*Northern Powergrid's response to 'a smart, flexible energy system' call for evidence from the Department for Business & Industrial Strategy (BEIS) and Ofgem*

## Key Points

- **Energy systems across the world are experiencing change on many fronts**, uncertainty about how new technologies will be deployed and political uncertainty. Berkshire Hathaway Energy, of which Northern Powergrid (NPg) is part, is seeing similar challenges everywhere it operates.
- The changes in the UK are particularly acute: the future shape of the UK energy system is not clear.
- **The broad structure of roles and responsibilities in the UK system works well**; indeed, we see regulators in other jurisdictions moving towards the UK model.
- **The challenge is to manage the system to allow for innovation and flexibility** of outcomes without introducing unnecessary risks and undermining investment in the sector.
- **Government and regulatory policy needs to recognise this and facilitate innovation, diversity and experimentation** while also maintaining the coherence and stability of the system overall. This is an obvious pillar of any Industrial Strategy.
- In terms of policy development for BEIS and Ofgem, **we believe that particular weight should be given to innovations in the system that create flexibility, or those that provide option value** – prioritising decisions (to either act or defer) that have low- or no-regrets associated with them.
- We believe that more **customer engagement and regulatory innovation will be needed** to unlock the potential of smart appliances and demand side response – applications are more advanced in some US states, in part, because there are fewer barriers to this.
- The strategic priorities for **the development of distribution charges need much clearer focus**.
    - **Ofgem should address the barriers and distortions that competition in distribution has introduced** to ensure the appropriate socialisation of certain costs.
    - Network charging needs to be reformed to **eliminate the scope that exists now for 'free riders'** between customer groups and the perverse incentives that undermine fair cost recovery.
    - We see **a future in which DNOs charge more active customers through bilateral contracts or market platforms**, with traditional charging structures remaining for passive customers.
- **The transition to more active Distribution System Operators (DSOs) merits careful consideration**. At a high level we believe that the owner of a network is best placed to operate it, but there are clearly certain functions which sit between different players in the market.
- **Both third party and network companies should be allowed to deploy and operate distributed energy resources** (like storage) - these types of asset could be vital tools in managing networks and network companies should be given some space to innovate.
    - **The de-minimis thresholds in the distribution licences could be calibrated to permit DNOs to take controlled but valuable steps towards becoming DSOs**, 'priming the pump' for more widespread competitive market-based mechanisms to emerge over the medium- and long-term.
    - **There needs to be a re-think of the funding routes available to support a 'whole energy system' approach for innovation projects** that target the delivery of customer benefits from greater *overall* efficiency, widening the focus from the current 'network only' innovation.
    - **We are committed to bringing our broad experience** of running energy companies internationally to help the Government and regulators **get the balance right and support economic growth**.

# Part 1 - Executive summary

## *Introduction*

1.1. We are at a time of unprecedented change and uncertainty for the energy system.

1.2. The rise of shale gas and oil in the US has both depressed prices and shifted the balance of power in global energy markets. Domestically, this has suppressed both gas and power prices and hastened the decline of oil and gas production from the United Kingdom Continental Shelf (UKCS), bringing forward concerns around security of supply and led to serious questions around the relative cost of new nuclear power.

1.3. Reforms in the UK, notably Electricity Market Reform, have in combination with more fundamental changes to cost bases, driven rapid changes to the UK power generation mix, where generation sits on networks, and how it plays in energy markets.

1.4. On electricity networks, the rapid rise of distribution-connected generation (pure generation and grid services); storage technologies such as battery storage; the start of mass-market deployment of plug-in hybrid and electric vehicles; and home automation have begun to mature and look set to start to play a significant role in the next five years.

1.5. Across networks there is continuing uncertainty around how domestic heat will be decarbonised (and at what pace), with the prospect of potentially large scale installation of domestic electric heat at some point in the next decade and, possibly, radical changes to how we use gas distribution networks (which might involve paring them back or moving to grid hydrogen).

1.6. Geopolitically, what Brexit means for the UK energy system is unclear: the extent to which EU rules and regulation will bite on the UK's energy arrangements and our physical connectivity to European networks will both be issues in the forthcoming negotiations and these issues are unlikely to be resolved early. At the same time the change of administration in the US means the route to and pace of global decarbonisation is less clear than we expected post the 2015 Paris Climate Change agreement.

1.7. What all of this means for the future shape of the energy system is currently unknowable; there are too many variables in play. However, we believe energy networks will be critical in enabling and facilitating intelligent efficient responses to these changes and challenges. To manage the uncertainty, the value of flexibility and keeping options open is likely to remain significant.

1.8. However there are some areas where it cannot be wrong to act now. In our current business plan we are deploying £83m of smart grid enablers. This effectively provides 'free insurance' for customers by upgrading some key control and communications infrastructure to ensure that our network is ready for all ranges of low carbon technology (LCT) roll-out scenarios.

1.9. At the same time, 'smart' technology is starting to be deployed at scale on our energy networks offering new opportunities to use networks more flexibly, increase efficiency, and enhance resilience.

1.10. These factors pose significant challenges to the energy system but also open up new opportunities for the energy system and importantly the economy as a whole; there is real scope for significant inward investment in this sector.

1.11. The corollary of this is that the energy system cannot be seen in isolation; it fundamentally underpins the wider economy. Poorly managed it can restrict economic activity, but when well managed it can help foster and facilitate growth. We believe that the energy system needs be at the heart of the Government's Industrial Strategy, positioned to facilitate development and growth. As a key part of the North of England economy we also consider it important to explore the extent to which energy is also part of the Northern Powerhouse strategy.

1.12. Allowing the energy sector to innovate and allowing disruptive technologies and approaches to emerge is rightly a key part of Government's strategy, but this needs to be facilitated and managed in a way that does not impinge on security of supply or undermine investment. Given unprecedented levels of uncertainty, as policy makers, BEIS and Ofgem need to give significant weight to flexibility and option value in the system over the next five to 10 years.

1.13. To square this circle it is critical that the Government and regulators hold to core principles of economic regulation (accountability, focus, predictability, coherence, adaptability, and efficiency) in order to attract investment to the UK at a reasonable cost of capital.

1.14. We believe that energy networks have a key role to play - facilitating market players to innovate and trial different approaches as well as innovating themselves. Distribution network operators (DNOs) are already to some extent operating as distribution system operators (DSOs) and we believe that the owner of assets should operate them but there is an obvious interface between the DNO/DSO and the system operator (SO)/transmission operator (TO) that needs to be better explored.

1.15. Both third party and network companies should be allowed to deploy and operate distributed energy resources (like storage) - these types of asset could be vital tools in managing networks and network companies should be given some space to innovate.

1.16. Further, the de-minimis thresholds in the distribution licences could be calibrated to permit DNOs to take controlled but valuable steps towards becoming DSOs, 'priming the pump' for more widespread competitive market-based mechanisms to emerge over the medium- and long-term.

1.17. These issues are not unique to the UK. Berkshire Hathaway Energy (BHE) operates energy networks and utilities in the United States and Canada. BHE has an on-going Transmission and Distribution working group collaborating by sharing experience and best practice in order to find optimal solutions to the common issues and opportunities facing the group's networks businesses. That work has informed this response; we will continue to feed in its findings to the UK policy process as it develops.

1.18. Finally, and most importantly, we believe that customers and consumers need to be kept at the heart of how the energy system works. All players should be focused on finding optimal solutions for customers, where possible providing choice, and always operating openly and transparently. We maintain our social licence to operate by being safe, (physically and cyber) secure and focused on our customers.

1.19. We welcome the dialogue on these important matters and look forward to discussing the points we raise in this response further.

### *Northern Powergrid and its role in the system*

1.20. NPg is a wholly-owned subsidiary of Berkshire Hathaway Energy (BHE), one of the world's largest energy companies. BHE is an international group made up of integrated power companies; electricity transmission and distribution network companies and gas pipeline operators.

1.21. In the UK, NPg runs the electricity distribution network that provides power to customers in the Northeast, Yorkshire and northern Lincolnshire. We are responsible for the safe, secure and cost-effective delivery of electricity to around eight million people in 3.9 million homes and businesses.

1.22. In practice we operate as one company, but we are regulated by the energy regulator, Ofgem, as two licensed businesses: Northern Powergrid (Northeast) Ltd. and Northern Powergrid (Yorkshire) plc.

1.23. We are one of the largest businesses in our region, directly employing over 2,200 people and a similar number of contractors. The majority of our annual investment in the UK is in regulated electricity networks - we typically invest £340m per annum.

1.24. Our network underpins the economy in Yorkshire the North east and North Lincolnshire, connecting homes and businesses to transmission network and to generation; we also connect a full range of generating assets to the overall energy system. We are directly important to our local economies though our commitment to on-going investment in our network and see our role as facilitating the effective and efficient operation of the overall energy system and thereby supporting growth in our region.

### *Berkshire Hathaway Energy*

1.25. Although it is a separate regulated business, NPg benefits from being part of the BHE group. BHE is a multinational energy company active across the entire energy supply chain through its various subsidiaries, most of which are in North America. BHE employs 21,000 employees worldwide, owns £53bn worth of assets, and invests more than £3bn per annum. BHE has 11.6 million customers and runs 34GW of generating assets. It operates 233 thousand miles of power transmission and distribution lines and 43 thousand miles of gas pipelines[1]. In addition to developing transmission and distribution networks we are also responsible for developing some of the largest wind and solar projects in North America; as of early 2017 we own 7% of US wind generation and 6% of US solar generation.

1.26. BHE believes that the best way to protect and build the value of the business is to:

- provide excellent customer service at competitive prices, with a commitment to continuous improvement;
- strive to meet the highest standards of safety and security (both physical and cyber); and
- strategically invest for the long term.

1.27. Being part of Berkshire Hathaway Inc. means we focus on building value rather than paying dividends. We believe that this long-term approach to investing and relatively conservative approach to running businesses is a powerful strategic fit with energy systems which require a lot of capital investment in assets that will last a long time.

### *Managing uncertainty*

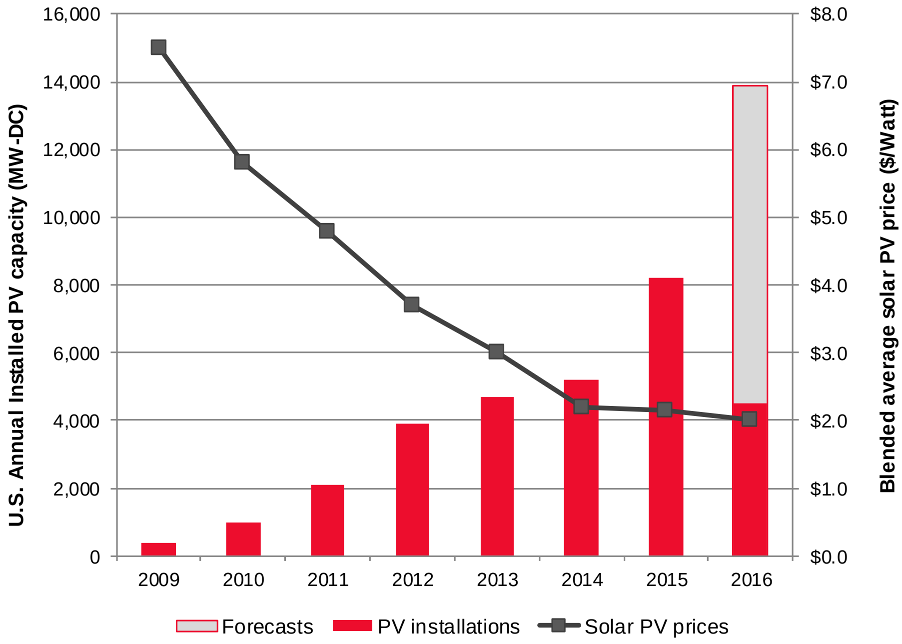
1.28. The following charts provide evidence of the volatility in the current energy system and evidence the nature of the unprecedented changes and uncertainty. The presence of subsidies in the market has had a major bearing on the deployment rates for both solar panels and heat pumps.

1.29. Solar PV has been the largest growth area in distributed energy since 2010 in the UK when the feed-in tariff was introduced. The pattern has been similar in the US where the following chart plots cost versus up-take.

1.30. The cost to install solar has dropped by more than 60% over the last 10 years, allowing rapid expansion and nearly 32GW of total solar capacity – enough to power 6.2 million homes.

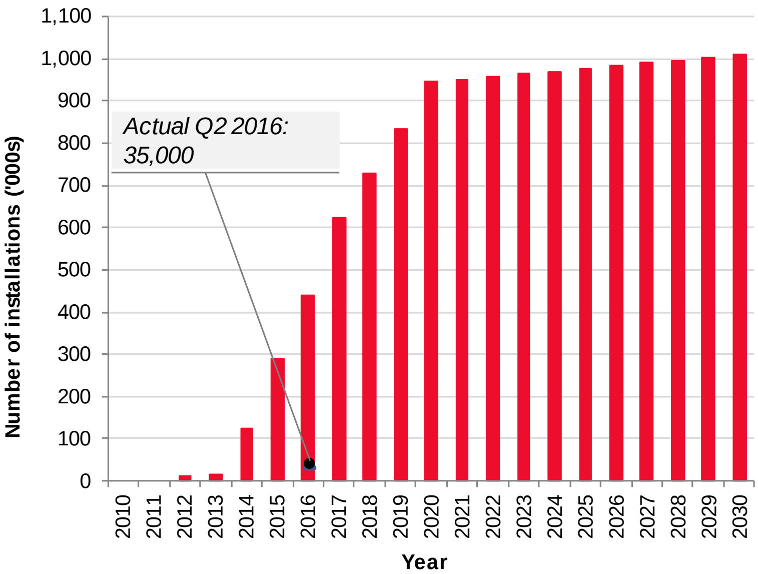
[1] For more information about BHE, refer to: www.berkshirehathawayenergyco.com/news/berkshire-hathaway-energy-fact-sheets

**Figure 1:** Rapid deployment of solar panels in the US[2]




1.31. The UK growth in heat pumps has followed a different path. Again this has been attributed to the economics of a subsidy regime that has proved insufficiently attractive to bring forward this type of low carbon heat. Forecasts from 2013 have failed to materialise with around 35,000 installations up to Q2 2016 versus a forecast of around 10 times that amount. This is shown in Figure 2.

**Figure 2**: 2013 forecast of Heat pumps deployment in high-penetration scenario, with 2016 actuals [3]




[2] Source: SEIA research – solar industry data (http://www.seia.org/research-resources/solar-industry-data)

[3] Source: Frontier Economics: Pathways to high penetration of heat pumps, Oct 2013, modified 2017

## Section 2: Removing policy and regulatory barriers

***We agree that the market and its structures must recognise and appropriately reward storage for the value it brings to the energy system and the consumers that fund it and depend on it.***

1.32. We support the BEIS and Ofgem in addressing challenges and ensuring a level playing field for storage and other sources of flexibility in delivering value for consumers. In considering the costs of network connection and use, charges set to recover appropriate costs should not in themselves be seen as barriers to entry but rather as a cost signal to the market that allows storage to compete alongside other technologies or commercial solutions.

1.33. We believe storage on the distribution networks could bring a range of benefits to the system, not limited to demand side response (DSR) but also increasing system capacity, flexibility and resilience[4]. For example, this could mean placing storage at a critical substation might allow additional generation to connect without additional line capacity, or placing storage at the end of a vulnerable overhead line to provide back-up.

1.34. We would like innovation funding mechanisms to allow DNOs to trial these approaches while also testing the wider value to the energy systems (for example, allowing other parties to deploy capacity).

1.35. In the medium- to long-term, the market-based deployment of storage for grid or energy services is preferable. But in the short term there is scope to adjust the de minimis limits on the innovation components of the price control in order to demonstrate viable use cases and allow DNOs to ‘prime the pump’. Ofgem should consider such a regulated solution. It may be for a time-limited period until such time as the other changes contemplated in this call for evidence are made. Rather than distort the market it could therefore facilitate a future market by providing useful sector learning on financeable business cases.

***The provision of flexible connections has become standard practice for generators and large industrial and commercial demand.***

1.36. Under arrangements for flexible connections that are now becoming standard customers receive a reduced connection cost and a quicker connection in return for accepting a curtailment on their production or use of electricity to manage within a physical limitation on the network. We expect that such flexible connections could become standard practice for storage operators too as we continue to engage with the developers through established channels that are already in place for distributed generators.

1.37. There is a need for closer working between the Great Britain (GB) system operator and DNOs to identify and manage the impact of significant volumes of distribution connection quotations as a result of a call for SO services. As occurred in 2016 for the enhanced frequency response tender there were over 19GW of connection quotations for 200MW of winners in the auction leading to unexpected and potentially avoidable abortive DNO design work that impacted connections customer service. In a related initiative, BEIS should continue to legislate for a fairer allocation of charges for connection offers as this should assist in driving the right market behaviours and reduce speculative enquiries where there is no cost implication for the person requesting the design service from the DNO.

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[4] Evidence is taken from our CLNR innovation project. For more information, refer to: ‘Key Learning Report: Optimal solutions for smarter network businesses’, available as report CLNR-L248 from the project library: www.networkrevolution.co.uk/resources/project-library/

1.38. As the number of connections grow, constraints on the distribution grid are likely to become more important. The management of such generation between the TO and DSO function is a issue that needs considerably more thought as roles and responsibilities evolve.

***Storage that delivers benefits for customers should be properly valued.***

1.39. Storage should be appropriately credited where it sufficiently assists network operation, for example by deferring reinforcement. However, storage is not the only technology that may export at times of peak demand and there needs to be clear justification for valuing it differently from other flexibility services that could also reduce network costs so that each technology may compete fairly. The starting point for changes to the charging regime is that charges should be cost-reflective.

1.40. It is appropriate to consider that market solutions for the provision of flexibility services should be prioritised if they deliver best value. In this way the value from storage may be 'stacked' to realise benefits from trading in the wholesale energy market, reduce the need for network reinforcement, and provide balancing services to the SO. However, for these multiple services to be realised the market may need to develop in stages to attract investment for more straightforward business cases in the early stages and increase both the operational and commercial complexity through time. Therefore, the regulatory arrangements should cater for storage to be used in any of these areas subject to a valid business case.

***In the near-term, storage should be permitted to compete alongside other network solutions and clarity of definition and regulatory treatment will be beneficial.***

1.41. Storage should compete with other network solutions, including other engineering or commercial solutions to assist network operators to manage the quality of supply or facilitate more connections by alleviating network capacity constraints. The RIIO price control framework provides incentives for network operators to deploy storage as a solution if it is least cost as does the licensing regime where network operators may own and operate storage subject to de minimis limits not being exceeded. Longer term, we expect that as a network operator we are likely to procure services from the market place that could be storage or DSR or some other solution that provides what we need.

1.42. We agree that the definition of storage should be clarified in legislation and codes in order to remove barriers to its deployment from inappropriate charging arrangements or regulatory risk. We support the definition of storage as provided by the Electricity Storage Network and the need to avoid inappropriate capture of network assets such as capacitors and transformers within the definition. In defining storage BEIS needs to recognise that bi-directional electricity storage requires different consideration to energy storage that is cross vector such as power to gas.

1.43. We agree with the assessment of the regulatory approaches available to provide greater clarity for storage, however there may be merit in differentiating between types of storage as this could open the door for positive material changes in the way different types of storage solutions could be regulated:

- Commercial storage providing behind the meter solutions;
- Directly connected commercial storage serving a market; and
- Directly connected 'network owned' storage plant providing network resilience and market services (in a similar way to transformers and capacitors with the addition of market services).

***We recognise aggregators as a valued route to market to connect the buyers and sellers of services***

1.44. This route is particularly valued where the sellers are customers in need of a third party to assist them in providing the expertise to maximise the return from their resources. Our smart grid trials have demonstrated how aggregators enable us to reach more customers and then contract with them to procure and reliably operate DSR as a viable alternative to conventional reinforcement of the network[5].

1.45. Working together with National Grid through both the Power Responsive campaign and the DSR Shared Services Working Group has suggested that aggregators could continue to assist in growing the market for the provision of energy services albeit the number and complexity of grid services products on offer needs an overhaul in order to grow the customer base offering flexibility. Some of the customers with whom we contracted for DSR via aggregators in our trials[6] could provide us with availability that was of value to us but did not meet the criteria required by the SO for its service requirements. This demonstrated that there is the opportunity to attract more participation in flexibility services by relaxing criteria.

## Section 3: Providing price signals for flexibility

***Cost-reflective charging is a policy decision which needs careful consideration in the context of other valid charging objectives such as ability to respond and price stability and predictability.***

1.46. Network charges serve two distinct purposes. The first purpose, cost-reflectivity, is to give price signals to users of the network, so as to encourage overall efficient behaviour. From this perspective, the relevant costs to be reflected in charges are forward-looking incremental network costs (which may be materially lower than average costs). Cost-reflectivity has two dimensions:

- In the short term, price signals might impact consumption/generation patterns of users already connected to the network. If the network price is high (perhaps because the network is operating at capacity), network users are given a signal to reduce load; and
- In the long term, price signals might impact investment decisions. For example, sustained higher network tariffs would provide a signal that it might be more efficient for customers to connect at a different network location or voltage.

1.47. The degree of accuracy of cost-reflective signals is a policy question. Here, there are trade-offs with other valid charging objectives, in particular:

- Ability to respond. If other factors constrain a customer's operating or investment decisions, they may not be able to respond to cost-reflective pricing, meaning there will be no efficiency benefit. Equally, the more complex a tariff is, the less likely customers are to be able to respond to those price signals; and
- Customers value stability and predictability of tariffs. Changes to the tariff design which entail large step changes relative to the status quo; or tariff methodologies which can result in volatile tariff changes year-on-year, should be avoided.

[5] 'Key Learning Report : The role of industrial and commercial and distributed generation customers', available as reports CLNR-L247 from the project library: www.networkrevolution.co.uk/resources/project-library/

[6] 'Report on CLNR Industrial & Commercial Demand Side Response Trials', available as reports CLNR-L098 from the project library: www.networkrevolution.co.uk/resources/project-library/

***New market models should be considered as well as traditional approaches but they must be predictable and fair.***

1.48. Cost-reflective distribution use of system (DUoS) charges is not the only way to encourage efficient outcomes in support of a smart, flexible energy system. Other instruments, such as constrained connection contracts or DSO contracts, can also deliver these outcomes - each channel could be used to send signals in relation to operation or investment. A coherent design needs to be adopted to ensure relevant price signals are sent once and once only where possible – i.e. to avoid double counting price signals, which would lead to inefficient outcomes. For this reason, the approach to network charging must be considered in parallel with the question of the DSO role – the approaches for each should not be considered separately.

1.49. The second purpose of network charges is cost-recovery (i.e. to ensure that networks recover their efficiently incurred sunk investments). Ofgem's regulatory model allows customers to benefit from low financing costs because it allows networks to recover efficient past investments from customers over time.

***Outcomes must be good for consumers as a whole and not benefit one sector at the expense of material downside to another – vulnerable customers need to be protected.***

1.50. In principle, cost-recovery can be achieved by tariffs which are specified in any number of ways – for example, they could be based on a charge per connection; a fixed capacity-based charge; or charges based on peak consumption. For the purposes of establishing a charging method for cost-recovery, the question to be answered is how to divide the burden of paying for efficiently incurred sunk costs between different customer groups.

1.51. In designing this, again there are trade-offs across a number of objectives. Charges to recover sunk costs (over and above estimated forward-looking incremental costs) should generally:

- be evidence-based and rational;
- seek to avoid changing or distorting customer behaviour, since, by definition, customer behaviour can have no impact on legacy costs;
- share the burden of cost recovery across different customers in an equitable way which is sustainable in the long term – users should not be able to modify their behaviour to avoid their fair share of cost recovery for sunk costs that then have to be borne by others (the 'free rider' problem);
- ensure that vulnerable customers are protected; and
- be relatively stable and predictable over time.

***More complex DUoS tariffs are unlikely to be the most appropriate solution in a smarter flexible future.***

1.52. In our view, introducing more complex cost-reflective tariffs in order to drive efficient behaviour is likely to have a number of challenges. We have seen evidence from our Customer Led Network Revolution (CLNR) study that customers struggle to understand and respond in efficient ways to overly complex network tariff structures[7]. We also observe that even today's relatively straightforward network pricing signals (i.e. the variation in tariffs depending on the time of day or week (based on the Red/Amber/Green identification) – are usually not passed through to end-users by suppliers. This further suggests that suppliers and customers are unwilling or

[7] 'Key Learning Report : The role of industrial and commercial and distributed generation customers', available as reports CLNR-L247 from the project library: www.networkrevolution.co.uk/resources/project-library/

unable to respond to more complex network charging, since the competitive market has yet to fully translate these signals into retail pricing strategies.

***Cost signals should be sent to those consumers that are able to respond at a time when they can make informed commercial decisions.***

1.53. Given these issues, we think that in future a smart and flexible energy system would best be supported by the existence of a clear DSO role, which could engage more ‘active’ customers through direct contracting and would also support cost-reflective revenue streams for providers of system flexibility. DSO contracting can be put in place in areas in which connection/despatch of demand or generation would be beneficial. There is the potential for a large number of contracts with parties (e.g. distributed generators, DSR or storage) to incentivise despatch at relevant times. This may imply the need for some degree of standardisation. But contracts could also allow the specification of duration and specific activation conditions (including penalties for non-delivery on obligations around despatch).

1.54. More passive customers could then retain the benefits (at a price) of a relatively more stable and predictable network charging framework, which ensures full cost-recovery. Under such a scenario, and given the objectives for charging outlined above, we think there would be a case for moving network charges further towards fixed capacity-based charges, which would enhance transparency and predictability for customers.

1.55. We discuss our views and evidence surrounding the DSO role more fully in Section 5. In the remainder of this section we focus on network charging issues.

***Governance of charging arrangements, including any fundamental reviews, need to be centrally led to ensure resolution of current distortions and future needs.***

1.56. It is clear that network charging developments will need to respond in a number of ways to the ongoing evolution of the sector. This raises questions about appropriate governance.

1.57. First, we believe that Ofgem needs to be actively engaged in charging developments and intervene early if change proposals are progressing in a way which ultimately are not going to be approved by Ofgem. This would improve the efficiency and effectiveness of the process and increase the likelihood of the timely implementation of change which would be in both the industry’s and the consumers’ interests.

1.58. Second, and more significantly, we believe that Ofgem needs to lead a fundamental review of distribution charging methodologies is required. The current charging methodology is common across the DNOs. However, it was developed from a set of widely varying methodologies that were previously being employed by different DNOs in different regions of the country and it was developed in the absence of significant potential for innovative technologies to enhance system flexibility in the near future.

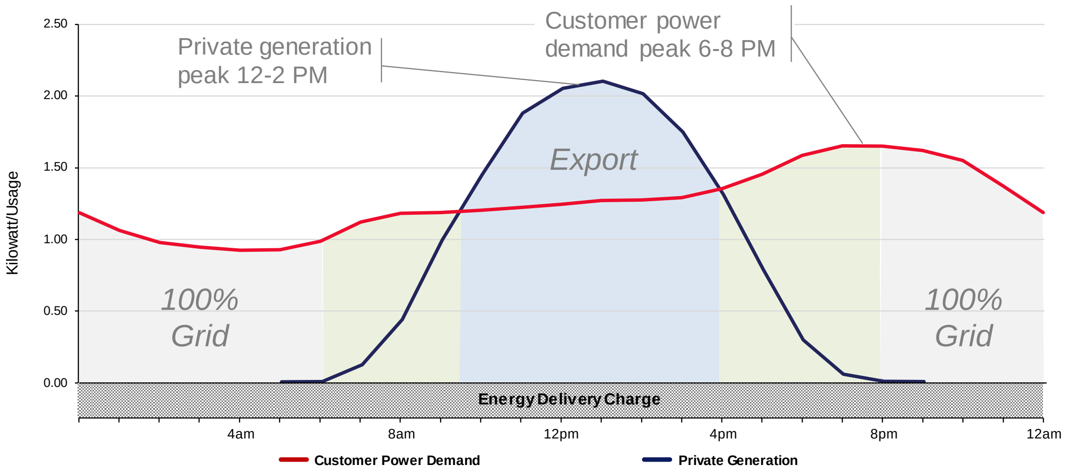
1.59. The world has since moved on significantly, and we consider that the methodologies are now sufficiently well ‘bedded in’ that Ofgem needs to remedy the market distortion issues that exist today and also undertake a fundamental assessment of how they need to change to be fit-for-purpose in a smart, flexible future. We think some key issues would be central to such a review:

- **Whole system cost-reflectivity and arbitrary distortions**: In future, it will be increasingly important that cost-reflectivity is considered from a ‘whole system’ perspective. Currently, there are different methods to derive grid charges for the transmission and distribution systems, and different methodologies employed at different voltages within the distribution system. These create arbitrary boundaries across which tariffs vary significantly and in a way which does not reflect system cost. Such arbitrary variations act as a distortion which could prevent the efficient development of smart, flexible energy systems. Where possible we need to eliminate opportunities for gaming at the boundaries between methodologies and within the methodologies themselves.

- **Consistency across different areas of charging and the DSO role:** We see three areas of charging that need to be considered simultaneously ensuring that relevant price signals are sent once and once only where possible, namely: connection charges; DSO contracts; and use of system charges. The role of connection in particular is important - the time of connection is currently when the distributor has the most direct contact/relationship with the customer, and when the customer can make informed decisions on their energy requirements and usage. Building in appropriate cost signals at this stage is the most likely means of influencing behaviours.
- **Equity across consumer groups and avoiding the 'free rider' problem**: Outcomes must be good for consumers as a whole and not benefit one sector at the expense of material downside to another. Ofgem needs to recognise the issues that exist today and set out to resolve them as it has already for embedded generator benefits. In particular, policy makers and companies need to consider the disproportionate effects on the most vulnerable, and the problems that arise from 'free rider' issues that exist today. Evidence includes:
  - Benefits for embedded generators that distort the generation market;
  - The private wire distortion that leads to investment inefficiency through replication of physical assets to qualify for lower cost commercial arrangements and unfairness in the sharing of environmental costs;
  - The independent distribution network operators (IDNOs) charging distortion that allows cherry picking of lower than average cost to serve customers and applying tariff support to the disbenefit of the generality of customers; and
  - The use of system charging distortions associated with solar PV where the 'deemed export' aspect of the feed in tariff is leading to inefficient solutions and inequitable outcomes for the less able to pay.

1.60. The last of these free rider problems is explained by Figure 3 that demonstrates how solar PV domestic customers still need the grid for 23.99 hours per day and should therefore pay for the fair use of system access (ongoing services and recovery of past investment).

**Figure 3:** Grid usage by a typical domestic consumer with solar panels[8]




***Fundamental review of charging arrangements does not require a significant code review but ongoing incremental changes will need to be robustly prioritised.***

1.61. We do not believe that Ofgem needs to undertake a formal Significant Code Review (SCR) process, which we accept takes substantial time and represents a significant burden. Instead, we believe that industry groups such as the Transmission and Distribution Interface (TDI) charging task force – in combination with Ofgem – could undertake such a review.

1.62. We believe that space for a fundamental review will need to be created. There are still a significant number of change proposals being raised and considered. Among these there may be some which are 'low regret' in that they are quick to consider and deliver or address major distortions. Beyond these, change proposals will need to be robustly prioritised as their processing will draw on the same resource as required for a fundamental review.

1.63. In our detailed responses to the questions we draw on a number of different sources of evidence before which include (but are not limited to) the following:

- NPg's CLNR project which provides significant learning opportunities;
- As part of BHE, our affiliate companies' experience in the US provides lessons from other jurisdictions;
- The Common Distribution Charging Methodology (CDCM) and Extra-high voltage (EHV) Distribution Charging Methodology (EDCM) reviews which are good starting points from which to move forward and better understand the current industry concerns; and
- The Citizens Advice report on tackling tariff design and managing the tariff transition.

## Section 4: A system for the consumer

### *Solutions are required for both active and passive customers…*

1.64. It is clear that consumers need to be central to the development of the energy system. Engaged consumers may be relatively active (consciously altering the time of energy use in response to a tariff) or more passive (for example possessing a smart appliance such as a refrigerator that is

[8] Source: Berkshire Hathaway Energy

changing its use of energy to deliver the same customer benefit but doing so in the background without direct real-time customer intervention).

***…with all parts of the energy supply chain then developing the market and the technology to access it.***

1.65. We agree with the four principles for smart appliances set out in the paper (interoperability, data privacy, grid security and energy consumption). However, what receives less prominence in the call for evidence is the need to establish a clear market in which customers can see the value from participation. And it is manufacturers too that need to see a clear market signal with regulatory support in order to encourage them to develop standards for, and subsequently manufacture, smart appliances.

1.66. In the same way that 'bolt-on' technology is being used to obtain longer, flexible, lower-cost life from the network assets, the same approach should not be overlooked to make consumer's existing assets function like smart appliances. One such technology is wifi-controlled 'smart plugs'; enabling remote operation of any device that is connected[9]. Our experience through operating customer trials is that the key to deployment of more smart appliances is their popularity with consumer[10]. The latter is influenced by the cost, the commercial availability of suitable products and the clarity and attractiveness of the market to which they provide access.

***Electric vehicles could be a truly transformational technology to provide low-carbon transport and flexibility services to the grid.***

1.67. As with other smart or low carbon technologies, the success of ultra-low emission vehicles will also be likely to hinge on similar variables to smart appliances. Involvement of the vehicle manufacturers in bringing forward new products that provide consumers with what they want at a price they can afford is once again paramount and the need for continued and increased engagement between energy and automotive sectors is rightly recognised.

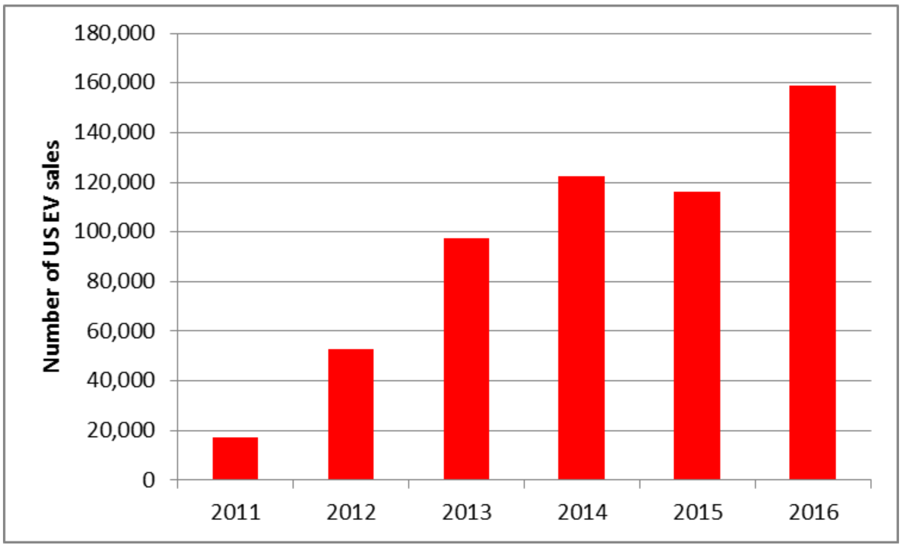
1.68. For electric vehicles (EVs), the technical performance of the battery (in particular with respect to range) will continue to have a significant influence on the development of the market. Vehicle users and the manufacturers will also wish to see development of the energy market to provide a clearer price expectation.

1.69. Although still a long way from parity with the traditional hydrocarbon-fuelled car, EV sales have been growing worldwide and this trend is set to continue as costs of batteries fall. Figure 4 plots the sales in the US.

[9] We are trialling this technology in the innovation project Activating Community Energy. For more information, visit: www.npg-ace.com/

[10] 'Key Learning Report : The role of domestic and small and medium enterprise customers', available as reports CLNR-L246 from the project library: www.networkrevolution.co.uk/resources/project-library/

**Figure 4:** Electric Vehicle sales in the US[11]




1.70. In terms of system benefits from smart charging of EVs, a financial incentive appears to be the best way to get people involved in peak-time avoidance i.e. the lower cost of off-peak charging. However, there is a psychological barrier to overcome as EV owners may not be comfortable with having limited control on the 'readiness' of their vehicle[12]. This has relevance to the market today with EVs seen mainly as a demand on the energy system co-incident with the legacy peak demand as well as a future where an EV owner may sell the storage contained therein as a resource to suppliers or network operators (known as 'vehicle-to-grid'). We support the proposal in the innovation section of the call for evidence for more demonstration projects in this area.

1.71. There are two energy industry unresolved barriers to maximising the value from EVs that we have identified; namely, how a network company accesses services (i.e. either managed charging or vehicle-to-grid) from the end customer when the primary commercial relationship of the customer is through the supplier, and the time and cost associated with the installation of fast-charger infrastructure.

### *The smart meter roll-out is the prime enabler to enable more DSR.*

1.72. Informing domestic and smaller non-domestic consumers about the transition to a smarter energy system should continue as a top priority through the course of the smart meter deployment. This will assist customers and energy companies to realise maximum benefits from the roll-out as it reaches critical mass such that aggregation opportunities may be leveraged to provide real-time or longer-term advantage. Engaging customers in smart energy will requires certain interventions. These should aim at improving the customers' understanding of the commercial propositions, addressing their concerns on data privacy issues, and making sure that the distributional impact of smart energy roll-out does not mean that some customer groups are excluded or disadvantaged.

[11] Source: Inside EVs monthly plug-in data (http://insideevs.com/monthly-plug-in-sales-scorecard)

[12] 'High Level Summary of Learning: Electric Vehicle Users', available as report CLNR-L254 from the project library: www.networkrevolution.co.uk/resources/project-library/

1.73. We recognise the barriers identified in the paper to large non-domestic customers providing DSR– i.e. cultural, regulatory, commercial and structural. Our CLNR project also identified that an additional barrier associated with providing DSR to DNOs is that the location of DSR provision in specific network-related geographic locations is difficult[13]. DNOs will have to improve engagement techniques to seek out and secure the DSR resource that is available. DSR provides an alternative to network solutions only if sufficient willing providers can be found on the relevant parts of the system to deliver a large enough reduction in network demand when required.

***Consumer protection mechanisms will need to recognise the different needs of active and passive customers…***

1.74. The implementation of smart grids provides the most significant near term test cases for ensuring that smarter energy systems are developed with consumer protection at their core. In particular, the roll-out of smart meters is requiring all industry companies to set out their plans for management of data and privacy. We have evidence that time of use tariffs can provide benefit but they are not suitable for all customers and the more vulnerable would likely be adversely impacted if exposed to critical peak pricing. In future, we need to design charging mechanisms and informed consents that recognise different types of customers – those that are more 'technology savvy' and keen to engage and those that wish to remain relatively passive and need some protection from market volatility. It is for this reason that in the charging section of this response we set out bilateral contracting as the optional route for those that want to engage more.

***…while cyber security methods require the widespread application of expertise and collaboration.***

1.75. Cyber security (often combined with physical building security) is one of the fastest accelerating business risks to all sectors of the economy. The interconnectivity of the future smart energy supply chain introduces a new level of exposure to cyber attacks. However, the industry is taking the right steps to mitigate these risks through the application of expertise and collaboration (including with government). Our approach must be to realise the benefits from interconnectivity while also putting in place 'fire breaks' and other mitigations to compartmentalise the impact of attacks when they occur.

## Section 5: Roles of parties in system & network operation

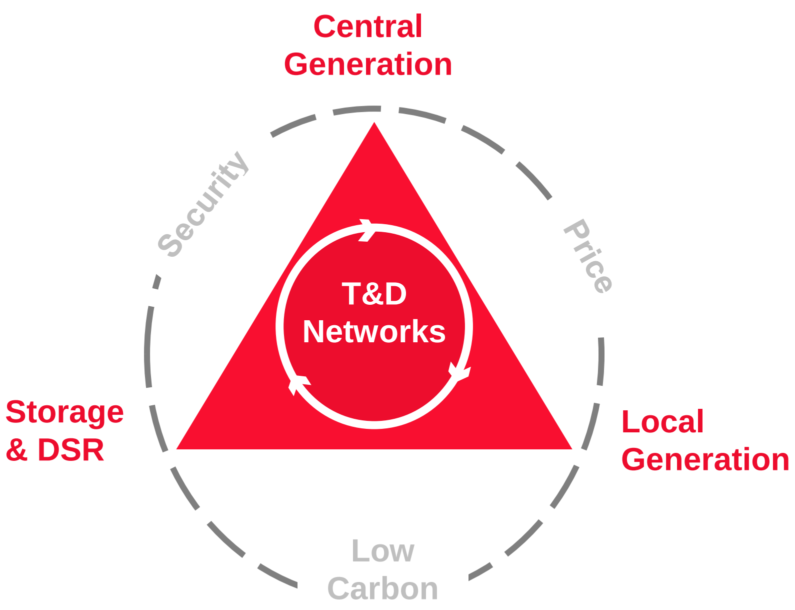
***To deliver benefits to customers, the consideration of changes to roles and responsibilities needs to span all industry parties.***

1.76. We welcome the discussion of the roles of different parties in system and network operation. It is essential that thinking on this topic is customer-centric so that changes are designed to advance the public interest, rather than being designed around technologies or existing industry processes and structures. It is also important that the consideration of roles and responsibilities covers all network operators, including IDNOs and private wire networks.

1.77. Networks are taking an increasingly central role in the energy system due to the change in the generation mix, the growth in distributed energy and the need to need to cost-effectively balance the competing drivers of security of supply and low carbon (as illustrated in Figure 5).

[13] 'Key Learning Report : The role of industrial and commercial and distributed generation customers', available as reports CLNR-L247 from the project library: www.networkrevolution.co.uk/resources/project-library/

**Figure 5:** The role of electricity networks in the energy system




***The transition by DNOs to DSOs is already delivering customer benefits…***

1.78. We agree that new activities and ways of working are needed to deliver a smart flexible energy system, and this includes DNOs taking on additional responsibilities. Indeed, DNOs are already moving along the spectrum from the traditional DNO towards a DSO role. For example, DNOs are already making increasing use of active network management (ANM) and looking for opportunities to contract for DSR services as an alternative to conventional reinforcement. These activities are already saving customers money in ED1.

1.79. The passive network of the past is changing to a more active network. We now have around 700MW of managed generation connections to obtain more capacity out of the network at key points.

***…and its further development will depend on the needs of the local customer base that varies in different parts of the country.***

1.80. How this part of our role develops will be a function of many exogenous factors, such as the take-up of Low Carbon Technologies (LTCs) and the capacity of our existing network. Different networks serving different areas of the country have different requirements, so there will inevitably be differences in the timing and order in which solutions will need to be deployed. A new set of roles and responsibilities for parties should be able to accommodate these differences in timing in order to facilitate the least overall cost solution for customers. Therefore, in the short term, whatever models are adopted must be flexible enough to be introduced on a needs basis.

1.81. Recent practical experience has demonstrated the need for improved linkage between the distribution and transmission networks. In particular, the issues caused for transmission in the South West of England by the increased volumes of distribution-network connected generation. These issues are not universal. In the NPg region we are not at this time seeing such significant impacts and the SO's System Operability Framework[14] identifies the NPg area as less in need of ANM solutions in the period to 2020. However, being able to deal with uncertainty in the need for and timing of the introduction of solutions is vital. Using scenarios enables parties to understand and plan for a range of situations, and using interim solutions is an effective way to buy time and optionality and avoid the potential for stranded investment. We are doing this now and will need to do more of this in the future as markets develop.

***More active network development with joined-up thinking between distribution and transmission is the short-term priority…***

1.82. In the short term, the key requirements are for DNOs to deliver an increasingly actively-managed network, matching customer needs with network conditions closer to real time; and for better interaction between actors in the whole energy system to ensure more efficient design and operation (particularly between network operators). The priorities for 2017 are to establish productive and effective transmission and distribution interface forums to work in parallel on making some low regrets changes today (e.g. developing efficient network planning processes) and to work through some of the more challenging and detailed questions (e.g. future market structures).

***…and it is important to keep options open to deal with the significant future uncertainty while more work is done on development of future industry structure models…***

1.83. In the longer term, it is likely that more fundamental change will be required, although we are not yet at a point where we know what the right industry model should be. The potential future models for efficient network planning and use of resources put forward in the Call for Evidence are reasonable views that need further scrutiny and development. A key question is whether the models presented represent the full range that should be considered (i.e. is there a wider spectrum that is not considered here). Also, what are the principles that need to be satisfied when determining which model is ultimately the most appropriate? More testing and trialling of different options will clearly be helpful in taking this forward.

***…and in parallel pursue no- or low-regrets actions.***

1.84. However, there are some areas where it cannot be wrong to act now. In our current business plan we are deploying £83m of smart grid enablers. This business case, supported by Ofgem at the ED1 price control review, effectively provides 'free insurance' for customers by upgrading some key control and communications infrastructure to ensure that our network is ready for all ranges of low carbon technology (LCT) roll-out scenarios.

## Section 6 Innovation

***Innovation support is most required for commercial trials…***

1.85. The areas identified in the call for evidence as potential areas for further innovation support are appropriate. Firstly, it is important to recognise that the innovation is as much required in commercial solutions as it is on specific technologies. Of the areas for innovation highlighted in the call for evidence only storage costs are a technical issue; the remainder of DSR, flexibility trading/optimisation and vehicle-to-grid are opportunities that must be explored through commercial innovation.

[14] www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

***…and in particular more support is required for 'whole energy system' trials where some 'measured risk' is appropriate.***

1.86. More demonstration projects are required and the current 'network only' innovation funding is insufficient for this purpose on its own. Ofgem needs to change direction on the Low Carbon Networks Fund and/or BEIS should provide additional funding for whole energy system projects.

1.87. Ofgem's network innovation funding can go some way to meeting some of these needs but it can only go so far. For example, the proposal to trial a flexibility trading and optimisation platform has significant overlap with the GB Flexibility Market bid that we led in 2012 and failed to win funding from Ofgem's Low Carbon Networks Fund competition. One reason for the rejection of our application was that it was by nature a cross-energy systems project and delivered value beyond the networks' business scope.

1.88. For DSR, we commend the need to carry out more trials and as per our comments in the smart appliances section of this response, we suggest that careful thought should be given to the market that is being developed and the available products that this may encourage. For an effective trial, there need to be sufficient technologies provided by manufacturers who see a market and are promoting their products with the required functionality to provide a discretionary load or to enable consumers to provide a response or service without an unacceptable service disruption. There is a significant desktop phase required to design such a trial to achieve maximum value from the investment. This is consistent with the comments on trial design promoted in the August 2016 Hubnet report 'A Review and Synthesis of the Outcomes from Low Carbon Networks Fund Projects'.[15]

1.89. Vehicle-to-grid looks like a highly promising commercial proposition, backed by the necessary technology, and its use should be further considered in line with the work proposed on understanding how to reduce battery costs. The work on battery costs looks best suited to Innovate UK funding whereby the intellectual property rights may be protected for the manufacturers that could engage in the trials.

***Innovation funding must also support the Government's Industrial Strategy.***

1.90. More generally, the opportunity to link the innovation priorities to the government's developing thinking on Industrial Strategy should not be missed. Perhaps most pertinent is the link to some of the smart technologies and the automotive sector in the UK.

1.91. As a key part of the North of England economy we also consider it important to explore the extent to which energy is also part of the Northern Powerhouse strategy. To that end we are supporting the work being undertaken by IPPR North to take this work forward – the Northern Energy Taskforce[16] and we consider that BEIS should continue to take an interest in its output.

[15] 'A Review and Synthesis of the Outcomes from Low Carbon Networks Fund Projects', August 2016, available from: www.ukerc.ac.uk/publications/a-review-and-synthesis-of-the-outcomes-from-low-carbon-networks-fund-projects.html

[16] For more information, refer to: www.ippr.org/publications/northern-energy-taskforce-a-call-for-evidence

# Part 2 - Responses to call for evidence questions

## Section 2: Removing policy and regulatory barriers

### Enabling storage

***Q1. 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.***

2.1. Yes, we believe the main issues have been captured but more consideration is needed on DNO ownership of storage. DNO ownership and operation of storage should not be ruled out if the market fails to provide the flexibility required or if a 'pump primer' is required in the absence of a functioning market.

2.2. We believe that all elements of storage costs need to be considered carefully to form a clear view on the appropriateness of the different components. Storage should compete with other solutions that offer similar or identical flexibility options for the system. For example, there are industrial and commercial customers that can also import or export and there are also generators of various types that provide network support at peak. This competition between different solutions should be on a level playing field and neither storage, nor demand side response nor generation should be given preferred treatment.

2.3. DNO ownership of storage can co-exist with other market based solutions. We understand that a DNO's participation may need to be constrained by regulatory limitations so that it does not discourage or crowd out other innovative storage options. But in principle, there is no reason to suppose that a DNO's involvement in storage would be detrimental or distorting of that market. Our CLNR project provided evidence of the technical benefits of DNO owned storage (noting that DNO investment needs to be efficient when considering different technical solutions for network issues). DNOs should be permitted to operate local storage for technical reasons and also for commercial reasons where there are clear benefits for consumers.

***Q2. Have we identified and correctly assessed the issues regarding network connections for storage?***

2.4. Yes, the issues regarding network connections for storage have been identified and correctly assessed.

2.5. We consider that there will be benefits in carrying out further work on standard design solutions for storage and more clarity on the typical operating regimes of storage. More work should be done to enable secure firm designs to address topographical network constraints and where export/import limiting systems may enable the full benefits of bidirectional storage systems.

***Have we identified the correct areas where more progress is required?***

2.6. Yes, with the inclusion of further work on standard design solutions, the correct areas for where more progress is required have been identified. NPg will continue to work with Ofgem and storage stakeholders in those areas, including via the various (National Grid Electricity Transmission) NGET, DNO, ENA standing groups and working groups, including:

- **Integrated System Planning Group** - (formerly the High Volts Group) which aims to find efficient whole system solutions;
- **Active Network Management Group** - which aims to manage flexible connections for both transmission and distribution and better understand any conflicts that can form

services required by NGET from customers connected to the DNO network, but that are controlled by ANM;

- **DSR Shared Services Working Group** – which aims to establish a set of contractual rules and processes to enable distribution and transmission to share flexible resources i.e. grid services from connected customers;
- **Statement of Works Group** - which aims to trial methods to provide distributed generation (DG) customers with better/quicker upfront information on grid works implications;
- **Charging Focus Group** - which aims to understand the issues associated with different commercial arrangements for transmission and distribution connected customers; and
- **DG DNO Steering Group** – working on improved processes for managing DG and queuing issues. The terms of reference should comfortably incorporate storage.

2.7. We strongly agree that managing connection offers more efficiently and providing flexible connection offers can improve arrangements for stakeholders. Table 3 in the call for evidence highlights that network operators need to continue to innovate to provide better information to storage customers and we agree. We also agree that this can be done by providing demand heat maps and commercial opportunities for storage. NPg updates its heat maps monthly[17] and provides a register of available capacity at each substation and where ANM is available. NPg's heat maps have been praised by stakeholders for the inclusion of demand head room in addition to DG head room. This should be particularly useful for storage developers.

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

2.8. Evidence to support these view can be found in.

- Reference: Optimal solutions for smarter network businesses[18]. Section 7.2 Real power dispatch (thermal) page 48; and
- Reference: CLNR closedown report[19]. Section 4 – the outcomes of the project. Dynamic demand side response page 13, table of deployment learning page 17.
- Q3. Have we identified and correctly assessed the issues regarding storage and network charging?

2.9. Yes in the main, including on whether storage should be defined as intermittent or non-intermittent. However there are also generators of various types and demand customers that provide network support at peak (similarly to storage) and BEIS needs to consider a categorisation process that produces the right outcomes for storage without creating unintended consequences for other connectees.

2.10. In respect of paragraph 9 of the call for evidence, we agree that the issue of whether storage should be treated as intermittent or non-intermittent for charging purposes can be addressed very quickly if not immediately at distribution level. Where storage is controllable, can be scheduled and can contribute reliably to network security its treatment as non-intermittent is appropriate. However, in considering storage in the review of the Common Distribution

[17] Generation and Demand Availability maps are available from: www.northernpowergrid.com/generation-availability-map and from: www.northernpowergrid.com/demand-availability-map

[18] 'Key Learning Report: Optimal solutions for smarter network businesses', available as report CLNR-L248 from the project library: www.networkrevolution.co.uk/resources/project-library/

[19] 'Project closedown report', available as report CLNR-G026 from the project library: www.networkrevolution.co.uk/resources/project-library/

Charging Methodology (CDCM) the categorisation of all types of export technologies need to be reconsidered. The concept of intermittent and non-intermittent may be out of date and a revised categorisation may be necessary in the medium term to reflect whether a generation site can be scheduled to support the network at the right time, for an adequate duration in the right way, irrespective of the weather (e.g. in respect of wind) or time of day (e.g. in respect of solar). Consideration also needs to be given for the future categorisation of mixed technology sites as evidenced by the development of generation mix 'behind the meter ' for example combining solar with storage or combining solar and biogas generation with storage (i.e. where some of the generation can be scheduled and some cannot).

2.11. With respect to paragraph 10 of the call for evidence NPg believes the network charging methodology under a smart, flexible energy system should have the following features:

- While cost-reflectivity for DUoS charges is an important objective, this needs to be balanced against the need for transparency; the degree of complexity involved; and the desire from customers for price stability/predictability;
- DNOs must be able to recover their efficient sunk costs. In this regard, the charging methodology must be sustainable, in the sense that customers perceive the distribution of this burden to be equitable across different customer groups; and
- The signals generated by network tariffs should be considered in the light of whether a DSO contracting role exists and the scope of that role, to ensure overall consistency.

2.12. Introducing more complex cost-reflective tariffs in order to drive efficient behaviour is likely to have a number of challenges. One issue will be whether competition in the retail market is effective in ensuring that supply companies actually pass on network tariff signals to their consumers. Another issue is whether customers are able and willing to engage in behavioural change driven by network tariffs.

2.13. Given these challenges, in our view customers could in future be regarded as either 'active' customers, who might then be steered through DSO contracting rather than tariffs, or passive customers, who might be charged more 'vanilla' use of system charges which ensure cost-recovery.

2.14. We potentially see three areas of charging that need to be considered simultaneously ensuring that cost signals are sent only once:

- Enhanced connection charges – the time of connection is currently when the DNO has a direct relationship with the customer and when the customer can make informed decisions on their energy requirements and usage. Offering baseline connection charges with the option of appropriate bespoke locational cost signals, should the network require them, at this stage is the most likely means of influencing behaviours;
- DSO contracting – can be put in place in areas in which connection/despatch of demand or generation would be beneficial. There is the potential for a large number of contracts with parties (e.g. distributed generators, DSR or storage) to incentivise despatch at relevant times. The contracts could also allow the specification of duration and specific activation conditions (including penalties for non-delivery on obligations around despatch). Costs would need to be based on a maximum willingness to pay based on present value (PV) of avoided network investment (or potentially estimate of lost load). There is the potential for this to be a separate regulated sector; and

- Use of system charges – if locational cost signals are being sent via connection, and/or DSO contracts then there is no need for DUoS charges to send any overly complex signals as it is more about the cost recovery of the efficient sunk costs.

2.15. A decision needs to be taken by Ofgem as to which signals should be sent through cost-reflective DUoS charges and which should be sent through other instruments, such as constrained connection contracts or DSO contracts. We consider the right way forward for charges is the three-way approach as specified in the preceding paragraph and we would welcome a clear policy intent from Ofgem that it agrees with this approach or endorses an alternative way forward. As patterns of network usage change and new technologies are introduced, it is important that energy policy keeps pace and customers pay their fair share of the costs. In order to facilitate this, regulatory intervention is required to ensure a level playing field in the market and to provide strong strategic oversight. Ofgem needs to be actively engaged in charging developments and provide early intervention if change proposals are not progressing in a way that are capable of being approved. This would improve the efficiency and effectiveness of the process and increase the likelihood of the timely implementation of change which would be in both the industry and consumers' interests.

***Do you agree that flexible connection agreements could help to address issues regarding storage and network charging?***

2.16. Yes, potentially, however we would welcome some detailed information from storage stakeholders if they believe they are unduly or inappropriately disadvantaged by current charging arrangements when compared to generators or other customers that also have import and export capacity requirements. However, NPg would highlight a distinction in the area of flexible agreements between connectees saving costs on their connections and customers more generally providing services to the energy system in exchange for a revenue stream:

- Offers and agreements for flexible connections i.e. for non-standard connections like ANM that can be used to connect storage customers (and generators) more quickly and efficiently; and
- Once connected to a network a storage operator is able to enter into additional contracts for the import / export of electricity and the provision of flexibility services. I.e. services to suppliers, the TSO or a DSO within a DSO model in addition to importing and exporting for electricity trading purposes.

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

2.17. Storage developers are best placed to provide this evidence of the impact of network charging on the competitiveness of storage. In evaluating the evidence, the appropriateness of the charging and whether there is a barrier to storage competing with other forms of flexibility should be the prime consideration. We believe that a key consideration must be that, a level playing field between distributed energy resources is required as opposed to favour being granted to one type (storage or another).

***Q4. Do you agree with our assessment that network operators could use storage to support their networks?***

2.18. Yes, storage should be used if it is the right economic and technical and economic solution to address particular network issues, to provide demand response or to develop the network to facilitate flexibility for the benefit of the total system.

2.19. We support the market-based deployment of storage for grid or energy services In the medium- to long-term. However, in the short term there is scope to adjust the de minimis limits on the innovation components of the price control in order to demonstrate viable use cases and allow DNOs to 'prime the pump'. Ofgem should consider such a regulated solution. It may be for a time-limited period until such time as the other changes contemplated in this call for evidence are made. Rather than distort the market it could therefore facilitate a future market by providing useful sector learning on financeable business cases.

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

2.20. Our interaction with storage developers suggests that it is the uncertainty of future revenue streams and the cost of the technology that holding back the development of a competitive market and not the absence of safeguards.

***Are there any circumstances in which network companies should own storage?***

2.21. Yes. Whenever it is economic to do so and a market-based solution is not forthcoming then it is appropriate for network companies to own and operate storage. Viable business cases for using storage for network uses of network resilience and avoidance of reinforcement have not yet justified its use. There are potential benefits of DNO ownership when storage for network benefits is combined with a mix of other developing ancillary services markets. DNOs should either be able to use 'network storage' for network resilience (where economic to do so) or also combined with the provision of market services subject to appropriate regulatory treatment. The more technically flexible the storage device is, the more use for system services it is likely to be and to facilitate wider market options.

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

2.22. Our evidence is that the cost/benefit of battery storage (at current prices) does not make it an appropriate investment for network resilience and avoidance or reinforcement alone. Our evidence is contained in the following references.

- Reference: Optimal solutions for smarter network businesses[20]. Section 7.2 Real power dispatch (thermal) page 48, and section 8 Over-/ under-voltage support page 50-54; and
- Reference: ESOF Good Practice Guide on Electrical Energy Storage[21].

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

2.23. Yes, however there may be merits in differentiating between different types of storage as this could open the door for positive material changes in the way different types of storage solutions could be regulated:

- commercial storage providing behind the meter solutions;
- directly connected commercial storage serving a market; and

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[20] 'Key Learning Report: Optimal solutions for smarter network businesses', available as report CLNR-L248 from the project library: www.networkrevolution.co.uk/resources/project-library

[21] 'A Good Practice Guide on Electrical Energy Storage', Energy Storage Operators Forum, December 2014. Available from: www.eatechnology.com/products-and-services/create-smarter-grids/electrical-energy-storage/energy-storage-operators-forum/esof-good-practice-guide

- Directly connected 'network owned' storage plant providing network resilience and market services (in a similar way to transformers and capacitors with the addition of market services).

***Please provide evidence to support your views, including any alternative regulatory approaches that you believe we should consider, and your views on how the capacity of a storage installation should be assessed for planning purposes.***

2.24. For evidence please see our response to question 4. We note that local authorities are increasingly interested in the opportunity to connect storage to provide flexibility service revenue streams.

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

2.25. Not entirely. While existing definitions seem to focus on how the storage technology works, there may be valuable additional regulatory clarity in combining how it works with a differentiation of the service it provides.

***If applicable, how would you amend any of these definitions?***

2.26. We have no concerns about the existing definitions in the context of how storage works.

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

2.27. There seem to be three categories of storage emerging:

- Commercial storage providing behind the meter solutions;
- Directly connected commercial storage serving a market; and
- Directly connected 'network owned' storage plant providing network resilience and market services (in a similar way to transformers and capacitors with the addition of market services).

2.28. Directly connected network storage that only provided network resilience and not market services does not need defining separately as this could be treated as network owned regulatory assets in the same way as capacitors and transformers.

## Aggregators

***Q7. What are the impacts of the perceived barriers for aggregators and other market participants? Please provide your views on:***

- ***balancing services;***
- ***extracting value from the balancing mechanism and wholesale market;***
- ***other market barriers; and***
- ***consumer protection.***

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

2.29. Aggregators provide a useful route to market by making a number of markets accessible to customers through a single contract with the aggregator.

2.30. The design of services can have an impact on the number of customers who can provide DSR services. We found as part of our CLNR trials that some of the customers with whom we contracted for DSR via aggregators could provide us with availability that was of value to us but did not meet the more stringent criteria required by the SO for its service requirements. This demonstrated that there is scope to relax some of the SO's criteria when delivering peak reduction services to DNOs. And by being more flexible with qualification criteria we were able to attract more participation from customers.

2.31. We recognise aggregators as a valued route to market to connect the buyers and sellers of services – particularly where the sellers are often customers in need of a third party to assist them in providing the expertise to maximise the return from their resources. Our smart grid trials have demonstrated how with aggregators we may reach more customers and then contract with them to procure and reliably operate DSR as a viable alternative to conventional reinforcement of the network.

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

2.32. Consumer protection should be the lead priority for Ofgem when considering action to address the potential barriers. A relatively high threshold needs setting with supporting quantified analysis before changes should be considered for potential market or barriers or impacts to other industry participants such as suppliers or generators; as change will automatically introduce increased cost and runs the risk of introducing undesirable and unintended results. The intended benefits need considering relative to these potential downsides.

2.33. As identified in the call for evidence, the evaluation required is about benefits (from removing perceived barriers) versus the costs to the various parties of introducing extra complexity. Another consideration is the risk of introducing unintended consequences from changes to a complex and inter-linked set of commercial relationships.

2.34. On consumer protection, the Power Responsive campaign is already seeking to grow the participation of the demand side. Consumers (in particular, domestic and smaller businesses) need to have a 'safety net' to accompany the introduction of smart meters and half-hourly settlement that will enable demand side response.

2.35. For the other potential barriers and issues, Ofgem should conduct further work to quantify the impact of the current arrangements to ensure there is a firm foundation and imperative for action being required that outweigh the potential downside risks of additional cost and unforeseen outcomes.

2.36. We are a member of the Energy Network Association (ENA) Transmission and Distribution Interface (TDI) steering group which provides oversight to the work underway to improve the co-ordination of DSR services. Reporting in to the TDI is the DSR Shared Services Working Group whose aim is to establish a set of contractual rules and processes to facilitate multiple electricity network operators being able to utilise and share services from the same providers in a manner that delivers the best end consumer benefit in security and cost. This work, together with the Power Responsive campaign, has shown that aggregators could continue to assist in growing the market for the provision of energy services albeit the number and complexity of existing SO grid services products on offer needs rationalisation in order to simplify the market and thereby grow the customer base offering flexibility.

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

2.37. As set out above, consumer protection needs to be prioritised since it is this group that could be most disadvantaged by inaction and the introduction of safeguards. Conversely, Ofgem should set out some conditions that would need to be met prior to triggering industry-led or regulatory step-in action. In these last two areas, further analysis must be undertaken by Ofgem prior to a decision being taken on the appropriate way forward.

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

2.38. We agree that a high uptake of DSR by consumers could lead to system stability issues and that this risk could manifest via large aggregators. More whole energy system innovation projects (academic modelling and physical trials) are required to identify the scale of the potential issues and the solutions that could be adopted. Our work with the Centre for Energy System Integration (CESI)[22] could be a useful route to build upon existing knowledge to develop this better understanding.

2.39. The increase in distributed generation and storage seeking to connect to the distribution network is driving an increased need for co-ordination and co-operation between DNOs, transmission operators (TOs) and the system operator (SO). The ENA DSR Shared Services Working Group is developing principles on how shared DSR can be utilised and what visibility is required by DNOs and SO when services are called. This work will include understanding and developing the required notification and communications processes and how services offered by other parties such as suppliers and aggregators fit in to this process.

2.40. The lack of visibility of disruptive loads connected on the system can also lead to system stability issues. Although there is a requirement on customers to inform the DNO of disruptive loads under the National Terms of Connection, there is no formal process for this and there is no obligation to notify the DNO about the connection of individual large domestic loads such as heat pumps and electric vehicles, even though these can contribute to network constraints.

2.41. An example of a new system peak was identified in our CLNR trials of heat pumps. These showed a distinct peak in consumption around 3am due to default timer settings for hot water heating. This 3am spike is clearly a product-specific occurrence with heat pumps programmed to come on at that time, but provides an important message for manufacturers, regulators and legislators that it would be better to build diversity into the appliances e.g. by randomising the defrost time between 2am and 4am. In the case of widespread heat pump deployment, steps may need to be taken to introduce diversity into heat pump operation, in particular the morning pick-up in demand.

2.42. Our CLNR trials of electric vehicles found that they present a fairly inflexible yet predictable load. All of the charging curves from the trials showed evening peaks, which indicates that people are probably coming in from work and putting the car on charge. Hence, the biggest issue we identified is the lack of diversity and flexibility in EV charging times. Domestic charging of EVs has raised the level of domestic peak demand but this is not yet a problem for network system design and operation. With greater concentration or if there were two EVs at a household, this would no longer be true. EV users are already establishing habits to charge their car when it suits them and this may be difficult to break even with appropriate time of use (ToU) tariffs. There is therefore a strong case for taking appropriate action to encourage off-peak charging behaviour at an early stage.

[22] CESI is funded by the Engineering and Physical Sciences Research Council (EPSRC) and is a collaborative academic/industry project centred at Newcastle University.

# Section 3: Providing price signals for flexibility

## System value pricing

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

3.1. The key enablers to access flexibility are smart meters with half-hourly (HH) settlement and the introduction of more cost-reflective retail pricing.

- The introduction of smart meters and HH settlement are currently progressing. We return below to some of the issues with this process which we believe need to be addressed.
- Cost-reflective retail pricing, shows the true cost of providing energy on a time of use (ToU) and potentially seasonal basis. This might involve retailers passing on signals from DUoS charges, but we believe a more likely enabler (in relation to network aspects) would be enhanced connection contracts and the introduction of DSO contracts in areas in which connection/despatch of demand or generation at relevant times would be beneficial. The contracts could also allow the specification of duration and specific activation conditions (including penalties). A well-functioning DSO could ensure that relevant providers of flexibility can access revenue streams which provide for more bespoke, location-specific solutions which is unlikely to be feasible under common charging methodologies.

3.2. Any new market platform will need to consider:

- The impact on the whole system;
- Be transparent with clearly defined data flows for the provision of flexible resources and contracted positions;
- Avoid undue discrimination;
- Be simple enough for parties to understand and effectively engage with; and
- Provide enough stability to encourage market engagement.

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

3.3. We do not believe that this question is targeted at DNOs. However, we would note that distributed energy resources (DERs) have a role to play in providing ancillary services and energy services to networks and to customers. The market is currently mostly focused on provision of services to the transmission system operator but new value streams are starting to emerge for flexibility to alleviate the need for network reinforcement.

3.4. Storage in particular, could be a valuable source of flexibility for network operators, offering an alternative solution which can be used to defer the need for traditional reinforcement or to support cheaper and faster network connections. These benefits include:

- Avoiding or deferring the need for network reinforcement;
- Providing grid services (such as enhanced frequency response (EFR) and voltage support); and
- Facilitating the decarbonisation agenda (e.g. electric vehicles (EV), photovoltaic (PV) and electric heat).

3.5. In addressing the question of who should be allowed to own and operate DERs BEIS/Ofgem will need to be clear about the underlying principles. -

3.6. System efficiency is arguably the most important principle - we recognise the advantages of going out to market for services rather than adding assets such as storage to the distribution network that could restrict the ability to value stack and obtain maximum value from the assets across different parts of the energy system. That said, there may be some advantages for the dedicated use of DERs for distribution businesses in certain situations where ownership by the DNO could benefit customers, in particular by providing increased access to security of supply.

3.7. Currently, DNOs are able to trade energy from storage as long as:

- The storage provides no more power than 10 MW per installation or 50 MW in the case of a generating station with a declared net capacity of less than 100 MW;
- The storage investments and turnover do not exceed the 2.5% 'de minimis' limits specified in the Distribution Licence, or the storage business has Ofgem's consent; and
- Any changes to the regulatory regime should look to accommodate different models for different circumstances; recognising that the adoption and use of DERs is in relatively early stages and we should be looking to enable a range of business models that will benefit customers rather than picking one solution that may or may not prove to be the optimum.

3.8. We note that some thinking in this area has already been done by the European Commission, whose recent proposed package of measures included some specifications/rules around the circumstances in which DNOs can own and operate storage[23].

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

3.9. Again, we recognise that this question is aimed at parties providing flexibility services and not DNOs. However, we observe from our interactions that business cases for developers are challenging since the flexibility services market is relatively immature. There is a shortage of long-term contracts or price signals to support a business case.

***Q14. Can you provide evidence to support any changes to market and regulatory arrangements that you consider necessary to allow the efficient use of flexibility. What might be the Government's, Ofgem's, and System Operator's roles in making these changes?***

3.10. Societal decarbonisation is changing the patterns of network use and introducing new technologies and it is important that energy policy, network codes and charging arrangements keep pace. The overall approach should be a balanced one which ensures that:

- Efficiently-incurred sunk costs are recovered and assets are not left stranded;
- Distortions do not encourage inefficient development of the energy system;
- Everybody pays a cost-reflective price but with a degree of protections (cross subsidy) to ensure that vulnerable customers are not unduly exposed to cost-reflective pricing; and
- Outcomes are good for consumers as a whole while recognising distributional impacts.

3.11. The issue of charging for generators is a growing one and needs to be addressed (which we recognise is part of ongoing charging reviews). However, unintended consequences from any

[23] https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

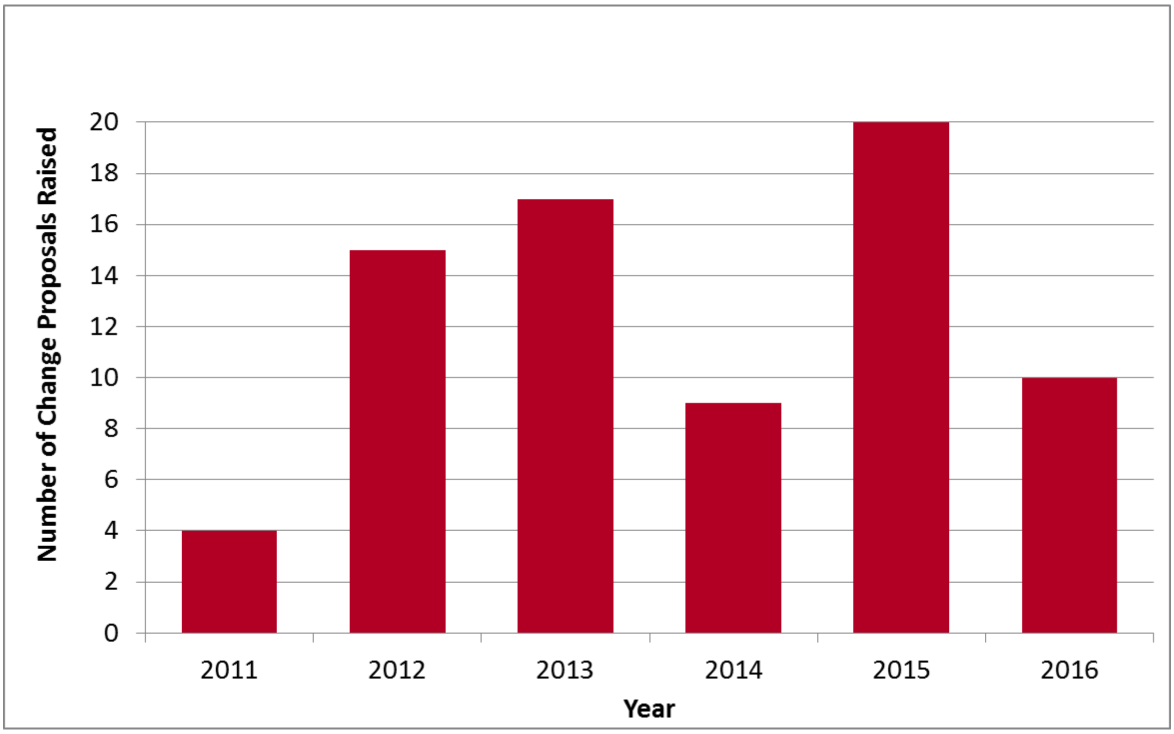
remedy must be avoided so as not to transfer the market distortion to other parts of the energy system and hence create new inequities.

3.12. In relation to distribution charging, we believe this has a number of implications.

- First, Ofgem needs to be actively engaged in charging developments and provide early intervention if change proposals are progressing in a way which ultimately is not going to be approved. This would improve the efficiency and effectiveness of the process and improve the likelihood of the timely implementation of change which would be in both the industry's and consumers' interests.
- Second, there should be a holistic review of charging arrangements in encouraging the efficient development of the energy system. However, the scope and objectives of any review need to be clearly defined before any work in undertaken.
- Third, to create space for a fundamental review of distribution charging methodologies, some prioritisation of ongoing change requests will need to be considered.

3.13. Figure 6 tracks the number of Distribution Connection and Use of System Agreement (DCUSA) change proposals in the UK, relating to distribution use of system charges, which have been raised since the common national charging methodologies were introduced into open governance. Whilst it is not unreasonable to expect a flurry of changes to be raised following the introduction of the common national methodologies, the rate of change has continued at much higher than envisaged levels. This could be interpreted as showing that governance is working fine and people are fixing problems as they see them, but we think that it is more an indication that fundamental change is required as there has never been a period of stability in the market.

**Figure 6:** Number of Distribution Connection and Use of System Agreement (DCUSA) change proposals[24]




[24] Source: Northern Powergrid

3.14. Processing ongoing incremental change proposals draws on the same resources that would be required to facilitate a fundamental review. While there may be low regret changes (including potentially defining the treatment of storage) which could be achieved through the existing modification process, the industry needs to be able to focus on developing an enduring solution without the distraction of numerous ongoing incremental changes.

3.15. Finally, we note that as part of any potential changes to market and regulatory provisions, transitional arrangements need to be carefully considered. They should look to provide the appropriate balance between preventing the further continuation of any charging distortions and ensuring appropriate levels of cost-reflectivity, charging stability, charging predictability and transparency for the users of the service. Any transitional arrangements should consider mitigating the risk of stranding investments that have already been made, particularly in cases where investors would have a reasonable case that they could not have foreseen the change at the time they made their investment decision. Transitional arrangements should be targeted as closely as possible to minimise the cost to consumers.

## Half-hourly settlement and smart tariffs

***Q15. To what extent do you believe Government and Ofgem should play a role in promoting smart tariffs or enabling new business models in this area? Please provide a rationale for your answer, and, if you feel Government and Ofgem should play a role, examples of the sort of interventions which might be helpful.***

3.16. We provide evidence that customer behaviour can be influenced by smart tariffs in a way which improves efficiency, and as such, we think Ofgem and Government has an important role to play in supporting their introduction.

3.17. We consider that the move to HH settlement provides the potential for wider benefits to be achieved by sending price signals to encourage a shift in demand away from peak times. Peak electricity demand poses a particular challenge both to network operators and to energy suppliers. A reduction in peak demand would allow existing networks to accommodate load growth with lower investment, and also reduce the cost of electricity generation during peak periods.

3.18. To explore the potential for peak reduction, our CLNR project has trialled a ToU tariff scheme[25]. By increasing electricity prices during the weekday peak period (4pm-8pm) throughout the year and reducing prices in off-peak periods, the tariff incentivised a shift in consumption out of the peak period. A static ToU tariff was used (i.e. the tariff remained constant and did not change dynamically depending on expected network loading).

3.19. On average, when compared to consumers in the control cell, consumers on the ToU tariff had lower consumption during the peak period on weekdays, and higher consumption at other times – indicating that the tariff achieved the intended behaviour change. There was a small net reduction (0.8%) in annual consumption, although this was not enough to be statistically significant. In particular, the trial showed:

- Lower electricity consumption during the peak periods (between 1.5% and 11.3% less than the control cell). This is in line with our qualitative CLNR research where customers claimed that they had changed the time of use of certain appliances;

[25] 'Insight Report: Domestic Time of Use Tariffs', available as report CLNR-L093 from the project library: www.networkrevolution.co.uk/resources/project-library/

- Lower average peak power demands during the peak period (between 3.2% and 12.5% lower than the control cell when averaged throughout the year and across all customers);
- On average, customers showed a lower maximum HH peak demand (between 2.1% – 10.3% lower than control cell) during the peak period; and
- At the time of greatest system peak demand – specifically a single half-hour in the year- there was no (statistically significant) difference in the mean peak demand observed between trial and the control cell.

3.20. We believe the need for Government/Ofgem to play a more active role in promoting the use of smart tariffs and provide clear strategic direction, leadership and vision is demonstrated by the issues with the current HH settlement programme where the suppliers' migration of profile class (PC) 5-8 customers (i.e. larger non-half hourly (NHH) connected customers) has been slow and there appear to be too many loopholes and extensions to timeframes to ensure this happens in a timely manner. For example, suppliers were required to install Automatic Meter Reading (AMR) meters for all PC 5-8 customers by 2014. They have since been required to provide migration plans to complete migration of these customers to HH trading arrangements by April 2017 and yet they are still suggesting that not all customers will have AMR meters installed or be moved to HH settlement by that date. We recognise that some customers will choose not to have their metering equipment changed, and that they are not required to do so, and therefore suppliers face difficult barriers to achieve the migration to HH settlement. We are concerned that this situation has continued for a significant length of time, beyond Ofgem's mandated deadlines.

3.21. We do not believe that the requirement of suppliers to take all reasonable steps to install HH capable meters provides the necessary confidence that such customers will be migrated and will continue to be excluded from the mandated migration in the absence of stronger regulatory influence.

3.22. We welcome and fully support Ofgem's recent sentiments in its open letter on this matter[26] and encourage Ofgem to reaffirm its position as we progress towards key deadlines to ensure migrations are completed as soon as practicable.

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

3.23. Given the examples discussed in the response to question 15 above, Government/Ofgem should be looking to take proactive action in the near term in continuing to address the supplier-led PC 5-8 customer migration issues and then to utilise the learning from this process to ensure a smoother transition for the mass market PC 1-4 customers. Delaying any further proactive intervention increases the risk of further market distortion.

3.24. The timing and implementation of any interventions needs to be coordinated with the availability of the relevant technologies. Smart meters and HH settlement are correctly identified as key facilitators of smart tariffs but it is also about the availability and development of new technologies. Making changes to industry governance arrangements (both in relation to charging, as discussed above, and more generally) and the implementation the remedies from the recent CMA energy market investigation[27] are key enablers. The removal of restrictions on

[26] The letter is available from: www.ofgem.gov.uk/publications-and-updates/open-letter-migration-consumers-profile-classes-5-8-half-hourly-settlement-under-p272-and-p322
[27] For more information: [www.gov.uk/cma-cases/energy-market-investigation](www.gov.uk/cma-cases/energy-market-investigation)

the number of supplier tariff types seems particularly important, as it will better enable suppliers to put more innovative products to the market and provide new offerings to consumers that could help facilitate the transition to a smarter, flexible energy system.

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

3.25. We are not aware of significant international evidence in this regard. However, there are three pieces of evidence which we think worth considering:

3.26. First, at the European level, there is a clause in the EC's recently published winter package which requires all countries to make sure final customers have, on demand, a day ahead price based tariff. Although this is presently just a proposal, it is likely that various pieces of evidence from other European countries will be advanced as part of these discussions.

3.27. Second, a key question for BEIS and Ofgem when considering how to encourage the development of smart tariffs is an understanding of how effective they are, and the conditions under which customers take-up and respond to such tariffs. Frontier Economics and LCP undertook a study for the Department for Energy and Climate Change (DECC), published on October 2015, evaluating the potential for DSR in the UK. This study referred to trials that had been carried out in other countries/jurisdictions (such as Ireland and California) as well as in the UK, which contained information about take-up of DSR contracts and the effect on demand[28].

3.28. Finally, we understand that in the Spanish market, in February 2014 the government changed regulated electricity tariffs (which can be chosen only by households and small businesses) such that for customers with a smart meter, the energy component of the new tariffs is equal to the electricity wholesale price, which in Spain changes every hour. Households which choose the regulated tariff pay a different price every hour. While this is not necessarily a policy which BEIS and Ofgem may wish to pursue, it may be that there is useful evidence resulting from this change which should be considered[29].

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

3.29. The current supplier hub principle does not mandate suppliers to offer smart tariffs, nor does it require that DUoS signals are passed on to end consumers. Suppliers' offerings are driven by the competitive market. Energy intensive users generally have energy managers who can monitor the market and provide advice and guidance such that understanding network charges and their implications is typically less of an issue for these customers. In contrast, smaller consumers are less likely to have access to such resources in order to keep up with the changing environment. Indeed, they may consider this as a role that their energy supplier would help them with.

3.30. We believe a more coordinated industry approach, with common DNO and supplier communication would have been beneficial and we look forward to being involved in lessons learned to improve the future consumer experience.

[28]'Future potential for DSR in GB', Frontier Economics, LCP and Sustainability First, October 2015. Available from: www.gov.uk/government/uploads/system/uploads/attachment_data/file/467024/rpt-frontier-DECC_DSR_phase_2_report-rev3-PDF-021015.pdf

[29]'Energy Policies of IEA Countries - Spain 2015 Review', International Energy Agency, July 2015, available from: www.iea.org/publications/freepublications/publication/IDR_Spain2015.pdf

3.31. We recognise that there are reasons for suppliers not offering smart tariffs. We are aware that in the HH market some suppliers already pass-through DUoS charges and ToU tariffs to consumers. In the NHH market, we note a number of possible explanations for not doing so, including that:

- Consumer and intermediary preferences for simpler tariffs, which are easier to understand and compare. (If this preference is driven by a lack of understanding of the smart tariffs being offered and the opportunities they present, this would suggest that short-term communication and engagement has failed; to the extent it reflects an underlying lack of consumer confidence in the energy market, this would suggest longer term failings need to be addressed in order to restore confidence);
- 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);
- Trade-offs between reducing the cost-to-serve and raising suppliers' costs of bill administration (standardised products are likely to be cheaper to administer); and
- Customers may not be very price elastic, and energy cost may be small in comparison to overall operating costs.

3.32. In relation to network charges in particular, analysis of our CLNR project demonstrated that customers did not change their pattern of use following the introduction of the new distribution price signal to avoid system peak. This might be partly explained by the discovery that, initially (in 2010 to 2012), for the sample population, only around 5% of suppliers had passed on the price signal to the end customer. It may be economically rational for energy suppliers, operating in a commercially competitive market, to absorb these signals but the overall effect of such action needs consideration in the future.

3.33. Further, in common with all other DNOs we have had Red/Amber/Green ToU charges for industrial and commercial customers since 2010. Since the introduction of ToU charges for industrial and commercial customers we have not seen evidence that this has delivered a reduction in peak usage.

3.34. The timebands and typical price differentials, in our area, are shown in Table 1 below. Customers on these tariffs represent 0.4% of our customer base (~14,000 customers), and 48% of the demand on the network (~17,700 GWh).

**Table 1:** Current demand tariff cost multiplier – NPg

| Band | Time | Current demand tariff cost multiplier – Relative to GREEN timeband | |
|---|---|---|---|
| Red | 16:00 to 19:30 Monday to Friday | ~ 100 x | ~ 150 x |
| Amber | 08:00 – 16:00 & 19:30 – 22:00 Monday – Friday | ~ 10 x | ~ 15 x |
| Green | 00:00 to 08:00 & 22:00 to 00:00 Monday to Friday<br>00:00 to 00:00 Saturday and Sunday | 1 x | 1 x |

3.35. Customer behaviour has hardly changed at all in response to these tariffs: the spread of units distributed has seen a maximum variation in the six-year period on red, amber and green units of 0.2, 0.4 and 0.6 percentage points respectively as demonstrated in Figures 7 and 8 below.

**Figure 7:** R/A/G Unit Split vs Strength of Cost Signal for LV HH Customers

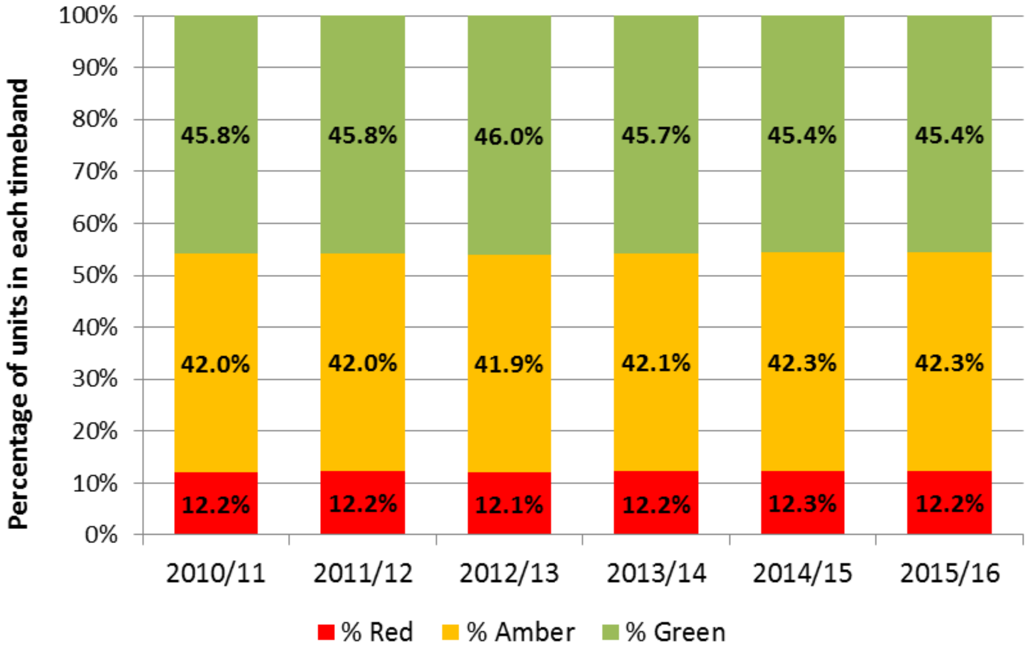
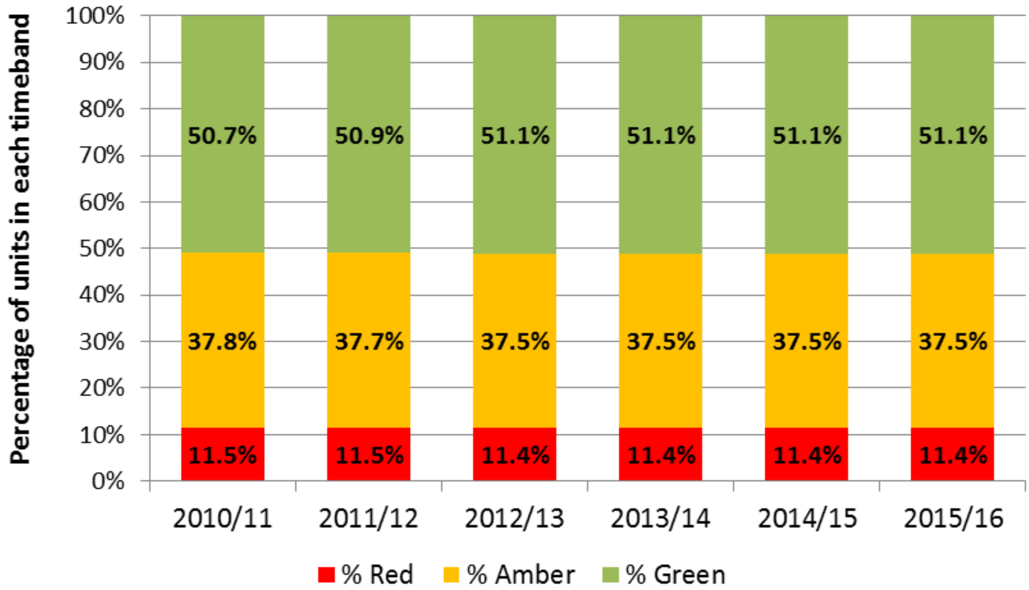



**Figure 8:** R/A/G Unit Split vs Strength of Cost Signal for HV HH Customers




3.36. In the light of this experience, we conclude that whilst a greater number of ToU distribution tariffs may have the merit of being more cost-reflective, they may fail materially to alter patterns of usage at the aggregate level where locational decisions have already been made by customers at the time they connected. Because of this, we believe that DSO contracting may be more effective in sending appropriate signals to those customers that are able, and willing, to react.

## Smart distribution tariffs: Incremental change

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

3.37. If the current charging methodologies[30] do present barriers to the development of a more flexible system the processes already exist whereby any DCUSA party can suggest changes to the charging methodologies. These would then follow normal governance arrangements and if the proposed change better meets the relevant objectives it would be approved for implementation. Hence we do not believe that distribution charges are currently acting as a barrier to the development of a more flexible system.

3.38. We are however, conscious that the timeframe for setting up working groups, issuing industry consultations and putting forward a change report can be quite time consuming. This is compounded by the fact that the approval of DCP178 'Notification period for change to use of system charges'[31] obligates DNOs to provide 15 months' notice of charges. This means that, today, the next opportunity for changes to be reflected in tariffs will be April 2019.

3.39. Clearly, this time lag would present a barrier should we require quicker tariff change but we do not see that imperative currently. If it was viewed as a hindrance then there would be a significant downside to changing the arrangement. Feedback from our own stakeholder engagement and Ofgem's consultation on the subject showed that this change to 15 months' notice brought about a number of potential benefits, including but not limited to:

- The advanced notice of charges should enable suppliers to reduce the risk premium they currently price into contracts with customers;
- Suppliers may also be able to offer a wider range of products to consumers; and
- Increased predictability of charges.

3.40. However, the new timeframes do not address underlying volatility, and may actually increase the size of step changes between years. Charging volatility is therefore an issue that should be addressed in the underlying models.

3.41. We consider the distribution charging methodologies are presently overly complicated and the tariffs in their current form cannot easily support short-term price signals. They were developed to introduce commonality at a time when there were lots of individual methodologies in place. The benefit of common methodologies now makes it easier in some ways to undertake more fundamental reviews, taking account of social and economic changes and the impact of new technologies and new ways of managing the network. We believe that future changes should be considered in the fundamental review category rather than incremental change (we note, however, that does not imply that a Significant Code Review is required).

3.42. The call for evidence also identifies that the network charging methodologies were not designed with storage in mind and so applying them to storage can create problems. The document rightly identifies a number of issues in this area such as:

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[30] There are currently two national charging methodologies for setting DUoS charges that are under open governance arrangements:

- The average charge calculated using the CDCM for low-voltage (LV) and high-voltage (HV) demand and generation users, which was introduced on 1 April 2010. Full details can be found in Schedule 16 of DCUSA;
- The joint demand and generation site specific EDCM for designated EHV customers, which was introduced on 1 April 2012 for demand and 1 April 2013 for generation users. Full details can be found in Schedules 17 and 18 of DCUSA.

[31] www.ofgem.gov.uk/publications-and-updates/distribution-connection-and-use-system-agreement-dcusa-dcp178-notification-period-change-use-system-charges

- the requirements for clear guidance on whether storage should be classified as intermittent or non-intermittent;
- the benefits from ensuring that ensure flexible connections are available for storage; and
- network charges should represent a cost-reflective and fair recovery of network costs without the risk of competition distortion.

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

3.43. There are some relatively simple changes that could be implemented to address storage. For example, the treatment of storage as intermittent/non-intermittent generation should be addressed. Similarly, some of the differences currently in place between NHH and HH settlement consumers could be considered. In particular, we believe it may be worth assessing whether it is fair that HH customers can reserve a level of capacity and pay for it regardless of whether or not they use it? Initiatives to manage under/over utilisation of capacity could be improved if there were different bandings/levels for consumers to assess providing incentives not to hold onto unutilised capacity.

3.44. Future technology developments will pose similar challenges as we move towards a smart, flexible system. This is the reason we are suggesting a more fundamental review is needed, as it will help to ensure that we address some of the policy decisions that would help to future proof any new approaches. As we noted above, we think industry resources would be better targeted towards such a fundamental review rather than dedicated to making incremental changes, provided the scope and objectives are clearly defined.

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

3.45. The different treatment of generators between the EDCM and CDCM has always been an area of concern.

- EDCM intermittent generators never receive a credit and not all non-intermittent sites do if they are seen to be driving the need for future reinforcement; whereas
- CDCM generators (both intermittent and non-intermittent) receive credits even if they are not helping the networks.

3.46. This inequality is driven by the charging methodologies rather than the impact that the customer has on the network.

3.47. Credits in the CDCM were seen as appropriate during the development of the methodologies because, in aggregate, the connection of such generators was expected to result in the deferral of reinforcement. Significant work has been carried out to look at CDCM generator credits and determine whether or not they should receive credits if they are in a generation rich area. The difficulty is the granularity of data, particularly at LV where we are seeing significant increase in Photovoltaic (PV) generation, which quite often is not metered. The complexity of assessing all generation on a site-by-site basis would outweigh the cost of the credits. Given this, there is a case to review generation charges/credits as a whole for all voltages and look for a different approach to ensure the appropriate balance is achieved.

3.48. There are also issues (and the potential for gaming) around the boundaries between charging methodologies, be that the EDCM/CDCM boundary or the transmission/distribution boundary.

Even within the CDCM there is the potential for distortions between the HH and NHH markets due to the different tariff structures.

3.49. It is important that the whole system is considered, not just the distribution network. We are currently participating in a Transmission/Distribution Interface (TDI) group which is looking at issues across different parts of the energy system. The TDI taskforce working group is documenting the interface issues and looking at the rights and entitlements across both transmission and distribution charges. These documents have been included in the final report which has been submitted to Ofgem[32] and will be the subject of stakeholder workshops in Q1 2017 along with proposals for the proposed scope of future work.

3.50. Much of the debate is around transmission charges rather than distribution charges and the group is now beginning to understand that not all of the issues originally listed are issues in their own right, but consequences of the different methodologies and the underlying embedded benefits. Whilst these seem to be more around connection issues and costs than use of system it has been a beneficial process to aid understanding. We believe that some of this work will assist Ofgem when it publishes more detailed views on the embedded benefit.

## Smart distribution tariffs: Fundamental change

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

3.51. It is inevitable the drivers of costs on the network will change over time as the market evolves. Historically the distribution networks have been demand dominated. The increasing focus on embedded generation and the desire to move towards a low carbon economy means that the way we plan, develop and charge for our networks also needs to change.

3.52. Low Carbon Network trials, innovative connection solutions and ANM should ultimately result in costs savings in the longer-term, as they are integrated into business as usual. However, in the short term there should be a review of both the connection and use of system methodologies to assess whether the locational signals that customers can react to should be confined to the time of connection, leaving use of system charges to recover the sunk (fixed) costs of wider reinforcement and operational repair and maintenance costs, and provide ToU signals if these are to play a part in the future pricing arrangements.

3.53. From a distribution perspective we potentially see three areas of charging that need to be considered simultaneously ensuring that cost signals are only sent once:

- Enhanced connection charges – the time of connection is currently when the DNO has a direct relationship with the customer and when the customer can make informed decisions on their energy requirements and usage. Offering baseline connection charges with the option of appropriate bespoke locational cost signals, should the network require them, at this stage is the most likely means of influencing behaviours;
- DSO contracting – can be put in place in areas in which connection/despatch of demand or generation would be beneficial. There is the potential for a large number of contracts with parties (e.g. distributed generators, DSR or storage) to incentivise despatch at relevant times. The contracts could also allow the specification of duration and specific

[32] 'Transmission and Distribution Interface Steering Group Report- December 2016', Energy Networks Association, available from: www.energynetworks.org/assets/files/electricity/regulation/TDI%20Report%20Dec%2016_final%20v0%2010%20211216.pdf

activation conditions (including penalties for non-delivery on obligations around despatch); and

- Use of system charges – if cost signals are being sent via enhanced connection, and/or DSO contracts then there is no need for DUoS charges to send overly complex signals – DUoS charges would send simple cost-reflective signals and ensure the cost recovery of efficient sunk costs.

3.54. We believe that the changes that have been identified in the CDCM and EDCM[33] reviews would be classified as fundamental reviews.

3.55. Ofgem's response to the EDCM[34] review included the following feedback:

- The work is a valuable contribution to the future direction of electricity charging;
- The industry need to take the next steps (either via DCUSA changes or further policy discussions);
- The CDCM review should also reflect these views, where appropriate;
- The views reflect the work with BEIS on a smarter and more flexible energy system;
- Consideration needs to be given to treatment of new technologies (e.g. storage);
- Other charging arrangements need to be considered (e.g. review of embedded generation, allocation of sunk/fixed costs); and
- Next steps should include more forward looking focus (e.g. storage, DSR, increasing DG, DSO role).

3.56. Subsequently a review of the CDCM has identified the following areas that should be considered for development:

- The costing model (500MW model) which forms the basis of the charges should be reviewed;
- Tariff structures need to be revisited to ensure the appropriate balance between cost reflectivity and cost recovery;
- The approach to IDNO charging should be reviewed;
- Consideration of future products (e.g. storage, DSR etc.); and
- Consideration should be given to combining the charging methodologies to remove some of the boundary issues.

3.57. The report will be submitted to Ofgem shortly and we feel that the CDCM and the EDCM should be considered jointly as part of a holistic fundamental review.

3.58. As part of further considerations, cognisance should be taken of previous work in the area. Two key pieces of study are the Citizens Advice report on 'The Tariff Transition Considerations for

[33] 'Report for the Distribution Charging Methodology Forum (DCMF) Methodology Issues Group (MIG)',Extra-High-Voltage Distribution Charging Methodology (EDCM) Review Group, December 2015. Available from http://www.energynetworks.org/assets/files/electricity/regulation/DCMF/EDCMReviewGroupFinalReport%2031Dec2015.pdf

[34] 'EDCM review – Ofgem views', Ofgem, October 2016, available from: www.energynetworks.org/assets/files/electricity/regulation/DCMF/DCMF%20MIG/EDCM%20review%20Ofgem%20letter%20to%20group%20Oct%202016.pdf

Domestic Distribution Tariff Redesign in Great Britain'[35] and the Eurelectric report on 'Network Tariffs'[36], each are summarised below.

3.59. The Citizens Advice report has some interesting analysis on the way that distribution tariffs could be developed for domestic customers. It notes that:

- The basic structure of domestic distribution tariffs has remained relatively unchanged for decades and the costs of the distribution system (including the poles, wires, transformers and substations as well as the operation and maintenance of this system) have largely been recovered through a simple tariff which includes a 'standing charge' (p/day) and a 'unit charge' (p/kWh);
- Consumers' relationships with the distribution system are changing. In some cases, consumers are installing distributed generation (DG) such as rooftop solar panels. This not only reduces the net amount of electricity that consumers use from the grid, but also introduces the ability to supply electricity to the grid. Further, the rollout of smart meters will eventually allow the deployment of new charging structures which were not previously feasible for small consumers. A growing need for flexibility on the demand-side to better integrate renewable generation will also change the relationship between the consumer and the power grid;
- Changing the design of the tariff could potentially offer many benefits in this new environment. But while there is growing momentum towards tariff reform for domestic consumers, there is uncertainty about the shape that the new tariffs will take; and
- Three important factors will determine the extent to which distribution tariff reform could impact consumers:
    - The degree to which consumers will be exposed to the structure of the alternative distribution tariff;
    - The future of HH settlement for domestic consumers; and
    - The share of the consumer's bill accounted for by distribution charges.

3.60. The report also discusses a number of alternative distribution tariff design options:

- A **higher standing** charge, whereby the unit charge is decreased proportionally relative to the existing tariff, such that the total revenue collected is the same in the absence of any change in behaviour. The theory behind this approach is that distribution network costs are sunk/fixed in the short run and should therefore be recovered through a fixed charge. Higher standing charges are simple and ensure that a minimum amount of distribution costs are collected from each customer. Common concerns about higher standing charges typically relate to the fact that they would increase bills for small consumers and would reduce the financial incentive to pursue energy efficiency;
- A **demand charge** based on a measure of a customer's peak demand. It is typically introduced as a third charge, alongside the standing and unit charges. The theoretical support for demand charges is that distribution costs are driven much more by distribution system peak demand than by total consumption, so a demand-based charge better aligns prices with costs. Demand charges have been offered to large customers for decades, would present an opportunity to improve economic efficiency in tariff design,

[35] https://www.citizensadvice.org.uk/about-us/policy/policy-research-topics/energy-policy-research-and-consultation-responses/energy-policy-research/tackling-tariff-design-the-tariff-transition/

[36] http://www.eurelectric.org/media/268408/network_tariffs__position_paper_final_as-2016-030-0149-01-e.pdf

and would provide a price signal that would encourage reductions in peak demand. Common concerns about demand charges typically relate to questions about whether customers can understand and respond to the new tariff structure;

- **Time-varying unit charges** would include a higher price during peak hours when there may be capacity constraints on the distribution system and lower prices during off-peak hours. ToU tariffs provide an actionable incentive for customers to reduce bills by changing consumption patterns or investing in energy management technologies. ToU tariffs are already a feature of the standard distribution tariff for large consumers in GB and are an option for domestic customers. Concerns about ToU tariffs largely relate to the ability or interest among customers in responding to the new price signal. There are also concerns that a unit charge is not necessarily an appropriate price signal for recovering demand-driven costs; and
- **Inclining block rates (IBRs)** charge consumers a price that escalates with consumption over the course of each billing period. Often, IBRs are designed to charge a lower than average price for a minimal amount of electricity consumption that is deemed necessary for basic services like lighting and refrigeration, and a higher price for consumption associated with 'discretionary' electricity consumption. IBRs are generally a policy tool that is used to encourage energy efficiency and reduce bills for small consumers of electricity. Concerns about IBRs often relate to there not being a strong cost-basis for this tariff structure, which could lead to economically inefficient investment decisions.

The above would not necessarily need to be considered in isolation and a hybrid approach might be a more desirable solution. However, care needs to be taken to ensure that charging structures which are designed to achieve social outcomes may not be cost-reflective and may lead to unintended consequences. For example, an inclining block structure may deter the connection of technologies such as heat pumps and EVs.

3.61. The Eurelectric report on 'Network Tariffs' also raises some interesting observations, the key messages are:

- DNOs[37] are key in enabling a successful energy transition, while still providing a high-quality service to all customers through the distribution system stability, power quality, technical efficiency and cost effectiveness in the future evolution of distribution networks towards a smarter grid concept;
- Full and timely recovery of network costs (operational expenditure, depreciation and a fair return on investment) is a necessary condition for DNOs to fulfil their duties. To this end, the impact of variations in consumption volumes on DNOs revenues should be neutralised economically and financially, otherwise they can hamper the sustainability of investment and increase the cost of capital;
- The structure of the distribution network tariffs, and in particular the balance between the capacity (€/kW) and the volumetric (€/kWh) tariff components, is an important issue for the entire electricity system;
- Tariffs should encourage overall system efficiency in the long run through price signals incentivising efficient distribution infrastructure services are provided, including: network access, guaranteed power availability, injection/withdrawal of energy and power quality;

[37] The report refers to DSOs but we use the term DNO here to refer to the conventions used in the UK.

- More capacity-based network tariffs (especially for LV consumers) reflect the higher network costs associated with peak demand and provide customers with incentives to reduce their peak load, resulting in a more efficient use of the network. They provide better incentives for a more efficient use of energy overall;
- They should also ensure an efficient and fair allocation of costs among different customer categories, avoiding cross-subsidisation between customer classes;
- Energy efficiency and demand response can be incentivised through a wide set of instruments. The increase in the capacity part of the tariff does not hinder the use of network tariffs as a complementary instrument for this purpose and reinforces the incentive for rational behaviour;
- ToU network tariffs charge different pre-defined prices at pre-defined times of the day or year. Such prices can be set up based on capacity (power), used or contracted. They incentivise a more efficient use of the network, support flexibility, and are compatible with EU policy objectives on energy efficiency and active demand response; and
- Dynamic network pricing assumes that the different states of the distribution network can give rise to differential pricing locally and closer to real-time. Its added value at household level has to be further studied, as dynamic pricing can entail higher complexity and implementation costs and can have an impact on suppliers' offers in some cases. On a complementary basis to incentivise flexibility via network tariffs, DSO can procure services from commercial providers (i.e. suppliers or aggregators) in the future.

Both of these reports support some of our thinking in these areas.

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

3.62. DUoS charges could be used to send both short term and long term signals at the same time effectively but that is likely to result in overly complex charging methodologies. As already outlined, coherent design is needed where relevant price signals are sent once and once only where possible; to avoid double counting price signals, which would lead to inefficient outcomes. We think that DUoS charges should:

- In practice, send broad-based signals through ToU volumetric charges utilising HH smart data to reflect the times when the network is most stressed and longer term signals in either fixed or capacity charges; and
- Recover efficiently incurred sunk costs.

3.63. DSO contracts and enhanced connection charges/agreements should send signals to more active customers, in order to support efficient operation and flexibilities needs at the time of connection and then in terms of operating patterns thereafter.

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

3.64. We are supportive of the work that Ofgem and the industry have carried out to date, and believe that we are the right party to provide local system balancing as a natural extension of the steps we are already taking to manage our network more actively and our knowledge of the local network requirements. However, clearly defining the scope of DSO activities is crucial as there is a need to ensure consistency and a common industry understanding. The chosen solution needs to look to the future and could involve radical change.

3.65. A decision needs to be taken as to which signals should be sent through cost-reflective DUoS charges and which should be sent through other instruments, such as constrained connection contracts or DSO contracts. Each channel could be used to send signals in relation to operation or investment, so coherent design needs to be adopted to ensure relevant price signals are sent once and once only where possible. In this sense, the approach to network charging must be considered in parallel with the question of the DSO role. Neither topic may be considered in isolation of the other.

3.66. We support the work that was undertaken by the Ofgem/DECC Smart Grid Forum Workstream 6, namely:

- Enhanced network monitoring and planning;
- Real time reconfiguration of the network;
- Commercial arrangements to manage the network under fault conditions;
- Active network management to manage voltage or thermal constraints; and
- Distribution system balancing.

We see the first four of these as extensions of current activity, with the final one requiring significantly more work as it is new and will require a step change in operation and may require additional development on distribution use of system charges.

## Other Government policies

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

3.67. The main area of concern that we can see is the how existing Government policies can have an impact on 'free riders' on the network. Dermot Nolan referred to this problem in his recent Daily Telegraph article[38] and we have shared with Ofgem our experience of the problem of free riders in the USA, the fact that we have our own free rider issues in Britain. It would be sensible to address these distortions before the problem gets worse. Some of these issues impact upon network pricing and regulation.

3.68. Insights from fellow BHE companies such as NV Energy in Nevada make good case studies.

- Private solar generation credit programs in certain US jurisdictions create a subsidy that flows to private solar generation customers;
- Between 2013 and 2015, Nevada experienced exponential growth in net metering[39] applications and a significant increase in the annual solar generation subsidy;
- The solar customers had more need for the energy network than ever before, but were not paying anything like their share of the fixed (i.e. predominantly network) costs;
- In December 2015, the Nevada regulatory body established a new pricing structure to be implemented over a 12-year period that separated the pricing of grid services (reflecting costs) from the valuation of excess energy (at opportunity cost to energy companies); and

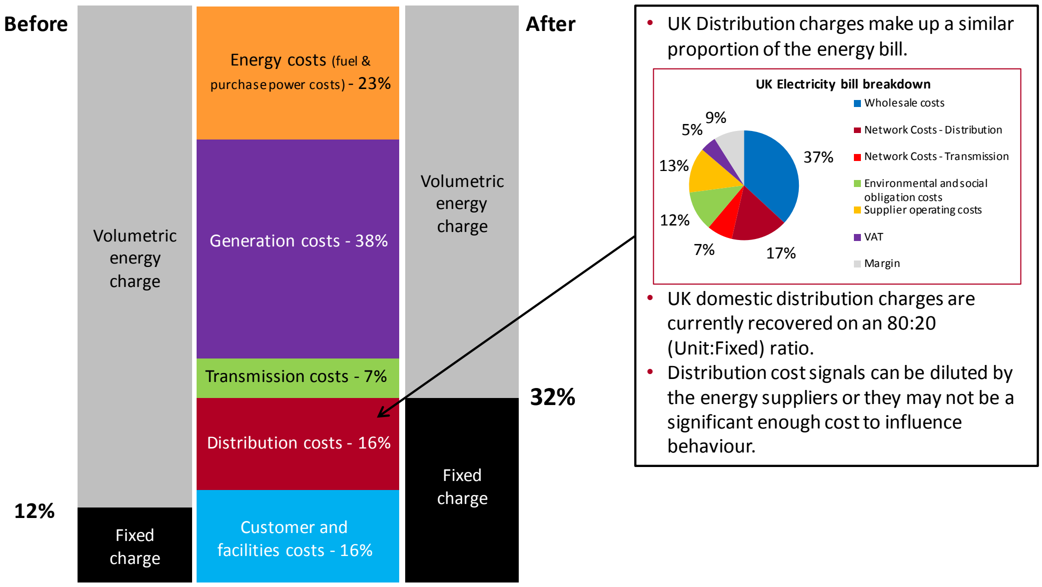
[38] http://www.telegraph.co.uk/news/2016/05/29/households-could-be-charged-annual-insurance-premium-for-access/

[39] Net metering is a tariff mechanism that credits rooftop customers for the electricity they export on to the grid by billing according to net energy use (i.e. import minus export).

- The private solar industry is challenging the decision in Nevada including the issue of whether grandfathering rights should be provided for those already on the net metering tariff.

3.69. Figure 9 below shows how the composition of the net metering tariff has changed to move distribution costs into the fixed element of the end user's charge.

**Figure 9:** Visualisation of the new pricing structure approved by the Nevada regulatory body in 2015

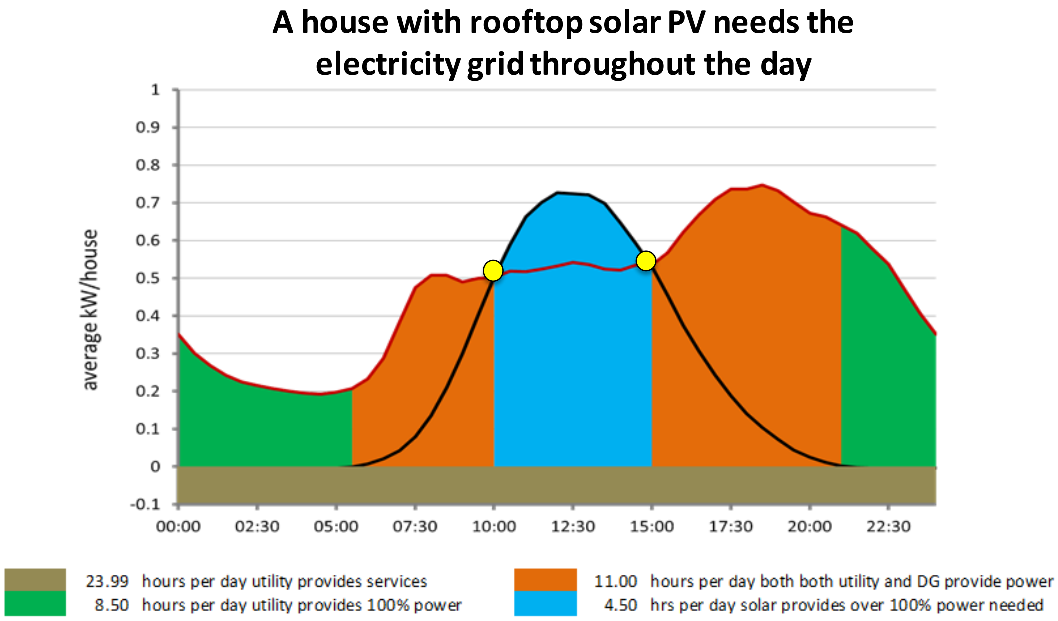



3.70. As patterns of network usage change and new technologies are introduced, it is important that energy policy keeps pace and customers pay their fair share for the costs. For example, there are at least four free rider type distortions in Britain that need attention, namely:

- Benefits for embedded generators that distort the generation market - The fact that below 100MW embedded generators can secure benefits from triad avoidance that are not available to over 100MW generators, or to those connected at transmission level, distorts the generation market;
- The private wire distortion that leads to unfairness in the sharing of environmental costs and inefficient network development - Suppliers that distribute their electricity through a 'private wire' arrangement avoid taxation that falls on licensed suppliers and create the risk of inefficient network development;
- The IDNO distortion that is detrimental to the generality of customers and is distorting the connections market - IDNOs are allowed to cherry pick lower than average cost-to-serve customers and apply tariff support. This disadvantages the generality of users, and distorts competition in connections; and
- The use of system charging distortion that provides undue benefit on those that can afford to install new technologies (such as PV) and reduce their metered unit consumption - Domestic generation owners are able to free ride on other customers by reducing their metered consumption whilst still fully benefiting from the networks to which they are connected (and that's before they might be paid for units they inefficiently used rather than exported).

3.71. Figure 10 illustrates the potential solar PV free rider issue in the UK, based on the CLNR data (i.e. a sample of ca.145 houses equipped with solar PV and monitored for 12 months in 2013). Generation and demand values displayed are the averages for the year. The red line shows the typical energy demand profile and the black line the typical energy export profile. This clearly shows that the customers are not off grid as for the majority of the day they are either pulling energy from the network, or pushing energy to the network. Hence, they should pay the appropriate price for the network and not be able to free ride on the back of other, potentially vulnerable customers, which the current charging structure with a high proportion of unit based charges allows then to do.

**Figure 10:** Typical energy demand profile and export profile of a house with rooftop solar PV




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

3.72. We recognise that this question is aimed at parties operating in the capacity market which we do not do. However, we note that there is already a process in place whereby change proposals can be submitted for evaluation and consideration. That said, any changes to the rules would need to ensure that undue discrimination way was not introduced and that a level playing field for all types of flexibility services is maintained.

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

3.73. In our view it is possible to separate the issues of incentivising the development of renewable generation and ensuring that generation is fully accountable for the costs and benefits which it imposes on the energy system.

3.74. In a recent publication[40], Frontier Economics sets out a taxonomy of the potential whole system impacts of different types of generation. They argue that it is important that the broader impacts of generation sources are taken into account in order to ensure that the right investments are made by market mechanisms (including auctions for technology neutral renewables support). We would generally agree with this as a principle – it is important that investors take all costs and benefits into account when making their investment decisions, in order that costs to customers overall are minimised.

3.75. Frontier indicates that there are two approaches to taking into account such wider costs and benefits. The first involves adjusting renewables support for specific technologies to take them into account. The second involves establishing technology neutral competition for support, but ensuring that the wider energy market regime ensures investors face the costs and benefits of their decisions (e.g. through network charging).

3.76. We believe that the second approach is the most appropriate. The calculation of the whole system impacts of different renewable generation technologies (or, for that matter, storage or demand response) is too complex to be undertaken centrally and used to adjust support levels. It is preferable that the broader energy market design (comprising network charges, imbalance charges, the capacity auction etc.) make sure that investors face the full system impacts (either costs or benefits) from their decisions. If all investors are on a level playing field in this regard, the market can then freely determine the most efficient technologies to meet demand and to meet climate change commitments.

[40] 'Energy Briefing', Frontier Economics, November 2016. Available from: www.frontier-economics.com/documents/2016/11/whole-in-one.pdf

# Section 4: A system for the consumer

## Smart appliances

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

- ***Yes***
- ***No (please explain)***

4.1. Yes, we agree with the four principles for smart appliances and with the reasons that justify the four principles.

4.2. We would add that domestic participation in dynamic DSR could be implemented through other low-cost alternative means such as smart plugs and whole-house monitoring.

- A smart plug measures the power that one appliance uses, allows a user to turn things on and off from a mobile device, but also provides the opportunity for suppliers, aggregators or DNOs to also control the plug to reduce the load at peak times. Ideally, there would be measures in place to ensure that all these different parties are not trying to exercise the same control over the same appliances at the same time for different purposes.
- Whole-house monitoring provides the homeowner with more control and the potential to deliver a larger response when called upon. This can be achieved through various ways including via smart meters, and in the interim, some trials are testing incentives using monitoring equipment connected to the meter tails and using the internet to transmit data.

4.3. Our innovation trial Activating Community Energy (ACE)[41] is currently trialling a DSR proposition based on smart plugs and whole-house monitoring that incentivises participation using gamification. The game, called GenGame, incentivises consumers to offer up appliances for remote control via the smart plugs and also to manually reduce whole-house consumption during certain periods by offering points and prizes based upon the response received. The interface with the participants is via mobile phones, tablets and personal computers. We expect to report on results after the next phase of trials running throughout 2017.

4.4. In addition, our experience in operating smart appliances has taught us not to overlook the technical complexity of integrating smart appliances with a telecommunications network in which information as well as commands need to be exchanged. The interoperability of the appliances is crucial to the ability for domestic DSR to deliver to the whole system, on its full potential. Some test cells in our CLNR project were adversely affected by technical issues resulting in the DNO being unable to communicate commands to the appliance in the absence of common communication standards, infrastructure and protocols amongst appliances and control systems. Another key point that we have seen echoed in other trials since (such as the technology trials operated by National Energy Action) is that low income households often do not have broadband and this has been installed specifically to operate smart appliance trials.

[41] http://www.npg-ace.com/

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

- ***Option A: Smart appliance labelling***
- ***Option B: Regulate smart appliances***
- ***Option C: Require appliances to be smart***
- ***Other/none of the above (please explain why)***

4.5. We propose that a common understanding amongst industry players of what qualifies as 'smart ready' is a necessary first step for any of these options. This definition could be built from an industry consensus, and communicated to the consumers in an appropriate way.

4.6. In addition, there is a need to establish a clear market in which both customers and manufacturers can see the value from participation. We have experienced a situation (in our CLNR trials) where a smart appliance manufacturer behaved rationally by not bringing products to the UK since they could not identify sufficient market opportunity. We expect that suppliers providing time of use tariffs may provide sufficient market signal to encourage more smart appliances to be offered to customers.

***Q30. 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:***

- ***Wet appliances (dishwashers, washing machines, washer-dryers, tumble dryers)***
- ***Cold appliances (refrigeration units, freezers)***
- ***Heating, ventilation and air conditioning***
- ***Battery storage systems***
- ***Others (please specify)***

4.7. A general point for all types of appliance is that the potential for DSR is maximised when the appliance allows for the DSR function to be automated, and the reliability of the device is not adversely affected during or following a DSR event. This minimises the inconvenience for the consumer and incentivises participation.

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

4.8. The CLNR trials were ground-breaking as they demonstrated the end-to-end process of a DNO successfully calling a response from a DSR supplier automatically using 'smart grid' systems and that direct control of appliances can reduce peak load. The small reduction in peak means that this intervention is unlikely to have much impact on distribution network planning. However, if the technology becomes more widespread (and particularly if mandated by product standards), this intervention could be of use for national system balancing.

4.9. This smart appliance technology is new and is expected to improve. The CLNR trials for wet appliances involved low numbers of customers so the results should be treated as indicative. Although technically capable, the trials demonstrated that communications would need to improve and that the relative infrequency with which most households use a washing machine (compared to other appliances such as heating) mean that this is considered unlikely to be a target resource for distribution companies to access flexibility.

4.10. The CLNR project trialled the use of DSR response for smart washing machines driven both by ToU tariff and via remote ‘on-demand’ signals from the DNO. The conclusions arising were:

- Relative to the control test cell, washing occurred more outside times of peak loads, indicating that the default setting of the appliance's control was effective in restricting use at these times. However, as they contribute relatively little to the network peak demand, working with washing machines alone will not deliver a satisfactory peak reduction.
- Also, the over-ride feature – while permitting the customer to use the machine at peak times, despite the default settings – may have served as a continuous reminder of the ToU pricing arrangement and so improved customer engagement. If energy control buttons on washing machines become more prevalent, i.e. through influencing product specification, finding ways to encourage engagement could prove to be a key success factor in reducing peak load.
- A certain amount of demand flexibility is inherent in domestic laundry tasks. By extension this may apply to similar processes such as dishwashing and tumble dryers[42].

4.11. Due to communication failures, 37% of DSR events in the trial were not received by customers. This highlights the need for continuing technical developments to increase the effectiveness of this type of DSR. Issues included the stability of the customer’s internet connection, the equipment being unplugged, teething problems with the control platform, and simply the distance between the appliance in the house and the control gateway. Unsurprisingly, the equipment needs to be ‘plug and play’ to encourage participation (this was not the situation with the trial equipment).

4.12. Further relevant findings of CLNR were as follows:

- Two thirds of trial participants chose never to engage the energy control function, the remaining one third used it at least once;
- There was significant variation in the demand profile between weekdays and weekends, with the weekend peak at midday being nearly twice the weekday peak at 9am, probably correlating with higher occupancy rates and people having more time to do domestic chores;
- When compared to the customers on the unrestricted monitoring trial control group, customers on the restricted hours trial showed a higher appliance demand in mornings and reduced appliance demand in the 4-8pm period. This indicates that customers may have planned their appliance usage ahead of the peak period. 10% of the trial participants who engaged on weekdays demonstrated near zero consumption during the 4-8pm peak;
- There was evidence of increased consumption on weekdays after 9pm, indicating customers delayed use of the washing machine until after the restricted hours period;
- Weekend consumption gave similar patterns in terms of a lower level of appliance use between 4-8pm even though the cheaper tariff applied across the full 48-hour period – i.e. learned behaviours persisted over the weekend even though the tariff did not reward it; and

[42] ‘Insight Report: Shifting domestic demand through appliance restriction at peak times’, available as report CLNR-L264 from the project library: www.networkrevolution.co.uk/resources/project-library/

- Peak consumption from the appliances was around 2kW although a high degree of diversity means that the average annual peak consumption attributable to the appliances is less than 0.05kW in any half-hour period.
- On the direct control trial, an average of 4% of customers who received a signal delayed the washing machine cycle, while a further 12% ran their machines during the DSR period. This is consistent with DSR having an effect on behaviour. On almost a third of occasions when the user attempted to start a cycle on the machine during a received DSR event, they delayed it.
- This is likely to underestimate the effect of the DSR events, since it is possible that users avoided starting cycles during the peak times, without using the delay function. By comparing the average washing machine power usage of individuals receiving DSR events to days without DSR events, we find a statistically significant (at the 5% level) decrease in average power during the 4-8pm peak window of 11W (the decrease in average power used between the peak time of 6-6.30pm is 26W, although not statistically significant).
- These results show that some consumers clearly do respond to events, although the small number of households interviewed asserted that there had been no change to their previous washing regimes. This discrepancy may reflect the fact that washing routines vary by household. For example, households which routinely carried out washing on weekends would be unaffected by the DSR events.

### *Cold appliances (refrigeration units, freezers)*

4.13. From our CLNR trials in the small and medium enterprise (SME) and domestic sectors we have evidence that cold appliances have the potential for a degree of flexibility, dependent upon household routines and business operations, provided that concerns about spoilage of food can be addressed. We have found that consumers' confidence in an appliance's ability to prevent spoilage increases the flexibility potential of such appliances; compared to a scenario when users have to rely on taking action themselves by manually overriding a demand response request. This has been confirmed by our experiences in a later innovation project:

- In our Activating Community Engagement project[43] we are trialling gaming approaches to community based demand reduction in households to address network constraints. Participants used smart plugs on appliances of their choice to provide demand reduction in response to signals from the network operator.
- However, because of some incidents where the smart plugs did not switch the appliance back on after an event, we initially advised participants not to use the smart plugs on fridges or freezers to avoid the risk of food spoilage.
- While we have made adaptations to address this issue, this experience has highlighted the need for reliability in ensuring that cold appliances successfully resume operation after an interruption.

4.14. In addition, a literature review from CLNR[44] found that the appliances used by SMEs that would be most amenable to providing flexibility are those where interruptions have the least impact on business operations. This is likely to be appliances such as space cooling, heating and

[43] http://www.npg-ace.com/

[44] 'Insight Report: Small and Medium Enterprises (SMEs) - Disaggregated Load, Time of Use Tariff and Restricted Hours Trials', available as report CLNR-L099 from the project library: www.networkrevolution.co.uk/resources/project-library/ f

refrigeration, where thermal inertia means that the effects of transitory decreases in power usage will not be significant.

4.15. Finally, independent from any consideration for the features of the appliances, its usage is also critical to the ability of cold appliances to contribute to a peak demand reduction.

4.16. The project carried out trials with SME customers and range of load types including chillers, shop floor fridges and walk in fridges. It examined in detail the load profile for a set of SME appliances, and qualitatively assessed their potential to provide flexibility to network owners. Although all three types of cold appliance were all from the same retail organisation, the pattern of energy consumption for the walk in fridges was different from the other two in that it had the highest demand during the night, suggesting that they were accessed for restocking overnight and are less likely to be accessed during the working day. Throughout the peak period therefore the potential for DSR is considerably less than for shop floor fridges and chillers.

4.17. This suggests that there are a broader set of factors which determine the degree of flexibility potential, beyond simply the appliance itself, such as patterns of business operations. The chillers and fridges in this case study were typically using most power on a consistent basis throughout the day including the evening peak period and therefore have the potential to provide some flexibility at the times when it is most likely to be needed.

### *Heating, ventilation and air conditioning*

4.18. This is a category in which we have a particular interest as a DNO. This is because thermal storage enables the decoupling of electricity use and heat production, which means that this category of appliances can rank high in terms of flexibility of usage by consumers and thus of DSR potential[45]. As such, we would suggest that one way to increase customer engagement with this category of appliances is to add thermal storage to a heating or cooling system, thereby allowing for the consumer to remain comfortable, even when an appliance is switched off for DSR purposes.

4.19. Trials of such heat pump combinations in the CLNR project showed that interruptions were successful for 67% of the time with the electricity consumption falling to zero during the control period, with no customer complaint about temperature fluctuations or report of inconvenience during the interruption event. The heat pump was set to build a store of heat for up to two hours prior to an interruption, which meant that the trial participant had a supply of hot water to see them through the peak interruption.

4.20. Such equipment is more suited to new build, where the design of the heating system is an integral part of the design of the whole house (mainly for reasons of space and retrofit). We observe that UK deployment of heat pumps is significantly behind some earlier 2013 studies and the practicalities of retrofit in addition to levels of subsidy appear to be key to this slow deployment.

### *Battery storage systems*

4.21. We are involved in an innovation trial that will provide evidence on domestic battery storage systems in the future. We have embarked on a project with residential customers with domestic-scale batteries coupled with solar PV[46]. Results will be available in 2019. We are testing the

[45] 'Future potential for DSR in GB', Frontier Economics, October 2015

[46] Distributed Storage & Solar Study, more information is available from the Smart Networks Portal on: www.smarternetworks.org/Project.aspx?ProjectID=1952

degree to which such arrangements, when optimised for customer benefit, would increase the amount of PV that could be connected before reinforcement is required.

4.22. We are interested in developing a vehicle-to-grid project. There is a need for further work on the commercial propositions to the consumer from all parties who want to procure flexibility from consumers with such storage. The potential benefit of such projects is a greater understanding of large scale, geographically distributed storage. We do not yet have evidence of what level of resource will be available through this technology and the commensurate scale of the potential benefits. We also need to consider how these benefits accrue to the vehicle owner, generators, suppliers and SO as well as the DNO.

### *Others (please specify)*

4.23. The CLNR project trialled the use of within premises balancing to reduce the export generation from PV by using in-home displays for manual balancing and also automated control units connected to hot water storage. The project concluded that manual balancing makes a very limited contribution to managing PV export but this situation was improved for automatic balancing[47]. This suggests that automation is a more effective way to optimise the combination of PV and hot water storage.

4.24. The sourcing of demand response by network operators currently falls under the provision of the European Demand Connection Code. This came into effect in 2016 and specifies information exchange requirements where a customer provides DSR to a network operator rather than a supplier and applies to all types of customers providing demand response, including domestic customers providing DSR via household appliances. The industry needs to understand the requirements of this code and consider how to enact it[48] including the requirement for the customer to provide information on their actual delivery of DSR. To the extent that this requirement does not apply where the customer is providing DSR to a supplier, this is potentially distorting and may act as a barrier to network operators sourcing DSR, particularly from smaller customers.

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

4.25. We believe that technology cannot be the only focus point to encourage take-up and penetration levels. It is important also to look at how these appliances fit into people's lives and homes; and examine the economics of these appliances and associated energy propositions.

4.26. Our CLNR trials took a socio-technical approach to understand sociological factors that influence customer engagement. It highlighted that, beyond technology, customer acceptance of the new appliance is key to the deployment and take-up of smart solutions. This includes space allocation for retrofit solutions in the house, perception of and confidence in performance of new solutions, willingness to compromise, and degree of flexibility to change domestic routines[49.]

[47] 'High Level Summary of Learning: Solar PV Customers', available as report CLNR-L244 from the project library: www.networkrevolution.co.uk/resources/project-library/

[48] The relevance of the code in the medium term will clearly be impacted by the Government's approach to Brexit but a reasonable planning assumption is that the obligations will endure for the foreseeable future

[49] 'Customer experience of demand side response with smart appliances and heat pumps', available as report CLNR-L097 from the project library: www.networkrevolution.co.uk/resources/project-library/

- The CLNR project found that heat pumps were not as popular with homeowners as expected, due to the 'hassle factor' of installation, space constraints, requirement for low temperature radiator/underfloor heating and due to low levels of insulation in rural off-grid properties. Some heat pump installations required planning permission from the local authority which caused delays.
- The 'smart' washing machines were almost universally welcomed, and appeared to be readily integrated into domestic life giving the participants the benefits of, and confidence in, using smart technology and implementing it into their domestic routines. However, as already discussed, a sizeable proportion of trial participants still used the override function to use the machine at peak times.
- In addition the operation of smart systems requires in most cases broadband and a phone land line; which is not present in every home.

4.27. On the economics of engaging with domestic and SME consumers for DSR, our work on tariff development[50] looked at the average load when operating of various types of appliances and technologies (refer to Table 2).

**Table 2:** Average load of household appliances when operating

| | | Average load when operating (W) |
|---|---|---|
| Cold appliances | Fridge | 20 |
| | Fridge-freezer | 43 |
| | Freezer | 33 |
| Wet appliances | Washing machine | 995 |
| | Dishwasher | 1,453 |
| | Dryer | 2,588 |
| Hot water heating | | 500 |
| Heat pumps | | 2,770 |

4.28. These figures need to be adjusted in two ways before the value of interrupting the load can be calculated.

- Interrupting the load only creates a value if the appliance is operating at peak. Cold appliances which are always switched on can be assumed to operate at their average load throughout the peak period. However, the average load of the other appliances needs to be adjusted to take account of the fact that they will not always be operating at peak times.
- Some appliances cannot be interrupted for the whole peak period.

4.29. These adjustments, and the resulting value of interruption by technology type, are set out in Table 3:

[50] 'Domestic and SME tariff development for the Customer-Led Network Revolution', available as report CLNR-L006 from the project library: www.networkrevolution.co.uk/resources/project-library/

**Table 3:** Value to DNO of household appliance peak avoidance

| | | Average load at peak (W) | Percentage of peak time that load can be interrupted for | Annual value of interrupting load at peak |
|---|---|---|---|---|
| Cold appliances | Fridge | 20 | 6% | <£0.20/year |
| | Fridge-freezer | 43 | 6% | |
| | Freezer | 33 | 6% | |
| Wet appliances | Washing machine | 53 | 100% | £2/year |
| | Dishwasher | 82 | 100% | £2/year |
| | Dryer | 126 | 100% | £4/year |
| Hot water heating | | 500 | 100% | £15/year |
| Heat pumps | | 1600 | 13% | £15/year |

4.30. The calculation of value is estimated for a distribution network in 2020. The analysis demonstrates that of these domestic appliances it is hot water and heating that provides the most significant payback to consumers. But even with these more valuable loads, the customer will likely need to 'value stack' in order to achieve any form of significant payment for flexibility services offered.

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

4.31. We agree that the impact of the change to a smart, flexible energy system needs to be assessed and minimised. We expect that established consumer organisations and those representing the interests of vulnerable customers will make a valuable contribution on the topic. However, we identify issues for those vulnerable customers that are fuel poor relating to the implications of the capital cost and rewards from participation in DSR.

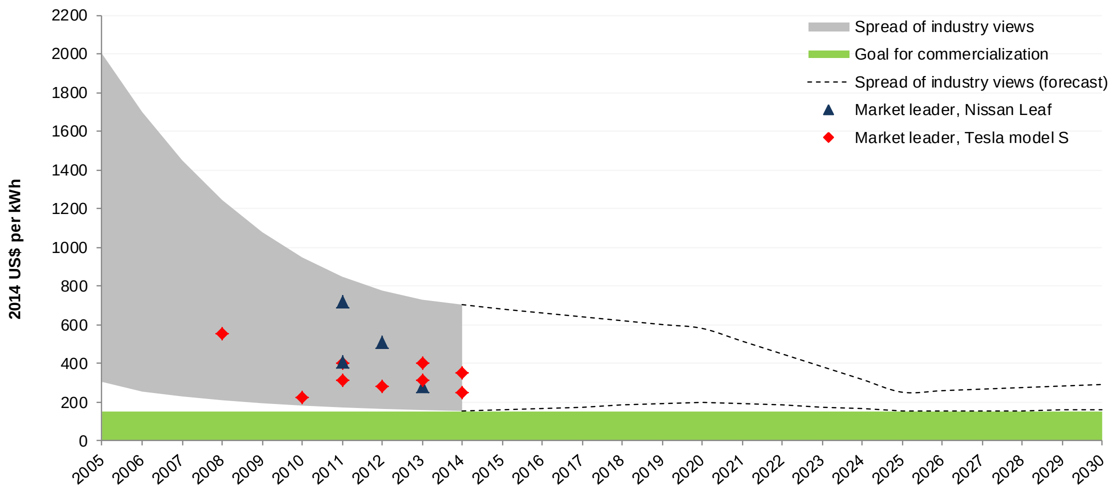
4.32. On the topic of capital cost of participation, it is recognised that smart appliances are today more expensive than non-smart versions. This might cause low-income households down a non-smart route, and exclude them from the new market. This is aggravated by the fact that wet and cold appliances have long replacement cycles and potentially even more so in lower income households.

4.33. Rewarding those able to participate in demand-side flexibility is done via reduced tariffs or via DSR payments. This may push additional costs onto the electricity charges paid by those who cannot participate. This needs monitoring as the market develops.

## Ultra Low emission vehicles

4.34. The falling cost of batteries is driving electric vehicles towards the mainstream. See Figure 11.

**Figure 11:** Project cost of battery storage for electric vehicles[51]




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

4.35. In order to encourage EV owners to avoid charging during the evening peak, industry is currently turning to the cost message through the use of ToU tariffs. Our own experience shows that the strength of the signal should not be underestimated. Analysis performed in CLNR[52] revealed that charging is very much concentrated in the evening, coinciding with the household peak. The EV charging curve closely follows the household demand curve, so we can assume that it is strongly correlated with household occupancy. EV users did not show signs of using timers or delayed charging, suggesting that making sure that the car was charged was their main priority. Time of use tariffs were not prevalent during the trials. As these become more available from retailers and as vehicle battery lives increase, we expect naturally that electric vehicle charging load will diversify further. More real customer observations will be required to validate this hypothesis.

4.36. Also, to a certain extent, reflecting network requirements through ToU requires the supplier's collaboration in passing through the variations in DUoS. This means that to be most effective for network purposes, any price signals from DNOs might have to be direct with customers (including via aggregators) rather than via suppliers. These comments might not apply to generation balancing or frequency response uses of vehicle-to-grid. The best approach to take therefore depends on the problem that is being addressed: whether this is managing increasingly uncontrollable generation, managing restrictions on the distribution and transmission systems, or both.

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[51] *Source: adapted from Björn Nykvist & Måns Nilsson - Rapidly falling costs of batter'y packs for electric vehicles (17 October 2014)* http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html

[52] 'High Level Summary of Learning: Electric Vehicle Users', available as report CLNR-L254 from the project library: www.networkrevolution.co.uk/resources/project-library/

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

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

4.37. There remains a barrier to utilising EVs to put electricity back into the network in that there is not yet clarification as to how storage devices should be classified and the treatment and obligations of storage. Therefore there is a lack of clarity of the requirements associated with these vehicles if they are to be used in this way.

4.38. Customer trust in the automated charging system will also need to be addressed. Anecdotal evidence from CLNR highlighted that customers sometimes struggled with the concept of not plugging the car in at home as soon as they got back from work; and they took satisfaction from witnessing it charging. If charging is delayed then they must instead trust that it will start charging later on in the evening, and be fully charged in the morning when they usually need it.

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

4.39. Hydrogen produced by electrical hydrolysis can be stored and then turned back into energy to either power hydrogen fuel cell vehicles or by being injected into the gas grid. An existing barrier is that there are presently regulations that limit to 0.1% the percentage of hydrogen in a supply from a natural gas system.

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

4.40. We engage with customers through a number of routes, including connections events, trade associations and the Power Responsive campaign.

4.41. Our twice-yearly connections customer events remain a key larger customer engagement forum. They are an opportunity for our customers to talk to us first-hand about the issues they are facing and how we can help. We have taken the opportunity at one of these events to run a focussed session for stakeholders on NPg's innovation strategy, incorporating storage, DSR and active network management.

4.42. As well as our own NPg hosted events, we support, attend and contribute to DSR engagement opportunities with the Major Energy Users Council (MEUC). As well as conferences we have also delivered training sessions to its members. It is through this trade organisation route that we consider large non-domestics often find out about DSR opportunities.

4.43. Finally, we are also involved with the Power Responsive campaign. In addition to taking a whole system view the SO, DNOs, energy suppliers and aggregators on the industry side this provides the opportunity to interact in detail with a number of larger customers who already undertake DSR and are seeking further opportunities.

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

4.44. Broadly, yes. Our CLNR trials identified a number of the barriers you have identified including cultural, regulatory, incentives and costs. However we do not recognise the regulatory barrier suggested for connecting an on-site back-up generator and we need to explore this further.

### *Cultural*

4.45. When recruiting customers, the initial customer drop-out rates can be high due to issues with contacting the sites, contacting the right person at the site, the size of a site's flexible load/generation and the nature of the service required. We found that the DNOs can build effective relationships with suppliers and with independent commercial aggregators for the purpose of providing DSR. We also engaged directly with one large customer and believe that it is possible for DNOs to build effective direct relationships with, for instance, the energy managers of national companies that operate multiple sites across the DNO regions and with the larger single site businesses. DNOs require the infrastructure to manage these relationships, either in-house or via a third party such as an aggregator. More work is required for the DNO (or its aggregators) to improve knowledge of connected customers to enable more efficient targeting but also to increase the knowledge of DSR amongst customers.

4.46. Customers found the CLNR contract terms relatively concise and easy to understand, particularly when compared to other DSR schemes. For future DSR schemes, customers would like a simple payment and penalty arrangement which allows some flexibility and for it to be aligned with the current SO demand side response schemes. Customers were willing to accept arrangements based on short term operating reserve (STOR) prices for the trial but business as usual pricing will be driven by a number of factors. DNOs will need to consider the deferred/avoided reinforcement costs, response reliability, the level of benefit sharing between the DSR provider and all customers whilst recognising that DSR providers are looking for bankable business cases. Further work is needed to evaluate whether different contracts/pricing structures might be preferable for different situations.

### *Regulatory*

4.47. The DNOs are relative newcomers to the DSR market and are effectively in competition with other products such as the National Grid Short Term Operating Reserve (STOR) and the demand side balancing reserve (DSBR) to mitigate the capacity margin squeeze. The key difference is that the DNOs are geographically constrained whereas National Grid has more choice and flexibility on which providers can call. Existing STOR participants were easier to recruit for a trial but it is currently not possible for providers to offer DSR to both National Grid and DNOs at the same time. An arrangement where the DNO, SO and TOs are able to share DSR resource may create value for all stakeholders and is under development through the ENA DSR Shared Services working group.

4.48. We do not however, recognise the issues associated with export connections to the distribution network for on-site back-up generation.

4.49. We have developed an online applications process for various types of connections including self-service, guide prices and timescales.

4.50. We have made improvements to our industry-leading demand and generation heat maps that give customers a red/amber/green status of available network capacity and help them identify suitable connections sites. We also now update the data on our heat maps and capacity register on a monthly basis to ensure customers have the most accurate and up to date information we can provide.

4.51. We acknowledge that constrained networks are an issue that is adversely impacting many customers trying to connect to different distribution networks across the UK. This includes our own customers in a few areas; but to a lesser extent than some other DNO networks. We have responded to this by providing customers with flexible connection offers and by developing a new replicable active network management solution that has been offered to customers.

4.52. As the technology landscape changes and develops, it is important that we can quickly adapt our services, processes and policies to accommodate the use of new technology on our distribution network. Export limiting devices are a technology where we have kept abreast of their development and use and in response to customers' requests we have already revised our policy on their use on our distribution network. In so doing, we are expanding the scope of the renewable energy solutions our customers can offer their clients. Ongoing discussions with our customers enable us to keep pace with new technological and commercial developments and react in a timely and effective manner. It is our intention to expand on this strategy in quarter one of 2017, with a series of technological workshops where customers can talk to us about what is on the horizon and how we can help.

### *Commercial (incentives)*

4.53. Our CLNR project also identified a barrier associated with providing DSR to DNOs: the difficulty in recruiting for DSR provision in some geographic locations over others. Our customer engagement research showed the feasibility of targeting specific geographic locations for the provision of DSR will be successful in some cases and not so in others but success could be improved with better customer information[53].

4.54. Identifying customers that are willing to offer the level of DSR response required by DNOs in a specific location is a significant challenge. The frequency of call off for providing services to DNOs is likely to be low. When it is required, it could be for four hours a day, and be needed for more than 10 days until normal network capacity is restored. This will limit the number of customers that are capable or willing to participate in these schemes unless there are sufficient providers to allow the response to be sequenced around the available resource. A solution to this issue could be to use a portfolio of customers to deliver the DNO's requirements. This approach opens the potential to reduce the obligations for the DSR provider which in turn could create a larger pool of customers for the DNOs from which to recruit DSR providers.

### *Structural (costs)*

4.55. Standby generation appears to be the most available and successful entry point for industrial and commercial (I&C) customers wishing to participate in DSR schemes as it provides a new revenue stream while minimising the number of changes and new risk to their business operation. Following this first step, customers may then consider engaging in developing DSR via load response, which may be more costly to set up and could be more intrusive to their core processes. The DNO sector needs to explore more fully the barriers to engaging more load turn-down resource in the RIIO-ED1 period and beyond.

4.56. Twelve of the fourteen participants in our 2014 CLNR trials provided the service via standby generation but we were successful in finding two effective and fast responding flexible loads. The first was provided by refrigeration plant operated by an ice manufacturer (0.6MW) connected at HV that was able to modulate its freezer load and the second was a gas compressor (5MW) connected at EHV that was able to defer a gas compression cycle.

[53] More information on the I&C DSR trials from the CLNR projects can be found in reports 'Key Learning Report : The role of industrial and commercial and distributed generation customers' and 'Commercial Arrangements Study – Phase 2', available as reports CLNR-L247 and CLNR-L145

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

4.57. DSR is a developing market in the UK and the most efficient route-to-market for DNOs has not yet been identified. A number of options are available to engage with this market, which include working with I&C customers directly, aggregators, energy suppliers and the SO.

4.58. In NPg, we have committed to introduce systems and processes to implement DSR before 2023 and are evaluating the optimal route to market. We have tested both working with aggregators and directly with I&C customers. We have also been involved in industry work, led by the ENA as part of the Energy Networks Futures Group (ENFG), to explore potential DSR sharing options between the DNOs, the TOs and the SO.

4.59. With regards to direct engagement, a key finding from the CLNR research was the difficulty in contacting I&C customers at particular network locations and, in particular, locating an appropriate person with the authority to engage in discussions on the provision of demand side response services. It recommended that a simple solution to give a helpful kick start to this engagement process would, data protection rules permitting, be for DNOs to have access to customer contact details for the half-hourly MPANs held by suppliers.

- The Master Registration Agreement (MRA) procedure MAP 22 was published on 1 September 2014 with the specific aim of providing customer contact details before winter 2014 to enable DNOs to contact customers following a power outage.
- The scope of the procedure is limited to passing of the following customer information from suppliers to DNOs: date and timestamp of extract; MPAN; full customer name; up to four e-mail addresses (subject to a supplier risk assessment); and up to four customer telephone numbers.
- It also states that distribution businesses will only use this customer information to contact the customer concerning disruptive events impacting that customer's connection to the network. This likely excludes contacting customers to engage in discussions regarding the provision of DSR services. A review of the MRA and possible amendment to enable DNOs to contact customers for this purpose would expedite DNOs establishing relationships with customers to develop and implement DSR solutions.

4.60. With regards to aggregators, we recognise that they bring a number of capabilities including the ability to:

- Identify customers with flexibility potential in our regions;
- Work with customers to develop the capability to provide flexibility;
- Provide technical assistance for customers with metering;
- Deliver equipment upgrades and communications;
- Execute commercial agreements to monetise the arrangements; and
- Implement operating procedures.

4.61. Experience from the CLNR project, the work with the ENA and observations from other LCNF projects reveal a number of potential current and future opportunities for accessing the DSR market. These could include, but not be restricted to:

- Building relationships with companies that have centralised energy management and have a widespread footprint in the DNO region operating on multiple sites (e.g. water, telecoms, local authorities, hospital trusts, supermarkets, etc.);
- Direct engagement with other significant known customers on the network;

- Working with National Grid for the sharing of STOR resource;
- Engagement via aggregators (including suppliers);
- Targeted marketing using MPAN information and load profiles and inviting companies to tender into a local capacity auction;
- In partnership with local bodies such as Chambers of Commerce; and
- Advertising through local media.

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

4.62. Informing domestic and smaller non-domestic consumers about the transition to a smarter energy system should continue through the course of the smart meter deployment. This will assist customers and energy companies to realise maximum benefits from the roll-out as it reaches critical mass such that aggregation opportunities may be leveraged to provide real-time or longer-term advantage. It would also make sure that the distributional impact of smart energy roll-out does not mean that some customer groups are excluded or disadvantaged. Some communication will need to be specific and aim for instance at improving the customers' understanding of the commercial propositions, and at addressing their concerns on data privacy issues. .

**Consumer protection and cyber security**

***Q40. Please provide views on what interventions might be necessary to ensure consumer protection in the following areas:***

- ***Social impacts***
- ***Data and privacy***
- ***Informed consumers***
- ***Preventing abuses***
- ***Other***

***Social impact***

4.63. In CLNR, we have tested ToU tariffs. They proved popular and were easily understood by domestic customers. The majority (60%) saved money on their energy bills (from £30 - £350) and demand in the 4pm to 8pm peak was up to ca. 10% lower than the control group. But it was also clear from our socio-technical approach that those with younger children tended to have daily routines that meant that these customers flexed their use of electricity less than others in the trial.

4.64. In moving to a smarter more flexible energy system, we are introducing more complexity, new risks, and new points of failure including new common points of failure and such failures have a social impact. For example a communications failure could result in loss of supply or in smart appliances either not responding or responding in an unintended way. Where a number of properties are communicating through a common communications point such as in a tower block, multiple households could be affected. The new complexity being introduced needs to be managed by addressing all the new issues such as who specifies the reliability and redundancy of communications links.

## *Data and privacy*

4.65. While recognising that the recipient of the data was academic and non-commercial, our evidence from CLNR suggests that data privacy is not a significant concern for the majority of customers. Our project partner British Gas contacted approximately 9,000 of their domestic customers with smart meters, asking for their permission for the academic project partner to use their data for the project and fewer than 1% of customers chose to opt out[54].

4.66. However, when it comes to the widespread business-as-usual use of smart meter data, we recognise the need for Ofgem to provide reassurance through clear and appropriate safeguards set out in a way that is easy for people to understand while also providing access for the parties that require it for purposes that are legitimate and acceptable to consumers. The DNOs have commissioned IPSOS MORI to conduct a poll which will provide robust evidence of to understand public sensitivity on this issue. The results will be available in early 2017.

4.67. Also, the industry should define what data is required to operate a smart flexible energy system so that the collection and sharing of data is clearly based on needs and benefits and so that common systems are developed to collect and share relevant data in a way that meets the customers' data privacy requirements. Types of data include: detailed consumption and generation data, the tariffs agreements customers have signed up for, the types of (smart) appliances a customer has, whether or not the customer has an EV and distance travelled each day, etc. In the process, we may find that there is a different data set required by suppliers to efficiently manage demand and generation, than that required by a DNO to develop an efficient and resilient network. Such conclusion would add complexity to the data privacy agreements and protocols that are required in order to operate a smart, flexible energy system. As an example:

- From a DNO perspective, consumption data is important, but this only presents the customer's net energy consumption and we need to understand all the factors that influences the customer's consumption of network units, including the various trading, generation and consumption components, which all add up and result in the net electricity demand visible to the DNO.
- Unless the DNO has visibility on what is driving the customer's net energy consumption (e.g. the operation of generation plant to reduce the net demand, influence of DSR instructions and response to supplier ToU tariffs, which may have reduced the net demand as seen by the DNO network) they could confuse the resultant power flows with pure load reduction, and plan the network accordingly.
- This increases the risk that the DNO makes inappropriate assumptions when planning the capacity of distribution networks (e.g. the DSR that was implemented last winter will be implemented again next winter and turn out to be wrong). If they do not have sufficient visibility of the factors that influence the observed net demand, the DNOs may continue to make conservative design assumptions, and deliver limited financial benefit over non-smart or alternatively make optimistic design assumptions, and hence deliver a higher risk network.
- It is therefore our view that this visibility risk must be addressed, and that obligations are placed on the various industry parties to share such data.

[54] 'Lessons learned from trial recruitment: Customer-Led Network Revolution trials', available as report CLNR-L036 from the project library: www.networkrevolution.co.uk/resources/project-library/

4.68. In addition, as the deployment of smart meters continues, consideration should be given to the volume of data that is collected, where it is stored, how it is processed and ultimately secured. Cloud storage services offer flexibility, but introduce new security risks.

4.69. We agree that it is essential that all parties (industry, regulators and consumer organisations) agree on data access and we acknowledge that this is still work in progress for network operators. The framework mentioned in DECC's 2012 data access and privacy paper only lets customers decide who accesses their data from a supplier's perspective and network operators are yet to submit to Ofgem for approval a needs case for using disaggregated customer data. For example, if DSOs are to procure DSR from customers, either directly or via a third party, they will need to have visibility of that response and the customer contact details to manage the contract and the relationship with the customer.

### *Informed consumers*

4.70. Our CLNR trials of ToU tariffs for domestic customers revealed that customers understood the concept of these tariffs. Even though more customers gained than lost from this trial tariff it is important to reduce the risk of customers signing up to a tariff that is inappropriate for their needs, only to find that their costs then increase rather than decrease. The analysis by consumer organisations of the ToU tariff by new supplier Green Energy shows that these concerns are shared[55]. In a smarter more flexible energy system, it is likely that pricing differentials between different tariffs may become increasingly significant, increasing both the benefits to the customer of choosing the right product while also increasing the costs of choosing an inappropriate product.

4.71. One way to mitigate this risk would be an online tool where customers could use their consumption profile to understand the impact of different products, with suppliers having an obligation to make consumers aware of the associated risks of a product eg if their consumption profile changes by a standard specified amount what the effect on their bill is likely to be. For customers who would not use such an online facility, it will be important to provide them with clear, more generalised guidance on choosing an appropriate tariff.

### *Preventing abuses*

4.72. We recommend that new market entities are at minimum, subject to obligations that are crucial to the efficient operation of a smart flexible energy system. This is because visibility is important: similarly, to the point made about data privacy, if an aggregator of domestic DSR works to reduce supplier peaks (which reduces in turn network reinforcement for DNOs) and experiences serious technical difficulties or goes out of business, the DNO will see a step increase in peak demand and may have insufficient network capacity. Unless the DNO is aware of the third party's activities and the effect that their actions have on network power flows, the DNO will not be able to take a view on the level of risk and potentially prepare mitigation plans.

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

4.73. We concur that cyber (and physical) security continues to pose a significant risk for every business and wish to keep our response, in this public paper, generic.

[55] The Guardian, 'Green Energy UK offers first electricity tariff based on time of day'. accessed on 10 January 2017, on www.theguardian.com/money/2017/jan/03/green-energy-uk-launches-first-time-of-day-electricity-tariff

4.74. Good collaboration is taking place between Government and industry, successfully identifying a number of channels by which parties may strengthen the energy system's resilience to the cyber threat.

4.75. NPg participates in such collaboration and has a plan in place to address the risks associated with the deployment of smart metering and the digitisation of energy systems. Continually improving our defences is one of our top priorities. This is done through strong governance and control over assets, and over the information that they generate.

4.76. We believe in an order of priorities which promotes securing the integrity of the energy system over commercial interests. A practical example of such hierarchy is as follows:

- In a smart energy system, a variety of devices will interact with parties that are external to the electricity network. This introduces new risk to a network's security.
- We would expect that network security is always a higher priority than the continuity of a device's data flow. i.e. If the system owner has to disable or disconnect a data connection to mitigate cyber security risk, they should be allowed to do so, even if this compromises the ability of the device's owner to earn money from a DSR arrangement.

4.77. Cyber security is as much a corporate responsibility for Berkshire Hathaway Energy, our US parent company, as it is for the UK and indeed US Governments. Internally, we are currently pursuing implementation of the Center for Internet Security Controls for cyber security as a collaborative project across all our group businesses in order to reduce risk, generate learning and share knowledge.

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

4.78. We would be happy to discuss these risks, their likelihood and impact with BEIS and Ofgem.

# Section 5: The roles of different parties in system and network operation

## Roles and responsibilities

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

5.1. We agree that the emerging system requirements that are set out in the paper's figure 1 'Drivers for change and system requirements' are a good starting point, but they need to be kept under review as some of the detailed requirements that will emerge may well not be completely foreseeable now. We need to monitor carefully market developments and be flexible enough to respond as new system requirements are identified. It is essential that thinking in this area is customer-centric so that changes are designed to advance the public interest. In addition, in order to deliver benefits to customers, the consideration of changes to roles and responsibilities needs to span all industry parties.

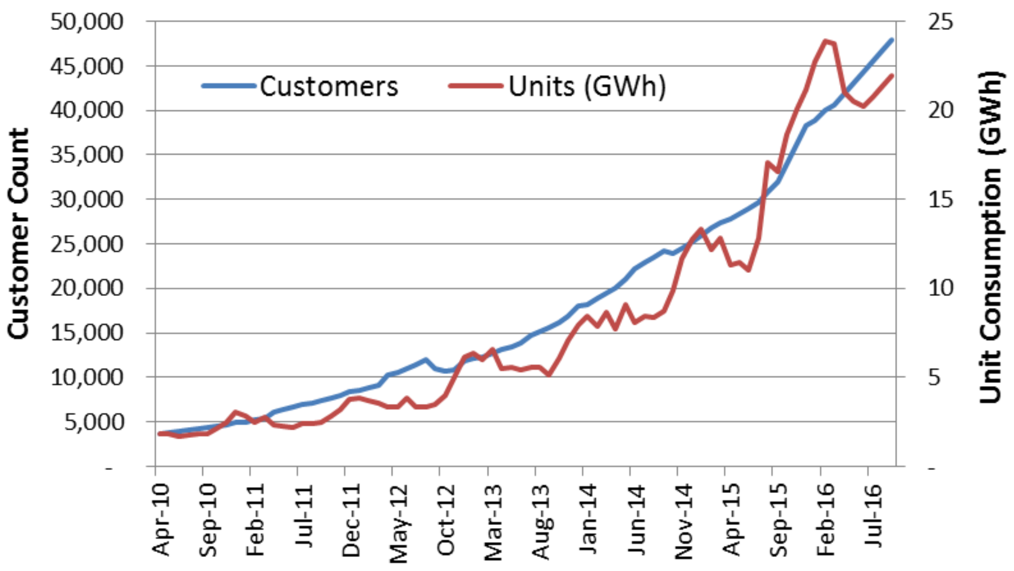
5.2. At the moment, we see that two of the drivers are particularly significant for the energy sector, namely: the replacement of centralised large synchronous generation with a large number of intermittent non-synchronous generation and a growing interest in local energy models.

5.3. While we consider that the paper's Figure 1 identifies the right system requirements, we note that the narrative around it refers to SO, TO and DNOs but does not explicitly mention other existing network players such as IDNOs or private wire network owners. This is an important omission. If the new arrangements are to be delivered in customers' best interests, then all network companies' governance arrangements and rules need to be consistent, regardless of ownership[56]. It is therefore necessary to include all licensed network operators (e.g. including IDNOs) and unlicensed network operators (such as private wire operators) in this review of roles and responsibilities.

5.4. This is becoming increasingly important as we are currently experiencing a significant increase in the number of customers connected to IDNO networks embedded within the NPg distribution area, and we expect the pace of increase will accelerate. Since April 2010 we have seen a 12-fold increase in the number of customers connected to IDNO networks, with recent growth in both customer numbers and units distributed in excess of 50% year-on-year as demonstrated in Figure 12. We do not have access to information on customers connected to unlicensed network operators.

[56] For example, DNOs and IDNOs currently operate to different network planning standards and there is currently no party with the obligation and ability to provide IDNO customers with SO function.

**Figure 12:** NPg Growth in IDNO Customers and Units




***Q44. Do you have any data which illustrates:***

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

5.5. The scale and cost of system impacts will be a function of many exogenous factors, such as the take-up of Low Carbon Technologies (LCTs) and the capacity of existing network. Different areas of the country have different requirements, so there will inevitably be differences in the timing, costs and the order in which solutions will need to be deployed. Therefore, in the short term, whatever models are adopted must be flexible enough to be introduced on a needs basis.

5.6. We offer evidence from the following sources to illustrate the current scale and cost of the system impacts described in the paper's Table 7:

- NPg Business Plan 2015-2023 - Expenditure[57];
- NPg Business Plan 2015-2023 – Smart Grid Development Plan[58];
- NPg Stakeholder Annual Report 2015-16[59];
- NPg Environment Report 2015-16[60];
- NIA project 'Improving Demand Forecasting'[61]; and
- NPg DPCR5 close-out report to Ofgem.

These are discussed in more detail below. Where possible we have tried to align our comments with the format of table 7.

[57] http://www.yourpowergridplan.com/som_download.cfm?t=media:documentmedia&i=1719&p=file

[58] http://www.yourpowergridplan.com/som_download.cfm?t=media:documentmedia&i=1724&p=file

[59] http://www.northernpowergrid.com/asset/0/document/2726.pdf

[60] http://www.northernpowergrid.com/asset/0/document/2724.pdf

[61] http://www.smarternetworks.org/Project.aspx?ProjectID=1982

### *Changing use of the distribution network by connectees has impacts on distribution network*

5.7. We have made our own assessment on how the changing use of the distribution network by connectees has impacted the distribution network and shared it in our 2014 business plan for the ED1 period. The assessment was based on the DECC scenarios for the uptake of LCTs, which are a key driver in connectees' changing use of the distribution network. The Expenditure section of our business plan sets out the scale of LCT uptake that our plan is based on and the costs of alleviating the associated network constraints using both traditional reinforcement methods and the most efficient (smart incremental) methods.

5.8. To do this using traditional methods would require us to invest circa £32m in the ED1 period[62] to reinforce the network. However, a more cost effective solution would be to use a mixture of traditional reinforcement and smarter solutions. This would cost £26m, a saving of £6m or 19%.

5.9. In addition, an increase in LCTs could also require us to replace a substantial number of 'looped services' with 'individual services' to cater for increased demand. In the ED1 period, we expect that this situation will occur most often in relation to clusters of social housing with PV. We expect that to unbundle the looped services using a traditional reinforcement approach would cost £54m. However, by adopting smart solutions and working with social landlords to fine tune their schemes, we expect this to reduce to £26m.

5.10. The total cost of addressing the impact of uptake of LCTs by the most efficient method (smart incremental) was forecast to be £52m in ED1 (refer to Table 4). .

**Table 4:** The costs and benefits of smartgrid enabled investment as proposed by NPg

| | Traditional reinforcement | Smart Incremental | Net benefit |
|---|---|---|---|
| Loop services | £54m | £26m | £28m |
| Incremental reinforcement | £32m | £26m | £6m |
| **Total 2015-23** | **£86m** | **£52m** | **£34m** |

5.11. The actual scale and impact of connectees' changing use of the distribution system in the first year of ED1 is set out in our latest Environment Report and Stakeholder Report and is summarised in Table 5 below.

5.12. Generation has shown itself to be highly sensitive to government policy. When feed-in tariffs and renewable heat incentives were scaled back by Government in 2015, this had a big impact on the level of LCTs connecting to our network. In particular, there has been more extra-high voltage generation (for example, solar farms) but less small scale generation than previously forecast. Take-up of electric heating and electric vehicles has also been lower than forecast. Figure 9 shows the low carbon technologies connected to our network in 2015/16 and supports the view that the changing use of the distribution network by connectees is being seen on, and is impacting, the distribution network.

[62] This covers an eight year period starting 1 April 2015. Costs are in 2012-13 prices

**Table 5:** Low-carbon technologies connected to our network in 2015/16

| | | Estimated capacity (MW) | Estimated volume |
|---|---|---|---|
| Load | Heat pumps | 7 | 1,352 |
| | Electric vehicle chargers | 6 | 1,054 |
| Renewable generation | Photovoltaic micro- generation | 71 | 22,097 |
| | Other distributed generation (mainly larger photovoltaic, onshore wind and biomass) | 288 | 359 |

5.13. In terms of future volumes, the rate of LCT uptake will continue to be sensitive to government stimuli and wider market development of LCTs. Nevertheless, we have not yet observed any changes that materially alter our medium to longer term view.

5.14. We have several areas where active network management has been deployed already and we will continue to coordinate with customers to ensure that we are able to efficiently connect LCTs. The need to deploy more of these flexible solutions will depend upon the rate of LCT uptake. Our Improving Demand Forecasting project will provide better forecasts of technology uptake and load for our GSP, primary and secondary substations and provide new insights for network planning.

5.15. While the scale of uptake of LCTs may be similar nationally, this may result in different cost and system impacts due to different characteristics of networks in different locations.

5.16. We are delivering cost savings through techniques that involve coordinating with customers: ANM schemes, offering constrained connections, and recovering capacity from customers. We expect this will continue in future. Indeed, looking beyond ED1 (i.e. from 2023 onwards) we anticipate higher levels of LCTs. In particular, we consider that the uptake of EVs has the potential to be the next big challenge for networks. ENA members have worked collaboratively to carry out a high-level assessment of the potential impact of more widespread roll-out of electric vehicles and the associated charging smart-charging infrastructure. Part of that work included an analysis of the potential network investment cost to support charging infrastructure for EVs, which identified that under some relatively ambitious but nevertheless plausible take-up scenarios there would be a need for substantial investments between now and 2040.

### *Changing use of the distribution network by connectees has wider system impact*

5.17. The potential for the changing use of the distribution network by connectees to have an impact on the wider system is evidenced by the fact that there is 3.6GW of distributed generation connected to our network resulting in five of the 44 grid supply points (GSPs) in our distribution services area, recording export to the transmission system in the last year, three in the Northeast and two in Yorkshire. Whilst all of these GSPs still have more days of net import than net export this demonstrates that the use of the distribution network is changing. We are starting to see - and so we have to manage - reverse power flows on the network as well as the traditional flows from the transmission system to homes and businesses. This, along with the fact that NGET has voltage control issues to manage because of the level of embedded generation in some areas, shows signs that the system has already irreversibly changed. Such impacts are only going to increase. The key unknown is by how much and how fast.

5.18. The wider system impacts that this can cause can be illustrated by the case of an on-site generation facility that is connected to our network, which subsequently became a merchant generator. This is typical of the type of situation that our network planners deal with as a result of changes to business ownership and operations. The effect of this change was a large increase in the amount of generation exported into the distribution network, which has a cost to both the DNO and the TO.

5.19. The cost of dealing with this through traditional reinforcement was estimated at approximately £30m, taking into account the NGET and NPg costs.

5.20. Instead, through working collaboratively with NGET, an innovative ANM solution was found where the generation facility now operates as part of a multi-customer ANM scheme across a wide area using the non-firm capacity of both NPg's and NGET's assets. The cost of this innovative solution was £1.5m.

5.21. While it is usually possible to implement an ANM solution instead of carrying out traditional reinforcement, the degree of cost saving will be dependent on local circumstances.

5.22. More information on this case study, is contained in section 3.5.1 of our confidential DPCR5 close-out report provided to Ofgem.

### *Use of distributed resources and novel techniques for local network management can have impacts on the wider system*

5.23. We have a number of schemes in place for managing export generation on local networks. We are aware that a generation plant providing STOR response to the SO is embedded within the part of our network that is actively managed under an ANM scheme which was implemented to enable more generation to be connected. In such cases, we recognise a risk that a STOR plant increases its output in response to a STOR request, and this could trigger the ANM system to call on other local generators to reduce their output to avoid overload. The combination of these actions would mean that, even though the STOR plant would be increasing its output as expected, there would be no real net reduction in generation as the actions of the DNO and the SO would counteract each other. We have not yet observed such a conflict, but will continue to look out for this.

5.24. However, as a DNO we do not have visibility of which distributed resources are providing services to the SO, so it is difficult to have a complete view of all cases where the actions of the DSO and SO might or actually do counteract each other. The TDI's ANM working group is aware of this issue and has met with the DSR Shared Services working group working group and as a result of this the SO is currently in the process of asking its distribution-connected providers of services whether they can share information with the host DNO about its contract with the SO and for which services.

### *Increasing need for distribution-connected resources to support system operation*

5.25. The replacement of centralised large synchronous generation with a large number of intermittent non-synchronous generation will inevitably mean that the SO will increasingly need to look to distributed-connected resources to provide services to support system operation. However, as explained above, as a DNO we have little visibility of the extent to which this is happening now and are not best placed to provide quantitative evidence on the need for this in future.

***Q44. Do you have any data which illustrates:***

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

5.26. Recent practical experience has demonstrated the need for improved linkage between the distribution and transmission networks; in particular, following the issues caused for transmission in the South West of England by the increased volumes of distribution-network connected generation. The priorities for 2017 are to establish productive and effective transmission and distribution interface forums to work in parallel on making some low regrets changes today (e.g. developing efficient network planning processes) and to work through some of the more challenging and detailed questions (e.g. future market structures).

5.27. There are efficiency gains to be realised through wider coordination between all the players in the whole electricity system. Further, wider coordination between the different energy vectors of gas, electricity and heat will make even greater efficiency savings possible. Through our involvement with the Centre for Energy Systems Integration, we are developing an understanding of the challenges and opportunities associated with more co-ordination across the entire energy system.

5.28. The greatest efficiency savings in the electricity system will be achieved by coordinating across as many parties as possible, not just between TO, SO and DNOs, but also customers, IDNOs, and private wire network owners.

5.29. As a DNO, some coordination with NGET is already part of our business as usual, with the level of interaction greater than it was previously. The recent 'customer immersion' event run by NGET provided an opportunity for us and for other customers to identify process improvements, including greater coordination with the TO and SO. This type of exercise has the potential to deliver more efficiency and more effective cooperation between the TO and SO and the DNOs across a range of network planning and system operation processes.

5.30. These savings from greater co-ordination are difficult to quantify and often involve confidential data. However, we have an example where coordination with the TO avoided reinforcement which would otherwise have been paid for via the price control. More details of this can be found in section 3.5.2 of our DPCR5 close-out report.

5.31. We also have an example where coordination with a private wire network operator avoided reinforcement. The solution allows our network to be supported by theirs in the event of an outage on our system, increasing firm capacity, thereby avoiding the need for installation of additional network for P2/6 compliance. The interconnectivity provides mutual support and should the private network have an outage, they can receive support from our network. For more details, please see section 3.5.3 of our DPCR5 close-out report.

***Q45. With regard to the need for immediate action:***

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

5.32. Networks will be central to the emerging system requirements and we agree that in the DNO to DSO transition, the DNO/DSO should continue to be responsible for operating efficient, coordinated and economical distribution networks and that this should include active use of new technologies, providers and solutions (i.e. what networks need to do now to facilitate different, non-network, outcomes in the future). Indeed, we are already deploying these to more actively manage our networks, in particular through implementing ANM (see our response to Q44 above) and industrial and commercial (I&C) DSR (albeit this is still small-scale reflecting our low network need at this time). Our smart grid implementation plan sets out our approach to these activities in response to the predicted growth in LCT connections. We will use smarter technologies when they are cost effective based on a needs-based implementation.

5.33. However, there is scope for an increased role for DSOs in delivering efficient network planning and local/system-wide use of resources and that this requires effective engagement between all the network parties (DSOs, the SO and TOs and also IDNOs).

***Q45. With regard to the need for immediate action:***

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

5.34. We agree that the further progress described is both necessary and possible over the coming year, firstly to ensure that current best practice is replicated consistently and nationally, and secondly to lay the foundations for the longer term.

5.35. To co-ordinate the development and implementation of new network operator roles and responsibilities, ENA members have agreed to the establishment of a new TSO-DSO Project within ENA to work in a structured way through 2017 and beyond. This will build on early work carried out by ENA’s TDI Group but will broaden the scope of this work, increase the pace of work through 2017 and ensure that Transmission/Distribution work and resources are effectively deployed to progress priority areas.

5.36. To ensure that the new group is effective, we make a number of recommendations: that the TSO-DSO groups objectives and terms of reference are established and clearly defined; that its work programme concentrates on the issues where action is most needed; that Ofgem and BEIS are represented or have the opportunity to provide input; that other stakeholders can influence the direction on the work the via an advisory group; and that the members of the group are sufficiently senior and have sufficient breadth to their knowledge (both technical and commercial understanding for example) to have decision making ability and authority. We expect that most of the issues considered by the TSO-DSO group will be within the remit of the network companies to address, but where regulatory or Health and Safety Executive (HSE) barriers are identified these will need to be raised with the relevant regulators.

5.37. Greater coordination between the SO and DNOs could potentially avoid the inefficient situation where SO and DNO actions can counteract each other. There is scope for greater co-ordination between parties to understand the extent to which this is happening and to identify a way of achieving greater efficiency. This is clearly a challenge, given the tension between the requirements of the different parties. However, there should be greater clarity of understanding between TSO and DSOs about the impact of issues on networks that do not belong to them: in particular, the impacts that calling specific resources may have on other resources because of local network constraints. It is also important that all valid aspects of customer flexibility benefit (for either transmission or distribution) should be transparent to the customer and any disbenefits to transmission or distribution operators are also visible and taken into account in the resource allocation decisions. These are issues that the TSO-DSO group will need to consider taking forward. In addition, as part of working more closely with the SO, we will continue to participate actively in the Power Responsive programme to understand how to progress opportunities to grow the market for demand-side management in a manner that benefits both participating customers and the efficient development of the energy system.

5.38. To ensure best practice is replicated, there will be a need to gather information and compare practices. This must be done with the understanding that different issues will arise in different locations due to different circumstances. Therefore there will be no one size solution that fits all and progression should continue to be based on location specific derogations and trials. ENW's CLASS project is a good example of this. However, issues should be addressed with a consistent set of underlying principles. This will provide a foundation that is sufficiently flexible for different players to introduce new smarter, more flexible solutions on a needs basis. This will be most effective with active involvement and support from Ofgem and BEIS. In this way, operational interfaces and practices can be improved in 2017 in a way that quickly delivers benefits. For example, one specific change that could be made is to increase the level of input from DNOs and the SO into the next T2 price control, so that there is better coordination between investment plans.

5.39. In addition, the 2017 work programme should also include a parallel activity that looks at the longer term role of the DSO.

***Q45. With regard to the need for immediate action:***

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

5.40. The existing legal and regulatory framework is largely fit for purpose such that the work programme set out in b) above can be progressed through trials and derogations.

5.41. For the reasons we set out earlier in our response, until the issues we identify with respect to network charging have been identified (see section 3 of this response), we do not consider that the transition ambitions will be met. This is therefore a priority area for action in 2017.

5.42. In addition, an increasing number of our stakeholders want to enter into local supply arrangements (for example to maximise their revenue sources; sell energy at cost to address fuel poverty; create and retain economic value-add locally). However, most of them find that implementing a local energy model is out of their reach under current market arrangements. This may be because the complexity of the energy supply chain makes it difficult to understand the options available to them (e.g. given licence exemption rules), the options are difficult to implement (e.g. require a large upfront capital investment) or because there are no options available under current market rules to allow them to deliver fully on their goals. This means that, rather than using commercial arrangements to meet their objectives they are instead adopting private wire solutions. This is an infrastructure solution to a trading issue that is almost certainly inefficient. It also involves a large upfront cost that can act as a barrier to the development of local markets.

5.43. Differences in the transmission and DNO price controls will also need to be addressed. Short term transition arrangements can be put in place until greater alignment can be achieved (see our answer to Q46). For example, these could allow joint requests by the TO and the DNO for re-openers to the controls, alongside using the TO-DNO Joint Technical Planning Meetings for co-ordination of working level activities to optimise overall network solutions. In addition, each should treat the other as a key stakeholder who would be consulted in the production and sign-off of each other's business plans. This should reduce the risk that one party's actions (or inactions) could adversely affect the other party.

***Q46. With regard to further future changes to arrangements:***

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

5.44. We think that further changes to roles and arrangements are likely to be necessary in the longer term, as the system impacts of the challenges identified in the call for evidence increase. This will reflect the increase in costs and benefits associated with changing industry arrangements that will make more wholesale change cost effective. Also, whereas we see much of the need for action in the transition phase to be led on a needs basis (often through trials and derogations), in the longer-term these requirements are likely to become more uniform across the country. At this point the changes to industry codes, licences and regulations will need to be on a national basis.

5.45. Such wholesale change will also be needed to ensure that the overall system is fit for purpose given the growing number of anomalies that arise if technology and commercial arrangements evolve faster than industry roles and arrangements.

5.46. The timing of these more fundamental changes will depend on a number of interdependent factors that are difficult to predict. For example, it will depend on network technology, customer technology, and innovation in the business models to serve these markets. The nature and rate of change will also depend in part on government policy and also on customer readiness to be an active participant.

5.47. While we have not tried to come up with a comprehensive set of longer terms activities that will need to be undertaken, we believe that some of the medium-term actions should include the following:

- Achieving better alignment between the DNO and TO price control periods needs to be considered. In particular, how to ensure that the different business plans are complementary and delivering an optimal set of outcomes for customers and other stakeholders. There are a number of options that must be considered by Ofgem with industry input:
    - Have a more explicit stakeholder role for distributors in transmission reviews and vice versa – the most immediate opportunity being at T2;
    - Use the mid-period outputs review in price controls to ensure continued alignment of outputs;
    - Change the timings so that price controls take place at the same time – potentially with a short T2 review that then allows T3 to alight with ED2; and
    - Possible additional incentives and DNOs and the TOs to encourage these parties to act to minimise whole system costs.
- The planning and technical standards for TO, DNOs and IDNOs and private networks need to be looked at as currently they operate to different standards in terms of tolerance of risk, particularly in relation to equipment failure and when assessing load issues and the need for reinforcement work. For example, exactly the same transformer would be rated at 60MVA by a TO and 72 to 78MVA by a DNO. Equally a TO is required by its security standard to provide security for both generation and demand while a DNO's security standard provides security for demand only. It is not clear how a DSO would rate equipment or secure load and differing assumptions on this will increasingly cause problems in any transition; and

- Regarding the operation of the distribution system, we consider that customer signals are better sent by constrained connection agreements and DSO contracts than by DUoS charges, for the reasons we set out in our responses to section 3. A medium term action is therefore to implement robust and transparent arrangements to enable services to be procured in this way.

5.48. The first of these issues would need to be taken forward by Ofgem, whereas the second and third issues could be taken forward by the TDI group.

***Q46. With regard to further future changes to arrangements:***

***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?***

5.49. The potential future models for efficient network planning and use of resources put forward in the Call for Evidence are reasonable views that need further scrutiny and development. The key remaining questions are the extent to which these expose the full range of models (i.e. ends of the spectrum) and what are the principles that need to be held most true in determining which model is ultimately most appropriate?

5.50. At this stage we are not yet at a point where we know what the right industry model should be, but the selected model should comply with the following principles.

- The future model should be good for a wide range of possible scenarios, including the cross-vector impact of policy decisions and technical developments which may affect electricity demand eg hydrogen as a fuel, renewable heat.
- Optimising the whole system depends on a structure for the sector which delivers optimal solutions for connected customers and for the wider public. The future model must therefore address whole energy cost, not just network issues, and must deliver advances in addressing the security/low carbon/cost objectives.
- The future model should therefore be based on a market-led, not a technology-led, view of the world based on 'commercial pull' rather than 'solution push' that uses markets and cost-reflectivity, where possible, to deliver the most appropriate solution and avoids 'free loading'.
- The model should be designed with appropriate separation of roles to provide transparency and to avoid the potential for conflicts of interest.
- The cost and complexity of implementing and operating a new model must be justified in terms of additional benefits delivered to connected customers and the wider public, including environmental benefits.
- There will be social implications associated with the different models. Opportunity to participate needs to be seen to be fair and consideration will have to be given to how the benefits of the models are shared across society. These are issues that Ofgem and BEIS need to consider early on in the model development.

- The new model should also be clear about which party is responsible for safety, noting that changes to operational practices may have safety implications which will need to be assessed.
- It is important that a particular model is not adopted without sufficient evidence, and trials as well as desktop exercises will be needed to inform discussion.

5.51. More work is needed to look closely at options for industry structures and the roles and responsibilities of the participating parties. It is important to distinguish between the role of managing the system and the role of planning the network, and to break down these high level roles into a number of functions and understand which party should be responsible for each function and which other party/parties are dependent upon the service delivered by that function.

5.52. Turning to the distribution part of the overall system, with their current responsibilities and experience in operating in a non-discriminatory manner, DNOs have the credentials to take on both of these roles and the work to determine the optimal model should address the following issues:

- The work should design and demonstrate a range of possible structures for the distribution sector and the functions and interactions between parties.
- The work should use a range of criteria to assess the relative merits of differing structures against the current structure of the sector (e.g. economic costs and benefits to customers, social and environmental costs and benefits, complexity, cost reflectivity, potential for conflicts of interest or free riding).
- It should be able to demonstrate the value that could be created by introducing DSO functionality.
- It should identify the industry players who may be responsible for functions in the new structure.
- It should set out how the introduction of DSO functionality affects DNOs and other players, and how and when DNOs need to adapt their processes, such as network operation and planning.
- It should set out possible transition pathways for DNOs from current functions towards the functions required in the new structure, and the other innovation projects and the implementation projects that will be needed to enable the transition.

# Section 6: Innovation

## Innovation

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

6.1. More support is required for whole energy system demonstrator trials and this may be achieved either by Ofgem changing the criteria for the networks innovation funding mechanisms or BEIS making available new sources of funding. Ofgem/BEIS should also remain alert to commercial or regulatory barriers restricting the deployment of proven technologies (as is being done for storage).

6.2. The Low Carbon Networks Fund (LCNF), Network Innovation Allowance (NIA) and Network Innovation Competition (NIC) framework have been relatively successful in supporting the development of new technologies, but cannot address the regulatory barriers or the commercial tipping points. The latter of these last two points is generally driven by customer demand and is perhaps not an area for specific support. However in the area of energy systems, where exploration of the effective and combined use of, for instance, gas and electricity assets is needed, there are significant regulatory barriers to funding of innovation.

6.3. Currently, sufficient economic and regulatory support is not there to allow this important, and higher risk, commercial and technical systems demonstration to take place. Energy systems trials are taking place through European funding mechanisms and modelling work is taking place through academic routes[63]. However, there is a need to make more funding available for energy systems demonstrator projects either through Ofgem making changes to the NIA and NIC funding arrangements or BEIS making available more direct funding for projects.

6.4. The call for evidence proposal to trial a flexibility trading and optimisation platform has significant overlap with NPg's GB Flexibility Market LCNF project proposal, submitted in 2012. This application for LCNF support identified some of the difficulties associated with funding for these cross-cutting energy systems approaches. In this project it was identified that benefits could fall to market sectors other than distribution and, as such, matching innovation funding would be required from the generation or supply sector in addition to the network innovation funding. The competitive nature of these sectors and the uncertainty in the business case meant that we were unable to find funding from individual companies that would be commensurate with the estimated benefits; and no other sector funding route was open to us.

6.5. There is a need to be able to perform real-world trials at adequate scale, possibly on a sub-regional basis, in order to develop confidence in potential innovative solutions. Additionally, and due to the difficulty of mapping inputs to outputs in these types of trials the precise cost-benefit to different industry parties is difficult to determine upfront and innovation support that does not require this to be determined at a very early stage would be useful.

6.6. This work on battery costs looks best suited to Innovate UK type funding whereby the intellectual property (IP) rights may be protected for the manufacturers with the expertise to engage in trials, who own the background intellectual property and will have a key interest in bringing improved technology to the marketplace. The IP requirements of the current NIA make DNO participation in this broad system development work and network trials difficult. However

[63] For example, the Centre for Energy Systems Integration (CESI) funded by the Engineering and Physical Sciences Research Council (EPSRC).

we believe that opportunities, such as this which support the Government's developing thinking on Industrial Strategy, particularly for the automotive sector, should not be missed.

6.7. With a number of the technologies developed and deployed through LCNF and other funding streams, technological issues have been relatively well proven. Commercial or regulatory barriers have slowed subsequent implementation.

6.8. A specific example is that of energy charges for storage. Currently storage providers pay for the energy they use charging the battery including any 'green' taxes. While this seems reasonable given the energy they are using is coming from a general mix that includes carbon intensive generation, it has the potential to double the green taxes paid by the end user – for importing energy into the merchant storage facility and then importing energy into the home. There are a number of ways of addressing this, but a holistic approach that tries to avoid as far as possible unintended consequences is required. It is possible that this might be as simple as refunding the 'green' taxes as the energy leaves the storage facility - it is after all clearly not carbon based generation at this point.

6.9. Simple regulatory methods based on an underlying logic such as this have a number of advantages. They minimise regulatory change while still making the new technology/technique's viability cost-reflective. They reward technologies that make best use of resources and are most efficient and expose the real commercial value. They minimise the need to pick winners.

6.10. To expose this real commercial value sufficient commercial offerings are required. For demand side response, we commend the need to carry out more trials as reflect in our comments in the smart appliances section of this response. Careful thought should be given to the market that is being developed and the available products that this may then encourage. For an effective trial, there need to be sufficient alternative technologies provided by manufacturers who see a market and are promoting their products with the required functionality (to provide a discretionary load or enable consumers to provide a response or service with no perceived service disruption). There is a significant desktop phase required to design such a trial to achieve maximum value from the investment and support for this type of work, preparatory to actual trials, would be useful. This is consistent with the comments on trial design promoted in the Hubnet report 'A Review and Synthesis of the Outcomes from Low Carbon Networks Fund Projects', August 2016.

6.11. An undertaking by Ofgem to review the regulatory position of new technologies and techniques at an early stage and in a holistic manner would assist with the transfer from trial to business as usual and offer real support to the innovative work already delivered.

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

6.12. Yes, these are the right areas and Ofgem/BEIS is correct to identify a range of areas with an appropriate weighting towards commercial areas. In supporting innovation, BEIS should be ensuring that there is a close alignment with the developing Industrial Strategy – there are opportunities to boost competitiveness in the areas of smart technologies for electricity generation, heat and transport.

6.13. The areas mentioned all have the potential to provide useful value to the country's energy system, but each of the different techniques will probably assist different areas more and a broad approach is therefore still required.

6.14. As an example vehicle-to-grid is likely to assist generators, suppliers and the system operator more than distribution network owners, due to the likely timing of availability of the service, whereas demand side response (including managed vehicle charging) will have a more uniform potential for benefit.

6.15. In particular combinations of different areas, perhaps domestic storage and managed EV charging, might release greater benefit together than either will do alone. For this reason consideration should be given to the interplay between technologies, applications approaches and commercial frameworks and trials aimed at testing this should be actively supported.

6.16. Vehicle-to-grid is a technology and approach that exposes some of the failings of the current funding mechanisms. It is a highly promising commercial proposition, backed by considerable technology investment. Its use needs to be further considered alongside work proposed on reducing battery costs.

6.17. Finally, it is essential to understand how all of the parts of future energy systems function together to optimise value for customers. Evidence pointing at the need for a greater focus on energy system approaches is provided by the example of making optimal use of wind generation resources. Moving away from a specific technology the general change in technologies available will have an impact. As energy generation and use patterns change, generation peaks may not coincide with times of network spare capacity and system peaks may not coincide with local network peaks, and frequency events might coincide with none of these. Consideration must be given therefore to competition between different techniques. Over-capacity of wind generation coinciding with the distribution network peak would mean that customers could not take advantage of low cost energy at a time when many of them would in fact like to use it. For this reason the sector must remain aware of the overall value to the system of various techniques, now and into the future, and value judgements must be made when supporting innovation and research.