Call for Evidence on a Smart, Flexible Energy System

Response by E.ON

Executive Summary

- A new approach is needed for connecting storage assets to the distribution network especially if the concept of Solar PV and Battery is to be developed in the UK. Storage units up to 16A phase should be installed in properties without any delays provided the manufacturer informs the Distribution Network Operator (DNO) within a set time period.

- We support a specific definition of storage which makes clear that a storage asset should be treated neither as generation or demand, and that it is explicitly stated that storage assets are both consuming and generating/ re-delivering energy. Any approach should end the current approach of double charging of government incentives schemes such as the Renewables Obligation.

- Barriers to co-locating storage assets on the site of existing renewable generation assets need to be addressed. We have proposed a solution which treats the storage asset and renewable generation asset as two independent plants with separate metering. This would ensure that the contributions made by each asset were clearly identified and preserves the integrity of the support afforded to the renewable asset.

- There are significant implications from the changes that would be required to the existing balancing and settlement arrangements to facilitate the participation of non-Supplier or Generator aggregators. If a decision is taken that would enable independent aggregators to directly operate in the balancing mechanism, there would need to be a mechanism in place to ensure that Suppliers are recompensed for the potential exposure that they may incur as a result of 3rd party aggregator actions as recognised in the proposed EU Balancing Code.

- Demand Side Response (DSR) is at a relatively early stage in its development, but has the potential to play a considerable role in meet the needs of the system in the future. As such we believe that large customers that are currently in this market are protected by existing commercial and consumer protection regulations and that there is no need to move to a licensing regime at this stage. We nevertheless welcome the ADE's development of a Code of Practice to provide customers with confidence.

- We have, and remain supportive, of the Power Response campaign. The campaign however must now address the longer term challenges and design the future balancing services market so that it provides a truly level playing field for any participant. Our proposal is based on having 5 standardised products to cater for fast positive response, slower positive response, negative response, positive reserve and negative reserve. This approach directly tackles the issue of complexity which has been widely acknowledged. A standardised approach would also support the use of auction mechanisms to efficiently procure each product transparently.

- Government and Ofgem should look to reduce and remove any potential regulatory barriers where they may exist in the market to the development of smart tariffs by energy suppliers. However they should not look to promote smart tariffs or interfere in the operation of the competitive market as this will risk creating unintended consequences and costs for customers. Ofgem's settlement reform project is a key enabler for promoting smart tariffs. Elective Half Hourly (HH) settlement will be available later this year, providing the market with the freedom to innovate and offer dynamic tariffs where there is customer demand for this.

- Ireland is encouraging customers to move to Time of Use (ToU) tariffs, largely in response to the system impacts of the generation market becoming increasingly dominated by wind which is complemented by a high proportion of customers having electrical heating. Given where the GB market may be heading, particularly in light of the broader decarbonisation challenge, Ireland is a country where there may be some important learnings to take.

- We support a holistic review of network charging to ensure that it is delivering for customers and is acting as an enabler rather than a barrier to new technologies, but are aware that Ofgem will be pursuing a more targeted review. Ofgem should nevertheless include distribution charges within such a review and use the opportunity to address any issues within the current system, for example, helping to ensure that all DNOs are taking a consistent position on the treatment of storage and on charging structures more generally.

- DUoS charges are currently skewed towards a volume based approach for recovery, which we believe is broadly reflective of the drivers of network reinforcement, especially where there is differential pricing within day. However there needs to be a greater understanding of the impact of prosumers on the network. They will be reducing the amount of power imported from the network, which is a positive impact on the system more broadly. However from an equity perspective, this will leave other customers to fund a distribution network's allowed income stream. Recovering at least some of the costs which are sunk on a fixed cost basis may have some merit going forward.

- We believe there is a need for the role of DNOs to change to become Distribution System Operators (DSOs). In moving to this new world, greater incentives need to be placed on them to actively seek out the most cost effective solutions for addressing local balancing constraints, through local flexibility markets. This would align with the new EU Clean Energy Package which suggests that business plans should include a section on how to use DSR and storage. However the procurement of flexibility at the DSO level may have an impact at the System Operator (SO) level and vice versa, so a much greater level of collaboration will be needed to ensure this operates efficiently.

- The Capacity Market (CM) is a key policy supporting the transition to a smart energy future. In the most recent auction, over 500MW of battery storage and 1.4GW of DSR was successful in achieving an agreement. This has been possible because of a fundamental principle of the capacity market – to treat all capacity on a fair and consistent basis - and allow genuine competition between conventional sources of capacity and less established sources of capacity. It is vital that this principle remains and that the CM does not begin picking winners or defining and discriminating between arbitrarily defined "good" capacity and "bad" capacity.

- We believe that any technical requirements for smart appliances should be joined up with those adopted within the rest of Europe as opposed to setting UK specific standards. On balance, we favour an approach based on the labelling of smart appliances. It is important however to consider what the appropriate functional requirements should be to enable an appliance to be labelled smart.

- Electric Vehicles (EV) represent a significant asset within a distributed energy system. One of the barriers to overcome is the management of a very large number of small units in contrast to fewer but bigger assets. A cost effective method in terms of the Internet of Things (IoT) concept is required where the aggregation of a large number of Plug-in Electric Vehicles (PEV) and the associated communication and management costs are commercially viable.

- Smart charging will also be essential for supporting the growth of EVs. Customers are likely to require sufficient assurances prior to adopting this. The automotive industry has a role to play here, for example, by incorporating smart charging vehicle features into their products which would support easy and intuitive engagement and offering warranties associated with the battery. The energy industry will be able to provide reassurance to users by supporting smart charging with managed Electric Vehicle Supply Equipment (EVSE) products and tailored tariff propositions, offering a convenient way for users to opt-in to ancillary services and enabling the user to configure the minimum State of Charge (SOC) of the vehicle battery to meet their specific traffic needs.

Consultation Questions

Enabling Storage

Q1. Have we identified and correctly assess the main policy and regulatory barriers to the development of storage? Are there any additional barriers faced by industry?

1. We welcome the issues that have been raised in the call for evidence regarding some of the challenges that developers face when considering storage opportunities.

2. Our experience in developing battery opportunities over the last couple of years has highlighted a number of barriers, with the most pressing issue being the lack of clarity around the definition of storage. In particular, distribution networks have treated storage as generation, which when coupled with Solar PV has led to the capacity at a particular site exceeding the current threshold of c.4kW. As a result, the process for a grid connection moves from a "fit and inform" approach (G83) to a much longer process which can hold up installations quite considerably, and which is used for much larger generation assets (G59). By providing a specific definition for storage, we believe there will be the ability to move to a model whereby a "fit and inform" approach can be adopted for storage units up to 16A phase as long as the Distribution Network Operator (DNO) is notified within 28 working days by the manufacturer. This should recognise that batteries will be used in many ways, including to maximise self-production.

3. A new definition for storage will also help to address the issue of double charging of government support schemes (including Renewables Obligation, Feed-in-Tariff, and Contracts for Difference), whereby at the moment, both the storage asset and the end consumer are paying levies charged on the volume of energy supplied. By removing this anomaly, the economics of a battery will improve. We look forward to greater regulatory clarity being provided here.

4. We have also come across a potential barrier in the context of co-locating a battery on the site of an existing renewable generation asset. The barrier arises if the metering arrangements on the site are unable to enable the existing renewable generation asset continuing to receive the support from a government scheme for all of its generation, including any used to charge the battery, or the battery having to incur the cost of licensed supply for charging, even though it received supply from a generator whose premises are on the same site as the battery.

5. We believe that the risks can be addressed by treating the storage asset and renewable generation asset as two independent plants with separate metering. The outputs and consumptions of the two plants would then only be brought together in accordance with the Balancing and Settlement Code's (BSC) complex metering arrangements. The complex metering arrangements would ensure that the contributions made by each asset were clearly identified and appropriate. Any supply

from the renewable asset to the battery would be recorded as export from the renewable plant. Any supply from the battery to the renewable plant would not be recorded as renewable generation by the plant. This separation of plants would preserve the integrity of the support from a government scheme, while allowing both plants to gain from the benefits of using a common connection to the local distribution system and co-locating a demand, the battery, on the site of an existing generation plant, the renewable generation asset.

6. Fair and equal access to markets is a potential barrier to storage. Whilst Enhanced Frequency Response (EFR) was a good example of an open and transparent market which investors were able to value relatively effectively, there are other balancing services where it is much more difficult to value potential income streams, such as Firm Frequency Response (FFR). This is partly because of the lack of standardisation in the process which makes it incredibly difficult to compare "like for like" tenders and therefore value products in order to build business cases. Moreover, the sheer number of products in the market today makes valuation of storage incredibly complex. Recognising that, for the foreseeable future, batteries will commercially work when they are able to provide multiple services, ranging from very fast frequency response to providing capacity during a system stress event in the Capacity Market (CM), it is important to be able to stack revenue streams and price this accordingly. There is considerable scope for improvement, particularly around the simplification of products required by the System Operator (SO), and to move away from bilateral negotiations and tenders to market based outcomes.

7. Storage can be used to provide alternative solutions for local DNOs. However whilst there have been a number of Low Carbon Network Fund (LCNF) projects which have sought to demonstrate the benefits which storage can provide to the network, there is more that can be done in this area to change mind sets and to treat this and the broader demand side as a realistic alternative to investing in upgrading the local network. We comment further on this aspect in our response to question 4.

Q2. Have we identified and correctly assessed the issues regarding network connections for storage? Have we identified the correct areas where more progress is required?

8. We would agree that most of the key issues have been captured. We are aware that network connection timescales can vary significantly across the country depending on location. Whilst we recognise that storage connections will require both import and export capacity, there needs to be a greater recognition of the benefits that storage can provide. This should include the ability to help alleviate local constraints as part of a more coordinated and holistic approach which seeks out the most cost effective solutions for the system as a whole.

9. Smarter solutions also need to be found when considering small scale storage, as we set out in our response to question 1. For these type of installations, an approach akin to that used for the

domestic solar PV market would appear a reasonable way forward, so that there is no delay in connecting batteries, thereby enabling the customer journey to meet their expectations.

Q3 Have we identified and correctly assessed the issues regarding storage and network charging? Do you agree that flexible connection agreements could help to address issues regarding storage and network charging?

10. We agree that network charging methodologies were not designed with storage in mind, and welcome the proposals aimed at addressing the treatment of storage, which can sometimes be viewed as intermittent generation, and therefore is liable to higher DUoS charges. It is clear to us that Storage is dispatchable and should therefore be treated on a consistent basis as a non-intermittent asset.

11. Storage assets are likely to be operated so that they are available to export during peak times, whilst importing power during off-peak periods, to capture the arbitrage effect. As such, we strongly believe that storage can have a positive impact and reduce a network operator's costs, which needs to be reflected in explicit payments from local flexibility markets. This is an area that should be explored as part of a wider review of charging arrangements.

12. We accept that storage will use the network when importing power, and so should make a contribution towards those costs. Excluding storage from such costs does not appear to be reasonable. However it is important that the charges set are cost reflective.

Q4. Do you agree with our assessment that network operators could use storage to support their networks? Are there sufficient existing safeguards to enable the development of a competitive market for storage? Are there any circumstances in which network companies should own storage?

13. The LCNF projects have demonstrated that storage can be beneficial to network operators. We agree that this could be used much more widely to help balance the system at the local level.

14. We also agree with the National Infrastructure Commission's recommendations that network owners should be incentivised by Ofgem to use storage and other sources of flexibility to improve the capacity and resilience of their networks as part of the transition to the active management of the system.

15. The recent EFR tender has shown that the storage market is already highly competitive. However we are aware of the potential for network operators to distort the market by simply rejecting installations or holding the process up via the G59 process. Arrangements needs to be clarified so that this risk for investors is satisfactorily addressed as we set out in our response to question 1.

16. We do not believe that network companies should own storage, in line with the current rules around unbundling. Instead our view is that via the regulatory framework (RIIO), incentives should be strengthened further so that network companies fully embrace the opportunities that storage provides, such as deferring or avoiding investments to the grid and better managing issues on their networks. In particular, they should be encouraged to test the market and procure cost effective flexibility services to address local system operator requirements. National Grid in this respect has led the way on how it should be done, and we believe a similar approach at the local level is needed. In this regard, we have been encouraged by WPD who have been promoting Demand Turn-Up in the summer via their sunshine tariff to make greater use of solar PV capacity between 10am and 4pm.

Q5. Do you agree with our assessment of the regulatory approaches available to provide greater clarity for storage?

17. We have provided comments on the different regulatory approaches in our response to question 6.

Q6. Do you agree with any of the proposed definitions of storage?

18. Whichever approach is taken, it should be introduced in a way so as not to detrimentally impact either current or planned projects as a matter of principle. There may therefore be merit in having a phased transition to any new regulations that are introduced.

19. The definition that is ultimately adopted for storage must address the barriers that have been highlighted. The definition which is taken forward should also be reflected in any scheme that a storage asset can participate in, or could be impacted by, in the case of co-locating with an asset which is eligible for other funding streams such as the RO and the FiT.

20. The definition should make it clear that storage should be treated neither as generation or demand and that it is explicitly stated that storage assets are both consuming and generating/ re-delivering energy, with an associate energy cost or loss which is dependent on the storage asset and particular technology type. As such the definition should encourage higher efficiency storage assets which will increase their environmental sustainability.

Q7. What are the impacts of the perceived barriers for aggregators and other market participants?

<u>Balancing Services</u>

21. The consultation references issues identified with independent aggregators accessing the balancing services required by the SO. However as the call for evidence states, independent aggregators can access balancing services directly, and have been successful in doing so. We do

not think there are barriers that are specific to independent aggregators, but accept that there are challenges for any aggregator in today's market design which needs to be considered within this call for evidence.

22. Bilateral contracts and a lack of transparency over pricing and requirements makes it more difficult for any aggregator to provide the full range of ancillary service products. By contrast, traditional generators who have been active in the market for some time will have internal knowledge of the value of these products and so can 'pick and choose' the most valuable products. If they are not successful in one service, they can fall back on others, allowing them to spread the cost of their service over a much larger number of products. This is not available to aggregators which means that their costs are spread across a smaller number of products, making them more expensive and less competitive.

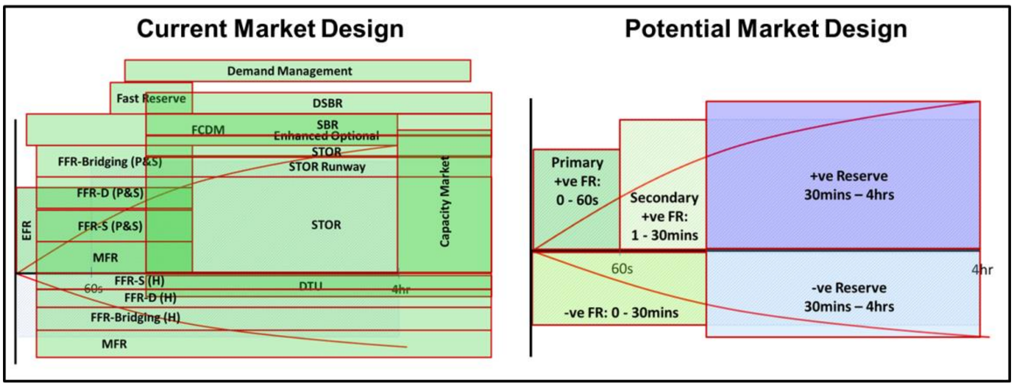
23. The large number of products and the high complexity of each product also makes it very difficult for new entrants as there is significant time and cost required to adapt services to match the individual requirements of each product. This means that it takes much longer than it should do for a new entrant to develop a business model where they can offer the full range of services and achieve maximum value for their customers.

24. Product requirements are designed around traditional generation and therefore create unnecessary costs and administration for any aggregator, in particular around complex and costly metering, 'baseline' calculation and methods for proving response. While these are each necessary elements, they need to be reconsidered in light of actual system requirements, and a "fit for purpose" approach adopted.

25. Existing long term contracts distort the market in favour of incumbents and allows them to 'lock in customers'. This therefore makes it a lot harder for new entrants to come into the market. We believe that much shorter term standardised contracts secured on the basis of open and transparent markets will deliver liquidity, the best deal for customers and ensure that there are continual opportunities for aggregators to offer their services into the market.

26. We have, and remain supportive, of the Power Response campaign. Our view is that the campaign must now address the longer term challenges and design the future balancing services market so that it provides a truly level playing field for any participant. This requires a small number of services to be purchased by the System Operator from markets that meet the requirements for keeping demand and supply in balance on a continuous basis. These services need to recognise the changing dynamics driven by decarbonisation, such that the tools are in place to manage the system needs at the lowest possible cost for customers. Markets rather than bilateral negotiations are the best guarantor of this, and deliver most value when like for like products are being

compared. This requires much greater standardisation in product design and a move away from the SO allowing parties to choose their own parameters.



27. Having undertaken some analysis of market design we have come to the following conclusions:

- A one product market that procures a single block of [x] MW of flexibility covering all timescales does not solve the issues we have previously outlined. Although it may seem like the optimal solution as it is the simplest, in reality it would shift the complexity of markets from the SO to aggregators as no one technology will be able to respond within milliseconds and last for up to four hours. A natural conclusion of the market structure is that all response would have to be dynamic (i.e. all flexibility responds to change in system frequency), removing the SO's ability to proactively call flexibility, which we consider to be valuable to the system.

- A solution where there are 5 standardised products (namely a fast positive response, slower positive response, negative response positive reserve and negative reserve) seems sensible, and would go a long way towards solving many of the issues in today's ancillary service markets. This approach directly tackles the issue of complexity, and standardisation would support the use of auction mechanisms to efficiently procure each product transparently. The overall effect would likely be to increase competition and decrease overall cost. There would be a reserve available that would allow the system operator to strategically dispatch flexibility to proactively stop issues before they arise.

- Secondary trading would be a welcome development in the ancillary service markets, but only full products should be allowed to be traded. For example, if you have a 30 second response contract, secondary trade would only be permitted for the full 30 second period, and not something less than this. This should allow conventional generators to trade out of their flexibility position if they are not "in the money" in the energy market (i.e. it should stop providers running out of an overall merit order) and also allow aggregators to switch assets in and out of the blocks that they have contracts to deliver, up until a reasonable point before time of delivery.

- We believe that auctions are achievable for both reserve and response products. It would provide the transparency that developers require in order to make better investment decisions and competition to ensure a good deal for customers.

Balancing Mechanism and Wholesale Market

28. The associated report to this consultation from PA Consulting was informative in setting out the potential issues with independent aggregators participating in the balancing mechanism and wholesale market.

29. There are significant implications from the changes that would be required to the existing balancing and settlement arrangements to facilitate the participation of non-Supplier or Generator aggregators. Elexon have recently started to explore these but more work would be needed to fully understand the true costs for these and how long they would take to implement.

30. If a decision is taken that would enable independent aggregators to directly operate in the balancing mechanism, there would need to be a mechanism in place to ensure that Suppliers are recompensed for the potential exposure that they may incur as a result of 3rd party aggregator actions. This is recognised in the proposed EU Balancing Code, although the process for establishing and agreeing these costs between parties would be challenging to agree.

31. There should be some consideration into a potential requirement for aggregators to have a licence to operate if they are to act independently in the balancing mechanism.

Consumer protection

32. For the customers that are currently engaged with providing DSR services, they are predominantly significant users of energy who have the resources to employ specialist expertise to help them take informed commercial decisions.

33. An expansion of the DSR market to small businesses and residential customers is likely over time, particularly as technology evolves. Smart metering will provide the required information to access the market, alongside half hourly settlement reform which will enable static (different pricing periods remaining fixed) and dynamic (prices could be set according to the prevailing wholesale costs) ToU tariffs. Increased on-site generation, storage, electric vehicles and heating will all contribute to a customer's ability to realise commercial gain from being more active in the market.

34. This will however expose them to more complex commercial arrangements with multiple different parties in the energy supply chain. We recognise that this has the potential to be confusing for them and could act as a barrier to the successful evolution of the market. Nevertheless it seems too early in the evolution of the market to require aggregators to either need a specific licence arrangement or use an amendment to the existing Supply Licencing route. Instead we believe a proportionate response would be to rely on existing commercial and consumer protection regulations in the context of balancing services. We welcome the ADE proactively engaging with members to develop a code of practice which in our view will help to provide customers with confidence whilst enabling this market to be nurtured over the next few years.

Q8. What are your views on these different approaches to dealing with the barriers set out above?

Balancing Services

35. The System Operator today operates in excess of 20 different products. Based on our own analysis we believe that the market could operate effectively with around 5 products as we have outlined above. This way the market is designed around the needs of the system, rather than on any one technology. It would enable aggregators to develop and provide the full range of products with relative ease. Furthermore customers will gain more value from their assets, increased competition and liquidity within each market and lower service costs for National Grid, meaning lower overall energy bills for end customers. An extensive redesign of flexibility services may be required in order to achieve a transparent, technology neutral and competitive set of services.

Consumer protection

36. If there was a clear case that customers were suffering a detriment from not being able to realise the benefits from providing DSR services then some action from Government and Ofgem in this area would be warranted. However at this point in time we cannot see a specific justification for requiring such a regulatory intervention. It therefore seems preferable at this stage for Government and Ofgem to maintain a monitoring situation and to see how the commercial market evolves.

Q9. What are your views on the pros and cons of the options outlined in Table 5? Please provide evidence for your answers.

Balancing Services and Balancing Mechanism

37. National Grid appears to be making moves in the right direction regarding the re-design of balancing services. However the time is now right for them to carry out a more fundamental review

of balancing services with an aim of simplifying the services, increasing competition and improving transparency.

38. We believe that the way forward for addressing issues within the Balancing Mechanism is via the Industry change process. It is important that any change proposals within the Balancing and Settlement Code (BSC) should be backed up by a robust Impact Assessment.

Consumer protection

39. At this stage we do not believe that there is sufficient justification of consumer detriment to require regulatory intervention. The creation of new specific Licence categories risks adding additional costs and barriers to market entry and unintentionally stopping the evolution of a commercial market for services. A preferable option is therefore to leave any incremental changes that are needed to industry to bring forward and manage via the existing governance processes.

40. Any industry proposals to introduce a more clearly defined role for independent aggregators would ultimately lead to a significant change for the industry. This change would need to be co-ordinated and managed across a number of industry codes, requiring a significant degree of cost benefit analysis. This could only successfully be managed in our view by the Significant Code Review (SCR) process and led by Ofgem.

41. Therefore our preference would be for Government and Ofgem to continue to monitor the evolution of the market in this area to make sure that it evolves in the right way, but be prepared to step in where needed to lead any major industry change that may be warranted.

Q10. Do you agree with our assessment of the risks to system stability if aggregators' systems are not robust and secure? Do you have views on the tools outlined to mitigate this risk?

42. There is the potential for some risk to be introduced by the high uptake of DSR, although this is dependent on the way it is controlled and instructed. It is agreed that some work should be done to quantify this risk and produce a robust evidence base that all parties have confidence in.

43. It is likely that the majority of the risk associated with this is around the impacts on the distribution network. If this is deemed to be the case, it will be important to ensure sufficient and consistent/standardised communications between aggregators, DNOs and the SO to allow any impacts to be identified and mitigated/controlled. A robust evidence base must be produced in order to justify any potential rules restricting the action that customers may be allowed to make to support DSR services.

44. It is worth noting that the potential risks to network stability of DSR activity has been considered by the Smart Metering Implementation Programme (SMIP) and randomisation has been built into smart meters. During the debate with BEIS on the development of this functionality there was not a clear articulation by the network operators as to what the specific risks were as result of customers taking DSR actions and the costs that this may incur.

System Value Pricing

Q11. What types of enablers do you think could make accessing flexibility, and seeing a benefit from offering it, easier in future?

45. Changes could be made to non-domestic building regulations to require new builds and refurbishments to have sub-metering of HVAC, lighting, heat pumps and other flexible equipment (generation and demand) along with energy management systems which are able to communicate with smart assets. All new demand sources (HVACs, lights, EV chargers, Refrigeration etc) should be designed with an agreed communication and control standard. These should directly relate to the technical requirements of the applicable balancing service products. This way, the cost of accessing smaller scale flexibility will be much lower, enabling a much greater proportion of the UK's flexibility to be marketed.

46. In order to access more distribution level flexibility, greater cooperation between the DNO and SO will be needed to ensure actions from one party do not adversely affect the other.

47. Half hourly settlement and freedom for innovative tariffs is a requirement for supporting behind the meter flexibility and enabling it to respond to price signals. We therefore welcome the Ofgem project which is focussed on delivering settlement reform, and believe elective half hourly settlement will enable innovation of this kind.

48. Another key enabler from our experience is in adapting the metering requirements, which in many cases have been designed for a generation centric view of the world. Cheaper metering solutions should be encouraged provided they deliver metering accuracy which is fit for purpose, as opposed to gold plating the requirements. Technology solutions such as remote metering for example should be encouraged that would enable smaller capacity to be aggregated in a cost effective way.

49. We have also in our previous responses (see question 7) set out how balancing services should evolve to make accessing flexibility easier in the future. Similarly we believe there should be a coordinated approach to tackling distribution network issues with a role for the SO to help ensure that markets which are created to help resolve local balancing constraints are standardised to help bring forward the most cost effective solutions.

Q12. If you are a potential or existing provider of flexibility could you provide evidence on the extent to which you are currently able to access and combine different revenue streams? Where do you see the most attractive opportunities for combining revenues and what do you see as the main barriers preventing you from doing so?

50. Flexibility solutions such as DSR and Storage will typically require a number of revenue streams to be stacked so that they are commercially viable. This however is no different to more traditional generation technologies.

51. There appears to be an increasing trend from the SO to require "committed" as opposed to "flexible" offerings such as in the procurement of the Short Term Operating Reserve (STOR). Flexible offerings are where a provider can vary the capacity and/or availability of a unit for different time periods to allow the utilisation of less predictable assets or to enable a unit to provide a range of services such as STOR and customer value optimisation such as TRIAD. The results of recent tenders shows that less and less flexible STOR assets are being accepted.

52. As we have explained in our response to question 7, one of the major barriers that we see in the market today for stacking revenue streams, even where products can be combined, is through the use of bilateral negotiations in some instances, and the lack of transparency and predictability of prices which this type of approach brings. Similarly even where there is in theory an emphasis on tendering, there is too much discretion which prevents the market from offering truly standardised products.

Q13. If you are a potential or existing provider of flexibility are there benefits of your technology which are not currently remunerated or are undervalued? What is preventing you from capturing the full value of these benefits?

53. Distribution connected flexibility should be able to provide services to the SO and DNOs, but there are currently limited opportunities to provide such network services. This is excluding an important source of value for such assets. As we also explained in question 12, the layering of products and values is not always permitted by the current rules, even though flexibility assets can provide a number of different services to the market. STOR, for example, specifically prohibits assets from providing any other services during contacted periods. This would prevent the asset being able to provide DNO services during contracted STOR periods.

54. Domestic batteries at present are unable to offer any flexible services to either the SO or DNO due to a lack of half settlement data and time of use static or dynamic tariffs that could be enabled from these changes. However the reforms that are being progressed by Ofgem provide an opportunity to unlock some of this value in the future.

55. System inertia is currently a by-product from spinning metal within traditional power stations. However as more of these type of assets are retired, there will be a need for the SO to secure these services from the market. If this approach is adopted, this could provide a valuable income stream to flexibility providers that can respond very quickly, almost instantaneously.

Q14. Can you provide evidence to support changes to market and regulatory arrangements that would allow the efficient use of flexibility and what might be the Government's, Ofgem's, and System Operator's role in making these changes?

56. We believe that there are four things that could be done to allow the efficient use of flexibility.

57. Firstly, markets should facilitate transparency through the use of standardised flexibility products, a single trading platform with visibly offered/accepted prices and minimum standards of data provided by market participants.

58. Metering requirements need to be set so they are fit for purpose but are not gold plated. As such, there needs to be a compromise between metering that can provide sufficient information to facilitate market transparency, and metering that is cheap enough so as not to be prohibitive to small aggregated assets.

59. Markets should be designed to encourage investment through a number of factors including clear and sufficient price signals to justify investment, markets that are open to all and unbiased, simple and transparent contractual arrangements, a system operator enabled to optimise the system over the longer term and which avoids creating stranded assets, and secondary trading allowing greater flexibility in delivering obligations.

60. We have estimated that implementing these changes (and therefore enabling smaller loads to compete in flexibility markets) could save the System Operator up to £1bn per year in 2030 when compared to the National Grid Gone Green scenario (using forecasts for balancing reserve requirements). The System Operator should take a leading role in ensuring that markets are more open to smaller loads to compete in.

61. Finally there is the transition from the DNO to Distribution System Operator (DSO). This should happen to help facilitate the coordination between local and system service requirements and to open up more distributed assets to providing system services. Enabling a greater percentage of distribution connected loads to compete in flexibility markets could also save the system around £0.8bn per year in 2030 when compared to the base case.

Smart tariffs

Q15. To what extent do you believe Government and Ofgem should play a role in promoting smart tariffs or enabling new business models in this area?

62. Government and Ofgem should look to reduce and remove any potential regulatory barriers where they may exist in the market to the development of smart tariffs by energy suppliers. They should not however look to promote smart tariffs or interfere in the competitive market as this will risk creating unintended consequences and costs for customers. The smart meter programme and Ofgem's settlement reform project are two key enablers for promoting smart tariffs and enabling new business models.

63. We accept that it is right and fair that costs should be allocated to those that incur them. Settlement of electricity costs should be allocated to those customers who are using it at specific times of the day. The move to Half Hourly (HH) settlement for residential and small business customers will therefore help to contribute to the evolution of the energy market by making electricity costs more focused and accurate. It will support innovation and the evolution of commercial offerings from electricity suppliers and aid in the development of the market for flexibility products for customers.

64. We support the phased approach that is being proposed by Ofgem for this project. As a first step it is necessary to map out exactly what the future process for electricity settlement should look like. This shouldn't be constrained by the existing model and should recognise the differences that have been introduced into the market since the current arrangements were established in the late 1990's.

65. A mandated move to HH settlement will have impacts upon the costs that individual customers incur for their electricity supply. This is inevitable and the implications of this need to be assessed and understood. Elective HH settlement will still provide the market with the freedom to innovate and offer dynamic tariffs where there is customer demand for this. Nevertheless an assessment of the distributional implications is an important part of the Ofgem project, and we believe it would be useful for this assessment to also explore and propose recommendations as to how a transition should best be managed from a customer perspective.

66. In particular it will be an important factor for the project to understand how the transition can be managed for those customers who are negatively affected and what messages should be sent to them to explain why change is happening. A key learning point from the BSC P272 mandated implementation of HH settlement for larger customers was that strong centralised communication is critical and was something that was missing from this project.

67. Good central communication will be important for maintaining customer buy in for any change and to avoid any negative implications for other industry programs. In particular the smart metering roll-out may be vulnerable to negative association if the communication regarding HH settlement is poorly managed, especially as the acceptance of smart meters by customers in the GB market is on a voluntary basis.

68. We agree that a decision on the way forward should be determined by mid-2018 and that it is unlikely that a mandate will be possible before 2021 when it is expected that there will be sufficient numbers of smart meters in customers' properties.

Q16. If deemed appropriate, when would it be most sensible for Government/Ofgem to take any further action to drive the market (i.e. what are the relevant trigger points for determining whether to take action)? Please provide a rationale for your answer.

69. Before considering any intervention, Government and Ofgem should investigate what is preventing smart based products from being offered if they do not emerge. There may be valid reasons as to why in a competitive retail market a Supplier chooses not to offer smart tariffs. Equally it may be that smart tariffs are not attractive to some customers today, and will require a number of factors to be in place to generate such demand.

70. Monitoring of the market is already underway by both BEIS and Ofgem as part of the monitoring of Supplier's smart metering deployments. This seems an appropriate course of action to take at this point in time.

Q17. What relevant evidence is there from other countries that we should take into account when considering how to encourage the development of smart tariffs?

71. There are a number of approaches that are being taken in the development of smart tariffs. These are predominantly driven by the specific requirements of individual markets and are therefore not always relevant to the GB market.

72. Spain for example is looking to mandate TOU tariffs for domestic customers with smart meters, but their drivers are linked to limiting peak load use of electricity for air conditioning.

73. Ireland is proposing a more consumer friendly approach to the deployment of smart tariffs that would see customers encouraged to move to ToU tariffs in the first instance. Here however the primary benefit is seen to be due to a generation market dominated by wind and a high proportion of electrical heating. Given where the GB market may be heading, particularly in light of the broader decarbonisation challenge, Ireland is a country where there may be some important learnings to take.

74. Evidence from Scandinavia shows that complex and inherently more risky electricity products can be attractive to some customers but only if they feel empowered to participate. Power prices here are closely linked to weather conditions and therefore predicting these and taking on the energy pricing risk is something that a number of customers feel comfortable in doing.

75. Recent evidence from Australia however shows that there is a clear preference from some customers with smart meters for much simpler tariffs based upon a fixed price per month.

76. These examples highlight that the evidence for smart tariffs from other countries is mixed, with perhaps Ireland being the most interesting comparison given that the market here is likely to exhibit some of these characteristics in the future.

77. The GB market already has a significant number of customers on Economy 7 and other similar ToU tariffs. The exact nature of the future smart tariffs that would be right for GB customers should be left for the competitive market to determine and not be an issue where Government or Ofgem should be seeking to intervene. The CMA proposals on simpler tariffs addresses what was a barrier to tariff innovation, which we welcome.

Q18. Do you recognise the reasons we have identified for why suppliers may not offer or why larger non-domestic consumers may not take up, smart tariffs? If so, please provide details, especially if you have experienced them. Have we missed any?

78. We have been promoting smart tariffs for our larger business customers which offer varying degrees of flexibility, from TOU tariffs through to flexible products where customers choose – based on wholesale market movements – when to purchase their energy. Demand for our flexible products has to date resided in the larger end of our customer base, where they may have more ability to shift load, and energy makes up a significant proportion of their operating costs.

79. Outside of our flexible products, we offer bespoke prices at several rates (generally between 2 and 6-rate Seasonal TOU products where Winter Day is a different price to Summer Day). In our experience, many of our customers are reliant on and prefer the simplicity that our current two rate tariffs offer. Low customer demand and an inability to shift demand between consumption periods limits many customers' choices as things currently stand, particularly in the less energy intensive sector.

80. We recognise that customers and Third Party Intermediaries (TPIs) may have increasing difficulty in comparing prices with the addition of smart tariffs, which will need to be addressed so as to avoid impacting broader engagement.

Smart distribution tariffs

Q19. Are distribution charges currently acting as a barrier to the development of a more flexible system? Please provide details, including experiences/case studies where relevant.

81. Currently, within the half hourly market, we do not believe that distribution charges are fundamentally acting as a barrier to the development of a smart and flexible system as they are already operating on a TOU basis (Red, Amber, Green tariffs). However we have not seen customers on a large scale actively taking actions to avoid DUoS charging. A review of distribution charges should amongst other things seek to understand why this may be the case, and to ascertain whether the current structure of charges needs to be refined to improve this outlook.

82. Distribution charges are however potentially acting as a barrier to the development of a more flexible system in the non-half hourly market, where DUoS is charged on a deemed load profile rather than actual demand. Consequently the tariff design does not incentivise customers to change demand at any particular point in time. However this is arguably a transitional issue as over time we will expect to see more customers move to HH settlement.

83. The driver for changing the current arrangements will be the evolution and deployment of new technology (energy storage, on site generation and electric vehicles). Estimating how quickly this will become a material issue will be challenging (estimates of PV growth significantly under estimate the rate of deployment compared with what was seen in practice) but is something that should be undertaken.

Q20. What are the incremental changes that could be made to distribution charges to overcome any barriers you have identified, and to better enable flexibility?

84. We support a holistic review of network charging to ensure that it is delivering for customers and is acting as an enabler rather than a barrier to new technologies, but are aware that Ofgem will be pursuing a more targeted review. Ofgem should nevertheless include distribution charges within such a review and use the opportunity to address any issues within the current system. Within this context, we note that the EHV Distribution Charging Methodology (EDCM) was reviewed in 2015 and the Common Distribution Charging Methodology (CDCM) is currently under review by the CDCM review group.

85. The CDCM differentiates between generation customers based on whether they are classified as intermittent or non-intermittent. Non-intermittent generators receive a credit based on their export in the red, amber and green timebands which vary by DNO. Intermittent sites receive a single unit rate credit as they are unable to change their generation profile in response to price signals. The CDCM definition for intermittency is based on whether the fuel source can be relied

upon. The current status of storage within the CDCM is not defined, but it is important that all DNOs treat export from storage as non-intermittent within the CDCM given that it is dispatchable. Amendments to the recognition and treatment of energy storage would help to ensure that all DNOs are taking a consistent position.

Q21. How problematic and urgent are any disparities between the treatment of different types of distribution connected users? An example could be that in the Common Distribution Charging Methodology generators are paid 'charges' which would suggest they add no network cost and only net demand.

86. The CDCM is a forward looking methodology that calculates charges to demand customers and credits to all generation and exporting storage customers. Generation receives a credit to recognise that their export is offsetting demand and reducing the need for reinforcement on the DNO's network.

87. Within the CDCM, all generators receive a credit regardless of where they connect or the nature of their local network. In some areas where a large number of generators connect and the level of demand is low, the export can drive reinforcement on the DNOs network, as we have seen in the South West of England in recent times. However, as the CDCM is an average methodology these generators will be receiving a credit in spite of the fact that they are causing additional costs that are picked up by demand customers. It is important to make these signals more cost reflective in support of a more flexible energy system.

Q22. Do you anticipate that underlying network cost drivers are likely to substantively change as the use of the distribution network changes? If so, in what way and how should DUoS charges change as a result?

88. DUoS charges are currently skewed towards a volume based approach for recovery. We believe that a volume based approach is broadly appropriate and reflective of the drivers of network reinforcement, especially where there is differential pricing within day.

89. However there needs to be a greater understanding of the impact of prosumers on the network. They will be reducing the amount of power imported from the network, which is a positive impact on the system more broadly. However from an equity perspective, this will leave other customers to fund a distribution network's allowed income stream. We are aware that in some other European countries, capacity based charging has been adopted. However to encourage a more flexible system, we would not encourage simply replacing volume based charges with capacity based charges, but note that recovering at least some of the costs which are sunk on a fixed cost basis may have some merit going forward.

Q23. Network charges can send both short term signals to support efficient operation and flexibility needs in close to real time as well as longer term signals relating to new investments, and connections to, the distribution network. Can DUoS charges send both short term and long term signals at the same time effectively?

90. The best way to send signals to support new investments and new connections would be via volumetric ToU tariffs. This would ease demand on the system at peak times but there has been little appetite from customers thus far in seeking to take actions to avoid DUoS charges. This may change in the future, however some thought needs to be given as to the implications of this for less energy intensive business customers who may not have the scope nor the flexibility to change working practices and move from traditional operating hours in order to place less demand on the system.

91. We believe a short term signal which the DNOs could provide is via the creation of local flexibility markets offering services such as demand turn-up and local balancing. However we strongly advocate coordination by the SO to ensure a standardised approach to the design of local flexibility markets is adopted and holistic solutions are brought forward. We note that the EU Clean Energy Package says that DNOs should say how they will use DSR on a two yearly basis as part of a network development plan. This is a sensible approach which encourages DNOs to consider flexibility markets as an option in a similar way that they currently consider capex options[1].

92. In theory DUoS charges have the capability of sending long term price signals to the market to respond to. A key requirement for making this happen is if customers at all levels can see the DUoS charges a number of years ahead with certainty that these charges will remain broadly in place over this period. This is an area which the RIIO framework should consider investigating, but note that this may be very challenging to achieve in practice.

93. Long term DUoS signals are unlikely to be sufficient on their own to incentivise storage assets for example. Other signals will be required which when stacked together can support the commercial case for flexibility, such as income from the capacity and ancillary service markets.

Q24. In the context of the DSO transition and the models set out in Chapter 5 we would be interested to understand your views of the interaction between potential distribution charges and this thinking.

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[1] Electricity Market Directive, Article 31 Para 2:"The network development plan shall also demonstrate the use of demand response, energy efficiency, energy storage facilities or other resources that distribution system operator is using as an alternative to system expansion.

94. It is clear that a DNO will need to transition to become a DSO. The interaction between distribution (including DNO, independent DNO (last mile) and private network operators) and transmission operators will need to improve to help manage the more flexible energy system of the future. However it is not clear to us that the structure of the DUoS charges will help facilitate this objective. This is better achieved via the price control arrangements that Ofgem has with the DNO, IDNO, TNO and TSO and ensuring that correct incentives to co-operate are in place.

Q25. Can you provide evidence to show how existing Government policies can help or hinder the transition to a smart energy future?

95. There is clear evidence that the capacity market is a key policy which is supporting the transition to a smart energy future. In the most recent auction over 500MW of battery storage and 1.4GW of DSR was successful in achieving an agreement. E.ON was able to grow its own smart energy portfolio in the CM with new agreements for over 160MW of DSR and a 10MW battery in the 2016 T-4 auction.

96. This has been possible because of a fundamental principle of the capacity market – to treat all capacity on a fair and consistent basis and allow genuine competition between conventional sources of capacity and less established sources of capacity. It is vital that this principle remains and that the CM does not begin picking winners or defining and discriminating between arbitrarily defined “good” capacity and “bad” capacity.

97. We do not believe new subsidy regimes are necessary to support the transition to a smart energy future, we believe value streams already exist to support smart energy. As we highlight throughout this response, the focus of policy makers should be on ensuring smart energy has access to these revenue streams and that flexibility procurement from the SO or DSOs is based on competitive price discovery and transparency. The capacity market has shown how fair competition, a level playing field and participation of emerging technologies can drive costs for customers to levels below many analysts’ expectations. Focus should now turn to ensuring newer sources of energy, flexibility and capacity can access other income streams on a fair, equal and competitive basis, in particular flexibility markets and ancillary services.

Q26. What changes to CM application/verification processes could reduce barriers to flexibility in the near term, and what longer term evolutions within/alongside the CM might be needed to enable newer forms of flexibility (such as storage and DSR) to contribute in light of future smart system developments?

98. We have participated in a number of CM auctions to date with DSR, storage and distributed generation. Whilst the process has worked overall there are a number of areas we think could be improved. We have submitted a number of CM rule changes to this effect[2].

99. In particular we believe there are a number of areas where processes can be simplified and aligned with other market arrangements, such as metering tests and overall metering requirements. We also believe certain prequalification timescales could be shortened which would allow DSR to participate more easily. This applies to prequalification and operation, for example, allowing DSR tests to take place during the prequalification window will allow more DSR providers to take part. Allowing tests such as the metering assessment to take place closer to the start of a deliver year will also help DSR capacity grow more quickly.

100. We note that BEIS's decision to reserve a much smaller amount of capacity for the T-1 auction for the 2020/21 delivery year is likely to have an impact on DSR. DSR providers find it harder to commit to capacity so far ahead of delivery. It is therefore crucial that policy makers focus on getting secondary trading to work. This is likely to be a key market for new DSR capacity in the absence of a T-1 market. Government has gone to a considerable amount of effort to review and reform secondary trading rule, but further work is required to make this a realistic option. This should be made a priority, and include a review of the penalty regime to understand the role it can play in developing a viable secondary trading market.

101. Given that new flexible capacity now has to commit in the T-4 auctions (because of the limited capacity reserved for T-1) it is important that policy makers consider additional flexibility in applications that may be necessary. For example, smaller generation capacity (which includes storage) is likely to need to aggregate into larger portfolios to participate in the CM. Whilst a DSR portfolio consisting of DSR components has a degree of flexibility, a portfolio of generating units cannot. We also believe both DSR and generating portfolios of smaller units should have the flexibility to add as well as remove components, so long as the capacity agreement overall is maintained. This means a capacity agreement secured in a T-4 auction can still be met even if precise plans for the units involved change during the 4 year period before delivery.

102. The interaction between balancing services and the CM is key. It is important that the CM Rules are updated as new balancing services emerge. For example the EFR service should be listed as a

[2] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/change-proposals?im_field_proposal_organisation=10549&filter_by=ds_field_last_updated&sort_by=ds_field_last_updated&ds_field_last_updated%5Bmin%5D=2016-10-01&ds_field_last_updated%5Bmax%5D&sort_order=DESC

Relevant Balancing Service in the CM Rules. In future new services should be added to this list before CM auctions take place.

103. As we highlight throughout this response, the CM is a good basis for rewarding new flexible capacity on a consistent basis with other forms of capacity. Policy makers should now focus on ensuring other income streams such as flexibility and ancillary services markets are also open to competition from new flexible capacity and are capable of taking advantage of this new competition to drive down the cost to customers.

Q27. Do you have any evidence to support measures that would best incentivise renewable generation, but fully account for the costs and benefits of distributed generation on a smart system?

104. Any support regime for renewable generation should account for the full system costs and benefits of that technology. As a first principle, we believe Government should move away from simple comparisons of levelised cost of energy (LCOE) when comparing generation technologies. A simple comparison of LCOE ignores many key cost elements of generation technologies which drive policy decisions today, in the cost of Green House Gas (GHG) emissions and the cost of capacity and flexibility required to ensure security of supply.

105. We would highlight that capturing such costs is challenging, particularly as the cost and benefits of different forms of energy, capacity or flexibility often depends on the generation mix at any point in time. For example the flexibility costs associated with wind generation will change as total UK wind generation capacity increases. Whilst in theory a market could allocate resources and account for these changes in costs, it would require all participants to be exposed to the true costs. We accept that this is not likely and could have other adverse impacts (for example the impact on consumers of imposing the "true" cost of GHG emissions). Therefore there is a role for Government in reflecting these costs and benefits through its regulatory regimes and therefore a balance to be struck between regular updates of the costs and benefits and predictability for investors who may be planning a number of years ahead.

106. We do not believe mature renewables such as onshore wind and solar require subsidy as such, but Government should design the CfD regime for such technologies which reflects an efficient carbon price and wider system costs in terms of flexibility or capacity, which we refer to as "subsidy free". This will encourage an efficient amount of renewable generation whilst delivering the lowest overall cost to customers.

107. There have been a number of attempts to quantify these additional costs and benefits which should be considered in any support regime. In particular we would highlight the Committee on

Climate Change's work in this area which explored in some detail these additional costs and benefits.

108. Renewable generators also have the potential to provide ancillary services such as frequency response. By moving to a "subsidy free" regime, we believe there will be more opportunities for mature assets such as onshore wind to offer these services into the market place. In contrast, the level of support provided under the RO and existing CfD contracts means that these assets will be the last to offer flexibility to the System Operator because of the potential for losing subsidy support during those periods in which it is called upon.

Smart appliances

Q28. Do you agree with the 4 principles for smart appliances set out above (interoperability, data privacy, grid security, energy consumption)?

109. Yes, the principles of interoperability, data privacy, grid security and energy consumption seem sensible. In addition to these, customer security should also be a key principle. There is a trade-off between interoperability and privacy and security and an appropriate balance must be found between these in order for customers to receive products and services that are useful, whilst protecting their information and securing the grid. As customers tend not to engage with security and data privacy topics until they are explicitly told about them, there may be a role for government to take action to inform customers about the risks.

Q29. What evidence do you have in favour of or against any of the options set out to incentivise/ensure that these principles are followed?

110. We believe that any technical requirements for appliances should be joined up with those adopted within the rest of Europe as opposed to setting UK specific standards.

111. Of the three options set out, we favour an approach based on the labelling of smart appliances. It is important however to consider what the appropriate functional requirements should be to enable an appliance to be labelled smart. We are not yet convinced of the merits of regulation and believe that manufacturers are best able to develop the most appropriate smart appliances as opposed to dictating what type of criteria, standards etc must be adopted. Similarly we would not advocate banning non-smart appliances and instead argue that the market should drive demand for smart appliances.

Q30. Do you have any evidence to support actions focused on any particular category of appliance?

112. No comment.

Q31. Are there any other barriers or risks to the uptake of smart appliances in addition to those already identified?

113. There may be some scepticism that many customers will wish to be exposed to highly volatile prices and that this could, on its own, mean smart appliances are not taken up if common standards are designed to be price driven. Conversely, regulating for a system which allows a supplier (or aggregator) to control a smart appliance themselves could allow for them to manage risk on behalf of customers whilst still offering a reward for the use of a smart appliance.

Q32. Are there any other options that we should be considering with regards to mitigating potential risks, in particular with relation to vulnerable consumers?

114. If dynamic pricing was to become the norm, this is likely to be challenging for many vulnerable customers. However it is not clear at this stage whether there will be sufficient appetite for this type of charging arrangement.

Ultra Low Emission Vehicles

Q33. How might Government and industry best engage electric vehicle users to promote smart charging for system benefits?

115. When considering this question, it is important to understand from a customer perspective what the perceived barriers to smart charging are likely to be. Whilst this list is not exhaustive, we have identified a number of areas where customers are likely to require sufficient assurances to adopting a smart charging system. This includes financial and non-financial benefits which will need to be suitably attractive; overcoming concerns that the vehicle may not be able to fulfil its primary task of transporting a customer to the required destination; fear that the vehicle may depreciate too quickly; and cyber security risks.

116. The automotive industry may support the user by incorporating smart charging vehicle features into their products which would support easy and intuitive engagement with managed energy services; manufacturer endorsement and promotion of the vehicle as more than just a car but also a "power bank"; protection against vehicle defects or faults that may occur while using the vehicle in the smart charging context via the warranty process; and a clear understanding of the resell value.

117. The energy industry will be able to provide reassurance to users by supporting smart charging with managed Electric Vehicle Supply Equipment (EVSE) products and tailored tariff propositions; providing a range of generating options including renewable supply; offering a convenient way for users to opt-in to ancillary services; enabling the user to configure the minimum State of Charge

(SOC) of the vehicle battery to meet their specific traffic needs; and providing convenient methods of payment.

118. There are a number of aspects which could be addressed by Government in order to encourage participation of PEV owners in smart energy services. Firstly the ancillary services landscape needs to be simplified as we have explained in our response. There also needs to be greater coordination of incentive schemes, covering both the purchase of the vehicle and the purchase of onsite generation. For example, it is not clear that a network operator should still be required to approve larger residential Solar PV arrays if the additional generation is to be used by the electric vehicle battery as opposed to placing additional demand on the local distribution network.

119. We also see merit in a coordinated campaign between the automotive industry, the energy sector and government that will educate the customer in the national context of how to participate as a recognised stakeholder in a more distributed energy system. The objective would be to encourage a lifestyle change in terms of energy conscious living and empowerment to be able to make a difference. We recommend in particular to reach out to the younger generation who are already exhibiting behavioural changes towards the use of energy and transport.

Q34. What barriers are there for vehicle and electricity system participants (e.g. vehicle manufacturers, aggregators, energy suppliers, network and system operators) to develop consumer propositions for the:

- **control or shift of electricity consumption during vehicle charging; or**
- **utilisation of an electric vehicle battery for putting electricity back into homes, businesses or the network?**

Vehicle Manufacturers

120. Vehicle manufacturers primarily develop a vehicle from a transport application point of view. Unless there is a commercial demand from the customer base that sees value in paying for vehicles equipped for energy services, there is a lot of uncertainty around the investment required to bring these types of products to market. However we are encouraged that some manufacturers are already incorporating V2X capability (Vehicle to Grid, Vehicle to Home, etc.) into their current range of products.

121. The successful implementation of V2X products requires a connected car concept which infers the need for a digital interface. Apart from Chademo which includes a CAN bus interface (widely used in vehicles as a Control Area Network connecting all digitally controlled devices in the vehicle from engine control, light control, etc), other EVSE charging standards fall short of supporting a connected car concept as part of the charging connection between the vehicle and the EVSE. This

could create a barrier in terms of technical standards that will be required to support scalability in the market.

122. Car manufacturers increasingly have the technical data required as evidence to determine the detrimental effect of using the vehicle battery for ancillary services in addition to satisfying the transport needs. Nissan has publicly declared that using their vehicle batteries in the V2X context will not affect the vehicle performance nor invalidate any warranties. It will be important to see other vehicle manufacturers follow suit as they expand into battery manufacturing businesses.

<u>Aggregators</u>

123. In the context of creating virtual power plants, a PEV represents a very small contribution towards ancillary grid services if seen in isolation. However, when considering this in the national context, aggregation represents a significant asset within the distributed energy system. One of the barriers to overcome is the management of a very large number of small units (i.e. vehicles) in contrast to fewer but bigger assets e.g. CHP plants, but this is very much the same challenge for supporting large numbers of domestic customers capable of offering DSR from shifting demand within their homes. A cost effective method in terms of the Internet of Things (IoT) concept for PEV is required where the aggregation of a large number of PEVs and the associated communication and management costs are commercially viable.

<u>Energy Suppliers</u>

124. In the context of energy supply from renewable sources, electric vehicle batteries presents an ideal, geographically dispersed energy storage solution which could significantly increase the utilisation rate of generation capacity from renewables while compensating for the supply uncertainties from these generation assets. Engaging the customer base to participate in load shifting requires a flexible and dynamic tariff landscape. Moving to elective HH settlement in the first instance is a key enabler for supporting such innovation.

<u>Network and System Operators</u>

125. Network and System Operators in the traditional sense tend to be distribution and transmission networks with no direct contact to the customer. We believe that their role should be limited to providing regulatory frameworks from which flexible services, such as PEV, can find a potential route to market. It is important therefore that the RIIO price control encourages aggregators to offer services to help balance the system at both the local and national levels.

Q35. What barriers (regulatory or otherwise) are there to the use of hydrogen water electrolysis as a renewable energy storage medium?

126. Energy storage in the form of hydrogen created from hydrogen water electrolysis is not a commercially viable option in terms of the cost of technology, energy conversion losses and the limitation in scalability in a decentralised energy system context

127. There are significant safety risks associated with the storage of large quantities of hydrogen and its application in the transport sector. Furthermore our analysis to date suggests that the cost of building a hydrogen infrastructure from scratch is prohibitive along with the cost of using fuel cells from a car perspective. This is set against the context of rapid reductions in the cost of battery storage which are forecasted to continue over the coming few years.

Consumer engagement with Demand Side Response

Q36. Can you provide any evidence demonstrating how large non-domestic consumers currently find out about and provide DSR services?

128. There are a number of channels which large non-domestic customers have used to find out about the opportunities which DSR services provide. This list is not exhaustive but includes sales calls from parties offering aggregation services, trade bodies such as the Major Energy Users Council (MEUC) and other industry energy forums, and National Grid's Power Responsive campaign.

Q37. Do you recognise the barriers we have identified to large non-domestic customers providing DSR? Can you provide evidence of additional barriers that we have not identified?

129. Yes, we agree with the broad themes set out as potential barriers to large non-domestic customers. We would highlight in particular the perceived lack of standards for aggregation services which has made some customers nervous about using their facilities for providing DSR services. This is why we are very supportive of the development of the ADE's Code of Conduct, which we believe will help to address this issue.

130. Metering requirements across ancillary services are inconsistent and sometimes require very costly metering solutions to be installed. Some of these costs are disproportionate for DSR providers and will negatively impact the economics of some options. This needs to be addressed so that the benefits for large non-domestic users providing DSR services can be realised.

Q38. Do you think that existing initiatives are the best way to engage large non-domestic consumers with DSR? If not, what else do you think we should be doing?

131. We have been supportive of the recent initiatives to support engagement of large non-domestic customers. As we have mentioned in other parts of this response, we would argue that reducing the complexity of the different services offered would help customers to understand the

offering and represents an important step towards getting them to engage in providing DSR services.

Q39. When does engaging/informing domestic and smaller non-domestic consumers about the transition to a smarter energy system become a top priority and why (i.e. in terms of trigger points)?

132. There are a number of milestones that need to be met before engaging smaller non-domestic customers but a key step would be when imbalance prices rise to a level where we can foresee it becoming cheaper to utilise Microbusiness DSR (including set-up costs) as opposed to going to 'cash out'. This would require a shift in the market and associated infrastructure to enable easier access to DSR capability. We would also consider smaller non-domestic customers as a priority when a trigger point is reached in terms of the portion of customers that request information about TOU Tariffs. At the moment, we do not see demand for this, but with the advent of EV and smart appliances interest may intensify.

133. We agree that at some stage in the future, the market will also become more attractive for domestic customers. One of the key ingredients for making this happen is the roll out of smart meters complemented by settlement reform. However the costs of accessing smaller flexibility sources will have to come down so that it becomes a cost-competitive option. As a matter of course, simplifying the framework would address the current complexity issue which larger customers already face, and is very likely to act as a major barrier for domestic customers if this is not resolved.

Consumer protection and cyber security

Q40. Please provide views on what interventions might be necessary to ensure consumer protection

134. The increase in connectivity between smart meters, connected homes and smart grids will result in vast amounts of customer data and intelligence being passed between many parties. The location of this data may well be unknown to the customer as will (potentially) the sale of that data to other third parties.

135. In this context it is important that customers have control, via consent processes, of who has access to the data and for the purpose of sharing that data. The compliance of organisations with the Data Protection Act and the emerging General Data Protection Regulations will also need to be taken into account.

Q41. Can you provide evidence demonstrating how smart technologies (domestic or industrial/commercial) could compromise the energy system and how likely this is?

136. There are three main elements required to provide a smarter, flexible approach to realise the aspiration of a smarter energy system:

- Smarter distribution/transmission networks (Smart Grids);
- Smarter consumer in-home devices (Connected Homes)
- Smart Meter roll-out (Smart Metering)

137. The present security position is that each of these elements has been designed individually with different security characteristics and protocols.

Smart Grids

138. Electricity networks utilise Industrial Control Systems (ICS) to manage their systems. The majority of these systems have been in place for many years. The security of these systems was not considered a high priority as they were only accessible from within the networks business concerned.

139. However, the increase in external communication connectivity and the ability of third parties to both access and disrupt ICS systems poses a challenge to UK Critical National Infrastructure. The current likelihood of this technology being breached and exploited is therefore considerably higher than in the past.

Connected Homes

140. Communications to these devices will be using existing technologies based upon current protocols such as those used in mobile telephony and wireless applications. These devices are exposed to the potential of a cyber-attack, either in their own right, or could be used to transfer malicious software to other elements. There is currently no specific security standard for the Internet of Things (IoT) products which leads to a wide range of delivered solutions. It is essential that IoT products are interoperable, consumer friendly and secure. This is recognised on an international basis through the Internet of Things Foundation (IoTF) who are conducting some work in this area. However, this is a new voluntary organisation, established in September 2015, and it is not clear that IoTF security protocols, being voluntary, will necessarily be adopted across all equipment manufacturers in all jurisdictions.

Smart Metering

141. The security aspects of smart meters have been designed into the solution from the outset with involvement from the UK National Cyber Security Centre (NCSC). A secure but ring fenced approach has been used to protect Critical National Infrastructure.

Q42. What risks would you highlight in the context of securing the energy system? Please provide evidence on the current likelihood and impact.

142. Please see our response to question 41.

Roles and Responsibilities

Q43. Do you agree with the emerging system requirements we have identified (set out in Figure 1)? Are any missing?

143. We broadly agree with the emerging system requirements that have been identified. However, it is important to understand how those requirements manifest themselves in terms of decision making as value transfers across different markets. For example, the requirement for efficient, whole system planning will need to be looked at in new ways to ensure that it considers all aspects of the system including energy markets, capacity markets and flexibility markets.

144. Planning decisions and signals need to be efficient across all of these markets in a consistent manner, ensuring they are all taken into account. A decision that may be most efficient with regards to the energy market may not be the most efficient for delivering flexibility or capacity. Likewise, it will be important that signals for generators, transmission and distribution owners/operators and demand will need to take account of these differential impacts. Historically, price signals have been directed at generators, whereas in the new system they will need to be effectively directed to transmission and distribution owners/operators, demand, and ultimately customers. These price signals or charges need to be clear and easily understood by customers in order for them to efficiently drive the correct outcomes.

Q44. Do you have any data which illustrates:

a) the current scale and cost of the system impacts described in table 7, and how these might change in the future?

b) the potential efficiency savings which could be achieved, now and in the future, through a more co-ordinated approach to managing these impacts?

Q45. With regard to the need for immediate action:

a) Do you agree with the proposed roles of DSOs and the need for increased coordination between DSOs, the SO and TOs in delivering efficient network planning and local/system-wide use of resources?

b) How could industry best carry these activities forward? Do you agree the further progress we describe is both necessary and possible over the coming year?

c) Are there any legal or regulatory barriers (e.g. including appropriate incentives), to the immediate actions we identify as necessary? If so, please state and prioritise them.

145. We believe there is a need for the role of DNOs to change to become DSOs. However, the current proposals are quite broad and generic in nature and they would benefit from more specific elements such as "DSOs shall be responsible for non-frequency ancillary services in the distribution system". Explicitly giving DSOs this type of role would send a stronger signal to DSOs and empower them to be able to do what is best for the system.

146. It is clear that there is an increased requirement for TO/SO/DSOs coordination, especially if DSOs will be attempting to solve issues with flexibility and not just network capacity. Given that local planning decisions and actions will clearly have an effect on the whole system, such decisions should not be taken in isolation, but considered more broadly through appropriate engagement. A use of resource may create local benefits (e.g. a DSO stopping local flexibility from being dispatched due to local constraints) but cause detrimental impacts more widely and hence a holistic approach is needed, driven by the DSOs and SO. This approach should apply to both planning decisions and use of resource to ensure the most efficient outcome.

147. We do not currently see appropriate incentives for DNOs to pursue flexibility solutions outside of innovation. We are not aware of any DNO business plans which focus on how to use flexibility through operational expenditure in order to reduce total expenditure even though LCNF projects have shown that this can be done.

148. There should be greater incentives for DSO flexibility in the UK. This could be encouraged by ensuring that the focus for DSOs is not just about how innovation through technology could help networks (on which there is already substantial activity) but also about how networks can facilitate flexibility through markets. New innovative flexibility markets could potentially remove barriers to DSO flexibility and create appropriate incentives in the process.

149. Additionally, the EU Clean Energy Package suggests that business plans include a section on how to use DSR and storage. Such a requirement would be helpful as it would reinforce the use of flexibility in the core of DSO activities.

Q46. With regard to further future changes to arrangements:

a) Do you consider that further changes to roles and arrangements are likely to be necessary? Please provide reasons. If so, when do you consider they would be needed? Why?

b) What are your views on the different models, including:

i. whether the models presented illustrate the right range of potential arrangements to act as a basis for further thinking and analysis? Are there any other models/trials we should be aware of?

ii. which other changes or arrangements might be needed to support the adoption of different models?

iii. do you have any initial thoughts on the potential benefits, costs and risks of the models?

150. We agree that further changes to roles and arrangements are required, particularly as DNOs transition to DSOs and are expected to begin to procure flexibility. The procurement of flexibility at the DSO level has an impact at the SO level and vice versa, so a much greater level of collaboration will be needed to ensure this operates efficiently. For example, actions taken by a DSO to manage a local constraint issue using flexibility could create a system balancing issue as such actions are not always zero sum in terms of MW. E.ON has experienced similar issues to this with HanseWerk in Germany, which tried to establish a flexibility market but with little SO collaboration. This has led to inefficient dispatch as the SO has no visibility of the imbalances created.

151. We believe that the models presented for both network planning and efficient local/system-wide use of resources seem to provide a sensible range of options to consider.

152. With regards to the network planning models, the key aspects to consider will be the arrangements, incentives and accountabilities across the two models. For the SO recommendation model, consideration needs to be given to how much weight the SO recommendations have with regards to TO and DSO decisions. If these arrangements are too weak, then they will provide very little steer and benefit, but if they are too strong, then effectively this model becomes the same as the single party planning model. However, with the right balance, this model could allow a holistic planning view to be followed but still allow some flexibility to DSOs on exactly how best to deliver this. The single party planning model would give the most consistent approach across the system, but reduces the scope for individual DSOs to find the best solutions which could lead to less efficient outcomes.

153. The models suggested for efficient local/system-wide use of resources also have a range of pros and cons which will need to be considered carefully. The DSO/SO procurement model would allow the SO and DSOs to work together to get the optimal system solution to a set of constraints which should maximise the benefits of actions and minimise the detrimental impacts. However, this could potentially create burdensome requirements for flexibility providers to provide bids and offers in every period even when there is no local constraint or system-wide constraint that they can influence. This could create a barrier for some flexibility providers and hence such a model

could benefit from a degree of forecasting of market requirements before flexibility providers are required to submit bids and offers.

154. The market signals and arrangements model could address the potential issue highlighted above, as flexibility providers would be able to choose whether to respond to the signals that were created. However, it is not clear that relying purely on market signals would be effective at delivering the requirements of the system. Whilst some flexibility products may work well in such an arrangement, there are others (such as those associated with system security) which need to provide a greater degree of certainty to the SO and DSOs. In such cases, it may still be necessary to have contracted products which work alongside those offered on market platforms. However, this need could potentially diminish over time as market signals became more established and predictable in reliably valuing those products.

155. The responsibilities in the system operation model should mean that the SO and DSOs have clear views on what each is responsible for and hence should avoid duplication of effort and dis-synergies. However, it may be difficult to determine what the specific responsibilities should be given the different levels of expertise and visibility of data and assets. For example, would the DSOs have the information available to jointly manage a system-wide or transmission constraint or would the SO have the local knowledge on how best to manage a local flexibility constraint. It would be highly likely that a significant degree of collaboration would continue to be necessary, particularly given the fact that some network issues impact each other and using resource to address one could create an issue in another area.

156. In practice, all the models have advantages and disadvantages and hence it appears that some combination of them is likely to deliver the best outcome. Creating market signals and platforms to allow the SO and DSOs to better coordinate access to flexible resources on a consistent basis to manage some of the local and system-wide issues would need to be combined with specific roles or responsibilities for either the SO and/or DSOs to then procure other flexible products where a greater degree of certainty from the system operator was needed.

Innovation

Q47. Can you give specific examples of types of support that would be most effective in bringing forward innovation in these areas?

157. We believe that the support for innovation should be aligned with policy priorities and business needs as the energy system transitions towards a more decentralised architecture and consumers become increasingly prosumers.

158. While vehicle-to-grid represents an important aspect for the development of innovative grid services, we expect to see an increase in self-consumption and a net reduction on distribution network demands, stimulated by a large portfolio of prosumer relevant products and services. In this context, the connected vehicle and IoT are important concepts to be demonstrated in terms of customer/prosumer engagement and delivery of secure digital managed energy services.

159. The innovation support needs to be aligned between the electrification of the transport sector and the decarbonisation of the grid to yield maximum benefits in terms of the system costs and the utilisation of generation from renewable sources.

Q48. Do you think these are the right areas for innovation funding support? Please state reasons or, if possible, provide evidence to support your answer.

160. We support the focus of innovation funding around commercial and residential automated DSR trials. Commercial and domestic DSR could have a large impact on system costs (especially with an integrated approach with EVs), but such solutions appear to be the furthest away from a commercial flexibility option. Investment in the commercialisation of such options would allow this significant benefit to be brought to the market to help achieve a low cost, smart energy system.

161. Innovation funding support for vehicle to grid demonstrations needs to be targeted more towards the development of smart charging solutions, which we believe provides the greatest potential benefit to the system.

162. In respect of storage costs, we expect the market to continue to drive costs down.. Therefore, any innovation funding in this area should focus on how the existing and future options can be integrated into grid-scale solutions.

163. Further to our answers on system and network operation, innovation funding support for developing appropriate routes for the SO and DSOs to procure flexibility on a consistent basis would be useful. Currently, there appears to be limited work in this area, and so this would help remove one of the key barriers for the transition of DNOs to DSOs.

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