Comments on the FTI Report on *Assessment of locational wholesale electricity market design options in GB August 2023*

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Ofgem note: This report was produced based on early, draft versions of the FTI report and appendices. As such, specific references may not match the published version of the FTI report.

I have been asked by Ofgem to review materials supplied by FTI Consulting[1] relating to their work on locational pricing in Great Britain. The brief from Ofgem is the following:

'The Consultant is required to take part in an independent academic review of the assessment of locational pricing commissioned by the Authority from FTI Consulting. The scope of work requires a reading of the FTI report with a specific focus on the assumptions and modelling approach used. Output should be a short report determining whether the FTI analysis and key findings can be considered as conservative or optimistic, with views provided on whether the key limits FTI have identified in their work are accurate.'

In what follows I refer to the main report as the FTI Report (FTI Consulting 2023a) and specific numbered paragraphs in the Report (FTI Consulting, 2023a) and Appendices (FTI Consulting, 2023b). I also make use of some of the numbered slides in the Final Modelling Results presentation (FTI Consulting and ES Catapult, 2023). I have decided to divide my comments into two sections. In the first, I offer some higher level comment on the nature of the exercise undertaken and what conclusions might be drawn from it for the future of electricity market design in Great Britain. In the second, I offer detailed comments on the main report and the appendices. These have informed my higher level comments. The comments are offered in the spirit of an academic report on a submitted thesis. The Report is a serious intellectual

[1] FTI Consulting (2023a), *Assessment of locational wholesale electricity market design options in GB, August 2023,* London: FTI Consulting; FTI Consulting (2023b), *Assessment of locational wholesale electricity market design options in GB Appendices, August 2023,* London: FTI Consulting; FTI Consulting and ES Catapult (2023), *Locational pricing assessment in GB: Final modelling results*, *Presentation to Stakeholders Workshop 3*, FTI Consulting, 6 June 2023, London and 13 June, Glasgow.

endeavour addressing an important policy question which deserves to face thorough questioning.

At the outset I want to commend FTI for the work they have undertaken and the way they have gone about doing it. They have been transparent as to their methods and how they have derived their results. Jason Mann and his colleagues have also been very willing to answer questions in public and private about what they have done. For this I am very grateful. The FTI Report is quite careful in saying when important modelling choices have been made in consultation with industry stakeholders. This has naturally constrained some of the modelling choices made by the writing team. It also important to acknowledge that in any exercise like this the number of model runs has to be limited and not all results can be presented. FTI has done a good job explaining what choices they have made in modelling and in presentation. I should also note that the mere fact of having some concrete numbers on the table with which to discuss this issue is of great value. I am also very grateful that the FTI team have provided me with extensive comments on an earlier version of these comments. I also wish to acknowledge very helpful comments from Ofgem colleagues.

I also want to acknowledge the helpful interactions I have had with many colleagues, across the world, on the issue of nodal pricing. A special thanks are due to my dear Cambridge colleague, Professor David Newbery, who inspired me to take an interest in this topic and has continued to give me the benefit of his insights throughout this process. All the views expressed in my report are my own and should not be taken to be shared with anyone with whom I am associated.

Section 1: High level comments

1. *The nature of the analysis undertaken*

A core part of the FTI Report focusses on the benefits of locational arising from relocations of generation within fixed scenarios of total GB generation given by the GB Electricity System Operator (NG ESO) in their Future Energy Scenarios (FES). While this, indeed, could be a substantial benefit arising from better locational signals for investment 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.

Thus the headline analytical focus of the FTI Report goes beyond that of previous studies of the impact of nodal pricing (or locational marginal pricing or LMPs). Indeed, the two academic assessments of the actual introduction of nodal pricing (Wolak, 2011, on California, and Triolo and Wolak, 2022, on Texas) focus on the dispatch savings resulting from better scheduling of generation to meet demand (in moving from zonal to nodal pricing).

There is little available quantitative evidence that suggests that generation location is determined by short run nodal (or zonal) prices, instead the evidence is consistent with the widely held view that generation location is primarily driven by joint optimisation of long-run transmission and generation costs (see Pollitt, 2023, for a review). By contrast the FTI Report is a unique take on a prospective cost benefit analysis (CBA) of LMPs based on the assumption that it might move large quantities of subsidised new generation to 'optimal' locations across GB. Indeed, 43% of total net benefits in the LtW (NOA7) scenario)[2] of nodal pricing identified in Report are due to the moving of huge quantities of generation and storage to locations closer to loads and population centres and this is a significant assumption in a small crowded island with substantial planning constraint issues. For instance, the analysis suggests 40 GWs of onshore wind, solar and batteries moves between onshore regions of GB on the basis on a move from national to nodal pricing by 2040 (Para 6.33).

The three FES related scenarios examined – Leading the Way (NOA7), Leading the Way (HND) and System Transformation (NOA7) - are all very ambitious. For the purposes of providing a more plausible range of outcomes it would have been good to have had a scenario based on Steady Progression, FES' least ambitious scenario.

2. *The discussion of what nodal pricing means in a GB context*

Rather surprisingly, the FTI Report does not devote many paragraphs (e.g. Para 2.22-2.26) to explaining what nodal pricing is or how it is meant to work. This is unfortunate because a GB system with a current peak demand of 50 GW, with 850 nodes, has an simple average nodal peak of 59 MW (though power follows multiple non-linear paths). However given that some nodes have much lower loads than this, there could have been some attempt to explain some generic categories of nodes and how nodal pricing influences power flows and how supply and demand are being equilibrated at the nodal level (to help understand the significance of incremental capacity and the nature of competition, as a large node with many generators is will behave differently to a small node with one generator).

A nodal pricing *system* consists of three elements: first, locational marginal prices at some but not all locations[3]; second, regulation of local market power which would otherwise arise due to significant market segmentation; and third, a system of financial transmission rights (FTRs) to mitigate the risk arising from increased price volatility. The FTI Report does not discuss the implications of the first for the accuracy of nodal prices at the transmission level; the key role of the second in limiting market power; and does not sufficiently acknowledge the implications of the third. The first does suggest that transmission level only nodal pricing may increase constraints in the distribution system; the second suggests that bid regulation rather than nodal pricing may be significant source of benefits (particularly for consumers); and the third is so significant in US markets in terms of both costs, transfer payments and risk mitigation that it should be explicitly incorporated into an overall cost-benefit of nodal (and zonal) pricing.

3. *The interpretation of existing state of knowledge on nodal pricing*

The FTI Report does not, in my view, reflect the previous literature analysing the impacts of locational pricing. The previous literature clearly says the following:

[2] £13.7bn / £24.0 bn are due to dispatch savings, leaving £10.3bn / £24.0 bn due to locational optimisation.
[3] Only higher level nodes are priced, nodes deeper within the distribution system (which may be constrained) are not priced.

a. The proven benefits of nodal pricing are in short run operational dispatch improvements NOT long-run siting decisions. FTI reports a paper which says this (MacIver et al., 2023 at Para 8.40). It also seems to misinterpret papers (Lundin, 2011, and Kahn and Mansur, 2013 below) which are about zonal price differences as providing support for the impact of nodal pricing on location. It does not report on other papers which find there is little evidence on long-term siting effects (see Pollitt, 2023). Instead of focussing to short run operational dispatch improvements, the FTI Report takes as it starting point the existence of long-term siting effects.

b. Nodal pricing in the US induces risk related costs. The mere fact of the need to introduce financial transmission rights (FTRs) in nodal market in the US is evidence of this (Pollitt, 2023). While risk can be hedged – hedging is expensive and its costs should be considered as a core part of any cost benefit analysis of a move to nodal pricing. The FTI Report argues that there is no reason to be believe that nodal pricing increases risk (Para 8.64-65).

c. The FTR market is inefficient and costly to consumers. The evidence on this is overwhelming and is not mentioned by FTI (see Pollitt, 2023 for a review). Based on FTI's modelling (at Para 7.75) of the congestion rent in a GB nodal pricing system would be that a US style FTR market would cost GB consumers up to £9bn in the LTW(NOA7) scenario (33% of £27bn). There would also be some part of this £9bn that would need to be subtracted from the net benefit. How much this would be is subtracted from net benefit depends on the perspective taken. [4]

d. The evidence is consistent with the view that some more locational pricing is beneficial to industry, but not necessarily nodal (or marginal zonal) pricing. The FTI discussion (at Para 2.83 and 2.86) appears to conflate the benefits of locational signals with the benefits of nodal prices. For instance, the only two papers it cites in favour of nodal pricing are actually about the benefits of zonal average pricing (Lundin, 2011, and Kahn and Mansur, 2013). One of these is about the benefits of more zones within a country, the other about differences in final prices between utility areas. Thus the first, is an argument for some more pricing granularity, the second is an argument for the importance of long-run locational price signals which translate into consistently different final average prices.

e. Nodal pricing is partial. For a core analysis that moves 50GW+ of capacity to different locations around GB, there should be a discussion of whether there might be important constraints inside the distribution system, below the level of the priced node. There is only a mention of how induced power flows through Ireland (Para A1.98) or continental Europe (Para 6.3, Box 6.3) might give rise to costly congestion or

[4] If part of this non-recycled congestion revenue is compensation for an aggregate increase in societal risk, this is a genuine welfare loss to the whole of UK society. Similarly, if some large part of the non-recycled congestion revenue represents a higher payment to foreign owners of capital it is a loss to UK welfare. Even if there is no increase in UK aggregate investment risk, but there is an increase in electricity system stakeholder risk then there is a welfare loss from the narrower perspective of consumers and producers in the electricity system. The FTI Report implicitly adopts this latter approach in its cost benefit analysis, by allowing a cost of capital to rise in the electricity system to be counted as a social welfare loss in its scenario analysis.

seams issues with our European neighbours (and Northern Ireland, another part of the UK), with whom we are interconnected.

f. Nodal pricing can exacerbate unpriced or mispriced externalities. A major conclusion from Triolo and Wolak (2022) is that nodal pricing reduced the financial costs of dispatch while raising CO2 emissions, to such an extent that the increased CO2 cost offset the financial benefits of cheaper dispatch. There is no discussion in the Report that moving generation closer to load centres in the UK might have similar local environmental effects. Indeed one of the reasons for the current location of GB generation away from load centres in the South of GB is because this does reflect implicit externality valuations (increase in building costs, visual pollution etc). Indeed the FTI raises an intriguing question when it discusses the potential additional value of emission reductions (Para 9.54ff) as to whether if these were priced properly then the modelling would give rise to different locations of investment to those modelled in the FTI Report.

4. The approach to zonal pricing

The FTI Report has only a short discussion of zonal pricing and what it actually means (see Para 2.32-2.34). There are actually three types of zonal pricing. First, the type that exists in Europe, where each zone is treated as a separate market with fixed transmission transfer capacities between them. This ignores loop flows. Second, the type where nodal prices are averaged are across a zone (as they are on the retail side in the US). Third, a type where loop flows are considered and a zone is treated as one node. FTI are using the third definition, but they could have used either of the other two. An advantage of the first, is that this it is what happens in Europe. An advantage of the second is that it does reflect what happens on the demand side to reduce risk on the demand side.

5. The three market pricing alternatives analysed

The FTI Report offers three alternatives: national pricing; 7 price zones; or 850 price nodes. 7 zones deliver most of the benefit of nodal pricing, while arguably avoiding some part of the potential costs arising from a sophisticated FTR system; a rise in the cost of capital; a backlash from Europe etc.

The FTI Report numbers show that if 7 zones avoided a cost of capital relative to nodal pricing, zonal pricing could be close in net present value (NPV) to nodal pricing. Though it might be that zonal pricing would cause some (but lower) rise in the cost of capital. The results reported in FTI Consulting and Energy Systems Catapult (2023) suggest nodal pricing has net benefits of £24.0bn under LtW(NOA7) (p.62)[5], while zonal pricing has net benefits of £15.3bn (p.62). However sensitivity analysis suggests that nodal pricing could lead to higher capital costs of £7.45bn (p.57), while exempting the demand side from nodal pricing could further reduce nodal benefits (p.76). This suggests that nodal pricing might be only slightly more beneficial than zonal pricing (£24.0bn-£15.3bn-£7.45bn= £1.25bn) if it saves on capital

[5] I assume all prices are in 2022 values, though the Report does not clearly say this. There is a minor discrepancy between the overall NPV figures for LtW(NOA7) on Slide 49 of the presentation and the main Report: £24.5bn vs £24.0bn.

costs.[6] The relative benefits are further reduced if the zonal scheme is cheaper to implement.

However, why stop there? A 27 zone Transmission Network Use of System (TNUoS) charge which reflected locational price differences would produce even more locational benefits, while still having less downside risks. It was disappointing that Ofgem and the stakeholder consultation process did not suggest that FTI model a larger but intermediate number of zones.

6. *Default assumptions about market re-design*

The FTI Report makes a number of detailed assumptions which are guaranteed to deliver consumer benefits (and benefits overall) by assumption for locational pricing, while not necessarily representing welfare improvements in reality.

Locational pricing segments the national market: assuming no change in bidding behaviour, this is likely to reduce prices by simply paying individual producers closer to their marginal costs. The Report (Para 2.37-2.52) assumes that this is what happens and does not discuss the fact that auction theory tells us that if the market is redesigned in this way, bidders will likely change their behaviour and raise their bids.

The Report notes (e.g. Para A1.29) that there are substantial mark-ups in the bids and offers that participants in the balancing mechanism (BM) submit, but assumes that there are no such mark-ups in locational marginal prices (though there are assumed start-up costs). This guarantees price benefits for consumers from more locational pricing - by eliminating mark-ups by assumption - and assuming that generators do not need to be compensated for mark-ups on marginal costs in locational markets and would not seek to alter their bids to recover such costs.

The Report assumes that while power flows are expensive to reverse in national markets, but that they are costless to reverse in nodal or zonal markets.

The Report shows that flows on interconnectors substantially alter with potentially higher prices abroad under locational pricing (e.g. Para 6.43). While it is understandable that FTI Report has to focus on domestic net benefits, UK public policy should be wary of energy policies with positive benefits for the UK but where there are a lack of global benefits due to negative effects on foreigners. Such wariness is warranted in this case if losses to foreigners might provoke any demand for compensation or a change in bidding behaviour across interconnectors or a lack of willingness to improve trade relations in electricity.

For CfD holders, the FTI Report assumes that they have their right to constrained off (Para 4.56-4.57) payments removed entirely and are dispatched in line with system cost minimisation. This changes their property rights and allows the SO to dispatch them in a way

[6] The numbers are not strictly to be combined in this way (the cost of capital sensitivity is based on LtW(NOA7) and the load shielding sensitivity is based on SysTr(NOA7)). The reported FTI modelling does not make it straightforward to compare their zonal and nodal pricing regime CBAs, while incorporating their sensitivity analyses. An important issue being would zonal pricing itself have some risk implications?

which minimises system cost. This does not necessarily require nodal (or zonal) pricing. However this raises the issue of the assumed counterfactual in the analysis, which is one of no change to the current national pricing arrangements. The Review of Electricity Market Arrangements (REMA) process is already examining changes to CfD payment rules (following BEIS, 2022) independently of the introduction of locational pricing.

Finally, the model assumptions ensure that there are no redispatch costs by design under nodal pricing (Para 7.41). However, in reality, nodal markets do still have some, non-trivial, redispatch costs. This is not discussed in the Report.

7. The modelling of new investment

The FTI Report adopts a least cost approach to delivering on the FES based scenarios that it analyses, i.e. it fixes capacity and selects least cost locations. It does not appear to make use of a forward looking rational expectations approach to whether a given capacity addition at the cheapest location will actually be profitable in the future. Given that a substantial part of the core modelling is about the benefits of locating investment in the right places, it is a potential issue that the modelling does not check whether an investment is actually profitable (rather than least cost) in a particular location.

For instance, an example discussion (at Para 6.26) suggests a battery is more likely to locate in the North of Scotland (GB1) than in the South of England and Wales (GB6). The problem with the example is that while the battery does make higher arbitrage revenue in GB1 than GB6, it may not be profitable in either location. The analysis does not check this, but instead assumes that the FES scenarios are delivered.

8. Sensitivity analysis conducted

The FTI Report does conduct sensitivity analysis. It models three NG ESO scenarios (all of which deliver the pathway to Net Zero) and it demonstrates the individual impact of a rise in the cost of capital, a consideration of the ‘pure dispatch effect’ and an exemption of demand effect. The FTI Report is clearly constrained in the number of scenarios that can reasonably be modelled and documented. It is also influenced by what Ofgem and industry stakeholders asked FTI to look at. However it is worth pointing out what the Report could have looked at and why it might have been worth looking at them.

The Report does not for instance look at the impact of different commodity price assumptions, a less ambitious decarbonisation scenario or a combination of assumptions which are less favourable to locational pricing.

It is somewhat unfortunate timing that the Report makes use of commodity prices on 20 April 2022 (Para A1.104), given that this day of high uncertainty in the immediate aftermath of the Russian invasion of Ukraine is, hopefully, fairly unrepresentative of the prospects for prices over the years to 2040. This should have suggested that some alternative commodity price scenario was required for the early years of the analysis.

The Report does not attempt to systematically isolate discrete sources of benefit from a nodal pricing regime that could be delivered by partial regimes (of the type we have now). These might have included using shadow nodal prices to schedule interconnectors or flexible loads or government CfD generators. While it was understandable that the Report's scope had to be limited, this does raise the issue of whether there were ways to deliver significant benefits from more partial use of locational signals without recourse to full nodal (or zonal) pricing.

9. The modelling results and their plausibility

The FTI Report finds substantial gross and net benefits. In its LtW(NOA7) Scenario (summarised at on FTI Consulting and ES Catapult (2023, p.62), the overall net benefits are almost £2bn per year (annualised over 16 years)[7]. For consumers the value is twice as large for the LtW(NOA7) scenario at £4.2bn p.a.[8] The price impact is a reduction in 9-14% of the wholesale price over the three scenarios. In terms of overall impact the benefits are significantly higher than for previous studies (which found cost impacts of 2-4%). The modelled losses to generators are £2.2bn p.a. under LtW(NOA7)[9]. These impacts are so large, they are likely to have second order effects. The claim in the Report (Para 82) that no investment impacts were likely from a policy induced permanent fall in the wholesale price of 10% seems a strong one. The loss of profit would likely result in capacity withdrawal and price rises by generators. Meanwhile the large reduction in price would raise the demand for electricity. The report does not assume a likely secondary impact of such a large fall and merely notes that such a fall is in line with the prospective price fall due to the New Electricity Trading Arrangements (NETA) in GB in 2001. The price impacts around NETA did produce significant second order effects in the form of generator bankruptcies and capacity withdrawals (NAO, 2003).

10. The overall assessments reworked

A simple reworking of the FTI Report numbers (in Table 1) shows how the apparently high overall benefits are substantially reduced with changes to assumptions. All of these results rely on very ambitious roll-out scenarios in the FES, which are themselves at the high end of what is likely to happen to GB capacity. The Table 1 numbers do not adjust for the possible need to compensate stakeholders in Ireland (NI and RoI) and/or wider European stakeholders within Trade and Cooperation Agreement (TCA) renegotiations.

While Table 1 combines numbers that cannot be directly combined, this table is illustrative of of what numbers could have been reported to allow for fuller comparisons of the impact of the scenario analysis. Figures taken directly from the FTI Report and FTI Consulting and ES Catapult (2023) are in Red.

Table 1: The CBA reworked

[7] £24.0 / 12.09 is the value of 16 year annuity which adds up to an NPV of £24.0bn, with a discount rate of 3.5%.
[8] £50.8bn / 12.09.
[9] £27.9bn /12.09.

£bn *Scenario*	Reported overall Net Benefit (1)	Net benefit for dispatch only (2)	Reduction for Load Shielding (3)	Congestion Rent (4)	Reduction for inefficiency of FTR market (20%-33% loss) (5)	Reduction for rise in cost of capital (6)	Adjusted total net benefit (7)= (2)-(3)-(5) or (2)-(3)-(6)
Nodal							
LtW(NOA7)	24.0	13.7	Est. 0	27.1	5.4-9.0	7.45	+4.7 to +8.3
LtW(HND)	14.4	Est.8.2	Est. 0	25.6	5.1-8.5	Est.7.45	-0.3 to +3.1
SysTr(NOA7)	13.1	Est.7.5	1.7	16.4	3.3-5.4	Est.7.45	-1.6 to +2.5
Zonal							
LtW(NOA7)	15.3	Est.8.7	Est. 0	18.0	3.6-6.0	Est.0	+2.7 to +8.7
LtW(HND)	7.1	Est.4.0	Est. 0	15.4	3.1-5.1	Est.0	-1.1 to +4.0
SysTr(NOA7)	6.2	Est.3.5	Est. 0	12.0	2.4-4.0	Est.0	-0.5 to +3.5

Source: Numbers in Red are from Slides 62, 73 and 75 in FTI Consulting and ES Catapult (2023).
Notes:
(2) The estimates are not reported by FTI. My estimates take the FTI Report share of full model savings attributable to dispatch from their reported estimate for LtW(NOA7) and applies this to the others scenarios.
(3) The estimates are not reported by FTI in their Report. In direct communication FTI report 'almost no impact' from load shielding for LtW(HND) and SysTr(NOA7).
(5) These figures are my calculations. This takes a range of values reflecting PJM's FTR revenue recycling rate of 67% at the high end. This 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 note I either subtract (5) or (6) from the overall benefit not both.
(6) The estimates are not reported by FTI. This assumes the same figure for cost of capital impacts for other nodal scenarios (as level of investment is similar). It assumes zero as lower bound of impact for zonal charging – it would probably be more than this. I do this to show a range of estimates. Note that even if the zonal estimates for cost of capital impacts were positive, they need to be higher than the upper bound in (5) to affect the final ranges.
(7) This calculates a new total assuming only dispatch effect, with load shielding and either the lowest or highest FTR cost OR a cost of capital impact, to give the range of values.

This table invites a number of observations. First, the FTI Report does not provide all of the numbers required to populate this table (all the numbers labelled Est.) and hence it is not possible do see the size of the impact of the sensitivity analysis on all of the main scenarios. Second, the LtW(NOA7) scenario, highlighted in the FTI Report (at Para 50 and 71) and FTI Consulting and ES Catapult (2023, at slides 49 and 61), has significantly higher NPVs than the other two. Third, there seems to be the possibility of negative outcomes for the LtW(HND) and SysTr(NOA7) because the benefits fall significantly, if only focussed on dispatch, but the likely losses due to risk mitigation measures (FTRs or rises in the cost capital) are still relatively high. Fourth, the difference between nodal and zonal prices is not clear cut, with the potential for zonal prices to yield higher NPV than nodal prices, as noted earlier. Fifth, while net benefits could be significantly lower than the headline figures in the FTI Report, there is likely an overall benefit from the introduction of some more granular price signals (either zonal or nodal).

11. Overall assessment of the FTI Report

Overall, the FTI Report is an impressive piece of analysis summarising an enormous amount of complex modelling. It produces some big numbers to suggest that the benefits of nodal pricing could be as high as 0.08 % of GDP p.a. over 16 years[10]. As such it demands serious consideration. It does make a strong case for the potential benefits of more locational pricing in GB electricity.

However, the headline results (at page 14 and 17 in the FTI Report) are overly reliant on the benefits of re-siting generation and storage to better locations. It does this by the questionable assumption that this would happen as result of system level least cost minimisation, rather than on the basis of profit maximisation. The evidence that this happens at scale does not exist for nodal markets and is weak for zonal markets. At its core the central analysis assumes that 10s of GWs of generation and storage would be moved by locational pricing to more cost favourable locations nearer demand centres. This is tantamount to assuming that nodal pricing can move onshore wind from Northern Scotland (GB1) south, or solar from Northern England (GB4) to Southern England and Wales. Of course, that would clearly save system costs ceteris paribus, but is it actually realistic, given that these numbers are on top of large base level rises in capacity?

More positively, the FTI Report does make a strong case for the potential benefits of more locational price granularity. Here the Report moves on to much stronger ground by raising four key locational issues which would individually yield significant net benefits.

First, has much of the planned £55bn of transmission expansion over 2025-2040 been correctly assessed? While the basic analysis in the Report does not directly relate to this, the Report raises the key question of whether transmission planning is being conducted (e.g. Para 98ff) using the right optimisation is one that demands a separate answer in its own right. FTI are to be commended for highlighting this.

Second, the FTI Report draws attention to is the importance of government CfD contract reform. The report rightly highlights that such CfDs incentivise the maximisation of output from low carbon generators, regardless of the shadow value of that output to the system as a whole (Para 2.113). It is an obvious tweak to future CfD contracts to alter them to allow the system operator to curtail all future government CfD generators in ways that optimise the system as a whole (see BEIS, 2022).

[10] UK GDP was £2491 bn in 2022 (https://www.ons.gov.uk/economy/grossdomesticproductgdp/timeseries/ybha/pn2).

Third, the FTI Report brings out the role of interconnectors in the GB system. Clearly, sending signals for more sensible utilisation of interconnectors is an important issue, which could for instance be partially addressed by including these in the existing TNUoS zonal charging regime.

Fourth, the FTI Report indirectly points to is the advantage of better price regulation of bidding in the BM (Para 5.10). A key benefit of nodal pricing as practiced in the US is that it effectively regulates the local market power of generators who would otherwise be pivotal behind constrained nodes otherwise requiring redispatch. This is precisely what does not happen at the moment in the BM, where the FTI Report notes that the evidence – from NG ESO - seems to be of clearing bids and offers substantially marked up above true economic costs. As the implementation of nodal pricing would necessitate a sophisticated scheme of monitoring and regulation of local market power in nodal markets, it would seem to be worth implementing such a scheme within the existing BM.

A further important point that the FTI Report raises is whether carbon prices are too low (Para 9.54ff) in the UK and whether they are actually fully reflecting the carbon externality. Using carbon prices which are consistent with net zero is a key element of cost effective decarbonisation of the electricity sector. FTI's analysis rightly highlights the potentially large economic impact of carbon mispricing on the location of generation (and by implication on the type of generation). Aligning the government's shadow cost of carbon with the external market signal is essential for any sensible net zero strategy within the context of the overall emissions cap in the Emissions Trading Scheme.

This brings to an evaluation of what FTI have done in terms of their 'technical assessment' case for introducing US style zonal or nodal pricing in Great Britain.

In line with all I have written above, the actual core analysis in the FTI Report is over-optimistic about the net benefits of zonal or nodal pricing in GB because of its assumptions around re-location in response to wholesale price signals for certain generators and batteries. The analysis also ignores the rebound effect on market power of the modelled large cut to generator profits, does not assess the profitability of individual relocations of investment or the inefficiency of an FTR system (which it suggests could be introduced along-side nodal pricing). These large potential negative effects mean that we simply cannot know from the FTI analysis whether there is a positive NPV from implementing nodal pricing per se. It is also the case that zonal pricing, combined with some smart use of nodally regulated prices in redispatch, would seem potentially superior to full nodal pricing if it could reduce the cost of the FTR system, while delivering a large share of the net benefits of better locational signals. Also, given that the existing system involves is a form of zonal charging, the FTI Report makes a strong case for a reform of zonal charges.

Finally, the impact on treaty negotiations with the EU needs to be considered in interpreting the FTI Report's domestically focussed CBA results. Electricity forms a significant element of the current UK-EU Trade and Cooperation Agreement (TCA) and this needs to be renegotiated from 2026 (see Pollitt, 2022). Regulatory alignment with the EU's electricity single market is a significant (and very positive) part of the TCA. Some negative value should be attached (by the

UK government) to the UK unilaterally proceeding with pricing reform that could currently be detrimental to UK-EU energy relations. Indeed, the FTI Report seems to suggest that nodal pricing could produce some negative welfare effects in the EU – further analysis of the size of UK-EU market effects of changes to our pricing regime is desirable in the context of upcoming treaty negotiations.

However the FTI Report does a great service in raising a number of big ticket items for market reform in GB. It would have been good if the Report had focussed more clearly on the calculation of the net benefits of each of these separately. A question that the Report does not discuss (because it was out of scope) is whether these items require full zonal or nodal pricing to be achieved or whether they can be addressed – with little downside risk - via bespoke changes to NG ESO transmission planning, price regulation in the BM, changes to government CfD contracts, application of TNUoS to interconnectors and increases in carbon pricing. There is, a priori, reason to believe that discrete changes in each of these areas would have captured a significant portion of the overall benefits identified in the FTI modelling.

It may be that we should think about nodal (or zonal) pricing as the only way to introduce better locational signals that reduce the inefficiency of the current system with respect to redispatch. It is also the case that there is now substantial experience with nodal pricing from the US (and other jurisdictions) which can be drawn on. However, it is also clear that the US experience raises serious concerns about the operation of nodal prices in practice (as documented in individual RTO/ISO State of the Market Reports and analyses of the efficiency of FTR markets, see Pollitt, 2023) which a GB system would have to address prior to implementation. I would hope that US experience could be – substantially - improved on, e.g. via hybrid uses of calculated nodal values.

12. What Ofgem should have asked FTI to model?

FTI have done what they were asked to do and have done so in a commendably transparent way. However when faced with major policy changes, there remains the possibility of policy optimism bias[11] on the part of the government entity commissioning the analysis, which affects the choices made within the overall CBA of the proposed policy change. Thus it is important to critically explore what FTI might have been asked to model, but were not.

First, FTI should have been asked to focus their modelling on the benefits of improved price signals for the efficiency of dispatch. The exercise undertaken did not clearly explore the possibility that existing redispatch was not efficient in its own terms. In particular the issue of whether consumers are overpaying for redispatch at the moment and that prices could better

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[11] See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/191507/Optimism_bias.pdf

reflect system costs? This would have been in line with existing modelling of the benefits of LMPs in the US.

Second, FTI should have been asked to explore a scenario with a more conservative set of assumptions which were less open to challenge. To name some of these: it could have shown the impact of lower (or indeed higher) commodity prices; it could have assumed that large generators would have located independently of which pricing regime was in place and that only smaller generators would respond to the pricing regime itself (as suggested in MacIver et al, 2023, p.12); it could have modelled an intermediate number of zones; it could have examined the impact of keeping all mark-up assumptions the same; it could have assumed some reasonable inefficiency and distributional effects away from consumers in the FTR market, based on the data in RTO/ISO State of the Market Reports. These changes would likely have reduced the size of the transfers and net benefits, bringing them more into line with previous studies and reducing the lower bounds on the range of reported overall net benefits of zonal or nodal pricing.

Third, FTI could have been asked to analyse other alternatives to full nodal pricing. The baseline assumption in the Report, of no default change to the current national market over the next 18 years, is a strong one. GB is already on a journey to introduce more locational signals into its electricity system (which this modelling exercise is part of). One alterative that could have been considered was pricing based on TNUoS zones and the application of these to interconnectors. Another, might have involved the use by NG ESO of shadow nodal prices. For instance these could have been used to algorithmically dispatch EV charging, electrolysers and heat pumps and future government CfD holders. These could have kept unit payments the same, but varied quantities across time according to shadow nodal prices. The basic LMP framework, as implemented in the US, predates the age of digitalisation and the advent of intermittent renewable technologies. It seems possible that a hybrid pricing arrangement could have delivered almost all of the benefits with fewer of the costs, in particular by avoiding the need for costly grandfathering and an expensive ongoing system of ARRs (Auction Revenue Rights) / FTRs, learning from the experience in use of US LMPs.

Finally, as the FTI Report has highlighted, there is a serious issue about whether transmission lines are going to be built in the right places. NG ESO needs to urgently reconsider whether in the light of this more granular modelling of overall system costs and whether even without nodal pricing but considering nodal costs, these are being positioned and sized correctly.

Section 2: Detailed comments

Main Report

Executive Summary

Para 11: A frequent misrepresentation – by NG ESO itself - is the sharpness of the recent rise in constraint costs in GB. Their representation is repeated here. It is true that the financial costs of constraints have risen sharply recently. However absolute constraint values are misleading, because they reflect wholesale energy prices which rose sharply in 2022. The total volume of constraints in 2022-23 was lower than in 2019-20 in MWh terms[12]. This highlights the importance on commodity prices to the overall cost benefit analysis and hence the need to provide some sensitivity of the results to commodity prices.

Para 16: 7 price zones are on a par with zonal pricing within Europe, where some European countries have a small number of pricing zones. However it would seem more obvious to make use of the 27 Transmission Network Use of System (TNUoS) charging zones that GB already has.[13] This would have allowed existing locational signals conveyed by transmission charges to be combined with the detailed modelling that FTI conduct.

Para 26: All three of the selected scenarios (LtW (NOA7), LtW (HND) and SysTr(NOA7)) involve extremely ambitious roll-out of both transmission and generation capacity. They cannot be expected to include a lower bound on possible outcomes given that slower growth in the UK economy and less ambitious climate policy implementation are distinct possibilities. One of these three scenarios could have been replaced by scenario based on the FES' Steady Progression scenario, which is much less ambitious (but possibly more realistic than the Leading the Way (LtW) and System Transformation (SysTr) scenarios). The subsequent analysis suggests that SysTr(NOA7), which gives similar overall outcomes to LtW (HND), could usefully have been dropped and replaced by Steady Progression. Recent government announcements on the pushing back of targets for replacement of fossil fuel boilers and the ban on new fossil fuel vehicles suggest the degree of ambition that was baked in to LtW and Sys Tr scenarios and the need to represent a wider range of possible futures[14].

Para 30: Figure ES-4 is a useful figure. The suggestion that nodal pricing is being extended globally is an important consideration. However it would have been informative to distinguish between jurisdictions with and without net zero policies in place.

Para 42ff: It is worth pointing out that the representation of wholesale prices in Figure ES-6 (and others like it in the FTI Report) exaggerates the variation in delivered wholesale charges that consumers actually pay because it does not include CfD support payments or transmission or ancillary charges (which so happen to be recovered over longer periods).

Para 46ff: The presentation of map in Figure ES-7 suggesting that current prices do not vary across the country exaggerates the current situation. It does not include TNUoS charges which vary, zonally. Given that nodal prices include pricing for congestion, it is not comparing like with like to suggest that nodal prices vary but a national price plus a transmission charge which prices for long run incremental costs (to relieve long run congestion).

Para 59: The implementation costs focus on one-off costs. A nodal (and zonal) pricing regime presumably has higher running costs than the current national scheme. It involves extra traders and hedging instruments, which should be valued as a real cost to the system. This is

[12] NG ESO figures: BM Constraints in 2019-20 were 20.0m MWs and fell to 14.3m MWs in 2022-23 (see MBSS data from March 2020 and March 2023, at: https://data.nationalgrideso.com/balancing/mbss

[13] See: https://www.nationalgrideso.com/document/235056/download

[14] https://www.gov.uk/government/news/pm-recommits-uk-to-net-zero-by-2050-and-pledges-a-fairer-path-to-achieving-target-to-ease-the-financial-burden-on-british-families#:~:text=The%20Prime%20Minister%20Rishi%20Sunak,eases%20the%20burdens%20on%20families.

not discussed anywhere in the FTI Report, but it may be a partial explanation for the apparent costliness of the Financial Transmission Rights (FTR) system in the US.

Para 69: It is somewhat overoptimistic to suggest that consumers might not have to compensate producers directly for their losses in the move to more granular pricing. This can take two forms: either direct compensation (as with competitive transition charges in the US following the introduction of wholesale market competition) or the allowing of higher payments under other mechanisms to ensure investment continues (such as generous low carbon support mechanisms to attract investment following low prices under NETA). Indeed, if the producer losses are expected to be as large as some of the modelling suggests, demand for compensation is more likely.

Para 71: The modelling finds that consumers in all regions benefit from a move to more granular pricing. The issue of whether all consumers benefit depends on the compensation regime and on the allocation of the congestion revenue. If consumers must compensate producers in their region and congestion revenue is put in a common national pot to reduce transmission charges then it is possible that GB6 consumers in the South of England and Wales would be worse off. Is this worthy of discussion?

Para 75: The statement in this paragraph is that 'We have found limited evidence that this would, in practice, be a material cost.' This statement ignores that fact that FTR regimes explicitly aim to reduce nodal price risk and that FTR regimes are costly. PJM's website states: 'Financial Transmission Rights or FTRs allow market participants to offset potential losses (hedge) related to the price risk of delivering energy to the grid.'[15] The suggestion that there is 'limited' evidence of an increase in risk related costs from nodal pricing is therefore incorrect (according to PJM). The material impact in the US is via the FTR market where it is apparently costly to hedge nodal price risks. The literature and ISO/RTO State of the Market Reports consistently find evidence of the costliness of nodal price hedging regimes (see Pollitt, 2023, for a discussion).

Para 81: There are likely to be ongoing costs from the implementation of nodal pricing as the increased complexity of hedging nodal pricing arrangements must impose additional costs on the system as a whole.

Para 82: There is likely to be some investment hiatus if nodal pricing has the size of impact that FTI Report models. A 9-14% fall in wholesale prices (including CfDs) is something that will create delays to some projects. Interestingly, investment did stall around the time of the introduction of the New Electricity Trading Arrangements (NETA) in 2001 and capacity was withdrawn.[16] How this might affect the CBA is unclear as delaying investment might actually raise the calculated NPV if it is subsequently delivered at lower cost, however if the required

[15] https://www.pjm.com/markets-and-operations/ftr

[16] Annual total electricity investment was lower in real terms in 2000-2004 than in was in 1999 (the year the NETA consultation results were published) (see: ONS Gross Domestic Fixed Capital Formation by Industry by Asset: All Assets SIC35). NAO (2003) reports several problems for generators as a result of NETA: 6-7% of all capacity was mothballed; British Energy was the subject of a government nationalisation and bailout; and TXU Europe would have gone bankrupt had it not sold its assets to E.ON.

investment is more expensive to deliver due to the need to provide additional compensation to attract it, that would reduce the NPV.

Para 85: Would consumer prices in Northern Scotland be lower than those in Northern Norway? This would presumably also be true of zonal prices (or national pricing with TNUoS reforms).

Para 87: Would low nodal prices would attract investment to Scotland and Northern England? This is on the assumption that nodal capacity is available at the scale required to support the investment. A large data center wishing to connect to the network might alter the nodal price – indeed network saturation of initially uncongested parts of the network have been an issue with data center investments (see Banet et al., 2021). This illustrates the point that incremental investment impacts are not, likely, driven by nodal price signals.

Para 89: Interconnector pricing is an important issue highlighted in the FTI Report. It would have been good to know just exactly how much of the overall benefits of granular pricing relate solely to the reform of interconnector pricing, as reforms which targeted the external borders might be implemented separately from more general pricing regime changes. The value of reform of interconnector reform within the whole analysis is not separately identified.

Para 95: The discussion of how reform affects prices paid for electricity to foreigners is an important one for national welfare. The report might discuss examples of how European welfare is quantitatively impacted by changes to our pricing regime, if for no other reason than to understand what the potential reaction of our neighbours – positive or negative - might be to our introducing nodal pricing, e.g. by demanding compensation, raising prices, reducing willingness to interconnect or restricting power flows.[17]

Para 96: The charging profiles of EVs might be affected by nodal pricing. We don't need a full nodal pricing regime to efficiently schedule EVs and heat pumps. This can already be done algorithmically with input from the system operator. This might have been discussed in the FTI Report.

Para 98ff: There is a really important discussion here about whether current transmission investment plans are efficient. Regardless of changing the full market pricing arrangements, this discussion raises the issue of whether shadow nodal pricing would help with the assessment of future transmission investment regardless of the implemented wholesale pricing regime. While it is true that nodal pricing could help facilitate improved investment planning, improved transmission investment outcomes are dependent on many other factors (such as getting planning permission and modelling future supply and demand correctly).

Para 100: The £25bn level of potential difference in the level of benefit from transmission investment depending on how it is assessed demands immediate re-consideration by NG ESO of the necessity of individual transmission investments.

[17] Sweden has faced criticism for pushing electricity constraints to its borders, and this has led to both infringement action by the EU and joint working between Sweden and Norway to resolve constraints imposed on each other. So this sort of issue does have real effects (see Rumpf, 2020 for a discussion).

Para 101: There is little evidence of large siting effects from nodal pricing in the US, though there is some limited anecdotal evidence (see Pollitt, 2023).

Main Text

Para 2.22-2.26: This is a short discussion of how nodal pricing is supposed to work, given the centrality of the concept to the whole FTI Report. The discussion does not mention the fact that nodal pricing schemes combine local price monitoring and financial transmission rights with the basic calculation of nodal prices. Thus nodal pricing regimes include a mechanism for regulating local prices and a mechanism for managing local congestion price volatility. There is also no discussion of the increment question: when calculating a nodal price how large a quantity increment do you assume (0.1 MWh or 1 MWh?) in calculating the marginal price? This is not actually discussed in the report and how it might influence the results. Pollitt (2023) raises these and other issues in discussing what do nodal prices really mean and what purpose do they actually serve?

Para 2.32-2.34: This is a short discussion of how zonal pricing works. It does not discuss the point that zonal prices can be an aggregation of nodal prices, which might give different prices from the other two types of zonal prices which are discussed in here. One advantage of zonal prices which make use of nodal prices is that they may better reflect constraint costs and that some nodal prices could be used by the system operator (SO) to calculate balancing mechanism (BM) actions or other SO calculations, without exposing all parties to them. The GB system already includes some zonal pricing elements (e.g. zonal generator and demand TNUoS charges).

Para 2.37-2.52: There is a helpfully revealing example discussed here of how nodal pricing produces a consumer benefit relate to national pricing. It is important to note that this reveals a truth and an assumption about nodal pricing. First, if all the bids stay the same nodal pricing MUST produce consumer benefits in such a case as this. It does so by segmenting the market into a low price and high price area, where consumers capture surplus from producers. This would be true of ANY national market which was arbitrarily sub-divided into higher cost bidders and lower cost bidders. Indeed the suggestion to do this is in line with Keay and Robinson (2017) two market solution for GB wholesale energy markets. Second, it assumes that no bids change as a result of the division of the market into smaller sub-markets. This is a strong assumption, which auction theory frequently highlights as being incorrect (see Krishna, 2010). In the US there has been extensive formal regulation of bids – via sophisticated market power mitigation methods - in nodal markets to prevent the increase in market power which would otherwise arise from market sub-division. Thus market monitoring is an important and necessary part of nodal pricing. Otherwise basic producer theory says that market subdivision raises markups.[18] Thus it would be in general incorrect to assume that bidders would not change their behaviour if the first order effects of nodal pricing were to reduce prices. However this is what the FTI Report assumes. It would be interesting to understand what typical nodes look like within the modelled GB system and whether there was likely to be a single pivotal bidder, with obvious market power, at many of them. Equally, if this element of nodal pricing is implicitly assumed to be in place, much of the benefit of

[18] Imagine the simple arbitrary division of a market with identical Cournot bidders into two submarkets. This raises prices in both submarkets, even in the absence of collusion.

nodal pricing does not arise from nodal pricing per se, but the regulation of individual generator bids which nodal pricing puts in place, which could be implemented directly in the BM.

Para 2.62: It is worth emphasising – as noted by FTI here - that nodal pricing has not produced any overall welfare benefit in the example, however it has moved a lot of money around between producers and consumers. Nor has it produced any short run operational benefit.

Para 2.70: It would good to unpack the extent to which dispatch is actually different in the FTI modelling. In theory it should not be different in real time, if redispatch is efficient and in line with implicit nodal values.

Para 2.73: The FTI Report mentions that nodal pricing precludes the possibility that self-dispatch could be more efficient than central dispatch. However, it is also the case that nodal pricing may make network reconfiguration by the network operators less attractive if it alters nodal prices in ways that give rise to need for compensation payments or introduces network operator induced price risk/uncertainty. Such network reconfiguration can give rise to substantial benefits. In the future networks will be able to better direct flows across their own networks (e.g. by adjusting reactance)[19]. A key assumption of nodal pricing – as modelled here - is that the network configuration is fixed at the time of setting the nodal prices and this is not necessarily true.

Para 2.76: Footnote 59. Lundin (2011) is not about nodal pricing it is about zonal pricing.

Para 2.79: Long run price signals dominate generator siting, there is little evidence that nodal pricing has much impact on location of generators or loads if they are not expected to persist.

Para 2.83: Footnote 61. Kahn and Mansur (2013) is not about nodal pricing it is about different final prices between utility service areas.

Para 2.91: This is an important point about how new transmission projects are currently being evaluated by NG ESO. Under the current national pricing system they are being evaluated by the extent to which they reduce constraint costs, whereas under a nodal price regime they would be evaluated by looking at overall economic welfare. Regardless of the pricing regime adopted, the SO should be using overall economic welfare impacts to evaluate new transmission projects.

Para 2.97: There is little hard evidence from the US that generators or loads do move in response to nodal (as opposed to averaged zonal) prices. The FTI Report does not produce any quantitative evidence to support this claim. Nodal prices are only part of the incentive to locate at a given location, they are volatile and given their granularity they may substantially change if a large increment of load or generation were connected at a given node.

Para 2.112: These statements about market power are generally theoretically and empirically incorrect, as I discussed above. It is Microeconomics 101 that reducing the number of firms in

[19] See Ullah et al. (2016).

the relevant market increases the Lerner Index (and hence market power). 750 years of economics (since St Thomas Acquinas) teaches us the benefits of wide area markets (see Pollitt, 2023). Either nodal pricing increases local market power or it involves a new form of regulation to prevent an increase in local market power (see Graf et al., 2021). This is distinct from the consumer benefits of market splitting of price stacked generation into sub-markets.

Para 3.14: Figure 3.2 – from NG ESO - showing rising constraint costs is misleading. The constrained quantity needs to be shown, not the just the cost which is a function of electricity market prices. As discussed above the quantity in MWs in 2022-23 is not at a peak.

Para 3.29: Why would EV charging be a particular problem given the geographic spread of charging and the potential for quantity based scheduling of charging? This would not require a formal change to the current electricity market but the use and smart contracting with algorithmic control (as discussed in Pollitt, 2021).

Para 3.38ff: This is a nice discussion and interesting Figure 3.7 on the spread of nodal pricing globally. However what does it actually show? It shows that since the beginning of the net zero era nodal pricing has not been adopted anywhere else and that the last adoption globally was in 2011 in Texas. It is important to note that the apparent growth in capacity, since 2010, is largely due to expansion in the US.

Para 4.14: The assumption that there are modellable long run benefits from re-siting supply and demand from nodal pricing is supposition which is not based on prior evidence of this happening in reality.

Para 4.16: This reveals that the short run analysis does not just focus on the same quantitative impact as previous studies of nodal prices (e.g. Wolak, 2011; Triolo and Wolak, 2022).

Para 4.18: It is important to say that there are other ways to reduce curtailment costs. These could involve different curtailment rules to better allocate available capacity, as is happening on the distribution system[20], and could happen for certain types of generators such as those who hold a government contract for difference (CfD). As noted elsewhere in the FTI Report, Ofgem are already investigating new licence conditions to reduce market power in the BM.[21]

Para 4.26: Dispatch efficiency could be improved by taking balancing actions in the BM in line with shadow nodal values (based on BM bids and offers), without the need for full nodal pricing.

Para 4.29: The FTI Report suggests that centralised scheduling could yield additional benefits. However the CMA (2016) concluded that self-dispatch was at least as efficient as central dispatch in GB, so there is little prior reason to think that there would be a direct benefit here.

Para 4.39: The FTI Report suggests that large new loads could benefit from nodal price signals. This is not true if they are so large that they reconfigure the network. Rather it is small

[20] See Anaya and Pollitt (2017) on the benefits of smarter connection rules.

[21] https://www.ofgem.gov.uk/publications/ofgem-launches-consultation-balancing-mechanism-reforms-protect-consumers

incremental loads that can benefit in theory from nodal price signals, not larger ones. It is at this point that some discussion of representative nodes would be useful. If GB demand peak is around 50 GW (though set to increase), 850 nodes translates to 59 MW per node at peak (though there are multiple pathways), however many will be less and some much more.

Para 4.43: The FTI Report is correct to fix the demands. There is little clear evidence for further re-siting benefits of nodal pricing, rather than zonal pricing (see comment on the earlier references on this).

Para 4.48: As noted here, governments don't find electricity price fluctuations desirable. If this is the case nodal price fluctuations might invite some sort of government enforcement action. It is therefore difficult to argue later on that increased nodal (or zonal) price variations have no 'risk' implication.

Para 4.56-4.57: The modelling assumes that CfD holders can be constrained off and not receive as much compensation as in the BM (none under nodal pricing). This assumed change under zonal and nodal pricing produces benefits to consumers (and the system as a whole) which could be achieved by removing such property rights within the existing system. Both seem unlikely to be achieved with no second round implications for consumers.

Para 4.73: The treatment of interconnectors in the cost benefit analysis raises the issue of whether a change to the GB pricing regime is a way of appropriating surplus from foreign producers (price rises on consumers abroad are not valued, while only 50% of any losses in congestion rents are captured by UK producers). A loss of producer surplus to foreigners guarantees a net gain to GB, even if the change is globally neutral. However this raises the issue of second order international effects. If other European countries change their power flows, restrict interconnector capacity, raise prices or extract compensation then some of this 'benefit' will be lost.

Para 5.7: As before the core analysis assumes long-run re-optimisation of location, which is a big assumption as to whether it will happen or not.

Para 5:10: The modelling of specific years within the 16 year time frame rather than every year raises issues of how representative these years are and whether different time profiles would materially affect the overall CBA (cost benefit analysis) results.

Para 5.10: The assumption of dispatching in the nodal model at short run marginal cost (SRMC) plus a start-up cost, without any assumed market power in nodal markets is a very strong assumption and ensures a consumer benefit relative to the use of the current BM. The modelling should report how much this assumed increase in the 'regulation' of bids actually effects the overall results. One assumes it is substantial, perhaps halving current BM costs(?), if the assumed mark-up for a gas fired generator in the BM is 129% over SRMC. As noted earlier a nodal pricing system is a way of better regulating individual bids within the energy market, IF it is combined with some cost based regulation of pivotal bidders as appears to be assumed here.

Para 5.24: The 27 TNUoS generation zones are an obvious starting point for a reform of zonal charges based on the existing zonal charging system that already exists for transmission in GB.

Para 5.35: Given that Leading the Way (LtW) and System Transformation (SysTr(NOA7)) both represent ambitious scenarios with respect to net zero, it would surely have made more sense for the CBA to have replaced one of these scenarios with FES's Steady Progression, as this is still a scenario with high probability of being the actual one. This would also be a more defensible lower bound scenario.

Para 5.42: The dispatch-only sensitivity is applied to the nodally optimised location. It is important to point out this is a strong assumption about the starting point which could change the dispatch-only net benefit in the CBA. This is because if location has been optimised for nodal pricing then turning off the nodal prices will result in a bigger change than in the case where location has been optimised on the assumption of no nodal pricing. A better 'pure' dispatch only sensitivity would be to assume that nodal pricing had no effect on siting and test the effect of changing the pricing regime. Indeed it would make more logical sense to assume that location has not been nodally optimised to test for the dispatch only benefit.

Para 5.44: Load shielding is the general situation in US nodal pricing. This should be the default assumption, not a sensitivity test. One could equally model the assumption that much of the flexible load could be dispatched to minimise system costs without nodal pricing, through smart contracting with algorithmic control (paid for by consumers through transmission charges). Hence load control benefits are, primarily, about control and smart contract design not nodal pricing per se.

Para 5.65: There is little hard evidence that any capacity would re-site in response to nodal pricing alone. This is especially the case given that the modelling assumes siting minimises system costs, not that it is individually profitable. No consideration is given to the fact that costs may be higher (or rise) at initially uncongested locations. A more reasonable assumption is that only battery capacity would be able to relocate as this could be, potentially, co-located with demand. However battery economics is particularly challenging based on price arbitrage alone.[22]

Para 5.65: It would be worth explaining how relocation works at an individual node, when not all capacity is added at once. The moved capacities are potentially large and the number of nodes in the analysis fixed, so how does the sequencing actually work in terms of incremental capacity changes and observed nodal price signals? Many nodes will rapidly become congested if capacity moves and the expected nodal prices equalise.

Para 5.69ff: Assumptions about commodity prices. It is somewhat surprising that the analysis includes no sensitivity analysis around commodity prices. April 2022 is not likely to be representative of a date on which to look at futures prices for gas. It would be good to clear that the prices shown in Figure 5.10 are real and in line with the real values in the CBA.

[22] See Sidhu et al. (2018) for a discussion of battery economics in the UK.

Para 5.77: Footnote 136 states the assumed mark-up for gas fired generators is 69% of SRMC in the BM (129% elsewhere?). There is an assumption that nodal pricing reduces the ability of fossil fuel generators to mark-up SRMC. There is no basis to this assumption on its own, unless there will be stronger bid regulation under nodal pricing.

Para 5.78: The assumption of market power in the BM (incorporated into assumed bid-offer prices) and the assumption of no market power in the nodal market ensures seemingly large consumer benefits from nodal pricing. The modelling should have attempted to compare like with like by modelling what if BM prices fell towards SRMC or nodal bidders raised their bids to reflect BM mark-ups. Nodal pricing style regulation of bids and offers in the BM is a policy alternative to full nodal pricing.

Para 5.79: It is reasonable to assume that there is a cost of reversing power flow on DC interconnectors in the BM. However the modelling assumes that if interconnector power flows reverse within the day due to nodal pricing it is not costly to change the power flow on a DC interconnector. This would appear to be give rise to larger benefits from more granular pricing than would be the case in reality.

Para 6.1ff: The assumption of a cost based dispatch and investment model with no attention to profitability has strong unmodeled implications. If the pricing regime changes result in large reductions in producer surplus there has to be an assumption that large transfers to producers would be required to meet minimum profit constraints, otherwise there might be a lack of new investment and the ambitious building programme of both generation and transmission envisaged in the modelled scenarios would not be realisable. In the case of this modelling exercise, it is difficult to believe that there would not be substantial rises in some combination of market prices, CfD payments, ancillary (including capacity payment) costs to compensate producers to ensure new build actually occurs.

Para 6.2: Important to restate that the three modelled scenarios are all ambitious with respect to new build (and future demand electricity growth). One of these should have been replaced with a less ambitious scenario such as NG ESO's Steady Progression.

Para 6.6: Once again, there is little hard evidence of large scale re-siting of capacity in practice under nodal pricing.

Para 6.19-6.20: The assumption for the zonal pricing regime is that there is a fixed allocation of re-sited capacity within zones. This is a strong assumption because it is already the case that siting decisions are influenced by constraint costs under flexible connection arrangements. This illustrates the problematic nature of assuming re-siting given that nodal costs are reflected to some extent in existing requests for connection. Footnote 148: This gives an example of three nodes with 5 GW, 3 GW and 2 GW initial connection of onshore wind and then imagines the allocation of an additional 3 GW of onshore wind connection. The zonal model is assumed to allocate this strictly in line with existing capacity. Why? Surely this an example where the new connection is so large that it would either be allocated in line with forward looking nodal pricing – under the direction of offered connection agreements - or where no different assumption can be made between zonal and nodal pricing. Nodal pricing is about the marginal cost of 1 additional MW (or 0.1 MW?), so this example raises the issue of what exactly nodal prices might be initially signalling in this case. This is because, in reality, GWs of capacity at individual nodes will be added over time and nodal prices will be changing over time, so what real time nodal prices will investors see and be expected to respond to? It further highlights that the siting of large quantities of onshore wind is usually more about local planning than about INITIAL nodal grid constraints. This example is a good illustration of why the FTI Report would have benefitted from giving more attention to actually explaining how nodal pricing was working within the model. Footnote 149: This footnote appears to say that the SO would not currently correctly direct the connection of large projects to better locations, or alternatively, not correctly reconfigure the connection to minimise system costs. This is in line with the genuinely worrying (and very useful) observation in the Report that current procedures for adding new generation expansion are not maximising whole system benefits.

Para 6.26: Box 6.1 is another revealing discussion. It discusses how more batteries are likely to site in the North of Scotland (GB1) than in the South of England and Wales (GB6). The example suggests that the daily price deviation is much greater in the North than the South of GB. However batteries may be unprofitable at both locations if only engaging in price arbitrage. The current cost of battery technology is around £0.5m per MW of capacity (and 2 MWh of storage). This gives a battery carrying cost (depreciation over 10 years + interest over 10%) of, say, around £0.1m per year. Batteries cycle once per day. If 1 MW/2MWh battery in the North of Scotland could discharge 2 MWh per day at a profit of £100 per MWh discharged that would only generate £73,000 per year which would not cover the cost of the battery.

Para 6.27-6.28: There are strong assumptions about the re-siting under nodal pricing. It might be reasonable to assume some batteries re-site (if profitable) and that larger quantities of generation do not change location. A reasonable assumption to test – even if not supported by current evidence - would be that nodes can absorb limited quantities of re-sited capacity.

Para 6.33: Figure 6.8 is very revealing and the scale of the re-siting envisaged by the introduction of nodal pricing. Nodal pricing is imagined to move large quantities of renewables by 2040 between regions of GB. c.25 GW of solar and onshore wind moves to the South of Wales and South of England. c.10 GW of offshore wind moves South. c.10 GW of batteries move to Scotland. c.5 GW of wind moves from north within Scotland. But why would this happen on nodal pricing alone? The offshore wind is under the direction of the Crown Estate / the CfD auction process / NG ESO. The solar is about local planning and investment appraisal. Batteries will require more than price arbitrage to justify investment in Scotland. Also what is being assumed about the fact that much of the battery and solar capacity is being connected at distribution level, which gives rise to potential constraints within the distribution system?

Para 6.43: The analysis assumes that the SO does not look at location when conducting its assessments of where to direct new large scale generation or how to configure the network. Box 6.3 suggests that redispatch actions worth £1.5m are required in the hour analysed. Is the SO not conducting optimal (constrained) redispatch? The SO could pay the both interconnectors not to flow at all for 1400*2*£7.7 (i.e. a fraction of £1.5m) if that would partially relieve congestion constraints within GB. This example again reveals that BM actions are assumed by the analysis to be much more expensive than the same action under nodal pricing. This suggests that improvements to the current operation of the BM (e.g. regulation of bids and offers and operation closer to real time) could yield substantial benefits with recourse to nodal pricing. The modelled price rise of £60 per MWh in France due to nodal pricing also suggests that there should be some consideration of the potential reaction of our European neighbours to the exporting of higher prices due to changes to our pricing regime.

Para 6.44: Box 6.4 suggests that EVs only respond to national prices under national pricing. Why? They can be exposed to shadow nodal prices via the BM and dispatched algorithmically? Why would their aggregators not be able to do this at least as well as under nodal pricing?

Para 6.66: The reduction in emissions due to nodal pricing is presumably largely based on the assumption of moving actual generation to more productive locations (it is sunnier in the South and there are more batteries in the North where they are utilised more) which might have happened in the absence of nodal pricing.

Para 6.72: Although it is understandable that the welfare analysis focussed on GB, it would have been useful to discuss the effects of changes to the pricing regime on welfare abroad as this might be significant and give rise to significant reactions from our European neighbours. No doubt they would welcome reductions in constraints, if this was the case.

Para 6.81: If constraints are being created within European networks as a result of nodal prices in GB these could be significant and worth quantifying, in connection with potential the assessment of wider welfare impacts and/or demands for compensation.

Para 7.6ff: The FTI Report does not focus solely on the benefits to dispatch efficiency of nodal pricing as per Wolak (2011) and Triolo and Wolak (2022). The benefits of focussing on dispatch efficiency alone is that this is about savings based on the currently envisaged system and does not raise issues of whether new investment is actually profitable. The approach of the FTI Report is to impose the size of the system and allocate it at least cost by location and then calculate locational prices. The resulting modelled system is not necessarily feasible or logically consistent with the need for new investments to be individually profitable. Thus the modelled prices and welfare outcomes in the FTI modelling are not feasible in the way that an assessment of locational pricing which fixed the existing system would be. This is a good reason why the two academic assessments of the welfare outcomes of nodal pricing focussed on dispatch efficiency.

Para 7.25-7.26: In looking at the modelled prices out to 2040, it is important to note that these are not the prices consumers would pay and the prices look very low in 2030 and 2035, raising issues of what additional support mechanisms would be needed to ensure profitability of existing generators, including via increased capacity payments. This highlights the ambitious nature of the new investment programme under LtW(NOA7) (and the other scenarios). It also raises issues about assumptions around future prices. A carbon price of £100 per tonne and a gas price of £40 per MWh (on the TTF) translates to £120 / MWh for electricity. If this was the marginal European wholesale price half of the time (and 0 the rest of time), this suggests an average wholesale price of £60 / MWh.

Para 7.41: It is a key observation of the FTI Report that nodal price modelling assumes no residual constraint management cost. It might good to explain this more carefully. So, there is no role for the SO in managing constraints in the system and if there is it only has to pay nodal prices? This rather begs the question of whether nodal pricing is a way of redefining constraints as a problem for network users to solve by adjusting their own supply and demand, not a problem for the SO. For instance if a constraint arises due to a line not being available is that just tough luck, or is the SO not obliged to compensate the users for reduced line capacity? Similarly, 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.[23] In 2022 this penalty amounted to \$4.64 / MWh (Monitoring Analytics, 2023, p.22)[24]. So the costs of redispatch are NOT zero under the PJM nodal pricing regime. Assuming that constraint management markets don't exist in nodal pricing regimes clearly begs some more explanation.

Para 7.48: Figure 7.11 rather suggests that the Report's estimates of constraints under LtW (NOA7) are significantly higher than for the other two scenarios. Why? And does this explain why the net benefits under this scenario are significantly higher than for the other two modelled scenarios.

Para 7.52: The fact that CfD payments are lower in regions with higher nodal prices suggests that the CfD regime could be made to favour more globally optimal locations in the absence of nodal pricing. Indeed why would a more cost optimal geographic dispersion of subsidised generation require nodal pricing? This highlights an important point that reforms to the government CfD regime could deliver benefits regardless of the wholesale pricing regime in place. This is something that is being considered as part of the Review of Electricity Market Arrangements (BEIS, 2022).

Para 7.75: These congestion rents in Figure 7.16 need to be recycled to consumers. In PJM this recycling is very inefficient. The FTR/ARR system in PJM has a recycling rate of 67%[25], so that in GB if congestion rent was £27bn discounted over the 16 years (using the discounted total in Figure 9.2), consumers could lose around £9bn of the £27bn of congestion rents due to them. The FTI Report does not discuss this phenomenon.

Para 7.98: Figure 7.23 illustrates that a significant change in surplus is coming from reducing market power in the BM (perhaps £6bn?). This suggests that even in the absence of nodal pricing steps to regulate market power in the BM could yield significant benefits to consumers.

Para 7.116: The near term reduction in producer surplus in Figure 7.27 is significant under the move to zonal or nodal pricing, this would seem to suggest the need for some form of compensation in order to maintain investment levels in the GB electricity transition?

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[23] https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/2022/20220405/20220405-item-04-transmission-constraint-penalty-factors-education.ashx

[24] 5.8% of load weighted nodal energy price of \$80.14 / MWh (see Monitoring Analytics, 2023, p.22, p.19).

[25] Monitoring Analytics (2023, p.77).

Para 8.14: The costs of introducing nodal pricing regimes in other jurisdictions is interesting. However are these really good points of comparison? Surely the cost of similar IT projects in UK electricity is informative. Here the track record is very poor and suggests substantial cost overruns relative to cheaper implementations abroad. The 1998 introduction of competition cost around £850m+ in GB[26] which was substantially higher than elsewhere. Given the UK's woeful record on controlling the cost of new IT systems it is difficult to have a priori confidence that the cost would be in line with implementations in the US.[27] Also, are there not extra running costs with nodal price regimes – clearly there must be more people involved in modelling nodal prices on an ongoing basis and trading FTRs etc.?

Para 8.15: There is plenty of evidence that substantial changes to the GB pricing regime would lead to delays in investment. The 2001 NETA was associated with a price drop and an apparent dip in investment (as reported above). More directly relevant to nodal pricing, one of the reasons for the failure of the non-fossil fuel obligation (NFFO) auction regime to deliver onshore wind projects in the late 1990s was the difficulty of moving from the original auction bid location in response to local objections. Mitchell and Conner (2004) note that the inability to easily move location was part of the reason for the low delivery rate of later NFFO auction rounds. Just moving location of a wind or solar project to exploit nodal prices is actually something that takes time and money (as envisaged by the modelling from as early as 2025. It IS likely to cause delays. However it is a good point in Footnote 173 that any major change (such as other possible changes under REMA) may already be leading to delays to investment.

Para 8.27: It would be probably sensible to invest in the capacity to calculate nodal prices regardless of the implemented pricing regime. It would seem to be unwise to invest in software which could not also be used to calculate both zonal and nodal prices.

Para 8.35: It is an interesting point whether volatility is higher in national, zonal or nodal prices. However it is important to point out that introducing daily price volatility induced by fossil fuel prices may exacerbate zonal and nodal prices more than simply looking at snapshot prices. Plus network line availability (planned and unplanned) will impact zonal and nodal prices more than national prices. So looking at the actual experience of nodal price volatility might have been more informative on this point.

Para 8.40: Footnote 178: MacIver et al. (2023) is a useful reference. They have some nice quotes from market participants in the US suggesting that in practice only really small generators and loads might move in response to nodal prices (if anything does). It would have been good to see the comments in this report reflected in one of the modelling scenarios.

Para 8.58: There is a good point here about non-diversifiable risk raising the cost of capital being different from the issue of reduced returns to investment for producers. This highlights the point that if the modelling suggests large reductions in producer surplus which must reduce returns to the point where some investment is no longer profitable, ceteris paribus. There has to be some adjustment upwards in the prices consumers pay either via CfDs, ancillary markets or via bid mark-ups (over SRMC) in the power market.

[26] NAO (2001, p.1).

[27] https://www.theguardian.com/technology/2014/aug/19/costly-trail-british-government-it-disasters-universal-credit

Para 8.59: Box 8.1 makes a good point about the fact that nodal pricing risk may be diversifiable across multiple locations. However diversification of risk is not free, it must raise transaction costs especially for small players. It is interesting that US nodal pricing markets clearly illustrate that initial holders of transmission Auction Revenue Rights to congestion (ARRs) do want to diversify risk by selling these AND that such diversification is expensive (see Pollitt, 2023). So while it is easy to argue that, in theory, risk can be diversified, what does this actually mean in practice? Risk diversification (via insurance markets) is not free and is, apparently, expensive when it comes to nodal pricing, as the lost consumer congestion revenue in the PJM case above illustrates.

Para 8.84: While liquidity may be unaffected by a move to nodal pricing, trading costs should surely go up given that ARRs/FTRs are now being auctioned and traded. This would appear to be one of the reasons for the cost of the FTR system. The FTI analysis should have considered this explicitly.

Para 9.7: Why is LtW (NOA7) chosen as representative when it does give significantly higher net benefits than the other two (which give quite similar results)?

Para 9.12: Table 9.1 is in general a reasonable assessment of the balance of the modelling, apart from on the re-siting of investment for which there is little prior evidence and which is based on modelling which does not ensure investment profitability. This should clearly be a red downward arrow, if the assumptions around this were relaxed to be more in line with likely reality.

Para 9.21: Figure 9.3 reveals large consumer benefits for the LtW(NOA7) and the other scenarios. This is significantly more than previous studies of the dispatch effects of nodal pricing, where the benefits were around 2-4% of operational costs in the wholesale market (so a lower percentage of prices paid) for the LtW scenario. Numbers of this size demand an explanation as to whether they are credible. Prices drop after CfD costs by 14% for LtW(NOA7). The effect on producer surplus is a reduction of £26.9bn after CfD payments. This is £2.16bn a year over 16 years[28]. Given that this must constitute a significant drop in expected profit margins it is difficult to see how this cannot require some compensation to maintain incentives to invest.

Para 9.25: The price drop around the time of NETA led to the bankruptcy of British Energy, the mothballing of 6-7% of capacity and fire sale of TXU Europe so it did have a significant effect on profitability. It is true to say, however, that there was no grandfathering. In the US the introduction competitive markets was sometimes accompanied by competitive transition charges[29], paid by consumers to companies, which did compensate incumbents for expected losses from wholesale competition.

Para 9.30: It is interesting that no region in Figure 9.7 is worse off in spite of very different supply and demand balances. Is this due to the fact that generation moves closer to demand?

[28] A 16 year annuity of 1 discounted at 3.5% is worth 12.09. So converting total discounted numbers over 16 years to an annual impact requires dividing by 12.09.
[29] https://regulationbodyofknowledge.org/glossary/t/transition-charge/

Para 9.30ff: Is it obvious that congestion revenue would be given back to consumers in that region? If it was it might blunt incentives to adjust behaviour. It could be that congestion revenue would be used to reduce transmission charges nationally, in which case this would change the distribution of the effects.

Para 9.40: It is an interesting that northern regions of GB would have much lower prices under nodal pricing. However in terms of attracting long term investment this would depend on what other countries did to create low energy price zones and hence would be a weak basis for industrial policy generally. It would be interesting to know how much additional demand individual regions could absorb, if say large mobile electricity intensive investments – requiring little labour - such as data centers were to move there to exploit lower prices.

Para 9.44: The year labels are missing from Figure 9.10.

Para 9.49: Looking Figure 9.11, does foreign producer surplus fall and is this then not measured in the CBA? This suggests that domestic CBA is potentially being impacted by appropriating surplus from foreigners. While this is of course a legitimate way to evaluate a domestic policy, it does raise the issue of whether there will be secondary effects abroad which could reduce the gains at home.

Para 9.54ff: This is an interesting discussion about carbon prices. However it does rather raise other questions. If the 'correct' carbon price had been used would this not have moved the location of generation and storage relative to the modelled scenarios? Carbon is priced and in the costs of the generators, so this is about the impact of a higher social cost of carbon than the 'market price'. However carbon which is traded should be valued at the market value according to public policy appraisal principles[30], so there is no theoretical basis for doing this additional analysis in conducting a CBA.

Para 9.61: Carbon emissions are a global pollutant. Given the impacts of GB pricing regimes on European power flows, the analysis should be careful to not argue that changes to UK carbon emissions will definitely not be offset by increases elsewhere. For instance, the analysis gives an example of reversing power flows from France and increasing gas powered output in France. The Triolo and Wolak (2022) analysis of the introduction of nodal pricing into Texas shows that mispricing carbon can raise CO2 emissions with nodal pricing. Therefore without a comprehensive analysis of European emissions it is premature to claim that UK changes will reduce total European emissions. Equally the movement of large amounts of generation South in the UK, as assumed by the modelling may produce lots of unpriced effects

[30] The current UK Government Green Book rules are confusing as to how to differentially treat traded and non-traded carbon savings (BEIS, 2023). Prior to 2021, it was clearly the case that traded emissions savings could only be included in policy appraisals at expected future carbon market prices, while only non-traded emissions could be valued at the (higher) social cost of carbon. The current rules only publish a single value for carbon (BEIS, 2021), while still requiring a differential treatment of traded and non-traded carbon savings. However, it is clear conceptually that within a CBA extra emissions savings in the electricity sector should only to be valued at expected future carbon market prices, given that at the marginal the marginal savings displaced elsewhere in the traded sectors are at that valuation.

(such as negative visual impacts for more people of energy investment or increases in local infrastructure investment costs) which are themselves unpriced.

Para 9.75: Given that the magnitude of the negative impact on producers (£26.3bn) in LtW(NOA7) £5bn (or 19%) does seem a small assignment of grandfathered value to producers, especially if an investment hiatus is to be avoided. A portion of the producer losses is attributable to a switch to SRMC pricing which would require extra allocation of revenue to ensure investment profitability. Thus the requirement to transfer some value to producers is not just a function of grandfathering which can expire, but a requirement for a permanent increase in attributed producer revenue (except indirectly through the planning process which may stop investments).

Para 9.86: Box 9.3 was an opportunity to comment on how strikingly inefficient this process of FTR rights assignment has been in the US. Again, the FTI Report is silent on this important issue. If in the US the impact of the introduction of nodal prices was much smaller than it is expected to be in GB, then there did not need to be much generator compensation. The much larger expected impact in GB is likely to trigger demands for much larger compensation.

Para 9.94: PJM and New York nodal markets have load shielding (though some loads can choose to be exposed to nodal pricing). It is important that load shielding is considered a core part of the analysis. However, it is good that the FTI Report recognises the importance of modelling this.

Para 10.23: The Report is to be commended for raising the issue of transmission investment. It is clearly of first importance that this investment is evaluated carefully. There is nothing to stop the SO making individual transmission investments on the basis of minimising system costs, taking into account nodal benefits, rather than on a more limited basis. It is also important to point out that there is a competition benefit from more transmission capacity, which has some value. The European single market area has benefited from increased wide area competition in terms of both lower prices and increased energy security.

Para 10.30-31: It is an excellent point that transmission investments should NOT be made on the basis of merely lowering congestion management costs. They should look at wider whole system benefits. If NG ESO is currently planning large amounts of new transmission investment on the wrong basis, it should re-evaluate its investment portfolio without delay. Getting this right is potentially of even greater benefit than changing the electricity wholesale pricing regime. Well done to FTI for giving NG ESO a further push to re-evaluate their Network Options Assessment approach. If nothing else comes out of this modelling exercise, highlighting this issue is important.

Para 10.39: Figures 10.11 and 10.12: Are these three types of generation in right order: the middle one looks solar? This illustrates the massive assumed shift of generation that in the nodal model is being attributed to nodal pricing alone. These are extremely ambitious numbers without nodal pricing, without assuming more generation CAN be moved between regions.

Para 10.43: Figure 10.13: It would good to also see the price impact of nodal pricing on neighbouring countries and understand the magnitude of their welfare effects.

Para 10:46: The international effects of nodal pricing are interesting. However to what extent could interconnector flow issues be addressed directly, e.g. with reforms to TNUoS charging or interconnector contracts?

Para 10.55: Flexible assets can operate under different contracts which might help address locational issues. For example, batteries could be contracted directly to the SO and used to better manage power flows to optimise transmission capacity and financed via transmission charges.

Para 10.60: Again, the point about the need to optimise c.£55bn of future transmission investment under NOA7+HND is well made by the Report and very important.

Para 11.1: The dispatch only savings is an important scenario to model. However it would have been possible to assume that the siting stays as per the national pricing regime and then look at the impact of nodal and zonal pricing on this. This is what is normally meant by dispatch only and in line with existing studies (Wolak, 2011; Triolo and Wolak, 2022).

Para 11.7: In line with the above, the dispatch only savings are exaggerated by the assumption of nodally optimal location. However it is interesting to observe the large difference that fixing location appears to make: NPV is reduced from £24.0bn to £13.7bn in the LtW (NOA7) scenario.

Para 11.31: The treatment of electrolysers is an important issue. Are these assumed to participate in the BM under national pricing? Clearly they would be used to relieve local constraints, under national or zonal pricing.

Para 11.45: An obvious baseline assumption is that load is equally flexible under national and nodal pricing, as this a matter of retail contract design and algorithmic control.

Para 11.57: A more reasonable assumption is that loads would be used flexibly in any pricing regime and that under a national pricing regime, there would be potentially more opportunity for EVs and Heat Pumps to be used to relieve constraints because of the reduced flexibility coming from other assets given there less than optimal location. At a minimum such loads could participate in the BM.

Appendices

A1.12: While it is reasonable to model no price reaction from Europe. This is clearly a potentially material negative impact on the CBA.

A1.21: It could be important to add a similar penalty price for reversing power flow on an interconnector due to zonal or nodal pricing. This is because this presumably, at least partially, reflects a genuine cost to reversing a power flow on a DC interconnector.

A1.25: It is important to be consistent between treatments of underlying costs across pricing regimes. If there is a cost to altering dispatch at short notice, this cost still exists in all pricing regimes, including nodal pricing.

A1.29: 129% uplift on SRMC of gas generators is a large mark-up to remove in nodal pricing. It does assume that it does not reflect genuine costs and/or that removing it will require a system of enforcement and, probably, compensation. It is of course genuinely worrying if generators are regularly receiving unjustified mark-ups on short run costs, as per footnote 2.

A1.33: The cost incurred in paying RES generators to be constrained is something which should be clearly identified in the overall cost benefit analysis. This is an element of the current regime could be altered going forward to eliminate such payments, if they were thought to be unjustified.

A1.59: It is unclear why the SO can't direct new large wind farms to cost optimal locations, under the assumption of either the existence or non-existence of zonal or nodal prices.

A1.67: Demand can be incentivised by SO contracts to relieve constraints, via putting incentives out to aggregators who then can jointly optimise the degree of difficulty of inducing response and the economic benefits of response. Demand does not require full nodal pricing for this to happen.

A1.70: The FTI Report does not discuss the extent to which flexible demand and distributed generation and storage are connected at the sub-nodal level and hence may face additional unmodelled constraints. Indeed the nodal pricing is assumed to relocate so much generation that there is an issue as to what impact this has on distribution system costs. The distribution system may be relatively more expensive to upgrade in the South than the North, impacting the overall CBA.

A1.73: The differential treatment of losses between nodal and non-modal models biases the results in favour of nodal models. The value of the assumed reduction in losses should be reported in the modelling, given that loss management might be improved in other ways without nodal pricing.

A1.81: Electrolysers presumably face locational incentives under zonal TNUoS and under the BM at the moment. So it is unclear as to whether the baseline in the national market is correct.

A1.96ff: This is a point in the FTI Report at which some discussion of TNUoS boundaries and what impact they might have is in order.

A1.98: The observation that nodal pricing creates significant congestion in Ireland is an important one, given that Northern Ireland is part of the UK and Ireland is our closest European neighbour. It seems unlikely that there would not be some implications for the CBA if there are significant negative impacts in Ireland.

A1.104: 20 April 2022 is the date of the commodity prices and commodity futures. This is hardly representative (we hope!) and hence it would seem to be important to have some sensitivity analysis around commodity price assumptions in the analysis.

A2.15: The assumption that the SO is not required to intervene at all to resolve constraints in nodal markets is a VERY strong one. PJM has a *transmission constraint penalty factor* which does cover redispatch costs (as noted above), so it is not correct to say this. Therefore some current redispatch costs would still be incurred under nodal pricing, whereas the nodal modelling constrains this to be zero. The discussion of nodal pricing should explain this and there should be some more conservativism in the assumption of no-redispatch under nodal pricing.

A2.23: There is an issue of timing in the CBA. Does delaying nodal pricing to and implementing other measures first have some learning option value, given that the value of some of the measures depends on siting and on the evolution of constraints?

A2.27: CfD contracts could be altered to reduce constraint costs, without the need for a nodal pricing regime.

A2.39: Prices are very low in 2040 and this does raise questions of whether all modelled investments (especially in storage) will be profitable at all their modelled locations.

A4.10: It is quite a strong assumption to assume that financing costs will not be raised for existing investments and that this would have no implications for investment and market bidding behaviour.

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