Enabling a high renewable, net zero electricity system: BEIS call for evidence

UK Energy Research Centre Response

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Introduction to UKERC

The UK Energy Research Centre (UKERC) carries out world-class, interdisciplinary research into sustainable future energy systems.

UKERC is a consortium of top universities and provides a focal point for UK energy research and a gateway between the UK and the international energy research communities.

Our whole systems research informs UK policy development and research strategy.

UKERC is funded by the UK Research and Innovation Energy Programme.

Currently in its fourth phase running from 2019-2024, UKERC delivers an ambitious programme of research on the challenges and opportunities for delivering the transition to a net zero energy system and economy. The programme brings together engineers, natural scientists and social scientists to generate evidence that informs real-world decisions.

Our research programme encompasses major themes on global energy challenges and their implications for the UK; the role of local and regional energy systems; interdependencies between energy systems and the environment; decarbonisation of specific sectors including transport, heat and industry; and transitions in energy infrastructures.

The programme is complemented by a set of national capabilities. These carry out systematic evidence reviews, host and curate energy data, map and monitor public engagement with energy systems, and improve the transparency and understanding of energy models. UKERC also supports the wider energy research community in the UK by promoting engagement with other stakeholders, supporting career development and capacity building, and enhancing international collaboration.

Contents

Opening remarks and key concerns

In this submission we focus on the allocation of wholesale market price risk, and how that affects both cost of capital and the likely availability of capital in the power market in Great Britain. The rising share of zero marginal cost generators such as wind and solar will have a significant impact on wholesale electricity prices, and the UK has set ambitious targets for such generators. The 40 GW offshore wind in 2030 target is the most obvious and immediate, but far greater roll out of zero carbon generation and a phasing out of unabated use of fossil fuels are prerequisites for net zero. A key challenge for the UK is to galvanise a large volume of investment in a historically short timeframe. We are therefore concerned that many of the questions the consultation poses appear to presuppose of the desirability of returning to a more 'merchant' or 'market based' solution space. This is highly problematic if the market in question is very similar to the largely energy-only market we have for the GB system today, where price is set by short run marginal costs.

The fundamental question for the consultation should not be how to transition renewables developers back into an energy-only market. Instead, the focus should be on how to design new arrangements that are operationally efficient and meet the needs both of consumers and of investors in low carbon generation technologies, in particular those that are double zero – both zero emission and marginal cost. This will be very challenging and take time. It is equally important to ensure that Government makes well-communicated provision for an extended transition predicated on cautious and gradual change over a significant timeframe.

Summary of UKERC's position

UKERC takes as a starting point that policy has shifted from subsidising new investment in emerging technologies in order to promote innovation and reduce costs, to enabling investment at scale using low carbon options that are largely cost-competitive on a levelised basis[1]. Philosophically, this could be viewed as moving from 'green subsidy' to 'low carbon contract', with governments intervening to ensure that the societal value of low carbon generation and needs of low carbon investors are aligned. In many markets wind and solar investment can now be financed at contract prices at or below average wholesale price. However, this is often predicated on long run contracts and a highly credit worthy counterparty.

Questions remain about the underlying market designs that create incentives for flexibility and deliver best value for customers whilst also providing incentives for generators to invest in low carbon generation – in substantial volumes[2]. A conventional 'energy only' wholesale/retail market is not well suited to deliver large volumes of new low carbon capacity at minimum cost to consumers. This is because a competitive wholesale market where price is set by short run marginal cost

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[1] International Renewable Energy Agency (2019) 'Future of Wind' Link

[2] Rhodes, A. Gross, R., Donovan, C. and Hindle, J. (2019) 'Electricity markets, incentives and zero subsidy renewables: Do Britain's power markets and policies need to change?' Link

(SRMC) will, in the long-run, tend to under compensate participants who have a high sunk cost and very low SRMC. As a result, such markets are likely to fail to deliver the investment in low carbon generation needed to meet ambitious carbon reduction targets.

One reason for this is the problem known as 'price cannibalisation' where price falls to low levels or even goes negative during spells when wind or solar output is high and demand is low[3]. Price cannibalisation has emerged as a phenomenon in a number of markets and has initially been associated with systems where renewable generation is in receipt of a subsidy, given priority market access, or largely insulated from time of day price signals. The GB market does not have priority access, but a combination of subsidies from the Renewables Obligation and the CfD mean that price cannibalisation is already visible during periods of low demand as were observed during the first Covid-19 lockdown.

However, price cannibalisation per se is caused by market fundamentals, not just by the presence of subsidies, and will occur as the total penetration of variable renewable energy (VRE) and/or inflexible generators rises to high levels, even without subsidy or contracted prices[4, 5]. This is because if outputs correlate and are largely independent of demand, marginal costs are zero, and short run marginal costs set wholesale prices, then in traditional energy-only markets price cannibalisation effects are inevitable. The upshot of this is that generators may not be able cover their fixed costs, and hence that low carbon generation is not forthcoming in sufficient volumes to meet decarbonisation targets. It could also cause generators to retire assets prematurely, when contracts or support schemes end.

There is then a separate question regarding how best to provide investment signals for the flexibility needed to accommodate rising shares of low carbon generation and to provide essential system services – through storage, demand response, schedulable generation or interconnection. It is important that low-cost sources of flexibility come forward to accompany the growing role of renewable and other low carbon sources of bulk electricity[6].

Underlying all of this debate is the difficulty of satisfying the principle that risks should be allocated to those best able to manage them, when these risks are multiple and linked. In particular, we see two main types of risk:

- Dynamic equilibrium risks. These pertain to a situation where physical infrastructure has largely been established, supply and demand are roughly in balance, and investment is largely driven by the need for plant renewal and incorporation of new innovations, consumer demands and business models.

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[3] Rhodes, A. Gross, R., Donovan, C. and Hindle, J. (2019) 'Electricity markets, incentives and zero subsidy renewables: Do Britain's power markets and policies need to change?' Link

[4] Cornwall Insight (2020) 'Wholesale Power Price Cannibalisation' Link

[5] Ostrovnaya, A., Staffell, I., Donovan, C., Gross, R. (2020) 'The High Cost of Electricity Price Uncertainty' Link

[6] Heptonstall, P.J., Gross, R.J.K. (2021). 'A systematic review of the costs and impacts of integrating variable renewables into power grids'. *Nat Energy* **6,** 72–83. Link

- Non-equilibrium risks. These pertain to systems that are in a state of flux, shifting to substantially different infrastructure for supply and different patterns of demand, with many of these changes driven by policy, and very little historical pricing information to inform future investments.

For at least the next 10 years, to get substantially onto a trajectory of zero carbon electricity during the 2030s, and meet goals such as the 40 GW of offshore wind, the non-equilibrium risks are substantial. The policy-dependency of many of these risks makes them potentially unsuitable to be wholly managed by the private sector. The rate of electrification and efficiency standards for heat and transport will be largely policy-driven, and determines overall demand in the market. Likewise, support for carbon capture, use and storage (CCUS) and nuclear and other low-carbon generation options affects overall supply, whilst the rate of infrastructure build-out for flexibility options such as hydrogen and interconnectors determines price behaviour in markets. The relatively early stages of this transition are perhaps the most uncertain. To tackle the transition over the next 8-15 years, a pragmatic approach would be to continue to commit to CfDs, perhaps modified in ways discussed here such as to include existing and repowering plant. Work could then take place in parallel on a new form of market that will facilitate the continuation of low carbon investment over the long-term and could be phased in as we get nearer to a new equilibrium situation, and it becomes clearer what the characteristics of this new system are.

In the long-term, if CfDs are to be removed, there would likely need to be some alternative form of long-run marginal cost price signal. Various options available in a new 'equilibrium' world make it possible for these signals to be driven less by government procurement decisions (or those of a central agency) than is the case today. Whether that is desirable is something that needs to be considered carefully, based on an assessment of what would lead to a least cost outcome.

As we move into 2021, UKERC's research will have a strong focus on these challenges and we will work with government and wider stakeholders on transition plans and longer-term options for market reform. Given the urgency of the task perhaps the main immediate requirement is for pragmatism and learning by doing, fine tuning policies to enable action and ensuring that we do not allow the 'best to be the enemy of the good'.[7]

[7] Keith Bell, University of Strathclyde (2020) 'UKERC Review of Energy Policy 2020' Link

Responses to Consultation Questions

Part 1. Maintaining growth in renewable deployment to meet net zero targets

Q1. How is the industry currently approaching developing renewables projects without CfDs? In what ways might non-CfD backed projects obtain revenue from wholesale and other markets, and secure investment?

The ability of renewable power developers to recoup investment costs from wholesale prices should be seen in the context of an expected drop in wholesale prices over time as the market shifts towards a predominantly carbon-free system. (See answer to Q2 for further discussion of this issue).

Within this context, for offshore wind, there are several drivers of project economics which further determine the potential role for obtaining revenue from wholesale prices.

- **Direct site and plant-specific characteristics**. For offshore wind, project economics vary considerably depending on the specific site characteristics such as turbine height, wind resource, sea-bed characteristics, distance to shore and potential planning constraints. The correlation of wind resource with the rest of the fleet can also be important in terms of the ability of plant to capture higher prices in the market.

- **Indirect costs** such as seabed leasing rights and network usage charges. The latter are determined as a regulatory cost depending on location, and aim to internalise network costs into the investment decision. These costs can materially impact the overall project costs (for example, in the recent Crown Estate Round 4 auction bids for sea-bed leasing options which reached record levels[8]), making it less likely that they will be able to recoup costs purely on a merchant basis.

- **Timing**. The revenue risks associated with price cannibalisation are lower in the early part of the 2020s, so plant built earlier are more likely to recoup a proportion of costs in the early years, but this revenue is put at increasing risk over time by expected falls in average wholesale prices.

- **Economies of scale** in project development costs arise from various sources, including bidding strategies for seabed leases, and the ability to share infrastructure across multiple sites. This can encourage companies to develop larger sites even if they don't expect the whole of the site to be covered by a CfD. This means that merchant plant are effectively bundled together with plant that are anchored by CfD support. An important example is the Seagreen project, which remains the only merchant offshore wind plant. The potential to oversize

[8] Graeme Wilson, Everoze (2021). 'Offshore Wind Astonishes and Perplexes'. Link.

offshore wind developments to exploit economies of scale has a positive effect in terms of value for consumers as it helps to build competitive pressure for the CfDs, tending to bring down the resulting auction prices.

In summary, there remains potential for a merchant component of offshore projects, but these will likely need to be anchored by CfD or other support mechanisms. Merchant opportunities are likely to reduce over time given long run expectations are for falling prices under current wholesale market designs in a system dominated by low marginal cost renewables (see Q2). Without more significant changes to the structure of wholesale markets, to replicate the revenue predictability that the CfD currently provides, it seems unlikely that this model for pure merchant plant will continue to play a growing role for offshore wind over the course of the 2020s.

High indirect costs such as seabed leasing and network usage charges may increase the cost of electricity generation, but do not necessarily represent higher costs to individuals. Network usage charges essentially represent an allocation of overall system costs, which ultimately have to be borne somehow by the consumer. For seabed leasing charges on the other hand, whilst these represent a cost to consumers, they represent a benefit to UK taxpayers. This somewhat offsets their impact on consumers, albeit with different distributional impacts which need to be considered.

For onshore wind, the overall costs are expected to be lower, so the immediate potential for merchant-only plant is greater than for offshore wind, but similar caveats apply around the likely long-term opportunity. A key issue will be how network costs are allocated. Much of the most cost-effective onshore wind plant are based in Scotland, whilst the big demand centres are in the south of England. If the cost of developing the network to transmit this power is allocated to wind power developers, it is less likely that they will be able to recoup these costs from raw wholesale prices if these decline over time as expected.

Q2. What do you consider to be the effects of increased low-carbon deployment on future wholesale power prices and renewable capture prices?

As the volume of wind and solar plant on the system increases, there are expected to be increasingly frequent periods when renewables become the marginal plant on the system. This means that they become the price-setting plant during those periods. Since the marginal (operating) cost of these plant is low by historical standards, we expect that wholesale prices will tend to drop over time as a result of increased deployment of variable renewables. Evidence of this effect was observed in GB markets during the first Covid-19 lockdown which caused significantly reduced demand, and altered time-of-use profile[9].

The prices that renewable energy sources are able to recoup from the market (capture price) will tend to decrease more rapidly than for the market as a whole, because of the correlation of output of any particular wind or solar farm with the

[9] Bell, K. and Hawker, G. (2020) 'Electricity demand during week one of COVID-19 lockdown' Link

overall fleet in the GB system as a whole. Windy days when wind farms are producing the most output will also be the days on which prices tend to drop the most[10].

The level of this price drop depends on several factors. The reduction in capture price will be less pronounced for plants located in areas where wind speeds are less correlated with the majority of the wind fleet, which creates some incentive to develop locational diversity of supply. The price drop will also depend on the mix of plant on the system, the cost structures of these plant, and the flexibility of system. Modelling indicates that including 40 GW of wind by 2030 on the GB system in line with government targets in a system with moderate improvements in system flexibility will likely create a significant downward impact on average wholesale prices, potentially suppressing them below the levels needed for companies to recoup the investment costs of building new plant.

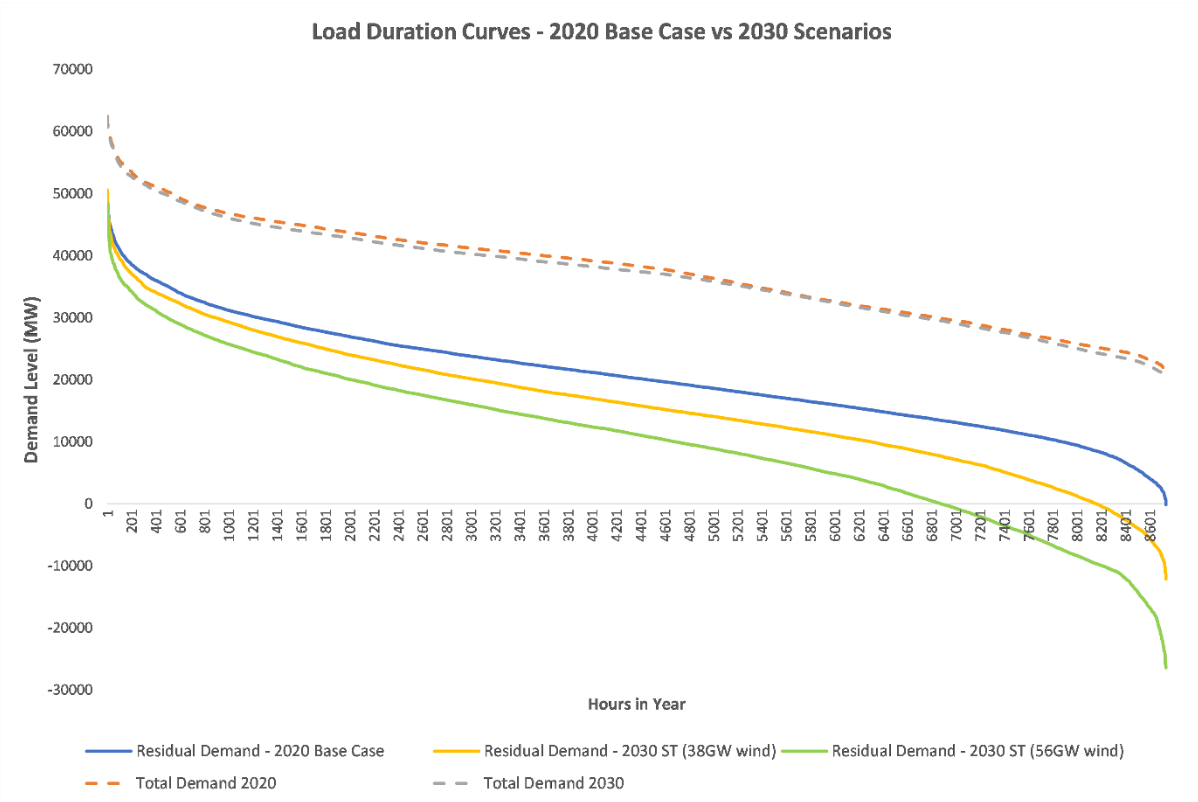
Modelling carried out by UKERC[11], derived from scenarios developed and published in Energy Policy[12], indicates that by 2030 residual energy demand could become negative (indicating conditions for negative prices) for up to around 500 hours a year with 38 GW of combined onshore and offshore wind. This increases to over 1500 hours under a scenario with 58 GW of combined wind (representing 40 GW offshore ambition). This is shown in Figure 1 where residual demand is demand in a particular hour less the sum of wind, solar, nuclear and hydro power available in that hour. Hourly quantities for demand and residual demand are used to form load-duration curves in which values are sorted from the largest on the left to the smallest on the right. The modelling takes account of current levels of system flexibility (including currently confirmed plans for interconnectors).

[10] Ostrovnaya, A., Staffell, I., Donovan, C., Gross, R. (2020) 'The High Cost of Electricity Price Uncertainty' Link

[11] Bell, K. and MacIver, C. (2020) 'Balancing and 'flexibility' in a power system', UKERC workshop on electricity market challenges

[12] MacIver, C., Bukhsh, W., Bell, K.R.W. (2021). 'The impact of interconnectors on the GB electricity sector and European carbon emissions' Energy Policy 151 Link

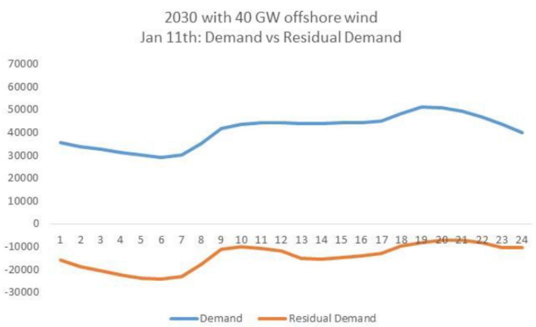
Figure 1: Load duration curve comparison for modelled 2020 and 2030 scenarios[11,12]



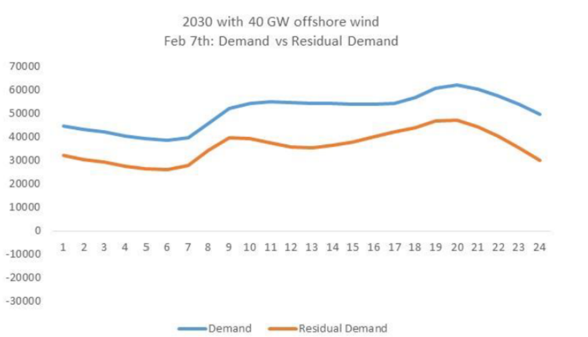
To put this into perspective in terms of the impact on daily demand and supply balance, the figures below from the same modelling show the residual demand staying negative for a full 24 hours on a windy winter's day in 2030 (left), contrasting with a day with moderate wind output (right) showing sustained high residual demand.

Figure 2: Modelled Daily Demand and Residual Demand in GB for sample 2030 days assuming 40 GW offshore wind[11,12]

Windy Winter day
- Maximum total wind output: 54.6 GW
- Maximum *negative* residual demand: 24.3 GW



Winter day with moderate wind output and high residual demand
- Maximum total wind output: 13.1 GW
- Maximum residual demand: 47.3 GW



Price stabilisation mechanisms such as CfDs protect renewable generators from these periods of low prices, but tend to exacerbate this price suppression by creating an incentive for wind and solar plant to continue offering generation into the market during periods of low price in order to recoup payments under the CfD mechanism. This can further reduce wholesale prices to below the operating costs of these plant, and even into negative pricing[13]. The new CfD contract withholds payment in these circumstances and should help to prevent prices going negative in future once their volume in the market is sufficient.

These low price periods create specific risks for plant that are coming out of price-support mechanisms such as CfDs or renewables obligations (ROs), which face fixed operating costs as well as fixed regulatory costs such as transmission network use of system (TNUoS) charges. If average capture prices are below these aggregate fixed costs, then existing plant may be forced off the system into early retirement, which would be a suboptimal outcome from a system cost point of view, as their contribution to aggregate energy supply would then be replaced by another plant with higher overall costs.

On the other hand, as indicated by the right-hand chart in Figure 2, there are likely to be extended periods (e.g. wind droughts) when residual demand is high, and prices could also be high as a result. The frequency and duration with which the wholesale market produces these periods of low and high prices is expected to be dependent on the extent of demand responsiveness and the flexibility of the system as a whole. In general, these price variations should bring forward providers of flexibility who can profit from these price variations. In turn, as they enter the market, they would tend to erode these price variations, tending to stabilise prices. This is addressed under **Q3**.

There is a wider question about the extent to which the wholesale market as it is currently designed is seen as the long-term future basis for power trading, or whether more fundamental market reforms are to be made to reflect the emerging new structure of the power system. This is addressed under **Q5**.

Q3. How viable will investment in new renewable projects based primarily on wholesale prices be in future? Could this investment case be supported if there was more extensive deployment of flexible assets such as storage?

Regarding the first question, we expect the viability of investment based purely on wholesale prices under current market design (i.e. prices based on short-run marginal cost) to reduce in the future – this issue is addressed in more detail under **Q1**. We also note analysis that indicates that price risk increases the cost of capital[13]. We would expect that if there is a desire to shift to a market basis for remunerating renewables, then more significant reform to wholesale markets will be needed in the longer-term to address the need for long-term price signals. These points are addressed under **Q5**.

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[13] Ostrovnaya, A., Staffell, I., Donovan, C., Gross, R. (2020) 'The High Cost of Electricity Price Uncertainty' Link

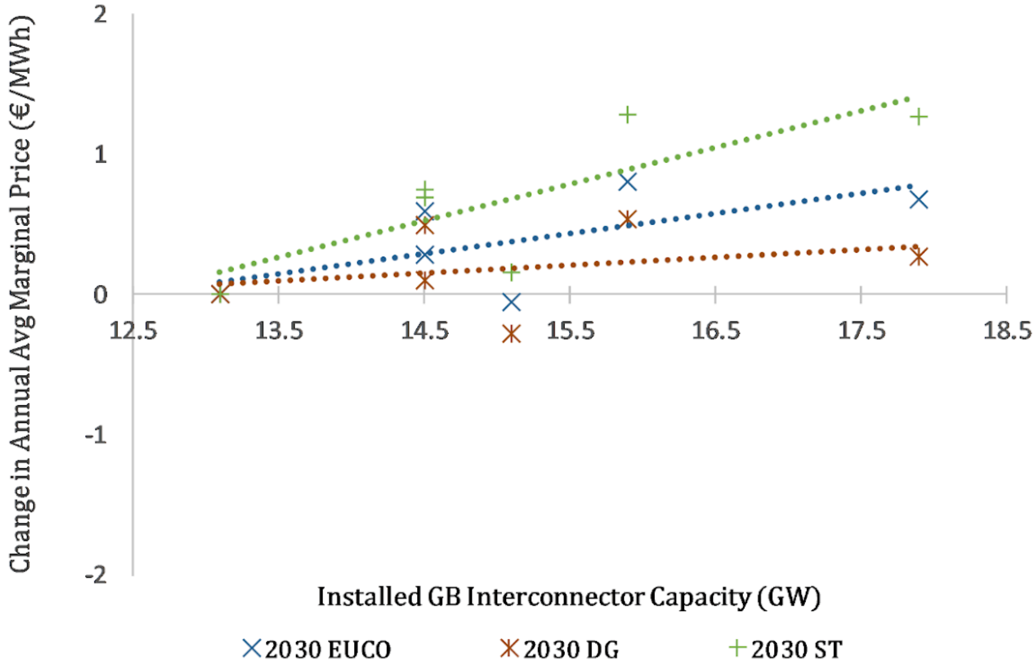
Regarding the second question, we expect that, all else being equal, greater system flexibility (on both generation and demand sides) can help to smooth out imbalances of supply and demand, reducing the frequency and duration of periods of low (and high) prices. This is desirable given the strong evidence that increased system flexibility reduces the cost of integrating renewables.[14]

The benefits of flexibility in terms of system costs should also in principle feed through to more advantageous market price conditions for renewables. Modelling by University of Strathclyde[15] illustrates this effect in relation to interconnectors. Currently, interconnectors tend to import cheaper power from the EU, reducing the cost of power in GB markets as a result. Under a 40 GW offshore wind scenario, this situation is expected to reverse to net exports from 2030 onwards. In this situation, increasing levels of interconnection tend to lead to an increase in the average price of electricity in GB markets. As well as increasing average prices, it is shown that increased interconnection has a significant bearing on the expected level of 'spilled' energy, i.e. that available from wind farms but where the level of demand plus export capacity in certain hours is insufficient to use it. In the scenario which considers 40 GW of offshore wind in GB, installing a total of 12.9 GW of additional GB interconnection capacity facilitates the additional utilisation of 1 TWh of wind energy per year compared with a scenario where no new interconnectors are added in the next decade.

[14] Heptonstall, P.J., Gross, R.J.K. (2021). 'A systematic review of the costs and impacts of integrating variable renewables into power grids.' *Nat Energy* **6,** 72–83. Link

[15] MacIver, C., Bukhsh, W., Bell, K.R.W. (2021). 'The impact of interconnectors on the GB electricity sector and European carbon emissions' Energy Policy 151 Link

Figure 3: Change in annual average GB marginal price under different interconnector and background scenarios[15]



Work by Ward et. al.[16] indicates that the business case for flexibility may be stronger than most energy models predict, because assuming a simple merit-order stack based on SRMC will tend to underestimate the actual price variability observed in real markets. This is due to factors that are usually omitted from simple stack calculations, such as the costs of ramping plant and other pricing behaviours.

Work by UKERC indicates a need for different types of system flexibility to achieve different services:[17]

- Flexibility – able to adjust production or consumption quickly and at short notice
- Schedulability – able to schedule power at any given time on a given day in the future
- Persistence – increase in production or decrease in consumption can be sustained for a period of time

Different technologies will show different characteristics in relation to each of these. For example, wind power can be flexible when it's windy, in that wind turbines can be operated at part-load so that they could adjust production quickly and at short notice. However, they are not schedulable, and their persistence would be weather dependent. Nuclear on the other hand is not really flexible, but is schedulable and persistent.

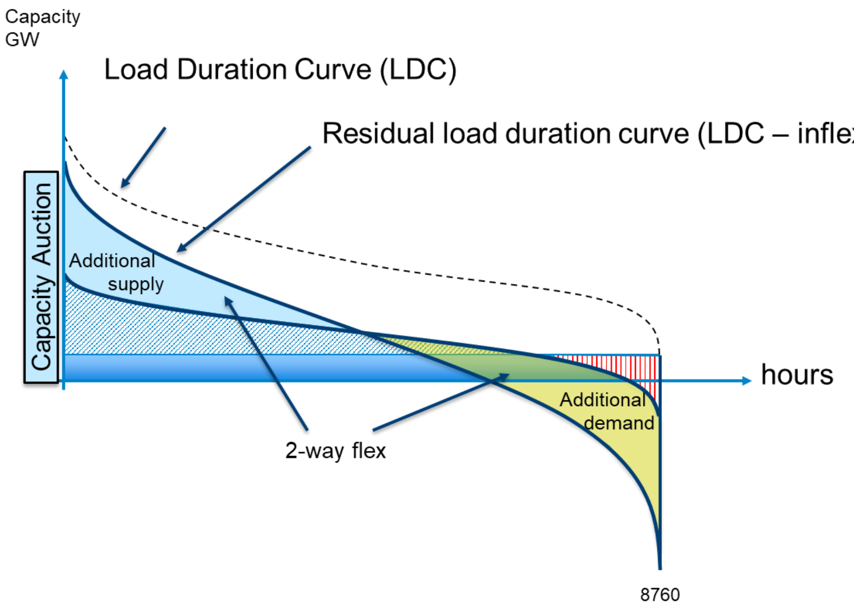
[16] K.R. Ward, R. Green, I. Staffel (2019). Getting prices right in structural electricity market models. Energy Policy 129 (2019) 1190–1206

[17] Bell, K. and MacIver, C. (2020) 'Balancing and 'flexibility' in a power system', UKERC/BEIS workshop on electricity market challenges.

In terms of balancing bulk supply and demand over the year (i.e. ignoring very short-term fluctuations and frequency controls), it is useful to visualise the problem in terms of a load duration curve. With an inflexible system, the load duration curve is expected to go negative, as noted in the modelling results shown above. Figure 4 indicates a residual load curve that would have a strong negative component. However, if the system has enough '2-way' flexibility (indicated by the regions marked 'additional demand' and 'additional supply'), then a substantial portion of this negative demand can be shifted from the right-hand side to the left-hand side of the curve, providing supply at times of peak demand.

One thing that becomes clear in this view is that the current market design is asymmetrical. Although current capacity auctions tend to incentivise investment in '1-way' sources of flexible generation on the left-hand side of the curve, they do not contribute to flexibility at times of peak supply on the right-hand side. This could be addressed through a number of mechanisms to incentivise investment in system flexibility, one option being an equivalent auction mechanism for negative capacity to make the solution symmetrical. Further discussion is provided under Q5.[18]

Figure 4: Illustration of residual load duration curve and impact of flexibility[19]



Key sources of 2-way flexibility include storage (incl. H_2), interconnectors, and flexible demand. On the demand side, electrification of heat and transport will significantly alter the nature and time profiles of demand, and the options available for making this demand flexible and more responsive to patterns of supply. A recent UKERC review of decarbonisation of heat noted the importance of flexibility in the

18 Blyth, W., Gross, R., Rhodes, A. (2020) 'Electricity Markets with a High Share of Variable Renewables: A review of issues and design options', Commissioned by SSE via Imperial Business Partners. Link

19 Blyth, W. (2020) 'Pressure for Change? Electricity wholesale markets and incentives in GB', UKERC workshop on electricity market challenges

use of electrical heat, indicating that this can best be achieved through smart operation of heating systems in well-insulated buildings which increases the options for electricity to be stored in thermal form.[20] This can reduce overall system costs through a potential reduction in peak generation and network demand[21]. Likewise, electrification of transport will also change both the profile and flexibility of demand.

One can envisage that in future the electricity system may reach a new (dynamic) equilibrium state, with high levels of variable renewables coupled with high levels of system flexibility. This flexibility would need to be of several different types, likely including a mix of increased demand response, electrical and thermal storage, and interconnection. Flexibility would be required over a wide range of timescales spanning milliseconds to seasonal. This can in principle improve the economic efficiency of the overall system (depending on the cost of those flexibility options), as well as in principle improving the economic case for variable renewables by helping to stabilise prices.[22]

However, there is an important difference between the economic case and the investment case for flexibility and storage solutions. The hypothetical existence of an economically attractive future equilibrium state of the market is not a sufficient condition to attract the investment needed to achieve that new state. The key difference relates to the inherent risks in the transition from the status quo to any new system state, and who is best placed to manage these risks. Some of the key characteristics of the transition have strong public policy-driven elements which may make it inefficient to allocate all the transition risks to the private sector. Sources of non-equilibrium policy-driven transition risk include:

- **Pace of change**. The government's 40 GW offshore wind target is the prime example, deliberately forcing the pace of scale up in the sector. Other examples include sector deals on nuclear.

- **Scale and structure of demand** will depend heavily on policy-driven changes such as the degree and pace of electrification of heating, transport and industry, as well as the thermal efficiency of buildings.

- **Delivery of system flexibility.** Some types of flexibility not only require significant infrastructure development (e.g. interconnectors, hydrogen, methane + CCUS), but also face significant levels of technical and policy uncertainty of their own. This makes them unlikely to be developed on a purely 'merchant' basis under current wholesale market arrangements due to the same difficulties of risk management. For example, interconnectors, which are technically relatively

[20] Jan Rosenow et. al. (2020) 'The pathway to net zero heating in the UK. UKERC Policy Brief.' Link

[21] Lowes, R., Rosenow, J., Qadrdan, M., Wu, J., (2020) 'Hot stuff: Research and policy principles for heat decarbonisation through smart electrification', Energy Res. Soc. Sci. 70, 101735. Link

[22] MacIver, C., Bukhsh, W., Bell, K.R.W. (2021). 'The impact of interconnectors on the GB electricity sector and European carbon emissions' Energy Policy 151 Link

mature, have a cap and floor to help stabilise revenues. Future CCUS and hydrogen infrastructure volumes are even more likely be influenced by policy.

When considering the future market arrangements for variable renewables, it is also essential to look at how these can also be used to ensure sufficient investment in system flexibility. However, not all flexibility options are market-ready. Whilst some options such as interconnectors and some storage options are already deployed at scale, other storage options require research into new materials and manufacturing methods[23], and a system-wide view is needed of how and when these can best be brought to market, and what support mechanisms may be needed to do so.

For example, analysis by the Climate Change Committee and others provides a role for inter-seasonal storage[24]. This suggests that a particularly important element of inter-seasonal storage could be green hydrogen, produced from renewable energy at times of lower demand, and stored in either new or existing gas storage sites. This hydrogen could be a zero-carbon balancing medium for a much more flexible energy system although other technologies such as compressed air storage or ammonia could perform a similar function. In any case, the novelty of these technologies and the associated demand risk mean that some more strategic policy support around inter-seasonal zero carbon storage may be needed to replace the current model of increasing fossil gas imports.

It would therefore seem useful from a policy perspective to differentiate between long-term market arrangements that might be put in place once a new electricity system structure and market equilibrium conditions have been achieved, and the interim policy arrangements that are needed to drive the system through the transition phase to this new state. This provides important context to the answer to Q4 about how much longer CfDs should be maintained.

Q4. How much longer after the 2021 allocation round should the current CfD be used? Is a price based on a short-run marginal cost market the most effective basis for a long-term renewables contract?

In order for offshore wind to meet the 40 GW target by 2030, the rate of installation needs to triple in the coming decade relative to the previous decade. This only seems feasible if the market is able to build on the experience of the previous decade. This very likely includes the need to replicate the success of financing models that have become established to deliver the first 10 GW. These financing models typically rely on the ability to raise relatively high levels of low-cost debt to keep the cost of capital low. This model relies crucially on the revenue stabilisation effects of CfDs. This is important not only for the financing structure of individual investments, but also for creating long-term signals on market structure and price

[23] Catherine Jones (2020) 'UKERC Energy Storage Landscape Report' Link
[24] Climate Change Committee (2020) 'Sixth Carbon Budget' Link

expectations during the long project development cycles needed for offshore wind (typically in the region of 8-10 years[25]).

It seems likely therefore that for offshore wind, some form of continued revenue stabilisation will be necessary over the next decade to maintain confidence and momentum in the market given both the magnitude of the scale-up required over this time period, and the significant uncertainties in the evolution of the wider system discussed under Q3. This process could conceivably be managed through incremental change to CfDs, or through transferring to some other type of equivalent mechanism, see Q5.

The situation for onshore wind and solar may be different. Whilst onshore projects will still be subject to problems of price cannibalisation under current wholesale market design, their lower cost base (also potentially including lower network charges, though not for island wind developments) means that these price reductions create less of a risk to projects. Although planning processes can be slow, in general the project development cycle is simpler and quicker than offshore projects, meaning that projects can be more agile to respond to changes in demand and are somewhat less exposed to systemic risks discussed in Q3. For some projects, their proximity to sources of demand means they may be more able to respond to localised market opportunities such as commercial PPAs. The relative speed of development of onshore projects also means there is greater capacity for policy-makers to be able to observe market behaviour between successive rounds of CfDs, and adjust accordingly.

Regarding the second question, alternative ways of providing long-term price signals for renewables contracts are addressed under **Q5**.

Q5. Are there any changes or alternatives to the wholesale market that might facilitate merchant deployment?

Wholesale electricity markets were historically designed to reflect the cost structure of a predominantly fossil-fuel driven system, largely based around recouping operational costs linked to the prevailing price of fossil fuels, with periods of supply scarcity and higher prices providing upside to recoup the capital costs.

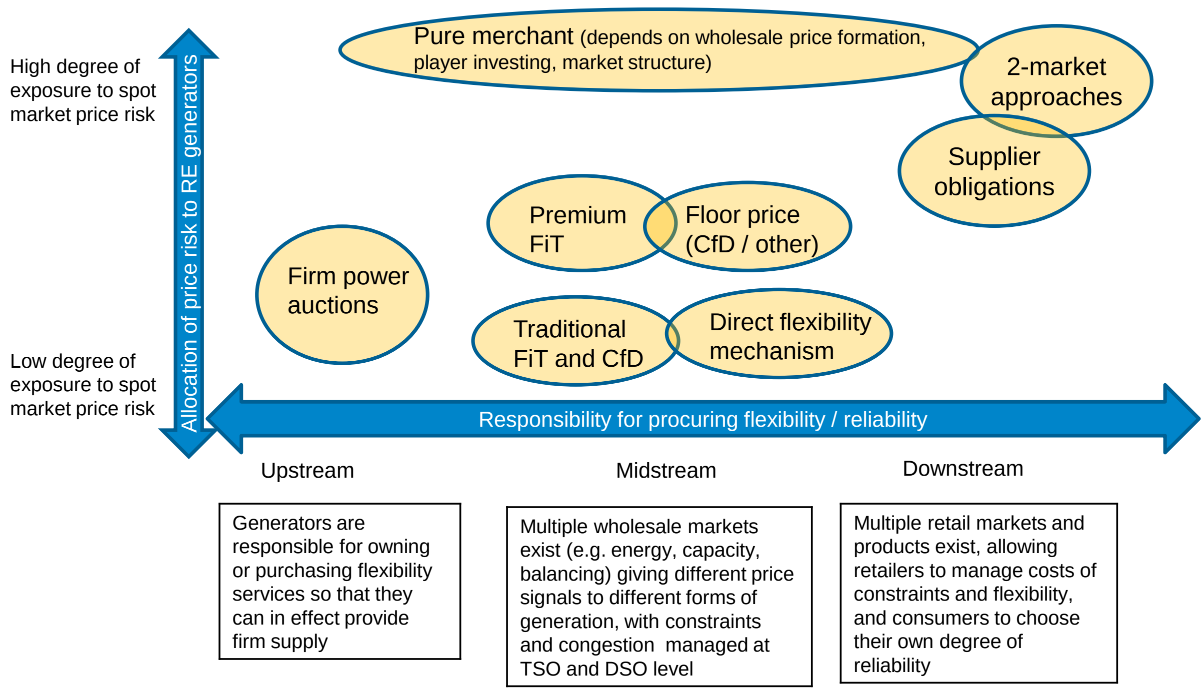
A low-carbon electricity system based on plant with high-CAPEX / fixed costs and low-OPEX costs may need a different design. A review of the literature on possible future design options recently carried out by Imperial College[26] shows that different market designs have different implications for who is exposed to merchant risk, and who is responsible for procuring the necessary levels of system flexibility to achieve a system that is efficient and reliable overall. In particular, because the financing mechanisms available to various players tend to be different, it is useful to separate out the extent to which responsibility for procuring system flexibility resources falls on

[25] Offshore Wind Industry Council (2019) 'Enabling efficient development of transmission networks for offshore wind targets' Link

[26] Blyth, W., Gross, R., Rhodes, A. (2020) 'Electricity Markets with a High Share of Variable Renewables: A review of issues and design options', Commissioned by SSE via Imperial Business Partners. Link

upstream players (i.e. generators), mid-stream players (T&D system operators), or downstream consumers.[27] The various options allocate these risks and responsibilities across these boundaries in different ways (Figure 5). These boundaries matter because organisations tend not to straddle them, so incentive mechanisms targeted in one area may not mobilise the expected technical and organisational solutions arising in other parts of the chain.

Figure 5: Alternative risk allocation and incentive schemes (Source: adapted from [26])



Various proposals have been made in the literature for market designs that would potentially improve the ability to remunerate CAPEX-intensive investments. The solutions identified by the Imperial College review fall into four categories:

A. Modifications to CfDs;
B. Redesign options for wholesale markets;
C. Replacing markets with more regulated structures;
D. Moving towards more vertically integrated utility models.

A: Modifications to CfDs

One relatively simple adaptation to the CfD that has been proposed[28] is to make the reference price in the contract a one-way floor price rather than a two-way contract for difference. Generators would be paid when the wholesale energy market price goes below a certain floor price, protecting them from periods of low prices. If prices were to rise above this floor, they would start to pay back these public monies until

[27] Blyth, W., McCarthy, R. and Gross, R. (2014) 'Financing the Power Sector: Is The Money Available?' Link
[28] Cornwall Insight. (2016). 'Safety net: the case for a CfD floor price' Link

the gross value of payments had been reimbursed, and then the investors would receive any additional upside beyond this. This upside should make the auctions more competitive, driving contract prices down below the level of current strike prices. The ability of projects to gain this upside should encourage value-creating behaviour by positively rewarding projects that are more flexible, or located in areas which are less correlated where they are able to generate during periods of higher value power.

In addition, modifications to CfDs may be needed to allow extended coverage of plant once they have moved beyond their initial financing period. As noted in **Q4**, there is currently a risk that existing plant with expired CfDs or RO contracts will be forced off the system early as a result of being undercut by new plant with CfDs, which would be an adverse outcome in terms of overall system costs. CfDs may therefore need to be modified to allow some option of extension beyond 15 years duration to allow plant to continue to recover fixed costs.

B: market re-design options

Taking the above idea a stage further would be to apply a **floor price to the whole market** which ensures prices for all plant do not drop below a certain level. This would offset downside risk similarly to Option 1, but for the duration of the plant life (not just for the contract duration), and would apply to all plant in the market, reducing technology choice distortions. One way of administering this would be to introduce a pool with mandated participation from buyers and sellers, and apply a floor to the traded prices in that market. This approach needs careful analysis to better understand the impacts such price constraints might have, both in terms of market behaviour and bidding strategies of generators, as well as the investment incentives for providers of system flexibility.

Another approach is to hold **auctions for demand** that aim to increase levels of demand during periods of peak supply. This helps address the asymmetry of current market mechanisms noted in **Q3** which should incentivise entry of more 2-way flexibility into the system, increasing the availability of demand counterparties, and helping to offset the price cannibalisation effect.[29] As well as supporting volumes of demand during these periods, such auctions could be designed to more directly support prices, for example incorporating a price floor mechanism by having a buyer-of-last resort. Similar auctions have also been proposed by Keay as a stepping-stone to his more generalised 2-market proposal outlined below.

Variants of a **2-market approach** have been outlined in the literature which separate the different features of variable renewables and schedulable plant, and let the market decide what they are prepared to pay for each, and how much of each should be procured:

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[29] Blyth, W., Gross, R., Rhodes, A. (2020) 'Electricity Markets with a High Share of Variable Renewables: A review of issues and design options', Commissioned by SSE via Imperial Business Partners. Link

- Keay[30] has proposed a 2-market solution in which consumers would be provided with a choice of two separate products, the first an 'on-demand' product, similar to the current wholesale energy market, and the second an 'as-available' product, linked to production from variable renewables where they would only be able to consume energy if it was being produced. Pricing in the second market would reflect long-run marginal costs of generation, which would in principle be attractive in circumstances where renewables are cheap, and carbon prices are sufficiently high to drive a price gap between the two markets. Consumers, moderated and intermediated by their suppliers, would be responsible for choosing their own level of security of supply depending partly on their own ability to moderate / shape demand, leading to explicit pricing and differentiation between consumers of this desirable characteristic of supply. The approach allows price intervention such as a feed-in tariff or some other kind of top-up to the price in the 'as available' market during the establishment of the market. Auctions could be used to help build up the demand for the product.

- Grenz[31] proposes a different two-product model based on auctions. One of these markets relates to flexible supply, the other relates to variable renewables. The auctions for variable renewables provide a pre-determined price for generation which can for pre-defined time periods reflect expected supply needs. These only pay out if the generator is available but does not dispatch. If the generator dispatches, they receive the market price. This ensures that renewable generators will only bid in prices above the contract price from the auctions, effectively ensuring a floor price for that time period.

The main benefit put forward for these proposals is that price differentials between the 2 markets would reveal the real costs and benefits of system flexibility. However, whilst they both have different ways to deal with price risk, there would seem to be considerable volume risk associated with both approaches, as it is not clear whether demand for the variable 'as available' product would match the amount in the market, especially during the fast scale-up phase of renewables over the coming decade. Questions about the availability of such contracts might be seen as a considerable investment risk. Counterparty risk is also a concern, as with other supplier obligation approaches discussed below.

Supplier obligations would put the onus on suppliers to meet certain criteria such as decarbonisation and reliability standards, and then let them satisfy these in the most cost-effective way.[32] This would allow suppliers to innovate in their ability to meet the needs of different consumers with different types of product. One of the concerns of this approach from the point of view of renewables investors is that they

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[30] Keay, M. and Robinson, D. (2017) 'The Decarbonised Electricity System of the Future: The 'Two Market' Approach' Link

[31] Christian Grenz (2017). 'Electricity market redesign – from a distorted short-run to a competitive long-run marginal price-setting mechanism', in design the electricity market(s) of the future. Proceedings from the Eurelectric-Florence school of regulation conference. Link.

[32] Energy Systems Catapult (2019) '*Towards a new framework for electricity markets*' Link

would not provide sufficient long-term investment security to allow renewable generators to scale up investment to the extent needed. Whilst supplier obligations could be set with a long-term horizon, there would be no obligation to enter into correspondingly long-term contracts, undermining the financial case. Another related form of this approach is the renewable portfolio standard, used widely in the US.[33] A concern raised for these approaches is that depending on the financial viability of electricity suppliers, they may create counterparty risk for owners of renewable energy projects, which may increase overall costs.

Equivalent firm power auctions have been proposed by Dieter Helm[34] in which the flexibility options are bundled together with the VRE sources, so that they can be addressed within a single auction for 'equivalent firm power' (Helm, 2017). This has the advantage of reducing the number of market mechanisms, since this equivalent firm power auction would effectively replace the CfD mechanism and much of the current capacity mechanism. If it were combined with an effective limit on carbon emissions, this could in principle create a mechanism that incentivises suitable 2-way flexibility options, since VRE generators would have an incentive to pair up with assets that could benefit from the periods of low-price. However, the disadvantage of this indirect approach is that achieving a system optimal solution would rely on the VRE and flexibility providers providing a pre-packaged 'firm capacity' offer. This could potentially limit market price discovery and innovation compared to a more direct incentive mechanism if it acts as a barrier to market entry for stand-alone providers of 2-way flexibility that do not have a readily packaged offer that fits organisationally with VRE generators (e.g. consumer-oriented demand response). This may lead to inefficient outcomes at the system level if only part of the market is mobilised to procure system flexibility services.

C: Replacing the market with a more regulated structure

In addition to these market-based options, there are a number of options for more regulatory approaches that could be taken. These would have the benefit of stabilising revenues for all types of investor, reducing the cost of financing, but also reducing commercial pressures to invest and operate as efficiently as possible. There are summarised by in a paper by Cornwall Insight.[35]

D: Utility-driven models

A third category of solution is that the structure of the market could in principle move back towards a more vertically integrated utility-style model. This would allow companies to manage some of the more structural risks and uncertainties associated with balancing supply and demand internally within their own balance sheets. Whilst this does not eliminate the risks, it allows companies more degrees of freedom to manage them and could allow them to benefit from current trends in the finance

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[33] Ed Birkett (2020). 'Powering Net Zero', Policy Exchange. Link

[34] Helm, D. (2017) '*Cost of Energy Review*' Link

[35] Cornwall Insight (2020) 'The net zero paradox: Challenges of designing markets to bring forward low marginal cost resources', Insight paper. Link

sector towards environment, social and governance (ESG) investing, meaning the stock values of companies that meet these criteria are tending to rise, potentially providing relatively low cost source of equity financing. If these trends continue, as some are predicting, this may signal both an appetite and a financial driver for companies to expand investment in this area. However, the return to big utility companies, whether or not linked to regional distribution monopolies, would go against the grain of current market trends which is favouring agile, mostly thinly capitalised suppliers. It is interesting to note meanwhile that although several of the proposed market solutions include an increasing role for these suppliers in helping manage the investment risk of the generators, it is yet to be proven that appropriate risk structures can actually be created with this market structure to deliver the volume and speed of investment required.

Perhaps the most striking observation that occurs in relation to the wide range of future solutions is that the term ‘merchant’ could have quite different meanings under different market or system solutions. Would a return to vertical integration with large utilities developing renewable projects and managing wholesale risks constitute merchant investment? Given the fundamental and far-reaching changes needed to meet net zero it appears odd to constrain the solution space solely to imagining how a market similar to existing wholesale, energy only structures could bring forward project financed and independent developments.

Q6. How can market participants be encouraged to provide contracts to secure low-cost investment in renewables?

The answer to this question depends on the type of market design being considered, as addressed under **Q5**.

For example, most of the **2-market solutions** outlined above are explicitly aimed at boosting the demand-side appetite for contracting with renewables suppliers. Some of these proposals take a mandated approach, requiring demand-side participants to increase the level of contracting with generators. Others assume that demand will arise naturally as a result of the growing cost differential between low-cost renewables and high-cost fossil fuels, coupled with an assumption that end-users and/or suppliers will increasingly be able to manage the demand flexibility that such advance commitments would require. Likewise, **supplier obligations** would create a similar economic rationale for contracting with low-cost renewables as part of their commercial portfolio management. The **demand auction** approach is something of a hybrid, relying on a centralised regulated body to hold the auction, but providing competitively-driven price discovery to the market. However, across all these solutions, the general principle is to find ways of establishing a long-run price signal for investors.

Some of the proposed solutions outlined in **Q5** bypass this issue. The **utility-driven** model basically internalises the problem of contracting between generators and suppliers by combining both within the corporate structure of the utility, whereas the **regulatory-driven** models essentially by-pass the problem altogether by centralising decision-making and ensuring regulated rates of return.

It is important to recognise that each of these proposed solutions represent very different risk profiles (e.g. likely length of contracts, price visibility, counterparty risk, ability to hedge in secondary markets, etc.). This affects the degree to which solutions are attractive to renewables investors, the extent to which they can manage and/or tolerate these risks, the impact on cost of capital and the implications for the rate of investment and ability to maintain momentum in the market towards a zero-carbon electricity system. However, it is important to be clear about the fact that a largely centralised and state-backed procurement model offers investors a very attractive environment in terms of counter-party risk. Many of the alternatives appear unlikely to be able to match this. The risks for each of these solutions and their impact on cost of capital or attractiveness to different classes of investors therefore need detailed analysis and scrutiny.

Part 2. Ensuring overall system costs are minimised

Q7. How could intermittent renewable generators change their operating or investment behaviour to respond to wholesale price signals?

In terms of current wholesale market design, the primary variable that is under the control of renewable generators in respect of investment is their choice of location (or orientation, for solar schemes) to the extent that this allows their output to be less correlated with other renewable generators on the system. Once the investment is made and capital costs are sunk, there is less that can be done to respond to spot prices unless projects are directly linked to storage or other flexibility solutions. The pros and cons of the latter are discussed further under **Q15.** It is possible for wind farms to be operated below peak output to respond to balancing needs, as we discuss in response to **Q3**. Operating variable renewables all of the time they are available maximises total output and minimises levelised costs, as well as providing the largest volume of zero carbon output. Whether it is cost effective overall (in terms of total system costs for consumers) to operate in an entirely unconstrained manner is a separate question that can only be answered through system modelling. If a degree of operational flexibility in the form of curtailment or turn down is desirable for wind or solar farms there is no reason why it cannot be delivered from an engineering perspective[36]. The alternative wholesale market designs discussed under **Q5** reflect different risk exposures, and would create different incentives to change their operating or investment behaviour.

Q8. What would be the impact on the cost of capital of introducing greater exposure to the market price for power?

In general, the greater the exposure to price risk, the higher the cost of capital. The impact of this can be significant[37]. However, in the context of the wider transition to zero-carbon, and the implied shift to a system dominated by variable renewables,

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[36] A similar capability beyond a certain, limited number of hours per year would be a different matter for a pressurised water nuclear reactor.

[37] Ostrovnaya, A., Staffell, I., Donovan, C., Gross, R. (2020) 'The High Cost of Electricity Price Uncertainty' Link

there is a much bigger question about whether the ‘market price’ as represented by current wholesale market design is an adequate financial structure to attract and underpin the necessary investment at all. Given the expectations about the likely erosion of wholesale prices over time under these scenarios (see **Q2**), it seems likely that wholesale markets will need to be redesigned in order to create a viable investment signal, as outlined under **Q5**. The different designs in that section have in common that they all try to create a long-term price signal in one form or another that allows investors to re-coup long-run marginal costs. However, they differ considerably in the way they achieve this objective, and some of the proposed solutions would likely incur additional risk to investors, raising the cost of capital. This may be efficient from a system point of view if the risks of poor investment choices are passed from public (consumer bills) to private (equity returns), as long as the risks being transferred are ones that private investors are in a strong position to manage.

Q9. In your view which of the potential options for providing increased exposure to market signals offers the greatest benefit to the consumer? Are there any other options that we should be considering?

Given the expected erosion of prices under current wholesale market design, (see **Q2**), the long-term solution needs to be adjustments to market structure. Various options are set out under **Q5**. It is important to note that long-run fixed price contracts offer consumers benefits, assuming bid prices are low. As we point out in several other answers, removing protection from wholesale price risks increases the cost of capital. The question then becomes whether the wider costs/market price peaks during low renewables output offset the advantages provided by the presence of low cost contracted generation and lead to increases in overall consumer bills. We are not aware of analysis that provides a definitive answer to this trade off. However, again as we discuss under Q5, incremental changes to the CfD could increase market signals. Of the various ways to do this converting the CfD into a low carbon floor price could offer consumer benefits. The reason is that it underwrites renewables investment so that investment continues to be attractive to low capital cost sources of finance and hence delivers low carbon projects at a low cost of energy. Removing the CfD without providing an alternative, whether a reformed CfD or different market altogether, could be detrimental to consumers as an increase in the risk profile of renewables projects would be likely to increase financing and hence generation costs. It may also result in a decline in renewables investment, with the result that emissions targets are missed. As we note in several of our previous answers and the introduction, given the many uncertainties a gradualist approach that permits a degree of experimentation would allow the various trade-offs to be revealed whilst ensuring that investment in low carbon assets is sustained.

Q10. Should CfD generators be incentivised to account for flexibility and wider system impacts, and/or to provide balancing services to the system operator? How could this be achieved?

Our general position on this is that there is no a priori reason that CfD generators are better able to offer balancing services than other market participants. If the question is whether generators should 'account' for their system costs then this opens up a complex set of issues. As balancing requirements arise at a system wide level and balancing services offer system wide benefits there is a long-established principle of the electricity system operator (ESO) procuring balancing services from those best able to provide them cost effectively. Whilst both variable generators and large nuclear generators tend to add to system balancing costs and increase requirements for operational flexibility it is not obvious that a least cost overall outcome will be achieved simply by exposing them to these costs, or by requiring them to contract for 'firm power'. This is particularly true if they have limited capacity to respond directly and/or if they are not well-placed to determine overall balancing requirements and/or contract for balancing services. If this results in over-procurement of balancing and flexibility, or contracting for relatively expensive balancing services, the outcome will be sub-optimal and unnecessarily expensive.

As we note in the answer to **Q15** the key concern should be to minimise overall system costs and hence total costs to consumers. It may be that a cost imposed by a CfD generator can be most cost effectively borne/offset by a completely separate market participant. It is sensible to ensure that incentives for balancing services/provision of flexibility are not closed to CfD operators and there are operational opportunities for them to contribute to system balance (see **Q3**). However, this is likely to lead to a least cost outcome if system wide services, that benefit system operation overall, are procured on a system wide basis. Further discussion of this topic is also provided in the answers to **Q15**.

Q11. Should the CfD mechanism incentivise minimum grid stability requirements (in CfD plants) to minimise system costs and help ensure secure and stable operation? How could this be achieved and what are the barriers?

At the moment, contributions to grid stability, i.e. ancillary services, are bought in dedicated markets or administered arrangements that are separate from energy markets. Resources connected to the system have certain capabilities mandated through, depending on the size of the resource, the Grid Code or different Engineering Recommendations. Within the Grid Code, distinctions are made between different types of resource, notably between synchronous generators and 'power park modules'. However, having a capability does not mean that it will be available or used at any particular time.

Grid stability encompasses many features few of which are available to all technologies. These features include: stores of energy that can be accessed at different rates and sustained for different periods to be able to offer fast or primary frequency containment, frequency restoration, or schedulable strategic reserve; the ability to operate at low levels of output (so that stability services can be offered with minimum displacement of other energy sources from the system); reactive power capability; high short circuit current; and control systems that can be tuned to help to dampen system oscillations. A generally critical feature in respect of contribution to particular types of grid stability is a resource's location (addressed in **Q12**).[38]

In addition to ancillary service markets, energy resources might win capacity market contracts. (A contract simply to be available during system stress events can be regarded as payment to contribute to system stability). Like many ancillary services, capacity markets are paid in respect of availability of power, possibly with additional terms related to volumes of energy produced.

The Grid Code and Engineering Recommendations stipulate capabilities for resources that are connected to the system; they do not specify what capabilities or mix of capabilities should be connected in future.

One option would be to continue to treat capabilities to contribute to stability – in a capacity market or ancillary service markets – separately from contracts for energy. However, the former contracts, in particular, are only for short durations, and have typically only been offered, as far as we are aware, for resources already connected to the system[39]. Moreover, the offering of capacity market contracts (starting either 1 or 4 years ahead) and ancillary services contracts (typically no more than a year ahead) only consider relatively short-term need. There is therefore a danger that there will be insufficient incentives for new assets to be built with the mix of physical capabilities required for future system stability, e.g. through the 2030s and beyond.

One possibility would be to mandate certain levels of all features useful to system stability. Because no one technology can offer all features on its own, this would require the development of hybrid resources, e.g. wind farms with large amounts of battery storage. As discussed in **Q10** in relation to 'firm power', a requirement of this nature imposed on all resources would be unlikely to lead an overall optimal provision[40].

Another possibility would be to weight CfD tenders according to contribution to different classes of stability service. Because many stability services could be provided by different forms of energy storage or by flexible demand, parties bidding for energy contracts would be competing not just with each other but, in respect of contributions to system stability, different types of resources.

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[38] All aspects of a power system's stability are inter-related but, to a reasonable approximation, they can be thought of as particular phenomena: frequency, angle and voltage stability, a list to which some academics are now suggesting the addition of "converter related stability". (See for example, Hatziargyriou, N., et al. (2020) 'Definition and Classification of Power System Stability Revisited & Extended', IEEE Transactions on Power Systems [Link](#)). All except anything primarily related to frequency stability depend on location on the system relative to loads and other sources of power.

[39] New 'stability pathfinder' contracts could be viewed as an emerging exception to this.

[40] Hybrid resources might have different components spread across different locations. However, as noted, most stability-related services are location specific.

A further option is to auction for energy contracts alongside long-term contracts for provision of stability-related services and to evaluate offers to both linked as parts of packages of offerings.

Whether bought through weighted multi-purpose CfD contracts or linked offers to separate energy and stability/ancillary service markets, identification of the optimal set of offers to accept would require the solution of a complex optimisation problem, with weightings even more difficult to identify than the de-rating factors used in the existing capacity market. However, it would not be impossible though transparency – a clear explanation ahead of an auction of what is needed and after it of why the results were as they were – would be difficult to achieve.

A lack of transparency has already been argued to be a feature of the simpler "stability pathfinders" run by the ESO[41]. While claiming to be technology agnostic, the specification of requirements in a first tender round appeared designed for only one possible technology[42]. Then, that particular technology – synchronous compensators – offered multiple features only one of which was taken into account in the tender evaluation. These other features would be useful for a second pathfinder[43]. A criticism of this second pathfinder is that the system conditions for which the requested services are judged by the ESO to be required have not been described, preventing potential participants from either better targeting their offers or challenging the ESO's assessments.

In summary, it is unlikely to be possible to find a perfect arrangement.

Q12. Do CfD projects receive the right incentives to locate in the optimum locations?

At present, a wide variety of factors influence location of projects receiving CfDs, including (but not limited to) richness of the energy resource, cost of land or of seabed licensing, location-specific construction costs, and electricity network connection and use of system charges. They will also include the potential for planning and consenting related delays to either the main development or the network connection.

The methodologies used to calculate network use of system charges – separate ones for transmission and distribution, something that can lead to distortions in siting decisions – are intended to reflect the costs of network developments to accommodate generation (or demand) at different locations. However, in doing that they are only approximate at best. Although they might be made more accurate, the penalty for doing so would be greater complexity[44]. Moreover, changes to the methodology, in the short-term, are a zero-sum game: there are winners and losers.

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[41] See, for example, Nedd et al. (2020), Operating a zero-carbon GB power system: implications for Scotland, Climate XChange, link.

[42] https://www.nationalgrideso.com/news/national-grid-eso-launch-stability-pathfinder-phase-one

[43] https://www.nationalgrideso.com/research-publications/network-options-assessment-noa/network-development-roadmap

[44] K. Bell et al., (2011). "Project TransmiT: academic review of Transmission Charging Arrangements". Link.

(In the longer-term, if the changes are in the right direction, consumers should benefit through a reduction in the sum of electricity production and the cost of network infrastructure as a consequence of the changed locational signals). Changes are therefore vehemently opposed by market actors who would be adversely affected by the changes, and change takes an inordinate amount of time.

As we have already noted, one thing likely to aid system balancing and reduce the variability of residual demand would be for wind farms to be sufficiently widely dispersed geographically that their outputs are less correlated and more diverse within short periods of time, thus smoothing the total availability of wind power for the system as a whole and reducing the periods of time which in extremely low wholesale market prices would be seen. Neither the existing, quite crude transmission network use of system (TNUoS) charge methodology nor the current CfD contracting regime encourage that.

Q13. Are there actions which Government should consider, outside of Ofgem's current electricity network charging reviews, to help incentivise efficient market behaviour regarding the location of renewable assets?

There is much room for improvement in respect of the accuracy of cost-reflectivity of locational signals in and consistency between the use of system charging methodologies for transmission and distribution. Genuine progress in Ofgem's current review ought to be extremely valuable.

It has often been argued that parties causing system balancing costs – in particular, those arising from network constraints – should pay for them, either directly (through 'polluter pays' allocation of balancing service use of system charges[45]), or that such costs should be minimised through trades that the network couldn't accommodate simply not being permitted. This latter approach is what a centralised pool based on locational wholesale market pricing would achieve.

Various commentators have advocated the introduction of locational marginal pricing (LMP) to a centralised electricity wholesale market and transmission network in Britain[46]. Some argue that it should be extended to encompass distribution connected resources as well. The main argument offered is that it would encourage greater efficiency in use of network capacity and remove the opportunity for generators, in particular, either simply to locate in places that have limited export capacity or to exploit export limits through the requirement for the system operator to 'buy back' generators' own production schedules. The main weakness cited is that the market is left vulnerable to locational market power, notably in respect of dependency on certain resources. However, in theory, that ought also to encourage investment in those locations by additional resources. Furthermore, the role of

[45] In practice, balancing costs can arise for a variety of reasons, not just because of network constraints. The other reasons include simple power balance on the system as a whole or the need to ensure frequency stability. Balancing actions taken by the system operator quite often address more than one problem.

[46] Most recently in Britain, commentary commissioned from AFRY by the Energy Systems Catapult makes such an argument – see Energy Systems Catapult (2019) 'Towards a new framework for electricity markets.' Link

network investment is often overlooked: export (or import) constraints would not be excessive if the network was reinforced to an appropriate level.

The volume of criticism of the current TNUoS charging methodology from stakeholders in Scotland, in particular, suggests that the locational signals inherent in it do make a difference. However, given that generation projects have continued to be developed and apply for connection in Scotland, it would appear that the higher TNUoS charges in the North are not a blocker, just that the developers, looking enviously at charges levied for sites further South, wish they did not have to pay so much.

One of the criticisms made of the TNUoS methodology more generally is that future charges are highly uncertain and introduce risk to new generation (or storage or demand) developments.

The locational signals present in the TNUoS methodology can be interpreted as an 'administered' proxy for those that would be present in LMP[47]. A common observation of prices in LMP-based arrangements is that they can be highly volatile, particularly in the presence of transmission network constraints. If future TNUoS charges represent a highly uncertain influence on investment, it might be speculated that LMP would represent an even more uncertain influence.

As a final observation on LMP, we would note that, anecdotally (we have not found a rigorous, published assessment of this), it is not having an influence on the location of new renewable generation in markets that use LMP. For example, in Texas, our understanding is that wind farms are being built where the wind and land resources are best, regardless of power network capacity. This is perhaps because they are protected from the adverse effects of low locational prices by the financial support mechanisms put in place to encourage the development of renewables. An analogy for Britain would be, with the introduction of centralised day-ahead trading based on LMP, low carbon generation behind a network export constraint in, say, Scotland being exposed to low wholesale market prices but being protected from them by the strike price in their CfD won in a GB-wide auction. This would have the consequence of the CfD top-up being larger than if the wind farm had been on the other side of the network constraint[48]. An alternative would be the strike price awarded in a CfD auction somehow being dependent on location and the likely top-up requirement. In the presence of LMPs, this would have the effect of, to some extent, sharing the price risk between the generation developer and consumers responsible for paying the top-up.

[47] K. Bell et al., (2011). "Project TransmiT: academic review of Transmission Charging Arrangements". Link.

[48] A PhD student at the University of Strathclyde, Shona Pennock, started to explore this issue in her thesis finished in 2019. Link. However, it should also be noted that the effect of LMP in Scotland will be reduced by reliable operation of the Western HVDC Link and by the new reinforcements indicated in the January 2021 edition of the Network Options Assessment.

Q14. Should the CfD do more to enable the sustainable growth, cost reduction and competitivity of UK supply chains and how could this be achieved?

This question opens up a very fundamental set of issues related to the relative priorities of cost reduction in particular technologies (for example offshore wind farms), overall energy system costs and industrial policy objectives such as the creation of UK supply chains or jobs. This is because each of these goals may be in conflict. For all of the reasons described in the answers above CfDs provide revenue stability that attracts investment. However, this may result in limited attention to system costs and therefore overall cost reduction, irrespective of whether the supply chain is UK based or not.

Similarly, it is possible that the competitive pressures created by CfD auctions may make it more difficult for less established supply chain participants to enter the UK market. Project developers will seek proven technologies and providers in whom they have confidence because delivery on time and in budget is central to cost control and profitability. Due diligence requirements and the technology performance guarantees needed to secure investment may also favour established supply chain companies over new entrants. Since established equipment providers in key parts of the supply chain are not UK companies there appear to be inherent tensions between minimising costs and creating opportunities for the UK-based supply chain to grow. Early literature on this topic highlights how the more market-oriented approach of the England and Wales 1990s Non Fossil Fuel Obligation appears to have been much less successful as an instrument of industrial policy than early Feed-in-Tariffs[49]. In the context of the current consultation the question has to be whether moving away from price support for renewables altogether in favour of a merchant approach would be even worse for a nascent UK supply chain. Put another way, would the price pressures on the supply chain created through auctions be even greater if the auctions were replaced by exposure to wholesale price risks?

One point that should not be overlooked is that the analysis we provide in answers to Qs 1 to 5 and in our opening section indicates that if capture prices are low then it is not obvious that investment will be forthcoming at all. Clearly, this would be a particularly bad outcome for the supply chain! New entrants will not be attracted to a market where long term viability is open to question. In this regard one of the key requirements of policy is that a careful and gradual transition is provided so that the supply chain does not have the rug pulled by precipitous changes to the CfD regime that undermine investment altogether. So it seems to us that a more material question than whether the CfD can do more to support UK companies is how to ensure that any future arrangements do not undermine the progress made in creating investment in offshore wind. Assuming that a careful transition is pursued that continues to drive investment the question is whether a generally higher price

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[49] Mitchell, C., (2000) 'THE ENGLAND AND WALES NON-FOSSIL FUEL OBLIGATION: History and Lessons. Annual Review of Energy and the Environment' 25, 285-312. Link

environment would be acceptable if it did more to create industrial opportunities in the UK.

Perhaps the best way to characterise this is that a stable, investable policy environment is a necessary condition for developing the UK supply chain, but it is not sufficient. If we take the need to protect investment as a given then it may be that the more active industrial policies the UK is now pursuing[50] are the key requirement. Direct investment in port infrastructure is an example, but it is important to compare recent UK provisions with those in other countries, given that the construction base for offshore wind can be either side of the North Sea. It may be that wider regional and industrial policies are more material than any detailed changes to the CfD to promote UK-based companies and one way to provide insights would be through inter-country comparison and case study research. However, it is also important to note that the usual concerns related to specialisation and division of labour apply. It could be better for consumers and more realistic to accept a degree of specialisation such that (for example) UK companies make blades and continental partners produce nacelles. Increasing local content seems to be a political imperative, and understandable in the context of 'levelling up' the regions and creating green jobs. Whether it is desirable for the entire supply chain to be UK-based is another question altogether.

Beyond these observations we do not have an evidence base on which to provide full answers to these questions. The increasingly blurred line between energy and industrial policies create a need for far greater attention to trade-offs and tensions between cost reduction and creation of UK-based companies in the offshore wind supply chain or other aspects of the 'green industrial revolution'. Together with policies that might drive emissions reduction across the economy while avoiding 'carbon leakage', e.g. the role of standards for 'embodied carbon' in products. UKERC would welcome the opportunity to explore these issues further in collaboration with BEIS and market participants.

Part 3. Supporting and adapting to innovative technologies and business models

Q15. What are the benefits of renewable projects using multiple low carbon technologies or being co-located with low-carbon flexible assets? Should the CfD support these projects and why?

The key concern of market design should be to minimise overall system costs. There is strong evidence that the cost of integrating variable renewables is lower when system flexibility is higher,[51] implying that policy-makers considering market design options for accelerating the shift to renewables should at the same time be considering how to ensure sufficient flexibility in the grid. However, there is much less evidence supporting co-location of different renewable sources and/or flexibility

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50 Offshore wind manufacturing investment support scheme: investment programme [Link](#)

51 Heptonstall, P.J., Gross, R.J.K. (2021). A systematic review of the costs and impacts of integrating variable renewables into power grids. *Nat Energy* **6,** 72–83. [Link](#)

assets. In some cases, it may make sense to co-locate variable renewables and storage (for example where this allows right-sizing of transmission infrastructure and appropriate choices of means of transferring energy, e.g. between and electricity network development and a pipeline or ships carrying hydrogen or ammonia).

Often, however, especially where infrastructure costs are less significant, it is likely to be more efficient from a system cost point of view for providers of variable power and providers of flexibility solutions to remain separate, geographically and/or organisationally. For example, flexibility provision from demand-side response, interconnectors and distributed sources of storage (e.g. in transport) are not generally suitable for co-location. Creating a regulatory distinction between different sources of system flexibility which favours co-location could therefore be distorting of the market, or increase overall costs. In general, there should be a presumption against policy mechanisms that force generators and flexibility providers together in favour of market design solutions that allow a range of providers to offer these different services as efficiently as possible.

Q16. What are the benefits of projects with assets in different locations, including projects paired with flexible assets? Should the CfD support these and why?

For the reasons set out in answers to **Q10** and **Q15,** geographical dispersion can offer less correlated outputs. This may improve capture prices if projects face wholesale prices and reduce system balancing costs. Whether the CfD should be geographically differentiated is another matter as it is easy to imagine perverse incentives – for example if a higher CfD were paid for West coast offshore wind farms when lower cost East coast sites are still available. It would be better to transition to a regime where market participants can secure more of any price upside (if operating out of sync with the rest of the wind fleet for example). For the reasons described in the answer to **Q15** we are of the view that unless it overcomes particular grid constraints then pairing per se is unlikely to be the best way to procure or incentivise flexibility.

Q17. What changes would Government need to make to the Contract for Difference regime to facilitate the coordination of offshore energy infrastructure, what would be the benefits and costs of making them, and could there be a similar case for other renewable technologies?

We noted in our answer to **Q16** that geographically differentiated CfDs might create perverse incentives. However, there could be benefits in respect of network development costs and delivery timescales. Bids for CfDs for offshore renewable generation might be invited for specified amounts of capacity development zone by development zone such that there could be visibility of and a high degree of certainty about the projects expected to go ahead there[52]. This would likely involve at least some element of 'anticipatory' network investment, albeit at quite low risk.

[52] Auctioning of CfDs zone by zone might also help to address issues arising from locational pricing in the wholesale market, discussed in our answer to **Q13**.

Importantly, it should also enable a coordinated approach to pursuit of planning consents for onshore sections of network. If the generator-build option for network development is still regarded as important to enable generation developers to take ownership of risks associated with delays to network development, the sequencing of sections of network development might be done in such a way as to enable it. However, it would still fall to some suitable authority to make the coordinated network design and specify the sequencing.

The challenges involved in gaining consents for onshore network developments, whether as part of regular network reinforcement or the accommodation of offshore renewables, should not be under-estimated. We note that the Government and Ofgem seem keen pursue arrangements for ‘competitively awarded transmission owner’ licences for onshore transmission. Care needs to be taken that uncertainties associated with what form these arrangements might finally take or arising from the arrangements themselves do not hamper the process of gaining consents and the timely development of network capacity. (Delays to network developments would be likely to lead higher than necessary constraint costs, perhaps amounting to hundreds of millions of pounds per year, or delays to operation of new low carbon generation).

Q18. What changes would Government need to make for the Contract for Difference to facilitate deployment of offshore wind as part of a hybrid offshore wind interconnector project, and what would be the benefits and costs of making them?

The arrangements suggested in our answer to **Q17** ought also to be capable of taking account of interconnector developments planned to cross particular zones. Alternatively, given a published set of zonal offshore network plans or some actual network capacity under construction or in operation, an interconnector developer might propose a project that fits with those plans (perhaps proposing some practical modifications) or is adapted to make use of the network that is in place or being put in place, e.g. teeing into it at a specified location.

At present, licensing arrangements prevent specific network assets from serving dual purposes of being interconnectors and connections to shore for wind farms. It ought to be possible to adapt these licensing arrangements to allow interconnection assets to be designated only as those that make the final link between two markets.

Q19. What role could international renewable projects play in our future generation mix in GB? Are there benefits to supporting these projects with government schemes and how could this be achieved?

Provision of power generation should in general be incentivised from whichever sources are most cost-effective to the GB system. International renewable projects have some advantages over domestic ones in that they are likely to be geographically more dispersed, and may therefore be less correlated with UK weather patterns, allowing provision of power at times of greater system value. This will be counter-balanced to some extent with the greater costs of transmission.

In the long-term, establishing a market-based mechanism that is set up to place value on these differentiated characteristics might help weigh up these trade-offs. But where overall project economics makes sense from an overall system cost point of view, they should be considered, subject to assessment of wider environmental and social impacts of the projects.

The idea that a UK Government scheme or UK consumers might fund or under-write a renewable energy project in another country has been proposed before, e.g, in the Irish-Scottish Links on Energy Study. If the project is cheaper to British consumers and avoids consenting problems, it might seem worthwhile. However, it might also be inconsistent with the industrial policy objectives discussed in our answer to **Q14**.

> **Q22. Similarly, can cost savings be achieved by repowering older projects, if so, how great are these cost savings, and what is the justification for these projects being supported through CfDs or any other government mechanism?**

We believe that the principal risk to policy is that older projects are prematurely closed as a result of price cannibalisation. As noted under **Q2**, there is a risk under current policy design that existing plant will be forced off the system before their useful technical and economic lifetime has elapsed due to the erosion of prices to levels below their fixed operating costs. As discussed under **Q5**, we believe there is a case for changing CfDs to provide optional contract extensions which would allow recovery of fixed costs under these conditions.

If this is correct then it is unlikely that repowering would proceed on a merchant basis. For all of the reasons set out in earlier answers much more fundamental issues are at stake, because of the propensity for short run marginal cost pricing to undermine the fundamental economics of renewables projects. It is possible that if effective resolutions to the fundamental problems are found then life extension and repowering will not need CfD or another government support mechanism. In the interim, for all of the reasons set out above, it is likely that they will. The cost base is lower, so the arguments we set out in **Q5** comparing on and offshore wind all apply to this question as well.