The Association for Decentralised Energy

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Bringing Energy Together

ADE Response | Smart Energy Call for Evidence 12 January 2017

Context

The Association for Decentralised Energy (ADE) welcomes the opportunity to respond to the Department for Business, Energy and Industrial Strategy (BEIS) and Ofgem joint Smart Energy Call for Evidence.

The ADE is the UK's leading decentralised energy advocate, focused on creating a more cost effective, efficient and user-orientated energy system. The ADE has more than 100 members active across a range of technologies, and they include both the providers and the users of energy. Our members have particular expertise in combined heat and power, district heating networks and demand side energy services, including demand response and storage.

Summary of recommendations

Enabling storage

- BEIS and Ofgem ensure a level playing field between storage and other forms of energy provision.
- BEIS pursues an integrated energy policy for storage, so that the potential for "virtual batteries" can be realised.
- BEIS introduces upfront A&D fees for connection applications at a modest level.
- BEIS and Ofgem ensure that DNOs take a more active role in managing new connections and explore alternative 'smart' mitigation options, such as active management approaches, or voltage limiting schemes, in accordance with their obligations under Section 16 of the Electricity Act and in discharge of their undertakings in the LCNF, NIC and NIA.
- The network security of supply standard (Engineering Recommendation P2/6) is updated to recognise non-build solutions such as DSR and storage.
- All DNOs should be required to offer flexible connection agreements on request from developers of all new generators or energy storage sites.

Network charging

- BEIS takes an active role ensuring the regulator reviews network charging and the embedded benefits issue in an independent, holistic and systematic way.
- BEIS considers the very real risks across the Government's wider policy ambitions of removing the embedded benefit, including the industrial strategy and business competitiveness, security of supply, and storage deployment.
- Ofgem reviews the current processes for code modifications (BSC and CUSC), which significantly favour the incumbent parties over new and decentralised energy providers, many of whom do not have access to the relevant processes.

Connections

- The network security of supply standard (Engineering Recommendation P2/6) should be updated to recognise non-build solutions such as DSR and storage.
- Regulations should allow DNOs to procure the services of storage and DSR, but not to own it directly, since this could undermine competition and would be in direct conflict with the ownership unbundling requirements of the Electricity Act 1989 and EU Electricity Directive 2009/72/EC.

Licencing

- If required, Ofgem should create a licencing regime for large-scale storage, with a de-minimis exemption for smaller installations, aligned with the existing generation exemptions.
- Ofgem should seek to adjust existing arrangements to remove current problems of double charging for storage, rather than through a new licence for all storage installations.
- The Electricity Act 1989 and associated grid codes should be updated to define new activities such as electricity storage and DSR, using the definition proposed by the ESN.
- BEIS should adjust the Capacity Market Regulations to enable energy stores and small generators to be aggregated regardless of whether they export or feed site load, and should enable mixed aggregation between DSR, energy stores and small generation.
- BEIS and Ofgem should be mindful of the many potential versions of energy storage which could provide electricity balancing, arbitrage and integration, potentially over different timescales to those which suit batteries, and across other energy sectors.

Balancing Services

- BEIS and Ofgem ensure National Grid reforms the current suit of Balancing Services to by:
  - Full transparency of contracts, pricing and requirements.
  - Clearly linking pay with performance.
  - Implementing competitive auctions.
  - Creating real-time and liquid markets.

Wholesale Market and Balancing Mechanism

- Ofgem reform the BSC to create a regulatory framework for the aggregator or a customer to register a Balancing Mechanism Unit (BMU) and ensure the implementation of Project TERRE allows non-BM participants to access the Balancing Mechanism and TERRE market, and sell their flexibility independent of suppliers, i.e. populate it with customer loads without needing to negotiate with or obtain the permission of those customers' suppliers.
- Ofgem take an active role and conduct a detailed review into the development and determination of how volumes are measured to calculate imbalance payments. The BSC panel and industry process is largely dominated by Balancing Responsible Parties (BRPs), leading to a lack of expertise non-traditional market participants, such as DSR aggregators and other flexibility providers, that significantly favours the incumbent parties over new providers.
- Beyond project TERRE, there will be a regulatory role for Ofgem to ensure that suppliers are not able to use contractual terms to dissuade, prevent or disincentivise their customers from providing DSR services and selling their flexibility in the Balancing Mechanism, Balancing Services and Project TERRE.

- If there is a change to the rules meaning supplier positions are adjusted after an action is initiated then the market should be given time for novel models which capture this value efficiently to emerge.
- Ofgem make the necessary regulatory changes to allow flexibility providers, from DSR and storage to flexible CHP and onsite generation, to access and sell their flexibility in the Wholesale Markets independent of any supplier, as access to the Wholesale Market will not be addressed through Project TERRE.

Other market barriers

Capacity Market

- BEIS and Ofgem should reform the Capacity Market to:
  - Allow all participants to access the same lengths of contract, including DSR providers and existing generators.
  - Set a minimum procurement level for every year-ahead capacity auction.
  - Simplify the testing and metering Rules, allow the flexible reallocation of DSR assets, and enable businesses to provide all types of DSR including Firm Frequency Response.

Additional flexibility benefits not currently captured

- BEIS and Ofgem should enable and ensures the System Operator explores how the additional flexibility benefits not currently captured in network services, which DSR and CHP bring to the system, such as black start, inertia/reactive power, reliability, speed, congestion/constraint/ voltage management, capacity freeing and carbon, can be accessed and valued appropriately.

Consumer protection

- Ofgem and BEIS continue to support and contribute to the development of the ADE Code of Conduct for non-domestic customers, followed by domestic customers.
- The System Operator requires aggregators to sign up-to a set of requirements, which demonstrate that aggregators are providing assurance to customers, in order to access Balancing Services, or to fulfil a specific aggregator role in the BSC.

Introduction

The way electricity is generated and used in the UK is changing dramatically. We are seeing increasing amounts of renewable generation, such as solar and wind, that is dependent on the weather, delivering too much electricity at some times and not enough at others. With coal power plants all expected to close by 2025 and an ageing nuclear fleet reaching retirement, we are also losing significant amounts of generation that might have filled in the gaps. On the horizon, we face new power demands from heat pumps and electric cars.

As we look to electrify heat and transport while increasing the amount of intermittent renewable generation, it is becoming more challenging to keep the system in balance at a reasonable cost to bill payers.

The role of local, user-led energy in a smart, flexible system

Demand-side response (DSR), storage and flexible generation such as combined heat and power (CHP), provided by businesses and the public sector reduce the need to build new power stations, while also avoiding substantial network investments and improving market competiveness for the benefit of consumers. We will continue to need the flexibility provided by traditional power plants, but without demand-side flexibility, balancing supply and demand will become significantly more difficult and expensive beyond 2030[1].

However, in a rapidly changing system, the end customer, who ultimately bears the costs, must be engaged if their support is to be maintained and their potential contribution is to be fully harnessed. If the customer is ignored, we may be unable to deliver the energy system changes needed to keep the lights on, power our economy and meet our carbon commitments.

Energy is at the heart of all businesses. It powers production lines, computing and industrial processes. Energy is also an important cost for many businesses, sometimes making up to half of production costs. A key focus of the Government's new industrial strategy will be supporting the global competitiveness of British businesses and that is driven in part by their cost base. Any industrial strategy must therefore consider energy.

Rising energy bills caused by increasing energy system and policy costs are directly impacting the profitability and international competitiveness of industrial and commercial energy users. The policy approach to date has not considered holistic, long-term solutions that help businesses control their energy costs and invest to support their long-term competitiveness. The need for businesses to have access to energy at prices that allow them to stay competitive while, at the same time, the country manages the transition to a low carbon energy system, can be seen as two sectors pulling against one another.

A smart, flexible energy system has to recognise the benefits the energy user brings to the system and must ensure that that value accrues to the user.

When seen from the user's perspective the tension between business energy cost and competitiveness, security of power supplies and emissions reduction, can be resolved. By encouraging businesses to invest in efficient generation and rewarding them for electricity system services, we can drive industrial competitiveness and the clean energy transition.

In recent energy policy, there has been a lack of focus or ambition to consider how industrial and commercial energy users might provide the answers to these energy system challenges. Policy traditionally focusses on the energy generation sector to address the issues. Yet, with energy users taking a greater interest in new technological solutions, a greater role for local generation

[1] Imperial College London & NERA Consulting, *Understanding the Balancing Challenge*, August 2012.

and energy management, there is now a clear potential to bring together business and energy to create a more productive, competitive, cost effective, resilient and lower carbon energy economy.

Key to a flexible and smart future system is the ability for assets to provide several different services, from security of supply and network management to carbon reductions and cost savings. CHP and DSR are such multi-capability assets that assist the whole energy system across many areas. For example, CHP can flex in response to renewable resource availability, while DSR can provide reserve and response allowing CCGT stations to remain at maximum efficiency.

This multitasking capability is one of the key elements that allows a system to become truly "smart" and energy users who provide such capability must be recognised and rewarded appropriately, be it for the energy security and system services they provide, or for helping to control and even reduce industrial and commercial energy costs.

Solving the challenges of our changing electricity system, at the best value to the consumer, is not an easy task. If we are to be successful we need to re-examine the way we secure the electricity supply, focus on the user as the centre of the energy system, and empower them to help manage it.

DSR potential in 2020

While businesses are technically able to participate in a range of different energy markets, from Balancing Services and the Capacity Market to the Balancing Mechanism, the structures of these markets currently prevent businesses providing DSR from competing on a level playing field and securing fair value. This deters participation.

We estimate that businesses providing DSR currently miss out on hundreds of millions of pounds per year because they cannot access the full value of these markets. At the same time, consumers are bearing higher costs than they would otherwise need to, because the tilted playing field prevents the lowest cost combination of supply and demand-side resources from being procured.

Opening up all markets to DSR providers and other types of flexible generation such as CHP, and storage, will cause a positive feedback loop, where bid prices in the Capacity Market will be lower because value is also accessed through the Balancing Mechanism and Balancing Services, and vice versa.

The ADE's recent report found that the total amount of potential DSR that could be secured across the industrial, commercial and public sectors, including highly efficient CHP assets and on-site back-up generation, can be conservatively estimated at 9.8 GW in 2020. This estimate includes:

- **2.8 GW** from industrial demand flexibility
- **1.7 GW** from commercial and public sector demand flexibility
- **2.3 GW** in flexible availability from the 5.2 GW of current on-site CHP capacity
- **3 GW** of on-site back-up generation capacity (non-CHP)

This DSR potential of 9.8 GW would represent 16% of the total winter peak demand and 33% of industrial, commercial, and public sector peak demand in 2020.

The size of available DSR will likely grow further beyond 2020, as the electrification of heat and transport intensifies, and the levels of industrial, commercial and eventually household participation increase.

Household DSR represents an important future opportunity, but is a more difficult challenge. By ensuring all current users have a route to market and can receive fair value for their flexibility, the Government will ensure that householders will be incentivised to deliver demand side flexibility when the necessary technologies have been put in place, while also ensuring that the current business and public sector opportunities are seized today.

Benefits to the system and consumer

Unlocking the UK's potential 9.8 GW of DSR capacity would deliver tangible benefits across the energy system and the UK's industrial, commercial, and public sectors, including:

- **Controlling system balancing costs:** A further 4.5 GW of the DSR potential could help increase competition to provide Balancing Services, making Balancing Services markets more competitive and controlling costs for consumers[2].
- **Lower-cost security of supply:** It is estimated the UK will need 4 GW of capacity to meet peak demand only during 50 hours of the year in 2020. If the UK deployed 4 GW of user-led DSR through the Capacity Market, our analysis shows the UK would avoid the need for 50 new OCGT power plants or over 1,300 new small diesel or gas engines: a net saving for consumers of £600 million by 2020, rising to £2.3 billion by 2035[3].
- **Improving businesses' competitiveness and profitability:** By gaining additional revenues from the electricity market through DSR, businesses in the industrial, commercial, and public sectors are able to reduce their energy costs, improving their competitiveness and their bottom line. Despite DSR only achieving a tenth of its estimated potential in the Capacity Market, businesses have already secured £100 million in value[4].
- **Lowering energy bills by reducing network costs:** Work by Imperial College London and the University of Cambridge Energy Policy Research Group found that DSR, as part of a flexible system, could deliver network investment savings of up to £8.1 billion a year by 2030[5].
- **Reducing emissions:** By using zero-carbon 'turn down' flexibility and by employing more local generation, DSR is able to displace fossil fuel generation that would otherwise run for fewer than 50 hours per year. This would avoid having to new build carbon-intensive plant to meet these limited periods, reducing emissions and helping the UK meet its carbon targets. For example, more than 650 MW of diesel engine farms cleared the Capacity Market auction in 2015, and a further 3.7 GW of reciprocating engines, of which 678 MW was declared as diesel, cleared in the 2016 auction. Had this capacity been provided by a mix of DSR and CHP, the same electricity-sector security would have been obtained with lower capital cost, lower emissions, greater security in local business connections, and greater security in another key energy sector – heat.

CHP's potential in a flexible energy system

Combined heat and power, the most efficient way of using energy from all fuels, has to be located on the energy user's site. It cuts energy use by up to 30%, driving down cost and emissions. It also provides system security and flexible generation to fill the gaps when wind and solar production is low.

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[2] Estimate based on industry analysis derived from National Grid's "Future Requirements for Balancing Services".

[3] Estimate based on the CAPEX and fixed O&M costs of small diesel engines. DSR costs are factored in the calculations, covering the costs associated with the site audit and metering incurred by DSR aggregators.

[4] Based on the DSR and CHP providers that secured contracts in the Capacity Market T-4 and TA 2015 auctions

[5] Imperial College London and Energy Policy Research Group (University of Cambridge), *Delivering Future-Proof Energy Infrastructure*, 2016.

CHP plant come in all sizes, from a 2 kW CHP providing heating and hot water to a household to a 1 GW plant providing high temperature steam to two major UK refineries. CHP plant supply heat and power to users that range from small hotels to huge industrial complexes.

There are more than 110,000 jobs located on businesses and industrial sites supported by CHP, helping to improve their manufacturing productivity, control their energy costs and protect long-term employment. The CHP fleet is concentrated in British industry, with 80% of the refining sector, half of the paper sector, a third of the chemical sector and 10% of the food and drink sector relying on the technology for their energy needs.

CHP, by generating power locally and capturing its heat efficiently, is a key part of the smart energy economy. The volume of gas saved by good quality CHPs to the UK economy is 18.6TWh per year, reducing gas imports by £302m in 2015.

The avoided distribution network losses from CHP are enough to power 318,256 households, or 1.2% of all UK households. A previous study by Imperial has shown that the value of CHP in the context of the UK distribution network would amount to £50-£100/kW of installed capacity.

Even when CHP operates part load, it still have lower efficiency losses than power station operating at part load because CHP is smaller and able to operate modularly, driving carbon savings, and are able to capture their heat, improving their overall efficiency compared to a power station.

CHP flexibility can deliver between 240 seconds and 20 minutes, depending on the type of technology (turbine or engine) or size. In comparison, coal power plants take 50-100 minutes and gas OCGT take 15 to 30 minutes.

Despite already serving as a key part of the UK economy, CHP could provide greater benefits. According to analysis undertaken by Ricardo AEA for the Department of Energy and Climate Change, only one third of the UK's cost-effective CHP potential has been reached.

Because heat (and 'coolth') can be stored far more cheaply than electricity, CHP can greatly enhance flexibility while creating cross-sector links. For example, a district heating network can be fed by a CHP generator, a large-scale heat pump, a biomass boiler, and low-grade heat recovery from businesses.[6] All of these sources can work together through the district heating network, sharing the heat and electricity burden in response to wind and solar generation and national demand. This makes district heating CHP into a virtual battery.

Highly efficient industrial and commercial CHP could become the key technology to integrate the energy policy and industrial strategy agendas. A major growth in CHP could increase UK generation capacity, add to local electricity system resilience and stability and help keep the lights on, all while reducing business and industry carbon emissions.

CHP is considered a win-win for its ability to simultaneously tackle emissions, flexibility, security and business energy costs. However, because its benefits are spread across different sectors, different markets and different policies, CHP can struggle to be recognised for the value it provides. For CHP to achieve its potential, energy users need to be rewarded for the energy security and system services they provide, helping to control, or even reduce, industrial and commercial energy costs.

[6] For example, Islington Borough Council's Bunhill CHP installation integrates most of these sources.

Response to the call for evidence

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.

The ADE agrees with the policy and regulatory barriers for storage identified in the call for evidence. However, it is imperative that markets do not discriminate between different forms of energy storage technologies; whether it is stored as thermal energy in hot water or frozen produce, or in lithium ion cells, and that consideration is given to the fact that the issues faced by storage, such as network connections and network charging, are also faced by other flexible generation, such as highly efficient combined heat and power (CHP).

In an integrated energy system, the combination of a district heating network, a CHP installation and a large-scale heat pump can create a "virtual battery". Such innovative arrangements should be included in arrangements to promote the development of storage.

Recommendations

The ADE recommends that:

- BEIS and Ofgem ensure a level playing field between storage and other forms of energy provision.
- BEIS pursues an integrated energy policy for storage, so that the potential for "virtual batteries" can be realised.

Q2. Have we identified and correctly assessed the issues regarding network connections for storage? Have we identified the correct areas where more progress is required? Please provide evidence to support your views.

The ADE supports the ongoing work of the Electricity Networks Association (ENA) as summarised in Table 3 of the Call for Evidence, and is involved in many of the working groups.

It is important to note again that many of the issues that are faced by storage, such as network connections and network charging, are also faced by flexible on-site generation such as CHP projects.

We set out several areas below that could be addressed to improve network connections for all flexibility providers.

Upfront Assessment & Design fees

Members have made us aware of several cases where CHP developers have been denied distribution network connections, and DNOs do not explore alternative 'smart' mitigation options, such as active management approaches, or voltage limiting schemes, as we understand is a DNO's obligation under Section 16 of the Electricity Act. When some members have pursued these issues more forcefully, some additional options have on occasion been provided by DNOs, although the practice is not consistent.

The introduction of upfront Assessment & Design (A&D) fees, as per the Government's call for evidence in March 2016, would allow DNOs to charge each applicant for the work that goes into a connection offer and would reduce the overall resource burden that DNOs face. Further, the connection offer cost would be more fairly allocated. Bringing this into force would go some way towards opening up network connections for the most serious parties, quickening the connections process for the most realistic projects.

Constrained networks

DNOs are required as part of their licence to comply with a security of supply standard known as Engineering Recommendation P2/6. This defines a set of standards and methodologies for how DNOs should evaluate security of supply, and the options they should consider when making new investments into their network. DNOs have traditionally responded to network constraints by building or upgrading assets such as cables and transformers, which can require significant time and money.

However, new technologies such as DSR and storage could also be used to relieve network constraints, and remove the need to expand the network. At present, Engineering Recommendation P2/6 does not explicitly recognise these "non-build" solutions. For example there is no standardised methodology for how DNOs should assess the network benefits of storage or DSR. This creates ambiguity, making it more difficult for DNOs to justify innovative approaches.

How CHP connections can help alleviate network stress

Members have made us aware of several cases where distribution networks charge businesses and industrial sites for the distribution connection, even though these users are not exporting and no investment is required related to that generator's export. These generators are instead being charged, through network connection charges, for the displacement of on-site demand, as the displacement of on-site demand results in a need to reinforce other parts of the network to handle the other displaced local renewable generation which might have served that demand.

In fact, in a smart, flexible energy system, local CHP and DSR will respond directly to the activities of other generation on the network. For example, high solar PV output could result in a reduction in CHP generation through a choice of mechanisms: natural variation (CHPs run less on sunny days), automatic network management or ANM (the CHP senses voltage rising as a result of high PV output and low demand, and responds to it), demand response (the CHP is signalled to turn down, or load is signalled to turn on, as a service to the DNO when PV output is high), or price (CHP moves production into higher priced periods when PV output is low). The approach taken by DNOs at present does not facilitate this beneficial interaction.

Other flexible generation

We are also aware that smaller (<10 MW) CHP developers are increasingly struggling to achieve connections on industrial and commercial sites. In some instances, the DNO has not provided any cost and time estimate but simply rejected a connection outright. This appears to most commonly occur with Western Power Distribution in one of its zones, who has told a CHP developer that no connections for a CHP are available until 2019, and Scottish Power Energy Networks, who has said that no connections are available until 2023.

Securing network connections has always been a challenge and recent work by Ofgem in Low Carbon Networks Fund (LCNF), the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC), has been positive. However CHP is seeing increased challenges in this area, a relatively new and troubling occurrence for CHP developers, which are typically located on sites with existing significant demand or in urban areas.

As discussed above, when CHP developers are denied distribution network connections, they often are not encouraged to explore alternative 'smart' mitigation options, such active management approaches, or voltage limiting schemes, despite the obligation on DNOs under Section 16 of the Electricity Act. It is regrettable that these innovations – many of which have received support under Ofgem's LCNF, NIA and the NIC – are still not part of the DNOs' business-as-usual connection toolkit.

Limiting of export opportunities
CHP, as a non-intermittent generator, is able to improve system productivity and reduce system stress by reducing system demand and by exporting their power when needed to help balance the system. Using low-cost thermal storage, CHP can schedule its export to the periods of greatest need, or in fact respond dynamically to events as they occur. However, over the past few years, distribution networks have increasingly refused to allow CHP operators export agreements.

The lack of export agreements severely restricts the participation of these sites in the electricity market, the Capacity Market, or Balancing Services due to the rules and regulations of these markets. This prevents highly efficient CHP generators from increasing competition in capacity and energy markets, reducing costs for consumers, and reducing carbon emission impacts in these markets.

Recommendations
The ADE recommends that:

- BEIS introduces upfront A&D fees for connection applications at a modest level.
- BEIS and Ofgem ensure that DNOs take a more active role in managing new connections and explore alternative 'smart' mitigation options, such as active management approaches, or voltage limiting schemes, in accordance with their obligations under Section 16 of the Electricity Act and in discharge of their undertakings in the LCNF, NIC and NIA.
- The network security of supply standard (Engineering Recommendation P2/6) is updated to recognise non-build solutions such as DSR and storage.
- All DNOs should be required to offer flexible connection agreements on request from developers of all new generators or energy storage sites.

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

Regarding flexible connections, please see our response to Q2.

Regarding network charging, the ADE agrees with the issues identified for storage and network charging. However, we would like to highlight particular concern regarding the current work on embedded benefits, which impacts not just storage, but all flexible generation, and has the potential to severely limit Government's ambitions for a smart and flexible future system.

The risk embedded benefit reform damages the smart energy system
Embedded generation offsets demand within the distribution network and as a consequence reduces network operators' costs at distribution and transmission levels. In return for this reduction in costs, most embedded generators are rewarded through a number of benefits that are not available to a transmission-connected generator. These benefits are referred to as embedded benefits and are intended to reflect the avoided cost of connecting directly to a distribution network. The benefits are also equally attributable to storage when it is exporting which is treated as generation for settlement purposes.

In most cases, embedded benefits are not 'benefits', but a recognition that distribution-connected generators and export from storage do not use the transmission network – rather, they reduce its use – and so should not pay for its use. As distributed generators and electricity storage are located close to demand, they cost consumers less in network infrastructure and are rewarded for this system benefit. This benefit is received by industrial combined heat and power generators, battery storage providers, and local generators such as hospitals and renewable providers.

Yet, as transmission network costs have increased significantly over the last 10 years the level of benefits for not using the transmission network has risen concurrently, and some have raised concerns about whether the benefits reflect the avoided costs of distributed generation and storage.

Ofgem published an 'open letter' in December 2016 which stated they see no evidence for an embedded benefit above £6/kW. However, if the embedded benefit is largely removed, the impacts across the Government's smart energy ambitions will be significant. We have set out some of these impacts below:

Increase in industrial manufacturers' energy costs. More than 375 UK industrial sites use combined heat and power (CHP) to generate their own electricity, including half of the paper and chemicals industry, 80% of the refining industry, and in the steel and food and drink and sectors. These CHP sites support more than 100,000 manufacturing jobs by controlling these sites' energy costs as CHP integrates the production of usable heat and power, in one single, highly efficient process.

Removing embedded benefits could result in an energy cost increase of £170m for industrial manufacturers who generate their own power. Some manufacturers in the chemicals and food and drink sectors face up to 20% increases in additional annual energy costs (up to £4.5m). One large chemical manufacturer has warned it might close entirely, losing up to 1,300 manufacturing jobs. An example of some sites which will be affected is included in Annex A.

Currently industrial sites also participate in 'triad avoidance' by reducing demand and by using back-up generation to reduce their power use during triad periods (if they do not use power from the network during triad periods, they do not pay transmission costs). National Grid estimates this participation at between 1.6 GW and 2 GW. If Ofgem begins charging triad to on-site demand, every industrial site which participated in triad avoidance could see their network costs rise by a total of £90m.

Significant risk to keeping the lights on in winter. More than 7.5 GW of distributed generation (equal to 7 large power plants) operates at peak demand, helping to keep the lights on by reducing the strain on the national network. For context, winter peak margins are expected to be less than 2.5 GW in coming years.

Because generators receive the 'embedded benefit' only when they operate at peak demand, its removal could mean they are no longer there to help keep the lights on. If just 33% of distributed generation stops operating at peak demand, Ofgem risks a security of supply crisis**.** However the regulator has undertaken no analysis of how removing embedded benefits could impact winter supply margins and has said it sees no reason to be concerned as changes "are unlikely to materially alter the short term risks to security of supply".

In addition, there are 2.1 GW of new build capacity which procured four-year-ahead Capacity Market contracts based on the embedded benefit regime. We are advised by engine farm developers that these projects are now at risk. For example, one developer in the southeast has predicted they will not deliver their more than 100 MW of new capacity for future Delivery Years.

If substantial new build capacity does not deliver, the Government will have to re-procure that capacity in 15 year-ahead auctions, potentially at high cost, increasing consumer costs. KPMG has estimated the total cost to consumers will be £285 to £945m over 15 years.

Higher energy costs on consumers. Analysis by Cornwall Energy found removing Embedded Benefits will add £282m to consumer bills, or £10 a household, by increasing the 2016 Capacity Market auction price. In addition to this figure, Cornwall Energy's analysis also found that removing the benefit would increase wholesale costs and balancing costs.

In contrast, National Grid estimates the embedded benefit costs consumers £293m a year. Therefore, under current values, consumers could be equal or worse off following reforms. However, the embedded benefit value is increases due to pressure from higher network costs, and there is a need to freeze the value to protect consumers until a full review is undertaken.

Damage to smart energy and storage ambitions. Removing the embedded benefit would impact the nascent smart energy and electricity storage sectors, which invest against these values. From wind to energy from waste to battery storage, this sudden shift would harm investors, harm investor confidence and hold back the Government's storage and smart energy ambitions.

Finance organisations which have reviewed the projects bidding into the most recent Enhanced Frequency Response auction have found that many of the successful bids assumed they both received the triad embedded benefit over the life of the investment, and that the investment helped a demand user avoid transmission costs by avoiding triad charges. If Ofgem removes both the exported benefit and the triad avoidance benefit, these battery storage projects will likely fail to deliver, causing significant damage to the UK's storage ambitions.

Risk of regulatory capture from the industry process

The recommendation to remove the Embedded Benefit came from the 'Connection and Use of System (CUSC) Panel', where six of the nine members represent large generation interests (Drax, SSE, Scottish Power, ENGIE, EDF, Uniper). Two of the members of the Panel (EDF and Scottish Power) made the original modifications to freeze or remove the embedded benefit, while Engie, Scottish Power, Uniper and SSE put forward alternative modifications to remove them entirely. No member of the Panel represents distributed generators or large industrial demand customers.

The representatives who work for all six organisations voted only for options which would remove the embedded benefit almost entirely. There is a risk that the Panel members did not have the expertise or experience to reflect the industry's views and knowledge in its decision and the industry self-regulation process has resulted in transmission generation parties voting to strengthen their own market position, with knock on effects and harm across all of energy policy.

Notably, the Citizen's Advice representative abstained from voting, stating in the CUSC Modification Report that while reform of the embedded benefit was needed, there was a lack of evidence on whether the consumer will be better off as a result of any of the specific modifications/alternatives. The Citizen's Advice representative wrote:

- "There was insufficient time available to fully analyse the impacts of the proposed solutions on consumers. This does make it difficult for me to take a reasonable and robust view of the various proposals."
- "Leaving matters to industry self-governance will deliver change, but that may not be the optimum route when many of the innovators are new to industry codes or may not even be code signatories. There are hundreds of millions of pounds at stake here, both for investors

and consumers, and there are many well-funded established industry parties who have an interest in the outcome of any changes."

Next steps for the Targeted Charging Review

Ofgem has committed to undertake a 'Targeted Charging Review' to follow its decision on CMP264 and CMP265. It remains very unclear what this Targeted Charging Review will include in its scope, as initially it was to just consider additional embedded benefits such as BSUoS and on-site generation.

By implementing changes only to the triad benefit received by exporting distributed generators, Ofgem will not be directly addressing its identified non-cost reflective charge. It would be more appropriate for Ofgem to address the level of the triad charge caused by the fast-rising demand residual, rather than the benefit received by distributed generators.

It is vital that Ofgem plays an independent, active and analytical role in any review process, rather than relying on individual CUSC modifications. An Ofgem-organised and independently-led review of Embedded Benefits should be integrated with National Grid's project to reform transmission charges to engender a careful, holistic and systematic approach, across both the transmission and distribution networks, and help deliver an enduring solution.

Under CMP264 and CMP265, Ofgem risks finding itself in a regulatory cul-de-sac, unable to fix new distortions which it had just created for on-site generators and demand reduction. More easily implementable solutions, which directly address the TNUoS demand residual, are available.

The TNUoS demand residual is not, as the Ofgem letter states, "largely fixed and sunk costs". The residual is a cost recovery mechanism, required because there are costs accrued on the network which have not been allocated to specific users. The level of the residual is arbitrary, based on a number of decisions made regarding the size of the locational charge's cost recovery, which currently only recovers 10% of network costs. Therefore distributed generators, by reducing demand on transmission networks, could be seen to have an impact on the costs captured within the residual charge.

We believe three steps would help address the fast-growing demand residual and these should be captured in any Targeted Charging Review:

- Reduce the demand residual by reviewing the size of the money recovered from the locational charge, which is currently limited to just 10% of the overall costs of the network.
- Reduce the demand residual by considering which specific network costs should be socialised.
- Review the triad signal and which costs of the residual, the year round charge and the peak charge are appropriate to recover through a peak demand charge, as triad is now, and which network costs are appropriate to recover through alternative methodologies.

Another CUSC modification proposal (CMP271), proposed by RWE, is also currently being considered by a CUSC working group. This modification proposal would help address a number of aspects of this more holistic approach, addressing why the residual makes up 90% of network costs and considering how best to recover this cost from network users. The proposal also successfully reduces the embedded benefit available to 'peaking generators' such as diesel in the short term until a more comprehensive reform is made available.

Recommendations

Network charging is a complicated and integrated area, with knock-on effects across the energy system. Rushed proposals could cause significant harm to industrial manufacturers, a wide range of distributed generators, and the UK's storage ambitions.

The ADE recommends that:

- BEIS takes an active role ensuring the regulator reviews network charging and the embedded benefits issue in an independent, holistic and systematic way,
- Ofgem ensures its Targeted Charging Review has a sufficiently wide scope to consider the underlying causes for the growing demand residual.
- BEIS considers the very real risks across the Government's wider policy ambitions of removing the embedded benefit, including the industrial strategy and business competitiveness, security of supply, and storage deployment, and ensures that any decision by Ofgem takes these impacts into account.
- Ofgem reviews the current processes for code modifications (BSC and CUSC), which significantly favour the incumbent parties over new and decentralised energy providers, many of whom do not have access to the relevant processes.

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

Under the "ownership unbundling" requirements of the Electricity Act 1989 and EU Electricity Directive 2009/72/EC, network operators are prohibited from generating or supplying electricity. These rules were put in place to prevent discriminatory behaviour by vertically integrated companies owning networks as well as generation or supply businesses. Although many DNOs are no longer owned by vertically integrated companies, the importance of the unbundling requirements to ongoing competition remains extremely high.

As currently defined, the unbundling requirements mean that DNOs are not allowed to own power storage devices, since they are classed as generation. Some DNOs have called for this to be changed so that they can own storage as part of their regulated business. However, we would urge Government not to allow DNOs to own storage, since this could undermine competition and would be in direct conflict with the ownership unbundling requirements set out above.

Network operators are monopoly businesses within their area of operation, and the direct ownership of storage could lead to discriminatory behaviour as well as internal conflicts of interest. By owning storage, DNOs would effectively buy a network management service from themselves, rather than through any form of competitive process, with the cost passed on to consumers. The same applies to DSR and other forms of flexibility.

The alternative would be for DNOs to procure storage as a service, rather than owning it directly. DNOs are incentivised under regulatory arrangements to identify the cheapest technology solutions to address network issues. Where storage is the most economical solution, this could be procured from storage operators through a competitive process, ensuring best value for money for consumers. This is similar to the OFTO system, in which licences for offshore transmission links are competitively tendered, which has led to consumer savings of £0.6-£1.2 billion to date[7].

DNOs also need to develop more sophisticated ways of connecting new generation capacity to the grid. The growth in decentralised energy has led to some parts of the network becoming heavily

[7] Source: Ofgem

constrained. As a consequence, companies often face very substantial costs to connect to the network, making projects uneconomical.

Some DNOs have started offering “flexible connection agreements” which offer a lower-cost route to connecting new capacity. However, the availability of these types of agreements varies across the country, since there is no obligation on DNOs to offer such agreements.

In some part of the UK there is a backlog of both generation and storage projects wishing to connect to the network. DNOs could think more creatively about how connection agreements for generation and storage could be coordinated to enable additional connections without compromising the network. However, this type of innovative thinking is held back by the current regulations (such as Engineering Recommendation P2/6).

Recommendations

The ADE recommends that:

- The network security of supply standard (Engineering Recommendation P2/6) is updated to recognise non-build solutions such as DSR and storage.
- Regulations allow DNOs to procure the services of storage and DSR, but not to own it directly, since this could undermine competition and would be in direct conflict with the ownership unbundling requirements of the Electricity Act 1989 and EU Electricity Directive 2009/72/EC.

Q5. Do you agree with our assessment of the regulatory approaches available to provide greater clarity for storage? Please provide evidence to support your views, including any alternative regulatory approaches that you believe we should consider, and your views on how the capacity of a storage installation should be assessed for planning purposes.

It is unclear whether a separate licencing regime is required for storage.

There are obvious benefits to be gained from developing a clear regulatory definition of storage as this could then be applied across all policies and industry codes. The case for a new licencing regime for storage is less clear cut. This could be beneficial from the perspective of providing greater clarity to investors. However, there is a risk that this could stifle innovation by limiting new entrants and disruptive business models.

Most storage devices are currently licence exempt, so creating a new regulatory regime would increase the administrative burden. Moreover, creating a new licence category for storage could lead to unintended consequences, such as allowing network companies to own storage. If Ofgem wishes to create a licencing regime for storage, then this should primarily be focused on large scale storage, with a de-minimis exemption for smaller installations, aligned with the existing generation exemptions.

Regulations must however be cautious in their treatment behind-the-meter storage where electricity is not re-exported to the grid but is consumed on site. For example, electric thermal storage is a form of demand and not supply therefore will not be interacting with the grid in the same way as storage that exports.

Recommendations

The ADE recommends that:

- If required, Ofgem create a licencing regime for large-scale storage, with a de-minimis exemption for smaller installations, aligned with the existing generation exemptions.
- Ofgem seek to adjust existing arrangements to remove current problems of double charging for storage, rather than through a new licence for all storage installations.

Q6. Do you agree with any of the proposed definitions of storage? If applicable, how would you amend any of these definitions? Please provide evidence to support your views.

The ADE supports the definition for electricity storage put forward by the Electricity Storage Network (ESN). We note, however, that electricity is not the only energy commodity which can be stored. The storage of heat or 'coolth' can equally benefit the electricity system. In an integrated energy system, the combination of a district heating network, a CHP installation and a large-scale heat pump can create a virtual battery. Such innovative arrangements should be included in arrangements to promote the development of storage.

There are two particular problems in the Capacity Market Regulations definitions of "storage facility" and "generating unit" which prevent smaller storage facilities – and certain small generators – from participating in the Capacity Market. A "storage facility" is defined to include a "generating unit", which has two effects.

First, aggregation of small generating units is not allowed unless they export electricity to a distribution network (regulation 8 paragraph 4), which means that behind-the-meter batteries such as might be found at a data centre, or small CHP generators such as are routinely installed at hospitals, are excluded from the CM unless they individually exceed 2MW in size.

Second, present electricity storage technology favours power over capacity, that is, batteries that can deliver very quickly, but not for very long. This makes them behave far more like load turndown demand response than power stations. Where they are small, they would be much better suited to aggregation with DSR capacity than with generation capacity, as they share the same characteristics. However, DSR capacity must be metered against a baseline of previous consumption, which is not appropriate for independent assets such as energy stores and CHP generators; these should be metered on generator output.

Recommendations

The ADE recommends that:

- The Electricity Act 1989 and associated grid codes should be updated to define new activities such as electricity storage and DSR, using the definition proposed by the ESN.
- BEIS should adjust the Capacity Market Regulations to enable energy stores and small generators to be aggregated regardless of whether they export or feed site load, and should enable mixed aggregation between DSR, energy stores and small generation.
- BEIS and Ofgem should be mindful of the many potential versions of energy storage which could provide electricity balancing, arbitrage and integration, potentially over different timescales to those which suit batteries, and across other energy sectors.

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?

While businesses are technically able to participate in a range of different energy markets, from Balancing Services and the Capacity Market to the Balancing Mechanism, the structures of these markets currently prevent businesses providing DSR from competing on a level playing field and securing fair value.

We estimate that DSR providers currently miss out on hundreds of millions of pounds per year because they cannot access the full value of the Capacity Market, Balancing Mechanism and Balancing Services. At the same time, consumers are bearing higher costs than they would otherwise need to, because the tilted playing field prevents the lowest cost combination of supply and demand-side resources from being procured.

Currently, the cost-effective opportunity for DSR is in the industrial, commercial and public sectors. While it is integral to a flexible and resilient future energy system that the potential for domestic DSR is unlocked, a move to more challenging sectors such as domestic, will require market structures to be equally open to all providers and the benefits they bring appropriately valued.

Further, opening up all markets to DSR providers and other types of flexible generation such as CHP and storage, will cause a positive feedback loop where bid prices in the Capacity Market will be lower as value is also accessed through the Balancing Mechanism and Balancing Services, and vice versa.

There are three areas of policy and regulation that need to be addressed:

- Fair access, transparency and competitive participation in Balancing Services.
- Independent access and participation in the Wholesale Markets and Balancing Mechanism; and
- Appropriate treatment in the Capacity Market, including testing and metering simplification and equal contract lengths.

Balancing Services

The current suite of Balancing Services is very complex for energy users to navigate, creating obstacles to DSR participation, and do not always place equal value on the services DSR can provide. Most of the current Balancing Services were designed with the operational characteristics of thermal generators in mind, rather than with the capabilities and needs of DSR in mind. This fixed view of how services should respond is a hindrance to the development of decentralised, digitised, and demand side led Balancing Services.

As National Grid has aims to procure up to 50% of Balancing Services from DSR by 2020 (approx. 4.5 GW), there is a need to look at the array of Balancing Services to ensure they are simple, user-focused, and designed to secure best value services, whether from generation, DSR, or storage. This review should also align with a growing role for distribution network operators as they become distribution system operators, allowing more decentralised solutions to come forward to balance electricity supply at a more local level.

The launch of National Grid's Power Responsive campaign in 2015 was a positive step in bringing attention to how the System Operator can facilitate a cost-effective DSR market through its Balancing Services. The long-term goal, as recognised by the National Infrastructure Commission, should be for *"a more strategic and transparent approach to the procurement of ancillary services and more cost reflective charging"*[8]

However, National Grid needs not just to focus on DSR demand turn down, but also to look to open up the marketplace to the full suite of available resources and allow all players to compete on a level playing field – whether centralised generation, distributed generation or turn-down demand services. With continuing closure of coal generation and the requirement for increasing amounts of replacement inertia, distributed generation will have a vital role to play and Power Responsive's focus on turn-down DSR may create new distortions.

We would encourage National Grid and Ofgem to work closely together to see how we can review the services in the round to deliver a cost-effective and more user-friendly system, based on the principles of transparency, simplicity, technology-neutrality and competitive markets to guarantee value for money for consumers. For example, at present there are still some services which are secured through bilateral negotiations, such as contracts for "Black Start" and payments to generators to provide inertia. National Grid recently awarded Black Start contracts worth £113 million on a bilateral basis to two companies – SSE and Drax. Bilateral contracts should be phased out as the Balancing Services develop, and market transparency made a central pillar of the market structure.

Recommendations on balancing services

The ADE recommends the following:

- **Full transparency of contracts, pricing and requirements.** National Grid and DNOs could improve transparency regarding the current and future needs of the system, and the likely requirement for Balancing Services. For example, this could include providing more information on the timing and parameters of forthcoming tenders. From discussions with industry participants, many of whom are not energy experts, we found that many are unclear about which services are being procured when, and the likely volume of each service required. Furthermore, members have advised that some market participants are not asked to participate in tenders and in some cases have been discouraged by the System Operator from participating. In the case of inertia, we are aware that some large generators are being paid to generate during low-demand periods, and yet there is not even an official 'inertia' service to compete for.

  By contrast, in the German system there are auctions at regular intervals, and all of the information about forthcoming and previous auctions is made available through a single auction platform[9]. National Grid has already made some improvements to the information provided to market participants, but more could be done to improve transparency.

- **Clearly linking pay with performance.** It is clear looking at many of the Balancing Services markets today that the different products are not fungible services. That is to say every provider is not providing the exact same service. In addition, it is clear that rather than driving

[8] National Infrastructure Commission, Smart Power, March 2016.

[9] Survey on Ancillary Services Procurement and Balancing Market Design, ENTSO-E

DSR and batteries to operate like generators there could be additional benefit for Grid by asking what other things a market participant could provide that would optimise their available benefits.

In the UK, service specifications are based on the physical/technical limitations of a particular technology type (e.g. FFR requirements are suited to large scale generators; EFR requirements are suited to batteries). A different approach, for example the performance score used in PJM, allows resources (individual or aggregated) that fall outside existing service definitions to be scored relative to their competitors and as such allows multiple technology types compete on a level playing field. Furthermore, it removes arbitrary cut-off points between individual services.

In the UK, resources that fall outside existing service definitions – such as the FFR Primary definition – cannot be used to provide frequency balancing, even though such resources may have value to National Grid. For example, a resource that can provide response in 3 seconds, ramp to maximum output in 8 second, with a duration of 15 minutes is not eligible for Primary FFR but could provide some assistance to balance the grid, and it would make sense for it to be able to earn a partial payment (depending on its performance). It is also often the case that DSR providers cannot offer the fixed, flat service profiles of a thermal plant for periods of a month or more, but rather can offer differently shaped service profiles. The current systems are not set up to accept such non-flat service profiles, which may offer some value to National Grid.

Under National Grid's current approach, such a resource would be unable to participate in the FFR tender. National Grid might be willing to strike a bilateral deal with the resource, but this is problematic, because it further reduces transparency.

In contrast, a performance score would evaluate the resource's potential contributions, and allow it to compete on a pay-for-performance basis with other resources. This approach can be better suited to DSR and non-traditional generators where the make-up of the aggregated portfolio may change over time where it may not be appropriate to use a 'set it, test it and forget it' approach.

- **Implementing competitive auctions.** As soon as performance factors are known and the services are fungible the markets can evolve from a tender process to a transparent, competitive auction process. In previous years the market has not been liquid enough for an auction to reach an efficient price with only a handful of participants. With new entrants to the market and National Grid requiring new service provision, the timing is ideal to introduce an auction. For participants with zero marginal cost of operation (and a high business risk of losing tenders) this allows them greater certainty. For parties with a high marginal cost of operation (e.g. fuel cost) and an opportunity to participate in multiple markets this allows them to exit the auction at an economic point.

  A more liquid market will allow National Grid the opportunity to discover true prices on a like–for-like basis and will be an economically more efficient way to procure the service. Where there is an increase in bidders with low fuel costs (DSR & storage) this will drive the price down and create a truly competitive market while de-risking entry for these new participants.

  Finally this could also allow a merging of the FFR and Mandatory markets rather than having an artificial separation between those which are BM units and those which are not.

- **Creating real-time and liquid markets**. The next logical step after a fungible product and an auction would be to take the step to real-time and liquid markets. It is our understanding that the current IT systems at National Grid would not support a real-time market. However, once the EBS upgrades are stabilised this approach may prove a better approach. The Balancing Mechanism is an example of such a liquid market. Other Balancing Services markets could move towards 30-minute markets with ex ante pricing, for example, and both the System Operator and DNOs could procure flexibility through a common trading platform.

Balancing Mechanism and Wholesale Market

Currently DSR providers are not able to sell their electricity generation or demand reduction either on the Wholesale Market or in the Balancing Mechanism without going through the licenced supplier of the customer that is providing the flexibility.

As aggregators are often competing directly with suppliers, this interaction poses a very significant and material barrier. There are four key barriers:

- The suppliers most active in the Balancing Mechanism (BM) are those which operate thermal generation fleets (vertically integrated energy companies). Hence by the supplier contracting with aggregators to provide them access to the BM, the supplier would be exposing the assets of another part of their business to increased competition. Despite the suppliers' growing DSR portfolios, there is no evidence that they are providing their customers with BM access. Analysis of BM trades for the current financial year to date reveals that only five (out of over 2,000) consumption units received bid or offer acceptances (BOAs), all of which appear to relate to embedded generators owned by particular suppliers. It is notable that suppliers have had the ability to bring customers into active participation in the BM since it was created in 2001, but have not made use of it.
- Some suppliers are also active in securing new DSR customers, and have a natural disincentive to support an aggregator working to secure businesses for the same customers.
- Suppliers are often active traders in the Wholesale Market and BM, using very large clip sizes, due to the size of their portfolios, and have little interest in the smaller clip sizes available for trading from DSR providers.
- There is no commercial advantage for a supplier to facilitate wholesale or balancing market trades on behalf of another market player, meaning that any arrangement which depends on actions by the supplier is only likely to occur in response to regulated requirements, creating costs to both regulators and suppliers.

In the case of customers wishing to sell their demand-side flexibility directly into the Wholesale Markets or BM, there is no clear regulatory route for them to do so as DSR providers are not recognised within the CUSC or the BSC (in contrast to traders, generators and suppliers). This restriction adds unnecessary transaction costs, preventing larger industrial energy customers from engaging directly in this valuable marketplace.

Prices in the Wholesale Market have previously peaked at £358/MWh[10], while the BM can see prices as high as £2,500/MWh in cases such as the Notification of Inadequate Supply Margin (NISM) last November[11], and the price cap will be doubling to £6,000/MWh from 2018[12].

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[10] APX, UK SPOT Market Price, 29 October 2014
[11] Elexon, System Price Analysis, May 2016.
[12] Ofgem, Balancing and Settlement Code (BSC) P305: Electricity Balancing Significant Code Review Developments, 2015.

The absence of DSR in these markets removes an opportunity for greater competitive pressure to reduce costs to consumers. By not being able to access this value, it also places DSR providers at a competitive disadvantage in other areas, such as the Capacity Market.

Regarding aggregators acquiring supply licences, the ADE believes that while this approach may work for some companies, it would be inappropriate and severely limit the growth of the DSR sector to make this a requirement for all aggregators. Supply licence requirements contain significant requirements which are completely unrelated to the provision of DSR services. Any licencing requirements to be applied to aggregators should be proportionate to the rather smaller risks aggregators pose. However, we consider the requirement for an aggregator to obtain a licence to be a much less severe barrier than the existing requirement *to be the supplier* (or secure an unobtainable bilateral deal with the supplier) of each customer whose demand-side flexibility an aggregator is offering.

This naturally requires independence from supply businesses, because if DSR development depends on holding that customer's electricity supply account, then an aggregator-supplier can only aggregate its own customers' loads. The larger DSR aggregators have contracted customer lists which are comparable to those of electricity suppliers, but deal with only a fraction of the energy consumed by those customers.

In order to achieve DSR portfolios of scale through the supplier route, an aggregator would have to become not just a supplier, but a vertically integrated supplier. This would entail, among a great many other things, providing credit cover for all of the energy consumed by the customer, not just for the percentage which is active in DSR.

Supplying electricity to a large commercial customer is an entirely different business activity from activating DSR within a selection of that customer's sites. A de-facto bundling of supply and DSR aggregation would harm competition and reduce customer service.

The ADE also agrees that any amendment of the BSC to allow independent access to the BM would be a significant change and one that would require broad industry cooperation and contribution to enact. One important point to note here is that the BSC is an important regulatory forum in which aggregators, as non-BSC parties, are not able to participate. Therefore, we would encourage Ofgem to review the current processes for code modifications (BSC and CUSC) which favour the incumbent parties over new providers.

We would emphasise that it is independent aggregators and direct customer participants who are responsible for the vast majority of the DSR capacity presently in the market. Only 11% of proven DSR volumes are associated with electricity suppliers, despite the suppliers having very much larger organisations and stronger balance sheets in comparison to aggregators.

Project TERRE

The ADE strongly supports Project TERRE, and is involved in the work of Project TERRE to establish independent access for non-BM participants into the Balancing Market. Project TERRE will only be successful if it allows independent access for non-BM participants and accepts the views of non-BM participants. We would encourage Ofgem to closely monitor the development of TERRE to ensure this is implemented effectively, with broad application, to meet Ofgem's objectives, and that the BSC Panel's approach is challenged by Ofgem where appropriate.

It is vital that aggregators (or other distributed flexibility providers) are directly involved in regulatory processes and decision making to ensure that rules are set up to allow all technologies to compete on a level playing field. For example, in the BM, the rules allow thermal generators to define intricate physical parameters (such as warm up time or warm down times) which are taken into account for their Bids and Offers; distributed technologies have very different physical limitations so it is important that rules allow these to be recognised as well (such as an energy recovery requirement for storage technologies).

It would make no sense for the mechanisms implemented to provide independent access for Project TERRE to apply only to the replacement reserves markets, when it should be straightforward also to apply them to all other flexibility markets. We have concerns that due to industry modification proposals different markets will have different approaches, creating confusion and distortions. Further, smaller, non-traditional players cannot actively participate in multiple modification processes, and therefore with multiple modifications, Ofgem's engagement will be even more important.

Supplier imbalance and compensation
When the SO dispatches flexibility from a non-BM provider in some way (for example by issuing a STOR call to a behind-the-meter back-up diesel generator) then current arrangements mean the supplier to this site would receive a cashout payment (System Imbalance Price, SIP) for their energy, as well as the non-BM provider receiving an energy payment for the dispatch. This is quite different to the treatment of BM generators, where the provider's imbalance position is adjusted to account for their Balancing Services dispatch.

The ADE agrees that this is a potentially significant but complex issue, which needs to be addressed in detail. In principle, the provider's imbalance position should be adjusted whenever the SO dispatches flexibility from any source (as it is done for BM generators now). Otherwise there are effectively two payments associated with any action (utilisation payment to consumer and cashout payment to supplier) and the system as a whole will pay the extra. Against this, the "extra" tends to be zero, as DSR providers price in the value of imbalance in their bids.[13] A number of other factors show that taking a simplistic approach to this issue will create major market problems.

If supplier's imbalance positions are corrected directly then suppliers will lose out, as in many cases this energy cannot be billed to the consumer as supply agreements do not include pass-through of SIP. This is because electricity supply contracts for industrial and commercial (I&C) consumers are designed around the overall business, not the small subset which practices DSR. Freedom to buy energy in this way, often setting prices or price profiles well in advance, is vital for I&C competitiveness in world markets. I&C electricity supply agreements therefore cannot be forced to follow rapidly changing prices on Wholesale Markets or be directly tied to volatile price signals such as SIP.

Among the other difficulties which would have to be considered are VAT treatment (currently, DSR services sold to the SO are considered to be services rather than energy and so attract VAT at the full rate), non-energy charges (where DSR reduces customers' actual energy consumption, the customers should not pay network use of system charges which they did not incur), questions of intent (reducing consumption as part of a service or as a price response can be hard to distinguish from operational reductions in consumption, which may occur at a different part of the same site) and metering (MPANs and existing Balancing Services metering are poor proxies for DSR portfolios – aggregated groups of DSR units will be made up of many MPANs and site meters each with different responses, while within one MPAN can be a mixture of elements, some of which perform DSR and some of which do not).

[13] Evidence provided by Welsh Power to National Grid imbalance working group, December 2016

As consumers become more active participants in the energy system (e.g. by offering flexibility services to the SO) then supply contracts will evolve to better reflect this. Contracts where consumers take on the responsibility for predicting their own consumption are becoming more common; in these, residual volume is settled at some pre-agreed price (sometimes a pass-through of SIP). However, there will always be major exceptions, and in fact these may have to remain the majority if UK businesses are to be able to control their input costs over the timescales appropriate for their businesses.

Further, there will be a regulatory role for Ofgem to ensure that suppliers are not able to use contractual terms to dissuade, prevent or disincentivise their customers from providing DSR services and selling their flexibility in the Balancing Mechanism, Balancing Services and Project TERRE. Without such a regulatory intervention by Ofgem regarding these contractual arrangements, there is a significant risk that suppliers could effectively restrict competitors – both other suppliers and aggregators – from purchasing demand side services from their supply customers. If this were to occur, it would effectively force customers to bundle their demand side service provision with their supply contract and prevent the creation of a competitive flexibility market.

Modification P354

It is very important that a cohesive and comprehensive approach and carefully considered methodology for tackling supplier imbalance is found through Project TERRE. We have significant concerns that modifications such as P354[14], which would remove spill payments from non-BM STOR providers, attempt to approach the issue of supplier imbalance in a rushed and piecemeal manner, allowing industry parties to push through sub-optimal solutions without sufficient expertise from non-traditional players.

The ADE believes that the issue of supplier imbalance cannot be tackled in isolation and Ofgem must take an active role in reaching the correct and cost-reflective outcome. No solution is tenable which does not include direct access to the BM for DSR and embedded generation including CHP. It is equally clear that the solution must both preserve the ability of UK businesses to buy energy efficiently for their core business operations, and to use DSR as an add-on revenue source where appropriate.

Recommendations for access to balancing and wholesale markets

The ADE recommends that:

- Ofgem reform the BSC to create a regulatory framework for the aggregator or a customer to register a Balancing Mechanism Unit (BMU) and ensure the implementation of Project TERRE allows non-BM participants to access the Balancing Mechanism and TERRE market, and sell their flexibility independent of suppliers, i.e. populate it with customer loads without needing to negotiate with or obtain the permission of those customers' suppliers.
- Ofgem take an active role and conduct a detailed review into the development and determination of how volumes are measured to calculate imbalance payments. The BSC panel and industry process is largely dominated by Balancing Responsible Parties (BRPs), leading to a lack of expertise non-traditional market participants, such as DSR aggregators and other flexibility providers, that significantly favours the incumbent parties over new providers.
- Beyond project TERRE, there will be a regulatory role for Ofgem to ensure that suppliers are not able to use contractual terms to dissuade, prevent or disincentivise their customers from

[14] https://www.elexon.co.uk/mod-proposal/p354/

providing DSR services and selling their flexibility in the Balancing Mechanism, Balancing Services and Project TERRE.

- If there is a change to the rules meaning supplier positions are adjusted after an action is initiated then the market should be given time for novel models which capture this value efficiently to emerge.
- Ofgem make the necessary regulatory changes to allow flexibility providers, from DSR and storage to flexible CHP and onsite generation, to access and sell their flexibility in the Wholesale Markets independent of any supplier, as access to the Wholesale Market will not be addressed through Project TERRE.

Other market barriers

Capacity Market

The Capacity Market was principally designed for large, centralised generators, and this has limited the ability of DSR providers and on-site generators to participate on a fair basis.

Examples from other markets show the impact of enabling decentralised energy to participate in Capacity Markets. The most cited example is the PJM electricity market, where market arrangements have evolved over time to allow different demand-side solutions to be rewarded for the services they can provide.

PJM's approach has led to a reduction of the average wholesale price of between 5% to 8% and a much larger reduction of peak wholesale prices[15]. Compared to the UK market, US markets also provide easier access for smaller, non-traditional providers of DSR to participate, with a minimum bid size in the range of 100 kW – 1 MW, compared to the UK's 2 MW minimum. This results in greater diversity of supply and generation, leading to increased reliability and system resilience.

Recent changes made to help address some of these challenges are welcome. However, often these do not go far enough and their benefits are negated by other reforms, which unintentionally damage both on-site generation and turn-down DSR.

Recommendations for Capacity Market

To support the participation of DSR and flexible distributed generation in the Capacity Market, the ADE recommends the following:

- **Fairness under contract lengths.** Allow all participants to access the same lengths of contract, including DSR providers and existing generators.

  Currently, new build power plants are able to secure 15-year contracts, while businesses providing DSR and existing generators are only able to secure one-year contracts. While the Government has said only new generation assets require long-term contracts due to their higher capital cost, this disparity in contact lengths puts new build generators at an unfair competitive advantage.

  One-year contracts mean Capacity Market participants are required to make critical investment decisions from year to year, raising Capacity Market bid prices and preventing better medium-term investment planning. The DSR market is relative new, with aggregators working to sign up customers, but without being able to provide them any long-term commitments. This lack of long-term commitments prevents customers from investing in the effort to participate in a single auction year.

[15] US Department of Energy, Benefits of demand response in electricity markets and recommendations for achieving them, 2006.

There are further competitive disadvantages designed into the market. New generation assets can factor in 15 years of guaranteed Capacity Market revenue in their auction bid price. In contrast, other Capacity Market participants can only bank on one year of revenue when bidding into the auction. For example, in the 2016 Capacity Market auction, DSR and existing generators received a revenue commitment of only £22.50/kW, while new generation assets received guarantees equivalent to £337.50/kW[16], allowing these participants to bid more competitively.

The lack of a long-term guarantee also prevents DSR providers from accessing lower-cost debt to meet their bid bond costs, further exacerbating the competitive advantage. Compared to new build assets who can 'bank' the up-front bid bond payment against their 15 year contracts, DSR participants face a high up-front bid bond cost against only a one year contract. Levelling bid bonds so that DSR can borrow against longer contracts would increase investor appetite in the DSR sector and grow its participation in the Capacity Market.

This approach undermines the supposed "technology-neutral" nature of the Capacity Market, by unfairly skewing the market towards new build generation and away from DSR and existing assets, all while increasing the cost to consumers. Equal contract lengths for all participants would result in a more competitive Capacity Market, significantly lowering the costs to consumers of delivering security of supply.

- **Certainty over future T-1 auctions.** Set a minimum procurement level for every year-ahead capacity auction.

The T-1 Capacity Market auction is held about one year before the capacity is needed and is considered an important route for flexibility resources to participate. The T-1 auction is critical to ensuring the system is able to cope with unforeseen supply shortages while keeping the lights on. The Capacity Market originally set a minimum amount of capacity to be procured in a year-ahead 'T-1' auction three years in advance.

Government has consistently recognised the value of a minimum T-1 set aside for the fledgling DSR market; however a shift in policy now means the Government has significantly reduced the set aside to 600 MW in 2019.

We welcome the continuation of a set aside. However, if the set aside is to be successful in creating certainty in the marketplace, the set aside for future auction years, should be set out in advance, based on delivered DSR in previous Capacity Market auctions, and committed to so the DSR market can adapt and plan accordingly.

As a flexible and easily dispatchable resource, DSR plays a key role in delivering the needed flexibility in a short-term auction. The T-1 'set-aside' has been a key building block of DSR's route to market. Without such assurance that a short-term market will be available, DSR providers will be unable to build up their customer base and supply chain. DSR providers are significantly less likely to invest time and money in providing new DSR services if there is reduced certainty about access to future markets.

Creating a permanent methodology for determining the set aside for the year-ahead auction will ensure that potential providers of short-term flexibility will have confidence there will be accessible value on an annual basis, ensuring Government is able to secure short-term flexibility when needed. Without such a minimum short-term market size, there is a substantial risk that the short-term flexibility market will not be available when the

[16] Discount rate not applied.

Government needs it, resulting in price spikes in the Capacity Market when T-1 auctions are held, significantly increasing costs to consumers.

- **Simplify participation.** Simplify the testing and metering Rules, allow the flexible reallocation of DSR assets, and enable businesses to provide all types of DSR including Firm Frequency Response.

  While recent reforms announced by Ofgem in May 2016 will make some rules simpler for Capacity Market providers, there remain a number of barriers to participation for DSR participants and smaller players. This challenge was recognised by the National Infrastructure Commission in its 2016 report, which noted that "rules around testing and the makeup of portfolios of capacity, unintentionally precludes the participation of demand flexibility and storage"[17].

  The Capacity Market Rules set out how participants can prequalify and take part in the auctions. The current Rules however are too prescriptive. A move to a more outcomes-based approach would drive down costs to consumers, while increasing participation from DSR providers and other non-traditional participants.

  There are three key areas where the Government and Ofgem could reduce complexity in the Capacity Market Rules:

  - **Testing and Metering:** BEIS and Ofgem should continue to reform the testing and metering provisions as currently they impose a high burden on businesses providing DSR, without demonstrable benefit.

    Many DSR participants are not energy market experts, and do not have the technical experience or resource to gather all the testing data that is required under the current Rules. As most metering is dealt with by licensed third parties, business energy users and small generator owners seldom have access to the documentation demanded.

    Gathering this and other information in the time available can be extremely difficult as it may require site shutdowns; these are often very difficult to arrange at (for example) a hospital or a datacentre.

    Recent BEIS and Ofgem reforms, such as risk-based testing in the Transitional Auction, are welcome but need to be extended and expanded across all Capacity Market auctions.

  - **Component reallocation:** BEIS should ensure that ESC implements the recent industry proposal to allow a form of DSR component reallocation, which was accepted by Ofgem, before the next Capacity Market auctions.

    In the Capacity Market, DSR participants will bid in a collection of different DSR components. Sometimes a DSR component, for example a refrigeration unit or motor, or an entire customer site, may cease to be able to respond due to an unforeseen breakdown or maintenance, or the site closing down. If the DSR provider is not allowed to manage its portfolio by adding a replacement compoent, it must reduce the total amount of electricity provided. Existing rules in the Balancing Services STOR and FCDM permit more flexible allocation and re-allocation and have proven to be highly effective in allowing aggregators to manage portfolios and maximise reliability.

    Ofgem accepted an industry proposal to allow a form of DSR component reallocation (CP124, CP129 and CP130)[18], in the 2016 round of Capacity Market Rule change proposals[19].

[17] National Infrastructure Commission, Smart Power, 2016.
[18] Capacity Market Rule change proposals – CP124, CP129, and CP130

However, Ofgem have been advised that the Electricity Settlements Company (ESC) is not able to implement the proposals until 2018 due to delays in setting up the new system.

The ADE has shown[20] that full flexibility in DSR component allocation and reallocation will improve competition and increase reliability in ways which existing CM Rules (volume reallocation, obligation trading) do not achieve. It is vital that BEIS and Ofgem ensure ESC implements the proposals before the next Capacity Market auctions.

- **Firm Frequency Response (FFR) participation:** Ofgem should enable FFR providers to carry out the DSR test, as supported by National Grid, allowing these assets to qualify for and participate in the Capacity Market.

  Providers of dynamic FFR face further barriers to participation. Firm Frequency Response is a demand response service classified as a relevant balancing service eligible to participate in the Capacity Market. However, a dynamic FFR provider cannot carry out the DSR test as it is currently stipulated in the rules and regulations and therefore cannot participate in prequalification for a capacity market auction.

  Ofgem agree it is important to find a suitable resolution for FFR issue and we welcome their commitment to examine the issue further. However, key to a suitable solution that facilitates the participation of FFR and is consistent with the objectives of the Capacity Market, is collaboration with the industry, National Grid and ESC to implement the changes. To date, we have seen limited progress in achieving this aim.

Additional flexibility benefits from DSR and CHP not currently recognised by markets

- **Black Start.** Contracts for Black Start are currently secured through bilateral negotiation, locking out the majority of the market, which could provide the same service on a more cost-effective basis. For example, National Grid recently awarded Black Start contracts worth £113 million on a bilateral basis to two companies – SSE and Drax.

  We would recommend decentralising black start arrangements by reducing minimum participation size, ensuring enough resource in the event of a black out in an increasingly more decentralised energy system. This will also increase competition and reduce the cost of this service.

  We would also recommend full transparency of contracts, pricing and requirements for black start arrangements to allow for competition and keeping the cost to the customer as low as possible.

- **Inertia/Reactive power.** There is currently no commercial National Grid service for inertia, but we are aware that large gas and coal plants are being paid to be online to provide inertia to the network. As coal closes, the amount of inertia payments being paid to the dwindling centralised coal capacity is likely to grow. The ability of DSR and CHP to contribute both inertia and reactive power is currently being developed in two large projects under the Network Innovation Competition (EFCC[21] and TDI 2.0[22]).

  We believe that the ability for the System Operator to access inertia and reactive power from a wider range of market participants, such as distributed CHP, is going to be increasingly important. It is inherently bad for consumers for large-scale plant to be paid to deliver inertia while distributed players are not allowed to compete.

[19] Ofgem: www.ofgem.gov.uk/system/files/docs/2016/09/open_letter_cm_rules_150916.pdf
[20] Submissions and responses in respect of Ofgem annual review of CM Rules
[21] Enhanced Frequency Control Capability
[22] Transmission & Distribution Interface 2.0

- **Speed of service.** DSR and flexible generation such as CHP can respond considerably more quickly than traditional thermal generation. Many DSR units can deliver in less than one second, while even the slowest CHP engines can ramp from zero to full power inside twelve minutes. In contrast, the most capable modern CCGTs require at least one or two hours to synchronise, while older power stations often require twelve hours or more. This DSR and CHP to provide very fast frequency response, which can be considerably more cost-effective than procuring inertia.
- **Reliability.** The nature of the DSR and flexible embedded generation such as CHP is that it is distributed throughout the country and there is no single point of failure. While a power station has a single point of connection to the grid, DSR is distributed throughout the country, usually near large cities and at the sources of highest demand. The diversity and distribution of DSR and CHP directly improve the security of national electricity supplies.
- **Congestion/Constraint/Voltage management.** The ability to reduce congestion and constraint and the need for voltage management, are not currently recognised in network services.

  CHP and DSR are naturally located much closer to the sources of demand than traditional generation such as nuclear, gas and wind, which typically place additional stresses on the network. Locating closer to centres of demand (i.e. London & SE, Northern Cities etc.) alleviates constraints, rather than causing additional congestion on the network, and also reduces the need for voltage management.

  We recommend Ofgem and the System Operator to consider how congestion, constraint and voltage management can be better accessed from a wide range of market participants, and ensure that the value CHP and DSR bring to the system are fully recognised.
- **Capacity freeing.** In order to provide response or reserve, power plants must decrease the amount of capacity they offer to the market. DSR and flexible generation such as CHP not only help integrate renewables, but also free up existing capacity to operate at generation levels at which it is most efficient. This also reduces thermal cycling on large plant, increasing its longevity and contributing further to long term security of supply.
- **Carbon/Efficiency.** As DSR is time-shifting processes that would have taken place anyway, operational efficiency is close to 100%. Members advise that for their clients the energy (or cost) neutrality of their service is paramount – any increase in energy bills can quickly erode the business case for the revenue generation.

  This compares to both the embodied energy and CO_2 in building a power station and the efficiency penalty for operating a generator in a frequency responsive, two-shifting or load-following mode.

Recommendations on flexibility value not recognised by current markets
The ADE recommends that:

- BEIS and Ofgem should enable and ensures the System Operator explores how the additional flexibility benefits not currently captured in network services, which DSR and CHP bring to the system, such as black start, inertia/reactive power, reliability, speed, congestion/constraint/voltage management, capacity freeing and carbon, can be accessed and valued appropriately.

Consumer protection

In discussion with Members and energy users, it became clear to the ADE that the lack of assurance for existing and potential providers of DSR in the industrial, commercial and public sectors, was limiting the engagement with, and uptake of, DSR. Further, National Grid often received calls to provide a list of 'trusted' aggregators.

Ofgem shared the ADE's concerns and agreed that additional assurance could help facilitate customer participation and prevent customer detriment in the DSR sector. A recent report by Energyst Media found that almost nine in ten businesses would help National Grid balance the power system if it did not adversely affect their operations, but only 27% of businesses surveyed were actively participating in DSR. Of the 73% who were not, half said they had not been contacted by an aggregator or supplier about DSR. For businesses to feel confident about DSR, they need to find trusted delivery partners and feel they can access expert advice.

ADE Code of Conduct

The ADE and Members met with National Grid, BEIS (then DECC) and Ofgem in Spring 2016, and agreed that additional assurance could help facilitate customer participation and prevent customer detriment in the DSR sector and the ADE would develop an industry-led Code of Conduct for DSR aggregators and aggregator suppliers. It was also agreed that the Code will need to have 'some teeth' to ensure compliance by participants.

Once the Code has been implemented, it is intended that a Compliance Scheme will be developed to ensure signatories to the Code are meeting the Code requirements. The ADE has proven experience in customer protection with its previous development and implementation of Heat Trust, the first independent heat customer protection scheme for customers on district heating schemes[23].

The Code is in development, overseen by a Steering Committee consisting of ADE DSR aggregator and supplier members, industrial, commercial and public sector representatives, and observers from BEIS, Ofgem and National Grid. The Committee has met four times to date and is on track to publish the Code for public consultation in spring 2017. The aim is to launch the finalised Code in summer 2017.

The ADE believes the Committee provides the right balance of consumer and industry representatives and will ensure the Code delivers standards that are proportionate and effective.

The Aim of the Code is to:

- Administer the activities of DSR aggregators, and suppliers who act as aggregators, signed up to the Code, when interacting with and serving non-domestic existing and potential DSR customers, to give confidence to those customers in the offerings of the companies/organisations signed up to the Code.

The Objectives for the Code are to:

- Set minimum standards of conduct for DSR aggregators, and suppliers who act as aggregators, and promote good industry practice, when interacting with non-domestic energy users in GB which already do, or potentially will, participate in DSR activities;
- Ensure any requirement set out in the Code is proportionate, effective and directly addresses an identified market need, and where possible that the identification of any market need is backed by clear evidence.

[23] Heat Trust: http://www.heattrust.org/

The ADE agrees that as DSR provision is currently dominated by large non-domestic consumers, the potential for household consumer harm is currently limited. However, as we expect that domestic and smaller non-domestic consumers will become increasingly engaged with DSR, it will be important that appropriate consumer protections are in place for this in future. We see the framework currently being developed for non-domestic customers as a foundation on which the industry can next build appropriate household consumer protections.

Recommendations

The ADE recommends that:

- Ofgem and BEIS continue to support and contribute to the development of the ADE Code of Conduct for non-domestic customers, followed by domestic customers.
- The SO requires aggregators to sign up-to a set of requirements, which demonstrate that aggregators are providing assurance to customers, in order to access Balancing Services, or to fulfil a specific aggregator role in the BSC. These requirements could be met through the Code of Conduct.

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

Please see response to Q7.

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

Please see response to Q7.

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?

The ADE would favour realistic analysis and measurement in this area, and would be concerned about the use of regulation to mitigate a theoretical problem which never materialises. There are several points to note.

First, DSR actions will naturally be in the direction which helps the system rather than harms it. Second, it is not clear that there is a conflict between local and national signals for DSR activation, because local high load will tend to correlate with national high load (as the latter is the sum of the former). Third, experience in system effects such as voltage deviations arising from co-ordinated actions of a very large number of individual loads is already available: the UK's famed TV pickups (switching on of domestic kettles following major television events) are of this type, and could be studied. Similar experience is also available from teleswitched electric storage heaters. Fourth, with the exception of inertia services (for which special consideration is already being given to stability effects within the Enhanced Frequency Control Capability project under NIC), diversity is provided by the natural communications delays and latency associated with DSR despatch.

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?

As the energy transition develops, energy users are increasingly supporting the energy system through DSR, on-site generation and energy management in a way that gives these businesses greater control over their energy costs and carbon emissions. As these efficiency measures improve the energy system's productivity, they also help minimise the costs for energy consumers as a whole.

In a rapidly changing system, the end customer, who ultimately bears the costs, must be engaged if their support is to be maintained. If the customer is ignored, we could fail to deliver the energy system changes needed to meet our carbon commitments. Energy users are vital to the energy debate.

As such, a key element of a smart, flexible system must be that the value the energy user brings to the system must accrue to that user, and any future market design should be based on the value provided to the energy system. For instance, as discussed above, while businesses are technically able to participate in a range of different energy markets, from Balancing Services and the Capacity Market to the Balancing Mechanism, the structures of these markets currently prevent businesses providing DSR from competing on a level playing field and securing fair value.

Price-based flexibility and contracted flexibility

The ADE welcomes the points raised in the call for evidence regarding price-based and contracted flexibility.

At present we have a single Wholesale Market across the whole of Great Britain. However, in reality, the geographic patterns of demand and supply are very different, and there are constraints within the system. For example, under the current market arrangements, energy retailers may purchase wind generation from Scotland, even if it is not possible for this power to travel to end users due to a network constraint. Network operators may then have to take costly actions to balance the system on both sides, by turning down the excess wind renewable generation, and turning on generation on the other side of the constraint.

The power market was designed for a system composed of large thermal power stations and few network constraints, and is not as well suited to a system with more distributed and renewable generation, and greater network constraints. A possible solution would be to move to a system of regional markets and pricing. This type of system would then create a locational price signal, encouraging generators to locate closer to demand and reduce their impact on the grid network.

Some have suggested that the Wholesale Market could be reformed to increase its temporal resolution by shifting gate closure closer to the point of delivery or moving to 15-minute settlement periods, as is the case in Germany. Such a change could create a more competitive and flexible Wholesale Market and allow generators and suppliers who are out of balance to trade and reduce their exposure, and may allow more balancing to take place within the market, reducing the need for the System Operator to take action outside the market. However, this could have unintended consequences for the growth of DSR and other providers of flexibility if changes are not made to enable independent access to the Balancing Mechanism and Wholesale Markets.

Before taking any steps to implement the changes described above, however, flexibility providers from DSR and storage to flexible CHP and onsite generation must be able to independently access and sell their power and demand reduction in the Wholesale Market and Balancing Mechanism.

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?

ADE members have cited the Capacity Market as a good example of a mechanism which allows the combination of different value streams, which we believe leads to a lower total cost of system operation. In contrast, there has historically been a collision between winter peak management through the Triad system, and Balancing Services. However, National Grid has recently begun to address this issue on a trial basis, and we hope that the results of this trial will be fed back to Ofgem in due course.

The most significant barrier is the inability of independent aggregators and direct-participant customers to access the value of their flexibility in the Balancing Mechanism.

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?

ADE members, including CHP and DSR providers, have cited black start, reactive power and inertia as technical capabilities for which they presently cannot be remunerated. National Grid is currently trialling DSR and CHP in reactive power and inertia roles, which we welcome. We are not aware of any progress on black start.

DSR, energy storage and CHP can all provide local network security and upgrade deferral services to DNOs. However, the deployment of these in business-as-usual contexts has been remarkably slow.

Please see Q7 for more detail.

More specifically, CHP is considered a win-win for its ability to simultaneously tackle emissions, flexibility, security and business energy costs. However, because its benefits are spread across different sectors, different markets and different policies, CHP can struggle to be recognised for the value it provides. For CHP to achieve its potential, energy users need to be rewarded for the energy security and system services they provide, helping to control, or even reduce, industrial and commercial energy costs.

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?

Please see response to Q7.

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.

The ADE agrees that more smart tariffs will become available in the non-domestic sector once half-hourly settlement is fully enabled. However, while Government and Ofgem should promote and support the use of smart tariffs, we believe it should be left to the market to find new business models and that Government and Ofgem should not intervene.

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.

The ADE does not deem it appropriate. See response to Q15.

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?

It is common practice in Denmark (for example, Skagen district heating[24]) to site generation close to demand, capture and store heat, and allow multiple heat sources including electrical heating and biomass to feed the heat network. Such installations, at all scales, have direct access to market prices (which is essentially what a smart tariff attempts to provide), and flex generation and consumption in response to these prices.

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?

The ADE agrees with the reasons identified.

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.

Many of the issues at the distribution level are set out in response to Q2 and Q3. However, we would also like to highlight the recent decision taken by Ofgem to approve Distribution Connection and Use of System Agreement (DCUSA) modification DCP228.

The proposal, submitted by British Gas, sought to amend the arrangements for scaling under the Common Distribution Charging Methodology (CDCM) as it was argued that the current approach to scaling significantly distorts the economic signals provided from the pre-scaled tariff rates, and therefore produces tariffs which are not reflective of the incremental costs of reinforcing the network.

The change essentially spreads the value of avoiding the Red DUoS charge to the amber and green band periods. According to the DCP228 Working Group Impact Assessments some customers could face increases (some more than 600%) in the distribution part of their energy bills whereas others would see decreases. While this varies across the different DNO areas, the

[24] Skagen district heating operational data is available at **http://www.emd.dk/desire/skagen/**

general pattern is that distribution charges for domestic customers will fall but those for non-domestic customers will increase.

This is a disappointing decision by Ofgem, as we believe that it will disincentivise customers from moving demand away from peak periods, and hence it will increase network demands and costs. We believe that a wider review of scaling issues is necessary, as argued in our response to the DCP228 consultation in February 2016.

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?

The ADE fully supports the changes being proposed under change proposals DCP 283 and 284.

DCP 283

The principle applied within the CDCM is that credits are applied for voltage levels above the voltage level of connection. For demand, costs are taken into account down to the voltage of connection. The rationale for applying credits above the voltage level of connection was set down when the CDCM was developed and was justified as the benefit of reduced reinforcement was perceived to be higher up the network. The requirement was set out in an Ofgem decision document in 20081 within Appendix 2 which outlines the principles and assumptions to be used when setting out the common distribution charging methodology. The relevant assumption is set out in 1.51 which states: "*1.51.The network is assumed to be demand dominated. Credit will be provided for offsetting demand on the distribution network above the voltage of connection*".

The Ofgem decision is based on Engineering Recommendation P2/6 as supported by ETR 130 Application Guide for Assessing the Capacity of Networks Containing Distributed Generation and applies to both intermittent and non-intermittent generation. The basic principle of P2/6 and ETR130 is that embedded generation can offset the need for network capacity depending on the reliability of the generator and its setup.

The more reliable the generator is the more the DNO can rely on it for network planning purposes. P2/6 sets out the reliability factors (labelled "f" factors) for different types of generation. Where a generator is intermittent, an additional persistence factor is also taken into account. When assessing the ability of an embedded generator to offset network capacity, P2/6 refers to a demand group. The demand group is not specified as a network level and the assumption within the CDCM is that the benefit will be realised at the next voltage level up (eg for a LV circuit the benefit will be realised at the LVS transformer).

High Voltage

At high voltage, DNOs typically exclude HV connected generators when considering the network required to meet the demand for a new customer. However, at the substation, they take account of any embedded generation and consequently less capacity may be required at the substation and voltage levels above. This principle suggests that the current principle within the CDCM of applying credits to the voltage levels above the voltage of connection is correct as the benefit to the DNO is only realised at higher voltage levels. We do not propose to amend the methodology for credits for HV generators.

Low Voltage Substation (LVS)

Embedded generators who connect directly at LVS do not currently get a credit for avoiding the use of the LV substation. However, the principle that the benefit is realised at the substation where the capacity can be reduced holds true even though the generator is connected directly to a LVS and it is therefore appropriate that LVS generators should receive the benefit at the voltage of connection. However, as the generator will only benefit the DNO if it can be relied on, we propose to extend the credits to the voltage of connection for non-intermittent generation only.

Low Voltage

Embedded generation connected to the low voltage network are not particularly visible to DNOs. When a DNO is planning the LV network, they are more likely to assess the maximum demand at the local substation with some consideration of any large generation that may be connected. At the LV network the presence of generation will be more diverse and therefore some of the benefits will be realised at the level of connection in addition to the higher voltage levels. We propose to take account of generation credits at the voltage of connection for LV connected generation by allocating a proportion of the demand costs at the voltage of connection as a credit to non-intermittent embedded generation at LV. We suggest a 75% sharing factor for the proportion of the LV demand charge that should be allocated to LV connected generation, but suggest that this value would need further consideration by the working group.

Treatment of customer contributions

Within the CDCM, demand charges are reduced by the customer contribution to take account of the amount paid up front when a customer connected. This customer contribution for demand is also applied to the calculation of generation credits. The impact of the application of customer contributions is to reduce the level of credits.

When a generator connects to the network, one of the benefits that is realised by the DNO is a reduced flow on the local network. This allows further demand customers to connect without the need for reinforcement and therefore they will need to make less or no customer contribution when they connect. Consequently, applying the customer contributions to generation credits, reduces the cost reflectiveness of the credit that is provided to embedded generation under the CDCM.

DCP 284

Under the CDCM, generation credits reflect demand charges at voltage levels above the voltage of connection, except for the application of scaling. During the development of the CDCM, scaling was excluded from the derivation of credits as the costs included within scaling were not seen to be avoided through the presence of embedded generation.

The recent DCUSA change proposal (DCP228) that has been approved by the Authority amends the way in which scaling is applied to demand charges. This change proposal provided more detail on what costs are recovered via scaling.

The DCP 228 change report identified the costs that are recovered via scaling mainly comprise of asset replacement and a portion of indirects costs. Paragraph 3.5 from the DCP228 change report is replicated below to provide clarity: *"3.5 DCP 228 is intended to be clearer in explaining that the shortfall or excess of revenue recovered from pre-scaled yardstick tariffs is a natural consequence of the incremental design of the CDCM. As the accompanying spreadsheet (Attachment 5) demonstrates, the CDCM recovers significantly more in peak charges than DNOs expect to spend on network reinforcement for the foreseeable future. This is because the CDCM provides incremental cost signals rather than total cost signals. Similarly, there are DNO costs which are not included in the CDCM (such as replacement costs and a portion of indirect costs), however these are not 'unidentified' as the DCP 123 form suggested, but rather they are intentionally excluded from the CDCM for the purpose of deriving the desired incremental cost signals. This CP is therefore clear in its intent that scaling should not be used to allocate any cost not included within the CDCM, but should rather be applied in a way which maintains the incremental cost signals produced by the prescaled tariffs."*

The value of indirect costs is unlikely to change depending on the level of demand or generation on the distribution network and it is therefore appropriate to not provide a credit to generation customers in this respect.

Change proposal DCP 284 considers the costs associated with the replacement of assets within scaling which, although it may not be an incremental cost for demand customers, is potentially an area of saving for DNOs through the connection of embedded generation.

DNOs replace assets as they reach the end of their useful life. If embedded generation is installed then the potential benefit to the DNO is that the asset may not need to be replaced as it is no longer required or the asset can be replaced with a smaller capacity asset which is therefore cheaper. The degree to which this occurs will vary depending on the type of generation, the degree to which it can be relied upon by the DNO and the arrangement of the network to which the generator is connected.

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

There should be disparities between the treatments of different types of distributed generation, depending on their impacts on network costs. Where distributed generation reduces the need for distribution network reinforcement, they should be rewarded for providing that benefit.

For example, non-intermittent generators located near demand, such as CHP generators in London, provide such a benefit to consumers, and should therefore be recognised, potentially in contrast to an intermittent generator located far from local demand.

Generation Dominated Areas

Within the CDCM, all generators receive a credit regardless of where they connect or the nature of their local network. In some areas, where a large number of generators connect and the level of demand is low, the export can drive a need for reinforcement of the DNO's network. However, as the CDCM is an average methodology these generators will be receiving a credit in spite of the fact that they are causing additional costs that are picked up by demand customers.

In principle, generators connected to areas of the distribution network that are considered to be generation dominated, should not receive credits from DNOs if they are the main driver of future reinforcement costs. Alternatively, credits for distribution generators at all voltage connections should be determined based on each generator's actual impact on the distribution network, as is currently the case for HV and EHV connections.

Cornwall Energy found that, with hindsight, the issue of generator dominated areas has not led to the increase in reinforcement costs for DNOs that was originally envisaged and the use of managed connections and active network management has reduced the need for a solution to generation dominated areas. It may well be the case that this has delayed the issue rather than removed it, in which case one would expect generation dominated areas to return as an issue if more embedded generation continues to connect. However, innovative measures applied to deal with clear needs are greatly to be preferred over rule-based measures to deal with theoretical needs. The many benefits which embedded generation brings – including diversity, loss reduction, engagement/empowerment, use of local green resources, heat capture – must not be lost as a result of overly conservative methods applied to network charging.

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?
Please see our response to Q21.

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?
Yes, DUoS charges do and should send both short term and long term signals, as transmission network charges currently do. While it seems unlikely that DUoS charges can become dynamic prices (as DNOs require known cost recovery), peak management service models can emerge which achieve the same benefit.

Ofgem should encourage DNOs to deploy as business-as-usual the dynamic network management techniques using DSR and embedded generation which they have already demonstrated under LCNF, NIC and NIA.

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.
Overall, DNOs need to undergo a culture change from a passive role to a far more active role in managing their networks. The move to DSO status is something that DNOs have neither been equipped nor incentivised to do to date, and the regulatory regime is holding them back from innovating as discussed in response to Q44.

We do not believe that DSOs should control responsive resources, as we said in our responses to questions on storage, as unbundling is vital for innovation and competition. Equally, we do not agree that DSOs should be a "gatekeeper" for other actors (like the TSO or the Wholesale Markets) to access DSR or flexible CHP within their networks. Such a role would create an institutional barrier which would impede any smart flexible approach other than those which directly answered a DSO need.

For example, DSOs have no need to achieve energy balance in their networks or to manage frequency, but must be conservative in their approach to network peak management. Such an approach might prevent users from engaging in the national energy balancing or frequency response activities on theoretical grounds, even if no real conflicts ever emerged.

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?
The Capacity Market is an example of a policy which both helps and hinders the transition to a smart energy future. On the one hand, the CM has enabled 1.4GW of DSR and 4.4GW of CHP to participate in securing supplies, lowering costs and reducing carbon costs. CHP and DSR are multi-capability assets which will also help in other areas. CHP can flex in response to renewable resource availability, while DSR can provide reserve and response allowing CCGT stations to

remain at maximum efficiency. This multitasking capability is one of the key elements that allows a system to become truly “smart”.

On the other hand, the CM has led to poor choices in new-build capacity, which is composed of diesel farms (38% efficient), which have no function other than peaking[25]. In contrast, CCGTs can exceed 60% efficient, and multi-capable CHP sites can exceed 80%.

In order to fully develop the potential for CHP and DSR in the CM, the policy needs only a small set of changes, which the ADE and others have already proposed to BEIS and Ofgem.

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?
See our response to Q7.

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?
The ADE has no comment.

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)**

The ADE agrees with the four principles. Consumers should be enabled to access all data related to their own use of electricity at all times. At the same time, consumers should be enabled to have control on their own data privacy and security. Each energy consumer should have the full right to decide which market player(s) will be allowed to access specific – standardised and machine-readable – data relating to the consumer’s own consumption, including new service providers.[26]

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**

[25] Some diesel farms provide secondary static frequency response, which is the least onerous and least useful variety of frequency response; National Grid’s need to procure it is strictly limited and is arguably already saturated. This is set out in National Grid’s regular frequency response requirements reports.

[26] For more information on this topic, please refer to the SEDC Position Paper on Data Access in the Electricity Market, September 2016

- **Other/none of the above (please explain why)**

The ADE has no comment.

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)**

The ADE has no comment.

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

Household-led DSR represents an important future opportunity, but is a more difficult challenge.

By ensuring all users have a route to market and can receive fair value for their flexibility, the Government will ensure that will be householders will be incentivised to deliver demand side flexibility when the necessary technologies have been put in place, while also ensuring current business and public sector opportunities are seized today.

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

The ADE has no comment.

Ultra-low emission vehicles

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

The ADE has no comment.

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?**

The ADE would highlight three points which must be considered in developing EV propositions:

- DNOs have stated that allowing charging of a large fleet of EVs on peak would require substantial network reinforcement. We would encourage Government to set a goal that EVs should be accommodated within existing networks with no EV-specific reinforcement. This is essentially a smart or responsive charging goal.

- Charging EVs on peak will increase peak demand at national level. This could result in fixed diesel engines being used to charge electric vehicles. This perverse outcome should be avoided. Smart charging by default will, in contrast, incentivise charging to periods of high renewable resource and/or low demand.
- Customers must be in control, and must be able to opt out of smart charging regimes if their needs require it. Members advise that their experience of I&C DSR shows clearly that if the customer has the ability to opt out, take-up of DSR is greatly increased but opt-out facilities are very rarely used in practice.

Q35. What barriers (regulatory or otherwise) are there to the use of hydrogen water electrolysis as a renewable energy storage medium?
The ADE has no comment.

Consumer engagement with Demand Side Response

Q36. Can you provide any evidence demonstrating how large non-domestic consumers currently find out about and provide DSR services?
It is important to bear in mind that DSR and other flexible generation such as highly-efficient CHP depends entirely on the actions of an energy user, whether that is an industrial manufacturer, a leisure centre, or a retail store. Through DSR, these users become active participants in the energy system, rather than merely passive bill payers.

Industrial, commercial, and public sector energy users are particularly well placed to provide flexibility through DSR. These organisations represent nearly 70% of UK electricity demand, are significantly larger in size, have more flexible electricity demand and more real-time information about their consumption, and many use extensive on-site generation. However, as businesses and public sector organisations are focussed on their primary operations, such as making paper or steel, simple and fair energy policy must accommodate them, rather than expecting them to cope with extreme complexity.

A recent report by Energyst Media found that almost nine in ten businesses would help National Grid balance the power system if it did not adversely affect their operations, but only 27% of businesses surveyed were actively participating in DSR. Of the 73% who were not, half said they had not been contacted by an aggregator or supplier about DSR. For businesses to feel confident about DSR, they need to find trusted delivery partners and feel they can access impartial advice.

Therefore, the work that we are doing to create a Code of Conduct is an important step forwards for the industry.

It is the experience of our members that the journey from awareness of DSR to active participation is a long one for most industrial, commercial and public sector organisations. Aggregators report that this process can take a year in many cases. Members also report instances where apparently promising DSR prospects, such as a steel recycler with a 30MW load, cannot be included within any existing DSR programmes because nuances within the rules make compliance impossible for that particular load type. Therefore the battle is not to ensure that customers "find out about DSR", but to ensure that the DSR programmes that exist are structured openly and admit novel propositions.

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?

The ADE agrees with the barriers identified to large non-domestic customers, and would like to also highlight the barriers discussed in response to Q7.

A reduction in the complexity of DSR programmes may help customers to understand opportunities, but in fact it is an increase in the flexibility of those programmes which would have the most positive impacts on new providers entering the market at an industrial level. Any reduction in complexity should not be at the expense of widening the variety of resources that can participate.

The ability to stack value is essential in providing an attractive proposition to providers and it is vital that this is enabled as much as possible. If providers are unable to stack this value, this in itself could act as a barrier – forcing customers to choose between activities, neither of which provides adequate business cases, is equivalent to excluding them.

In general, providers should be able to provide multiple services from the same party, if they meet the technical requirements of both. Services should only be mutually exclusive if there is a direct technical reason for this. An example of good practice in this area is the design feature of the CM, wherein wholesale energy trading, Balancing Mechanism participation or provision of Balancing Services, are all compatible with CM. By stacking value, the price which customers must charge for each activity is reduced, leading to a lower total cost of system operation. This also incentivises construction of flexible assets, such as CHP generators with heat stores.

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?

See response to Q7, Q36 and Q37.

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)?

Household-led DSR represents an important future opportunity, but is a more difficult challenge. By ensuring all users have a route to market and can receive fair value for their flexibility, the Government will ensure that will be householders will be incentivised to deliver demand side flexibility when the necessary technologies have been put in place, while also ensuring current business and public sector opportunities are seized today.

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**

See response to Q28.

Q41. Can you provide evidence demonstrating how smart technologies (domestic or industrial/commercial) could compromise the energy system and how likely this is?
The ADE has no comment.

Q42. What risks would you highlight in the context of securing the energy system? Please provide evidence on the current likelihood and impact.
The ADE has no comment.

Roles and responsibilities

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

Q44. Do you have any data which illustrates:
a) the current scale and cost of the system impacts described in table 7, and how these might change in the future?
b) the potential efficiency savings which could be achieved, now and in the future, through a more co-ordinated approach to managing these impacts?
The ADE does not have specific data. However, we set out much of our thinking in response to Q2, Q3 and Q4.

As discussed above, currently Engineering Recommendation P2/6 does not explicitly recognise "non-build" solutions such as DSR and storage. For example there is no standardised methodology for how DNOs should assess the network benefits of storage or demand response. This creates ambiguity, making it more difficult for DNOs to justify innovative approaches. Some DNOs have experimented with these technologies under the Low Carbon Networks Fund (LCNF), but at present these are not being pursued by DNOs in their normal course of business (despite this being a condition of LCNF funding).

In the move from DNO to DSO, a key element will be the interaction between the need to balance at locally and take local actions in each distribution network with the ability for DSR aggregators and providers to interact across the national system. For instance, if there is no national standardised framework through which aggregators are able to access each DSO, there will be substantial barriers, both structural and monetary, for DSR to grow.

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?
The ADE agrees with the proposed roles, however would like to highlight the points raised in response to Q24 and Q44. We would like Government and Ofgem to insist that DSR providers and CHP operators are in future invited to participate in discussions relating to the DSO/TSO boundary and their contribution to each (previous discussions excluded the very operators of the capacity which was under discussion).

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?
The ADE agrees with the further progress described.

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.
The ADE has no comment.

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?
The ADE has no comment.

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?**

The ADE has no comment.

Innovation

Q47. Can you give specific examples of types of support that would be most effective in bringing forward innovation in these areas?
In discussions with members, it is our understanding that the most transformative application of machine learning for grid balancing comes from unlocking and utilising flexibility in demand-side power consumption. Such algorithms can find creative ways to reschedule the power consumption of many demand and generation assets in synchrony to keep the grid in balance while helping to minimise the cost of consuming that power for energy users.

With sufficient data, a machine learning model can look at a sequence of actions leading to the rescheduling of power consumption and make grid-scale predictions saying "this is what it would cost to take these actions". The leading edge in deep reinforcement learning shows how, even with very large scale problems like this one, there are optimisation techniques we can use to offer 'zero marginal cost flexibility'.

Such innovation would be bought forward with support via the market access detailed above as well as direct grant funding.

The added value public funding brings to such innovation is scale. Recent breakthroughs in machine learning offer incredible opportunities for the UK energy market, meaning that DSR aggregators would not need to send specialists in BMS or water pumps to each and every asset that wants to connect with the smart grid, instead reinforcement learning could be figuring the parameters and performance expectations of many machines at an unprecedented scale.

Unlocking 'zero marginal cost' flexibility through this innovation would constitute a significant GB-led breakthrough in machine learning.

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.
See response to Q47.

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