Department of Energy & Climate Change

United Kingdom Response to Commission Consultation

Energy Market Design

October 2015

General

The UK Government welcomes the opportunity to contribute to the Commission consultation on a new energy market design. We share the Commission's view that modernisation of electricity markets across the EU is necessary to facilitate the delivery of our ambitious decarbonisation objectives in the most efficient and cost effective way. We agree that this requires a flexible EU electricity market in which all market players, both on the supply and demand side, can play an active part.

In the UK we have already been through the process of modernising our electricity market with the design and successful launch of our Electricity Market Reform (EMR). We believe EMR is the best suited vehicle to facilitate the UK's transition to a low-carbon economy whist securing energy supplies at least cost to consumers. Our flagship renewables support scheme, the Contract for Difference (CfD), is designed to work with the market by exposing generation to competition while minimising overcompensation. We are also amongst the first EU Member States to explore cooperation mechanisms including cross border opening of our renewables support scheme.

Our Capacity Market has been carefully designed to support and complement developments in the internal energy market and to be consistent with it and wider EU energy policies, for example the development of an active demand response, improved scarcity pricing, support for further interconnection and increased competition. We are also the first EU Member State to allow interconnection to participate in the Capacity Market, by allowing interconnectors to bid directly in the capacity auctions from 2015 and hold capacity obligations in a way similar to other capacity providers.

The design and implementation of EMR has given us a unique perspective on the challenges of energy market design and valuable experience which we stand ready to share with the Commission and other Member States. We are also committed to working with our EU partners to identify where possible common approaches to common challenges.

However, it must be acknowledged that the reform of EU electricity markets is a complex process that needs to ensure that the diversity and specific requirements of EU Member States' markets are carefully considered and accommodated. One-size will not fit all. Therefore we urge the Commission to discuss thoroughly with Member States, regulators and all relevant stakeholders before issuing any proposals.

The UK Government's responses to the questions in the consultation are set out below.

1) Would prices which reflect actual scarcity (in terms of time and location) be an important ingredient to the future market design? Would this also include the need for prices to reflect scarcity of available transmission capacity?

Yes, the UK government agrees that prices that reflect scarcity are a core feature of efficient markets and will be an important part of the future market design. Furthermore, we agree with the Commission that 'the introduction of a capacity mechanism should not jeopardise the benefits of efficient market functioning […]. This is why it is important that the mechanism does not interfere with the operation of market rules' (Commission Staff Working Document on Generation Adequacy, Section 6.4, page 29). The GB Capacity Market is not intended to replace and will not distort the functioning of the GB electricity market. Indeed, the Capacity Market has been designed to complement the market signals that already exist aimed at ensuring capacity adequacy in a market that allows for efficient dispatch decisions.

The Capacity Market was introduced in GB in conjunction with other measures that strengthen the underlying price signals in the energy-only market:

- Day-ahead market coupling has been introduced and will lead to more efficient use of interconnectors which we believe will enable a greater reliance on interconnectors for security of supply. We also believe that the completion of the coupling of intraday and balancing markets will ensure the efficient use of the resources available to the system at times of need and should be implemented as soon as possible.
- Imbalance or cash-out prices provide market participants with incentives to ensure that the volumes of electricity they sell or consume match the volumes they have contracted to sell or consume. Ofgem has reformed the way the current market operates so that prices rise closer to the true value of preventing blackouts and support a responsive demand side. They have done this by a) making cash-out prices more 'marginal', b) including a cost for non-costed actions (e.g. voltage reduction) into the cash-out price calculations based on an administrative value of lost load to consumers (up to £6,000/MWh), c) reforming the way reserve is incorporated in cash-out prices and d) moving to a single cash-out price. The first tranche of these reforms comes into effect in late 2015.
- The energy regulator, Ofgem, has reformed the transmission charging regime in GB under Project TransmiT[1] which relates to generator Transmission Network Use of System (TNUoS) charges. These charges recover the costs of building and maintaining the network. The new regime will implement a more cost reflective approach ensuring more efficient use of the network, thereby keeping down costs for all GB consumers. The new charging regime will come into effect in April 2016. More locational charging was also identified by the UK Competition and Markets Authority (CMA) in its report of 7 July[2], as something which could deliver real benefits to consumers.

The core principle underlying the GB Capacity Market is that a resource (Demand Side Response (DSR) or generation, etc.) ought to arrange its commercial affairs in terms of sales, dispatch,

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[1] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit

[2] https://www.gov.uk/government/news/cma-sets-out-case-for-energy-market-reform

maintenance etc. in exactly the same way as it would in the energy-only market, so there should be no distortion of the normal commerce that would otherwise prevail. The difference the Capacity Market makes is largely in terms of ensuring investor confidence that allows long-term investment decisions to be taken.

In GB, the reformed cash-out arrangements and transmission charging regime aim to send efficient price signals in the energy market. In this way, the Capacity Market and the energy-only market must be considered as a systemic whole – not two separate markets. This is a fundamental design principle which has guided the design of the GB Capacity Market.

However, we also recognise that prices within the GB electricity system are not fully reflective of scarcity or other costs associated with the generation, transmission and consumption of electricity. Prices which more accurately reflect the true cost of electricity can incentivise greater levels of flexibility, in particular DSR and storage, to come onto the system – by creating an incentive to demand or release electricity at times that are beneficial for the system. In turn, greater levels of flexibility can enable a number of benefits: savings from the more efficient use of renewables, lower levels of network reinforcement and less peaking plant. Prices which are more reflective of scarcity can also support more effective network management through signalling to distributed generation when it is optimal to export onto the network.

As such, the UK is considering how to support the development of clearer price signals that reach the end customer. For example, half hourly settlement for domestic and SME customers is an important enabler on the demand side and is something that Ofgem is pursuing. Ofgem has already carried out initial thinking on this issue with an industry expert group, and will work closely with Government in the coming months to develop an implementation plan, taking into account other significant changes such as the smart meter roll-out. However, as noted in response to question 2 below, price signals are not the only thing that incentivises customers – greater levels of understanding regarding the non-price factors that influence customers' decision making within the electricity market would help to create stronger incentives.

It is the UK position that efficient price signals are crucial, but it is up to Member States to decide the best way to achieve this at national level.

2) Which challenges and opportunities could arise from prices which reflect actual scarcity? How can the challenges be addressed? Could these prices make capacity mechanisms redundant?

In theory, the electricity market should provide incentives for investment in sufficient reliable capacity. However, the GB electricity market – like many others – faces market failures, exacerbated by new pressures such as the increase in intermittent forms of energy, which mean there is a significant risk that this will not be the case. During the development of the GB Capacity Market, the Government identified a number of market failures in relation to generation adequacy, that scarcity pricing alone may not fully be able to address:

- The first market failure is that reliability is a public good. Customers cannot choose their desired level of reliability, since the System Operator cannot selectively disconnect them, and consumers do not respond to real-time changes in the wholesale price. It can therefore be expected that capacity providers will not provide the socially optimal level of reliability in the absence of intervention. This may also lead to high costs to society as a result of having an unreliable electricity supply. Scarcity pricing if passed through to end consumers could also send difficult social and political messages to customers in regions where there are high levels of fuel poverty or where industrial and commercial companies may already face competitive disadvantage.

- The second market failure is the 'missing money' problem. In theory the inability of consumers to select their desired level of reliability could be addressed in an energy-only market by allowing prices to rise to a level reflecting the average value of lost load (i.e. the price at which consumers would no longer be willing to pay for energy) and allowing generators to receive scarcity rents. However:
    - Current wholesale energy prices do not rise high enough to reflect the value of additional capacity at times of scarcity due to the fact that charges to generators who are out of balance in the balancing mechanism (cash-out) do not reflect the full cost of the balancing actions taken by the System Operator (such as voltage reduction).
    - Furthermore there is a lack of certainty that prices will peak to high levels, even if they can. Investors are concerned that the Government regulator will act on a perceived abuse of market power, for example through the introduction of a price cap. They are also concerned that prices simply will not rise – for example, if wind capacity performs better than expected, reducing the opportunities for more expensive dispatchable capacity to run.

- The third market failure is that the electricity market has significant barriers to entry, effectively restricting the number of participants in the wholesale electricity market. The regulatory risk, lack of forward liquidity, and the challenges of 'missing money' mean that there are real barriers for new market entrants to overcome if they are to invest – particularly if they need to secure project or debt finance.

That said, the UK Government believes that there is real value in ensuring that scarcity pricing is strengthened so that more decisions are based on prices in the energy market. Should Ofgem's cash-out reforms work well to address market failures, sharper cash-out prices have the potential to reduce the cost of procuring capacity through the Capacity Market, so that the price paid for capacity could fall to zero in the auction.

However, we still believe that the Capacity Market and cash-out reform have distinct but complementary roles in seeking to ensure security of electricity supply in the short-medium term. We decided that it was better to introduce the Capacity Market as well as supporting reform of the cash-out arrangements, rather than simply to rely on the cash-out reform for the following reasons:

- While cash-out reform should strengthen energy market investment incentives in the long term, it is expected to have a more limited impact on overall levels of investment in the short and medium term. This is because generators sell almost all their energy in forward markets. However, over time the cash-out reform will lead prices in forward markets to rise as generators exploit arbitrage opportunities between forward markets and the price in the balancing mechanism;

- Cash-out reform cannot address the increased riskiness of investment in thermal capacity as the power sector decarbonises: thermal capacity will increasingly run as backup and will have to recover its fixed costs through earning high prices on the few occasions where there is scarcity and prices spike;

- In practice, the potential for scarcity rents is only likely to induce investments if a liquid market develops for 'reliability options' trading around a real-time price – whereby suppliers pay generators a fixed price in exchange for an option to buy energy at a strike price. This is unlikely to emerge under Ofgem's reformed cash-out arrangements but could develop if a balancing electricity market is introduced that can act as a robust reference market for options trading.

- Even though cash-out reform is due to be implemented within the expected timeline, it is unclear what level of confidence investors will have in the new arrangements. This is because when prices are allowed to peak to high levels, it becomes increasingly difficult for the regulator or Government to understand whether very high prices are efficient market operation or profiteering. This means that generators may continue to be averse to offering energy at a high price (for fear of investigation for market abuse), or that they may expect the Government to intervene and cap wholesale prices if price spikes became more frequent in the future. Besides this, given that more marginal cash-out prices are likely to also be more volatile and given the general risk aversion of market participants, it would be reasonable to assume that a more conservative (discounted) view of the revenues would get factored into investment decisions.

Ofgem is considering these issues through the "Future Wholesale Markets" project, the purpose of which is to evaluate what a wide cross-section of market participants anticipate and what their outlook on the electricity wholesale market is. It will explore how the interaction between energy, capacity and balancing markets will affect stakeholders and their future investment decisions. The introduction of fundamental regulatory and government policy reforms (eg EMR, Electricity Balancing Significant Code Review[3], Secure and Promote[4]) and the release of the CMA's provisional findings mean that now is the right time to evaluate the GB electricity wholesale market holistically. The project has been gathering evidence through bilateral meetings with industry parties to evaluate views on the outlook for electricity wholesale markets in the 3-5 year timeframe. This intelligence will form an input into Ofgem's thinking on the regulatory policy agenda for electricity wholesale markets, alongside other inputs such as the CMA findings, future government policy, Wholesale Market Indicators (WMI) and continuing integration with the internal energy market.

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[3] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review Led by Ofgem this review was launched to address concerns on electricity balancing arrangements and in particular concerns that cash-out prices were not creating the correct signals for the market to balance.

[4] https://www.ofgem.gov.uk/electricity/wholesale-market/liquidity Secure and promote aims to boost liquidity and access to the market and ensure that the market provides the products and price signals needed for effective competition.

A move to more marginal cash-out prices is likely to increase volatility and make it more complex for players to risk manage their exposures. During the transition phase, this is likely to cause an increase in costs but over time could lead to the market for such hedging products becoming more liquid, particularly at the balancing end of the market.

Prices that reflect scarcity by location could lead to prices at different physical locations diverging. In an extreme scenario it can lead to a kind of market splitting with persistently different prices on either side of transmission constraints. This has potential to reduce the liquidity in the forwards markets as the volumes get split with the markets. As we move to such a paradigm, the increase in basis risk initially could be material and not entirely rational, as the market learns to price it accurately.

However, prices which reflect actual scarcity in terms of location can lead to more optimal investments in transmission capacity reinforcement and better match new generation capacity with centres of consumption. They can also improve the business case for time-of-use tariffs.

Also, as noted in answer to question 1, prices which more accurately reflect the true cost of electricity can incentivise greater levels of flexibility (such as DSR and storage) to come onto the electricity system. Trials conducted in the UK with domestic customers (who do not have smart appliances) have found that customers are responsive to price signals in the form of time-of-use tariffs. For example, one trial[5] found that customers shifted on average 96W (or 7.8% of demand) out of the peak period in response to a static time-of-use tariff. And a literature review on international trials found that response levels can increase by 60-200% with automation[6] - supporting the push towards interoperable smart appliances. It is unclear how representative these trials would be in normal system operation, but we are encouraged by these results.

However, there are a number of challenges associated with supporting flexibility services through clearer price signals. For example, suppliers may decide not to pass on price signals to customers; and the level of price variation may not be sufficient to shift customers' behaviours.

As such, in addition to changes such as half-hourly settlement for domestic and SME customers, additional changes may need to be considered to support more cost-reflective pricing for end customers. For example, time-of-use network charging, that could also vary by location, would produce a more material price differential as well as help to manage risks where wholesale prices are low, but the network is constrained. There would be real challenges in designing and implementing a time-of-use network charging regime, if desired, as regulated monopolies need to re-coup a set amount of costs, which would be harder to predict in a dynamic world. However, it may be possible to overcome such challenges through effective design of charging regimes and associated regulations, achieved through wide consultation and effective modelling. It should be stressed that the Third Energy Package makes network charging a duty of the independent regulatory authority which is Ofgem in GB.

We also know that price is not the only driver of customers' behaviour, and that consumers, especially domestic customers, are 'sticky' i.e. the majority do not change electricity supplier, even if economically beneficial. The UK Government has made it quicker and easier to switch energy

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[5] Customer-led Network Revolution (2015) "High Level Summary of Learning Domestic Smart Meter Customers on Time of Use Tariffs" – one of the Low Carbon Network Fund trials.

[6] Frontier Economics / Sustainability First (2012) Demand response in the domestic sector – a literature review of major trials

supplier, working with the industry to halve the time it takes to switch and Ofgem is now leading work to move to next day switching within five years. The UK Government has also supported switching through its successful ‘Power to Switch’ campaign. However, with respect to encouraging customers to change the time at which they consume/export/store electricity, we will need to be conscious of the non-price factors that may have a more significant impact on their behaviour than the price factors.

3) Progress in aligning the fragmented balancing markets remains slow; should the EU try to accelerate the process, if need be through legal measures?

Legal measures are being put in place to align balancing markets in the form of the Balancing Code in electricity.

The Balancing Code does raise some complex issues that Member States and the Commission will need to work through carefully. It will be important to ensure that attempts to align balancing markets do not prevent further innovation or make it more difficult for balancing markets to respond to market changes or smart energy changes.

Proposing new or amending existing legislation places significant resource pressures on smaller regions or jurisdictions and could signal regulatory instability to market participants. Proposing further legal changes beyond the agreement of the Balancing Code would not be helpful at this point.

4) What can be done to provide for the smooth implementation of the agreed EU wide intraday platform?

The considerable delay in the development of the intraday platform is of significant concern to the UK. Coupled markets allowing cross-border intraday trading are important in bringing EU power markets together. The importance and size of the intraday market is expected to grow as intermittent generation and other innovative forms of generation and demand increase.

The day-ahead market has been coupled for GB since January 2014 but intraday market coupling is unlikely until 2017 because of delays in developing the platform. In addition, the current specification to which the platform is being developed does not meet the needs of the GB market or the requirement of the code for Capacity Allocation and Congestion Management (CACM) as it will not be able to handle losses or price intraday capacity. Both of these things are important for GB merchant interconnectors.

This creates a significant risk for GB: in the short term the delay in intraday market coupling is placing pressure on our power market; and in the medium term GB will miss out on the benefits that a more timely development of the intra-day market would have brought.

The EU should speed up this process while at the same time delivering a robust solution.

5) Are long-term contracts between generators and consumers required to provide investment certainty for new generation capacity? What barriers, if any, prevent such long-term hedging products from emerging? Is there any role for the public sector in enabling markets for long term contracts?

Even in a stable, liquid market with good visibility of future demand and capacity, long-term contracts between market participants are necessary for investment to come forward. The only exception is for large, vertically integrated energy companies which are able to manage the risks internally.

The UK requires significant investment in new generation by 2030 to address rapid closure of existing capacity. However, as mentioned above, experience in the UK has shown that significant investment does not tend to come forward without long term contracts, and Power Purchase Agreements (PPA)s/ tolling agreements where they exist are not currently sufficient for attracting finance. Long-term contracts help provide investment certainty for new generation capacity – investors generally require assurance that capital and operating costs will be covered by expected revenues, resulting in reliable repayment of debt and the delivery of reasonable returns to equity.

Renewable generation investors generally require assurance of subsidy to top-up market revenues and finance their projects. This can be achieved by a fixed feed-in tariff (essentially a long-term contract with consumers), a premium payment (often converted to a stable revenue stream through an offtake contract) or a variable premium (a long-term contract for difference with consumers). We believe the introduction of the CfD in the UK provides sufficient incentives for investment in renewable energy to come forward at a lower cost of capital and therefore at a lower cost to consumers. By providing support through a variable premium, the CfD gives investors price security throughout the duration of the contract, reducing their cost of capital, whilst protecting consumers from excessive support if wholesale prices rise. Costs are minimised further through competition, which has seen a significant reduction in the level of support provided to generators.

Under the CfD, generators are required to sell their output on the market, and are responsible for any imbalance costs. It is often the case that (particularly smaller) generators will need to lock in a contract with a supplier/offtaker for their power before they are able to secure project finance, with a limited number of offtakers considered 'bankable' for these purposes. In order to widen the pool of offtakers available, we introduced the Offtaker of Last Resort (OLR), which guarantees generators a buyer for their output at a fixed and significant discount to the market price. Though the OLR will be unattractive to the vast majority of generators, its presence assures lenders over the worst-case scenario for the project, and supports the ability for generators to secure project finance.

Conventional generation investors also need assurance of expected revenues through tolling contracts, PPAs or separate fuel supply and offtake contracts. It is challenging to secure sufficiently long-term contracts in the market, which would be the ideal scenario.

We believe that the introduction of the Capacity Market in GB was essential to provide incentives for sufficient investment in capacity to meet the enduring reliability standard. It was designed to ensure as wide participation as possible from a range of investors to increase competition. It will also provide strong incentives for continued investment in maintenance and staffing of existing generation because the penalty regime and potential over-delivery payments provide strong incentives for delivery of energy at times of system stress.

Traditionally, as well as gas fired projects being brought forward by the independent sector, the large integrated utilities have provided much of the investment needed to ensure security of supply, funding projects from their balance sheets. However, thermal generation had not come forward before the intention was announced to introduce a Capacity Market[7], demonstrating the 'missing money' problem outlined in the response to Question 2. The key factors behind the lack of investment in the UK can be summarised as follows:

- Increasing renewable generation is causing more uncertainty for thermal generators, as they are facing lower and far less predictable load factors - and less predictable revenue over the long term
- Clean spark spreads have remained low for several years and the scarcity rents which should in theory arise are not being seen at a level which would enable investment (plus, even if that were the case, the increased risk and uncertainty would add a risk premium to investment)
- Whilst price signals might improve over time (the arguments for cash out reform) there is high uncertainty over this, as the resulting lack of investment is due not only to current low prices but also to the uncertainty in the future
- Our response has been to introduce the Capacity Market to give a four year look ahead of revenue – but even within that, it has been necessary to give longer term certainty for new generation capacity to provide a platform for enabling investment
- GB is partly reliant on independent generators for new capacity and to provide competition:
  - They will generally require project financing and lenders are still clear they will not take merchant risk and so will only finance to the extent debt service is backed by longer term certainty.
  - Even for equity funded projects or utilities (who will have a hedge via their retail positions), investors will be reluctant to commit major investment where the market fundamentals remain poor unless they have longer term revenue certainty.

Approximately 50% of the current pipeline of consented generation in GB (i.e. prospective generation projects that have received the planning permission required to begin construction) is from independent generators. The participation of independent generators in the Capacity Market is important not just to increase competition in the Capacity Market itself, but also to increase competition in the electricity market, so the Government has sought to ensure the Capacity Market enables independent generators to proceed with project-financed projects. That said, incumbent utilities would also require a robust and reliable investment climate in order to make a large long-term investment.

Project finance lenders are not taking sufficient market risk under current UK energy market conditions to lend against these projects. Energy market revenues may increase as capacity margins tighten, but even so, we expect some barriers to remain in relation to the market bringing forward products to support long-term investment in major energy projects. In addition to the points made about market failures outlined in the response to Question 2, it is also the case that new efficient CCGTs cannot expect to operate baseload since they will have higher running costs than the increasing volume of low carbon capacity being brought onto the system. In these conditions, project finance lenders will only lend where debt service can be met by revenues which are

[7] While some 5GW of new CCGT plant was commissioned in the period from 2009 to 2013, this resulted from earlier investment decisions and, barring Carrington CCGT (880MW) due to be commissioned in 2016, no further investment decisions have been taken.

secured under either a capacity agreement alone or mixture of a capacity agreement and other long term power purchase agreement, so that repayment of debt is not exposed to the uncertainty of the energy market. Similarly, a project can only be bankable if liabilities (including potential Capacity Market penalties) can be clearly managed.

In creating an investment climate, it is crucial to ensure that the measure taken is bankable – either through private law contracts (e.g the UK's Contracts for Difference) or, with a regulated intervention, by creating certainty (there is no point in simply having a longer term contract if it is not backed up in other key risk aspects). So for the GB Capacity Market, the Government needed to ensure that the overall risk profile of the reward and liabilities was sufficiently stable to attract investment. The Capacity Market design balances the need for proper incentives and redress in case of failure to perform with the need for it to be a bankable mechanism to enable projects to attract finance. Key aspects of the Capacity Market design aimed at bringing forward new investments are:

- Longer-term capacity agreements for new build. New capacity providers will be able to access longer-term capacity agreements of up to 15 years, which guarantees part of their future revenue stream.
- A penalty regime which incentivises reliable capacity but which is 'bankable' for new investments, particularly from independent generators. The penalty regime (along with the pre-qualification process and testing regime) is designed to ensure that only reliable plants are awarded capacity agreements, but a monthly penalty cap ensures that a plant is not exposed to the uninsurable risk of a single major loss of revenue which could bankrupt new projects.
- Robust governance and change control provisions: although the Capacity Market is not designed as a private law investment contract, it is nevertheless important for all participants, and particularly for new capacity providers, that there is a transparent governance process. Future changes in the Capacity Market Rules must address a set of pre-determined objectives, and can only be made after consultation with industry.
- In addition, the main terms of individual capacity agreements will be grandfathered in respect of future rule change. This ensures that the Capacity Market design can be changed or exited from if needed, but provides assurance to investors that the main commercial terms of their agreements will be honoured.
- Supporting the development of DSR: through transitional arrangements and the year ahead auction, which will allow DSR to compete against conventional generating capacity and so increase competition in both the energy and capacity markets.

The GB experience has proven this Capacity Market design to be effective. It is considered by the market to be bankable for project finance. It brought forward 9.2GW of new plant bidding into auction and also brought forward 2.6GW of new investment including smaller new build which also needs a longer term investment certainty.

However, there are also issues and risks associated with long term agreements to be considered and these agreements potentially risk locking in consumers at a higher price over a longer term if future capacity prices fall (e.g. a cheaper technology or improved energy market rents). This is why competition must feature as a core design principle.

In summary, the Government believes that, certainly for the short-medium term, long-term agreements in the GB Capacity Market will provide the best value for money for consumers by ensuring generation adequacy to the Reliability Standard and by reducing the barriers to entry for independents, thereby encouraging competition in the Capacity Market auction and the GB wholesale electricity market.

In the long-term, it is possible that PPAs and tolling agreements may be sufficient for attracting finance but for the moment, they are not readily available due to poor market fundamentals. They are still required under a capacity market type mechanism but it is possible for new investment to come forward based on shorter PPA tenors provided the project is also backed by the Capacity Market. Where an investment is supported via an arrangement based on output, it is important to ensure liquidity for any offtake. OLR ensures that new investment can proceed with the certainty of back-up offtake arrangements, albeit that developers face a higher basis risk in terms of his strike price.

To the extent that the market is unable or unwilling to offer long-term contracts, government-supported contracts play a crucial role in enabling investments and helping technologies and markets mature, while ensuring the de-carbonisation targets and security of supply objectives are met. In an ideal scenario, however, we consider it would be optimal for markets to develop and government-supported contracts to reduce in importance. This would require integration of renewables across the interconnected markets, robust pricing for carbon and long-term support regimes that do not interfere with price formation.

6) To what extent do you think that the divergence of taxes and charges levied on electricity in different Member States creates distortions in terms of directing investments efficiently or hamper the free flow of energy?

Certain taxes and levies (and exemptions from levies) can have quite a substantial effect on investments or the free flow of electricity across borders, especially as we move to a coupled market with substantial interconnection capacity between Member States.

The particular effects depend on the nature of the charges. For example:

- **Taxes or levies on generation.** Where taxes or charges are imposed on the output of electricity generators, these may feed through into the wholesale electricity price (particularly if they affect the short run marginal cost of generation for price setting plant). This can have a distorting effect on cross-border electricity flows, potentially leading to electricity flowing in a way that does not reflect market fundamentals. For example, the extent to which transmission charges borne by generators or the level of renewables tariffs borne by customers differs between countries, will uplift wholesale prices to a different extent. In increasingly coupled markets, this could distort the price differential between markets and the economics of flows across interconnectors.

- **Taxes or levies on supply**. These do not in principle have a direct distorting effect on cross-border electricity flows or investment, because they do not affect the wholesale price of electricity and therefore the price that a generator gets for selling its electricity in different countries. However, when granting state aid approval for renewable support schemes, the Commission has required that where a levy is imposed on electricity supply in a country to fund the support scheme available to certain generators in that country, imports of renewable electricity must be exempted from contributing to the cost of the support scheme. This exemption <u>does</u> lead to distortions to cross-border flows, because it increases the price that foreign renewable generators can get for their electricity in another Member State compared with the price that domestic generators in that Member State can get, and the price the generator would get in the Member State in which the electricity is generated. This incentivises cross-border flows of renewable electricity in a way that does not reflect market fundamentals, distorting competition and increasing costs for consumers without any benefit.

For example, the mandated renewable import exemption for the small-scale feed-in tariff scheme in the UK has led to a big increase in imports of renewable electricity (from 177 to 19,000 GWh between 2011 and 2015), an increase in costs for smaller electricity suppliers of around 10%, higher prices to UK consumers, and windfall profits for foreign renewable generators. This effect is likely to increase as payments to CfD generators start being made over the next few years, and when the exemption is extended to imports of nuclear electricity in the 2020s (as required in the State aid approval for Hinkley Point C). This distortion could be easily eliminated by removing the requirement under State Aid rules to exempt imports from domestic levies.

- **Taxes or levies on consumption.** As with levies on electricity supply, levies on consumption of electricity do not have a distorting effect on cross-border electricity flows, unless there are exemptions for electricity supplied from other countries. An example of such a charge is the UK's Climate Change Levy (CCL), payable by businesses customers. This does not affect cross-border electricity flows, as it is payable on all electricity consumed by business customers, regardless of its source.

7) What needs to be done to allow investment in renewables to be increasingly driven by market signals?

Investment in renewables is already driven to some extent by market signals, but due to the market not placing a sufficient value on renewable resources or avoided emissions, these have needed supplementing across the EU through subsidy. Technology advances and the development of supply chains and contracting strategies have generally driven costs down. The major renewable electricity generation technologies are approaching grid parity at different rates and from different starting positions. Market signals can helpfully be broken down into long-term wholesale price (investment signal), real-time wholesale price (dispatch signal) and any locational prices (location signal). Their impacts on renewables are as follows.

- Locational network charges provide a disincentive to locating renewables far from demand, but this effect can be outweighed by greater renewable resources in remote areas.
- Investment signals tend to be insufficient, not only in magnitude but also through lack of contracting options to match financing terms such as forward (10-15 year) fixed-price offtake contracts.
- Dispatch signals have limited effect on renewable electricity generation that has zero marginal costs of operation, other than the signal to stop generating when the wholesale price drops well below zero.

The UK has a clear preference for incentivising investment in low-carbon electricity generation, including but not limited to renewables, by means of private finance through revenue support based on metered output covering the expected financing period of the plant. We consider that the advantages in economic and financial terms over capital grants or capacity-based payments are compelling, ensuring that the costs are paid for at the time when benefits are accrued. Based on these considerations, renewables developers are periodically invited to bid competitively for a CfD (a 15-year private law contract to pay the difference between the strike price and a market reference price for all metered output produced by the generator). The available budget is assigned to three pots (established technologies, emerging technologies and biomass conversions) across various delivery years and reserve (maximum) prices are established for each technology. The first allocation round held in 2014/15 was successful in delivering savings relative to the reference prices of 12-14%. The biomass conversion pot was not used and it is intended that all the pots will ultimately be merged in order to deliver least-cost, technology-neutral allocation. The challenge in moving to technology-neutrality is that technologies with potential for long-term deployment and cost-reduction such as offshore wind can be crowded-out. The UK strategy aims to deliver the optimum long-term deployment.

The current energy market investigation by the CMA has provisionally concluded that, compared to the previous green certificate renewables support scheme, the properties of CfDs will encourage investors to accept a lower level of support and that through the competitive allocation process, CFDs should provide a more efficient means of providing support.

The CfD scheme has been designed to be as efficient and market-based as possible, thus in line with the Commission's state aid Guidelines, CfDs issued after 2016 will no longer make payments at all during periods of negative pricing that exceed six hours. Possible future reforms to the CfD would be to move towards year-ahead market reference prices for all technologies and to create a flexible CfD for fuelled renewable technologies, in each case to improve dispatch and maintenance planning incentives.

As renewable electricity generation technology costs fall, we anticipate that strike price bids in CfD allocation rounds will progressively approach the level of expected forward wholesale prices, but that the value of the resulting CfDs would be in revenue stabilisation and project financing. Further into the future it is anticipated that renewables should be able to be built on a fully merchant basis.

8) Which obstacles, if any, would you see to fully integrating renewable energy generators into the market, including into the balancing and intraday markets, as well as regarding dispatch based on the merit order?

We do not see significant obstacles to fully integrating renewable energy generators into the market. In the UK, renewables (apart from installations smaller than 5MW that are supported through the small-scale feed-in tariff scheme) already face full balancing responsibilities. Because most renewables (with the exception of biomass) are not dispatchable, generators typically enter into power purchase agreements with offtakers who pay the generator a discount to the market price for their power, and who enter bids into the intraday and balancing markets on the generator's behalf. These arrangements incentivise generators and / or offtakers to forecast generation output as accurately as possible, thereby minimising overall costs to consumers. Ofgem's Balancing Significant Code Review will sharpen cash-out prices, thus increasing the incentive of generators to forecast accurately.

We do not see fundamental issues with dispatch based on the merit order. However, the way that subsidy or support payments are paid can affect dispatch decisions as payments based on output can distort the merit order (for example, at times of negative prices, or for fuelled stations such as biomass generators). To a certain extent this may be desirable, since strict merit order-based dispatch could mean that baseload renewable generators such as biomass (which typically have high short-run marginal costs) would very rarely operate, requiring much higher levels of intermittent renewables to meet renewable and decarbonisation targets, which may come at higher overall cost to consumers. Higher carbon prices or alternative ways of making support payments (such as paying on availability) could lead to more optimal merit order-based dispatch.

Please also see our response to question 4 regarding intraday market coupling.

9) Should there be a more coordinated approach across Member States for renewables support schemes? What are the main barriers to regional support schemes and how could these barriers be removed (e.g. through legislation)?

In principle, more coordination across Member States on how they design their support schemes can be beneficial by enabling transparency and comparison between Member States while discouraging overcompensation. However, in practice there are significant differences between Member States (e.g. level of interconnection, renewable potential, political priorities, existing renewable capacity and existing obligations for supporting renewables) that justify Member States setting up different schemes that work best with their market. Also, the impact of renewable support policy on consumer bills is a highly sensitive policy area and therefore one that will be difficult to agree on at regional or EU level.

We are in favour of cooperation mechanisms and of opening our schemes to foreign generation in principle. The UK was amongst the first EU Member States to explore cooperation mechanisms including opening its renewables support scheme to cross-border participation and published a position paper on the subject in August 2014.[8] However, these are novel, complex projects, and require technical and regulatory solutions specific to each Member State. Therefore our view is that implementation of cooperation mechanisms should be left to the discretion of Member States.

We consider the updated state aid Guidelines for environmental protection and energy along with the Commission's 2013 Guidance for the design of renewable support schemes already provide a framework that will facilitate a more coordinated approach for renewable support schemes.

10) Where do you see the main obstacles that should be tackled to kick-start demand-response (e.g. insufficient flexible prices, (regulatory) barriers for aggregators / customers, lack of access to smart home technologies, no obligation to offer the possibility for end customers to participate in the balancing market through a demand response scheme, etc.)?

We support the work the Commission is undertaking in the framework of Ecodesign to consider standards for smart appliances, which will be a key means to unlock the significant potential for

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[8] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/340932/DECC_Non-UK_CfD_August_2014.pdf

demand-response in the domestic sector. We consider that the following design elements will be key if the Ecodesign work is to deliver outputs that maximise the potential for DSR in this sector:

- An approach of open interfaces based on open standards (rather than a single prescriptive standard) will create benefits for different market players including consumers, suppliers and aggregators.
- The work should aim to deliver a set of principles that ensure open interfaces based on open standards are realised across the EU, allowing industry to innovate and develop the optimal technology solutions once the overall outcome being sought is clear.
- Appropriate security provisions for smart appliances will be key to ensuring that they do not present a risk to the energy system as a whole, for example by increasing their vulnerability to cyber-attack.

In addition, while the current preparatory study is limited in scope, we consider there are other relevant areas that should be considered as part of the smart appliance agenda given their contribution to domestic load – in particular heating, ventilation and air-conditioning controls, heat pumps and hot water controls.

At a whole system level, the UK Government recognises the potential value of DSR[9] and energy storage in helping to make our energy system more flexible and resilient, and thinks that both forms of flexibility should be considered in tandem as part of the European electricity market design work. As such, we support both DSR and storage through the Capacity Market and innovation funding. More than £80m public sector controlled support has been committed to energy storage research, development and demonstration activities in the UK since 2012. Additionally, National Grid (GB's system operator) has set an ambition for 30-50% of balancing capability to be available from DSR by 2020, as part of its programme of work to increase participation of industrial and commercial sites in the balancing market.

We are also conducting research into the existing and potential volumes of DSR; in addition to investigating the potential barriers to deployment of energy storage and DSR – and possible mitigating actions. This work is in the early stages and will require further development, but initial findings suggest that there could be a number of obstacles affecting the ability of DSR and storage to compete on a level playing field with traditional players in the GB electricity market.

First, there is limited flexible pricing in the GB electricity system. The majority of consumers have no incentive to alter when/how they consume electricity as they do not face the real-time cost of electricity in their bills. This lack of cost-reflectivity also means that product manufacturers have a weaker business case for developing smart appliances as there is no cost saving available to the consumer. As per questions 1 and 2, we are therefore considering how to support the development of clearer price signals that reach the end customer. For example, half hourly settlement for domestic and SME customers is an important enabler on the demand side. Ofgem, has already carried out initial thinking on this issue with an industry expert group. It will work closely with Government in the coming months to develop an implementation plan, taking into account other significant changes such as the smart meter roll-out. Once more segments are able

[9] It is important that work at European level recognises that the term DSR encompasses a range of technologies and solutions. In particular, there is the difference between generation-led and demand-led DSR; and also in the forms of DSR that can be offered by different sectors – industry, domestic and small & medium sized businesses (SMEs).

to be half-hourly settled, we also recognise the need to raise awareness among consumers of the financial opportunities available with DSR. However, as noted in response to question 2, price signals are not the only thing that incentivises customers[10] - greater levels of understanding regarding the non-price factors that influence customers' decision making within the electricity market would help to create stronger incentives (i.e. overcoming the barriers to consumers changing their behaviour, such as concerns around loss of 'control').

A lack of domestic customer engagement in switching tariffs is also likely to act as a barrier to DSR and storage. However, the roll-out of smart meters for domestic and smaller non-domestic customers across GB by 2020, which can record when energy is consumed, combined with stronger incentives to shift consumption (e.g. time of use tariffs), increasing availability of smart appliances (supported through Ecodesign consideration of smart appliances as discussed above), and the move to one-day switching, is expected to go at least some way to overcoming the lack of customer engagement, by providing consumers with both the incentive structures and the ability to participate more actively in the market.

Technology risk is another obstacle: As new technologies, smart solutions face the risks and costs (mainly capital expenditure for storage, and operating expenditure for DSR[11]) associated with being a first mover, reducing competitiveness and increasing investor uncertainty. This is why we are investing innovation funding into the development of smart solutions; and National Grid have developed a programme to increase awareness and understanding of DSR opportunities within the industrial and commercial sectors. A strong focus on supporting the development and commercialisation of flexible solutions through EU innovation funding would help to overcome this obstacle.

Initial analysis suggests that other barriers affecting DSR and storage could include:

- A lack of market value for the full benefits of flexibility and distribution of this value – some of the benefits offered by DSR or storage are not currently monetised (e.g. inertia); and the (potential) benefits offered by a particular DSR action or storage device may be distributed throughout the energy system (e.g. to networks who could defer or avoid upgrading an asset, to renewables developers who could reduce their connection costs, to the system operator who may benefit from smoother demand/supply curves).
- Existing policy and regulation that is designed around a traditional / conventional electricity system, which technologies like DSR and storage do not fit neatly into – although policies such as the capacity market have been specifically designed in such a way as to ensure that DSR can participate whilst offering an equal level of reliability as generation.
- Information asymmetry for potential providers of DSR and storage about where it is most needed, and what is potentially achievable from their customer base and what is potentially achievable from their customer base.

[10] For example, survey data suggesting that just under half (44%) of all households had ever switched their energy suppler with just over a quarter (25%) doing so within the last three years indicates that despite the potential for significant monetary savings, price is not the only driver that needs to be considered.

[11] Aggregators in GB tend to reference operating costs as their highest cost due to the time taken to get customers on board e.g. due to the need to run pilots as this is a new technology for many businesses

- Existing incentives and cultural barriers for regulated monopolies (e.g. Distribution Network Operators) who could potentially use DSR and storage as an alternative to network reinforcement.

The UK Government and Ofgem are working together to better understand these potential obstacles, consider how they can be best addressed and the potential implications of an increase in flexibility services for e.g. customer bills.

As part of the effort to overcome these obstacles Ofgem, has published a Flexibility Position Paper. This sets out the key areas that they will be focusing on in the short term to increase participation of flexible solutions on the system, namely: the role of aggregators in the market; regulatory barriers to storage and how these can be overcome; awareness raising of the demand response potential of industrial and commercial customers; supporting DNOs to take a more active role in network management and consideration of how distribution charges may need to evolve for a smarter electricity system.

11) While electricity markets are coupled within the EU and linked to its neighbours, system operation is still carried out by national Transmission System Operators (TSOs). Regional Security Coordination Initiatives ("RSCIs") such as CORESO or TSC have a purely advisory role today. Should the RSCIs be gradually strengthened also including decision making responsibilities when necessary? Is the current national responsibility for system security an obstacle to cross-border cooperation? Would a regional responsibility for system security be better suited to the realities of the integrated market?

National Grid is a founding member of CORESO, and we recognise and appreciate the value of RSCIs which are working well in the current environment.

We believe that CORESO may be considering how its current advisory role would operate in light of certain specific future topics. Through ENTSOE, TSOs are already taking forward initiatives to develop the role of RSCIs for the benefit of consumers, notably by expanding their geographical coverage. Today, RSCIs operate ahead of real time which already provides significant benefits. It should be noted that a gradual strengthening of RSCIs would require significant developments in the areas of IT and resourcing.

We do not believe that the current national responsibility for system security is an obstacle for cross-border cooperation if the codes are implemented as planned. Therefore, we believe that regional responsibility for system security is not currently necessary and can be left at a national level.

12) Fragmented national regulatory oversight seems to be inefficient for harmonised parts of the electricity system (e.g. market coupling). Would you see benefits in strengthening ACER's role?

The UK Government is open to considering proposals to strengthen the role of ACER in areas where this would allow the maximum benefit to be derived from the internal market as it becomes more integrated and energy policies develop further. For example, it may be efficient to enable ACER to take decisions on cross-border issues where EU Regulations (network codes) require decisions to be taken by all national regulatory authorities. Another area where ACER might be given stronger powers is in the effective oversight of the functions of ENTSO-E and ENTSO-G whose members increasingly operate at regional level and play a key role in the development of the internal energy market.

However, it is important to ensure that ACER's decisions take full account of and address Member State specificities. Therefore ACER's decisions should continue to be subject to approval by its Board of Regulators.

13) Would you see benefits in strengthening the role of the ENTSOs? How could this best be achieved? What regulatory oversight is needed?

Considerable progress has been made in developing the internal energy market thanks to the cooperation of TSOs through the ENTSOs. In just a few years, the ENTSOs have produced drafts for all the gas and electricity network codes. In parallel, day-ahead market coupling has become a reality and intraday will hopefully be soon, in some Member States at least. This was achieved thanks to an effective sharing of responsibilities between national TSOs and the ENTSOs. There are significant differences between TSOs in terms of the size/characteristics of the transmission systems they control, the national regulatory frameworks within which they operate and their defined responsibilities. It is therefore important that TSOs are able to take account of their specific national characteristics when developing new policies within ENTSOE. The value of any increase in the role of the ENTSOs would need to be clearly demonstrated and, if a case were made, adequate regulatory oversight would have to be ensured.

14) What should be the future role and governance rules for distribution system operators? How should access to metering data be adapted (data handling and ensuring data privacy etc.) in light of market and technological developments? Are additional provisions on management of and access by the relevant parties (end-customers, distribution system operators, transmission system operators, suppliers, third party service providers and regulators) to the metering data required?

Smart meters will lead to a step change in the amount of data that will be available about energy consumption; access to this data will help consumers reduce energy consumption, assist energy suppliers[12] (e.g. through theft detection and the development of time-of-use tariffs) and provide enhanced system visibility to distribution network operators. The UK Government has developed a Data Access and Privacy Framework[13] which is designed to protect consumers' interests, enable proportionate access to data by authorised parties and promote competition and innovation in the energy services market.

The fundamental principle underlying our approach is that consumers should control how their personal data (including consumption data) is used, except where it is required for billing/other regulated purposes. Regulatory obligations exist that ensure data is protected while on the metering device, when in transit and once it reaches its intended destination (e.g. the energy supplier).

[12] In Great Britain the rollout of smart meters will be delivered by energy suppliers.

[13] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/43046/7225-gov-resp-sm-data-access-privacy.pdf

In line with current data protection legislation, specific access rights and provisions are in place within the UK in relation to the management and access of metering data by particular groups:

- Energy suppliers can access monthly energy consumption data for billing and regulated purposes. They must obtain explicit consent to obtain data more granular than daily and consumers can opt-out of sharing daily data. The onus is on the supplier to explain clearly what data will be accessed, for which purposes and what choices consumers have. Competition in the market is expected to encourage suppliers to develop new and innovative products that benefit consumers, in return for access to more granular data.
- Distribution network operators can access consumers' energy consumption data for regulated purposes, provided that they aggregate or otherwise anonymise it. Their plans for doing so are subject to approval by Ofgem.
- Consumers can share energy consumption data with third parties, such as switching sites and energy service companies. Third parties must verify the identity of the individual making the request and secure their explicit consent for data access and provisions are in place to audit them.

The UK Government has committed to keep the Data Access and Privacy Framework under review to ensure that these provisions remain appropriate and take into account changes to market arrangements and technological developments. The Framework will also be aligned with any changes emerging from EU reform of data protection rules (due to be completed in 2015).

On the question regarding distribution system operators, the UK Government and Ofgem are working together to consider the potential for DNOs to participate more actively in local system balancing and network planning to optimise the whole electricity system. This work is at a very early stage, and conclusions have yet to be reached.

15) Shall there be a European approach to distribution tariffs? If yes, what aspects should be covered; for example tariff structure and/or, tariff components (fixed, capacity vs. energy, timely or locational differentiation) and treatment of self-generation?

We believe that effective price signals are crucial to the efficient operation of the electricity system, and this will become ever more important as networks become smart and the system becomes more diverse.

The treatment of distribution tariffs is one element of the work we are doing to support the development of clearer price signals that reach the end customer. We would envisage that such tariffs could include any/all of the components mentioned (e.g. fixed, capacity vs. energy, timely or locational differentiation), as well as other incentives such as financial recognition of the provision of demand-side response/distributed generation etc.

However, there are also practical considerations, such as the industry structure, generation mix, nature of metering infrastructure/extent of smart metering, approach to charging for and/or rewarding distribution-connected generation etc which may result in Member States arriving at different conclusions on the appropriate tariff structures.

In light of the above, the UK Government is very much of the view that distribution tariffs should remain a decision for Member States.

16) As power exchanges are an integral part of market coupling – should governance rules for power exchanges be considered?

We consider that the CACM code provides for sufficient regulation of power exchanges in their capacity as market coupling operators. Power exchanges are also subject to a range of measures including REMIT, competition and financial legislation as well as regulation where they are a monopoly provider. Further EU regulation of power exchanges does not seem proportionate.

17) Is there a need for a harmonised methodology to assess power system adequacy?

While we recognise that there may be advantages in some harmonisation based on principles that allow flexibility, one-size will not fit all. We consider that any methodology must respect the differences between Member States, both in terms of their historic approach to assessing capacity and impact of different composition of demand and generation on capacity adequacy assessments. Member States must also be allowed to continue to carry out additional analysis (using alternative methods where deemed appropriate) of adequacy and take resulting measures if deemed necessary. To accommodate the specificities of our diverse systems any decisions relating to security of supply should not be made on the basis of one rigid methodology.

18) What would be the appropriate geographic scope of a harmonised adequacy methodology and assessment (e.g. EU-wide, regional or national as well as neighbouring countries)?

While we acknowledge there will be benefits to an EU-wide model which could provide a more accurate view of overall EU capacity, inevitably it will not be able to provide an accurate assessment of adequacy in particular Member States. It could pose serious risks for security of supply in some Member States and impose unnecessary costs on consumers. Therefore Member States must be allowed to continue to carry out additional assessments as mentioned in question 17 and to coordinate with their neighbours. We believe that existing procedures work well.

We look forward to discussions at forthcoming meetings of the Electricity Coordination Group where we can *inter alia* exchange views on generation adequacy assessments at EU level or regional level.

19) Would an alignment of the currently different system adequacy standards across the EU be useful to build an efficient single market?

Capacity adequacy standards reflect a Member State's trade-off between cost and reliability. Our view is that ultimately this is a political decision which needs to take into account the individual circumstances in a Member State and is not appropriate or desirable to be harmonised at European level. A 'one-size-fits-all' approach would also not necessarily reflect the interests of small, isolated markets with limited interconnection such as Northern Ireland.

While it is important that countries creating national capacity adequacy standards consider those in other neighbouring countries (particularly those with which they are interconnected), we consider that this decision is more appropriately taken at Member State level.

It is also our view that irrespective of whether it is the Member States' choice to decide capacity adequacy standards, until there is a fully functioning internal market, it is practically impossible to have EU-wide standards, because of security of supply issues.

20) Would there be a benefit in a common European framework for cross-border participation in capacity mechanisms? If yes, what should be the elements of such a framework? Would there be benefit in providing reference models for capacity mechanisms? If so, what should they look like?

The principle of participation of interconnected capacity in capacity mechanisms is important. In the UK, it has been a major focus in recent years to enable participation in the Capacity Market because it is expected to increase the pool of competitors and ensure fair treatment for interconnection. This is important because the introduction of the Capacity Market may have an effect on the wholesale electricity price in GB, thereby potentially affecting the revenue that may ordinarily have been expected.

Eligibility for the first Capacity Market auction held in December 2014 included GB located capacity only. This was because, notwithstanding widespread consultation, a workable solution to incorporate non-GB capacity proved elusive. We considered simply extending eligibility to non-GB capacity but the necessary international agreements to permit this could not be put in place in the timescale available. Furthermore, the value for money and security of supply issues could not be resolved. This is because EU rules governing the internal energy market make it impossible to guarantee flows of electricity to GB during stress events. A full description of the design choices considered by the UK can be found in the "Consultation on Capacity Market supplementary design proposals and Transitional Arrangements"[14], published in September 2014.

Since then, we have worked extensively with stakeholders to find a workable interim solution. Interconnectors will participate directly in the capacity auctions for the delivery year 2019/20. The T-4 (four-year-ahead) and T-1(year ahead) auctions for this delivery year will take place in 2015 and 2018 respectively. Interconnector owners will be the bidding parties and will become the holder of a capacity agreement up to the level of their de-rated capacity. They will receive the clearing price in the auction and will hold the capacity obligation in line with requirements for all other resources. The rationale for these design choices was published in the response to the consultation in January 2015[15] and in the impact assessment[16] that accompanied the policy.

The UK Government has always stated that this is an interim solution until a common EU approach for the participation of cross-border capacity in capacity remuneration mechanisms is introduced. We believe that any solution needs to hold value for money for consumers as a core feature, and we would therefore favour a lean solution with a light administrative regime. Furthermore, it should respect market coupling and the value to Member State security of supply of any solution must be clear and simple to communicate at national level to stakeholders and the wider public – in spending consumers' money to ensure security of

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[14] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/358461/CM_October_Condoc_FINAL.pdf

[15] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/396505/Government_Response_to_CM_Supplemetary_Design_Consultation_v.pdf

[16] http://www.legislation.gov.uk/ukia/2015/31/pdfs/ukia_20150031_en.pdf

electricity supply, the benefits of these transfers must be evident. Equally, if the resources do not end up providing a benefit to security of supply, there should be some recourse to that money. The hurdle that all good policies must pass is a positive Impact Assessment and we would urge the European Commission to ensure that any solution would pass such an assessment at Member State level.

A reference model may be helpful, particularly for Member States that are beginning to consider this complex issue – as mentioned above, the UK considers the principle of participation to be crucial. It ensures not just competition but also preserves the optimum balance between domestic and overseas capacity, reinforcing the value of interconnection. Finally, any model should be lean, administratively light, provide value for money for consumers and preserve a level of flexibility for Member States to ensure that the solution can be effectively integrated into the design of the national measure and existing regulatory treatment of interconnectors in the Member State.

21) Should the decision to introduce capacity mechanisms be based on a harmonised methodology to assess power system adequacy?

As discussed in our answer to question 17 and 18, we would have concerns on decisions relating to security of supply being tied to a prescribed methodology, without allowing sufficient Member State flexibility.

We believe that Member States should be allowed flexibility and not be tied to a prescribed methodology, but do not think that the decision to introduce a capacity mechanism should be taken lightly, and the need for such a market intervention should be monitored post implementation.

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