UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Response to *Review of Electricity Market Arrangements*[1]

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1. Introduction

The REMA *Consultation*'s high level objective (at p8) is "ensuring that our market arrangements support consumers by facilitating a low cost, low carbon and secure electricity system", later and importantly qualified to read (at p43)

> We do not consider that existing market arrangements are likely to deliver our ambition for a decarbonised and secure electricity system by 2035 at ***least possible cost*** to consumers, and put us on a pathway to a meet our 2050 net zero target. We therefore conclude that there is a strong case for change. (Emphasis added)

The main argument of this response is that quite modest changes can be made very quickly to deliver most of the required changes to the market design. It is also desirable to consider and start the process of making more radical changes that will make the electricity market better suited to longer-term challenges, but there is no need to scrap most of the current features of the market while making these more radical changes.

Since the *Consultation* was launched, the urgency of dealing with the current energy crisis has prompted calls for immediate and more radical changes. Again, while this response is focussed on the underlying problem of delivering "a decarbonised and secure electricity system by 2035 at least possible cost to consumers" it also argues that there are policy interventions that would address the current energy crisis without disturbing the longer-run market and institutional design arrangements.

The key features of the present market arrangements worth keeping are

(i) the use of (and timetable for) auctions for renewable energy, which to date have been remarkably successful in driving down delivery costs,
(ii) the predictable payment stream the auction delivers, enabling secure low-cost finance (mainly bonds) and hence lowering the delivered cost of electricity,
(iii) a capacity auction to procure adequate de-rated capacity for security of supply,
(iv) continuing to refine the pricing and procurement of ancillary services for reliability and flexibility,
(v) locational cost-reflective generation transmission tariffs, and
(vi) retaining real-time prices set at the marginal cost of acquiring power.

Modest changes to the design or the CfD with FiT contracts can address some of the flaws in existing contracts and make holders more market responsive, while network charges can similarly be relatively easily adjusted to improve investment location signals. Both

[1] This response sets out the general case for market reform and the specific steps that would deliver rapid improvements as well as some of those changes that would take longer to implement. It supplements the detailed response to the *Consultation* that the author with others at EPRG are separately submitting.

reforms could (and should) be introduced before the next round of renewables auctions. The next few sections set out these and related reforms in more detail.

2. The size of the decarbonisation challenge

The size of the challenge of decarbonising electricity by 2035 is clear:

> Our scenarios indicate that around 300GW of capacity could be needed by 2035, up from around 100GW today. That means that over 10GW of new capacity is required on average each year until 2035, against an historical average of 5-6GW.

More granular detail is provided in the April 2022 *British Energy Security Strategy* (BEIS, 2022). The target is 50GW of offshore wind by 2030, up from 11 GW today (compared to peak demand of roughly 60 GW.) The *Strategy* expects a *five-fold* increase in deployment of PV by 2035 (to 40 GW by 2030),[2] implying total Variable Renewable Electricity (VRE, i.e. wind and PV) of 105-124 GW by 2030,[3] up to twice 2030 peak demand.

The latest auction for Renewable Electricity (RE) ran on 7 July 2022,[4] and secured 10.8 GW, shown in Figure 1 (also showing the target rate of expansion from National Grid's *Future Energy Scenarios* 2022).[5] All the on-shore wind came from Scotland, reflecting the current Government's hostility to on-shore wind in England.

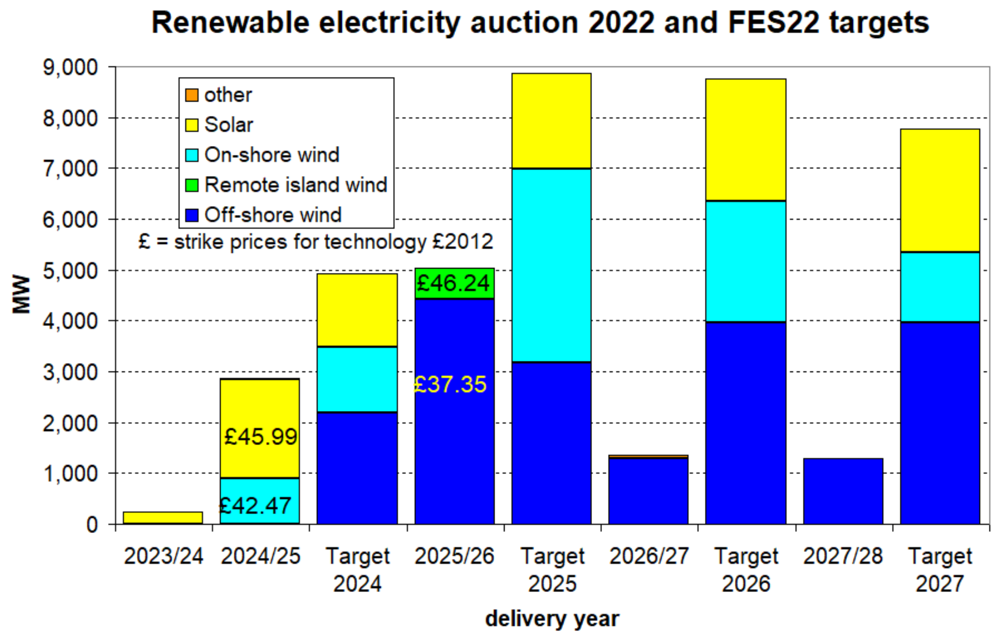

Figure 1 Auction results for July 2022 by technology, delivery year and strike price

[2] Given the ambition, this is taken from FES 2022 *Leading the Way*.
[3] From *Consumer Transformation* to the most ambitious *Leading the Way* in FES 2022.
[4] see https://www.gov.uk/government/news/biggest-renewables-auction-accelerates-move-away-from-fossil-fuels
[5] The calculations are based on *Consumer Transformation* that does not hit the BEIS off-shore wind target until 2035. (Only the ambitious *Leading the Way* achieves that.) The target capacities are only given for 2030. The implied annual increments are based on projected output but smoothed.

Note: Three off-shore wind farms with total 3.8 GW have three phases and it is assumed that one third will be delivered in each year following the first date, 2025/26. Auction prices are £(2012) and to update to 2022 prices multiply by 1.27.

The largest volume procured was for off-shore wind. However, only about 4.5 GW of off-shore wind might be delivered by 2025/26. If the target of 39 extra GW of off-shore wind by 2030 is to be achieved, and if it takes 3+ years from auction award to commissioning, the remaining 28 GW will need to clear in the next few auctions, requiring a considerable increase in the current rate of just over 4 GW/yr. The *FES* (2022) 2030 target for the less ambitions *Consumer Transformation* (CT, which only delivers 44 GW by 2030) implies that this rate of off-shore building will have to rise to *commissioning* 5-6 GW/yr. towards the end of the decade. The REMA *Consultation* cites research published by RenewableUK that shows the UK's total "pipeline" (including those already operating) of offshore wind projects stands at 86GW.[6] Excluding plant already operating reduces the volume to 73 GW, of which 56 GW (77%) are in planning, under development or in the process of securing a lease, many of which will fall by the wayside without the encouragement of an announced and steady flow of auctions.

Similarly, to meet the BEIS *Strategy* solar PV target, about 4 GW needs to be added each year, but in the peak year of the current auction only 2 GW was secured (admittedly, for arrays > 5 MW, so if smaller arrays can match this pace then the target could be achieved).[7] Given the faster delivery of solar PV this target is feasible, while delivery seems to be adequate to meet the less ambitious *Consumer Transformation* target.

About 900 MW of on-shore wind and another 600 MW of island wind was procured, all in Scotland. The *Strategy* admits that on-shore wind is the cheapest renewable electricity (RE), and that there is already 14 GW installed, but after many years in which the Government prevented it competing for support it finally accepted them for the next (presumably after lengthy consultation) round of auctions, although:

> Our plans will prioritise putting local communities in control. *We will not introduce wholesale changes to current planning regulations for onshore wind* but will consult this year on developing local partnerships for a *limited number* of supportive communities who wish to host new onshore wind infrastructure in return for benefits, including lower energy bills. (BEIS, 2022, p18, emphasis added)

Clearly, this came too late for English developers who were not eligible to bid for contracts in the July 2022 auction. The *FES 2022* reflects this hostility, showing installation rates falling and output peaking in 2028 before declining (as new-build lags retirement). Again, this is inconsistent with the objective of meeting carbon targets at least cost to consumers. The Climate Change Committee recommends that the UK should more than double its onshore wind capacity from 14.2GW now to 29GW by the end of the decade. That

[6] https://www.renewableuk.com/news/599739/Offshore-wind-pipeline-surges-to-86-gigawatts-boosting-UKs-energy-independence

[7] The latest data show that for PV < 10kW (domestic) the annual rate of installation to Aug 2022 is only 319 MW (https://www.gov.uk/government/statistics/solar-photovoltaics-deployment)

implies an urgency in overcoming political and local opposition to on-shore wind as soon as possible (by offering local financial benefits or profit sharing as suggested in the quote above) to enable developers to bid in the next CfD auction. The "mini budget" of 23 September appears to be moving in this direction, ending the prohibition of on-shore wind in England.[8]

3. Reforming the CfD with FiT for renewable electricity

Under the current CfD with FiT, a successful bidder receives the clearing strike price s £/MWh on *metered* output for 15 years from commissioning. Thus on-shore Scottish wind will have a strike price of £$_{2012}$42.47 =£$_{2022}$53.94/MWh, considerably below the current wholesale price. The developer is responsible for selling output in the market (or to an off-taker) and receives (or pays, if negative) $m_h(s - p_h)$ where m_h is metered output in hour h, and p_h is the reference (day-ahead) wholesale price in that hour. This contract has a number of disadvantages. First, there is no incentive for the developer to respond to real-time market prices, for example by offering to reduce output to assist in balancing, or to hold some capacity back to offer flexibility services, either of which might be more valuable to the system than the day-ahead price suggests. There is also an incentive to generate when prices are below the avoidable cost of generating, as the strike price will be higher than this. Worse, it can encourage production when the real-time price falls to or below zero, risking that dispatchable plant might close-down and start-up at considerable cost, when the economic cost of suspending output from VRE is zero.[9]

The CfD with FiT contract can be revised easily to avoid these problems by copying the format of conventional Contracts for Difference (CfDs). A standard CfD is a purely financial contract that pays the strike price s on an agreed volume, M, regardless of whether producing or not. The generator decides to generate solely guided by the spot price as the CfD pays $(s - p)M$ when the market price is p, and the generator makes profit $(s - p)M + (p - c)y$ if producing y when the avoidable cost c is below the market price, and if $p < c$, does not produce, avoids making a loss $(p - c)y$ by setting $y = 0$, and just receives $(s - p)M$.

The solution is to make the contract payable not on metered output, but on day-ahead forecast output of that technology at that location. The developer would designate a preferred forecasting agency to provide day-ahead hourly forecasts of the capacity factor θ_{rh} for its own technology (e.g. by using power curves and wind forecasts) at its location h. The generator would secure a yardstick contract in the periodic renewable auction at the strike price s for capacity K. The proposed yardstick CfD (YCfD) would pay $(s - p_{rh})\theta_{rh}K$ when the spot price is p_{rh} (in hr h, location r).[10]

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[8] See e.g. https://www.energylivenews.com/2022/09/26/has-the-government-given-the-green-light-to-more-onshore-wind/

[9] The current CfD with FiT contract does not pay if day-ahead prices are negative for six or more hours – see https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/441809/Baringa_DECC_CfD_Negative_Pricing_Report.pdf

[10] In the absence of nodal pricing $p_{rh} = p_h$.

There is another potentially undesirable feature of the fixed length (15 years) CfD with FiT, in that it over-rewards development of high capacity factor VRE in distant on-shore locations when the support price is above the expected output-weighted wholesale price. This was a serious issue under the previous Renewable Obligation (RO) scheme, which added about £50/MWh to the wholesale price, and led to a considerable over-payment to wind farms in more remote but windy locations. It is clearly not an issue now but might re-emerge if future output-weighted wholesale price fell below the strike price, and so it may still be a desirable correction to make.

To an approximation, the capital cost of VRE is independent of location, and so over a fixed number of MWh the present discounted value (PDV) of revenue will be almost independent of location and hence more closely aligned with the capital cost. (Higher capacity factors will deliver that number of MWh more rapidly and hence will have a slightly higher PDV). If the lowest capacity factor (CF) sets the clearing price, and if the contract is for a fixed number of years, higher CF VRE farms will earn higher revenues and hence higher (infra-marginal) rent. If instead the contract were for a fixed number of MWh/MW of capacity (i.e. for a fixed number of full operating hours, e.g. 40,000) then the advantage of the higher CF would be much reduced, reducing the cost of the auction.

The combined result of these two changes would be a Yardstick CfD (YCfD) that would pay $(s - p_{rh})\theta_{rh}K$ when the spot price is p_{rh} (in hr h, location r) for the first N MWh/MW (i.e. full output hours), where p_{rh} indicates that if at some date nodal pricing is introduced (discussed below) the contract would not need changing.

The argument against this output-limited rather than time-limited contract is that provided the Transmission Network Use of System (TNUoS) charges correctly signal the full incremental cost of extra capacity at each node, then it may still be desirable to encourage high CF windfarms at high TNUoS charge locations, although this does assume that the necessary grid reinforcement can be delivered in the same timescale as the new entrants take to commission. Comparing the two options of time or output-contract lengths will require a realistic assessment of grid reinforcement timescales.

There are two additional challenges that VRE contracts must handle – how to deal with and pay for curtailment and local congestion. Curtailment arises as an inevitable consequence of high VRE penetration levels, as peak: average output ratios are 3 or 4:1 for wind and 9-11:1 for PV. Figure 2 shows that by 2030 each of wind and PV separately will produce more than demand in many hours. Figure 6 of the REMA *Consultation* shows that by 2035 prices could be driven to zero 50% of the time as a result of surplus (spilled) VRE.

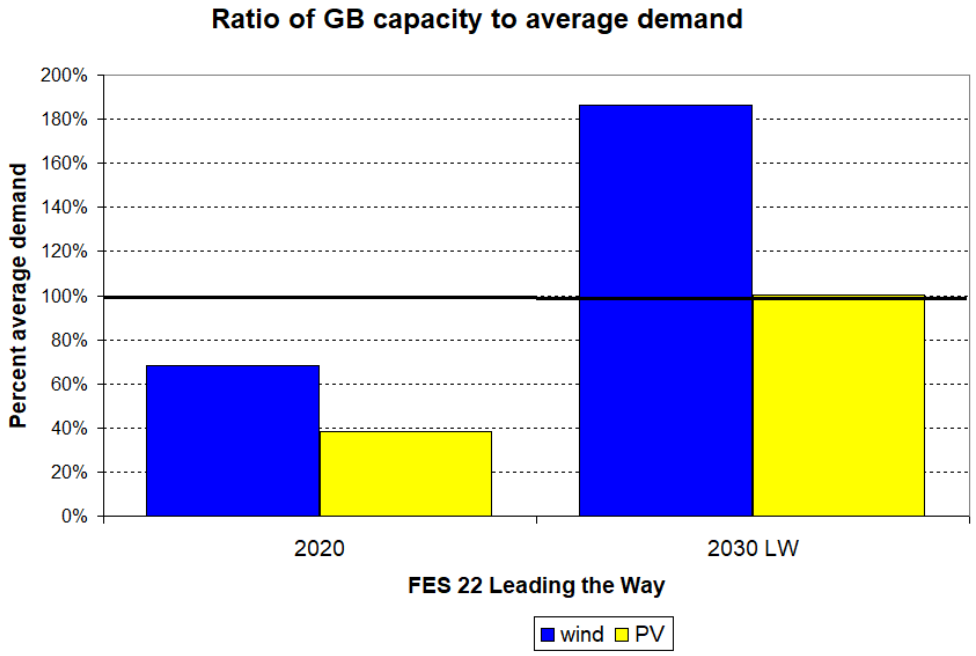

Figure 2 Ratios of wind and PV peak output to average demand
Source: FES (2022)

When VRE is in country-wide surplus (after exporting when neighbouring countries are not saturated, and injecting into storage until full) the efficient wholesale price should fall to the avoidable cost of the marginal curtailed generator (zero for PV, £4-10/MWh according to BEIS, 2020; NREL, 2018). YCfD holders would still receive the excess of the strike price over the (low) day-ahead market (DAM) price on their (high) forecast output, but would choose not to generate if the real-time price falls below their avoidable cost – in effect they would self-curtail. If they were instructed to curtail they would still receive the contract payment *less* their avoidable cost[11] as their lost profit that contributes to their capital finance cost.

Congestion arises because the network is constrained and cannot export the output from specific locations. This time the DAM price might be quite high and if VRE is constrained off under the YCfD it would only receive a smaller amount (or might even have to pay back). The simplest solution under current pricing rules (i.e. without nodal pricing) would be to again pay the lost profit, as with existing constraint payments. The "full operating hours" during this period would in both cases be the forecast output per MW, relevant for an output-defined contract (and a further argument for that contract form).

There is another modest change that would further reduce uncertainty and risk and hence the cost of finance. At present any generator connected to the transmission system pays a zonal Transmission Network Use of System (TNUoS) charge to reflect the changing incremental cost of delivering power from different zones. Figure 3 shows the variation in TNUoS charges across GB for base-load and wind generators.

[11] To be specified in the YCfD contract.

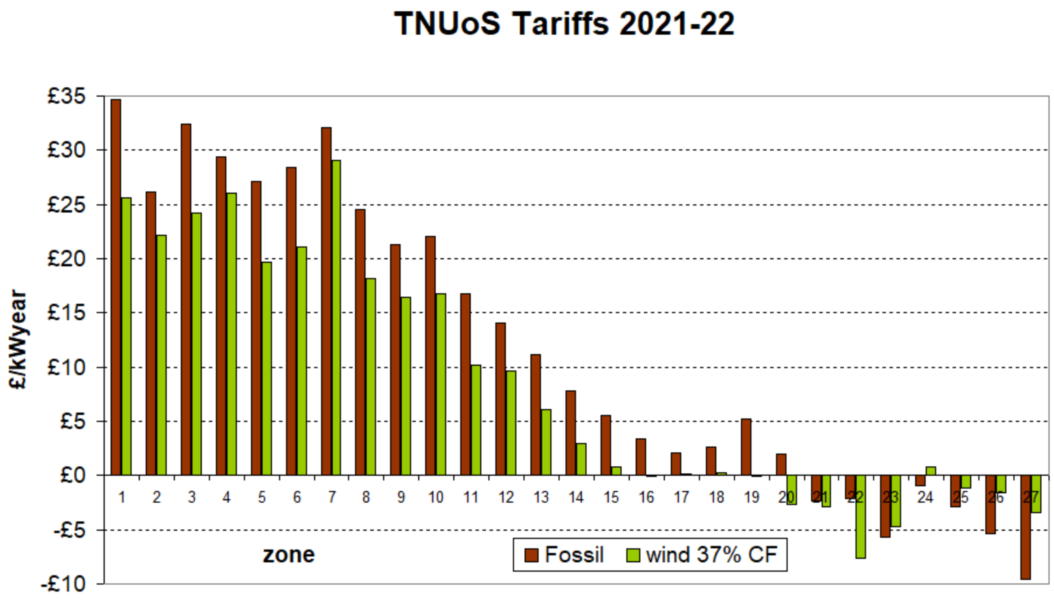

Figure 3 Transmission Network Use of System charges 2022
Note: Zone 1 is North Scotland moving down the country to zone 27 in Cornwall. Negative charges imply payment to the generator if generating in peak (Triad) hours
Source: National Grid ESO (2022)

Major TNUoS changes are discouraged as they would undermine the predictability of future grid charges, so there is considerable stability within each price control. National Grid ESO goes to some lengths to assure stability and predictability via its *Seven Year Statements*.[12] But looking over the much longer future contract life of a CfD, there is clearly some uncertainty about future grid charges, particularly as the volume of VRE is ramped up and transmission constraints become more significant and TNUoS charges are adjusted to steer entrants away from export constrained zones.

The solution is simple, and already applies to the charges for using the transmission from the off-shore wind farm to the on-shore connection point. These charges are set for a period of 20 years and are per MWh, not per MW of entry capacity (although there is little difference in that the average CF of an individual windfarm is predictable so there is a 1:1 equivalence).[13] The solution is to offer 15 or 20 year contracts at a fixed cost per unit of capacity at each node on the network, which could be adjusted each year for the next round of entrants without affecting existing contract holders (who, after all, cannot relocate once they have invested). The details on how to set this are discussed in the next section.

The developer of mature VRE (like on-shore wind, PV, and increasingly off-shore wind) would now know on entering the auction almost exactly what her predicted revenue

[12] See CUSC, §14.29 at https://www.nationalgrideso.com/document/141131/download
[13] Thus for a 45% CF wind farm £1/MWh is equivalent to £3.945/kWyr.

and costs would be over the life of the contract, on the back of which cheap bond finance should be readily secured.

4. Improving locational investment signals

The REMA *Consultation* (p18) the following objective:

> Our market arrangements will also need to ensure that the cost of operating the system is minimised (meaning the full value of all assets across the transmission and distribution networks is harnessed). A key part of this will be ensuring that our arrangements send appropriate temporal and locational signals, both in terms of where to invest and which assets to dispatch, and that prices are sufficiently granular to drive efficient and flexible behaviour. This should result in lower consumer bills, but it will also be important that consumers are not unfairly exposed to costs that they cannot control.

A large part of the cost of operating the system is the network cost, and although there is considerable discussion about the potential of nodal pricing to optimise the use of the transmission system and reduce operating costs, there is no discussion in the REMA *Consultation* about the role of network planning. Nodal prices are best thought of as signalling short-term transmission constraints that will change as the network is reinforced, but the nodal price differences across different nodes will fall far short of paying for the cost of the reinforcing that link.[14] It will often be the case that the optimal reinforcement is located in a quite different part of the network, so nodal prices give at best weak investment signals to the Transmission Owner. Instead NG ESO uses an Investment Cost Related Pricing (ICRP) methodology set out in Section 14 of the Connection and Use of System Code described thus

> 14.14.6 The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy.

Given the high cost of transmission and distribution network investments it is critically important to ensure that these investments are coordinated with generation investments, so that the location of new generation and the investment in the network to evacuate the generation minimise ***total systems cost***. This oversight reflects underlying but unstated differences in philosophy (market-led or planned) that this section discusses. When it comes to improving network planning, at least for off-shore wind, National Grid ESO's (2022a) *Pathway to 2030*, and the associated *Network Options Assessment 2021/22 Refresh* represents a considerable advance on the previous approach. It proposes that:

[14] Pérez-Arriaga et al., 1995; Newbery (2011)

> A more centralised and strategic approach to network planning is needed to deliver better outcomes, by integrating the connection of offshore wind farms to shore with the capability to transport electricity around Great Britain.

This is illustrated by comparing the costs of coordinated planning with the earlier developer-led model in which each off-shore wind farm was connected by a single radial link to an on-shore connection point. By considering all transmission links both off- and on-shore with the expected sequence of off-shore wind farms, radial links can in some cases be replaced by links connecting several wind farms. The ESO's *Holistic Network Design* for offshore wind deployment reports that

> …the costs of the offshore network infrastructure required in the recommended design would be around £32 billion. These costs relate to connecting the 23 GW of offshore wind which is in scope of the *HND*. The total cost of onshore infrastructure recommended between now and 2030 is £21.7 billion across 94 projects. These costs relate to the full set of onshore network reinforcements required to connect 50 GW of offshore wind by 2030. (Totalling £54 bn. NG ESO 2022a, p23 and fn. 30)

The aim of optimising assets should include ensuring that the location of generation and supporting network expansion assets are ***jointly*** optimised, and that their dispatch is also at least cost. The ESO's *Holistic Network Design* for off-shore wind shows the benefits of considering the totality of off-shore wind developments in an integrated way, planning both on-shore and off-shore to minimise the transmission costs (investment and avoided congestion) to meet the committed off-shore wind farms. However, this is a long way short of minimising total system costs, which requires more on-shore wind, where the network needed will depend sensitively on where these on-shore wind farms are located and how they are dispatched.

The benefits claimed in the *Holistic Network Design* relate just to planning for off-shore wind. Eirgrid/SONI 2021 *Shaping our electricity future Technical Report* provides a more embracing (but still only network focused) study of on- and off-shore generation and network development. This compares and evaluates four approaches to planning network development. The first, generator led, assumes the transmission owner (TO) can jointly plan where to locate both generation and transmission:

> This approach focuses on minimising grid developments by re-considering the preferred locations of new generation. … New onshore renewable generation are located at existing relatively strong onshore transmission nodes. (Eirgrid/SONI 2021, p26).

The second, the Developer-led approach, is essentially the current, i.e. Business As Usual, approach allowing developers to choose where to locate (and Ireland has very poor transmission charging signals for efficient location). The network is then reinforced to allow developers to secure connection agreements in the developers' preferred locations (typically where they are also pursuing planning consents). The third is the Technology-led approach:

> This approach evaluates opportunities to apply technologies in a way that is new to Ireland and Northern Ireland. In particular the approach focuses on the use of HVDC systems. … The approach also considers the use of new technologies to dynamically

> control power flow in the transmission network in order to maximise the available local capacity to avoid network constraints. (Eirgrid/SONI 2021, p38).

The fourth and final is the Demand-let approach:

> The Demand-Led approach considers influencing new Large Energy Users to locate at stations across the transmission network where capacity exists. It also considers close to renewable sources rather than concentrating in already congested areas distant from renewable sources. The scale of new grid development is therefore minimised. (Eirgrid/SONI 2021, p46).

The four approaches are compared in Table 1, where the generation costs are derived from the medium cost versions in BEIS (2020).

Table 1 Comparing the approaches

Approach	On-shore wind GW	off-shore wind GW	PV GW	network cost millions	RE costs millions	total millions	RE in 2030
Generation-led	5.8	5.2	1.2	€ 853	€ 20,314	€ 21,167	70%
Developer-led	10.2	2.15	2.6	€ 2,308	€ 20,409	€ 22,717	63%
Technology-led	10.2	2.15	2.6	€ 2,144	€ 20,409	€ 22,553	70%
Demand-led	10.2	2.15	2.6	€ 670	€ 20,409	€ 21,079	70%

Sources: Eirgrid/SONI (2021) and BEIS (2020)

Note: includes infrastructure costs. The RE target for 2030 is 70%

Developers prefer cheaper (for them) onshore wind while the TO prefers more off-shore wind (perhaps because developers might pay for the off-shore link, reflecting the low on-shore network cost in the table). When the TO makes the choice of generation and/or load location it clearly avoids considerable network costs although at the expense of higher RE costs. Table 1 shows is that the BAU developer-led approach (and the other two in which transmission is also reactive) are more expensive than the generation-led approach in which the location of the generation is steered by transmission opportunities. Nevertheless, the total system cost is still cheaper, encouraging more off-shore wind to displace the lower CF on-shore wind and PV.

The technology-led solution appears to accept developers' choices but considers more HVDC and power electronic technologies to reduce cost (slightly, compared to just developer-led). Given the rapid development of power electronics it is assumed that National Grid is actively exploring such options, particularly where they can address difficulties in securing permits for new on-shore overhead lines, and to avoid the hugely costlier off-shore HVDC links between coastal points. In this context Ampion in Germany is exploring upgrading existing pylons to carry both AC and DC, as shown below. Along long stretches of the route, only the insulators that carry the conductors need to be replaced (the HVDC is the right hand set: gleichstrom = DC).

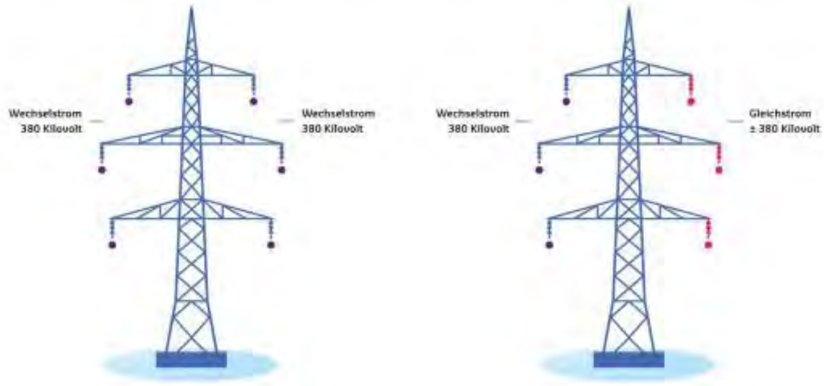

Figure 4 Ultranet's proposed method of adding additional HVDC capacity
Source: https://www.amprion.net/Grid-expansion/Our-Projects/Ultranet/

A simpler solution might be just to have another set of power lines parallel to existing lines (a popular solution readily seen from the windows of the Eurostar in France and Belgium).

Of course, if the Government is willing to maintain its opposition to English on-shore wind, then it should admit to the public that the cost of meeting its targets will be higher (definitely not least-cost). The rest of this part assumes that the Government is serious about finding a way to overcome on-shore wind farm objections, and part of that will be finding good sites for those on-shore wind farms quickly to allow coordinated transmission planning.

5. Contrasting approaches to minimising system cost

The prevailing philosophy guiding the electricity supply industry is to leave decisions to the market and rely on transmission charges and network regulation to decentralise investment choices and competition to minimise costs. A more radical alternative is to reconsider the former CEGB model (and most other pre-unbundling electricity companies) in which the location of new power stations and the required network upgrades were considered jointly to minimise the total cost of investment, operation and congestion.[15] Clearly, the old vertically integrated model is no longer acceptable, but unbundling can be retained by creating an Independent Design Authority (IDA) that would sit happily with the publicly owned not-for profit Future System Operator.[16] That option will be considered in more detail in §5.2 and, as it is more radical, is likely to take longer to implement. It is therefore worth considering whether there are simpler and quicker ways to improve the coordination between transmission and generation investment.

[15] See Strbac et al., 2013, 2014.
[16] As announced on 6 April 2022 – see https://www.nationalgrideso.com/news/eso-heart-new-future-system-operator

5.1. Retaining but improving the current transmission charging regime

At present off-shore wind farm connections are paid for (usually by the windfarm developer) and then the connection cost is returned to the developer by auctioning the link. The developer receives the connection cost as a lump sum that is paid back by an offshore transmission charge per MWh for 20 years to the Offshore Transmission Owner, or OFTO. As with other regulated assets the cost of OFTO finance is therefore very low, allowing the developer to keep more revenue to finance the repayment of loans and equity backing the wind farm. In contrast on-shore generators face an annual charge per kW that can change each year, and is so less predictable over the life of the immovable generation asset.

TNUoS charges are, as noted above, intended to give efficient locational signals, although they are averaged within the 27 Generation zones. The value of the zonal TNUoS charges is less important than the variation across the country, which gives signals about the relative cost of connection in different locations. The balance of regulated revenue is collected by a (small) uniform zonal addition to generation G-TNUoS charges and most (over 80%) is collected from Load (mainly distribution network operators, DNOs). In the EU the average G-TNUoS charge in most countries is zero,[17] with all revenue collected from Load. The ESO continues to adjust levels so the average Generation tariff is between €0-2.5/MWh.

National Grid ESO "also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years. This analysis is based on data included within the *Seven Year Statement*." (CUSC §14.29). If this takes into account the likely future location of new generation (given the TNUoS signals) and future transmission reinforcements, this goes a considerable way to encouraging efficient location to deliver power to consumers at least cost. However, the calculations used to set the annual TNUoS charges assume the necessary reinforcement takes place reasonably quickly, which may not be plausible in all cases. There are several minor improvements that can be made quite readily. The first is to estimate for each node what reinforcement would make sense, predicting the likely future pattern of connections for the relevant part of the system. Where there will be short-term export constraints, either the connection could be offered as non-firm (i.e. with no compensation for congestion management by reducing output, meaning no lost-profit compensation) for a stated number of years, or the TNUoS charge should be set at a higher level for the same number of years to recover the cost of constrained-off payments, as a supplement to the enduring charge at that location.[18]

If in future the ESO moves to Locational Marginal Prices (LMPs) transmission charges will have to adapt, although in a relatively modest way. In the spirit of reducing future tariff uncertainty, the ESO would need to offer Financial Transmission Rights (FTRs) or Transmission Congestion Contracts to offset the risks that volatile spot LMPs introduce. However, LMPs do not recover the incremental cost that additional generation at the node imposes on the transmission system, and so an adjustment would need to be added in any move to LMP to reflect the full incremental cost of accepting power at that node.

[17] https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/201209_ENTSO-E%20Transmission%20Tariff%20Overview_Synthesis%202019.pdf

[18] See e.g. https://www.eirgridgroup.com/site-files/library/EirGrid/Firm-Access-Review-2021.pdf

This would follow a similar route to the current calculation of G-TNUoS charges. Given forecasts of the location of future investments in generation and transmission, the ESO would compute the hourly shadow LMPs for connection at each node as far ahead as plausible. Given the generation profile of each technology (i.e. the hourly output) of a representative sample of possible future years the annual output-weighted shadow LMP would be discounted back to the present, and then annuitized as an annual charge per kWyr (as in Figure 3) fixed (or indexed) for 15 or 20 years. The LMP element of the connection tariff would then be the reference node *less* this annuity (so low LMPs indicating low value at that node and would carry a high TNUoS charge). The difference between these costs and the incremental cost estimates (the ICRP described above) guiding TNUoS would then be added to the FTRs hedging the LMPs. Equivalently, in moving from the current system of charging, the ESO would provide the FTR to those already holding a full TNUoS contract.

Each year the calculations would be updated but existing TNUoS contracts would be unchanged. This avoids the problem of only adjusting annual TNUoS periodically so as not to disrupt past decisions. Existing TNUoS charges could also be grandfathered to allow full flexibility in setting forward-looking tariffs. Combined with the right long-term contract for VRE this would maintain the current philosophy of decentralised decision making, leaving developers to decide where to connect and National Grid planning its transmission upgrades (as it does for on and off-shore transmission in the ESO's *Holistic Network Design*). The case for this approach rests on two arguments. The first is that the combination of a long-term TNUoS charge and a yardstick/deemed CfD hedges developer revenue while exposing output decisions to spot prices. The second is that as a regulated utility with the ability to pass on cost increases to Load (and uniformly to all Generation) there is no difficulty in making the transition at a year's notice.

5.2. *The Independent Design Authority*

In the more radical and central planning version the IDA would investigate the optimal location and sequencing of future generation as a spatial development of the ESO's *Future Energy Scenarios*, building on the methods developed in the *Holistic Network Design*. It would go further by choosing the location, timing and type of new generation, and taking account (as in the *HND*) of constraints on potential generation sites, of particular importance for on-shore wind, and to a lesser extent, solar PV. This would be achieved by active engagement with and improvements of the planning process, with the added opportunity to offer incentives to local communities to accept new developments. The size of the necessary local incentive would allow different potential sites to compete with each other.

The sites, with associated long-term TNUoS charges (that would emerge from the system plans) would then be offered in the periodic Yardstick CfD auctions (described above and in Newbery, 2021b) to site developers, who bid for capacities. It may be desirable to design a more complex auction in which developers offer at a uniform energy price, but indicate their preference for sites by offering either premia or discounts on the announced TNUoS charges. An IDA would be less tempted by the high asset value and associated revenue streams of off-shore HVDC and thus might more vigorously explore cheaper on-shore options.

5.3. Nodal pricing

Nodal pricing (or Locational Marginal Pricing, LMP) considerably simplifies (by decentralising) system balancing as it indicates clearly (for generators exposed to real-time prices) where generation should be increased or decrease to resolve constraints. Crucially, it requires central dispatch, at least for sufficiently many dispatchable generators to set reliable LMPs. Much of the potential benefit derives from efficient scheduling using the more detailed complex bidding that central dispatch needs, rather than the over-simplified energy-only bids that the current market design relies upon. It is the core of the Standard Market Design in the US, and has been successfully operated for decades in different countries across the world (as noted in the REMA *Consultation*, p69). The extensive evidence on the benefits of LMP suggest that the cost of moving is paid back by system benefits in two years or less in a GB-size system: Neuhoff et al. (2013) estimate cost reductions between 1.1% and 3.6% for the EU, and Aravena and Papavasiliou (2016) find savings of 2.8% for Central Western Europe. Eicke & Schittekatte (2022), in their article countering the frequent criticisms of LMP, also provide more extensive references covering case studies of the gains from LMP in other countries and states.

While PJM made the transition from zonal to nodal pricing over one weekend, the US already had central dispatch. While central dispatch can be voluntary, the charges for accessing the transmission system would be mandatory, calculated as the central hub less the local LMP (and hedged with FTRs). Apparently ESO needs years to set up the security-constrained dispatch system and the critical settlement systems, so this is a reform that it is well-worth setting in motion, and ensuring that all prior reforms are compatible with LMP. Meanwhile, the main gains lie in ensuring good investment location decisions with long-term TNUoS contracts, with the transition arrangements described above.

6. Addressing the current energy crisis

Many commentators (e.g. Grubb, 2022; Keay, and Robinson, 2017; Keay-Bright and Day, 2022) have argued against marginal cost pricing and suggested more or less radically abandoning the current market design completely. Their appealing argument is that VRE and nuclear power have very low marginal (and in some cases lower average) cost than the price set by the marginal carbon-inclusive gas and coal plant, and that the considerable infra-marginal rents they earn should be passed through to consumers through the market or markets somehow or other.

This is quite unnecessary, certainly for any future RAB-financed new nuclear power and all existing CfD with FiT contracts, whose counterparty, the Low Carbon Credit Company (LCCC), already receives the difference between the wholesale and strike price. As more new entrants are covered by long-term contracts any infra-marginal rents will become available to the public sector automatically. A sensible new market design can be simply characterised as one with competition *for* the market (via auctioned long-term contracts) followed by competition *in* the market (with marginal pricing). The infra-marginal rents can be passed back to consumers via equivalent long-term contracts, adopting a stepped tariff of the kind long in use in e.g. California, which increases the tariff above a baseline.[19] At the

[19] E.g. https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-1.pdf

next re-setting of the tariff (presumably on April 1 2023) the Government could announce that the first 200kWh/month (or 2,400 kWh/year) would be at the low capped rate, but that all consumption above that rate would be at wholesale-related rates. The regulator might also cap this additional rate based on forward contract prices as with the previous capped system, but one might equally argue that retailers could compete to offer better marginal rates (subject to close scrutiny of their financial ability to make such offers, based on their collateral and contract positions). (but without a price cap). Alternatively, or in addition, those with heat pumps could be offered a low-carbon contract, perhaps subject to being locally dispatched.

Retaining marginal pricing is critical for incentivising efficient energy dispatch and use, notably for time-of-use pricing, which will be attractive to some (larger) consumers with schedulable load. The aim of good market design is to provide good hedges to reduce risk and cost while preserving short-term market signals. This is already the case through the CfD market for large loads, and can be extended to cover the rest of the market with some creative contact design.

Whether it is legal or feasible to impose new and closer to average cost contracts on existing generators is not clear to me. The current buy-out price for the 2022-23 obligation period is £52.88 per ROC (Renewable Obligation Certificate),[20] which is added to the current very high wholesale price for renewables holding RO contracts (before 2017 but continuing in some cases to the 2030s). As a first step, if legal, the ROC market price could be driven to zero by removing the obligation for suppliers to buy ROCs. More generally, as the excess of RO contracts over the original cost of the VRE is publicly paid for one might argue that they are no longer in the public interest and should be referred to the CMA to be reset. All nuclear stations are held by EdF, who wishes to sign a RAB contract for Sizewell C. Perhaps they could be persuaded to accept similar RAB contracts for existing plant.

A second step would be to abolish the Carbon Price Support that adds £18/tonne CO_2 to the UK ETS price, and replace the UK ETS with a carbon price tax that rises at a pre-determined (carbon-target consistent) rate, providing more stability and predictability to its future level. The current Carbon Price Support again gives unjustified infra-marginal rent to all low-C generation without CfDs with FiTs (including bio-mass).

7. Summary

There is no need for some of the more extreme radical reforms to the current wholesale market, merely a continuation of the direction of travel towards more competition *for* the market followed by competition *in* the market. Minor adjustments to the CfDs with FiTs and TNUoS tariffs could achieve most of the immediately available gains of more efficient location choices and more market response. Longer term desirable changes to introduce nodal pricing and perhaps an Independent Design Authority could be set in motion as they will take longer to deliver. The role of the LCCC could be usefully clarified, and the balance and level of levies on electricity reconsidered, particularly as gas is exempt, distorting the shift to low-

[20] https://www.ofgem.gov.uk/publications/renewables-obligation-ro-buy-out-price-mutualisation-threshold-and-mutualisation-ceilings-2022-23

carbon heating. Short-term fixes to address the current energy price crisis should ideally preserve incentives at the margin to respond to high prices while providing support for a fixed number of kWh per month (or year) to domestic customers without over-compensating the wealthy.

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