Please find attached the joint response from npower and Innogy to the joint BEIS / Ofgem Call for Evidence "A Smart, Flexible Energy System".

Introduction

npower (npower Group plc) is one of Britain's leading energy companies, and is part of the innogy SE group. We serve around 5.1 million residential and business accounts with electricity and gas and have recently launched our own DSR aggregation service.

innogy Renewables UK Ltd is one of the UK's main renewable electricity developers. We operate over 1GW of renewable generation, including onshore wind, offshore wind and hydro. We are reviewing both our operational and development pipeline to consider options to improve flexibility.

innogy SE is Germany's leading energy company, with revenue of around €46 billion (2015), more than 40,000 employees and activities in 16 countries across Europe. With its three business segments Grid & Infrastructure, Retail and Renewables, innogy addresses the requirements of a modern, decarbonised, decentralised and digital energy world. Its activities focus on its 23 million customers, and on offering them innovative and sustainable products and services which enable them to use energy more efficiently and improve their quality of life.

Executive Summary

We welcome BEIS and Ofgem's focus on ensuring a swift transition to a more flexible system. It is essential that the Spring 2017 Plan that follows will set clear actions and milestones to facilitate increased system flexibility in the near term 2017-2020 in the context of a coherent longer term Strategy.

Our response (please see the responses to the individual questions) is predicated on high-level principles which we believe are essential to the effective and efficient development of a future smart and flexible electricity market.

In order for a smart and flexible system to develop, it is crucial that the system is considered holistically and is not addressed through discrete, "silo" thinking and actions, which will preclude the development of a future-proof system that cost effectively delivers the necessary levels of flexibility in a way that benefits the whole system and all market participants.

Recent examples of decisions being considered separately (such as the Ofgem Embedded Benefits review) must be avoided and we continue to recommend that a Significant Code Review be undertaken– as any ongoing approach based on incremental improvements does not and cannot address many of the key issues facing network companies now and in the future.

Our list of key principles, applicable throughout our response is shown below:

- Network access and network charging must continue to be technology neutral. Government / Ofgem should not seek to "pick winners" through amendments that may favour storage over other providers of system flexibility.
- Flexibility needs to be considered in the broader sense, extending beyond generation / consumption flexibility to other requirements of the system, such as inertia and voltage.
- Care must be taken not to conflate storage with flexibility and in particular battery storage with the wider range of storage technologies.
- Network operators must continue to comply with existing unbundling requirements– network owners and or operators must continue to be prevented from owning or operating storage assets, (in the same way they are prevented from owning generation or offering supply) Otherwise they can distort the energy market and the market for ancillary services which are essential for all generators, suppliers and independent storage operators alike.

- Final consumption levies should only be applied once; however any loss associated with the utilisation of a storage device, is the final consumption and should continue to be liable for those charges.
- BEIS and Ofgem must provide clear strategic support to the development of smarter markets – this includes ensuring swifter decisions are taken and implemented by network operators, who cannot be allowed to “drag their feet”.
- All current and future flexibility services must be appropriately procured and remunerated.
- Appropriate consumer protection will be required and in some instances, this will require additional protection to be developed, in particular for future smart enabled products and services (such as DSR or smaller scale battery devices) targeted at domestic and / or microbusiness customers.
- Ensuring the successful (and cost effective) roll out of smart meters to domestic and smaller non-domestic customers is the priority. Until the smart meter roll out has completed, Government and Ofgem should avoid directly seeking to engage consumers on specific flexible products or services (such as Time of Use tariffs / mandatory Half Hourly Settlement).
- We support greater coordination between the TSOs and DSOs in future, and, we believe the establishment of an independent System Operator (SO) is required to ensure the development and delivery of a forward focused, more cost effective system.
- Project TERRE has the potential to radically amend the market for reserve balancing services and wider stakeholder engagement must be delivered to ensure all current and future market participants are aware of and can input into the proposed policy and regulatory developments.
- Barriers that limit the viability of hybrid sites (i.e. generators + storage and generator – generator) must be addressed ASAP.

In addition to our answers to your specific questions we would like to submit further evidence of the benefits of enabling increased system flexibility (see ‘Supplemental Evidence’). New Imperial College research shows that the costs of integrating renewables are relatively low compared to popular debate and that the move to a flexible system and managing the existing system better will bring benefits to consumers by reducing spend on extra capacity and infrastructure.

Supplementary Evidence Annex

The National Infrastructure Commission (NIC) has already presented high quality, convincing evidence of the value to the consumer from increased system flexibility in its Smart Power Report[1]. Amongst others, UKERC suggests that not only is a smart system an enabler for decarbonisation but indeed that the savings from innovation in energy system management “*will be much higher if UK renewable energy targets are achieved*”[2]. In addition to our answers to your specific questions we would like to submit further evidence of the benefits of enabling increased system flexibility. New Imperial College research shows that the costs of integrating renewables are relatively low compared to popular debate and that the move to a flexible system and managing the existing system better will bring benefits to consumers by reducing spend on extra capacity and infrastructure.

The case for System flexibility - Imperial College Study

The recently adopted 5th Carbon Budget will require the construction of new low carbon generation capacity capable of producing around 260TWh of electricity by 2030, equivalent to more than three quarters of all current output. All credible scenarios imply that this can only be achieved by deploying

[1] National Infrastructure Commission (2016) **Smart Power**

[2] UKERK (2014) Scenarios for the Development of Smart Grids in the UK
http://orca.cf.ac.uk/57649/1/Scenarios_for_the_Development_of_Smart_Grids_in_the_UK_Synthesis_Report%5B1%5D.pdf

a significantly increased volume of renewable generation – likely to be around 50GW, predominantly from a combination of onshore and offshore wind and solar PV.

In November 2016 Imperial College published a study[3], commissioned by innogy and others, which explored the cost implications of significantly increased levels of variable renewable generation. The study involved a number of scenarios to investigate the impact of varying degrees of system flexibility on the system integration costs of renewable generation in 2030. A 'no progress' scenario is created which represents a useful counterfactual to assess the benefits of flexibility. This scenario only included existing levels of flexibility and did not assume any improvement in the years to come. While useful for illustrative purposes we note that this counterfactual is already out of date since the recent Enhanced Frequency Response tender from National Grid will deliver 200MW of new storage by end of 2017. The counterfactual is compared with other scenarios described in Figure 1 below.

The Imperial College analysis was used to inform the E3G report "Plugging the Energy Gap"[4] recommendations that "Ongoing market reform will be essential to support delivery of this plan. The Government should mandate Ofgem to ensure the regulatory regime and market mechanisms create a coherent system that is sufficiently flexible to support cost-effective delivery of the necessary volumes of low carbon generation." We welcome this call for evidence as a first step towards this

Figure 1 – Description of cost scenarios used to investigate cost implications of system flexibility.

Scenario	Description	Comment
No progress	Current levels of interconnection, no new storage, zero update of demand side response	Broadly the current situation
Low flexibility	10GW of interconnection, 5GW of storage and 25% uptake of demand side response potential	Can be considered as 'business as usual'
Mid flexibility	11GW of interconnection, 10GW of storage and 50% uptake of demand side response	Likely to require some new policy initiatives
Modernisation	As in Mid Flexibility but with a range of measures to improve system operation (concerning wind predictability, capability to provide ancillary services etc.)	Would involve modernising system operation practises, to meet 21st century standards
High flexibility	15GW of interconnection, 15GW of storage and 100% uptake of demand side response	Would require significant new policy push to increase flexibility

Source (E3G paper), based on findings of the Imperial College Study[5].

The Imperial College analysis illustrates that even relatively modest improvements in system flexibility allow increased volumes of variable renewable generation to be accommodated cost-effectively on the power system. This opens up options for government to deploy more low cost low carbon technologies, whilst maintaining security of supply, thereby avoiding unnecessary increase in energy bills.

[3] The full report, *Whole-system cost of variable renewables in future GB electricity systems* by Prof. Goran Strbac and Dr. Marko Aunedi can be found at https://www.researchgate.net/publication/310400677_Whole-system_cost_of_variable_renewables_in_future_GB_electricity_system

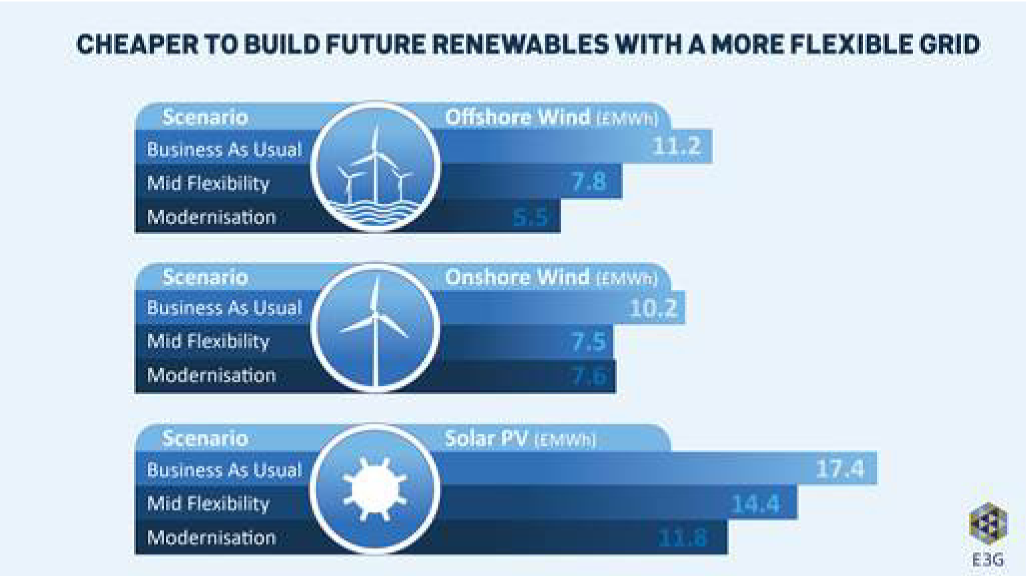
[4] The E3G Report "Plugging the Energy Gap", by Simon Skillings, Tom Lafford, (2016) can be accessed at https://www.e3g.org/docs/Plugging_the_Energy_Gap.pdf

[5] Ibid

The study found that the cheapest way to decarbonise the UK power system involves flexibility and large volumes of renewable generation. This built on the findings of the National Infrastructure Commission's "Smart Power" report, which indicated that system flexibility could deliver savings of £8bn per annum. Please see Figure 2 (System Integration costs £/MWh by technology in 3 core scenarios in 2030.

Furthermore, through the modernisation scenario, the study identified the significant cost reductions that can be delivered through optimisation of the system via improved system operations such as; contracting wind generators being able to provide synthetic inertia and frequency response, allowing wind generators being able to provide reserve when curtailed and the improved forecasting of wind.

Figure 2. System integration costs (£/MWh) by technology in three core scenarios at 2030



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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.

We agree that this call for evidence (CfE) outlines the main perceived barriers to electricity storage (as set out in paragraph 2 of the document). However, traditional forms of storage should not be overlooked when considering options for flexibility; clearly 'new storage' – predominantly batteries have been prioritised within this CfE and BEIS and Ofgem (and future procurers of flexibility services must maintain a technology agnostic approach). Pumped storage for example, can provide other services over and above battery storage – such as system inertia. The UK power system will need a range of different types of storage accessing the markets relevant to their technical capabilities.

Some other significant barriers facing electricity storage that are missing:

- In the Capacity Market (CM), Enhanced Frequency Response (EFR) is not considered a relevant ancillary service, even though Firm Frequency response (FFR) is and this issue is not being resolved speedily enough.
- The use of open ended capacity obligations is not appropriate and unfairly discriminates against non-traditional flexibility providers.
- Dampened investor certainty: the ongoing lack of clarity regarding Transmission Network Use of System (TNUoS) charging and the issue of embedded benefits, which is affecting the broader market, may also have an impact on storage developers' business plans.

<u>Any new or amended policies need to remove barriers for all existing and new flexibility providers – rather than be designed seek to support specific technologies or "pick winners</u>". We are not alone with this view and note that the NIC called for a diversity of options for flexibility; BEIS and Ofgem should take this on board. I.e. "Flexibility can come from a selection of existing and emerging technologies. There is a large amount of untapped potential which could revolutionise the way we view and operate our system and result in lower costs".

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.

Application and Design (A&D) Fees

Given the volume of connection applications received (ca. 19GW of storage **applications** to Distribution Network Owners (DNOs), according to the CfE), <u>we restate our call for introducing appropriate Assessment and Design (A&D) fees for all connections in order to deter speculative and multiple applications.</u> The application of A&D fees to the party that creates work for DNOs is cost reflective and will reduce the overall burden placed on successful project from bearing the costs of speculative applications being processed.

If Ofgem and BEIS continue to remain undecided on the need to allow DNOs to charge reasonable, cost reflective A&D fees per application rather than socialising the costs across all customers, as at present, we ask that BEIS and Ofgem urgently assess the costs of currently socialising these charges and publish the results.

Price Control Frameworks

Currently, while network companies are obliged to offer the most efficient connection this is interpreted by network companies as the cheapest build solution. Non-build solutions aren't offered automatically. Although we have moved from RPI-X to RIIO, networks are fundamentally still rewarded by spending on building and replacing networks. This should change.

Please note, the following comments relate to the headings and content contained within Table 3 of the CfE.

Clarity on connections process:

We would welcome greater clarity on connection process, and agree on the need for swift, further action regarding the ongoing review of P2/6. The engineering safety standards on system security need to include a definition of storage and should ensure that all DNOs provide project owners with a consistent, transparent communication channel to ensure that the developer has confidence that the inherent flexibility of storage (and other forms of behind the meter DSR) are modelled appropriately by the DNO planning and commercial teams.

New technologies such as DSR and storage could and should be used to relieve network constraints and reduce the costs of traditional network constraints reinforcement (whereby the DNO has a vested interest in building and/or upgrading assets) - Engineering Recommendation P2/6 does not explicitly recognise these "non-build" solutions.

<u>There needs to be a more consistent and joined up approach across the different DNOs</u> Ofgem must remain part of these ongoing discussions, particularly if there are changes to the definition and licencing rules that need to be taken into consideration. The road map document to be published in early 2017 must clarify the timescales for the delivery and implementation of the suggested changes / recommendations.

We would also seek clarity and consistency on how DNOs will in future treat the installation of battery sites located behind the meter, both for larger I&C customers as well as within domestic premises, in particular re the need to ensure consistent approaches relating to the information being provided to network operators and suppliers and consistency in costs / delivery times for onsite inspections etc. – given the potential impact such installations may have on the system, demand shape and supplier portfolios in future.

Lack of information on where to connect storage, inhibiting full system benefits of storage being realised.

We welcome the progress made by some DNOs in terms of producing heat maps which include demand / areas of high or anticipated congestion, in order to provide information to flexibility providers to target specific areas of potential commercial opportunity. Transparent network information provision is imperative to ensure that the storage (and other flexible technology) is developed at appropriate locations that will better facilitate utilisation of the existing network capacity.

To go one step further, there should be competitive tender for deferring network reinforcement by lower cost smart solutions. There is no monetary value attributed to avoided network reinforcement and this will act as a key barrier to the emergence of truly commercially viable third party storage. There should be payment awarded to the most competitive solution – either to the network owner for conducting the reinforcement or to cover the cheaper costs of the 'flexible solution'. Third party providers need to be rewarded for deferring network reinforcement – without this we can see from the Leighton Buzzard example that non-network owned storage assets would be unviable. In light of the announcements within the Clean Energy Package published on 30th November 2016, we note the proposals that would prevent Transmission Operators (TOs), Transmission System Operators (TSOs) DNOs or in future Distribution System Operators (DSOs) developing, owning or operating storage assets, except in very specific cases (with ex ante approval from the national regulator[6]. We support

[6] Recast on common rules on the internal market for electricity Directive, Article 36 (section 1)

those proposals to ensure a competitive market can develop, based on appropriate pricing signals. The provision of timely, comprehensive information regarding where storage (and or other providers of flexibility could locate) should be seen as a pre-requisite.

Cost and time of connecting - High cost of connecting / Lack of capacity for fully firm connections

The costs of connection appear to be ever increasing for all market participants. While there is pressure for low carbon generation and innovative technologies to deliver cost reduction, network costs can act as a general barrier to this goal being fully realised.

We fully support the greater use of flexible connections in order to align the contract for storage and its expected usage / network impacts to facilitate quicker and more efficient connections.

Storage, like other connection applicants should also be offered flexible connection agreements. We do not believe storage should be developed to primarily provide services to the transmission system (such as the recent EFR tender) that do not take account of the any associated impacts on the distribution network, where all of the new storage will be connected.[7]

We agree that further work is required to better align flexibility products for both the DNOs and SO and we comment further on this in our responses to questions in section 6.

Storage may need to queue for a long time behind generation for a connection even if it can relieve constraints.

In general we welcome the ENA's work on connection queue management[8]. Clearly the status quo arrangements are not ideal with customers being exposed to connection lead-times of several years regardless of their consenting status. These new queue management guidelines can also be applied to storage. We ask that Ofgem monitor whether the DNOs apply these voluntary measures and if improvements are not seen then regulatory measures may become appropriate.

Should Storage be able to jump the connection queue?

Network access must continue to be technology neutral.

We disagree with the proposal to allow storage to "queue jump". It is not possible to guarantee that a storage unit will act as expected at the desired points in time for the lifetime of the storage asset. Therefore it would be incorrect to assume that the storage would by default alleviate network constraints. Network access must remain non-discriminatory, and so storage should be treated as any other generation connection applicant.

As set out earlier the introduction of appropriate Assessment and Design (A&D) fees for all connections, would deter speculative and multiple applications and therefore help manage the queue size.

Another measure that could speed up the connection process for all connection applicants (including storage), would be to set Guaranteed Standards of Performance on the time for delivery of network stability studies. The review of network supply characteristics today can be extremely slow and there is currently no pressure or incentive on DNOs to conduct these studies in a timely manner.

[7] Outcome of the 2016 T-4 auction

[8] http://www.energynetworks.org/assets/files/news/publications/Reports/ENA%20Milestones%20best%20Practice%20Guide.pdf

Network charging for storage

Network charging must remain technology neutral – it generally needs to improve to ensure it is cost-reflective.

The question posed by the CfE perpetuates old style thinking by maintaining the old definitions of 'intermittent' vs 'non-intermittent'. We are aware that a Common Distribution Charging Methodology (CDCM) working group is also looking at this question at present. Instead of this approach that tweaks the status quo we need new time of use DNO tariffs, in particular 'smart DSO tariffs' to procure the relevant services from the relevant participants at the most efficient price.

Network charges – import and export costs

We fully agree with the views expressed in paragraph 11 that network charges should represent a cost reflective and fair recovery of network costs, and that storage (whereby it both imports and exports) should continue to pay network charges for both the import and export of the power and not seek to obtain different treatment to the consistent application of costs facing other users (and providers of flexibility). We need smart distribution charges.

Whilst we note the concerns highlighted in paragraph 12 of the CfE regarding the cost recovery of Distribution Use of System (DUoS) and Transmission Network Use of System (TNUoS) charges on demand customers during the peak period, – we would suggest that were a storage operator to import power from the grid at peak times, that they should pay those peak prices (particularly given the stated benefits of greater flexibility shown on page 21 of the consultation; which include:

a) Defer or avoid investment in network reinforcement and
b) Reduce the need for a significant increase in reserve generation capacity).

The CfE erroneously makes the comparison between a storage unit and generation in terms of import – this is misleading given the different impacts on the system (and the potential arbitrage opportunities for exporting, not importing at peak times). Generators usually need import connection too for auxiliary services and as such they do also pay import DUoS.

We believe a more relevant comparison would be with other forms of flexibility, such as DSR (whether turn down load or a combination with on-site generation), both of which would be liable to pay both import and export charges as determined by their usage of the system.

We dispute the issue that the CfE (paragraphs 13 – 15) raises regarding the disparity of Balancing Services Use of System (BSUoS) charges applied to standalone storage (when compared to the BSUoS charges for generation, DSR or co-located storage. We request that neither Ofgem nor BEIS seek to amend such charges. BSUoS charges are and must continue to be applied consistently across all the parties liable for these charges.

We note the proposals in paragraph 15 relating to further imminent work on allocation of fixed / sunk cost recovery including for storage, and therefore will comment further at that stage. That said, we note given the preference to ensure flexible connection agreements (with the intention of better aligning storage development with the active use of the system) we believe it is slightly perverse to seek to remove some of the charging signals associated with the network use, precisely because the storage facility would both import and export.

Final Consumption levies

We accept and support the intent to reduce the risk of some final consumption levies being charged; potentially multiple times, on the same kWh of electricity.

However, it is important for cost-reflectivity to ensure that those storage operators (embedded within a supplier's consumption account) retain the liability for the losses their storage technology creates (i.e. the difference between the imported power in and exported power out) – as those losses are in effect the "final consumption" of that site.

This is an important consideration to prevent other market distortions in the provision of flexibility, given that alternative sources of flexibility – such as turn up Demand Side Response (DSR) (increasing import power) would be liable for the same final consumption levies on their imported power.

We do not believe a simplistic solution of abolishing the charges (or exempting some storage sites or even creating a different asset class to avoid the issue) would be appropriate or send the right pricing signals – (particularly for onsite storage which is designed to reduce spill from on-site generation and or to offset some peak usage). Any removal of these final level consumption levies would need to be applied to the supplier's consumption account (from where most of the charges accrue) as otherwise, other customers will become liable for those avoided costs. .

A potential fast track solution to this issue - relating to the levies associated with Renewable Obligation (RO) / Feed in Tariff (FIT) and Contracts for Difference (CfD) would be to utilise the processes being designed to exempt identified electricity intensive users from the costs of RO / FIT and CFD through the proposed Electricity Intensive Industry (EII) exemption, thereby removing the associated power volumes from the supplier's account. The certification process (currently managed by BEIS) could be amended to require storage facilities to register their sites, including the relevant technical details that would determine the associated loss factor of the installed storage.

The level of exemption could be set at the annual loss % associated with the particular storage technology/ and or planned. This is important given the risk of high losses incurring (when the battery is not in regular use), and this should also act as an incentive to install the most efficient technologies. Periodic reconciliation of the associated losses could be implemented to account for changes in the loss rates over time.

However, we do not accept the rationale that storage users should be exempted from the costs of the capacity mechanism (the Operational Cost Levy and the Obligation Levy), as this would be entirely contrary to the need to send effective price signals (as outlined in chapter 3) that incentivise demand away from the peak periods.

We believe the treatment surrounding the partial exemption of Climate Change Levy (CCL) costs; can be managed through existing provision within the Finance Act. We believe that the current rules for CCL (as contained within the Finance Act 2000 in Schedule 6 (Articles 18-22) do allow for an exemption on the basis that the power is not being used for final consumption and there may be scope to clarify the use of storage within these exemptions.

Planning for storage

The planning process for storage needs to be clear, easier to navigate regardless of which part of the UK development is happening in.

We call for a clear decision on what "use class" storage falls under in terms of planning, which recognises that fact that storage encompasses so many different technologies. There is some confusion regarding this, given the fact that the Planning System has only had to recently start dealing with battery storage applications.

Storage Decommissioning

We note that the CfE appears to be silent on the longer term issue of the long term life-cycle of battery storage - plant decommissioning.

We believe that Ofgem and DEFRA should coordinate views to consider introducing controls to ensure all owners/developers have a plan (and an obligation) to decommission and also manage cell replacement responsibly at the end of life. The aim would be to reduce the risk of less responsible operators benefiting commercially in the short term and then exiting the market leaving a potentially uncontrolled legacy of '[containerised chemical / hazardous waste]' across the GB power network. Government should consider the appropriateness of the battery storage industry establishing a central, enduring funded model for chemical recovery – early dialogue should allow the sector to recognise associated decommissioning costs (and rules that may evolve over time) and factor these into their business models from the outset. *Ref Disposal of Hazardous Waste directive / DEFRA.*

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.

The consultation documents states that "network charging methodologies were not designed with storage in mind". We do not believe this to be the case. Although it was not designed specifically with storage in mind, the current methodology does cover off both uses that storage requires – i.e. imports and exports. Network charging in general needs a review to ensure that it is consistent with the investment drivers associated with the relevant network security standards.

For example, transmission investment is associated with both generation and demand under the Security and Quality of Supply Standards (SQSS). Cost reflective charges should recognise the incremental marginal costs associated with generation and demand at particular sites. With respect to storage sites, imports and exports from the site may result in incremental costs associated with reinforcements for both the exports and the imports.

The consultation document highlights an issue associated with intermittent or non-intermittent classification. This is somewhat misleading. The issue of the intermittent/non intermittent classification of sites relate to the investment consequences associated with the categorisation of the site. For example, if the site is exporting at the peak and there is a peak charge associated with exports, then it is consistent that the site is exposed to the relevant peak charge (this could include for example an embedded benefit for distribution connected generation). We support the related review of the transmission demand charging arrangements via CUSC modification proposal CMP271.

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

No – for the reasons outlined below.

Network operators can and should use new technologies to provide products and services to support these networks, <u>but this should not be assumed to be storage per se</u>. If storage offers the right solution to the network issues, then network operators must procure the flexibility services via competitive tendering from independent providers of the required flexible services (the network operator should remain technology and provider agnostic).

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

We have a fundamental objection to network companies owning and operating storage as we feel this is akin to network companies owning generation. This would distort the energy market and the emerging markets for ancillary services.

Network operators' involvement must be limited to the procurement of storage services via competitive tendering for third party suppliers of the required flexible services. (Note the network operator should remain technology agnostic in how flexibility is delivered).

We are concerned that a competitive market for storage (or more precisely the flexibility that storage can provide) could be undermined if in future network owners or operators seek to use allocated innovation funding to trial new proposals (that could include storage). We would also note our concern at the current situation whereby commercial subsidiaries of regulated distribution companies appear to be able to own [and potentially operate] storage assets (some of which are located on DNO's property). We are concerned about the degree to which these commercial subsidiaries are truly separated from the regulated businesses- on the face of it the boundaries appear very fuzzy. Ofgem and BEIS must ensure such developments will be prevented in future.

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

No. This would inhibit the development of a competitive market.

Any new and even existing R&D DNO projects should only be temporarily owned by DNOs - they should be transferred to third parties for ownership and operation by tender after a set period.

Please provide evidence to support your views.

We agree with the assessment contained within the CfE that network operators could use storage to support their networks, particularly to manage local constraint issues, but this relationship should be based on the competitive market, whereby the network operators should openly tender for the service required, rather than seek to own / operate such an asset themselves (or via an un-regulated subsidiary business).

We note the experience of the Leighton Buzzard storage facility trial (conducted with significant Low Carbon Network Funding) showed that the storage facility was able to deliver a peak shaving service to the DNO (and also reactive power) but that this was only for a small proportion of time (only 97 hours over 48 days). We appreciate that the funding for this trial was to demonstrate the ability to defer network reinforcement and to investigate the ability for storage systems to stack revenue streams; which it did.

However the progress report makes clear that services for DNO are unlikely to provide sufficient revenue and utilisation alone. This underscores our clear view that storage assets should neither be owned nor operated by DNOs / DSOs or any subsidiary businesses. We note the findings from the trial[9] stated:

"Commercial benefits: Revenues from multiple ESS applications can be stacked to improve the business case for storage…In the case of the DNO owned storage, as shown in the SNS trials documented in this report, reinforcement deferral by means of peak shaving is required only for a fraction of the whole year, particularly during evening periods from late October through to March

[9] section 4.1 of the report published in June 2016

each year. In parallel, ***Due to high fixed operating costs, the ESS should not be idle:*** *The fixed operating costs of ESSs connected to the distribution network are mainly comprised of auxiliary consumption costs and fixed capacity costs.*

We believe there is a clear risk of a conflict of interest where DNOs are the beneficiaries of additional storage on the network, the knowledge-holders of where this is best located, and also the developers / owners of storage via subsidiary businesses, and we remain concerned that the existing safeguards (primarily through unbundling requirements) may be insufficient to prevent DNOs or their unregulated subsidiary businesses from installing storage in future.

We would welcome a clear and unambiguous statement from Ofgem and BEIS in this regard, to prevent future market distortion from occurring.

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.

Our priority is to ensure that network companies (owners and or operators) are unable to participate in either supply or generation activities. We have a fundamental objection to network companies being able to own or operate storage. There is good reason for prohibiting them from doing so (the basis for the unbundling requirements) as they can distort the energy market and the market for ancillary services which are essential for all market participants – generators, suppliers and independent storage operators alike. Any changes to Licencing must also ensure that the Network Owner / Operator License is also amended to ensure they cannot own or operate storage.

It is this overriding requirement that means we do not and will not support option D or any other future option that could "blur" the current unbundling principles.

We appreciate there may be merits in either option B or C but we do not believe the options as set out provide sufficient clarity as to what might be included (or not) with a proposed "modified generation licence that "*could take account of the non-generation aspects of storage".*

We believe our suggestion; (please see our response to question 3) with regards to how to treat the issue of final user consumption levies also obviates any perceived need to change the status of storage in order to prevent storage becoming liable for some of the final consumption levies.

We note also the likely time constraints required to change primary legislation would likely cause delays and risk investor hiatus if the rules will be changed in the future.

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.

As per our response to the BEIS consultation ***"****Consultation on changes to the CFD contract and CFD regulations (May 2016*)" we specified a preference to use the ESN agreed industry definition, rather than the definition that is currently used within the Capacity Market regulations. This is driven in part through the need to ensure future hydro storage sites are not discriminated against. We believe the Capacity Market definition precludes hydro sites, as the storage (the reservoir) may be at some distance removed from the generating unit.

The definition for electricity storage needs to be future-proof, noting that in future additional forms may need to be covered (including electricity to gas, or seasonal heat storage may be required).It would be helpful if any future electricity storage definition is codified and used consistently within all legislation and regulatory frameworks and documentation, to avoid any future unintended consequences.

REMOVING POLICY AND REGULATORY BARRIERS - AGGREGATORS

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

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

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

At present we believe there are a number of barriers facing aggregators (and other parties), including suppliers relating to access to the balancing services market. These include the lack of transparency and procurement process for these services. Given the range of products, time availability and requirements it can be difficult to identify and present the opportunities for participation in many of the available balancing services from a DSR perspective (whether that is provided direct from the customer to the system operator (SO) or via a third party (an aggregator or potentially supplier).

According to the report published by National Grid into the volume and provider of non-balancing services and volumes 2015-16), that for those non BM services provided by DSR, this accounts for only 16% of the expenditure, with the report confirming that *to date, STOR has been the most successful service for accessibility to DSR providers".*[10]

However, we would note that all recent research into the willingness of providers of flexibility (particularly larger Industrial and Commercial (I&C) customers who are able to load shift) remains relatively low, given the perceived difficulties of justifying the investment / changes to production runs versus the perceived benefit and uncertainty associated with regulatory change and other market dynamics (e.g. the TSO's review of balancing services required and DEFRA's current consultation 'MCPD and emission controls for generators') .

We believe there are some specific areas of concern / barriers that are contributing to the reluctance by many larger I &C customers, whose plant / equipment would be suitable to provide flexible services, choose not to. These include:

TSO's review of balancing services

Aggregators and larger DSR providers can and do successfully access balancing services directly. National Grid; in their role as System Operator (SO), have acknowledged concerns about the difficulty associated with navigating through the range of ancillary services to ensure that an asset is valued appropriately and can access and satisfy an appropriate range of complementary range of services i.e. delivering different services to the SO/DSO at different times of the day/year.

However depending on the service, there can be a lack of transparency and logic associated with the procurement process (including the product specification, (overlapping) duration of response etc. Whilst National Grid has acknowledged the issue and has pledged to review their services (***noting this intent was initially highlighted to the sector back in 2015***); the lack of progress to date further undermines confidence in the sector.

[10] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937379

This is particularly important if a business customer were required to invest in asset controls (or synchronising capability) in order to deliver the DSR services; for example - should they risk their financial investment by developing capability to deliver services to the SO that could be ‘retired’ by the SO in the near future?

We accept the perceived barriers facing aggregators in that the imbalance cash flow resulting from an aggregator’s balancing actions does not accrue to those parties responsible for the action, and that therefore balancing actions taken by aggregators may need to be offered at a higher price that would otherwise be the case.

This is an area where aggregators' and energy suppliers' interests are not aligned, as suppliers (currently) hold the balancing risk. Aggregators can mitigate balancing risk, but contract with the SO who has no risk, whereas suppliers have no means available to mitigate this risk other than via contracting via the within day market. It is unclear to us as to what degree consumers could benefit in general; given there would be some clear redistributive effects between flexible and inflexible consumers. The extent of this redistribution would in part depend upon the magnitude of the increase in DSR actions, but those inflexible customers could pay more [in risk premia] to account for the reduction in portfolio benefit that suppliers have and share with their customers (i.e. overall imbalances are netted off on wider portfolio basis).

We would note that if any future changes are not implemented correctly – i.e. on the principle that the supplier’s account remains “whole” then there is a high risk that supplier imbalance costs will increase (due to actions taken outside of their control) which will in turn be passed back on to consumers in the form of higher risk premia and cost.

Embedded benefits review

Whilst we welcome the commitment from Ofgem to clarify the outcome of the current CUSC modifications concerning the embedded benefits review, we believe this uncertainty regarding the future of Transmission TNUoS Charging (Triad) currently further undermines confidence in the DSR sector. National Grid, as TSO need to clarify whether or not Triad avoidance delivers value (avoided cost of transmission/generation assets/reinforcement) – and if so, to what extent.

As TNUoS is a major variable in DSR engagement (and to any major business energy budget) National Grid should provide some guidance in to reasonable structures of transmission charge changes that are fit for purpose as an enduring model in to the 2020s (recognising the related, coincidental price-signal dynamics associated with DUoS Red-Rates and CM-Supplier Recharge periods) also factoring in any system constraints associated with the electrification of transport / heat which could coincide with traditional periods of GB Winter Peak.

DEFRA emissions review

Behind the meter generation (BMG) is currently considering the consequences of the current review into BMG and this resultant uncertainty further undermines confidence in the DSR sector and the reasonableness of short periods of self-generation to ensure productivity is maintained during system stress events.

DNO/DSO market for active network management

The transition from DNO to DSO operations should be encouraged further through the next stage of price control reviews and innovation competitions, noting the tangible success of Low Carbon Network Fund projects and ongoing Network Innovation initiatives in their successful demonstration projects aimed at enabling smart network solutions.

However we believe that DNOs should focus on creating the appropriate incentives and models to support best practice network operations and allow the market to provide the most appropriate, efficient solutions – i.e. focus on creation of a market including dynamic price signals for UoS, deployment of storage, EV charging and smart/DSR solutions rather than duplicating resource found elsewhere (including creating customer facing sales teams to develop DNO-led DSR capability. (Please also see our response to question 9).

Not only is a DSO-led DSR service operationally inefficient (resource wise and ensuring the appropriate, wider market bundled service opportunities are offered to the prosumer) but there is the risk that any bilateral DNO intervention will expose the supplier to imbalance exposure. We should also consider how the DNOs who are less concerned about network capacity and constraints highlight opportunities for development in the appropriate areas of their distribution network.

Aggregators becoming Balance Responsible Parties

We believe there are both positive and negatives for aggregators (and the ultimate providers of the flexibility), based on the perceived value versus downside risk and costs to implement and reconcile these activities. Please also see our comments relating to Project TERRE below.

We remain concerned that the changes referenced (but not decided) within this CfE, such as the proposals to change / limit or reduce the level of embedded benefits / Transmission charging arrangements will likely result in greater uncertainty and further compromise changes to the willingness of larger customers to consider providing increased flexibility through DSR and therefore the level of potential and realised DSR flexibility in the short to medium term.

European legislation

We note the potential impact of changes outlined in the [current draft] of the European Balancing Code; both in terms of increased opportunity for bids / offers to be submitted by non-balancing mechanism participants (which would include aggregators) and therefore the need to address access to the BSC outside of the regular process and the proposed Project TERRE (P344) process.

Dependent upon the eventual outcome of the ongoing P344 process (with the expected framework process to be finalised by March / April 2017 for consultation) it is hard to know the level and scope of benefits to consumers and or impact on the market, other than those initial results from the impact assessment conducted by ACER (at a European level).

Our expectation remains that if Project TERRE develops effectively, a large (and increasing) volume of balancing actions will be included with the process, which will provide greater opportunities for all providers of flexibility (as well as potential risk for current providers of longer reserve, such as STOR),

Extracting value from the balancing mechanism and wholesale market

We believe there will likely be benefits for the consumer in providing greater access and transparency for balancing mechanism pricing and wholesale market impacts relating to the changes through Project TERRE. There will however be consequences, which some customers (both large and small) may not welcome; i.e., more granular pricing may become the norm, in order to more efficiently price contracts, (please see our response to questions 15 and 16 to the questions relating to smart tariffs).

As the success of DSR Aggregators continues, (potentially contradicting the message of ‘barriers to DSR’) the scale and frequency of DSR events will naturally affect suppliers’ imbalance position (when an aggregator enacts a DSR event for a consumer it alters the consumption volume of the consumer’s Balancing Responsible Party (usually their electricity supplier), so as the aggregator is profiting from the event, it is reasonable to keep the supplier (who is often working at extraordinarily tight margins) financially ‘whole’ for the period in question.

In a post Project TERRE world, we believe it is right that each active party meets its contractual responsibilities and that no party should be able to benefit (or be damaged through the actions of a third party). However the industry should consider carefully the potential requirement for and costs associated with significant system changes (Forecasting, Reconciliation and Billing Systems and the associated time required to deliver such change).

We are unclear as to whether or not the costs associated with the Project TERRE process already include the associated and necessary changes to industry systems, recognising there will likely also be costs incurred by suppliers, aggregators and other third parties to update their systems to provide sufficient compliance and audit trails - in order to identify and trace significant numbers of balancing actions enacted either directly by a prosumer or through a third-party and the resultant remedial actions required to keep the Balancing Responsible Party (most likely the supplier) whole.

This will be critical in terms of the contractual relationships that will need to develop between the aggregator and their customers, as well as changing relationship between the customer and their energy supplier.

It is for this reason that we firmly believe greater consumer protection must be developed now, before the market frameworks change.

DSR Code of Conduct

We fully support the proposals under discussion through the Association of Decentralised Energy (the ADE) in relation to the DSR Code of Conduct being developed and see this as an important first step in ensuring customers have access to clear, non-ambiguous language relating to their expected benefits, contractual requirements, and essentially, recourse to support and advice advise in the event of negligent, incorrect or misleading claims being made.

That said, we are concerned that the voluntary Code of Conduct (as currently envisaged) may not have the necessary teeth, to ensure enforcement or compliance by the part of any future rogue operators. We also agree that the proposals (as drafted) do not and should not be used for smaller SME or domestic customers, given the more significant and rigorous consumer protection requirements.

Question 8) what are your views on these different approaches to dealing with the barriers set out above.

Please also see our response to question 9 in relation to this question.

Given the ongoing uncertainty as to how the market will develop and evolve; particularly in respect of the impact of BREXIT and the degree to which the UK will remain obligated under European regulations and directives relating to Electricity, as well as the unresolved (or ongoing issues) relating to proposals for network charging, – we cannot provide specific views on the different approaches as sent out within the call for evidence, as these will all likely be impacted by the external changes noted above.

That said, we have some clear principles, which we believe will be critical to ensuring the development of a more flexible and smarter market in the future. We suggest any proposed changes, in particular with rules relating to the removal of perceived barriers to aggregators must be considered, with clear cost benefit analysis being undertaken before changes are made.

Any amendments to the design and procurement for balancing services by the SO or in future DSO need to be on the basis of providing the most efficient outcomes; there should be no interventions that discriminate either for or against different technologies and / or market participants.

npower and our customers require confidence that a truly competitive market for flexibility and storage will develop and therefore assume that natural monopolies (i.e. the TSO, DNO/DSO) particularly with regulated income (or any non-regulated commercial subsidiary therein) should be prohibited from participating directly in those markets. Instead the SO and ideally in future an Independent System Operator (ISO) should be required to prescribe the service that is required and then allow the market to provide solutions based on conventional procurement models. This is particularly important in the future when increased storage or DSR provision will result in greater innovation (both in terms of technical and commercial developments) - leading to more layering and dovetailing of products and services.

We remain concerned that were DSOs able to contract directly with aggregators to manage / relieve local congestion, there would be similar impacts on the supplier's imbalance account, but that these would not be reconciled, with potentially suppliers and their wider customer base effectively paying for the flexibility provided to the DSO via a third party. We would also note that in order for such a market to develop, this would require DNOs / DSOs to create new customer facing teams to manage these contractual relationships, which would result in duplicated resources, leading to greater cost. This would not be a desirable outcome, (please also see our response to question 7).

Whilst Project TERRE should address many of the perceived barriers (probably including allowing aggregators to become signatories to parts of the BSC); taking on the associated risks and responsibilities that this brings, many other questions remain unresolved and these will need to be addressed through this CfE and through ongoing engagement with industry.

Our high-level expectation is that, in the event of aggregators becoming BSC parties (either as a result of Project TERRE or more fundamental regulatory change) we believe it is critical to ensure commensurate regulation of this sector. This will become more important as customers enter into binding contractual arrangements, that will likely result in changes in the way the customers' flexibility is rewarded. By this we mean, as the aggregator holds the responsibility to deliver the flexibility, their contractual relationship with the customers may change, exposing the customer (and the aggregator) to greater risk and reward.

Ensuring appropriate customer protection and recourse (for all customers) will be critical to ensure consumer trust and engagement with greater flexibility. Npower is currently participating in the ADE Code of Conduct for aggregators, aimed at the larger end of the DSR market. However, without real "teeth" or regulatory oversight, we believe that some customers may experience a sub-standard service or be open to mis-selling / abuse.

We note the potential mismatch between the requirements on suppliers through the introduction of more Principles Based Regulation, and currently through Supply Licence Condition (SLC) 7B and Standards of Conduct for non-domestic customers (microbusiness customers) and 25CStandards of conduct for domestic customers) and aggregators may result in customers receiving different standards of care, even if both parties were signatories to a future aggregator Code of Conduct.

For the future, we would firmly encourage the SO / DSOs to limit (or focus through additional 'weighting') their procurement of DSR services to only those aggregators who are signatories to the Code of Conduct.

Our view is that the regulator needs to take the lead in implementing change, as there is currently no commercial imperative to drive industry led change, as the benefits accrue to aggregators rather than suppliers.

In addition, controls will be needed to ensure the principle remains that Supplier contract positions are held whole, regardless of any third party actions. This will require an industry process, systems and governance, which needs to be regulator led (and may be the outcome of the ongoing Project TERRE process}. If this principle is not enforced, there is a risk that this will lead to further distortions, inefficiencies and higher costs to consumers.

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

Please see our comments relating to the options (outlined Table 5 of the CfE) in Tables 1 and 2 below.

Table 1 - Barriers to market

Approach	*Barriers to market*	*Pros*	*Cons*
Monitor	*" A watching brief" – perhaps shared with the SO, to monitor market access to barriers and issues*	*Doesn't require regulation, will facilitate more evidence based analysis in future but should be based around a degree of certainty that the 'watching' brief should be reviewed in an appropriate timescale.*	*Given level of change (through code Mods for project TERRE etc) this is not tenable – Ofgem decisions will be required on Project TERRE model in Q2/17*
Industry led change	*BSC or C16 modifications*	*Project TERRE (Mod P344) is already resulting in industry led change and is expected to deliver a model for Ofgem to review consult upon in March / April 17.* *BSC modification preferable given need for associated codes/ requirements to be acceded too (including Grid Code / ability to communicate with Grid / ensure data transfer etc* *Allowing an industry led solution is likely to ensure all potential unintended consequences on all impacted parties are considered and where possible mitigated.* *We believe changing market access via the BSC would be the most efficient route for change, given the known changes / requirement resulting from Project TERRE.*	*Project TERRE process does not include analysis or calculation of any rebound effects (as customers shift load) and associated impacts.* *Lack of clarity regarding how implementation of Project TERRE will impact on broader Balancing Mechanism and market for additional balancing services procured by TO and in future DSOs which may not be addressed (with any resultant supplier imbalance remaining at the supplier (and their customers' risk)*
Regulator Steps in	*Obligation on suppliers*	*Would remove need for significant changes to BSC.* *By requiring suppliers to contract directly (we'd recommend a standardised framework to reduce complexity) it would enable faster access and could minimise customer issues where there are associated impacts on the bill.*	*Potential for commercial conflict where supplier is working on behalf of a competitor (particularly if the supplier itself is an aggregator)* *Placing the obligation on suppliers may reduce customer trust / perceived independence of both aggregator and supplier (and potential conflict of interest if customer doesn't deliver in line with contractual requirements* *Direct regulation of aggregators would still be missing,*

			risking worse consumer outcomes.
	GAR or licence aggregators	*We believe GAR - enabling Ofgem to assume some regulatory powers would be helpful; both in terms of ensuring appropriate consumer protection. We noted that the proposals under Project TERRE are likely to result in this outcome, with aggregators being required to accede to the BSC (or at least parts of it) and becoming balance responsible parties in their own right (for those actions covered by the Project TERRE process).* *Licensing aggregators could reduce differences (vis a vis supplier standards of conduct / principles based regulation) etc and would provide suitable avenues for redress if required.* *Given range of consumer protection required, particularly at the smaller end, seems unlikely that these can be achieved without formal regulation.*	*Aggregators may view need for formal licence requirements (and associated responsibilities) as too difficult to meet /less lucrative and exit the market.* *Unclear on timescale for Ofgem to get the appropriate vires to authorise regulatory approach to cover independent aggregators.*

Table 2 - Consumer protection

Approach	*Barriers to market*	*Pros*	*Cons*
Monitor	*" A watching brief" – monitor consumer concerns and microbusinesses / domestic DSR*	*Reduces risk that over-regulation reduces ability for new and disruptive business models to develop* *Allow market-forces to gauge level of natural take-up, without interventionism.* *May help ensure targeted interventions where there is genuine market interest.* *Potential for lower interest until smart roll out complete and or HH settlement made mandatory unlikely before 2020*	*Unlikely to have sufficient consumer protection in place to prevent mis-selling to early adopters/ those customers with existing PV who may be encouraged to consider battery storage / aggregated options for additional revenue* *Allowing an unregulated market to develop may damage future acceptance and take up in light of emerging issues* *Unclear how any consumer protect breaches would be tackled with the risk of lowering consumer confidence in participation.*
Industry led change	*Voluntary Code of Practice:* *e.g. ADE code of conduct for larger non-dom customers*	*Likely to deliver appropriate minimum level of protection / consistency in approach to offering DSR services via a TPI (non-supplier)* *Perceived to be a minimum/ acceptable barrier to entry (on the subject of consumer protection) for market participants (?)* *Likely to minimise costs administrative and participant burden, will provide flexibility for change if left to industry* *Will deliver minimum requirements, allowing providers to differentiate through differentiation (including potentially in levels of service etc)* *Process already underway, with intention to deliver by 2017 (? Or 18) with substantial industry backing*	*Likely for difference in regulatory approach between aggregators (not required to meet Standards of Conduct / Prescription Based Regulation levels – unlike suppliers)* *Only targeted at larger end of non-domestic customers.* *Provides no guarantee of service levels for consumers or procurer.* *Enables non-signatories to provide substandard service / products without official recourse* *No current proposals aimed at smaller non-domestic / microbusiness customers who are more likely to be susceptible to sales hype (mis-selling)* *Perceived conflict of interest with an industry-led initiative?* *Unclear how a voluntary code of practice would be 'socialised' / communicated to the wider consumer base, and other industry users for a wider 'buy-in.*

			In comparison to the 'monitor approach' any time delay or lag to implement either a voluntary or mandatory code may act as a perceived barrier to entry.
	Mandatory code of practice (SO or equivalent requires sign up to access balancing services	*Would provide regulated basis for accreditation, allowing greater compliance and enforcement action (delivering greater customer protection and trust).* *Removes financial incentive to avoid signing up to code of practice (and associated costs)* *Places independent aggregators on similar level to licensed suppliers to meet equivalent Standards of Conduct (and associated requirements on accurate information, treating customers fairly etc)* *Would be possible to set differentiated levels for different customer types, removing risk of ambiguity / protection based on type of aggregator.* *May help ensure interoperability of equipment (particularly in future for smaller consumers)* *May provide certainty for provision of balancing services to other parties (not just TO) in terms of relationship / accreditation with aggregators*	*Cost and perceived administrative burden to comply* *Legislative requirement to provide regulator with vires to deliver.* *Risk of duplication with requirements to meet BSC requirements (as anticipated through project TERRE process).* *In comparison to the 'monitor approach' any time delay or lag to implement either a voluntary or mandatory code may act as a perceived barrier to entry*
Regulator Steps in	*GAR or licence with codes of practice*	*We believe GAR - enabling Ofgem or equivalent to assume some regulatory powers would be helpful, both in terms of ensuring appropriate consumer protection. We noted that the proposals under Project TERRE are likely to result in this outcome, with aggregators being required to accede to the BSC (or at least parts of it) and becoming balance responsible parties in their own right.*	*Aggregators may view need for formal licence requirements (and associated responsibilities) as too difficult to meet /less lucrative and exit the market.* *Unclear on timescale for Ofgem or other regulator to get the appropriate vires to authorise regulatory approach to cover independent aggregators.*
	GAR or licence aggregators	*As above – with additional requirement through licencing of aggregators likely to ensure full compliance*	*Cost of acquiring licence and compliance may be seen as too high / barrier to entry.* *May be unnecessary for early market development (pre 2020 smart roll out / HH elective)*

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 the risk?

System Stability – compromised network stability as a result of significant, simultaneous actions

We believe that the supply businesses and DSR community are dependent on insight from National Grid, (as the SO), the DNOs and a number of academic institutes that have been commissioned to undertake studies and scenarios exploring SO/DSO operability issues associated with any number of significant events – Largest Loss of Load, Renewable Characteristics, explicit and implicit DSR events etc.

National Grid (as the SO) has already published headline data on the scale of tangible DSR experienced as a result of Triad activity in winter 2015/16 (at >2000MW of consumer demand change) and are undertaking several studies in to the implications of other disruptive developments on network characteristics including any ramification of 200MW+ battery dynamics on network resilience.

Grid's Future Energy Scenarios (FES) and System Operability Framework (SOF) should aim to inform of the influence that their prescribed service obligations, (delivered by compliant aggregator systems) have on cross-system operations and perhaps share studies more widely to enable more active influence of ancillary service design to reduce the risk of unnecessary, (unforeseeable) coincidental +/- shifts in load.

The SO and all parties should also consider the inter-related dynamics of true, load-shifting DSR events and any resultant rebound (*i.e. if production has ceased or refrigerated plant has been curtailed there is likely to be a consequential correction at site resulting in an increase in power requirement across the grid*) this will not only have an impact on the TSO/DSO but also the supplier / BRP whose hedged position may be compromised for a second time – noting depending on the DSR counterparty, this rebound may be immediate or may lag as a result of technical constraints at the site.

It is important for both consumers and the wider system that aggregators' systems and processes for load control are robust and secure. As credible commercial businesses, aggregators' systems should be fully compliant with all obligations set-out by the SO i.e. able to fully satisfy performance characteristics prescribed for each product and service and also secure (as reasonable from cyber-threat) and robust with adequate disaster recovery procedures in place.

ToU tariffs could also be influential – as per the Triad example noted above, whilst npower strongly encourage further uptake of ToU tariffs and contracts; the strength of price signals is likely to result in further change in behaviour over which the SO will have little or no direct influence. However the associated behaviour, whilst potentially large is likely to be more forecastable and less dramatic than for instance, a short period of instantaneous grid Frequency-related event.

PROVIDING PRICE SIGNALS FOR FLEXIBILITY – SYSTEM VALUE PRICING

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

<u>The definition of flexibility that Ofgem have given in this CfE refers only to generation/consumption flexibility and not to other requirements of the system (such as inertia, voltage etc) which will also need to be considered for the system to truly be flexible</u>. In our view these are inextricably linked and should be considered together rather than in silo.

This CfE largely overlooks existing assets of the system and the value they could add to efficient and flexible system operation, given the regulatory and market landscape to provide a widened portfolio of services. A significant enabler of system flexibility would be a change to the way ancillary services are designed and procured.

The current design and procurement of these services has been suitable for the system operating traditionally however, as the CfE acknowledges, the system has changed. A reform of how services are designed and procured, to align better with the flexible system of the present and future, will work to maximise the number of generators and users with access to service provision and ultimately result in a more flexible, competitive and efficient system for the consumer.

While at the TSO level there are some products already available – these need revision to widen the pool of providers. We note the relevance of the proposals contained within the draft European Network Code (Article 25) for the creation of a suite of standard products that will be required However, we have greater concerns at the DNO / DSO level where it is not clear what ancillary services are desired or should be provided. Local distribution level service procurement is needed with clear price signals and transparent methodologies. This should actively complement the way the transmission system is operated.

We would also like to raise some points about network operators managing the longer term availability of generators:

- A key outcome of the flexible system should be avoiding the curtailment and constraining of renewable energy generation so that the best value is gained from investment in this capacity. Providing a monetary value to curtailment can provide the economic signal for avoiding such action. We note that currently this is absent at the DNO level and that this should be one of the enablers.
- As owners of distributed generation plants, we also experience significant issues with the way in which DNOs in particular manage outages. Generators are rendered out of action for excessive periods of time. There is a lack of regulation to limit the duration of outages and indeed there appears to be insufficient financial incentive to deliver the works that necessitate the outage quickly. This is compounded where works are required both at the transmission and distribution level because there appears to be little coordination to limit the costs and inconvenience to DG Users. Such outages can last several weeks. If there was an option whereby generators could make payments for over-night work by the network companies, this could be a solution to accelerate and resolve issues. The network companies need to be able to accept such payments by the regulatory framework. Another measure would be to ensure that 'lost generation' impacts were included in the way Ofgem deems the network companies to be conducting work 'efficiently' vs 'inefficiently.

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?

We access what we can (as a supplier, DSR aggregator, and generator) in accordance with the rules It is evident to us that these rules were designed for an old system of central generation and non-smart demand.

As an active supplier, DSR aggregator and DSR asset owner npower have developed a specialist in-house team and technology to enable effective commercial operations for individual assets across a range of revenue streams. We focus on accessing value from a combination of ToU cost avoidance (Triad, DUoS Red-Rates and from 2017, the Capacity Mechanism Supplier Recharge) plus where an asset is capable, grid services such as Short Term Operating Reserve (STOR) and / or Frequency services.

Any generation assets that have DNO approval to export will also benefit from Power Purchase Agreement revenues. These assets may also be able to benefit from supplier balancing opportunities if the wholesale market becomes more volatile and will ultimately be offered into the Capacity Market auctions as we believe there is logic in this complementary activity and additional value, however the current pre-qualification requirements are considered too onerous from a resource perspective (involving significant, dedicated administration).

Barriers to more rapid uptake of flexibility access which have undermined investor confidence and deterred business customers from participating include: the ongoing uncertainty regarding future Transmission Use of System charges, recent changes to distribution charges (reducing the price time-of-day price signal differentials), the TSO's declared, but unfulfilled consolidation of balancing products, burdensome Capacity Market administration, DEFRA's MCPD emissions review and the frequent policy interventions.

Please see Table 3 (in response to question 13) which outlines the flexibility services that our renewables business and retail business can provide.

One key barrier to greater provision of services is that everything is currently procured in silo. There needs to be open access across all revenue streams (to be able to access incentives and ancillary services together e.g.: CfD barrier to being in the Capacity Market.

Hybridising sites to incorporate co-location of generation and storage can utilise existing grid connections and smooth the shape which appears at point of connection (export curve). Ofgem needs to ensure regulations enable this for new sites and ability to retrofit too.

The ancillary services (AS) market is under review by National Grid, currently the National Electricity Transmission System Operator (NETSO), they have highlighted there is "significant potential for simplification of products to deliver economic efficiency". We agree with this observation and recommend any AS market review should take account of the following:

a) full range of AS products recently procured (What products have been procured);
b) technical overlaps between current products (What do products do, and related technical specifics at point of procurement);
c) product valuation (price of service provision);
d) product usage (volume of product procurement, and annual service cost)
e) procurement practice, per product (including timing of procurement process)
f) interactions between the Balancing Market and directly procured AS products,

We believe that consumers stand to secure significant benefits from improved system efficiency by maximising competition in the procurement of a simplified, and reformed, AS product list.

We would particularly emphasise three aspects of such a review that merit detailed consideration:

1. Firstly, a rationalisation of any new product list is required, should consider those technical requirements needed by today's (and tomorrow's) power system for efficient operation, and not simply be based on the evolution of historic thinking/products. It is vital the new AS product lists takes full account of what technical service offerings are available today, and likely to be available tomorrow;
2. Auction liquidity within historic/current NETSO procurement practices has been harmed by the timing at which such procurement takes place.
3. Lastly, we would highlight the need for an independent review of the AS market. We recognise there to be significant conflicts of interest for National Grid to manage, and the overall process of reform would benefit from Ofgem being given, by BEIS, a clear mandate to lead such reforms independently of NETSO/NGET.

Revenue stacking

Revenue stacking already occurs to some extent with the UK power system today. The means by which service providers may bid to provide a particular product (e.g. capacity availability in the CM), whilst taking account of other revenues accessed from parallel service provision (e.g. Ancillary service provision, and/or embedded benefits) is accommodated for within both the wholesale market, the CfD auctions, and the Capacity market auctions. Revenue stacking can benefit the consumer by minimising the overall volume of service providers required for efficient operation of the power system, as well as minimising the cost of such service provision through increased competition.

However the current GB electricity market design arguably undermines competition within the provision of system services (be that capacity, low carbon energy, or ancillary services) by unnecessarily obstructing greater degrees of revenue stacking through

(a) lack of market access (e.g. Old or new CfD/RO plant cannot access the CM), and
(b) lack of open procurement (e.g. as per above, timing or procurement negates optimised competition by discriminating against variable generation plant).

We recognise that any improved enablement of market access/revenue stacking would require thoughtful consideration, particularly regarding plant in receipt of historic support and the need to avoid windfall gains. However in future the integration of procurement practices within each of the BIG3 markets (see diagrams below), has significant potential to better reflect efficiency of service provision across all of the BIG3 markets.

We recommend BEIS and Ofgem jointly consider the benefits afforded by opening access to all of the BIG3 markets to all market participants. Please see Figures 3 and 4 below, which illustrate this.

Figure 3: Whole system analysis: Delivering 2030 power system at least cost BIG3 markets – Evolving market dynamics

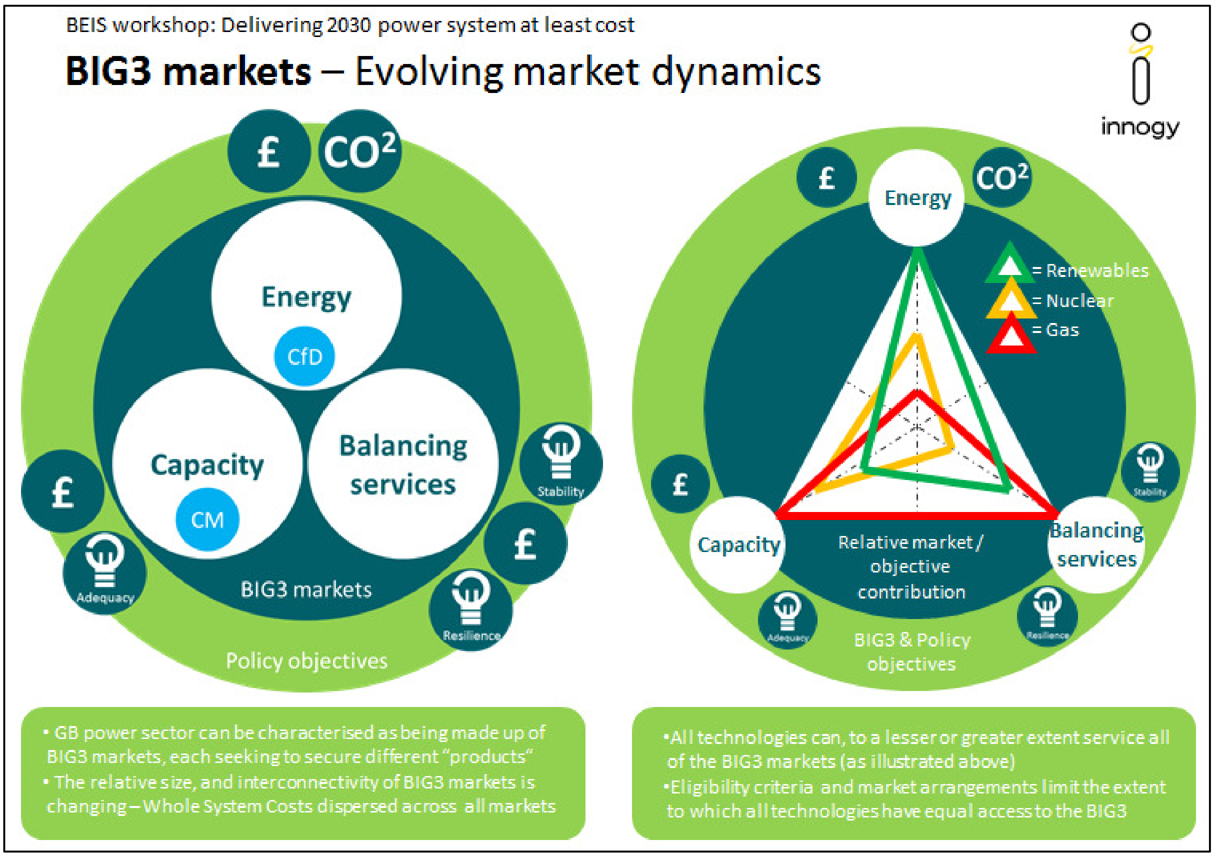
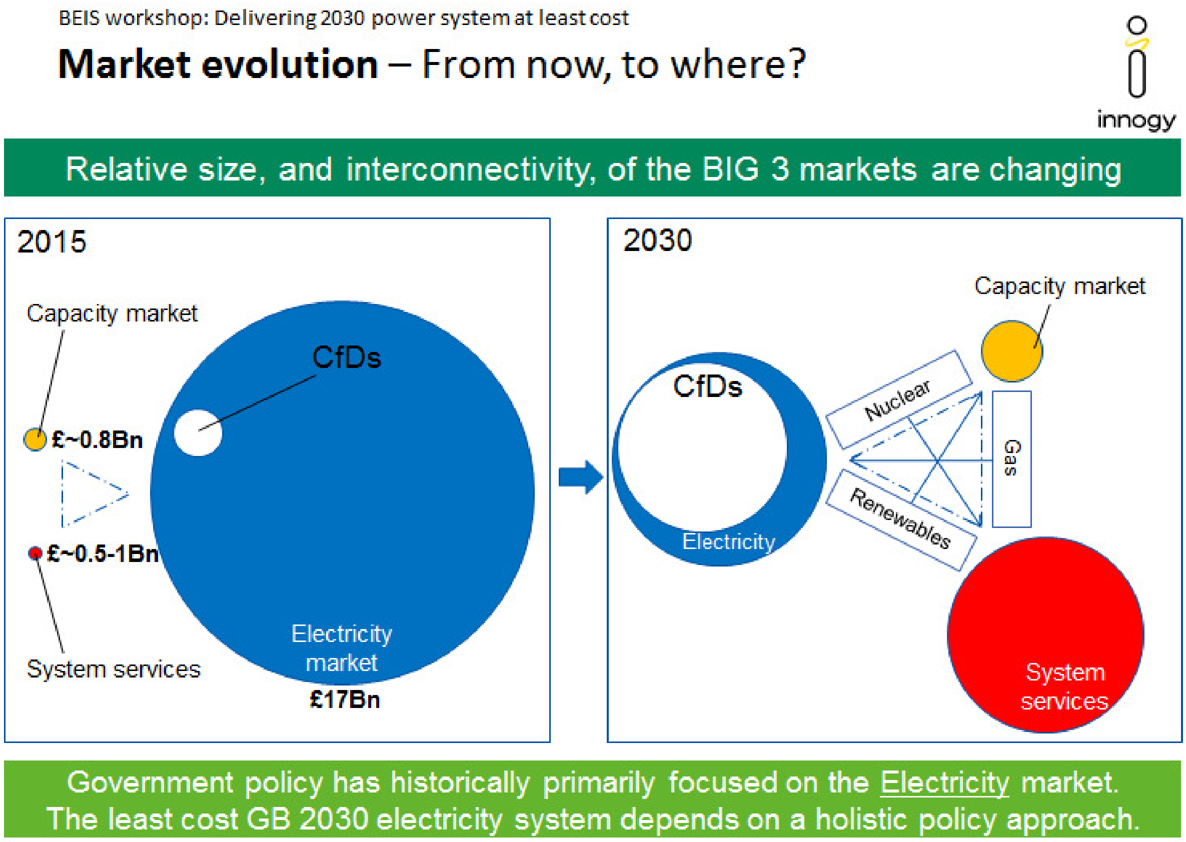


Figure 4 – Relative Size and interconnectivity of the BIG3 markets.

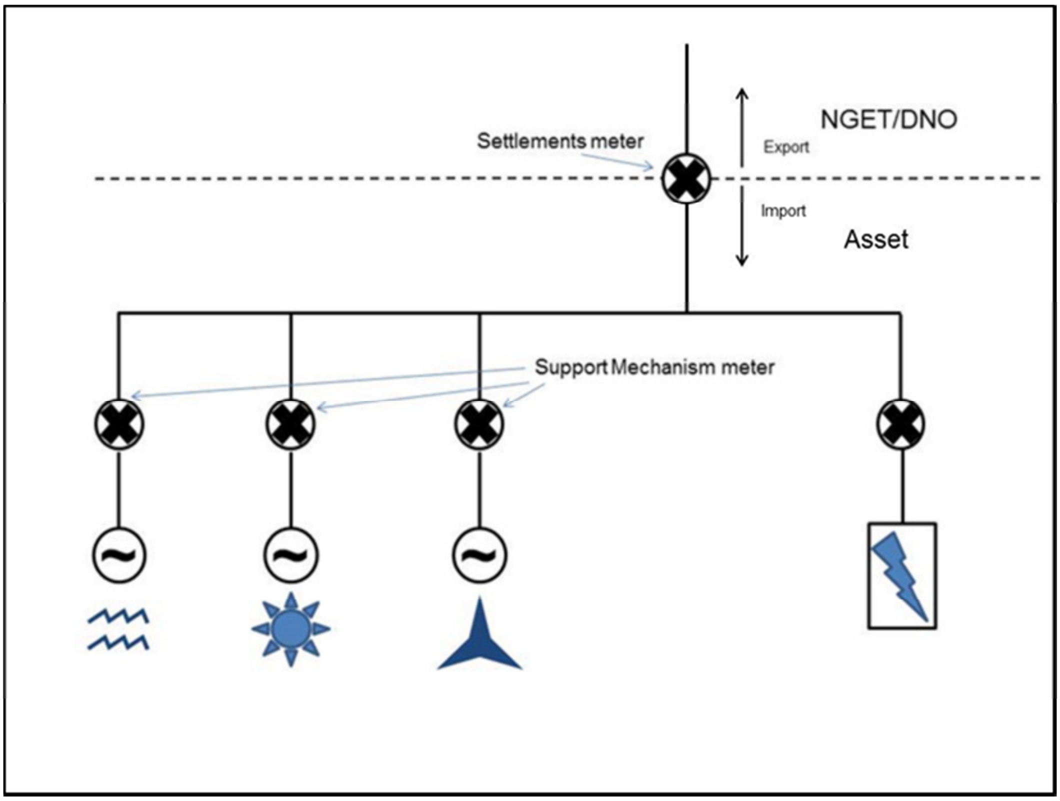


To minimise total system costs, interactions between the "BIG3" markets must be better understood by industry and policy makers and require address in a holistic manner. Innogy also recognises that evolving market dynamics highlights the increasing merit of ancillary service market reform, given the anticipated increase with which the overall power system will rely on this particular market.

Interactions with support mechanisms

A single point of metering is unable to distinguish between the different types of energy (green/brown) generated at different times. We support and would like to feed in to the review by Ofgem and BEIS to resolve this challenge – potentially by using support mechanism meters at a lower level. Please see Figure 5 below that illustrates how this could be addressed.

Figure 5 – Interactions with Support Mechanisms and how to distinguish different types of energy



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?

The current system for balancing and ancillary services has been developed for the participation of large synchronous fossil fuelled generation. It requires market reform to be ensure that the modern flexible system can be delivered at least cost to the consumer.

We believe the call for evidence should consider (a) what the system needs and (b) the best way to provide these in a flexible world with Distributed Generation.

As an operator of onshore, offshore and hydro sites and as a supplier offering and managing aggregation capability we can provide you with an insight into the technical capabilities of our plants. See table 3 below. It should be recognised that a-synchronous generation can be part of the solution in terms of providing flexibility. While the technical capabilities exist or can be unlocked with modification for many ancillary services, the key issue for renewables is the deficiencies or absence of a commercial framework.

For distributed generators one of the clear wins would be enabling them to compete for reactive power services. Specifically in relation to Reactive Power provision for DNOs we would like to support the conclusion of the Smart Grids Forum Storage & DG Subgroup[11] that "3.45….DNOs have a need for reactive power support on occasion.5 Individual DNOs may include reactive capability in a connection agreement, but mandating may not be the most economic and efficient solution. This is because different providers may be more cost-efficient than others, and mandating would not facilitate the development of a more dynamic market for reactive provision. 3.46. In **Action 3D**, we propose reactive power services to DNOs could be enabled by the development of a mechanism, in collaboration with the off-takers of distributed generation, to enable DNOs to communicate to DG and storage, and to remunerate these for reactive services.6

The Report also observes that "3.106. For reactive services from distribution connectees to the TSO, there is currently no provision in the charging methodology or a mechanism for appropriate reward to DG for this service. **Action 12A** notes that NGET should: (i) further update need for reactive power in the SOF and (ii) continue discussions with industry and other stakeholders via the ENA ENFG workstream".

For our DSR and aggregation services, please see question 12 re value.

The cross-system (TSO – DSO) interaction between DSR activity and distributed generation output as a result of TSO enactment of services are not adequately recognised and should influence the ancillary service design to ensure any benefit (or detriment) to the DSO is recognised and compensated appropriately.

[11] https://www.ofgem.gov.uk/sites/default/files/docs/ws6_final_report.pdf

Table 3 Changes needed to enable DSR and Renewables to participate in existing flexibility markets

Service	Description	Key barriers, what would need to change to be able to provide?
Mandatory frequency response	Mandatory Frequency Response is an automatic change in active power output in response to a frequency change and is a Grid Code requirement.	Commercial framework needs to change between DG and DSOs if reconfiguring smaller generators to provide FR is useful. Technical requirements on droop need to soften to accommodate new market entrants
Firm frequency response	Firm Frequency Response (FFR) is the firm provision of Dynamic or Non-Dynamic Response to changes in Frequency.	Need storage and aggregators to be able to compete and also to be co-located with renewables. TSO engaging with the industry to understand the dynamics of the sector in order to value and access the inherent flexibility that is available (when the asset is active) Planned reduction in threshold from 10MW to 1MW in April 2017 is welcomed. Ongoing, slow review of services undermines prosumer / developer
Frequency control by demand management	FCDM provides frequency response through interruption of demand customers.	TSO contracts team have indicated that they will be retiring the FCDM service meanwhile their review of services undermines prosumer / developer confidence
FFR bridging contract	Enabling smaller (<10MW contracted volume), demand-side providers a route to access the FFR tendered market	Bridging terms less relevant as a result of planned reduction in threshold from 10MW to 1MW in April 2017
Enhanced frequency response	A new service aimed predominantly at storage assets to provide frequency response in 1 second or less.	1 second response is too tight for renewable generators to be able to participate in this market. Call for a Fast Frequency Response product – 5 second delivery maintained for at least 10 seconds. Late changes to specification during the initial EFR procurement exercise meant npower activity was diverted on to other projects. The resultant low value outturn suggests that the EFR market is under-valued
Fast reserve	Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt	For wind - wind resource is the barrier here and storage again is the longer term answer. Need storage to be able to compete and also to be co-located with renewables For DSR Current 50MW volume threshold for participation is a barrier to entry

	of an electronic despatch instruction from National Grid.	
Short term operating reserve (STOR)	Short Term Operating Reserve (STOR) is a service for the provision of additional active power from generation and/or demand reduction.	For wind - wind resource is the barrier here and storage again is the longer term answer. Need storage to be able to compete and also to be co-located with renewables Current market dynamics and low tender valuation means any STOR activity is entirely dependent on winter-peak price arbitrage (i.e. Triad Avoidance). A significant proportion of our STOR portfolio will be delivered through BtM Generation as STOR price signals are insufficient for a typical business to cease production when called.
BM start-up	The BM Start-up Service gives National Grid on-the-day access to additional generation BMUs that would not otherwise have run, and which could not be made available in Balancing Mechanism timescales.	Renewables do not sit idle – generators run when it can and therefore will not be suited to this product.
STOR runway	STOR Runway is a contracting opportunity for Demand Side Providers to support the growth of new volume in to the STOR market.	See STOR Notes above
Enhanced optional STOR	This service is where National Grid has a requirement for provision of a volume of an Enhanced Optional STOR Service from non-BM Providers on a trial basis for this winter (which winter? 2016/17?)	Enhanced Optional STOR is competing directly with winter-peak periods (inc Triad) and is therefore not commercially compelling for our DSR client base.
Demand turn-up	Demand Turn Up has been developed to allow demand side providers to increase demand (either through shifting consumption or reducing embedded generation) as an economic solution to managing excess renewable generation when demand is low.	DTU is not commercially compelling for our DSR client base currently but we would expect values to increase over time

Transmission Constraint Management	A transmission constraint arises where the system is unable to transmit the power supplied to the location of demand due to congestion at one or more parts of the transmission network.	Lack of commercial framework
Contingency Balancing Reserve	DSBR is targeted at large energy users who volunteer to reduce their demand. SBR is targeted at keeping power stations in reserve that would otherwise be closed or mothballed. DSBR is targeted at large energy users who volunteer to reduce their demand during winter weekday evenings between 4 and 8 pm in return for a payment. These services will act as a safety net to protect consumers, only to be deployed in the unlikely event of there being insufficient capacity available in the market to meet demand.	N/A
Maximum Generation	The Maximum Generation Service allows access to capacity which is outside of the Generator's normal operating range in emergency circumstances.	
Intertrips	Intertrip services are required as an automatic control arrangement where generation may be reduced or disconnected following a system fault event.	
Black Start	Black Start is the procedure to recover from a total or partial shutdown of the GB Transmission System which has caused an extensive loss of supplies.	evaluate technical requirements to explore the use of multiple embedded service providers as well as individual large transmission connected generation and address the absence of a commercial framework required to justify the investment.
SO to SO	SO to SO services are provided mutually with other Transmission	N/A

	System Operators connected to the GB Transmission System via interconnectors.	
Obligatory Reactive Power Service (ORPS)	The Obligatory Reactive Power Service is the provision of mandatory varying Reactive Power output.	Rather than an obligation a new ancillary service market for Reactive Power Provision should be created. This is in line with the conclusions of Smart Grids Forum WG6. Note: Old machines are not technically capable. New turbines: no commercial/contractual framework inhibits optimising this service.
Enhanced Reactive Power Services (ERPS)	The Enhanced Reactive Power Service is the provision of voltage support that which exceeds the minimum technical requirement of the Obligatory Reactive Power Service.	
Demand Side Response	For businesses and consumers, DSR is a smart way to save on total energy costs and reduce their carbon footprint. Through encouraging greater participation, NG envisages turning an industry problem into a customer opportunity.	Ongoing TSO review of services undermines system development confidence– i.e. risk of developing IT capability for a service which may become redundant or where value could deteriorate

One further barrier to investment in flexible solutions is ‘investor confidence’. Regarding this challenge of providing confidence to invest in flexibility (be that new storage, retrofitting generation or making additional investments into DSR capability.) - Government needs to reassure investors and banks that these market opportunities will be enduring. This is by clearly setting out the system requirements of today and tomorrow and regulating to ensure the services should be procured on a rational, transparent basis.

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

In terms of the ancillary services coordinated by the NETSO we feel a reform to open access to all possible market participants is due. Ultimately, we see the need for an Independent System Operator (ISO) - (please also our response to question 45).

In addition, the era of DSOs could be a real game-changer in unlocking flexibility via proper system value pricing. DSOs working more effectively with the TSO with a common, holistic view to facilitating the establishment and running of ancillary service markets for distributed generation, storage and aggregators to compete within. Unlocking the potential of distribution connected users (both supply and demand) will be essential and the most efficient delivery for this will be through competitive markets rather than the command and control approach that DNOs tend to take at present.

BEIS/Ofgem must commit to delivering key milestones within a timescale as further uncertainty can only be prohibitive to progress and lead to loss of momentum and engagement, particularly where consumer buy-in to flexibility is concerned. This includes legislative and regulatory reform without delays and with as much certainty and upfront information as possible. In order for intelligent investment decisions to be made now, which will be fit for the future, this information is needed as soon as possible and in sufficient detail to promote investor confidence.

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.

npower already offers a wide range of Time of Use (smart) and pass-through contract and tariff structures to non-domestic half-hourly settled customers. However the vast majority of customers (by customer number) still opt for "simple" one or two rate, 'bundled' contract structures.

npower would encourage an Ofgem endorsed industry wide roll-out of more cost-reflective ToU charging structures which would enable customers to understand the explicit price signals that affect their business day-to-day and also ensure all commercial activity (inc DSR and battery storage) is recognised and compensated more appropriately. However we do appreciate that Ofgem may consider this change as an unpalatable effect on customer choice so we would welcome further dialogue with Government or OFGEM to consider potential transitional models and the role of the regulator as an independent "champion" of the benefits.

It is also worth noting that any transition to ToU contracts could have an impact on an end user's profile of cashflow throughout the year and so may also by viewed by customers as a further disincentive.

Third Party Intermediaries (TPIs) also have an increasingly important role to play here and should be encouraged by the regulator to develop their portfolios based on the established benefits of ToU tariffs to their customers. Given that a significant proportion of the non-domestic portfolio are managed and influenced by TPIs we see Ofgem's influence here as an essential enabler to more widespread understanding of the benefits of ToU contracting. According to recent analysis from Cornwall, TPIs control 77% of the I&C market for power sales – and therefore their influence should not be underestimated. This may require less sophisticated TPIs to enhance their price comparison approach and invoice validation role to ensure a variety of ToU tariffs can be accurately compared before they offer guidance to customers.

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.

npower also offer a range of pass-through options to customers and regularly invest in system developments to support the option of passing through of new industry costs e.g. the costs associated with the Contracts For Difference and Capacity mechanism costs. Again, these options are open to all half hourly settled customers but are often not chosen by smaller non domestic customers who prefer to fix their costs to provide greater budget certainty.

As a prudent supplier to non-domestic customers, our preference is for pass-through contracts (these are contracts which show the actual costs associated with all the different Use of System costs, capacity market, RO, FIT, CfD) which also mean we can minimise the addition of any risk premia associated with fixing uncertain and volatile costs **thus offering the end user a better price**. We actively promote pass-through options to our customers, but based on experience, we continue to find that smaller non domestic customers tend to prefer fixed price contracts. npower would encourage an Ofgem endorsed industry wide roll-out of more cost-reflective ToU tariff structures which would ensure all commercial activity undertaken by larger half-hourly metered customers is recognised and compensated more appropriately. Again TPIs need to be in a position to accurately compare a range of pass through options.

With regards to our domestic and microbusiness customers, we believe the most appropriate time for Government / Ofgem to take further action to drive the market to support the take up of smarter ToU tariffs **should only start once the smart meter roll out has completed.** This is to ensure that the fundamental issue of ensuring the installation of millions of smart meters is not derailed or negatively impacted through customers becoming concerned that their costs will increase due to ToU / peak pricing (and therefore refuse to allow the installation of a smart meter).

If there is to be any explicit Government / Ofgem intervention, this should be timed so that the impact of any such intervention will pre-empt/coincide with any decisions on building significant new generating capacity or grid reinforcement. Benefits of flexibility will be greatest at these points in time and offsetting any new infrastructure spending would allow the benefit of flexibility to be quantified.

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?

We note the recent EU Clean Energy Package publication proposals, particularly the proposals for Billing (contained in Article 18 of the recast Electricity Directive), which if enacted, would require more dynamic pricing for all consumers and greater disaggregation of customers' bill components, which may help overcome the current inertia / customer reluctance to consider more sophisticated ToU tariffs.

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?

Broadly yes, we recognise the reasons identified. We would note [for context] that within the call for evidence, the larger non-domestic sector is defined as load profile classes 5 – 8. From our experience, we would consider larger non-domestic customers to be those customers who were already Half Hourly settled (not those PC 5-8 who are or have been impacted by P272).

We note that the issues identified (re a reluctance to accept ToU tariffs / pass through costs) can often also apply to much larger sites. With regards to the assumed barrier relating to the trade-off we do not differentiate cost to serve for pass through or multiple rate structures for larger non domestic customers as we have invested in scalable system capability to manage them. The "trade off" described in the CfE does not influence the tariff structure we offer to the customer, rather we would suggest both TPI influence and customer preference are the key drivers relating to the end user's tariff decision to continue to opt for simple one or two rate tariffs.

PROVIDING PRICE SIGNALS FOR FLEXIBILITY – SMART DISTRIBUTION TARIFFS – INCREMENTAL CHANGE

Please note these overarching comments regarding the options outlined in the Smart distribution tariffs section; both incremental and fundamental change.

<u>We believe that the current distribution tariff design does not and cannot offer a means to ensure a fair or appropriate system of cost recovery. Whilst some incremental changes could deliver some short term "wins" we believe that any ongoing approach based on incremental improvements does not and cannot address many of the key issues facing network companies now and in the future.</u>

We recognise and accept the likely difficulties that will be associated with making fundamental reform of the distribution charges methodology but would urge both Ofgem and BEIS to seriously consider the potential for improvements from a wider systems perspective, rather than seek to address the known flaws and charging issues that result from a system that was designed to manage a different network.

The CfE does not seek to address the differing issues that arise from the different types of cost associated with managing, operating and maintaining the distribution networks, particularly in the future the costs associated with the transition to and acting as a DSO - noting only that a further Ofgem consultation on fixed / sunk network costs will be considered in future.

Whilst we will respond to that consultation in due course, we would suggest that until the issue of non-direct network costs are considered (including in future the roles and responsibilities of Distribution System Operator), it will be difficult to determine how better to ensure more effective pricing signals.

<u>Finally, we believe that the degree of transformation required makes it inconceivable that this could be managed through the existing DCUSA change process, and instead it seems likely that additional powers for Ofgem may be required to deliver the necessary magnitude of change.</u>

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.

<u>Yes. Distribution charges are currently acting as a barrier to the development of a more flexible system, in, both in their design and charging structure.</u> We would also note that some recently approved modifications, including D228 have reduced the size of this DUoS signal for DSR by reducing the differential between time of use rates, thereby undermine the intent to encourage more flexible use of the system and will further discourage larger users (in particular) from considering investment in more flexible products and services.

We are concerned the current Industry changes process hinders development on creating a more flexible system. Large players dominate and often dictate what changes can occur and when. We believe delays in the decision making process can and do hinder innovation, which will likely create additional barriers to delivering more flexibility.

The Common Distribution Charging Methodology (CDCM) was introduced in 2010 – and there has not been anything as big as that since – however, the number and size of incremental changes to the CDCM; have grown significantly.

We would highlight the difference between the CDCM compared to the Extra High Voltage (EHV) Distribution Charging Methodology (EDCM), which provides individual site specific charges for those sites connected to the Extra High Voltage network. There is a potential barrier for storage connecting at this level, given the likely higher costs incurred by a storage site, due to the large import capacity.

In the short term, Distribution charges do act as barrier i.e. local private virtual networks. For example, we have experience of a local council which has both a generation and demand site situated less than a mile apart. The council is liable for the associated TNUoS and DUoS charges, which doesn't take account of the netting off that would be possible within a virtual private network. A virtual private network could reduce their costs and be more cost reflective of their impacts on the system. Overcoming challenges with current distribution methodology would open up more avenues for increased flexibility.

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?

We note that a recent change to the EDCM has already been raised (Modification DCP274) just charging for the export capacity based on the difference between the Maximum Export Capacity and the Minimum Export Capacity, although we do not accept this proposal achieves its intent (to better facilitate competition) as by doing so it would simply distort the market for other forms of flexibility and allow the storage developer to avoid paying the costs of capacity (either import or export associated with the site).

The creation of a local use tariff could help overcome the barriers to increased flexibility by allowing the reduced network impacts of having both local supply and generation reflected in the applied charges, however this would likely result in an increased level of complexity on the associated tariffs to ensure sufficiently granular charging (which, given existing consumer reluctance to more complicated tariffs, may deter take up).

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

<u>The issue of how to address any disparities between the treatment of different types of distribution customer will be best resolved with the full holistic reform of charges rather than another piece-meal change. The aim of the holistic review should be to ensure cost-reflective outcomes.</u>

This chapter separates the issue of low voltage (CDCM) charging from the other network charging arrangements. We feel that a harmonised approach to all network charging should be taken across low, high and transmission level voltages.

PROVING PRICE SIGNALS FOR FLEXIBILITY – 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?

We note the transition in distribution network development from mostly importing power from the transmission system with little need for more active management at the distribution level. There needs to be recognition that in some DNO areas, the distribution networks are now exporting and greater {more active] network management is required (leading to more DNOs becoming DSOs) – with likely changes to the incentives and costs associated with being a DSO rather than a more passive DNO.

We expect that as the need for more capacity (on some networks) increases, this will drive recognition and reward for customers that can provide flexibility, with a greater risk of sunk costs being charged on those customers who cannot avoid them.

Given the fundamental changes in the network structure and the changing use of the system, it is vital to ensure that all parties connected to the distribution system; be they demand, supply or a mixture of both are liable to pay for the services they receive or continue to have access to and therefore ensuring those costs are actually cost reflective of their impact on the network is critical.

How this can be achieved needs to be set out as a priority for Ofgem and BEIS following this call for evidence. It will require a full review of the system and will require some potentially difficult political decisions. However, ensuring that distribution networks are appropriately funded through cost reflective charges for all customers, rather than simply continuing to deliberately socialise costs across the wider customer base will be critical to ensuring proper pricing signals can be delivered.

Similarly, other policy costs, such Assistance for Areas with High Electricity Distribution Costs Scheme), also undermine the intention to ensure   cost reflective charges (in terms of those customers who contribute towards those costs). Increased volumes of behind the meter generation (for example customers with PV who avoid network charges on the basis of reduced consumption) are unlikely to be paying a fair proportion of their costs they actually impose on the network (particularly in those areas where there are local constraints due to high levels of unconstrained export).

A real and increasing risk remains that as more customers avoid the current network charges (through improved energy efficiency and / or use of behind the meter generation), the level of costs (to recover the operational costs of managing the networks and other sunk costs) will be recovered through fewer and fewer kWhs, resulting in a vicious and distortive cycle whereby those customers who cannot afford or do not have suitable properties to install behind the meter generation will pay a higher proportion of the network costs required for the network's operation, despite their relatively low impact on the network.

To meet these future challenges (particularly if the network evolves to develop more local balancing and potentially an ever decreasing charging base, we suggest a fundamental rethink of the charging basis for distributed connected users, with potentially as a minimum, a cost reflective capacity charge per connection type, that would recover the residual costs of the network (irrespective of whether the customer physically uses the network – as unless the customer has physically disconnected, there will be associated costs that should be appropriately paid. Effectively prosumers, even if generally self-sufficient have a 'back-up' service provided to them from being connected to the network.

A volumetric approach to the Use of System charges with fully cost reflective tariffs (which would include peak periods for both demand and export) would facilitate greater engagement with flexible system use.

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?

<u>Long term price signals could be provided through connection charging with medium term pricing signals coming from the costs associated with the operation of the network and short term pricing signals being provided via the DSO.</u>

Distribution tariffs should comprise three key components:

- Those that reflect the cost of system operation via DSO charges (mainly kWh tariffs);
- Those that reflect the location marginal signals via DNO tariffs (mainly capacity tariffs); and
- Those that reflect the recovery of the distribution networks allowed revenue via DNO tariffs.

End user tariffs should include the distribution charges and the pricing signals from the wholesale electricity market. This would ensure, for example, that users have an incentive to reduce consumption at times of peak demand, shifting this to increase consumption when electricity is cheaper. Cost reflective distribution tariffs must work tariffs related to energy prices to provide the most efficient solution for end use customers.

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.

We believe an independent SO would in future be required to ensure there are no conflicts between the needs of the TSO and DSO, We are concerned that a segmented network approach would introduce too many complexities, including commercial sensitivities, particularly if both TSO and DSO were seeking to procure services from a single user – which could cause conflict between the need to resolving both local and national requirements.

<u>We envisage DSO licence area/s to emerge through tender of the DSO function</u>. Note these may or may not end up as one DSO for each DNO (please also see our response to question 45). DSOs would be able to procure services to aid the operation of their network areas. The impacts of their local balancing activity must not conflict with the operation of the transmission network - the ISO would be well placed to ensure coordination of this.

PROVIDING PRICE SIGNALS FOR FLEXIBILITY –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?

A level playing field is needed across all markets to allow the most efficient deployment of all technologies, including storage.

Renewable generation is technically able to offer ancillary services. For example wind is flexible at all operating ranges with a flexible export limit, no ramp rate limit, a diverse capacity and it is available when the system needs are higher. However, the ancillary services market design has a number of barriers which prevents intermittent renewable generation from competing e.g. the tendering process and the need for a long-term guarantee on availability of generation. By developing policies which would enable wind and solar to participate in a smart, flexible energy future by providing these ancillary services, Government would be helping to future-proof the system.

As the CfE makes clear, there is an issue with co-locating storage with renewable sites (particularly intermittent generation) due to support mechanism related regulations. The implementation structures between RO and CfD differ, meaning that a solution for one scheme may not translate to the other. We expect more existing renewable sites to become co-located with storage and it is important that solutions are found that do not compromise the generator's existing accreditation (either under RO of CfD) whilst allowing smarter utilisation of the networks. In the meantime we would recommend that Ofgem produce'Guidance for generators' setting out clearly the factors and considerations that generators should consider in developing storage on sites with existing accreditations.

For new capacity, the CfD design needs to be reviewed to reflect the system benefits of hybrid sites. Policy measures should also be taken to allow a new site to access wider market revenues. This would enable lower CfD bids, provided that the other revenue streams were stable and predictable.

With regards to the comments within the CfE relating to the FIT. We are not convinced that developing time of use export for smaller FIT installation (as noted in the CfE) is the greatest priority in terms of incentivising renewable generation as well as accounting or the costs and benefits of distributed generation on a smart system. We do however note the current work being undertaken by Ofgem to consider the impacts on deemed export through the introduction of smart meters and how in future such export volumes will be measured and settled.

We believe the bigger issue to be resolved remains the distortion regarding the lack of levelisation of the metered export payments (in contrast to the FIT generation payments) – noting that the implications of smart metering will also impact on this issue.

We urgently call for BEIS and Ofgem to reverse the effect of the FITs Order 2013 that removed the net metered export payments from the FIT levelisation fund. Reinstating this would remove the commercial distortion that current Mandatory FiT licensees face; with the resultant higher costs for customers.

It could also facilitate increased innovation by encouraging more voluntary FIT licensees to continue to contract with larger (>30kW) FIT generators, potentially facilitating the introduction of more local balancing / increased flexibility schemes in the future.

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?

<u>It is important that the CM is designed in a manner that is technology neutral. Conventional generation, storage and DSR can currently participate in the CM. However, the participation of RO and CfD accredited renewables is inhibited, failing to enable full use of assets already on the system. We recognise that the penalty regime needs to be improved in order to ensure that variable generation can participate efficiently. De-rating needs to be removed and secondary trading arrangements need revision.</u>

We support EnergyUK's call for a 'functioning, fair and transparent' secondary trading regime for the CM. Challenges include the potential for sudden influx when margins are low but EnergyUK suggest the benefits outweigh the risks. Performance testing and a well-managed brokerage system would enable generators to trade away their obligations when extenuating circumstances prevent their fulfilment. This would minimise costs to generators and therefore consumers as the alternative to such a trade would be use of the balancing market post gate closure which would be significantly more costly.

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 most important change that is required is the development of cost reflective distribution tariffs that properly relate to the costs of system operation, the costs associated with network investment and fair and equitable recovery of the network allowed revenues.

A SYSTEM FOR THE CONSUMER – SMART APPLIANCES

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

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

Yes, we agree with the four principles identified, in particular the need for interoperability to help ensure that in future multiple appliances (and any associated apps) can work together efficiently.

Our research has consistently shown that in order to engage customers effectively with future propositions, relating to connected (or smarter) homes, a key requirement is that the products and services are simple and easy to use – in particular if multiple systems or Apps are used in tandem. If it is complicated, customers do not and will not engage with smarter products and the potential for using their energy more flexibly will not materialise.

Q29) What evidence do you have in favour of or against any of the options set out to incentivise/ensure that these principles are followed? Please select below which options you would like to submit evidence for, specify if these relate to a particular sector(s), and use the text box/attachments to provide your evidence.

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

It is our position that further home appliances are smart technology enabled and can enable customers to operate these remotely will enable further energy innovation relating to specific Time of Use tariffs, usage consumption and related products and services.

From a consumer and industry perspective, when customers purchase these devices it would be helpful if it is explained what works with it (e.g. what works with Nest, what works with d-link, compatible and non-compatible products) to avoid consumers buying smart devices/appliances that cannot communicate together and provide a more enhanced eco-system.

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)**

In early 2016, npower's Energy Risk Management department conducted internal research, overlaying the original findings from its 2010 smart meter trials with the costs and profiled use of different appliances / power usage patterns. The results from this internal study strongly match the findings of research published by Smart Energy GB and the Low Carbon London trial in 2014, i.e. that wet appliances (washing machines and dish washers etc) were the activities where domestic consumers felt they could be more flexible around their behaviour. Activities linked to a fixed routine (such as boiling a kettle, cooking, lighting) were deemed to be inflexible and less easy to adjust. However, the assumed level of incentivisation required to deliver the flexibility was seen to be far higher than the likely savings that could be realised through shifting the consumption period from a peak to an off-peak period.

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

Cost of the appliance (if non-smart alternatives are allowed to continue to be sold, with the risk of distorted markets and social impacts if lower income / vulnerable customers are not able to access the opportunities (or pay for the costs avoided by those customers who can).

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

We would also recommend that Government and Ofgem continue to engage with consumer advice stakeholders, in particular Citizens Advice given the need to ensure that vulnerable customers are appropriately supported to remain engaged, noting that the issues that may arise extend beyond the role and responsibilities of energy suppliers. We would also note our response to questions 9 and 40 (relating to consumer protection and regulation options).

A SYSTEM FOR THE CONSUMER - 3b ULTRA LOW EMISSION VEHICLES

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

Government and industry might better engage electric vehicles through the use of consistent policies to support low emissions vehicles (in particular EVs). Continuation of funding for innovative solutions and / or grant funding for charging point installations would also support the wider roll out of EVs. However, (please also see our response to question 15), until the roll out of smart metering has completed and mandatory HH settlement implemented, there are unlikely to be significant opportunities for EV users to benefit from (or provide support through their EV charging regime).

It is will be important to ensure that the primary purpose of EVs (that of low carbon/ low emission transportation) is not undermined, and the potential benefits of EV ownership in order to offer services to grid are not over-stated.

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?

As per our response to question 33, until smart metering has completed and HH settlement introduced (with the attendant ToU tariffs) we believe barriers will remain barriers to the take up of smarter ToU tariffs and propositions specifically targeted at EV owners.

There may also be issues of relating to the ownership of or access to the charging point (which may facilitate the vehicle to grid charging) – we would recommend these and similar issues be considered now, in advance of the wider take up of EVs

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

The major barrier is cost. Methane reformation is a much cheaper source of H2, even with Carbon Capture and Storage.   Battery storage is probably a lot cheaper than H2 production, although the latter gives longer term storage.

A SYSTEM FOR THE CONSUMER - 3C) CONSUMER ENGAGEMENT WITH DSR

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

The DSR community (including npower) have actively marketed DSR for a number of years and the larger non-domestic customers have successfully engaged and participated. National Grid's Power Responsive campaign and specialist industry publications (inc Utility Week and Energyst) have dedicated significant copy to the whole balancing services and DSR agenda over the last 24-months. We believe this often results in leads generated from Grid's shortlist of Commercial Aggregation Service Providers http://www2.nationalgrid.com/UK/Services/Balancing-services/Demand-Side-Response/

In addition to the research published by Ofgem in October, npower has recently launched its Energy HQ proposition, whereby npower, will provide a comprehensive range of services and products to larger I&C customers, which includes (but is not limited to offering in-house DSR aggregation services, portfolio optimisation and advanced real-time metering, reporting and analytical tools). To date, this approach has generated significant customer interest and we believe this will provide another route for customers to gain information and insight into the opportunities, likely costs and benefits of investing in or utilising existing assets to provide flexible services.

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?

Yes, we recognise these barriers and would also raise the issue of:

(a) the ongoing uncertainty regarding future Transmission Use of System charges (Triad avoidance is a significant financial motivator due to the strength of the price signal

(b) recent changes to distribution charge models (reducing the time-of-day price signal differentials)

(c) the TSO's declared, but unfulfilled consolidation of balancing products (consolidating the range of products) – undermining confidence in investing in the correct service capability

(d) burdensome Capacity Market administration

(e) Behind the meter generation (BMG) is currently considering the consequences of DEFRA's current review of MCPD emissions and this resultant uncertainty further undermines confidence in the DSR sector

(f) frequent policy interventions.

As an active supplier and DSR aggregator we believe the value of the aggregation community is delivering an overarching commercial operation that optimises revenues / cost avoidance opportunities for a single flexible asset – meaning that business customers can focus on their day jobs while a specialist manages DSR responsibilities.

It is therefore alarming that this call for evidence refers to *"wider opportunities for engaging in DSR, such as contracting directly with DNOs"* which undermines the value of DSR as it:

- adds yet another counterparty in to a large non-domestic customer's scope, creating further confusion
- a bilateral, single service is unlikely to recognise and reward the full value of the prosumers flexibility. A specialist aggregator with a wide pool of value to access is best placed to optimise.
- a bilateral service with the DNO, resulting in behavioural change of the consumer could expose the supplier to additional costs (which may result in compensation from the prosumer), please also see our response to question 7.

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?

We agree that the existing initiatives provide an appropriate means to engage with larger customers, however we believe more must be done to highlight the opportunities of DSR. That said (as per our response to question 7), the ongoing lack of clarity regarding future Use of System charges, recent changes to distribution charges (through D228) and the frequent interventions within energy policies has created significant uncertainty, which must be addressed.

We remain hopeful that the intended milestone document (to be published in Spring 17) will commit this and future Governments to the delivery of a smarter, more flexible market that customers can see the benefits of participating within. A large part of this will be the frameworks developed to facilitate closer coordination of products and services between the SO and DSOs as well as the development of fair and predictable system costs, which enable larger users to appropriately plan.

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)?

Given the peak roll out of smart meters for both domestic and smaller non-domestic customers is expected in 2019, (following the potential decision to proceed with HH mandatory settlement for all customers) we believe that would be the most appropriate time for Ofgem, BEIS and other key stakeholders (such as Smart Energy GB) to consider including more information on the opportunities and benefits of becoming a more active participant, rather than a passive consumer of energy.

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**

Please also note our comments in response to question 9 regarding consumer protection.

From a consumer perspective it is important that customers are treated fairly. This principle is one of the cornerstones of the Supply Licence. Where time of use tariffs are offered by suppliers domestic consumers will be protected through the existing Supply Licence conditions. These ensure that customers are protected from miss-selling and are fully informed of the arrangements they are entering into. The supply license also places obligations on suppliers to ensure that consumers have appropriate cooling off periods, communications and billing are clear, and that staff are appropriately trained and monitored. Vulnerable consumers including those facing financial hardship are also offered clear advice and protections under the supply licences.

In considering the development of new or novel DSR or aggregation services that do not require the provider to hold a supply license it is important to replicate similar protections for domestic consumer that are currently afforded by suppliers. This becomes especially important to customers that may be in a vulnerable situation where their ability to alter the pattern of their demand may result in an inability to respond to price signals.

We also agree and welcome the commitment of Ofgem to undertake further research into the wider social impacts of DSR and future flexibility services. This should also cover the distributional effect of the benefits of these services to ensure that policy design can focus on delivering benefits to consumers in the widest sense and in line with Ofgem's recently published regulatory stances.

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

We already operate a risk –based approach to security within npower and innogy with iterative risk management and control selection and implementation. Mandated security standards are under consideration within the EU as part of the new cyber security law for ICS ad SCADA systems, these standards will likely require certification against ISO 27001.

There are already minimum standards for security that apply to suppliers, generators and distributers of energy, and minimum standards that equipment must adhere to (e.g. meters etc.) – these are usually bundled up into the relevant licence obligations.

We believe the main risk that exists in the Smart Home today would be the number of disparate and potentially unpatched In Home Devices that customers\users may connect to their home network. Smart fridges, kettles, Amazon Echos (other brands are available!) etc. that may give an attacker a way to compromise other aspects of the in-home system including the energy system.

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

The main risks to highlight in terms of security in the energy system would be:

- Loss of Persona Identifiable Information (PII) data through insecurity of the in-home system (without controls - impact: high, likelihood: high)
- Loss of energy supply to a home\homes due to malicious behaviour in the upstream system or the in-home system, leading to vulnerable customers being without power. (without controls - impact: high, likelihood: medium-high)
- Instability on the Grid due to multiple homes being disconnected from supply simultaneously. (without controls - impact: high-devastating, likelihood: medium-high)

Without any system controls, these risks would have a high-devastating impact and a medium-high likelihood on wider industry.

However, it is worth noting that we have implemented controls in our systems commensurate with the level of risk due to both the industry-level security requirements (which are part of our Supply Licence and Smart Energy Code (SEC) obligations) as well as our internal risk assessments.

THE ROLES OF DIFFERENT PARTIES IN THE SYSTEM AND NETWORK OPERATION

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

Some elements are missing from this depiction of the emerging system requirements and drivers. Increasing interconnection and becoming further integrated into a European energy market are additional key drivers for system change that are missing. BEIS must also reflect on the changes coming in via Project TERRE (Modification P344).

While DSOs are flagged as an immediate action – the current RIIO-ED1 does not accommodate the role of the DNO to move to that of a DSO. Indeed this has been parked to RIIO-ED2, commencing in 2023. We question BEIS and Ofgem - should the current price controls be reopened and/or a separate regulatory allowance be made for DSO activities?

We should rapidly move beyond Active Network Management (ANM) and other trials to create a more open, holistic ancillary services markets to satisfy the combined/ [mutual] needs of the DSO and TSO.

It will be important (to avoid duplication of resources / costs) that in future any procurement mechanism (such as that envisaged under Project TERRE) can be expanded or made accessible to those DSOs seeking to contract flexibility services, so as to ensure:

a) a level playing field, ensuring any resultant imbalances are "made good" and the supplier position kept "whole" and
b) products and services are appropriately designed to maximum the opportunities for flexibility.

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?

Whilst we would look to the DNOs, TSO (through their System Operability Framework and Network Options Assessment) and the ENA to provide data and evidence of the current scale and cost of system impacts, we believe that there is an issue with an ongoing lack of transparency and clarity of the complex dynamics influencing different parts of the networks at different times (of the day / year) or under different weather conditions which we know can create network congestion and/or 'non-build' opportunities supportable through DG, storage or DSR flexibility.

The current opaque model and system planning activity has created a model that can inhibit development of renewables and other forms of DG and whereby the DNOs can seek to charge developers potentially unnecessary and sometimes prohibitive reinforcement and protection costs. This issue is as a result of some of the 'more established' legacy network planning models continuing to assume that all connected DG could under 'worst case scenarios' be producing power at all times, including wind and Solar PV (recent commentary suggest continue to assume 24/7/365 for solar PV generation).

A more co-ordinated, open approach to managing local and regional network dynamics should be able to produce more efficient outcomes, delivered by the market and avoid unnecessary reinforcement work (or costs being born by the marginal plant).

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?**

Yes, we fully support closer DNO-DSO-NETSO-TO coordination.

Such coordination needs to become standard and needs to bring visible benefits to users. Today we are far from this and suffer from a lack of basic coordination. For example between different TOs (e.g. in the agreement on appropriate expansion factors used for sub-sea cable costs this lack of coordination has led to TNUoS price shocks for generators). Another example is the weak coordination between DNOs and TOs for outage planning.

There is also the example of the way certain DNOs [inc WPD & UKPN] failed to recognise the impacts of incremental increases in Distributed Generation (DG) that has now led to the situation that due to constraints on their network and that of NGET, they will not accommodate any further generator connections.

We would note some concern regarding the expectation that the current DNOs will automatically transition into becoming DSOs. We are unclear as to why this assumption would be made and indeed whether the potential for a broader DSO role; (contracting counterparty) could be developed, to reduce any potential conflicts arising from the need for more active network solutions are fully integrated into investment planning.

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?**

We feel that the full separation of the SO role from National Grid via the establishment of an ISO would be an important step in ensuring that coordination with the ISO leading in terms of establishing whole-system-network investment priorities.

We agree that further progress is both necessary and possible over the coming year, although we would note ongoing delays in the existing formal change fora and would then suggest that direct and unambiguous messaging from both BEIS and Government on the importance of delivering these changes would be very helpful.

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

We note the recent notification from Ofgem relating to the intended publication of the incentive for the System Operator from 2018. We are unclear as to how Ofgem intends to consult on the appropriate incentives, if there are likely to be additional changes in their role / responsibilities for more collaborative working.

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?

Yes, we do believe further changes will likely be required as more active network management is required and more opportunities for consumers to respond / provide flexibility services.

We believe a redefinition of current role and arrangements will be required to ensure there is clear accountability and governance. This should also ensure there are no conflicts of interest and a level playing field for all market participants. A fair and cost reflective {charging] model will need to be implemented and active participants need to be accountable for their actions i.e. a DNO should create the market for flexibility rather than enact DSR events bilaterally (exposing the supplier and consumer to financial exposure).

The three models proposed in Figure 2 of the CfE: 'DSO/SO Procurement Mechanism'; 'Market Signals and Arrangements' and the 'Responsibilities in System Operation' all appear plausible and each has their own merits, specifically: the 'DSO/SO Procurement Mechanism' appears at first sight to be the most simple to implement (and its application potential within the Project TERRE process) but the 'Market Signals and Arrangements' appears to reflect the efficient balancing model that prevails in the Netherlands (which is not dissimilar to GB in terms of climate, consumers and generation dynamics).

However we need to be mindful of the balance between significant changes that are economically reasonable, and can be delivered in a realistic timescale whilst also recognising that some fundamentals need to be addressed to future-proof GB system operations.

The associated tariff development and changes need to be managed to minimise sudden price shocks to less-sophisticated consumers, we believe the prospect of greater coordination and planning of network requirements and charging in future is a further illustration of the need for Ofgem to undertaken a full significant code review to identify, understand the wider context of proposed changes to network charging.

That said, whilst we note the current 15 month notice period does mitigate some of the risk associated with changes to DUoS tariffs, there are likely to be longer term investments under consideration that could be impacted The earlier regulatory and proposed policy clarity is available, the better.

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

- **I. whether the models presented illustrate the right range of potential arrangements to act as a basis for further thinking and analysis? Are there any other models/trials we should be aware of?**
- **II. which other changes or arrangements might be needed to support the adoption of different models**
- **III. do you have any initial thoughts on the potential benefits, costs and risks of the models?**

We note the models shown in Figure 2 (page 80 of the CfE - in particular the DSO / SO procurement mechanism –may offer a close correlation to the proposed mechanism for the Project TERRE procurement system – if those proposals proceed.

We would suggest that at the publication of the P344 working group report – further consideration be given to any additional costs that would be required to facilitate the development of access for procurement activities from future DSOs (or single DSO entity).

INNOVATION

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

LCNF and the Network Innovation Competitions have produced a number of extremely useful project outcomes and the open reporting should be applauded. npower have been involved in several schemes over the years. Again further funded developments should aim to focus on more explicit issues – so whilst certain DNOs have delivered real change through innovative solutions (reflecting the stress / congestion in their network), other DNO schemes appear to have lost sight of value and delivered against less tangible issues with 'softer' results.

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.

Please see our responses below to the suggested right areas for innovation funding support:

Commercial and residential automated Demand Side Response (DSR) trials

Further funded trials to address the limited commercialisation of DSR in the residential and Small and Medium Enterprise (SME) sectors are unnecessary. The DSR market is relatively immature and the focus of the sector has been on the delivery of flexibility through larger industrial and commercial customers' assets – typically in multiples of over 500kW due to conventional business/commercial efficiencies. Evolution of capability, pushing down through the market towards small businesses and residential customers will appear naturally via the market as SMART metering and DSO/SO requirements are established i.e. in a market where flexibility is valued at c£30,000 per MW per annum, DSR is much less tangible to a 2kW Residential or a 20kW SME customer (where they could receive £60 or £600 per annum respectively).

The sector does have issues with complexity and cost of developing DSR products and services but also lacks confidence in stable product specifications, reward, regulatory vagueness and U-turns.

Flexibility trading/optimisation platforms

We would require further clarity in relation to Ofgem objectives:

The DSR community has developed rapidly over the last 5-10 years in the UK and Europe and has successfully created a number of innovative platforms for the current suite of balancing services. The implications of this section appear to support development of a **single, central hub** to manage a pool of flexibility requirements accessed by service providers.

While there may be some efficiencies associated with this central hub model, Ofgem/BEIS risk jeopardising confidence of those businesses that have invested heavily in their DSR businesses and could appear to be seeking to "pick a winner", which would run counter to the aims of the innovation funding.

Vehicle to grid demonstrations

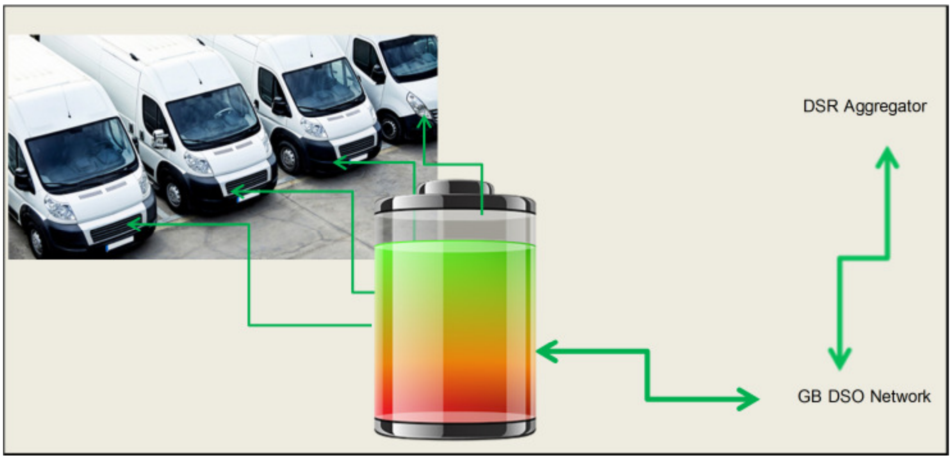
We would suggest that any commercialisation of Vehicle to Grid flexibility will initially be based on optimising scale e.g. an aggregator accessing fleets of EVs or an entire estate of public access EV-charge points.

We would encourage an EV, local community (or business depot) battery charge hub trial to develop commercial models and better understand technical efficiencies i.e. rather than a single EV plugging in to the grid – a larger number of EVs would connect to a large, centralised, battery hub . If established, the vehicles would recharge from the power stored in the hub-battery while the DSR solution provider would also use the hub battery as a commercial device available **<u>at all times</u>**:

- for EVs to connect to and take charge for conventional e-mobility
- as a single, large efficient device for
  - +/- price arbitrage
  - +/- reserve and/or frequency services
- Noting that the 'hub battery' model would be permanently in location and therefore of more value to the DSR provider and SO (when compared to the individual EVs which may only be on site for a limited number of hours per day).

Please see the illustration of this proposal in Figure 6 below.

Figure 6 – Battery Hub Model



Noting that the value of flexibility from EV-to-grid services would otherwise need to accept that the discharge/charge dynamics are less influenced by price arbitrage but should instead reflect the battery depreciation associated with n+1 charge cycles (which may also compromise vehicle warranty), the above model seeks to avoid this issue.