Review of Electricity Market Arrangements
Responses to Consultation Document Questions

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10 October 2022

Chapter 1. Context, vision, and objectives for market design

1. Do you agree with the vision for the electricity system we have presented?

Yes, in large part, although it does miss out certain key elements or does not draw out points as clearly as needed. One obvious omission is glossing over the failure to secure on-shore wind—the cheapest low-carbon solution—and only hints at the need to engage with communities and the planning process to secure approvals/consents. It also avoids (but defers to another consultation) addressing the faults in the UK ETS and the Carbon Price Support (which is now redundant and positively harmful for consumer bills) given the high current level of the carbon price. It is welcome that the Consultation tangentially recognises that the environmental and social burdens placed on electricity but not on gas distort the choice of low-carbon technologies, but the need to speed up the shift towards electricity and away from natural gas on environmental and energy security grounds should be more explicit. Viable near-term measures are not highlighted, for example, removing or greatly reducing the RO on suppliers could lead to a collapse in the ROC price (currently over £50/MWh) and hence reduce the windfall profits of RO-supported renewables. More broadly, it also fails to address GB's relationship to the European single market in energy and the desirability of co-ordination with European energy policy and the elimination of remaining trade barriers and distortions between UK and EU electricity and carbon markets.[1]

2. Do you agree with our objectives for electricity market reform (decarbonisation, security of supply, and cost effectiveness)?

Yes, at a high level, although what is lacking is a sense of urgency, given the long lags in getting anything on-shore (wires in particular) built compared to the closeness of the 2030 and 2035 targets. Moreover, each of these three main objectives is significantly more difficult given the Russian invasion of Ukraine and will be so not just in 2022 but likely for at least the next few years[2] *and the document, does not take these tensions and trade-offs seriously enough. We do, however, welcome the overall 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

[1] Pollitt, M.G. (2022) "The further economic consequences of Brexit: energy." *Oxford Review of Economic Policy* 38 (1): 165–178; Guo, B. and D Newbery, (2022) The Cost of Carbon Leakage: Britain's Carbon Price Support and Cross-border Electricity Trade, *Energy Journal*, 44(1), also EPRG WP 2005 at https://www.eprg.group.cam.ac.uk/eprg-working-paper-2005/ ; Guo, B. and D Newbery, 2021. The cost of uncoupling GB interconnectors, *Energy Policy*, 158, 1-15, at https://doi.org/10.1016/j.enpol.2021.112569 Also EPRG WP 2102 at https://www.eprg.group.cam.ac.uk/eprg-working-paper-2102/; Newbery, D., G. Castagneto Gissey, B. Guo, P. E. Dodds (2019). The private and social value of British electrical interconnectors. *Energy Policy* 133, 1-37, https://doi.org/10.1016/J.ENPOL.2019.110896 . Also EPRG WP 1913 at https://www.eprg.group.cam.ac.uk/eprg-working-paper-1913/.

[2] As evidenced by natural gas futures for 2023 and 2024. See https://www.theice.com/products/910/UK-Natural-Gas-Futures/data?marketId=5351154

assets to dispatch, and that prices are sufficiently granular to drive efficient and flexible behaviour."

Chapter 2. The case for change

3. Do you agree with the future challenges for the electricity system we have identified? Are there further challenges we should consider? Please provide evidence for additional challenges.

   - *Increasing investment in low-carbon generation is clearly central and scenarios include a possible near trebling of renewable electricity (RE) capacity by 2030 (FES, 2022 Leading the way,[3] and the REMA Consultation Fig 1). This will require a clear commitment to a sequence of auctions of long-term contracts underwritten by the LCCC, and clearly cannot be left to merchant investors unaided by that contractual support.*

   - *While procuring RE looks feasible given suitable commitments, delivering the required transmission and distribution network investment in time looks far more challenging and probably requires a major re-think on securing planning consents. As an example, the inquiry into the Beauly Denny line began in early 2007, took almost a year to conduct receiving over 17.000 objections, and heard from 300 witnesses at a cost of £10million.[4] Approval was given in 2010 and the line became operational in 2015 over 8 years after the inquiry was launched, which is the time from now to the end of 2030.*

   - *Efficient location decisions of generation plant are critical to minimising system cost.*

   - *System reliability will require the procurement of suitable types and volumes of flexibility.*

   - *Price volatility requires well-designed hedging instruments that mitigate financial risk but also preserve efficient operational decisions, both for generators and retailers/consumers. The current CfDs with FiTs provide revenue assurance but lack incentives for operation, while the TNUoS charges are sensibly designed to reflect the incremental cost to the network for connecting in different zones, but could benefit from being offered as long-term contracts, just as OFTO contracts are for 20 years.*

Price cannibalisation (REMA Consultation p27) is not a problem for the period of the auctioned CfD provided the auction establishes satisfactory long-term revenue assurance (which is should if well-designed). It will likely mean that the strike prices of existing contracts will in future diverge from average wholesale prices (at the moment they are below the very high crisis prices, but could, with massive entry of renewables, be above average wholesale prices). The CfD is needed to remove such policy-driven price risks at least during the period of the CfD. Developers will have to take a view of wholesale prices after the end of the contract, but by then they will likely have recovered

[3] National Grid ESO, 2022. *Future Energy Scenarios*, at https://www.nationalgrideso.com/future-energy/future-energy-scenarios

[4] Tobiasson, W., Beestermöller, C., & Jamasb, T. (2016). Public engagement in electricity network development: the case of the Beauly–Denny project in Scotland. *Journal of Industrial and Business Economics*, *43*(2), 105-126. Siting of transmission lines is a perennial problem around the world from Germany to the United States, see, for example, Vajjhala, S. P., & Fischbeck, P. S. (2007). Quantifying siting difficulty: A case study of US transmission line siting. *Energy Policy*, *35*(1), 650-671.
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most if not all of their debt finance. If short term hedges are available at the end of the initial auctioned long-term contract, perhaps even at prices linked (as in the current capacity auctions) to those struck for new VRE, much of the longer-term revenue will also be de-risked, lowering procurement risks and cost. It would be reasonable to recover the difference between the counterfactual fossil cost and the outcome wholesale price via additional capacity charges on consumers, and to return any profits from the falling cost of CfDs received by the LCCC to consumers.

New flexible assets are likely to need longer-term contracts for their flexibility services. It is likely that these will need to be pre-announced with pre-determined prices before the assets are procured in a capacity/reliability auction.

There are several important wider considerations that the REMA programme needs to consider, as part of its ambition to take a "whole-system approach":

One stems from a recognition that the electricity system and future gas markets will be increasingly integrated in a net zero world. Synthetic methane, synthetic liquid fuel and hydrogen, can all be produced using hydrogen from electrolysis combined with CO_2 captured in biomass power plants[5]. They can also be produced via steam reformation of methane with CCS, using conventional methane.[6] Global markets for this type of hydrogen will likely emerge and arbitrage prices between the two sources of 'green' gas and liquid fuel., A key challenge is to think through the implications of these sorts of 'coupled' energy markets and how to manage the global price volatility they will induce.

Another issue related to this is the future taxation of energy.[7] High gasoline taxes have had extremely positive long run effects for the UK: raising revenue, reasonably efficiently pricing the many externalities – carbon, local pollutants, congestion and international security costs - associated with fossil fuel use and dampening the imported inflationary effect of global price volatility. We have seen the consequences of not taxing natural gas in the same way, and the large distortion that long-run overconsumption of natural gas has implied for overall natural gas use, heating price volatility and increasing dependence on gas imports. Electrification of residential heat, which is critical to both the UK's net-zero ambitions and to anticipating the size of a future power system, has also been discouraged by keeping VAT for natural gas at 5% and this will eventually need to change if we are serious about our net-zero commitments. Attention must be paid as to how energy taxes can be evolved over time to better price all the externalities associated with energy use while taking account of the distributional impacts of such needed changes.

4. Do you agree with our assessment of current market arrangements / that current market arrangements are not fit for purpose for delivering our 2035 objectives?

Up to a point – a set of quite modest and readily introduced changes to CfD contract design and network charges combined with a commitment to a trajectory of auction procurement could address many of the problems relating to investment, and such

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[5] See: Pollitt, M.G. and Chyong, C.K. (2021), 'Modelling net zero and sector coupling: lessons for European Policy makers', *Economics of Energy and Environmental Policy*, Vol.10(2): 25-40; and Chyong, C.K., Pollitt, M., Reiner, D., Li, C., Aggarwal, D. and Ly, R. (2021) *Electricity and Gas Coupling in a Decarbonised Economy*, Centre on Regulation in Europe.

[6] Mac Dowell, N., Sunny, N., Brandon, N., Herzog, H., Ku, A.Y., Maas, W., Ramirez, A., Reiner, D.M., Sant, G.N., Shah, N. (2021) The hydrogen economy: A pragmatic path forward, *Joule*, 5(10), 2524-2529,

[7] Newbery, D. M. (2005). Why Tax Energy? Towards a More Rational Policy. *The Energy Journal*, *26*(3), 1–39.

changes would help deliver the 2035 objectives at least cost. [8] *This is clearly recognised on p39* "The CfD scheme limits market exposure"

Also, EPRG's 2025 modelling[9] *suggested that: if carbon and fossil fuel prices are sufficiently high, then the current energy market—combined with appropriate ancillary services markets—can deliver the continued role of low-carbon generation. This is the world we are currently in. At the same time, however, the efficient management of energy price volatility in a way that minimises overall system cost is an issue, due to the potential for raising the cost of capital to fixed-cost-dominated generation technologies.*

However, the current energy-only self-dispatch system with firm access and a uniform price is not fit for efficient operation with high variable renewable electricity (VRE) penetration and the resulting increased need to manage balancing. It suggests a move to voluntary central security-constrained optimal real-time dispatch with its implied nodal pricing and subsequent requirements of suitable hedges, following the US Standard Market Design. The System Operator will also need to procure increasing amounts of inertia and adapt grid standards such as curtailment (via SNSP and ROCOF).

We agree that the current market lacks sufficiently strong locational signals although the TNUoS G charges show a comparable spread across GB to current annual capacity payments (£45/kWyr) and are designed to deliver prices equal to the marginal cost of accommodating increased generation in each zone.[10] *It is possible that these signals could be further refined down to the nodal level, but the key short-run change would be to offer long-term contracts that freeze the transmission charge on entry, and are compatible with any future change to locational marginal prices (LMPs) (which will not be sufficient to provide the required long-term locational signals). We agree that that there are currently limited temporal signals for flexibility but it might be simple to achieve these via security-constrained central dispatch and appropriate ancillary service payments. Marginal spot pricing is central to nodal pricing and most of its adverse effects can be obviated through suitable hedging contracts (FTRs, CfDs, etc.).*[11] *Liquidity may decrease but retail market reform (a return to the pre-1998 system) might remove many of the political objections to reduced liquidity, the social value of which is anyway reduced by the use of suitable long-term contracts.*

At the same time, a key lesson from the US experience is that nodal pricing primarily helps with the short run management of the system. Building transmission and distribution capacity in the right places and in the right quantities is far more important to long-run system costs.[12] *Using long-run modelling of where generation capacity is likely*

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[8] Newbery, D., 2018. Evaluating the case for supporting renewable electricity, *Energy Policy,* 120, 684–696. https://doi.org/10.1016/j.enpol.2018.05.029 Earlier version EPRG 1706: 'How to judge whether supporting solar PV is justified' at http://www.eprg.group.cam.ac.uk/eprg-working-paper-1706/ ; Newbery, D., M.G. Pollitt, R.A. Ritz 2018. Market design for a high-renewables European electricity system, *Renewable & Sustainable Energy Reviews*, 91, 695-707; https://doi.org/10.1016/j.rser.2018.04.025 ; also EPRG 1711 at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2017/06/1711-Text.pdf

[9] Pollitt, M. and Chyong, C.K. (2018), *Europe's Electricity Market Design: 2030 and Beyond*, Brussels: Centre on Regulation in Europe (CERRE).

[10] National Grid ESO, 2022. *Final TNUoS Tariffs for 2022/23*, at https://www.nationalgrideso.com/document/235056/download

[11] See Eicke, A. and Schnittekatte, T. (2022), *Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate, An MIT Energy Initiative Working Paper February 2022.*

[12] Joskow, P.L. (2022), *Transmission Expansion to Support Efficient Decarbonization of the U.S. Electricity Sector*, Talk to CEEPR-KEPCO-EPRG Annual Conference in Korea, 28th June.

to be added and what the least cost location of additional network capacity would be given planning constraints is more important overall than a switch to nodal pricing.

We agree that the current interface between the ESO and DSOs needs improvement, and that it will likely need to evolve with new learning from Network Innovation Competitions and their counterparts.

Chapter 3: Our Approach

5. Are least cost, deliverability, investor confidence, whole-system flexibility and adaptability the right criteria against which to assess options?

Yes, but speed of deliverability, optionality, and consumer acceptability are all critical and so also need to be considered.

6. Do you agree with our organisation of the options for reform?

Figure 8 is a useful summary of various different policy options.

However, it does not capture that choices on one policy dimension interact with—and may constrain—choices on other dimensions. For example, a move to nodal pricing in the wholesale considerably weakens any rationale for "split by characteristic" in terms of technology. Similar concerns apply e.g. to how "equivalent firm power auction" interacts with other dimensions of wholesale policy design.

At the same time, some of the options are not serious alternatives to each other and some half-baked ideas have been given undue prominence (e.g. Dutch subsidy).

The last line of Figure 8 is rather a melange of lines higher up.

7. What should we consider when constructing and assessing packages of options?

Add in 'deliverability in a timely manner' – complete redesigns adopting elements not road-tested elsewhere in the world are likely to be time-consuming, counterproductive and alienating. In contrast, looking around the world to see what solutions exist and work well is likely to be more defensible and successful if they can be adapted to the current UK context. Some reforms, like setting up central dispatch and associated settlement systems, are likely to take several years, so an early indication of future plans is desirable, while making sure that short-term improvements are consistent with future changes such as a move to LMPs.

More broadly, it is important for the UK to do things which are compatible with the likely desirable future evolution of European electricity, gas and carbon markets. The UK has an opportunity to lead Europe by example – the EU is already looking at extensions of CfD auctions for low-carbon technologies - and we should implement policies we should like to see adopted in the EU. As the Trade and Cooperation Agreement (TCA) between the UK and the EU has recognised energy is an important part of the post-Brexit settlement, but the TCA and its energy clauses expire in 2028.[13]

Chapter 4: Cross-cutting questions

8. Have we identified the key cross-cutting questions and issues which would arise when considering options for electricity market reform?

One issue is the extent to which energy policy should be a UK-wide policy or be fully devolved to nations or lower-tier political levels. While the four nations and local

[13] Pollitt (2022) op cit.

authorities can support national policy, they cannot drive it. We exist in an integrated set of energy markets, where energy trading and the exploitation of least cost opportunities is essential to energy security, lower cost and minimising environmental impact. We would caution against any naivity that suggests that a significant decentralisation of energy policy would somehow add up to achieving what are very challenging national targets. There is no evidence that local initiatives on energy policy make much difference in aggregate in the UK. Local successes are almost always manifestations of national initiatives.[14] Tough choices within planning processes will be required and we should attempt to avoid the problems that have beset countries like the US and Italy where local objections have prevented large scale beneficial energy investments in the national interest going ahead. Fortunately, we have offshore options (for both generation and transmission) which many other European countries lack.

9. Do you agree with our assessment of the trade-offs between the different approaches to resolving these cross-cutting questions and issues?

You are correct to conclude on p52 "that market forces alone are currently unable to deliver our objectives." *The intervention might be more driven by an enhanced and publicly-owned Electricity System Operator (ESO) with forward network design capabilities (an Independent Design Authority, or IDA), which means a more devolved approach (although the Government is still needed as the credit-worthy counterparty to contracts, combined with Ofgem's role in credible network investment regulation that commands confidence and drives down the WACC). The IDA may require Ofgem to accept anticipatory investment finance rather than a reactive approach (e.g. the poorly thought-through <u>connect and manage</u> approach to RE).*

It is less clear what is meant by "there is a strong case for continued intervention – including through the establishment of other markets in which the government plays a more central role – to deliver objectives which cannot be independently met by the market." *At present auctions for renewables and capacity adequacy already exist (otherwise they would need to be created) and they provide competition* ***for*** *the market, leaving short-run efficiency to competition* ***in*** *the real-time market (with or without LMPs). The ESO is continually refining better methods for procuring ancillary and flexibility services, which will grow in importance.*

Also on p52: "there can be limits to the effectiveness of competition between different technology types. First, it may be difficult to design a single market that appropriately values all the attributes that the electricity system needs, and fairly takes into account the very different characteristics of participating technologies, like how much of their cost is upfront or ongoing, or the kinds of risk they need to manage." *This has always been the case and an obvious way forward is to explicitly value these upfront, via the degree to which different technologies are supported with initial CfD contracts at different prices. We already do this for early-stage technologies. However, once built, all technologies should compete in a single short-run electricity market, as the electricity they produce is what we value This includes renewable energy, which implies that the CfD with FiT needs to be replaced by a deemed or Yardstick CfD that pays on forecast, not metered, output. It is however also important not to overstate the value of diversity or learning among renewable energy technologies as clearly costs do matter and more renewables*

[14] See for example this account of the impact of Leicester's award-winning energy policy: Lemon, M., Pollitt, M. and Steer, S. (2015), 'Local Energy Policy and Managing Low Carbon Transition: The Case of Leicester, UK', *Energy Strategy Reviews*, Vol.6 (January): 57-63.

currently do make the system more diverse (according to the Shannon-Weiner index, while gas continues to have the largest market share of any technology)[15]*. Again, the current auctions create different pots for different technologies designed to address such problems, and provided they are exposed to market signals (through deemed/yardstick CfDs) their different characteristics should not create particular problems. In the capacity market provided all ancillary and flexibility services are properly priced (and correctly anticipated by participants) and the network charges are aligned across the the higher voltage national transmission system and lower voltage distribution networks the technology choice can be left to the auction. Clearly it is important to ensure these conditions are met. Carbon capture, utilisation and storage (CCUS) does indeed need a more holistic approach and specific support, just as new nuclear power needs a different support model (such as the RAB model), but these interventions are consistent with other market reforms (such as LMP) and improved contracting.*

You are also correct on p54 to be "cautious about how far decentralised models can go," *especially given the difficulty of ensuring that all the price signals will guide efficient decisions. Many prices have to trade off efficiency with cost recovery and that can rapidly lead to regulatory arbitrage rather than genuinely cost-reducing innovations. The ESO (2022) Holistic network design to support offshore wind deployment*[16] *provides a good example of such integrated planning for a part of the network. A more radical approach would be to create an Independent Network Design Authority to actively seek out the least cost location of future generation and network investments, and even procure consents and then auction off the sites, but much can still be achieved through the current network tariffs. However the experience with the National Infrastructure Commission has shown that quasi-independent bodies can only be given limited authority with respect to actual authorisation of new infrastructure expenditure if such expenditure is underwritten by the state.*

The discussion of effective competition glosses over the fact that on-shore wind is currently prevented from competing, even though it is increasingly likely to be the least-cost decarbonisation option. A failure to address this head-on undermines the credibility of the Government's commitment to least-cost solutions and we welcome the statement in the recent "mini budget" that these restrictions will be relaxed.

10. What is the most effective way of delivering locational signals, to drive efficient investment and dispatch decisions of generators, demand users, and storage? Please provide evidence to support your response.

This question needs to be broken down into components.

The most important immediate change is to make new generation investment and loads face the costs of their location. In the short run, we could move to non-firm connection arrangements for those who wish to connect to the existing network, perhaps coupled with a timetable of when reinforcements would allow firm connections.[17] *This would immediately make better use of the existing network by encouraging location at points of the network where connection capacity is available. It would also suggest where extra transmission and distribution capacity is required should there be obvious demand for new connection, triggering incremental increases in network capacity. Recent decisions*

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[15] See Grubb, M., Butler, L. and Twomey, P. (2006), 'Diversity and security in UK electricity generation: The influence of low-carbon objectives', *Energy Policy*, 34(18): 4050-4062.
[16] National Grid ESO, 2022a. *Pathway to 2030 - A holistic network design to support offshore wind deployment for net zero* at https://www.nationalgrideso.com/future-energy/the-pathway-2030-holistic-network-design
[17] See e.g. https://www.eirgridgroup.com/site-files/library/EirGrid/Firm-Access-Review-2021.pdf

by Ofgem to move away from more cost-effective connection charging in the distribution system has been a mistake.[18]

Much of this can be done by simply offering long-term (e.g. 20 year) connection agreements, based on the current methodology for setting TNUoS G tariffs, perhaps refined down to nodal level, with adequate provisions for any future moves to LMP, but noting that LMPs alone provide inadequate investment signals. That would require comparable long-term Financial Transmission Rights that would hedge the volatility of LMPs, and would make up part of the total long-term transmission charge. These contract charges would remain in force (indexed suitably) for the life of the contract but would be revised as often as new information changes the forecasts for subsequent entrants.

Even if parties are not directly exposed to LMPs they can provide information to guide investment decisions by network companies on where to add investment, or on how network capacity can be reconfigured within a meshed network, by optimally altering existing network flows. Calculated LMPs can also be used for strategic acquisition of load demand and supply turn up and turn down at particular nodes in the network.

To avoid excessive infra-marginal rents to high-capacity factor wind and solar farms, the CfDs for VRE should be payable on forecast output at the day-ahead stage for each hour and could be paid on a fixed number of full operating hours. When VRE is curtailed or constrained off the deemed operating hours when not generating would be those in the forecast as that would form the basis of the payments. Negative bids by VRE would be ruled out (existing contracts may need side-payments of some form).

Operational decisions for VRE would be largely addressed by these two changes, but for flexible plant nodal pricing would seem essential and that requires voluntary central dispatch with mandatory transmission charges derived from LMPs for those not dispatched.[19]

11. How responsive would market participants be to sharper locational signals? Please provide any evidence, including from other jurisdictions, in your response.

Given that LMP requires central dispatch for a sufficiently large fraction of flexible assets to deliver reliable prices, and given that a security-constrained dispatch should considerably improve on output decisions, in an operational time-frame that would seem assured. As noted in Eicke and Schittekatte (2022, which gives these citations) 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. Also, for evidence on the overwhelming importance of the right level of transmission capacity in the US context, see Brown and Butterud (2021)[20]*.*

However, location investment decisions have a longer time horizon and are highly dependent on planning and other consents, the availability and nature of grid connection agreements (firm or non-firm, deep or shallow, LMP-based or not, etc.) and so will depend on resolving many other constraints. There may be a strong case for the ESO/INDA pro-actively securing sites that are on the least-cost expansion path and then

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[18] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-charging-and-access-reform/distribution-network-charging-arrangements

[19] See for evidence *Eicke, A. & T Schittekatte (2022) op cit.*

[20] Brown, P.R. and Butterud, A. (2021), 'The Value of Inter-Regional Coordination and Transmission in De-carbonizing the US Electricity System', *Joule*, 5 (1): 20 January 2021: 115-134.

auctioning off the right to build (as for off-shore wind farms in the North Sea and for new nuclear).

12. How do you think electricity demand reduction should be rewarded in existing or future electricity markets?

Demand flexibility should be rewarded as this will be increasingly valuable in a future energy system. We do need to design contracts which encourage deep demand reduction in response to system condition and which encourage highly distributed energy storage. A more electrified energy system (for both heating and transport) will reduce latent storage in the energy system (of gas and gasoline). Thus, individual loads should be encouraged to have more back-up generation and storage (if commercial or industrial) and more highly distributed storage (if households) via for instance storage in individual devices. This could involve the signing of internet style rationing contracts which would allow devices to be switched off in reverse priority order[21]. This would encourage investment in devices with storage capacity. New large loads, such as data centres, should be required to have storage or back-up generators and to make these available to the SO for ancillary services to support the overall system[22].

Chapter 5: ***A net zero wholesale market***

13. Are we considering all the credible options for reform in the wholesale market chapter? *And also some incredible options such as the two-market solution discussed in the next answer.*

14. Do you agree that we should continue to consider a split wholesale market?

No, this is not a good idea. Electricity is the same product in real time and hence all technologies should compete in the same short-run markets both for energy and ancillary services. Any supposed advantages can be achieved at lower cost and with less disruption by suitable contracts, and any design such as this that has no track record anywhere in the world must be deeply suspect as the laws of physics are the same everywhere.

15. How might the design issues raised above be overcome for: a) the split markets model, and b) the green power pool? Please consider the role flexible assets should play in a split market or green power pool – which markets should they participate in? – and how system costs could be passed on to green power pool participants.

Two-market solutions are untested and risky,and appear to fundamentally misunderstand how markets work.[23] Within each technology there are a range of marginal costs, which can be instantaneously very high. Bringing back nuclear power production quickly after an outage might involve very high marginal costs or replacing renewables that cannot export from behind a constraint can also involve very high marginal costs. Thus even for supposedly intramarginal technologies splitting the market does not make sense and would reduce aggregate output at any given price.

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[21] See Pollitt, M.G. (2021), 'The future design of the electricity market', In: Glachant, J.-M., Joskow, P.L. and Pollitt, M.G. (eds.) *Handbook on electricity markets*. Cheltenham: Edward Elgar, pp.428-442.

[22] See Banet, C., Pollitt, M., Covatariu, A. and Duma, D. (2021), *Data Centres and the Grid: Greening ICT in Europe.* Brussels: Centre on Regulation in Europe. https://cerre.eu/publications/data-centres-and-the-energy-grid/

[23] For a longer discussion of two market solutions see Section 2.2 of Pollitt, M., von der Fehr, N-H., Banet, C. and Willems, B. (2022), *European Wholesale Electricity Market: From Crisis to Net Zero.* Brussels: Centre on Regulation in Europe.

Then there are technologies such as biomass, which is a low carbon technology (assuming it meets stringent sustainability criteria) and might be considered within the lower price tier of a two-market solution. However, the price of biofuel will be determined by the price of fossil fuels with which it competes on world markets. Indeed, we have seen wood pellet prices increase significantly in the current gas crisis. The same applies to other technologies where the raw input (e.g. landfill methane or waste) competes with fossil fuels.

Then there is also the question of why a generator that was supposed to be in the low-price market would not invest in storage or combine with a fossil fuel generator and say they were a flexible generator wishing to be paid the higher price. In proposals by Keay and Robinson (2017)[24] and Grubb and Drummond (2018)[25] these issues are ignored. Keay and Robinson (2017) even suggest that some generators could choose which of the two markets they wanted to be in; this would either lead to them opting for the higher price market or them staying in the lower price market and arbitraging the prices to be the same. Neither do these two papers discuss the obvious outcome that while prices might be lower than before in one market, they would almost certainly be higher than before in the other market. The transaction costs of trading in and between the two markets could be extremely high.

16. Do you agree that we should continue to consider both nodal and zonal market designs?

Any change should avoid intermediate and costly changes to especially the settlement systems. Given that security-constrained central dispatch solves so many other problems the main priority is to set that as a target, and not pretend that the energy-only market can be saved by a move to zonal markets. Of course, LMP would need to be associated with FTRs for existing generation to avoid huge objections from those losing out. Zonal energy-only markets are more prone to the inc-dec game[26] which is harder to mitigate (as in an energy-only market fixed costs have to be recovered by varying the offer price). An LMP market with bidding controls such as enduring complex offers or automatic cost-based substitutions for significant deviations can mitigate market power more transparently and effectively as fixed costs are covered by the complex bids (as in the former Electricity Pool).

It would be important to do a detailed assessment of the benefits of the move to nodal pricing, versus longer term pricing of location or the use of average nodal prices across larger areas (as happens in practice on the demand side in the US). Widely quoted

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[24] Keay, M. and Robinson, D. (2017), *The Decarbonised Electricity System of the Future: The 'Two Market' Approach*, The Oxford Institute for Energy Studies at https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/The-Decarbonised-Electricity-Sysytem-of-the-Future-The-Two-Market-Approach-OIES-Energy-Insight.pdf .

[25] Grubb, M. and Drummond, P. (2018*), UK Industrial Electricity Prices: Competitiveness in a Low Carbon World*, Report Commissioned by the Aldersgate Group, February 2018, UCL Research Report, at https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett/files/uk_industrial_electricity_prices_-_competitiveness_in_a_low_carbon_world.pdf .

[26] See e.g. http://www.ceem-dauphine.org/assets/dropbox/P%C3%A4r_Holmberg_presentation%2C_CEEM_Conference_on_Nodal_pricing%2C_201119.pdf; Sarfati M and P. Holmberg, 2020. Simulation and Evaluation of Zonal Electricity Market Designs, *Electric Power Systems Research* 185(2):106372; https://doi.org/10.1016/j.epsr.2020.106372

analysis done so far, such as Energy Systems Catapult (2022), is not actually analysis of nodal pricing, but of zonal pricing.[27]

We should however consider whether the existing TNUoS charging system could be better calibrated. The system should be extended to include interconnectors and the prices could be made less volatile from year to year by offering long-term contracts at the time of connection.

17. How might the challenges and design issues we have identified with nodal and zonal market designs be overcome?

If the concern is with the consumer side then the default contract for domestic consumers could be a national or regional (as at present) average reference price. Note that consumers in different zones already face different charges without complaint. Those consumers signing flexibility contracts (for EVs, batteries, DSM etc.) could face LMPs with a default guarantee that over the year they would be no more costly than their national or regional average.

Liquidity may fall—for example, PJM has a churn rate of roughly half the very high rate of the EEX. Whether this is a significant cost depends on the range and quality of hedging contracts and the nature of retail competition (whose star is surely waning).

The main problem is developing replacement settlement systems. That can be costed and compared to the benefits. The evidence cited above suggests that the payback of moving to LMPs for a GB-size system should be less than two years.

There is surely no problem with interconnectors, given that Norway has small zones that are approaching nodal pricing at the interconnection landing point. Given the mess Brexit created for efficient dispatch over interconnectors at least we can get this one right.

18. Could nodal pricing be implemented at a distribution level?

Everywhere in the world that has thought about this has not done it (e.g. France, US, Australia). It is complicated and the prices would be highly non-linear and difficult for connectees (and DNOs) to predict. Small reconfigurations to the local network would make big differences to nodal prices. Local market power and its monitoring would be an acute problem. Nodal prices could, however, be calculated by distribution companies and used to guide their own investments and procurement of flexibility, but exposing their connectees to them seems premature although there are models for local balancing that could approximate LMP, as recognised on p72. Ofgem's Network Innovation Competition is looking at several such proposals.

19. Do you agree that we should continue to consider the local markets approach? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.

They should not be ruled out and there are various trials underway here and abroad, but more evidence is needed. Certainly, local markets make recovering network costs more

[27] See Energy Systems Catapult (2022), LOCATION, LOCATION, LOCATION: Reforming wholesale electricity markets to meet Net Zero, Energy Systems Catapult.

problematic but that is part of the larger problem of recovering costs in a future in which a higher fraction of total costs are fixed.

However, local market are mostly non-proven in spite of a large amount of experimentation.[28] *Wide area markets are what make a difference in electricity, because they increase competition and reduce market power. The issue with local markets is that effective competition is very difficult and transaction costs are very high. We used to have local electricity systems (akin to local markets), but we got rid of them because they were not cost effective.*[29]

20. Are there other approaches to developing local markets which we have not considered?

Almost certainly but there is no need to rush into this step until more evidence is available. The main problem at present would seem to be collecting more data on DNO-connected VRE, addressing constraints on DNs and managing the ESO/DSO interface. It might be possible to have competition across localities providing the bids are adjusted to a common basis. This can ensure bids to produce at a particular location and satisfy a local need can compete against one another. This could be done by learning lessons from auction design whereby local bids can be made to compete across localities (as in spectrum auctions).[30]

21. Do you agree that we should continue to consider reforms that move away from marginal pricing? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.

It depends what you mean. Real-time pricing clearly needs an element of marginal cost-based dispatch, but recovering the larger part of total costs will be increasingly dominated by the fixed element, with all the problems of shared and common costs, Ramsey pricing moderated by equity/fairness considerations. Most consumption (as measured by the number of consumers, not MWh) will be largely insulated from spot prices, with flexibility contracts directed to those best placed to provide them, likely a modest fraction. If existing renewable (and possibly nuclear) contracts were replaced by long-term suitable CfDs, then these fixed price contracts could be passed through to end-consumers (e.g. by offering a fixed number of kWh/month at these contract prices). There would be a good case for offering such contracts to electric heat pumps in return for enabling them to be dispatched to manage peaks and local network constraints, as they are the other side of the decarbonisation agenda.

22. Do you agree that we should continue to consider amendments to the parameters of current market arrangements, including to dispatch, settlement and gate closure?

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[28] For a review see: Anaya, K.L. and Pollitt, M.G. (2021), 'How to Procure Flexibility Services within the Electricity Distribution System: Lessons from an International Review of Innovation Projects' *Energies,* 14 (15): 4475. https://doi.org/10.3390/en14154475

[29] For an account of the poor performance of the fragmented electricity industry in the inter-war period in the UK, see: Foreman-Peck, J., and Millward, R. (1994), 'International Comparisons of Performance in National Networks in the Inter-War Period', *Public and Private Ownership of British Industry 1820–1990*Oxford, 1994; online edn, Oxford Academic, 3 Oct.2011), https://doi.org/10.1093/acprof:oso/9780198203599.003.0007.

[30] This idea is discussed in Anaya, K. and Pollitt, M. (2020), A Review of International Experience in the use of smart electricity platforms for the procurement of flexibility services (Part 2 – Main Findings), Project Merlin Milestone 2 Report, p.17. The idea is inspired by Paul Milgrom's book: Milgrom, P.R. (2017), *Discovering Prices: Auction Design in Markets with Complex Constraints*, New York: Columbia University Press.

Probably, to the extent they do not conflict with or hinder moves to enduring solutions.

23. Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?

Probably changes to the procurement of ancillary services. If it is possible to more readily/cheaply introduce LMPs for balancing, and provided that this does not cause distorting arbitrage with the day-ahead market that idea (originally put forward by National Grid) might be re-examined.

We still need to continue simplifying ancillary services products and moving towards co-optimisation of energy and ancillary market bids[31]*. This would ensure efficiency in the procurement of ancillary services.*

Chapter 6. Mass low-carbon power

24. Are we considering all the credible options for reform in the mass low carbon power chapter?

We welcome the recognition that they will all need to be based on (p79) "competitively allocated, long-term, private law contracts between generators and a government-owned counterparty, as these seem likely to remain the most cost-effective way of delivering our investment requirements." *Increasing rather than aiming to further reduce market risk seems undesirable, as the possible incentive/innovation benefits can be more readily secured by closely following experiments round the world, where the same laws of physics apply.*

25. How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?

This raises the question of how to recover network costs from local VRE. An efficient tariff might require a standing charge based on simultaneous peak demand with the energy component based on the loss-adjusted value of local energy (high when importing, low when exporting if at the same time as other VRE produces). This comes back to how to evolve to more efficient management of constraints on local networks, which is a work in progress.

Also, despite the question of the framing in terms of benefits, it is important to recognise that the costs of small-scale VRE are higher than grid-scale installations. Although distributed renewables can reduce network losses on local circuits they can also create congestion on lines and transformers, and are best considered as part of local energy community choices. The main distortion to avoid is net metering,and ensuring that the wealthier who are more likely to invest in domestic VRE are not cross-subsidised by poorer customers as a result of poor network tariff design.

26. Do you agree that we should continue to consider supplier obligations?

Given the huge mess we are in with competitive asset-light (and fly-by-night) suppliers we find it hard to see any good reasons. It would seem to add risk when cost reductions require reducing risk.

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[31] See Greve, T., Teng, F., Pollitt, M. and Strbac, G. (2018), 'A system operator's utility function for the frequency response market', *Applied Energy*, 231 (1 December): 562-569.

27. How would the supplier landscape need to change, if at all, to make a supplier obligation model effective at bringing forward low carbon investment?

We need tighter regulation of who can be a licensed supplier. This should require greater capital requirements and a degree of competency in the energy sector and risk management. The government and Ofgem have been too keen to encourage entry for entry's sake into the retail supply business, without regard to whether the owners of such businesses passed a reasonable 'fit and proper person' test. What is needed is competition between 10+ reasonably sized competent firms, to have competitive market.

28. How could the financing and delivery risks of a supplier obligation model be overcome?

With difficulty, but ensuring that their contracts with generators and consumers were collateralised and marked to market.

29. Do you agree that we should continue to consider central contracts with payments based on output?

No. These prevent the increasingly desirable response to real-time market signals, such as reducing output or offering balancing services that are made unattractive with payment on metered rather than forecast output (which turns the contract into a financial hedge, leaving the plant to respond to the real-time market).

30. Are the benefits of increased market exposure under central contracts with payment based on output likely to outweigh the potential increase in financing cost?

With a suitable contract there should be no increase in financing cost, and arguably a decrease if combined with long-term transmission contracts, and assured hedges against any future LMPs.

31. Do you have any evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms?

Not immediately, other than VRE PPAs are sold at a discount, suggesting the current energy only market is costly when VRE developers have to seek buyers. Note that we would be opposed in any case to output-based payments as currently operated under the CfDs with FiTs.

32. Do you agree that we should continue to consider central contracts with payment decoupled from output?

*The reason for decoupling payment from output is to make the contract more like a standard purely financial CfD. In the yardstick/deemed CFD the payment at the strike price is on the forecast day-ahead output, and pays regardless of metered output. The output choice will be made looking at the various options of offering in the intraday, flexibilitiy or balancing markets or, under LMP, at the real-time price. This exposure to prices encourages responses to real time pricing while the day-ahead forecast output financial contract provides on average a perfect hedge at the strike price.*How could a revenue cap be designed to ensure value for money whilst continuing to incentivise valuable behaviour?

We believe there is a VRE contract in Spain that pays a fixed amount per MWh for a fixed number of hours per year (e.g. 1800 hours), perhaps averaged over five years.[32]

34. How could deemed generation be calculated accurately, and opportunities for gaming be limited?

The developer would nominate a preferred supplier of local hourly output forecasts for his RE at the day-ahead stage (e.g. based on predicted wind modulated through the right power curve). The contract would be a CfD on this forecast output at the auctioned strike price (combined with the right TNUoS locational charge) for a fixed number of full operating hours. If curtailed or constrained-off the payment would be the lost profit – the forecast volume times (the strike price less the avoidable cost of e.g. £4-10/MWh for wind, zero for PV, specified in the auctioned contract or audited/benchmarked). This mimics the current constraint payments, and would count towards the fixed number of full operating hours, so not unnecessarily overpaying for constraints.

Chapter 7. Flexibility

35. Are we considering all the credible options for reform in the flexibility chapter?

36. Can strong operational signals through reformed markets bring forward enough flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment? Please consider if this differs between technology types.

De-risking should lower procurement costs.

37. Do you agree we should continue to consider a revenue cap and floor for flexible assets? How might your answer change under different wholesale market options considered in chapter 5 or other options considered in this chapter?

It would seem worth pursuing and would seem resilient to introducing LMPs, which seem to have considerable advantages for encouraging flexible assets to locate sensibly. The cap might be tapered with a sharing mechanism on revenues above a certain level.

38. How could a revenue cap and floor be designed to ensure value for money? For example, how could a cap be designed to ensure assets are incentivised to operate flexibly and remain available if they reach their cap?

Averaging over a sufficient period (5 years?) with a possible reset based on later market intelligence on reaching the cumulative cap might be worth exploring.

39. Can a revenue (cap and) floor be designed to ensure effective competition between flexible technologies, including small scale flexible assets?

Worth trying, but perhaps with simpler solutions for small scales (or encourage them to be aggregated?).

40. Do you agree that we should continue to consider each of these options (an optimised Capacity Market, running flexibility-specific auctions, and introducing multipliers to the clearing price for particular flexible attributes) for reforming the Capacity Market?

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[32] Barquín, J., P. Rodilla, R. Cossent, C. Batlle (2017). "Obtaining best value for money in res auctions: a capacity-based with an embedded menu of contracts approach". Working Paper IIT-17-177A at https://repositorio.comillas.edu/jspui/handle/11531/23913

Designing good auctions is a skilled activity and complexity is often a turn-off for potential participants. Offering contracts at fixed prices for various flexibility services to those winning in the auction might encourage them to bid with the danger of procuring too much (limit the volume) or too little (more difficult). Successive auctions might be able to converge on sensible prices and volumes. See also answer to 47.

41. What characteristics of flexibility could be valued within a reformed Capacity Market with flexibility enhancements? How could these enhancements be designed to maximise the value of flexibility while avoiding unintended consequences?

Speed and duration of response, but it would be hard to value all the desired attributes separately. It might be worth studying the DSR programme in the island of Ireland (and any other high VRE jurisdictions like California, Texas and some Australian states).

42. Do you agree that we should continue to consider a supplier obligation for flexibility?

This sounds expensive in transaction costs but it might be worth commissioning cost-benefit studies of existing examples – which may not however address the future high VRE world. It is however worth considering obligations on new large loads, such as data centres, to provide flexibility to the grid.

43. Should suppliers have a responsibility to bring forward flexibility in the long term and how might the supplier landscape need to change, if at all?

Given past experience with small suppliers going bankrupt this seems a stretch.

44. For the Clean Peak Standard in particular, how could multipliers be set to value the whole-system benefits of flexible technologies? And how would peak periods be set?

The standard answer to clean anything is a suitable predictable and credible future carbon price. See A47.

Chapter 8. Capacity Adequacy

45. Are we considering all the credible options for reform in the capacity adequacy chapter?

Probably yes.

46. Do you agree that we should continue to consider optimising the Capacity Market?

This sounds sensible. An important issue going forward is the extent to which the current design of the Capacity Market is compatible with having only abated gas-fired power by 2035.

47. Which route for change – Separate Auctions, Multiple Clearing Prices, or another route we have not identified – do you feel would best meet our objectives and why?

The main problem procuring capacity with the right characteristics of flexibility and sustainability is that the value of the various characteristics varies sharply with the supply/demand balance that varies over time (and for some services like voltage support over space). It is also becoming clear that a multi-attribute auction is unlikely to be successful beyond two attributes (e.g. price and length of contract). This problem has been extensively explored by the SEM Committee when reforming the all island of Ireland CRM.[33] Some attributes like low-C can be properly priced and should be – e.g.

[33] See e.g. https://www.semcommittee.com/capacity-remuneration-mechanism

through a proper carbon price floor backed if necessary by a CfD on this floor. Other attributes could be offered on medium-term (e.g. 5-8 year) contracts at regulated prices set for the contract duration and updated at each capacity auction, leaving capacity to be procured and then if eligible to sign such contracts. These contracts would be with the ESO and backed by the Low Carbon Contracts Company (LCCC) as at present, and would share the risk of procuring the wrong long-run solution between the developer and effectively consumers. If, as time evolved, these attributes when bought spot had reasonably predictable long-run average prices, then the contracts could be shortened.

48. Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?

It is not necessary to decide immediately as with annual auctions the details can be evolved as necessary and as information/evidence flows in from this and other markets.

49. Are there any other major reforms we should consider to ensure that the Capacity Market meets our objectives?

*Reliability options[34] have attractions but need strong market surveillance and market power mitigation (as evidenced in the SEM (of the island of Ireland) where bids cluster just below the RO strike price), and may need a real-time scarcity floor price based on VoLL*LoLP. There are problems dealing with capacity that cannot be dispatched because of network or stability reasons. We suggest keeping a watching brief on all other auctions around the world and be prepared to change the detailed design each year by providing an updated Auction Information Pack, as in the SEM.[35]*

50. Do you agree that we should continue to consider a strategic reserve?

No – it seems perverse to deny useful assets the opportunity to participate in the market while their presence will remove some revenue from other capacity bidding in the auction. (In the theory of electricity market design, a centralized capacity market and a targeted strategic reserve are equivalent under a set of stylized assumptions.[36])

51. What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?

Reform the carbon pricing system to a predictable increasing carbon-consistent price trajectory and think of ways of making it more credible than the last attempt – e.g. by offering forward markets with a carbon stabilising bank issuing and withdrawing permits.

52. Do you see any advantages of a strategic reserve under government ownership?

No. Obviously, in principle, a strategic reserve that can be filled and then depleted in an optimal manner would be appealing. In practice, however, the perennial problem with government strategic reserves is that they are usually managed badly. They are made available too little, too late do not anticipate the nature of the problems that arise in the

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[34] See e.g. https://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_8.pdf

[35] https://www.sem-o.com/documents/general-publications/Final-Auction-Information-Pack_FAIP2425T-4.pdf

[36] See P. Holmberg and R.A. Ritz (2020), "Optimal capacity mechanisms for competitive electricity markets", *The Energy Journal*, 41:SI, pp. 33-66. Also EPRG Working Paper 1921, https://www.eprg.group.cam.ac.uk/eprg-working-paper-1921/

future and are not sized appropriately given the unanticipated challenges and hence don't justify their large carrying cost.

53. Do you agree that we should continue to consider centralised reliability options?

Yes, keeping an eye on associated market rules that emerge to deal with problems encountered in other markets such as market power.

54. Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.

*They have the attractive property of allowing trade over interconnectors to be market price driven, so that imports and exports are driven by the VoLL*LoLP that should reflect the proper value of available power.*

55. Which other options or market interventions do you consider would be needed alongside centralised reliability options, if any?

Adequate market surveillance and market power mitigation.

56. Do you agree that we should not continue to consider decentralised reliability options / obligations? Please explain your reasoning, whether you agree or disagree.

No, this needs radical reform of retailing, adds complexity and cost, and risks strategic bankruptcy.

57. Are there any benefits from decentralised reliability option models that we could isolate and integrate into one of our three preferred options (Optimised Capacity Market, Strategic Reserve, Centralised Reliability Option)? If so, how do you envisage we could do this?

The main issue is the need for capacity in particular regions where there are enduring transmission constraints in stress periods. The SEM addresses this through pay-as-bid for out of merit need locational capacity, subject to audited costs. There may be other models in other markets (PJM?) that merit study.

58. Do you agree that we should not continue to consider a capacity payment option? Please explain your reasoning, whether you agree or disagree.

The capacity market should provide incentives to be available in stress periods, measured by the Loss of Load Probability, which is typically almost zero in most hours but very high in stress hours. Generators should therefore be penalised if not providing their derated output in these hours, by requiring them to buy at the scarcity price. The SEM of the island of Ireland originally had an administratively set capacity payment which over-encouraged entry as it was based on an inevitably conservatively set cost of new entry. It was replaced by a capacity auction (for Reliability Options) that greatly lowered the cost to consumers.

59. Do you agree that we should not continue to consider a targeted capacity payment / targeted tender option? Please explain your reasoning, whether you agree or disagree.

This needlessly isolates expensive valuable assets from satisfying other needs.

60. Do you agree with our assessment of the cost effectiveness of a targeted capacity payment / targeted tender option, and the risk of overcompensation? If not, why not?

Yes.

Chapter 9. Operability

61. Are we considering all the credible options for reform in the operability chapter?

Assuming that LMPs have been introduced, probably, otherwise LMPs would seem an essential element.

62. Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable?

63. Do you support any of the measures outlined for enhancing existing policies? Please state your reasons.

64. To what extent do you think that existing and planned coordination activity between ESO and DNOs ensures optimal operability?

Existing arrangements need to be supplemented by the ability of the ESO to contract with the DNOs for the provision of ancillary services.[37] *We have suggested the value of contracts with the ESO which incentivise DNOs to manage ancillary costs within their own areas. Provided these can be done in a way which adequately pools risks across the whole of GB these could increase efficiency.*

65. What is the scope, if any, for distribution level institutions to play a greater role in maintaining operability and facilitating markets than what is already planned, and how could this be taken forward?

We are in a period of experimentation with the DSO. DSOs are becoming more active and they could play an increasing role in coordinating power, heating and transport decarbonisation at the regional level.[38] *However we should see how this evolves globally. Radical reorganisation might be contemplated, such as integrating gas and electricity distribution networks within the same company. Some DSOs want to experiment with a fully legally separated SO function. Others want to adopt a more integrated approach. Different models may work differently.*

66. Do you think that the CfD in its current form discourages provision of ancillary services from assets participating in the scheme? If so, how could this best be addressed?

Yes, but the deemed CfD delinks the contract payment (by making it a financial contract on the forecast not metered output) from exposure to market prices, and hence provides incentives to respond to whatever market incentives develop.

67. Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? If so, how could this be achieved?

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[37] See Kim, S.W., Pollitt, M.G., Jin, Y.G., Kim, J. and Yoon, Y.T. (2017) "Contractual framework for the devolution of system balancing responsibility from the transmission system operator to distribution system operators." *Energy Policy Research Group Working Papers*, No.EPRG1715. Cambridge: University of Cambridge.

[38] See Pollitt, M., Giulietti, M., Covatariu, A. and Duma, D. (2022), *The Active Distribution System Operator (DSO): an international study*, Centre on Regulation in Europe.

See answer to Q47.

68. Do you think that co-optimisation would be effective in the UK under a central dispatch model?

Yes, central dispatch seems the cheapest route to most of the required reforms.

Chapter 10. Options across multiple market elements

69. Do you agree that we should not continue to consider a payment on carbon avoided for mass low carbon power?

Yes, we should drop this idea. What we need is to extend the carbon market to heating and transport and if the EU do the same, rejoin or couple to the EU ETS. A single market for carbon seems the logical way forward for carbon pricing on the path to net zero.

70. Do you agree that we should continue to consider a payment on carbon avoided subsidy for flexibility?

No, see above.

71. Could the Dutch Subsidy scheme be amended to send appropriate signals to both renewables and supply and demand side flexible assets?

72. Are there other advantages to the Dutch Subsidy scheme we have not identified?

No, we suggest dropping this idea.

73. Do you agree that we should continue to consider an Equivalent Firm Power auction?

74. How could the challenges identified with the Equivalent Firm Power Auction be overcome? Please provide supporting evidence.

We don't support the Equivalent Firm Power auction. It simply begs too many questions about how best to de-rate VRE, which at present can be addressed through the capacity procurement calculations. The problem with VRE is that they are almost equivalent to a single plant when it comes to non-availability (due to high correlations), so the risks of none being available require special study, while placing the obligation to supply in stress periods on VRE makes them non-viable as investments (or requires them to not offer into the EFP auction). It is best to price energy, reserve, frequency and voltage control separately and let the market value individual generators on the basis of their ability to supply these services in real-time and under long-term contract.