Comments on FTI's Assessment of locational wholesale electricity market design options in GB[1]

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The brief: Ofgem has commissioned independent academic reviews of analysis Ofgem commissioned from FTI Consulting on the potential benefits and costs of introducing locational pricing in GB. The FTI work is high-profile analysis which Ofgem plans to publish later in the year. The suppliers are to provide short written reports (either individual or combined) setting out their views on:

- the assumptions and modelling approach used by FTI and whether, on balance, FTI findings represent a conservative or optimistic assessment of the potential benefits, and
- whether the key limitations identified by FTI are accurate.

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.

EXECUTIVE SUMMARY

FTI have been commendably clear about the assumptions on which their modelling is based and in clarifying the elements that contribute to net economic benefits. They have considered a sensible range of variant assumptions, and tested the sensitivity of their results to particular features of their model: specifically, whether there would be significant differences in siting decisions of generators in response to locational pricing and if so with what impact on net benefits, and the gains that flexibility assets and Demand Side Response (DSR) might derive from locational prices. As a large part of the consumer gains are at the expense of producer surplus, they address the extent to which these may be counteracted by "make-whole" Financial Transmission Rights allocated to incumbent generators, although these are only illustrative and seem low. They also compare the Network Options Assessment 7 (NOA7) planned network expansion plans with the more ambitious Holistic Network Design (HND) plans, and find that more (but costly) network investment relieves congestion constraints, reduces the need for ex-post balancing actions, and hence very considerably reduces the net benefits of locational pricing. Examining the sensitivity to different network expansion plans demonstrates their importance and addresses the limitation of solely relying on one expansion plan, although FTI has not accounted for the possible additional network costs of this variant.

[1] I am indebted to Jason Mann of FTI for clarifying various assumptions underlying their report and for their comments on an earlier draft, and to Ben Hobbs, Peter Cramton and Frank Wolak for their insights from various market surveillance committees in the US for regions with locational pricing.
[2] Declaration of interests: FTI is a sponsor of our EPRG annual Spring Seminars, and presented a shortened version of the slides at our May 2023 Seminar. Newbery is a NED of CEPA, a consulting company that with the Energy Systems Catapult produced an earlier report (October 2021) to Ofgem on *Nodal pricing to drive innovation for consumer benefit*.

FTI provides extensive comparisons of future energy developments by contrasting the more ambitious National Grid ESO's *Future Energy Scenarios* (FES) *Leading the Way* (LtW) FES scenario with the more modest (but perhaps more realistic) *System Transformation* (SysTr) alternate, which forecasts greater reliance on nuclear generation, less offshore wind generation and lower consumer flexibility. SysTr delivers about half the net benefits of LtW, but these are still far higher than the transition costs. **The limitation of solely relying on the most optimistic future energy scenario has been correctly addressed by considering this alternate and more pessimistic scenario**.

This review concentrates on the net economic benefits, as the allocation of congestion revenues between consumers and producers is a separate largely political decision on who should gain and who lose from any change. If producers are to be kept whole then much, perhaps most of the consumer gains will be reduced to the net benefits. FTI clearly presents both gross and net benefits in all the summary graphs, leaving it to the reader to decide which elements are of interest. This addresses the limitation that considerable make-whole payments may need to be made to generators and FTI illustrates their impact (but probably understates their size).

This review first tests whether the latest FES (FES23) materially affects the findings. The later FES versions project less fossil and more variable renewable electricity (VRE), which makes balancing the system in real time more challenging, and which therefore is more likely to show greater gains from central dispatch and locational marginal pricing (LMP). In this regard **FTI's assumptions understate the potential net gains from LMP**. The rest of this report first examines the long-run (investment) impacts of locational pricing, and second, then its short-run impacts.

In the long-run the significant assumption in the base case is that locational pricing (both LMP and zonal pricing, ZP) will influence the location (but not the total amount) of new generation connections. This tends to understate the important role that locational network charges already play in guiding investment location decisions. FTI recognises this as a critical and arguable assumption and therefore provides estimates holding location decisions constant across all variants, but only presents results for LMP, not ZP (and not for SysTr). Holding location constant reduces the net benefits (net present value discounted at 3.5% real) from £24 bn to £13.7 bn (LtW, NOA7). FTI points out that Transmission Network Use of System (TNUoS) charges provide locational signals for investment and could (with minor but important reforms in my view) considerably strengthen their effectiveness (and would in any case need supplementing with locational hedges if LMP is to give good investment signals). To the extent that LMP gives additional locational investment signals that might be lacking from network charges, **FTI's modelling may understate the gains from LMP holding location fixed, while overstating them by assuming location is significantly affected by LMP**.

Perhaps the most contentious issue that potentially disadvantaged utilities will raise is the fear that LMP will raise the weighted average cost of capital (WACC). FTI argue, in my view convincingly, that this is unlikely with suitable hedging arrangements, but acknowledge in Appendix 4 §4.11 that the impact of WACC uplift over 2025-2040 is an extra cost of £7.45bn for the LtW (NOA7) scenario and £5.46bn for the SysTr (NOA7) scenario. This would materially reduce the net benefits, particularly holding investment locations constant, reducing net benefits from £13.7 bn to £6.2 bn (LtW, NOA7), and from £13.1 bn to £7.6bn (SysTr, NOA7).[3] **This key limitation appears to have been accurately investigated**.

In the short run, if exactly the same plant, storage, demand side flexibility and interconnectors (in amount and direction) are dispatched under the current (GBP) and locational pricing (and location decisions are held constant), then the net benefit of locational pricing should be zero, although there would be very large transfers from generators to consumers as generators are paid additional amounts to move from their infeasible Final Physical Notifications. FTI accepts efficient dispatch but in its base model assumes under LMP plant will be differently located and so different plant will be called on, improving the outcome. In the case in which FTI holds location constant all the £13.7 bn net benefits would seem to be attributed to i) flexibility and DSR, but mostly from ii) the benefit for efficient interconnector use.

The very considerable advantage of locational pricing is that it allows the market to schedule each interconnector flow based on local, not GB averaged, prices. This is important as Scotland is increasingly constrained in exporting to England but is now connected to Norway, whose prices are buffered by the shadow value of stored hydro. In many cases Scotland would be exporting and England importing under locational pricing but importing under GBP. Thus flow direction are materially affected by locational pricing, even after allowing for actions in the balancing market, presumably as a result of the cost of changing interconnector flows in real time. If better dispatch across interconnectors in the real-time market can be achieved and at lower cost (for which the gains seem to be large but so are the obstacles to achieving them) then **FTI's short-term interconnector benefit may be slightly overstated**.

As GB is an electrically isolated network only connected to other networks through DC links there would seem no advantage of taking an intermediate step to ZP and/or stopping short of full LMP. It would be more difficult to introduce LMP on the synchronised European network, particularly given the bid format structure of the EUPHEMIA pricing algorithm. Only if it were intended to introduce LMP but this necessitated a considerable delay and if ZP could be introduced rapidly and would provide familiarity with hub trading would there be a case for ZP as an intermediate step, largely justified by improving interconnector trading.

Even in the most pessimistic case, the ratio of net benefits to transition costs is high, and justifies as rapid a move to locational pricing as feasible, while pursuing other design options that improve investment location decisions without delay. Incumbents who fear that they would lose under locational pricing might be reassured by a commitment to transitional contracts that make them whole, but these will need careful design to avoid over-generous transfers at the expense of consumers, and should be time-limited.

In conclusion, ***the FTI headline net benefits that assume investment location is guided by locational wholesale prices are optimistic, but the more relevant net benefits holding location constant seem conservative, while the consumer benefits are optimistic.***

[3] Email clarification from FTI

FTI’s report has clearly documented, and as far as it is possible to judge, accurately considered the limitations of their report. Their case for locational pricing is persuasive.

1. Counterfactuals and time horizon

The benefits of a policy are measured against a specified counterfactual – what the world is assumed to look like if the proposed reform does not take place. FTI is commendably clear on this. The counterfactual is that the current system of GB-wide single pricing (GBP) continues until 2040. The two alternative reforms are full locational pricing (LMP, over c850 nodes in GB) and zonal pricing (ZP, over seven zones defined by significant boundary congestion). FTI is clear in pointing out that in any electricity system before delivery, the System Operator, SO, operates a security-constrained "optimal" dispatch. (See chapter 2A §2-7 et seq., especially §2.19 and §2.37.)

A key part of GBP is that transmission access and charging arrangements are assumed unchanged. This is problematic as the current REMA consultation is clear that location is an important subject of potential reform, and if locational wholesale pricing is ruled out then other reforms that improve investment location decisions are likely to be considered and possibly implemented. FTI is sceptical that this is possible and base a considerable part of their case for locational pricing as a single reform that would avoid the need to reform many other parts of the system – an insurance policy that would work with or without other reforms. This report will stress that there are other reforms that can achieve part (perhaps half) of the benefits of locational pricing, and which should in any case be actively considered.

The key difference between LMP, which requires central dispatch and delivers a security-constrained optimal dispatch, and zonal (including country-wide) self-dispatch is that under self-dispatch in the final moments before dispatch the SO is constrained to use the flexible generation (and other sources of flexibility) that are offered into the balancing market or mechanism. Under present contract designs, renewable generators do not face real-time prices and hence are not available to offer flexibility services. FTI's modelling assumes that the same plant is available in the day-ahead and real-time markets and so cannot benefit from

> Improved dispatch resulting from the SO's role in scheduling at the day-ahead stage (versus gate closure one hour before real-time). This means that the SO should be better able to optimise dispatch, as its decisions can be more fully considered. (§2.72)[4]

As noted later, this almost certainly (qualifications later) **understates the benefits of LMP**. One main difference is that plant offering to increase output into the balancing market adds an uplift of 129% on top of fuel plus carbon costs (A1.29) while bids to reduce output are efficiently priced at the avoidable fuel plus carbon cost (except for contracted renewable generation). The uplift directly creates a transfer from consumers to producers and could distort the choice of balancing actions.

Generation and demand are kept the same across all designs, with two FES scenarios: the base case *Leading the Way* (LtW), and variant *System Transformation* (SysTr). LtW is described as the fastest credible decarbonisation strategy involving significant lifestyle change, using a mixture of hydrogen and electrification for heating. SysTr is described as

[4] Changes in font indicate a quotation.

using hydrogen for heating (implying less electricity demand), with consumers less inclined to change behaviour, and lower energy efficiency. Compared to LtW, SysTr has lower overall levels of generation due to less demand, and more generation by nuclear and CCS gas (A2.14). Fossil fuels retire later and can be flexed to manage congestion, resulting in less need for interconnectors to manage constraints in SysTr (NOA7, A2.20). Another significant difference between the two scenarios is the amount of flexible consumer load that acts either as storage or facilitates time shifting. Table 1 shows that under LtW many more heat pumps (more electrification, not so needed if replacing gas with hydrogen for heating) and relatively more EVs with a considerably faster roll-out.

Table 1 Flexible assets of consumers[5]

Battery electric Vehicles

	2025	2030	2035	2040
System Transformation	1,605,646	6,746,642	19,897,599	33,170,566
Leading the Way	3,159,568	14,273,961	30,997,615	35,010,175

Heat pumps

	2025	2030	2035	2040
System Transformation	769,639	1,886,929	3,664,932	6,803,893
Leading the Way	2,630,993	8,337,800	14,744,343	19,613,809

FTI's LtW case therefore takes the Government's commitment to decarbonise electricity rapidly seriously, but includes a possibly more realistic variant to avoid criticism that it has taken the scenario that is most taxing and therefore most favourable for LMP. In addition, the network expansion and topology are the same for all market scenarios, with the base case (NOA7) and one variant (Holistic Network Design, HND). HND involves considerably more network investment, reducing constraint costs and reducing the net benefits of locational pricing, so this is an important variant. However, the extra network investment is costly, and FTI does not appear to include these costs, which could be large, when assessing the net benefits of HND:

> The recommended design leads to an additional £7.6 billion of capital costs[6] due to the additional offshore infrastructure, but this is outweighed by the £13.1 billion savings in constraint costs that are expected to result from the additional network capacity this infrastructure provides. (NG ESO 2022, p6)

Finally, in the base case, generation and flexibility assets are assumed the same in total quantity but under locational pricing would be responsive to locational price signals and as such differently located. As an important variant their location is held constant (at the LMP-optimal location) across all market designs. This review considers, for reasons given below, that it is the task of the ESO to ensure efficient location decisions, which should not

[5] Source: Email correspondence with Jason Mann of FTI

[6] All cost savings are calculated over a 40-year asset life period, starting in 2030, using 2021 prices, unless otherwise stated.

therefore be wholly ascribed to locational pricing. The appropriate comparison is the dispatch-only variant (holding location constant). Past attempts to improve transmission pricing have been disappointing, but the main reason for this would seem to be a reluctance to consider reforms that grandfather existing connection agreements to free up the option of offering more appropriate contracts to new entrants. The aim of transmission location signals is to guide new investments, as existing assets cannot move. Any changes to existing charges are zero-sum games, as the total revenue is fixed so that any change will disadvantage some while benefitting others. New entrants, on the other hand, could be offered long-term contracts that give the ESO's best current estimate of least system cost expansion locations without disturbing incumbents. An optimistic view of REMA is that all such options will be carefully evaluated. A pessimistic view is that only the "market", or locational wholesale prices, can address these locational distortions.

Most of the comparisons are given as the Present Discounted Value (PDV) from 2025 to 2040, where FTI uses "a discount rate of 3.5% as stipulated in the Green Book." (§5.89)

1.1. Sensitivity to FES issue date

FTI had to take the best forecasts available at the time of freezing data inputs to their model runs, so it is no criticism to note that later forecasts are different. It is valid to ask whether these updates amplify or reduce FTI's estimated benefits. For some purposes calibration of the installed generation mix and outputs will be important. It is difficult to compare the GBP final generation mix with FES21 and FES23 as the former are only presented in total TWh, not deviations from FES21 (for which only the *pre-dispatch* differences are available in Box 6.2, p133). Total generation by fuel is shown in fig 6.9, p132 (NOA7 + LtW). The major differences compared to various editions of FES are shown in table 2 (note the FTI figures are approximate as taken from a graph).

Table 2 Generation under various assumptions, LtW, TWh and shares

	2030			2040		
	FTI	FES21	FES23	FTI	FES21	FES23
Fossil Fuel	47	6	18	0	0	0
nuclear	36	37	33	40	35	64
Offshore Wind	200	210	206	325	371	411
Onshore Wind	58	90	97	100	114	119
Total wind	*258*	*300*	*303*	*425*	*485*	*529*
Solar	38	36	38	60	61	62
subtotal	379	380	392	525	581	655
total generation	425	418	437	590	644	710
	shares					
Fossil Fuel	11%	1%	4%	0%	0%	0%
nuclear	8%	9%	8%	7%	5%	9%
Offshore Wind	47%	50%	47%	55%	58%	58%
Onshore Wind	14%	22%	22%	17%	18%	17%
Total wind	61%	72%	69%	72%	75%	75%
Solar	9%	9%	9%	10%	9%	9%
subtotal	89%	91%	90%	89%	90%	92%

The main differences are in fossil fuels and wind (displaced by fossil fuel in FTI). By 2040 both FES21 and FES23 LtW shows a considerable increase in domestic generation, but the shares of the different fuels remain similar across sources. However, one important difference between FES and FTI data is that FES figures ignore transmission constraints and the subsequent adjustments in the balancing market, while FTI figures are the actual dispatch post gate closure and post balancing actions. This can make a considerable difference as FTI's like-for-like fossil generation in 2030 is 18 TWh rather than 47 TWh, and thus closer to FES21 (and very close to FES23).[7]

As an explanation for some of the differences, FTI uses FES21 constructed before the energy crisis while FES23 uses more recent fuel price forecasts. (Commodity prices in FTI's model were calibrated on the 20 April 2022, see A1.104.) There is a substantial difference in that FTI's scenarios retain fossil generation longer and in larger amounts – by 2035 FTI still shows 25 TWh and reaches no fossil fuel by 2040, and not 2035 (the Government target). The reason given is that gas prices are assumed to remain higher on the Continent than in GB, leading to more fossil generation and exports to the Continent (Box 6.2, p133, but note that FTI, unlike FES, does not include interconnectors in the generation and this needs to be assessed separately). The other reason is that the hourly wind output differs from that in FES21 although the average capacity factors are adjusted to be the same.

Since FTI completed its report, FES23 has been published, showing very substantial differences with FES21 and a substantial increase in total generation in later years. In terms of capacity in 2030, FES23 has 4.6 GW less fossil than FES21, 1.7 GW more solar and 3.5 GW more wind than FES 21. Summarising, comparing FTI for 2030 against FES23, FTI has

[7] Subsequent clarification by FTI

about 45 TWh less wind, 29 TWh more fossil, and slightly (3 TWh) more nuclear. For 2040, FTI has 104 TWh less wind (but the wind share of total generation is about the same as FES23) and about 24 TWh less nuclear than FES23, but about the same solar. While these differences appear material, less Variable Renewable Electricity (and more flexible generation) in FTI's modelling would seem to be **a conservative assumption**, in that more VRE creates more challenges for balancing the system that LMP might help.

Table 3 below is constructed very roughly from the graphs in Figs. 6.19 and 6.21. FES23 has interconnector net exports of 37 TWh in 2030 (shown as negative generation and a considerable reduction from the 71 TWh in FES21), while FTI has roughly 78 TWh net under GBP (= 111-33). Only percentage changes are shown for LMP (Fig. 6.21, p150), making comparisons difficult – table 2 is the result of applying these percentages. By 2035 FES21 has 111 TWh net exports (FES23 has 84 TWh), while FTI has roughly 124 TWh net exports in GBP, 116 with TWh LMP, so the reduction under LMP compared to GBP mildly underestimates their flexibility and hence LMP advantages.

On balance, then, ***FTI's generation scenarios appear conservative*** and thus may understate the full benefits of LMP (and ZP).

Table 3 FTI's estimated interconnector flows in TWh, 2030 and 2035

	2030	TWh				2035				
National	FR	NEW	IE	NO	all	FR	NEW	IE	NO	all
Exports, X	40	53	10	8	111	49	72	16	16	153
Imports, M	16	5	2	10	33	15	4	2	8	29
Total = X+M	56	58	12	18		64	76	18	24	
zonal										
Exports	36	50	10	10	106	49	71	16	17	153
Imports	16	6	2	10	34	14	4	2	8	27
total	52	56	12	19		63	75	18	24	
change TWh	-4	-2	-1	1	-4	-2	-1	0	0	-2
nodal										
Exports	28	50	10	11	98	40	67	17	19	143
Imports	18	6	3	9	37	14	4	2	8	28
total	46	57	12	20		54	71	19	27	
change TWh	-10	-1	0	2	-9	-10	-5	1	3	-11

When it comes to presenting the results in order to better understand the sources of differences, and specifically the role of both changes in asset location and the role on network expansion, it would be useful to have results at 5-year intervals, rather than just providing a net present value over the whole 15-year horizon. Table 9.3 (p205) does present consumer benefits at 5-year intervals (undiscounted), primarily as a percentage of the cost of electricity

+ CfDs, where they decline from 17% in 2025 to 13% in 2040. However, these high percentages massively overstate net benefits and so are not very helpful. Figures 9.1 and 9.2 (LtW (NOA7), p200) summarise the various contributions to the zonal and nodal net savings over the whole period (and A3-21 and A3-22 similarly do so HND scenario), but the results by 5-year intervals are only available by sub-categories. It would be possible, but time consuming, to break the overall net savings into 5-yr periods, to see how much of the net savings arrive soon (and are hence likely to reflect the immediate impact of market design changes) and how much arrives later (and may be impacted by other policies under each market design intended to rectify inefficiencies).

This is particularly important when examining the impact on interconnector flows as scheduled by the market, as the various figures (6.19-6.21) suggest that total flows fall under ZP and even more under LMP, but benefits increase. This is presumably because inefficient flows that reduce net benefits are reduced, and some beneficial flows discouraged by GBP become profitable under ZP and LMP, but without benefits disaggregated by source and date it is hard to say. The annual cash value of interconnector flows under each pricing model at the key dates (broken down into inefficient flows reduced and efficient flows allowed) would help identify the source of the net benefits (and also what difference there is between ZP, which ought to ensure efficient trade flows if zone boundaries isolate each interconnector, and LMP), but such information may be considered commercially sensitive.

1.2. Location decisions

When it comes to the central question of guiding location decisions, the main text is somewhat misleading in emphasising the role of the wholesale market and, at least in some paragraphs, overlooking the important role of transmission charges:

> 2.79 Overall, therefore, under national pricing, the wholesale market does not influence siting decisions of market participants. This runs the risk of encouraging generators to site in areas of the network that are not beneficial to the energy system as a whole, because the transmission system limits the extent to which they can produce. This could increase costs to customers as the SO needs to take a greater volume of actions (and therefore incur greater cost) in the BM.

At present, all participants, including those making entry decisions, face highly zonally differentiated Generation Transmission Network Use of System (TNUoS) charges. These are designed to signal the Long-run Marginal Cost (LRMC) of grid expansion for each technology through National Grid ESO’s Investment Cost Related Pricing (ICRP) methodology adjusted to reflect different generation capacity factors. Figure 1 shows the strong locational signals, for fossil generation on base load varying by £45/kWyr across GB (compared to early capacity auctions that cleared at below £20/kWyr). At a high 80% capacity factor, this would average £6.40/MWh but considerably higher per MWh as capacity factors fall with rising VRE. For VRE with a 37% capacity factor, the range is still £36/kWyr but now an average of £11.6/MWh. By 2028/29 NG ESO (2023) forecasts a range of

£30.85/kWyr (£8.8/MWh) for dispatchable generation and for VRE (45% CF) £37.5/kWyr, £9.5/MWh.

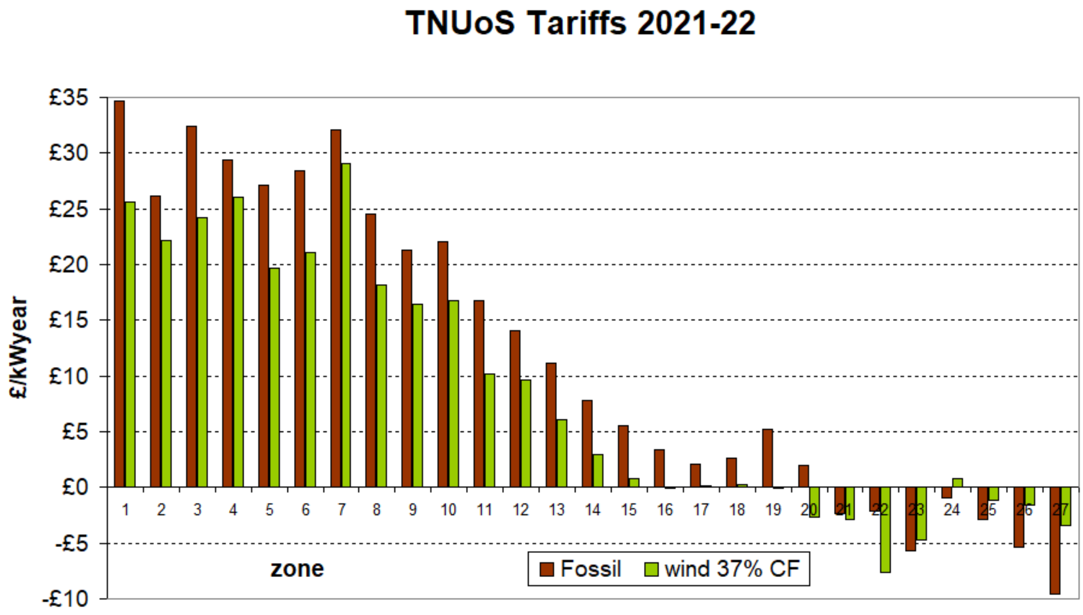

Figure 1 Generation Transmission Network use of System charges for 2021-22
Source NG ESO
Note Zone 1 is in the far NW of Scotland. Zone 27 in SW England (Cornwall)

The main problem is that the charges are only slowly changed and at best give a (very) long-run estimate of future connection costs: the Winser report (HMG, 2023) argues for accelerating transmission delivery from planning to commissioning from 14 years to 7 years. At any moment TNUoS tariffs will almost certainly be a poor guide to the ability of the network to accept new entrants at each node. This problem can be addressed by offering existing connections the status quo - continuing with charges set according to the published CUSC methodology. New entrants would be offered contracts for each connection point based on the ESO's best forecast of the system cost of locating that technology at that node. Where predictable upgrades are anticipated in the next five years, different contracts starting in later years could be offered. The main difficulty with this reform is that the calculations behind each contracted charge would likely to more opaque and complex than the current CUSC methods, which conveniently (but wrongly) assume that lines can be adjusted instantly and incrementally along all existing way-leaves.

Making the ESO a public-interest company (the Future SO) subject to close industry and regulatory scrutiny, may help, but lobbying, litigation and delay may make this option problematic. One of the merits of the FTI report is that it demonstrates just how valuable better location guidance will be, and so it seems reasonable to assume in the counterfactual that transmission charging will be reformed as part of delivering least-system cost investment for the Government's 2035 targets. How quickly this might be done is debateable but under the current REMA consultation, if LMP or ZP are ruled out, the high value and urgency of developing better TNUoS charges (and contracts) needs emphasising. FTI recognises this in fn. 66:

> Second, it is also theoretically conceivable that transmission charges may be adjusted to account for the impact on participants of the new transmission investment and so influence siting decisions (see our discussion of TNUoS transmission charges below).

Paras 2.92 et seq. discuss this at greater length, seeming to imply that LMP gives both more time varying signals over the course of a year and hence more efficient signals than an annual charge, and less obviously that

> the evolving nature of the GB energy system means that the optimal transmission charge is likely to change significantly over time. This can be problematic where decision making is lengthy and subject to rent-seeking behaviour by affected parties.

This comment conflates two issues – short-run dispatch signals and long-run location decisions where the unpredictability of future TNUoS charges is argued to be a drawback. Given that future LMPs are probably even more unpredictable, the criticism of TNUoS appears to be an argument for long-term connection agreements (as would be the case with deep connection charges and the current OFTO charges). The conclusion (in §2.97) is that

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

As a very important sensitivity, section 11 considers a

> dispatch-only sensitivity, that assesses the benefits of transitioning to a nodal market design under the assumption that efficient siting under a national model can be achieved through alternative mechanisms such as central planning. This tested by using the siting decisions from the nodal market design in the national market model (discussed in Section A). (§11.1, p241)

Assuming the same location choices under all three scenarios is arguably a better counterfactual than assuming REMA ignores the role of transmission charging in addressing unsatisfactory location choices. Regen (2023) concurs, and points out the considerable range of existing locational signals. The urgency of improving network planning has been made very clear by the Winser Report (HMG, 2023):

> the ‘queue’ to connect to the transmission grid is extremely congested, with more than 230GW of generation projects in the connection queue (compared to c.80GW of generation

> currently connected).[8] This has resulted in renewable energy developers and other connection customers receiving connection offers for the 2030s, slowing the energy transition. …
>
> The Holistic Network Design (HND), published in July 2022, provides a strategic blueprint for the coordinated connection of 23GW of offshore wind to the network by 2030. The HND will be followed by the Centralised Strategic Network Plan (CSNP), to be delivered in 2024-2025 by the new independent Future System Operator (FSO).[9] The CSNP is intended to provide a blueprint for the whole transmission network to enable coordinated and accelerated network development, including alignment between onshore and offshore networks. …
>
> The focus on transmission infrastructure is both important and urgent, but not sufficient for achieving Net Zero. Generation, storage, distribution networks and demand are all relevant to the infrastructure discussion, although not within the scope of this study.

The implication of this last quote is that there is an urgent need to integrate network and generation location decisions, and should now be high on the political and regulatory agenda. That is not to say that LMP does not help improve network investment decisions. Wolak (2020) notes that an LMP design makes the transmission planning process much more straightforward because the economic benefits associated with a proposed upgrade can be computed based on the wholesale energy cost reduction.

Similarly, FTI notes that location decisions can be influenced by a range of other policies (at §2.113), importantly including the design of auctioned contracts for new generation: "For example, we assume that future CfDs for generators include locational signals in locational market designs." (§2.114).

The consequence of treating location decisions the same under GBP and LMP is considerable – the net benefit under the base case falls from £24 bn to £13.7 bn, or by half.

[8] See https://www.nationalgrideso.com/industry-information/connections/connections-reform

[9] The creation of the FSO is being introduced through the Energy Bill, currently passing through the Houses of Parliament (https://bills.parliament.uk/bills/3311)

1.3. *Surplus analysis*

The most striking impact of LMP is the large increase in consumer surplus and an almost corresponding decrease in producer surplus – the net social surplus is much lower than either. In the US, transitions from zonal to nodal pricing have normally had to keep whole the losing party (here, generators) by awarding them FTRs or their US equivalent Congestion Revenue Rights (CRRs).[10] In the move from ZP to LMP in California the Market Surveillance Committee of the California ISO[11] cited as one principle for allocating CRRs was "the goal of avoiding significant wealth transfers between market participants[12] in the transition from the current zonal-pricing market" (p3). Email correspondence with Professor Ben Hobbs (member of the California ISO [Market Surveillance Committee](#)) confirms this:

> The basic approach of allocating them freely to present market parties is conceptually the best (under a minimize income shifting objective) but as you point out is hard given the quantity uncertainty. An alternative perspective is that if most of the grid has been paid for by consumers (as in the US), they should get the rights and then resell if they want.
> In California, this is what's done (reselling is done through an auction). A persistent complaint of the market monitor and others is that they are resold at less than their expected value for reasons that are debated. This results in an apparent transfer of transmission rent from consumers to the buyers of the rights (according to the market monitor, on the order of 10^5 $/yr, but smaller in 2019-2021 after reforms, popping up again in 2022 due to higher congestion costs). This is the loudest complaint about transmission rights in California. The picture is complicated by having multiple types of rights and transactions as we discuss in our Opinion, and it can be argued that the actual loss of rent that consumers suffer is somewhat or a good deal smaller. We may be revisiting that issue."

Clearly the allocation of CCRs or FTRs is a key element in the transition and on the principle of non-expropriation would likely be allocated to incumbent generators (at least for a transitional period). The design of these transitional rights will be a key element in any reform, and if done poorly will likely be at the expense of consumers. FTI recognises this to some extent in its final sensitivity section at §9.74-75 (p217):

> - allocating a subset of FTRs over a defined temporary period to certain market participants to immunise them to variations in the difference between the trading hub price and the locational price; and/or
> - maintaining a single price exposure to certain cohorts (e.g. through the settlements process).
>
> 9.75 Inevitably, the greater the size and duration of the support for existing investments when transitioning to a more granular locational market design, the smaller the consumer benefits that would arise in the transition to a nodal market.

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[10] There is a useful set of references at https://lmpmarketdesign.com/ftr.php
[11] At http://www.caiso.com/documents/070418_mscfinalopiniononcongestionrevenuerights.pdf
[12] It is not clear from the quote which market participants are referred to, but FTI in an email exchange claim that it was to avoid disputes between Load Serving Entities rather than between consumers and generators.

The “illustrative” transfer back to producers is shown in fig 9.15 at £5 bn. but this is likely to be a significant understatement compared to the net producer cost of £36.8 bn (fig 11.7). New entrants would probably adjust their entry decision to make similar returns under all pricing options, although revenues from the balancing market are likely to be less bankable than those hedged with FTRs under locational pricing.

1.4 Time period

An important aspect of comparing market designs is the time period over which the counterfactual is assumed to hold, which FTI take as 2025-2040. Clearly as Variable Renewable Electricity (VRE) increases its penetration and as new more flexible plant is needed to improve system balancing, the stresses on the current market design are likely to increase, to the point that they will inevitably need to be addressed. One solution is to reinforce the network to minimise congestion, but this is likely to be costly unless better location signals are developed, as FTI’s discussion of variant HND suggests. One might hope that G-TNUoS would be modified to address such concerns, and if so would reinforce the more appropriate counterfactual as one with the same investment locations as LMP and ZP.

The 2025 start of the calculations is optimistic if, as NGESO suggests, implementing LMP might take up to 5 years from any REMA decisions. It would be helpful to have the NPV also calculated for the period 2030-2040 (longer than 2040 takes us into uncharted territory).

1.5. Curtailment

The remaining and key determinant of market pricing differences will be the treatment of VRE curtailment, which increases rapidly with penetration. Newbery (2022) shows that marginal curtailment is typically 3+ times average curtailment, so that the last MW of installed VRE will be curtailed 3+ times the average. FTI shows curtailment levels in Fig 6.17 p144 rising from about 18 TWh under all designs in 2025 to 28 TWh under LMP in 2030, when wind output is shown as about 258 TWh (Table 2 above), presumably after curtailment. By 2035 FTI shows curtailment at 38 TWh under LMP, with all wind generating about 380 TWh. If, under LMP, potential wind rises from 258+28 = 286 TWh to 380+38 = 418 TWh, average curtailment ***falls*** from 10% to 9%. Without more ability to export and store (including in EVs) one would expect a rapid rise in curtailment under any market design as higher levels of VRE output in above average capacity factor hours exceeds domestic demand.

By 2035 FTI shows curtailment at 70 TWh under GBP compared to 38 TWh under LMP. A large part of the curtailment reduction is probably from better siting, which might be achievable with a more pro-active FSO directing VRE locations. Figure 2 shows the steady increase in curtailment of Scottish wind, reaching 19% in 2020 (2021 was a low wind year and curtailment fell to 13%, as expected). Almost (perhaps all) these curtailments arose because of balancing actions to address transmission constraints, so the marginal curtailment of locating more wind behind these constraints could be 40% or more.

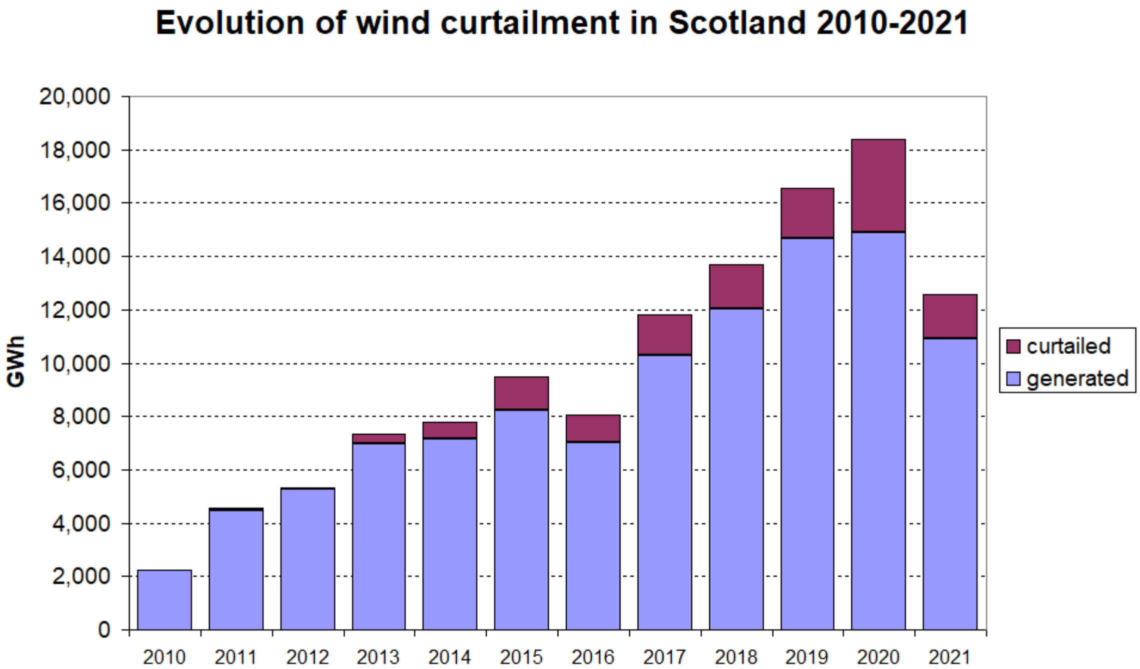

Figure 2 Wind curtailment in Scotland, 2010-2021
Source: Renewable Energy Foundation at https://www.ref.org.uk

Figure 3 shows the curtailment for individual Scottish wind farms in 2020 by date of commissioning, and shows a slight upward drift for later commissioned wind farms for curtailment in 2020, some of which experienced very high rates of curtailment.

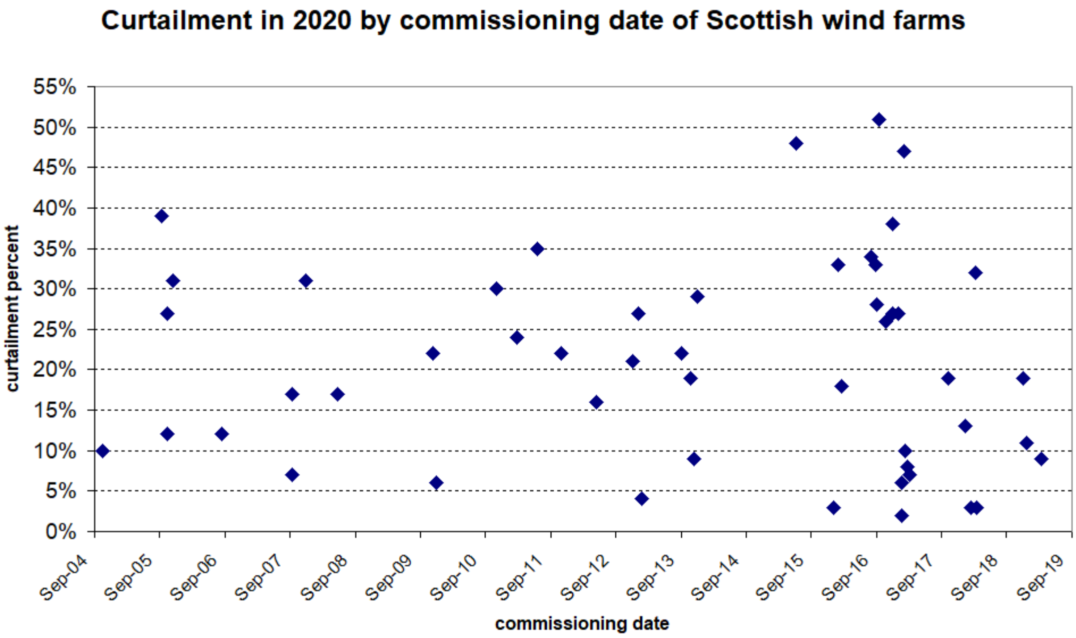

Figure 3 Wind curtailment in Scotland in 2020 by date of commissioning
Source: Renewable Energy Foundation at https://www.ref.org.uk

High rates of curtailment because of grid congestion indicates a strong need to ensure future generation connections are directed to areas currently less congested. Improving location decisions will surely be high on the agenda of a Future SO. FTI assumes grid topology is held constant across market designs that take into account forward looking transmission investment plans under NOA7 and the more ambitious HND. In FTI's report, curtailment impacts the allocation of rents, and increases the claimed benefit from improved location decisions. To some extent the latter benefit would disappear in the variant in which FTI holds location decisions constant.

1.6 Implementation costs

The claim is that the transition to LMP might cost £500 million (§81), based on international evidence. However, almost all that evidence is from systems with central dispatch, which would also have to be introduced in GB. Arguably the main cost is the software to handle transactions as the ESO can already calculate the LMPs. The move from the Pool to NETA cost £$_{2001}$500 million but perhaps software is cheaper now. In any case the cost is small compared with the benefits, which might be from roughly £500 million/yr (SysTr)[13] to £1 bn/yr (LtW), in both cases ignoring relocation benefits.

2. Consumer vs. Social surplus

The first and most obvious difference between LMP and the current single GB pricing designs is that under the current GBP model generators (and other flexible resources offered to the ESO) are paid to change their Final Physical Notifications (FPNs) to achieve a security-constrained dispatch, while under LMP these assets are only paid on the security-constrained dispatch locational prices. The difference is that consumer payments are therefore lower under LMP, but much of the apparent cost saving to consumers is a transfer payment from generators to consumers. FTI provide an excellent worked example in §2.37-§2.62. As noted above, who receives the congestion revenue rights (CRRs or FTRs) is a largely political and/or legal decision, and would probably be allocated back to the generators who are disadvantaged by the reform.

FTI's approach to modelling the net surplus is commendably sensible and conservative,[14] as they assume that the same set of generators are available for dispatch under all pricing schemes:

> 2.72 However, our assessment does not capture the full effects of locational pricing on dispatch as we do not assess all of the potential impacts of centralised scheduling relative to self-scheduling. For instance, this means we do not take account of the potential benefits such as:
>
> - Improved dispatch resulting from the SO having broader and deeper information about plant capabilities, meaning that, for instance, it can better optimise across the wholesale market and the market for ancillary services.
> - The potential benefits of centralised scheduling within an hour

[13] FTI does not give figures for SysTr holding investment location constant, so this is based on assuming they would be half those under LtW and using a 3.5% discount rate.
[14] See e.g. Jha and. Wolak (2023) for the benefits of central dispatch at the day-ahead stage.

- The ability to co-optimise energy and reserves more easily than in a self-scheduling market.
- Improved dispatch resulting from the SO's role in scheduling at the day-ahead stage (versus gate closure one hour before real-time). This means that the SO should be better able to optimise dispatch, as its decisions can be more fully considered.

2.73 Conversely, there could be scenarios with more efficient dispatch under a self-scheduled market design than a centrally-scheduled design. For instance, if the SO lacks the depth of information held by market participants, it may be unable to forecast variations in load or intermittent resource output as well as market participants in making its scheduling decisions. As another example, difficulties in incentivising the SO could mean that it does not make optimal use of the information it receives, suggesting that dispatch could be more efficient when it has a more limited role.[15] Such potential effects of central scheduling are also not included in our assessment.

In the FTI report (Fig 9.2, p 200) consumers are shown benefitting by £50.8 billion (NPV, 2025-2040, LtW, NOA7) under LMP but the net social surplus is only £24 bn, the difference of £26.8 bn are transfers from generators to consumers. However, with planned improvements in network planning and delivery under HND, the net benefits fall to £14.4 bn (fig 9.4), only half that assuming no response by NGET to the revised FES targets. However, HND requires extra network investment and it is unclear how large this is from the main body of the FTI report nor from the appendices. FTI notes

> … Although, it is important to note that we have not factored the additional cost of the transmission assets that are deployed in the LtW (HND) scenario relative to LtW (NOA7) into this assessment. We return to this topic later in this summary. (§67 p17)

> … A large increase in transmission build is likely to be costly as well as politically challenging. (§114, p29)

As noted above, the HND reveals

> The recommended design leads to an additional £7.6 billion of capital costs[16] due to the additional offshore infrastructure, but this is outweighed by the £13.1 billion savings in constraint costs that are expected to result from the additional network capacity this infrastructure provides. (NG ESO (2022, p6)

It would be helpful if FTI could disaggregate the extra network costs and benefits when moving from NOA7 to HND as the extra £7.6 bn. investment cost is clearly material but as it is included in all scenarios, it should not affect the relative benefits of a move to locational pricing. As an aside it is also not clear how much of the saving that HND claims in constraint cost savings are true net benefits – see the Appendix below.

[15] Such considerations were important drivers of the NETA reforms. See Ofgem/DTI (1999), 'The New Electricity Trading Arrangements' (link).
[16] All cost savings are calculated over a 40-year asset life period, starting in 2030, using 2021 prices, unless otherwise stated.

Under NOA7, £11.9 bn. is a reduction in revenue paid to renewable CfD holders, which is presumably a mixture of revenues under CfDs (and ROCs) before market reform, and those after (although it should be possible to design support contracts that extract rent almost equally efficiently under all the market designs). Assuming that the payments are for existing contracts, that likely reflects the incentives of past support schemes to locate in high wind areas, which will under LMP experience lower local prices. Under the RO scheme that will directly reduce total revenues (unless they are kept whole with FTRs). Under the CfD with FiT much will depend on the reference price. At present the relevant reference price is the Intermittent Market Reference Price (IMRP):[17]

> The Intermittent Market Reference Price is calculated using day-ahead data received from EPEX SPOT and N2EX. An IMRP is calculated for every hour of the day pursuant to condition 21 of the Contract for Difference Standard Terms and Conditions.

If the IMRP is the LMP hub price but the renewables sell at the LMP they will lose (unless granted FTRs to the hub), but could argue that they are being expropriated as the hub reference price is no longer a suitable reference price. If they are paid on a reference day-ahead nodal hourly price they will be kept whole and the consumer cost of the contracts will be as before (but there will be an apparent loss to consumers of buying power at that node from the renewables at the strike, rather than the on average lower market price).

One should also be cautious about transfers between producers and consumers for future investments, as these will depend on network charges, which will need to be adapted for any change in market design, and which in any case are open to change under REMA. Even without LMP, TNUoS contracts can (and should) be reformed to give the best location signals for future investors (offering a long-term contract that allows new entrants a different, forward-looking contract while grandfathering existing connection agreements). A sufficiently competitive market for new investments should give rise to the same rents (ideally normal rates of return) under either market design (again assuming intelligent TNUoS and associated contracts such as Financial Transmission Rights), although balancing market revenues are less bankable and may even lead to a higher WACC.

Perhaps surprisingly, the net benefit under ZP (same assumptions) is £15.3 bn., 65% of that under LMP, suggesting that the main gains are reducing congestion at the zonal boundaries (although 35% is still accounted for by resolving internal constraints). If the boundaries are correctly drawn, ZP should largely address inefficient trading over interconnectors, which are problematic under GBP (see below).

The remainder of this review will therefore concentrate on ***net savings*** from LMP (and zonal pricing, ZP). The difference with current pricing will depend on the difference in prices under the two market models (LMP and ZP) and those under a single GB price (GBP), all of which follow from the Plexos modelling with the assumed volume of generation, level of demand, network topology and interconnectors, which are the same for all market designs. Plexos can determine the optimal dispatch and claims to be able to model prices:

[17] See https://www.emrsettlement.co.uk/settlement-data/settlement-data-cfd-generators/

> Using the UK market as an example, PLEXOS models every generator so that at minimum they recover their operating cost and then determines the minimum bid price of a generator asset by factoring in operating costs, the volume of electricity each generator can offer, and constraints on the flexibility of the generator to ramp.[18]

It is less clear how accurately Plexos can model the short-run behaviour of market prices. Ward et al. (2019) argue that merit-order based models produce far less volatile prices than observed in the market, and that this understates the value of storage, flexibility responses and interconnector flows. They suggest adjusting unit-commitment models to replace the step-like variable cost functions with upward sloping supply functions, which offer below variable cost in low-demand periods and above variable cost in high-demand periods. The quote from Plexos above suggests their model attempts to recover costs by more sophisticated bidding than just offering short-run variable costs, and if so this criticism of energy models may not apply. But to the extent that Plexos may understate likely price volatility it will also understate the gains from storage, flexibility responses and interconnector flows. It is not clear how this impacts the differential between market pricing designs, but it might mean that the gains from more granular (locational) pricing are understated.

While the total volume and type of generation installed at each date is the same, the location is determined by the market pricing model (with a sensitivity in which locations are the same for all designs). A critical issue to explore is the extent to which differences attributable to market design are correctly attributable (and not to assumptions on network charging, which is a separate design choice to LMP, ZP, or GBP).

3. Net (socio-economic) benefits

The key elements likely to influence the difference between LMP (and ZP) and the current single GB pricing designs are:

In the short run:

1. Differences in flexible generation committed day-ahead and dispatched.
2. Differences in flexibility/time shifting resources. These include decentralised: demand-side response (DSR); electric vehicle (EV) charging; heat pumps (HP); and electrolysers; and centrally dispatched (by the ESO) battery and pumped storage.
3. Differences in flows over interconnectors.

In the long run:

1. Differences in the amount, type and location of generation and demand caused by differences in locational price signals.
2. Differences in volumes of investment caused by changes in perceived risk/WACC.
3. Differences in the amount of network investment caused by different patterns of generation and load.

[18] https://www.energyexemplar.com/price-forecasting

4. Long-run impacts

Long-run differences need to be discussed first as they are more significant than short-run impacts as they persist for the life of the assets and are irreversible. The three long-run differences are discussed below.

4.1 *Locational decisions*

As noted, locational investment decisions are best guided by long-term network contracts with the ESO or DSO regardless of the choice of market design. The proposed Future SO should be given a mandate to ensure efficient investment location and hence the power to design efficient transmission contracts with new entrants. Whether this guidance takes the more limited form of signalling via the terms of the contracts, or whether the FSO secures all the necessary consents for each site and auctions them (just as the off-shore regime secures specific sites for new wind farms) is a matter for REMA and doubtless other consultations but the Winser report certainly stresses the importance and urgency of more timely transmission planning and delivery. Ofgem can ensure that the NGET receives the correct revenue by adjusting the levels of the average Generation and Load tariffs, as at present, without disturbing the locations signals set by the FSO.

With the correct network contracts (which will need careful design), the amount, type and location of generation should be efficient, subject to the information available to the FSO. I would argue that the FSO should be able to replicate the same locational investment signals with GBP and LMP with appropriate long-term network contracts, provided that under LMP the FSO issues suitable Financial Transmission Rights (FTRs) to hedge the LMPs. Hence, the first potential difference should not exist under appropriate network contracts, whose design is in any case a separate matter for REMA.

In a key sensitivity, §11.17 and figs 11.4-5 (p244-5; slide 73) show that leaving location decisions the same under GBP and LMP reduces the net benefit (PDV 2025 to 2040) from £24 bn to £13.7 bn, so whether a modest reform of ESI TNUoS contracting could deliver efficient location decisions under GBP is clearly material and would achieve half the net social gains of LMP under this scenario. The contrast between the two net benefits signals the importance of the FSO's task and of designing efficient connection contracts to minimise total system costs.

4.2 *Risk impacts*

This will undoubtably be the main issue that generators who fear that they might face lower prices (e.g. those with assets in Scotland) will concentrate on, as an apparently small change in the Weighted Average Cost of Capital (WACC) of 50 basis point (0.5%) has a large negative impact on net benefits, reducing them by £7.6 bn (under LtW). FTI argue (§8.48 et seq, p191; slide 54) that this risk is negligible, and this seems correct although clearly disputed by some market respondents (§8.57). It is always difficult to judge whether the rather scanty evidence from one jurisdiction would hold in GB, but first principles are a sound place to start. The cost of risk is reflected in the WACC, which depends on the ability of the investor to reduce risk by averaging over time (it is the risk that annual income departs from the current annual average that counts) and across investments (e.g. through a portfolio of geographically dispersed power plants). Risks that cannot be adequately internally hedged as above can often be mitigated by risk-reducing contracts with other parties.

It is open under REMA to propose suitable long-term contracts to remove any differences in risk under different market designs (via CfDs and FTRs). Price risk is already addressed by CfD with FiTs, and if new renewable electricity contracts are replaced by yardstick or "deemed" contracts, more market exposure can be combined with mitigating price risk and, to a large extent, volume risk (by making the contracts apply to full operating hours, not calendar time). FTI largely concentrates on beta risk on the assumption that idiosyncratic risk can be minimised by diversification. They note that CfDs remove (or could with some minor tweaks remove) most market risk as they would sell at the hub (as under GBP), while output risk averaged over the life of the investment should be negligible. FTI do not cite but it is worth noting that the WACC dramatically dropped with the move from ROCs (that expose revenue to market risk) to CfDs with FiTs (that hedge, excessively, price risk). Otherwise, there is limited relevant evidence but some from international experience:

> 8.62 The case studies of countries that have adopted locational wholesale pricing, discussed in Appendix 4, do not suggest strong effects of locational pricing on either the pace or cost of renewables investment. Jurisdictions both with and without locational pricing have seen rapid increases in the capacity of renewable generators in recent years. Instead, factors other than market design, particularly the geographical characteristics of a region and the nature of policy incentives, appear to be more important drivers of investment in generation capacity." (p195, also slide 54).

Peter Cramton (served on the Board of Directors of the Electric Reliability Council of Texas) responded to my queries about US experience:

> I question whether nodal pricing increases risk to investors, especially to the point where it significantly increases the cost of capital. Five-minute price volatility is not a good measure of risk for an investor. The investor cares about how revenues vary over long durations, not in real-time. The investor has many ways to manage risk. The most common is to have a diversified portfolio of resources. The day-ahead market hedges real-time price risk. Forward energy markets and the FTR markets allow hedging of longer-term risks. The system operator should support all these complementary markets.

Frank Wolak (former Chair, Market Surveillance Committee, California Independent System Operator until 2011) concurs:

> Like Peter, I am puzzled why one would think that LMPs introduce more risk and raise the cost of capital relative to a zonal market design. I think that transitioning to LMP should increase liquidity in the forward energy market and as a result reduce short-term locational price volatility. Under the zonal design in GB and other European markets it is increasingly the case that a generation unit receives a INC or DEC instruction as-offered or as-bid in real-time to obtain a physically feasible real-time operating level. These INC and DEC prices are difficult for a generator to hedge and the total cost of these balancing actions are spread across all loads on a per MWh basis, different from LMP which sets higher short-term prices at locations that are more expensive to serve.
>
> A few months ago I found the following quote on the National Grid ESO web-site:
>
> > In 2020, the ENCC issued 1,800 daily balancing instructions to market participants. Today, balancing services regularly exceed 50% of national demand.[19] For reference, the average was just 5% in 2012.
>
> I think it is unlikely that these balancing instructions are the least cost way to achieve real-time physically feasible operating levels for generation units in the GB market. Moreover, the price bids and offers resources submit are likely to reflect exercise of unilateral market power.

The remaining, and potentially significant cost if mismanaged, is the extra cost of the additional hedging FTRs needed to manage the difference in volatile LMPs and the less volatile hub price. Ben Hobbs noted above of the

> apparent transfer of transmission rent from consumers to the buyers of the rights (according to the market monitor, on the order of 10^5 \$/yr but smaller in 2019-2021 after reforms, popping up again in 2022 due to higher congestion costs).

This largely arises because the agents who need the hedge (generators selling at each node and buyers buying from different nodes) have to bid for these in quite illiquid auctions that are poorly arbitraged – perhaps because the logical arbitrageurs are large financial institutions that can aggregate and thus offset risks, and they have market power. The cheapest solution is for the FSO to offer FTRs at fair market price (with no risk premium), as they are regulated and thus assured of covering their full cost. As an automatic aggregator (standing behind both sides of transactions, and receiving in the first instance the congestion rent) the FSO faces no net market risk and should therefore avoid transferring rents from the consumers to buyers.

FTI is clear that the value of mitigating risk is large (e.g. possibly £7.6bn) and this underlines the importance of good contract design, much of which is in the hands of the Government in setting the terms of its auctioned contracts, and the FSO in its connection agreements and FTRs. (See also §4.4 of this report).

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[19] Note that FTI draws attention to this at §3.12

4.3 *Network investment*

As to the third difference, again, if the FSO is instructed (as seems logical) with ensuring efficient location signals for all types of generation (and other assets such as grid-scale storage and electrolysers) to minimise system costs, then the location decisions should be the same under all market designs.

> FTI use Plexos which:
> For the zonal and nodal market designs only –the LT model determines the optimal evolution of generation capacity (GW):
> - Finds the lowest-cost combination of generation plants (of all technologies)…
> - …that meets the minimum capacity margin,…
> - …constraints on CO_2 and other emissions…
> - …for each price zone
>
> For the national market design, we will align total capacity and location with the FES scenarios

The network evolution is pre-determined (either NOA7 or HND). Future investment in flexibility services and their location may well be influenced by LMP, as prices in export-constrained periods should be lower under LMP giving sharper and more profitable signals to such services. However, if the FSO contracts for such services and dispatches them under GBP, and if the FSO were to give better location signals for their location, then the difference might be reduced. There is, however, the questions of mitigating risk for flexible generation (and designing suitable transition contracts), discussed in the next section.

4.4 *Contracts for flexible generation under LMP*

A standard Contact-for-Difference used by dispatchable generation is a purely financial hedge, in amount M MW, with a strike price s, that is paid to or collected from the issuer (usually a generator), $(s – p)M$, so that output decisions are based on the spot price, p, compared to the avoidable cost, c. Thus if $p < c$, the generator would not generate but replace its output by purchases in the spot market at price p, and receive $(s – p)M > 0$ (as $s > c$ to make it sensible to write the CfD). If $p > c$, the generator receives $(s – p)M$ (from the CfD) + $(p - c)M = (s – c)M > 0$.

Under LMP the relevant price for operating decisions is the nodal price, p_n, while for liquidity traders will wish to contract at the hub price, p_h. If it is thought desirable to hedge the basis risk, this can be achieved by the ESO offering FTRs $(p_h – p_n)M$ that must be exercised if and only if $p_n > c$, where the generator must declare c (possibly indexed to a spot fuel and carbon price) annually. Assuming the generator holds a hub-based CfD, if $p_n > c$, the generator will receive $(p_h – p_n)M + (s – p_h)M + (p_n - c)M = (s – c)M > 0$. If $p_n < c$, the generator will just receive (or pay) $(s – p_h)M$. One difference is that there is longer a guarantee that this is positive, if $p_h > s > c > p_n$.

If this cost, averaged over the year, is material, it could be subject to a soft cap offered by the ESO (e.g. no compensation until a certain level, then a share of the extra cost up to possibly an upper cap, above which full compensation).

It is not clear that there is any need for an FSO hedge for batteries and DSR as these should become more profitable with the increased volatility of LMPs (as investors agree, see §8.57).

5. Short-run impacts

Under some strong assumptions, listed below, dispatch might be the same under the current BM/GBP as under LMP (or ZP). If these assumptions are not all satisfied there will likely be differences in dispatch. One key difference that FTI stresses is that LMP, in contrast to GBP and ZP, requires central dispatch, which should ensure that the set of plant committed day-ahead can meet all the transmission constraints and security requirements at least cost, less likely under ZP. This would be guaranteed if all plant truthfully submitted their costs and operating parameters, but, as FTI is aware (see §2.72-2.73) full information may not be available to the SO:

> 2.73 Conversely, there could be scenarios with more efficient dispatch under a self-scheduled market design than a centrally-scheduled design. For instance, if the SO lacks the depth of information held by market participants, it may be unable to forecast variations in load or intermittent resource output as well as market participants in making its scheduling decisions. As another example, difficulties in incentivising the SO could mean that it does not make optimal use of the information it receives, suggesting that dispatch could be more efficient when it has a more limited role. Such potential effects of central scheduling are also not included in our assessment.

Table 12.2 (p259) qualifies the benefits from central dispatch as follows

> Operational benefits: our modelling does not account for operational benefits from centralised scheduling vs self-scheduling as well as other dispatch benefits. For example, we do not consider the impact of the ability to co-optimise energy and reserves more efficiently in a nodal market.

Frank Wolak comments:

> The system operator in GB starts from generation schedules at gate closure that are increasingly unlikely to be physically feasible because of the growing share of intermittent renewables and number of interconnections with the GB market. Generation schedules at gate closure are not expected to be least cost on a system-wide basis given expected real-time locational demands. Jha and Wolak (2023) describes how a day-ahead LMP market with a real-time LMP market can reduce the cost of serving load, particularly during stressed system conditions.

On balance, as VRE becomes more important and the need for balancing actions increases (which it has, dramatically), **FTI's assumption here is conservative.**

The first source of difference in dispatch under LMP and ZP (including GBP) is:

4.5 Differences in flexible generation committed day-ahead and dispatched

Under GBP, flexible generation can sell in the day-ahead market (DAM), the intra-day market (IDM) or in the balancing market (BM). If the Balance Responsible Party (BRP, in this case a generator) is in a likely import-constrained location where additional supply may be needed in the BM, with likely higher prices there, it would logically reduce its offers (if any) to the DAM to be able to offer into the BM. Conversely in an export-constrained location it should logically offer its full output in the DAM, and expect to bid to buy back more cheaply in the BM. FTI's assumptions are

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

FTI assumes that all plant will be dispatched in strict merit order (on the basis of short-run marginal cost, see §5.10) and so if location decisions are held constant (and DSR and interconnectors are ignored), FTI's might be expected to lead to the same dispatch, but this does not automatically follow, as the set of plant to deliver a security-constrained solution in the balancing market would only be the same if the (shadow) LMPs calculated by the SO in taking balancing actions were sufficiently similar to those computed under LMP. In addition, FTI notes in Table 12.2:

> our modelling does not account for operational benefits from centralised scheduling vs self-scheduling as well as other dispatch benefits. For example, we do not consider the impact of the ability to co-optimise energy and reserves more efficiently in a nodal market

If most of the dispatch differences are driven by different plant locations (which I argue should as a first approximation be held constant), then most of the short-run benefit stem from flexibility and interconnectors, discussed below.

Compared to the fixed location investment case, then FTI's assumptions are conservative but in the case of location-responsive investment they are probably optimistic.

Frank Wolak offers useful comments on the efficiency of LMP vs GBP (or ZP):

> .. in a multisettlement LMP design, suppliers submit start-up and minimum load offers as well as energy offer curves and operating reserves offer curves for all 24 hours of the day in the day-ahead market. The system operator then finds the as-bid consumer surplus and as-offered producer surplus maximizing combination of energy and ancillary services quantities for each resource for all 24 hours of the following day subject to the aggregate supply equalling the aggregate demand for energy and all ancillary services given the configuration of the transmission network. These generation unit-specific day-ahead energy and ancillary

> services schedules and LMPs and ancillary services prices are financially binding. In real-time a similar optimization problem is solved to meet the realized locational demands for energy to yield real-time LMPs.
>
> A significant source of benefits from transitioning to LMP is the ability to co-optimize energy and ancillary services in the day-ahead and real-time markets. (See Wolak, 2011, Triolo and Wolak, 2021). The shift to LMP from zonal designs happened at the same time as co-optimization of energy and ancillary services in the day-ahead and real-time markets in both regions (i.e. California and Texas). In the early California market, the operating reserves markets cleared after the day-ahead zonal energy market. Suppliers to the operating reserves markets knew which generation units had been taken in day-ahead energy market and were therefore able to exercise unilateral market power in the operating reserves market particularly during high energy demand periods. Operating reserves costs were 13% of annual energy costs in 1998, 5.7% in 1999, and 6.8% in 2000, three years with very little intermittent wind and solar energy in California. During the last three years of co-optimized operating reserves markets outcomes in California with approximately 25% of annual energy from intermittent wind and solar resources, annual operating reserves costs were less than 2.0% of annual energy costs.

Efficient dispatch will also depend on the treatment of legacy contracts with any move to different pricing regimes. At present, ROC and CfD holding generators have incentives to bid considerably below their operating costs as they are paid on metered output, and can, provided not for more than six hours per day, even bid negative prices. As a result, they may be curtailed last when they should be curtailed earlier (as their avoidable costs are lower than fossil plant and they incur no start-up costs to avoid). If the curtailment order is changed with a move to LMP (which will depend on how reference prices are then set), the dispatch may differ between pricing models. However, this is subject to changes in setting the reference prices, which could be considered a separate reform to changing the pricing rules. The simplest change would be to rule out negative bids for all VRE, given that it can instantly ramp down and then up when prices rise above zero.

4.6 *Differences in flexibility/time shifting resources.*

The second source of differences, already mentioned in Wolak's quote above, is differences in the use (and location) of flexibility resources, including storage (see table 5.3, p110). The assumption of no difference with LMP is likely to be increasingly violated for certain categories of supply and demand, with the passage of time. Thus slide 83 shows quite different storage use under LMP compared to GBP:

> In 2035, the % of hours where batteries (in aggregate) were operating in an opposite manner in the nodal relative to national market runs (i.e. charging in one and off or discharging in the other) was 23%.

Some of the benefits of LMP involve the relocation of storage to Scotland where nodal prices are more volatile, and some from the improved use made of that volatility. If location is held constant across designs, then the remaining benefit would be just from price volatility at each location.

Box 6.4 (p137-9) shows that charging EVs could also be quite different under LMP, with increased charging in hours where some areas have low LMPs and reduced charging in the same hour in areas of high LMPs:

> We find that overall, for modelled year 2035, that in 28% of hours, there is a difference in the timings of EV charging between a national and nodal market. (§97, ES-14, p26 and Slide 82)

In order to identify the contributions of consumer-controlled flexibility resources (EVs, heat pumps), FTI in ch. 11 B explore the impact of shielding consumers from nodal prices:

> 11.22 The load shielding sensitivity tests the impact of "shielding" consumers from the locational price at their connected node. Instead, we test the impact of exposing all consumers (both domestic and nondomestic) to a uniform average national wholesale price in each hour, while retaining locational pricing for generators, battery storage and electrolysers. The purpose of this sensitivity is to test how the estimated system benefits of nodal pricing change when flexible consumer load, provided for example through smart charging of EVs and heat pumps, is unable to optimise consumption around the local price at the connected node.

The full benefit of scheduling EV use in later years also includes V2G (i.e. using the battery in the EV to sell power back to the grid, acting more like a storage device). It would be perverse to allow consumers to charge their EVs at the national price and sell back at a nodal price, so the model shielding of consumer EVs requires finding a scenario in which there is little V2G. In later years under the LtW scenario this would make a very substantial difference (see Table 1 of this report), and so FTI confines its comparison to SysTr:

> In the LtW scenario, V2G forms a significant proportion of system flexibility in the latter modelling years, with a maximum potential of 39GW by 2040. The extent of V2G adoption under the LtW scenario means that the assumed pricing treatment of V2G assets by policymakers would impact the modelling outcomes for the load shielding scenario. For example, while a load shielding policy might generally cause price-responsive load to shift to hours that require higher-cost generation to operate to meet demand, the continued operation of V2G assets in a 'system-optimal' manner, by virtue of their exposure to the nodal wholesale price, could largely negate the price impact of this.
>
> By comparison, V2G represents a very small proportion of system flexibility in the SysTr scenario across the modelled period, at less than 4% of total flexibility, meaning the exclusion of V2G from shielding should have a relatively a low impact on modelled results. As a result, we have focused our assessment of the load shielding sensitivity on the SysTr scenario. (Box 11.1, p249)

The separate contribution of such demand-side responses to net social benefits (PDV 2025-40) is the difference in their presence (£13.1bn, fig 11.11, SysTr (NOA7) p254) to removing them £11.4bn (SysTr, fig 11.12, p255), or £1.7 bn, and unlikely to be delivered under GBP or ZP. However, this still leaves storage and interconnectors as major sources of flexible response to LMP (and ZP).

4.7 *Differences in flows over interconnectors*

Interconnector flow differences appear to be a key source of large benefits from LMP. Fig 7.3 (p159 and Slide 27) shows the differences between LMP and GBP under a situation of moderately high wind in NI and Scotland (17/01/2040 at 5pm) leading to a GBP of £126/MWh, but under LMP, zero prices in the North, £135/MWh in the Midlands, £104 in Wales and £158/MWH in the South.

Figure ES-11 (p23 also at fig 6.12, p136 and Slide 79) shows the impact on interconnector flows at 09/03/2030 at 8am, where under GBP the north imports 4.2 GW into a GB price zone of £13.9/MWh and exports 14 GW from the south. Under LMP the north has a price of £0/MWh, the south of £81.4/MWh and the flow direction changes on three interconnectors (four counting EWIC which now exports to GB while Moyle continues to flow out of Scotland). The cash value of these trades is £478,700 in that hour. The efficient value is £151,840 but the improvement in net benefits of correcting the adverse flows and repricing the rest is £576,710 per hour, or about £30/MWh on the original trade volume of 19 GW (which falls to 13.9 GW under efficient trade).

The ability to export surplus wind to Norway while importing cheap French electricity into the south is clearly valuable and would be greatly impeded, as it could at best only operate in the balancing market, which faces numerous obstacles. Fig 6.2 (p148 and Slide 80) shows very large annual changes in flows in both directions under LMP.

The key question is whether the FSO, noting high surplus wind in export-constrained zones that are still importing, can reverse such inefficient trade flows in the BM, and if so whether that could undo all or most of the inefficiency. FTI has identified important obstacles to reversing flows in Table 5.5, p115, which assumes that the cost of reversing flows is a penalty price of €130 falling to €100 (in line with the ESO's historical treatment of interconnectors in the BM).[20] This is explained in appendix A1.21:

> A1.38 We assume that changing flows on interconnectors by one MWh costs €130 in 2025 and €100 in 2030. This assumption is required as the balancing markets of neighbouring countries are not modelled explicitly, which would be the basis of offer and bids in practice. However, changing flows on an interconnector would likely require constraining-on gas generators in a neighbouring country. As a result, we have set interconnector offers to a level slightly above the SRMC of CCGT plants.

The goal of ENTSO-E and the Integrated Electricity Market for several decades has been to deliver efficient use of interconnectors, first with market coupling at the day-ahead stage and more recently integrating intra-day trading and balancing markets (under TERRE). However, this goal potentially conflicts with the EU's aim to maximize opportunities for competitive access of consumers in each country to access supplies from any other country, in line with their concept of a Single Market. This has most recently been manifest in the 70% rule, under which "Transmission System Operators are required to ensure that at least

[20] Jason Mann of FTI has clarified this, as representing the predicted cost of Continental gas-fired generation that is assumed the supplier of balancing actions, based on the same future fuel prices used in the Report.

70% of the transmission capacity is offered for cross-zonal trade, while respecting operational security limits."[21] The problem with this rule is that while it may be a legal requirement it ignores the laws of physics, in that it can force SO's to incur considerable internal redispatch and congestion costs in order to make the interconnector capacity available to 70% of Net Trading Capacity (NTC). In the large German zone in some years only 20% of NTC has been released for cross-border trading under the day-ahead auction platform. Schönheit et al. (2020, p1) analysed the markets and grids of Central Western Europe "during two representative weeks of 2016. The results show the increasing market coupling welfare is more than offset by rising congestion management costs, leading to net welfare losses. In the best case, the generation plus congestion management costs within Central Western Europe rise by 7.25% when increasing the minRAMs from the current 20% to 45% and a minRAM of 70% is 6.28% more expensive compared to a minRAM of 20%."

At present cooperation between the UK and EU is stalled under the Brexit *Trade and Cooperation Agreement* (TCA), although with the intention of replacing the current arrangements with more efficient solutions. As of March 2023 these trade barriers remain apparently still unresolved but there is pressure to improve trading with increased VRE.[22] The original TCA prevented the UK from participating in cross-border balancing markets, and although there was an intention to move to a replacement system of coupling with access to balancing actions, this appears to have been stalled.[23] However, it is unduly pessimistic to assume that the UK cannot cooperate with its neighbours, and it is worth noting that as the DC links are fully controllable their NTS is normally 100% made available, so the 70% rule would likely not impact GB. What is not yet clear is how the 70% rule would complicate trading arrangements with the EU, and whether that varies with pricing rule.

When comparing LMP with ZP, if each interconnector to a different EU price zone is in a separate GB zone (which would require a considerable increase in the number of zones in the future) then most of these trading benefits might be achievable under ZP, but much would depend on the problem of releasing capacity on interconnectors without incurring internal congestion costs. At best, ZP could be nearly as good as LMP for interconnector trade, but still inferior for time-shiftable demand (EVs, Batteries, Pumped Storage, DSR).

6. Other factors not modelled

Table 12.2, p259 lists factors not modelled and their possible influence of benefits. They are listed in the order of the table with my comments:

4.8 *Fixed transmission build*: with LMP and ZP a different expansion plan with some economies of avoided transmission might lead to additional benefits. HND leads to lower benefits from LMP, which suggests the two are substitutes, with LMP demonstrating that some network investments otherwise passing the "congestion

[21] https://documents.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Cross-zonal-capacity-70-target.aspx

[22] See https://www.energy-uk.org.uk/publications/cross-border-trading-yep-blog/

[23] See https://publications.parliament.uk/pa/cm5803/cmselect/cmeuleg/119-xiv/report.html dated March 2023

benefits>investment cost" would be economically unjustified. This points to the need for a more comprehensive cost-benefit analysis of network investments.

4.9 *Fixed capacity mix* The capacity and technology mix are taken from FES21 (although their location and use are responsive to LMP and ZP). It is not clear why a move away from GBP should lead to different investments, which are largely driven by capacity auctions (for capacity adequacy) and RES auctions, althoiugh merchant entry may respond differently to the difference pricing regimes. Much will depend on the effectiveness of the TNUoS contracts plus FTRs that I would argue are needed in any scenario.

4.10 *No demand re-siting* Encouraging energy-intensive industries (e.g. data centres) to low price zones/nodes should increase net benefits of those reforms.

4.11 *Operational benefits* The evidence from Wolak and California suggest that this could be considerable.

4.12 *Consumer exposure* Moving away from this would reduce modelled benefits, but is already considered in the demand shielding sensitivity (and does reduce benefits by £1.7 bn in SysTr).

4.13 *Policy support for existing generation* Grandfathering reduces consumer benefits as noted above but not net benefits

4.14 *No change in cost of capital* Clearly an increase in the WACC for new investment will have a major impact reducing net benefits. This is a risk to be mitigated by careful contract design and if unaddressed would be material. The uncertainty introduced by a failure to announce such contract redesign will also reduce benefits by creating an investment slow-down. The plausible uplift sensitivity of 50bp (0.5%) uplift on the WACC of dispatchable and merchant generation increases financing cost by £7.6 bn under LtW would have a very significant impact on net benefits. FTI only gives the cost as one to producers, passed on to consumers, but this is a real cost, unless one believes it is just a transfer from the electricity to the finance sector.

4.15 *Re-siting assumptions* could go either way, and requires as a matter of urgency (to minimise investment droughts) clarification on the role of the Future SO and a remit to actively plan for and put in place instruments to deliver least system cost investment.

4.16 *No other reforms assumed* This was a defensible position taken by FTI and in the text they note changes (e.g. to the role of G-TNUoS charges and CfD design) that might achieve many of the benefits of improved investment location without LMP/ZP. It implies that as part of REMA the relevant alternatives presented by FTI are highlighted, not just the headline consumer gain from the base case (the most attractive from this perspective).

4.17 *Frequency of rezoning* In the past TNUoS boundaries have been reconfigured to address changed flow patterns and new congestion boundaries (guided by the set of nodes over which LMPs remain reasonably similar). This only affects ZP, and if done intelligently should increase ZP net benefits (but might be resisted if it disadvantages some consumers who lose from rezoning. An argument for LMP which handles congestion automatically.

4.18 *Modelling year* Delaying the implementation date of 2025 should reduce the benefits of market reform. FTI's assumption that this in itself pushes out the end date is inappropriate. If, as seems very clear, the benefits of locational pricing are positive then the sooner the change is announced the better, even if full implementation takes some time. As the net benefits of LMP are larger than ZP (and both are better than GBP) a rapid decision to make the change is desirable to reduce uncertainty and investment droughts. Even if the decision is delayed the sooner there is clarity on risk-reducing measures and other reforms that are needed anyway the better. Such announcements should clearly state how grandfathering would work (with a suitable sunset clause), how domestic consumers can continue to enjoy an average hub wholesale price (network charges are already zonal) and that all future contracts will be made compatible with future pricing changes.

Taking these qualifications as a whole, they do little to undermine the case for locational pricing and, making comparisons with the correct scenario (assuming same investment locations) suggest that ***FTIs analysis is conservative***.

7. Summarising the sources and sizes of net benefits of LMP

The starting (or base case) point for the net benefits of LMP (LtW (NOA7) is

£24 bn (LtW (NOA7) fig 9.2, p200)

With a different FES scenario (SysTr) compared to the base case this drops to

£13.1 bn (SysTr (NOA7) fig 9.6, p204)

or to slightly less than half the base case.

Compared to the base case but with network investment the net benefit falls to

£14.4 bn (LtW (HND) fig 9.4, p203)

or by nearly £10 bn.

Assuming the **same generation locations** under all designs compared to the base case:

£13.7 bn (LtW (NOA7) fig 11.4, p244)

The benefits of better location attributed to LMP compared to holding location decisions constant at their LMP optimum is thus £24 bn – 13.7 bn = £ 10.3bn. This is the prize that the FSO should be pursuing regardless of which market design is chosen.

Using DESNZ's shadow carbon cost (to reach net zero) rather than market pricing of carbon ***increases*** net benefits to (table 9.7, p215)

£41.9 bn (LtW (NOA7))
£28.1 bn (SysTr (NOA7))
£26.1 bn (LtW (HND))

but this is relative to the rather high fossil generation in the base case.

The benefits of consumer flexibility have been estimated from SysTr above (p254-5) at

£1.7bn

4.19 Benefits of zonal pricing

The starting (or base case) point for the net benefits of ZP (LtW (NOA7) is

£15.3 bn (LtW (NOA7) Table ES-1)

With a different FES scenario (SysTr) compared to the base case this drops to

£6.2 bn (SysTr (NOA7) Table ES-1)

or to slightly less than half the base case.

Compared to the base case the net benefit falls to

£7.1 bn (LtW (HND) fig A3-21)

or to less than half the base case.

Unfortunately, there are **no summary benefits for ZP holding location constant**.

Using DESNZ's shadow carbon cost rather than market pricing of carbon ***increases*** net benefits to (table 9.7, p215)

£25 bn (LtW (NOA7))
£10.5 bn (SysTr (NOA7))
£12 bn (LtW (HND))

but this is relative to the rather high fossil generation in the base case.

8. Conclusions

While some of the finer details are less clear FTI make a strong case that the net social benefits of LMP are a considerable multiple of plausible implementation costs. This remains true under the less optimistic (but perhaps more realistic) SysTr scenario. Much of the net benefits appear to derive from efficient use of interconnectors and storage, once location decisions are held constant across scenarios. Holding location constant seems the correct counterfactual if, as seems urgent and desirable, NG ESO and specifically the proposed Future SO are mandated to ensure they deliver better investment location choices. REMA has consulted on a range of reforms, some of which would deliver better location decisions without any change to wholesale market designs. Of these perhaps the simplest is forward-looking long-term contracts for transmission charges, with charges for existing generation grandfathered (i.e. allowed to retain the current charges generated by the CUSC methodology). Some of the current short-term congestion problems could be avoided by the simple change of prohibiting any negative bids by renewable electricity generators. Reforming CfDs for renewable generators to make them responsive to real-time prices would also help.

With net benefits of £13.7 bn (LtW, NOA7) holding location constant and implementation costs of less than £1 bn, the case for LMP is overwhelming. This benefit might be somewhat lower if some of the current impediments to improved interconnector use were removed, but the gain from improved scheduling that reflects the local opportunity costs of trade appear material and were not included.

The benefits of ZP allowing location to respond to zonal prices are £15.3 bn compared with £24 bn under LMP (NOA7, LtW), or 64% of LMP (but only 47% of the smaller net benefits under SysTr). Unfortunately, FTI does not give the dispatch sensitivity holding location constant for ZP. If it bears the same relation as LMP of holding location constant (57%) the net benefit of ZP in this preferred scenario would be £8.7 bn. Any additional benefits from improved investment location decisions rely on a pessimistic view of the other reforms on offer, which in my view are needed in any case and can be simply and quickly introduced.

FTI's estimates appear conservative, as they ascribe little net benefit to improvements in scheduling plant to deliver a security-constrained dispatch, although some of the net benefits might be achievable by better coupling of interconnectors over all time frames (although the 70% rule puts this at risk). Excessive network expansion is an expensive way of avoiding congestion and as expected would reduce the net benefits of locational pricing, but at considerable extra cost.

The main concern, examined and dismissed on the (rather sparse) international evidence by FTI, is that poor long-term hedging contract design could raise the cost of finance, perhaps by as much as £7.6 bn. If so, that could seriously impact net benefits of locational pricing and stresses the importance of risk mitigation by careful contract design for new generation investment, particularly for flexible capacity. Suggestions of how this may be done are discussed above in this report.

One point to stress is that the headline high figures for the consumer benefits of locational pricing are overstated as transition contracts to keep existing generators at least partly whole are politically likely and would be at the expense of the large consumer gains, most of which are pure transfers from generators to consumers, and hence not net social gains.

As GB is an electrically isolated network only connected to other networks through DC links there would seem no advantage of taking an intermediate step to ZP and/or stopping short of full LMP, based on the claim that the net benefits of LMP are considerably greater than ZP. Matters might be quite different on the synchronised European network as it would be hard to introduce central dispatch for the whole network. Only if it were intended to introduce LMP but this necessitated a considerable delay and if ZP could be introduced rapidly and would provide familiarity with hub trading would there be a case for ZP as an intermediate step, largely justified by improving interconnector trading.

Even in the most pessimistic case, the ratio of net benefits to transition costs is high, and justifies as rapid a move to locational pricing as feasible, while pursuing other design options that improve investment location decisions without delay. Incumbents who fear that they would lose under locational pricing might be reassured by a commitment to transitional contracts that make them whole, but these will need careful design to avoid over-generous transfers at the expense of consumers, and should be time-limited.

In conclusion, ***the FTI headline net benefits that assume investment location is guided by locational wholesale prices are optimistic, but the more relevant net benefits holding location constant seem conservative, while the consumer benefits are optimistic.***

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Appendix: Qualifications arising from future changes to system optimisation

FTI uses NOA7, whose methodology notes that

> 4.20 The TOs submit power system models to the ESO for each year being modelled. The ESO uses these along with FES data to produce complete power system models of the GB network and shares these for analysis. Additional models and modelling information for different scenarios and network options are also submitted such that the ESO and TOs have adequate information to carry out the necessary option analysis.

The power system models simulate constraint costs under different network configurations, which are then added to the network costs:

> 2.80. Each of the permutations has a series of cost implications. These are either additional capital and constraint costs if the option is delayed (and further additional costs if the option is restarted at a later date) or inefficient financing costs if the project is progressed too early.

This seems logical but to be a full least system-cost methodology the costs and outputs of the investments should also be included. The NG ESO's 2021 *FES* (used by FTI) notes in its Methodology Annex (at p19):

> The scenario narratives provide the uncertainty envelope that determines the emphasis placed on the different types of generation technology within each scenario. Each power station is placed accordingly within their technology group in order of likelihood of that station being available in each year.
>
> The placement of a power station within this likelihood is determined by several factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that power station, are also considered. The contracted capacity or TEC Register provides the starting point for the analysis of power stations which require access to the NETS. It provides a list of power stations which are using, or planning to make use of, the NETS. Although the contracted capacity provides the basis for most of the entries into the total generation capacity, the analysis is not limited to generators with a signed connection agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre-connection agreement) are also considered.

Thus the two processes (of supply modelling, dependent on demand forecasts) and network planning appear to be separate, in that the supply modelling ignores network constraints, while the network planning seeks to minimise the sum of constraint costs and network costs. Later on it appears that the ESO uses a more sophisticated (but less granular) model to approximate system costs (although the role of transmission constraints is unclear).

> For our net zero scenarios, we use a cost-optimisation model, the UK Times Model[24] (UKTM), to guide them towards the target. UKTimes was developed at UCL with support from WholeSEM, the UKERC, and UK Government, to provide analysis of future energy systems. In meeting the carbon reduction target, UKTM selects the least-cost solution among all the possible sector and technology developments, through calculating all cost components

[24] https://www.ucl.ac.uk/energy-models/models/uk-times

> including capital cost, fixed and variable operational cost etc., transferring future costs into present value using a discount factor.
>
> UKTM simulates the whole energy system, considering energy demand, supply, electricity and gas networks and interconnectors. On the demand side, it uses the specific demand profiles for different products in residential, commercial and industrial sectors, as well as various vehicle types in transport sector. Efficiency factors for different products in all future years are included. The model also contains seasonal demand profiles. This combines to give an annual view of demand and supply.

It seems clear that if the generation location and network were co-optimised the total cost would be lower. This should be the case independent of market design, but only if the FSO is charged to minimise system cost (which would seem to be the main reason for creating an FSO). Whether this is done by using sharper price signals to decentralise location decisions, or the more radical approach of securing consents and connection assets and then auctioning sites (as for off-shore wind farms) is a largely political choice.

What is less clear is that if an FSO takes this system approach in future, how far this would impact the difference between LMP, ZP and GBP.