9.43. Average prices in other European countries evolve similarly to prices in GB, due to similar developments across the markets and because of the high level of interconnection between the different European price zones.

[217] The modelling of European countries is simplified compared to the modelling of the GB side, as the main purpose of this report was to estimate the effect on GB. More detailed description of the European side of the model is provided in Appendix 1.

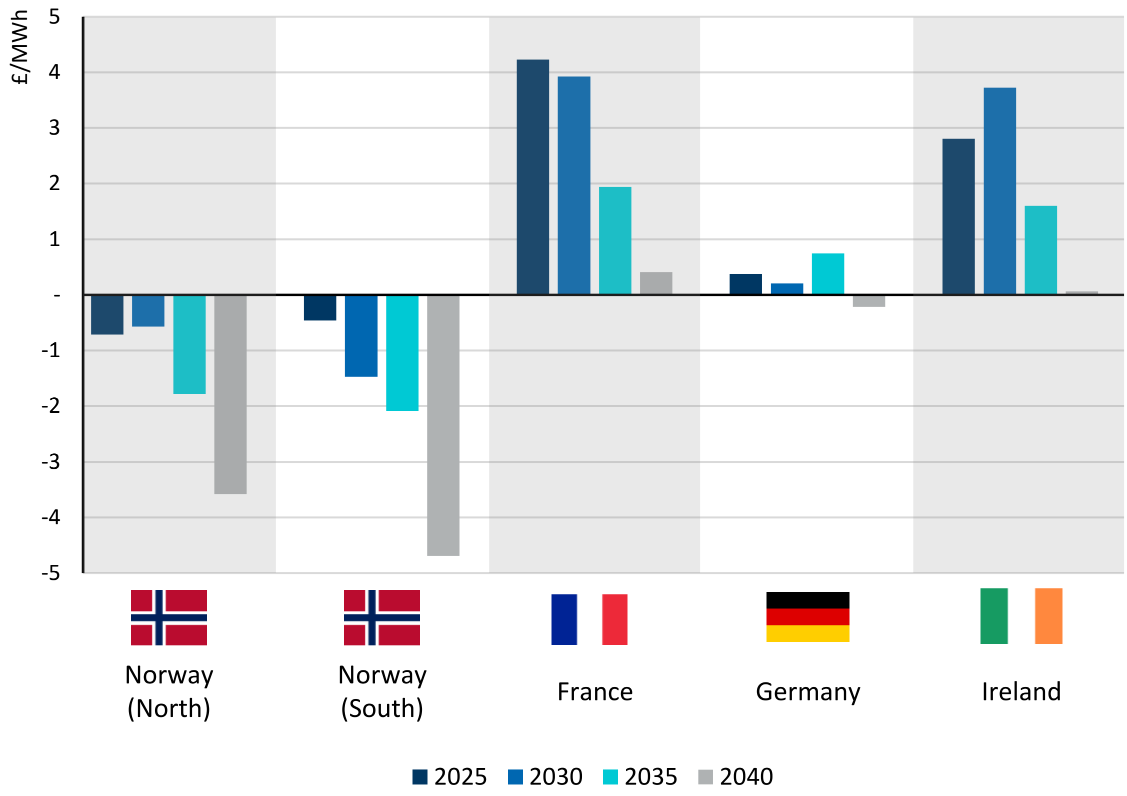
9.44. Prices decrease in all countries between 2025 and 2030, as low marginal cost renewable generation is rolled-out and prices are less frequently set by fossil fuel generators. However, prices increase from 2035 onwards, as demand for electricity increases in parallel with the electrification of transport, heating and industry.

9.45. On average prices are lowest in countries with the most renewable generation, such as Norway and in countries with significant nuclear capacity, such as France. Prices are higher in countries with high demand and relatively lower renewable generation, such as Germany.

9.46. Moving to nodal or zonal prices in GB from the status quo arrangement would lead to changes in the way in which the two wholesale markets are linked, which would affect interconnector flows between GB and other European countries, as described in Section 6F. Different flows on interconnectors to and from other European countries impact the operation of generators in those countries and, in turn, the wholesale prices in those markets.

9.47. In Figure 9-11 below, we present how prices in selected European countries change, as a result of moving to nodal pricing in GB.

Figure 9-11: Change in average wholesale prices in selected European countries as a result of a nodal market design in GB – LtW (NOA7)



Source: FTI analysis

9.48. As Figure 9-11 above shows, nodal pricing in GB has different effect on the connected countries, depending on the level of interconnection and on where the interconnectors from each country connect in GB.

9.49. Prices in Norway decrease under the presence of a nodal pricing regime in GB. This arises as the interconnectors between Norway and GB land in either northern England or Scotland. Both of these regions are forecast to have lower prices under nodal pricing relative to a national market and interconnectors export from these areas more often. This allows Norway to utilise wind energy from GB that otherwise would be curtailed under the status quo. These effects increase in size across the modelling period, as the interconnection level between the two countries increases by assumption under FES 21.[218]

9.50. By contrast, prices in France and Ireland increase as a result of nodal pricing in GB, as both of these countries are well connected to the southern part of GB, where prices increase under locational pricing. As a result, interconnectors from countries located closer to southern Britain export more to GB as a consequence. In some hours, these countries experience large shifts in prices (as shown in Box 6-3), which leads to an increase in annual average wholesale prices in those countries.

9.51. The effect on countries like Germany, where the interconnection level is smaller compared to the size of the market, is limited. The change in flows is not sufficient to change the price materially in most hours.

C. Socioeconomic impact of reduced carbon emissions

9.52. In Section 6E, we discussed how the GB energy market decarbonises faster under both zonal and nodal markets relative to the national market. Although emissions under all market arrangements reach similar levels by 2040 to reflect Net Zero objectives, the zonal and nodal markets have lower emissions in all other years relative to the national market. In aggregate, this means that locational pricing leads to lower total emissions over the modelling period, as shown in Table 9-5 below.

Table 9-5: Total emissions in 2025-2040, million tonnes

Scenario	National	Zonal	Nodal
LtW (NOA7)	-14	-67	-114
LtW (HND)	-55	-81	-120
SysTr (NOA7)	55	30	-32

Source: FTI analysis

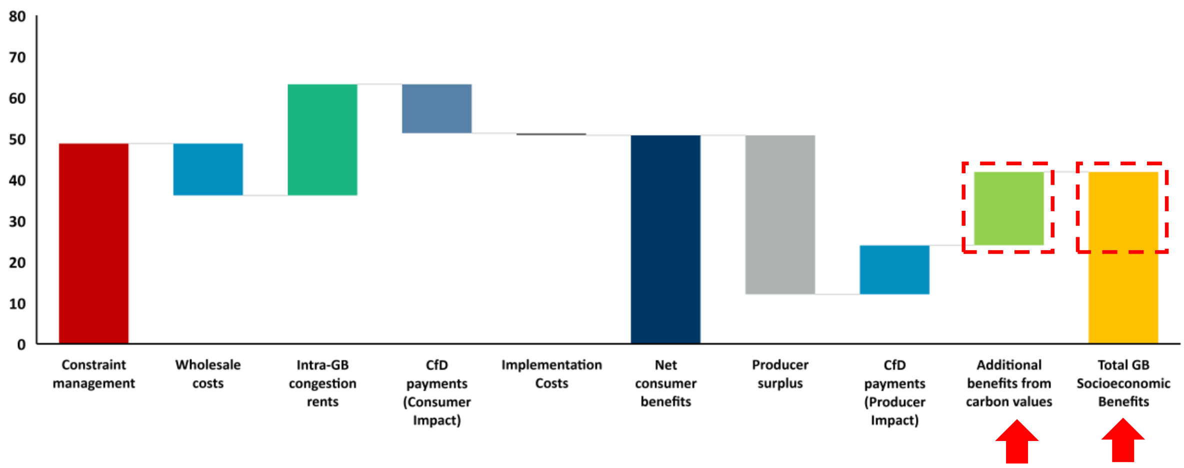
[218] We note that some stakeholders in Norway have sought to prevent the increase in interconnection capacity to GB (and other countries) on account of concerns that such interconnection would increase local prices. See for example the discussion of NorthConnect published in NRK on 16 March 2023 (link). In our assessment, Norway would, under a GB nodal pricing regime, receive significantly greater volumes of very low-cost renewables generation from Scotland which could potentially mitigate these stakeholder concerns. Greater GB-Norway interconnection would therefore increase the exports from GB to Norway which in turn would lower wholesale prices in Norway more than if the GB market had a national price. Furthermore, and as noted elsewhere in this report, this would, on the face of it, appear to be make better use of the storage potential of the Norwegian energy system.

9.53. As shown in Table 9-5, locational pricing markets in all scenarios lead to lower emissions than in the national market in aggregate over the modelling period. In particular, carbon emissions are significantly lower in the nodal market relative to the national market, with c.65 to 100 MtCO2e of lower emissions. This is driven primarily due to the utilisation of renewable resources and flexibility assets more efficiently in locational pricing markets, thereby reducing the proportion of electricity generated via fossil fuels.

9.54. The reduction in carbon emissions in locational pricing markets could have a considerable impact on overall socioeconomic welfare depending on the monetary value attached to carbon emissions. In policy appraisals in the UK, these monetary values, known as carbon values, are assigned by DESNZ with the intention of measuring the societal cost of emissions.[219]

9.55. Our CBA presented earlier in this chapter only includes the direct financial impact of locational pricing on consumers and producers, i.e., it does not consider the additional impact on socioeconomic welfare when assigning the carbon values provided by DESNZ to reduced emissions. We show in Figure 9-12 below how assigning carbon values to changes in emissions might affect the CBA of our locational pricing assessment.

Figure 9-12: Illustrative impact of assigning carbon values on our CBA



Source: FTI analysis

9.56. As observed in Figure 9-12 above, the additional value from the reduction in emissions could be represented as an additional benefit, leading to an increase in socioeconomic welfare. We describe our calculation of this additional benefit below.

[219] BEIS (2023), 'Valuation of energy use and greenhouse gas (GHG) emissions' (link). In the UK, carbon values are determined based on a "target-consistent" or "abatement cost" approach as opposed to a "social cost of carbon" approach.

Calculation of the benefits from reduced carbon emissions

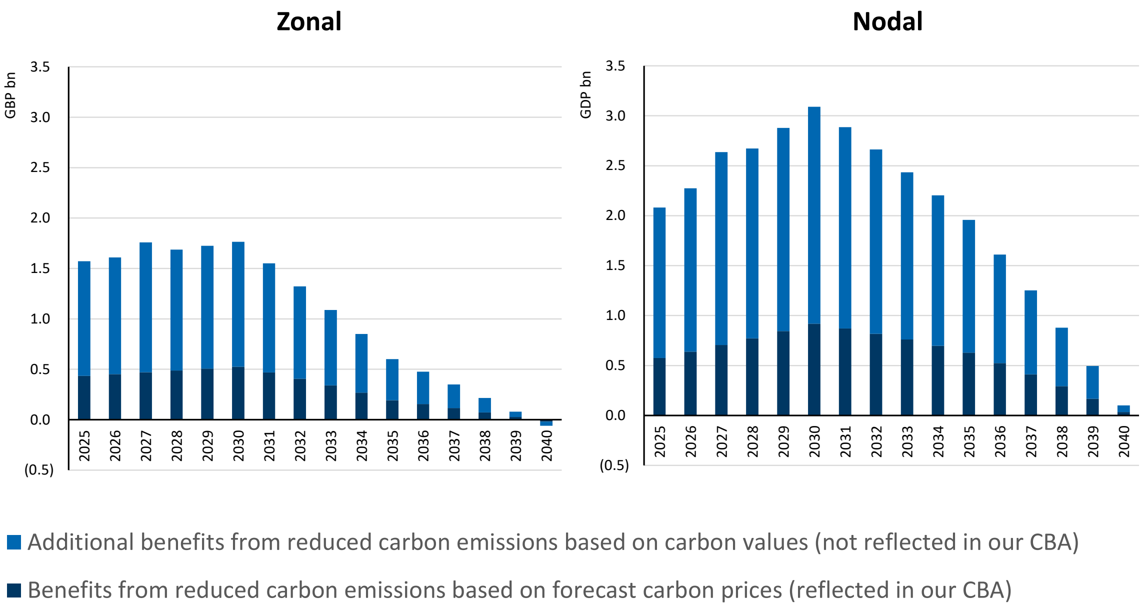
9.57. In our core CBA, the reduction in carbon emissions is reflected as a consumer and societal benefit as a result of reduced spending on carbon taxes (administered through the UK ETS). These savings are based on the forward carbon prices assumed in our analysis which are reflected through changes in the wholesale price. The lower wholesale price, in turn, leads to consumer benefits. As such, our assessment includes a **monetised portion of the benefits caused by reduced emissions, based on forecast carbon prices**, through the reduction in total electricity costs in locational markets.

9.58. The carbon price is a directly observable cost set by a market (such as the UK ETS). It is *distinct* from the carbon values used in policy appraisals. Carbon values, which are set by policymakers, are intended to reflect the full societal cost of carbon emissions. As such, these carbon values will typically be higher than forecast carbon prices. In the UK, carbon values have been specified by DESNZ up to 2050.[220]

9.59. Our core quantitative analysis therefore **does not capture the impact of locational pricing on the societal cost of carbon emissions based on carbon values.**

9.60. In order to estimate this impact, we multiply the forecast reduction in emissions in each year by the difference between the carbon price assumptions used in our assessment and the carbon value assigned by DESNZ in each year. The overall benefits, split into the benefits already captured in the analysis and the incremental benefits due to the reduced emissions, are shown for zonal and nodal market arrangements under LtW (NOA7) in Figure 9-13 below. These benefits represent the expected societal benefits resulting from lower carbon emissions from the electricity market.

Figure 9-13: Annual benefits from reduced carbon emissions under zonal and nodal market designs relative to the national market design, LtW (NOA7)



Source: FTI analysis

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[220] BEIS (2021) Valuation of greenhouse gas emissions: for policy appraisal and evaluation, (link).

9.61. The figures above show that quantified benefits from reduced carbon emissions are greatest in early years when locational pricing is expected to reduce emissions significantly compared to national pricing due to the faster integration of renewables. Nodal pricing leads to a faster reduction in emissions than zonal pricing and therefore greater benefits. By 2040, all market arrangements are projected to achieve Net Zero, resulting in negligible emissions and therefore identical carbon savings between market arrangements.

Impact of reduced carbon emissions on CBA

9.62. To allow for comparison, we discount the "additional" benefits of reduced carbon emissions (based on carbon values) across the modelling period for each scenario and market arrangement, as shown in Table 9-6 below.

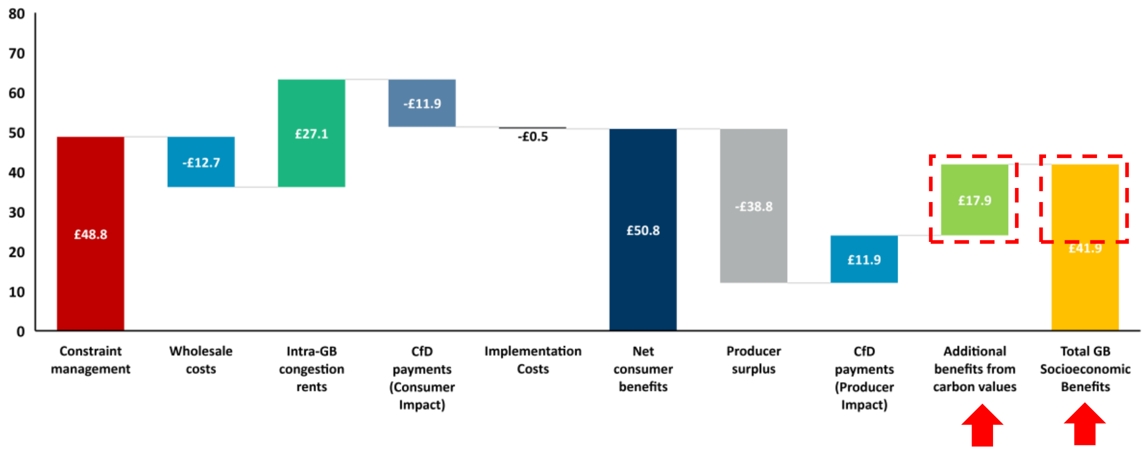
Table 9-6: Discounted additional benefits from reduced carbon emissions based on carbon values (GBP bn)

Scenario	Zonal	Nodal
LtW (NOA7)	9.7	17.9
LtW (HND)	4.9	11.7
SysTr (NOA7)	4.3	15.0

Source: FTI analysis based on DESNZ's carbon values

9.63. Overall, our assessment indicates that a move to more locationally granular pricing results in significant benefits from reduced carbon emissions across all modelled scenarios. In line with the trends observed throughout our modelling results, the magnitude of benefits is the greatest under LtW (NOA7). This increases socioeconomic benefits considerably as shown in Figure 9-14.

Figure 9-14: Impact of carbon valuation on our CBA of LtW (NOA7)



Source: FTI analysis

9.64. Table 9-7 below shows the impact of carbon valuation on GB socioeconomic benefits across all scenarios.

Table 9-7: Impact of carbon valuation on our modelled GB socioeconomic benefits (GBP bn)

	Excluding impact of carbon valuation		Including impact of carbon valuation	
Scenario	**Zonal**	**Nodal**	**Zonal**	**Nodal**
LtW (NOA7)	15.3	24.0	25.0	41.9
LtW (HND)	7.1	14.4	12.0	26.1
SysTr (NOA7)	6.2	13.1	10.5	28.1

Source: FTI analysis based on DESNZ's carbon values

9.65. The significant impact on carbon emissions highlights a critical non-monetised benefit of locational pricing. This could support the acceleration of Net Zero objectives, and/or provide headroom for the decarbonisation of other industries.

D. Transitional and mitigation measures

9.66. Inevitably, given that a move to a locational market design would lead to changes in financial flows, certain cohorts of market participants could be significantly impacted. As set out in Section 9A, even though such reforms may lead to increased consumer benefits in aggregate, some cohorts of market participants may experience a reduction in revenues due to market outcomes from locational pricing.[221]

9.67. As such, policymakers may choose to implement certain measures to either (1) ease the transition for certain market participants; and/or (2) reduce the overall impact of locational prices on certain market participant cohorts. These measures may reduce the overall benefits to consumers – any attempts to dampen the locational effect on wholesale prices or reallocate consumer surplus to market participants would unavoidably reduce consumer benefits.

9.68. In this sub-section, we discuss:

- the **overall impact of transition and mitigation measures**;
- the **grandfathering of existing investments** as a transitional measure, where one approach to delivering this policy objective would be to **allocate a portion of FTRs** to specific market participants over a defined temporary period instead of selling them through a market auction; and
- providing a **single uniform price exposure** for certain cohorts of participants in the energy system either long-term or over a defined period.

9.69. We discuss each in turn.

[221] The impact of these future changes in revenues may be reduced by the fact that a switch to a locational pricing market would occur several years into the future allowing investments and forward contracting to be made in light of those expectations.

Impact of transition and mitigation measures

9.70. Given that the impact of locational pricing on individual market participants is uncertain, policymakers might wish to consider rules that cushion the financial impact of the transition. This may be desired to reduce possible abrupt "cliff-edge" disruptions to revenue streams and cost profiles, or to reduce the risk of contractual disputes and honour the "grandfathering principle" by allowing existing contracts to be "weaned" off or tapered down towards expiry. This goal would need to be supported by a firm decision to transition to a specific market design, allowing several years for market participants to plan around the change.

9.71. This effect could be realised during the implementation period of the locational market design, with any transitional measures ending before a "go-live" date. However, policymakers may wish to extend transitional measures beyond this date, for example to allow contracts entered prior to the discussion of implementing locational market designs to expire.

9.72. The measures that shield existing investments from the effects of a policy change, in this case a move to a locational pricing regime, are known as "grandfathering".[222] This can range from a relatively light touch approach (e.g., by only maintaining existing contracts) to a relatively heavy-handed approach (e.g., by guaranteeing the expected revenue stream under the previous market design). In the GB context, examples of these approaches could include:

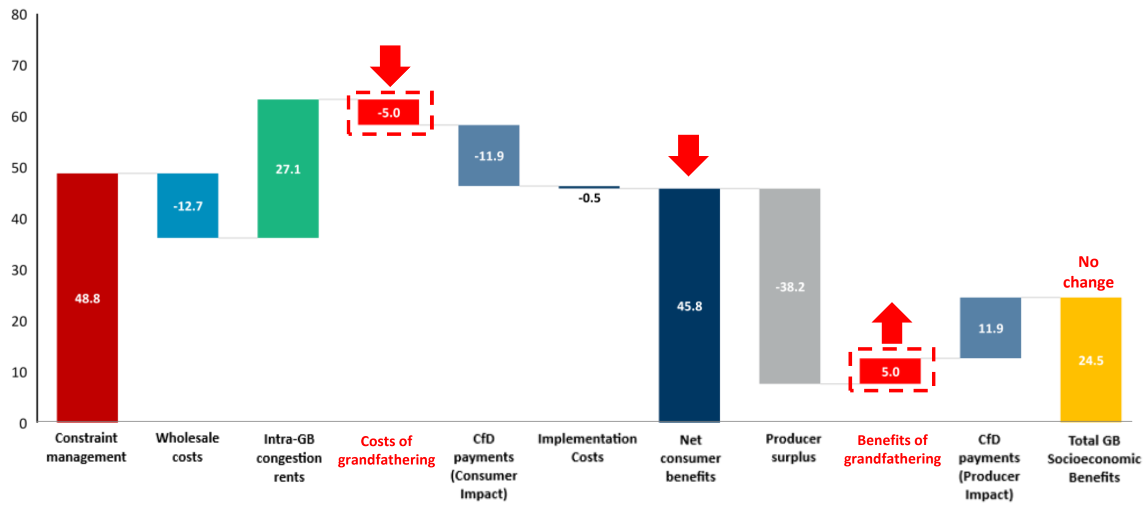
- maintaining pre-zonal or nodal contract terms for certain market participants (e.g., existing CfDs);[223]
- allocating a subset of FTRs over a defined temporary period to certain market participants to immunise them to variations in the difference between the trading hub price and the locational price; and/or
- maintaining a single price exposure to certain cohorts (e.g., through the settlements process).

9.73. Inevitably, the greater the size and duration of the support for existing investments when transitioning to a more granular locational market design, the *smaller the consumer benefits that would arise* in the transition to a nodal market. This is illustrated in Figure 9-15 below.

[222] We note that "grandfathering" policies need to be considered carefully by policymakers to avoid the risk of unintended consequences. For example, if policymakers agree to grandfather to all contracts signed ahead of a locational market "going live", market participants may be incentivised to enter into as many advantageous contracts as possible ahead of that date.

[223] We have assumed that the current contractual terms of any market participants such as CfDs would be respected in the transition to a nodal or zonal market. Notably, in practice, policymakers would need to set a fixed date early on in the transition after which all new contracts would *not* be grandfathered – this is to avoid unintended consequences where market participants would seek favourable contracts. Given the continued operation of these contracts, we have not assumed any aggregate "investment hiatus" – although we note that some parts of the system will be less financially attractive to site at after a transition to locational pricing. Conversely, some sites will be more financially attractive to site in.

Figure 9-15: Illustrative example of the effects of transitional and mitigation measures



Source: FTI analysis

9.74. As can be seen in the figure above, such measures, assuming no distortion to the market, would effectively reallocate a portion of congestion rent benefits from consumers onto producers. This results in the following:

- The amount of benefits allocated to consumers is reduced.
- The amount of benefits allocated to producers increases (by the equivalent amount to the reduction in consumer benefits).
- In the short-term, this leads to no change to socioeconomic welfare, which means that any grandfathering policies represent a pure transfer in surplus.

9.75. Ultimately, the precise extent and design of transition and mitigation measures remain a policy choice and judgement. Policymakers will have to consider and balance the overall trade-offs on the extent of continued investor support against greater consumer benefits.

9.76. Policymakers will also have to consider the potential impact of grandfathering on market participant decisions in the longer-term. For example, grandfathering an investment for an asset that would otherwise have closed might affect market outcomes, and in turn, socioeconomic welfare, instead of a simple transfer.

9.77. We also recognise the myriad of further options and complexity to policymakers, for example on what constitutes as "existing" (e.g., whether it refers to generators that are operational or includes investments with a Final Investment Decision, or planned investments with awarded renewable contracts), as well as whether certain cohorts of new investors should be protected. We do not assess these options in our assessment.

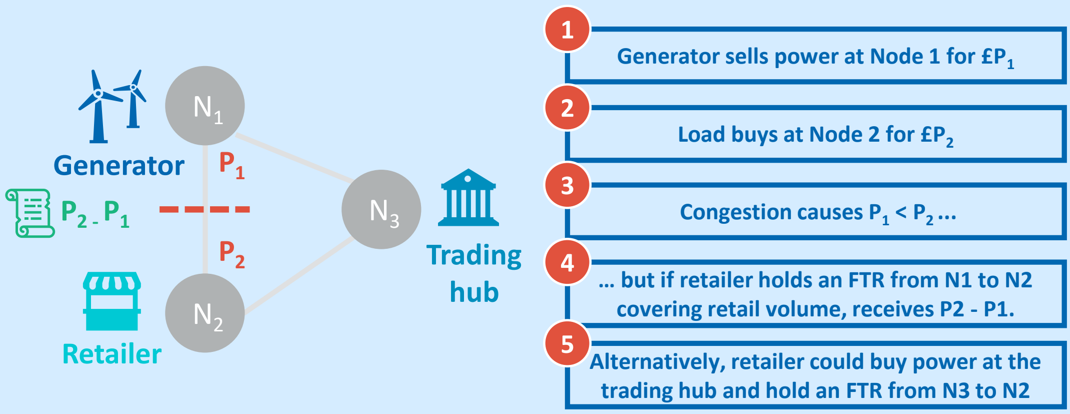
9.78. We discuss two tools that could be used to grandfather existing investments below – the allocation of FTRs and maintaining a single uniform price to certain cohorts.

Allocating FTRs

9.79. As described in Box 9-2, FTRs are financial instruments that compensate the holder for the value of congestion costs. In effect, FTRs award the holder an entitlement to the congestion charges, that is the price difference between two locations (known as the “source” of the electricity and the ”sink” where it exits or is consumed). This is described further in Box 9-2 below.

Box 9-2: Illustrative example showing how FTRs work

Figure 9-16: Indicative example demonstrating FTRs



Source: FTI analysis

Benefits to generators:

1. A generator can sell power forward at a trading hub and buy an FTR to hedge congestion between its location and the trading hub. Using the example above, the generator can hold an FTR from N1 to N3, receiving P3 - P1 at settlement (as well as P1 in the wholesale market).
2. It can also use the same FTR to hedge sales to different buyers at the hub in different periods.
3. The FTR hedges congestion charges so the generator is essentially selling power at the trading hub price (plus or less any credits or charges for incremental losses).

Benefits to retailers:

4. Similarly, a power consumer or retailer can buy power forward at a trading hub and buy an FTR from the trading hub to its load to hedge congestion charges.
5. The buyer can similarly use the same FTR to hedge purchases from different buyers at the trading hub in different periods.
6. The FTR hedges congestion charges so the buyer is essentially buying power at the trading hub price (plus or less any credits/charges for incremental losses).

9.80. FTRs have been used widely as a hedging tool against congestion charges for markets that have nodal pricing. In zonal markets, equivalent instruments can also be developed for the same purpose, albeit across zonal boundaries rather than a node-to-node or node-to-hub basis.

9.81. FTRs are typically sold through competitive auctions administered by the SO. They can usually be sold in subsequent auctions to reconfigure the allocation. The auction proceeds are typically returned to consumers because consumers fund the cost of the transmission network.[224] This reflects the congestion rent benefit to consumers.[225]

9.82. However, policymakers could decide to *allocate FTRs* to market participants directly, thereby protecting them from outturn variation in prices between the relevant node and hub. The level of protection depends on the quantity of FTRs relative to the transmission capacity as well as the duration of such contracts.

9.83. In effect, allocating FTRs instead of auctioning them would reduce the auction proceeds, and also shift congestion rents from consumers to the recipient of the freely allocated FTRs (as congestion rents collected will be used to settle these FTRs). As above, with regards to our CBA assessment, this would reduce consumer benefits but leave our assessment of socioeconomic benefits unchanged.

9.84. We set out a high-level case study in Box 9-3 below on the experience of using FTRs to grandfather existing generation investments in the US when transitioning to a nodal market design.

Box 9-3: Grandfathering in the US when transitioning to a nodal market design

Grandfathering of generation investments:

There has been **little-to-no grandfathering of generator entitlement** to use of the transmission system to date. However, investments have been grandfathered in a few cases, including for:

1. certain regulated **vertically-integrated utilities** (SPP & MISO), where the entitlement to use the generation system to meet their load has been converted into a corresponding allocation of FTRs; and
2. generators with **explicit capacity-based contracts** for use of the transmission system, who had contracts grandfathered for their remaining duration and given the option to convert to FTRs. However, the contractual charges for transmission service were in excess of the value of FTRs, so the agreements were terminated as soon as possible.

To date there have been **minimal issues with existing renewable investments** (as they were typically under contract with the retailer who purchased FTRs and/or received them in the allocation process).

The amount of grandfathered FTRs typically decreases over time as contracts expire. The largest concentration of grandfathering can be found in SPP and MISO with a mix of vertically-integrated utilities and integrated transmission providers.

224 Payments made by retailers will always exceed payments received by generators as long as there is congestion in the market.

225 The revenues raised by FTR auctions are based on *expected* congestion rent which may be different from actual congestion rent. Congestion rent is created in the market depending on actual prices and flows. These are passed to holders of FTRs. If proceeds from the FTR auctions are lower than the congestion rent collected, this means that consumers receives less than the full congestion rent benefit – but this is represented as a transfer from producers to consumers, not a reduction in socioeconomic welfare.

Support to retailers

In US regions like NYISO, ISO-NE and PJM where most load is served by competitive retailers, several approaches have been taken:

1. NYISO: One-time allocation of historical entitlements to use of the transmission system to the customers of individual transmission owners, which was were converted into Auction Revenue Rights ("ARRs").[226] ARRs are a variant of FTRs and are not tradeable. The auction revenues attributable to a specific ARR were credited to the consumers of that transmission owner through a reduction in transmission charges for embedded costs of the grid. Long-term transmission contracts are grandfathered within this design.
2. ISO-NE: ARRs from all generation assigned to retailers in each load zone. Some specific FTR entitlements flow out of contracts between municipal utilities and the transmission owners.
3. PJM: Retailers nominate ARRs from their generation resources to their load each year. There is a complex grandfathering process of prior year designations as part of the capacity market resource adequacy design. These ARRs can then be converted into FTRs in the annual FTR auction, or the retailer can in effect sell the ARR using proceeds to buy another FTR.

9.85. As with the principle of grandfathering existing investments, allocation of FTRs is primarily a policy choice. The design of FTRs, its auction process and market, and allocation process does not impact our overall CBA results set out in Section 9A.

Maintaining single uniform wholesale electricity prices for specific market participants

9.86. Instead of allocating FTRs (and in effect allocating congestion rents), policymakers could also maintain single wholesale electricity price exposure to specific market participants.

9.87. For example, policymakers may choose to only expose consumers to a uniform national price (or uniform zonal price if a nodal market design is implemented). Retailers, and ultimately the end-consumer, would be exposed to the average nodal price in the relevant area (e.g., on a load-weighted average basis) through the settlements process. However, generators (and storage providers depending on the policy choice) would continue to be paid the nodal price.

9.88. Inevitably, while this shields the impacted consumers from the locational variation in prices, a uniform price would reduce overall consumer benefits by providing inefficient price signals to price responsive load (as in the case in the current market design). For example, a uniform price may incentivise consumers in high-demand areas to increase electricity consumption due to the low uniform price relative to the nodal price that would otherwise have been incurred.

9.89. We briefly set out several key design elements that could be considered. These are:

- the type of consumers to be included in the load shielding measure (e.g., industrial demand, other large demand users, domestic consumers, storage and interconnectors);
- the extent of "shielding", e.g., whether uniform prices are based on a national or zonal average price;

[226] The ARRs are called Existing Transmission Capacity for Native Load ("ETCNL") in NYISO.

- how the uniform prices are calculated and implemented in the settlement process (e.g., as load-weighted nodal price); and
- the ability for consumers to “choose” the type of price exposure.

9.90. On the last design element described in the previous paragraph, consumers could be given the ability to *choose* whether to be exposed to a locational price or not, thereby being able to benefit from either approach. This is the option adopted in several jurisdictions including PJM and MISO and is proposed for IESO’s nodal market. Box 9-4 below describes the proposed design in IESO.

Box 9-4: IESO’s approach to load shielding

In IESO’s design and implementation of a nodal market, policymakers are planning to shield consumers from the nodal price by exposing them to a uniform zonal price. However, consumers would be allowed to “opt-out” of the uniform zonal price and settle at the nodal price.

The **uniform zonal price** would be calculated based on the average load-weighted nodal price in each zone. This calculation would exclude the load of consumers who opted to pay under the nodal price. Additionally, any financial surplus from congestion rent or losses would be subtracted from the cost of meeting load.

Consumers could choose to pay the **nodal price** at their location. These consumers would not benefit from the allocation of congestion rents and loss surplus. This approach is in part designed to allow consumers in export-constrained areas time to observe the operation of a new market for a period of time before opting into the nodal price.

The ability to opt-out of the uniform zonal price also reduces the incentives for large consumers located in low nodal price areas to install inefficient behind-the-meter generation as to avoid paying a higher uniform zonal price. Rather than making such inefficient investments, consumers can simply opt to pay the nodal price.

9.91. Ultimately, the choice of whether to shield certain cohorts such as consumers from locational prices, as well as the detailed design of implementing this feature, is a policy choice and is outside the scope of our assessment. As such, we do not consider the impact of shielding specific market participants in our overall CBA results set out in Section 9A.

9.92. However, given the importance of this measure from a policy perspective, we have carried out a sensitivity to our quantitative assessment. We discuss our findings further in Chapter 11.

10. Impact on the benefits of incremental transmission investment

10.1. In Chapter 4, we identified that more granular locational pricing could potentially lead to a change in the method for evaluating the economic benefits of transmission enhancements. At the commencement of this study we did not envisage testing how the benefits of transmission investment might alter between market designs. Rather, after consultation with stakeholders and Ofgem, we agreed to keep the configuration of the transmission network constant when assessing the benefits between the three market design options.

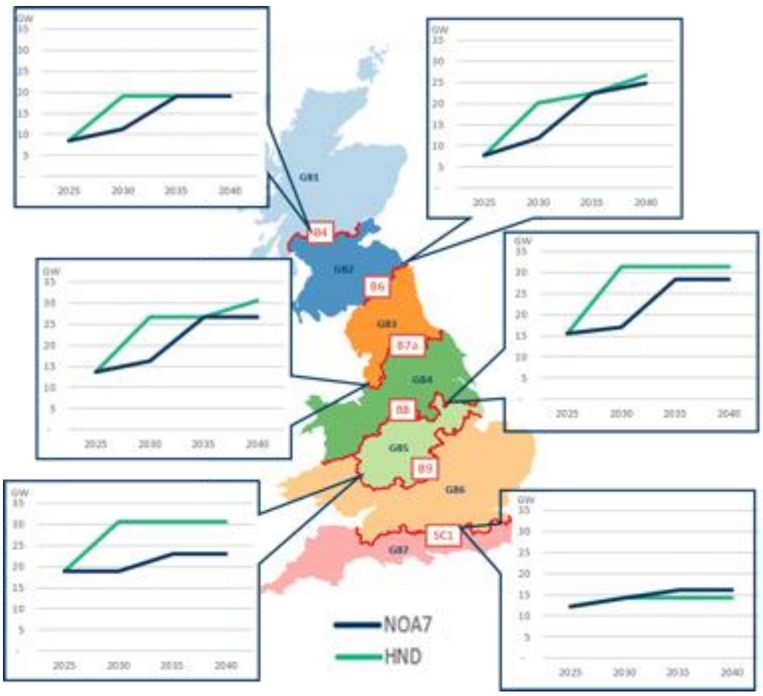
10.2. However, our analysis evaluated locational pricing options against a pair of scenarios that differed in the rate of transmission network build-out: the LtW (NOA7) scenario reflects a forecast of ambitious transmission network development, and the LtW (HND) scenario represents a further, even more ambitious, upgrade to the transmission network. Comparing these two scenarios allows us to evaluate how the case for incremental transmission investment would change between market design scenarios.

10.3. In this chapter, we first explain the background to our approach for assessing the benefits of transmission, and then present our findings for both the national market design and the nodal market design and compare the two sets of results and finally set out our conclusions.

A. Background to approach

10.4. Figure 10-1 below shows some of the main differences in transmission network capabilities across the main transmission boundaries in the model (albeit in practice, we model a nodal representation of the network) between the LtW (NOA7) scenario and the LtW (HND) scenario.

Figure 10-1: Transmission capacities across key boundaries in GB

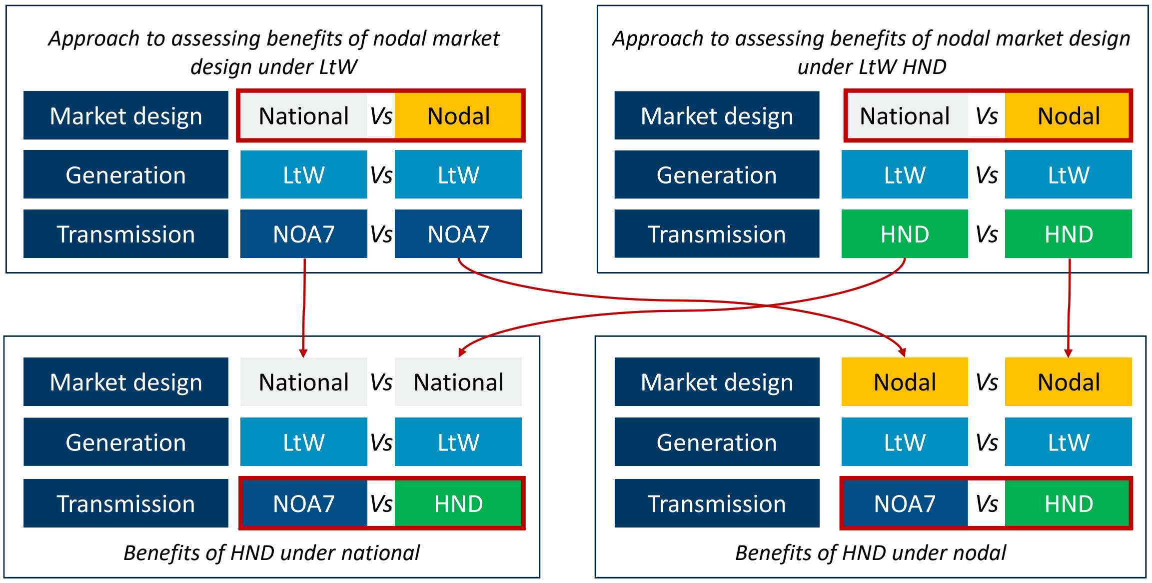


Source: FTI analysis

10.5. As Figure 10-1 above indicates, the LtW (HND) scenario envisages a faster roll out of transmission relative to the LtW (NOA7) scenario in the northern GB as well as incremental enhancements in the southern half – notably the reinforcements across the B9 boundary.

10.6. Therefore, the LtW (HND) scenario represents an adjustment to the level of transmission investment, while holding the generation and demand assumptions constant (i.e., as per the LtW (NOA7) scenario). We can therefore evaluate the benefits of the proposed HND transmission enhancements relative the NOA7 level of transmission, while keeping the generation and other background assumptions constant (as per the LtW scenario), under each market design. This does not require us to do additional modelling – but rather can be assessed from comparing data from existing model runs, as shown in Figure 10-2.

Figure 10-2: Schematic of assessment methodology



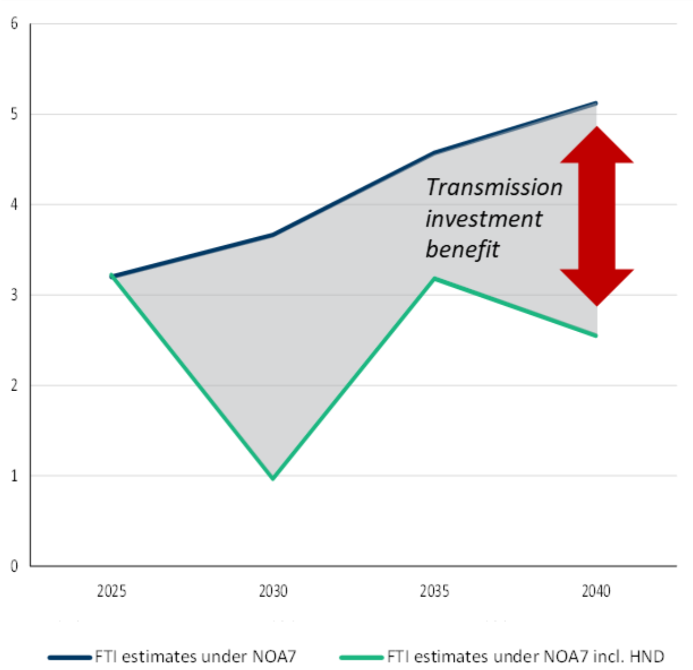
Source: FTI analysis

10.7. As Figure 10-2 illustrates, our assessment initially focused on the impact of locational price granularity, keeping generation profiles and transmission capacity constant across different market designs. Our model runs for this assessment can also therefore be repurposed to keep market design and generation profiles constant, while comparing the impact of different transmission capacities, as shown in the lower two panels.

B. Benefits of HND transmission investment under national market design

10.8. As discussed in Chapter 2, under a national pricing regime the benefits of the transmission enhancements will manifest themselves in reduced constraint management costs incurred by the ESO. Figure 10-3 below reproduces our estimates of constraint management costs under the LtW (NOA7) scenario and the LtW (HND) scenario shown earlier in Chapter 7.

Figure 10-3: Constraint management costs forecast under LtW, with transmission capacity as per NOA7 or HND, GBP bn



Source: FTI analysis
Note: Constraint costs are depicted in real terms and have not been discounted.

10.9. As Figure 10-3 indicates, additional investment in the transmission network associated with the HND scenario brings a significant reduction in constraint management costs – particularly in 2030 when the difference in the transmission network capabilities between the two scenarios is most pronounced.

10.10. The difference between the two trajectories of constraint management costs is £28bn over the 16-year modelling period from 2025 to 2040. This would be the potential benefits that might reasonably be assessed to accrue under the national market design for the incremental transmission investment associated with the LtW (HND) scenario relative to the LtW (NOA7) scenario. Indeed, we understand that this is broadly the methodology currently adopted by ESO in its Network Options Assessment – albeit in a simplified form.[227]

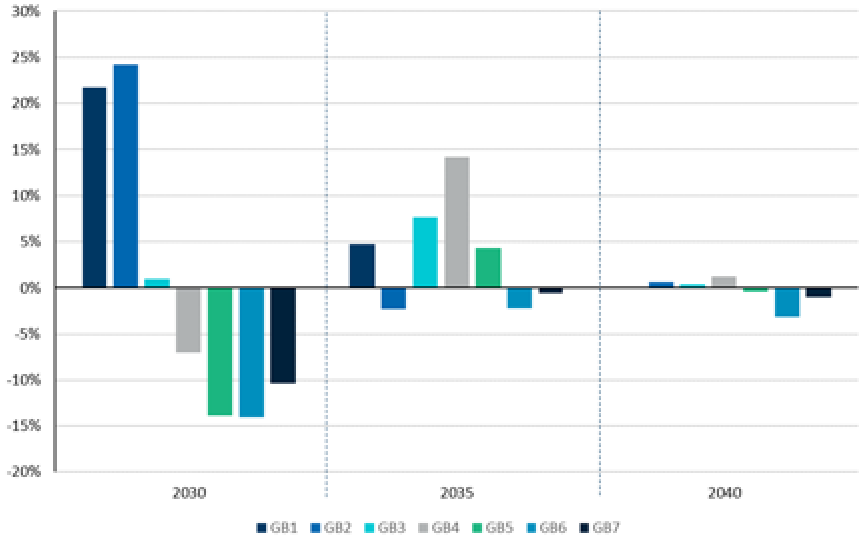
[227] See the NOA methodology, published by the ESO in 2020 (link) that describes the approach that ESO take to assessing the benefits of network reinforcements.

C. Benefits of HND transmission investment under a nodal market design

10.11. We explained in Chapter 2 that, in a nodal market, the resolution of transmission constraints is inherent to the market design itself and that there is, therefore, no requirement for the ESO to incur constraint costs by intervening in the market to resolve congestion as per a national (and, albeit to a lesser extent, zonal) market design. An implication of this is that the benefits of enhanced transmission manifest themselves differently: in a nodal market design, transmission investment leads to changes in wholesale prices in some parts of the system (which impacts producer and consumer surpluses), as well as the overall congestion rents that arise in the settlement process.[228]

10.12. Figure 10-4 below illustrates how the incremental transmission investment changes nodal prices under the LtW (HND) scenario relative to the nodal prices observed under the LtW (NOA7) scenario. As elsewhere in our report, for ease of exposition we have load-weighted the average of the nodal prices for each of the seven zones.[229]

Figure 10-4: Percentage change in LtW (HND) nodal prices relative to LtW (NOA7) nodal prices across GB price zones



Source: FTI analysis
Note: The values presented in the figure above are in real terms and have not been discounted.

[228] The assessment of the benefits of enhanced transmission in a nodal market are therefore somewhat analogous to the current approach for assessing the benefits for electricity interconnectors. A key part of the interconnector benefits assessment is a consideration of the price changes that are likely to occur in each market because of the transmission upgrade, the resulting impacts on consumers and producers in each country, and the congestion rents earned on the cable itself. See, for example, Ofgem (2021) 'Interconnector Cap and Floor Regime Handbook', (link).

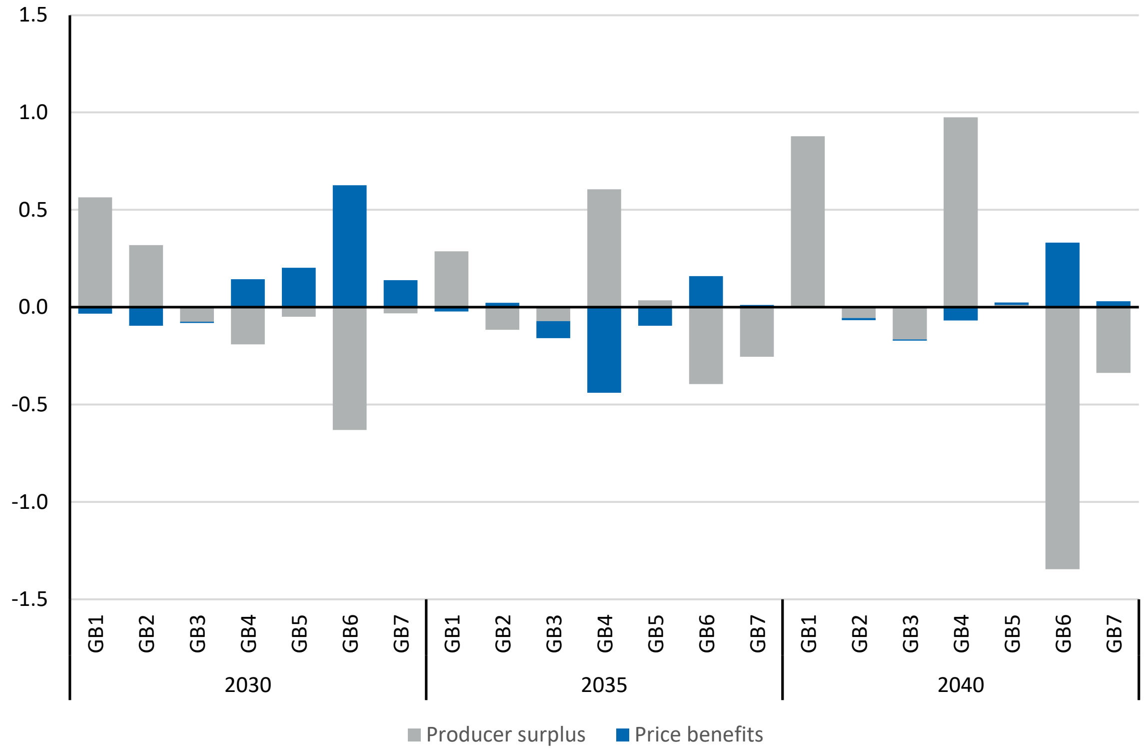
[229] We do not compare results in 2025 as there are no differences in the transmission capacity between the two scenarios in this year. The additional transmission capacity under LtW (HND) is reflected in our 2030 modelling year onwards.

10.13. As Figure 10-4 above illustrates, annual average nodal prices move as we would expect given the additional transmission in the LtW (HND) scenario. Notably, in 2030 when there is significantly more transmission in the HND scenario connecting Scotland to England than in the NOA7 transmission scenario, average nodal prices in the export-constrained Scottish regions (GB1 and GB2) increase by c.20%, whereas in more southern parts of England prices fall as a result of being able to access greater volumes of electricity generated at lower cost and conveyed via the new transmission lines.

10.14. By 2035, the differences in the transmission build between the LtW (NOA7) and LtW (HND) scenarios relate principally to the B9 boundary, which is in southern England. Hence, north of the B9 boundary average nodal prices are generally higher in the HND scenario, whereas south of the B9 boundary, nodal prices are lower. The same, albeit more muted, effect also occurs in 2040.

10.15. Given the change in prices that are observed under a nodal pricing regime and the change in electricity flows across the network as result of transmission investment, we can now calculate the change in the consumer and producer surpluses that arise as a result of the change in prices and volumes. Figure 10-5 below shows the impact.

Figure 10-5: Consumer price benefit and change in producer surplus, GBP bn

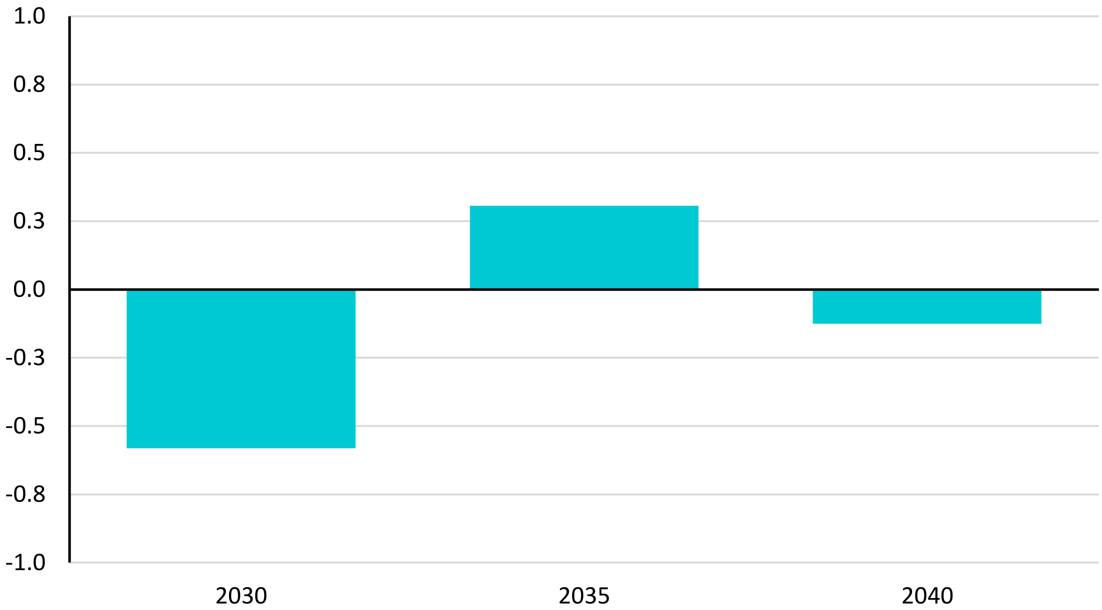


Source: FTI analysis
Note: The values presented in the figure above are in real terms and have not been discounted. Price benefits above represents the consumer surplus generated due to changes in the wholesale price.

10.16. As Figure 10-5 above illustrates, in regions where nodal prices generally increase as result of the enhanced transmission, the producer surplus increases and the consumer surplus decreases. The opposite is also true. This is in line with our expectations given the price changes shown previously in Figure 10-4.

10.17. In addition to the change in consumer and producer surpluses discussed above, a socioeconomic evaluation of a transmission investment would also need take account of the change in congestion rents. This could be in aggregate either positive or negative – the additional transmission increases the volume that is conveyed across the system, thereby increasing congestion rent, but narrows the spread between low- and high-priced regions, thereby decreasing congestion rent (on the existing transmission lines as well as new ones). Which effect prevails is an empirical question and will vary for each individual transmission enhancement. Figure 10-6 below illustrates how the congestion rents vary as a result of the enhanced transmission investment associated with HND.

Figure 10-6: Difference under the LtW (HND) scenario relative to the LtW (NOA7) scenario of intra-GB congestion rents across the modelling period, GBP bn

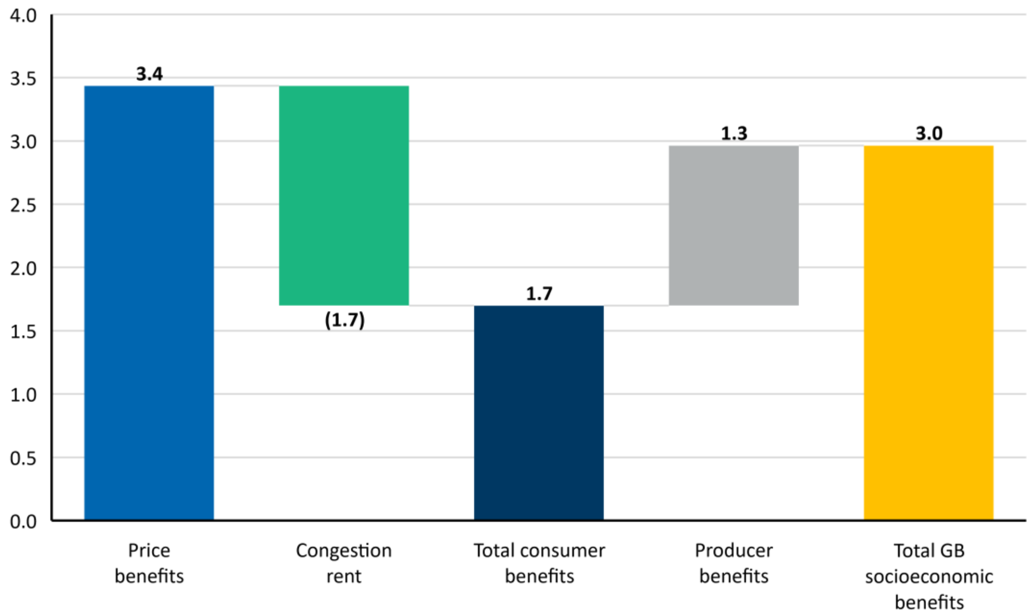


Source: FTI analysis
Note: The values presented in the figure above are in real terms and have not been discounted.

10.18. In the LtW (HND) scenario we have modelled, we find that there is an aggregate decrease in congestion rents earned of £1.7bn over the modelling period of 2025 to 2040 as a result of the enhanced transmission.

10.19. Aggregating the total benefits to both consumers and producers and the change in the congestion rents for the entire period allows us to assess the benefits of the HND transmission enhancement under a nodal pricing regime. This is set out below in Figure 10-7.

Figure 10-7: Socioeconomic benefits of HND transmission investment relative to NOA7 transmission investment under a nodal pricing regime in GB (2025-2040), GBP bn



Source: FTI analysis
Note: The values presented in the figure above have been discounted. Price benefits above represents the consumer surplus generated due to changes in the wholesale price.

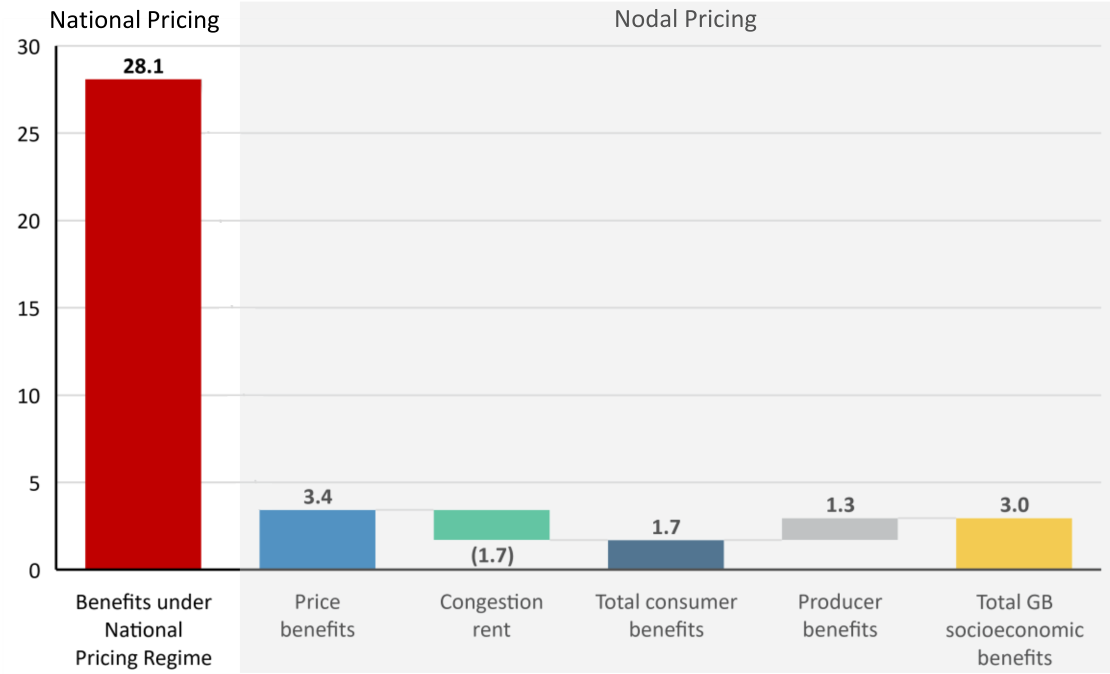
10.20. As Figure 10-7 above shows, the benefits of HND transmission enhancements that accrue under a nodal pricing regime are c.£3bn. We note that, of this, c.55% of the benefits accrue to consumers and c.45% accrue to producers.[230] We have not included in this assessment the changes to the CfD payments. To the extent that these change, they would represent a change in both consumer and producer benefits – but there would be no change in the overall socioeconomic welfare.

D. Comparison of assessment of benefits of transmission enhancements under a national and under nodal pricing market

10.21. Figure 10-8 below compares the benefits of the same level of transmission enhancement, albeit evaluated under a national pricing market design and a nodal pricing market design.

[230] From a strict socioeconomic perspective, impacts on consumers and producers should be treated equally as we have represented above. However, we note that while some regulatory authorities adopt this approach, others, have deviated from it and have focused more on consumer impacts. Ofgem, for example, have tended historically to place less weight on producer impacts and more on consumer impacts in its approach to assessing the benefits of proposed interconnectors. See our 2018 study for the Australian market operator, AEMO, for further details of different approaches to assessing transmission investment business cases (link).

Figure 10-8: Benefits of enhanced transmission investment under a national and nodal pricing regime in GB (2025-2040), GBP bn



Source: FTI analysis
Note: The values presented in the figure above have been discounted. Price benefits above represents the consumer surplus generated due to changes in the wholesale price.

10.22. As Figure 10-8 illustrates, our assessment of the magnitude of the difference between the benefits of a given set of transmission investments under a national pricing regime and a nodal pricing regime is material. Indeed, it would appear that the benefits for this particular transmission enhancement example are c.90% lower under a nodal market than under a national pricing regime.

10.23. We have not sought to evaluate the costs associated with the HND transmission enhancement. However, our analysis would suggest that if the estimated incremental cost of the transmission reinforcements of HND relative to NOA7 was greater than £3bn over the period 2030 to 2040, then the investment would, under a strict socioeconomic assessment approach in a nodal market, be net detrimental to society. Our understanding is that to proceed under the current regime, the exact same investment would need to be estimated to cost less than £28bn over the same period to be judged net beneficial.[231]

[231] We note that the comparison of transmission benefits presented here evaluates the "economic needs case" for a given transmission investment. See our 2018 study for the Australian market operator, AEMO, for further details of different approaches to assessing transmission investment business cases (link). Other factors that we are aware of that typically might enter into a transmission assessment process include reliability and "public policy" needs. The latter was introduced in the US as part of FERC Order 1000 and could be used in the assessment of transmission needed to connect generation assets to meet environmental targets. It would seem to us that the level of non-economic benefits would be invariant to the market design (for example, the same volume of renewable generation capacity is connected in each market design scenario) and therefore the same level of "non-economic" benefits would accrue for the transmission enhancement that we assess.

10.24. To date, there has been considerable debate on the potential benefits of nodal pricing that might arise from improved siting or dispatch of generation. However, there appears to have been limited consideration of the potential impact of nodal pricing on the need for incremental transmission network investment including the way in which the network should be expanded and/or enhanced.

10.25. Given the magnitude of the difference shown above in our assessment was considerably larger than we had expected, we have carefully interrogated the data and verified the results. After extensive review of our analysis, as well as discussions with Ofgem and with the ESO, we believe that there are three main drivers of the difference in the assessment of benefits of the HND transmission upgrade that arises in the two market designs. These relate to:

- first, the way in which BM bids and offer assumptions are used to evaluate congestion costs, which in turn, impact the assessment of benefits of transmission enhancements;
- second, the fact that our modelling assumes some change in the siting decisions of generation that arise as a result of stronger incentives in locational wholesale market which results in changes in locational generation patterns; and
- third, the changes in the operating profiles of flexible assets and, in particular, interconnectors, that would arise as a result of a transition from national to nodal pricing that we highlighted earlier in Section 6F and impact significantly on flows across the system.

10.26. We discuss each in turn and then set out some concluding remarks on this topic.

Forecasting congestion costs

10.27. One driver of the difference in the benefits assessment of the HND transmission upgrade arises from assumptions used in the participant bidding strategy in the BM and how the constraint management cost forecast data is then deployed to assess transmission benefits. In this regard, under a national pricing regime, the level of benefit of a transmission enhancement is derived from two sources:

- First, a reduced need for the SO to pay to constrain on generators (typically sited in the south of GB) in the BM. By virtue of the increase in transmission capacity, these generators will be displaced by greater volumes of lower cost generation that can reach the market from generating units that would otherwise have been constrained off.
- Second, a reduced need for the SO to pay (or be paid) to constrain off generators (typically sited in the north of GB).

10.28. The first of these is, in part, an efficiency gain that arises as a result of the incremental transmission investment – represented by a reduction in the production cost (as more generation located in export-constrained locations that were previously curtailed can now be utilised). However, the offer prices that we have used in the BM to evaluate the forecast level of congestion for thermal plants (that are typically constrained on in the earlier years of our modelling period) reflect an uplift to the market clearing SRMC. As discussed earlier, the pay-as-bid design creates an incentive to submit offers that deviate from marginal cost. We, and the ESO, calibrate this uplift on the basis of historically observed BM bidding behaviours. As we noted previously, some of the uplift is likely to reflect start-up costs. It will, however, also reflect the idiosyncratic nature of the pay-as-bid BM, the locational value of electricity, and potentially also a degree of market power. Hence, while some of the uplift may reflect underlying costs (e.g., start-up costs), which is an efficiency gain, it also potentially includes other non-socioeconomic cost factors.

10.29. The second element is, as we discussed in Chapter 2, a transfer payment from consumers to generators and does not reflect underlying costs as evaluated under a socioeconomic basis. Rather, it tends to reflect the degree of compensation that a generator requires to forgo operating to meet its commitments in the wholesale market and, in practice, is often likely to reflect the strike prices of CfD contracts (relative to the prevailing wholesale prices) of wind generators. Hence, this element of the reduction in cost can only be a reduction in transfers from consumers to generators. While no doubt welcome from a consumer perspective, this has zero economic value from a socioeconomic perspective.

10.30. Our methodology for assessing constraint management costs has been discussed at length with ESO and, indeed, as we reported in Chapter 7, our forecast is reasonably close to the ESO forecast. As we described earlier this therefore provided us comfort that our methodology for the constraint management cost forecast is reasonably robust (or at least accords with the ESO approach).

10.31. It therefore appears to us that there is a risk that using an estimate of the constraint management cost savings to assess the potential economic benefits of a transmission enhancement potentially risks overstating these benefits compared to an approach in which the benefits are evaluated on a conventional socioeconomic basis. The main reason for this is that the BM bids and offers do not completely reflect underlying economic costs. Rather the NOA methodology appears to conflate both economic cost savings (that arise from the reduced need to incur costs of constrained-on generators) *and* non-economic cost savings. These non-economic cost savings include the transfers that incur in the BM as a result of participants including uplifts in bids and offers from the underlying cost, as well as the transfers to compensate constrained-off plant – particularly those that hold CfDs. Moreover, we note that the risk of overvaluing the benefits of transmission enhancements appears to be true under the current national pricing regime.

10.32. We would note that we have discussed this finding with the ESO. They had, independently of our analysis and findings, recently identified this issue internally as part of their review of the NOA methodology[232] and had initiated internal analysis of their own on the topic.

Change in generation location and output

10.33. As we discussed earlier in this report, when we analysed the impact of changing from a national to a nodal market design, we assumed that there would be some changes in the siting decisions of generators in response to locational price signals (albeit limited by real world factors described in Chapter 5). Given, under a nodal pricing regime, transmission enhancements will lead to changes in nodal prices, it is methodologically consistent for us to assume that there would be the same impacts on generating siting decisions too.

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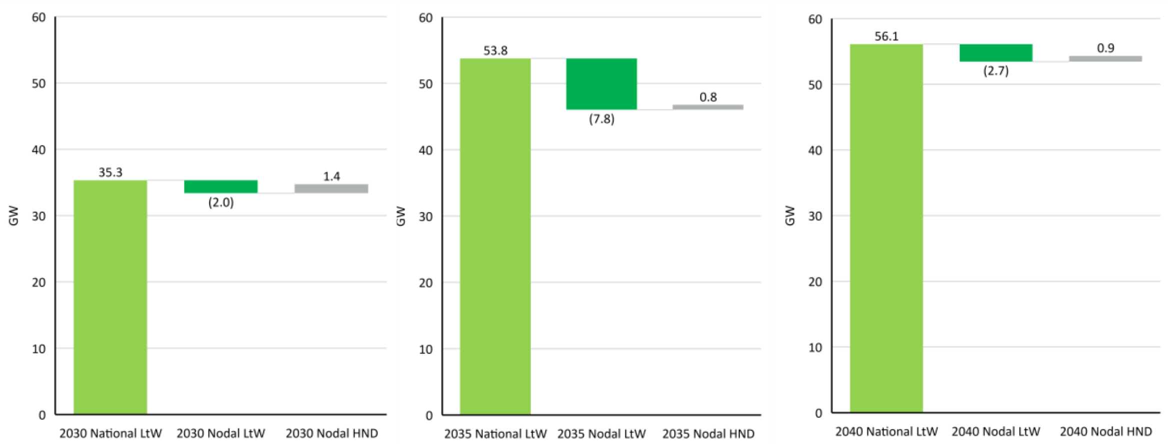
[232] National Grid ESO, Consultation on the Draft NOA 2023 Methodology, (link).

10.34. For example, the lower nodal price in LtW (NOA7) in Scotland relative to the national pricing market design leads to a reduction in wind generation opting to site in Scotland. However, under the HND scenario, higher average nodal prices observed in Scotland (as show above in Figure 10-4) encourage slightly greater volumes of wind capacity to site in the region relative to the NOA7 scenario. Figure 10-9 illustrates the difference in the volume of wind generation in Scotland for 2030 to 2040 under the LtW scenario for the national market design, the nodal market design under NOA7 and the nodal market design under HND.

Figure 10-9: Differences in the projected volume of onshore and offshore wind capacity in Scotland (GB1 and GB2) in 2030, 2035 and 2040 under national and nodal market designs



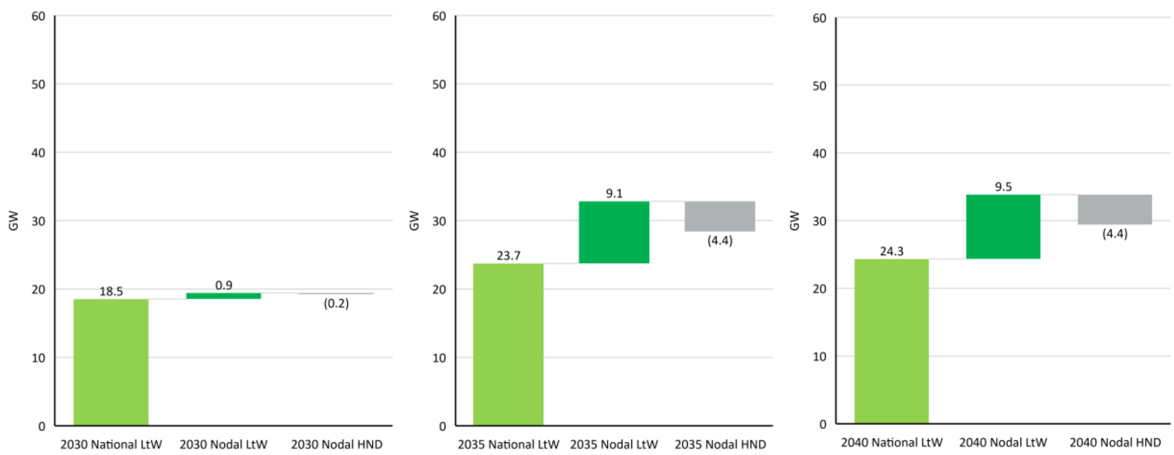
Source: FTI analysis
Note: In the charts above, a positive number indicates an increase in capacity relative to the scenario to the left, while a negative number indicates a decrease in capacity relative to the scenario to the left.

10.35. As Figure 10-9 above illustrates and as indicated earlier, a switch to a nodal pricing regime from a national pricing regime reduces the volume of generation that sites in Scotland (as we explained in Chapter 6). In 2030 this effect is somewhat muted as we assumed that all current projects in (even the early stages of) development proceed as planned at the current planned location. This effect unwinds by 2035 under the LtW (NOA7) scenario, as wind generation capacity is c.15% lower in Scotland under a nodal pricing regime relative to a national pricing regime. By 2040, the increasing roll out of wind generation capacity across the country (and given the assumed restrictions on re-siting elsewhere in the country) means the difference in installed wind capacity between a national market and a nodal market under the LtW (NOA7) scenario is only 2.7GW – i.e., under 5%.

10.36. Figure 10-9 also illustrates that the enhancement in the network included under the LtW (HND) scenario mean that, as capture prices increase slightly in Scotland, there is a small increase in capacity of wind generation that opts to site in the region. This accords with our intuition that additional transmission investment would, under a nodal pricing regime, likely encourage greater volumes of generation capacity in the part of the network that has had its export capabilities enhanced as a result of the transmission investment.

10.37. The converse is true in the south of England in that, under the LtW (NOA7) scenario, a nodal market design induces more wind generation to site in the southern zones relative to a national market design. However, under the LtW (HND) scenario, the lower prices that arise because of the transmission enhancements induce less wind generation capacity to site in that part of the country. Figure 10-10 below illustrates this effect.

Figure 10-10: Differences in the projected volume of onshore and offshore wind capacity in southern England (GB6 and GB7) in 2030, 2035 and 2040 under national and nodal market designs.

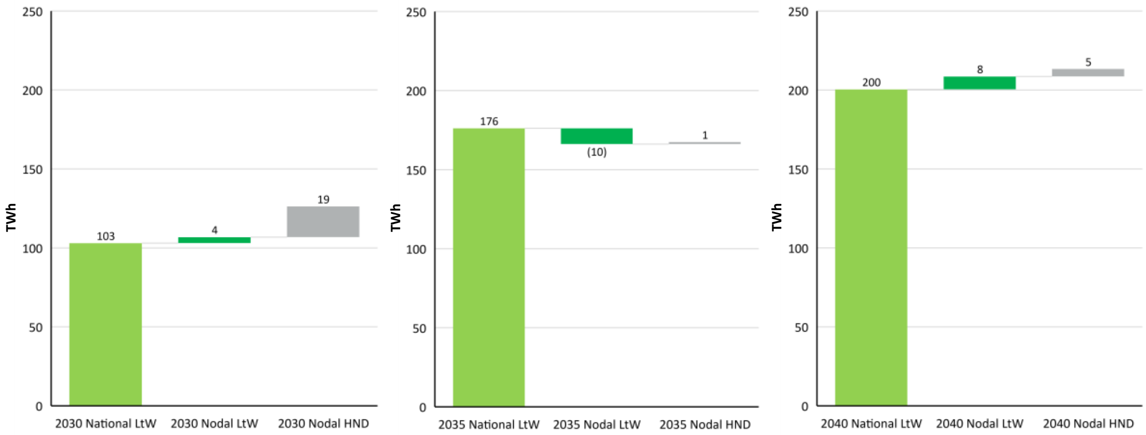


Source: FTI analysis
Note: In the charts above, a positive number indicates an increase in capacity relative to the scenario to the left, while a negative number indicates a decrease in capacity relative to the scenario to the left.

10.38. As noted, Figure 10-9 and Figure 10-10 illustrate that there is relatively little change in siting decisions of generators in 2030. This is mainly due to our assumptions set out in Chapter 5 that projects already in (even early stages of) development proceed as planned in their respective locations. By 2035, the change in location is more marked as new unannounced projects opt to site differently from the siting decisions assumed in the FES. For the same reason, the impact on generation siting of the HND transmission upgrade is more marked in our analysis in 2035 than in 2030.

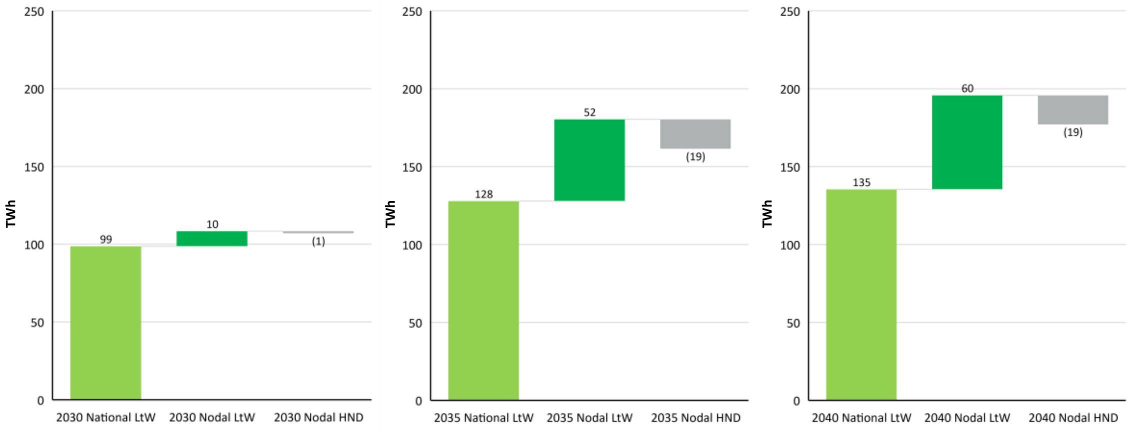
10.39. The effect manifests itself in the change in the levels of output by wind and solar resources in each of the regions. Figure 10-11 and Figure 10-12 below illustrate the changes in output for both solar and wind generation in 2030, 2035 and 2040 for the northern and southern regions of Great Britain.

Figure 10-11: Differences in the projected renewables generation (solar, onshore wind and offshore wind) in Scotland (GB1 and GB2) in 2030, 2035 and 2040 under national and nodal market designs.



Source: FTI analysis
Note: In the charts above, a positive number indicates an increase in capacity relative to the scenario to the left, while a negative number indicates a decrease in capacity relative to the scenario to the left.

Figure 10-12: Differences in the projected renewables generation (solar, onshore wind and offshore wind) in southern England (GB6 and GB7) in 2030, 2035 and 2040 under national and nodal market designs



Source: FTI analysis
Note: In the charts above, a positive number indicates an increase in capacity relative to the scenario to the left, while a negative number indicates a decrease in capacity relative to the scenario to the left.

10.40. Figure 10-11 and Figure 10-12 above shows that in 2030, there is little change in output, by region of solar and wind renewables resources, reflecting our underlying assumptions on the location decisions of generation. The one exception is that the additional transmission that comes online by 2030 under the HND scenario allows for a significant increase in renewables output in Scotland under a nodal regime. By 2035, however, greater location of renewables generation in the south that is assumed to occur under a nodal pricing regime leads to a material increase in renewables output in the south (and a modest reduction in output in Scotland). As we would expect, the impact of HND somewhat reverses this effect as, under a nodal regime, HND encourages marginally more generation to site in the north and less to site in the south.

10.41. Overall, therefore, the fact that nodal pricing offers the potential to encourage some re-siting decisions would, in the GB context, potentially led to more generation to site in the south of the country. In turn, greater production of electricity nearer centres of demand would, everything else equal, impact on the need for incremental transmission. Hence, in these circumstances and as our analysis confirms, the benefits of additional transmission are inevitably somewhat reduced.

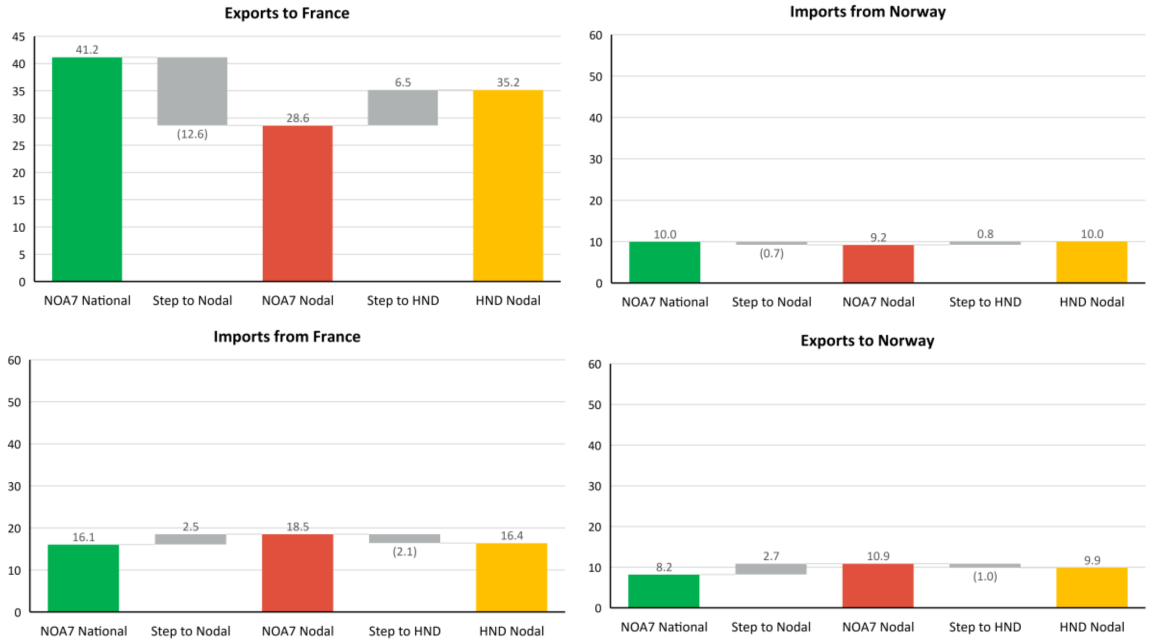
Change in interconnector flows and use of other flexible assets

10.42. In the previous subsection we explained that, to the extent that locational wholesale market price signals impact on siting decisions for generators (and demand) then, everything else equal, there would be a need for less transmission. However, it is also the case that locational pricing offers improved operational signals – particular to some classes of assets such as interconnectors, storage and demand side flexibility which could potentially lead to significant changes in the way such assets are scheduled to operate by the wholesale market. For example, as indicated in Figure 6-12 in Chapter 6, under a nodal pricing regime we would anticipate a significant reduction in market scheduled exports from GB to France and an increase in scheduled imports from France to GB as a result of the increase in the wholesale market price in the southern part of GB. The opposite would be true of interconnection from Norway that connect in the north of GB.

10.43. This change arises because, under a national regime, the GB market design assumes infinite transmission capacity within the GB market footprint and therefore sometimes encourages flows from Norway (and Scotland) to transit through England for onward export to France. The physical realities of the transmission system are such that in practice these transit flows cannot always be accommodated and instead, the ESO needs to intervene to address the imbalances (the costs of which, as we have shown earlier in this report, are recovered from consumers). By design a locational market incorporates the physical realities of the network in the way in which prices are formed and, in so doing, prevents the market from scheduling infeasible flows across the system.

10.44. Given that an impact of HND would, relative to the LtW (NOA7) scenario, be to increase prices in the north of the country and reduce prices in the south (as per Figure 10-4 earlier in this subsection) then we would anticipate an increase in exports from GB to France and a reduction in imports from France to GB with the opposite impact occurring in flows to and from Norway. Figure 10-13 below illustrates this effect for flows to and from France and Norway for 2030.

Figure 10-13: Differences in the projected interconnector flows to France and Norway in 2030 under national and nodal market designs, TWh



Source: FTI analysis

10.45. As Figure 10-13 illustrates, a transition from a national pricing regime to a nodal pricing would, for 2030, result in a c.15TWh change in net flows to France (with exports to France decreasing by c.12.5TWh and imports to GB increasing by c.2.5TWh). Enhancing the grid as per the HND scenario, leads to a c.8.5TWh change in net flows to France, with a c.6.5TWh increase in exports to France and c.2.1TWh reduction in imports.

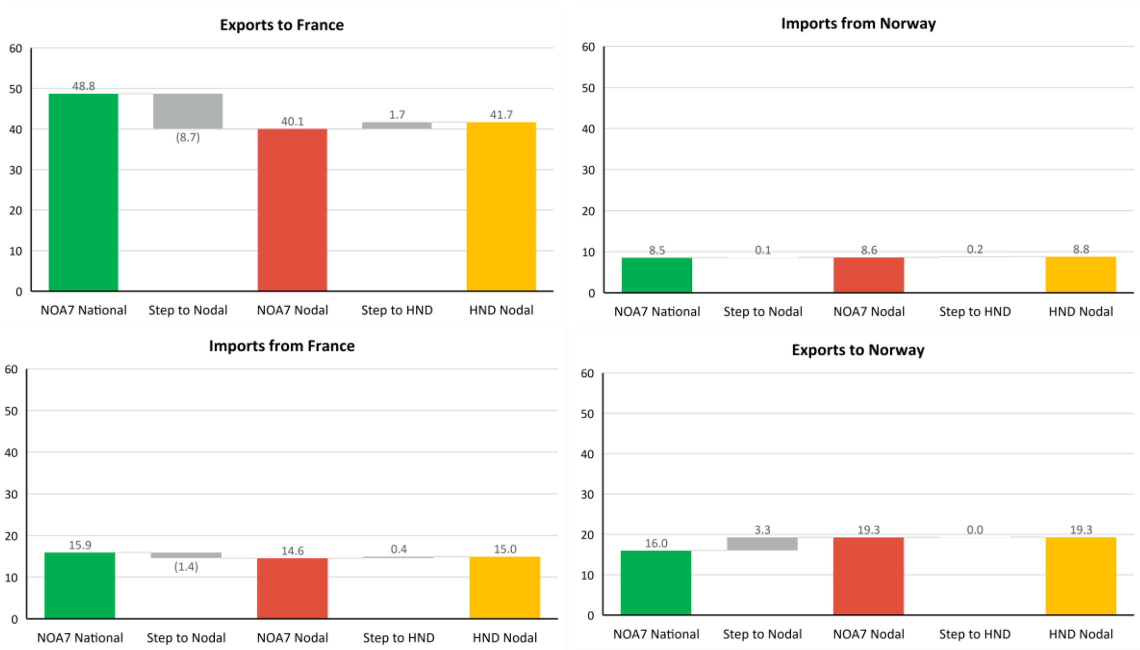
10.46. Norway would experience the opposite effect - with a net change in flows of c.3.5TWh (with c.2.7TWh increase in exports to Norway and a c.0.7TWh reduction in imports from Norway) in the transition to nodal pricing under the LtW (NOA7) scenario. Under a nodal pricing regime, the HND grid expansion facilitates an additional c.0.8TWh of imports from Norway in 2030[233] and a c.1TWh reduction in exports to Norway.

[233] The fact that the HND enhancements leads to more imports in a nodal regime than a national regime is a counter intuitive result. It arises as a nodal pricing regime sometimes leads to exports from Scotland to Norway that are then transited through Norway for import back to GB south of the B6 boundary.

10.47. Our results for 2030 shown above in Figure 10-13 emphasise the point that under a national price regime, wholesale market price signals will frequently lead to a situation where interconnectors are exacerbating congestion. For example, the GB market price in a national market will often indicate that Norway interconnectors should flow into GB, when the physical realities of the transmission system are such that such inflows would in practice exacerbate congestion. Instead, exports to Norway at these times would be beneficial to the GB system. This is the effect that nodal pricing would deliver through the wholesale market. The reverse is true to France with exports to France under a national pricing regime frequently exacerbating congestion in GB when in fact imports would be beneficial to GB.[234]

10.48. By 2035, this effect, although directionally the same in most cases, is more muted. This is shown below in Figure 10-14.

Figure 10-14: Differences in the projected interconnector flows to France and Norway in 2035 under national and nodal market designs, TWh



Source: FTI analysis

10.49. By 2035, the impact of flows on interconnectors of both a transition to nodal pricing (as shown by the comparison of national LtW (NOA7) and nodal LtW (NOA7) outputs) and the impact of the HND transmission upgrade (as shown by the comparison of the nodal LtW (NOA7) and the nodal LtW (HND) outputs) is less than in 2030. The reason for this is due primarily to the relatively significant change in generation siting (particularly in the south) that reduces the change in interconnector flows relative to the 2030 outputs (in which, as we showed above, there is little change in location). Even so, in 2035, when there are significantly greater volumes of renewables locating in the south under the nodal NOA7 scenario there is a still a reduction of 10TWh in net flows to France.

234 Note that all interconnectors from GB to all other countries have some change in flows as a result of changes to the market design and to the transmission grid. We have highlighted the flows to and from Norway and France as the impact is most marked for these interconnectors as they tend to connect to the GB system at its extremities and in turn have the most pronounced impact on the flows on the GB transmission grid.

10.50. A final point to note is that the HND transmission upgrade may well facilitate flows across the network to other countries. In 2030, the HND transmission upgrade in GB allows for an increase of 22% in exports to France and an 11% reduction in imports from France under our nodal pricing scenario. This has a potentially material benefit to the French consumer – where average annual wholesale prices falling by 9% in France to those shown in Figure 9-9, were GB to implement nodal pricing and then also undertake the HND transmission upgrade.

10.51. We have in this analysis, highlighted the way in which a transition to nodal pricing changes the scheduled flows on interconnectors. In so doing, interconnectors would always be scheduled to operate in a way that is consistent with the prevailing configuration of the transmission network, rather than sometimes against it. Hence, overlaying additional transmission, as per our HND scenario, will inevitably therefore be less beneficial in a nodal regime than in a national regime because the scale of the physical imbalances in the system, absent the incremental transmission investment, will be less.

10.52. While we highlighted interconnectors in the analysis above, the same effect is also true of other flexible assets such as batteries and also the demand side. As we have shown earlier in this report, locational pricing improves operational signal to batteries and to that portion of demand that can flex its consumption of electricity (such as vehicle charging) so that they operate in line with the physical characteristics of the network. In turn, this will reduce the benefits of additional transmission.

E. Overall conclusions of impact on benefits of transmission investment of move to locational pricing

10.53. Intuitively, as locational pricing leads to wholesale market outcome in which the scarce capacity of the transmission network is allocated efficiently through the wholesale market, we anticipated that the potential benefits of enhancing the transmission network would be lower, which in turn would imply potentially less costs need to be incurred by consumers. However, the magnitude of the difference – that the benefits of the HND transmission enhancement were nearly 90% lower under a nodal pricing regime relative to a national pricing regime - came as a surprise. Hence, we should emphasize that, at this stage, we would caution against extrapolating too widely to other transmission investments as further investigation of different transmission configurations is needed to ensure a more robust assessment.

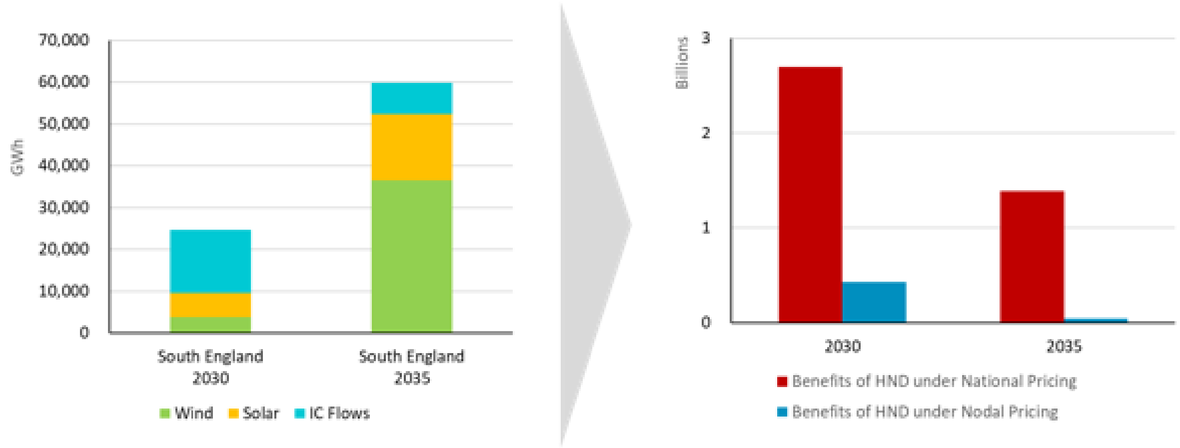
10.54. We believe that there are three reasons for the sizeable difference. The first is an issue associated with the way in which BM bids and offers feed into the transmission investment case under a national market design and is not directly related to the choice on wholesale market design. The other two reasons are, however, highly relevant to the debate on market design.

10.55. First, locational wholesale price signals could encourage generation to site in locations that are closer to centres of demand which, everything else equal, will reduce the need for transmission. The converse could be true for large users of electricity that will be encouraged to site in areas of the network close to low-cost generation that is itself sited in regions that are often export constrained. In turn, this would also reduce the need for transmission investment. As discussed earlier in this report we have not sought to capture the potential benefit of demand re-siting as part of this study but note it as a potential upside to our base case assessment.

10.56. While the first reason relates to improved investment signals that potentially arise from locational pricing, the second reason relates to improved operational signals. Locational pricing, and nodal pricing in particular, provides the price signals that ensure that flexible assets, notably interconnectors and batteries, are scheduled to work with the configuration of the transmission grid rather than, as is often the case, against it. The same will also be true of demand side that can offer flexibility in response to price signals. Having a market that is designed to use the existing controllable flexible assets of the system in a way that helps the system balance, rather than potentially exacerbating tensions in the system that the current national market design creates, must inevitably reduce the requirement for transmission.

10.57. The balance between the investment and operational impact on the need for transmission investment that arise from improved locational signals is empirical and will, in our modelling, depend on our assumptions that feed into it. However, it is worth noting that the two effects are to a degree offsetting, in that less responsiveness to price signals by newly locating plant (as some have argued will in practice be the case) will result in greater changes in the operating patterns. We can see this effect in our results. Figure 10-15 below illustrates the change in interconnector net flows and generator output in 2030 and 2035 in the south of Britain (which is one of the main drivers in the need for transmission investment) and the difference in the benefits case for transmission in those years that arise as a result of a change from national to nodal pricing.

Figure 10-15: Net change in inflows in South of England as result of change between national and nodal pricing under the NOA7 scenario and benefits of HND transmission upgrade in 2030 and 2035



Source: FTI analysis

10.58. As Figure 10-15 indicates, in 2030 most of the change in net flows in the south (c.60%) is result of change in flows in interconnectors, with less exports to France from GB and more imports from France to GB. The additional c.40% is made up of some increase in renewables output located in the south. The relatively limited change in output of renewables under a nodal regime in 2030 is because, as we explained earlier, that due to our assumptions there will be very limited change in siting decisions in 2030. With better operational signals arising under nodal pricing leading to significant changes in flows on interconnectors (and better use of other flexible assets which we have not shown here), then the benefits of adding additional transmission are significantly reduced as compared to when evaluated under a national regime – with difference of c.84% in 2030 in the benefits case (as indicated in the right chart).

10.59. With greater variability in the siting of generation in 2035 (given our assumptions on the siting impact of nodal pricing) we observe the opposite effect, with the investment signals arising from locational signals impacting on siting decisions and therefore having a greater impact on the need for transmission enhancements. While the difference in the NOA7 and HND transmission scenarios is much reduced by 2035 (with a few minor and one major transmission enhancement only) these locational effects of nodal pricing, together with enhanced operating signals, mean that the benefits of the transmission enhancements are almost entirely negated – with a c.97% difference observed between the benefits case under a national and a nodal regime.

10.60. Hence, it is both the operating and investment signals from locational pricing that lead to the reduced benefits of transmission. And, to the extent that our assumptions on siting are considered over optimistic (as some stakeholders argue), then it would follow that we would anticipate a greater impact on operating flows which would lead, directionally at least, to a similar reduction in the benefits case for transmission.

10.61. To conclude, we understand that the current plans for transmission expansion amount to c.£55bn (which encompasses both the NOA7 investments and the HND investments). While we would recommend further investigation is needed, our analysis would suggest that a move to locational pricing creates both operating and investment signals to market participants that significantly reduces the benefits of incremental transmission investment and, in turn, therefore, potentially the need for such levels of investment. This could therefore represent a potentially significant additional benefit to consumers of locational pricing over and above that identified earlier in this section.

11. Sensitivity analysis

11.1. In this chapter, we consider the two sensitivities introduced in Chapter 5 to test the impact of specific hypotheses or policy options raised by Ofgem and stakeholders. The two sensitivities are:

- a dispatch-only sensitivity, that assesses the benefits of transitioning to a nodal market design under the assumption that efficient siting under a national model can be achieved through alternative mechanisms such as central planning. This was tested by using the siting decisions from the nodal market design in the national market model dispatch run (discussed in **Section A**); and
- a load shielding sensitivity, that assesses the benefits of transitioning to a nodal market design but with consumers being "shielded" from the variation in prices caused by more locationally granular pricing but rather continuing to face an average national price (discussed in **Section B**).

11.2. This chapter outlines the key modelled outcomes that are affected by the sensitivities, as well as the overall CBA as conducted in Chapter 9, for the two sensitivities outlined above.

A. Dispatch-only sensitivity

11.3. In our dispatch-only sensitivity, we isolate the benefits derived from increased locational granularity of prices by controlling for the benefits that arise from the more efficient siting of generators. We do this by using the capacity siting decisions determined under the nodal pricing market but incorporate these in our national pricing model dispatch run. This therefore mimics the effect of a national scenario where generators are already assumed to be sited efficiently (potentially through other alternative policy measures).

11.4. A comparison of a national pricing regime under this scenario and a nodal pricing regime under LtW (NOA7) allows us to isolate the benefits caused specifically by locationally granular prices, as generators are sited identically under both market designs.

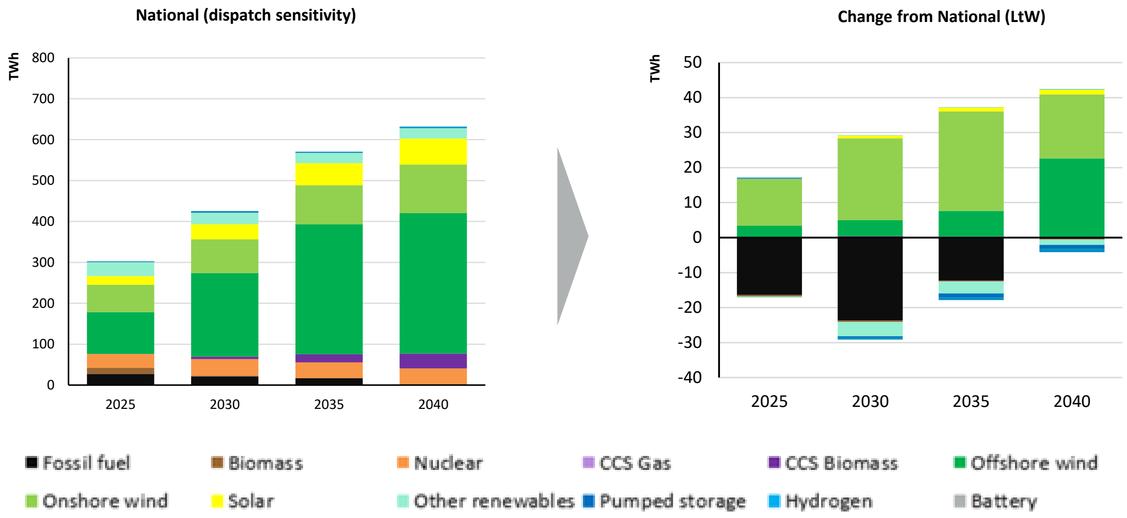
11.5. We conduct this assessment because it has been cited by many stakeholders that other mechanisms, such as an "enhanced TNUoS" regime, a locational capacity mechanism and/or better central planning may be able to encourage more economically efficient siting decisions than those in the FES. This would therefore imply that some of the benefits of locational wholesale electricity prices could be achieved through other (arguably more centralised and dirigiste) measures.

11.6. Below, we set out the key outcomes of the assessment, specifically generation profiles, constraint management costs and CfD support payments, as well as the overall benefits to consumers and GB socioeconomic welfare. We compare these outcomes to our results for the national LtW (NOA7) scenario for reference, and conduct the overall benefits assessment relative to the nodal pricing market design for LtW (NOA7) in order to quantify the benefits that arise purely as a function of the locational granularity of prices.

Generation

11.7. In Figure 11-1 below, we depict the generation profile of a national market design that uses the capacity as sited under a nodal market. We also compare this against the generation profile of the national LtW (NOA7) scenario, i.e., the comparison in the panel to the right is calculated as the generation volumes with generators sited under a nodal pricing regime, relative to the generation sited under a national pricing regime.

Figure 11-1: Generation by technology – Dispatch sensitivity



Source: FTI analysis

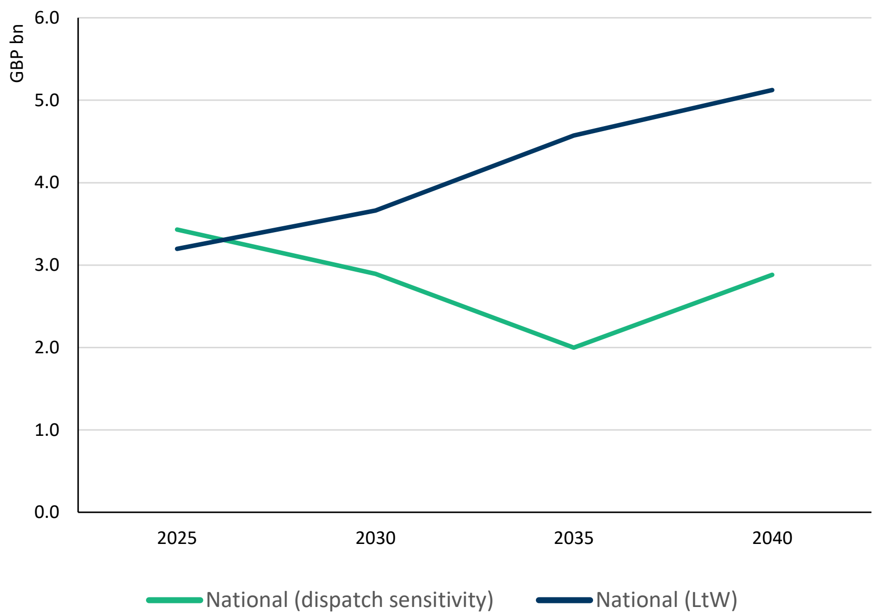
11.8. As seen in Figure 11-1, the trend in technology mix is broadly consistent with the generation profile observed under a national market design for LtW (NOA7). Two main effects can be observed:

- First, the siting of greater volumes of generation in the south of GB allows greater volumes of renewables generation on the system.
- Second, the overall generation levels are higher in 2035 and 2040 when using nodal siting decisions, by 4% and 6% respectively. As the demand profiles are the same under both scenarios, the net increase in generation is a result of due to greater export opportunities in the dispatch-only sensitivity.

Constraint management costs

11.9. In Figure 11-2 below, we depict the constraint management costs incurred under a national market design in the dispatch-only sensitivity (capacity sited as under a nodal market) relative to the constraint management costs incurred under a status quo national market design.

Figure 11-2: Constraint management costs – Dispatch sensitivity



Source: FTI analysis

11.10. As shown in Figure 11-2 above, while constraint management costs are generally lower over the forecast period, as a result of improved siting of generators relative to the FES 21 base case assumptions.[235]

11.11. However, the rise in constraint management costs in 2040 for the dispatch-only sensitivity demonstrates that economically efficient siting is insufficient in addressing all the constraints that are likely to arise as the capacity and generation mix evolve under the LtW (NOA7) scenario.

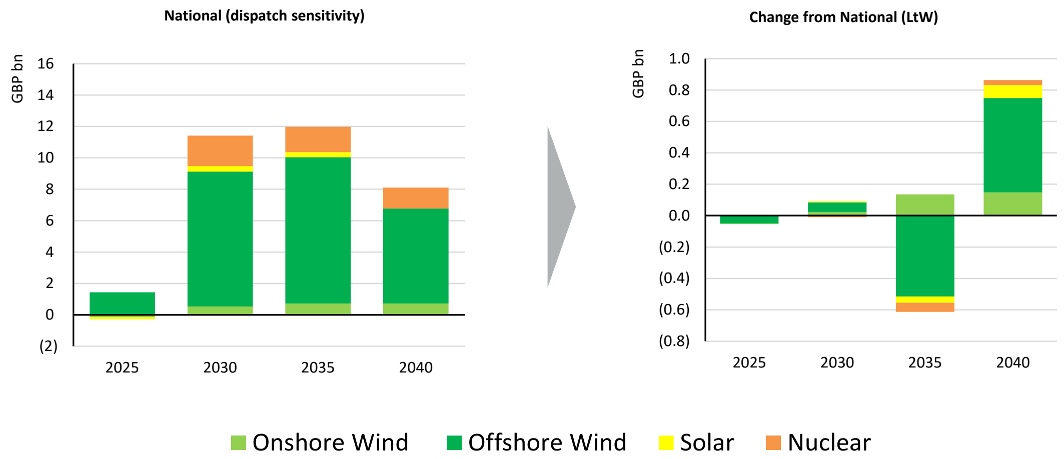
11.12. Notably, despite the centrally-directed capacity siting being "optimal" given it as sited as per the signals in a nodal pricing market, the annual constraint management costs continue to exceed c.£2bn under the dispatch-only sensitivity. Overall, in terms of the NPV of constraint management costs over the modelled period, the system continues to incur around 68% of constraint management costs despite the optimal capacity siting.

CfD support payments

11.13. In Figure 11-3 below, we show the net expected CfD support payments between consumers and producers under the dispatch-only sensitivity. As discussed previously, a positive value indicates a net payment from consumers to producers.

[235] While constraint management costs are generally lower over the forecast period, the constraint management costs in 2025 are marginally higher in the dispatch-only sensitivity relative to the status quo market. This potentially counter-intuitive result is because capacity siting decisions are based on locational prices over the forecast period rather than in a single year (albeit limited by our technology-specific siting assumptions).

Figure 11-3: CfD support payments – Dispatch sensitivity



Source: FTI analysis

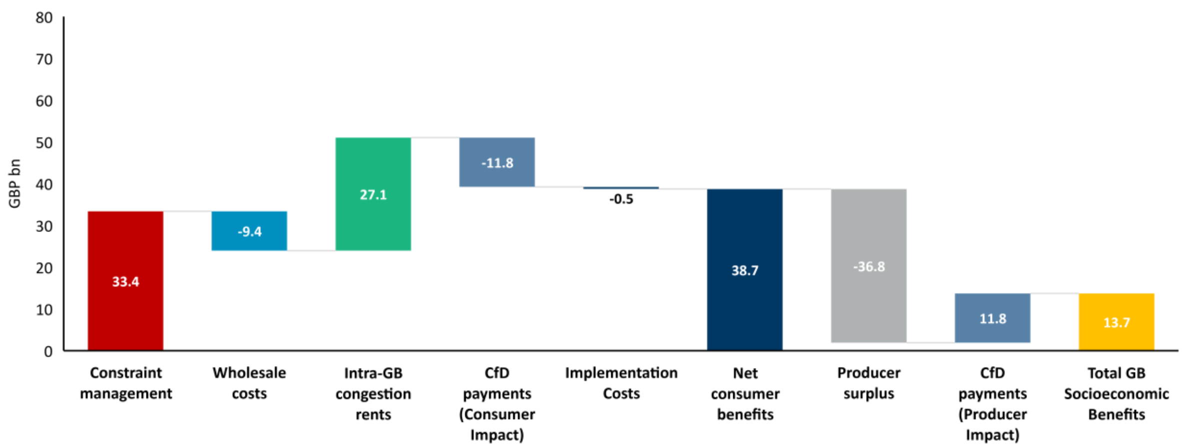
11.14. Figure 11-3 indicates that the trend in payments, as well as the proportion of payments made to the different technologies, are broadly in line with the CfD support payments under the status quo market.

11.15. However, CfD support payments are marginally lower than the status quo in 2035 but marginally higher than the status quo in 2040. This is due to small changes in the wholesale prices between the two scenarios, which are a result of the differences in capacity siting as the strike prices and generation profiles are broadly consistent between both scenarios.

CBA results

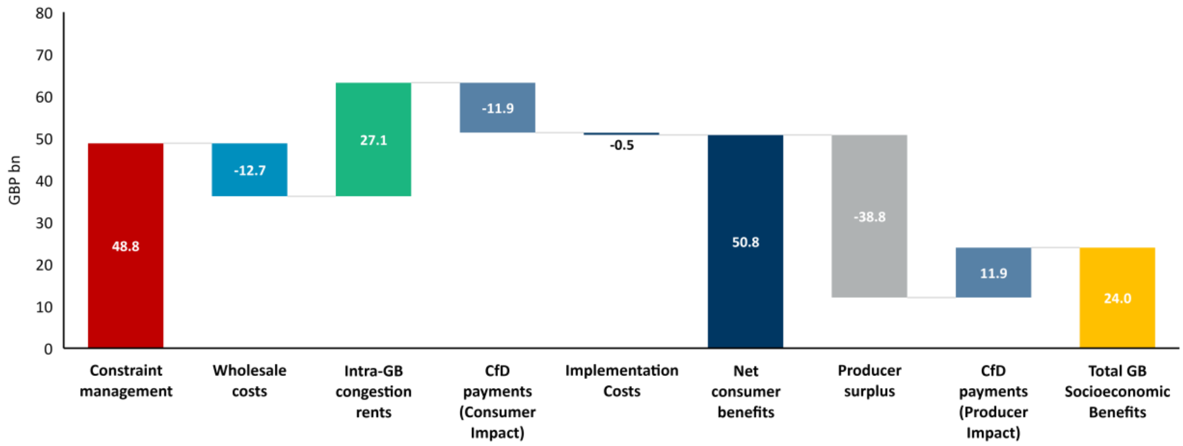
11.16. In Figure 11-4 below, we set out the overall impact on consumers and socioeconomic welfare for the dispatch-only sensitivity. This should be viewed relative to the benefits of nodal to the status quo for LtW (NOA7), which is presented in Section 9A (Figure 9-2) and repeated for ease of comparison below in Figure 11-5, in order to isolate the benefits derived from increased locational granularity.

Figure 11-4: Overall Cost Benefit Assessment for a nodal market design under LtW (NOA7) relative to a national market design under the dispatch sensitivity (2025-2040)



Source: FTI analysis

Figure 11-5: Overall CBA for a nodal market design relative to a national market design (2025-2040) – LtW (NOA7)



Source: FTI analysis

11.17. As observed in Figure 11-4 above, despite generators already being sited optimally (assumed to be achieved through some other policy mechanism), transitioning to a nodal market still results in £38.7bn in net consumer benefits and £13.7bn in total GB socioeconomic benefits. These are assumed to be the benefits achieved through more granular locational pricing.

11.18. Relative to the benefits of a nodal market relative to the *status quo national market*, the transition to a nodal market in the *dispatch-only scenario* leads to consumer benefits and socioeconomic benefits that are c.24% and c.43% lower respectively. This reduction in the proportion of the benefits in the dispatch-only sensitivity are driven as a direct result of more efficient siting of generators under the nodal market.

11.19. In the dispatch-only sensitivity, the majority of consumer benefits continue to be driven by the reduction in constraint management costs achieved by nodal siting decisions, albeit at a lower amount when the status quo national market design is used as a counterfactual. There is no change in the intra-GB congestion rents between the two sets of analyses as there is no change to the modelled nodal market outcomes under this sensitivity (national markets have no intra-GB congestion rents). Additionally, we only see a marginal change in CfD payments under the dispatch-only sensitivity.

11.20. Overall, this sensitivity demonstrates that consumers specifically, and GB more widely, would still accrue significant benefits in a move to greater locational granularity of wholesale prices, even if the siting decisions of generators were determined optimally by a central planning function.[236]

[236] To the extent that other policy mechanisms failed, in practice, to deliver optimal siting of generation and storage, then we would anticipate a higher level of congestion costs incurred under a national market (i.e., greater than the £33.4bnset out in Figure 11-4. In turn, it follows that the benefits of a transition to nodal pricing would be greater to the extent that other policy mechanisms were less optimal than hoped by policymakers.

B. Load shielding sensitivity

11.21. The load shielding sensitivity tests the impact of "shielding" consumers from the locational price at their connected node. Instead, we test the impact of exposing all consumers (both domestic and non-domestic) to a uniform average national wholesale price in each hour, while retaining locational pricing for generators, battery storage and electrolysers. The purpose of this sensitivity is to test how the estimated system benefits of nodal pricing change when flexible consumer load, provided for example through smart charging of EVs and heat pumps, is unable to optimise consumption around the local price at the connected node.

11.22. In theory, a load shielding policy would be expected to lead to an increase in average annual wholesale prices and the total cost of meeting demand, relative to "unshielded" locational pricing. This is because flexible demand that is shielded from the locational price would consume without regard to the limitations of the transmission network and, in turn, move a portion of consumption to sub-optimal hours from a system perspective.

11.23. For example, under locational pricing, at a node with excess solar generation capacity, flexible demand from EVs and heat pumps would be expected to charge up in the sunniest hours of the day, when the local price would likely be lowest. However, if flexible demand is shielded from the locational price, this demand would instead charge up when national average prices were lowest without consideration of local conditions, and may do so even if the true nodal price at the connected node were actually much higher.

11.24. In the following sub-sections, we set out our load shielding assumptions, our underlying modelling approach, the impact of load shielding on consumption and dispatch, and the overall socioeconomic welfare impacts of introducing locational pricing with load shielding.

Load shielding assumptions

11.25. There are several factors to consider in the design of a load shielding policy, in particular the extent to which different types of load should be shielded from the locational wholesale price at their connected node. We have identified four key items that policymakers would need to consider, as set out below:

- First, is whether shielded demand should be exposed to a uniform *national* wholesale price, or a uniform *zonal* wholesale price, and how these uniform prices would be calculated (typically as the load-weighted average of nodal prices in the relevant region).
- Second, is which *groups of consumers* should be shielded from locational wholesale prices, for example whether industrial and commercial consumers should also be shielded from locational prices in addition to domestic consumers.
- Third, is which *types of consumption* should be shielded. For example, uptake of V2G technology is expected to enable a "two-way" participation in electricity markets by domestic consumers, with EV owners selling surplus power back to the grid when prices are high. Notably, allowing domestic consumers to pay a shielded uniform price when charging EVs, but receive the unshielded nodal price when discharging power back to the grid (in line with other generators and grid-connected storage) seems potentially highly distortionary.

- Fourth, is whether consumers would be able to *opt out* of a load shielding policy should they prefer to pay the local price at their connected node. In addition to both domestic and non-domestic consumers, this would be of particular importance to developers of electrolysis capacity, which are expected to rely on low wholesale power prices as a key driver of their project economics. A compulsory load shielding policy would also potentially reduce the ability of locational pricing to incentivise demand to re-locate to export-constrained regions.[237]

11.26. For the purposes of this sensitivity assessment, we have assumed that shielded demand would be exposed to a uniform national wholesale price, calculated in each hour as the load-weighted average of nodal prices across GB. All domestic consumers and industrial and commercial consumers are assumed to be shielded from the locational price at their connected node, instead paying the uniform national wholesale price in each modelled hour.[238] However, we assume that all electrolysers, the majority of which are located in Scotland, would opt to receive the nodal price at their connected node.

11.27. In practice, this means that in our modelling of the sensitivity, the only forms of flexible demand for which a load shielding policy might influence the underlying pattern of consumption are the smart charging of price-responsive EVs and heat pumps.

11.28. One challenge to the set-up of this sensitivity assessment is on whether to apply a load shielding policy to the charging of V2G assets. On one hand, most V2G assets are likely to belong to domestic consumers who would face a shielded price in this assessment. However, exposing V2G assets to the shielded price but leaving traditional grid-connected batteries to the prevailing nodal price may lead to distortionary outcomes (for example, V2G assets could earn outsized returns in export-constrained areas).

11.29. As a result, to be consistent with batteries and other generators, we assume that V2G assets are exposed to the unshielded nodal price when both charging and discharging. Price-responsive flexible EV demand (that is not part of V2G) and all inflexible EV demand face the uniform national wholesale price in each modelled hour in our sensitivity assessment. Figure 11-6 below highlights the deployment of EVs with fixed charging, flexible charging, and V2G participation under the LtW and SysTr scenarios.

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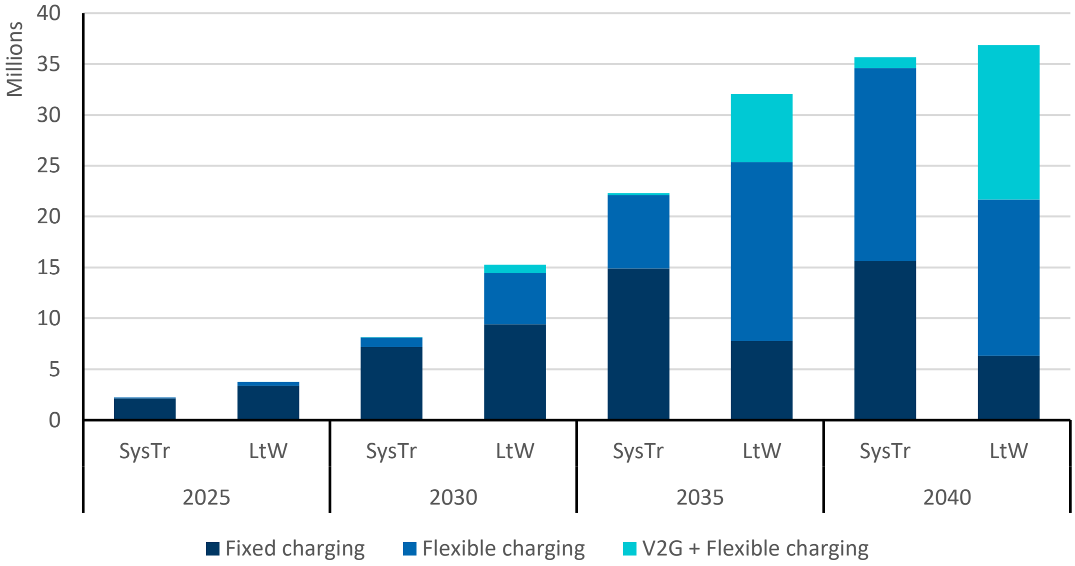
[237] As noted elsewhere in this report, we have not sought to evaluate the potential benefit of locational pricing arising from the relocation of demand in any of our modelled scenarios or sensitivities.

[238] As described above, policymakers may wish to treat domestic consumers but not industrial and commercial consumers separately. We have not distinguished between them in this sensitivity to show the “lower bound” of the benefit of nodal pricing that would remain with shielding.

Figure 11-6: Number of EVs with fixed charging, flexible charging, and V2G participation, LtW and SysTr



Source: FES 21

11.30. As can be seen from Figure 11-6 above, in the SysTr scenario, V2G uptake is relatively low across the modelling period, with the power used for V2G representing less than 1.5% of <u>flexible</u> EV demand in all modelled years. However, under the LtW scenario, the proportion of V2G uptake is significantly higher. Box 11-1 below describes the implications of this on the choice of the energy scenario modelled for this sensitivity.

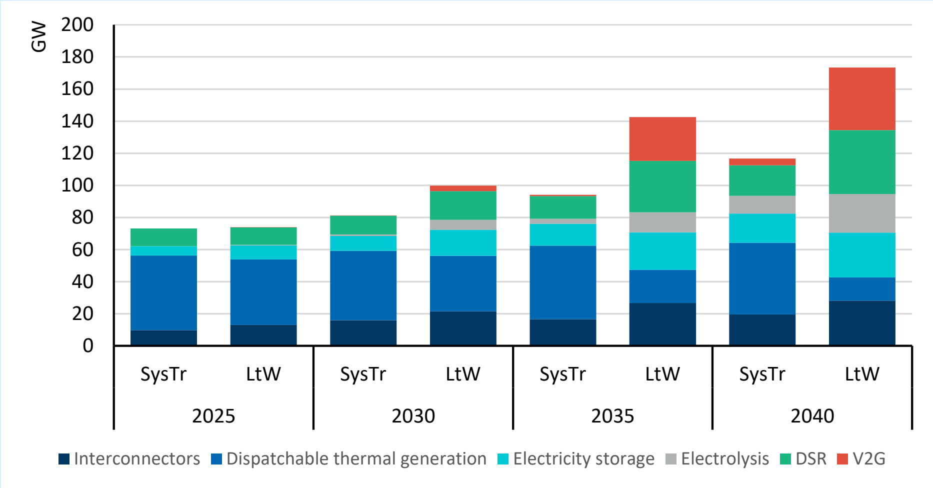
Box 11-1: Challenges to modelling load shielding for LtW (NOA7)

To model the load shielding scenario, while demand faces a "shielded" national average price, all generators and batteries continue to optimise dispatch around the local price at their connected node.

A key decision in our modelling of the load shielding scenario is that we assume that policymakers would ensure that V2G assets continue to be exposed to the nodal price when both charging and selling power back to the grid. This does not affect the majority of EV demand, formed of both price-responsive smart EVs (which adjust their charging profiles in response to wholesale prices but do not discharge power back to the grid), as well as "fixed demand" inflexible EVs.

In practice, we would expect domestic consumers (as opposed to industrial and commercial consumers) to form a large proportion of V2G participation. This means that, in our modelling, a proportion of domestic demand remains "unshielded" even under a load shielding policy. Instead, a portion of domestic demand optimises its consumption and production relative to the local wholesale price. This has the effect of dampening the impact of a load shielding policy, by continuing to allow a proportion of demand to optimise relative to the "system-optimal" nodal price. This is particularly relevant for the LtW scenario, as highlighted in Figure 11-7 below, which shows the forms of system flexibility available in the LtW and SysTr FES scenarios.

Figure 11-7: Supply and demand flexibility in Leading the Way and System Transformation, 2025-2040 (GW)



Source: National Grid ESO, FES 2021

In the LtW scenario, V2G forms a significant proportion of system flexibility in later modelling years, with a maximum potential of 39GW by 2040. The extent of V2G adoption under the LtW scenario means that the assumed pricing treatment of V2G assets by policymakers would impact the modelling outcomes for the load shielding scenario. For example, while a load shielding policy might generally cause price-responsive load to shift to hours that require higher-cost generation to operate to meet demand, the operation of V2G assets in a "system-optimal"' manner, by virtue of their exposure to the nodal wholesale price, could largely negate the price impact of this.

By comparison, V2G represents a very small proportion of system flexibility in the SysTr scenario across the modelled period, at less than 4% of total flexibility, meaning the exclusion of V2G from shielding should have a relatively a low impact on modelled results. As a result, we have focused our assessment of the load shielding sensitivity on the SysTr scenario.

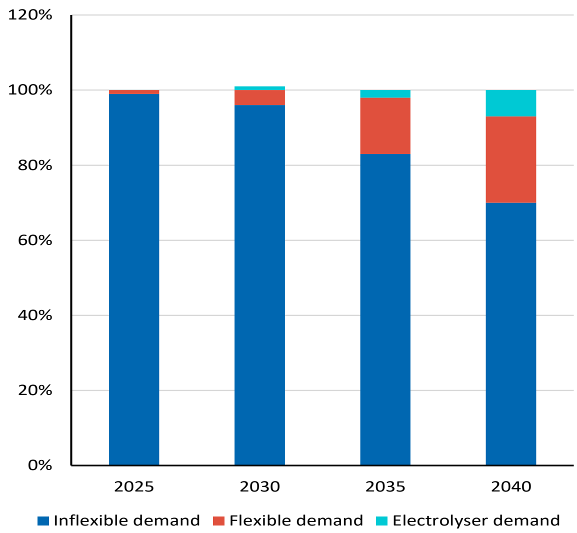
However, given the greater penetration of price-responsive demand in LtW scenario, a load shielding policy would likely have a very material negative effect on consumers should policymakers opt to shield V2G assets from the local nodal price.

11.31. Figure 11-8 below shows the proportion of demand that is price-responsive in the SysTr (NOA7) scenario. The three categories of demand are:

- **Inflexible demand** which is demand that is not price-responsive, such as domestic consumers turning on their electrical appliances in certain hours regardless of the prevailing wholesale price. It is shielded from the locational wholesale price in our modelling, affecting the price paid by consumers in different regions, for example increasing the wholesale price in Scotland while reducing the price paid at nodes further south. However, by its nature, this change in the wholesale price faced by inflexible demand does not influence the underlying pattern of consumption.
- **Flexible demand** is the portion of demand that is price-responsive, namely the smart charging of EVs and heat pumps by domestic and commercial consumers, which is shielded from the locational wholesale price in our modelling. The shielding of flexible demand alters the aggregate locational price impacts in our CBA, by shifting consumption to less efficient hours from a system perspective.

- **Electrolyser demand:** we assume that all price-responsive electrolysers would opt out of a load shielding policy and continue to pay the nodal price at their connected node.

Figure 11-8: Proportion of different types of demand in SysTr (NOA7)



Source: FTI analysis

11.32. As observed in the figure above, the proportion of demand affected by load shielding is very low in 2025 and 2030 but increases to 18% by 2035 and 30% by 2040. We assume for the purposes of our modelling that the uptake of price-responsive demand technologies would remain unchanged under a load shielding policy.

11.33. On the generation side of our modelling, all generators and batteries continue to pay and receive the nodal price at their connected node.

Modelling approach

11.34. As set out above, the aim of the load shielding sensitivity is to test the extent to which locational pricing would continue to deliver benefits should consumers be exposed to a single, imperfect national price, rather than the locational price at their connected node, while continuing to expose generators and grid-connected storage assets to the local price at their connected node. In theory this will lead to an increase in average annual wholesale prices and the total cost of meeting demand, with flexible load moving consumption to sub-optimal hours from a system perspective.

11.35. The Plexos software that is used is, by design, calibrated to model dispatch on a “least-cost basis”, with the purchase of energy by flexible demand assets optimised according to the marginal value of energy at each point on the network. It is not designed to model both a full nodal dispatch that accounts for all transmission constraints while simultaneously optimising flexible demand around a single, imperfect, national average price.

11.36. As a result, we have developed an approach, set out below, that provides an approximation of the impact of a load shielding policy on flexible demand.

11.37. In our modelling of the current national market design deployed elsewhere in this report, flexible load in the "pre-transmission constraint" model runs responds to a single, albeit imperfect, national price, rather than the locational price at each individual node. Using the "solar-heavy node" example above, smart EVs and heat pumps charge up when the national average price is lowest, rather than in a sunny spell when the local nodal price is at its relative lowest.

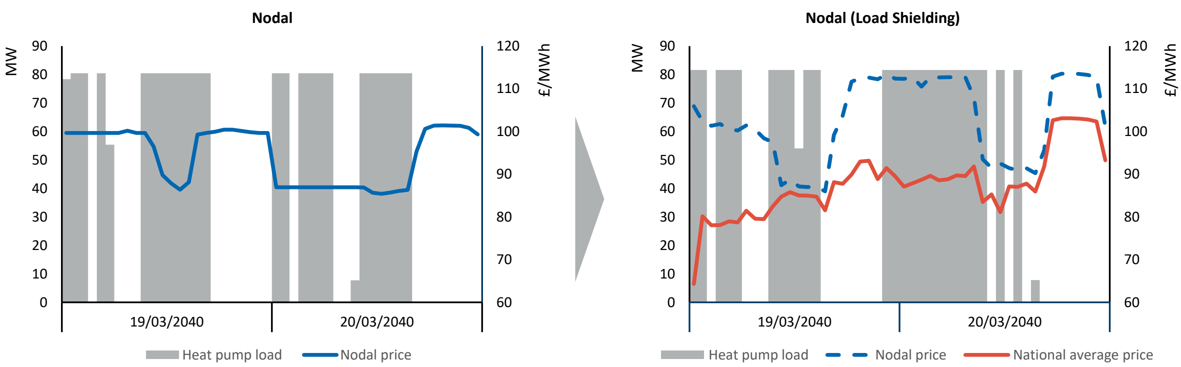
11.38. To model the load shielding scenario, we take this "imperfect" load profile of smart demand from the national model and set it as a fixed demand profile in a new nodal model run.[239] In doing so, we use the outcomes generated by the current market design as a proxy for the impact that a load shielding policy could have on flexible demand. We then see how nodal dispatch adjusts to this new demand profile, before calculating associated consumer and producer impacts in the manner followed in Chapters 5 and 6.

Dispatch impact

11.39. Without load shielding, flexible demand in a nodal pricing regime is incentivised to operate in a "system-optimal" manner, consuming in the hours when the local price is lowest. In this way, the private benefit of low-priced consumption aligns with the system-optimal "least-cost" outcome. However, with load shielding, masked price signals could distort this coupling of private and system interests, should the national average price faced by consumers differ from the system-cost of serving demand at particular points on the network.

11.40. Figure 11-9 below presents a comparison of the behaviour of smart demand under our nodal and load shielding model runs for SysTr (NOA7), focusing on the behaviour of flexible heat pump demand at the Chessington GSP across a two-day period in March 2040.

Figure 11-9: Hourly heat pump demand with nodal pricing, without and with load shielding



Source: FTI analysis

[239] In an ideal methodology for the sensitivity, flexible load would optimise around a single average national price which <u>includes</u> the impact of transmission constraints on individual nodal prices. By using a pre-gate closure load profile which, by nature, does not account for the impact of transmission constraints on national average prices, our proposed approach will likely lead to additional differences between the "ideal" and "shielded" load profiles for flexible demand.

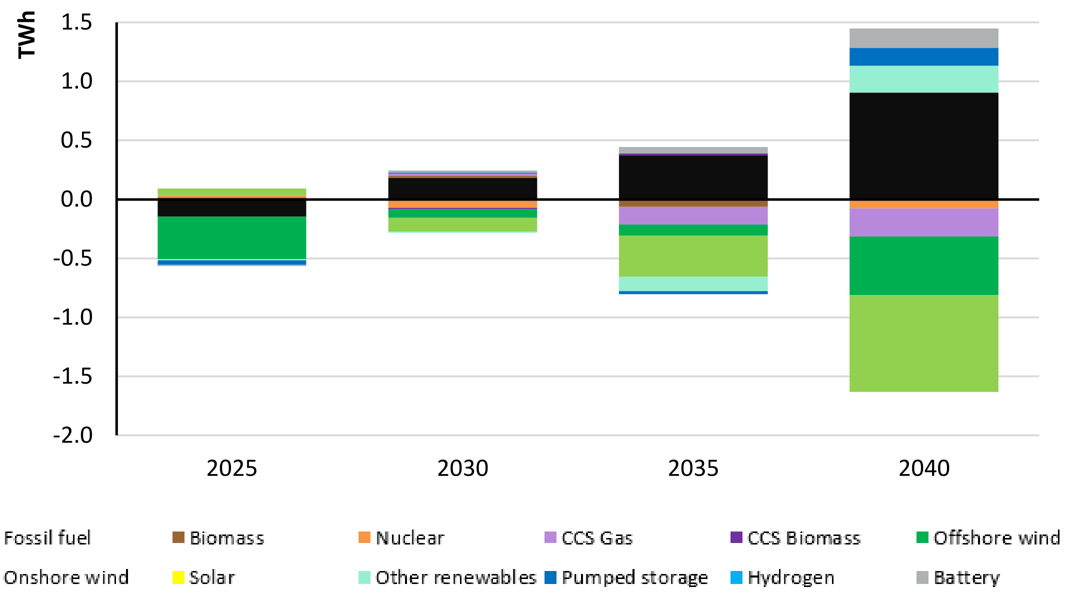
11.41. As set out in Section 5D and Appendix 1, in our modelling flexible heat pump demand seeks to optimise a set level of demand across each day at least-cost. The left panel of Figure 11-9 depicts that under the nodal model, flexible load concentrates its consumption in the lowest-priced hours of each day. Where possible, the displayed heat pump avoids consuming in higher-priced hours but is sometimes forced to do so (for example in the early hours of 19 March) to ensure that the minimum daily demand threshold is met.

11.42. The right panel of Figure 11-9 depicts that load at the node instead faces a lower national average wholesale price. For comparison, the true "system cost" of serving demand at the node in each hour is represented by the dashed line. The difference in the displayed hourly nodal price between the two model runs is driven by the variation in hourly smart demand across all GB nodes.

11.43. It can be seen that, with load shielding, the heat pump still sometimes performs "system-optimal" actions, for example charging in the majority of the lowest-priced hours on 19 March. However, on 20 March, influenced by an artificially low average wholesale price, the heat pump directs the majority of its daily consumption towards hours with the highest system-cost, and in general, flexible load fails to follow the lowest-priced hours.

11.44. The resulting impact of load shielding on dispatch is shown in Figure 11-10 below, which compares the annual generation mix under <u>nodal</u> pricing with and without load shielding for the SysTr (NOA7) scenario. A positive value indicates an increase in generation by a specific technology in the load shielding sensitivity run, relative to the unshielded nodal run.

Figure 11-10: Change in generation mix with load shielding relative to an unshielded nodal market design – SysTr (NOA7)



Source: FTI analysis

11.45. It can be seen from Figure 11-10 above that a load shielding policy would be expected to lead to a re-balancing of generation between renewable generation resources and flexible alternatives. In particular, with load shielding, output from wind generators falls, replaced by thermal alternatives, largely gas CCGTs. This impact increases across the modelling period, caused both by the increasing proportion of smart demand on the GB system and the increased deployment of renewable generation capacity, which leads to more hours with excess renewable generation.

11.46. This demonstrates that a load shielding policy would shift some price-responsive demand away from hours with high output from local renewable generators. Without load shielding, flexible demand consumes in hours where the local wholesale price is lowest, which generally correspond with periods of high, and often excess, renewable generation.

11.47. However, with load shielding, imperfect wholesale price signals cause flexible demand to consume in less efficient hours, often when local renewable generation is lower. By shifting demand away from hours of high renewable output, load shielding leads to both increases the curtailment of wind generation and increases the use of thermal generation in alternative hours of consumption.

11.48. Table 11-1 and Table 11-2 below show the impact of this change in dispatch on the generation-weighted average wholesale price received by generators, comparing outcomes under an unshielded and a shielded nodal market design under the SysTr (NOA7) scenario. Importantly, Table 11-1 and Table 11-2 do not adjust for the impact of CfD support payments on generator revenues.

Table 11-1: Generation-weighted wholesale price received by generator under a nodal market design – SysTr (NOA7) (GBP)

Zone	2025	2030	2035	2040
GB1 – Northern Scotland	37.34	15.18	21.03	19.59
GB2 – Southern Scotland	41.29	13.97	17.91	20.62
GB3 – Upper northern England	70.95	24.26	29.71	39.09
GB4 – Northern England and northern Wales	77.25	28.45	31.58	35.70
GB5 – Midlands	85.35	44.76	50.47	59.42
GB6 – Central	82.37	30.40	31.88	34.31
GB7 – Southern Coast	82.62	32.93	35.62	31.39
GB – Average	69.11	25.86	29.03	31.33

Source: FTI analysis

Table 11-2: Percentage change in generation-weighted wholesale price received by generators under load shielding – SysTr (NOA7)

Zone	2025	2030	2035	2040
GB1 – Northern Scotland	0.6%	-0.3%	0.8%	-0.6%
GB2 – Southern Scotland	0.3%	-0.3%	0.5%	-1.6%
GB3 – Upper northern England	5.5%	0.2%	0.5%	1.0%
GB4 – Northern England and northern Wales	4.1%	0.3%	0.1%	0.5%
GB5 – Midlands	1.6%	0.1%	1.0%	2.0%
GB6 – Central	1.8%	0.2%	1.7%	3.4%
GB7 – Southern Coast	1.7%	0.3%	1.0%	4.1%
GB – Average	2.6%	0.2%	1.0%	2.0%

Source: FTI analysis

11.49. It can be seen in Table 11-2 above that, with load shielding, generators in England and Wales receive higher average prices in all modelled years. By causing load to shift to less efficient hours, load shielding increases the need for higher-cost flexible generation. This increases both the hourly cost of generation in specific hours and annual average nodal wholesale prices in those locations.

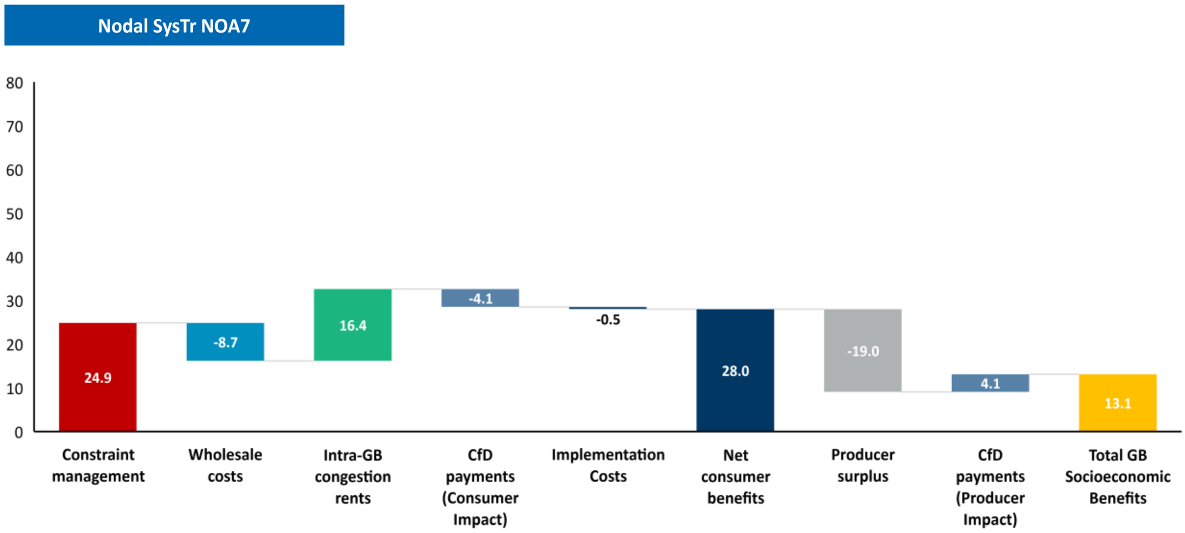
11.50. In Scotland, however, the impact of load shielding on the average wholesale price received by generators varies across modelled years, driven by two opposing factors. On the one hand, load shielding leads to more regular periods of excess wind generation, where prices fall to near-zero with renewable generation being curtailed, lowering the average capture price of renewable generators. However, flexible generators sited in both Scottish zones, mostly CCS Biomass, benefit from higher prices in periods of low-wind output.

11.51. The average wholesale price received by generators, and therefore the average price paid by consumers, increases in all modelled years.

Socioeconomic welfare impacts

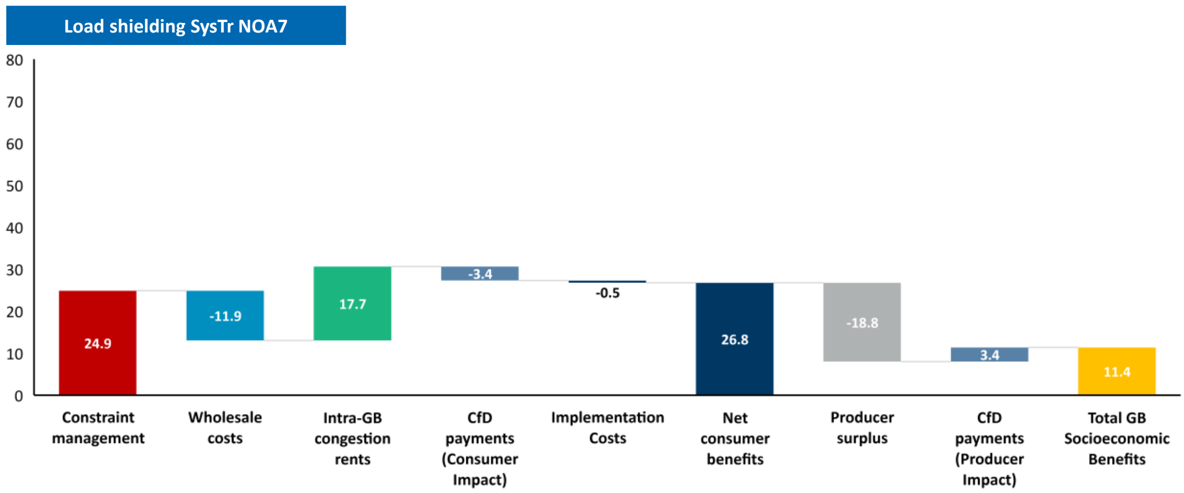
11.52. Figure 11-11: Overall Cost Benefit Analysis for a nodal market design relative to a national market design (2025-2040) – SysTr (NOA7)Figure 11-11 and Figure 11-12 below compare the socioeconomic welfare impact of a nodal market design under our core unshielded SysTr (NOA7) scenario, as presented in Section 9A, with outcomes under the load shielding sensitivity. The modelling of the current market design does not change between the unshielded and shielded model runs (in effect all demand already pays a shielded price under the current market design), so the impact of nodal pricing on the reduction in the costs of constraint management is unchanged.

Figure 11-11: Overall Cost Benefit Analysis for a nodal market design relative to a national market design (2025-2040) – SysTr (NOA7)



Source: FTI analysis

Figure 11-12: Overall Cost Benefit Analysis for a load-shielded nodal market design relative to a national market design (2025-2040) – SysTr (NOA7)



Source: FTI analysis

11.53. It can be seen from Figure 11-12 above that wholesale costs increase by £3.2bn across the modelling period under load shielding, driven by the shifting of flexible demand towards sub-optimal hours, requiring higher-cost generators to operate to meet demand, while the avoided costs of congestion management remain unchanged.

11.54. The impact of this on consumers is somewhat tempered by two countervailing effects. First, a £1.3bn increase in intra-GB congestion rents. With load shielding increasing the system price at particular points of the network, driven by a less efficient use of flexible demand, an increased divergence of local prices between connected nodes increases the congestion rents that is passed back to consumers.

11.55. Second, a £0.7bn decrease in the CfD support payments made from consumers to producers. As highlighted above, load shielding increases the average wholesale price received by generators sited in England and Wales and reduces the average price received by generators sited in Scotland. In turn, this increases the CfD support payments required for Scottish wind generators, but reduces that required for nuclear, wind and solar capacity sited in England and Wales. The net effect of this is a small decrease in total CfD support payments.

11.56. For GB producers, raised average GB wholesale prices increases the average revenue received by generators across GB. However, as highlighted above, load shielding also leads to an increase in the average cost of generation, with increased curtailment of low-cost renewable generators and a resulting increased use of higher-cost alternatives. The net result of these two effects is a £0.2bn increase in producer surplus relative to the unshielded nodal pricing scenario. However, this benefit to producers is countered by a £0.7bn decrease in CfD support payments received from consumers.

11.57. Overall, the impact of a load shielding policy is a 13% reduction in the socioeconomic benefits that could be delivered by a transition to nodal pricing, reducing the benefits by £1.2bn for consumers and £1.7bn for GB overall.

11.58. Importantly, our modelling cannot capture the broader negative impact that a load shielding policy could have on the development and uptake of price-responsive demand technologies across the GB system. By reducing or removing effective price signals to end-consumers, a load shielding policy would reduce the ability of price-responsive demand technologies to provide flexibility to the system. To the extent that this reduces the incentive for demand-side operators and technology providers to innovate, and indeed reduces the value to the system of an increased uptake of such technologies by end-consumers, a load shielding policy could limit the deployment of an important form of low-carbon flexibility for the future system.

11.59. Further, as we noted earlier in this section, there are a range of different policy levers available regarding the extent of the application of the load shielding policy. Given the roll out of more flexible demand, we would anticipate, as we have shown here, that all of them would be costly to consumers relative to one in which nodal prices are not adjusted. Different policy choices only effect the extent of the cost to consumers. Hence, we would suggest a different range of options and scenarios be modelled to fully understand the consequences of load shielding should policymakers wish to consider this issue in more detail.

12. Conclusions

12.1. As discussed in the first three chapters of this report, discussions and consideration of more granular locational wholesale electricity pricing have increased around the world, as well as in GB, given the evolving nature of energy supply and demand conditions brought forward by decarbonisation objectives and technological advancements.

12.2. In the GB context, these conditions have been placing additional burdens on consumers beyond the intentions of the original NETA design, particularly through the increasing cost and role of balancing the electricity system. Furthermore, while Net Zero objectives provide key opportunities in addressing climate change, concerns have been raised that the cost of meeting these objectives may be materially higher than they need to be under the status quo market design.

12.3. Against this backdrop, our assessment considered the potential costs and benefits of introducing locational pricing into the GB wholesale electricity market, which has been informed by substantial stakeholder engagement and in-depth modelling of future electricity market.

12.4. We set out a summary of our assessment in **Section A**, followed by our final concluding remarks in **Section B**.

A. Summary of our assessment on locational pricing market design

12.5. Our **assessment approach, methodology and assumptions** have been set out in Chapters 4 and 5. In these chapters we discussed our overarching approach which have been underpinned by the guiding principles to be as transparent, straightforward, clear and robust as possible. Our assessment relied on a set of input assumptions based on as much publicly available information as possible, which were subsequently agreed upon with Ofgem following discussions with stakeholders. These input assumptions were utilised in various analyses, including our power market modelling, which produced detailed capacity, generation and price profiles at each hour and node. These analyses enabled us to calculate expected aggregate consumer and socioeconomic benefits for each locational market design relative to the status quo market design for each scenario.

12.6. Chapter 6 sets out the **outcomes on physical output** from allocating capacity to different locations when it is economic to do so, subject to varying limits, based on locational pricing. We observed the impact on generation, congestion impact, curtailment emissions and interconnector flows. Overall, our assessment shows that the zonal and nodal market designs, compared to the status quo national design, are expected to produce a different allocation of capacity across GB, as investors would consider inter-zonal and intra-zonal constraints respectively in their siting decisions. We find that more efficient dispatch and re-siting of generation capacity is expected to lead to significantly reduced congestion volumes for the SO to resolve (or none in the case of a nodal market), lower curtailment volumes, lower emissions and more efficient use of two-way assets such as interconnectors.

12.7. Chapter 7 sets out **pricing and financial outcomes** from our analysis, based on the physical output of each unit and demand profiles at each node. We observed the impact on wholesale cost of electricity, constraint management costs, CfD support payments, which in sum showed the total variable cost of electricity, as well as the producer impact. Overall, our assessment shows that the zonal and nodal market designs produce a lower total variable cost of electricity to consumers. These locational market designs also lead to lower inframarginal rents for producers, resulting in lower producer surplus, even when considering the increased transfers from CfD support payments.

12.8. We also assessed three **wider system impacts** of locational pricing beyond our quantitative modelling assessment in Chapter 8. These are:

- First, on **implementation costs**, we explored a range of CBAs covering jurisdictions that have transitioned to nodal pricing and had bilateral discussions with the ESO and vendors for SO systems. As a conservative estimate, we have selected the top end of the range of potential implementation costs (for the SO as well as market participants).
- Second, we explored the potential impact on the **cost of capital** based on a high-level assessment of the risks faced by market participants, stakeholder evidence and international evidence. In this assessment, we concluded that both the magnitude and direction of any effect of locational pricing on the cost of capital are unclear, and to the extent that they might exist, they could be mitigated by market or policy tools. As such, we have assumed no change to the cost of capital of market participants in our assessment but have conducted a sensitivity to indicate the potential impact if a change were to occur.
- Third, we assessed the potential impact on **market liquidity** from more granular locational pricing. However, we have not found any evidence of any market liquidity issues in nodal markets that use trading hubs and FTRs. We do not observe any potential liquidity issues in power exchanges in PJM relative to GB. As such, we have assumed no impact on market liquidity in our assessment.

12.9. In **Chapter 9**, we set out our consolidated CBA results across the three scenarios. We highlight the figures below in Table 12-1.

Table 12-1: Results of consolidated CBA analysis (£bn, 2022 prices)

Scenario	Zonal		Nodal	
	Consumer benefit	Socioeconomic welfare	Consumer benefit	Socioeconomic welfare
LtW (NOA7)	30.7	15.3	50.8	24.0
LtW (HND)	18.7	7.1	34.2	14.4
SysTr (NOA7)	15.2	6.2	28.0	13.1

Source: FTI analysis
Note: Covering the modelling period of 2025 to 2040, and discounting to 2024.

12.10. Overall, we expect that these results are a conservative estimate given our assumptions. We set out several key assumptions that might affect our results (in either direction) in Table 12-2 below.

Table 12-2: Key assumptions which could affect the overall CBA

Key assumptions	Likely impact on results if assumption relaxed
Fixed transmission build: Based on ETYS, NOA7 and information provided by ESO. Does not vary across market designs. We set out in Chapter 10 an assessment of why less transmission is likely to be required in locational markets due to improved locational and operational price signals for market participants.	↑
Fixed capacity mix: Overall generation capacity and technology mix is fixed to FES 21. Allowing the capacity mix across technologies to change between national and locational market designs could increase consumer and socioeconomic benefits and reduce the costs of achieving Net Zero.	↑
No demand re-siting and inward investment: We have fixed the location of demand across each market design assessed. Locational market designs could incentivise demand to site in different locations and/or attract further investments by energy-intensive companies which could lead to further benefits beyond those assessed.	↑
Operational benefits: Our modelling does not account for operational benefits from centralised scheduling as well as other potential benefits from using a security-constrained economic dispatch. For example, we do not consider the impact of the ability to co-optimise energy and reserves more effectively in a nodal market.	↑
Consumer exposure to locational prices: We assumed all consumers are fully exposed to locational pricing. Shielding consumers (or specific consumer types) from locational prices would reduce the estimated benefits.	↓
Further policy support for existing generation: Compensating the investments of some cohorts of existing generation for reduced revenues would lead to a reduction in consumer benefits (offset by higher producer revenues). This would not lead to changes to socioeconomic welfare unless interventions distort market incentives.	↑↓
FTRs confer full congestion rent benefits to consumers: We assume that all FTRs are auctioned at efficient prices (i.e., with perfect foresight). Any differences between FTR auction revenues and congestion rent collected in the settlement processes would affect consumer benefits (in the form of a direct transfer with FTR holders). There would be no change in socioeconomic welfare unless there is an inefficient risk transfer.	↑↓
No change in cost of capital: We assumed no change in cost of capital due to lack of evidence, but an increase would reduce the estimated benefits, and a decrease would increase the estimated benefits.	↑↓
New generation capacity re-siting assumptions: Assumptions on technology siting were developed in discussion with stakeholders. Any changes to these assumptions could impact the overall benefits in either direction.	↑↓

Key assumptions	Likely impact on results if assumption relaxed
No other reforms assumed: Our status quo assessment is based on the current market structure and policy landscape. Further changes (e.g., network charging, Capacity Market reforms) could change the overall benefits.	↑↓
Choice and design of zones: Our seven-zone model is based on the six most constrained boundaries which is fixed in the modelling period. Alternative zonal boundaries would change the benefits of our zonal pricing assessment, while periodic rezoning, if assumed in our assessment, would be expected to increase the benefits.	↑↓
Modelling year: Delaying the start of the modelling period, while keeping the length of the modelling period the same, could lead to multiple effects in either direction. Overall, the net benefits are uncertain as they would depend on the energy system beyond 2040 – and in particular whether the benefits in later years would exceed the foregone benefits in early years.	↑↓

Source: FTI analysis

12.11. We undertook a distributional analysis showing the spread of consumer benefits in each region of GB (for both the zonal and nodal models). We observed that while the wholesale price impact may vary considerably, net consumer benefits are positive in each region.

12.12. We highlight that a transition to locational pricing would reduce carbon emissions faster – estimating between 25 and 100 MtCO2 less emissions between 2025 and 2040 relative to a national market. When applying DESNZ's carbon values, which is not considered in our modelling CBA results presented above, socioeconomic welfare increases by a further £4.3bn to £17.9bn depending on the scenario.

12.13. Our assessment also assumes that the transition to locational pricing occurs at a single point in time. We therefore considered the qualitative impact of any transition and mitigation measures that may be required. We explained the impact of grandfathering of existing investments and how that sets a trade-off between consumer benefits and producer benefits. More specifically, we also explored two broad types of transitional and mitigation measures – the allocation of FTRs and providing a single price exposure.

12.14. In **Chapter 10**, we set out our findings on two key sensitivity analysis following our discussions with stakeholders. These sensitivities are:

- A **dispatch-only sensitivity** which tests the benefits of more granular locational pricing *without* the benefits of re-siting generation. This sensitivity was conducted on the basis that several stakeholders believed that improved re-siting of generation and storage could be achieved via other policy mechanisms. In our sensitivity we find that even with the optimal siting of generation and storage, a transition to a nodal market still delivers considerable consumer benefits at £39bn (albeit c.24% lower than our LtW (NOA7) scenario).

- A **load shielding sensitivity** which tests the benefits of more granular locational pricing while shielding consumers from these locational prices. This sensitivity was conducted on the basis of a potential policy desire to shield consumers from the locational price at their connected node. In our sensitivity we find that, with load shielding reducing the ability of flexible demand to optimise around the "system-optimal" nodal price, wholesale costs rise by £3.2bn relative to "unshielded" nodal pricing for the SysTr (NOA7) scenario. However, "shielded" nodal pricing still generates net benefits of £26.8bn for consumers across the modelled period.

B. Concluding remarks

12.15. Overall, our assessment shows a positive case for transitioning to a locational market design from a consumer perspective, with a nodal market design having greater benefits than a zonal market design.

12.16. Furthermore, as several of our assumptions and approach could be considered conservative (for example by assuming total capacity is constant across each market design or that demand does not site differently relative to FES 21), we expect the benefits to be higher in practice. Additional benefits are also likely to arise from the potential reduced need for transmission enhancements under a locational pricing regime and we have noted that the benefits assessment would be higher still if we adopted the DESNZ approach for evaluating the benefits of reductions in carbon emissions. We should also note, however, that amending some of our assumptions might lead to a smaller increase in consumer benefits, such as by removing the volume risk exposure of existing CfDs or through an increase to the cost of capital.

12.17. Given the widespread impact on the GB energy system and the contentious nature of this debate, we have sought an independent and robust approach, setting out our assessment process as transparently as possible. As such, we welcome further stakeholder scrutiny of our methodology and to test the robustness of our findings.

12.18. These modelled benefits are consistent with the experience of other electricity markets that have transitioned to more locational market designs. Notably, we are not aware of any major electricity markets that have sought or are seeking to reduce the locational granularity of their wholesale electricity markets in recent years.

12.19. We trust that this report has been informative for policymakers, industry and consumers. We hope that the findings can contribute further to discussions on the best approach to delivering Net Zero on behalf of GB consumers and citizens.

Appendix 1 Detailed modelling results

A1.1 In this report, we relied on FTI's in-house pan-European power market model, which we augmented with a nodal representation of GB and calibrated according to the relevant FES 21 scenario. The model runs on the Plexos Integrated Energy Model platform.

A. Modelling framework

A1.2 This platform is a dispatch optimisation software based on a detailed representation of the market supply and demand fundamentals at an hourly granularity. Plexos takes into account the power plant characteristics, minimum generation levels, variable operating expenses, realistic bidding patterns by generators, losses on transmission lines, and demand flexibility among other factors to allow for the modelling of new-build capacity.[240]

Overview

A1.3 The Plexos model optimises dispatch in two phases:

- First, the long-term ("LT") model is used to determine the optimal capacity evolution, based on the combination of generating units that minimises the wholesale cost for consumers. The LT model uses perfect foresight and a simplified chronological load modelling approach to perform this least-cost optimisation exercise;[241] and
- Second, the short-term ("ST") model which takes the capacity from the LT model as given and determines the least-cost generation dispatch and the optimal demand pattern on an hourly basis. The ST model also estimates flows and losses on the transmission network, as well as the prices at each node. The ST uses a SRMC pricing algorithm, where generators bid at a function of their SRMC and start-up costs, and will be dispatched if the wholesale price is greater than or equal to their bid.

LT model

A1.4 As mentioned above, the LT model is used to determine the optimal evolution of generation and storage capacity across the modelling period. However, in order to ensure a consistent treatment of the three modelled market designs, the total capacity of each technology in each year is fixed to the relevant FES scenario. As a result, the LT is used to optimise the location of assets on the GB network for this modelling exercise.

A1.5 For the national model (which is based on the current market design), we do not optimise the build-out of generation and storage capacity. Instead, the size and location of all assets is derived from the relevant FES 21 scenario, using both the public FES datasets and data confidentially provided by ESO. The FES capacity forecast is developed with extensive stakeholder engagement and accounts for the expected impact of current policy drivers (e.g., TNUoS) on asset siting decisions.

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[240] Our modelling uses a DC load flow analysis, considering only thermal flows and not voltage levels or stability.
[241] A simplified chronological modelling approach refers to the aggregation of hours into blocks when determining the optimal generation capacity allocation.

A1.6 For the zonal and nodal markets, the LT model is used to optimise the size and location of generation and storage assets across the GB network, with assets responding to the impact of locational pricing signals. Importantly, the ability of new assets (that are not in development) to site at different locations is limited by a number of technology-specific constraints, to ensure that the new siting under nodal and zonal market arrangements remains both feasible and realistic.

A1.7 Under nodal market arrangements, the capacity build-out is optimised for each node within these constraints.

A1.8 Under zonal market arrangements, the capacity build-out is optimised for each zone, but not for each node. The split of capacity between nodes within a zone is based on FES 21:

- For technologies where new sites are available with shorter lead times and adjustable project sizes (onshore wind, solar, grid-connected storage and distribution connected hydrogen generation), we split new capacity across the nodes in each zone in proportion to the split of new capacity in FES 21 in the same zone.
- For technologies where projects are limited to their sites either wholly or to a significant extent (CCS Biomass, CCS Gas, offshore wind), we rank projects in each zone based on their completion date in the relevant FES 21. Projects are built in the same order within each zone, but the pace of build-out is adjusted for each zone to match the results of the zonal LT.

A1.9 Due to the intensive computing processing power required in the modelling, we have been presented with two trade-offs when running the LT model. These are:

- The level of granularity of the load modelling: as modelling each hour for the capacity build-out would be too computing resource intensive, the hours are usually aggregated into blocks which are then optimised in sequential steps. Increasing the number of blocks in each year allows the modelling to be more precise but also leads to increased resource use and run times.
- The number of years of foresight considered in the modelling: the LT model optimises the capacity built each year by looking into the future for a specified number of years. However, increasing this time horizon leads to increased computing resource use and run times. The incremental benefit of increasing the time horizon also diminishes over time, since benefits beyond the first ten years are heavily discounted.

A1.10 The optimal approach to managing these trade-offs may differ across asset types. For example, generation assets with longer lifetimes would benefit from a longer modelling horizon, which includes at least ten-year foresight. However, storage assets require more granular load modelling, in order to capture price variations within each day, as most of the revenue for storage assets is derived from arbitrating between low prices at night and high prices at the afternoon peak.

A1.11 Due to the increased complexity introduced by the nodal representation of the GB transmission system, it is not possible to run an LT model with at least ten-year foresight and granular enough load modelling to capture intra-day price differences. As such, we split the LT model into two parts:

- First, the **generation LT,** which is used to optimise the build out of new generation assets. This LT uses a ten-year horizon and models demand in 24 blocks per month; and
- Second, the **battery LT,** which is used to optimise the build out of new grid connected storage assets. This LT uses a five-year horizon and models demand in 21 blocks per week.

A1.12 For the LT models, only GB is modelled explicitly to reduce the modelling complexity. The prices in neighbouring European countries followed a fixed price profile, which is an output of the status quo national market ST model using the capacity build-out from FES 21 and the TYNDP.

ST model

A1.13 As described above, the ST model finds the least cost generation mix and optimises the demand patterns on an hourly level. This allows the model to estimate flows and losses on the transmission network as well as prices and demand levels at each node of the system. The core ST model is used to model outcomes on the wholesale market for each market design.

A1.14 We model each European country explicitly in this stage of the modelling.

A1.15 All market arrangements are modelled using a full nodal representation for GB, rather than, say, using only a single GB node for the national model, enabling the analysis of demand and generation levels at each node across each market design. To differentiate between market designs within the modelling, we instead alter the transmission capacity of circuits and transformers between models. This involves the following:

- For the national model, all intra-GB transmission assets have an unlimited capacity, allowing power to flow freely across the whole GB network.
- For the zonal model, all intra-zonal transmission assets have unlimited capacity, but all inter-zonal assets have ratings restricted to their assumed physical capacity.
- For the nodal model, all transmission restrictions are enabled.

A1.16 Losses on the GB transmission network are only modelled for the nodal market arrangements. In order to ensure a fair comparison between the market designs, demand levels are uplifted for the zonal and national market models to include losses on the transmission levels.

A1.17 The bidding of generators is a function of their SRMC and start costs and they are dispatched if the market price exceeds their bid.

A1.18 While we assume that all intermittent renewables have an SRMC of effectively zero, we differentiate between merchant, CfD and ROC generators to ensure that generators that receive subsidy support are dispatched ahead of merchant assets.

Redispatch model

A1.19 As described above, the core ST model is used to model wholesale market outcomes under each market design. However, under a national or zonal wholesale market this can often lead to a scheduling of generation and demand that is not compatible with the limits of the transmission grid. To resolve these constraints under the status quo, generation is constrained-on and off through the BM to create a dispatch that is actually feasible. A similar mechanism is assumed to be in place under a zonal wholesale market.

A1.20 To compare the true system cost under the different market arrangements requires a comprehensive modelling of the balancing mechanism, given its significant (and increasing) role in the current market design. To model the BM, we run an augmented ST model (the “redispatch model”) to forecast how the ESO balancing actions would impact the final post-balancing generation mix.

A1.21 In this augmented ST model, we:

- enable transmission limits on each circuit and transformer between nodes to ensure that the post-balancing dispatch is feasible;
- fix demand at each node to the load profile generated by the relevant wholesale market ST run, assuming that demand is not able to participate in the BM;
- fix generation from technologies that are assumed to not take part in the BM (i.e., nuclear and run-of-river hydro) to the wholesale market outcome of the core ST run; and
- add a "penalty price", linked to the marginal cost of a gas plant, for increasing or decreasing flows on interconnectors relative to the outcome of the wholesale market ST, in order to ensure that interconnectors are only constrained-on if there are no lower cost alternatives available. This is in line with the ESO's historical treatment of interconnectors in the BM.

A1.22 We then compare the output of each generator under the wholesale market model and the redispatch model. The difference in generation for each generator provides the volume of constrained-on and off generation in each hour.

A1.23 To calculate payment for these constrained-on and off generation, we estimate bids and offers for each technology. We assume that generators base their bids and offers on their true costs, and they do not reflect market power.

A1.24 For bids, we assume that each technology is bidding in a way that ensures that they are indifferent between being constrained-off and getting dispatched.

A1.25 For offers we assume that generators require a payment to cover the SRMC of their additional generation. We also apply an additional uplift, calculated based on the historically observed average difference between generators' SRMC and BM offer price. This uplift is intended to capture the additional costs which may be incurred by generators altering their intended dispatch at short notice.

A1.26 We have validated this modelling approach with the relevant ESO team that produces the ESO's own forecast of congestion costs. As a result, our congestion forecast aligns with the ESO estimates as discussed in Section 7B.

A1.27 Offers and bids for each technology participating in the BM is described Figure A1-1 below and are described in the following paragraphs.

Figure A1-1: Assumed BM bid and offer prices

Technology	Cost to ESO Bid	Cost to ESO Offer
Fossil fuel	- Fuel cost - carbon cost	Offer Uplift + Fuel cost + carbon cost
Biomass	- Fuel cost	Offer Uplift + Fuel cost
CCS Biomass	Carbon price – Fuel cost	Offer Uplift + (Fuel cost – carbon price)
ROCs renewables	ROCs[1]	(theoretical only so no price assumed)
CfD renewables	CfD strike price – Wholesale price	(theoretical only so no price assumed)
Merchant renewables	£0	Offer Uplift
Batteries	- Price Paid	Price Received + Offer Uplift
Other Storage Technology	- Marginal Value	Marginal Value
Hydrogen generation H_2	- Marginal Value	Marginal Value
Interconnector	Cost of reversing flow €130 / €100[2]	Cost of reversing flow €130 / €100[2]

Source: FTI analysis based on discussions with stakeholders and agreement with Ofgem
Note: we assume the following technologies do not participate in the BM – DSR, nuclear, hydro (run-of-river) and small-scale thermal.
[1]The number of Renewable Obligation Certificates ("ROCs") will depend on technology. For simplicity, we assumed 1.9ROCs for offshore wind and 0.99ROCs for onshore wind which is the average per technology from DESNZ.
[2]The cost of reversing flow per MWh is assumed to be €130 in 2025 and €100 from 2030 onwards.

A1.28 **Thermal plants (fossil fuel, biomass) bids** are assumed to reflect the cost savings associated with not generating. No uplift is assumed compared to the actual savings, due to contractual terms in the connection agreement for thermal generators.

A1.29 **Fossil fuel plant offers** are assumed to be based on the SRMC of fossil fuel plants (fuel cost plus carbon price) and on an offer uplift expressed in percentage terms. This offer uplift is calculated by comparing historic offer prices of gas generators with their historic SRMCs,[242] calculated based on historic fuel prices. The uplift applied is c.129% and is intended to reflect uplifts in the BM offer on top of the SRMC, which includes other costs, such as start costs and the uplift due to the nature of the pay-as-bid market of the BM. [243]

[242] We have calculated the average offer price by weighing historic offer prices with the volume of accepted bids, using Elexon data on Offer accepted volumes and Offer prices

[243] Since we are estimating this uplift over the SRMC based on historical data, it could include the effect of market power, if this has been an issue historically on the BM.

A1.30 **Biomass offers** are assumed to be based on the SRMC of biomass (fuel cost) and an offer uplift. Due to limited data on biomass offers, we have assumed that this is 50% of the historic absolute uplift for gas generators, which is c.£18.9 per MWh.

A1.31 **CCS biomass** is assumed to behave in the same way as biomass, the only difference being is that the SRMC is reduced by negative emissions costs.

A1.32 **ROC and CfD renewables** are assumed to require a payment from ESO to be turned down, which compensates them for the lost subsidy. In the case of renewables with ROCs this would equal the ROC payment, while for CfDs this would be difference between the wholesale price and the strike price.[244] No assumption is made regarding their offer prices, as these generators do not get material constrained-on payments in practice.

A1.33 We assume that **merchant renewables** bid at their marginal price**,** which is £0 per MWh and as a result can be constrained-off without any payments from ESO. However, they require payments from the ESO to be constrained-on, which we assumed to be equal to 25% of the absolute historical uplift for as generators, c.£7.6 per MWh.

A1.34 **Battery bids** are assumed to reflect the cost saved by being turned down through the balancing mechanism. This is proxied by the average price paid by the given battery for charging on the wholesale market in the given week.

A1.35 **Battery offers** are assumed to reflect the alternative revenue they would otherwise earn on the wholesale market and an offer uplift. The alternative revenue is proxied by the average price received by the given battery in the given week. Due to the limited historic data for batteries on the BM, the uplift is assumed to be equal to 50% of the absolute historic uplift calculated for gas generators (c.£18.9 per MWh).

A1.36 For **other storage** technologies offers and bids are assumed to be based on the marginal value of an extra unit of energy in storage. This is calculated by our model and is used to calculate the bid prices for storage asset.

A1.37 Similarly for **hydrogen generation**, we use the marginal value to calculate the bids and offers, which represents the marginal value of an additional MWh of hydrogen in storage.

A1.38 We assume that changing flows on **interconnectors** by one MWh costs €130 in 2025 and €100 in 2030. This assumption is required as the balancing markets of neighbouring countries are not modelled explicitly, which would be the basis of offer and bids in practice. However, changing flows on an interconnector would likely require constraining-on gas generators in a neighbouring country. As a result, we have set interconnector offers to a level slightly above the SRMC of CCGT plants.

[244] CfD generators might be willing to pay to be constrained-off, if the wholesale price is higher than their strike price, as this would require them to pay back the difference if they actually generated.

A1.39 This assumption is also reflective of historical ESO actions to balance thermal constraints on the grid. Historically, most export constraints have been resolved by turning down wind generation behind the constraint and turning up gas generation in front of the constraint, rather than reversing interconnector flows. Nearly all interconnector reversals have been undertaken to resolve import constraints.[245]

CfD support payment calculation

A1.40 Generators that hold CfD contracts are guaranteed to receive the same strike price for each unit of electricity generated. As a result, in theory they would be willing to generate regardless of the prevailing wholesale market prices. However, as part of the CfD contracts they are required to not bid negative into the wholesale market if the clearing price has been below zero for at least six hours.

A1.41 As a simplification, we assume in our modelling that this requirement is present in all hours and CfD generators bid zero in the wholesale market. However, CfD generators are still dispatched ahead of merchant generators from the same technology.

A1.42 CfD support payments are calculated outside of the model based on the:

- **Actual generation,** which refers to post-balancing mechanism[246] generation under the zonal and status quo national market;
- **Strike price**, which is based on the actual strike price for generators that already hold CfD contracts and BEIS's LCOE projections for new units who are assumed to obtain CfDs in the following years; and
- **Reference price**, which is the average price received on the wholesale market by each generator.

B. GB generation capacity

A1.43 The primary source for the modelling assumptions regarding generation capacity is FES 21, augmented with datasets published by ENTSO-E when FES data is unavailable.

Capacity and location of generation and storage assets

A1.44 The location and generation capacity for assets connecting on the distribution grid is based on the Building Block data of FES 21. This dataset provides the capacity build-out between 2020 and 2050 for each technology at each GSP.

A1.45 The location and generation capacity for assets connecting to the transmission grid is based on a confidential dataset provided to us by the ESO's FES team. This is the same dataset that provides inputs for the FES modelling and includes capacity, commissioning date, decommissioning date, and the connecting node for each existing and forecasted future asset that connects to the transmission grid directly.

[245] NG ESO (2023), 'Markets Roadmap' (link).

[246] As described above, CfD generators that are constrained-off on the BM receive a constrained-off payment equalling their expected CfD support payments.

A1.46 The location of new generation capacity is optimised under the nodal and zonal market arrangements, subject to technology-specific constraints, as described below.

Technical characteristic

A1.47 For confidentiality reasons, the ESO were unable to share the data used in the FES modelling regarding the technical specifications of thermal plants and the forecasted climate profiles for intermittent renewable generation.

A1.48 As a result, we rely on datasets published by ENTSO-E, that form a basis of their various modelling exercises including TYNDP and the European Resource Adequacy Assessment ("ERAA").

A1.49 Assumptions on thermal plant characteristics are based on the PEMMDB, which provides efficiency, emission rate, start-up cost and typical outage profiles by generation technology and the age of the assets. Each thermal plant within the FES datasets is matched to a category within the PEMMBD.

A1.50 Inputs on climate profiles for intermittent renewable generators are based on the PECD, which provides the hourly capacity factor for each technology across different GB regions, divided into five onshore and twelve offshore zones. Each intermittent renewable generator within the FES datasets is matched to the relevant geographic zone.

A1.51 Importantly, the forecasted annual capacity factors of renewable generation technologies differ between the PECD and FES assumptions. In order to ensure that our scenarios remain consistent with the FES datasets upon which they are based, we have adjusted the PECD capacity profiles to match the FES annual capacity factors. In effect, our climate profiles follow the hourly profile of the PECD climate forecasts, scaled to reach the annual capacity factor set out in the FES dataset.

Technology-specific LT constraints

A1.52 As described above, we reoptimise the capacity build-out of new generation assets under nodal and zonal pricing, to reflect the consequences of new price signals. However, there are several constraints applied to this optimisation to reflect real-world limitation, such as geography, planning consents and site availability.

A1.53 We developed these constraints based on a set of technology specific resources to make sure that any build-out under nodal and zonal market arrangements remains realistic and feasible. In cases of uncertainty, we have chosen conservative estimates and relied on the existing FES 21 assumptions, as much as possible. The specific constraints by technology are listed below:

A1.54 **Hydro, pumped storage and other renewables** are not reoptimised, as these projects require very specific geographies and are unlikely to be able to respond to prices by siting at new locations.

A1.55 **Nuclear** is not reoptimised, as it can only be built at specific sites and due to the lead-up time for new projects, the choice between sites is unlikely to be affected by price signals. While in theory SMRs (which are included under both LtW and SysTr) could incorporate price signals in their siting decisions, we also fix these to FES 21, in order to provide a conservative estimate of the impact of locational pricing on asset re-siting.

A1.56 **Non-CCS thermal and biomass** are not reoptimised, as nearly all of the new capacity for these technologies is expected to come online in the next few years, under the modelled scenarios. Consequently, most of the projects are already in progress and would be unable to take pricing signals into account.

A1.57 **CCS gas and biomass** is reoptimised in our modelling subject to several constraints:

- Only nodes within industrial clusters are available as connection nodes for new generation capacity;
- Clusters are assumed to come online in the year when the first project is built in each cluster according to FES 21. No new CCS generation capacity is allowed to locate in a cluster before this date; and
- The total generation capacity in each cluster is limited to the total maximum CCS capacity observed in each cluster in FES 21.

A1.58 **Generation capacity using hydrogen as a fuel** is reoptimised in our modelling subject to several constraints:

- Small-scale hydrogen capacity, connecting to the distribution grid (included in both LtW and SysTr) is allowed to site at the GSPs that have hydrogen generation capacity under FES 21, or at nodes within the hydrogen clusters;
- Large-scale hydrogen capacity, connecting to the transmission gird (included only under SysTr) is allowed to connect at nodes within hydrogen clusters; and
- Each hydrogen cluster comes online in the year with the first project in FES 21 in the given clusters and maximum capacity within the cluster is limited similarly to CCS capacity.

A1.59 **Offshore wind** is reoptimised in our modelling subject to several constraints:

- All committed projects (under construction or CfD awarded) must be built under all market arrangements;
- New offshore wind projects can connect at nodes with existing or planned offshore wind capacity under FES and at other coastal nodes;
- Maximum capacity in each sea area[247] in 2030 is limited to the total capacity already awarded under Crown Estate and Crown Estate Scotland leases[248] or to the total offshore wind capacity in 2030 in FES 21 in the given area; and
- Maximum capacity in each sea area in 2040 is limited to twice the total capacity already leased out, or the total offshore wind capacity in 2040 in FES 21 in the given area, whichever is higher.

[247] We have split the waters around GB into eight zones and assigned all existing leases, excluding cancelled project to one of them. The areas used were: South Coast, Celtic Sea (including Bristol Chanel), Irish Sea, Western Scotland, Northern Scotland (including Outer Hebrides, the waters around Orkney and Shetlands and the Moray Firth), North Sea – North (area around Firth of Forth), North Sea – Mid (Dogger Bank, Hornsea, Outer Drowsing), North Sea – South (waters around East Anglia).

[248] The limit for the Celtic Sea is increased to 5GW for 2030 and 10GW for 2040 to accommodate the forthcoming lease round in the Celtic Sea, The Crown Estate (link)

A1.60 **Onshore wind in Scotland and Wales** is reoptimised in our modelling. New onshore wind can connect at nodes with onshore wind capacity in FES 21 and is limited to twice the amount in FES 21 at each node.

A1.61 **Onshore wind in England** is fixed to FES 21 in England to reflect challenges in obtaining planning constraints for new onshore wind farms in England.

A1.62 **Solar** is reoptimised in our modelling. New solar capacity is restricted to nodes with solar capacity in FES 21 and is limited to twice the amount in FES 21 at each node.

A1.63 **Grid connected storage assets** (excluding pumped storage) are reoptimised in our modelling. New capacity is restricted to nodes with storage assets in FES21 and new capacity at a node is limited to 400MW every 5 years.

A1.64 **Domestic batteries** are not reoptimised in our modelling, as these are linked to the location of demand which we treat as fixed across the market arrangements.

C. GB demand

A1.65 As is the case for generation capacity, demand assumptions are based on FES 21 wherever possible, but are augmented with data by ENTSO-E where necessary.

A1.66 The location of demand is not optimised under any of the modelled market arrangements and is taken exogenously from FES 21.

A1.67 Demand in our modelling is split into four categories:

- **Baseline** demand represents consumption from existing sources. Demand from this category is expected to decrease in the short-term due to efficiency gains, while it is expected to increase from the late 2020s or early 2030s dependent on the scenario, as a result of increased electrification;
- **EV** demand represents consumption from all types of electric vehicles (cars, buses, HGVs, etc.). EVs are represented in a separate category, due to the different demand profile compared to existing demand represented in the baseline category;
- **Electric HP** demand represents consumption from electrified heating. HPs are represented in a separate category, due to the different demand profile compared to existing demand represented in the baseline category;
- **Electrolyser** demand represents consumption from grid connected electrolysers. Due to the flexibility associated with electrolysers, it is split into a sperate category and modelled differently compared to other demand types.

Annual demand levels

A1.68 Annual demand levels for baseline, EV and HP demand are based on the FES 21 Building Block data. This dataset provides GSP level demand data for several demand categories, which were aggregated into three demand categories mentioned above.

A1.69 GSP level demand data in the Building Block dataset is presented net of distributed generation at each GSP. To account for this, we apply an uplift to baseline generation based on the total GB demand data presented in FES 21. The uplift is calibrated for each year, so that the building block data across GB matches the Total Customer Demand data in FES 21.

A1.70 A further uplift is applied to baseline, EV and HP demand to reflect losses in the distribution system, which are not modelled.

A1.71 Total installed electrolyser capacity per GSP is also provided in the Building Block dataset. We use this data to develop an assumption regarding the electrolyser capacity at each minor FLOP zone,[249] which is then split across nodes proportionate to the intermittent renewable capacity installed at each node. This is necessary since the original FES 21 allocation of electrolysers would have led to local constraints on the system and very high prices in the areas with high electrolyser capacity.

A1.72 Each electrolyser has a target capacity factor in our modelling, which is derived based on the total installed capacity of electrolysers and total electrolyser demand in each year in FES 21.

A1.73 All four kinds of demand are uplifted in our national and zonal modelling to reflect losses on the transmissions system, as these were not modelled explicitly under these market arrangements. However, the same uplift is not added under the nodal modelling, because transmission losses were modelled explicitly.

Demand profile

A1.74 Hourly demand profile data is not available from FES 21. As a result, we rely on the demand profiles published by ENTSO-E and publish as part of their ERAA, as an input.

A1.75 These are used as an input for baseline demand, fixed EV demand and fixed HP demand.

Demand flexibility

A1.76 FES 21 includes several types of demand flexibility. We implement these in our modelling in various ways, depending on the way the flexibility is provided.

A1.77 **Smart EV charging** is reflected in our model by splitting demand from EVs into two sub-categories: fixed and flexible. Fixed EV demand follows fixed demand profiles. While flexible EVs optimise their consumption within each day to minimise the overall price paid. The daily consumption level is set by the aggregation of the hourly EV demand profile. The proportion of flexible EVs is based on the share of consumers engaged in smart charging, as per FES 21.

A1.78 **V2G** behaves the same way as batteries (charging when prices are low and discharging when prices are high), so we have modelled them as battery units. The capacity of these batteries is based on the potential available V2G capacity as presented in the Building Block data of FES 21.

A1.79 **Smart HP consumption** is reflected in our model by splitting demand from HPs into two sub-categories: fixed and flexible. Fixed HP demand follows fixed demand profiles. While flexible HPs optimise their consumption within each day to minimise the overall price paid. The maximum weekly and daily consumption level is set by the aggregation of the hourly HP demand profile. The proportion of flexible HPs is based on the share of HP units, which are accompanied by various forms of flexibility technology, as per the FES 21.

A1.80 **DSR reduction** is reflected in our model as a generation technology participating in the wholesale market. Following bilateral engagements with the FES team we have implemented two tiers of demand shedding:

[249] FLOP zones refer to Flow Optimisation zones and are used in various ESO modelling.

- The first category represents DSR reduction from **industrial and commercial** consumers and is limited by the number of hours that it can be activated in. Max capacity available to turn down across GB is based on I&C DSR impact at peak in FES 21 and is split across nodes based on the Building Block data describing the number of industrial and commercial consumers at each GSP; and
- The second tier represents DSR reduction from **residential** consumers and is activated at a given price. The price is calibrated in each year, such that it is higher than the SRMC of all generator units. As a result, this is only dispatched as a last resort, or in cases when the extra generation is only needed for a few hours and the starting of thermal units would be too expensive due to start costs. Total capacity available to turn down is based on residential peak shifting in FES 21 and is split across nodes based on the Building Block data describing the number of domestic consumers at each GSP.

A1.81 **Electrolyser** capacity and demand is fixed in our model to FES 21 at each node. As described above, electrolyser capacity per node is based on the Building Block data, and the total electrolyser consumption across GB is split across electrolysers proportionally to their capacity. Based on the capacity and the target capacity factor, each electrolyser optimises its consumption to minimise the cost paid across the year.

D. Intra-GB transmission network

A1.82 We have developed a representation of the full GB transmission network for our nodal modelling, which includes all nodes and assets connecting nodes at or above 275kV in England and Wales and 132 kV in Scotland.

Data sources

A1.83 We use several resources published by ESO and have complemented this with data received directly from the ESO, as well as with several bilateral discussions with the ETYS and NOA team.

A1.84 The representation of the current grid is based on Appendix B of ETYS, which includes detailed technical data on each line, cable, HVDC, transformer, etc. of the current grid. This includes data on the topology, seasonal rating and resistance of each asset, all of which are necessary for modelling the flows on the GB transmission grid.

A1.85 Changes to the transmission grid up to 2031 are primarily based on ETYS, as it also provides detailed data on the addition of new assets, changes to existing assets and the removals of existing assets. This data was only changed if project specifications or completion dates have changed in NOA7 or NOA7 Refresh. Changes up to Year 5 in the ETYS were assumed to be in place by 2025, while changes up to Year 10 were assumed to be in place by 2030.

A1.86 We have also cross-checked this data against the relevant NOA for each scenario and if discrepancies existed, we have updated the data in the ETYS to match the description in the NOA, including the topology of the project, the new ratings and the date of the implementation.

A1.87 Under the SysTr (NOA7) and the LtW (NOA7) scenarios we rely on NOA7 to develop our representation of GB transmission grid and to cross-check the ETYS data.

A1.88 We have received the detailed description of most NOA7 projects, which we use to develop these assumptions regarding the new, changed and removed assets as part of each project. The completion date of each project is based on the relevant NOA7 scenario, as described in the NOA7 report.

A1.89 In cases, where the detailed description is not available, we base the topology of the new assets on the description of the projects available in the public domain, while the technical data (rating and resistance) is based on similar projects.

A1.90 Under the LtW (HND) scenario we rely on NOA7 refresh and the HND to develop our assumptions beyond 2030 and to augment our assumptions up to 2030.

A1.91 Several projects included in NOA7 refresh and HND are also included in NOA7 and allow us to rely on the same data provided by ESO for these projects, as we did for the other scenarios.

A1.92 However, this scenario included some new projects, where the detailed project description is not available from the ESO. For these projects, we rely on the project descriptions provided in the NOA7 refresh report, the HND report and ESO's interactive map, to create assumptions regarding the topology of each project. Assumptions regarding the technical characteristics of each project are developed based on similar projects.

Adjustments to ratings

A1.93 Based on discussions with ESO, we have established that ETYS and project specific data includes post-fault ratings. As we are modelling an intact system, the use of pre-fault rating is more appropriate. We de-rate each AC circuit by 0.82 to reflect this.[250] This approach is identical for all scenarios.

A1.94 To reflect contingency constraints (N-2) on the network, we divide the rating of each double circuits with the Onshore Security Factor (1.76)[251], on top of the pre-fault de-rating. As a result, each double circuit is de-rated by 0.47[252] compared to the original ESO post-fault rating. This approach is identical for all scenarios.

Zonal transmission modelling

A1.95 For the zonal modelling, we have selected zonal boundaries based on ESO's congestion forecast for the next ten years, which is developed with the assumption that recommended transmission reinforcements go ahead.[253] This ensures that zonal boundaries cover the main existing boundaries on the systems, as well as ones, which are likely to emerge, as a consequence of mostly already committed projects. The final set of boundaries used in the modelling were:

- B4 - SSEN Transmission to SP Transmission: The border between the two transmission owners ("TOs") is forecasted to be the most congested intra-Scotland boundary;

[250] The de-rating factor is based on technical guidance published by ESO on current ratings for overhead lines (NG TGN(E) 026: Technical Guidance Notes - Current Ratings for Overhead Lines)
[251] Based on CMP357: To improve the accuracy of the TNUoS Locational Onshore Security Factor for the RIIO2 Period)
[252] (1*0.82)/1.76=0.47
[253] National Grid ESO (2021), 'Electricity Ten Year Statement', p.7 (link).

- B6 - SP Transmission to NGET: The transmission border between Scotland and England is currently the most congested boundary on the system and is expected to remain one of the most congested boundaries despite significant transmission reinforcements;
- B7a - Upper North of England: The transmission boundary that is expected to become the most constrained by early 2030s, as reinforcements through the B6 boundary move the constraint further South and new offshore wind connects in the area;
- B8 - North of England to Midlands: Similarly to B7a, this transmission boundary is expected to become more constrained, as other boundaries further North are reinforced and large new offshore wind projects connect in the North of England (Dogger Bank and Hornsea), making it one of the most constrained boundaries on the GB system by the early 2030s;
- B9 - Midlands to South of England: Similarly to B7a and B8, this boundary becomes more constrained, as other boundaries are reinforced and new offshore wind generation connects tot eh system; and
- SC1 - South Coast: This boundary is expected to remain a constrained boundary until the 2030s due to mainly the significant number of interconnectors that connect on the Southern side of this boundary. The boundary can be binding in both ways, depending on whether GB is exporting or importing in the given hour.

E. Other assumptions

A1.96 This section sets out the set of remaining assumptions used in our modelling.

Other European countries

A1.97 Assumptions regarding generation, demand, markets and interconnection capacity between zones is primarily based on TYNDP 22.

A1.98 This Includes the assumptions regarding market arrangements for each European modelled country. For most countries, this reflects the current market arrangements, however there are some exceptions. For example, TYNDP 22 models the market in the Republic of Ireland and the market in Northern Ireland as two separate markets with limited transmission capacity between the two of them. While this does not align with the status quo, we have followed the assumptions set out in TYNDP 22, as otherwise nodal markets in GB could lead to significant congestion within Ireland, which are likely to be addressed.

A1.99 Assumptions regarding the interconnection between GB and other European countries follow the relevant FES 21.

A1.100 Generation and demand data for other European countries is adjusted by the FTI team to better align with national capacity build-out plant and to ensure security of supply in each country.

Commodity prices

A1.101 The forecast of commodity prices in our modelling is based on a blend of future curves and long-term benchmarks. The choice of these futures and benchmarks follows the choices made by ENTSO-E, as part of their TYNDP modelling.

A1.102 The calibration of prices for the main commodities used in GB was done in the following way:

- **Gas** prices faced by GB generators follows the UK National Balancing Point ("NBP") Natural Gas futures until 2025 and is based on the Announced Pledges scenario of the World Economic Outlook 2021 ("WEO 21");
- **Carbon prices** paid by fossil fuel generators in GB follows the UKA Futures until 2025 and is based on the Announced Pledges scenario of WEO 21;
- **Biomass** prices are not fixed exogenously in the modelling. Rather the total available biomass supply is fixed in each modelled year according to FES 21 and the model optimises the use of this across biomass and CCS biomass generators; and
- **Hydrogen** is treated similarly to biomass and the total supply is fixed in each year based on FES 21. The use of hydrogen is then optimised endogenously.

A1.103 The calibration of commodity prices faced by European power plants are developed in a similar way. Gas, carbon, coal and oil prices followed the relevant local future curves and long-term benchmarks, while biomass, hydrogen and biomethane consumption is limited and the model endogenously optimises the use of them across each year.

A1.104 Commodity prices in our model were calibrated on 20 April 2022.

Appendix 2 System Transformation (NOA7) modelling results

A2.1 This appendix sets out our detailed analysis and results for the System Transformation scenario which is based on the generation, demand and network assumptions set out in FES 21 and NOA7.

A2.2 We set out the following outcomes:

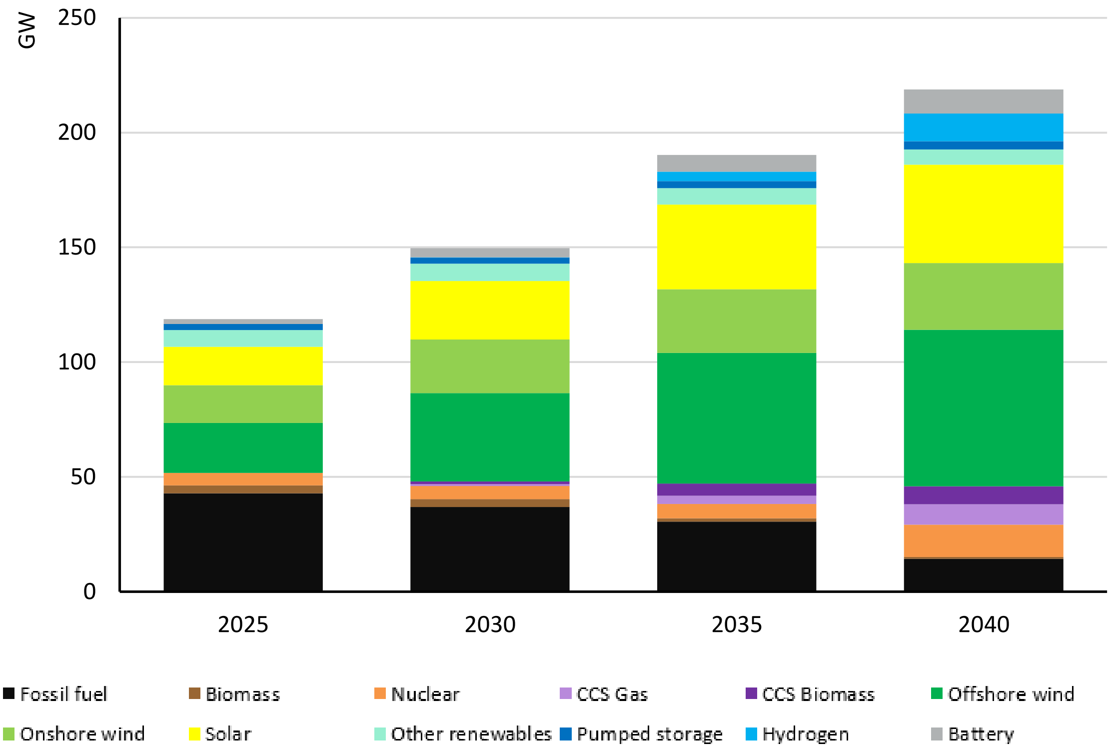
- Capacity and generation outcomes, including the:
  - capacity mix and its different location under the three modelled market arrangements (**Section A**);
  - generation mix on the wholesale market (**Section B**);
  - constrained-on and off generation in the BM (**Section C**);
  - curtailment of renewable generation (**Section D**); and
  - emissions associated with the generation mix (**Section E**).
- Pricing and financial outcomes, including the:
  - change in wholesale electricity prices and cost faced by GB consumers (**Section F**);
  - reduction in the cost of congestion management (**Section G**);
  - changes in CfD payments from consumers (**Section H**);
  - total electricity cost for GB consumers which includes intra-GB congestion rents (**Section I**); and
  - changes in producer surplus on the wholesale and balancing mechanism (**Section J**).

A2.3 We then summarise the key results of the CBA in **Section K**.

A. Capacity

A2.4 Figure A2-1 below shows the aggregate GB installed capacity under the SysTr (NOA7) scenario.

Figure A2-1: Installed capacity – SysTr (NOA7)



Source: FES 21

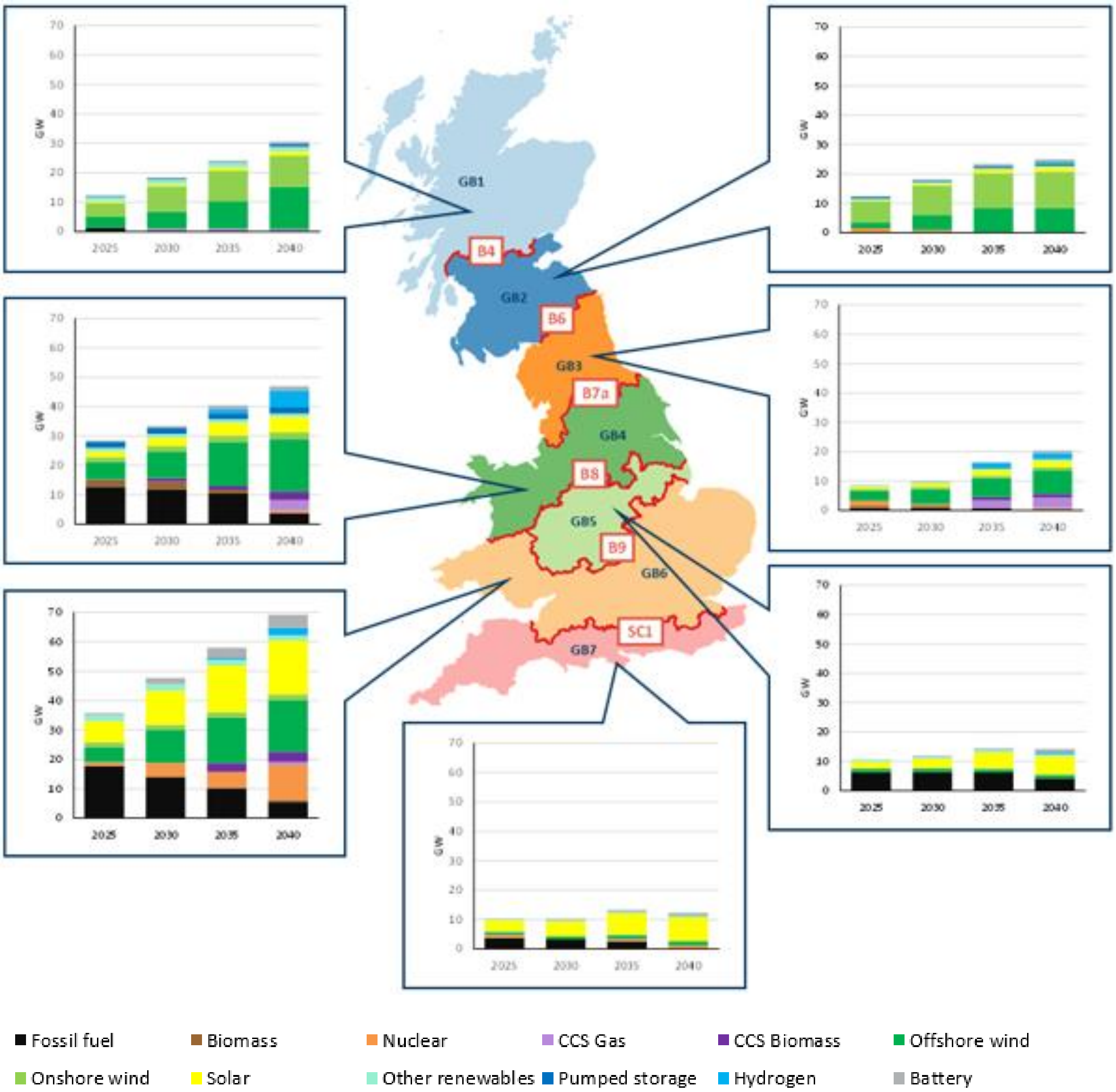
A2.5 As shown in the figure above, the SysTr (NOA7) scenario demonstrates:

- a steady decrease in fossil fuel capacity;
- significant increase in intermittent renewable capacity, especially offshore wind;
- adoption of new generation technologies, such as CCS Gas, SMRs and Hydrogen; and
- high storage capacity (including compressed air and liquid air storage).

A2.6 This scenario reaches Net Zero by 2050, but with a slower transition compared to LtW (NOA7).

A2.7 In line with our other modelling, the overall generation capacity per technology across GB was kept fixed under the different market arrangements. As stated previously for LtW (NOA7), the siting of existing and new generators under the national market (i.e., the current market design) is fixed in each year to the relevant FES scenario, based on a detailed confidential dataset provided by the ESO. Generation capacity by region can be seen in Figure A2-2 below.

Figure A2-2: Installed capacity grouped by zone under the national market - SysTr (NOA7)



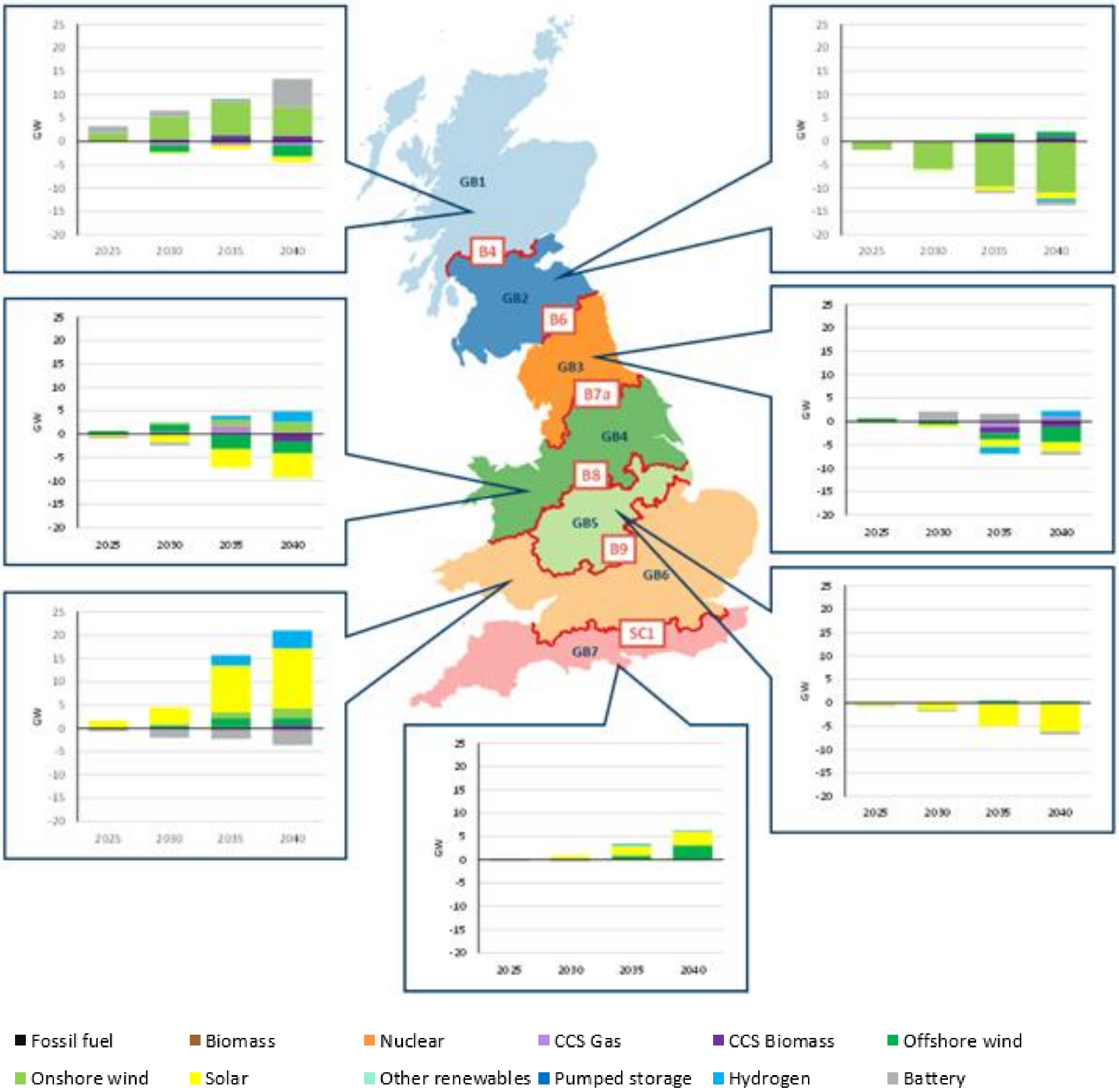
Source: FES 21

A2.8 Compared to LtW (NOA7), generation capacity by region under SysTr (NOA7) differs in the following ways:

- Fossil fuel generation capacity reduces across all zones throughout the modelling period, but at a slower rate in comparison to LtW (NOA7).
- Offshore wind is deployed in all suitable areas throughout the modelling period, albeit to a lower rate than under LtW (NOA7).
- Solar capacity increases in England across all zones relative to LtW (NOA7);
- Increased nuclear capacity siting across GB6, with a reduction in nuclear capacity in GB3, and
- As in LtW (NOA7), majority of grid-connected storage is forecast to be installed near large demand centres, with the vast majority installed in GB6.

A2.9 Siting of new generation assets was reoptimised by Plexos under zonal and nodal market arrangements, as described in Chapter 5. The change in capacity in each zone as a result of moving from the current wholesale market design to a zonal model under SysTr can be seen in Figure A2-3 below.

Figure A2-3: Change in location of generation capacity between zonal and national market - SysTr (NOA7)



Source: FTI analysis

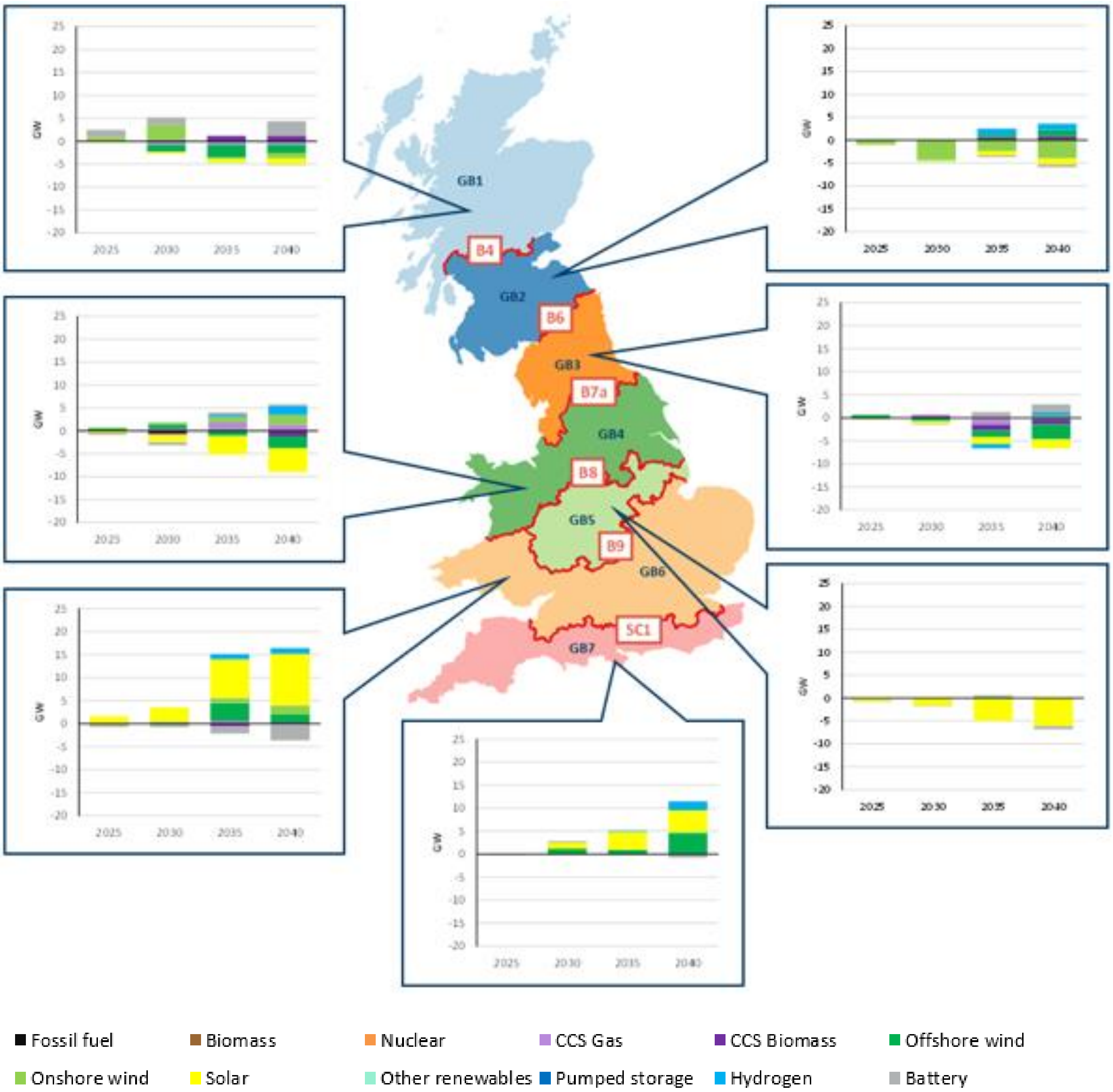
A2.10 The differences in re-siting observed between the zonal and national market arrangements for SysTr (NOA7) are broadly in-line with the differences observed across the same market arrangements for LtW (NOA7), albeit to a lesser extent. Specifically:

- solar capacity is expected to relocate to southern zones;
- onshore wind capacity is expected to relocate away from the southern Scotland (GB2) and to northern Scotland (GB1);
- offshore wind capacity is expected to relocate from northern zones to the Celtic Sea; and

- grid-scale batteries relocate away from southern zones to Scotland.

A2.11 The change in capacity in each zone as a result of moving from the current wholesale market design to a nodal model under SysTr (NOA7) can be seen in Figure A2-4 below.

Figure A2-4: Change in location of generation capacity between nodal and national market - SysTr (NOA7)



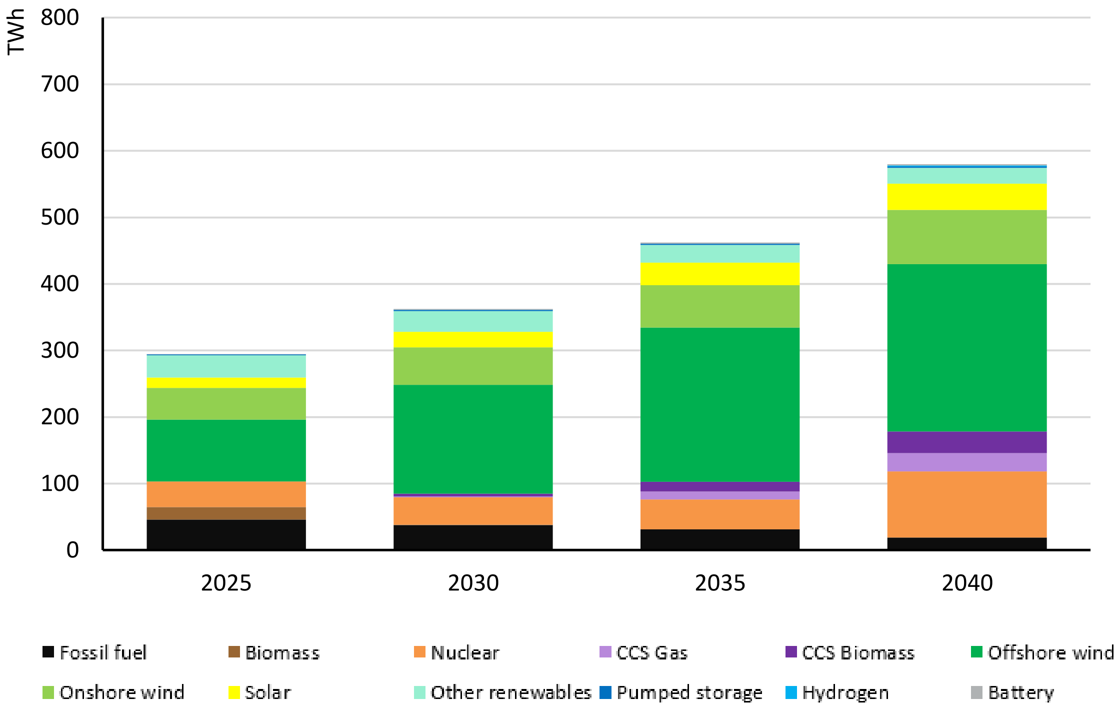
Source: FTI analysis

A2.12 The trends observed in Figure A2-4 above are in-line with those observed in both the evolution under zonal market designs for SysTr (NOA7), as well as the trends observed under the nodal market design in LtW (NOA7).

B. Generation

A2.13 As discussed in Section 6B, we also compare the despatched generation mix between market arrangements, for instance, Figure A2-5 below shows the despatched generation mix under SysTr (NOA7) under the national market.

Figure A2-5: Generation by technology under the status quo national market - SysTr (NOA7)

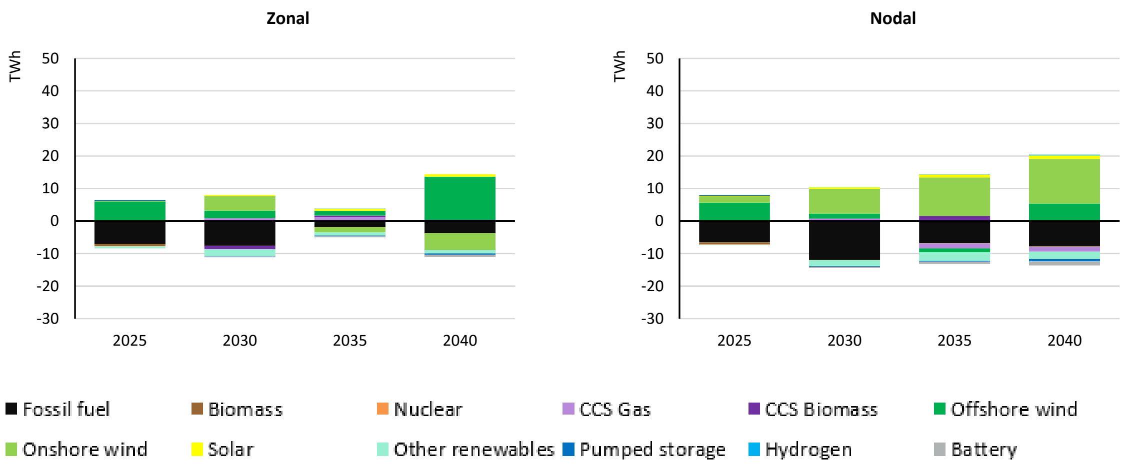


Source: FTI analysis

A2.14 The generation mix under SysTr (NOA7) broadly follows the evolution of the capacity mix. Specifically, we note lower overall levels of generation under SysTr (NOA7) relative to LtW (NOA7) due to less demand, and more generation by nuclear and CCS gas.

A2.15 Figure A2-6 below shows the expected change in the post-balancing generation mix when moving from the current market design to a zonal or nodal market design, on the left and right, respectively. As discussed previously, the ESO is not required to intervene in order to resolve congestion on the system under the nodal market design.

Figure A2-6: Changes in the zonal and nodal generation mix relative to the post-balancing national generation mix - SysTr (NOA7)



Source: FTI analysis

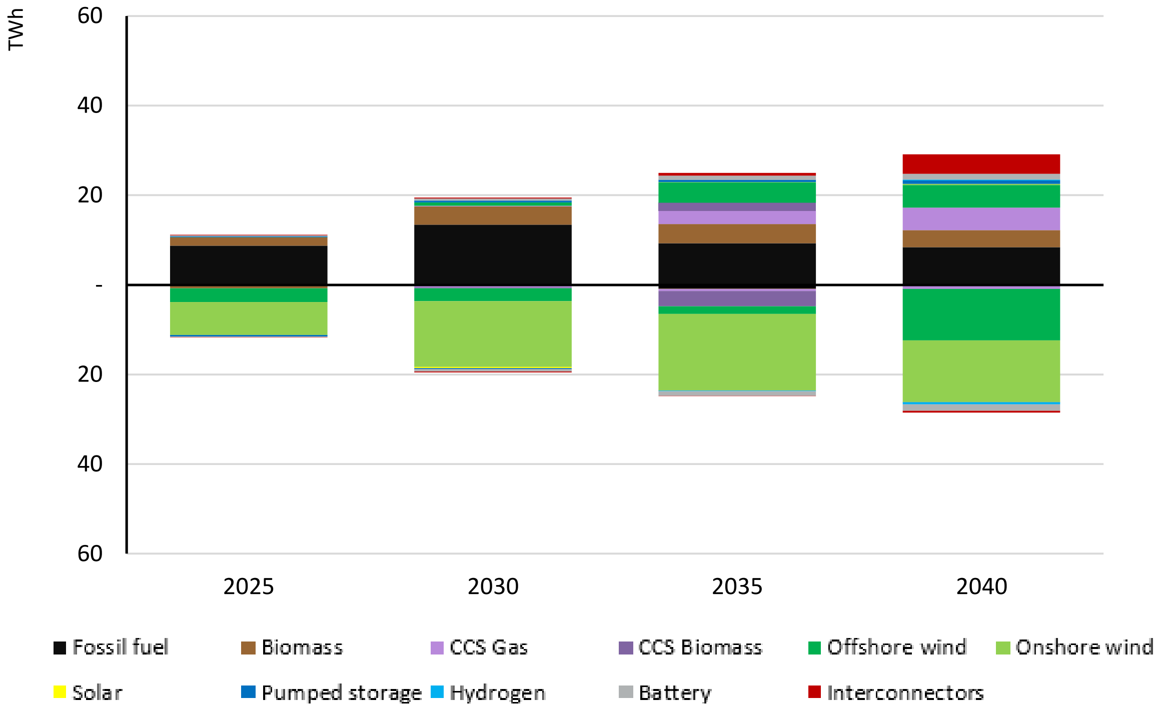
A2.16 The changes under SysTr (NOA7) roughly correspond to the trends observed under LtW (NOA7). Specifically, we see that transition to more locationally granular pricing results in reduced generation by fossil fuels due to the changes in the siting of intermittent renewable generators and two-way assets across GB.

A2.17 This is supported by the increase in wind generation observed across both the zonal and nodal market designs as shown in Figure A2-6 above.

C. Congestion impact

A2.18 As discussed in Chapter 4 and Section 6C, the national market design requires congestion management by the ESO in response to transmission constraints. Figure A2-7 below shows the evolution of constrained-on and off generation under the status quo national market for SysTr (NOA7).

Figure A2-7: Constrained generation under the national market - SysTr (NOA7)



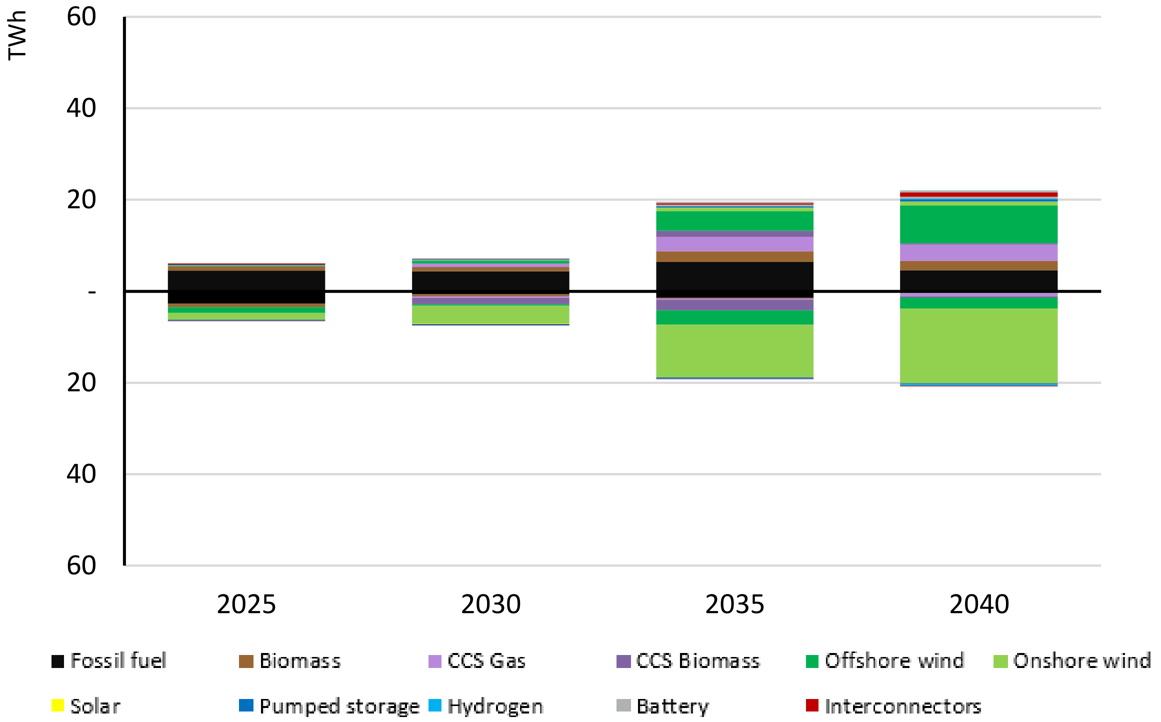
Source: FTI analysis

A2.19 The trends observed under SysTr (NOA7) closely follow those observed under LtW (NOA7), in that predominantly onshore and offshore wind are constrained off, whilst fossil fuel generators are constrained on.

A2.20 Fossil fuels are expected to retire later under SysTr (NOA7), which is one of the scenarios key differences to LtW (NOA7), and therefore fossil fuels can be flexed to manage congestion over the entire modelling period as opposed to just in the first decade. This results in less need for interconnectors to manage constraints in SysTr (NOA7).

A2.21 Similarly, constrained-on and -off generation under a zonal market for SysTr (NOA7) is shown in Figure A2-8 below, and as stated previously, we would expect to see lower constrained volumes under the zonal market design relative to the national market design due to the increased efficiency of price signals.

Figure A2-8: Constrained generation under zonal markets - SysTr (NOA7)



Source: FTI analysis

A2.22 The trends observed in the national model persist under a zonal market design with the increased need for constraint management across the modelling period, and a similar mix of technologies being constrained on or off, albeit at lower volume levels.

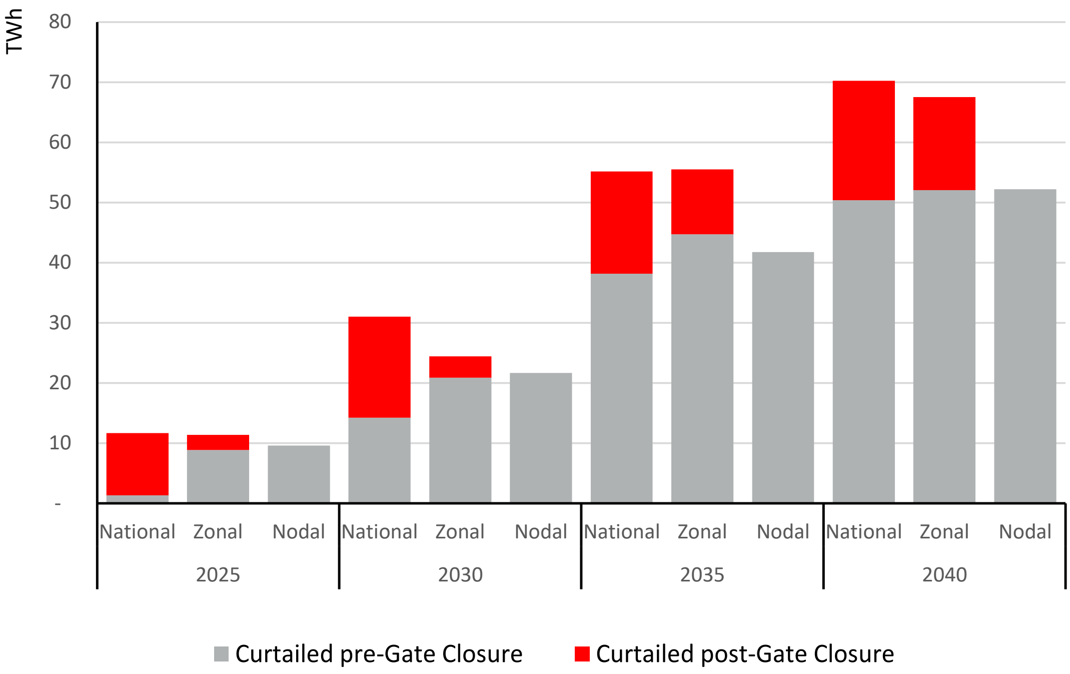
A2.23 Similar to our findings for LtW (NOA7), while the selected zonal boundaries appear to eliminate the majority of required redispatch actions in the early modelling years, increasing constrained volumes in the 2030s suggest that new intra-zonal boundaries emerge on the system over time, potentially necessitating re-zoning at regular intervals to ensure that the zonal wholesale market continued to reflect the physical network over time.

D. Curtailment

A2.24 As discussed previously, wind generation can be curtailed pre- and post-gate closure, and we would expect greater pre-gate curtailment under locationally granular pricing due to the increased visibility of transmission constraints under those market designs.

A2.25 In Figure A2-9 below, we present both forms of wind curtailment across all three market arrangements.

Figure A2-9: Wind curtailment - SysTr (NOA7)



Source: FTI analysis

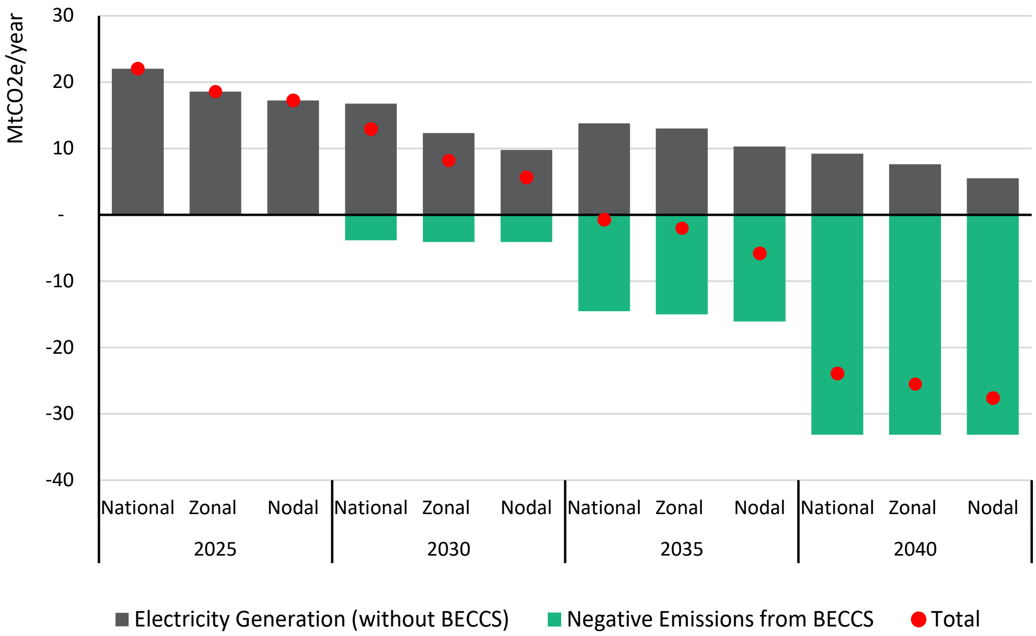
A2.26 As observed under LtW (NOA7), more locationally granular pricing results in more efficient utilisation of wind generation via reduced overall curtailment.

A2.27 The reduced proportion of wind generation under SysTr (NOA7) results in a significantly muted impact on curtailment from transition to zonal pricing, but a more perceptible decrease in overall curtailment from transitioning to a nodal market design. Over the 16-year modelling period, moving to nodal markets reduces wind curtailment by c.160 TWh, while zonal markets lead to a c.52 TWh reduction.

E. Emissions

A2.28 Figure A2-10 below compares the level of emissions under the three market designs under SysTr (NOA7).

Figure A2-10: Emissions from electricity generation - SysTr (NOA7)



Source: FTI analysis

A2.29 By design, SysTr (NOA7) is meant to achieve Net Zero by 2050, albeit at a slower pace than under LtW (NOA7). As a result, all three market design arrangements result in similar emission levels by 2040. The nodal market design is however still lower in emissions than the two less locationally granular market designs.

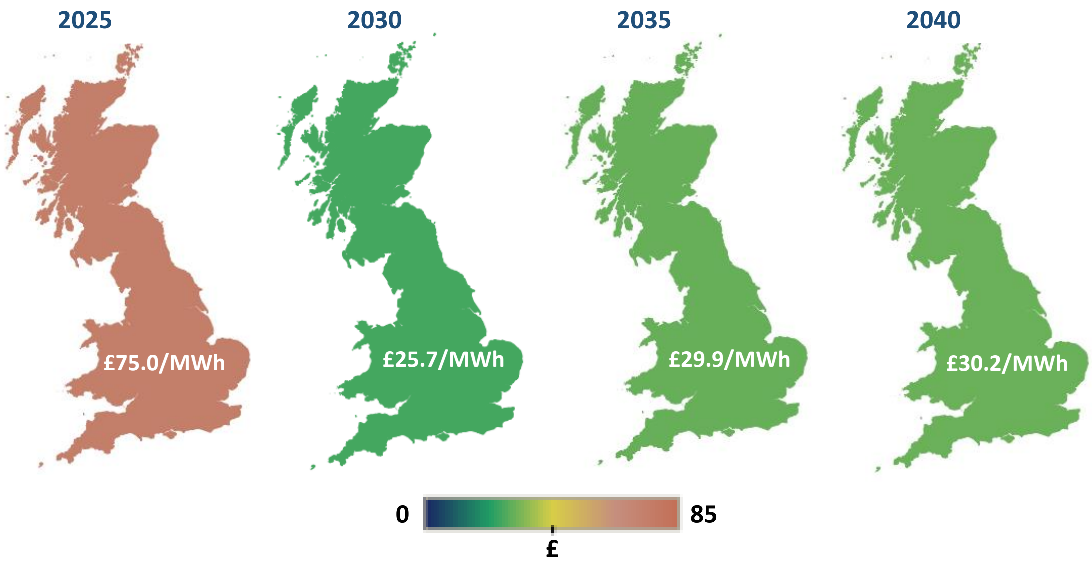
A2.30 This broadly follows the trend observed under LtW (NOA7) as zonal and nodal market designs reduce emissions to a greater extent in each modelling year relative to the national market design. This is due to more efficient siting of intermittent renewable generation and allows more locationally granular market designs to reach Net Zero targets earlier relative to the status quo.

F. Wholesale electricity price

A2.31 In this section we discuss the variation of time-weighted annual average wholesale electricity price across the modelled period, for the different market arrangements. This provides an indicator of longer-term price trends.

A2.32 Figure A2-11 below shows the variation in time-weighted average wholesale electricity price across the modelled period, for the national market arrangement.

Figure A2-11: Wholesale market price under national market – SysTr (NOA7)



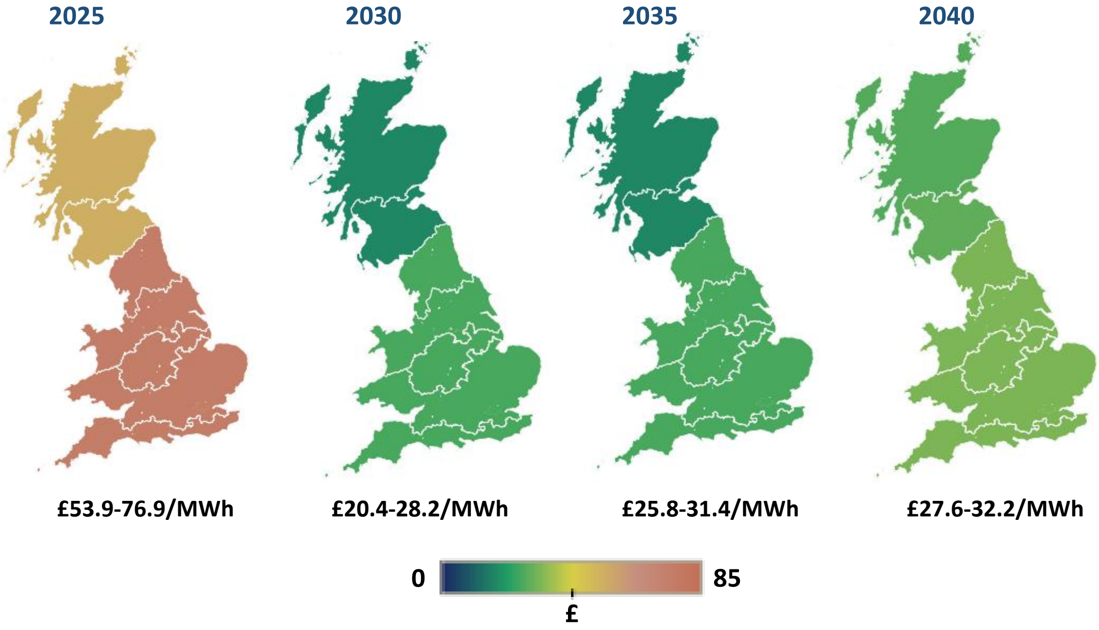
Source: FTI analysis

A2.33 As shown in Figure A2-11, wholesale price in the national market falls from £75.0 per MWh in 2025 to £25.7 per MWh in 2030, displaying the same trend as that seen in LtW (NOA7). This is largely due to the assumed fall in the gas price, and also due to an increase in renewable generation. From 2035 onwards the wholesale price increases gradually, to £29.9 per MWh in 2035 and £30.2 per MWh in 2040. This gradual increase in prices is partly due to increased electricity demand and an assumed increase in the carbon price, as explained further in Section 7A.

A2.34 In 2040, under SysTr (NOA7), the 2040 annual average wholesale price is significantly lower than under LtW (NOA7) which in contrast has an annual average price of £50.9 per MWh. This is due to the total demand in GB being lower under SysTr (NOA7), because of lower electrification of transport, heating and industrial processes.

A2.35 A similar trend in wholesale price evolution is seen under the zonal market arrangement. Prices decrease significantly in 2030, before steadily increasing again in later years. This can be seen in Figure A2-12 below.

Figure A2-12: Wholesale market price under zonal market - SysTr (NOA7)



Source: FTI analysis

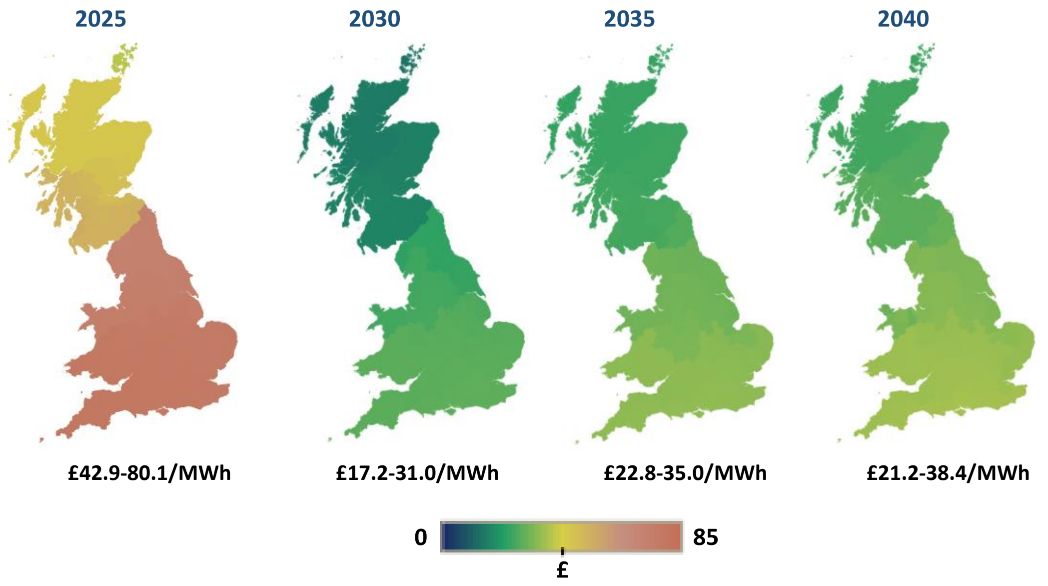
A2.36 As shown in Figure A2-12, wholesale price in zones GB1 and GB2 are expected to be lower than the national average price shown in Figure A2-11 across the modelled period, whereas zones GB3-GB7 are expected to have slightly higher prices than the average.

A2.37 Average annual zonal prices in GB1 are expected to be the same as in GB2 in 2025 and 2030, before diverging in later years as wind capacity in GB1 increases. For zones in England and Wales, from 2030 onwards average prices in GB4 are the same as in GB5, and average prices in GB6 are the same as in GB7. This result is largely due to re-siting of capacity which reduces the price differential between zones.

A2.38 Price spreads across GB converge in later years, due to new large-scale transmission projects coming online and re-siting of generation to more southern zones. This follows a similar trend to LtW (NOA7), except with lower prices due to lower total demand.

A2.39 The evolution of wholesale price under a nodal market is similar to under zonal, as shown in Figure A2-13. The trend is similar to that seen for LtW (NOA7), apart from the lower prices in 2040, as discussed above.

Figure A2-13: Wholesale market price under nodal market - SysTr (NOA7)



Source: FTI analysis

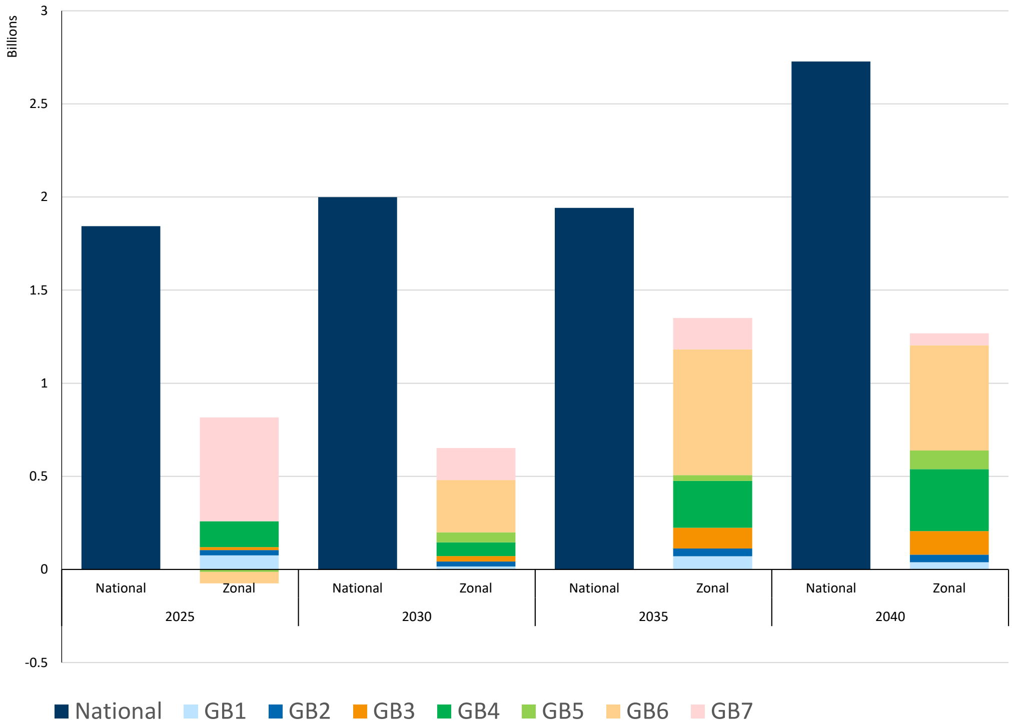
A2.40 Under a nodal market, there is a larger spread of prices in each year and no two zones have the same annual average price, as all transmission boundaries and losses on all lines contribute to the determination of the wholesale market price.

A2.41 As seen in LtW (NOA7), in 2025 and 2030, B6 is expected to be the main transmission boundary, but new boundaries emerge in later years (for example, across the Midlands and in Northern Scotland).

G. Congestion cost

A2.42 Our modelling allows us to assess congestion costs under SysTr (NOA7) for both the national and zonal market arrangements, similar to our assessments for LtW (NOA7) and LtW (HND). This is shown in Figure A2-14 below.

Figure A2-14: Constraint costs under national and zonal market arrangements - SysTr (NOA7)



Source: FTI analysis

A2.43 Forecasts of congestion costs broadly follow the forecasts of congestion volumes. As seen for our assessment under LtW (NOA7), congestion costs are higher under the national market design than under the zonal market design, as the zonal wholesale electricity price now incorporates transmission constraints along the zonal boundary lines. Notably, congestion costs are also lower under SysTr (NOA7) than under LtW (NOA7), due to the differences in demand profiles, as well as capacity and generation profiles.

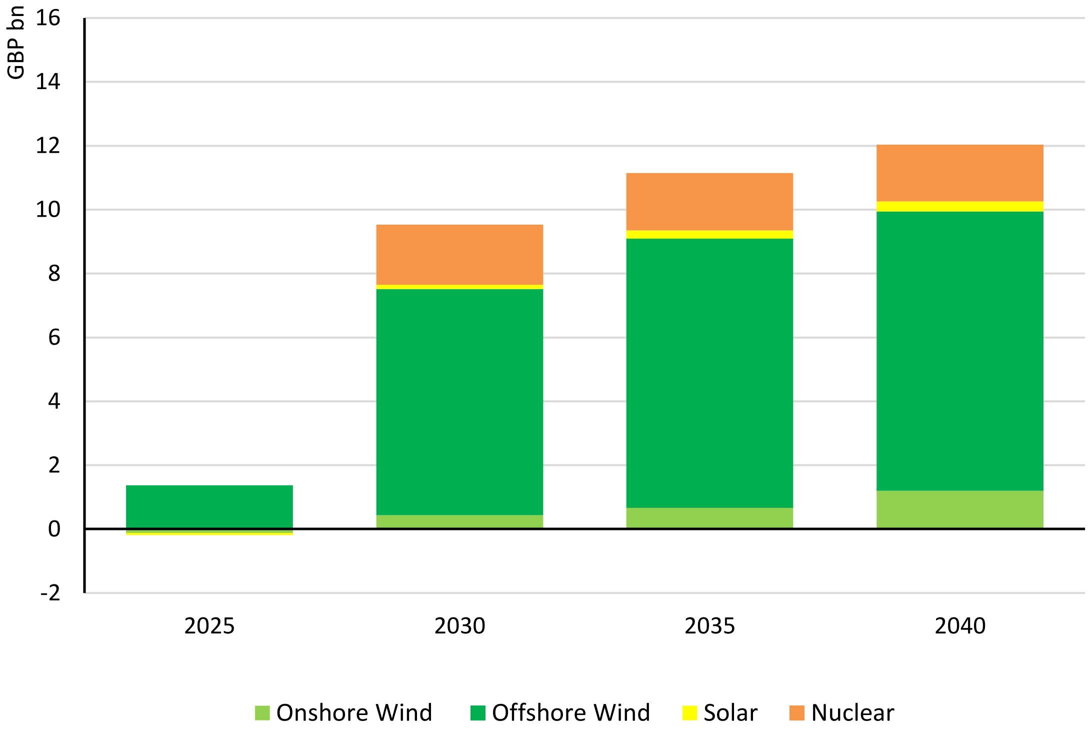
A2.44 Under the national market design, this allows us to observe the distinct increase in congestion costs in 2040, caused by the increased need to flex interconnectors in order to manage constraints, as fossil fuels begin to get phased out to allow GB to achieve Net Zero by 2050 under this FES scenario.

A2.45 As addressed previously in our assessment of zonal market designs, we observe a distinct increase in congestion costs partway through the modelling period, which indicates that the boundaries used to delineate the zones across GB are effective at initially reducing constraints. However, over-time, the main congestion boundaries move within zones as opposed to between zones. In order to combat this, the system would need to be periodically reviewed and re-zoned. Our discussion of the underlying drivers of the estimates can be found in Sections 5D and 7B.

H. CfD support payments

A2.46 Figure A2-15 below shows CfD payments under a national market. CfD payments are fundamentally linked to the prevailing wholesale price in each hour – specifically, when wholesale price is lower than the agreed CfD strike price, producers will be compensated by consumers. CfD support payments therefore give an indication of how much certain generators will benefit from a given market arrangement.

Figure A2-15: CfD support payments under the national market - SysTr (NOA7)



Source: FTI analysis

A2.47 It is clear from Figure A2-15 that under a national market design, there would be significant CfD support payments from consumers to producers under SysTr (NOA7) (indicated by the positive value of CfD support payments across the modelled period).

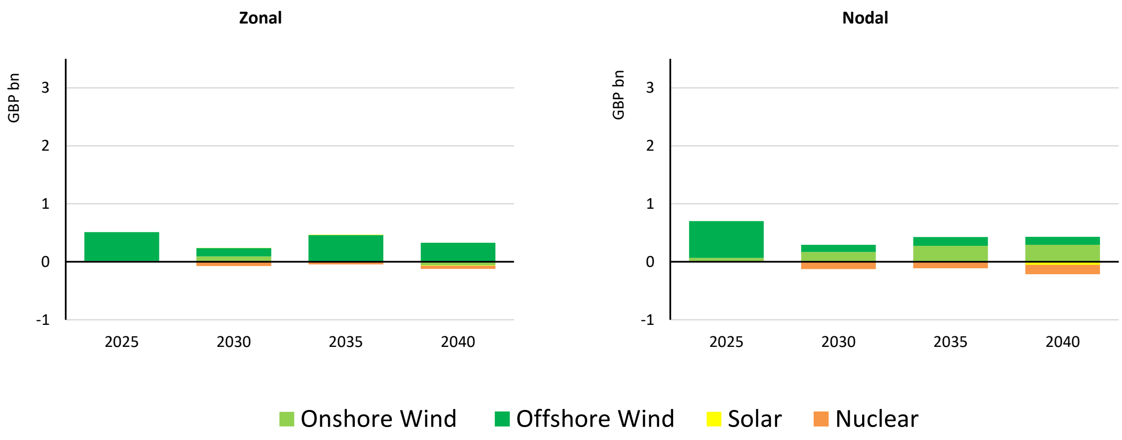
A2.48 As seen in LtW (NOA7), offshore wind generators receive the majority of payments, for the reasons described in Section 7C. Onshore and solar generators receive smaller amounts of payments, and nuclear support payments begin in 2030 with the commissioning of Hinckley Point C.

A2.49 Under SysTr (NOA7), CfD support payments increase from 2025-2040. The significant increase in the 2030s is driven by a fall in average wholesale prices, as seen in LtW (NOA7). The overall increase in payments is less significant under SysTr (NOA7), as this scenario is characterised by a smaller reliance on renewables than LtW (NOA7). In particular, this means a lower reliance on offshore wind in 2030 and 2035, and therefore a smaller magnitude of support payments for these generators.

A2.50 However, under SysTr (NOA7) CfD support payments remain high into 2040, unlike in LtW (NOA7) where they reduce in this year. This is because SysTr (NOA7) is characterised by lower wholesale prices in 2040, due to a lower total GB demand profile.

A2.51 Figure A2-16 shows CfD support payments under zonal and nodal market arrangements compared to a national market arrangement.

Figure A2-16: Changes in CfD support payments under zonal and nodal relative to a national market - SysTr (NOA7)



Source: FTI analysis

A2.52 Figure A2-16 shows that under nodal and zonal market arrangements, CfD payments to offshore wind generators increase. However, particularly in later years, this increase is less than that seen under the LtW (NOA7) scenario. This is because of the greater renewable rollout under LtW (NOA7), and in particular greater offshore wind capacity.

A2.53 In terms of other forms of generation, trends under SysTr (NOA7) are similar to those observed in LtW (NOA7) (explained further in Section 7C). In particular, this relates to:

- solar CfD support payments increasing only slightly under zonal and decreasing under nodal;
- support payments to Hinkley Point C decreasing due to an increase in wholesale price at Hinkley Point C's zone and node.

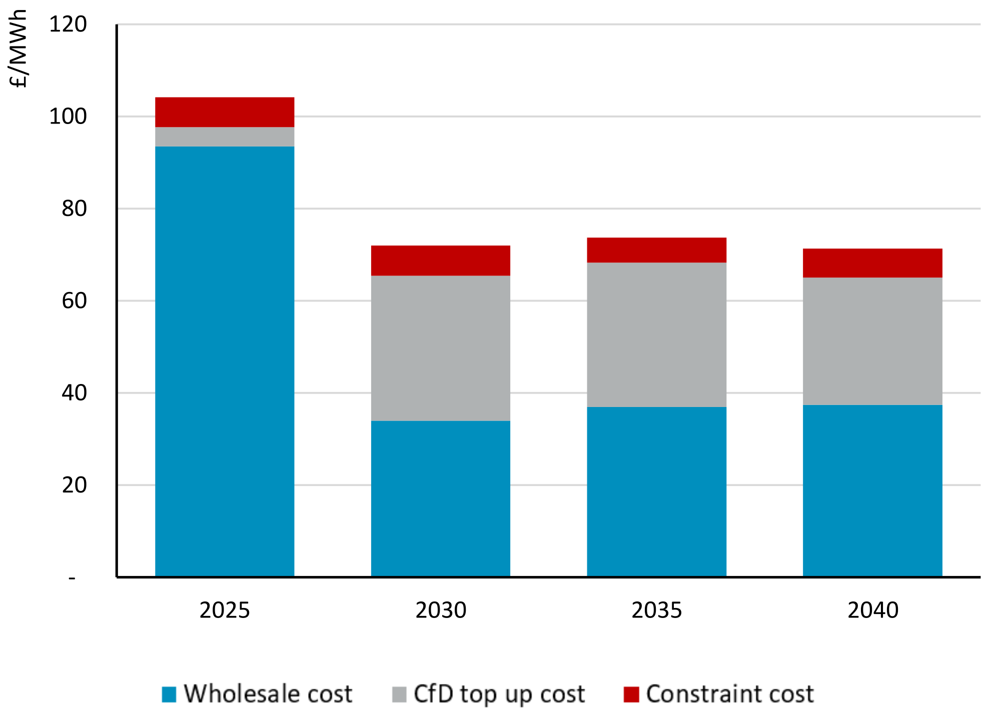
A2.54 The smaller reliance on renewables in the SysTr (NOA7) scenario compared to LtW (NOA7) causes the difference between CfD payments under zonal and nodal pricing compared to national to be smaller under SysTr (NOA7).

I. Total electricity cost

A2.55 As assessed for the LtW (NOA7) scenario, adding up wholesale costs, congestion costs and CfD support payments allows us to estimate the actual variable cost of electricity generated on the system, in order to therefore understand how much consumers are paying under different FES scenarios and market arrangements.

A2.56 We do this firstly by assessing the cost under the national market design in Figure A2-17 below followed by the cost under the zonal and nodal market designs, respectively, in Figure A2-18.

Figure A2-17: Total variable cost of electricity - SysTr (NOA7)



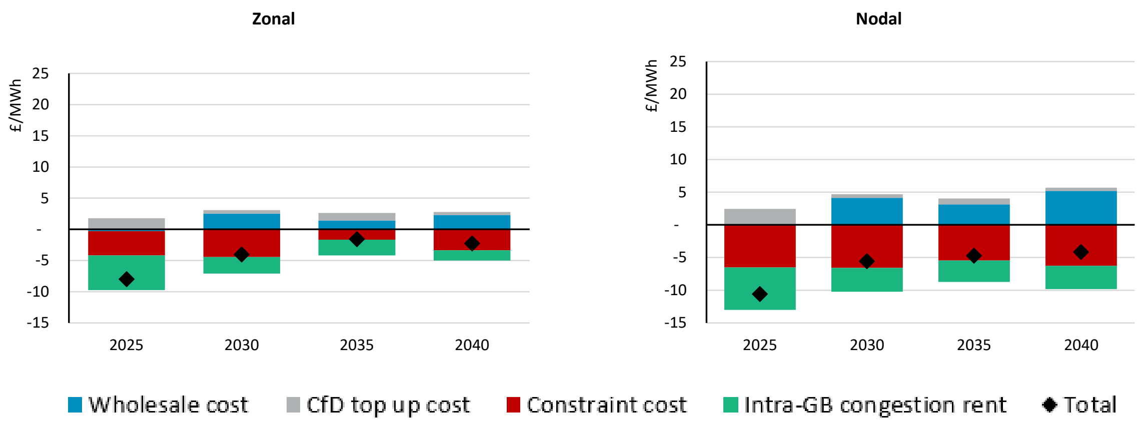
Source: FTI analysis

A2.57 The trends observed under SysTr (NOA7) are broadly in line with those observed under LtW (NOA7), in that wholesale cost makes up the majority of variable cost across the modelling period. Notably, the proportion of variable cost that is made up of CfD support payment cost increases significantly from 2030 onwards, due to the expected increase in the share of generation with CfD contracts from then onwards.

A2.58 Additionally, the difference between the wholesale prices observed in those periods relative to the strike prices results in an increase in the excepted CfD support payments and therefore in the proportion of the variable cost that is made up of CfD support payments. Constraint costs make up c.8% of the annual cost per MWh over the entire modelling period.

A2.59 All of the components of total electricity costs change under the zonal and nodal market arrangements, as described in the previous three sections of the chapter and as seen in Figure A2-18 below.

Figure A2-18: Changes in the total variable costs of electricity under zonal and nodal markets - SysTr (NOA7)



Source: FTI analysis

A2.60 The change in total variable electricity costs under locational pricing is similar for the SysTr (NOA7) and LtW (NOA7) scenarios (explained further in Section 7D). This has the following key features:

- reduced constraint costs;
- increasing wholesale costs;
- increased CfD payments; and
- additional intra-GB congestion rents which reduce total costs to the consumer.

A2.61 This results in reduced total variable electricity costs across for all years across the modelled period, under both zonal and nodal market arrangements.

A2.62 As the changes to constraint costs and intra-GB congestion rents are less significant under SysTr (NOA7) than under LtW (NOA7), the overall reduction in total variable electricity costs from moving towards locational pricing is smaller for SysTr (NOA7).

J. Producer impact

A2.63 As stated in Section 7E moving to nodal or zonal prices will impact producers through:

- wholesale prices impacting revenues in the wholesale market.
- a reduction in congestion costs reducing revenues in the BM; and
- CfD payments, which depend on wholesale and strike prices, as well as generation volumes.

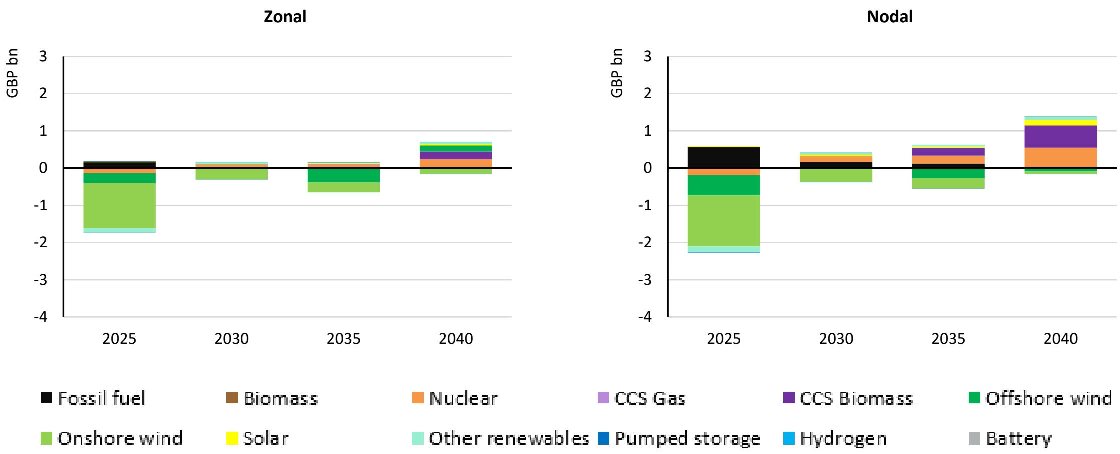
A2.64 We look at the effect of each of these components individually and in aggregate to understand the full extent of the effect on producers.

Wholesale market

A2.65 As explained in Section 7E, generators will receive different revenues through the wholesale market under more locationally granular pricing, due to differences in both prices received and the volume of generation.

A2.66 Figure A2-19 below shows the change in producer surplus in the wholesale market under zonal and nodal market designs.

Figure A2-19: Change in producer surplus on the wholesale market by technology - SysTr (NOA7)



Source : FTI analysis

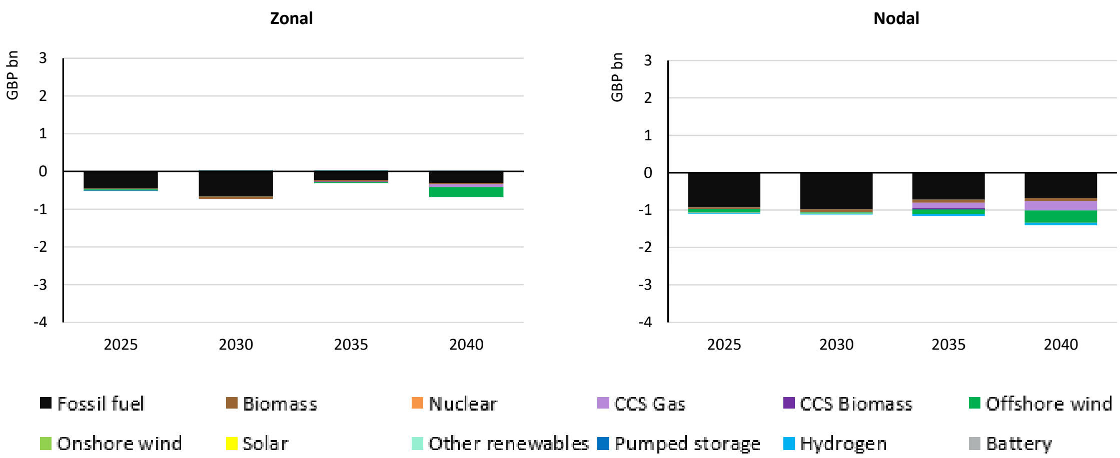
A2.67 Figure A2-19 above shows that wholesale market producer surplus decreases for onshore and offshore wind generators under a move to more locationally granular pricing. This is because these technologies site primarily in locations where wholesale prices fall relative to the national market. Additionally, as outlined in Section B of this appendix, generation volumes increase for onshore and offshore wind under zonal and nodal market models. This implies that the fall in prices outweighs the increase in generation volumes.

A2.68 Conversely, nuclear and CCS biomass generators site primarily in locations where wholesale prices rise, so wholesale market producer surplus increases for these technologies.

Balancing mechanism

A2.69 BM revenues in the SysTr (NOA7) scenario decrease under more locationally granular pricing, due to the decreased need to constrain generation either on or off via the BM under both zonal and nodal markets. Figure A2-20 below shows the change in producer surplus from the balancing mechanism, by technology, under zonal and nodal market arrangements.

Figure A2-20: Change in producer surplus from the BM - SysTr (NOA7)



Source: FTI analysis

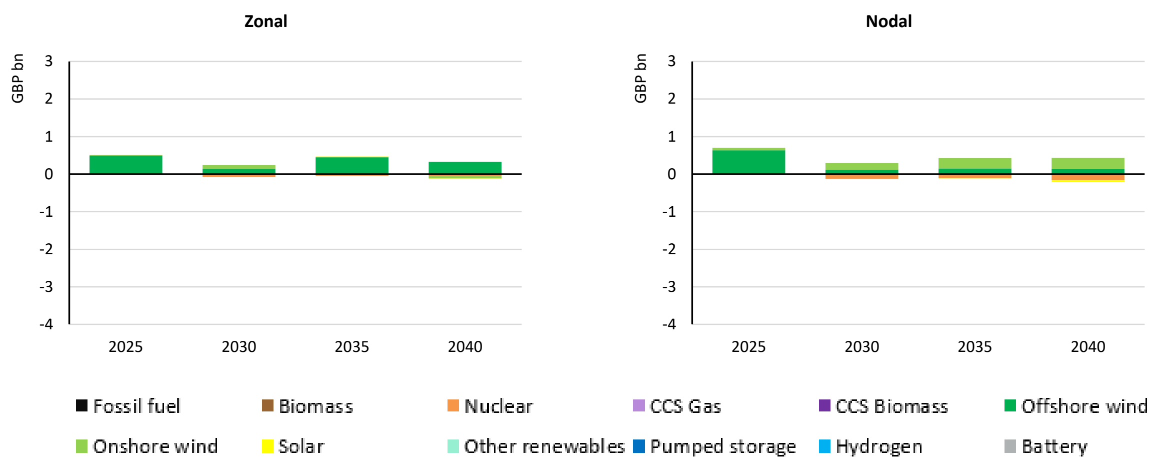
A2.70 Changes in producer surplus arising from the BM primarily affect fossil fuel generators, as is the case under LtW (NOA7). This impact persists throughout the modelling period because under the SysTr (NOA7) scenario fossil fuel generators are online for longer than under LtW (NOA7) and therefore face lost BM revenues in all years modelled.

A2.71 CCS gas is also a key technology under SysTr (NOA7) and is constrained-on under the national and zonal market models. Therefore, it faces reduced BM revenues for the same reasons as fossil fuels. Similar to the behaviour observed under LtW (NOA7), offshore wind receives constrained-off payments under a national and zonal market model, resulting in lost BM revenue for offshore wind generators under more locationally granular pricing.

CfD support payments

A2.72 CfD support payments change under locational pricing due to changes in the wholesale price and in the generation mix. Changes in wholesale prices result in changes in the CfD payment per MWh, therefore changing the aggregate CfD payments made to the CfD contract holder. Figure A2-21 below shows the changes to producer surplus from CfD payments, by technology, under a change to a zonal and nodal pricing model.

Figure A2-21: Change in CfD support payments - SysTr (NOA7)



Source: FTI analysis

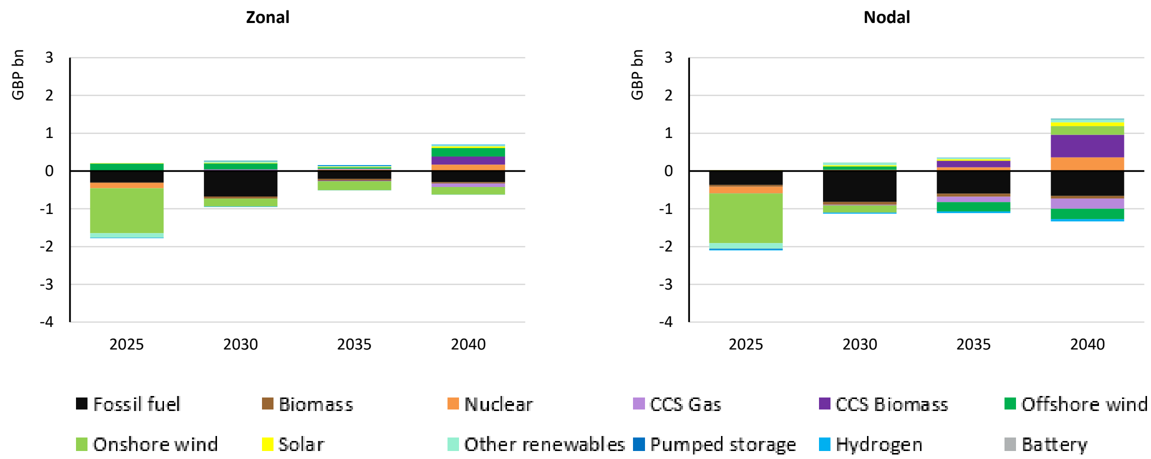
A2.73 Changes in CfD payments mirror the changes in wholesale market producer surplus for technologies with CfD contracts, as is the case under LtW (NOA7). Offshore wind generators receive an increase in CfD support payments to compensate them for the fall in revenue in the wholesale market.

A2.74 Under SysTr (NOA7), there is less offshore wind capacity, relative to LtW (NOA7). Therefore, the reduction in wholesale producer surplus, and corresponding increase in CfD payments, is smaller under SysTr (NOA7).

Overall impact on generators

A2.75 As discussed above, the overall change in producer surplus under a zonal or nodal market model accounts for changes in producer surplus in both the wholesale and balancing market, as well as changes in CfD payments. Figure A2-22 below shows the overall impact by technology for each year modelled.

Figure A2-22: Change in total producer surplus – SysTr (NOA7)



Source: FTI analysis

A2.76 As is the case under LtW (NOA7), the most significant effect is on fossil fuel generators, who see a reduction in their overall producer surplus under a more locationally granular pricing model in all years modelled. This is almost exclusively due to the loss of BM revenues from constrained-on payments.

A2.77 Although offshore wind generators see a reduction in wholesale market revenues, particularly in 2040, this reduction is reversed by the CfD payments that they receive. Non-CfD onshore wind generators do not receive higher CfD payments to replace the lost wholesale market revenues, so face a significant decrease in their producer surplus in 2025.

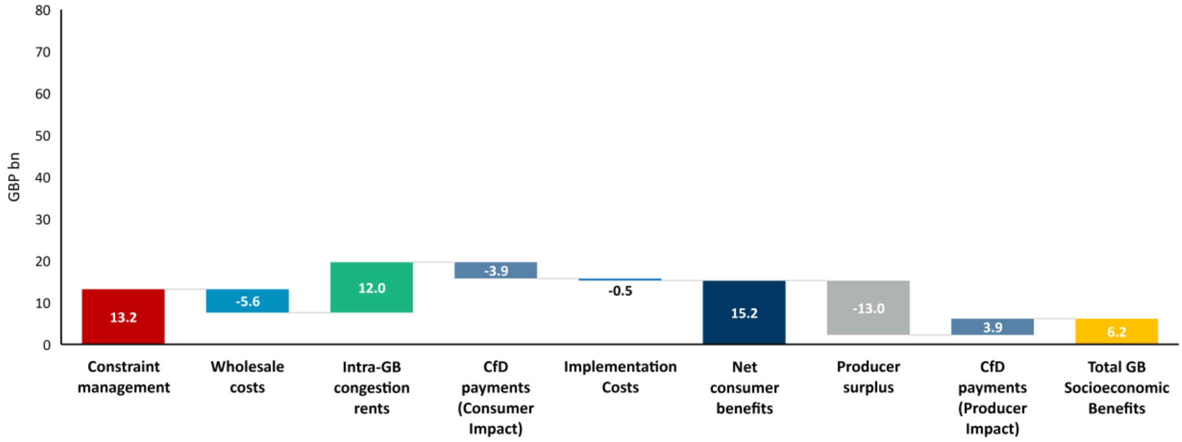
K. CBA results

A2.78 Our overall assessment of impact indicates that there are both consumer benefits and socioeconomic welfare benefits from transitioning to more locationally granular pricing under the SysTr (NOA7) FES scenario. In line with our assessment for LtW (NOA7), benefits are far greater from transitioning to the nodal system relative to transitioning to the zonal system.

Overall impact of locational pricing

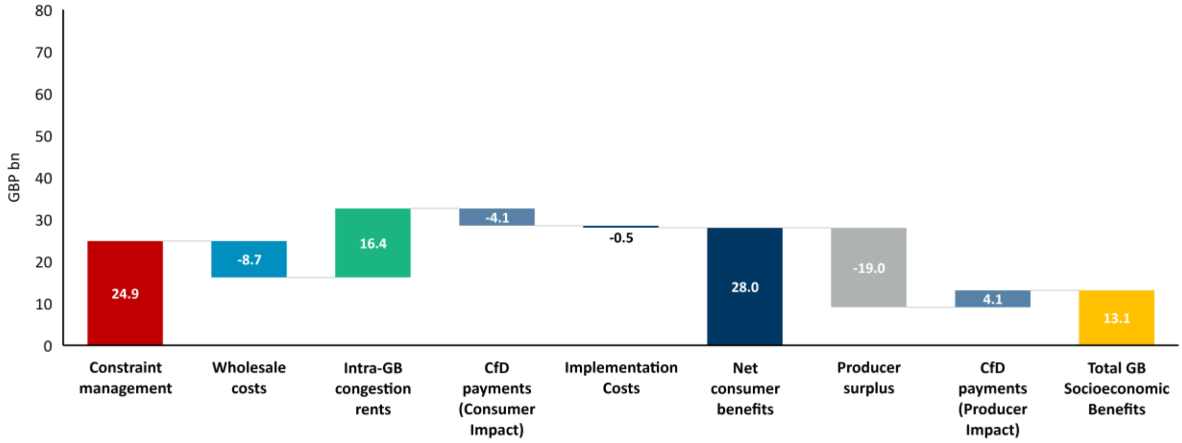
A2.79 Figure A2-23 and Figure A2-24 below show the breakdown of consumer benefits and overall socioeconomic welfare for both zonal and nodal market arrangements in the SysTr (NOA7) scenario.

Figure A2-23: Overall cost benefit assessment for Zonal SysTr (NOA7) relative to National SysTr (NOA7) – 2025-2040



Source: FTI analysis

Figure A2-24: Overall cost benefit assessment for Nodal SysTr (NOA7) (relative to National SysTr (NOA7)) – 2025-2040



Source: FTI analysis

A2.80 As shown in the above figures, our analysis shows that transition to a zonal market produces a net consumer benefit of £15bn and socioeconomic benefits of £6bn whilst transitioning to a nodal market produces a higher net consumer benefit of £28bn and socioeconomic benefits of £13bn.

A2.81 In both the zonal and nodal cases, overall consumer benefits are driven primarily by benefits from reduced constraint management costs and increased intra-GB congestion rent, and reduced by higher wholescale cost and larger CfD support payments.

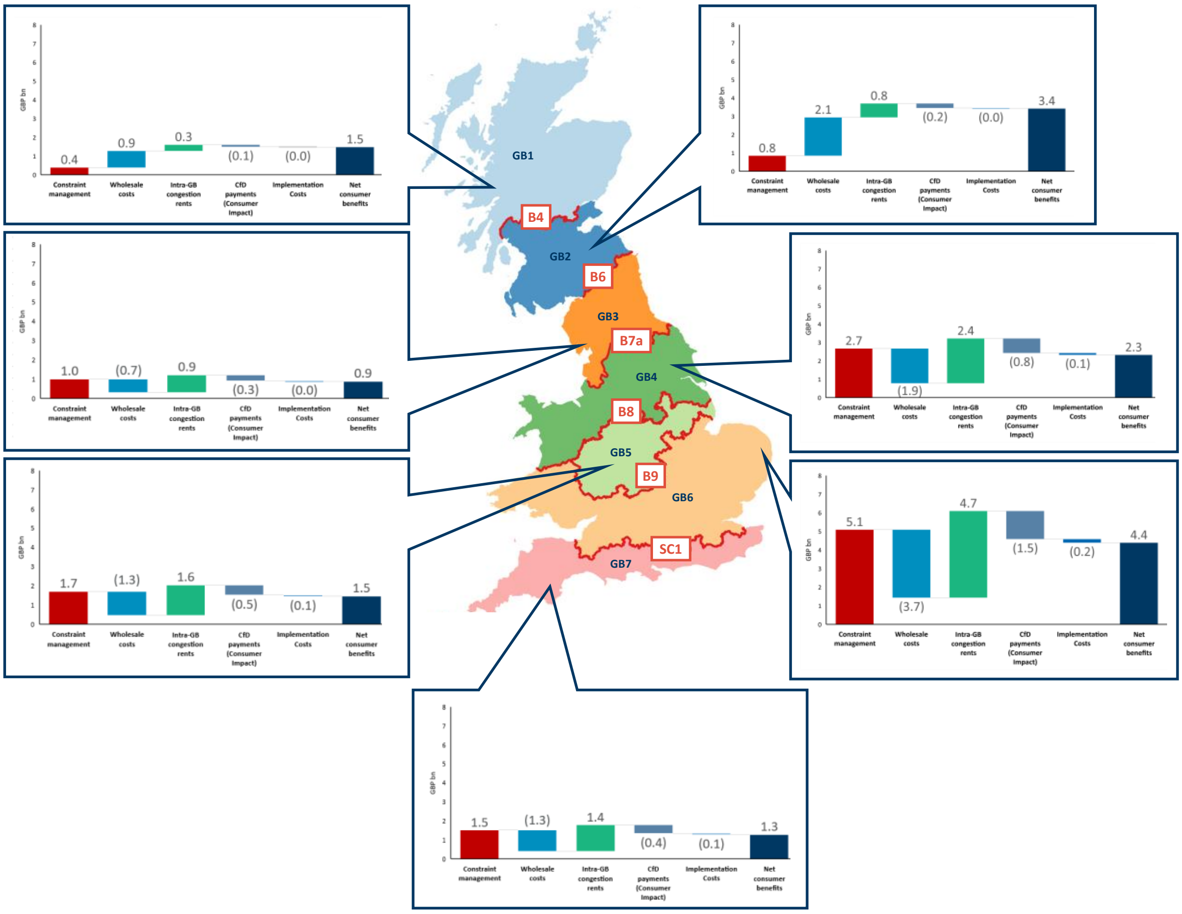
A2.82 Our overall assessment is based on several conservative assumptions which could increase consumer benefits and socioeconomic welfare. These assumptions are the same as those detailed in Section 9A.

Regional impact of locational pricing

A2.83 As discussed in Section 9B the overall consumer benefits can be disaggregated into the seven designated zones across GB to estimate the benefits to consumers in different parts of GB.

A2.84 We show the distribution of benefits (and costs) borne by consumers as a consequence of transitioning to a zonal pricing regime in Figure A2-25 below. This equivalent to a disaggregated version of Figure A2-23.

Figure A2-25: Distribution of consumer benefits from transitioning to a zonal pricing regime - SysTr (NOA7)



Source: FTI analysis

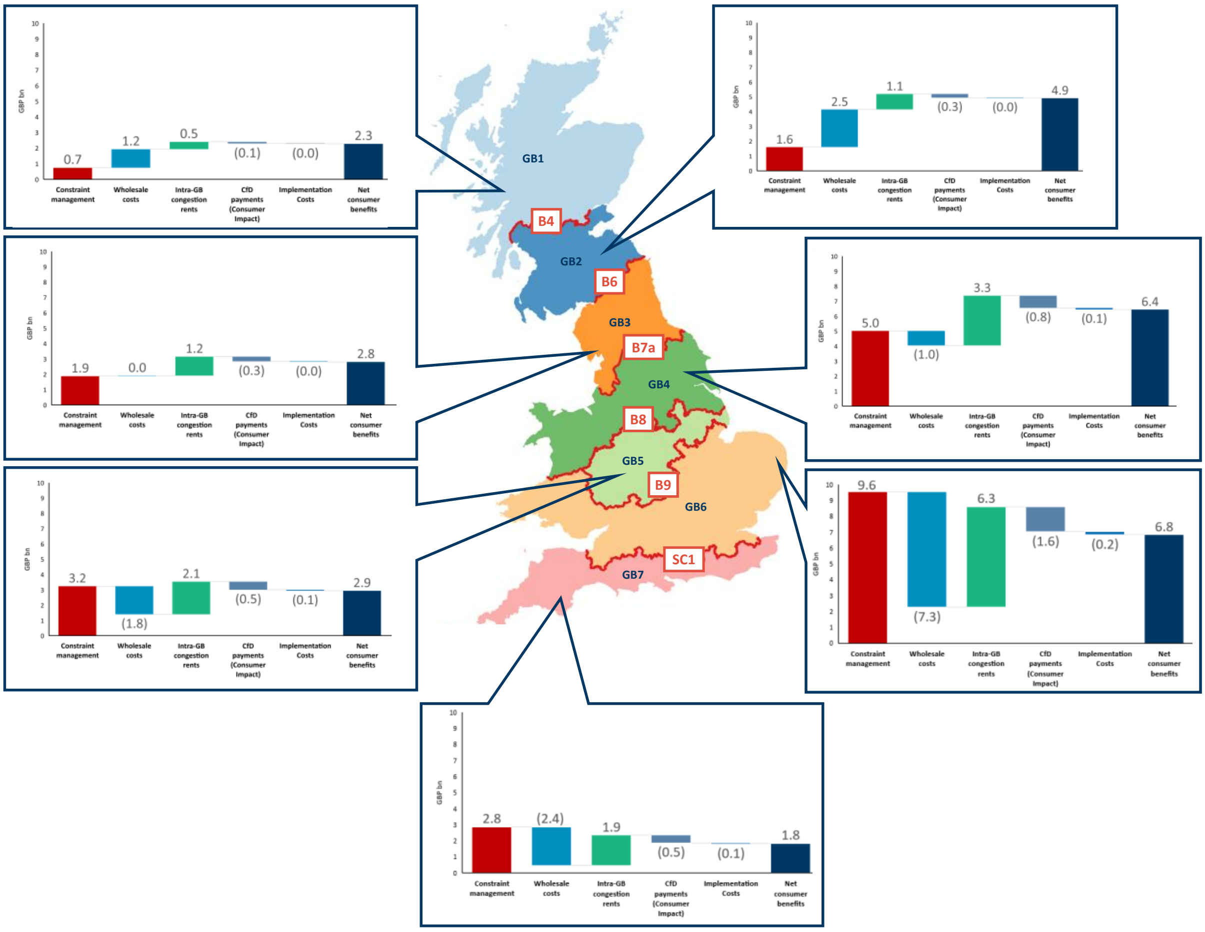
A2.85 As shown in Figure A2-25 above, consumers across all seven zones benefit from transitioning to zonal pricing. The extent to which they benefit varies as a result of the wholesale price and consumer load across the respective zones.

A2.86 The distribution of benefits aligns to the distribution observed under LtW (NOA7), specifically:

- all zones benefit from a reduction in constraint management, particularly in zones with high consumer load. However, this reduction is by a lesser amount than under LtW (NOA7);
- wholesale prices reduce under zonal pricing for Scottish zones (GB1 and GB2) resulting in lower costs to consumers, but increase for zones in England and Wales, resulting in greater costs to consumers. Again, these changes are of smaller magnitude than under LtW (NOA7); and
- CfD support payments paid by consumers increase across all zones in GB, but by a smaller magnitude than under LtW (NOA7).

We conduct similar analysis for the distribution of benefits and costs of transitioning to a nodal pricing regime. This is shown in Figure A2-26 below, aggregated into the relevant zone in which the node is located.

Figure A2-26: Distribution of consumer benefits from transitioning to a nodal pricing regime - SysTr (NOA7)



Source: FTI analysis

A2.87 As shown in the figure above, consumers across all zones benefit from a transition to nodal pricing, to a larger extent than from a transition to zonal pricing. The magnitude of these benefits depends on wholesale price and consumer load in the respective zone.

A2.88 Similar to the zonal case, the magnitude of distributional benefits is smaller under SysTr (NOA7) than under LtW (NOA7), particularly for zones with high consumer load (GB4 and GB6). This reflects the overall lower consumer benefit of SysTr (NOA7) compared to LtW (NOA7).

Appendix 3 Leading the Way (HND) modelling results

A3.1 This appendix sets out our detailed analysis and results for the Leading the Way (HND) scenario which is based on the network assumptions set out in the ESO's NOA7 Refresh plan (which includes the HND network build profiles).

A3.2 We set out the following outcomes:

- Capacity and generation outcomes, including the:
  - capacity mix and its different location under the three modelled market arrangements (**Section A**);
  - generation mix on the wholesale market (**Section B**);
  - constrained-on and off generation in the BM (**Section C**);
  - curtailment of renewable generation (**Section D**); and
  - emissions associated with the generation mix (**Section E**).
- Pricing and financial outcomes, including the:
  - change in wholesale electricity prices and cost faced by GB consumers (**Section F**);
  - reduction in the cost of congestion management (**Section G**);
  - changes in CfD payments from consumers (**Section H**);
  - total electricity cost for GB consumers which includes intra-GB congestion rents (**Section I**); and
  - changes in producer surplus on the wholesale and balancing mechanism (**Section J**).

A3.3 We then summarise the key results of the CBA in **Section K**.

A. Capacity

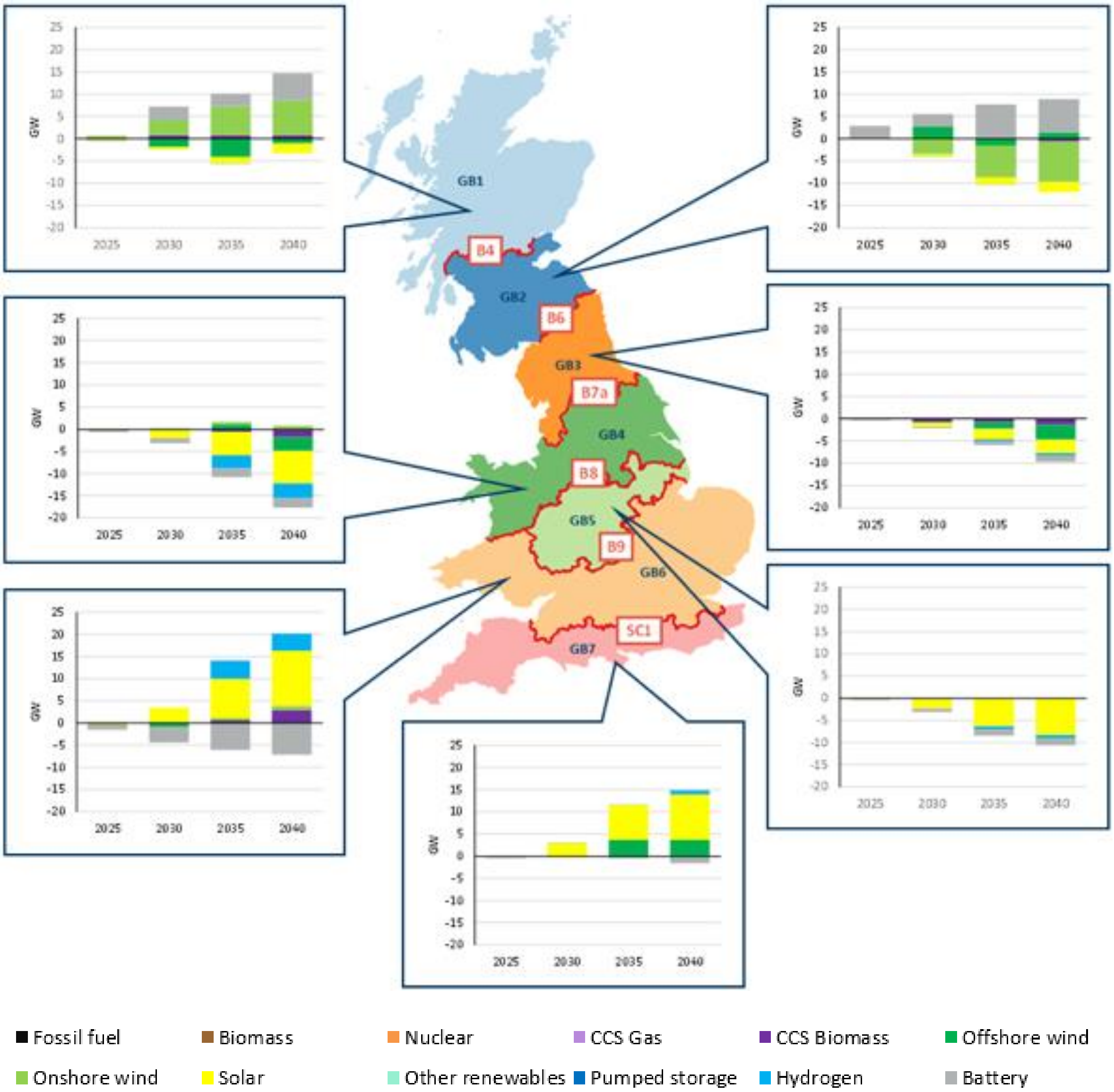
A3.4 Aggregate GB installed capacity under Leading the Way HND ("LtW (HND)") is the same as under Leading the Way NOA7 ("LtW (NOA7)") and was kept fixed under the different market arrangements, with the only difference between these scenarios relating to the transmission capacity across GB.

A3.5 As stated previously for LtW (NOA7), the siting of existing and new generators under the national market (i.e., the current market design) is fixed in each year to the relevant FES scenario, based on a detailed confidential dataset provided by the ESO. This is the same for LtW (HND) as under LtW (NOA7) and is shown in Section 6A.

A3.6 Siting of new generation assets was reoptimised by Plexos under zonal and nodal market arrangements, as described in Chapter 5. This siting differs from the siting under LtW (NOA7) due to the changes in price caused by different transmission capacities across GB.

A3.7 The change in capacity in each zone as a result of moving from the current wholesale market design to a zonal model under LtW (HND) can be seen in Figure A3-1 below.

Figure A3-1: Change in location of generation capacity between zonal and national market – LtW (HND)



Source: FTI analysis

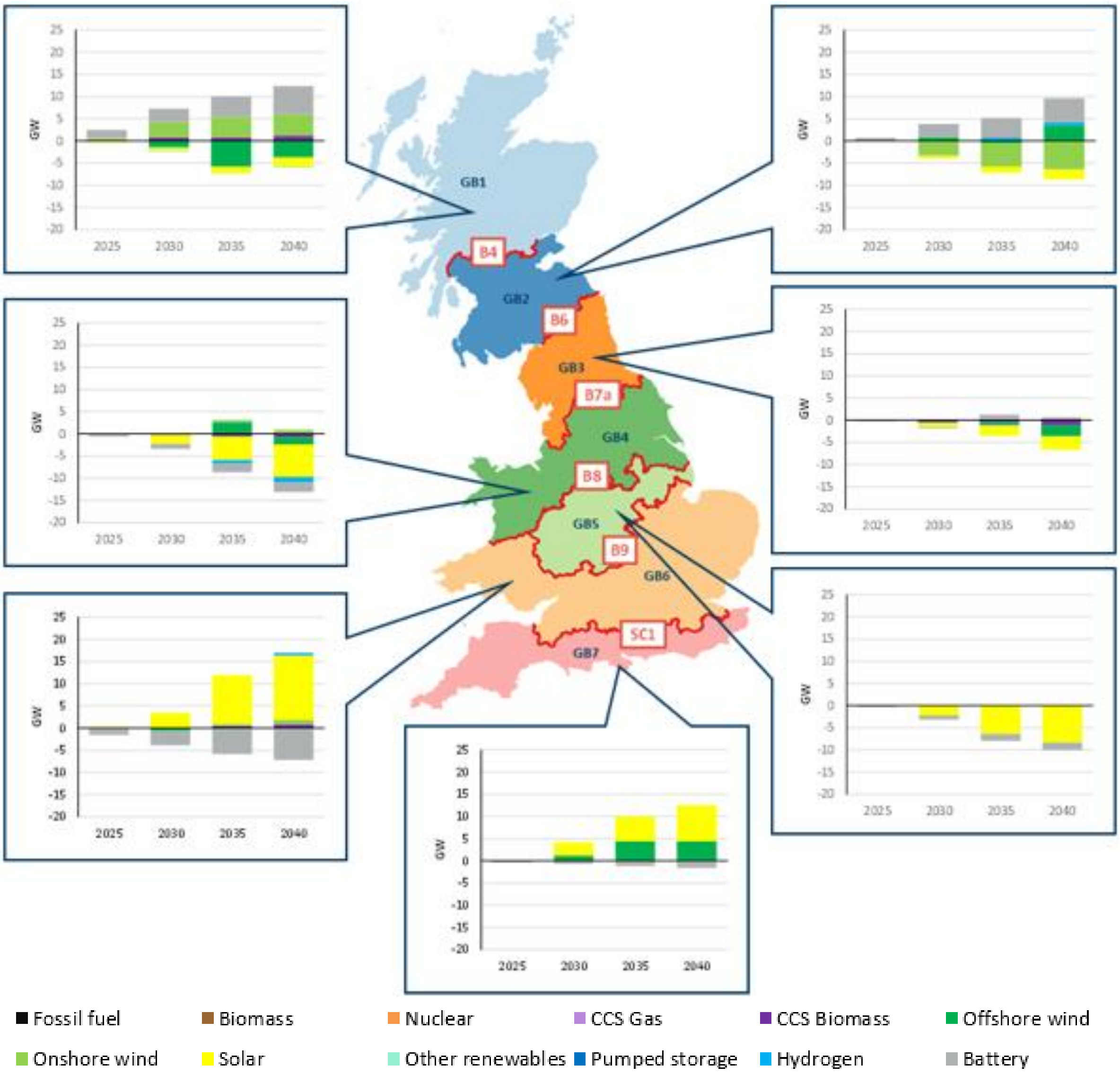
A3.8 The differences in re-siting observed between the zonal and national market arrangements for LtW (HND) are broadly in-line with the differences observed across the same market arrangements for LtW (NOA7). Specifically:

- solar capacity is expected to relocate to southern zones;
- onshore wind capacity is expected to relocate away from the south of Scotland (GB2);
- offshore wind capacity is expected to relocate from northern zones to the Celtic Sea; and
- grid-scale batteries relocate away from southern zones to Scotland.

A3.9 Similarly, in our modelling of the nodal market design, the total capacity of each technology in each year remains fixed to that set out in the relevant FES 2021 scenario. However, we allow some new-build generation capacity, and all grid-connected storage assets, to site at different nodes in response to prevailing wholesale market price signals.

A3.10 The change in capacity in each zone as a result of moving from the current wholesale market design to a nodal model under LtW (HND) can be seen in Figure A3-2 below.

Figure A3-2: Change in location of generation capacity between nodal and national market – LtW (HND)



Source: FTI analysis

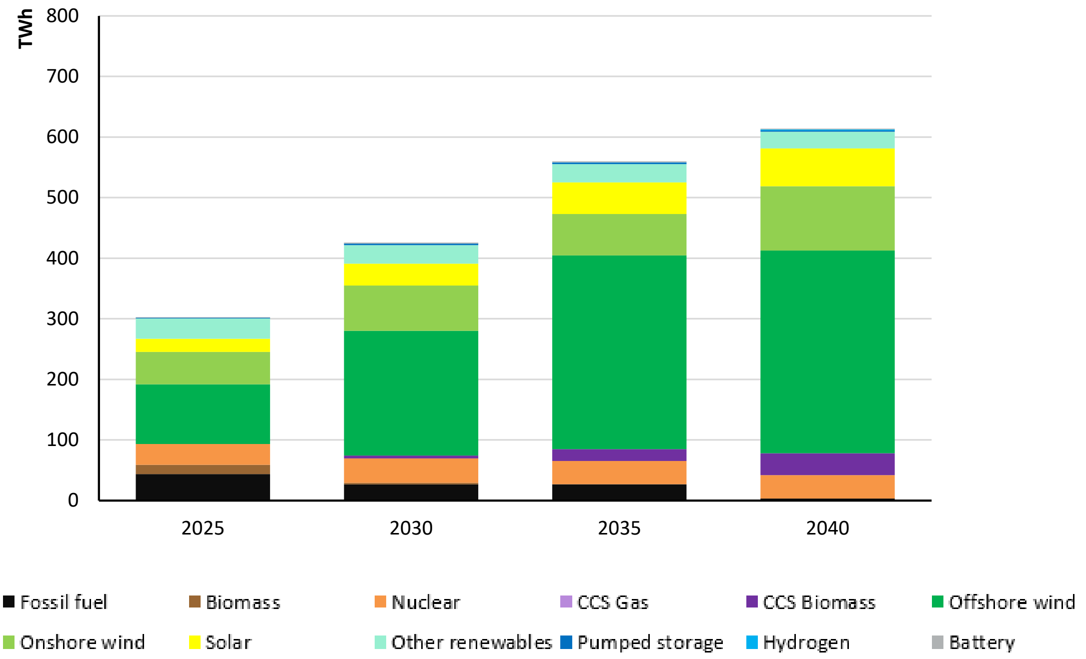
A3.11 The trends observed in Figure A3-2 above are in-line with those observed in both the evolution under zonal market designs for LtW (HND), as well as the trends observed under the nodal market design in LtW (NOA7).

A3.12 Further discussion of capacity siting trends and the underlying drivers can be found in Section 6A.

B. Generation

A3.13 As discussed above in Section 6B, we also compare the despatched generation mix between market arrangements, for instance, Figure A3-3 below shows the despatched generation mix under LtW (HND) under the national market.

Figure A3-3: Generation by technology under the national market (base case status quo) – LtW (HND)

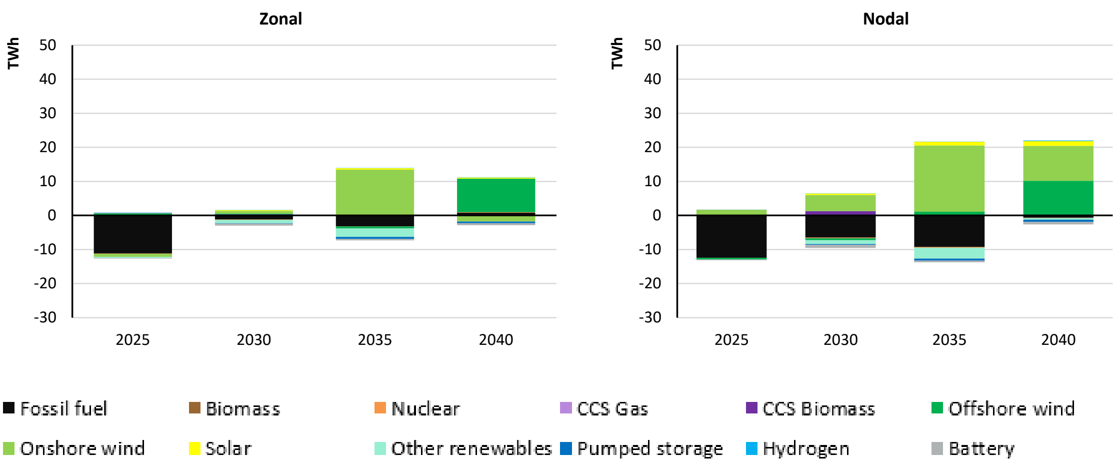


Source: FTI analysis

A3.14 The trend observed under the national market for LtW (HND) is broadly in-line with the trend observed under the same for LtW (NOA7), i.e., generation mix follows the evolution of the capacity mix.

A3.15 Figure A3-4 below shows the expected change in the post-balancing generation mix when moving from the current market design to a zonal or nodal market design, on the left and right, respectively. As discussed previously, the ESO is not required to intervene in order to balance the system under the nodal market design.

Figure A3-4: Changes in the zonal and nodal generation mix relative to the post-balancing national generation mix – LtW (HND)



Source: FTI analysis.

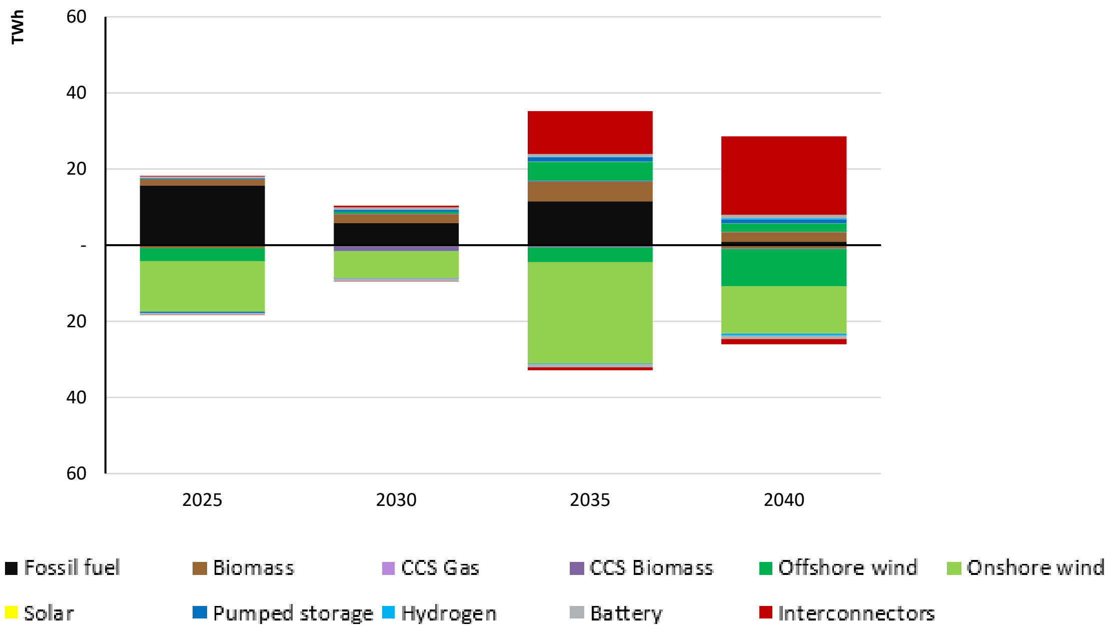
A3.16 Similar to LtW (NOA7), the transition to zonal and nodal markets results in a reduction in the amount of power sourced from fossil fuel generators prior to the phasing out in 2040, which is made possible by better siting of intermittent renewable generators, more efficient use of two-way assets and demand optimisation.

A3.17 However, relative to LtW (NOA7), the reduction in fossil fuels is smaller when transitioning to locationally granular pricing under LtW (HND), as the additional transmission capacity under this scenario from 2030 onwards is better equipped to transport the power from renewables generators. Relatedly, there is a smaller increase in intermittent renewables generation under LtW (HND) relative to LtW (NOA7).

C. Congestion Impact

A3.18 As discussed in Chapter 4 and Section 6C, the national market design requires congestion management by the ESO in response to transmission constraints. Figure A3-5 below shows the evolution of constrained-on and off generation under the status quo national market for LtW (HND).

Figure A3-5: Constrained generation under the national market – LtW (HND)



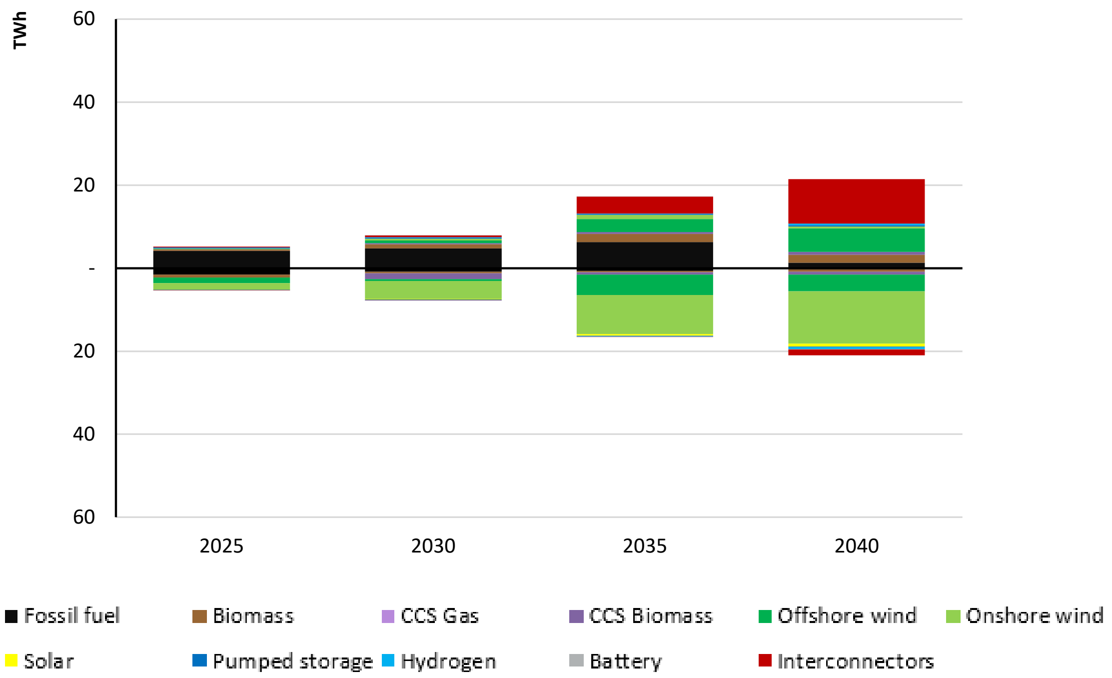
Source: FTI analysis

A3.19 Similar to the national market under LtW (NOA7), predominantly onshore and offshore wind are constrained off, whilst fossil fuel generators are constrained on from 2025 to 2035, with Interconnectors expected to provide increasing amounts of flexible capacity from 2035 onwards.

A3.20 Notably, however, the constrained generation decreases in 2030 and 2040 relative to the modelled year prior. This is caused by significant investment in transmission capacity in those years, allowing the system to bear greater generation and therefore reducing the need for constraint management.

A3.21 Similarly, constrained-on and -off generation under a zonal market for LtW (HND) is shown in Figure A3-6 below, and as stated previously, we would expect to see lower constrained volumes under the zonal market design relative to the national market design due to the increased efficiency of price signals.

Figure A3-6: Constrained generation under zonal markets – LtW (HND)



Source: FTI analysis

A3.22 The trends observed in the national model persist under a zonal market design with the increased need for constraint management across the modelling period, and a similar mix of technologies being constrained on or off, albeit at lower volume levels.

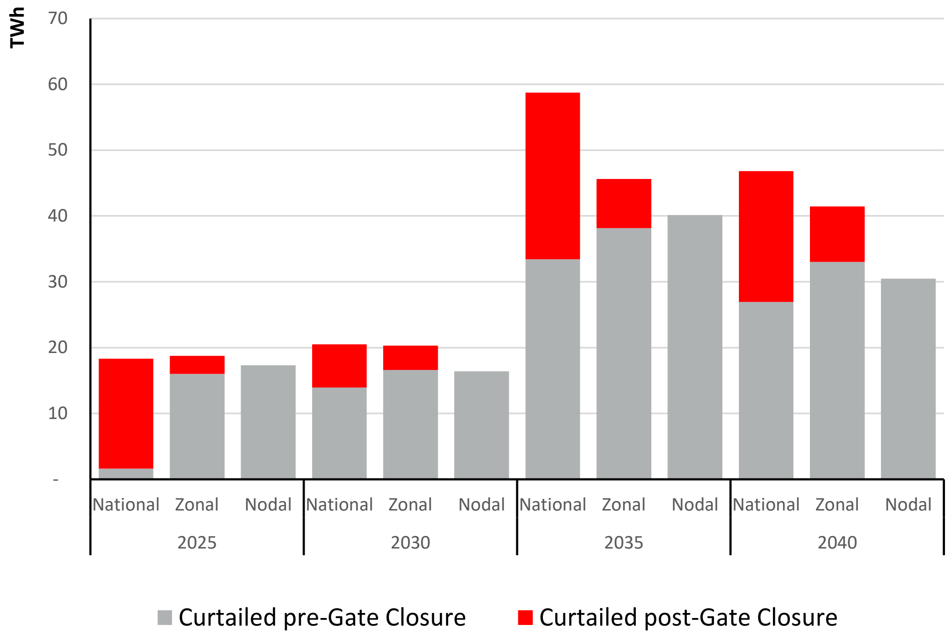
A3.23 Similar to our findings for LtW (NOA7), while the selected zonal boundaries appear to eliminate the majority of required redispatch actions in the early modelling years, increasing constrained volumes in the 2030s suggest that new intra-zonal boundaries emerge on the system over time, potentially necessitating re-zoning at regular intervals to ensure that the zonal wholesale market continued to reflect the physical network over time.

D. Curtailment

A3.24 As stated in Section 6D, wind generation can be curtailed both pre- and post-gate closure. We would expect greater pre-gate closure curtailment under zonal and nodal pricing due to increased visibility of transmission constraints under those market designs, consequently resulting in a smaller decrease in post-gate closure curtailment.

A3.25 In Figure A3-7 below, we present both forms of wind curtailment across all three market arrangements.

Figure A3-7: Wind curtailment – LtW (HND)



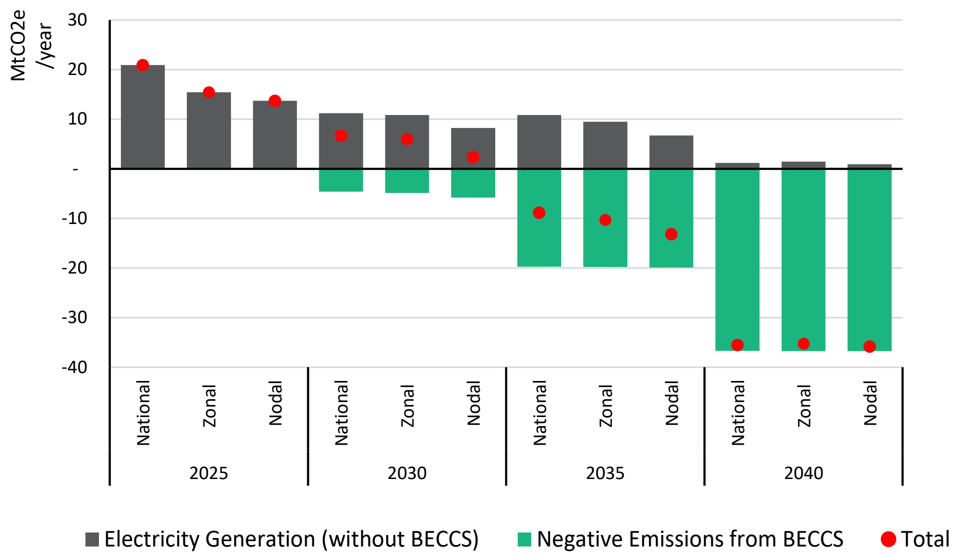
Source: FTI analysis

A3.26 As observed under LtW (NOA7), more locationally granular pricing results in more efficient utilisation of wind generation via reduced curtailment, especially in the later modelling years. Over the 16-year modelling period, moving to nodal markets reduces wind curtailment by c.165 TWh, while zonal markets lead to a c.81 TWh reduction.

E. Emissions

A3.27 Figure A3-8 below compares the level of emissions under the three market designs under LtW (HND).

Figure A3-8: Emissions from electricity generation – LtW (HND)



Source: FTI analysis

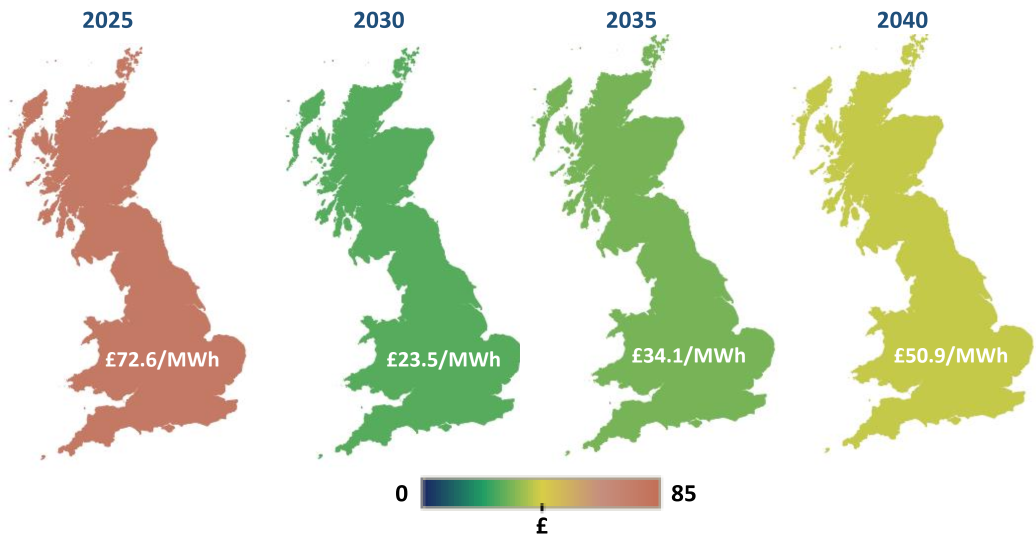
A3.28 Similar to our assessment under LtW (NOA7), all three market arrangements achieve the same emission levels by 2040 as fossil fuel generation is phased out. However, prior to this, more locationally granular market arrangements reduce emissions to a greater extent in each modelling year relative to national pricing arrangements, allowing GB to reach Net Zero targets earlier.

F. Wholesale electricity price

A3.29 In this section we discuss the longer-term price trends under each market design option for the LtW (HND) scenario. These trends are demonstrated by the evolution of annual time-weighted average prices over the modelled period.

A3.30 As the only difference between LtW (HND) and LtW (NOA7) is the transmission build out, national annual average prices are the same under both scenarios. These prices are shown below in Figure A3-9 and discussed further in Section 7A.

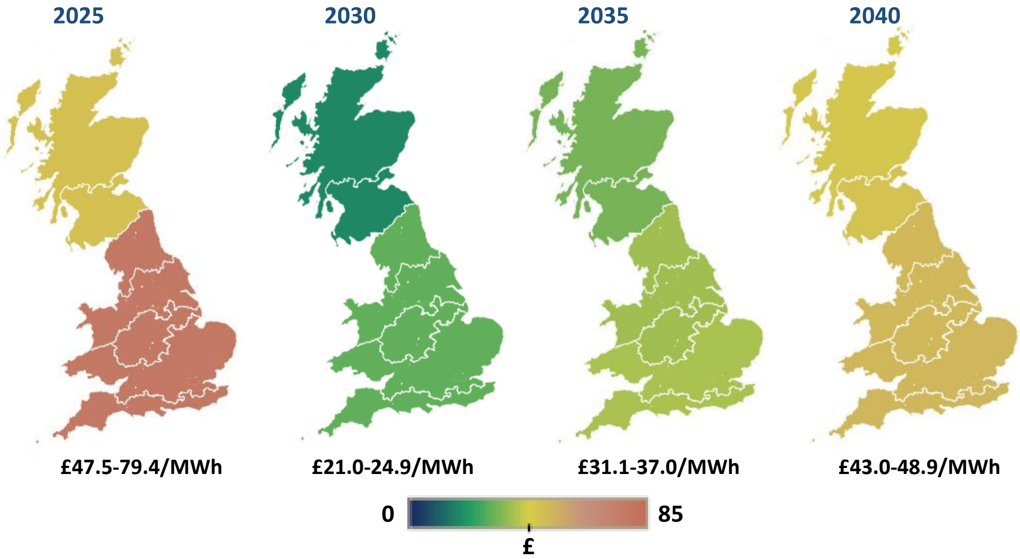
Figure A3-9: Wholesale market price under national market – LtW (HND)



Source: FTI analysis

A3.31 Under a zonal market arrangement, wholesale prices evolve similarly to under a national market arrangement, as shown below in Figure A3-10.

Figure A3-10: Wholesale market price under zonal market – LtW (HND)



Source: FTI analysis

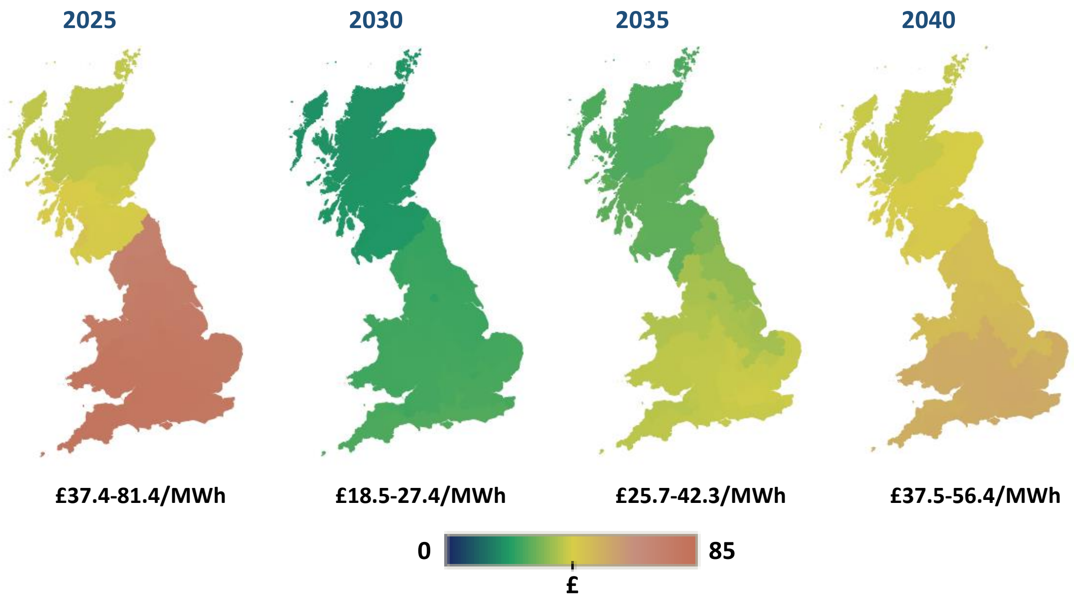
A3.32 Figure A3-10 demonstrates that under LtW (HND) wholesale prices under a zonal market follow similar trends as seen in LtW (NOA7). This has the following key features (discussed further in Section 7A);

- annual average prices in GB1 and GB2 are lower throughout the modelling period than the national price, and are coupled from 2025-2035;
- prices in zones GB3-GB7 remain close to one another across the modelled period, and are higher than the national average from 2025-2035; and
- re-siting of capacity causes the limited price differences between zones within England and Wales and within Scotland.

A3.33 In 2030, the spread of zonal prices across GB is smaller under the LtW (HND) scenario than LtW (NOA7). This is due to the accelerated transmission build-out in 2030 under LtW (HND), which allows price spreads across GB to narrow more quickly. Benefits of increased transmission build out are also seen in the slightly lower prices across all zones in 2040, compared to LtW (NOA7).

A3.34 Nodal wholesale prices, shown below in Figure A3-11, evolve similarly to zonal prices, with lower prices than national for nodes in Scottish zones (GB1 and GB2) and higher than national in the most southern zones (GB5-GB7). Average prices in GB3 and GB4 are above the national average in 2025 and 2030, and below it in 2035 and 2040.

Figure A3-11: Wholesale market price under nodal market – LtW (HND)



Source: FTI analysis

A3.35 The evolution of average wholesale prices under a nodal market for LtW (HND) is similar to that in LtW (NOA7), with the following key features (discussed further in Section 7A):

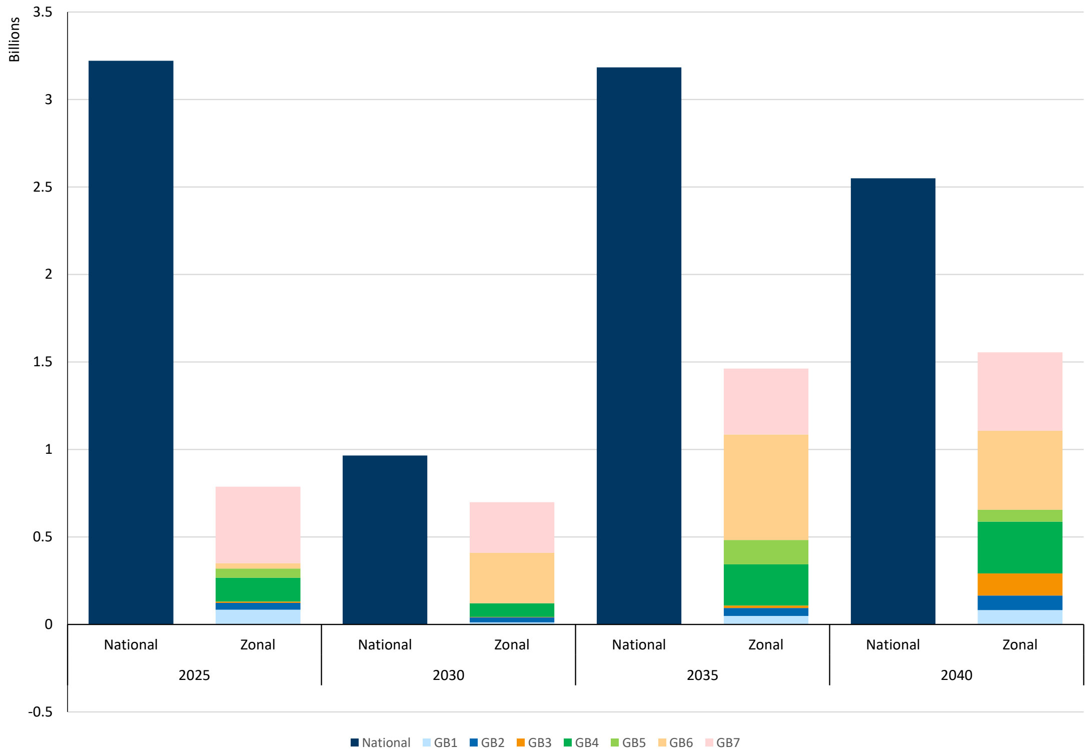
- in each of the modelled years, the spread of prices across GB is much greater than under zonal, and prices between zones differ more often;
- prices in zones GB3-GB7 remain close to one another across the modelled period, and are higher than the national average from 2025-2035;
- re-siting of capacity means that there are limited differences between zones within England and Wales and within Scotland;
- in 2025 and 2030 B6 is expected to be the main transmission boundary, but new boundaries emerge in later years (for example, across the Midlands and in Northern Scotland).

A3.36 As seen in the zonal case, under the nodal market design for LtW (HND), the price dispersion across GB is smaller than under LtW (NOA7) due to increased transmission build out.

G. Congestion cost

A3.37 Our modelling allows us to assess congestion costs under LtW (HND) for both the national and zonal market arrangements, as shown below in Figure A3-12.

Figure A3-12: Congestion costs – LtW (HND)



Source: FTI analysis

A3.38 In line with our assessment of congestion costs for LtW (NOA7), congestion costs are higher under the national market design than under the zonal market design. This is because under the zonal system, GB is divided into zones along several main transmission boundaries, allowing for the congestion along those boundaries to be accounted for in the scheduling stage.

A3.39 Across both market designs, congestion costs broadly follow the congestion volumes shown in Figure A3-5. Under the national market design, this allows us to observe the drop in congestion costs due to the increased transmission capacity in 2030 and 2040 under the LtW (HND) scenario, whereas the increased transmission capacity has a less distinct impact on zonal congestion costs due to the zones being divided using the main congestion boundaries.

A3.40 The estimates of congestion costs under the national market design for LtW (HND) have been published by the ESO and broadly align with our own estimates.[254]

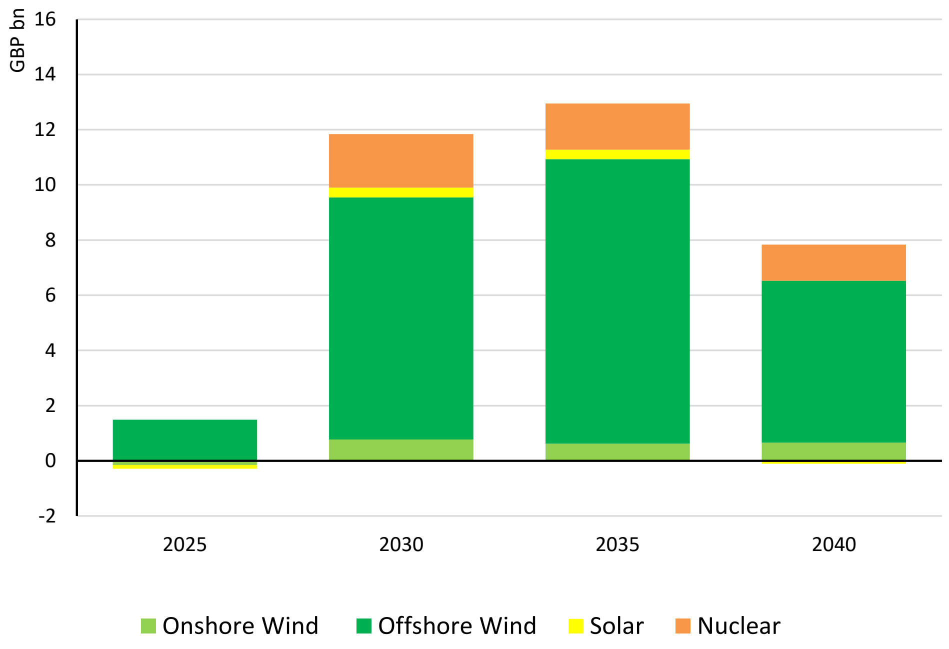
A3.41 As the generation mix and demand profile under our LtW (HND) scenario is identical to under our LtW (NOA7) scenario, the trends observed across technologies and the modelling period are broadly similar, but to a lesser extent due to the increased transmission capacity in this scenario. Our discussion of the underlying drivers of the estimates can be found in Sections 5D and 7B.

254 National Grid ESO (2022), 'Modelled Constraint Costs – NOA 2021/22 Refresh', (link).

H. CfD support payments

A3.42 Figure A3-13 below shows CfD payments under a national market. CfD payments are fundamentally linked to the prevailing wholesale price in each hour, as when wholesale price is lower than the agreed CfD strike price, producers will be compensated by consumers. CfD support payments therefore give an indication of how much certain generators will benefit from a given market arrangement.

Figure A3-13: CfD support payments under the national market – LtW (HND)



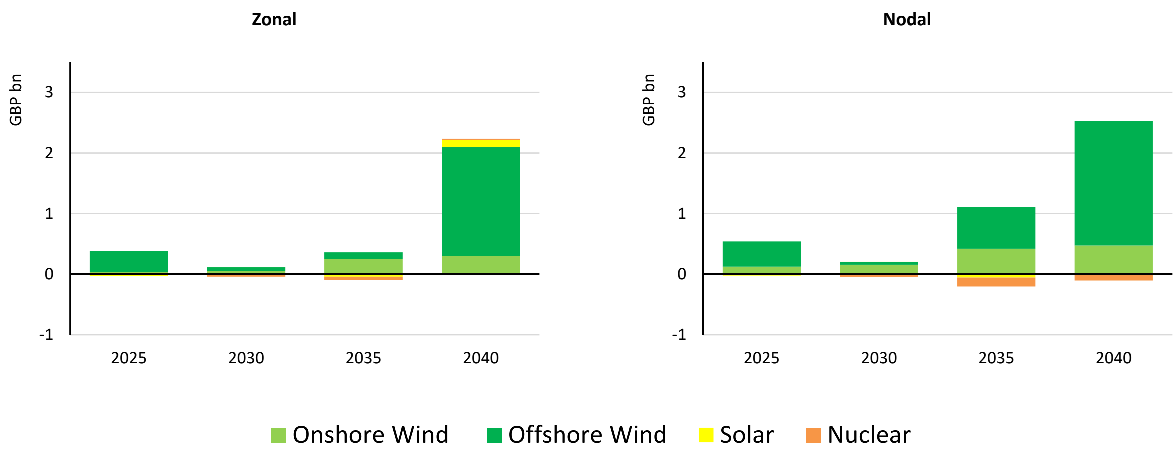
Source: FTI analysis

A3.43 Figure A3-13 shows that under the current national market design, CfD support payments result in significant payments from consumers to producers in the LtW (HND) scenario. The trend observed is broadly similar to that observed for LtW (NOA7) (explained further in Section 7C). In particular:

- these payments are greatest in the 2030s, due to a reduction in average wholesale prices;
- across the modelled period the majority of payments are received by offshore wind generators, due to the large number of generators being awarded support payments and relatively high strike prices;
- onshore wind and solar support payments are much lower, due to lower strike prices and higher average wholesale capture prices; and
- nuclear CfD support payments begin in 2030 when Hinkley Point C is commissioned, amounting to over £1bn per year from then on.

A3.44 Figure A3-14 shows the forecasted change in CfD payments that would arise under a zonal or nodal market design relate to national.

Figure A3-14: Changes in CfD support payments under zonal and nodal relative to a national market – LtW (HND)



Source: FTI analysis

A3.45 Under zonal and nodal market designs, CfD support payments increase for offshore and onshore windfarms, as shown in Figure A3-14 and as seen in LtW (NOA7). In 2040, this increase is greater for offshore windfarms in LtW (HND) than in LtW (NOA7), as greater transmission capability reduces capture prices by a larger amount.

A3.46 In terms of the other generators, lower wholesale prices in renewable dominated areas lead to results similar to those seen in LtW (NOA7) (explained further in Section 7C). These relate to:

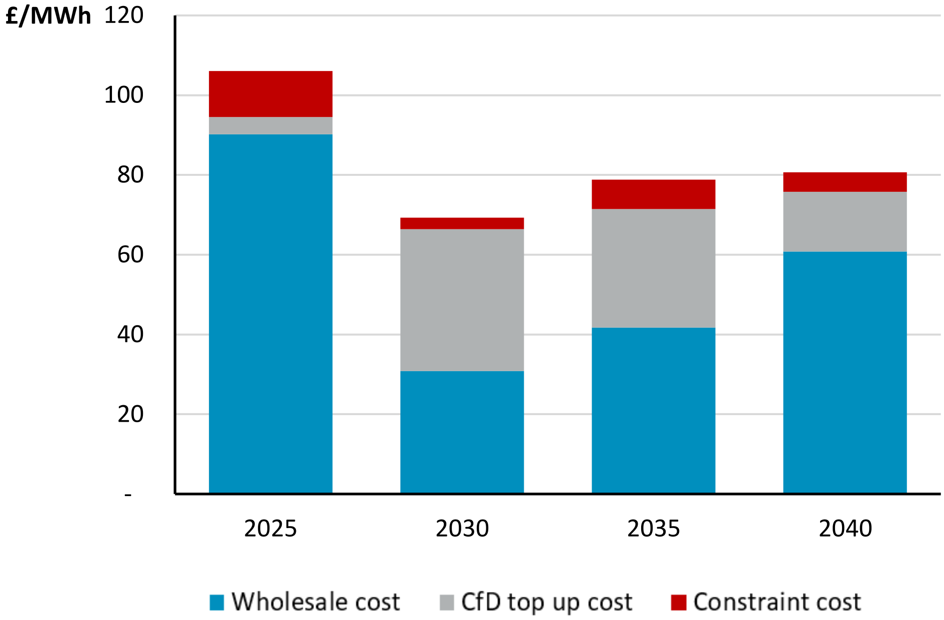
- CfD support payments to solar farms increasing only marginally under zonal markets and decreasing under nodal; and
- support payments to Hinkley Point C decreasing.

I. Total electricity cost

A3.47 As assessed for the LtW (NOA7) scenario, adding up wholesale cost, congestion costs and CfD support payments provides the actual variable cost of electricity generated on the system, allowing us to understand how much consumers are paying under different market arrangements.

A3.48 We do this firstly by assessing the cost under the national market design in Figure A3-15 below followed by the cost under the zonal and nodal market designs, respectively, in Figure A3-16.

Figure A3-15: Total variable cost of electricity – LtW (HND)



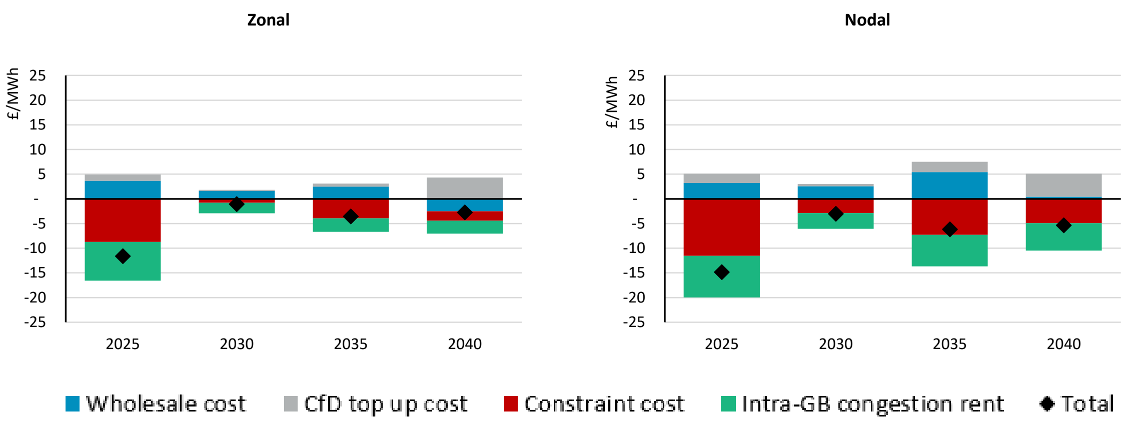
Source: FTI analysis

A3.49 The trends observed under LtW (HND) mimic those under LtW (NOA7) with wholesale prices making up the majority of variable cost in 2025, 2035 and 2040, but with CfD support payment costs the majority of variable costs in 2030. This relationship is caused by the expected increase in the share of generation with CfD contracts from 2030 onwards, that is offset by a subsequent increase in wholesale prices (and therefore drop in CfD support payments) from 2030 onwards. We discuss this further in Section 7D.

A3.50 Constraint costs make up approximately 11% of total cost in 2025, which drops to 4% by 2030 before increasing to approximately 8% between 2035 and 2040.

A3.51 All of the components of the total electricity costs change under zonal and nodal market arrangements, as described in the previous three sections of this chapter, and as seen in Figure A3-16 below.

Figure A3-16: Changes in the total variable costs of electricity under zonal and nodal markets – LtW (HND)



Source: FTI analysis

A3.52 As can be seen in Figure A3-16, locational pricing under LtW (HND) leads to similar changes in total costs as those observed under LtW (NOA7) (explained further in Section 7D). This has the following key features:

- congestion costs decrease under locational pricing as transmission constraints are taken into account pre-gate closure;
- wholesale costs increase under locational pricing, as some generators which would be paid through the balancing market in the national market arrangements instead are paid through the wholesale market;
- CfD costs increase due to the location of both existing and new CfD generators; and
- intra-GB congestion rents, caused by the difference in prices between connected nodes and zones, are assumed to be an accrued benefit to consumers, thereby decreasing total electricity costs.

A3.53 The decrease in total costs caused by a move to locational pricing is smaller under LtW (HND) than under LtW (NOA7). This is largely due to the savings related to constraint costs being less significant. Despite this, total electricity costs are still reduced in all modelled years by a move to locational pricing.

J. Producer impact

A3.54 As stated in Section 7E moving to nodal or zonal prices will impact producers through:

- wholesale prices impacting revenues in the wholesale market;
- a reduction in congestion costs reducing revenues in the BM;
- CfD payments, which depend on wholesale and strike prices, and generation volumes.

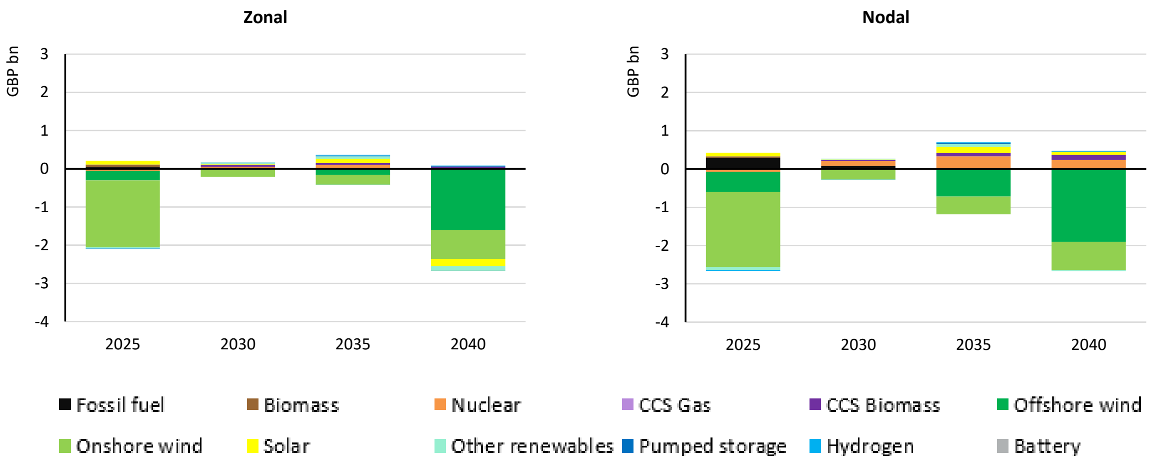
A3.55 We look at the effect of each of these components and total effect as well, to understand the full extent of the effect on producers.

Wholesale market

A3.56 As explained in Section 7E, generators will receive different revenues through the wholesale market under more locationally granular pricing, due to differences in both prices received and the volume of generation. Under LtW (HND), there is an increase in transmission capacity across GB, reducing the spread in prices between high- and low-price locations relative to LtW (NOA7). As a result, generators in lower price zones see a smaller reduction in revenues under LtW (HND) when moving to a more locationally granular market design than under LtW (NOA7). Similarly, those in higher price zones see a smaller increase in revenues.

A3.57 Figure A3-17 below shows the change in producer surplus in the wholesale market under zonal and nodal market designs.

Figure A3-17: Change in producer surplus on the wholesale market by technology – LtW (HND)



Source: FTI analysis

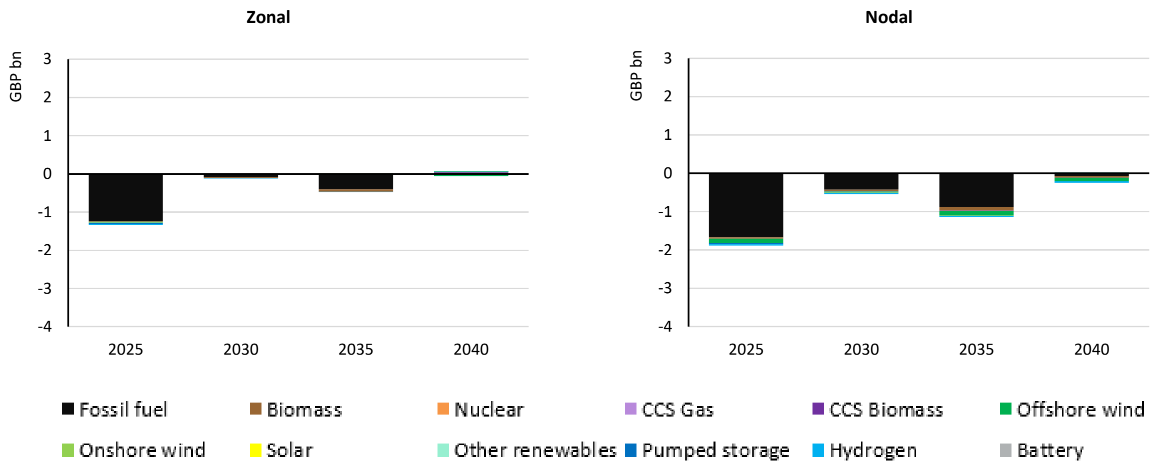
A3.58 The trends in the wholesale market are broadly similar to those under LtW (NOA7). Wind generators make up most of the capacity in the areas where wholesale prices decrease across the modelling period, so wholesale market revenues for these technologies are expected to fall in under both the zonal and nodal market designs relative to national. Conversely, generators sited in zones or nodes where wholesale prices increase, such as nuclear and fossil fuels, are expected to see an increase in wholesale revenues under a zonal or nodal pricing model.

A3.59 As discussed in Section F of this appendix, when additional HND transmission capacity comes online in 2030, the spread of zonal prices across GB falls relative to LtW (NOA7). As the price decreases faced by wind generators will not be as large, the impact on wholesale market revenues is reduced compared to LtW (NOA7). Similarly, the price and revenue increases faced by nuclear and fossil fuel generators will be smaller. By 2040, transmission buildout under LtW (NOA7) more closely matches that under LtW (HND), so the price spread, and therefore the effect on wholesale revenues, is similar across the two scenarios.

Balancing mechanism

A3.60 As is the case under LtW (NOA7), BM revenues in the LtW (HND) scenario decrease under more locationally granular pricing. The volume of electricity despatched through the BM decreases under a zonal market and there is no electricity despatched through the BM under a nodal market. Figure A3-18 below shows the change in producer surplus from the balancing mechanism, by technology, under zonal and nodal market arrangements.

Figure A3-18: Change in producer surplus from the BM – LtW (HND)



Source: FTI analysis

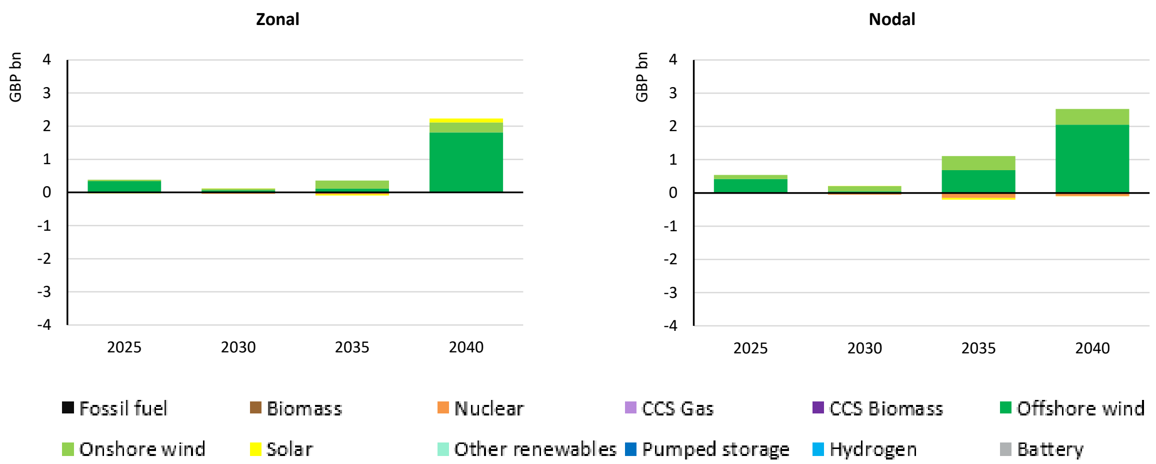
A3.61 Changes in producer surplus arising from the BM primarily affect fossil fuel generators, as is the case under LtW (NOA7). In 2030 and subsequent periods, as outlined in Section C of this appendix, constrained volumes fall under a national market model relative to LtW (NOA7), reducing BM payments to generators. Consequently, when moving to a more locationally granular pricing model, the BM revenues lost by fossil fuel generators is smaller under LtW (HND).

A3.62 Offshore wind also loses some producer surplus through the BM, as they no longer receive constrained-off payments under a nodal pricing model.

CfD support payments

A3.63 CfD support payments change under locational pricing for two reasons, wholesale price changes and changes in the generation mix. When wholesale prices change, then the CfD payment per MWh changes, so the effect on aggregate CfD payments to contract holders depends on the location of the generators and the change in wholesale prices that they face. Figure A3-19 below shows the changes to producer surplus from CfD payments, by technology, under a change to a zonal and nodal pricing model.

Figure A3-19: Change in CfD support payments – LtW (HND)



Source: FTI analysis

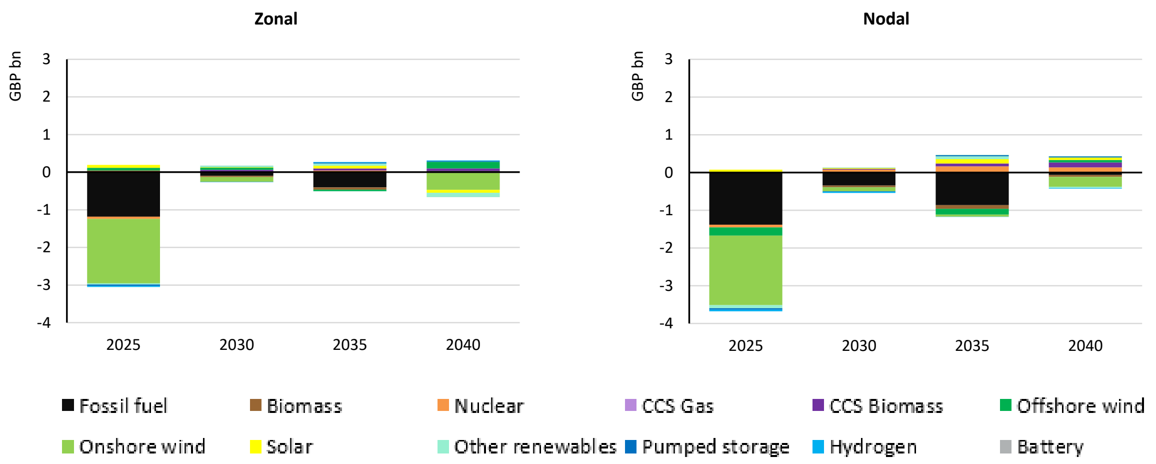
A3.64 Changes in CfD payments mirror the changes in wholesale market producer surplus for technologies with CfD contracts, as is the case under LtW (NOA7). Offshore and onshore wind generators receive an increase in CfD support payments to compensate them for the fall in revenue in the wholesale market. This increase is largest in 2040, when transmission constraints lead to a larger fall in the wholesale prices faced by many offshore and onshore wind generators under locationally granular pricing.

A3.65 CfD payments to onshore and offshore wind also increase due to the increased prevalence of these technologies in the generation mix under both a zonal and a nodal market design, as outlined in Section B of this Appendix.

Overall impact on generators

A3.66 As discussed above, the overall change in producer surplus under a zonal or nodal market model accounts for changes in producer surplus in both the wholesale and balancing market, as well as changes in CfD payments. Figure A3-20 below shows the overall impact by technology for each year modelled.

Figure A3-20: Change in total producer surplus – LtW (HND)



Source: FTI analysis

A3.67 As is the case under LtW (NOA7), the most significant effect is on fossil fuel generators, who see a reduction in their overall producer surplus under both a zonal and nodal market model between 2025 and 2035 until their phase out. This is almost exclusively due to the loss of BM revenues from constrained-on payments.

A3.68 Although offshore wind generators see a large reduction in wholesale market revenues, particularly in 2040, this reduction is reversed by the CfD payments that they receive. Non-CfD onshore wind generators do not receive higher CfD payments to replace the lost wholesale market revenues, so face a significant decrease in their producer surplus in 2025.

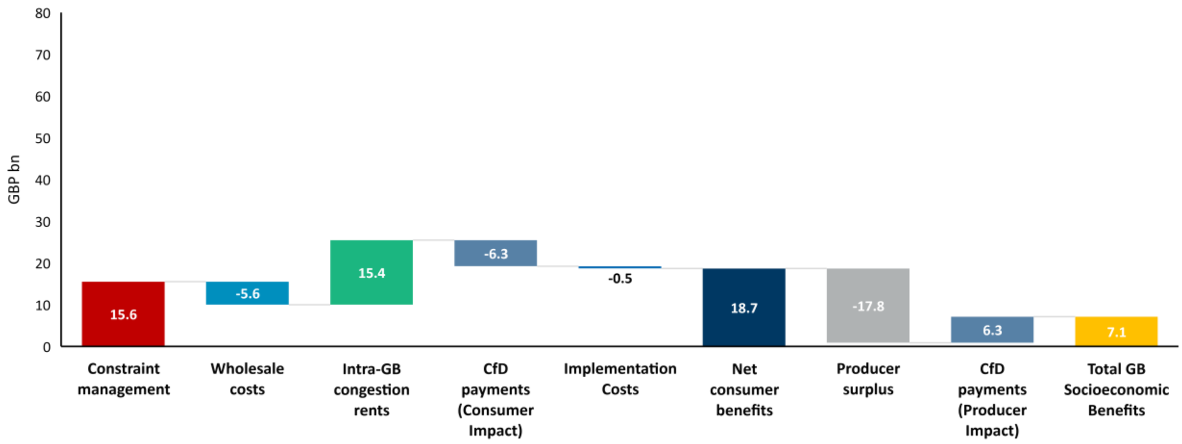
K. CBA results

A3.69 Our overall assessment of impact indicates that consumers and socioeconomic welfare benefits from transitioning to more locationally granular pricing. In line with our assessment for LtW (NOA7), benefits are far greater from transitioning to the nodal system relative to transitioning to the zonal system.

Overall impact of locational pricing

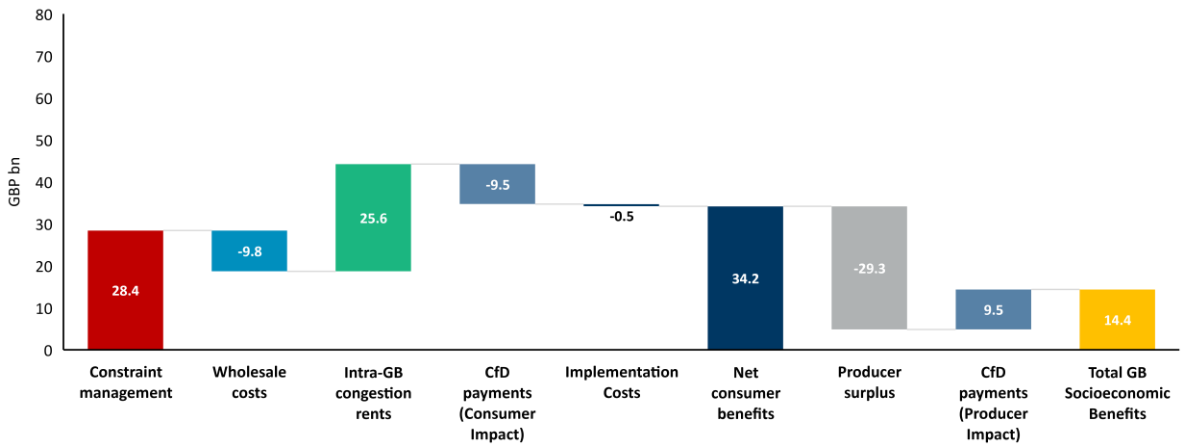
A3.70 Figure A3-21 and Figure A3-22 below show the breakdown of consumers benefits and socioeconomic welfare for both the zonal and nodal market designs in the LtW (HND) scenario.

Figure A3-21: Overall cost benefit assessment for Zonal LtW (HND) (relative to National LtW (HND)) – 2025-2040



Source: FTI analysis

Figure A3-22: Overall cost benefit assessment for Nodal LtW (HND) (relative to National LtW (HND)) – 2025-2040



Source: FTI analysis

A3.71 As shown in the figures above, our analysis estimates a net consumer benefit of £19bn and socioeconomic benefits of £7bn of transitioning to a zonal market design under LtW (HND). Relatedly, our assessment of transitioning to a nodal market design produces a higher net consumer benefit of £34bn and socioeconomic benefits of £14bn.

A3.72 In our assessment for LtW (NOA7) and LtW (HND), the overall consumer benefits from transitioning to either a zonal or market design are driven primarily from the benefits from constraint management, followed by intra-GB congestion rent. These benefits are partially reduced from higher wholesale costs (as the value of congestion reflected in locational wholesale prices) and larger CfD support payments.

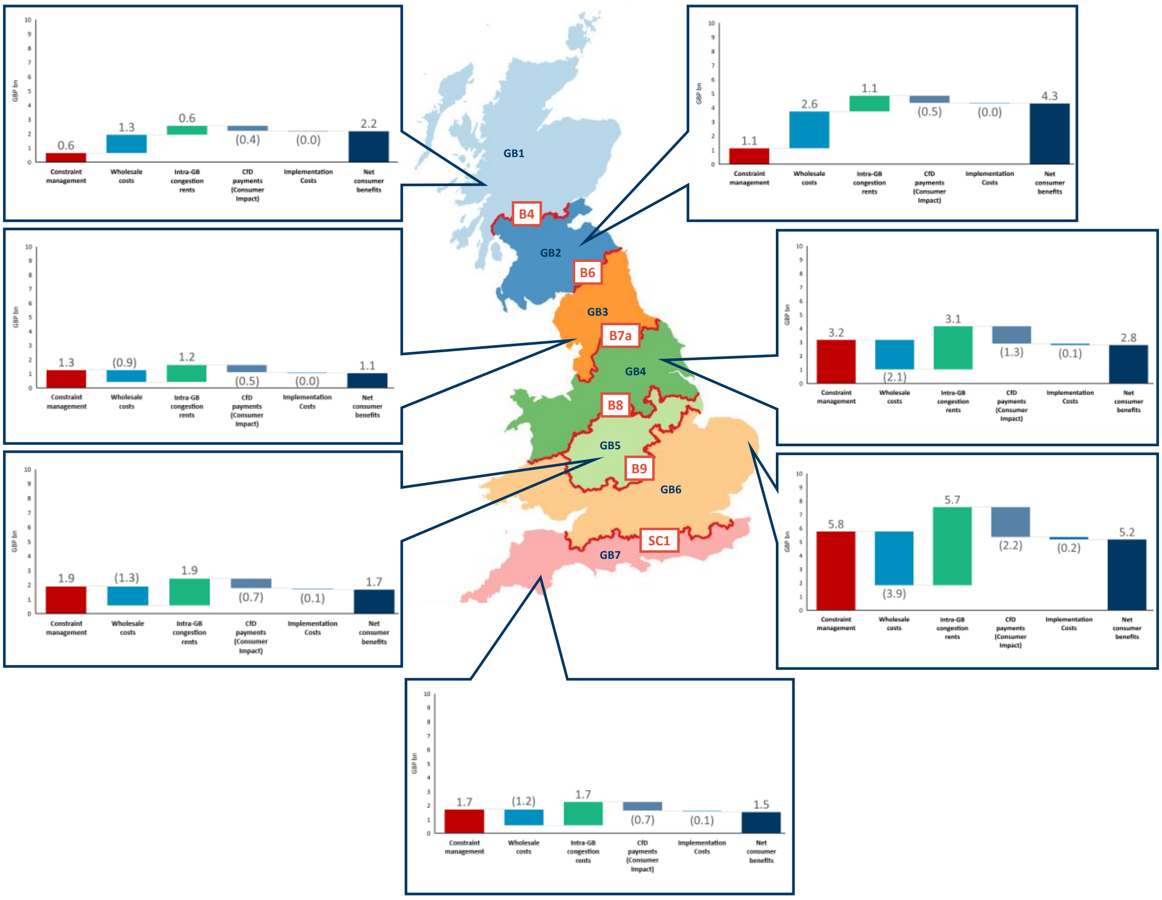
A3.73 Our overall CBA results for LtW (HND) is also discussed in Section 9A, where the limitations of our methodology are also outlined specifically.

Regional impact of locational pricing

A3.74 As discussed in Section 9B, the overall consumer benefits can be disaggregated into the seven designated zones across GB to estimate the benefits to consumers in different parts of GB.

A3.75 We show the distribution of benefits (and costs) borne by consumers as a consequence of transitioning to a zonal pricing regime in Figure A3-23 below. This is equivalent to a disaggregated version of Figure A3-21.

Figure A3-23: Distribution of consumer benefits from transitioning to a zonal pricing regime – LtW (HND)



Source: FTI analysis

A3.76 As shown in Figure A3-23 above, consumers across all seven zones benefit from transitioning to zonal pricing. The extent to which they benefit varies as a result of the wholesale price and consumer load across the respective zones.

A3.77 The distribution of benefits aligns to the distribution observed under LtW (NOA7), specifically:

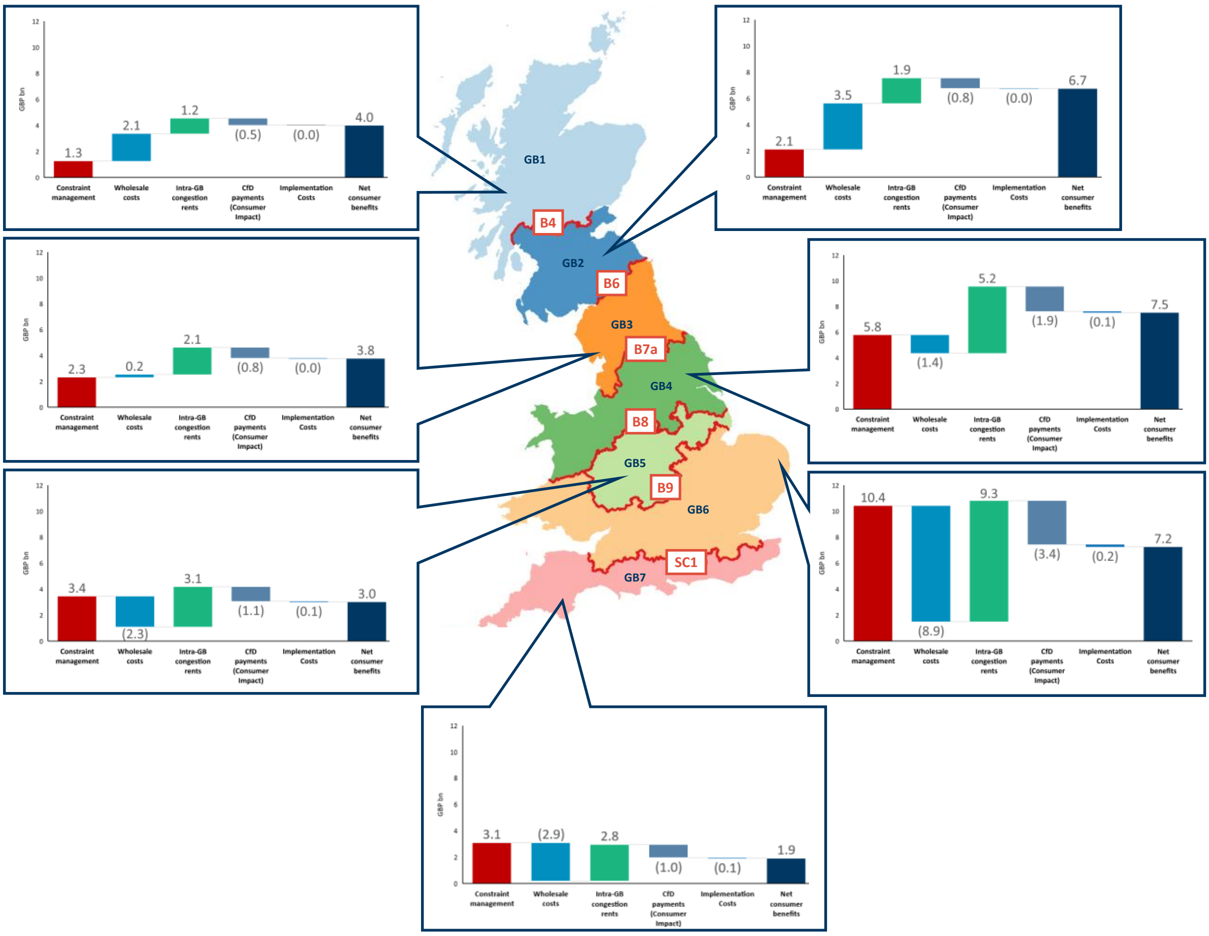
- all zones benefit from a reduction in constraint management, particularly in zones with high consumer load;

- wholesale prices reduce under zonal pricing for Scottish zones (GB1 and GB2) resulting in lower costs to consumers, but increase for zones in England and Wales, resulting in greater costs to consumers; and
- CfD support payments paid by consumers increase across all zones in GB.

A3.78 The extent to which constraint management and CfD support payments affect consumers in a certain zone is dependent on the number of consumers present in the relevant zone.

A3.79 We conduct similar analysis for the distribution of benefits and costs of transitioning to a nodal pricing regime. This is shown in Figure A3-24 below, aggregated into the relevant zone in which the node is located.

Figure A3-24: Distribution of consumer benefits from transitioning to a nodal pricing regime – LtW (HND)



Source: FTI analysis

A3.80 As shown in Figure A3-24 above, consumers across all zones benefit from transitioning to nodal pricing, and the size of this benefit depends on the wholesale price and consumer load in the respective zone.

A3.81 Distributed benefits compared to national pricing are shown to be greater under nodal pricing than they are under zonal pricing. In particular:

- there is a greater reduction of constraint management costs under nodal than under zonal;

- wholesale prices reduce by a greater amount for Scottish zones (GB1 and GB2) under nodal than under zonal, and also reduce in GB3; and
- intra-GB congestion rents are significantly higher under nodal than under zonal.

Appendix 4 Cost of Capital

A4.1 This appendix sets out the two cost of capital sensitivities previously described in Section 8B in more detail. These sensitivities are:

- the **plausible uplift sensitivity**, which considers an increase to the WACC based on a plausible set of assumptions for each technology (**Section A**).
- the **extreme WACC sensitivity**, which considers what the uniform uplift to the WACC would need to be to negate the expected benefits of locational pricing, when applied to only technologies that are merchant or have CfDs. This approach does not account for differences in risk exposure that might arise from locations, technology type or regulatory support mechanisms (**Section B**).

A. Plausible uplift sensitivity

A4.2 To test what a potential plausible sensitivity that would uplift the WACC might be, we adopt the following four-step approach:

- First, we estimate the potential tiered increase to the WACC depending on each technology type and market risk exposure.
- Second, we set out the capacity profile by technology as provided by the FES.
- Third, we convert the new-build capacity profile to determine the Capex costs, and subsequently the financing costs for each technology.
- Fourth, we apply the change in WACC to financing costs across the whole modelling period between 2025 and 2040.

A4.3 First, we estimate what a reasonable tiered increase to the WACC might be based on the technology type and market risk exposure. Our assumptions and justification are set out in Table A4-1 below.

Table A4-1: Assumptions and justifications for WACC

	Price Risk	Volume Risk	Rationale	Assumed Uplift
RAB Financing *Non-Hinkley Point C nuclear; CCS*	↔	↔	▪ Market participants that are RAB-financed are **guaranteed a return on investment**, therefore will **not be affected** by the potential change in price or volume risk	0bps

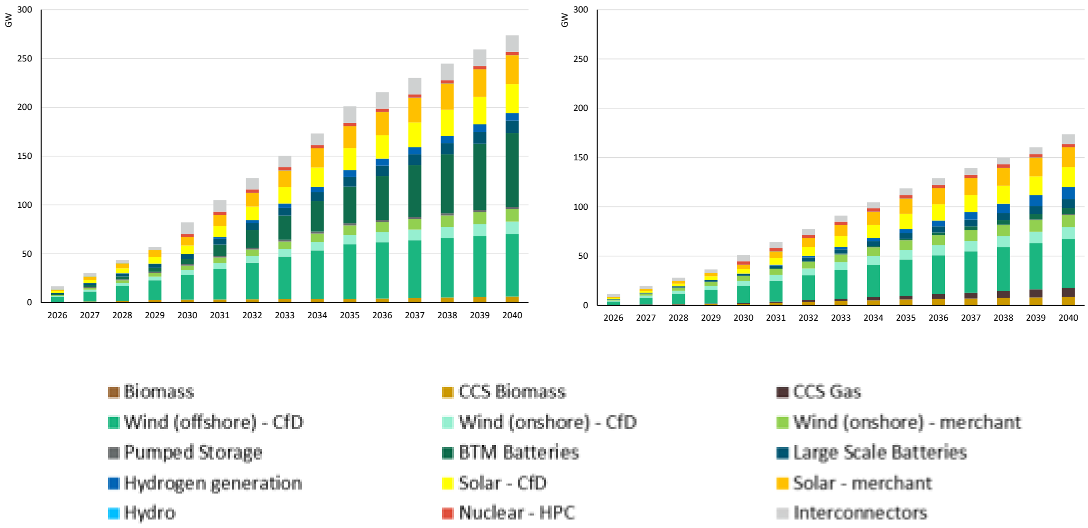
	Price Risk	Volume Risk	Rationale	Assumed Uplift
Contract for Difference *Wind; Solar; Hinkley Point C*	↔	↑	▪ CfDs provide price certainty for debt financing in the first 15 years, but some volume risk to generators located behind constraints ▪ Cost of equity impact for CfD holders is likely minimal as the beta of renewable assets have limited correlation with the market. Returns to equity are mostly derived beyond 15 years. ▪ A 50bps uplift is considered as a midpoint between limited and high-risk exposure.	50bps
Merchant *Merchant renewables; thermal*	↑↓	↑↓	▪ Merchant market participants may experience a change in their risks and the direction and magnitude of the impact will largely depend on the specific non-diversifiable risk profile at the relevant node. ▪ Some market participants will also benefit from reduced volatility of BM revenues. ▪ We assume a 50bps uplift for merchant technologies.	50bps
Cap and Floor *Interconnectors*	↑↓	↑↓	▪ Like other merchant technologies, interconnectors and batteries may also experience a change in their risks that affects their bankability. ▪ However, both interconnectors and batteries are exceptions in that they could benefit from the greater price arbitrage opportunities due to the additional price and volume risk. Additionally: - For interconnectors, floor arrangements provide revenue certainty for debt financing in the first 25 years. - Some feedback provided by the battery developers indicated lower risk ▪ Therefore, we apply 0bps uplift for both interconnectors and large-scale batteries ▪ We apply a 0bps uplift for BTM batteries as their capital costs are unlikely to be affected by wholesale prices.	0bps
Batteries *Large Scale*	↑↓	↑↓		0bps
Batteries *Behind the Meter ("BTM")*	↔	↔		0bps

Source: FTI analysis

A4.4 Second, we set out the capacity profile by technology provided by the FES (which is used in our modelling). To delineate between new capacity and retired capacity, we have assumed that 5% of existing capacity is expected to retire each year.[255] The resulting capacity expansion can be seen in Figure A4-1 below.

[255] This assumption has a minimal impact on the results.

Figure A4-1: Capacity expansion per technology for LtW (NOA7) and SysTr (NOA7)



Source: FES2021 (LtW)
Note: The LtW (NOA7) and LtW (HND) scenarios have the same capacity projections

A4.5 As can be seen in Figure A4-1 above, the LtW (NOA7) scenario has a much larger and faster deployment of capacity, particularly with offshore wind and BTM batteries to reflect greater demand and acceleration to Net Zero.

A4.6 Third, we then convert the new-build capacity profile to determine the Capex costs, and subsequently financing costs for each technology. We rely on externally verifiable sources.[256]

A4.7 Table A3-2 below sets out our assumptions for these calculations:

- A straight-line depreciation over an asset life of 25 years for solar and wind, 15 years for batteries and 40 years for other technologies.
- A base WACC of 7% across all technology.[257]

Table A3-2: Asset life and estimated cost per technology

	Economic asset life (years)	Estimated 2035 cost per MW (£'000s)
Biomass	25	1,689
CCS Biomass	25	3,157
CCS Gas	25	1,058
Wind (offshore) - CfD	30	1,920
Wind (onshore) - CfD	25	1,048
Wind (onshore) - merchant	25	1,048
Pumped storage	40	2,896

[256] These are: (i) European Commission ASSET study on Technology Pathways in Decarbonisation Scenarios; and (ii) BEIS Electricity Generation cost report.
[257] The base WACC does not affect the incremental impact in our assessment.

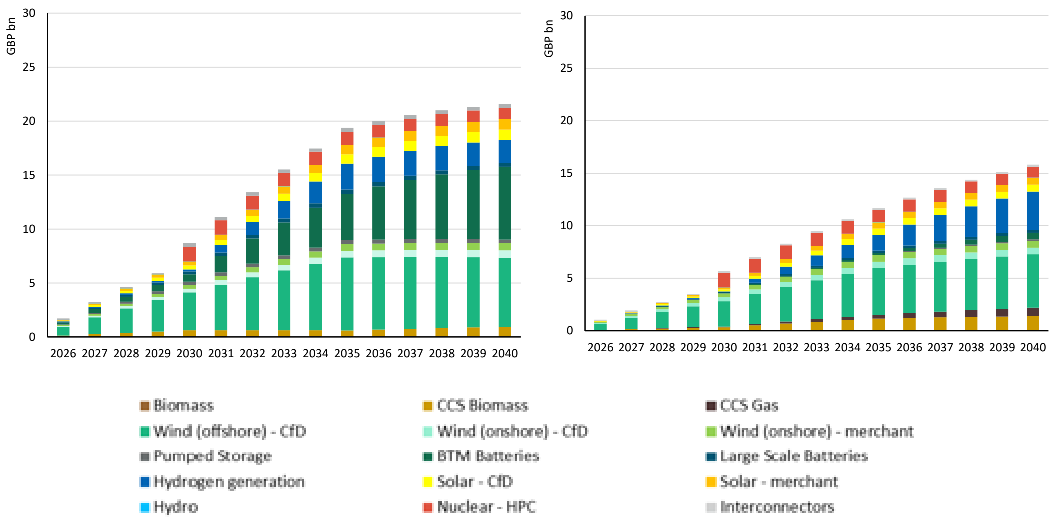
	Economic asset life (years)	Estimated 2035 cost per MW (£'000s)
BTM Batteries	15	1,912
Large Scale Batteries	15	783
Hydrogen generation	25	5,068
Solar – CfD	35	571
Solar – merchant	35	571
Hydro	40	2,293
Nuclear	40	5,792
Interconnectors	25	N/A

Source: European Commission's ASSET study (2018), BEIS Electricity Generation cost report.
Note: IC cost assumptions were based on information taken from individual interconnector project assessments.

A4.8 Capex investment in each year is calculated as the product of the increase in capacity in that year and the estimated cost per MW.

A4.9 With these assumptions, we then calculate the financing costs for each technology as shown in Figure A4-2 below.

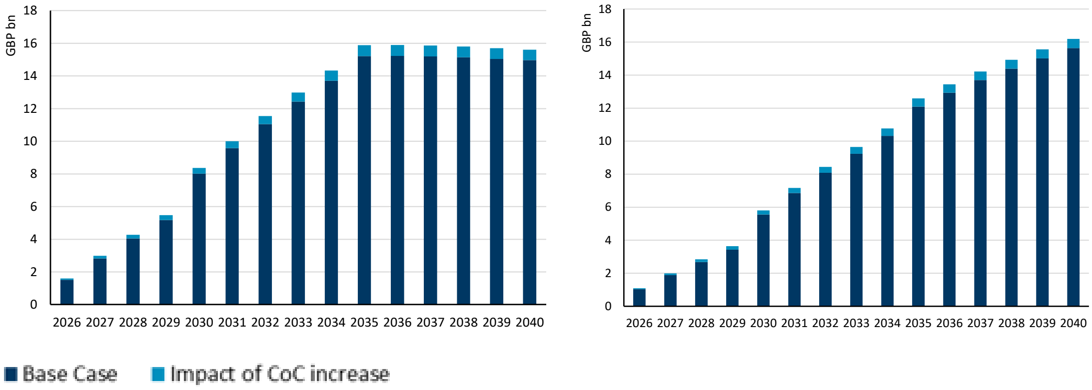
Figure A4-2: Financing cost per technology for LtW (NOA7) and SysTr (NOA7)



Source: FTI analysis

A4.10 Fourth, we apply the change in WACC across the whole modelling period between 2025 and 2040. In practice, a proportion of the WACC uplift, if it occurs, may be transitionary. The overall impact on financing cost can be seen in Figure A4-3 below.

Figure A4-3: Impact of WACC uplift on financing cost for LtW (NOA7) and SysTr (NOA7)



Source: FTI analysis

A4.11 We have applied the above change in WACC across the whole modelling period of 2025-2040. The impact of WACC uplift over 2025-2040 is **£7.45bn for the LtW (NOA7)** scenario and **£5.46bn for the SysTr (NOA7) scenario**. This impact represents an increase to the cost to producers which would be reflected in greater wholesale prices (reducing consumer benefit).

B. Extreme sensitivity

A4.12 As an extreme sensitivity, we have also analysed the increase in WACC required to negate the benefits from moving to locational pricing. We applied a uniform increase in the WACC, applied to only new-build technologies that are merchant or have CfDs over the modelling period.

A4.13 As summarised in Chapter 9, the consumer benefits from transitioning to a more granular locational market are set out in Table A4-3 below.

Table A4-3: Consumer benefits from transitioning to a more granular locational market

Scenario	Zonal market	Nodal market
Leading the Way	£30.7bn	£50.8bn
Leading the Way (HND)	£18.7bn	£34.2bn
System Transformation	£15.2bn	£28.0bn

Source: FTI analysis, Chapter 11

A4.14 From the results in Table A4-3, this allows us to calculate the increase in WACC required to negate the benefits. This is set out in Table A4-4 below:

Table A4-4: WACC increase required to negate consumer benefits for zonal and nodal markets

Scenario	Zonal market	Nodal market
Leading the Way	2.06%	3.41%
Leading the Way (HND)	1.25%	2.29%
System Transformation	1.39%	2.56%

Source: FTI analysis

A4.15 As shown in Table A4-4 above, the increase in WACC required to negate the benefits of a transition to a more granular locational market is higher than a potentially reasonable level. This does not also account for the differences risk exposures that might arise from locations, technology type or regulatory support mechanisms.

Appendix 5 Glossary

Term	Definition
AC	Alternating Current
AEMC	Australian Energy Market Commission
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy & Industrial Strategy
BESS	British Energy Security Strategy
BETTA	British Electricity Transmission and Trading Agreements
BM	Balancing Mechanism
BSUoS	Balancing Services Use of System
BTM	Behind the Meter
C&F	Cap and Floor
CAISO	California Independent System Operator
CAPM	Capital Asset Pricing Model
CBA	Cost Benefit Assessment
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CEGB	Central Electricity Generating Board
CfD	Contracts for Difference
CT	Consumer Transformation
DECC	Department of Energy and Climate Change
DESNZ	Department for Energy Security and Net Zero
DSR	Demand Side Response
DUKES	Digest of UK Energy Statistics
ENCC	Electricity National Control Centre
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
ERCOT	Electric Reliability Council of Texas
ESC	Energy Systems Capital
ESO	National Grid Electricity System Operator
ESO-DSO	Electricity System Operator - Distribution System Operator
ETYS	Electricity Ten Year Statement
EV	Electric vehicle
FAQ	Frequently Asked Questions
FERC	Federal Energy Regulatory Commission
FES	Future Energy Scenarios
FTI	FTI Consulting
FTR	Financial Transmission Right
GB	Great Britain
GSPs	Grid Supply Points
HND	Holistic Network Design

HP	Heat Pump
HVDC	High-Voltage Direct Current
IESO	Independent Electricity System Operator
IRENA	International Renewable Energy Agency
ISO	Independent System Operators
ISO-NE	Independent System Operator New England
LMP	Locational Marginal Pricing
LT	Long Term
LtW	Leading the Way
MBIE NZ	Ministry of Business, Innovation and Employment, New Zealand
MISO	Midcontinent Independent System Operator
NBP	National Balancing Point
NDA	Non-Disclosure Agreement
NEM	National Energy Market (Australia)
NETA	New Electricity Trading Arrangements
NG	National Grid
NGC	National Grid Company
NOA	Network Options Assessment
NPV	Net Present Value
NTS	National Transmission System
NYISO	New York Independent System Operator
NZMR	Net Zero Market Reforms
OECD	Organisation for Economic Cooperation and Development
OTNR	Offshore Transmission Network Review
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PJM	Pennsylvania-New Jersey-Maryland
REMA	Review of Electricity Market Arrangements
REMIT	Regulation on Energy Market Integrity and Transparency
ROCs	Renewable Obligation Certificates
SRMC	Short-Run Marginal Cost
SMR	Small Modular Reactor
SO	System Operator
SPP	Southwest Power Pool
SP	Steady Progression
SQSS	Security and Quality of Supply Standard
ST	Short Term
SysTr	System Transformation
TNUoS	Transmission Network use of System charge
TSO	Transmission System Operators
TYNDP	Ten-Year Network Development Plan
V2G	Vehicle-to-Grid
WACC	Weighted Average Cost of Capital

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