FTI Consulting: response to academic commentary

October 2023

1. We are grateful for the wide range of stakeholder comments we have received throughout our work on behalf of Ofgem on the potential costs and benefits of moving to locational wholesale pricing. This includes, most recently, separate sets of comments commissioned by Ofgem from Professor Keith Bell and Dr Callum MacIver (jointly), Professor David Newbery and Professor Michael Pollitt.

2. The academic commentary contains several points that we recognise and appreciate. However, there inevitably remain areas of disagreement, and this note is intended to explain what we see as the most important areas where our approach differs from that proposed by one or more of the academic commentators. It is not intended to be a comprehensive description of all areas of disagreement.

3. The three main areas of disagreement are:

   A. the appropriate **policy counterfactual** for the assessment;
   B. the appropriate **counterfactual for network build** for the assessment; and
   C. the experience of **locational wholesale electricity markets in practice**.

4. We also highlight the key areas where some of the academic commentary appears to have misunderstood our assessment as set out in our report, before concluding.

5. In the appendix, we outline several well-known academic studies discussing the benefits of locational wholesale electricity pricing.

A. The policy counterfactual

6. Defining a reasonable counterfactual is a key part of any cost-benefit analysis. The counterfactual should describe what is expected to happen in the absence of the reform under consideration – in this case, the introduction of locational wholesale electricity pricing.

7. Our approach to the counterfactual was agreed with Ofgem in 2022 and discussed extensively with stakeholders as part of our work. Our base case counterfactual uses the very detailed assumptions developed by the ESO on exactly when and where generating plant will locate on the system over the period 2025 to 2040. This dataset was developed by ESO as part of its Future Energy Scenarios ("FES") and is used to model a range of future congestion costs and, in turn, planned enhancements to the transmission system. Our counterfactual base case also drew on detailed plans of the evolution of the transmission system that the ESO has developed as part of the transition to Net Zero.

8. The ESO's plans assumed that the current market design and approach to transmission charging would remain unchanged. That is, the status quo market conditions were assumed to prevail for the ESO's planning purposes. We were asked by Ofgem to adopt these assumptions as our status quo counterfactual as it was its view that this approach was in line with HM Treasury's Green Book.[1] Indeed, the Green Book states that "*Business As Usual (BAU) in Green Book terms is defined as the continuation of current arrangements, as if the proposal under consideration were not to be implemented.*"

9. Because the ESO Future Energy Scenarios are based on a wide range of stakeholder feedback, the scenarios should provide a balanced view of the factors that are likely to influence the future location of generation and storage. This includes how network charging and other policies are expected to affect locational choices.

10. We understand that some of the academic commentary have suggested that an alternative counterfactual should have been considered to include significant changes to existing policies. For example, Professor Pollitt argues that *"[i]t seems possible that a hybrid pricing arrangement could have delivered almost all of the benefits with fewer of the costs…"*. However, consistent with best practices of policy appraisals, adding as yet unspecified and untested improvements to the current policy should not form the basis of a counterfactual – if such standard were applied to policy in general, there would rarely be a case for change as it would always be conceivable that a better policy might be developed at some point in time.

11. Furthermore, we note that while some of the more unknown and untested policies may be developed in good faith, it is critical that they are appraised and evaluated on their own basis as actual outcomes may be very different from forecasts. For instance, the Connect and Manage policy introduced in 2010 was, in part, based on an overly optimistic view of constraint management costs. Analysis done for DECC in 2010 forecasted c.£1bn of constraint management costs over the next decade, versus a c.£3bn actual outturn in costs.[2]

12. In this context, a parsimonious approach to the counterfactual is likely to be preferable to assuming significant policy changes that have not been fully considered, nor successfully implemented elsewhere.[3]

[1] HM Treasury (2022) The Green Book, (link).

[2] See DECC's Impact Assessment on 'Proposals for improving Grid Access' (link). Out of the c.£1bn of forecasted costs, about c.£200m was attributed to the Connect and Manage policy. 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 to the network under the policy, the initial forecast may have underestimated the cost to consumers by up to a factor of 10.

[3] For example, Professor Newbery concludes that *"[i]f better dispatch across interconnectors in the real-time market can be achieved and at lower cost (for which the gains seem to be large but so are the obstacles to achieving them) then FTI's short-term interconnector benefit may be slightly overstated*." While we agree in principle, the political, technical and practical difficulties seems to us to be very substantial.

B. The counterfactual for network build

13. A second area of disagreement is on the scope for build of the transmission network in the counterfactual. In our approach, for both the counterfactual and the locational-pricing scenarios, we model two transmission build scenarios (NOA7 and HND) that represent network plans developed by the ESO and approved by Ofgem under the Accelerated Strategic Transmission Investment ("ASTI") framework.

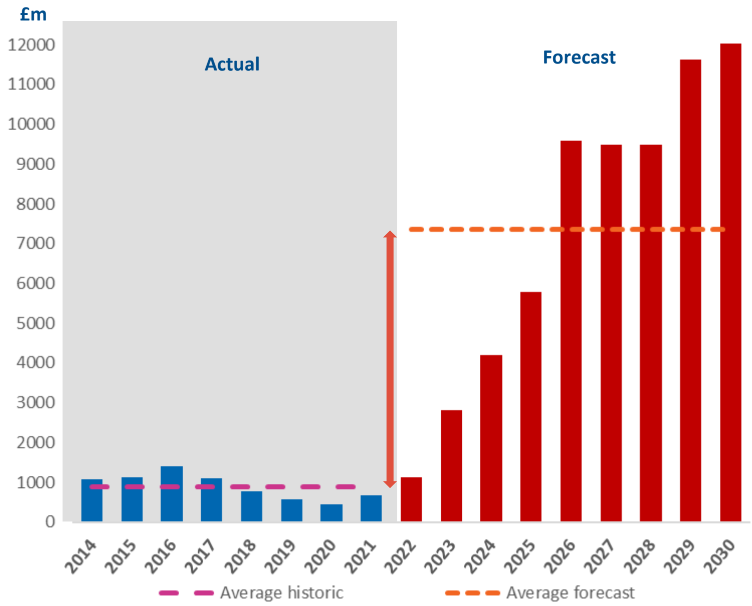
14. Professor Bell and Dr MacIver identify, correctly, that the network build assumptions are insufficient to enable all of the expected generation build in the Future Energy Scenarios to be incorporated with low constraint costs into the energy system. They state that *"[t]here is, for example, a very large amount of new offshore wind generation connected in Scotland but no network reinforcements other than those in the HND (which, we understand, go out only to 2031).[4]We question whether the combination of generation and network capacity is credible".* Other things equal, assuming more network build, or network build which is more closely matched to generation build (than in the NOA7 or NOA Refresh), would tend to reduce the expected benefits of locational pricing (before considering the additional costs of building the network itself).

15. We believe that our approach to modelling network build is preferable, and indeed more appropriate for the purposes of this assessment, for the following main reasons:

- First, it is worth noting that our approach incorporates a very significant increase in network build compared to recent experience, particularly in our HND scenario (see Figure 1 below; these costs continue on to 2041). While even faster build-out might be achievable, there is also a risk that these plans may be delayed.

[4] The HND is 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. The HND seeks to simultaneously consider 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, detailing more than £53.7bn of new grid infrastructure that would be required.

Figure 1: Comparison of average annual expenditure to deliver HND reinforcements (incl. NOA7)



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

- Second, the recent GB experience of a mismatch between generation and network build is a common experience in almost all liberalised energy markets around the world.[5] This suggests that it is likely to be over-optimistic to assume that greater coordination in generation and network build can be improved without more granular locational pricing.
- Third, as Professors Bell and Dr MacIver note, network build is not costless.[6] A full analysis of the costs and benefits of a closer match between network and generation build would need to take account of the costs of rolling out more transmission network, as well as the benefits.

[5] Bloomberg New Energy Finance ("BNEF") reported in March 2023 that over 1,500GW of wind and solar projects are waiting to be connected to the grid in Europe and the US (link).

[6] In their commentary of our report, they highlight that one area of potential underestimate in our CBA is the "*neglect of the cost of transmission and the theoretical possibility that, with stronger locational signals, less would need to be built*".

C. The experience of locational wholesale electricity pricing in practice

16. The third area of disagreement is on how locational pricing market designs, particularly nodal markets, work in practice. We note several apparent misconceptions that appear to underpin the comments of academic commentators, in particular around the following three key points:

(1) The extent that new generation siting decisions could respond to locational wholesale electricity prices.

(2) The design of Financial Transmission Rights ("FTR") markets and the impact on benefits.

(3) The need for redispatch in nodal markets and the link with other ancillary services

17. We discuss each in turn briefly.

(1) New generation siting decisions

18. First, some of the academic comments suggest scepticism with the extent of resiting of new generation that would occur as a result of locational pricing. For instance, Professor Pollitt states that "*there is no prior evidence that nodal pricing does result in substantial relocations of investment on the timeframe of the study (the next 18 years). There is however evidence that average (as opposed to marginal) zonal prices do make a difference to location."* It is not clear to us exactly what distinction is being drawn here, as the impact of locational prices on generator revenues in a zonal market would also apply to a nodal market. Certainly, it would *a priori* be very surprising, and contrary to fundamental economics, if investors did not take into account expected prices, along with other factors, when deciding where to site a generation plant.[7]

19. Of course, we understand that investors will also consider a wide range of other factors outside of locational wholesale electricity prices such as geography, resource availability, planning consents and site availability. Therefore our modelling approach to new generation siting incorporates very significant real-world constraints on the location of plant, for example through the use of Crown Estate lease information, to ensure that generation build-out remains feasible and realistic.[8, 9]

20. In any case, we also test a sensitivity where new generation is sited optimally in all market designs in our so-called "dispatch-only" sensitivity, in effect proxying for a perfect central planner or a perfect TNUoS regime. In this sensitivity, we find that there remain significant benefits from locational pricing even if it did not affect the location of plant at all.

21. We would separately note that our siting assumptions are also conservative in that we do not consider how the siting decisions of new demand, or inward investment from outside GB, may be impacted by locational pricing. Experience of, for instance, aluminium smelters and data centres in Iceland and northern Norway suggest that this is likely to be highly

[7] It would be particularly surprising if investors took account of expected prices in a system with zonal prices, but did not do so in a system with nodal prices

[8] We only allow the model to optimise the location of new-build generation. Existing generation, and generation in development do not re-site under a locational market design.

[9] For an in-depth discussion of our siting limit assumptions, please refer to Section 5D and Appendix 1 in our report.

conservative assumption on our part, and likely means that this is one factor that implies an underestimation of expected benefits of locational pricing. One recent example from September 2023 is the announcement that H2 Green Steel will build the world's first large-scale green steel plant and Europe's first giga-scale electrolyser in Boden, Sweden, which is located in a low price zone in north Sweden. We do not consider it to be unreasonable that similar investments could be made in Scotland or northern England under locational pricing, as these areas would have among the lowest wholesale electricity prices in all of Western Europe.

(2) Impact and design of Financial Transmission Rights ("FTR") markets

22. Second, in our report, we explain that FTRs are a key feature of nodal markets as financial products to help market participants hedge their price risk. FTRs are settled using the congestion rent that arises and is collected from the settlement process (as revenue collected from load will exceed payments to generators). In turn, FTRs are typically auctioned, with auction proceeds going to consumers. In our CBA, we assume that FTRs confer the full congestion rent benefits to consumers. This is because consumers fund the cost of the transmission network and are *prima facie* entitled to the rent that arises.

23. However, policymakers may also decide to allocate a portion of FTRs to market participants (in effect, being provided for free). Additionally, the total proceeds from FTRs auctioned might be lower than congestion rent collected for various reasons such as imperfect foresight. In these two cases, consumer benefits might decrease, and if this were the case would be offset by an equal and opposite increase in producer benefits – but socioeconomic welfare, under our assessment, remains unchanged. Moreover, a considerable portion of low cost FTRs, if made available, would flow through to consumers through lower tariffs offered by competitive retailers.

24. These two cases are commonly observed in US nodal markets reflecting both the policy choices that are required when deciding how to auction or allocate FTRs, and also the intrinsic challenges of designing such a regime. However, Professor Pollitt appears to misinterpret the experience of the FTR market in the US. He argues in his commentary that the inefficiency of the FTR market results in a 20% to 33% loss in socioeconomic welfare. This assumption is justified with reference to the PJM market monitoring report.[10] However, Professor Pollitt appears to misunderstand that this loss to consumers is not a socioeconomic inefficiency or cost – rather it arises in PJM because of the way FTRs (and a similar product called ARRs) were allocated, relative to the way the market monitor would have preferred FTRs to be allocated.[11, 12] Therefore, any potential cost impact should be netted off the consumer benefits and *not* the socioeconomic welfare he presented in Table 1 of his commentary. Professor Pollitt justifies this approach stating "*[t]his assumes that the reduction in consumer revenue is inefficiency, in part due to risk compensation and in part direct costs of the FTR system. This may be an overestimate as some could be a transfer…"*. However, based on our understanding of the factual evidence of FTR designs in

[10] Monitoring Analytics (2023), 'State of the Market Report for PJM 2022' (link).

[11] Notably, some of the benefits from the allocation of FTRs, or selling them at a discount, would also pass-through to end-consumers through their tariffs in a competitive retail market.

[12] For a discussion of this issue and a proposed remedy see e.g., the following presentation from Monitoring Analytics (link).

the US, we emphasise that this effect should be considered as a transfer rather than a potential overestimate of socioeconomic welfare.[13]

25. Ultimately, while the underlying feature and economics of FTR markets is common across US ISOs, there is considerable variation in allocation rules and auction design. If GB were to transition to a nodal market design, policymakers and market participants could develop a different design than adopted in the US.

(3) The need for redispatch in nodal markets and the link with other ancillary services

26. Third, some of the academic commentators mention that there is still a need for some form of redispatch in nodal markets. We highlight two comments:

- Professor Pollitt argues that the SO in nodal markets would still need to resolve constraints on the network. He writes "*if post gate closure constraints arise, has the SO no obligation to organise redispatch in real time (e.g. within the 5 minute window)? PJM has something called a transmission constraint penalty factor which pays for the resources it needs to purchase in order to effect redispatch*".
- Further, Professor Bell and Dr MacIver state that "*[n]either market participants nor the ESO or market operator will have perfect foresight on, in particular, demand and the availability of renewables when a centralised dispatch is being carried out. There will therefore still be a need for intraday action, including a BM*". We understand that the authors consider there will be additional intraday actions and cost required in a nodal market, akin to redispatch costs in the BM.

27. Considering these two remarks, it appears that both academic commentators might have misunderstood some of the fundamental features of nodal markets. The real-time market in nodal markets are based on a security-constrained economic dispatch that is carried out every 5 minutes,[14] with dispatch instructions sent to each resource every five minutes, and with settlements based on those 5-minute prices and 5-minute output.[15] This 5-minute dispatch is the market, and hence "*post gate closure constraints*" as stated by Professor Pollitt do not exist. These 5-minute dispatch instructions will generally differ from the day-ahead market schedules of on dispatch units, but these differences do not require an out-of-market settlement or market as any differences between day-ahead market schedules and real-time output are settled based on these 5-minute real-time prices.

28. In our report, we clarify that redispatch actions in a national market such as in GB involve the constraining on and off of resources to resolve a mismatch between the scheduled market outcome and the physical capabilities of the network. This arises in a national market as a consequence of the omission of network constraints when clearing the

[13] Professor Pollitt's main reference for his conclusions is his own recent paper: Pollitt (2023), *'Locational Marginal Prices (LMPs) for Electricity in Europe? The Untold Story'*. However, his descriptions of the experience of FTRs appear in some respects to differ substantially from the findings of US-based experts (see references in the Appendix).

[14] Five minutes is the typical interval adopted. Most US ISOs will send out new dispatch instructions more often if there is a material event within the normal dispatch interval such as loss of a major generator or transmission line.

[15] Invoices are on an hourly, rather than 5-minute basis to simplify billing. This is accomplished by calculating generator settlements based on output weighted 5-minute prices over the hour. This is mathematically identical to settling every 5-minute interval.

wholesale electricity market with a single price, and also arises in a zonal market, albeit to a lesser extent. No such redispatch actions are required in a nodal market as explained above – nodal prices are determined in the 5-minute dispatch which takes into account both network constraints, as well as changes to load and the output of intermittent resources, leading to a schedule that balances net demand and is consistent with the capabilities of the transmission network.

29. Separately, the cost of balancing actions needed to maintain system frequency stable are not considered in the analysis as they are required in any market design – whether national, zonal or nodal. As such, we have not considered how changes in locational wholesale pricing could impact the needs for these frequency-related balancing actions.[16]

30. Additionally, Professor Pollitt appears to confuse the Transmission Constraint Penalty Factor ("TCPFs") with redispatch costs in national or zonal markets. TCPFs, which is one of several "penalty factors", is applied to the nodal dispatch software manage the trade-off on the extent to which it is economic for a constraint of a transmission line to be temporarily violated. In other words, TCPFs are applied to ensure that the costs incurred to *avoid* violating a constraint is commensurate to the benefits of avoiding them (as violating a constraint beyond the thermal rating would lead to additional costs from "wear and tear" and also increases the risk of an outage).

31. The use of TCPFs is a relatively recent innovative feature of nodal market designs that reduces the need for the SO to make arbitrary decisions. For example, if the constraint was relaxed too much on an ad hoc basis, constraints can be violated at very low cost. Likewise, if the constraint is not relaxed enough, this could lead to excessive costs in dispatch.

32. Indeed, SOs may set different penalty prices for violation of different types of transmission constraints and also set different penalty prices for violating transmission constraints by a larger or smaller amount. The ability for the SO to allow transmission constraints to be temporarily violated at an appropriate cost is a common tool that applies to all nodal market designs in the US. In the GB context, such temporary violations of the rated capacity of transmission lines is a relatively commonplace activity by the ESO – for example, it may consider it preferable to allow additional power to flow across a transmission line in excess of its rated capacity rather than undertake a costly BM action. We have not sought to capture these effects in our modelling as, in the overall context of our work, it is a relatively small detail and would appear to apply equally in all market designs – albeit in a different manner.

33. Similarly, Professor Bell and Dr MacIver appear to confuse the need for intraday actions in a nodal market as an additional BM cost of nodal markets, driven by deviations between the real-time market and the day-ahead market. As explained above, the real-time dispatch that balances real-time net load is not an out-of-market process akin to the BM; it is the market. While it is true that there is a cost associated to intraday processes, we have not considered this cost as it is a *feature in all market designs*.[17] For example, the

[16] However, we do note that a centralised scheduling market could have additional benefits from balancing actions, such as through the co-optimisation of energy and frequency/reserves.

[17] As such, we do not explicitly model both day-ahead market and real-time dispatch solutions in any market designs.

assumption of perfect foresight between the day-ahead and real-time stages applies to all market designs – it arises as more information is revealed leading to additional cost to market participations. Indeed, in GB, these costs could arise either through internal adjustments to physical notifications or imbalance prices in national markets.[18] Moreover, a portion of SO intraday processes in nodal markets are balancing costs that apply in all market designs, notably ancillary services in GB.

D. Specific areas of mischaracterisation of FTI's report

34. In addition to the relatively wide areas of disagreement outlined above, we have identified some statements in the academic commentary which we believe misunderstands or misstates our report. We describe (non-exhaustively) some of them here.

35. Most notably, we believe that the section entitled "*The overall assessments reworked*" in Professor Pollitt's commentary, and the accompanying Table 1, misstates our results in a way that is inaccurate leading to mistaken conclusions. This is for two main reasons.

36. First, in column 2 of Table 1, Professor Pollitt uses the share of net benefit for the "dispatch-only" sensitivity that we calculated for the LtW (NOA7) scenario and applies the same proportion to the other two scenarios. The argument for adopting this approach is that the locational benefits could be delivered through locational transmission charges instead. As noted above, we are sceptical on this point.

37. However, even if we assumed this was the case, it is entirely incorrect to use the percentage of benefits attributable to dispatch that we calculated in the LtW (NOA7) scenario and apply to the other two scenarios. Given the very different make-up of the generation and transmission asset bases in the SysTr (NOA7) and LtW (HND) scenarios, the split between locational and dispatch benefits would also be very different. Although we have not calculated it directly, Figures A2-4 and A3-2 in Appendix 2 and Appendix 3 respectively show that there would be a lower volume of new generation opting to site in different locations under a nodal market for the SysTr (NOA7) and LtW (HND) scenarios relative to the LtW (NOA7) scenario. Given this, it is possible, if not likely, that the proportion of dispatch benefits in a locational pricing market design would be higher for the LtW (HND) and the SysTr (NOA7) scenarios relative to the number used in Table 1.

38. The second reason, as explained above in more detail, is on his application of consumer to producer transfers due to FTR allocations as an *economic welfare loss* in column 5. As explained above, that any such transfers, most of which will be driven by policy choices, would not affect socioeconomic welfare.

- In Professor Newbery's review, he states that:
  - we are "*solely relying on the most optimistic future energy scenario*". We rely on all three scenarios, but present LtW (NOA7) as it is the first scenario modelled in our assessment. Our full results for the SysTr (NOA7) and LtW (HND) scenarios are in Appendices 2 and 3 respectively; and

[18] See Herrero et al. (2018) (link) for a discussion of the extent to which intraday adjustments are currently possible in US nodal markets and how to further extend the possibility for intraday trade (as in European intraday markets) in nodal markets while keeping the efficient centralised dispatch logic of the ISO model.

- our "*consumer benefits are optimistic"* because there would likely be significant grandfathering of access rights to generators. We highlight that the extent of grandfathering and/or the protection of existing investments is primarily a legal question and a policy choice. Therefore we have only described the effects briefly in our report and consider a more detailed discussion to be outside the scope of our assessment.[19]

- In Professor Pollitt's review, he states that:
  - we do not "*devote many paragraphs… to explaining what nodal pricing is or how it is meant to work".* Our report sets out the both the economic theory of nodal pricing and how it works in practice, particularly in Chapter 2. We did not go into further detail on how the dispatch algorithm would work as well as the precise pricing mechanisms as they seemed to us to be less relevant for the purpose of the report; and
  - we assume that "*power flows are expensive to reverse in national markets, but that they are costless to reverse in nodal or zonal markets"*. This is not true – reversing schedules can be costly in a zonal market, within zones, which we assess. There is, however, no need to "reverse" scheduled flows in a nodal market as scheduled flows are consistent with the configuration of the transmission network (described above).
- In Professor Bell and Dr MacIver's review, they state that:
  - our assessment does not consider the financial viability of individual generators, which could lead to higher "*prices of their offers of energy or, for new generation able to bid for Government-back CfDs, their bids in a CfD*". It is true that we do not generally consider the financial viability of individual generators, either in the national pricing or the locational-pricing cases. This means that we assume that the generation capacity mix in the FES scenarios is financially viable, and that it would remain so with locational pricing.[20] However, we *do* consider the financial viability of generators that bid for new CfD contracts, since their bids have to ensure that their levelized cost is covered;
  - it is "*absolutely critical to test whether… the prices used in both BM costs assessments and locational pricing assessments are reasonable"*. Our BM bid and offer assumptions are based on historical evidence and triangulation with the ESO's own approach; and

[19] We note from our results, some of the gap between producer and consumer surplus are attributable to new generators and would not be affected by grandfathering. We have also assumed that all existing CfD contracts would continue. Additionally, any discussion of grandfathering would have a wide range of considerations, for example the potential netting-off of the locational charges in TNUoS, the legal implications of specific contracts, rules and codes, and the policy choices to balance competing consumer and producer benefits.

[20] It was not necessary to consider the financial viability for every individual generator as we assumed the capacity mix would be fixed to the FES across all market designs. Indeed, if this assumption had been relaxed, the additional loss of revenues to individual generators may need to be considered – although this may well lead to greater benefits of locational prices as the capacity mix would be optimised with respect to the configuration of the transmission network.

— our results are overestimated in part due to "*relatively little transmission reinforcement being modelled after 2030*". We follow the transmission build-out post-2030 as set out by the ESO's NOA7 or NOA Refresh assessments, both of which includes considerable transmission investments, consistent with the anticipated generation roll-out.

E. Closing remarks

39. To close, we are very grateful for the discussion and challenge raised by Professor Newbery, Professor Pollitt, Professor Bell and Dr MacIver, who have contributed to the evolution of the GB electricity market and design since its inception. For further consideration, we have set out a range of literature of other leading academic thinking around the world in Appendix 1 to provide additional insights into how locational market designs work.[21] We hope that this memo provides further clarity on our assessment of the costs and benefits of locational wholesale electricity prices in GB.

[21] Two of these academics, William Hogan and Scott Harvey, who have been in part responsible for the development of US nodal markets, have been key contributors to our assessment. Tim Schittekatte, while not involved in this engagement, has recently joined FTI.

Appendix 1: Selection of international academic studies on locational wholesale electricity markets

A. Empirical evidence of the benefits from the US:

1. Wolak, F.A., 2011. Measuring the benefits of greater spatial granularity in short-term pricing in wholesale electricity markets. American Economic Review, 101(3), pp.247-252. link
2. Zarnikau, J., Woo, C.K. and Baldick, R., 2014. Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market? Journal of Regulatory Economics, 45, pp.194-208. link
3. Triolo, R.C. and Wolak, F.A., 2022. Quantifying the benefits of a nodal market design in the Texas electricity market. Energy Economics, 112, p.106154. link

B. Estimations of the benefits in the European context:

4. Green, R., 2007. Nodal pricing of electricity: how much does it cost to get it wrong? Journal of Regulatory Economics, 31, pp.125-149. link
5. Leuthold, F., Weigt, H. and Von Hirschhausen, C., 2008. Efficient pricing for European electricity networks–The theory of nodal pricing applied to feeding-in wind in Germany. Utilities Policy, 16(4), pp.284-291. link
6. Neuhoff, K., Barquin, J., Bialek, J.W., Boyd, R., Dent, C.J., Echavarren, F., Grau, T., Von Hirschhausen, C., Hobbs, B.F., Kunz, F. and Nabe, C., 2013. Renewable electric energy integration: Quantifying the value of design of markets for international transmission capacity. Energy Economics, 40, pp.760-772. link
7. Aravena, I. and Papavasiliou, A., 2016. Renewable energy integration in zonal markets. IEEE Transactions on Power Systems, 32(2), pp.1334-1349. link

C. Discussion of evidence and qualitative arguments:

8. Hogan, W.W., 2002. Electricity market restructuring: reforms of reforms. Journal of Regulatory Economics, 21, pp.103-132. link
9. Neuhoff, K., Hobbs, B.F. and Newbery, D., 2011. Congestion management in European power networks. Berlin: Climate Policy Initiative. link
10. Baldick, R., Bushnell, J., Hobbs, F.,B., and Wolak, F., 2011. Optimal Charging Arrangements for Energy Transmission: Final Report. Report Prepared for and Commissioned by Project TransmiT, Great Britain Office of Gas & Electricity Markets. link
11. Neuhoff, K. and Boyd, R., 2011. International experiences of nodal pricing implementation. Working Document (Version July). Berlin: Climate Policy Initiative. link
12. Adib, P., Zarnikau, J. and Baldick, R., 2013. Texas electricity market: getting better. In Evolution of global electricity markets (pp. 265-296). Academic Press. link
13. Weibelzahl, M., 2017. Nodal, zonal, or uniform electricity pricing: how to deal with network congestion. Frontiers in Energy, 11, pp.210-232. link
14. Eicke, A. and Schittekatte, T., 2022. Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate. Energy Policy, 170, p.113220. link
15. Harvey, S. and Hogan, W.W, “Locational Marginal Prices and Electricity Markets,” October 17, 2022. link

D. Discussion of evidence and illustration via numerical examples/modelling:

16. Harvey, S.M. and Hogan, W.W., 2000. Nodal and zonal congestion management and the exercise of market power. Harvard University, 21. link
17. Ehrenmann, A. and Smeers, Y., 2005. Inefficiencies in European congestion management proposals. Utilities policy, 13(2), pp.135-152. link
18. Holmberg, P. and Lazarczyk, E., 2015. Comparison of congestion management techniques: Nodal, zonal and discriminatory pricing. The Energy Journal, 36(2). link
19. Sarfati, M., Hesamzadeh, M.R. and Holmberg, P., 2019. Production efficiency of nodal and zonal pricing in imperfectly competitive electricity markets. Energy Strategy Reviews, 24, pp.193-206. link
20. Lété, Q., Smeers, Y. and Papavasiliou, A., 2022. An analysis of zonal electricity pricing from a long-term perspective. Energy Economics, 107, p.105853. link
21. Aravena, I., Lété, Q., Papavasiliou, A. and Smeers, Y., 2021. Transmission capacity allocation in zonal electricity markets. Operations Research, 69(4), pp.1240-1255. link