A Smart, Flexible Energy System

A call for evidence

Contents

Executive summary

Introduction

1.1. SSE's core purpose is to provide the energy people need in a reliable and sustainable way. Our commitment to our customers is underpinned by our planned infrastructure investment that will total over £5bn during the next 5 year period.

1.2. This response covers the views of SSE plc (SSE), which comprises three principal business segments: Wholesale - producing, generating and trading electricity and gas; Networks - transmitting and distributing electricity, and Retail (including enterprise) - supplying electricity and gas and related services to homes and businesses. We are the only company listed on the London Stock Exchange with such a balance of energy businesses.

1.3. We welcome the opportunity to respond to the Call for Evidence (CfE) on a Smart, Flexible Energy System issued jointly by Ofgem and BEIS. We commend Ofgem and BEIS for collaborating on what we believe is a very important piece of work.

SSE Position

1.4. We share the view that evolving to a smarter, more flexible electricity system is vital to ensuring secure and affordable electricity for consumers now and in the future. We believe that consumers' interests are best protected by a transition of the DNO towards a more active DSO role. Given our existing experience in many aspects of this role and the innovative, customer-orientated approach we have taken to date, we are well-placed to contribute to the evolving policy framework.

1.5. It is important that the regulatory and policy framework is fit for purpose to enable efficient markets for flexibility to develop whereby all providers, including customers, are able to compete. We agree with Ofgem and BEIS' intention to promote industry-led change and market-based solutions. Whilst it is apparent that in some cases regulatory change is potentially required to remove barriers, we support an incremental approach whereby impacts can be reviewed and the best solution can be chosen from an evidence-based perspective. This will lead to a better outcome than selecting a model for immediate wide-scale reforms - that approach has the potential to de-stabilise the market and investment plans and will not be in the interests of customers.

1.6. Our views on the specific sections covered in this call for evidence are briefly summarised below:

Removing Policy and Regulatory Barriers

Storage

1.7. The current market framework is not designed with electricity storage in mind. Further work will be required to the current market and regulatory arrangements, including on charging, before the true benefit of electricity storage can be realised. We believe, (and our innovation programme supports this view) that it is in the interest of customers that storage of all scales, including bulk storage, should be considered relevant to the development of a smart flexible energy system. We therefore recommend that the market does not bias towards any particular technology but instead rewards the relevant services and reflects the true network cost and benefits of storage.

1.8. Pumped storage has a long history of providing flexibility to the grid and continues to have a very important role to play for the system. We therefore consider there to be a significant benefit attached to further deployment of pumped storage and other bulk storage technologies. The lack of certainty, over the long term, that available revenues will sufficiently stack up to make the project viable is the main barrier to the delivery of large-scale bulk storage. The investment case for new build interconnectors faces very similar issues to new bulk storage. However, this barrier can be overcome by a Cap and Floor mechanism and we believe that a similar mechanism should be extended to pumped storage and other forms of bulk storage.

Role of aggregators

1.9. Aggregators could be an important component of a smart flexible system and we welcome further examination of the benefits, risks and opportunities that are offered and the role that aggregators can play in bringing additional efficiencies for system management and the energy market. We are of the view that the role of aggregators needs to be regulated in order to appropriately integrate this market participant into the market. This will also ensure that consumers are adequately protected and that the visibility and forecasting necessary to allow the management of network constraints can be guaranteed.

Price Signals

System value pricing

1.10. Any new framework needs to put the interests of customers at its heart. With customers and market participants becoming increasingly 'smart' and agile it is important that a smart flexible energy system is set up to send effective price signals and cost reflective charging. In particular, we recommend that existing network charging arrangements (connection, use of system, transmission and distribution) need to be examined holistically and any distortive signals should be addressed as a priority. To better facilitate effective competition between all users of the network, including storage assets, which may be connected to the transmission network, the distribution network, or behind a demand meter, the network charges for distribution and transmission should be brought closer into line with each other. There is a risk that if distortions are caused by inconsistencies between these different network charging arrangements, then there will be a distortion to investment and dispatch decisions which will ultimately result in a less efficient outcome and higher costs to customers. We recently provided evidence[1] to Ofgem in response to its consultation on Embedded Benefits that demonstrated the extent to which existing distortions are costing the bulk of consumers more. Consequently, whilst we support a holistic review of network charges we believe that more urgent attention is required on the TNUoS residual to avoid consumers supporting economically inefficient investment and dispatch decisions.

1.11. We also believe that an extensive review of the system services that are required by the System Operator (SO) should be undertaken. We consider elements of the DS3 programme, as introduced in Ireland to incentivise and improve system performance and capability, to be a step in the right direction when it comes to providing transparency of the services that are available to support the system and providing

[1] See attached documnet1

opportunities for existing parties and new entrants to participate in their provision. We note that Ofgem has recently published a consultation[2] setting out its thoughts on the further separation of the SO role within National Grid and we will be responding in due course.

Settlement and Smart tariffs

1.12. Half Hourly Settlement (HHS) is contingent not only on a significant penetration of smart metering but also on the ability of market participants to access the Half Hourly data collected from the smart meters. As we have explained in our recent response to Ofgem's consultation[3], whilst Mandatory HHS opens up opportunities to transform the energy market, this data barrier needs to be overcome at an early stage in the Significant Code Review. Therefore our view is that mandatory HHS should not be implemented until after Smart meter roll out is completed.

1.13. We believe that whilst BEIS and Ofgem have a role to play in facilitating the market, new tariff structures including smart tariffs should be developed in response to customers. The evidence from the trials that we have been involved in (as a supplier and network operator) suggests that smart meters and better information about energy consumption patterns are the key enabler for customers' take-up of innovative new tariffs.

System for Consumers

1.14. We agree that evolution towards a smart, flexible energy system must prioritise the interests of the end consumer. To this end, we are supportive of a consumer-centric approach that will thoroughly examine the risks to consumers as a priority. Particular attention should be given to ensuring that domestic customers, particularly the vulnerable, are supported and are able to realise the benefits of these evolving arrangements, thus minimising any unintended consequences. For example, there is a risk that vulnerable customers will pay more as fixed costs, that need to be recovered, are avoided by other end users who lower their share of the costs (through actions such as installing behind the meter generation). Integral to this is prioritising the review of charging arrangements so as to avoid market distortions being created. We support BEIS and Ofgem's examination of the role of smart appliances, electric vehicles and DSR and our comments on the particular risks, benefits and challenges of these can be found in the main body of this response.

Roles of Different Parties

1.15. We agree with the assessment that the changes taking place on the electricity system will have an impact on the roles and responsibilities of different market participants. In particular, DNOs will need to transition to new roles and are best positioned to support the efficient connection and utilisation of new flexible and dispatchable resource below the Grid Supply Point (GSP). By taking account of network constraints, stability requirements and existing connection arrangements, DNOs can take charge of local planning decision making to meet the interests of all their customers. We believe that DNOs can help to

[2] Future arrangements for the electricity system operator - 12 January 2017

[3] Mandatory Half-Hourly Settlement: aims and timetable for reform – SSE response submitted 6 January 2017

increase access for new entrants to participate in the national provision of ancillary services and the Balancing Mechanism by sharing a BSUoS incentive and coordinating resource use with the SO.

1.16. As a result of the challenges of operating remote networks, we have experience in many aspects of the role and function of a DSO. For instance, we have already been involved in Active Network Management (ANM) and we anticipate this need growing in future. Furthermore, our commitment to equitable, non-discriminatory solutions has led to the development of Constraint Managed Zones (CMZs). These allow distributed energy resources to compete and capture value that otherwise would have to be spent on traditional reinforcement. In addition, our rich portfolio of DNO innovation projects has allowed different technologies and providers of flexibility to be tested and evaluated (see Appendix 1).

1.17. Our DNO business has strong links with local communities, which we intend to further develop as part of our transition to a DSO. For example, we are collaborating with Community Energy Scotland, V-Charge (an aggregator) and the Mull and Iona Community Trust on a project called 'Assisting Communities to Connect to Electric Sustainable Sources' (ACCESS). This project puts customers at the heart of the solution by investigating the use of smart electric heating for balancing low carbon generation in a way that optimises their thermal comfort. Due to the DNOs' understanding of local network flows and the needs of their customers and communities, we believe they are best positioned to work with aggregators to realise the full benefits of their flexible resource i.e. maximising primary (local) and secondary (national) utilisation at least cost.

1.18. We are therefore proactively engaged in and are well placed to support and lead work on what needs to be done to enable the transition to DSO. There is more work to be undertaken to predict all the challenges, risks and possible unintended consequences that may arise in what will inevitably become a more complex and less predictable operating environment. However, we believe that the majority of issues with the interface between the TOs/SO and DNOs should be able to be addressed via greater coordination and a re-evaluation of the regulatory frameworks for TOs and DNOs to facilitate new flexibility providers in a way that is cost efficient for all consumers.

1.19. Our core objective is to continue to work on realising new flexible resources that avoid disruption and maximise customer benefits. To achieve this, we recommend an incremental approach would be the most appropriate to ensure that standards are maintained, whilst the industry is afforded time to work together to develop best practice and the operating costs and risks associated with these solutions are verified in a non innovation funded environment.

Innovation

1.20. We believe that innovation is of vital importance to the development of the efficient, flexible networks that will be required in the future. The emergence and uptake of low carbon technologies, electrification of transport and decarbonisation of heat will provide significant challenges to the GB electricity networks. Innovative solutions will allow networks to provide better services at lower cost, whilst opening up new marketplaces for other industry participants. All of this should facilitate the objectives of ultimately providing lower cost and sustainable electricity supplies for consumers as well as the chance to contribute to the efficient functioning of the country's energy infrastructure.

1.21. The portfolio of innovation projects we have undertaken as a DNO (see Appendix 1) has been fundamental in improving our understanding of the opportunities, risks and practicalities of utilising and coping with this increased flexibility. This understanding has provided us with the data and confidence to pioneer on business as usual deployments of CMZ and Active Network Management amongst other examples.

1.22. The one common theme of the learning from all these projects has been the rapid growth of complexity even within relatively simple implementations of elements of a DSO's operation. Interaction between communications infrastructure, customer behaviour and local economics very quickly intertwine to create unexpected outcomes. Given that these existing projects have been relatively simple in comparison to a full DSO implementation and have not addressed some of the more dynamic aspects such as true markets, it is critical that innovation and the structured trialling of concepts continues to grow and evolve.

Conclusion

1.23. The call for evidence highlights that technological change coupled with the mass market rollout of smart meters in GB will transform the energy system as it shifts to accommodate low carbon, sustainable energy sources as well as changes in demand. Many parties have taken the opportunity to become involved in the provision of flexible products and services and, as a result, there is a wide range of commercial arrangements in place. In addition, we consider that there is already a substantial level of concurrent and transformational industry change which needs to be taken into consideration to ensure that potential competing objectives are appropriately assessed and the solutions found do not lead to inadvertent unintended consequences.

1.24. In our detailed response, we have sought to highlight the substantial body of evidence and practical experience that we can provide to inform the next phase in the development of a smart, flexible energy system. SSE considers that it is ideally placed to support BEIS and Ofgem in this process and looks forward to working with all stakeholders to achieve the best outcome for all energy consumers.

2 Removing policy and regulatory barriers

Executive summary

Storage

2.1. The current market framework is not designed with electricity storage in mind. Further work will be required to the current market and regulatory arrangements, including on charging, before the true benefit of electricity storage can be realised. We believe, (and our innovation programme supports this view) that it is in the interest of customers that storage of all scales, including bulk storage, should be considered relevant to the development of a smart flexible energy system. We therefore recommend that the market does not bias towards any particular technology but instead rewards the relevant services and reflects the true network cost and benefits of storage.

2.2. Pumped storage has a long history of providing flexibility to the grid and continues to have a very important role to play for the system. We therefore consider there to be a significant benefit attached to further deployment of pumped storage and other bulk storage technologies. The lack of certainty, over the long term, that available revenues will sufficiently stack up to make the project viable is the main barrier to the delivery of large-scale bulk storage. The investment case for new build interconnectors faces very similar issues to new bulk storage. However, this barrier can be overcome by a Cap and Floor mechanism and we believe that a similar mechanism should be extended to pumped storage and other forms of bulk storage.

Role of aggregators

2.3. Aggregators could be an important component of a smart flexible system and we welcome further examination of the benefits, risks and opportunities that are offered and the role that aggregators can play in bringing additional efficiencies for system management and the energy market. We are of the view that the role of aggregators needs to be regulated in order to appropriately integrate this market participant into the market. This will also ensure that consumers are adequately protected and that the visibility and forecasting necessary to allow the management of network constraints can be guaranteed.

Enabling storage

Question 1:
Have we identified and correctly assessed the main policy and regulatory barriers to the development of storage?
Are there any additional barriers faced by industry?

2.4. We agree that reducing the barriers and unlocking the opportunities available to all types of storage and other types of flexibility in the market is necessary in order to ensure the best value is extracted from these services so the customer and the system in general can benefit.

2.5. As outlined in Ofgem's 7th December 'Innovation and Regulation' report, well-functioning competitive markets put pressure on companies to find new, better ways of doing things. We agree with Ofgem's opinion that, innovation spans technologies, systems and business models and it is important to ensure that new businesses and technologies face a level regulatory playing-field.

2.6. We believe that the policy and regulatory barriers that have been outlined in this call for evidence are, in broad terms, correct but consider that some other key barriers have been missed. For example, many of the barriers are predominantly focused on smaller-scale distribution connected storage which in our view will not, on their own, be sufficient to address the issues faced by new bulk storage projects.

2.7. We believe that poorly drafted policy could be a barrier to the most cost effective and environmentally sound solutions. In the process of encouraging the use of storage, narrow definitions of "storage" shut out alternative solutions that provide the same functionality. By way of example, our innovation programme has shown that Energy Vectors, Pump Storage, (retrofit or new) Compressed Air Storage, Thermal Storage, Demand Side Response and Management etc. all provide very similar and, in some applications, identical services to the networks and the wider system. This is not only in the context of trials but also in practice, e.g. in the Netherlands, Thermal Stores are used to provide frequency response services, short term reserve and network constraint management.

2.8. The use of all of these technologies have their limitations in terms of, scale, speed of response and duration of the services they can provide. By way of example, in our innovation programme we have observed that batteries are of limited value to network operators where a particular network is export constrained and subject to a high load factor. In this case the export constraint that is limiting the ability of generators to export also prevents the battery from discharging meaning that once charged, the battery cannot be discharged without constraining the very generation it is supposed to be assisting. In contrast new flexible demand and energy vectors do not suffer from this particular problem. Similarly there are scenarios where batteries provide a more suitable solution than energy vectors or new flexible demand.

2.9. The key point is that any attempt to promote storage should promote all forms of "Flexibility", with the incentives being linked to the capabilities and applicability of the solution to a particular problem rather than a specific technology.

2.10. New storage assets can be a vital and valuable asset to enable the development of a more efficient and secure low carbon energy system at a lower cost to customers. However, there are fundamental economic barriers in the existing market structures, and if these are not addressed the potential size of the storage market may not be realised. Storage /flexibility could provide many services and benefits to society and there needs to be an accessible mechanism for rewarding this flexibility. The benefits include: avoided transmission and distribution network reinforcement, higher utilisation of renewables, lower system operating cost, lower system fixed cost, better fuel security and better energy system resilience. However, the current market arrangements are not designed to recognise these benefits through any additional return to the storage operator.

Market distortions

2.11. A fluid storage market at a national level is a reasonable proposition; within a local DSO constrained zone market fluidity is far more challenging. Individual generators, loads and storage will often have the ability to affect the need for services relatively easily. An over-reliance on a dynamic market in local areas has significant potential for abuse and perverse incentives. In designing any system it is key that these factors are considered and mitigated.

2.12. As we have stated above, the current regulatory arrangements are not designed with electricity storage in mind and as a result the mechanisms in place for the collection of revenues (such as TNUoS, low carbon levies and Capacity Mechanism levy) introduce distortions to both investment and dispatch where they are not cost reflective. These distortions incentivise inappropriate outcomes, thereby resulting in higher cost to customers over the long-term. It can also mean that higher cost projects are able to out-compete lower cost projects. It is important that market, regulatory and policy, price signals are cost reflective so that the economic incentive faced by developers is in line with the interests of society.

2.13. As noted above, electricity storage has the potential to drive changes in, and deliver, a wide range of benefits to the GB electricity system. However, there is no one type of storage, or specific technology which can provide all these benefits and therefore, in our view, different types of storage, at different scales will be essential if the full potential and value of storage is to be realised.

2.14. Within the current GB market, there are a number of non-cost reflective charging structures which can provide indirect subsidises to smaller scale storage assets connected to the distribution system, or behind customer meters. These take the form of "avoidance benefits" and include, for example, the avoidance of low carbon levies (such as the Renewables Obligation (RO), Contracts for Difference (CFD), Feed in Tariff (FiTs), Warm Home Discount (WHD), and Capacity Mechanism (CM)), as well as avoidance of both the costs of operating and investing in the distribution and transmission networks. These non-cost reflective charging structures distort effective competition which results in otherwise economically viable storage projects being crowded out by more expensive and less economically viable projects, resulting in higher cost to society and higher customer bills. It is essential that these market distortions are examined fully and properly addressed so that the competitive market can operate effectively to deliver better value for customers and a more economically efficient outcome.

SO/DNO coordination

2.15. We believe that co-ordination between the Network Operators in particular regarding a whole-system approach to the use of resources from across the system including distribution-level procurement of flexibility actions is necessary. For example, there are scenarios where storage could be incentivised to connect in order to address both a constraint on the distribution network (for example, related to demand load at the winter peak) and a transmission constraint (for example, related to generation exports at the summer trough). This could defer the need for network reinforcement. Co-ordination between distribution and transmission should be specifically permitted under the connection and charging rules in order to extract the maximum value from the connected storage and other sources of flexibility.

Benefits of bulk storage and pumped storage

2.16. Pumped storage has a long history of providing flexibility to the grid and can provide services that cannot be provided by battery storage and which continue to have a very important role to play for the system. We therefore consider significant benefits can be realised with further deployment of pumped storage and other bulk storage technologies.

2.17. Currently pumped storage is the only storage technology that can be deployed at the tens of GWh scale and can provide long duration storage which enables it to provide reliable capacity over an extended period of time. It has the highest efficiency of all currently available storage technologies at up to 80%, furthermore, it is able to respond quickly to system requirements (in under 15 seconds when in spinning mode). Given these qualities it has the capability of providing a broad range of system benefits including load balancing for variable renewable generation both over the daily grid demand cycle and, in the case of new build projects, over a multi-day range and seasonal weather cycles.

2.18. Additionally, modern, advanced pumped storage technology with variable speed drives provides grid flexibility and stabilisation ancillary services in both generating and pumping modes at an as yet unrivalled scale. These services include frequency regulation, dynamic load following, fast reserve, voltage regulation, black start capacity, and strategic reserve.

2.19. The unrivalled volume and duration of storage provided by bulk storage will become increasingly important as larger volumes of flexibility become a requirement for the system. This need was identified in a recent report by DNV GL which stated:

> *"non-hydro distributed energy storage systems can contribute to balancing net- demand and keeping the system stable. However, their relatively small energy storage capacity together with the dynamic operating regime under which they are expected to operate will limit their capability. Bulk fast-response and reliable large-scale energy storage capacity will therefore be needed in the UK"*[4]

[4] DNV GL : The Benefits of Pumped Storage Hydro to the UK, Scottish Renewables, 30th August 2016 http://scottishrenewables.com/publications/benefits-pumped-storage-hydro-uk/

2.20. The growing need for all of the services offered by pumped storage was highlighted in National Grid's 2016 'System Operability Framework' (SOF). In which, regarding future frequency management requirements, the SOF highlighted a continuing and ongoing decline in the provision of necessary inertia on the system concluding that "*the lowest level of system inertia will reduce throughout the decade and the proportion of time when the system runs at low inertia will increase*[5]" Pumped storage is able to play a key role in cost effectively increasing levels of inertia, as also recognised in the SOF, which stated "*instructing pumped storage units to act as synchronous compensators by spinning in air…has the effect of increasing inertia, or to pump, which has the combined effect of increasing inertia and demand*[6]"

2.21. Beyond direct system services, deployment of new pumped storage can provide a number of broader benefits to the UK. We commissioned Baringa[7] to undertake quantitative analysis of the wider societal benefits that development of new pumped storage could deliver. This analysis concluded that a new pumped storage development could deliver a number of social welfare benefits through a reduction in variable costs of generation; reduction in other capital and fixed costs to the system by displacing the need for alternative generation capacity; and reduction in the cost of curtailing wind and reduced need for investment in transmission network reinforcement. The Baringa analysis valued these benefits at around £70m per annum in 2030. Furthermore Baringa's work identified a number of key areas where new pumped storage could deliver reductions in customer bills, specifically through reduction in wholesale price; reducing the cost of managing transmission network constraints; reduction in the cost on bills of the CfD support scheme; reduction in the cost to the System Operator to compensate renewable generators for lost subsidy revenue in the case of curtailment; and avoided subsidy payment from new build renewables. Baringa's analysis estimated the customer bill benefits to be around £215m per annum in 2030. We would be happy to share more detail on these findings with BEIS and Ofgem.

Barrier to development of bulk storage - Failure to recover long-run marginal cost

2.22. Given the identified benefits, we believe the consideration of policy and regulatory barriers to the development of storage must, along with those identified in this call for evidence, also include consideration of barriers to the deployment of bulk storage such as new pumped storage.

2.23. Bulk storage, such as pumped storage or compressed air caverns are a major infrastructure investment, with large upfront capital costs and significant lead times, coupled with long operational lives and low operational costs. However, the current electricity market does not provide the revenue certainty required to make an investment decision for such projects, and project developers are faced with the risk that the expected revenues will not be sufficient to cover the capital and fixed costs. Developers of all projects; including pumped storage; seek to 'stack' the available revenues from the energy market, capacity market and balancing services. However, for the scale of investment required, revenue stacking alone does not provide sufficient certainty of a compelling business case for investment to proceed. This is due to a number of issues, including:

- Competitive short run marginal cost commodity markets fail to recover long-run marginal costs;
- The evolution of UK Government policy and subsequent impact on the value of future revenues is highly uncertain;

[5] System Operability Framework November 2016, National Grid, November 2016
[6] Ibid
[7] We would welcome the opportunity to discuss this analysis in more depth with BEIS and Ofgem.

- Developers are not ‘recompensed for a number of the broader economic benefits that their projects would provide to society (as outlined above) resulting in ‘missing markets’;

- Pumped storage provides a number of services for which there is not currently an available market, such as the provision of inertia;

- Revenues earned from ancillary services come from short term contracts (generally 1 to 2 years) making future forecasting highly risky. This barrier is equally applicable to all developers of storage;

- Similar infrastructure-type energy investments, such as interconnector projects, face very similar investment issues to pumped storage and compete to provide many of the same flexibility services. However interconnectors are currently advantaged by the availability of the Cap and Floor mechanism which helps to provide the required future revenue certainty to enable investment.

2.24. Competitive markets push prices down to short-run marginal cost, so that market participants recover their marginal cost, but do not recover a return on their original investment (sunk cost). This applies to wholesale price arbitrage as well as the fast response flexibility services which batteries seek to deliver. This is a significant problem for large, bulk storage which is initially very capital intensive due to its nature (it is built for the long term, is durable, does not require to be replaced regularly and can provide a much broader suite of services than other forms of small-scale, short-term storage). The conventional solution in economics is that the requirement for high capital (sunk) costs acts as a barrier to entry, so that the market is under supplied and the market clearing price remains high above marginal cost, however, this can also lead to an under supply of services required by the system. This issue is already successfully dealt with through existing competitive market mechanisms within the energy market including the Cap and Floor for interconnectors, the Capacity Mechanism for dispatchable plant, and the CfD for low carbon plant, and it is essential that the UK Government and Ofgem give similar consideration to enable the development of storage, in particular bulk storage.

2.25. The lack of certainty, over the long term, that available revenues will sufficiently stack up to make the project viable is therefore the main barrier to the delivery of large-scale bulk storage such as new pumped storage. This conclusion is supported by the analysis undertaken for us by Baringa, which considered the potential for pumped storage to derive earnings from operating in the energy market and by bidding into the capacity and balancing markets. The modelling concluded that the revenue for pumped storage is highly uncertain and may not be sufficient to cover capital and fixed costs under a number of scenarios modelled (including Baringa’s Reference Market scenario).

Potential solution

2.26. As outlined above, the investment case for new build interconnectors faces very similar issues to new bulk storage. However, this barrier can be overcome by the Cap and Floor mechanism. It provides interconnector developers with the necessary long-term certainty for investment. We believe that a similar mechanism should be extended to pumped storage and other forms of bulk storage.

2.27. Under a Cap and Floor regime, storage projects would continue to rely on revenue from energy arbitrage, the capacity mechanism and provision of ancillary services, however the addition of a regulated “floor” would act as an overarching risk reduction instrument that will unlock investment into this technology. For this reason, it is the most suitable support mechanism for preserving an efficient and economic price signal for storage operators to dispatch and operate across the whole range of different markets. As is required for the interconnector Cap and Floor regime, we would expect that storage developers would be required to submit a business case for their project to undergo a process of assessment and evaluation, including cost-benefit analysis, to determine if the project qualifies for the Cap and Floor mechanism. This would ensure that only economic and efficient projects in the interests of consumers are granted a bulk storage Cap and Floor contract. Furthermore the design of the mechanism is intended to ensure that the cost to consumers is limited, by requiring that investments deliver value for money.

Question 2:
Have we identified and correctly assessed the issues regarding network connections for storage?
Have we identified the correct areas where more progress is required?

2.28. We agree that getting a timely and fairly priced network connection is important for all customers, including storage customers. Consideration should be given to the specific issues facing storage so these can be integrated into the solutions which are being developed for all customers.

2.29. The cost that a storage unit would impose in the network depends on how it is connected and also how it intends to use the network. From a connection charging point of view, it is possible to differentiate between storage that is connected as a “firm” capacity, with no shape, that can operate at any time of the day or day of the year (be that peak or trough), and storage that is connected as a flexible connection, which can be controlled by Active Network Management (ANM) and operates to a pre-agreed / defined period. The network costs for these two types of connection would be different.

2.30. A third type of connection is one where, although there is no ANM controlling the export or import, the storage connection requesting party provides information about the commercial profile that the storage unit is going to operate under. If a storage network user is able to provide this information, it may be possible in some cases to use this profile for the network analysis performed to determine the network connection charges and the need for reinforcement. However, given the new market arrangements introduced by the Balancing Network Code it is unlikely that such market certainty can be provided by the party wishing to connect.

2.31. We consider that a ‘smart’ connections process which assesses technologies based on their technical capabilities and ability to fit onto the network without the requirement for reinforcement would be better suited to meeting both network operator and developer needs. Network constraints can be caused by various issues and whilst storage can alleviate some of these issues or be connected and not further exacerbate them, we consider that other providers of flexibility could potentially serve the same purpose and should be assessed in the same manner. We agree that if storage is assessed to be the most economical way to resolve a particular network issue then there should be the potential to "fast track" the connection where this does not commercially impact other parties with signed connection agreements. It is important to ensure that any process which is developed does not consequentially create more uncertainty for anyone already trying to connect.

2.32. As a DNO we have initiated work in a number of areas to improve connections.

- In order to provide more clarity on the connections process for storage SSEN ran a dedicated Battery Storage Workshop for customers last year and these are now a key part of Stakeholder Engagement Events such as the Connection Surgeries run by Major Commercial Contracts Managers. These have informed our approach to storage connections. SSEN produced one of the first supplemental application forms for battery storage designed to obtain pertinent information and facilitate connections. This was adopted by the ENA and identifies charge/discharge periods, tendered services etc. Currently under P2/6, connection applications for storage need to be assessed on their impact on the network at both maximum export and maximum import, and their possible interaction with both demand and generation constraints. We are involved in the current review of the P2/6 standard and are able to provide the learning from our own analyses.

- To help develop industry understanding on how storage paired with current connections will affect the network and define processes for new or modified connections, SSEN contributes to a number of ENA workshops addressing storage such as the Domestic Storage Discussion Group, the DNO DG Steering Group – Technical Workstream, the Energy Networks & Futures Group and the DG Technical Forum.

- SSEN is committed to providing better information to storage customers. We already have demand heat maps in place. These are can be viewed on our website (www.ssen.co.uk). As well as showing areas of constraint they also show planned Transmission works and will soon be updated to show planned reinforcement to the Distribution network. We are also currently trialling a Constraint Managed Zone which, while technology agnostic, is open for battery storage to alleviate a demand constraint.

- SSEN has developed a standard process for all flexible connections which will be introduced once the necessary regulatory approval has been given. For storage, the requisite information to facilitate a flexible connection is captured on the ENA supplementary application form and can be accommodated as part of the connection. Storage services are not currently targeted at the DNO but invariably at National Grid or via Aggregation. If they were aimed at the DNO then a flexible connection for storage could be better aligned to the local grid requirements.

- The alignment of flexibility products, such as Enhanced Frequency response (EFR) and constraint management, between DNOs and the SO is an important step towards a more integrated, smarter system. The TDI Steering Group was set up by the ENA in late 2015 with a number of focussed work subgroups including the Statement of Works process, High Voltage Management, Shared Services, Active Network Management, the consistency of T-D charging and more integrated T-D approaches to providing network capacity. Whilst the TDI groups have made significant progress, it became clear that the rate of progress expected by stakeholders would require a change in approach to delivery. A proposal was submitted to the ENA Board meeting on the 6th December 2016, with the Business Leaders of the Network Operators, Transmission Operators and System Operator giving their commitment to a long-term project to be led by ENA to progress these objectives by adapting to a new project structure. Along with the other DNOs, SSEN has committed to provide resources to support, fund and steer the project.

Question 3:

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?
Please provide evidence to support your views, in particular on the impact of network charging on the competitiveness of storage compared to other providers of flexibility.

2.33. The basic principle behind network charging is to ensure system costs are recovered in a cost reflective way and to provide forward looking price signals. Ofgem's ongoing work on charging arrangements for embedded generation, for example, will address some of the issues regarding storage and network charging.

2.34. It is important to ensure a level playing field for all users be they (i) new or existing, (ii) demand or generation or storage (iii) owned by commercial operators or network operators; so that developments lead to as efficient an outcome as possible.

2.35. For storage, emphasis should be placed on ensuring:

- **Distribution connected storage should not be paid for avoiding revenue collection charges**

  Ofgem has correctly identified the market distortion caused by Triad avoidance benefit through which distribution connected generation are paid by suppliers for effectively providing a "tax avoidance" service to suppliers. This distorts competition between transmission and distribution connected storage and results in higher cost to customers. There is an opportunity to correct this distortion through the approval of particular the Workgroup Alternative Code Modifications (WACMs) identified for CMP264 and CMP265.

- **Behind the meter storage should not be paid for avoiding retail levies**

  Ofgem has previously correctly identified the market distortion where customers install storage behind a demand meter for "tax avoidance" purposes so that they can benefit from avoiding paying revenue collection elements of various charges including transmission network charges, distribution network charges and low carbon levies. These avoidance benefits represent a form of value which is only available to behind the meter storage, but is not available to storage connected to either the distribution network, or the transmission network. This results in a distortion to competition which will tend to result in the wrong type of storage (unjustifiably favouring very small scale storage) being built in the wrong place (which crowds out efficient location decisions) doing the wrong thing (behind the meter storage dispatch will tend to arbitrage tax avoidance opportunities instead of genuine economic value to the system) and result in worsening inequity (the taxes become disproportionately paid by the poorest and most vulnerable customers who are least able to make use of behind the meter storage to avoid paying them, while the most sophisticated customers enjoy the benefits).

- **Transmission connected storage should be subject to the locational TNUoS charge but not the Demand Residual**

  TNUoS charges currently fail to recognise the benefit which storage assets can provide for the transmission network. For example, a storage asset located in Scotland can absorb surplus wind generation to reduce the cost of managing constraints. This reduces the need for network reinforcement and can result in a lower cost of the transmission network. However, currently TNUoS demand charges do not reflect this benefit because the negative Year Round locational charge (which could reflect the locational benefit of storage in Scotland) is currently applied on a non-cost reflective charging base (Triad) and crowded out by the non-cost reflective Demand Residual charging element. Therefore there is an opportunity for TNUoS demand charges to be improved to be more cost reflective so that the Year Round tariff element can more appropriately charge/rewarded for the locational costs/benefits to network investment which storage assets can provide.

- **Transmission connected storage should not pay TNUoS demand revenue collection levies.**

These ‘taxes’ should be collected through the final consumer.

- **Distribution connected storage should not have to pay retail levies.**

  These ‘taxes’ should be collected through the final consumer.

Classify storage as intermittent or non-intermittent

2.36. We are aware that there is a certain amount of uncertainty on the part of storage developers when it comes to estimating their network charges. With the other DNOs we are currently involved in industry discussions on the review of the Common Distribution Charging Methodology (CDCM) and we are keen to engage with Ofgem to formulate a unified approach to storage connections to solve this problem.

2.37. For network charging purposes, all users of the network (including storage assets) should be charged cost reflectively based on the cost(s) of the network that they give rise to. This includes how and when it operates (for example, whether it is connected under a flexible connection agreement with, for example, active network management contracted by the network operator). The connection charging for storage should be based on how it is connected (such as flexible or non-flexible) and its use-of -system charges should be based on what import and export profile it is likely to have. This will differ between technology types and how the owners of the assets choose to operate them.

2.38. A Grid Code Working group (GC0096) has been set up in order to address the issue of classification for transmission connected storage technologies and it would be sensible to ensure that the same assessment is done for distribution connected storage. We would welcome further engagement with Ofgem and industry to ensure this happens.

Potential DUoS charging solution for storage

2.39. We believe there would be benefit in developing a new category for DUoS charging, with storage being classed as either:

- Firm storage, connected without a flexible connection without ANM, and where the import and export capacity are requested on a 24/7 basis.
- Flexible storage, connected with ANM which guarantees that the coincidence to system peak and therefore cost drivers would be very small or non-existent.
- “Commercial” storage, where an assumption can be made on the most likely profile that the export and import of these units will take.

2.40. The industry should be able to work with storage groups in order to achieve the best modelling methodology for these new categories, in a similar way that generation and IDNO charging methodologies have been derived in the past.

Flexible connections for all connections, including storage

2.41. Various types of flexible connection are already available, and we support further work in this area to ensure network charges reflect the actual connection and operational costs to the network operator of any asset connecting to the network.

2.42. Most importantly we consider that any modifications to charging arrangements should take place through the existing industry modification processes to ensure the delivery of solutions which are in the best interest of consumers.

2.43. To better facilitate effective competition between all users of the network, including storage assets, which may be connected to the (i) transmission network, or (ii) the distribution network, or (iii) behind a demand meter, the network charges for distribution and transmission should be brought closer into line with each other. There is a risk that if distortions are caused by inconsistencies between these different network charging arrangements, then there will be a distortion to investment and dispatch decisions which will ultimately result in a less efficient outcome and higher costs to customers.

Question 4:
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?

2.44. Storage can be a valuable source of flexibility for network operators in so far as it offers an alternative solution to avoid or defer the need for other forms of network reinforcement and can potentially support faster network connections. There may be cases where there is insufficient incentive for commercial developers to connect storage resources where they are needed, even where those resources would have a beneficial impact upon the network as a whole.

2.45. Network operators will continue to have the option to utilise storage as a service provider and this should continue as the default route. We have noted some aspects of network charging for storage services which need reform but the general principle should be to provide commercial developers of storage with incentives from efficient price signals by the network operators.(including for ancillary service provision). This is the best route to enable the development of a competitive market for storage.

2.46. Whilst the current regulatory treatment of storage allows network operators to own and operate 'generation' assets if they are exempt from requiring a licence (with storage currently falling under this classification), the current de-minimus levels could constrain the option for further development by network operators' of solutions to reinforce the network (e.g. storage). Whilst the default position should be that these solutions should be deliverable through the competitive market, there may be scenarios where this option is not made available to the network operator. For example: in a very highly constrained network where access to other markets is restricted and revenue stacking is unlikely or difficult; where the economics of service provision is challenging for geographical reasons; or where the service provided by the storage unit is linked to other existing assets owned by the network operator.

2.47. These issues should be considered more fully in order to ensure the most cost effective solutions to network reinforcement can be delivered. Mechanisms should be put in place to ensure that what is in the best interests of the consumer is achieved. If there is any risk that network operator ownership would distort the market then existing protections can be expanded to ensure that this is fully addressed. Ultimately this process should identify whether the market can provide the more cost effective solution.

Question 5:
Do you agree with our assessment of the regulatory approaches available to provide greater clarity for storage? Please provide evidence to support your views, including any alternative regulatory approaches that you believe we should consider, and your views on how the capacity of a storage installation should be assessed for planning purposes.

2.48. There are many benefits in creating regulatory clarity for electricity storage. Further consideration should be given to the various types of electricity storage and the different ways in which they operate in the market and thus what effect this will have on the cost of the network. Any definition or change to regulatory treatment should also take account of existing storage providers such as pumped storage and how these technologies may be affected.

2.49. We do not believe that continuing with the existing regulatory approach is appropriate given the level of uncertainty this creates for not only developers of storage and network operators but also other users of the network. Continuing with the existing approach has the unintended consequence of treating storage as both generation and demand, which is reflected in the network charges that are payable, as well as the double-charging of final consumption levies.

2.50. The regulatory treatment of storage should be reflective of the activities it undertakes in the market, which, in turn, leads to network impacts and their associated costs. We consider classifying storage as a distinct set of activities is the correct approach and a decision as to whether primary legislation is required rests upon whether alternative and quicker solutions are sufficient to address the current barriers faced by storage. To this end we believe options B-D should be assessed based on the barriers that have been identified.

Question 6:
Do you agree with any of the proposed definitions of storage?
If applicable, how would you amend any of these definitions?

2.51. We believe that the Energy Storage Network (ESN) and Capacity Market definitions accurately reflect the overarching activity of storage.

2.52. Having set a high level definition it may also be necessary to differentiate between types of storage if appropriate.

2.53. It is important that any definition takes into account existing forms of storage, including, for example, pumped storage. Consideration should also be given whether further distribution connected storage definition should be developed (See Section 2.39 – 2.40).

2.54. As already noted above, a Grid Code Working group (GC0096) has been established to help address this issue of classification for transmission connected storage and an equivalent work stream should be established to address all types of storage.

2.2 Aggregators

Question 7:
What are the impacts of the perceived barriers for aggregators and other market participants? Please provide your views on:
balancing services;
extracting value from the balancing mechanism and wholesale market;
other market barriers; and
consumer protection.
Do you have evidence of the benefits that could accrue to consumers from removing or reducing them?

2.55. We agree with the barriers that have been identified. In particular the barriers to extracting value from balancing services and the market in general, which is a problem for aggregators[8] and also to varying degrees an issue for all market participants regardless of their business model. Please see further details in our response to Question 8 and our responses to the questions set out in Chapter 3 on 'System value pricing'.

Opportunities and risks to consumers

2.56. As highlighted in PA Consulting's report 'Aggregators – Barriers and External Impacts', published alongside this call for evidence, consumers who have demand that is capable of being flexible can make use of this capability. They can do this by reaching an agreement with their supplier or an aggregator to switch off or reduce demand at particular times in return for a saving on the cost of their energy consumption. If this activity is undertaken through the consumer's supplier then it will either, form part of the supplier's portfolio balancing activities ahead of gate closure, or if undertaken in response to bids/offers submitted by the supplier in the Balancing Mechanism (BM) then an agreement will be reached on how the resulting saving will be shared with the consumer. However if the activity is undertaken via an aggregator who is not also the consumer's supplier, this would mean the actions are impacting on the measured imbalance position of another market participant (the supplier).

2.57. As highlighted in the call for evidence, there is a real risk that suppliers' imbalance positions will be affected if the deployment of aggregator services and Demand side response (DSR) increases and is not managed through the appropriate mechanisms. It is very important that this issue is examined and resolved in advance of wider aggregation and DSR involvement in the Balancing Mechanism to avoid a position where consumers are left out of pocket as a result of increased imbalance costs and other levies (e.g. network charges) which may increase as a result of improperly managed aggregation/DSR. The materiality of this issue and implications for cost recovery will need to be fully understood as part of this project.

2.58. It is also important that the aggregation business model does not become a distortionary "tax" avoidance service for sophisticated customers, while the most vulnerable or less engaged customers may be left to pay a disproportionately high share of the costs of the system.

Interaction with DNOs

[8] In the context of providing demand side response to the TSO, we see the references in the consultation to 'aggregators' as also including all Third Party providers.

2.59. Aggregators can play an important role in the provision of services to the DNO, for example to provide constraint management through DSR. In order to support the network, DSR must be incentivised to (i) be made available in the right location and (ii) be capable of responding for the duration and frequency required by the DNO. Transparency on location and use is also necessary for the purposes of managing the demand curve on the network.

Question 8:
What are your views on these different approaches to dealing with the barriers set out above?

2.60. We agree with Ofgem's view that regulatory arrangements should allow all party access to markets where this supports whole system efficiency, and that in order to do this certain barriers need to be addressed and additional protections may need to be introduced to ensure most efficient outcome for consumers.

Balancing services barriers

2.61. We agree that improvements can be made to the transparency of the current procurement process for balancing services. Beyond improvements in the product specification for providers of DSR, we would welcome a more extensive review of the system services that can be procured by the SO. We consider elements of the DS3 programme, as introduced in Ireland to incentivise and improve system performance and capability, to be a step in the right direction when it comes to providing transparency on the services that are available to support the system. Further work should be done by the SO along with stakeholders to identify and incentivise the necessary services that are required for the continuous, secure operation of the electricity system. This should include new products that are needed to complement the transition towards an electricity system with high levels of intermittent and embedded generation. The ability for market participants to tender to provide 'bundled' services as well as longer term contracts should also be made available. And the process for procuring services should be more transparent and competitive to allow any provider of flexibility to offer this service at a competitive price. Some form of auction procurement mechanism should perhaps be considered. We consider Ofgem's upcoming fundamental review of the SO incentives to be timely and would welcome further engagement with Ofgem and National Grid on the details.

2.62. We expect a strong SO-DSO interaction will also be necessary to facilitate the best use of system services across the network. Further commentary on this can be found in our response to Section 5 of this call for evidence.

Barriers to balancing mechanism and wholesale market participation

2.63. We think a defined role for aggregators within the Balancing and Settlement Code (BSC) could be an appropriate approach to allow them direct access to the balancing Mechanism (BM). This would ensure the services they provide are integrated efficiently into the system.

2.64. Visibility of any demand reduction and generation is important for the SO, DSO and other market participants. The impact of increasing volumes of embedded generation is already affecting the ability for efficient balancing of the system due to limited transparency of what is happening at distribution level. This issue is equally applicable to activities undertaken by aggregators or by DSR providers directly to reduce demand on the network. Steps should be taken to improve the quality and visibility of generation and demand activities taking place at distribution and transmission level, perhaps by publishing information gathered in accordance with the GLDPM[9] for the Common Grid Model and the regional operational security analysis.

2.65. We expect the implementation of Project TERRE (Trans-European Replacement Reserves Exchange) will provide useful insight into the barriers that are faced by non-BMUs in offering balancing services and any potential issues faced by the SO and DSO as a result of procuring these services. In particular, the project will be looking at data provision and other responsibilities that should be required by participants, and how to measure and understand the consequences of non-delivery.

Consumer protection

2.66. We agree that if there is a perception that the services offered by aggregators are unfair or misleading then this could act as a barrier to consumer engagement. We think it is appropriate to consider aggregators as part of the ongoing work on TPIs but would suggest that, given the role aggregators have in actively managing consumers' energy use, it will be appropriate to assess them based on the specific services they will be offering and what impact this will have on the consumer. As a supplier can offer the same type of service to the consumer (e.g. an agreement to vary demand at particular times) consideration should be given to what level of protection and service must be provided by a licenced supplier in this area so this can be applied to licensed aggregators providing the same service. The supply licence places obligations on suppliers to protect consumers and offer a certain level of service or face significant penalties if they fail to do so. Aggregators should face equivalent obligations and be subject to the same risk of penalty. Consumers should be able to easily compare the options available to them so they can choose what is best for them. This approach allows aggregators and suppliers to compete on a level playing field for the services they intend to offer and gives assurance to the consumer that they will receive an appropriate level of service and protection regardless of with whom they have entered into a contract.

Question 9:
What are your views on the pros and cons of the options outlined in Table 5? Please provide evidence for your answers.

2.67. Industry codes play a vital role in allowing innovative business models and technology to become integrated into the energy system, and in maximising the benefits that they can deliver. Being party to the BSC is important, in so far as it governs electricity balancing and settlement in Great Britain by placing incentives on market participants to actively balance their energy position or subsequently face exposure to the imbalance price which is derived from additional balancing activity required to be undertaken by the SO after Gate Closure.

2.68. With the potential for increased participation of aggregators and other Third Party providers of DSR, the key is to ensure that their participation in the wholesale market does not undermine the incentive for individual market participant balancing.

2.69. To enable direct participation in the BM, we believe it should be a requirement for independent aggregators or any other new participant to become a relevant trading party under the BSC so that the

[9] Generation and Load Data Provision Methodology.

portfolio of flexible demand they intend to offer is visible as a single BMU. We understand that the BSC does not currently make any provision for the role of an aggregator and they would currently be classed (for the purposes of the BSC) as a “third party”. To address this issue we consider that the introduction of an ‘Aggregator Licence’ may be a pragmatic approach. Under this, licence conditions could be designed to enable direct aggregator participation in the BM, address the requirement for any necessary compensation process to suppliers, and to outline standards for consumer protection.

2.70. In the absence of a regime which allows aggregators to participate directly in the wholesale market, we do not think an obligation should be placed on suppliers to enter into agreements with aggregators for the provision of services. As outlined in the call for evidence, retail competition and half-hourly settlement will provide the correct incentives for suppliers to help their customers make the best use of their flexibility, whether that is through additional services offered directly by the supplier or through an aggregator.

2.71. As has been highlighted in the call for evidence, cross-party impacts must be considered more fully before further steps are taken to remove particular barriers for aggregators and other market participants offering DSR. We believe that the potential saving/cost to the consumer of this activity is yet to be fully understood.

Question 10:
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?

2.72. We agree that it is essential that an aggregator’s systems should be robust and secure such that their reliability is equivalent to that of existing providers of balancing services such as transmission connected generation. In particular, it would be a distortion of competition and inconsistent with the objective of moving towards a “smarter” system if aggregators could obtain a competitive advantage in the balancing mechanism by cutting corners and avoid incurring the cost of developing robust, secure and reliable systems. Failure to achieve this could result in less robust and less secure aggregation based services crowding out more secure providers of balancing services which in turn could lead to a less robust and less secure energy system over all.

2.73. We also agree with the assessment of risk to DNO system stability and believe that it is important to both consumers and the wider system that aggregators’ systems and processes for load control are robust and secure.

3 Providing price signals for flexibility

Executive summary

System value pricing

3.1. Any new framework needs to put the interests of customers at its heart. With customers and market participants becoming increasingly ‘smart’ and agile it is important that a smart flexible energy system is set up to send effective price signals and cost reflective charging. In particular, we recommend that existing network charging arrangements (connection, use of system, transmission and distribution) need to be examined holistically and any distortive signals should be addressed as a priority. To better facilitate effective competition between all users of the network, including storage assets, which may be connected to the transmission network, the distribution network, or behind a demand meter, the network charges for distribution and transmission should be brought closer into line with each other. There is a risk that if distortions are caused by inconsistencies between these different network charging arrangements, then there will be a distortion to investment and dispatch decisions which will ultimately result in a less efficient outcome and higher costs to customers. We recently provided evidence[10] to Ofgem in response to its consultation on Embedded Benefits that demonstrated the extent to which existing distortions are costing the bulk of consumers more. Consequently, whilst we support a holistic review of network charges we believe that more urgent attention is required on the TNUoS residual to avoid consumers supporting economically inefficient investment and dispatch decisions.

3.2. We also believe that an extensive review of the system services that are required by the System Operator (SO) should be undertaken. We consider elements of the DS3 programme, as introduced in Ireland to incentivise and improve system performance and capability, to be a step in the right direction when it comes to providing transparency of the services that are available to support the system and providing opportunities for existing parties and new entrants to participate in their provision. We note that Ofgem has recently published a consultation[11] setting out its thoughts on the further separation of the SO role within National Grid and we will be responding in due course.

Settlement and Smart tariffs

3.3. Half Hourly Settlement (HHS) is contingent not only on a significant penetration of smart metering but also on the ability of market participants to access the Half Hourly data collected from the smart meters. As we have explained in our recent response to Ofgem's consultation[12], whilst Mandatory HHS opens up opportunities to transform the energy market, this data barrier needs to be overcome at an early stage in the Significant Code Review. Therefore our view is that mandatory HHS should not be implemented until after Smart meter roll out is completed.

3.4. We believe that whilst BEIS and Ofgem have a role to play in facilitating the market, new tariff structures including smart tariffs should be developed in response to customers. The evidence from the trials that we have been involved in (as a supplier and network operator) suggests that smart meters and better information about energy consumption patterns are the key enabler for customers' take-up of innovative new tariffs.

System Value Pricing

Question11:
What types of enablers do you think could make accessing flexibility, and seeing a benefit from offering it, easier in future?

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[10] See attached document
[11] Future arrangements for the electricity system operator - 12 January 2017

[12] Mandatory Half-Hourly Settlement: aims and timetable for reform – SSE response submitted 6 January 2017

3.5. The electricity System Operator (SO) plays a vital role in managing the electricity system and through the provision of the right incentives will continue to play an important role in enabling better access for providers of flexibility. Going forward this role will be increasingly taken up by the DSO.

3.6. To enable better access and use of flexibility we believe an extensive review of the system services that are offered by the SO should be undertaken. We consider elements of the DS3 programme, as introduced in Ireland to incentivise and improve system performance and capability, to be a step in the right direction when it comes to providing transparency on the services that are available to support the system. We suggest further work should be done by the SO, along with GB stakeholders, to identify and incentivise both new and existing providers of flexibility to offer the services that are required for the continuous, secure operation of the electricity system. This work should include identifying new products that are needed to complement the transition towards a power system with high levels of intermittent and embedded generation. The ability for market participants to tender to provide 'bundled' services as well as longer term contracts should also be made available. Making the process for procuring services more transparent and competitive is also crucial to encouraging providers of flexibility to offer services at a competitive price.

3.7. Whilst new routes for accessing flexibility should be pursued, it is equally important to ensure focus is placed on making the best of existing market solutions, many of which are currently under-utilised. Pumped storage, for example, has the ability to offer flexibility to the system on a significant scale, both consuming excess generation and providing extra capacity when demand peaks. Through the use of pre-gate closure contracts, large pumped hydro plant can reschedule their environmental water runs in summer months to suboptimal market periods to assist in the management of network constraints.

3.8. A further example can be seen as regards our Glendoe hydro station, which was developed to operate as a synchronous condenser with the ability to provide a considerable range of voltage regulation to the system two years ago. However, despite agreeing an enduring contract for the service with the SO, it has never been utilised and no revenue has been returned to recover the cost of the work.

3.9. Beyond making the best of already available market solutions, it is necessary that BEISand Ofgem consider options for unlocking new flexibility opportunities across the electricity system. This includes opportunities for large-scale, transmission connected storage such as new pumped storage which, unlike other forms of storage, can support the system by storing and then flexibly generating a significant volume of electricity continuously over a sustained period of time (days rather than minutes). We refer to section 2.16-2.27 above for our further views on this topic.

Question 12:
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?

3.10. The expansion of renewable generation, improvements in energy efficiency and the continuing drive to phase out inefficient fossil fuelled plant has changed the face of the GB electricity market. Most notably, it no longer benefits from a diverse array of plant and the depth of price that goes with it. As a result, generating plant and other providers of flexibility are increasingly searching for and reliant on revenues available, such as through the Capacity Mechanism and contracting directly with the System Operator (SO) for ancillary services.

3.11. In our capacity as a provider of pumped storage we have access to compete for revenue streams gained through the provision of balancing and ancillary services to the SO, however we have struggled to achieve benefit from those offered, leaving our assets underutilised and under compensated. We believe that a more flexible and value-driven approach to contracting for such services would ensure a more efficient outcome for the system.

3.12. If the SO does not look to procure a mix of contract types, such as bundled products, then the use of new and existing flexibility assets will not be optimised in the most efficient way. If the SO was to procure bundled products, such as those pumped storage is able to offer, flexibility that is currently available would be better utilised and procured more cost effectively.

Question 13:
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?

3.13. We have a historical involvement in providing flexibility as the owner and operator of the 300MW pumped storage facility at Foyers. We understand the important role storage can play in providing the system with greater flexibility whilst reducing costs for consumers and we support further deployment of storage technologies across the GB, including the deployment of new pumped storage.

3.14. Bulk storage, such as that provided by pumped hydro, is a unique provider of flexibility as it can both reduce pressure on the network in times of high power output by consuming electricity as well as generating electricity when demand requires. More widely, large scale pumped storage provides a broad number of important services to the system, including both services for which there is not currently an available market, such as the provision of inertia, and the provision of broader economic and societal benefits which are not reflected in the revenues available to pumped storage. These broader benefits include reducing or deferring additional transmission investment by reducing variation in generation exported from high renewable areas; reducing balancing and service costs including through limiting the amount of renewables generation curtailment; and reducing wholesale price volatility. Baringa[13] recently undertook analysis of the broader societal benefits developments of new pumped storage could deliver and estimated these to be worth at least £70m per year. However a number of these services are not currently incentivised or remunerated. Utilisation of these advantages could have significant benefits for system optimisation and cost.

3.15. The SO has an incentive to balance the electricity system in the most cost effective manner possible, and yet it will frequently elect to pay windfarms not to generate electricity rather than instruct storage facilities to absorb it. This is often at a huge cost dis-benefit, with the majority of wind farms being paid in the region of £65/MWh negative to reflect the loss of ROC from having to curtail their generation. Meanwhile pumped storage assets bidding below this price, and even frequently at £0/MWh, will not be utilised by the SO to absorb excess electricity during periods of surplus. For example in September this year several wind farms were bid back at prices ranging from £-60.03 to £-153.89/MWh, despite both Foyers pumped storage units bidding at £0/MWh with 25 machine hours of pumping available, neither were utilised to help balance the system.

[13] We would welcome the opportunity to discuss this work in more depth with BEIS and Ofgem.

3.16. From our own experience it is common for pumped storage facilities to have available storage volume at the end of these weather driven surplus events. We suggest that the system could be used more cost effectively and efficiently if the SO is required to ensure that all available storage is filled ahead of renewable curtailment.

3.17. Despite the benefits it can provide, as detailed in Q11, it is not currently possible for new pumped storage projects to be taken forward given the revenue streams available are too uncertain to allow investment. Given the range of benefits which pumped storage can provide, including the broader societal benefits outlined above, we consider that the Government and Ofgem should extend availability of the existing 'Cap and Floor' mechanism available to new electricity interconnectors to pumped storage projects.

Question 14

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?

3.18. As outlined above, the SO has a key role to play in unlocking the value and making most efficient use of flexibility on the system. To most efficiently use flexibility and maximise system benefit we believe that the SO should be able to be more dynamic in its approach. Please see our response to Question 1 on some of the changes we believe should be made to the current system services regime to incentivise the efficient use of flexibility. Going forward this role will be increasingly taken up by the DSO, please see section 3.45 with regard to balancing payments and compensation.

3.19. We believe the SO should be incentivised to manage surplus events in the most energy efficient manner, for example, by introducing a requirement that all willing storage schemes are full following a surplus event. This would likely require a separate framework agreement which places storage operators under an obligation to not aggravate surplus events if they are being used to impound surplus energy. We would readily subscribe to this principle, if it also applied to all other operators of storage facilities in GB.

3.20. We recognise that the two year SO incentives may be a limiting factor on the SO's ability to adapt and change its approach. We therefore welcome the intention by Ofgem to consult on a more enduring SO incentive scheme as we hope this will provide the SO with the security to be able to enter into longer term contracts as well as giving it the confidence to be bolder in its decision making. We appreciate that this may require changes to the SO licence conditions.

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? Please provide a rationale for your answer, and, if you feel Government and Ofgem should play a role, examples of the sort of interventions which might be helpful.

3.21. The Government and Ofgem should focus on making sure that network price signals faced by suppliers are cost reflective so that that market participants are incentivised to respond in a manner which delivers value to the system and drives efficiency. The development of the proposition for customers should be a matter of innovation and competition between suppliers. There should be minimal prescription by Government and Ofgem on the form of these offerings.

3.22. With the smart-meter roll-out progressing, we recognise that there is a significant opportunity to develop smart tariffs and other more bespoke propositions that provide an enhanced offering for customers. We have, for example, suggested at the TCMF[14] the application of a 'Smart TRIAD' whereby all customers TNUoS charges are linked to the average of their individual three highest demand periods over the year, as measured by their Smart / HH meter(s). We strongly believe that whilst the Government and Ofgem have a vital role to play in facilitating this market, it is not their place to actively drive or promote new tariff structures or business models as this could lead to market distortion. Instead focus should be on providing appropriate guidance and governance to ensure the market can develop appropriate arrangements whilst safeguarding customers.

3.23. Importantly, we would want to avoid the confusion, complexity, and negative impact on competition associated with over-prescriptive rules, which we saw with the tariff bundling rules within SLC 22B of the supply licence conditions. As BEIS and Ofgem will be aware, the CMA recommended the removal of these rules following their recent investigation into the energy market.

3.24. We would support principles-based guidance that offers appropriate customer protection and the necessary business clarity. Principles-based regulation will enable suppliers to innovate freely and quickly as the market changes.

3.25. That said, there a number of actions the Government and Ofgem can take to facilitate the market. We are uncertain as to how mandatory half-hourly settlement (HHS) can be scalable and reliable without mandating the extraction and use of half-hourly consumption data. As BEIS and Ofgem are aware, this is currently voluntary and customers can change their preference at any time.

3.26. As half-hourly consumption data is a vital enabler to HSS and this consumption data can only be obtained from a smart meter, we suggest that the timescales for smart roll-out and mandatory HHS should be closely aligned to ensure that a critical mass of meters are installed before any wide-scale change to half hourly settlement procedures. This will reduce the risk to industry of having two settlement periods in operation simultaneously, which is inefficient and not cost-effective.

3.27. Without access to customers' half-hourly data we are prevented from running tariff comparisons and developing a range of propositions that incentivise and reward customers for their flexibility, and unable to create bespoke propositions to suit their usage patterns.

3.28. It must also be recognised that due to limited Wide Area Network availability a small proportion of customers will not be able to get a smart meter and will therefore not be able to settle half-hourly.

3.29. We recommend that any move to mandatory half-hourly settlement should be aligned across the industry, with half-hourly settlement made mandatory in coordination with DUoS half-hourly settlement. To fail to do this would increase complexity by utilising non-half-hourly profile shapes to provide half-hourly settlement for customers.

3.30. Beyond this, we are concerned that some of the current licence requirements, and in particular the obligation to provide cheapest tariff messaging, may be incompatible with the aspiration of driving smart tariffs and more bespoke tariff offerings. As part of its Future Retail Regulation (FRR) workstream, Ofgem has been looking at introducing a greater degree of flexibility as regards personal projections for customers. This will be a necessary change to facilitate tariff innovation. We support Ofgem's review in

[14] Transmission Charging Methodology Forum.

this area and believe that the interactions between smart tariffs and consumer communication requirements should be examined in more detail. In this regard we welcome that Ofgem has said that it will prioritise prescriptive mandated customer communications in its Forward Work Plan.

Question 16.

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.

3.31. As referenced above, we believe that BEIS and Ofgem have a role in facilitating market innovation rather than actively driving change. To this end their focus should be on letting the market develop, and we believe that delivering principles-based rather than prescriptive regulation will be critical in achieving this. We therefore welcome Ofgem's work under the FRR workstream, which is designed to achieve these objectives.

3.32. This is a complex time for the industry; therefore it is imperative that changes to obligations and market structures are not made before suppliers are in a position to act and to offer smart tariffs to customers.

3.33. As with any major change we recognise there is a crucial body of work to be done to ensure customers are brought in and engaged with change, and central to this is responding to the customer voice. Going forward we therefore recommend that BEIS and Ofgem work in partnership with suppliers to make sure progress is made in an appropriately timely manner, that engages customers, addresses their concerns and doesn't prejudice the market.

Question 17

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

No comment.

Question 18.

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?

3.34. We agree with the assertion in the consultation that customers generally do not want complicated non domestic tariffs. Customers with half-hourly meters already have the opportunity to ask for 'smart' tariffs however, approximately 4 out of 5 of our half hourly customers have chosen single or day/night tariffs over seasonal time of day tariffs (SToD) and we have only been asked to develop one bespoke tariff for a major energy user. This evidence would suggest that there is little appetite for these types of tariffs at present; however we continue to engage with half hourly customers to help understand what propositions may be of interest. Reflective of this aversion to complexity is the growing use of TPIs in the market; these have continued to drive simplification to allow ease of comparison.

3.35. We would flag here that in the event that the majority of larger non-domestic customers did want smart tariffs, where such tariffs encourage TRIAD-avoidance, there could be impacts on less-sophisticated customers who would be left to pay a disproportionate share of energy costs. We would reiterate our earlier point that it is important to examine issues relating to cost reflectivity and fairness of charging arrangements at the outset in order to remove unfair outcomes for customers. This should be a priority issue for Ofgem and BEIS.

3.36. We also agree with the call for evidence document that offering particularly complex, bespoke tariffs may raise administration and billing costs. Instigating billing system changes to deliver complex tariffs would increase suppliers' cost to serve and, without a great appetite for complex tariffs, this would not be a cost-efficient development for customers. Therefore (as made clear in our response to Question 16) we are of the view that the development of smart tariffs should be market driven, as this will make sure propositions and necessary system updates are delivered in line with customer demand.

Smart Distribution Tariffs - Incremental Change

Question 19

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.

3.37. This is a complex issue. Currently, in so far as distribution charges may be used to provide simple incentives for overall reductions in peak usage, they could benefit generation differently depending on their point of connection. This could lead to distortions in investment decisions compared with transmission connected assets, potentially resulting in an inefficient mixture of flexibility of sub-optimal investments in aggregate. In principle, this could be a barrier to moving towards a smarter and more flexible system overall. On the other hand, it must be recognised that a shift to more cost reflective charges faces practical challenges particularly in terms of presenting messages to customers in a form in which they can understand and act upon. This is particularly true for domestic customers but it must also be acknowledged that the aggregate customer response to distribution time of use differentials has not been strong even for the bulk of business customers. For example, we have considered the effect of DUoS price signals on LV and HV half-hourly metered customers in the South England Southern Electric Power Distribution and Scottish Hydro- Electric Power Distribution distributed services areas (DSAs). Despite considerable changes to the relative red, amber and green time band prices, the total volumes consumed in each band during the past six years has remained very stable.

Question 20

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

3.38. As discussed above, appropriate changes to the charging methodology and their impact on overall flexibility system is a complex issue, but it can remove barriers which could otherwise make it more difficult. One thing to keep in mind when trying to design a system to reward flexibility through DUoS tariffs is the possible unintended consequence of punishing customers who are unable to respond, since the methodology for recovery of a relatively fixed allowed revenue amount would translate this into higher costs for those customers who cannot respond to signals. In so far as the price differentials are not truly reflective of incremental cost differentials, this would be a particularly unwelcome outcome.

3.39. If any changes were to be made to charges in an attempt to drive behaviour change, we would encourage change towards simpler and more predictable signals, rather than more complicated and volatile ones. Simpler and more predictable tariffs could encourage participants who are deterred by complexity, to participate in the market and would also provide a stable and predictable market accessible to new entrants.

3.40. As acknowledged in the consultation document, we appreciate that tariffs will need to strike a balance between complexity and cost reflectiveness, and as stated above we believe that it is important that those unable to respond to signals are not unfairly penalised. We therefore suggest that a multi-faceted approach to distribution charges could be pursued to encourage flexibility whilst safeguarding costs for customers unable to react to price signals.

3.41. Currently a large proportion of distribution charges reflect previous investment costs that are now sunk, we recommend that this focus is maintained to provide investment certainty and predictable pricing.

Question 21

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.

3.42. As a network operator we are actively engaged in the work of the Extra-High-Voltage Distribution Charging Methodology (EDCM) Review Group and the Common Distribution Charging Methodology (CDCM) Review Group of the Distribution Charging Methodology Forum (DCMF). Both of these groups look to continually improve the charging methodologies and address limitations. The initial findings from both Reviews have identified areas of further investigation and potential solutions to overcome the limitations and accommodate evolving innovations. We do not consider there to be any urgent disparities or problematic areas requiring intervention ahead of these two industry forums.

Smart Distribution Tariffs – Fundamental Change

Question 22

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?

3.43. It is mostly legacy investment decisions that drive network costs, not load or capacity (although these may of course dictate investment decisions) so we would not expect the cost drivers to change. As the majority of costs are sunk with charges focused on cost recovery there are few substantive changes that could be made.

3.44. However, as noted above, with transition occurring towards a more prominent role for DSOs and active distribution networks DUoS charges could be wholly focused on network investment cost (sunk cost recovery and reflecting the cost(s) of network investment caused by users) with other price signals (balancing mechanisms, ancillary services, bilateral contracts for flexibility such as CMZ) used to provide the forward-looking pricing element.

3.45. In the future, depending on the nature of flexibility services and their payment, DSOs may be required to make balancing payments and compensate users for loss of network access. These market costs increase volatility and risk, creating an additional cost to be recovered by the DSO via a separate local balancing charges (akin to BSUoS) recovered, cost reflectively, from all the applicable parties (i.e. demand, storage, generation, DSR etc.). It will be important to establish that these costs are more than offset by the other benefits that customers receive so as to ensure an efficient overall service and prevent increases to electricity bills.

3.46. We would stress that whatever changes may occur, there will be a need (as for TNUoS charges) to socialise cost as much as possible. Revenue collection elements of charging should be collected in a way which meets the principles of being (i) fair and (ii difficult to avoid. These principles are necessary in order to avoid distortionary and economically inefficient avoidance action by relatively sophisticated customers which could cause an unfair and inequitable proportion of costs being paid for disproportionately by the most vulnerable and least engaged customers and also higher costs to customers overall. It might be pragmatic to move towards applying revenue collection to a more capacity related charge or half-hourly time of use volume tariff combining both capacity and volume mechanisms where practicable. As noted above, this aspect of work needs to be prioritised.

Question 23

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? Should they do so? And if so, how?

3.47. The approach to the collection of DUoS charges should be consistent with the way TNUoS charging is applied and both should include an appropriate combination of different charging elements for (i) sunk cost recovery which is fair and difficult to avoid in a way which does not distort investment or dispatch decisions and (ii) cost reflective price signals related to the cost of network caused by the investment and dispatch decisions made by users and therefore does provide an incentive for network users to respond to them. It is important to be clear that the application of cost reflective network charges should only be used for the purpose of reflecting the cost of the appropriate network (DUoS for distribution and TNUoS for transmission) and that network charging should not be used as a price signal for any other policy purpose. For example, network charging should not be used to collect the additional cost of flexibly operating/balancing the network (e.g. equivalent to BSUoS for transmission assets) and should not be used as a tool to encourage any generalised reduction in demand at particular times, or any generalised shifting of load between periods other than that justified to reflect only the relevant network investment cost.

Question 24

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.

3.48. The current range of DNO flexible solutions, for both connections and capacity (such as Active Network Management and Constraint Managed Zone) rely upon bilateral contracts stating site specific requirements and approaches. As these solutions become more widespread there is significant benefit to be had in exploring a set of national terms. This would improve market access by reducing administrative burden; ensure non-discriminatory treatment of users across GB and also operational use by reducing the variety of contract forms.

3.49. Likewise the development of scenarios such as the shared procurement, market signal or local balancing concepts as per Section 5 of the call for evidence will all require increased visibility of current and future electricity flows (offered and committed) at a more granular level. These activities do not generally take place at the DNO level today and will require the development of appropriate platforms and mechanisms. This may require the inclusion of new participants in industry codes such as the Balancing and Settlement Code (BSC) and the Distribution Connection and Use of System Agreement (DCUSA) (or the flexibility equivalent to DCUSA) for storage and aggregators. The costs of developing and implementing these new systems will need to be considered in the overall analysis of costs and benefits to customers.

3.50. It is possible to envisage new DUoS tariffs for storage which reflect the impact of constrained charging and peak export (or import) coincident with peak local demand, if these become the common characteristics of a storage connection. (See Section 2.39 – 2.40)

Other Government policies

Question 25

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

3.51. If we are to develop a smart system, where customers and market participants are agile and sensitive to price signals, then we must ensure that these signals encourage the most efficient investment and dispatch decisions. We are concerned that current policies cause a number of distortions that are a block to developing a true smart flexible system, and a risk to the equitable allocation of levies on customers. We therefore welcomed the recognition of this in Ofgem's Open letter on charging arrangements and National Grid's ongoing charging review.

The Balancing Mechanism

3.52. To enable a smart system it is important to ensure that charging arrangements do not distort competition. We therefore believe consideration of the application of Balancing Mechanism cash-out prices is required, as it currently provides distorted charges and an economically unjustified benefit to certain types of generation (discussed in response to Question 27) and co-located storage, in particularly incentivising the co-location of storage behind a CfD generation meter.

3.53. Balancing Mechanism cash-out prices are designed to provide an efficient cost reflective price signal. However, the magnitude of the price signal differs depending on how an embedded generator or storage is connected to the network in a way which does not reflect differences in the network cost. Current cash-out arrangements result in parties providing balancing services being 'paid as bid', while parties out of balance are charged on a 'paid as cleared' basis.

3.54. This means that the cash-out price faced by parties out of balance will tend to always be more valuable to them than the cash-out price paid to other parties who provide balancing service by competing in the Balancing Market. This difference currently provides a distorted price signal for dispatchable embedded generation or storage to co-locate behind a generation meter (of a non-firm generator such as wind, or PV) so that they are able to self dispatch within the gate closure period and in this way avoid competing with other generators in the Balancing Market. Behind the meter generators are therefore able to directly access the more valuable "paid as cleared" cash out prices, sometimes referred to as "NIV chasing", despite these prices not being available to otherwise identical generators who are connected directly to the distribution, or transmission network instead.

3.55. There is a risk that if the barriers to co-locating storage are removed before the distortions to market competition are corrected, then this could cause economically inefficient investment and dispatch decisions which could result in higher costs to customers.

Feed-in-tariffs (FIT)

3.56. We believe that there are important defects within the deemed charging methodologies which discourage FiT customers to effectively participate in providing smart and flexible services and engaging with the wider system.

3.57. While we appreciate that deemed export was intended to be a stop gap until the rollout of smart meters, the system in place has some inherent negative impacts on the industry's move towards flexible demand management. Currently more than 90% of our FIT customer base is receiving a deemed tariff rate for export. Deemed tariffs fail to expose customers to price signals representing the value to the system of their exports, this distorts the decisions customers make and does not incentivise them to respond to the needs of the system, hindering any transition towards smart flexibility.

3.58. Deemed export customers are incentivised to consume all of their onsite generation themselves because this can be done 'free of charge' to them. This approach does not drive the best use of electricity, potentially encouraging them to use more electricity or use electricity less efficiently, rather than exporting it to system where it could displace electricity generated from gas CCGT or coal. This failure to value the exported electricity to be reflected by the price signal faced by customers, distorts their decisions regarding flexing their demand or behaviour change, ultimately hindering the move towards smart flexibility.

3.59. The incentive for onsite consumption also encourages "behind the meter storage", with energy stored so that customers are able to consume this energy on site at a different time. Although the customer would be able to use the stored energy instead of importing energy from the network at a different time, this use of storage may not necessarily best benefit the system or the consumer. There may be circumstances when customers may be storing energy when the wholesale electricity prices are relatively high and when it should be exporting, offering a benefit to the grid and the customer.

3.60. Until the FIT meter estate is transitioned to smart, a potential solution to these barriers could include a smarter approach to customer pricing. A transition to half hourly metering and half hourly pricing, as well as export tariffs which reflect wholesale market prices, would present customers with smarter price signals so that the incentives faced by customers better reflect the genuine value to the energy system. It would also be helpful to apply the same principles suggested earlier for TNUoS and DUoS, namely to ensure that revenue collection to pay for policy costs (including FiT, RO, CfD) is done in a way which is fair and difficult to avoid to minimise distortionary action such as sophisticated customers using self supply to avoid paying their fair share of these policy costs. These improvements would mean that when customers made decisions regarding their own demand flexibility, those decisions would better help the transition towards a smart flexible system.

3.61. We note that the transition to a smart energy future may not be a smooth customer process. We have listed examples below of where we see impracticalities and risks in the current administrative process:

- Customers on deemed rates may be reluctant to exchange their meters for a smart meter, as the more accurate export payments delivered by a smart meter could lead to them receiving lower payments.
- We are also concerned that transition from deemed to metered export may not be straightforward. The production of an export MPAN can be an arduous task and will often rely on third parties to engage and be responsive, with the process taking anything from one week to several months. Furthermore, with multiple suppliers requesting export MPANs, there will be an increased pressure on operatives which may result in further delays.

- Ofgem have recently confirmed via an E-UK workshop that the creation of an export MPAN is optional i.e. only required when the supplier wants to do so for settlement purposes, however we believe that the creation of an export MPAN is an essential part of the administrative process required to provide payments based on export readings i.e. to register and obtain the readings.

- If a FIT customer is with a non-mandatory supplier, but is with us for FITs, we must rely on their present supplier to raise the relevant requests to generate an export MPAN. We also note that only the import supplier will receive a change of device notification when a SMETS meter is installed; the FITs licensee will not receive this prompt unless they are also the import supplier. While FIT generators are required to make the FIT licensee aware of a change of device we consider this an unnecessarily impractical step in the process given the consequences i.e. non-compliance.

3.62. It is important to ensure that the price signals faced by FiT customers for dispatch and investment should be improved to be more "smart" and cost reflective before those customers are encouraged to become more involved in flexibility through further regulatory or policy interventions. If distorted price signals continue to provide incentives for customers to act in ways which are detrimental for the economic value of the overall system, then there is a risk that greater customer participation could result in these detrimental outcomes becoming even worse.

ROCs

3.63. As detailed in Section 2 of this submission, we consider it is important that appropriate network charging is in place to ensure the correct investment incentives exist for the development and deployment of storage. This is equally applicable to the development of locating storage alongside other forms of generation, such as renewable plant. Appropriate co-location of storage can provide a range of benefits to the system and can have particular value in avoiding costs of new network investment. As such it is important to ensure that interaction with existing policies and regulations do not artificially hinder the deployment of co-located storage.

3.64. We consider that current Renewables Obligation (RO) legislation limits the use of batteries within the 'generating station' creating a significant barrier to deployment. Based on the current drafting it is unclear whether onsite consumption for the purpose of storage would comply with the 'permitted ways' set out in Section 32B (10) of the Electricity Act (1989). We would ask for clarity on this and a modification of the legislation, if necessary.

3.65. We would also ask for clarity on metering arrangements, should storage be co-located. The current RO legislation states that claims should be based on 'gross output data', as such if a battery was installed behind the meter total gross output would not be reflective of power generated, as some of this would be consumed before output by the battery, jeopardising renewable obligation certificates (ROCs) revenues. Similarly the definition of 'input electricity', currently the total amount of electricity used by the station for purposes directly related to its operation, would be incorrect as the amount of input electricity metered would include any input to the battery.

3.66. Input electricity is not eligible for ROCs, so we would also need confidence that the metering arrangement or calculations were proven to not include any input electricity to the battery that was then re-exported through the meter. Without clarity that appropriate metering arrangements are in place it is unlikely that industry will have confidence to take steps to fit storage that could ultimately provide advantageous flexibility to the system.

3.67. The scheme costs of various low carbon policies are currently disproportionately borne by electricity customers and should instead be collected more widely. We have consistently argued that the most appropriate approach would be to collect the cost of low carbon support schemes from general taxation since this more closely reflects the nature of these policy driven costs. Alternatively, if these costs are to remain on energy customer bills, then they should be collected from the users of all energy, not just electricity. If this issue is not addressed, then it can perpetuate and worsen distortions in the investment and dispatch decisions which customers make regarding choosing between fuel types. For example, sophisticated customers can currently import gas, which does not incur low carbon policy costs, to burn in a behind the meter gas engine to displace the need to import electricity, which does incur low carbon policy costs. In this way, sophisticated customers are facing an increasing incentive to arbitrage between importing electricity to import gas instead in order to avoid paying their fair share of policy costs. Other examples include customers who may be dependent on electricity for their heating, so they are forced to pay a disproportionately higher contribution to low carbon policy cost than other customers who use gas for their heating. This exacerbated issues of fuel poverty, since it is often among the most vulnerable customers at risk of being fuel poor who are more likely to be dependent on electric heating and therefore it can be groups who are at most risk of fuel poverty who are disproportionately making the highest contribution to low-carbon policy costs. Application of policy costs to all energy would better facilitate the move towards a smarter low carbon energy system because it could remove a barrier to the electrification of heating. Currently, the electrification of heating including the use of heat pumps appears more expensive than it really is because it is liable to pay for policy costs, while the alternatives of gas heating is not, which makes transition towards a low carbon energy system more difficult.

Question 26

What changes to Capacity Market (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?

3.68. Newer forms of flexibility should be able to participate in the Capacity Market on an equal basis to other resources provided they are able to provide the firm capacity which is required. Incremental improvements to the CM to reduce barriers to participation are being made and SSE has no additional suggestions to raise in this response. However, the question suggests that BEIS and Ofgem believe that the CM should enable newer forms of flexibility. The Capacity Market was designed to ensure that there is sufficient reliable capacity to provide electricity security to GB and flexibility is not specifically rewarded within the Capacity Market. SSE believes that this should remain its driving interest and the majority of flexibility should be procured and rewarded in other markets (intraday, ancillary services, balancing mechanism).

3.69. At present the Capacity Market rules do not require that the duration capability of the capacity provider is assessed or factored into how much de-rated capacity they are eligible for. This means that resources which can only provide reliable capacity for half an hour are rewarded on the same basis as providers who can generate for longer. Resources with lower duration capability may have lower capex costs and therefore have the potential to undercut other bidders. This means that the best providers of both flexibility and capacity could be crowded out of the Capacity Market and result in an electricity system failing to be able to deliver genuine capacity when customers need it. We therefore advocate changes to the Capacity Market to ensure that duration capability is factored into both the testing and de-rating regimes.

Question 27

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?

3.70. As a company committed to providing energy to our customers in a sustainable manner, we fully support the government's activities to drive investment in renewable generation. In our view the best way to deliver this, whilst ensuring costs and benefits are accounted for, is by ensuring the appropriate price signals are in place to drive investment in the most economically efficient technologies. We believe current charging methodologies are not sending the right price signals to drive the best investment and dispatch decisions and that these distortions provide a barrier to delivering a true smart flexible system, as well as a risk to the equitable allocation of levies on customers.

3.71. For example, current charging arrangements do not fully account for the costs and benefits of distributed generation. The proposed changes to the Connection Use of System Code (CUSC) set out in modifications CMP264 and CMP265 would better reflect the costs and benefits of distributed generation by removing the TNUoS demand residual element of Triad avoidance as an embedded benefit. This is a similar issue to that identified by BEIS in their proposal to remove the Capacity Mechanism retail levy as an embedded benefit for embedded generation. These are two of the largest distortions which exist within the current charging arrangements, however there are many other distortions which should also be addressed as part of a wider review of charging arrangements. These include the application of TNUoS demand charges, DUoS charges, BSUoS, losses and the collection of low carbon levies (including RO, CfD and FiT).

3.72. There is a different type of distortion in the form of missing markets, where potential benefits to the system are not currently being adequately compensated for. For example one type of renewable that we believe is being penalised by the current charging arrangements, with the service it can provide not adequately utilised, is wind. Wind farms can provide synthetic inertia, which could partially compete with enhanced frequency response from batteries, but current market arrangements do not pay them for this service so they do not provide it.

3.73. Critical to making the system 'smart' is designing markets to provide efficient price signals, so that participants are incentivised to respond in a way which delivers a more economically efficient result, at a lower cost to the system and customers. Key to this is correcting the current charging arrangements, and in particular those for distribution generation and demand customers. Although charging arrangements have always been distortionary, in the past customers were not enabled to be "smart" so were not particularly responsive to price signals. With a move to make customers and market participants more responsive to price signals we believe it is essential to first make sure those price signals are providing appropriate incentives.

3.74. Although in our view the problem is most apparent with regard to distribution connected generation and behind customer meters, we believe it also applies to locational charges, interconnectors, storage, balancing market and many other aspects. Our response to Ofgem's Open Letter of 29th July 2016 on charging arrangements for embedded generation goes into more detail on these issues.

3.75. We believe consideration is also required as to how the application of Balancing Mechanism cash-out prices may provide distortionary charges for embedded generation, and this has been discussed above in our response to Q25.

3.76. We note that market distortions are also driven by compliance with the Grid Code, with small scale renewables subject to weaker technical specifications which enables them to be cheaper. This not only causes complexity problems for network management but can also contribute to small scale renewables such as PV and micro wind being able to unfairly crowd out some larger scale renewables projects.

4 A system for the consumer

Executive summary

4.1. We agree that evolution towards a smart, flexible energy system must prioritise the interests of the end consumer. To this end, we are supportive of a consumer-centric approach that will thoroughly examine the risks to consumers as a priority. Particular attention should be given to ensuring that domestic customers, particularly the vulnerable, are supported and are able to realise the benefits of these evolving arrangements, thus minimising any unintended consequences. For example, there is a risk that vulnerable customers will pay more as fixed costs, that need to be recovered, are avoided by other end users who lower their share of the costs (through actions such as installing behind the meter generation). Integral to this is prioritising the review of charging arrangements so as to avoid market distortions being created. We support BEIS and Ofgem's examination of the role of smart appliances, electric vehicles and DSR and our comments on the particular risks, benefits and challenges of these can be found in the main body of this response.

Smart Appliances

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

4.2. We agree with the four principles set out in the Call for Evidence.

4.3. In the Call for Evidence document smart appliances include 'battery storage systems'. Whilst SSE acknowledges that these could provide services similar to conventional appliances such as domestic heaters; we believe that devices such as batteries should be considered differently due to their ability to export power back to the electricity network. As highlighted in chapter 2 exporting power potentially creates a number of physical and financial related issues that need to be addressed in order to maintain network security and to ensure an equitable market. Therefore if an appliance is able to export onto the wider system it should have additional controls and design protocols.

29. What evidence do you have in favour of or against any of the options set out to incentivise/ensure that these principles are followed? Please select below which options you would like to submit evidence for, specify if these relate to a particular sector(s), and use the text box/attachments to provide your evidence.

4.4. We believe it is better for GB consumers that technical requirements for appliances are consistent with Europe in order to avoid a situation whereby GB has its own specific requirements. Consequently SSE supports the UK channelling its work on smart appliances through the European Eco-design framework. Eco-design is a well-established approach that has demonstrated its success by promoting manufacturers to produce more efficient appliances. At the same time it has helped consumers to better identify their options and benefits.

4.5. Whilst a number of smart appliances have been developed and are already available in the market, quantitative evidence of their benefits for consumers via new domestic DSR services is in short supply. A lack of price signal is a commonly cited issue; nevertheless, modelling of potential benefits in a range of scenarios demonstrates that many appliances do not yield significant monetary value in terms of their DSR capabilities. Further, there is no concrete evidence available that end users are willing to make effort to actively increase the value and flexibility of their appliances.

4.6. We believe that new large scale field trials are required to understand the willingness of domestic end users to engage with appliances in order to realise their DSR potential. For example this should include evidence gathering of how willing end users are to delaying wash cycles, and for what price they are willing to accept a delay. This will then help inform what the possible uptake and use of smart appliances will be and therefore what actions the regulator and the energy industry need to take; e.g. the extent to which the different options below need to be progressed for different appliances. In our New Thames Valley Vision (NTVV) trial we found that commercial end users were engaging, in terms of their voluntary participation to install Honeywell kit and accept automated load management (DSR), however, recruiting participants for a household DSR scheme proved to be more difficult.

Option A: Smart appliance labelling

4.7. This option is likely to influence early adopters and those who are already interested in DSR related services. However, it is unclear whether this would convince the majority of consumers to purchase smart appliances. We recommend more research, for example through Eco-design, to understand the impact of smart appliance labelling. One of the key challenges with this approach is simplifying information on the possibilities that DSR capabilities offer, in a way that is reflective and understandable for consumers at the time of purchasing.

4.8. A key question in relation to customer uptake will be the decision making process. Our experience in the NINES[15] project, with regards to rolling out domestic DSM, has been that social housing provides a means of deploying smart solutions (particularly heating) at scale where a landlord is making the decision. Landlords are more receptive to incentives e.g. a social and environmental target, and are likely to initially create a greater uptake in comparison to the large overhead associated with engaging with the private market which tends to more organic in growth.

4.9. We believe the role of the community is paramount; our SAVE[16], ACCESS[17] and NINES[18] projects have all demonstrated that communities can help with the uptake of new flexible, low carbon solutions where the engagement with these communities is tailored to the local drivers. More information on these projects can be found at https//www.ssepd.co.uk/innovation/.

Option B: Regulate smart appliances

4.10. This is the most favourable option; however, caution will be required in practise to achieve this. For example, the development of smart appliances has provided a number of learning points, which should help to avoid costs and improve the end outcome. The focus should be on minimal standards that facilitate innovation but protect consumers and do not create additional risks to network resilience.

[15] https://www.ssepd.co.uk/NINES/
[16] https://www.ssepd.co.uk/save/
[17] http://www.accessproject.org.uk/
[18] https://www.ssepd.co.uk/NINES/

4.11. The specification of Smart appliances will be important; at low volumes the combined effect of smart appliances are relatively benign however when aggregated they can quickly create unintended effects on the system. This requires careful design and consideration of the "at scale" impact. A good example of this scenario can be seen in the NINES[19] projects where but for the inclusion of the ability to alter the frequency response of heating systems remotely it can be shown that frequency responsive appliances can add to system instability. This needs to be regulated at least through standards.

4.12. Similarly Cyber security is a key consideration here, the ability to switch millions of devices on or off remotely in an unannounced synchronised manner has the potential to destabilise the system or overload local networks. This same risk could apply to badly written code hence robust standards are critical.

4.13. We believe a 'secure by design' principle should be taken with regards to smart or connected appliances. For example, common default passwords should be avoided that would allow remote access and all data should be encrypted to a high-standard.

Option C: Require appliances to be smart

4.14. Experience suggests that this would not be interest of consumers as it restricts innovation and market led developments. Furthermore it removes consumer choice, as it cannot be said that everyone will want smart or connected devices. By regulating appliances in this way there is a possibility that BEIS, Ofgem and the electricity industry are at a higher risk of reputational damage.

4.15. This issue was highlighted when in 2013 ENTSO-E suggested to the European Commission that a microchip could be added to new domestic appliances to temporarily switch them off in certain conditions i.e. at a pre-set grid frequency threshold point. Subsequently The Mail on Sunday[20] and other news outlets published articles highlighting the possible intrusion to consumers' lives, as well as the additional appliance costs these modifications would bring. This story also highlighted the tension between the needs of individual consumers, the System Operator and appliance manufacturers.

30. Do you have any evidence to support actions focused on any particular category of appliance? Please select below which category or categories of appliances you would like to submit evidence for, and use the text box/attachments to provide your evidence:

4.16. Large-scale domestic DSR is likely to suffer predominately from acceptance issues, which is mainly an issue of inconvenience, trust, disruption and cost benefit. This suggests that initially the focus should be on high-value appliances, which can help deliver other benefits to end users such as improved thermal comfort. Figure 4.1 below demonstrates 'high-value' in terms of network impact and energy consumption. This is particularly important for the consumer who pays their supplier on a volume basis, whereas for network operators the benefit primarily comes from the rated capacity of the appliance. Figure 4.1 therefore emphasises that heat and hot water are the most valuable appliances for DSR with respect to both benefiting consumers and network operators.

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[19] Ibid

[20] http://www.dailymail.co.uk/news/article-2315863/Big-brother-switch-fridge-Power-giants-make-millions--pay-sinister-technology.html

4.17. The proposition of smart appliances has gained traction over the last decade as research into demand flexibility has become of greater interest. Whilst there is no formally adherence to a definition of smart appliances they typically imply the direct control of appliances in order to provide a form of DSR. A European Commission funded project involving nine organisations labelled 'Smart-A' has provided valuable insight into the potential of smart appliances[21.]

4.18. With respect to smart washing appliances the Smart-A project looked at the physical, behavioural and financial prospects of adjusting the operation of appliances remotely. It was found that flexibility was restricted by the dependency on behaviour change by end users. For example, in order to usefully change the load profile of a washing appliance, the end user must place the wash load inside the machine and allow the aggregator to control when it is subsequently operated.

4.19. With regards to consent, the NINES[22] project has two notable findings. Firstly, despite participation not being from volunteers but rather from consenting to proceed, the general feedback has been positive with respect to the operation of demand responsive heating appliances. Secondly, irrespective of the category appliance the 'effort' perceived to be required to engage in DSR is similar; this reinforces the point that energy intensive appliances are likely to be of most interest because of their stronger economic proposition.

4.20. An important consideration is the interaction between the Electric vehicle (EV) challenges and the adoption of Smart Appliances. A standard domestic connection would not be able to supply an EV, electric Shower, electric heater and oven switched on concurrently in a home. Whilst the SSE My Electric Avenue[23] project did not investigate this directly, its findings provide the basis to this thesis. Due to the increase in peak load the domestic wiring of the home would require an upgrade as would the service connection, currently both would be costs incurred by the individual customer. Smart appliances combined with suitable home hubs offer the customer the benefit of managing the load on their own side of the meter without the expense of upgrades. This is an important benefit of DSR that needs to be communicated to customers.

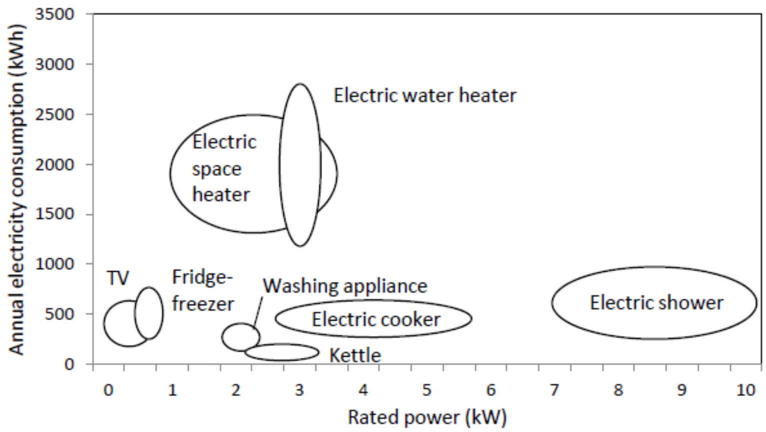

Figure4.1: Relationship between power of major domestic appliances and annual electricity consumption

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[21] Oeko Institut, 2013. Smart-a project. Available at: http://www.smart-a.org/
[22] SSEN will be organising NINES dissemination events to share learnings in March 2017
[23] http://myelectricavenue.info/about-project

4.21. This may cause unacceptable inconvenience to end users, particularly since the majority of end users are reported to currently never use an appliance delay timer whereas only 15% saying they do so often[24.] Consequently appliance flexibility, in terms of remote switching on and off, is likely to be limited to a range of a few minutes to a maximum of a couple of hours, especially for washing machine use[25].

4.22. From a consumers point of view the financial incentives of using smart appliances is likely to be decisive in their decision making, however, current estimates put the value of a single appliance as only up to 6 euro/year[26.] Given the additional concerns regarding safety, as well as the additional cost and complexity of smart appliances, there is significant uncertainty regarding the uptake of many types of smart appliance.

4.23. Unlike smart appliances, hot fill appliances have the advantage of being a proven and consumer accepted technology that has similar production costs to conventional cold fill washing appliances. The use of pre-heated hot water rather than auxiliary heating within the appliance, can allow water to be heated either by more environmentally friendly methods, or else be time shifted in order to provide flexible demand. Perhaps most importantly the use of hot fill does not lead to end user inconvenience – as they can continue to use their washing machine and dishwasher in the same way.

4.24. Research sponsored by us and undertaken at the University of Reading[27] has demonstrated the flexibility and carbon savings of using hot fill appliances. Monitoring of new hot-fill appliances developed by Beko showed that 38% and 67% of electricity consumption could be time shifted in dishwashers and washing machines respectively. Extrapolating this data to look at 500 British households, figure 4.3 shows that peaks in electricity demand can be significantly reduced by hot fill use. Importantly, these findings were taken from fourteen households over a period of 18 months, whereby a range of end user groups behaved normally. Further to this hot fill appliances had significant benefits when connected to district heat networks. Results from our Zero Carbon Homes project in Greenwatt Way[28] demonstrated the ability of hot fill appliances to make more efficient use of locally installed zero carbon hot water supply (figure 4.2). This further highlights the advantages of developing approaches that can support multi-vector low carbon systems via hot water storage.

[24] Stamminger, R., 2008. Synergy Potential of Smart Appliances. Brussels. European Commission.
[25] Seebach, D., Timpe, C. & Bauknecht, D., 2009. Costs and Benefits of Smart Appliances in Europe. Oko-Institut,
[26] Silva, V., 2009. Value of Smart Domestic Appliances in Stressed Electricity Networks. Imperial College.
[27] Saker, D. Coker, P. Vahdati, M. Millward, S., 2015. Assessing the benefits of domestic hot fill washing appliances. Energy and Buildings, 93, pp.282–294.
[28] https://www.sse.co.uk/help/energy/energy-efficiency/greenwatt-way#item1

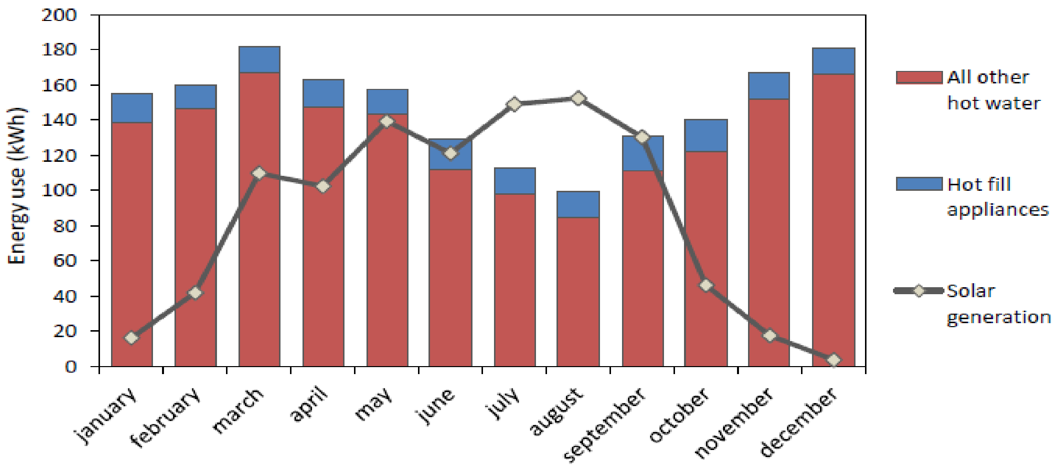

Figure 4.2: Example of a 3-person household using hot fill appliances with a solar hot water system connected[29]

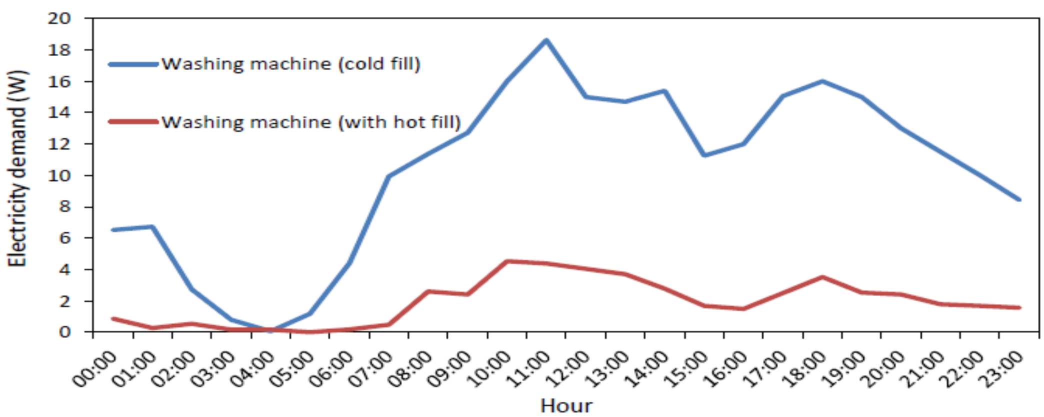

Figure 4.3: simulation of load profiles of hot vs cold fill only appliances from 500 households[30]

[29] Saker, D. Coker, P. Vahdati, M. Millward, S., 2015. Assessing the benefits of domestic hot fill washing appliances. Energy and Buildings, 93, pp.282–294.

4.25. We recommend that Ofgem and BEIS consider the role that existing technologies such as hot water storage systems and hot fill appliances can play when transitioning to a more flexible system. Whilst there is significant uncertainty around consumer take up of new technologies such as batteries; hot water cylinders have provided important flexibility (albeit under-utilised) for decades, yet millions have been removed from households over the last fifteen years (as combi-gas boilers have been installed). Furthermore, whilst there is numerous factors contributing to this, cost and convenience are cited as the main drivers that have led consumers to prefer combi-gas boilers. However, due to the de-carbonisation of electricity and greater inflexibility of GB generation, it is feasible that electricity will during periods of the day be cheaper than gas. This demonstrates the importance of factoring opportunity cost when Ofgem and BEIS consider policy and regulatory decisions.

4.26. In order to better incentivise DSR measures using domestic appliances, such as hot-fill, we believe action must be taken on the recovery of policy costs from electricity bills. Fixed costs are rising from low carbon levies and the capacity market levy, which means the retail price of electricity will increasingly appear more expensive to the consumer compared with other fuels such as gas and oil. This is despite the underlying operational cost (including carbon) being significantly lower by using electricity. Hence this approach to collecting levies distorts consumer behaviour and competition, because it is logical for end users to switch to and potentially lock in fossil fuel heat sources. The more consumers switch away from electricity, the more all other consumers pay per kWh because the levies are fixed costs – this then leads to a negative spiral, despite the obvious benefits associated with utilising low marginal cost renewable generation. Recommended solutions to collecting these socialised costs include:

- collecting the cost of low carbon policies from general taxation;
- or collecting levy costs from all types of energy (electricity, gas, oil, transport fuels);
- or collecting levies from a standing charge related to capacity instead of a commoditised £/MWh charge (a standing charge on all energy)

4.27. The third option involving a move to capacity based charging has the benefit of also addressing network charge levy issues, whereby volume based charging unfairly penalises end users that do not have behind the meter generation.

4.28. If this is not corrected then it is likely that the £/kWh cost of levies on electricity will keep increasing, which will make decarbonising heating through electrification unfeasible, despite the clear societal benefits.

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

4.29. We are concerned with the risk that smart appliances will have the potential of removing electric load diversity from current end use. Figure 4.4 shows the importance of load diversity in terms of reducing the need for network reinforcement and additional capacity. The diversity of 10,000 households effectively

[30] Simulations by University of Reading (Saker, D., Coker, P.J., Vahdati, M. & Carey, C., 2013. The potential of hot water tanks and hot fill appliances to help balance power systems and reduce CO2 emissions. In 7th International conference on the energy efficiency of domestic appliances and lighting. European Commission.)

means that less than 20% of the network is required than if each individual household had its own network. Diversity is caused by individual end users operating devices in a largely randomised way – albeit with general trends towards using more appliances at certain times of the day.

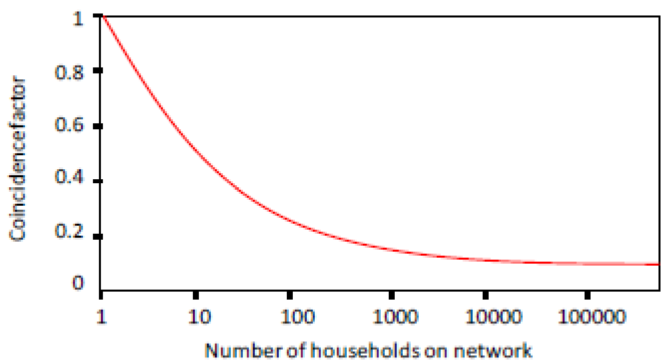

Figure 4.4: impact of load diversity on the electricity network

4.30. The mass rollout of smart or connected devices risks removing existing diversity as more appliances are controlled by agents or aggregators responding to price signals for set 30 minute (settlement) periods. This issue has already been dealt with when the transition to Radio-Teleswitching of electric heating occurred in the 1970s. A key learning from that process was that individual devices were required to have a random offset of +/- 3minutes to prevent large peaks and network capacity issues.

4.31. All smart appliances with the capability to be remotely switched should contain a randomised offset to ensure that loads do not switch at the same time. This randomisation should, where practically, be proportionate to the size of the load and the number of connected devices. For example a 10 kW rated device should have a longer randomisation time interval than a 1 kW device by a factor of at least ten. This random offset needs to apply both to loads switching off as well as on; otherwise there is a risk that cyclic loads such as refrigerators and hot water heaters will by synchronised thereby increasing demand peaks. Exceptions could potentially be made in cases where appliances are in frequency-operation mode, as these individual variations should be smaller.

4.32. Care also needs to be taken to ensure that the customers, equipment providers and installers are also aware of the impact a new smart solution has on domestic and commercial wiring. If load diversity is not adequately spread behind a customer meter then the customer will encounter issues with their supply such as interruptions and blown fuses. We therefore emphasise the importance of putting in place information provision to network operators if third parties install kit with the aim of controlling load – this includes batteries.

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

4.33. Our SAVE[31] project and NINES[32] have engaged directly with communities that include a significant proportion of vulnerable customers. In the case of Housing Associations and Council properties, where

[31] https://www.ssepd.co.uk/save/
[32] https://www.ssepd.co.uk/NINES/

the capital cost of heating and insulation are usually carried by the Landlord, there a number of ways of addressing this challenge.

4.34. However, vulnerable customers living in private accommodation with responsibility for funding their own appliances and heating are much harder to reach. Care needs to be taken to ensure that the move to smart does not leave people behind and even worse result in them effectively subsidising those that can afford Smart controls and appliances.

Existing issues

4.35. We support the growth of low carbon technologies and market-led investment, whether this occurs on the distribution or transmission network. Nevertheless we believe that flexible resources need to be competing on a level playing field, whether this is for capacity, energy or balancing services; including in terms of paying cost reflective charging.

4.36. We believe that current arrangements are providing some market participants an opportunity to push system-wide costs to wider network users. For example distributed generation responding to Triad signals has risen to between 3-5 GW. Whilst this level of response and engagement is welcome and demonstrates the value of simple and sharp price signals, as the underlying dispatch signal is based on a flawed methodology, the end result is the shifting of sunk costs between end users, rather than adding value to the system.

4.37. The existing method of cost recovery of policy costs is also potentially penalising types of end users. For example, end users with Solar PV panels receive Feed in Tariffs (FiTs), which are paid through Suppliers who subsequently levy the cost to their customers on a volume basis. This means that end users with Solar PV panels are being subsidised by all other users, and as the number of Solar PV users increases, the costs to non-Solar PV users also increase on a per capita basis. This is also the case with regards to other fixed costs such as network charges, since as more users self-supply the costs again increase on those users without behind the meter generation because recovery is done on a volumetric basis. This issue is not to do with the support mechanisms such as FiTs, but rather the method of cost recovery, which could become further exasperated if end users utilise on site DSR or batteries.

4.38. The issues set out above disproportionately hit vulnerable end-users who are less able to self-supply. Furthermore, national housing data demonstrates that households defined as ‘fuel poor’ are more likely to use electric heating (which is often inefficient), are associated with higher building fabric losses, and are less able to switch fuel supply due to being off the gas grid. All of which means that these customers end up paying a higher proportion of subsidies to other end users with distributed generation.

4.39. We believe action needs to be taken to protect vulnerable customers from higher prices, particularly fixed costs that are unavoidable from a societal perspective i.e. low carbon levies, network charges and other policy costs. Part of resolving this lies with BEIS. We, for example, have been a supporter of putting socialised parts of the electricity bill in general taxation to help distribute costs more fairly – this has the added benefit of making DSR measures more cost reflective, as currently less than 50% of a typical electricity bill is from wholesale electricity related costs.

4.40. Further action is required to help prevent end users gaining from ‘tax arbitrage’ by self-supplying instead of importing electricity; which has had ‘tax’ (such as network charges, RO, CM, FiT levies etc.,) paid; from the network. Stronger action is also recommended from Ofgem, in terms of reforming network charges to make them more cost reflective and equitable. For example, demand customers with behind the meter generation should not be able to avoid paying their share of the cost to have network infrastructure in place, because these customers still obtain a full benefit from the reliability and security of the network even if they may use it less frequently than other customers. It is important to add here that in some cases distributed generators exporting is causing additional costs in terms of transmission constraints and grid stability, although these costs are currently not appropriately reflected by charging arrangements and are instead being socialized across other users.

Opportunity to de-carbonise heat

4.41. After considerable focus on decarbonising electricity, one of the industry's emerging challenges is tackling the decarbonising of heat, which represents almost half of the final energy consumption in the UK and is therefore an essential element in meeting decarbonisation targets.

4.42. We have been involved in a range of projects that have looked at different scales and technologies. For example we are collaborating with Community Energy Scotland, V-Charge (an aggregator) and the Mull and Iona Community Trust on a project called 'Assisting Communities to Connect to Electric Sustainable Sources' (ACCESS)[33.] This project aims to develop a smart, active local network that balances local renewable energy sources with new electric storage heaters. Managing electric heating in this way provides a virtual district heating network without as much disruption and cost as commissioning new underground heat networks.

4.43. As DECC's decarbonisation strategy [34] highlighted: "technologies that use electricity to generate heat…are well placed to become major low carbon heating technologies in the coming decades".

4.44. Electric storage heaters are often seen as an ineffective and costly method for heating a home, and have not been deployed significantly under the Energy Company Obligation (ECO). Yet modern high heat retention storage heaters bring many benefits as they are able to provide efficient heating and produce cost savings of 20% on an annual household heating bill.[35] Given the higher proportion of electric heating in Scotland when compared to the rest of the UK (13% compared to 9%)[36], not only would the installation of new electric storage heaters contribute towards the decarbonisation of heat, but they would also provide an alternative means for consumers living in off-gas grid properties to heat their homes affordably. In addition, there is the potential for new generation storage heaters to contribute to the management of peak demand, through demand side response capabilities; this has already been demonstrated in the NINES[37] project, which has used flexible smart electric thermal storage load to balance over 100 MWh of local inflexible generation[38]

4.45. As a high proportion of consumers depending on electric heating are also more vulnerable we believe there is an opportunity to tackle all three elements of the energy trilemma. Whilst it is for Ofgem and BEIS to decide how best to support this, we see the removal of policy costs on electricity bills and more reflective carbon emission factors on electricity use as sensible routes. The latter would help electric storage heaters secure ECO funding and be on a level playing field with other carbon reduction solutions.

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[33] http://www.accessproject.org.uk/
[34] The Future of Heating: A strategic framework for low carbon heat in the UK' 2012
[35] http://www.dimplex.co.uk/assets/Downloads_PDF/Kema_Report.pdf
[36] Energy in Scotland 2016.The Scottish Government, p. 75.
[37] https://www.ssepd.co.uk/NINES/
[38] http://www.ninessmartgrid.co.uk/our-project/

Ultra low emission vehicles

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

4.46. The majority of this should be achieved through Supplier's offering new time of use tariffs for electric vehicle users, which could layer on system balancing incentives e.g. frequency response if the communication system facilitates this. From a DNO perspective smart tariffs do not currently account for local constraints therefore they will need to highlight to customers why smart charging is necessary. This should involve clearly laying out the key figures around the estimated impacts and costs from EV uptake on the distribution network, and how the reinforcement costs are ultimately borne by those EV customers and so it's in their interests to embrace managed EV charging in order to protect the electricity system and reduce the need to carry out costly and disruptive upgrades/repairs.

4.47. Many of the issues described previously in our response to question 32, which relate to improving currently non cost reflective charging arrangements e.g. to avoid causing distortions favouring behind the meter storage, also apply to EVs. If these network charging issues are not addressed, then the investment and dispatch decisions which customers make with regard to their car batteries may be distorted and inefficient, resulting in higher costs to customers overall, particularly with the most vulnerable and less engaged customers being disproportionately worse off.

4.48. Nevertheless, whilst cost reflectively and cost efficiency in terms of investment decisions is welcome, this needs to be balanced with the benefits that the socialisation of costs brings. We believe this trade-off is for BEIS and Ofgem to determine, but we would welcome guidance on what the policy objective is here as it will affect decisions taken by DNOs and investors in smart technology (suppliers, aggregators, tech companies). A particular grey area is emerging around EVs and whether a 'carrots or sticks' approach is correct for apportioning the reinforcement costs associated with EV charging and discharging. we would prefer market based solutions to be adopted by EV users that can accommodate the needs of DSOs, however, if users and/or third parties i.e. dispatch controllers do not engage then the DNO/DSO may look to have the ability to limit charging/discharging and/or levy constraint/access related costs. However, if this is the case then should it be different for other devices that have similar kW import/export capabilities behind the customer meter? (Batteries, showers etc).

4.49. We disagree that customers should only pay for the volume of energy they either import or export on the network. As the majority of network costs are fixed i.e. sunk this results in customers avoiding costs e.g. through the use of behind the meter generation self-supply that are then picked up by other consumers This is flawed as all customers require access to the network for security of supply equally, regardless of their proportionate use. We emphasise the need to address this problem, otherwise investments in distributed energy resources (DER will be made based on distortions whilst the bulk of customers will unfairly pay more. In order to address this issue we believe that other methods of cost recovery, such as standing charges that use a capacity metric could be fairer. This would help separate out the costs associated with network capacity and could lead to more equitable ways of incentivising and/or charging constraint management/reinforcement.

4.50. Educating existing and aspiring EV customers on the ability of managed EV charging to act as a network protection tool, like another kind of fuse in the system, will be invaluable to ensuring that when a DNO needs to manage EV charging to avoid overloading a circuit, it will be understood and ultimately appreciated by customers for allowing their property/street/neighbourhood to continue to receive a secure supply of electricity – especially those without EVs who may feel that their supply quality is being unfairly jeopardised by those with EVs.

4.51. This education exercise should also provide information around the opportunities managed EV charging affords them, including the potential mechanisms by which customers can achieve further benefits around earning revenue, reducing costs, reducing bills, reducing disruption and connecting more EVs (as noted in the Call for Evidence paper). Examples should be drawn from existing international schemes which allow customers to do just this. The focus for customer messaging should probably be around the opportunities for them to have greater control and more intelligence in the use of electricity via their EVs and charging points, including participating in DSR for financial benefits, with a strapline around how it will also help protect networks, and in turn remove additional costs, alluding to the network benefits.

4.52. Where a network is not subject to constraints then the driver for managed EV charging should be smart tariffs that focus on national or regional balancing, this is relatively straight forward. However, where the network is constrained then smart Tariffs as currently envisaged will not have the granularity or the speed to provide the network with the control necessary to beat protection systems.

4.53. As a local network becomes overloaded there is a small window of opportunity to react to the overload before protection in the form of fuses or circuit breakers start to switch off parts of the local network. In this situation a smart charge controller needs to be able to react to an instruction to reduce the charge within minutes, At the moment the UK system is being designed for a half hourly response. Similarly the overload on the network could be limited to a handful of homes in a particular street; local monitoring and aggregation combined with knowledge of the instantaneous load on the network can be used to share out the network capacity allowing effective EV charging. In the My Electric Avenue [39]projects this technique was used to increase the network overload thresholds typically from 40% EV penetration to 100% EV penetration.

4.54. As noted in the Call for Evidence, our Smart EV project is seeking to understand the best way to engage with customers around the concept of managed charging, and we are confident that the collaboration from the energy and automotive industries combined with the consultation issued to stakeholders will provide a logical and optimal strategy for this emerging concept.

4.55. We fully support the Department for Transport's proposed measures in their Modern Transport Bill, especially the plan for all new and renewed infrastructure to have managed EV charging capabilities, as this will ensure that customers can readily participate in any smart charging scheme and immediately see the benefits. Removing additional steps or processes for customers and/or industry to go through before being able to participate is essential.

4.56. The Smart EV project is also assessing the level of choice and reward deemed optimal for a managed EV charging solution, and so these findings should also be able to feed into the thoughts on a future system for the consumer.

4.57. Providing customers with a level of choice over whether they allow their EV to be subject to managed charging reduces the confidence a DNO can have in the solution from a network protection perspective, as there will be no way of knowing the level of response we can expect and it may mean that the system becomes ineffective in protecting the network. We recognise the significant opportunities that come with giving customers the means to input/adjust parameters relating to their EV for managed charging,

[39] http://myelectricavenue.info/about-project

such as a time by which they would want to have a certain state of charge (SOC), or periods when they would prefer not to be affected by managed charging. However, emerging evidence, for example demonstrated in the Customer led Network Revolution trial[40], suggests that an override function limited to a specific number of uses per year increases customer acceptability of managed control and is not necessarily used by the consumer.

4.58. We are particularly keen not to discriminate against customers, whether they are customers with or without an EV that is being actively managed. For example a situation in which only 3 EVs in a street are available for managed charging, whereas the other 6 EV owners have opted out, could leave the 3 EVs to be subjected to intensive charge management. Consequently the three 'flexible' EVs will possibly have to wait until the other EVs on the local network have been charged and the peak demand is reduced, which is unfair to them. It is worth noting that this issue will also apply to other distribution energy resources. This emphasises both the importance of having cost reflective price signals and protections for vulnerable consumers that may be subject to more volatile prices.

4.59. If the ability for customers to opt out is removed, and providing them with ability to input preferred periods of curtailment (or times when they need a certain SOC) is preferred, then a level of reward may be necessary to support continued EV uptake.

4.60. We believe that influencing customer choices through incentives, penalties and regulations will be necessary for customers to embrace managed EV charging. Linking managed EV charging capabilities to subsidies, conditions of sale and costs to customers will create compelling reasons for customers to favour managed EV charging and achieve widespread implementation/acceptance. Some ideas of measures that could support promoting managed EV charging and ensuring acceptance/use are:

- Linking subsidies towards EVs and EV charging points to the requirement to participate in local DSR activities e.g. by aggregators.
- Allowing DNOs to only permit connection of domestic fast chargers that will participate in local DSR activities or the customer pays the full cost of connection/reinforcement.
- Limiting the associated connection costs to customers that participate in DSR activities; this for example can be achieved by exposing EV charging to cost reflective price signals.
- Supporting solutions that will increase the benefits of smart chargers to users and thereby increase implementation (and in turn reduce the burden on the network at times of peak demand). Whilst we are technology agnostic solutions such as domestic storage or in-home DSR could offer significant potential.

4.61. Ultimately the provision and level of a reward will be influenced by the organisation(s) that will be providing it, such as DNO, supplier or DSR specialist/aggregator. Looking purely at the requests DNOs will make for managing EV charging, if rewards were to be paid, then they would need to be linked to the cost of the reinforcement which is being deferred. We believe this requires further investigation in terms of the costs and benefits to consumers.

[40] CLNR, Commercial arrangements study report, Phase 2, Element Energy, 2015. Page 8, 4th paragraph

34. 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?

Commercial related issues

4.62. Each different participant has a varying degree of interest in understanding and managing consumption patterns. As EV uptake increases alongside technology improvements and cost reductions it is likely that issues of range anxiety should decrease, whilst interest in lowering vehicle charge costs through new tariffs should increase. Nevertheless currently there is a lack of any direct financial gain or loss for the end user, who would otherwise drive market alterations; this could at least be partly addressed by more accurate smart metering and greater cost reflectivity in their electricity bill.

4.63. EV users will always require a full vehicle charge at certain times; i.e. when they wish to use the vehicle; which to some extent limits the times at which any charge they take from the network (or discharge onto the network, if applicable) can be made. Discharge, for example, is likely be most valuable (in terms of the market price) at times of peak demand on the network which, historically, tend to be just when the majority of such vehicles would either begin operation (in the morning), or require vehicle charging (in the evening). The volume of EVs required to make a significant difference in capacity terms is very high, therefore it is unlikely that this will be an issue in the next five years, however, further trials such as WPD's Electric Nation are welcome in understanding the technical capabilities and behaviour factors that will influence this opportunity.

Network related issues

4.64. Findings from innovation projects such as SSEN's 'My Electric Avenue' project show clustering of EVs will cause issues long before market saturation (32% of all GB circuits will experience issues when EV uptake on a street exceeds 40% of households). This work investigated how technology can be used to manage EV charging, to not only protect networks, but also to facilitate the connection of more load such as EVs. It is therefore recommended that there is need for localised managed (either through control or shifting) EV charging during periods of peak demand on a network.

4.65. A significant issue for DNOs is around the hierarchy of signals in managed EV charging – i.e. if a supplier or aggregator issues a signal that conflicts with a signal from a DNO seeking to protect the network those EVs are connected to, whose signal takes priority? Protecting the distribution networks is vital, because should a third party issue a signal that leads to customers' EVs suddenly charging at the same point in time, this could lead to constraints at the lowest feeder level (the distribution network) and potentially cause network issues such as voltage drops and power outages as network assets are overloaded. This finding was demonstrated in the My Electric Avenue project[41], which showed that EV clusters can cause network issues. Without successful network operation at this level, participants/stakeholders will not be able to achieve their desired response and the reputational damage to the electricity and automotive industries will be significant, with damage to consumer confidence potentially affecting the further

[41] http://myelectricavenue.info/about-project

uptake of EVs. It is worth noting that greater responsibility for DNOs as part of a transition to a DSO could alleviate this issue, as the DSO would act as an intermediary between third parties and the customer.

4.66. We see the opportunities for customers to have greater control and more intelligence in the use of their energy via their EVs and charging points, including participating in DSR for financial benefits, as being the focus of future managed EV charging systems. However providing DNOs with the ability to enforce a level of network protection is so crucial that we feel this should form the basis for all of these other capabilities. We believe that if a DNO detects that a network is under strain it should be able to instigate managed EV charging directly or override third party signals to prevent managed EV charging activities such as V2G, DSR, etc. from damaging the network, until there is sufficient capacity on the network to do so. However, consideration will be required to ensure that in these cases the Network Operator manages EVs in a fair way that avoids discrimination.

4.67. There is a need for all parties involved in offering managed EV charging services to act responsibly and not claim ignorance about not understanding the potential impacts to other parts of the energy system as the reason why they should not have a level of flexibility in their issuing of signals and/or the level of response they should be able to elicit for a particular area.

4.68. Taking into account views expressed by the Society of Motor Manufacturers and Traders (SMMT) we are keen that the energy system is not deemed to be unfairly targeting EVs as means of managing network protection – ideally in the future it will be possible to allow customers to determine via a smart hub/smart meter how they wish to manage the load at their property in response to a signal from a supplier or aggregator, as they may wish to prioritise their EV charging and instead shift their cooking/washing activities outside the peak demand period.

4.69. A potential barrier for any party seeking to implement managed EV charging could stem from the fact there is no standard agreed in the UK for managing communicating with, and managing the charging of, EV chargers. It is crucial, therefore, that standards are agreed between the energy, automotive and electric vehicle supply equipment (EVSE) industries to avoid there being a large number of different types of system and technology in the market and connected to the networks that are incapable of communicating and facilitating managed EV charging. Our Smart EV project is seeking to address this by informing an Engineering Recommendation (or similar standard) for the control of EV charging.

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

4.70. The challenge and opportunity with hydrogen is that it cuts across several energy vectors. At the moment it does not make sense to use hydrogen as electricity storage because of low round trip efficiency of initial conversion to hydrogen (via electrolysis) and then the re-conversion back to electricity (perhaps, say, via a fuel cell). Nevertheless it does have obvious use as transport fuel and it could have a limited role in de-carbonising heat as steam methane reforming is also likely to be deployed in this area. Hydrogen may help with renewable variability but production levels are unlikely to be reliable unless the primary focus of the renewables was based on hydrogen production.

<u>Our Project Involvement</u>

4.71. Our network business (SSEN) is a key partner in the Aberdeen Hydrogen Project which has investigated the risks and opportunities around future roll-out of electrolysis for hydrogen production.

4.72. As part of this project we undertook an LCNF and NIA funded project: Impact of Electrolysers on the Distribution Network. This project investigated controllability of the electrolyser and impact of electricity pricing on the operating profile of the unit. Electrolysers have the capability to act as demand responsive load, and to follow output from a renewable source such as wind to produce 'green' hydrogen. This could be of use in areas with high levels of constrained generation, where the H2 can be stored long term to even out seasonal generation fluctuations, or transported to other areas (although the long term storage or transportation will lead to increased H2 losses and higher costs).

4.73. The trials showed that electrolysers, utilising local generation, can offer network balancing services and have the advantage of not requiring imported network electricity once energy is converted into hydrogen. This is particularly important in constrained parts of the networks, as other technologies such as batteries can exasperate constraints due to their charging requirements.

4.74. The project found that the bulk of the ten-year cost for a hydrogen refuelling station (using electrolysers) is the electricity (>90% of CAPEX + OPEX over ten years based on the Aberdeen Hydrogen Refuelling Station). Therefore current time-of-use charges should provide an incentive for developers to avoid operating electrolysers during the Red time band, as a balance against the additional CAPEX costs associated with oversizing of storage or electrolysers.

4.75. Electrolysers may be found to be 'in competition' with other technologies such as storage batteries or DSR. Research should be undertaken to understand the pathway to the potential future value of hydrogen, as if the relative future value of stored hydrogen measured against the equivalent value for stored electricity could influence investment decisions and impact on the development of the hydrogen economy. It should be further noted that hydrogen produced by electrolysis will only provide a portion of the volume required; estimated by the UK H2Mobility report as 51% of the hydrogen required for transport. As mentioned earlier in this report, electrolysis would not be an efficient means to meet demand for heating.[42]

4.76. We were also a partner in the HyHouse project[43] which investigated the implications of leaks of different gases within a domestic property. It found that hydrogen dispersed and did not reach expected concentrations, with the energy content not exceeding a methane leak. It concluded that the risks associated with a hydrogen leak, and impacts of any explosion or fire, were broadly similar to that of natural gas. Nevertheless, further work is needed to understand the implications of leaks in a confined space or underground pipework. Detection and management of leaks and ventilation requirements need to be clearly defined to prevent significant build ups.

4.77. We view the largest potential benefit of hydrogen storage over batteries as the potential for much larger storage duration i.e. once you have the hydrogen, it is relatively cheap to store it compared with batteries. This is a similar benefit to pumped hydro, which is the most successful global storage medium for utilities worldwide. The key challenge for hydrogen will be matching the round trip efficiency of technologies such as pumped hydro (c.80%), as this affects the marginal energy cost and its ability to compete.

Consumer engagement with Demand Side response (DSR)

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[42] http://erpuk.org/wp-content/uploads/2016/10/ERP-Hydrogen-report-Oct-2016.pdf
[43] http://www.igem.org.uk/media/361886/final%20report_v13%20for%20publication.pdf

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

4.78. We believe a lot of this is currently through trade shows and supplier or aggregator communications; however our view is that current mechanisms could be improved as part of a joint industry effort supported by BEIS and Ofgem. Whilst National Grid's Power Responsive campaign has been very welcome in terms of promoting DSR, we have concerns with how it is being approached. Firstly, as the scheme is based on incentivising DSR services as a whole, it should be better coordinated with DNOs and Suppliers, however currently it is centred on SO led incentives. Secondly, there is a risk that it is focusing on large end users that are already engaging, whereas the majority of end users are not being reached. Thirdly, SSE is concerned that the SO is creating new system services that are either not available to all technologies or else that are shifting value away from existing markets towards bilateral contracts. For example the new demand turn up service is an energy based service, yet it is being incentivised as a system service by the SO; we would therefore welcome evidence on how this is providing an equitable price signal.

4.79. Despite the above criticisms, we acknowledge that traditionally the SO and DNOs have largely operated separately in terms of managing system issues. We feel that now is the right time to significantly increase coordination between all Network Operators in order to get consistent, equitable and consolidated messages to all market participants.

4.80. Qualitative evidence collected by our teams suggests that businesses typically find out about our schemes through innovation or sustainability focused managers. During SSEN's flagship NTVV project that trialled DSR; the local chamber of commerce was particularly useful as a promoter and facilitator. Our experience and partnership with Honeywell as part of the NTVV project demonstrated a high level of interest in DSR at a local level. By working with Honeywell we delivered a coordinated engagement package with 30 commercial customers signed up and participating.

4.81. We are hopeful that a market of products designed with DSR in mind will to evolve, particularly with heating and cooling systems that have a high thermal inertia (See Appendix 1) on technologies such as "IceBEar" in the NTVV project.) This could also include intervention on industrial end use, with added buffering to permit the energy intensive part of the process to be aligned with DSR requirements. We are encouraged by the recent technological developments that are happening in this area and will explore how these can benefit our business customers.

37. 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?

4.82. We believe that a significant proportion of non-domestic end users do not widely recognise DSR as being a financial proposition. This is either due to a lack of knowledge of their electricity use, or else a lack of visibility of how DSR could be beneficial to them, without either being an inconvenience or disruption to normal operational practice. Larger businesses are likely to focus on the financial trade off of using DSR for revenue growth versus any disruption to business operation.

4.83. It is also concerning that the DSR market has been almost entirely focused on a small collection of large energy-intensive users/sites with existing on-site generation – as these are able to justify the cost-benefit and are targeted by aggregators. A driver behind this is that current arrangements do not differentiate between onsite generation and genuine load shifting in terms of wider costs; e.g. network use charges, levies (RO, FiTs etc) tax, carbon and pollutants. In order to engage and incentivise the majority of consumers that do not have onsite generation, it is recommended that Ofgem and BEIS identify approaches to levelling the playing field to ensure all network and other charges, levies etc., are recovered equitably from all consumers.

4.84. The issues noted regarding barriers to non-domestic demand side response in the Call for Evidence document are essentially the responsibility of aggregators to manage when engaging with potential clients. The role of BEIS and Ofgem should be to facilitate the development of a regulatory framework that facilitates DSR, by for example reviewing current arrangements and whether they can be improved upon. This could include reforming network charges and other socialised costs to make them more equitable and sustainable in the long-term.

38. 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?

4.85. We advocate the continued engagement with community groups and non-domestic customers by DNOs in their transition to a DSO. With greater clarity regarding the DSO's role and empowerment it will be possible for these organisations to arrange industry events to bring together stakeholders and promote DSR provided by community groups and non-domestic customers etc., to the market place via aggregators and other Third Parties (but not via DSOs – who may, along with the SO, contract with the aggregators et al to utilise the DSR capacity / volume). We believe that DNOs are best placed to facilitate this type of engagement due to their deeper knowledge of their network areas and customers. Innovation projects led by DNOs have demonstrated the benefits of a more local approach, for example by utilising council support to identify and increase sign-ups. We see a collaborative role for DSOs alongside aggregators in recognising and identifying those customers "best for DSR" e.g. in terms of location (constraints), appropriate load shape and ensuring minimal disruption and costs in terms of the network.

4.86. We further believe more could also be done to promote participation by emphasising the social and sustainability aspects, which could give incentives to large household-name companies and others with a sense of social responsibility. The reduction of red tape and greater ease of maximising commercial potentials could also work as an incentive.

4.87. It is essential to ensure that network charging arrangements are improved to collect these charges in a way which is fair and cost reflective first, before larger scale participation in DSR is encouraged. Otherwise, a higher participation in DSR may take place to arbitrage charging arrangements which, instead of delivering better value to society, could instead result in higher costs to customers overall and in particular disproportionately higher costs for those most vulnerable and less engaged customers who are less able to participate in DSR activity.

39. 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)?

4.88. In the case of electric heating and hot water there is already an immediate requirement to engage with consumers to both re-incentivise managed charging (in a way that lowers costs) and improve thermal comfort. We estimate that over 2,000,000 households have switched from using storage heaters to less carbon efficient fuels such as oil, or else to direct electric heating. This has resulted in the removal of over 5 million hot water tanks and 6 million storage heaters, which equates to the loss of over 65 GWh of storage and is equivalent to 20,000 large utility-scale batteries. We advocate regulatory and policy support that can help preserve space and hot water storage systems as these are valuable flexible assets; this could partly be achieved by addressing the issue of accrediting DSR with carbon credits in a similar way to other ECO schemes. By targeting funding towards vulnerable customers with electric heating systems such as the ACCESS project (see Q31), there is an opportunity to develop new DSR capability whilst also lowering bills and improving thermal comfort (new smart thermal electric storage heaters using DSR by Dimplex have demonstrated this).

4.89. In the longer term we view customer acceptance and reputation as key. Innovation in the domestic environment should become market based, with regulations focusing on consumer protection and license conditions. The risk is that the reputation of the electricity industry becomes dented by either exposing consumers to unexpected prices, unscrupulous behaviour by aggregators, or by technological failures resulting in inconvenience.

4.90. We envisage that if DSR happens in clusters without DNO involvement this could lead to network related issues. Ideally DNOs should be a key facilitator and not a barrier, and this could be helped by greater visibility and engagement with aggregators e.g. obligations on aggregators and suppliers to provide visibility of their anticipated volumes, profiles and recruitment for defined areas. In order to engage with end users, simplicity will be crucial as experience shows that complexity is a barrier – ideally domestic customers will have one point of contact that will be licensed as the balancing responsible party for those customers' site(s).

Consumer protection and cyber security

40. Please provide views on what interventions might be necessary to ensure consumer protection in the following areas:

- Social impacts

4.91. Vulnerable customers may be penalised as other end users reduce their costs but the total 'socialised' costs e.g. network and policy costs stay the same. This has already happened with TNUoS costs whereby non-domestic users have avoided costs thereby raising costs for domestic users. Any new framework needs to put the interests of these customers at its heart, firstly by ensuring cost-efficient infrastructure is developed and secondly by ensuring cost reflective charging.

- Data and privacy

4.92. The move to a smart, more flexible energy system will require a substantial rise in the amount of personal data held by industry. With this level of data in circulation comes a heightened level of risk to information security and data fraud. In order for the energy and smart system to cope with this considerable increase in the amount of data and risks, a proportional data management system may need to be formed. This system should be capable of supporting the integration of DSR, storage and overall system flexibility whilst protecting consumers' personal information. However, we consider this is an intervention in the market that BEIS and Ofgem should take very seriously and therefore treat with robust and careful consideration. The system is and will continue to be complex and ever changing, and with the large number of stakeholders involved, interventions should not be hurried.

- Informed consumers

4.93. A key challenge when moving to half hourly settlement and customers contracting with aggregators and other Third Party DSR providers is how to find the balance between informing customers and simultaneously acting in their interests. For example many revenue streams will be dynamic and will require automation or fast decision making by end users. It will be very important that the customer fully understands the terms of any agreement and any exposure they have to negative consequences, whether this is financial or physical; e.g. the availability of heat/hot water/vehicle charging. Where practical, the customer should always be allowed to override an aggregator or supplier DSR action (whilst recognising that this will cost the customer financially) unless it could compromise network resilience, which would be dictated by network operators who will, in turn, be expected to make a corresponding constraint payment to the affected customer. This further demonstrates the importance of harmonised systems between DNOs, the SO and third party aggregators and/or suppliers.

- Preventing abuses

4.94. We agree that it will be important to ensure customers' data is appropriately protected and that they understand how their data will be used. As we transition to a more flexible energy system with multiple parties.

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

4.95. Before Radio Tele-Switch meters there was a major problem in which synchronised switching of electric heating caused spikes in demand and additional system operation cost. Radio Tele-switching alleviated these issues by permitting electric heating load to be staggered and spread overtime and remotely adjusted through a central control unit.

4.96. We believe there could potentially be a risk to GB networks associated with the transition of metering systems to smart from the present day systems. A significant issue will be the demise of the Radio Tele-switch system and the transition to load and tariff switching controlled by smart meters. This brings with it a significant change as currently DNO's act as the Radio Teleswitch access providers meaning they will no longer see any significant changes to load switching times, whereas under the new smart metering regime all load and tariff switching will be undertaken by suppliers.

4.97. Whilst the UK communications coverage for smart metering is a high percentage, the small percentage not covered is predominantly in our SHEPD area. As a result of this area also being non-gas, the absence of an alternative to Teleswitch from 2020 onwards and no smart meter based alternative this present a major challenge.

4.98. In our NINES[44] project during initial commissioning the frequency response setting was found to be creating unintended consequences. This was rectified quickly and remotely, however, this was a direct result of the level of rigour associated with a trial. In a live environment a particular product getting onto the system and behaving in a destabilising manner may not be identified until the volumes installed are large enough to have a measurable impact, and therefore may not be readily modified or rectified. As a result, testing, auditing, standards and remote reconfiguration are going to be key requirements for an at scale deployment of Smart appliances.

4.99. It is likely that new metering systems will encourage innovation and we will experience the development of new tariff offerings by suppliers some of which may also directly (or indirectly) control customer load switching. This will present challenges for both system balancing (if large numbers of customers are involved) and for DNO/ DSO's who may experience sudden/ unexpected changes in network loading.

[44] https://www.ssepd.co.uk/NINES/

However, this can, to some extent, be anticipated by the network operators based on prevailing (and forecast) market prices; i.e. at times of highest prices, it can be expected that DSR will be maximised whilst, conversely, demand can be expected to increase at times of minimum prices. We have taken steps to mitigate potential increase in coincidence of load by proposing a recent change to DCUSA (DCP204[45]), which has now been implemented. Throughout the development of DCP204 there was significant engagement with the suppliers and Network Operators in the working group. However, it was of concern that not all suppliers fully understood the issue of network resilience and what it entailed. We are concerned that not all market innovators (suppliers, aggregators etc) may appreciate the local network constraints and grid stability issues that could limit DSR activity without robust cooperation. Therefore without greater engagement as part of a DSO transition there is a significant threat of the electricity network being compromised.

4.100. We commissioned EA Technology to produce a detailed report and summary paper detailing the consequences in our SHEPD region of disabling Radio Tele-switch and transferring load control to suppliers. This focused on existing network loading primarily associated with space and water heating and the consequences of new low carbon technology load were not really considered in the study. The results estimated that the additional value of capital expenditure required to meet additional demand if the Radio Tele-switch service was disabled was £718m.

4.101. Radio Tele-switching had the advantage of using Low Wave (BBC radio) transmitters that were both highly reliable and difficult to compromise in terms of modification or interruption. Any new system to enable DSR and new tariffs will have to provide at least a similar level of reliability and security – if for example this includes using the internet it is likely that there will be significant challenges with regards to transmission range and security.

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

4.102. Not enough regulation or coordination risks electricity imbalances and thermal or voltage issues being experienced on low voltage feeders. To prevent these issues DSOs will need greater authority to manage, from a physical perspective, aggregated load to ensure network resilience, whilst recognising that, in principle, where consumers are constrained as a result that they may expect to be appropriately compensated by the DSO.

4.103. Emphasis should be placed on the visibility of data for DSOs; whether it is dispatch signals or consumption; although priority should be given at least initially to locations with higher sensitivities and kit or devices that have a higher impact; e.g. a higher power draw such as electric vehicles. Learnings can be taken from our Active Network Management scheme that have been developed in the Shetlands, which has involved much greater monitoring and control of disaggregated devices. We believe network operators should work together with all stakeholders to ensure standardisation in this space, whilst recognising that developments in terms of the EU Network Codes may already address some aspects of this. One of the key issues is how data gets from a third party to network operators (and vis versa) and

[45] The Objectives of DCP204 were to:

- To replicate existing functionality around tariff time switching and load switching for a smart regime. The CP is not seeking to introduce a like for like replacement but rather to replicate the method through smart metering.
- To simplify the security restriction notice process, in a way that describes an escalating process supported by different types of notice.
- To mandate randomisation, for all meters that support randomisation, up to a period of 600 seconds.
- To introduce a standard template that all Distributors will use to notify Suppliers of demand controlled areas.

whether this is secure. It is likely that regulations will need to focus on ensuring all parties meet requirements on this as it will be these entities that are coming to market with innovative solutions and technologies.

4.104. We have initiated the proposal SECMP0025 'Electricity Network Party Access to Load Switching Information' in order to address some of the aforementioned issues. In summary, this proposal seeks to enable Electricity Network Parties to have access to information from the Smart Metering System relating to load switching carried out by Smart Meters or Smart Meter connected Devices. It also proposes that the Smart Metering System informs Electricity Network Parties when changes are made to existing load switching regimes.

4.105. Whilst there is a debate on how batteries are treated in regulations, the DSO will be principally concerned with how batteries behave in terms of importing electricity from or exporting electricity to the network and reactive power. This should be considered when any regulatory changes are being made, especially as different batteries will behave in very diverse ways in terms of power, efficiency and ramping up or down. For example, whilst a battery can help ease network constraints or help with network congestion, they also risk exasperating both of these issues when they operate in reverse; i.e. discharge to charge mode. Therefore careful consideration will be required in how to physically monitor and control batteries in order to secure the system, whilst recognising that, in principle, if a user is constrained by the network operator that appropriate compensation will be provided to them by that network operator.

4.106. When electricity is exported onto the network and subsequently data associated with that export is placed onto an IT system, there is undoubtedly a heightened risk of a data security breach. This risk appears across all levels of the supply chain from critical national infrastructure (SCADA etc.) to smart devices in homes (ransomware attack, ID fraud, malicious hacking etc.). As such it is essential that the breadth of this key infrastructure is suitably secure.

4.107. There are robust standards that have been adopted internationally, and kept updated, so the risk from cyber-attack, whilst always a threat, can be mitigated against with some level of confidence and we support GB adopting / applying those standards or developing similar standards

5 The roles of different parties in the system and network operation

Executive Summary

5.1. We agree with the assessment that the changes taking place on the electricity system will have an impact on the roles and responsibilities of different market participants. In particular, DNOs will need to transition to new roles and are best positioned to support the efficient connection and utilisation of new flexible and dispatchable resource below the Grid Supply Point (GSP). By taking account of its network constraints, stability requirements and existing connection arrangements, DNOs can take charge of local planning decision making to meet the interests of all their customers. We believe that DNOs can help to increase access for new entrants to participate in the national provision of ancillary services and the Balancing Mechanism by sharing a BSUoS incentive and coordinating resource use with the SO.

5.2. As a result of the challenges of operating remote networks, we have experience in many aspects of the role and function of a DSO. For instance, we have already been involved in Active Network Management (ANM) and we anticipate this need growing in future. Furthermore, our commitment to equitable, non-discriminatory solutions has led to the development of Constraint Managed Zones (CMZs). These allow distributed energy resources to compete and capture value that otherwise would have to be spent on traditional reinforcement. In addition, our rich portfolio of DNO innovation projects has allowed different technologies and providers of flexibility to be tested and evaluated (see Appendix 1).

5.3. Our DNO business has strong links with local communities, which we intend to further develop as part of our transition to a DSO. For example, we are collaborating with Community Energy Scotland, V-Charge (an aggregator) and the Mull and Iona Community Trust on a project called 'Assisting Communities to Connect to Electric Sustainable Sources' (ACCESS). This project puts customers at the heart of the solution by investigating the use of smart electric heating for balancing low carbon generation in a way that optimises their thermal comfort. Due to the DNO's understanding of local network flows and the needs of their customers and communities, we believe they are best positioned to work with aggregators to realise the full benefits of their flexible resource i.e. maximising primary (local) and secondary (national) utilisation at least cost.

5.4. We are therefore proactively engaged in and are well placed to support and lead work on what needs to be done to enable the transition to DSO. There is more work to be undertaken to predict all the challenges, risks and possible unintended consequences that may arise in what will inevitably become a more complex and less predictable operating environment. However, we believe that the majority of issues with the interface between the TOs/SO and DNOs should be able to be addressed via greater coordination and a re-evaluation of the regulatory frameworks for TOs and DNOs to facilitate new flexibility providers in a way that is cost efficient for all consumers.

5.5. Our core objective is to continue to work on realising new flexible resources that avoid disruption and maximise customer benefits. To achieve this, we recommend an incremental approach would be the most appropriate to ensure that standards are maintained, whilst the industry is afforded time to work together to develop best practice and the operating costs and risks associated with these solutions are verified in a non innovation funded environment.

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

5.6. We broadly agree with the system requirements that are emerging; and would welcome further clarity from Ofgem and BEIS, as well as from further industry work, on how this will be implemented in practice.

5.7. We believe that the overarching objective should be to solve the energy trilemma, with emphasis on what is best for consumers now and in the future. The last few years have shown that the energy industry is able to respond positively to the trilemma challenges when arrangements allow and promote them to do so. For example, the uptake of low carbon technologies (LCT) has grown at a remarkable rate as a consequence of policy decisions made by Government[46].

5.8. Despite the unprecedented growth of LCT on distribution networks, their future remains unclear and there is a wide range of solutions and technologies that are competing with each other in terms of delivering the energy requirements that consumers desire. For this reason we are cautious of prescriptive regulatory frameworks, as this is not necessarily advantageous from a system efficiency point of view, nor is it often future-proof.

5.9. In this respect we recommend that a more holistic, principles based approach, is taken by policy-makers that can support the requirements for consumers now and in the future. For example, the focus of the Call for Evidence has been on the role of distributed assets and operation, but it remains unclear how TOs and flexible, smarter assets, on the transmission network will play a role in the transition to a low carbon system. If arrangements are looked at in isolation there is a risk of stranding existing assets and creating longer term price increases to consumers.

5.10. With regards to Figure 1 in Chapter 5 of the Call for Evidence, we believe that more emphasis should be placed on Security of Supply aspects. For example this could include the ability of Network Operators to respond to exceptional or unpredictable events, which is critical to customers receiving reliable energy. Furthermore, account needs to be taken of the impact of large scale industrial renewables, international developments such as European Network Codes Brexit, and the fact that policy decisions are to an extent dictating the pace of change.

5.11. As outline above, the economic benefits of using distributed energy resources clearly increase with the level of deployment for example, we support emerging technologies such as storage devices that can help solve the energy trilemma. We also support further work that addresses the new risks that these technologies bring to national infrastructure in the form of 'Combinatorial Risk'. This effectively describes the increasing interdependence on communications, IT, cybersecurity, customer behaviour and contracted service delivery. As a result it is important that the industry establishes a means of communicating and evaluating this risk to allow informed decisions to be made. This could possibly follow the principles of existing metrics like 'Health and Load Indices' however, to date no industry innovation projects have explored this challenge in detail.

5.12. We believe the Future Power Systems Architecture (FPSA) work initiated by DECC and the Energy Systems Catapult is a good opportunity to develop thinking on future system requirements, without being constrained by current market arrangements or pre-determined future scenarios. This work should help identify how arrangements can be evolved that is practical in terms of a working physical framework.

44. Do you have <u>any data</u> which illustrates:

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

5.13. In our role as a DNO that is responsible for responding to the unique challenges of managing remote networks, we have experience in many aspects of the role and function of a DSO. On Shetland, Orkney and the Western Isles we have deployed Active Network Management, Reactive Power

[46] Variable low carbon generation on the distribution network currently accounts for over 21 GW (80% of total) of the installed capacity on distribution networks.

control through Statcoms, Voltage management and scheduling of Radio Teleswitching load. In addition, our rich portfolio of DNO led innovation projects has allowed features of a DSO to be tested and evaluated including:

- Network Visibility and Monitoring
- Domestic and Commercial Flexibility
- Chemical and Thermal Energy Storage to provide network services
- Energy Vectors to allow transfer of energy between energy systems
- Advanced Active Network Management Systems

5.14. As a result our DNO business is well placed to support and enable the transition to DSO and we believe that an incremental approach is preferred, predominantly as a result of the complexity that the new operations involve. Given our strong links with local communities we are already taking incremental steps in that direction.

5.15. In Shetland, we are the de facto system operator because of the island network's need for dedicated frequency support and its disconnection from the main GB electricity network. Shetland demonstrates the role that DNOs can potentially play, as well as the importance of location. We envisage that other locations, due to their geography, existing network constraints, and changes in supply or generation patterns will face similar issues to Shetland. Through bodies such as the ENA we believe DNOs can agree common approaches to overcoming these challenges; the extent to which they are required will depend on market developments.

5.16. The increase in exported volume of energy from GSPs demonstrates the need to address charging arrangements and issues such as embedded benefits, as existing arrangements have been designed for one way flows from the transmission network to the distribution network. Going forward we believe DNOs should have a key role in facilitating the use of distributed energy resources on the transmission network i.e. national balancing markets. This role would allow DNO/DSO to act as a gateway at the GSP, in a way that optimises resource use and existing assets, and therefore lowers wider costs to consumers e.g. the replacement of transformers.

Table 1: Exporting GSP data (North region data to be added)

GSP	Number of Hours Substation Exported in year	Time of Maximum Export	Value of Maximum Export (MW)
Bramley (ANDO-THAT)	0.00	10:03 15/10/2015	244.04
Chickerell	57.52	17:36 16/12/2015	95.86
Cowley	9.10	21:59 14/12/2015	391.57
Fawley	66.69	08:00 16/12/2015	143.00
Melksham	0.02	14:31 19/07/2015	92.09
Willesden	0.00	12:17 01/07/2015	120.34
Alness	4332.5	01:00 07/11/2015	72.65
Ardkinglas	6954	09:30 05/05/2016	18.516
Ardmore	3231.5	01:30 27/11/2015	23.072
Beauly	61	02:30 16/11/2015	3.86
Braco	2870	03:30 18/08/2015	55.746
Bridge of Dun	419	05:30 18/07/2015	8.394
Carradale	5573	01:00 20/11/2016	78.24
Cassley	5250	02:30 28/10/2016	14.27

Ceannacroc	3236.5	02:30 02/06/2016	22.718
Clachan	4898	23:30 26/01/2016	48.51
Coupar Angus	2222.5	00:30 24/08/2015	29.852
Dallas	7349.5	01:00 29/12/2015	91.2
Dounreay	5676.5	21:00 05/10/2015	57.54
Dunbeath	3831	04:00 31/03/2016	2.788
Dunoon	2686.5	02:30 08/12/2015	24.974
Dunvegan	4285.5	08:00 08/11/2015	25.81
Dyce	188.5	02:00 02/01/2016	6.864
Fasnakyle	7120.5	24:00 29/02/2016	39.782
Fiddes	4106	01:00 27/03/2016	52.992
Fort Augustus	2350.5	01:30 27/03/2016	10.556
Fort William	169.5	22:30 12/03/2016	5.88
Glenfarclas	7551.5	22:00 23/12/2015	63.552
Grudie Bridge	8084.5	02:30 19/12/2015	27.12
Keith	2388.5	01:00 02/01/2016	59.71
Killin	8249.5	08:00 19/12/2015	21.35
Kinlochleven	7431	02:00 04/07/2015	18.25
Kintore	562.5	01:00 03/09/2015	18.704
Lairg	7796	24:00 13/04/2015	39.48
MacDuff	4075	22:30 26/03/2016	21.336
Mybster	5349	23:30 20/08/2015	36.79
Orrin	6821	02:00 14/04/2015	40.648
Port Ann	2558	12:00 22/12/2015	19.754
Quioch	7548	22:30 15/12/2015	20.004
Rannoch	8020	15:00 22/01/2016	55.34
Shin	8329.5	09:00 05/12/2015	32.904
Sloy	3722	01:30 18/12/2015	3.976
St Fergus Gas	3455	15:00 18/07/2015	12.71
St Fillans	6849	12:00 16/02/2016	22.542
Strichen	5102.5	07:00 03/01/2016	25.318
Tarland	2656	24:00 17/07/2015	13.976
Taynuilt	4478.5	03:00 10/11/2015	34.114
Thurso	4439.5	23:00 05/10/2015	48.204
Tummel Bridge	6670.5	01:30 21/12/2015	38.06

The interaction between network refurbishment and network reinforcement

5.17. A key factor in the decision to deploy any flexible solution has to be the remaining asset life of the existing constrained network assets. Failure to take this into account could result in double investment in both conventional asset replacement and flexible solutions in a situation where the conventional asset capacity can be increased for a marginal cost. This example emphasises the need for the DNO/DSO to be at the heart of informed decision-making at a local, regional and national level.

The timing and impact of smart devices

5.18. Initially it is expected that network related issues driven by smart appliances will be limited. My Electric Avenue demonstrated that if the roll out of EVs was uniform across the country then 40% of all homes could have EVs before the local networks would have significant issues. However, this assumes a uniform uptake and does not factor in clustering that will alter this percentage and bring the constraint issue to specific areas far earlier than the national in terms of the uptake curve. It is anticipated that the same pattern will occur for smart appliances.

5.19. As a result we believe that the early years of smart device deployments are going to focus on network monitoring, modelling and the anticipation of new constraints. This will allow areas to be addressed one by one in terms of their requirement to have Active Network Management. This theory is borne out by the adoption of embedded generation, which first challenged the DNO ten years ago in the remotest elements of the network such as Orkney and the Western Isles. It has taken a number of years for this issue to be seen in the wider network. A rapid change in government policy could alter this.

Inconsistencies between different market participants

5.20. We recognise that there are barriers that DNOs currently face in the use of flexibility to manage network constraints. For example the inconsistency of regulatory approach between the transmission and distribution network can result in conflicting drivers in the decision-making processes of flexibility providers and consumers. A key output of this exercise should be the alignment of these principles. In the future, depending on the nature of flexibility services and their payment, DSOs may be required to make balancing payments and compensate users for loss of network access. (See 3.45)

5.21. In broad terms we fully support a level playing field that does not discriminate against resources located on different network levels. With regards to the treatment of supply, demand and storage, resources should be treated according to their import and export onto the network using a technology neutral principle.

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

5.22. As a DNO we report annually on progress towards using smarter and more innovative approaches to saving customers money. The full report can be found on our website [47]; below provides a summary of what has been achieved to date:

- SSEN has demonstrated the capabilities of Active Network Management (ANM) through its deployment in North and South regions. For example ANM has released 45 MW of additional capacity in the Isle of Wight.
- SSEN's NINES project examined the complexity of managing large volume of distributed generation both individually and across the whole system and has demonstrated that the basic DSO model can work efficiently.
- SSEN's 'Bidoyng' work has improved network reliability and availability and produced savings of £1.6m across our network.
- On SSEN's HV network £1.5m of savings have been made by live line tree cutting.

[47] https://www.ssepd.co.uk/Library/StakeholderEngagementPublications/

- SSEN's NTVV project has demonstrated the capabilities of commercial automated DSR, as well as domestic solutions, which can divert solar PV generation into hot water tanks to alleviate network congestion.
- SSEN's My Electric Avenue has shown the importance of having visibility and DNO engagement ahead of efforts to electrify transport and a transition to ULEVs – in itself this can help promote market investment in managed EV charging solutions and cross-party engagement.
- SSEN has also been involved in community energy led schemes such as project ACCESS, which is helping to realise local balancing solutions between LCTs and end user with electric heating on the remote isle of Mull.

5.23. Ofgem and BEIS have estimated a potential value of (17 -40bn) for the transitioning to a more flexible energy system. Whilst we support the findings, we would welcome greater transparency on the more granular detail. This would give market participants greater confidence in their decision making.

5.24. With respect to Automated Network Management, a key consideration is where the associated saving is realised, as only a proportion of the savings return to the customer via DUOS charges. Whereas a large proportion of the benefits are seen by communities and generators in the form of reduced connection charges, or else more typically in creating a scenario in which a particular scheme is bankable and would otherwise have not gone ahead. Therefore it is important that when during the decision making process a project's savings for the DNO is not considered as the only driver.

5.25. Due to the above factors, we believe priority should initially be given to harmonising existing network arrangements in a way that promotes a level playing field. Subsequent issues around market access will be dependent on the ability for distributed energy resources to comply with the same requirements as larger units (whether this is facilitated through an aggregator or not). In theory a unified market approach between all resources is welcome, however, in practice the cost and complexity of achieving this versus the benefits will require close scrutiny. For example, De-minimis thresholds exist to avoid deterring small scale assets from connecting, however these thresholds distort the market, therefore a transition to more flexible system will have to deal with this trade off carefully.

45. 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?

5.26. We agree with the Call for Evidence assessment that DNOs are transitioning towards new roles in light of the changes taking place on the electricity system. We view this transition as involving more proactive management of the distribution network with greater coordination between transmission and distribution network operators, the SO, as well as with the customers connected to the network (demand, generation, storage).

5.27. We believe that the DSO will be best placed to take account of the interests of customers and communities at a local level. Our DNO business has strong links with local communities, which we would like to further develop as part of our transition to a DSO. For example we are collaborating with Community Energy Scotland, V-Charge (an aggregator) and the Mull and Iona Community Trust on a project called 'Assisting Communities to Connect to Electric Sustainable Sources' (ACCESS).This project puts customers at the heart of the solution by investigating the use of smart electric heating for balancing low carbon generation in a way that optimises their thermal comfort.

5.28. DNOs have been actively working with many forms of flexibility including, for example, energy storage devices. Therefore DNOs are well informed and have shared the abilities and limitations of these technologies as part of their dissemination programmes.

5.29. As a network operator we are able to identify a number of specific situations in which the procurement of flexible solutions is the preferred solution on a TOTEX and optionality basis. We believe that the volume of such opportunities will increase as flexibility becomes more prevalent and becomes a marginal cost. On that basis we welcome moves to encourage the embedding of and access to flexibility.

5.30. Through industry alliances and greater cooperation, we envisage progressive development of the DSO role through ED1. We believe that the focus should initially be on what actions are required to deal with conflicts or immediate system requirements and ensuring that costs by DNOs in support of smart flexible systems.

5.31. Ahead of new regulatory and policy decisions on a move towards DSO flexibility we believe that more work is required to enable informed decisions, particularly, in relation to the cost of implementation, the cost of operating, risks and benefits. When at a large scale, distributed flexible systems will require a paradigm shift, in terms of transitioning from relatively passive network operation to new intelligent systems that manage significant complexity. Progressing work in areas such as the Isle of Wight and Shetland will help industry understand how GB can tackle this in a way that benefits end users.

5.32. We are focused on providing the best possible outcome for the customer. We believe that as a DNO our experience in dealing with end users and small generators means that we are in a good position to provide value to customers by taking on a more active role in the distribution network. And we understand the local communities and can better deliver the best outcome rather than a centralised approach.

5.33. For example, our commitment to non-discriminatory solutions has led us to develop Constraint Managed Zones (CMZs) as a DNO. This allows distributed energy resources to compete and capture value that otherwise would be spent on traditional reinforcement. Under the RIIO framework we have encouraged and incentivised new flexibility providers to come forward. Whilst CMZs have only recently been developed we are encouraged by the interest and engagement that we have received from industry so far.

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?

5.34. We advocate a combined approach to make progress in the areas discussed by Ofgem and BEIS. The market can drive a lot of the changes but may not be able to address all of the issues. Therefore, the legal and regulatory framework must evolve over time to drive change and support the evolution of the market. An example of this is how to maintain network resilience and grid stability when large thermal generators are being replaced by non-synchronous and non-dispatchable generators. This demonstrates the importance of harmonising markets and rules, whilst ensuring that capabilities of providing energy, inertia, capacity and reactive power are monetised and providers can compete on a level playing field.

5.35. We view it as essential that any change to the structure of the industry maintains and develops strong connections with the political, social and welfare needs of communities at a local level. This reinforces the core role the DNO/DSO can play as it is best placed to understand and deal with these issues.

The recent decrease in generation output from large scale thermal generation has been mainly replaced by renewable generation, a significant proportion of which is on the transmission network. The Call for Evidence has focused on distribution networks and the changes taking place, however, whilst local small-scale generation, demand and storage solutions could be the most economical in some locations and/or for solving particular issues, the same can be true for large scale assets on the transmission system, which benefit from economies of scale.

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.

5.36. Our Network business is preparing to deal with the forthcoming changes and believes that currently it has the right tools to do so under n the RIIO framework. Many of the coordination requirements are being addressed through industry engagement e.g. the ENA's TDI working group; we welcome Ofgem and BEIS' continued participation in this forum.

5.37. Uncertainties exist due to Brexit on how the legal framework for system operation will change or not. For instance, developments in European Commission regulations will be important to realising a clear legal framework for system operation, for example the Transmission System Operation Guideline (TSOG) is instrumental to this. Furthermore, EU Network Codes are set to have a positive impact by mandating controllability. The Requirement for Generators is an example of this which will require all new generators above 800W to have minimum controllability by 2019. Whilst we view these new requirements as positive we believe that GB could benefit from potentially fast tracking these changes.[48]

5.38. We agree that models should be assessed to ensure that arrangements are fit for meeting future system requirements efficiently. We expect that there will be greater clarity on both long-term system requirements and appropriate models for transitioning to in the next five years.

5.39. In summary, we agree with Ofgem and BEIS that it is more appropriate to let industry find market based solutions in the first instance, before signalling any major reforms to arrangements. Precluding market based solutions with policy or regulatory reforms risks picking technology or business model winners and may undermine competition and innovation.

46. 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?

5.40. The majority of issues with the interface between SO/TOs and DNOs should be alleviated by greater coordination and these parties applying more flexible rules when conflicts of interests occur. Due to the recent and unprecedented nature of transmission and distribution interface issues e.g. exporting GSPs it is uncertain to what extent legislative and regulatory changes are required to avoid conflicts. However, it is clear that it is important to ensure that any such potential conflicts or overlap between SO and DSO actions are identified and managed for the benefit of consumers across the UK.

5.41. Currently the SO has limited experience liaising with smaller industry players, and has been largely limited to working with TOs, DNOs and several large generators/aggregators. In contrast, DNOs have extensive experience of working with communities, small generators and providers of flexible services. Whilst we support the principles of National Grid's Power Responsive campaign, which is to have greater participation in balancing services from the distributed energy resources, we believe that this has lacked cross-DNO engagement. The procurement of balancing service without DNO involvement will inevitably cost more and will cause conflicts between local and national security of supply. We therefore think that DNOs should be at the centre of facilitating and promoting demand side balancing services in collaboration with the SO.

5.42. The precise meaning of 'DSO' in terms of the responsibility requirement and differences with respect to current DNOs' roles are currently unclear. We are currently undertaking work to understand different DSO models and whether they are equitable for customers and the wider market.

[48] For example in Germany following the EEG 2014, installations with a capacity over 100 kW (including CHP) is required to install the control and communication equipment. Solar PV with a capacity between 30 kW and 100 kW may decide between installing the control and communication equipment that allows the reduction of generation output remotely or face being limited to 70% of their maximum effective exported capacity.

Nevertheless we believe that a focus should initially be on what actions are required to deal with conflicts e.g. between the SO and DNOs or immediate system requirements, rather than on roles.

5.43. The shift towards a DSO model, whereby the DNO has full control and visibility of all resources connected to its network is a significant market evolution, which will at some point require changes to the regulatory framework. While the requirements of all participants are being accommodated there needs to be an awareness of the unintended consequences of actions. What is best for one party may cause complications for another. We are progressing new analysis of the different models that could be carried out in order to understand the nature of the challenges involved and would welcome the opportunity to discuss it with Ofgem.

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?

5.44. We appreciate the issues Ofgem and BEIS are trying to tackle in presenting the different models. Due to the complexity and uncertainty of market developments, we are undertaking further work to better understand different models and how they affect our ability to act in the best interests for our customers, as well as our business. As mentioned earlier we believe there is an opportunity to inform industry of the practicalities, opportunities and risks of the DSO transition by undertaking further work in areas such as the Isle of Wight and Shetland.

5.45. Whilst we are still examining the models in detail, we would be happy to discuss our views with BEIS and Ofgem once we have reached a more developed position. In this Call for Evidence response we have set out some initial observations at this stage.

Network planning

5.46. We believe a local element to system planning should be retained in all cases. It is our view that DNOs are best placed to manage local grid stability and constraints in a way that meets end users' expectations. A clear process for determining the trigger point for reinforcement must be defined in cases where a constraint is limiting the ability of a DSR provider to provide services at a national level. For example a constraint costing £1m to reinforce could be responsible for holding back several million pounds worth of flexibility. Therefore the consideration here should be: what is the trigger, and how is this managed transparently. There are a number of options but these will be determined by several factors, such as does the DSO pay for the inability to access the market, or does this provide the investment signal?

Real-time market operation:

5.47. If a local balancing mechanism is to be implemented, based on bids and offers consideration will need to be given to how or whether it should be integrated into the existing national Balancing Mechanism. We believe that the current method of transmission constraint management is fair and can help provide a locational signal for network development that has wider system benefits e.g. the Western Isles Link between Scotland and England. If applied to distribution networks this could also help promote dispatchable energy resources to be developed in cost efficient locations and could be integrated into CMZ regions.

5.48. We recognise that the characteristics of supply and demand have evolved significantly, and are likely to continue to evolve. This is creating new challenges to system development, network operation and market structures. As there is a wide range of supply and demand scenarios that remain feasible going forward, we consider a principle based approach that supports incremental and proportional intervention from Ofgem and BEIS, would be pragmatic. These principles should focus on delivering equitable flexibility markets by levelling the playing field between market participants and realising value for consumers without reducing security of supply.

5.49. We believe that in the short term the focus should be in three key areas:

CONTROLLABILITY

- As the Call for Evidence highlights there is now an estimated 28 GW of generation connected to distribution networks, which is necessitating a more active role for both the SO and DNOs. We believe the initial priority should be placed on the monitoring and control of distributed generation assets (including storage).
- Requirements should be placed on all new distributed generation units above an appropriate threshold to have a minimum standard of control and metering capability[49] as set out under the Requirements for Generators code.
- Additionally Ofgem should undertake a CBA to determine whether certain generator types that are already installed should meet the same criteria as above, and when this should apply.
- This will allow DSOs to develop full system models of their networks, which could then be integrated into national models, thereby improving the System Operability Framework that National Grid currently produces, as well as helping to meet the Common Grid Model obligation.

DISPATCHABILITY

- In order to realise a smarter, more flexible energy system distributed energy assets need to be ready to change state in response to signals
- Following this DNOs, TOs and the SO will have greater visibility of assets, with asset owners/operators being able to declare their status and availability. This is in line with the Generation and Load Data Provision Methodology (articles 10 & 11) set out by the European Commission.
- With regards to the system operator interface, we believe at a minimum, it is appropriate for DNOs to monitor resources behind each Grid Supply Point (GSP).
- The DNO is best positioned to support distributed energy resources with accessing system wide markets in a way that optimises the use of existing distribution network assets.
- For example a GSP BMU could be created whereby a DNO/DSO platform enables distributed energy resources to offer flexibility to the wider system, whilst taking account of local constraints. This platform will also help realise the objectives of Project Terre (Trans-European Replacement Reserve Exchange), which aims to allow all resources to compete together to correct system imbalances.

FAIR AND REFLECTIVE PRICE SIGNALS

- In order to deliver cost-efficient solutions to consumers, greater coordination is required when managing resources for capacity, network constraints and balancing services – the focus should be on having a platform in place that allows resource use to be optimised through cost reflective price signals. This would also meet the objectives set out by the CACM and Project Terre.
- Whilst locational marginal pricing theoretically improves cost reflectivity, there is a significant cost to realising this down to the lowest nodes e.g. 11 kV. This trade off also needs to consider if it's in consumers' interests to expose all users to locational price signals, or how to avoid distortions if only a subset are exposed.

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[49] For example, we would like to see mandatory notification of installation of all new distribute energy assets above 0.8 kW on the network. This will allow better network planning for areas that are developing constraints.

- We support a simplification of arrangements that separate out unavoidable costs e.g. existing network assets that provide security of supply, with price signals such as BSUoS that better reflect the cost or opportunity of dispatching flexible resources.
- First and foremost existing network charge arrangements (connection, use of system) need to be examined holistically and any distortions addressed as a priority

MAINTAINING LOAD DIVERSITY

- Standards must be developed to alleviate the risks of local network overloads due to new demand side measures.
- For example DNOs should be made aware of the connection of smart devices (above a reasonable threshold) i.e. loads that can be remotely switched on or off.
- Standardised processes will need to be developed that allows DNOs to be the gatekeeper of aggregated switching; otherwise there is a substantial risk that faults will occur due to load switching.
- Smart or managed devices must be regulated in a way that ensures security from cyber-attack and simultaneous switching i.e. through random offsets.
-

5.50. The above principles could be largely achieved by derogations and code modifications after consultation. It is also worth noting that EU Network Codes, such as the Requirements for Generators, are having a positive impact, by mandating controllability. Consequently we do not see any current justification for changing the RIIO framework before industry-led routes are given a chance to succeed.

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

5.51. Whichever model is taken forward we believe that flexibility should be monetised as much as possible in the wholesale market, which involves energy trades pre gate-closure. Following gate closure the Balancing Mechanism should in principle allow all flexible resources to compete with the caveat that network constraints will limit participation and therefore in some cases require compensation. To ensure fair access and efficient congestion management DNOs will need to transition to DSOs who can actively monitor their networks in real-time. However the extent to which this will be required will depend on the volume of Distributed Energy Resources (DER) that is willing and capable of participating.

5.52. Currently the volume of DER that accesses the Balancing Mechanism via Suppliers and Aggregator partnerships is relatively small. If this grows significantly, future DSOs can help avoid the issue of aggregators having special rights whereby they avoid paying the fair cost for the underlying energy. In line with article 4.1 of the European Commission’s Clean Energy Package we believe that balancing markets should not discriminate between different market participants e.g. aggregators, suppliers and generators. We are also keen to avoid arrangements that disadvantage or deter new distributed energy resources from connecting; this is why we are keen to work with other DNOs to develop best practice guidelines on non-firm connections.

5.53. Balancing supply and demand requires System Operation that includes both the Balancing Mechanism and system services (ancillary markets), which dispatchable distributed connected resources (DER) can already access via suppliers. The use of these resources for balancing is recovered through BSUoS costs that are levied on generation and demand users. Any future incentives for the DSO to help balance supply and demand will need to be reconciled with these arrangements. We favour an approach that involves collaboration between the SO and DSOs, in which they are able to remunerate market based resources based on their system-wide value. This should help to avoid Network Operators competing directly with resources (or themselves) and should also lead to the avoidance of under or over-compensation.

5.54. In our view, it is essential that for all types of charging arrangements, each element of any charge should be clearly classed as falling into one of two categories (and never both): (1) Economic price signal or (2) Revenue collection. This means charges such as DUoS and TNUoS should not try to achieve the same result as BSUoS charges, which is related to short-run energy imbalance costs. We are concerned that currently there is an overlap between price signals and recovery mechanism that is creating market distortion and greater uncertainty for investors.

5.55. We recommend that a technical roadmap is developed that addresses how existing arrangements below a GSP can be evolved towards the active management of capacity, system balancing and connection management, which is also in line with arrangements on the transmission network. Whilst this is a significant undertaking, a clear strategy that is industry-led will lead to longer term success. This will also consider developments taking place such as the EU electricity DSO entity.

5.56. As the above highlights our belief is that many of the issues can be solved by closer industry engagement and collaboration. Nevertheless guidance is sought from Ofgem and BEIS on particular policy principles such as network charges, how to price in security of supply and how to protect vulnerable customers.

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

Maintaining Network Resilience

5.57. Electricity supply is an essential service and its importance will only increase as transport and heat increasingly come to depend upon it. It is important that in considering design-change for the industry that the ability to manage shocks to the system is considered, these shocks might include storm events, industrial action, IT and communications failure, cyber-attack, black start, and market-led events. These aspects should already be covered in the System Defence Plan which comes into effect from spring 2018.

Avoiding unintended consequences

5.58. It is important that any change in industry structures and markets do not create perverse incentives, such as incentivising the prepositioning of new demands and generation in stressed parts of the network with subsequent triggering of constraint payments.

Legacy commitment

5.59. Given the large volume of embedded generation on the system and the interaction between legacy connection agreements and those likely to be present under incremental change it is essential that the transitionary arrangements respect the underlying "bankability" of these schemes, many of which are owned and operated by communities.

Understanding and managing new risks

5.60. The Call for Evidence is very clear on the benefits of a move to flexible solutions (and we recognise these benefits), however there is inadequate exploration of the risks and costs at this stage. Taking the time to fully understand and manage the risks needs to be treated as a priority consideration above any perceived need to rapidly facilitate innovative change/new market models. Examples of these risks include:

- A reduction in reliability as a result of increased interdependence between communications, IT and the electrical network.
- Increased overall exposure of electrical networks to cyber-attack, because of the greater access to devices controls.

- Networks operating with a higher load factor and reduced capacity margins with resulting reductions in the ability of the system to absorb events or rapid change in use.
- Enhanced sensitivity to weather related events which cause concurrent volatility in communications infrastructure, Demand profiles, renewable generation availability and network faults.

5.61. We believe it is critical that decisions of this significance are only made with all the facts quantified including the risk delta, cost and benefits.

6 Innovation

Executive Summary

6.1. We believe that innovation is of vital importance to the development of the efficient, flexible networks that will be required in the future. The emergence and uptake of low carbon technologies, electrification of transport and decarbonisation of heat will provide significant challenges to the GB electricity networks. Innovative solutions will allow networks to provide better services at lower cost, whilst opening up new marketplaces for other industry participants. All of this should facilitate the objectives of ultimately providing lower cost and sustainable electricity supplies for consumers as well as the chance to contribute to the efficient functioning of the country's energy infrastructure.

6.2. The portfolio of innovation projects we have undertaken as a DNO (see Appendix 1) has been fundamental in improving our understanding of the opportunities, risks and practicalities of utilising and coping with this increased flexibility. This understanding has provided us with the data and confidence to pioneer on business as usual deployments of CMZ and Active Network Management amongst other examples.

6.3. The one common theme of the learning from all these projects has been the rapid growth of complexity even within relatively simple implementations of elements of a DSO's operation. Interaction between communications infrastructure, customer behaviour and local economics very quickly intertwine to create unexpected outcomes. Given that these existing projects have been relatively simple in comparison to a full DSO implementation and have not addressed some of the more dynamic aspects such as true markets, it is critical that innovation and the structured trialling of concepts continues to grow and evolve.

Question 47
Can you give specific examples of types of support that would be most effective in bringing forward innovation in these areas?

Commercial and residential DSR

6.4. As a network operator we believe DSR is a growing area of the industry which has the potential to provide significant benefits to DNOs in terms of reducing load at peak times and therefore deferring reinforcement on constrained networks. (For our specific position on aggregators please see the section on Removing Policy and Regulatory Barriers).

6.5. We have already run a number of innovation projects in this area and these have given us the confidence to begin to move some of these solutions to business as usual. This confidence can only be gained by undertaking a broad range of trials over a prolonged period to address as many risks as possible and validate the learning. These projects include Northern Isles New Energy Solutions (NINES) and New Thames Valley Vision (NTVV) which have successfully demonstrated that both commercial and domestic scale DSR can be successfully deployed on the distribution network.(Further detailed information can be found at https://www.ssen.co.uk/DistributionInnovation/

6.6. These projects were primarily technical in nature and aimed to understand the impact of DSR on the network as well as the communication, IT architecture and control requirements. The projects only undertook a limited amount of commercial innovation and largely relied on working within the existing market arrangements. Whilst this has given us the confidence to start to utilise DSR to manage network constraints, there is much more that could be achieved if a wider range of commercial arrangements involving a wider range of stakeholders could be undertaken. This would include developing the commercial relationships including the allocation of risk and reward amongst market participants, along with a clearer understanding of the priorities and potential conflicts between the stakeholders; such as the SO, DSO, supplier, generator and aggregator; as well as the conflicts of interest within the DSO itself if it wishes to also be a market participant (in terms of, for example, providing balancing related services to the TSO). Potentially this could include further larger scale projects to validate the learning from DNO projects.

6.7. In areas with network constraints, DNOs can use DSR as a means of deferring or avoiding expensive network reinforcement. SSEN has looked to implement this in our Constraint Managed Zones which for the first time would see a GB DNO use a demand side service to manage a distribution constraint.- http://news.ssen.co.uk/news/all-articles/2015/06/constrained-managed-zone/. Whilst we have established that it is possible for DSR to be used in this manner, there is a requirement for more research in this area.. DNOs will require a localised service to be able to use DSR to resolve local constraint issues, therefore to be successful DNOs must be able to exercise some control over the provision of DSR on a local basis in order that they can better manage the constraints on their network. However, the affected market participants will expect to be paid the prevailing market price if they are utilised by the DSO rather than, say, the TSO or other market participants to balance the wider system (or the other users' balance position). It is thought that these services would be most likely obtained from I&C customers and not domestic, given the concentration of domestic customers needed to deliver a reliable response to system peak when needed.

6.8. Similarly, a better legislative/regulatory definition of aggregators will provide more certainty in the market place and encourage growth in this area.

6.9. Part of the reason for the low uptake of residential DSR is the high cost of acquisition of participants and the relatively low amount of response that can be provided by each domestic customer. This cost may reduce as there is greater penetration of smart appliances into homes which can then be utilised to reduce or shift network loads. Without this development residential DSR is likely to remain an unattractive option for aggregators.

Trading Platforms

6.10. A national trading platform, with bids placed on it by aggregators, suppliers, generators and other market participating parties would allow efficient allocation of resources on the network to alleviate constraints. As familiarity with the idea grows and given developments with the EU Network Codes a we anticipate moving from a number of trading platforms to a single GB market platform and ultimately to a pan-European framework.

6.11. In order to develop this model there needs to be good communication between DNOs and TOs in order to manage flexibility services to provide the greatest benefit to customers, for example by providing DSR services to the TO at times of high generation but also providing DSR to the DNO at times of high demand, and well defined periods in between whilst recognising that either network operator may need these services at 'conflicting' times. As the definition of aggregators and regulation of storage become more concrete both of these areas can be expected to grow.

6.12. So far the innovation work carried out by DNOs which has involved DSR has generally only focussed on a single technology or provider to solve a specific network issue. For example, industrial demand response in the NTVV project. If the capabilities from different groups of network customers can be combined then it should be possible to deliver a much wider range of services to the DNO. For example combining energy storage with distributed generation and DSR will address a wide range of network constraints. This will require significant technical and commercial innovation to develop an effective market for these services much of which is already in place, or will shortly be in place, as a result of the EU Network Codes. Crucial to this will be a change in the role of the DNO from being largely passive to a much more active DSO type role whereby it facilitates the market whilst not itself being a participant in the market.

Storage Costs

6.13. In terms of Lithium Ion battery storage, costs are already falling as the production of these devices increases. What is less understood is the role of different types of storage in the market and the different types of service that each technology can provide. These range from electricity storage to frequency response and phase balancing as well as other services. Better definition of storage by the services it provides will create separate market segments that will drive better innovation towards a service based goal rather than a generalised storage device that tries to cover all segments of the markets.

6.14. It is also important to realise the value of storage, whilst recognising that with more providers of the service to the market the greater the risk that this value will decline. Currently certain types of storage need to stack revenue streams to make the recovery of costs over a relatively short lifespan in order to have a viable business proposition. However, even at the current price levels we have seen a significant number of connection applications for some energy storage technologies. This was largely in response to the NGET call for 200MW of Enhanced Frequency Response (EFR) capability, and has shown that there appears to be a viable market for energy storage in GB. This is forecast to grow as the requirement for ancillary services and flexibility continues to rise as identified in the NGET Future Energy Scenarios, and National Infrastructure Commission Reports. For emerging storage technologies it is important to be realistic about the longer term values of energy storage in order that development funding is concentrated on those technologies with the potential for future commercial success. The development of emerging energy storage technologies could be stimulated through the creation of simple and valuable market places for stored energy services in conjunction with funded trials. This applies equally to residential and industrial technologies.

6.15. There are a number of other storage technologies that are increasing either in technological maturity or in utilisation. Investigating innovative use of options such as hot water storage, storage heaters and pumped storage could open up significant resources to benefit distribution networks. Developing technologies such as flow batteries, other forms of chemical storage and even power to gas could provide services to the industry as the scale of delivery increases and the cost decreases. These services will also cover a spectrum of services from short term EFR to large scale discharge of energy stored in bulk, and all emerging services in between.

Vehicle to Grid

6.16. Our network business has already investigated the impact of Electric Vehicles (EVs) on the distribution network through our initial work on the My Electric Avenue project. This is being further developed in the Smart EV project which involves working with a full range of industry stakeholders to develop an industry wide set of standards for the smart charging of ULEVs. The focus has been on ensuring that the predicted roll out of ULEVs can be accommodated with as little cost and disruption to customers as possible. At present the work has not extended to investigating the use of EVs to support the network.

6.17. It would seem that EVs could provide large scale services to networks however the batteries they carry are optimised for size and weight and would, intuitively, seem to not be the right choice for providing network support. Given that Li-Ion battery lifespans are dictated by a number of charge/discharge cycles this kind of service would potentially shorten the lifespan of the vehicle battery and pass the cost of the service onto the owner of the vehicle. However, this kind of service may open up different commercial avenues in the way EVs are marketed and sold, potentially with third parties owning the batteries and gaining income from the network service while the vehicle owner benefits from lower prices for the car.

Question 48

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

6.18. We fully support the development of different network service markets through innovation that will reduce costs for consumers. We would caution against the favouring of one particular technology over another where the benefits of each are not fully defined. Instead, identifying a service that requires developing and has a conceptual business case against the counterfactual then encouraging the market to find solutions would seem to be a better way of approaching a challenge. For example, while vehicle to grid services would work, it would be worthwhile exploring whether this service could be provided by PV or DSR. New technologies should be able to compete on a level playing field and be judged on their impact on the network, impact on demand profiles and their reliability. What is important is the ability to monitor the uptake of new technologies on electricity networks so that the impact of these innovative products can be understood and any impact on the network can be prepared for and addressed in an appropriate and efficient manner.

Confidential Additional Information

The key focus of our innovation activities is to ensure that they deliver value for our customers and the business. In many instances this can be achieved by delivering the innovation and successfully transferring it to business as usual. However, the output and learning from the portfolio can also provide value by identifying future potential issues in a timely enough manner to allow us to take appropriate actions in advance. This is best illustrated by the work we have undertaken on the potential impact on the network of the widespread uptake of electric vehicles on the low voltage network. This along with other elements of our portfolio has informed the development of our LV strategy.

Our experience has shown that maximum benefit is created by combining learning from across the portfolio of multiple projects to create an outcome which is greater than the sum of the parts. In a similar way we have developed our portfolio in an incremental manner in order to retest and validate the outcomes of our earlier projects until we reach a stage where we are sufficiently competent to deploy the innovation.

We have used the portfolio to build this body of knowledge in specific areas and show how we take this forward into business as usual and to identify other gaps and opportunities. Specific areas we have covered are detailed in Appendix 1 and include:-

- DSO preparedness
- Energy Storage
- Active Network Management
- Demand Management

The wide variety of knowledge, learning and experience we have gathered in the delivery of our portfolio can be illustrated by the models we have developed for each of these areas.

Therefore, we believe that we have developed a deep understanding of the technical, commercial and regulatory challenges associated with each of these areas , including practical experience of procurement, design and deployment of the techniques and would be happy to provide further information should this be required.

Appendix 1: Summary of demonstration projects that SSE has been involved in to date

Project	Description	Website
My Electric Avenue	Investigated how distribution networks can cope with charging clusters of electric vehicles	http://myelectricavenue.info/
Smart EV project	Follow on project from My Electric Avenue that aims to identify a standardised mechanism to charge plug in vehicles	https://www.eatechnology.com/products-and-services/create-smarter-grids/electric-vehicles/smart-ev
EV Network Group	Facilitates a dialogue between low carbon automotive and utility sectors, as well as the UK Government	http://www.lowcvp.org.uk/projects/fuels-working-group/EVNetworkGroup.htm
NINES	Introduced new methods to manage the distribution network in the Shetlands following work carried out in Orkney	https://www.ninessmartgrid.co.uk/
Orkney Smart Grid	Demonstrated Active Network Management in the constrained Orkney area via an Energy Storage System	https//www.ssepd.co.uk/innovation/
Thames Valley Vision	Explored solutions to avoiding traditional network reinforcement by engaging with stakeholders and trialling new approaches	http://www.thamesvalleyvision.co.uk/
Samuel	Demonstrated a new grid data measurement system that permits control and verification of demand response using existing infrastructure	http://www2.nationalgrid.com/UK/Our-company/Innovation/Projects/NGET-Project-Samuel/
ACCESS	Aimed at optimising renewable energy potential on the Isle of Mull using smart electric heating charging	http://www.accessproject.org.uk/
Real Value (Ireland)	Pan European Horizon 2020 project investigating smart electric thermal storage as a virtual power plant	http://www.realvalueproject.com/
SAVE	Aims to trial and establish the extent to which energy efficiency measures can manage peak demand and help avoid network reinforcement	https://www.ssepd.co.uk/save/
ERIC	This project has installed over 180 kWh of Moixa Smart Battery Systems across Social and private Housing in Oxford. This demonstrated benefits of using distributed storage that can help increase self-consumption of solar PV energy.	https://localisedenergyeric.wordpress.com/

Appendix 1: Summary of technologies that SSE has helped demonstrate and report on

Technology	Overview	Key findings
Energy Storage & Management Unit (electrical storage)	The NTVV project has deployed 25 ESMUs connected mid-way along LV feeders in the Bracknell area to assess the possibility of using power electronics, with or without energy storage as a means to resolve network issues. Specific functionalities included: • Phase balancing • Peak management • Demand reduction • Power Factor correction • Loss reduction • Improve voltage regulation • Reduce Harmonic content • Frequency response The control of ESMUs using smart analytical short term forecasting has also been assessed.	• Energy storage remains an expensive technology to deploy and system complexity is high. Specific performance in each functionality are summarised: • Phase balancing, Peak management, Demand reduction, Power Factor correction, and voltage regulation were each seen to be improve by effective application and control the ESMUs. • Loss reduction can be demonstrated by virtue of the improved phase balance, but remains compromised by the net operating losses of an ESMU (power electronics have efficiency limitations) • The correct place to reduce harmonic content is at the busbars (feeder source), and not mid feeder; the provision of a closed loop (with sensors) solution for a mid feeder deployment is uneconomic. • Frequency response was demonstrated to work and could provide an “added value” service to the grid, particularly if ESMUs are aggregated • The operational experience gained revealed the extent of fan noise associated with the cooling system for both the batteries and the power electronics. This was problematic on feeders with predominantly domestic customers and constrained some operations. • A centralised approach was adopted to the control system to facilitate easy deployment of smart control. A future deployment would need to be simplified and de-centralised to reduce the scale of communications and system complexity.The technology readiness level is insufficient for immediate BAU deployment and the technology cost thresholds do not currently compare favourably with reinforcement costs.
Cold thermal storage	The Ice Bear is built to alleviate AC load from	• The Ice Bear can provide about 35kWh of cooling with optimum

(Ice Bear)	commercial premises at peak times through energy storage in the form of Ice. With dimensions of 2.5 x 1.5 x 1 m in dimension the bulk of the unit itself is a large thermal storage tank. The Ice Bear will operate in two basic modes, Ice Charge and Ice Cool. In Ice Charge mode (typically enacted across night time off peak) the Ice Bear will freeze water inside the device creating a large block of Ice. As the network reaches peak demand the Ice Bear will be able to start it's Ice Cool mode, switching away from a traditional AC unit, the Ice Bear can provide cooling to a building through the Ice stored over night.	operation on a 30kW unit • Majority of benefits from Ice Bear fall to the network as opposed the customer (who benefits slightly from off-peak tariffs) • To a DNO alone an Ice Bear is not currently commercially attractive • A stronger business model can be built through stacking benefits of increased off-peak usage and decreased peak usage across customers, the DNO, TNO and Generators. • The size of the Ice Bear unit is mitigating given 'best' applications (more costly reinforcement and high AC load) are likely in cities where land space is of a premium. A more dense phase change material may overcome this problem.
Hot water thermal storage (EMMA)	The EMMA device is built for domestic properties with Solar PV and a hot water tank. It looks to resolve issues of excess PV on the network and the associated voltage rises they can cause. EMMA works by diverting excess generation from the network to a customers hot water tank which acts to store the effectively 'free' energy.	• The EMMA device provides significant benefits to the DNO and the customer. It is capable of alleviating an average of 500W of generation per application. • Customer recruitment for EMMA is challenging given need to identify PV and hot water tanks and to recruit an appropriate number of participants to solve network issues. • The EMMA device could support/add value to connections of new housing estates with significant amounts of PV, by engaging a developer at an early stage both customer recruitment and install costs can be minimised.
Hot thermal storage (Quantum)	Controllable domestic storage and water heaters with a frequency response capability, which were demonstrated as part of our NINES project. Remote temperature sensors are deployed in households to offer more intelligent heating, which uses algorithms that 'learn' based on user input, temperature readings and the price of electricity.	• Customers' heat demand can provide a role in managing networks. • Dimplex found that smart Quantum heaters are up to 20% more energy efficient than conventional storage heaters[50] • The trials also demonstrated that thermal comfort can be improved as the heaters deliver more when end users require it • Using remote control and frequency sensors, the new heaters can provide greater network support and charge at times of lower carbon intensity.

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Automated Demand Response (commercial)	Automated Demand Response (ADR) will allow a DNO to alter the consumption profile of a commercial customer in order to benefit the network. NTVV ADR trials have looked solely at load-shedding (reducing load) on 30 customers, compiling over 2000 load-shedding events. The automated of demand response means a DNO can load-shed pre-agreed equipment on a customer's premises at the press of a button from a remote portal.	• Focusing on local benefits, council support and deferred reinforcement provided a successful means of recruiting ADR customers. • Legal documentation is the biggest sticking point in procuring ADR on a site. • Load Shedding Strategy documents provide a shared insight into the load being shed on a premises and expected load-shed for both the DNO and the customers. Through defining additional parameters of load-sheds i.e. higher level emergency shed, low level regular sheds, seasonal sheds etc. • Each site has individual limits to its load-shedding capabilities. Close customer engagement can allow this limits to be found • Trials tested an average of 1.5 load-sheds per week with some load-sheds giving customer no notice (shed no longer then 1 hour) and up to 4 hour load-sheds on other sites • Trials signed participants up with no initial financial incentive at all.
Electrolysis (hydrogen storage)	Investigated the potential impact of electrolysers on the distribution network by running a series of trials which controlled three electrolysers in Aberdeen while providing enough hydrogen to fuel ten buses.	• Electrolysers capable of following highly variable set points resulting from following output from a windfarm or solar farm, and balancing local demand. • Electricity costs make up >90% of ten-year running costs, so additional CAPEX is justified to enable electrolysers to avoid running during Red timebands.

[redacted]