UKERC
UK Energy Research Centre

A SMART, FLEXIBLE ENERGY SYSTEM

The UK Energy Research Centre's (UKERC) Response to the Ofgem/BEIS Call for Evidence

January 2017

Lead author:

Keith Bell (University of Strathclyde) and UKERC

Contributors:

Nick Eyre (Oxford University) and UKERC

Graeme Hawker (University of Strathclyde) and UKERC

Giorgio Castagneto Gissey (University College London) (questions 1-6 in section 2)

Paul Dodds (University College London) and UKERC (questions 1-6 in section 2)

Sarah Darby (University of Oxford) and UKERC – (questions 28-32 in section 4)

James Irvine (University of Strathclyde) (questions 41 and 42 in section 4)

Greig Paul (University of Strathclyde) (questions 41 and 42 in section 4)

Jim Watson (Director, UKERC) (questions 46 and 47 in section 6)

Contents

Summary of our response

Scope of the Call for Evidence and objectives in respect of flexibility

We welcome the attention being paid by Ofgem and BEIS to the need for flexibility in Britain's electricity system. In our view the main reason to support electricity system flexibility is that it can help minimise the costs of meeting the UK's statutory climate targets whilst ensuring that system security is not compromised. The electricity system's ability to adapt to changing demand in timescales of years down to minutes and varying availability of power from different resources will be extremely important to meeting these policy goals. Furthermore, action is needed so that those consumers that are best able to adapt their patterns of use of electricity have sufficient incentives and rewards for doing so. One manifestation of the main goal in accommodating future generation and demand is an objective to maximise the utilisation (across each year of operation) of electricity system assets, i.e. generators, network components and storage facilities.

Whilst the title of the call for evidence focuses on 'a smart, flexible energy system', most of the raised relate to the *electricity* system. We have therefore focused most of our responses on electricity rather than the energy system as a whole. Our responses are selective. We have only answered those questions where we can offer relevant evidence, based on our research and expertise.

Electricity storage

Many storage technologies are relatively costly at present but have potential for cost reduction. Experience from other technologies, e.g. solar PV and wind, suggests that growth of a market for a technology can reduce costs, and incentives can play an important part in creating that market.

The structure of use of system tariffs and the way storage is currently treated by them present barriers to the uptake of storage. We note that examples from other countries could provide useful models for reformed treatment of storage in Britain. Distribution network operators (DNOs) in Italy and in Belgium are allowed to own and operate battery storage, and there is no evidence that this has prevented the competitive functioning of the generation and supply markets. Italy allows DNOs to control batteries if this choice can be justified throughout a cost-benefit analysis showing that the storage system is the most cost-efficient way to solve an identified system problem, as opposed to potential substitutes, such as building a new line. Belgium enables DNOs to operate batteries if they do not alter the competitive functioning of markets.

Flexible demand

The Call for Evidence proposes definitions of a "smart energy system" and "flexibility". These focus on the role of information technology in providing the ability *"to integrate the actions of users"*. Our view is that technology alone will not achieve the changes necessary to realise a "smart energy system" or the desired levels of flexibility on the demand side. An important dimension, reflected in the UK Government's existing approach to smart metering, is to ensure that consumers understand the reason for and outputs of 'smart' meters. We believe that the Call for Evidence underestimates the importance of active citizens and communities in delivering smart systems and flexibility. This citizen engagement with the energy system, if implemented carefully, could help to build trust in smart systems – and help to drive widespread adoption.

When discussing the potential contributions of the demand side to meeting emerging system challenges at least cost, we believe there is value in (a) distinguishing between demand reduction (achieved either through energy efficiency or through changed uses of energy, or through both) from flexible demand and (b) in respect of the latter, distinguishing between demand side response (rapid responses to unplanned events on the system) and demand side management (planned changes to the time profile of demand).

We believe that two keys to realising the potential of flexible demand are as follows:

1. making it as easy as possible for electricity consumers to control or schedule their use of electricity, or to have the confidence in service providers who can do so on their behalf;
2. maximising the share of the benefits of demand flexibility that accrue to electricity consumers.

Both of the above are likely to depend on services, products and innovations by parties other than the electricity user.

The roll out of 'smart' meters and smart systems generally should be seen as a facilitator of informed consumer decision making, not a substitute for it. Government and Ofgem need to continue to require consumers to be informed about smart meters and displays at the point of installation.

Pricing and tariffs

In addressing potential pricing or tariff arrangements, we believe that two key principles should be kept in mind:

1. incentives should be directed at those parties that are able to respond to them;
2. risks should be borne by those parties best able to manage them.

We believe that one key objective in new pricing arrangements should be to incentivise flexibility on the demand side and, as a consequence, reduce the need for reserve generation and the associated capital and operating costs. It might also help to reduce network costs relative to the case of there being no demand flexibility.

Uptake of time of use (ToU) and more complex tariffs in households and small and medium-sized enterprises (SMEs) will be constrained by unfamiliarity with the concept and the potential complexity of some tariff arrangements. Active consumer decisions to move the point in time at which energy services are used are only likely if there is a significant and transparent consumer benefit. Moreover, some important demand flexibility opportunities rely on the storage of energy (thermally or electrochemically) without changes to the timing of the service gained from use of energy. Examples of energy services that can benefit from storage include electric vehicle charging, hot water tank heating and short term switching of refrigeration and air conditioning, as well as the long established option of storage heating.

We note that a number aggregators and smaller retailers/suppliers have expressed the view that the dominance of the retail/supply markets by 'the big 6' and their vertical integration with generation interests significantly impact on the offering of attractive ToU tariffs. This, they argue, is because greater participation by the demand side in system balancing would take business away from their generation interests.

Placing the costs and benefits of monitoring and management of consumer load profiles more clearly on individual suppliers provides an incentive that does not exist with the existing approach of using sets of standard load profiles.

Procurement of system services

It should be made easier for *collections* of ancillary or capacity services to be evaluated and compared with alternatives taking into account locational issues where they are significant, e.g. in helping to manage imports of power into an area or provide black start services. We would urge an alignment of procurement processes and associated tender rounds to allow combinations to be considered. However, in order that physical facilities that can provide only one or two services can still participate in relevant ancillary service markets, each service should still be priced separately even if an apparent premium is paid to some providers (by virtue of the combination being cost-effective).

The changing generation mix is likely to give rise to a need for different volumes of dynamic services and, potentially, new services such as faster controlled responses, lower minimum stable generation or higher ramp rates. New ancillary services and associated markets might be defined. As far as possible, the definitions of these services should focus on what is really of value to the electricity system as a whole, and not on the way it happens to be delivered by particular technologies.

Price or use of system charging signals can and should be used to incentivise distributed generation (DG, i.e. generation connected within a distribution network) to connect at locations where the adverse impacts on the network are minimal. However, at some point, it is likely that adverse impacts, such as a need for active management (meaning some curtailment) of generation or network reinforcement are necessary and incentives on DNOs to carry out the most economically efficient actions will be critical.

Interactions between transmission and distribution

An oversight in GB electricity supply industry developments since liberalisation has been the neglect of interactions between transmission and distribution, and the failure to see the electricity infrastructure as part of one system, regardless of voltage level. Price signals should reflect, as far as possible, whole electricity system costs. In our view, this points to a need for a quite fundamental review of network charging arrangements across distribution and transmission, and not just to tinkering with distribution arrangements.

Present day arrangements, in particular the fact that only the transmission network licensees have the established means in terms of facilities, processes and expertise to actively operate their systems and not just (as in the case of most current DNO practice) to respond to faults or to adopt isolated, simple examples of automated ‘active network management’ (ANM), at best risk a great deal of inefficiency in meeting future needs and, at worst, system instability and blackout.

Simple, concrete action to improve the quality of data exchanges between DNOs and National Grid is long overdue and should be undertaken regardless of any more radical reforms of networks and their regulation or commercial arrangements.

Industry leadership

We do not agree with the Call for Evidence’s assertion that “the onus is on industry to address these requirements in the first instance”. The speed of many of the changes affecting the power system is a direct or indirect result of Government policy and the extent of likely future change is highly dependent on future policy, especially related to renewable generation and the electrification of transport and heat. BEIS and Ofgem can and should play a major role in providing clarity and leadership not just on system issues, but also on developments independent of the network licensees that are the fundamental drivers of change.

One key lesson in respect of the DNOs’ and, on their behalf, the Energy Networks Association’s (ENA) leadership to date of innovation of GB power system methods, processes, standards and codes is that the reforms that we believe are now required cannot be left to them to take forward. It might be argued that the National Electricity Transmission System Operator (NETSO) should assume a leadership role. However, it will be open to the same criticism of lack of independence as the ENA. In the absence of any other suitable body, leadership would seem to fall to Ofgem or BEIS. Although Ofgem and BEIS might argue, perhaps with reason, that they lack the knowledge to take a more active part, we believe that leaving leadership to the network licensees is much too passive and risks excessive delays in proposals for change being formed and tested.

Roles in planning and operating the future power system

Future arrangements for energy trading and system operation should be structured such that:

- there is competition and choice for consumers;
- the system can be safely operated in accordance with relevant physical limits;
- energy consumers' access to the system is enabled;
- the overall cost of the system is minimised with use made of suitable signals, such as locational prices or tariffs, aimed at parties able respond to them;
- there is scope for innovation.

Regardless of exactly how roles and responsibilities are attributed to different network licensees and connected parties, it will be important to have a common set of high level principles that apply across the power system regardless of location and voltage level, and a consistent set of standards and codes in respect of energy trading and retail, system access and connections, network investment and maintenance, system operation, and system resilience. The standards and codes should take due account of scale and spatial and temporal interactions.

One general economic principle is that risk should be borne by those parties best placed to manage it. In the case of risk associated with planning and operation of distribution networks, it should be self-evident that a DNO has better access to information to enable its management than the operator of a connected DG and should therefore be obliged to take on some of the risk associated with, for example, curtailment of generation.

An enhanced role for the NETSO – whether as an Independent System Operator (ISO) or not, whether for-profit or not – increases reliance on a single monolithic service provider. In deciding which parties should have which roles in future, we believe the following should be considered:

- How can the NETSO be encouraged to innovate and improve?
- What benefits might come from having a range of parties all fulfilling similar functions (albeit perhaps with spatially delineated scope) whose performance can be compared one with another?

- Which parties have the requisite network knowledge and, if they currently lack all the expertise required to deliver future needs at least cost, can they acquire it?
- What information and communication technology (ICT) developments are required to facilitate different role models and do some, e.g. single, large ICT systems, entail greater risk than many smaller ones?

Evidence and access to data

One particular challenge, faced by anyone attempting to develop evidence highlighting the extent of the challenges the power system faces or in support of particular interventions, is access to relevant data describing the GB power system now from which possible future scenarios can be developed. This is hindered by much of what is required to model the GB system being regarded as "commercially confidential" even though it is sometimes hard to envisage what commercial advantage might come from having it or commercial disadvantage might come from disclosing it. The UK Government and Ofgem should take steps to improve access to system data.

1 Introduction to the UK Energy Research Centre's Response

We welcome the attention being paid by Ofgem and BEIS to the need for flexibility in Britain's energy system. The system's ability to adapt to changing demand for energy in timescales of years down to minutes and varying availability of power from different resources will be extremely important to meeting energy users' expectations for reliable supply at least cost while still meeting decarbonisation targets. Whilst the title of the call for evidence focuses on 'a smart, flexible energy system', most of the raised relate to the *electricity* system. We have therefore focused most of our responses on electricity rather than the energy system as a whole. Our responses are selective. We have only answered those questions where we can offer relevant evidence, based on our research and expertise.

Electricity is just one of a number of energy vectors, albeit an extremely important one: the technology underpinning the 'information age' and a 'knowledge economy' depends on it as does much of industry and many of the facets of modern life that are often taken for granted. Although one objective in respect of policy towards the electricity system will be to make it as cheap for energy users as possible, this objective cannot be divorced from the need to meet statutory emissions reduction targets to help tackle climate change, and the imperative of maintaining the security of the electricity system. The UK has very favourable renewable resources that are already making a significant contribution to our electricity mix. Renewables accounted for 25% of electricity generation in 2015. They can generate much more than this, though that will not be without challenges. Some renewables are approaching a point where they will soon be cost competitive with fossil generation, especially if carbon costs are taken into account. Moreover, these and other low carbon sources of electricity could present strategic opportunities for UK industry if industry has sufficient confidence to invest in the medium to long-term.

In spite of challenges that are being increasingly well recognised, a largely decarbonised electricity system remains will be crucial for the decarbonisation of the economy as a whole – including decarbonising at least part of the UK's demand for energy for heat and for transport. Indeed, as we note in our discussion of the issues raised in section 3.2 of the Call for Evidence, electrified heat and transport demand combined with appropriate energy storage facilities can be valuable sources of flexibility for the electricity system. In addition, the heat and electricity systems are currently coupled through the gas system that delivers a large part of the fuel and some degree of flexibility (for example, gas can be stored) for both and, in future, might be coupled through a hydrogen system that might also be linked to transport infrastructure.

The following sections of this response follow the chapter structure of the Call for Evidence. In this initial section, we raise make some points about the underlying assumptions of the Call for Evidence that are not addressed in our responses to specific questions.

In general, the initial section of the Call for Evidence sets the context very well. However, it is stated in paragraph 10 that *"efforts to make our energy system smarter are complementary to bringing forward new generation gas"*. Gas-fired generation offers one option for flexibility. Whilst we agree that gas-fired generation could play a significant role in UK electricity generation in the medium term, this role will need to be limited in the absence of CCS technologies being available[1]. Furthermore, smarter systems are part of the way that the use of gas can be reduced. Flexibility can be provided by flexible generation (such as gas), but also by storage, interconnection and flexible demand. Greater deployment of the last three options will therefore tend to reduce the requirement for new gas capacity. Competition within the Capacity Market has already revealed that this can be a significant effect. However, as UKERC has argued recently, the Capacity Market needs to be reformed so that supply, demand and other types of capacity are treated equitably[2].

The role of markets in energy policy is not represented entirely accurately in the Call for Evidence. We understand that Ofgem is required to carry out its functions "wherever appropriate by promoting effective competition". Furthermore, paragraph 14 of the Call for Evidence states that *"at the centre of our approach is ensuring effective markets and competition"*. We agree that competition is very likely to be critical in bringing forward innovation in many areas of the system and support the proposals in the Call for Evidence to achieve this. However, there are some limits – most obviously with respect to networks – where regulation is required to protect consumer interests. Development of the regulatory mechanisms already begun by Ofgem to promote innovation in the networks (such as RIIO) will be critical to development of smarter systems. There are also important limits to the effectiveness of competition in some aspects of retail supply. These have been reported in very great detail in the recent report by the Competition and Markets Authority[3]. Our analysis[4] is that new services, many of them dependent on 'smart' systems, are the most likely sources of competition. Traditional energy supply business models have been less effective in securing effective consumer engagement and therefore require regulation to protect consumers, particularly vulnerable consumers.

The Call for Evidence also neglects the importance of demand reduction in future energy systems. In paragraph 6, it is claimed that the future is likely to be *"more power hungry"*. We suspect that this refers to electricity demand, but the context of the paragraph is the energy system as a whole. We agree that electricity demand may begin to rise as transport and heat are partly electrified. However, all plausible future low carbon UK *energy* systems have an

1 Ekins, P. et al, 2016. The Future of Gas in the UK. Research Report. London: UKERC.
2 UKERC, 2016. Review of Energy Policy. UKERC Policy Briefing. London: UKERC.
3 CMA, 2016. Competition and Markets Authority. Energy Market Investigation. Final Report.
4 Eyre, N., Lockwood, M., 2016, The governance of retail energy market services in the UK: A framework for the future. UK Energy Research Centre.

overall decline in energy use, and electrification of heat and transport will be an important part of this process as both electric heating and transport systems can be significantly more efficient than the existing dominant technologies. Smart systems can have an important role to play in delivering demand reduction as well as demand flexibility, but the Call for Evidence tends to neglect the former. Our specific suggestions for energy efficiency policy are set out in more detail elsewhere[5]. In the context of this Call for Evidence, the role of much stronger action on energy efficiency and its links to smart systems warrant further attention.

Paragraph 4 of the Call for Evidence proposes definitions of a "smart energy system" and "flexibility". These focus on the role of information technology in providing the ability *"to integrate the actions of users"*. Our view, supported by evidence[6], is that technology alone will not achieve the changes necessary to realise a "smart energy system" or the desired levels of flexibility on the demand side. An important dimension, reflected in the UK Government's existing approach to smart metering, is to ensure that consumers understand the reason for, and outputs of, 'smart' meters. The Call for Evidence underestimates the importance of active citizens and communities in delivering smart systems and flexibility. This citizen engagement with the energy system, if implemented carefully, could help to build trust in smart systems – and help to drive widespread adoption.

We note that, in spite of its publication having been delayed by the EU Referendum, the Call for Evidence provides no reference to international developments. Of these, we believe that Brexit has particular potential to impact on the issues raised in the Call for Evidence. A number of sources of flexibility, notably interconnection, are potentially affected by UK plans to leave the EU and the approach taken to Brexit. In addition, all issues related to electrical products currently rely on EU legislative processes. These will need to be kept in place or replaced by UK equivalents with international inter-operability, in a timely fashion, if progress is to be made in the development of smart systems. Furthermore, there are currently well-developed processes at a European level, led through the European Network of Transmission System Operators for Electricity (ENTSO-E) and complemented by work in the Council of European Energy Regulators (CEER) that, under current arrangements, will lead to changes in GB electricity system standards and codes. We also note that gas supply security 'solidarity' arrangements are made at a European level. We appreciate that Government has said that it is not yet in a position to set out detailed plans, but it would be useful to have an analysis of the issues around the electricity system, how the use of electricity might be affected, and what the options might be.

5 See http://www.ukerc.ac.uk/news/ukerc-calls-for-urgent-action-on-uk-energy-during-this-parliament.html
6 For example, see Darby, S.J., Liddell, C., Hills, D., Drabble, D., 2015. Smart metering early learning project: synthesis report. Department of Energy and Climate Change, London.

2 Removing policy and regulatory barriers

Chapter 2 of the Call for Evidence (CfE) focusses on one category of flexible technology (storage) and one category of market actor (aggregators). We agree that there are important new developments in both areas and that these merit full consideration. However, the structure of the chapter does risk neglecting issues that cut across different categories of technology and/or market actors. It is important to maintain a level playing field and therefore to consider the unintended barriers that might arise by neglecting cross-cutting issues.

One example is the treatment of different flexible resources in the capacity market. The shorter contracts allowed for flexible demand and storage in the Capacity Market arguably constitute a regulatory barrier by comparison to generation. The debate has clearly been considered in detail in other places and our views are recorded elsewhere (e.g. UKERC'S 2016 Energy Policy Review[7]). For the purposes of this Call for Evidence we simply restate our view that a cross-cutting approach in which different flexible resources are treated equivalently is preferable.

2.1.1 Storage

Our responses to questions 1 to 6 have been led by Giorgio Castagneto Gissey and Paul Dodds of University College London.

The removal of regulatory barriers could facilitate a smoother integration of energy storage resources in the UK power system. While the changes proposed by Ofgem and BEIS generally address this issue, we see several areas where the changes may risk introducing subtle new barriers, or do not fully address current barriers to the deployment of storage resources. We point out these issues and propose ways to promote a more extensive and inclusive integration of energy storage in the UK electricity systems. Our response primarily relates to regulatory barriers, issues related to ownership and operation by network companies, and challenges related to the nature of market design.

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? Please provide evidence to support your views.***

The CfE identifies and correctly assesses the main policy and regulatory barriers to the development of storage. We note how some of the mentioned barriers involve wider considerations, and that there are a number of key additional barriers.

[7] UKERC, 2016. Review of Energy Policy. UKERC Policy Briefing. London: UKERC.

We agree that the regulatory treatment of storage currently represents the most pressing issue that prevents the progression of storage. Based on evidence from numerous official documents, literature and regulations, our work has identified a substantial number of policy and regulatory barriers to the development of storage. A number of additional barriers to those mentioned in the CfE exist, and these can have a crucial impact on the incentives for both innovation and deployment. Our recent report[8] and policy briefing[9] identify these additional challenges as:

1. a lack of any form of direct support for storage;
2. the absence of verified needs and roles for storage declared from an official government source, including advice on business models and regulatory viability of these, for each domain;
3. up until the introduction Enhanced Frequency response in the second half of 2016, a lack of very fast response balancing and ancillary markets;
4. the absence of unified and conclusive EU and national legal and regulatory frameworks, and regulatory differences between national markets;
5. uncertainty regarding the ownership and operation of storage assets;
6. the lack of policy/regulatory reflection of the substantial dependency of storage on wider electricity system developments;
7. competition with other balancing and ancillary service assets;
8. uncertain public attitudes towards storage[10];
9. a lack of ancillary service performance accuracy payments, such as within the frequency response service;
10. the presence of open-ended contracts for delivery of electricity at any time during long periods in the capacity market, via open-ended capacity contracts, which cannot practically be met by storage;
11. the sharpening of cash-out pricing in the Balancing Mechanism, something that has been much discussed in recent years and which, in our opinion, remains important in providing incentives to potential investment in and utilisation of storage.

---

8 Castagneto Gissey and Dodds, 2016, Regulatory barriers to energy storage deployment. An overview of the UK market, RESTLESS, http://www.restless.org.uk/project-results

9 Castagneto Gissey et al., 2016, Regulatory barriers to energy storage deployment: the UK perspective, RESTLESS, http://www.restless.org.uk/project-results

10 Public attitudes against energy technologies are discussed in Pidgeon et al., 2014, Creating a national citizen engagement process for energy policy. PNAS 111:p13606. While there are currently no studies addressing citizens' views of energy storage technologies, a lack of understanding of these and their physical characteristics could provide substantial barriers. These issues are under investigation for the first time in three ongoing EPSRC projects.

A number of these barriers are derived from the regulatory definition of storage, and introducing a new definition (as discussed in Q5 below) would likely facilitate the removal of several barriers to storage.[11] We recommend that Ofgem/BEIS identify such relationships between barriers, in order to better understand and remove barriers to deployment. Figure 1 shows relationships that we have identified. Other barriers, such as the final three listed above, are technical market rules that practically (and perhaps unintentionally) reduce the competitiveness of storage technologies in some existing markets where they might on the surface be expected to thrive.

Many storage technologies are noticeably costly at present but have potential for cost reduction. Experience from other technologies, e.g. solar PV and wind, suggests that growth of a market for a technology can do much to reduce costs, and incentives can play an important part in creating that market[12]. Such support has previously targeted generation technologies rather than technologies such as storage, which contribute to system balancing and stability. Storage could provide a key contribution to integrating high levels of renewables into the electricity system, but at the moment the incentives for renewables do not reflect the system integration challenges that they create. One approach, adopted by California, is to require renewable generators to invest in storage assets to reduce the impacts of intermittent generation.

11 Castagneto Gissey and Dodds, 2016, Regulatory barriers to energy storage deployment. An overview of the UK market, RESTLESS, http://www.restless.org.uk/project-results

12 See, for example, National Renewable Energy Laboratory, 1999. What are the Appropriate Roles for Government in Technology Deployment? and DECC, 2013, Roadmap to a brighter future

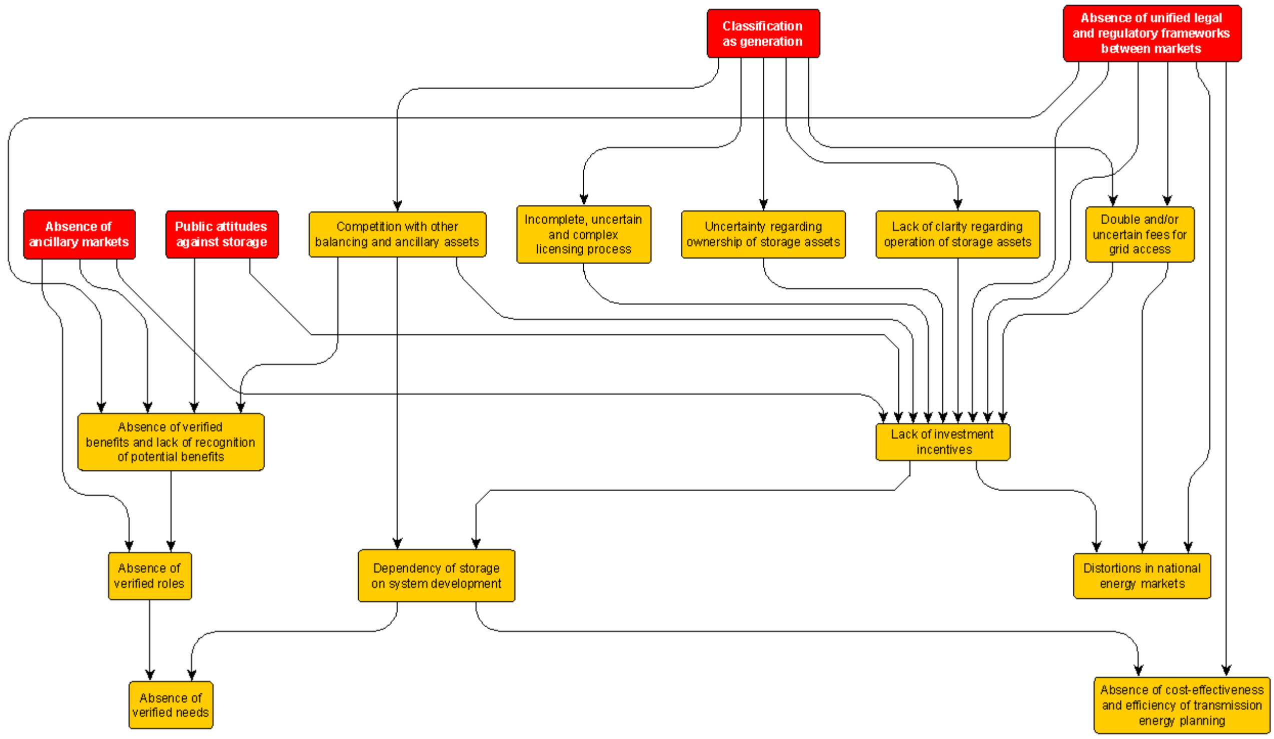

Figure 1 – Relationship between barriers to energy storage deployment in the UK electricity markets.

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? Please provide evidence to support your views.

We broadly agree with the identification of the issues regarding network connections for storage as set out in the CfE.

It remains unclear how network connections will be priced in the future to reflect the unique characteristics of electricity storage. Depending on the generation portfolio, location and choice of storage technology, it could support the electricity system by meeting peak loads, reducing peak network flows and hence managing network constraints. One approach for the Government to consider would be charging models and network connection tariffs that reflect the size, use and location of the storage connection[13].

At present, use of system electricity tariffs, such as TNUoS[14] and DUoS[15] charges currently do not provide incentives for charging of storage during periods of high electricity demand

13 US Department of Energy, 2013, Grid Energy Storage
14 Transmission Network Use of System
15 Distribution Use of System

and they have been shown to improve the arbitrage value of storage.[16] However, tariffs specifically relying on the time of export may be more effective in avoiding generation curtailment and relieving network constraints. This issue is clearly linked to the types of business models used by the Distribution Network Operators (DNOs) and the transmission licensees. The DNO Contracted and Contracted Services model could better support the operation of storage so long as the tolling contracts between DNOs and the third party operating the storage were not too complex (as these could affect system flexibility and security). In many respects, storage and additional network capacity represent alternatives to each other. We encourage Ofgem and the Government explore alternative regulated business models for network owners and system operators to reduce impediments to storage investments, including both ownership constraints and avoiding disincentives where storage could reduce network income. The scope for a choice to be made between investing in storage at a given location instead of extra network capacity should be widened where it can be shown that storage is the most economic option taking into account all the services it can offer.

Incentives could be provided for heat maps to offer providers useful information about demands throughout the network and might incentivise deployment of storage in optimal locations in distribution networks.

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.***

The definition of storage as an intermittent or non-intermittent generator is a key issue because TNUoS and DUoS charges can be substantially different. Storage is currently recognised as non-intermittent, implying that it can connect to the distribution network and be relied upon to generate at peak times, which seems appropriate.[17] Defining storage as intermittent would increase the cost of deploying storage by increasing the network tariffs.

A competitive market for storage is one where storage is treated equally to other generation resources (and with other sources of system flexibility as argued earlier in this submission). At the moment, this is not the case since transmission-scale storage must pay double TNUoS, for charging and discharging, double DUoS charges, as well as the Climate Change Levy (CCL). If the generator is under 100 MW, as will be the case for most electricity storage

---

16 Strbac et al., 2016, Can storage help reduce the cost of a future UK electricity system?, Report for the Carbon Trust

17 Strbac, 2008, Demand side management: Benefits and challenges, Energy policy, 36(12), pp.4419-4426.

in the near future, they are not liable to pay TNUoS, but must still pay DUoS tariffs. These double charges do not reflect the complementary benefits of energy storage to the networks in balancing the wider electricity system – one moves electricity in time, while the other moves electricity across space. In most cases, storage is used for balancing, which does not contribute to congestion but instead can relieve it. Therefore, it might be appropriate to apply lower network fees for storage that better reflect the role of storage in the electricity system. Flexible connection agreements could be useful to lower network tariffs to be paid by storage providers if they were appropriately implemented. This specifically entails enabling storage to be charged with network tariffs that reflect the fact that storage is likely to export power at times of peak load, and import power at times of peak generation, reducing the market tightness and stress on the network.

Furthermore, the way in which storage is treated under the CCL framework remains unclear. The CCL is calculated at the point where electricity is delivered from generation to a UK distribution or transmission system; however, if export of electricity from a storage device relies on the import of electricity (from a Levy Exemption Certificate-owning generator) and then the export of this electricity, the issuing of a new LEC at the point of export (since storage is considered a generator) implies a double LEC. Therefore, it could be argued that storage should not be eligible for LECs, which currently represent a considerable barrier to the optimal deployment of storage resources.

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? Please provide evidence to support your views.***

<u>Do you agree with our assessment that network operators could use storage to support their networks?</u>

Storage can already provide a cheaper alternative to distribution network reinforcement in some niche locations.

As the share of intermittent renewable generation increases, the value of storage in moving excess generation at times of low demand in order to meet demand peaks will greatly increase. Electricity markets need to be designed to encourage the optimal deployment and use of storage to support the system. (See our answer to question 3).

The unbundling regulations in the Electricity Directive require DNOs to employ a third party to operate a small storage device, in order not to affect the competitiveness of the generation and supply markets; on the other hand, transmission licensees are completely banned from owning or operating any form of storage. With their superior information about electricity demands through space and time, network companies are in the best position to realise and optimise the value of storage within the system. However, their ability to do so with present regulations would undermine the competitiveness of storage. Given an incentive to minimise long-run costs of system balancing, a truly independent system operator that can commission storage but can profit neither from energy arbitrage nor from an enlarged asset base could maintain the competitive functioning of the generation and supply markets.

Whether the value streams to storage from grid services are effectively realised depends on the methodology used to reward storage for the operational benefits they supply to the system with grid services. While flexible connection agreements can help storage access value from its provision of flexibility, policies aimed at improving ancillary market signals could be a key factor in enabling higher levels of energy storage deployment. For example, it is our understanding that the frequency response service only involves an availability payment, and does not provide any separate payment for performance accuracy, which could be useful in improving the value of storage.

Are there sufficient existing safeguards to enable the development of a competitive market for storage?

The development of a competitive market for storage depends on the provision of a level-playing field between storage and other resources, as well as how storage is utilised by network operators and how storage services are sold within the electricity system.

A number of business models for ownership of distribution-scale storage have been proposed.[18] Among these, the issue of respecting horizontal integration unbundling and thus safeguarding competition in the generation and supply markets is, in our view, considerably less important in the DNO Contracted and Contracted Services business models since the distribution businesses would take a reduced role in asset operation under these models. These challenges may be overcome by allowing distribution businesses to be actively involved in buying and selling energy for balancing purposes, e.g. through use of storage, in a way similar to National Grid. Yet, this may result in the distortion of competition and restrictions to avoid trading for any other purpose that does not directly involve balancing the system must be required, thus activities such as speculative trading should be banned in such case.[19]

While the DNO Contracted and Contracted Services business models entail the most balanced compromise between commercial risk for the DNO and the operating third party, the viability of these models depends on the complexity of the tolling contract, and whether

18 UK Power Networks, 2014, Smarter Network Storage business model consultation
19 Pöyry, 2013, Storage business models in the GB market, Report to Elexon

the third party is willing to take on long-term risk for additional value streams.[20] Ofgem should monitor the simplicity of these contracts in order to prevent these from impinging on system flexibility and efficiency. Similarly, market-based price signals attached to DUoS charges should ideally incentivise the third party to take on long-term risk for additional value streams in a way that safeguards consumer prices and system flexibility.

A well-structured tolling contract would be one which gives the third party as much control over the asset as possible without negatively affecting network security. Furthermore, under the DNO Contracted model, there is more flexibility for the DNO to share some of the commercial risk if the DNO can take some merchant exposure, but this needs to be appropriately incentivised, through appropriate signals.

A detailed appraisal of the benefits and potential concerns of these business models might remove some ownership and operational barriers and encourage investment.

<u>Are there any circumstances in which network companies should own storage?</u>

Network companies should be allowed to own storage if it can be ensured that they treat storage as an integral part of the system, although this could require rules that ring-fence them from interacting with other markets.

DNOs in Italy and DSOs in Belgium are allowed to own and operate battery storage, and there is no evidence that this has prevented the competitive functioning of the generation and supply markets. Italy allows DNOs to control batteries if this choice can be justified throughout a cost-benefit analysis showing that the storage system is the most cost-efficient way to solve the identified problem, as opposed to potential substitutes, such as building a new line. Belgium enables DSOs to operate batteries if they do not alter the competitive functioning of markets.[21] Given the benefits that network companies would be able to provide to the system by using storage, they should be given a chance to do so if they are able to show that storage is more cost-efficient compared to alternatives and in the case their ownership of storage did not alter competition in other markets.

If a DNO decided to deploy storage today using the generation licence exemption, it might overspend its capital allowance, but would only receive little income via the restrictive *de minimis* requirements.[22] If a DNO used a 'standard' approach to justify its use of storage

---

20 UK Power Networks, 2014, Smarter Network Storage business model consultation
21 DG ENER, 2012, The future role and challenges of energy storage
22 The de minimis requirements are included in the distribution licence and require that: (i) total turnover from non-distribution businesses shall be one of 2.5% or less of total revenue of the DNOs from distribution; and, (ii) aggregate investments in non-distribution activities shall not be over 2.5% of the DNOs issued share capital, its consolidated reserves and it share premium.

(i.e. conventional asset replacement, or reinforcement), its activity would need to be assessed based on the expected efficient costs for the substitute asset type, which would feed into its revenue and the regulatory asset value. This assessment reflects a key barrier to storage deployment in that it fails to consider the whole set of benefits to the wider energy system that storage could deliver, aside from those delivered to the DNO itself.

Similarly, it can be argued that transmission licensees should be allowed to own storage if they can show that storage is the most cost-efficient solution to the identified network problem, and if they can show that the competitiveness of markets is not altered. Italy and Belgium have more flexible approaches to TSO ownership than Britain. Italian law allows TSOs to build and operate batteries, if this can be justified with a cost-benefit analysis that shows the cost-efficiency of storage compared to alternatives.[23] Belgium similarly allows TSOs ownership of storage devices if this does not prevent the competitive functioning of markets.[24] Similar approaches could be considered for Britain.

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.*

We are concerned that the assessment focuses on the need for a new definition. Our work suggests that previous experience from the gas market, whilst defining gas storage as an independent asset class,[25] was not sufficient to remove regulatory barriers,[26]. In that case, the European Commission has raised concerns that current regulations are insufficiently specific on required strategic stock levels to ensure security, and that regulations should consider the relative roles of interconnection capacity and local production.[27] A regulatory approach that improves the ability of storage to access revenue streams not only in terms of capacity but also from ancillary services would improve the business case for storage.

Since storage is never a positive net electricity generator, it can be argued that it does not act as a generator and should not be liable to pay tariffs as a generator, including DUoS tariffs. The payment of the CCL as a generator and consumer could similarly be reviewed. Since the CCL does not relate to the use of network capacity, one approach would be to waive the CCL payment of storage as a generator, while maintaining the payment as a

23 Italian decree law 93/11, Art. 36, par.4

24 Belgian Electricity Act, Article 9(1)

25 Ofgem, 2015, Guidance on the regulatory regime for gas storage facilities in Great Britain

26 Castagneto Gissey et al., 2016, Regulatory barriers to energy storage deployment: the UK perspective, RESTLESS

27 DG ENER, 2015, Energy Storage: Which Market Designs and Regulatory Incentives Are Needed? Report for European Parliament

consumer. This could be justified by the net generating position of storage, which would point to its sole payment as a consumer, which might better reflect its benefit to the system in integrating intermittent renewable capacity.

6) *Do you agree with any of the proposed definitions of storage? If applicable, how would you amend any of these definitions? Please provide evidence to support your views.*

We broadly agree with the definition provided by the Electricity Storage Network (ESN), which has so far also been supported by industry. However, this definition does not fully differentiate storage from other forms of generation, nor does it fully differentiate it from network equipment such as transformers. The definition could be amended to reflect the net negative flow of electricity from the device and the fact that electricity is converted into other forms of energy before being reconverted back into electricity, in order to fully differentiate it from other generators and network equipment.

An alternative definition of Electricity Storage could be:

> 'A means of converting imported electricity into a form of energy that is stored and can be reconverted into electrical energy; is unable to produce a positive net flow of electrical energy from the device; and for which, given sufficient margin to increase or decrease the state of charge, the timing of imports and exports can, under normal operating conditions, be controlled independently of each other and the voltage at the point of connection to the power system.' [28]

The wording 'that is unable to produce a positive net flow of electrical energy from the device' would effectively differentiate storage from other generators, but would not exclude storage from being recognised for its generation and demand properties. This definition might enable the setting of a network tariff that reflected the weighted sum of generation and consumption tariffs to better reflect its role as both a generator and a consumer.

The reference to control of the timing of imports and exports is intended to ensure that network assets such as capacitors and transformers are not caught by our proposed definition but to leave the way open for supercapacitors to be treated as Electricity Storage[29].

2.2 Aggregators

7) *What are the impacts of the perceived barriers for aggregators and other market participants? Please provide your views on:*
   a) *balancing services;*

---

28 This definition is based on one that was initially proposed in Castagneto Gissey et al., 2016, Regulatory barriers to energy storage deployment: the UK perspective, RESTLESS.
29 E.g. IEA, 2014, Technology Roadmap Energy Storage

b) extracting value from the balancing mechanism and wholesale market;

c) other market barriers; and

d) consumer protection.

Do you have evidence of the benefits that could accrue to consumers from removing or reducing them?

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

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

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?

3 System Value Pricing

Our responses to the questions posed in chapter 3 of the Call for Evidence have been led by Keith Bell with contributions from Nick Eyre and Graeme Hawker.

The UK Energy Research Centre has recently published a working paper[30] that aims to provide an accessible summary of the need for enhanced flexibility on the power system and improved transmission-distribution coordination. We therefore do not go into the full motivation here but refer readers to that paper. However, here we highlight what we see as a need for greater clarity in respect of the terms used to describe the potential contributions of demand, i.e. a 'taxonomy' of "management of demand". We believe this will be important when considering which ancillary services the demand side might offer, how much of each might be available, how they might be accessed and what risks might be associated with depending on them, e.g. will they be delivered and delivered quickly enough when required. It is also important when considering price signals such as via half-hourly tariffs or use of system charges.

The taxonomy we propose is illustrated in Figure 2. It, in turn, drew on ideas in a number of other publications, e.g. by EPRI[31] and CIGRE[32].

30 Transmission-distribution coordination and transition to more actively operated distribution: why it matters. Keith Bell, UKERC 2017

31 C W Gellings, The Concept of Demand-Side Management for Electric Utilities. Proceedings of the IEE, 1985. 73(10): p. 1468-1470.
32 CIGRE Working Group C6.09, Demand Side Integration, Technical Brochure TB 475, CIGRE, Paris, 2011.

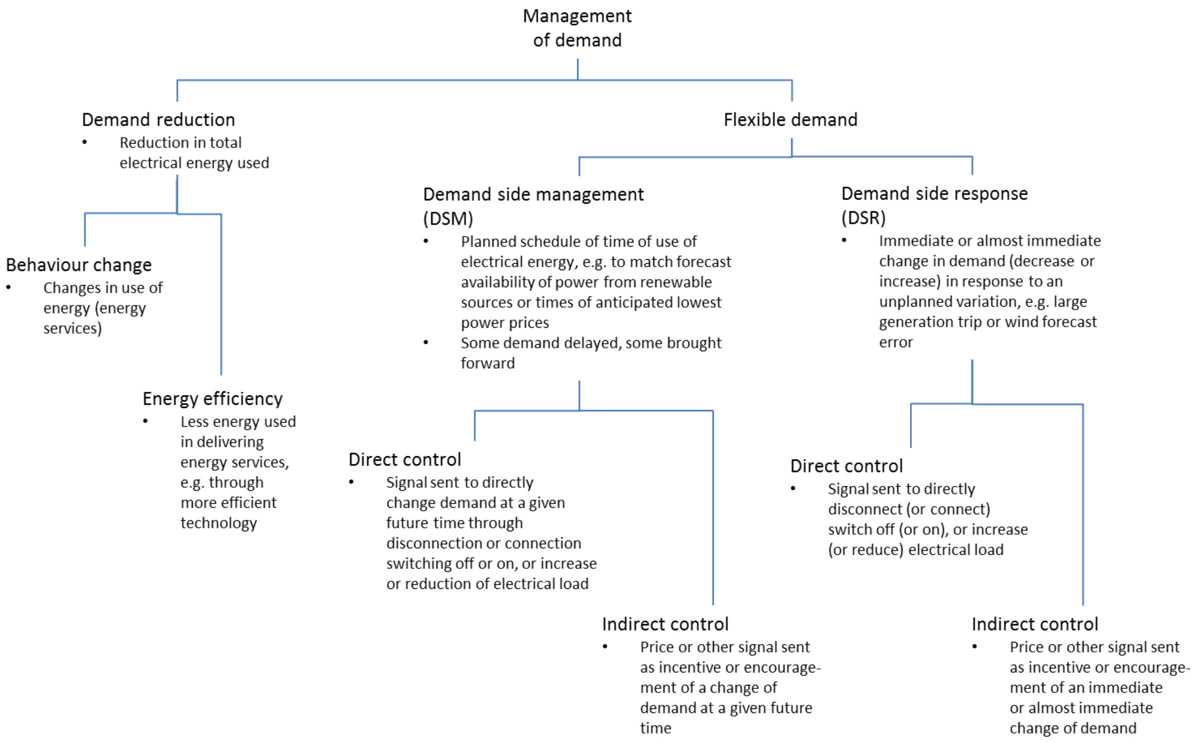

Figure 2 – A taxonomy of management of demand

Frequency response on the GB power system is an automatic, real-time response to observed changes in system frequency, those changes being generally unintended and unavoidable. Taking a lead from this, we define *Demand Side Response* (DSR) as a response to some unplanned change – this could be a change in system frequency, for example, or a rise in loading on an overhead line to near or above its thermal limit, perhaps due to a fault on another line.

If the sum total demand is not fundamentally being reduced, all that is being done is changing the time at which demand needs to be met. Exactly when that later increase in demand takes place is uncertain and could come at a very inconvenient time[33].

Demand Side Management (DSM) seeks to overcome the problem with DSR by considering a period of time and scheduling different levels of demand at different times within that period, under the constraint that the total demand for energy is met within that interval and that instantaneous demand for power neither exceeds nor falls below certain, defined limits. Given that power prices or power from renewable resources vary within the given time interval, the objective might be either to minimise total cost of energy in that period or minimise total 'spilled' or curtailed renewable energy. The downside of DSM is that, in order

33 It can be envisaged that a demand-side response could involve the energy service, or some part of it, being foregone completely rather than being delayed. However, we would expect this to be no more than a small component of DSR.

to be fully effective, it depends on good time series forecasts, e.g. of ‘underlying’/inflexible demand, the amount of demand that is flexible, prices, and of intermittent sources of generation (e.g. wind or solar power).

Because they both involve changes to patterns of demand relative to what would otherwise have occurred, we bring DSM and DSR together under the collective heading of *Flexible Demand*. The key difference between DSM and DSR, as we see it, is that DSM is *planned* – albeit perhaps at short notice or for a short period – while DSR is a response to something that is *unplanned*[34].

There are we what we call ‘direct’ or ‘indirect’ methods by which DSM or DSR might be actuated[35]. Both are affected by uncertainties but the former should be something in which a system operator can have more confidence[36]. A price signal – whether a real-time price or a ‘static’ tariff – is an indirect control[37]; there is reliance on electricity consumers being influenced by the signal to change when they use electricity or to reduce use right now. How many of them do that and by how much is subject to uncertainty, though over time it ought to be possible to assemble reasonable statistical models to allow a good prediction of patterns of demand or levels of response.

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

The concept of system value is welcome, but the practice will need to reflect the complexity of future systems. The appropriate price needs to reflect costs from the wholesale market,

---

34 In respect of conventional system management procedures, an analogy can be seen between DSM and ‘unit commitment’ and between DSR and ‘response’ and ‘reserve’. However, even the latter might need to be planned to some extent: some ‘headroom’ (margin to increase something) or ‘footroom’ (margin to decrease something) are generally required to be available at a particular time just in case it is needed. This need for margin might lead to particular pricing arrangements: one fee for being available to provide a response; another for utilisation when the response is actuated. Correct remuneration for either of these depends on being able to measure or accurately estimate how much is provided.
35 In chapter 3, the Ofgem/BEIS call for evdience uses the term ‘price flexibility’ which seems to be analogous with indirect control. ‘Contracted flexibility’ seems to be that which allows the use of direct control.
36 There might be failures or delays to communications or failure of a switch to operate, but they should be rare. However, e.g. when a demand reduction response is sought, there is also some uncertainty about the exact level of demand and what proportion of it is controllable. Something cannot be switched off if it is already switched off.
37 Different forms of pricing arrangements are each a form of indirect control. Some seek to influence a ‘sensible’ scheduling of demand; others seek to elicit a change right now.

grid and flexibility costs (i.e. ability to flex within a half hour and provide ancillary services). Signals for investment also need to include capacity costs. The move towards increased use of very low marginal cost generation is increasing the periods of time with low short run marginal costs, and therefore low wholesale market prices. The appropriate cost signals for investment (long run cost) versus operation (short run cost) may therefore differ very significantly. This implies that average prices may fall in wholesale markets, but rise in capacity and flexibility markets. Within any one particular geographical area, it is difficult to envisage these markets being effective as anything other than 'single buyer' procurement markets, pointing to the continued importance of governance and regulation of monopoly licensees (e.g. system operators at various scales).

Flexible generation, flexible demand, two-way storage[38] and network capacity all have the potential to provide useful system services. In many respects, these offer different types of flexibility and, in certain respects, providers of flexibility in different locations, can be seen offering alternatives to each other. For example, two forms of 'flexibility' are the ability of generators to reduce outputs and, given sufficient notice, their ability to increase output. As well assisting the National Electricity Transmission System Operator (NETSO) in the management of overall system power balance, these help to resolve local power imbalances within the limits of the network connecting two or more areas, mainly through the balancing mechanism. However, in the medium to long term, sums spent on 'bids' and 'offers' to address local imbalance can be reduced through investment in additional network capacity that allows local deficits of demand relative to generation to be addressed by importing surpluses from other areas.

As will no doubt be discussed by other respondents to the Call for Evidence, one particular difficulty at present is represented by the range of different services and their associated procurement and remuneration arrangements. The different services reflect different temporal and spatial aspects of system operation; few, if any, potential providers of flexibility can offer all of them. Thus, while the definitions of some services might be revised to better reflect what is needed and what can realistically be provided, e.g. 'primary', 'secondary' and 'high frequency' response[39], the different categories are useful. However, it

38 The electricity system already makes considerable use of energy storage and the flexibility it represents. However, the vast majority of it concerns only a one-way energy conversion, e.g. from the chemical energy embodied in a mass of coal or methane into electrical energy. The conversion processes associated with fossil fuels and nuclear fission are also relatively slow to get started or to ramp up or down.

39 At the launch event for the 2016 System Operability Framework, National Grid acknowledged that the current definitions of primary and secondary response are probably not totally fit for purpose. Because some providers, e.g. wind or solar, might be able to offer

should be made easier for *collections* of services to be evaluated and compared with alternatives. For example:

- could a multi-year contract for availability of generation, exports of power from storage or reductions in demand, akin to contracts offered in the capacity market but taking account of location and of the duration of availability of power at key times other than simply system peak demand, represent a cost-effective alternative to extra network capacity to serve the highest levels of imports into an area? Or, having conducted a market test to see whether such services might be both available and cost-effective, could a lack of positive outcomes from such a test help to reduce uncertainty on the need for extra network capacity and, as a consequence, accelerate its delivery?
- could a particular generator be cost-effective in respect of the *combination* of capacity, response, reactive power and black start services[40] when, viewed solely in respect of, say, capacity, it seems more expensive than alternative sources of capacity that succeed in meeting total system need?

Under present arrangements, some services are not considered at all, e.g. availability to meet local demand in a particular area in the longer term, or the procurement processes take place at different times from each other and completely independently of each other, e.g. capacity, response, black start and reactive power capability.

Although there are likely to be considerable challenges in comparing many different combinations of services from different providers, we would urge an alignment of procurement processes and associated tender rounds to allow combinations to be considered. However, in order that physical facilities that can provide only one or two services can still participate in relevant ancillary service markets, each service should still be priced separately even if an apparent premium is paid to some providers (by virtue of the combination being cost-effective).

Such a step ought to ensure that the total cost of the various services is minimised and should help generators, flexible demand and storage gain confidence in accessing multiple income streams. Such income streams will be increasingly important in an electricity system in which most energy comes from sources with very low marginal costs which, in competitive markets at times when there is no scarcity, would normally be expected to lead to low wholesale prices. Many of these sources have high capital costs; without sufficient income from sources other than the energy markets, their costs might not be recoverable.

---

a cost-effective high frequency response service without also being cost-effective for low frequency response, we would add high frequency response to that list.

40 For the last two of these – reactive power and black start – the value is associated with the location.

However, in order that costs finally passed through to energy users are not excessive, care should be taken to ensure that service providers (a) are actually available when required, (b) do not get paid twice for the same action and (c) do not get paid for capabilities that are inherent in the equipment used and cannot *not* be delivered when earning income from energy or other services[41]. (The ability to evaluate combinations of services ought to alleviate the risks associated with the last of these).

As we discuss in our answers to the questions posed in chapter 5 of the Call for Evidence, the potential for distributed energy resources (DER, i.e. generation, storage or flexible demand connected at distribution voltages) to provide services is becoming increasingly important. (DER also has the potential to increase the total cost of services excessively if not managed correctly). For flexible demand to contribute, it must be possible to remunerate it correctly and this depends on measuring it correctly. Half-hourly metering of demand promises to be a key enabler of DSM. However, the service provided by DSR (as we have defined it above) may be required to be delivered within a few seconds and, if there is some possibility of it not being delivered, would require some kind of extra monitoring in addition to half-hourly metering.

One thing that is becoming apparent from some academic studies, past evaluations of the impacts of allowing single generator units larger than 1320MW to connect to the GB system, and can be inferred from National Grid's System Operability Framework, is that the changing generation mix is likely to give rise to a need for different volumes of dynamic services and, potentially, new services such as faster controlled responses, lower minimum stable generation or higher ramp rates[42]. New ancillary services and associated markets might be defined. As far as possible, the definitions of these services should focus on what is really of value to the system and not on the way it happens to be delivered by particular technologies. One example is 'inertia response'. The core requirement for the power system is a very fast response to changes in the balance between generation and demand. Defined in one way, only synchronous generators directly coupled to the grid would be able to

---

41 Examples of this includes generators with inherent capability to generate or absorb reactive power. They must be connected to the system in order to sell active power; up to certain levels of reactive power, there is no impact on active power exports from also producing or absorbing reactive power and we are not aware of evidence that such production or absorption incurs any significant cost to the generator. Another example is the use of a synchronous generator directly coupled to the grid. Whenever there is a change in system frequency, it inherently produces an 'inertia response' which cannot be avoided.
42 Although it is smaller than the GB system, the power system on the island of Ireland is also an islanded system and experiences there of changing generation patterns provide an interesting point of study in respect of what we might expect in GB. The system operator there has introduced a number of new ancillary services.

provide it. In principle, 'technology agnostic' definitions should promote competition between technologies even if, in practice, one particular technology has distinct advantages over others.

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?

The UK Energy Research Centre is not an existing or potential provider of flexibility and so we do not answer this question.

13) 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?

The UK Energy Research Centre is not an existing or potential provider of flexibility and so we do not answer this 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?

Evidence of a need for change to existing regulatory and commercial arrangements is represented by:

- the gradual increase, over a number of years, in the total cost of balancing services;
- the large sums paid in recent years by the NETSO for generators to absorb reactive power;
- the significant increase in the cost of availability of black-start services from generators;
- the introduction by National Grid of a new ancillary service, that of Enhanced Frequency Response (EFR).

New ancillary service markets might be opened up and have the potential to drive investment in new equipment or equipment with enhanced capabilities. However, the full value of some of these services might not be revealed for some years. One potential provider of different ancillary services is combined cycle gas turbine (CCGT) generation. Existing CCGTs in Britain were not generally designed for flexible operation; however, we understand that some newer designs do offer, for example, faster ramping or lower minimum stable generation (MSG), albeit at higher capital cost. Investment in new CCGT capacity is anticipated by many to take place in the next 2-3 years. This is likely to be before new ancillary services have been established or the value of enhanced ramping or lower MSG has been revealed. However, new CCGT plant would normally be anticipated to operate for between 20 and 30 years, i.e. to still be in operation when enhanced capability is required. One option would be for Ofgem to require new CCGTs to have enhanced dynamic capabilities now rather than leaving it for a market that is yet to emerge to provide incentives to the provision of such capabilities? The benefits of doing this should be compared with the potential penalties arising from making general power system requirements too specific to particular technologies (which might reduce the level of competition between different technologies) or to the potential costs of retrofitting existing stations to make them more flexible at a later date. Alternatives to a general capability requirement include (i) allowing the service buyer to tender for capabilities somewhat in advance of need or (ii) allowing negotiation on enhanced capability and associated remuneration for the cost of that enhancement as part of a connection agreement.

One difficulty with any of the above approaches lies in defining how much of a particular capability will be needed by the system. Inherent in that are (a) the need for detailed system modelling of future scenarios and (b) the risk of stranded assets. As well as requiring not just the development of credible future scenarios (in more detail than common in, for example, National Grid's Future Energy Scenarios), but *judgements about* those that could be more likely, (a) requires considerable power system modelling expertise[43]; and (b) is likely to require a pragmatic approach such as adoption of what are judged to be least regret actions.

3.1 Smart Tariffs

Time-of-use (ToU) or locational pricing acts as a signal to users of electricity, generators or owners of storage to behave in particular ways, e.g. to orient their consumption or production towards particular times and away from others, the goal being to minimise the total cost of energy over a period of time or to maximise the social welfare. As such, pricing arrangements can act as incentives. However, although a particular arrangement might, in the long-run, succeed in meeting the overall goal, the variability and uncertainty associated with certain pricing arrangements also entail risk to individual parties. In addressing potential pricing or tariff arrangements, we believe that two key principles should be kept in mind:

1. incentives should be directed at those parties that are able to respond to them;
2. risks should be borne by those parties best able to manage them.

43 Such forecasting and modelling expertise is required in any case and would allow National Grid – or others – to move beyond what the three System Operability Framework reports have done to date, i.e. to show that there are problems, and instead to also show some potential solutions.

We believe that one key objective in new pricing arrangements should be to incentivise flexibility on the demand side and, as a consequence, reduce the need for reserve generation and the associated capital and operating costs. It might also help to reduce network costs relative to the case of there being no demand flexibility. As Ofgem/BEIS have noted in their Call for Evidence, it will, however, be important to note "the potential social impacts of the smart tariffs that are enabled by half-hourly settlement, as different types of consumers will be affected in different ways, with some less able to benefit than others." For example, some Low Carbon Networks Fund (LCNF) trials of flexible demand have shown very little flexibility being offered by small commercial users of electricity and little apparent benefit from flexibility on the part of domestic consumers[44]. However, other trials (though small) have shown that, given suitable advice and support, domestic consumers, including those in social housing, can offer flexibility and benefit from incentives to adopt particular patterns of use of electricity.

We agree that uptake of ToU and more complex tariffs in households and small and medium-sized enterprises (SMEs) will be constrained by unfamiliarity with the concept and the potential complexity of some tariff arrangements. Active consumer decisions to move the point in time at which energy services are used are only likely if there is a significant and transparent consumer benefit. Moreover, some important demand flexibility opportunities rely on the storage of energy (thermally or electrochemically) without changes to the timing of the service gained from use of energy. Examples of energy services that can benefit from storage include electric vehicle charging, hot water tank heating, and short term switching of refrigeration and air conditioning, as well as the long established option of storage heating. In principle, individual decisions to switch-on or switch-off these technologies can be made without direct reference to the consumer, either by a supplier/aggregator (direct load switching) or a smart device. Informed consent remains critically important, and this requires higher levels of engagement with energy and higher levels of trust in the energy industry than the current norm. Without this the option of more simple tariffs at slightly higher cost will remain more attractive. In the short term at least, we expect these factors to be more limiting than the technical potential, which is clearly very large.

Various academic studies – such as that on electricity system flexibility produced for the Committee on Climate Change or the National Infrastructure Commission – have quoted large numbers in respect of potential savings arising from flexibility, including from flexible demand. However, many academic studies need to make significant assumptions and these are rarely fully substantiated. Technical potentials for demand side flexibility are often

[44] See, for example, the review of LCNF projects available here: http://www.ukerc.ac.uk/publications/a-review-and-synthesis-of-the-outcomes-from-low-carbon-networks-fund-projects.html

included, but without an assessment of how much of that potential can be realised in practice, once social and economic constraints have been taken into account. The overall realisable potential for demand flexibility, both DSM and DSR, is still to be determined. Some useful initial discussion on this can be found in, for example, a report produced by Sustainability First and published in April 2015 – "GB electricity demand – realising the resource" – and, in respect of the domestic sector, "Further Analysis of the Household Electricity Survey Early Findings: Demand side management" by Cambridge Architectural Research Ltd, Element Energy & Loughborough University from November 2013.

We believe that two keys to realising the potential of flexible demand are as follows:

1. making it as easy as possible for electricity consumers to control or schedule their use of electricity, or to have the confidence in service providers who can do so on their behalf; ;
2. maximising the share of the benefits of demand flexibility that accrue to electricity consumers.

Both of the above are likely to depend on parties other than the household consumer. Commercial products, e.g. 'home energy management systems', might become available that consumers can buy and use such that their electricity consumption becomes, unlike what is offered by ''smart meters"[45], genuinely 'smart'. However, the financial benefits depend on what contractual arrangements consumers have for the supply of their energy. This, in turn, depends on a plethora of parties and services in the wider electricity sector. The aforementioned report by Sustainability First discusses some of these which we summarise in Table 1 below in respect of potential co-parties to different demand side contracts, the envisaged benefits to the co-parties and existing mechanisms.

Table 1– potential co-parties to flexible demand contracts

Co-party	Benefit to co-party	Scheme
System operator (SO)	• Frequency response • Reserve	• Enhanced frequency response • Short-term operating reserve (STOR) • Demand side balancing reserve
Distribution network operator (DNO)	• Defer or avoid network reinforcement to meet peak power flow	• Use of system charging • Faster access for new connections • Payment through innovation

[45] What have hitherto commonly been called 'smart meters' in the UK would be better understood as 'advanced metering infrastructure' (AMI) since very little of what they do can be described as 'smart'.

		schemes
Transmission owner (TO)	• Defer or avoid network reinforcement to meet peak power flow	• Use of system charging • Faster access for new connections
Supplier/retailer	• Help manage wholesale procurement risk • Offer services to SO	• Variable half-hourly pricing • Economy 7 / Economy 10 • Voluntary load management
Aggregator	• Help manage wholesale procurement risk • Offer services to SO	• Variable half-hourly pricing • Voluntary load management
Capacity market	• Reduced need for generation capacity	• Capacity market

Demand side aspects of the Capacity Market and what the System Operator buys are slowly becoming better developed. A number of aggregators are already active in procuring, offering and managing demand side services but, as is discussed in the Ofgem/BEIS Call for Evidence, there are a number of regulatory questions concerning their status. In respect of DNOs, TOs and suppliers/retailers, there is much room for improvement. However, it may also be noted that, given the existing electricity system infrastructure and the costs of system balancing, the magnitude of potential financial benefits to electricity users is currently limited or perceived to be so. As the Call for Evidence notes, there is "a perception among suppliers and intermediaries that the value created through consumer response to smart tariffs is insufficient to be worth pursuing for consumers other than the largest users e.g. due to limited wholesale price differentials" and there are "trade-offs between reducing the cost-to-serve and raising suppliers' costs of bill administration". Nonetheless, as we discuss below in our answer to question 15, we believe that the big suppliers are, at present, serving customers poorly.

The benefits that can be expected when demand for electricity grows for the charging of electric vehicles, or to provide more electric space and storage heating, should be substantially larger than those perceived at present, though there is still a need to keep administration costs to a minimum. A healthy, competitive market will be essential to keeping those costs down.

15) 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.*

The roll out of 'smart' meters and smart systems generally should be seen as a facilitator of informed consumer decision making, not a substitute for it. We share the doubts expressed by many stakeholders about whether licensed suppliers were the best choice to implement 'smart meter' roll out. However, that decision has been made and we would not support reversal at this point. Instead, we believe it remains important for the roll out process to include engagement with households. This has clear measurable benefits[46]. Government and Ofgem need to continue to require consumers to be informed about smart meters and displays at the point of installation. This is a necessary part of the process of smart system development, not an unnecessary additional cost burden. If requiring this approach leads to a need to extend the smart meter roll out timetable, that would be preferable to a roll out that bypasses consumer engagement.

What the Call for Evidence calls 'smart tariffs', in particular time-of-use (ToU) pricing, already exists, at least to some extent, and has existed for a number of decades. In respect of smaller consumers, the most pertinent are 'Economy 7' and 'Economy 10'. Their original purpose was to encourage electricity use at times of low demand and, as a consequence, help to reduce electricity unit commitment and despatch costs. Although growth of solar PV and wind have resulted in greater variability of 'net' or 'residual' demand, i.e. that which remains to be served after utilisation of available weather-dependent renewables, demand overnight is still low and the original motivation for these tariffs is still material. However, as noted by the Competition and Markets Authority (CMA) review of the energy markets, consumers are actually *penalised* – not rewarded – by the biggest suppliers for being on these tariffs. As far as we are aware, the CMA failed to come up with any significant reason why. However, we note that a number aggregators and smaller retailers/suppliers have expressed the view that the dominance of the retail/supply markets by 'the big 6' and their vertical integration with generation interests significantly impacts on the offering of attractive ToU tariffs. This, they argue, is because greater participation by the demand side in system balancing would take business away from their generation interests.

The main immediate role that we see Government and Ofgem playing is to address reasons why existing 'smart tariffs' for smaller consumers provide no benefits to consumers. Our view is that vertical integration of retail/supply and generation is likely to be significantly and adversely impacting on the offering of benefits of so-called 'smart tariffs' to consumers. Although the CMA asserted that there was no evidence of vertical integration

46 See Darby, S.J., Liddell, C., Hills, D., Drabble, D., 2015. Smart metering early learning project: synthesis report. Department of Energy and Climate Change, London.

having an adverse impact on consumers as a whole, we are not convinced that the analysis was robust with respect to the offering of ‘smart tariffs’.

Given the growing variability of wholesale market and flexibility costs, we believe that Government and Ofgem should require the use of half-hourly settlement wherever possible. We therefore support the announced plan to do this. We agree that the set of issues identified in paragraph 9 of the Call for Evidence needs to be addressed. We recognise that there is not a simplistic link between the settlement process and supplier tariff structures and that suppliers will not automatically roll out ‘smart’ tariffs because of the issues set out above. However, placing the costs and benefits of monitoring and management of consumer load profiles more clearly on individual suppliers provides an incentive that does not exist with the existing approach of using sets of standard load profiles.

Below, e.g. in the answer to Q23 and in our responses to the questions posed in chapter 5 of the Call for Evidence, we discuss interactions between transmission and distribution and lessons that can be learned from experiences with transmission system commercial and regulatory arrangements and how they are reformed.

To some extent, the main distinction between transmission and distribution, i.e. the nominal network voltages that are labelled as one or the other, is arbitrary. However, some other differences can be observed. These include the tendency, at least historically, for generation developments to exploit economies of scale and therefore to connect at transmission voltages. It is similar economies of scale – both amount of power and distance – that drove the development of high voltage network capacity in the first place and the consequential high impact of single faults that led to the meshed configuration of transmission. Largely as a consequence of that, the concepts associated with optimal, ‘active’ management of the power system, i.e. system operation, have always been used at transmission levels but, to the extent that they were ever used at distribution levels, many were forgotten about by distribution utilities decades ago. The historic concentration of influences on the transmission system in the hands of relatively few actors each of which were responsible for large volumes of energy has, compared with distribution, arguably led to more active participation in working groups concerned with various transmission codes and more active development of those codes. However, even then, progress to address emerging issues has often been painfully slow. One example was ‘Project TransmiT’ which took more than 5 years to implement a relatively minor change to Transmission Network Use of System Charging arrangements[47].

47 The change that was finally implemented in April 2016 was certainly minor relative to that advocated by some academic contributors to the project, i.e. fundamental change of the wholesale market to adopt LMP.

Perhaps the single most important reason why there has been more active engagement in transmission arrangements is that each party stands to gain – or to lose – so much that it can justify the devotion of fairly significant resources to each working group. For example, if the reward or the penalty to a single party for some particular change is a few million pounds per year, it will be worth that party committing a few people to working full-time on the working group. One reason why changes are so slow is that each change results in both winners and losers, and the losers will sometimes do their best to block the change regardless of what is best for the system (or consumers) as a whole. On the other hand, the issues have also often been big enough for Ofgem to pay close attention to each one and to lean on the NETSO to provide what Ofgem wants to see as independent leadership to the processes. This is, in our view, in stark contrast to reforms of arrangements relating to distribution. These – whether associated with engineering standards or charging arrangements – have largely been left to the DNOs, represented through the Energy Networks Association (ENA) and the impression we have is that Ofgem's engagement has been almost entirely passive. In addition, the DNOs have, through the various innovation funds, required the carrot of significant sums of their customers' money to engage with the major changes now happening on the electricity system and find new, better ways of managing the system[48]. To date, their use of those funds has been more concerned with new bits of kit than with methods or processes, including codes and standards, for managing the system[49].

One example of the DNOs' slowness in updating their methods relates to their main load-related investment planning standard, Engineering Recommendation (ER) P2. As the Ofgem/BEIS flexibility Call for Evidence notes, "much network reinforcement is decided according to forecast peak load, which is dependent on the likelihood of network capacity being used at the same (peak) time." However, it has been argued by one of the authors of this response that (a) a focus on a very sharp peak associated with neglect of operational measures and (b) inconsistent approaches to the task by different DNO engineers can lead to sub-optimal solutions and this, in turn, could have been addressed by some relatively

48 The DNOs are likely to argue, perhaps fairly, that their historic price review settlements gave them little or no incentive to do anything other than conduct established 'business as usual' at ever lower costs and that they have succeeded in doing just that.
49 See D. Frame, K. Bell and S. McArthur, A Review and Synthesis of the Outcomes from Low Carbon Networks Fund Projects, UKERC/HubNet, August 2016.
http://www.ukerc.ac.uk/publications/a-review-and-synthesis-of-the-outcomes-from-low-carbon-networks-fund-projects.html

simple changes to ER P2 at the time of the last revision (from ER P2/5 to ER P2/6) regardless of the fundamental review led by the ENA that is now inching slowly forwards[50].

For us, one key lesson in respect of the DNOs' and, on their behalf, the ENA's leadership to date of innovation of methods, processes, standards and codes is that the reforms that we believe are now required cannot be left to them to take forward. One particular point to note is that the ENA is not a disinterested body; rather, it is, in effect, a trade body whose role is to represent the interests of network companies. Given their greater experience with many of the relevant issues and in the leadership of industry working groups, it might be argued that the NETSO should assume a leadership role. However, it, too, will be open to the same criticism of lack of independence as the ENA. In the absence of any other suitable body, leadership would seem to fall to Ofgem as the independent industry regulator.

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.

We currently lack relevant information to say exactly when which action should be taken. However, we note that Ofgem's promise to review progress on transmission-distribution interaction issues in late 2017 suggests that it is being left to the network licensees to lead work. Although Ofgem might argue, perhaps with reason, that it lacks the knowledge to take a more active part, we believe that this is much too passive and risks excessive delays in proposals for change being formed and tested.

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?

The writers of this response are not, themselves, familiar with exact arrangements in other countries. However, we note that the following countries are likely to provide to some useful lessons:

- The US where, in the PJM market, for example, the demand side seems to be particularly significant. However, we note that introduction of demand side markets has not been without its problems (requiring various revisions of arrangements) and that many of the services relate to demand in summer months. This is important as there is likely to be considerably more flexibility in respect of cooling demand than, as would be required in winter, heating demand.

50 See K. Bell, A successor to ER P2/6: existing issues and lessons from "Flexible Networks for a Low Carbon Future", University of Strathclyde, 2015, available https://pure.strath.ac.uk/portal/en/publications/a-successor-to-er-p26(87639367-6367-4d39-b48c-ab6afa423e35)/export.html

- France, where a significant proportion of demand for heat is met by the electricity system, where much of the generation fleet has limited flexibility and where many electricity consumers are already on ToU tariffs with some degree of direct control of load.
- The island of Ireland, where the penetration of renewables is proportionally higher than that in Britain and where system balancing issues are comparable to those in Britain.
- Germany where, in the retail market, switching of suppliers must already be effected in 5 days or less. This is significant because effective competition among suppliers will be critical to tariff innovation and ease of switching is fundamental to effective competition.

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?

We do recognise what the Call for Evidence says in respect of "a perception among suppliers and intermediaries that the value created through consumer response to smart tariffs is insufficient to be worth pursuing for consumers other than the largest users e.g. due to limited wholesale price differentials" and "trade-offs between reducing the cost-to-serve and raising suppliers' costs of bill administration". However, we note that the roll-out of an advanced metering infrastructure (AMI, i.e. so-called 'smart meters') should significantly reduce suppliers' excuses with respect to administration costs. Moreover, AMI should also reduce the time taken to switch suppliers and enhance confidence in correct billing either side of the switch. Ofgem and BEIS should monitor the suppliers' prices and offerings very carefully as AMI is implemented.

We also draw attention to our response to Question 15.

3.2 Smart Distribution Tariffs – Incremental Change

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.

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?

21) How problematic and urgent are any disparities between the treatment of different types of distribution connected users? An example could be that that in the Common

Distribution Charging Methodology generators are paid 'charges' which would suggest they add no network cost and only net demand.

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?*

The development of distributed generation (DG) is already impacting significantly on the power system in Britain. Simplistic arrangements that treat DG always and only as reducing demand and, as a consequence, reducing the need for network capacity are inadequate because, depending on the DG's location, its presence can lead to increased power flows. In addition, without adequate management, DG can result in problems with excessively high voltages.

Until very much more demand is flexible than it is at present, DG will be much more controllable than demand. Moreover, because of the wide range of different influences on the location of demand, it is likely to be much more effective to use price signals to influence the location of new generation than it is to influence the location of demand.

Price or use of system charging signals can and should be used to incentivise DG to connect at locations where the adverse impacts on the network are minimal. However, at some point, it is likely that adverse impacts, such as a need for active management (meaning some curtailment) of generation or network reinforcement are necessary and, as we discuss in our responses to the questions raised in chapter 5 of the Call for Evidence, incentives on DNOs to carry out the most economically efficient actions will be critical.

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?*

The questions posed here and in paragraphs 18-23 of the Call for Evidence are highly relevant but have insufficient scope in that they relate not only to distribution but also to transmission charging and signals.

An oversight in GB electricity supply industry developments since liberalisation has been the neglect of interactions between transmission and distribution, and the failure to see the electricity infrastructure as part of one system, regardless of voltage level. This oversight has arguably not had a major impact until the last few years when DG has grown significantly. Now, as well as appropriate signals to location within either a distribution or a transmission network and to temporal behaviour, there should be signals which adequately reflect the relative costs of connection and utilisation of generation (and storage and, to the extent that it can respond to signals, demand) at different voltage levels, and these signals should reflect, as far as possible, whole electricity system costs[51]. In our view, this points to a need for a quite fundamental review of charging arrangements across distribution and transmission, and not just to tinkering with distribution arrangements. (See our answers to the questions raised in chapter 5 of the Call for Evidence for discussion of the potential impacts of failing to resolve interactions between transmission and distribution). Regardless of exactly how roles and responsibilities are attributed to different network licensees (see section 5 of the Call for Evidence and our responses) and connected parties, it will be important to have a common set of high level principles that apply across the power system regardless of location and voltage level, and a consistent set of standards and codes in respect of energy trading and retail, system access and connections, network investment and maintenance, system operation, and system resilience[52]. The standards and codes should take due account of scale and spatial and temporal interactions.

Correct incentives in respect of network infrastructure and system balancing costs have, to date, received considerably more attention in a transmission context than in distribution. Many of the issues will be similar and debates in respect of transmission can help to inform discussion of distribution pricing and charges. Among the issues that is debated from time-to-time is whether the GB wholesale market should be fundamentally reformed to adopt real-time locational marginal pricing (LMP). Locational prices vary in time reflecting the fact that total demand, the availability of power from different sources and transfers of power across the network vary through the year and, in general, network limits are only reached from time to time. According to its proponents, the short-term operational signals succeed also in providing long-term investment signals to network owners, generators, potential owners and operators of storage and the demand side. In some jurisdictions, e.g. New York state, consideration is being given to extending these arrangements down to distribution voltages.

In our view, there are some theoretical attractions to real-time locational pricing. However, the practical issues should be carefully thought through before adopting LMP. These include the quality of system modelling, the success – or otherwise – in providing correct and timely signals to investment and the ability of smaller parties to manage the uncertainties and

---

51 An example of a whole system impact relates to connection of generation to a distribution network that sits within a net exporting transmission zone. Connection and operation of any generation within that zone, whether transmission or distribution connected, leads to increased exports from that zone. On the other hand, operation of new DG within an importing transmission zone reduces the level of import.
52 'Resilience' includes the containment of and recovery from disturbances, not just prevention of adverse impact.

associated risks, whether they will therefore be dependent on 3rd parties, e.g. suppliers or aggregators, to manage them for them and whether 'the market' can be relied on to incentivise good, cost-effective performance by these 3rd parties.

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.

See our answers to questions 22 and 23.

3.3 Other Government Policies

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

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

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?

4 A system for the consumer

In this section, we provide some responses to the questions about consumer protection and cyber-security (Qs39-42). We have made some comments on domestic and small non-domestic energy users elsewhere in our response, in particular in our general comments in section 1 and in section 3.

4.1 Smart appliances

28) Do you agree with the 4 principles for smart appliances set out above (interoperability, data privacy, grid security, energy consumption)? Yes/No (please explain)

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.

a) Option A: Smart appliance labelling

b) Option B: Regulate smart appliances

c) Option C: Require appliances to be smart

d) Other/none of the above (please explain why)

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:

a) Wet appliances (dishwashers, washing machines, washer-dryers, tumble dryers)

b) Cold appliances (refrigeration units, freezers)

c) Heating, ventilation and air conditioning

d) Battery storage systems

e) Others (please specify)

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

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

4.2 Ultra-low emission vehicles

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

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:

a) control or shift of electricity consumption during vehicle charging; or

b) utilisation of an electric vehicle battery for putting electricity back into homes, businesses or the network?

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

4.3 Consumer Engagement with DSR

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

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?

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?

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)?

4.4 Consumer Protection and Cyber Security

Our responses to the questions 41 and 42 have been led by James Irvine and Greig Paul of the University of Strathclyde.

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

a) Social impacts

b) Data and privacy

c) Informed consumers

d) Preventing abuses

e) Other

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

Smart technologies could compromise the energy system in two ways – firstly through direct control or actuation, and secondly through indirect actions which can be used to influence or affect the power system.

Direct control of equipment which is improperly exposed on the internet presents a significant risk – Shodan (a search engine for internet connected equipment) indicates that there are 320 MODBUS devices currently exposed to the internet in the UK[53], including Telemecanique programmable logic controllers (PLCs). Legacy protocols such as these are not intended for connection to public networks, and do not feature any security, authentication or access control – anyone with access to the system may connect and directly interact with the equipment.

Improperly secured domestic devices can be rapidly taken over by attackers, as seen recently, e.g. distributed denial of service (DDoS) attacks due to the Miral botnet on internet of things (IoT) devices with default passwords. If these devices permit the control of loads within the home, this could give a single attacker control of a wide range of loads on the network[54]. Similar weaknesses have recently been reported built-in on devices with heating elements[55]. Were an attacker to switch a large number of such domestic devices within a short period of time, this would compromise power system integrity.

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

Current risks can be considered to fall into one of the following areas: inserting or changing command signals to directly control equipment on the power network; blocking command signals to prevent control of the network; inserting or modifying sensor data to cause the legitimate network control systems to take inappropriate action; blocking sensor data to blind the network; or interacting with interconnected networks which may have knock on effects on the power network (such as home automation devices or public telecommunication networks). Often, parts of the network which would seem of lower importance on their own can, in aggregate, become critical. For example, the security of an

---

53 MODBUS is a serial communications protocol originally published in 1979 for use with programmable logic controllers (PLCs). According to Drury, Bill (2009). Control Techniques Drives and Controls Handbook, (2nd ed.). Institution of Engineering and Technology, it is now a commonly available, royalty-free means of connecting industrial electronic devices.
54 See http://www.techhive.com/article/2099002/belkin-fixes-wemo-security-holes-that-gave-hackers-access-to-home-appliances.html and http://www.networkworld.com/article/2226371/microsoft-subnet/500-000-belkin-wemo-users-could-be-hacked--cert-issues-advisory.html
55 See http://www.infoworld.com/article/3137963/security/update-your-belkin-wemo-devices-before-they-become-botnet-zombies.html

individual smart meter is not of great concern beyond an individual subscriber, but GCHQ recently had to intervene to require improved security since there may be a potential vulnerability that could affect all smart meters. That would have been a serious issue[56].

Often, a determined attacker will use several of the above approaches. This could be seen with the attack on the power system in Ukraine which was months in the planning, with original phishing emails sent to employees many weeks before the actual attack to allow hackers to build a picture of the network and control systems. Employees at three utilities were then locked out of their systems while circuit breakers were opened to disrupt supply, with the firmware on the communications modules previously re-programmed to prevent remote access from being used to close the breakers again. This caused the actual outage. Two main control rooms also had their uninterruptible power supply (UPS) systems attacked, to ensure that the grid operators would have no visibility or control of their network through usual systems, causing further challenges in bringing the grid back up. The utilities' call centres were also attacked to prevent customers from reporting faults[57].

Another major risk is in the quality and security of software used – research has found a wide range of vulnerabilities within most systems, from firewalls and virtual private network (VPN) units (used to control and protect telecommunications networks) by Juniper[58], Cisco[59], Fortinet[60] and others, through to the industrial control systems themselves[61]. These kinds of vulnerabilities throw into question the security assumptions made by operators of energy networks, where it is assumed that firewalls and other networking equipment are secure, and that VPN systems used will prevent unauthorised parties from entering. With VPNs widely used for remote site administration and access, this presents a major risk, especially when, in order to avoid outages or loss of access, energy network users do not routinely update the software on these devices.

A final risk is around the application of policies and procedures – network operators have a variety of information available to them from the Centre for the Protection of National Infrastructure (CPNI), the National Cyber Security Centre (NCSC) and other sources such as

---

56 See http://www.theinquirer.net/inquirer/news/2451793/gchq-intervenes-to-prevent-catastrophically-insecure-uk-smart-meter-plan
57 See https://www.wired.com/2016/03/inside-cunning-unprecedented-hack-ukraines-power-grid/
58 See https://www.engadget.com/2015/12/17/juniper-networks-finds-backdoor-code-in-its-firewalls/
59 See http://arstechnica.com/security/2015/10/backdoor-infecting-cisco-vpns-steals-customers-network-passwords/
60 See http://arstechnica.com/security/2016/01/et-tu-fortinet-hard-coded-password-raises-new-backdoor-eavesdropping-fears/
61 See https://www.wired.com/2013/10/ics/

the Energy Networks Association (ENA), but these guidelines are typically designed at a high level, for management use, focused on the building of policy. There is very little information available for practitioners to refer to and implement, in order to ensure the practical security of the systems they deploy, for example, in setting up a VPN in the field, and to ensure the security assumptions they make are valid and acceptable. There is also a major risk caused by the conflict between availability and security. While in the IT space, confidentiality is the priority, followed by integrity and finally availability, in the industrial control sector the priorities are reversed: availability first, then integrity, then confidentiality. Afraid of outages, providers often do not wish to enforce strong security policies that might result in a false-positive causing a loss of service. This extends to a general attitude of not patching working systems. Combined with lack of visibility of the installed equipment-base, this leads to widespread use of outdated, unpatched systems within substations and other secondary sites, where equipment affected by many vulnerabilities sits unmonitored.

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

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

In our view, the drivers for change are broadly correct.

We would be inclined to add the following to the list of requirements:

- Openness to innovation. Given the content of Chapter 6, this is clearly the intention, but it is not immediately evident from this diagram.
- Governance arrangements that facilitate broader consumer engagement. The complexity of some of the issues should not be allowed to obscure the need for greater consumer engagement and accountability.
- Tariff structures appropriate to consumers. Some of the other emerging requirements might be read to imply that the aim is simply to produce cost reflective prices for all system users. There is a broad recognition that highly complex tariffs for all household users is not a realistic objective. Of course, simplified tariffs may make the delivery of other emerging requirements more difficult, but we believe that the implications of complexity should be recognised at the outset.

Based on the analysis in the Call for Evidence itself and other parts of this response we think it would be helpful to add the following to the list of drivers for system change:

- Storage, meaning two-way storage (capable of converting to and from electrical energy) which provides a means of addressing variable 'net demand' but also represents a potential alternative to network capacity or a complement to it. The costs of various technologies are falling and performance improving so it is clearly one of the "new flexible technologies" and may warrant explicit recognition.

Another factor that might be regarded as a driver for change is the growth of interest in "local energy systems" that are currently seen by many, primarily outside the electricity industry, as desirable, not least as a way of overcoming what are seen as barriers to connection of DER. There is a risk, currently attracting much attention in, for example, the US and Australia, that distribution use of system charging based on annual energy transfers rather maximum power exchanges risks either under-recovery of network costs or placing an excessive cost burden on distribution network users that lack the means to reduce their import of electricity from the network. This danger seems to be recognised by Ofgem and BEIS in the discussion presented in paragraphs 15-23 of the Call for Evidence. However, "local energy systems" also present an opportunity. If they can be operated in such a way as to cap the import from or export to the network[62], they can contribute to the minimisation of network costs. Furthermore, they would represent another layer in the hierarchical approach to system operation we mention in our discussion of different models of interaction between transmission and distribution in our response to Q46. However, in order that whole electricity system costs can be minimised, it will be important that the characteristics of each "local energy system" are appropriately defined, e.g. any voltage or frequency dependency of the net transfer. There is also a need for developers of such local energy systems to be adequately informed on the costs and benefits of different network access options[63].

One further key element is perhaps missing: there are many possible ways of addressing the challenges presented, above all, by the very different patterns of generation emerging compared with what we had in the past. Large, schedulable, fossil-fuelled generating units are being replaced – partly by many weather-dependent, small generators, notably wind and solar. Their variability and the uncertainty of output plus rules that do not currently mandate monitoring for the smallest installations make system operation – the minute-by-minute balancing of generation and demand and the respect of network limits – very challenging. Appropriate pricing of services delivered and services used should be fair in taking into account both the contribution technologies make towards supporting flexibility and security and any consequential costs (e.g. for system balancing).

In principle, flexible demand can be an important, cost-effective tool in helping to manage the system. However, exactly how to encourage and utilise flexibility on the demand side is an open question. As we discussed in our responses to the questions posed in chapter 3 of the Call for Evidence, some mechanisms – 'indirect control' – rely on incentives such as price signals but leave an element of uncertainty as to the responses to those signals; others – 'direct control' – give greater certainty but are likely to be less attractive to the majority of energy users. As the various mechanisms get rolled out and before they become well-established and characterised, uncertainty regarding the daily variability of demand will grow. There is also uncertainty regarding the underlying level of demand for electricity associated with possible growth for, for example, electric vehicle charging and more electric heating.

62 Paragraph 22 of the call for evidence mentions one way in which this might be achieved.
63 This need is common to developers of any DER and represents a particular challenge in light of the small scale of developments and what is often a lack of prior knowledge on the part of the developers. We feel that DNOs can and should do more to help inform connection applicants. However, we also believe that it would be reasonable for DNOs to recover at least some of the cost of such support from applicants.

In simple terms, one manifestation of the main goal in accommodating future generation and demand is an objective to maximise the utilisation (across each year of operation) of electricity system assets, i.e. generators, network components and storage facilities.

Arising from the increased diffusion of distributed energy resources (DER), another omission from the drivers is the need for improved coordination between the National Electricity Transmission System Operator (NETSO) and distribution network operators (DNOs). Although new social, legal or commercial arrangements and improved monitoring down at lower voltages might not be strictly necessary to meet the growing challenges, in our view they are very likely to be critical to doing so at least total cost.

In respect of 'emerging system requirements', the system requirements listed in Figure 1 of the Call for Evidence are not just 'emerging' but have always been there. If that is the case, one might ask where the need for change comes from. As we noted earlier in our answer to this question, we believe it comes from changing generation patterns, in particular the increasing contribution from weather-dependent renewables and an increased number of smaller generators, many of which are distribution connected; the possible growth of demand for electricity to charge electric vehicles and to decarbonise some part of the demand for heat; and the need to accommodate those changes at least cost. This implies the active monitoring and control of a great many more connections to the power system, at all voltage levels, than are actively managed at present. Present day arrangements, in particular the fact that only the transmission network licensees have the established means in terms of facilities, processes and expertise to actively operate their systems and not just (as in the case of most current DNO practice) to respond to faults or to adopt isolated, simple examples of automated 'active network management' (ANM), at best risk a great deal of inefficiency in meeting future needs and, at worst, system instability and blackout[64]. New technologies need not be viewed solely as drivers of change; they can also be regarded potential contributors towards meeting emerging requirements. However, except where there is a clear need for demonstration and testing and where positive outcomes from such tests would allow appropriate future deployment to contribute to meeting system needs at least cost, new technology should not be deployed simply for its own sake and responsibilities for its ownership and operation should be clearly defined.

One might question whether *all* parties need to have visibility of existing and future network or what "appropriate visibility" means. There is much to be debated regarding which parties have visibility of how much. However, as a minimum, either the NETSO or operators of distribution networks need to have greater observability and controllability in respect of DER than they have now.

64 Some examples of potential problems are already being seen and are discussed by National Grid in the 2016 'System Operability Framework'.

44) Do you have any data which illustrates:

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

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

We first make some observations on what is listed in Table 7 of the Call for Evidence.

- More accurately, growth of distributed generation (DG) and technologies such as heat pumps or electric vehicles, do not lead to reduced network capacity but to reduced network capacity headroom or margin, the extent of which depends on location. Co-location of demand and generation is not, in itself, innovative but there are questions about how it is incentivised and how the different characteristics of generation, demand and storage 'behind' a meter can still be recognised such that the dynamic behaviour of the system as a whole can be modelled with sufficient accuracy.
- It is true that growth of DG can have adverse impacts on transmission. One example is, arguably (though with limited evidence, see below), in respect of high voltage issues. Another is in respect of transmission regions that are already net exporting and which, due to connection of DG, become even more net exporting. One general issue is simple lack of visibility of operational conditions down in the distribution networks.
- In Table 7, it is stated that "it is critical that there are appropriate data flows and coordination of investment planning between parties to mitigate the impact of [evolving generation and demand patterns] where possible." In our opinion, simple, concrete action to improve the quality of data exchanges between DNOs and National Grid is long overdue and should be undertaken regardless of any more radical reforms of networks and their regulation or commercial arrangements. As far as we understand, the main data exchanges between DNOs and National Grid are those required by the Grid Code. For example, schedule 5 of the Data Requirements section of the Grid Code requires DNOs to provide information to National Grid on forecasted demand (both active and reactive power) at each grid supply point, DG and the network characteristics relevant to the estimation of fault levels two voltage levels below transmission. As far as we aware, what is provided by most DNOs is very limited and, in some cases, inaccurate. For example, demands are provided only in respect of local peak and not in respect of year-round variation and have been seen to be inaccurate in respect of power factors (with consequences we outline below), and the assumptions made in respect of DG operation (which has the effect of reducing the net demand seen at a GSP) are not made clear. In our opinion, more extensive, clearer and more useful requirements in respect of data provision could

be written without too much difficulty and the DNOs should be required to comply with them.

The scale of impacts arising from changes to generation and demand patterns is difficult to determine. Quite how much new generation of different types will connect where by when and how demand will change by – say – 2030, is highly uncertain. The impacts are many – the need for network connections, for enhancement of network thermal capacities, for voltage control facilities, for more or faster frequency response and controlled generation or demand ramping, for revised system defence measures and for new black start services – and the modelling of them is highly complex[65]. Very few analysts in Britain have tried to quantify the impacts. Two studies of which we are aware are:

- "Managing Flexibility Whilst Decarbonising the GB Electricity System" produced by the Energy Research Partnership[66] which primarily addressed generation dispatch in 2030 and the potential costs of system inertia constraints or periods with an excess of renewable energy;
- "Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies" produced by Imperial College and NERA Economic Consulting on behalf of the Committee on Climate Change (CCC)[67].

Both of the above studies use highly simplified system models. The first makes no attempt to model network limits or inter-temporal constraints on generation whereas the latter does, at least to some extent. Relatively simple models can provide useful insights and are an essential first step to understanding where the key issues and sensitivities lie and help to better articulate the objectives of further modelling. The first of the above reports is open about the assumptions made but the second report, which is similar to analysis by the same authors for the National Infrastructure Commission, E3G and Drax, requires careful reading to appreciate which factors have been included in the modelling, how that modelling has been done and where the data have come from.

One particular challenge faced by the authors of the above reports, and anyone else attempting to develop evidence highlighting the extent of the challenges the power system faces or in support of particular interventions, is access to relevant data describing the GB power system now from which possible future scenarios can be developed. This is hindered

---

65 For discussion of power system modelling challenges such as in system planning or the representation of power electronics, see http://www.theiet.org/sectors/energy/resources/modelling-reports/papers.cfm

66 See http://erpuk.org/project/managing-flexibility-of-the-electricity-sytem/ and a commentary on the report here: http://www.ukerc.ac.uk/publications/security-of-electricity-supply-in-a-low-carbon-britain.html

67 See https://www.theccc.org.uk/publication/value-of-flexibility-in-a-decarbonised-grid-and-system-externalities-of-low-carbon-generation-technologies/

by much of what is required to model the GB system being regarded as "commercially confidential". This includes data as diverse as the parameters of generator transformers connected to the transmission system, where automatic voltage control is or is not used on distribution networks and the levels of demand that can be seen at 11kV substations. Lack of access to relevant data by parties other than the network licensees places a high dependency on studies conducted by the licensees, requires other parties such as academics to make assumptions that might not be robust (thus invalidating their findings), prevents licensees' findings from being challenged and hinders innovation.

In 2014, Workstream 7 of the Smart Grid Forum launched a project – "DS2030", funded through the Network Innovation Allowance[68] – aimed at future needs of the distribution networks were identified with consideration of both traditional and non-traditional reinforcement (i.e. 'smart' solutions). Even though not all of its original objectives were met, this project has succeeded in developing some clear and, we believe, useful learning for distribution planners and has demonstrated the value of access to models and data (discussed further in the Appendix to this response).

One example of system problems that came as a surprise to the system operator due to poor data has been that of high voltages on the transmission network at times of low transfers of power from transmission to distribution. It has led to considerable sums of money being spent on constraining on transmission connected generation in order that they can absorb excess reactive power and to proposals for investment in new shunt reactors being formed too late for the normal price review cycle[69].

Normally, the transmission network investment planner would use forecasts of future scenarios to make a judgement on whether the system would be operable in compliance with the Security and Quality of Supply Standard (SQSS) using existing facilities (and what the operational cost of such facilities would be) or if there would be economic justification for investment in new network facilities. Future demand, both active and reactive power is a key dimension of each future scenarios. In practice, we understand that what transmission planners typically use is simply the 'net demand' as seen at the interface between transmission and distribution, i.e. at the grid supply points (GSPs) and that they depend on DNOs' schedule 5 submissions (mentioned above) for the relevant values at each location. Our understanding is that the investment planners believed that the system would be operable in the coming years. However, when the time came, the system operator observed

---

68 See http://www.smarternetworks.org/Project.aspx?ProjectID=1623#downloads
69 The result of this is that the associated capex allowance is not part of normal price control settlement. A transmission owner must then either fund the investment itself or seek approval for an 'income adjustment event'. We understand that National Grid did the latter but that its request was rejected in the summer of 2016.

that the ‘net’ GSP demand was lower than had been expected and that the net reactive power demand was significantly lower than expected. This and very low power flows on the transmission network resulted the network’s shunt reactive power gain being significantly higher than the series reactive power loss and, as a consequence, surplus reactive power and excessively high voltages. If allowed to persist or get worse, high voltages can lead to breakdown of electrical insulation, excessive fault levels or tripping of generation.

To address reasons why the GSP demands, in particular the reactive power demands, were so low, National Grid initiated a Network Innovation Allowance project, ‘REACT’, in collaboration with a number of DNOs[70]. The main findings were, seemingly, that energy users’ loads connected within the distribution network use less reactive power relative to active power[71] than in the past (not reflected in normal forecasting and data exchange processes) and that data exchanges had failed to reflect changes to the distribution networks that results in the networks themselves having a lower net consumption of reactive power. There were also effects from operation of DG.

Experience in respect of the changed characteristics of loads and the distribution networks and impacts on transmission voltages shows the limitations of current processes. They also illustrate the need for improved coordination and data exchange between transmission and distribution if the more dramatic changes that many anticipate in respect of DER are not to be mismanaged.

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?*
- *b) How could industry best carry these activities forward? Do you agree the further progress we describe is both necessary and possible over the coming year?*
- *c) Are there any legal or regulatory barriers (e.g. including appropriate incentives), to the immediate actions we identify as necessary? If so, please state and prioritise them.*

We do not agree with the emphasis of paragraph 12 of the Call for Evidence that “the onus is on industry to address these requirements in the first instance”. The speed of many of the changes affecting the power system is a direct or indirect result of Government policy and the extent of likely future change is highly dependent on future policy, especially related to renewable generation and the electrification of transport and heat. As we note in our answer to Q15, we are not confident that the network licensees will drive changes to arrangements

70 See http://www.smarternetworks.org/Project.aspx?ProjectID=1861

71 That is, the power factor is closer to 1 and the ratio of reactive power (Q) to active power (P) is smaller.

for the planning and operation of the electricity system at the necessary rate. BEIS and Ofgem can and should play a major role in providing clarity and leadership not just on system issues, but also on the developments independent of the network licensees that are the fundamental drivers of change.

The Call for Evidence notes that "We recognise that [services such as load reduction through reduction of distribution network voltages] need to operate on a level playing field with other flexibility sources and will continue to monitor arrangements to ensure they work in the interests of consumers." There are different aspects to a 'level playing field' in respect of services. This can mean that services:

- can be compared in a clear, consistent and fair way;
- have equal entitlement to fair remuneration.

Fair remuneration means that reasonable costs can be recovered but should not mean that payment is made for services that incur no costs. An example of this is utilisation of the inherent capability of generators in such a way that has no impact on ability to sell energy or on operating costs, e.g. utilisation of the normal reactive power capability that is available at maximum active power output.

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?

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

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

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

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

We offer some answers to these questions under five headings:

- Some initial comments on chapter 5 of the Call for Evidence
- Actions on distribution networks: asset-based interventions versus operational measures
- Incentives and access to information
- Different models of interaction between transmission and distribution
- Key questions to inform future arrangements

<u>Some initial comments on chapter 5 of the Call for Evidence</u>

The Call for Evidence says “DNOs must engage to understand the requirements of their stakeholders, including traditional generators and demand customers, as well as local authorities, community groups and other interested parties.” In our view, that is true but it is not quite enough just to say “must engage”. Many DNOs claim that they already do engage. What, precisely, should they be seeking to learn or to help stakeholders to learn?

Ofgem/BEIS “see value in transparent and integrated markets. We expect to see such approaches used wherever it is most efficient to do so.” This seems reasonable to us, but one key point of argument is who buys services, in particular: the NETSO, or DSOs?

The Call for Evidence points towards possible models for activities in relation to ‘Network Planning’ and ‘efficient local/system-wide use of resources’. We believe that care should be taken that "network planning" and system operation/utilisation of resources are not seen as two, entirely separate things. The purpose of network planning is to enable system operation such that the long-term total cost of assets and operational measures is minimised (subject to a reliability constraint if that is not somehow costed in the operational measures).

The Call for Evidence mentions “creating a signal for flexible resource that could turn up demand to help match generation in that local area. Alternatively, changes could be made to system access arrangements, such that pricing for a given level of access more dynamically reflects system constraints, and to give consumers greater choice over their preferred level of access.” This is all good in theory, but it only works in practice if parties affected by signals have the ability to respond to them. Also, “market participants would react in response to the price signals”. The usefulness of this depends on the extent to which prices reflect problems that are coming rather than those that have already arisen, and if they do only the latter, whether the time lag in responding to the signals puts reliability of supply at risk.

One thing the Call for Evidence highlights is the possibility of DSOs contributing to the management of system frequency. One way in which this could be done would be by procurement within their areas of certain proportions of the total response (and reserve) requirements. That would be analogous to how it is done in the European synchronous area and was done in GB prior to the British Electricity Trading and Transmission Arrangements (BETTA). However, the European arrangement is being increasingly criticised on the grounds of (a) failing to take account of 'imbalance netting' between different areas and (b) failing to procure the most cost-effective resources for response and reserve.

<u>Actions on distribution networks: asset-based interventions versus operational measures</u>

Through price signals or liabilities for network reinforcement costs, DER can be strongly disincentivised either from seeking a connection in a particular place or from connecting at all. If there are other, more suitable locations with available network capacity that the connectee can use, the connection can be made without a need for deeper reinforcement; provided the cost of re-orienting the DER for a different location is not excessive, from the perspective of total system cost or total social welfare this gives the ‘right’ outcome. However, as the volume of connected DER increases, the amount of available network capacity is likely to become exhausted and some reinforcement would appear to become necessary. In this case, though, a ‘fit and forget’ approach is unlikely to maximise social welfare. Both demand and the power available from generation vary in time and some temporary restriction of utilisation of the available DER is very likely to reduce the necessary enhancement of network capacity. As illustrated in Figure 3, the optimal level of network capacity is that at which the incremental cost of network capacity (arising from asset-based interventions including ‘build options’) equals the incremental value of avoided DER curtailment (where curtailment is an example of an operational measure or ‘non-build option’).

Occasional and temporary restriction of the operation of DG implies a more ‘active’ operation of a distribution network than has usually been the case in the past, and a need for the network operator to be continually aware of the network’s state and to be able to send a signal to the DG to change its operating point. Rather than increase staffing levels in the control room, many DNOs have sought to achieve this via automated ‘active network management’ (ANM). Where both the network constraint and the DG action to relieve it are very clear, this can be straightforwardly implemented via measurement of the relevant network state and a signal sent directly to the DG control system, analogous to automatic generation control (AGC) used on some transmission systems for decades. More robust forms of ANM will include some ‘failsafe’ rules for modification of the DG set-point in the event of, for example, failure of communication of the network measurement. Furthermore, some are now being designed to include the measurement or estimation of real-time thermal ratings. However, because it is – for them – a new approach, DNOs have tended to make use of innovation funding to help pay for ANM. According to UKERC and HubNet’s review of LCNF projects[72], ANM is now regarded as a credible ‘business as usual’ option to offer to DG connection applicants.

72 See : http://www.ukerc.ac.uk/publications/a-review-and-synthesis-of-the-outcomes-from-low-carbon-networks-fund-projects.html

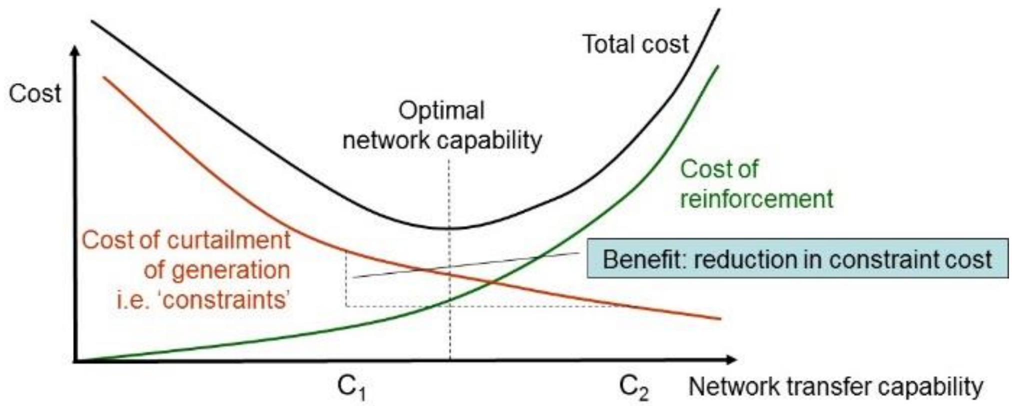

Figure 3 – the economic level of network capacity

The benefits of ANM to connection applicants are (i) the reduction of the cost of the connection and (ii) reduction of delays to connection that may arise due to the need for planning approval for a conventional network reinforcement and its construction. However, experiences of some DG operators suggest some problems: (i) levels of curtailment are greater than they were led to expect by the DNO when they accepted the ANM-based connection offer; and, if they apply to connect in to a part of the network already subject to an ANM scheme, they are curtailed more than the party that connected first.

Other potential interventions by DNOs designed to maximise the utilisation of existing infrastructure, facilitate access and reduce or defer the need for network reinforcement include the more general use of real-time ratings (and the associated necessary monitoring) of overhead lines, transformers or underground cables, network reconfiguration, i.e. movement of normally open points, and use of energy storage or flexible demand. However, according to the UKERC and HubNet LCNF review, few of these are currently regarded by all DNOs in Britain as established 'business as usual' options. While solutions like ANM provide a deferral to network upgrades in the near-term, the long-term optimum trajectory may involve more network investment than is immediately apparent. In order to determine whether future bottlenecks in implementation[73] might impede achievement of emissions targets, any major decarbonisation trajectory requires assessment of the rate at which infrastructure changes should be enacted[74]. For this reason, the RIIO process should take into account the longer-term energy transition rather than purely the goals of the immediate submission period.

73 This includes the equipment supply chain, construction and commissioning resources and network access.

74 One example relates to heat decarbonisation. One option for that would be extensive roll-out of heat pumps the delivery of which and any consequential upgrades to distribution networks would place great pressures on supply chains. Another long-term option would involve use of hydrogen which, in turn, would also require extensive changes to equipment.

In seeking to achieve market-led and competitive measures, it should also be borne in mind that in certain (remote or highly urbanised) parts of the network, the number of local market participants may be highly constrained and limited to a small set of commercial operators. This creates potential for market power. However, potential for market power in respect of flexible resources also exists in cases where particular generators, aggregators or suppliers gain dominance in any particular location.

Additionally, network planning needs to consider all vectors (electricity, gas, heat) as decarbonisation trajectories imply a greater interaction between systems. The costs and benefits of changes to energy services across all vectors may not be balanced. There is no specific mention in the Call for Evidence of heat strategies, which may be a key driver of DNO planning and operational scenarios.

<u>Incentives and access to information</u>

ANM-related connection offers are typically 'non-firm' in that the connectee receives no compensation for curtailment. The business case for a generation development, for example, then depends entirely on how much energy can be physically exported and sold compared to the costs of the development, not how much energy was available. Greater than expected curtailment may mean that the costs cannot be recovered. Under such circumstances, the connectee may be well advised not to depend on the DNO's forecasts of curtailment. However, few connectees have access to information on the network's configuration and limits. In addition, many developments are within groups that include at least some demand where the network constraint concerns the net export, and the connectee again lacks time series of demand to compare with available generation output. Furthermore, both generation and demand can be quite different from one year to the next, e.g. due to variations in weather. In other words, under typical arrangements in GB, the DG developer carries all the risk and the DNO carries none. Although it might be argued that the DNO's regulatory settlement and cost of capital are predicated on low or no risk, there would also appear to be, aside from whatever behaviour is driven by the 'totex' element of RIIO (see the discussion below), no strong incentive to innovate to find cost-effective solutions to problems in the overall best interests of energy users. On the other hand, one general economic principle is that risk should be borne by those parties best placed to manage it. In the case of risk associated with operation of the network, it should be self-evident that the DNO has better access to information to enable its management than the operator of a connected DG.

One key to the success of any future arrangement is whether it enables – or encourages – the correct balance to be struck between 'asset-based' solutions that require capital expenditure, and operational measures. Usually, a correct decision depends on having access to all relevant information as well as incentives that drive towards lowest whole system cost (including both investment and operational costs over the medium to long term) or maximum social welfare. In that context, the following questions might be asked in respect of decisions affecting distribution and who takes them:

- Does the NETSO have enough knowledge of actual conditions on the ground within distribution networks, which options are feasible, and what they are likely to cost?
- What scope is there for changing an option in light of better information, e.g. regarding the actual cost (that becomes apparent in light of detailed design work or a procurement process) of the option that was initially chosen?
- If the DSO/DNO is still making a decision and only needs to 'consider' the NETSO's assessment, why does the NETSO need to be involved?

The present regulatory environment would seem to be relevant. One of the features of RIIO regulation[75] for the distribution licencees is that there is a 'totex' allowance (rather than separate capex and opex allowances[76]) which, in principle, allows a DNO to compare asset-based interventions with operational measures and to adopt the cheapest means of complying with basic licence requirements. However, this is different from the apparent direction of decision making and responsibility at a transmission level where the trend is towards a cost-benefit analysis comparing possible asset-based interventions with operational measures being carried out by one party (the NETSO) but final decisions on capital expenditure and the detailed design of new network facilities being left to a different party, either one of the three incumbent transmission owners or, as introduced under the 'Integrated Transmission Planning and Regulation' (ITPR) initiative, a 'Competitively Awarded Transmission Owner' (CATO). It is our understanding that one of the starting assumptions for ITPR is that, as a consequence of a large part of their income being determined by the size of the asset base, network licensees are always incentivised to over-invest in assets[77].

As well as the assumption that network owners have perverse incentives there is an implicit assumption in ITPR that the NETSO is, and always will be, competent to carry out its duties in the best possible way. An enhanced role for the NETSO – whether as an Independent System Operator (ISO) or not, whether for-profit or not – increases reliance on a single monolithic service provider. How can it be encouraged to innovate and improve? What benefits might come from having a range of parties all fulfilling similar functions (albeit

75 RIIO stands for Revenue = Incentives + Innovation + Outputs
76 'Capex' is capital expenditure, 'opex' is operating expenditure and 'totex' is total expenditure.
77 Our opinion is that this incentive, while a relevant consideration, has been over-stated. For some discussion, see Transmission-distribution coordination and transition to more actively operated distribution: why it matters, Keith Bell, UKERC 2017

perhaps with spatially delineated scope) whose performance can be compared one with another?

The NETSO or an ISO with an enhanced role in respect of operation of distribution networks will, in the short-term at least, be dependent on the DNOs for provision of information. DNOs are supposed to provide a certain amount of data now but, as far as we are aware, it is not done well. (See our answer to Q44). Why is this? Is it because there is no incentive to do it well or no penalty for doing it badly?

Different models of interaction between transmission and distribution

Some authors, e.g. Bell in a paper on future distribution system operation[78], have proposed that management of large numbers of actors and system states might be effectively managed through the delegation of the management of sub-systems to different parties. The key to such a hierarchical approach is the definition of where the interfaces between layers of the hierarchy lie and how the relationships between different parties interacting at that interface are managed. The key to the latter is exactly what information is exchanged and how often. Perhaps the most obvious locations for interfaces are (a) across different voltage levels and (b) across minimal cutsets[79]. The information passing should be as infrequent as possible and involve as little data as possible but not so infrequent or minimal as to be useless.

DeMartini and Kristov in California have outlined some models for future distribution operation, real-time facilitation of DG and interaction with the wider electricity system[80]. These are:

- Model A – "Total ISO" in which an independent system operator (ISO) models and optimizes the whole system, with visibility of distribution grid conditions and all DER above a low size threshold, e.g. 0.5 MW modelled at actual locations. In this model, a DNO has minimal new functions, its operational role being limited primarily to ensuring safety and the reliability of assets.

78 Keith Bell and Simon Gill, "Enabling distributed energy resources: Priorities for future active operation of distribution networks and interactions with transmission", accepted for CIRED 2017, 24th International Conference on Electricity Distribution, Glasgow, 12-15 June 2017.
79 A 'cutset' is a set of branches of a network that, if removed from the network, would completely disconnect a source of power from a sink. A 'minimal cutset' is a cutset in which all the branches in the cutset must be removed from the network in order to carry the disconnection of source and sink.
80 Paul De Martini and Lorenzo Kristov, Distribution Systems In A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight, Berkeley Lab, October 2015.

- Model B – “Minimal DSO” in which an ISO optimizes the whole system, including large numbers of small DERs, but models DERs only at the transmission-distribution (T-D) interface with little or no visibility into the distribution system. In this model a DNO has a significant coordination role, managing DER responses to ISO dispatches as well as DER services provided to the distribution network.
- Model C – “Market DSO” which maximizes the DNO role in operational coordination, i.e. in the terms used in GB, it becomes a DSO, and minimizes the complexity for an ISO’s optimization of the system. This model has two variants – C1 and C2. In Model C1, the ISO sees only a small number of aggregate DERs at each T-D interface; a DSO is the coordinator of various aggregators. In Model C2, the ISO sees only one resource at each T-D interface; a DSO is the aggregator for all DERs below that interface.

The electricity regulator in the state of New York in the US is encouraging potentially radical reform of the electricity market in its ‘Reforming Energy Vision’ (REV)[81]. Its primary feature is an extension of centralised wholesale electricity trading based on locational marginal pricing down to low voltage nodes within distribution networks for which the main challenge is seen as the development of a suitably large and powerful software platform capable of managing hundreds of thousands of data points and computing and communicating locational marginal prices (LMPs) at regular intervals.

In Britain, SP Energy Networks has published a “DSO Vision” in which four possible operational models are outlined, shown in Figure 4 in respect of their relative positions vis à vis observability and control of DER by a transmission system operator or a DSO:

1. “Total TSO”
2. “DSO DER manager”
3. “Transmission support”
4. “Total DSO”

81 See http://rev.ny.gov/

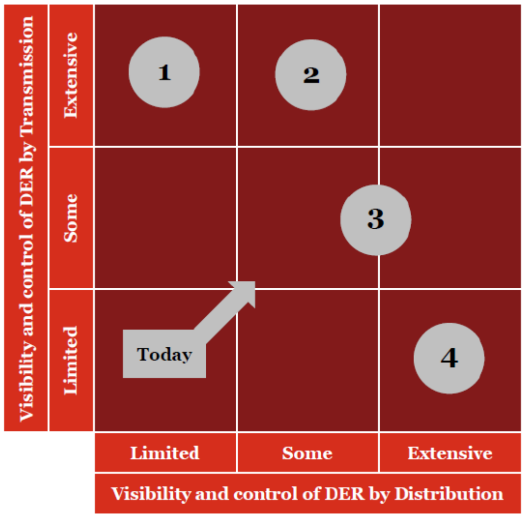

Figure 4– system operation models from SP Energy Networks' "DSO Vision"

Key questions to inform future arrangements

Future arrangements for energy trading and system operation should be structured such that:

- there is competition and choice for consumers;
- the system can be safely operated in accordance with relevant physical limits;
- consumer access to the system is enabled;
- the overall cost of the system is minimised with use made of suitable signals, such as locational prices or tariffs, aimed at parties able respond to them;
- there is scope for innovation.

Some corollary questions arise from these objectives:

- What contributions can DER make to ancillary services and which party or parties are best placed to procure them, e.g. a transmission system operator or a DSO?
- Is the facilitation of peer-to-peer trading in real-time or near real-time a worthwhile and realisable goal, or does forward trading suffice to give the main useful signals?
- Can owners/operators of DER interact with and respond in a rational way to signals such as half-hourly locational pricing, or do the smallest parties require specialist agents, e.g. aggregators, to act on their behalf or order that risks can be managed?
- Which arrangements provide adequate signals to investment in additional network facilities and which parties, e.g. regulated network owners, should respond to such signals?

The models set out by DeMartini and Kristov acknowledge the scale of the data management challenge. In principle, a "Total ISO" (Model A) might model and control the whole system down to within the distribution network. However, DeMartini and Kristov describe this as "not practical, due to operational complexity, system control challenges, and regulatory jurisdiction issues". Model B – "Minimal DSO" – addresses some of those problems through an ISO modelling only the effect of each DER at the transmission-distribution (T-D) interface with the DSO responsible for articulating those effects and implementing any DER actions called upon by the ISO. In our opinion (which should be tested by relevant modelling), one problem is that, by virtue of the nesting of different network limits and the non-linearity of voltage/reactive power limits, the effect of each DER at the T-D interface and the margin for variation is not the same for each one and actions taken with respect to one DER change the margin for available in respect of another, i.e. the headroom for increases and footroom for decreases,. While approximations are possible, the lack of accuracy in the model is likely to entail other, 'outside the market' re-dispatches or a very conservative setting of limits meaning that the cheapest resources will be under-utilised.

Model C – "Market DSO" – further reduces the number of variables seen by the ISO by articulating only the aggregate effect of all DER at each T-D interface (in GB terms, each grid supply point) such that, in variant C1, there are very few and, in C2, only one virtual DER at each location. Unlike the earliest ideas of virtual power plants (VPPs), this virtual unit has a physical meaning with location as well resource specific active and reactive power limits. In this model, the ISO (or, in GB, the NETSO) optimises its system up to T-D interface. As well as quantifying the planned, scheduled or forecast physical position of the virtual DERs, the DSO quotes an envelope of allowable changes and associated costs. Unlike in Model B, it is responsible for buying actions from individual DERs in response to changes bought by the ISO and makes use of a more detailed model of the distribution network than would be used in Model B. That is, in essence, it optimises the local system to satisfy a given interchange at the substation. This is similar to the hierarchical model outlined above which goes a step further in recognising that there can be nested groups within each group of aggregated DERs with different progressively more local DSOs managing details behind each interface.

The New York REV platform model is, in effect, a version of the "Total ISO" with a single, all-encompassing, market arrangement cleared by a central algorithm. However, there remains the challenge of deciding how finely grained this should be: should it include, in the extreme case, every toaster when there is the possibility, as DeMartini and Kostov put it, of "diminishing returns to complexity"? It should also be noted that a centralised market clearance in a physical constrained system is only as good as its model of the system. Just as with zonal pricing, to neglect some details of the system means losing the price signals arising from the limits that are not modelled resulting in a need for a system operator to take action 'outside market' to respect those limits. Distribution networks in most countries at present are not modelled at all at lower voltages; to extract and reconcile data from often very old and sometimes incomplete paper records is a major challenge. Then, there is the possibility of congestion being relieved by network reconfiguration, i.e. opening and closing of open points, actions that introduce integer variables into an optimisation used to compute locational marginal prices. Finally, there is the ever-present exposure to the exercise of locational market power.

A not inconsiderable amount of consumers' money, through various innovation funds, has already been spent by DNOs in Britain on building up network models, with more funding still sought. But, as far as we are aware, there has been little evident sharing of the methods between DNOs. Moreover, as far as we are aware, these models are 'static' in that (a) they are not updated in real-time as operational conditions change and (b) they do not include 'active operation' actions that a DSO might take. In addition, our understanding is that the NETSO has been investing in a new energy management system that is intended to include new system optimisation features but is yet to be delivered and does not include any additional 'reach' into the distribution networks. In other words, in spite of the sums already spent on system modelling, considerably more would need to spent regardless of which future system operation model is adopted. In our view, the deliverability and maintainability of the associated ICT systems should be part of the evaluation of models of future system operation and how the transition from current practice can be achieved. One aspect that should be considered is whether the risks associated with one large, all-encompassing ICT system would be bigger or smaller than those associated with a number of smaller systems that have defined interfaces allowing interactions between different network utilities to be managed and whether the latter approach would allow concepts, data exchanges and software to be trialled on a smaller scale before being rolled out more widely.

6 Innovation

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

Further innovation will be essential if the potential of system flexibility is to be realised, and broader energy policy goals are to be met. Against this background, we welcome the increasing role that Ofgem has played in providing incentives for innovation over the past few years. The Low Carbon Networks Fund (LCNF) is a notable example, and has been cited in the Call for Evidence as the source of much of the evidence that underpins BEIS and Ofgem work on smart, flexible systems.

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

UKERC and HubNet commissioned and recently published a systematic review and synthesis of LCNF projects[82]. Therefore, we have based our answer to this question on some of the main findings from this review. Its main findings can be summarised as follows:

- 'Active' management of generation connected to the distribution network and flexible industrial and commercial demand should both be viable 'business as usual' options.
- Voltage control equipment, which has performed well in trials, could be used more often and can release network capacity more cheaply than historical 'fit and forget' solutions.
- Battery storage is not yet cost-effective, and flexible domestic demand not yet effective in avoiding the need for network reinforcement. Both innovations require further development both in terms of implementation and the commercial frameworks within which they might be used.
- The DNOs reach mixed and sometimes contradictory conclusions on other innovations such as real-time thermal ratings of network branches and network reconfiguration for power flow management.
- Many LCNF projects focussed on equipment that was, to date, unfamiliar to DNOs in Britain. Knowledge has been gained on commissioning and operational performance, but more now needs to be done on system level methodologies and business processes such as optimal operation, support for investment decision making, and commercial and regulatory frameworks.

The UKERC/HubNet review recommended that support for network innovation is continued in order that learning can be built upon and the revival in DNOs' ability to lead research,

---

82 See : http://www.ukerc.ac.uk/publications/a-review-and-synthesis-of-the-outcomes-from-low-carbon-networks-fund-projects.html

development and demonstration is consolidated. Furthermore, it recommended that work in understanding potential innovations at medium 'technology readiness levels' (TRLs) should be recognised and rewarded even if the TRL advancement does not immediately lead to full commercial deployment of the technology. It also urged a deeper appreciation by both network licensees and Ofgem of the scientific process in particular in respect of (a) the design of trials/experiments in order that robust evidence can be gained and (b) the clear reporting of results, including of those innovations for which were results were not what was expected.

The main original definitions of TRLs have come from aeronautics sector in which safe, reliable operation in a 'real world' context is paramount. Other definitions agree with this but add in a further distinction between a TRL of 8 and one of 9: 'commercial viability', of which one main test is whether investors have confidence in it and the ability to make a return on an investment. In other words, in some cases all that might be required to move from TRL 8 to 9 is that investors are given access to some evidence that changes their *perception* of a technology or business process.

We believe that rewards for success should recognise the relative risk and uncertainty involved in developing ideas and trialling innovations at different TRLs and should place an appropriate balance of emphasis between: good project management; the quality of evidence produced and conclusions on how a TRL has been progressed; what TRL an innovation has reached; and whether investment is justified in seeking further TRL progress. However, we would also urge caution when Government or Ofgem are asked to fund 'demonstrations' of expensive technologies or processes that have not yet reached a TRL of 7 or 8 or for which the following are not defined: (a) the learning outcomes expected from the demonstration and (b) the path to commercial viability or 'business as usual' that is anticipated given a positive outcome from the demonstration. Such innovations are likely to benefit from smaller scale testing or desktop analysis that can inform subsequent demonstration work; provided such testing and analysis are specified and conducted well and the results are properly disseminated, we no reason why testing or analysis of promising innovations at TRLs of lower than 8 should not be funded through Ofgem-led funding schemes.

However, the transition to a low carbon electricity system could be achieved with lower costs if some technology or process risks are taken in the short to medium term. An important lesson from LCNF is that such risks should be built in to innovation programmes. The government and regulator therefore need to accept that there will be some innovations that, while initially appearing to be positive, turn out to be more expensive or problematic to commercialise. Therefore, in encouraging DNOs to be innovative, publicly funded innovation programmes should not penalise them for individual innovation 'failures' – and should be concerned with ensuring that a portfolio of projects are funded that, taken together, meet the overall programme objectives.

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.

The four areas outlined in the Call for Evidence are good priorities for future support. Our review of LCNF highlights some others in addition to these (see summary above, for example). An advantage of these priorities is that they are not wholly concerned with technological innovation. As the Call for Evidence illustrates, realising the potential of smart, flexible electricity systems is partly about the development and deployment of new technologies, and partly about the new market arrangements, business models and social relationships that are likely to accompany those technologies. This is particularly relevant to the automated DSR and flexibility trading themes.

If future funding focuses on these areas, a number of considerations should be taken into account:

- The desirability of a balanced portfolio of individual projects across these themes;
- The need to ensure that individual innovation projects take proper account of their relationship to the system as a whole; and
- The importance of supporting projects led by a range of different firms and other actors

The third of these considerations is a response to one of the potential downsides of Ofgem's innovation programmes. For good reasons, they have focused on encouraging innovation in regulated network companies. Whilst this has strengthened the capacity of these companies (particularly DNOs) to innovate, it has also tended to lead to rather incremental innovations. Having complementary funding available (e.g. the £50m available directly from BEIS) will enable this innovation programme to support projects that are not led by DNOs – and provide much needed support to new entrant firms, for example.

7 Appendix: access to data

Much of the Call for Evidence asks for evidence to support assertions. This is, in our view an entirely reasonable request and is made more explicit in question 44 which asks the following.

> Do you have any data which illustrates:
>
> a) the current scale and cost of the system impacts described in table 7, and how these might change in the future?

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

Table 7 of the Call for Evidence lists and gives examples of various system impacts arising from changing use of the distribution network by connectees, use of distributed energy resources (DER) and increasing need for distribution connected resources to support system operation. Although some physical network demonstration projects, e.g. those supported by the Low Carbon Networks Fund, have observed some impacts of distribution connected resources, the scale of what can be observed on the actual network to date is limited, both because the number of DER installations is very far from having reached the level that can be expected in the coming years, and the range of different conditions in which they have operated (e.g. different times of year and different weather conditions) has been too limited to have statistical significance. A significant degree of modelling is therefore required (as it would be, in any case, if key relationships between observed DER behaviour and system impacts are to be inferred).

As we note in our answer to Q44, one particular challenge faced by anyone attempting to develop evidence highlighting the extent of the challenges the power system faces or in support of particular interventions is access to relevant data describing the GB power system now from which possible future scenarios can be developed. This is hindered by much of what is required to model the GB system being regarded as "commercially confidential" even though, in our opinion, it is hard to envisage in respect of much of it quite what commercial advantage might come from having it or commercial disadvantage from come from disclosing it. Lack of access to relevant data by parties other than the network licensees places a high dependency on studies conducted by the licensees, requires other parties such as academics to make assumptions that might not be robust, thus invalidating their findings, prevents licensees' findings from being challenged and hinders innovation.

In this Appendix, we give some examples of what we see as good and practice in respect of making data available to independent analysts.

Good practice

SP Energy Networks' "Flexible Networks" LCNF project

Flexible Networks for a Low Carbon Future was a Low Carbon Networks Fund innovation project, led by SP Energy Networks. As part of the project, network monitoring equipment was installed in eight primary (33/11kV) and over 150 secondary (11kV/415V) substations in three test areas. Monitored quantities included voltage and current and derived quantities included real and reactive power and power quality. Measurements were generally taken at outgoing circuits, although in some cases transformers were also monitored.

For the purpose of evaluating real-time ratings of transformers, for certain primary substations, transformer temperature measurements were collected for part of the study period, as were weather measurements.

SP Energy Networks and the University of Strathclyde have been working towards providing access to the complete data set (which is hosted by the University of Strathclyde) in response to requests.

Data is generally tabulated at 10-minute intervals, although some substations and quantities are tabulated at 1-minute intervals. Not all substations were monitored for the complete study period, and there are known to be significant gaps in some data series.

Supporting information is also being made available as part of the data set, including more detailed descriptions of the monitoring approach; charts showing daily availability of data by substation; and distribution network diagrams and models.

DS2030 project managed through the ENA

As part of the RIIO-ED1 price control process[83], a software product developed and marketed by EA Technology, "Transform", was used to give estimates on the costs savings that might arise from use of 'smart' distribution network interventions. According to EA Technology, Transform enables DNOs "to optimise the investments they need to integrate smart grid technologies into existing networks, with the lowest possible amount of new engineering work and maximum cost-efficiency" and "draws on a number of factors including the operating characteristics of devices and their relationships to other technologies within a system"[84]. However, it is our understanding that significant doubts have been expressed by DNO engineers regarding the simplifications used in Transform.

In 2014, Workstream 7 of the Smart Grid Forum launched a project – "DS2030", funded through the Network Innovation Allowance – aimed at "addressing the modelling compromises that are inherent in Transform's parametric network modelling approach. Transform's parametric representation of typical distribution networks are to be converted into nodal models in order to explore, through appropriate network studies, how the Transform solutions 'work' and what currently unforeseen challenges might emerge"[85]. More explicitly, the work aimed at a more rigorous assessment of the technical viability of different 'smart' interventions and their respective costs and benefits than is possible using Transform.

83 See https://www.ofgem.gov.uk/network-regulation-riio-model/riio-ed1-price-control

84 See https://www.eatechnology.com/products-and-services/create-smarter-grids/transform-model%C2%AE

85 See http://www.smarternetworks.org/Project.aspx?ProjectID=1623

In September 2016, 4 network models (notably based closely on real-world networks) representing a spectrum of distribution networks from 132kV down to 11kV (but also including some domestic LV modelling) were made available via the "Smarter Networks Portal" in form that can be readily imported into a standard commercial power system analysis software package. The accompanying project reports are sufficient for external users to be able to work with and extend the modelling used in DS2030, and have already attracted substantial interest, permitting useful research to be undertaken on applying research to 'real-world' networks. It should be noted that the released models are not absolutely identical to the actual ones used in the DS2030 project, but that rather than block access altogether some minor amendments have been made to ameliorate commercial issues, and this is a desirable resolution to such concerns.

A mix of good and less good practice: a reduced GB system dynamic model

Most issues around stability of the electricity system and its ability to successful transition from one balanced state to another cannot be addressed with 'steady state' models that neglect the dynamics of the system and which determine, among other things, the volume of need for a number of different ancillary services. Although some steady state or 'quasi steady state' models might try to represent the effects of dynamic issues through the quantification of some additional constraints[86], quite what value to use for these constraints depends on more detailed dynamic modelling. However, while independent researchers can try to make use of generic dynamic models, they lack access to the details of control system configurations and plant parameters that would allow them to quote results for the GB system with any confidence[87].

Two of the main stumbling blocks are perceptions of commercial confidentiality and interpretations of certain clauses of the 1989 Electricity Act. In response to this, National Grid has developed a reduced model of the GB transmission network augmented with a number of dynamic generator and controller models, and made this available to academics to work with. We are aware of the model being published as early as in 2013. The latest version is a 36 zone representation of GB with generation, differentiated by type, and real and reactive demand evaluated for each zone. The model also includes equivalent branch impedances calculated via a reduction of the high voltage lines on the actual system as well as generic models of generator automatic voltage regulator (AVR_ and governor controllers for dynamic studies although there is no consideration of the dynamic performance of demand.

86 Recent analysis undertaken by Imperial College for the UK Government and the Committee on Climate Change uses such an approach.
87 For further discussion, K.R.W Bell, and A.N.D. Tleis, "Test system requirements for modelling future power systems", IEEE Power & Energy Society General Meeting, Minneapolis, July 2010.

National Grid's initiative to make a reduced GB system model available is very welcome but there seem to remain limitations to the model which in turn limit the confidence with which results can be interpreted. Earlier versions came with a limited set of documentation which detailed some of the underlying assumptions and showed a degree of validation in terms of generic AVR and governor models plus evaluation of system losses and fault level performance compared with National Grid's full GB model which were said to show an "acceptable degree of accuracy". However, we are not aware of any published validation of whole system response in terms of voltage profile or frequency response to certain fault conditions and the latest version comes with little explanatory documentation which again raises questions as to the suitability of the model for certain studies and makes interpretation of results difficult.

In a separate initiative, the power systems group at the University of Strathclyde, supported by some funding from the Engineering and Physical Sciences research Council and UKERC, has been working on the development of a different, simplified representation of the GB transmission network (intended to give a more realistic picture of network thermal limits than would come from a network 'reduction') and used generic generator and controller models 'tuned' to approximate the kinds of responses to certain, critical disturbances that would be expected on the actual system. The researchers have received welcome support from SP Energy Networks on testing of the model and some advice from National Grid on scheduling of frequency response and modelling of loads. They intend to make the finished model available to researchers in other institutions. (Draft versions are already available).

Poor practice: the REACT project

As part of our response to Question 44 of the Call for Evidence, we described a recent Network Innovation Allowance project – 'REACT' – established to address reasons why the GSP demands, in particular the reactive power demands, were so low[88].

The budget for the project was around £315k. A research group was engaged at the University of Manchester to address the main questions over a two-year period. We understand from them that almost all of their time was taken up in assembling models of a limited number of DNO areas and relatively little spent exploring potential solutions to problems and their potential costs.

It may seem surprising that DNOs do not already have extensive 'load flow' models of their networks, but historic operational practice has generally not required it for lower than 132kV or, depending on the location, 33kV. Given the growth of DER and the need for more extensive active operation of distribution, the models assembled at Manchester are potentially an extremely useful resource for researchers to test different operational

88 See http://www.smarternetworks.org/Project.aspx?ProjectID=1861

philosophies and the cost-effectiveness of different types of equipment, i.e. exactly the things that the DS2030 project commissioned by Workstream 7 of the Smart Grid Forum sought to address (and which ended up spending considerable time assembling its own models[89]). Furthermore, it is our understanding that one of the conditions of NIA funding is that results and data should be disseminated. However, our request for access to the models was declined by the project leader on the grounds that confidentiality agreements between the various network licensees involved in the project – National Grid and the 3 DNOs whose networks were modelled – did not permit it. To us, this seems perverse given that the models extended only down to 11kV at which level few individual network customers are connected (and whose data could, in any case, be anonymised) and that, as far as we understand, the DNOs should make network models available as part of their Long-Term Development Statements (although, in practice, special requests need to be submitted).

8 Acknowledgement

Contributions to this appendix from the following people, all at the University of Strathclyde, are gratefully acknowledged: Ian Elders, Callum MacIver, Qiteng Hong and Marcel Nedd.

89 It should be acknowledged that the main questions being addressed by the REACT project might have led to network areas being modelled that were not the best for the DS2030 project to study.