Renewable Energy Systems Limited
Beaufort Court, Egg Farm Lane, Kings Langley
Hertfordshire WD4 8LR, United Kingdom
T +44 (0)1923 299 200, F +44 (0)1923 299 299
E info@res-group.com, **www.res-group.com**

Date: 12/01/17
To: smartenergy@beis.gov.uk

Dear Sir/Madam

Written response to the BEIS & Ofgem call for evidence on a smart, flexible energy system

RES is one of the world's leading independent renewable energy companies working across the globe to develop projects that contribute to our goal of a secure, low carbon and affordable energy future. We develop, construct, finance and operate onshore wind, solar PV, transmission network and energy storage assets. In over three decades of operation, we have developed 10% of the UK's onshore wind capacity and 12GW of wind globally, developed 1.3GW of solar PV globally, built over 1,600km of transmission network outside the UK, and become a world leader in energy storage. We have used that storage experience in the UK to work closely with NGET to develop the new Enhanced Frequency Response service.

We welcome the work done by BEIS and Ofgem in promoting the flexibility agenda and that "enabling a smarter, more efficient energy system is a priority for government". We welcome this call for evidence and are grateful for the opportunity to contribute to the discussion. We believe our position working across generation, storage and networks means we are well placed to provide an informed opinion on the issues presented.

Whilst we recognise that this call for evidence covers a wide range of topics, much of our feedback concerns electricity storage. Electricity storage can be delivered at scale today with no subsidies, provides a versatile and low cost solution to real and increasing system operation challenges at distribution and transmission level, and enables a low carbon future at least cost to the consumer. We believe it is a key enabler of GB's secure, clean and affordable energy future, and strongly support the removal of barriers to its deployment.

Our response contains detailed answers against most of the call for evidence questions. A number of key themes arose in our responses which we have highlighted here:

- **We welcome the commitment to a delivery plan – the timeliness of progress and barrier removal is critical to the success of the flexibility agenda**. The plan needs to:
    - Define clear milestones and objectives, recognising urgency in removing barriers for storage.
    - Ensure clear ownership for the coordination of these complex regulatory and policy changes across all parts of the existing electricity market framework.
    - Incorporate a framework to monitor progress along with key performance indicators. An important consideration here is the necessary transparency for investors to manage policy risk associated with complex reform processes.

- **We welcome the commitment to remove barriers to market entry for smart flexible technologies**. The most important enabler to the removal of storage barriers is the rapid confirmation of an accurate definition that clearly differentiates storage from demand and generation assets. For next steps, we would encourage BEIS and Ofgem to:
    - Confirm the ESN definition of 'energy storage' and your intention for this to be used across policy and regulatory development until such a time as an appropriate licence regime can be defined. An open letter to industry stating the chosen definition, published in the timeliest manner possible, could be a suitable method of doing this.

- Confirm that Final Consumption Levies are only intended to be charged on the basis of net consumption, i.e. true end use consumption, for energy storage. An open letter to industry, published in the timeliest manner possible, could be a suitable method of doing this.
- Waste battery regulations present a further barrier - the potential liabilities placed on individual developers could significantly increases overall costs unless an industry-wide solution is found.

Additionally, we encourage BEIS to set out a strategy for embedding flexibility provision in planning frameworks, such that:

- Devolved administrations can capture and support low-carbon flexibility in national planning policy
- Local administrations are encouraged to consider low-carbon flexibility in local development plans
- EIA regulations are clarified for electricity storage, principally projects larger than 1 hectare.
- Careful consideration is given to the threshold for storage to be considered national infrastructure.

• **We welcome the commitment to reform market signals and incentives to encourage the delivery of the optimum mix of flexibility technologies**. The following key activities would significantly facilitate this objective:
  - An urgent review of the procurement of ancillary services by the Transmission System Operator, with a view to offering a longer duration, better coordinated services which permit ‘stacked’ offers.
  - Flexibility providers will increasingly be located on the distribution network, yet their services can be useful to the DNO, TO and SO. It is essential to coordinate of the needs of these network licensees to avoid unreasonable contract restrictions which prevent a service provider from assisting other licensees in times of need.
  - Similarly, flexibility services should be given due consideration in optimised system planning.
  - Immediately trial active distribution network services in place of traditional network reinforcement. Such trials should incorporate investable service contracts with commensurate terms. Vastly improved coordination between DNO and TSO is required for successful implementation and prevent wasted resource.
  - Initiate a holistic review of transmission and distribution network charging, with a view to highly visible, transparent and low-volatility price signals which can best enable long-term solutions such as electricity storage. Continued piecemeal charging modifications with no holistic oversight will not achieve this.
  - Implement changes to capacity market rules to appropriately cater for new flexibility services, such as EFR, in coordination with updates to the TSO’s applicable balancing services.

• Any reforms to bring about flexibility must be cognisant of the actual system integration costs of the various generation technologies, and hence the value and need for timely provision of flexibility. As such we commend the recently published E3G report “*Plugging the Energy Gap*” based on analysis by Imperial College, which shows that even moderate levels of flexibility delivered in a timely manner can permit over 45% of GB’s electrical energy needs to be met from renewable sources with relatively small integration costs.

We look forward to continuing the discussion with yourselves and the development of this work. Please do not hesitate to contact us should you have any questions or if we can be of any assistance.

Yours faithfully,

Patrick Smart
Head of Energy Networks
RES Group
E : patrick.smart@res-group.com
T : +44 (0)191 3000 452
M : +44 (0)7500 229 648

Dr. Graham Pannell
Energy Networks Lead – RES Group
ENA DG-DNO Steering Group Vice-Chair
E : graham.pannell@res-group.com
T : +44 (0)1923 299 492
M : +44 (0)7824 349 600

RES Response to the BEIS & Ofgem call for evidence on a smart, flexible energy system

Introduction

1. Delivery of a secure, affordable decarbonised power sector at least cost to consumers is of paramount importance to the UK economy and all recent evidence highlights the importance of ‘smart flexible’ services in realising this outcome.

2. For the foreseeable future, the current electricity market arrangements cannot be relied upon to deliver the necessary and desirable investment in new-build assets. With between 130TWh and 160TWh of generation assets retiring in the 2020s, it is clear that we need further market reforms that will ensure the right investment is taking place. There is a growing body of evidence that clearly highlights the urgent need for smart flexible solutions, such as DSR and storage, in order to facilitate increasing penetrations of low carbon generation.

3. The recently published report by E3G and Imperial College[1] highlights that whilst only a moderate amount of smart flexibility is needed on the system before 2030 to avoid high system costs this must also be delivered in a timely manner to avoid short term costs spikes.

4. The recently published Carbon Trust and Imperial work[2] provides the beginning of picture of what an optimal mix of flexible technologies looks like and is a valuable addition to the evidence base, despite the generation input assumptions being misaligned with the most recent evidence on generation costs and current levels of renewables deployment.

5. We therefore welcome this detailed and considered Call for Evidence (CfE) and the intention to define a clear delivery plan. We strongly encourage BEIS and Ofgem to make sure this plan is set within a broader vision of a holistic electricity market reform with clearly defined responsibilities and which is coherent with the objectives of this CfE.

6. Additionally, in light of the importance that Smart Flexibility is rolled out in a timely manner, we look forward to a clear delivery plan with key milestones, success indicators and timely, measurable goals alongside an industry strategy which looks beyond 2030, to best equip industry to meet the challenges at least cost.

---

[1] Plugging the Energy gap, 15/11/16 - https://www.e3g.org/library/plugging-the-energy-gap
[2] An analysis of electricity system flexibility for Great Britain, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf

Chapter 2: Removing Policy and Regulatory Barriers

Enabling Storage

1. Have we identified and correctly assessed the main policy and regulatory barriers to the development of storage? Are there any additional barriers faced by industry? Please provide evidence to support your views.

7. We welcome BEIS and Ofgem's work to investigate and remove barriers to storage and other sources of flexibility. We agree that the barriers listed in the call for evidence represent barriers to the development of an effective market for energy storage. We have further identified the following additional barriers:

1.1 **Waste liabilities**

8. Current waste battery regulations place a potentially large financial liability on storage developers through the requirement to take back, free of charge, batteries already on the market (even if sold by a different party, and of a different scale and technology to that sold by the developer). For each developer, this financial liability is only limited by total market size. Our experience is that the supply chain will not take this liability on, meaning that developers are carrying this whole liability. This is not economically efficient and will increase the cost of projects, either through increased cost of capital (to cover the risk of these liabilities) or the cost of insurance to mitigate the risk. We support the overarching requirement that requires responsible treatment of batteries at the end of their life, but believe that this current legislation does not implement that requirement in a way that is efficient, least cost to consumers, or reflective of an individual party's impact. Battery suppliers are best placed to deal with end of life disposal at the least cost. We expand on this point in ***Appendix A - Waste Batteries and Accumulators Regulations 2009***, which is an explanatory note on this issue.

1.2 **Ancillary services for System Operation**

9. Another key barrier is the way that most ancillary services are procured by the System Operator (SO). The SO has historically procured ancillary services from large transmission-connected generators and the processes to do so are designed in this regards. Given the changing generation mix, the SO will increasingly need to procure ancillary services from numerous smaller distribution-connected services providers such as storage and DSR. Additionally, ensuring best value for money requires open competition between all market participants. Other than the new Enhanced Frequency Response (EFR) balancing service, the Ancillary service market and how these services are being procured has changed very little in principle and this is an issue for providers of Smart Flexibility. A holistic review of these services is required.

New market entrants require appropriate contract terms

10. The first issue arises from the duration of ancillary service contracts. Most SO ancillary service contracts are 1-23 months in duration. This has worked well when the SO has been buying services from parties who have a separate underlying long-term revenue stream (i.e. long established conventional generators). However, going forward, the lowest cost source of ancillary services is likely to be dedicated service providers; this was well evidenced by the EFR results which showed that new build storage was under half the cost of NGET's alternative service providers. In order to encourage these low cost sources of ancillary services in sufficient volume as to create an effective market to the benefit of consumers, contract durations for new build assets need to be longer than the 1-23 months currently offered. One positive example is new EFR capacity which is contracted for 4 years. However, if the SO continues to offer shorter term contracts, then low capex high opex solutions (e.g. diesel) will be favoured – whilst these seem lower cost when viewed over the limited timeframe of the contract, their high opex means they are poor value for consumers when viewed over the medium and long term. Studies show that the electricity system will need increasing amounts of flexibility on

an enduring basis. Reflecting this requirement in the SO ancillary service procurement strategy is likely to bring flexibility onto the system and at long term best value for consumers.

11. We welcome the example set by the Capacity Market Transitional arrangements, which recognise that new DSR capacity is highly desirable for the long term benefits but requires differential treatment in the short term - it is under the same principles that we consider longer term contracts for new market entrants to be appropriate.

SO funding arrangements

12. The current SO funding arrangements discourage NGET from taking a longer term view in procuring ancillary services. Specifically, we believe that one barrier to the SO issuing longer term contracts is that their Balancing Services Incentive Scheme (BSIS) is currently only of one year's duration. Given the funding uncertainty for NGET beyond the end of this period, it does not incentivise NGET to enter into longer term contracts. Ofgem should incentivise the SO over an appropriate period to better facilitate value delivered over the medium and long term.

Misaligned procurement of ancillary service

13. The procurement of different services by the SO are not aligned, with any benefits and efficiencies of a coordinated approach overlooked. A simple step would be to align the start date and contract terms of different services. This would enable service providers to bid for multiple services at the same time and enable lower cost 'bundled' service offerings to be made. This is a win-win: the service provider has a lower risk business model and the SO gets lower cost services. We believe that the SO does not require regulatory or legislative changes to implement this, although a longer term BSIS might encourage SO thinking around these efficiencies.

1.3 Monitor and value constrained electricity generation

14. Under existing connection agreements, the great majority of distribution generators, and many transmission generators, have connection arrangements where they are constrained off at no-cost. In doing so the cost of network constraints is internalised to the cost of generation and no clear price signal emerges to inform network investment decisions, or in this case a price signal that flexibility providers could respond to. We believe it is important to monitor and measure the energy that is being lost through these constraints. Without visibility of this lost value, it can't be determined whether network reinforcements or flexibility solutions would represent better overall value. This issue is particularly important for DSOs to make informed decisions on network solutions, as distribution constraints have no established precedent for constraint measurement.

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

15. As Vice-Chair of the ENA/DNO-DG steering group delivering on Ofgem's *Quicker and More Efficient Connections* we are actively supporting the work noted in the Call for Evidence. The steering group's work has highlighted a **major issue of underutilised capacity**, where DNOs have little authority to recover unused capacity for use by new applicants (such as storage). UKPN, for example, provided data showing **more than 55% of capacity 'contracted out' by operational generation remained completely unused**[3], and is therefore a barrier to new connectees. More support from Ofgem is required on this issue specifically.

[3] http://www.ukpowernetworks.co.uk/internet/en/our-services/documents/dg-customer-forum-25022016.pdf

16. There is an absence of useful up-front quantitative data to help **assess constraints arising from a new connection**[4], whether a 'flexible' or a more traditional connection. Such uncertainty hampers deployment of storage, and prevents entrants from identifying where storage can best support the network. The DNOs, through the ENA, should be obliged to prioritise and establish a common best practice for such information provision which could be delivered within a year.

17. There was a disconnect between National Grid's first EFR tender (total 201MW) and formal applications to connect to DNO networks to deliver EFR (totalling several GW!), this resulted in a misuse of DNO resource; we therefore strongly support the greater alignment of SO and DNO to avoid such mistakes, as described in the CfE.

18. On the theme of best use of DNO planning resource to best progress new projects such as storage, we also strongly re-iterate our support for the reintroduction of Assessment and Design fees ("A&D fees"), as set out in our response to the DECC call for evidence on A&D fees, issued in March 2016. The absence of a reasonable and cost reflective charge to obtain an offer of terms to connect from an electricity distribution licensee is leading significant volumes of spurious applications resulting in significant cost to the consumer.

19. We would also highlight that **distribution** connected or "embedded" storage plant is subject to a **"deep" connection charging regime**, which means that they are typically exposed to a proportionately far higher up-front connection charge than equivalent plant connecting at transmission voltage[5] [6] – such embedded plant have therefore already made a significant contribution to network costs, with proportionally less remaining network cost recovery to effect useful operational cost signals. This is both a distortion between transmission and distribution plant and a hindrance to effective system operation. This provokes the need for a holistic review of transmission and distribution charges (both UoS *and* connection charges) as they apply to all users of the total system, rather than narrowly scoped interventions[7].

3. Have we identified and correctly assessed the issues regarding storage and network charging? Do you agree that flexible connection agreements could help to address issues regarding storage and network charging? Please provide evidence to support your views, in particular on the impact of network charging on the competitiveness of storage compared to other providers of flexibility.

20. On <u>Storage and network charging</u> - there is considerable uncertainty, lack of visibility, no reliable way of interpreting a new Extra High Voltage (EHV) project's future charges – and even if so, such charges can be changed by an order of magnitude by the actions of other existing and new users of the DNO system. As a case study, we set out these observations in a presentation to DCMF in January 2016 (minutes available from DCMF website[8]), which showed that the current charges are: i) <u>not</u> reflective of a user's impact on the network, ii) do <u>not</u> signal a user to operate in a manner useful to the network and iii) are <u>not</u> transparent, such that estimating a new site's charges in advance is practically impossible. This all points to the need for a review of these tariffs, a point we discuss in our answers to questions 19-25 under chapter 3.

21. The current charging methodologies incentivise providers of flexibility to locate in areas *without* constraint. Any future structure must provide confidence (in terms of value and minimum contract length) of flexibility

---

[4] Ofgem consultation and RES response to the 2016 Incentive on Connections Engagement: https://www.ofgem.gov.uk/publications-and-updates/consultation-distribution-network-operators-2016-submissions-under-incentive-connections-engagement

[5] RES response to Ofgem Embedded Benefit open letter https://www.ofgem.gov.uk/publications-and-updates/responses-our-july-open-letter-charging-arrangements-embedded-generation.

[6] NGET review http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/.

[7] CMP264 workgroup and code administration consultation responses, available from: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

[8] http://www.energynetworks.org/electricity/regulation/distribution-charging/distribution-charging-working-groups.html

services such that these users are appropriately incentivised to locate in constrained network areas where they can be of most use – this would be through clear visibility of locational-based price signals or through location-based contracts for flexibility which do not unreasonably preclude contributions to other system-service contracts. The latter will require a TSO to take a reasonable risk-based approach to service availability from distribution-connectees in aggregate, as any individual distribution-connectee will from time-to-time have to prioritise a local DSO service.

22. We suggest that "Flexible connection arrangements" better belongs alongside question 2 on network connections. Please see our comment under question 2 on **assessing constraints arising from a new connection**: "Flexible" connections are just one end of a continual spectrum of reliable network access. The *option* for such connections must be made available to all connecting customers, but hand-in-hand with best-practice information which permits an informed commercial decision – this information should be easily available, quantitative, and accessible for all connection types ('flexible' or otherwise). Furthermore, there needs to be consideration of how existing customers can increase their network access rights in time (i.e. the connection becomes less 'flexible'), so that the customer can be enabled to participate in other market mechanisms – essentially, in order to facilitate providers of flexibility, there must be an option to increase network access if appropriate, and any contractual connection restriction should always be minimised by the relevant network operator.

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

23. We agree with your assessment that "storage can be a valuable source of flexibility for network operators" – the capabilities that storage can provide are well placed to solve a number of the key challenges that network operators increasingly face, such as post-fault thermal constraints and voltage issues. We agree that the RIIO framework should theoretically provide the right incentives for the TOs and DNOs to consider using service based solutions as an alternative to traditional network reinforcement. As such we are disappointed that network companies have not yet embraced this opportunity and offered service contracts which give investable price signals.

24. We strongly support DNOs being able to access the benefits of storage. Based on project economics and the ability of third parties to participate in service markets that the DNOs might be prohibited from (for example, by unbundling requirements), we feel that third party owned storage providing services to DNOs and other markets will likely be the best value deployment in most scenarios.

25. We support the wider roll out of the type of service-based solution as currently trialled by Scottish and Southern Electricity Networks' (SSEN) through its "CMZ" project. However, we would caution that this project also served to demonstrate the significance of considering investor priorities in drawing up contract terms, in order for such solutions to be deliverable. Such terms must recognise that the service provider is one of a suite of reliability tools available to a DNO at any location and any penalties need to be commensurate. Furthermore, early and continued coordination between TSO and DNO (DSO) is critical to avoid unnecessary barriers to timely implementation.

26. Whilst there appears to be limited downside to the DNOs testing the market in all cases, we accept there may potentially be last-resort scenarios where DNO ownership of storage is the best value solution to the consumer. This could be where only a small amount of storage is needed (so the overheads of third party finance would be disproportionately high) or where needed exclusively for a single network issue (so there is little/no scope to earn revenue from service markets that the DNO would be prohibited from). However until such scenarios are properly evidenced, we agree that competitive procurement should be used in the first instance.

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

5.1 **Planning Issues**

27. **Not "generation", nor pumped hydro**: Electricity storage technologies such as batteries do not involve the generation of electricity, but merely the import of electricity from a source, the storage of that electricity as a commodity, and then the export of that electrical energy to another user. Furthermore, battery storage systems are of a vastly different nature and scale to pumped hydro schemes or large scale gas or oil storage facilities; they therefore have very different and reduced impact on environment and amenity, and in spatial planning terms may be treated differently.

28. In our recent experience various planning authorities across the UK have differing views as to the classification of battery storage development, ranging from light-to-general industrial uses, storage & distribution uses and "sui-generis" uses, which adds uncertainty to new development. To our knowledge, no planning authorities to date have considered them as electricity generating stations, nor to require Environmental Impact Assessment (EIA).

29. Given the different technologies and scales of electricity storage possible, we **would recommend that they are consistently classed "sui-generis"**, as such a use on its own and not belonging to a class. These developments could then be determined in accordance with any relevant national and local planning policy and guidance. We would further recommend that each planning system within the UK amends its use-class order to include electricity storage developments within the list of sui-generis uses.

30. In addition to this amendment to subordinate legislation in terms of the use-class orders, we would recommend an update to the relevant schedules to the devolved administrations' **EIA regulations**. Amended regulations are required to be in force by 16th May 2017 to implement EIA Directive 2014/52/EU and it should be possible here to add clarity as to the scale of non-generating electricity storage development requiring EIA. We would consider a site area of 1 hectare to be an appropriate threshold for EIA purposes, as development below that scale can be adequately considered through the normal planning application process.

31. We agree with your suggestion that any associated National Planning threshold needs to be considered for storage. We agree that the 50MW threshold needs to be reviewed for storage, along with whether MWh and technology type should also be taken into account. Storage projects above 50MW may nonetheless be best considered under the town and Country Planning Act.

32. We would also welcome further national planning policy and guidance on electricity storage from the devolved administrations to support the roll-out of low-carbon flexibility evidenced in the CfE and related documents. Scottish Planning Policy (2014) contains some limited policy guidance, but more is required. Local administrations should be encouraged to consider low-carbon flexibility within their development plans.

33. We would recommend that each devolved administration prepares and consults on national planning policy (and related siting and design guidance) on low-carbon flexibility including electricity storage to provide much needed clarity and support.

5.2 **Licensing options**

34. We are grateful to BEIS/Ofgem to have advanced their thinking to this point and for the options presented.

35. Electricity storage solutions derive their revenue through system and network optimisation services, not by generating power. Thus smart flexible technologies help improve the economics of generation assets and reduce costs of network and system management, which is how they generate economic surplus for consumers. Storage is therefore a separate type of asset, which needs to be clearly recognised in its definition and treatment under the panoply of electricity market arrangements.

36. Our views on any licensing solution will ultimately depend on the specific obligations they impose on the licence holder. However it is critical that any licensing development does not delay the removal of known barriers. We therefore welcome that you are considering introducing a definition outside of a licence – this will introduce a definition more quickly and we agree that a definition can be introduced and given ‘weight’ without having to wait for inclusion in a licence. It is of course essential that any subsequent licence uses the same definition as that already introduced by BEIS/Ofgem.

37. We would therefore encourage the rapid confirmation of the Electricity Storage Network’s proposed definition in a manner that can be used to facilitate legislative and regulatory changes in line with these characteristic and propose that BEIS and Ofgem consider if this can be achieved through an *Open Letter*.

38. Consideration of appropriate treatment of electricity storage within the statutory and licensing regime can progress in parallel with a codified definition, thus avoiding any unnecessary delays. We look forward to contributing to next steps in this area.

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

39. We strongly support the work to develop an appropriate definition for electricity storage. We agree with your assessment that a definition is a very useful tool in reducing barriers to storage in permitting prompt and effective work across multiple industry codes. We welcome that you are considering introducing a definition outside of the issue of any licence option – this will introduce a definition more quickly and we agree that a definition can be introduced and given ‘weight’ without having to go in a licence. It is of course essential that any subsequent licensing option uses the same definition as that already introduced and agreed.

40. We consider that any definition should meet three key principles. Any prospective definition should be assessed against these principles.

    1. The definition should not use the words “generation”, “demand” or “supply”, or any variations of those words. This is because these words have defined meanings within the 3rd Package and also in national legislation. Using them would risk inadvertently linking storage to one of these activities – this could needlessly create confusion, and create legal problems and licensing issues in the future. Keeping storage separate from existing activities is a no-regrets move, and doesn’t prevent any of the licensing options described in the call for evidence.

    2. The definition should be neutral to technology, location, size and use-case – it should include all storage. No requirements are imposed by creating a definition so there is no need to exempt any type/size/use-case/party at this stage; we are simply creating a common way to describe storage. Exemptions only need to be introduced when the definition is used to create requirements on storage. When that happens, exemptions should go in the body of the legislation/code that contains the requirements (as is current practice in the UK), rather than changing the definition.

    3. The definition should be as clearly worded as possible, so that it is easy to use and can be translated into all European Union member state languages. Regardless of our future status in the EU, we will continue to trade electricity with EU member states and so want to retain the option of inputting into the development of any trade partner’s regulatory or legislative changes on storage.

41. We consider that following these criteria will create a definition that is robust and, critically, doesn't preclude any regulatory/licensing solutions, market and commercial arrangements or code requirements at this stage, i.e. it can be have a broad application across policy areas. Of all the definitions we have seen so far, we consider that the ESN proposed definition best meets these criteria. We do not support the Capacity Market definition given its use of the term "generating unit".

42. As per question 5, we consider that the issue of licence options for storage can be pursued in parallel with, and effected subsequently to, a common codified definition.

Aggregators

Questions 7-10: n/a.

Chapter 3: Providing price signals for flexibility

System Value Pricing

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

43. We welcome that BEIS/Ofgem are seeking to approach the flexibility agenda in a holistic manner and broadly agree with the aim and principles set out in this section.

44. We firmly believe that it is only through holistic approach to reform of the electricity market that we will be able to deliver a secure and decarbonised power sector in the most cost effective way for consumers. This is particularly important in light of the fact that most of the new build generation and smart flexible solutions will be supported through long term contractual arrangements such as the Capacity Market and Contract for Differences. Barriers and market defects to these for new flexibility providers are addressed in our answers to questions 12, 13, 14, 25, 26, 27.

45. In line with this we highlight the need for a reform of ancillary services. Such reform must ensure that all market participants can access these without unnecessary mutual exclusion across different services, and enable maximum participation across services.

46. There is a need to consider how new flexible solutions can be delivered quickly in light of high entry barriers, barrier discussed elsewhere in the CfE and this response. One approach to address a distortion in the Capacity Market would be to permit participation of more low-carbon providers of flexibility by relaxing unnecessary restrictions in standard contract terms of ancillary service agreements, for example in permitting providers to infrequently prioritise local system services, or on investable contract lengths.

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

47. There are limited opportunities currently to combine multiple revenue streams with a single asset. This is because (i) existing contracts as offered by different parties within the system have not been aligned to enable this 'stacking' (i.e. are unnecessarily mutually exclusive), and (ii) because contracts which could be stacked to create a business case at a particular location are not available (e.g., *investable* distribution network constraint contracts are yet to exist). Point (ii) is dealt with elsewhere in this response, so the following adds detail to point (i).

48. The contract terms for each of i) ancillary services provision ii) distibution system service provision and iii) Capacity Market delivery must all be coordinated to remove unnecessary mutual exclusion, and enable an asset to be remunerated for the full value it can provide. Some examples are:

    a. Frequency services contracts are not set up to allow occasional provision of other locational commercial services (e.g., distribution constraint services). This should be straightforward as frequency is a national service and thus the SO (in conjunction with the DNOs) can note the likelihood of any individual local service being called contemporaneously and procure accordingly.

    b. Capacity Market terms need to be updated to account for Enhanced Frequency Response.

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

49. As previously, the market is not yet offering investable distribution service contracts nor investable transmission-deferral service contracts (either could reduce or avoid infrastructure spend). Work is also needed to allow distribution-connected assets be remunerated for provision of reactive power services.

50. Longer term, energy storage will add value in balancing and wholesale markets as well as contract services markets. Price signals bringing assets into these markets are presently short-term and volatile, hence favouring low-capex/high-opex technologies over higher capex/lower opex technologies. This counts against energy storage and is thus a barrier to the system getting the low-carbon flexibility needed to reduce cost in totality. Long term visibility, transparency and volatility should be a focus of any reconsideration of balancing market, wholesale market and network cost price signals.

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

51. On 23rd Aug 2016 we submitted CP162[9] requesting that the new Enhanced Frequency Response balancing service from national grid be included in schedule 4 of the capacity market rules in line with para. 3.2.2.6 of the Final government position on the Capacity Market rules[10]. The pre-existing absence of clarity from Ofgem has had an unnecessary and detrimental impact to bids made by storage in the recent 2016 T-4 capacity market auctions and continues to be a source of uncertainty in efforts to secure investment for successful bids. We would strongly urge Ofgem to provide clarity on the intended result prior to March 2017 to permit finance to be secured for EFR delivery this year.

52. Additionally we are concerned that there is not a more streamlined process to capture such corrective changes that National Grid could and should apply to their balancing services.

53. To avoid future issues, we would encourage Ofgem to request that National Grid produces and maintains a list of Balancing Services that qualify for schedule 4 of the Capacity Market rules, thus facilitating a coherent framework and clear ownership.

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

n/a

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

54. We have mentioned that the importance of timely action in order to ensure that smart flexible solutions are rolled out in line with the needs of the system - and how this is support by evidence in the recent report we

[9] https://www.ofgem.gov.uk/publications-and-updates/res-group-capacity-market-rules-cp162
[10] Implementing Electricity Market Reform - Finalised policy positions for implementation of EMR, DECC, June 2014

commissioned along with Innogy and Scottish Power from Imperial College and E3G[11] , which conservatively calculates the System Integration Costs of variable renewables against a benchmark of nuclear generation costs.

55. This report explains that if smart flexible capacity is not increased in the sufficiently in the short term then the UK consumers could face price spikes in order to maintain system stability. Figure 1 taken from the report and copied below provides an illustration of the importance of timely implementation.

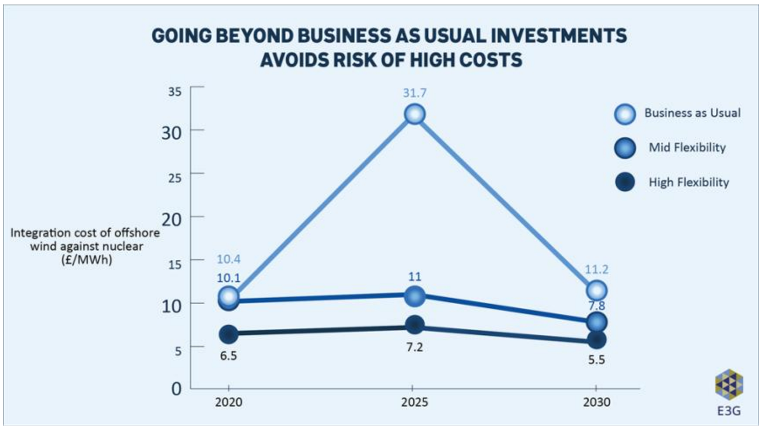

Figure 1 – System Integration Costs of offshore wind, as compared with nuclear generation, in three scenarios of available flexibility provision.

56. The work from the Carbon Trust published alongside this Call for Evidence broadly provides good foundations to understand the impacts of timely flexibility delivery - however we are concerned that the generation capacity assumptions are very inaccurate and not economically rational. By way of simple example, the forward looking assumptions of total solar PV installation are less than the amount currently deployed. Expanding on this work, using generation capacity assumptions more in line with the most recent data on generation costs and existing deployment (at all levels, including distribution), could provide government and industry with a more valuable benchmark against which to determine the scale and timeliness of smart flexibility provision required.

57. In any case believe that it is of paramount importance that we remove barriers to electricity storage projects as fast as possible, for which the immediate priorities include a common codified definition.

58. Immediate priorities also include: access to capacity market participation by flexibility providers, coordinated updates to the Applicable Balancing Services and related reforms to the ancillary services by the end of 2017. DNOs, acting in trials, should be able to implement investable flexible service contracts in this timeline, which are coordinated with the changes above.

59. Finally, it is important that a holistic review of network charging arrangements is initiated Q1 2017. Continued uncertainty around charging arrangements increases the risk profile of all new-build projects and any premium associated with these risks will be passed on to consumers.

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

n/a

[11] Plugging the Energy gap, 15/11/16 - https://www.e3g.org/library/plugging-the-energy-gap

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

n/a

Smart distribution tariffs

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

60. Current DUoS arrangements are a significant barrier. There is considerable uncertainty, lack of visibility, no reliable way of interpreting a new Extra High Voltage (EHV) project's future charges – and even if so, such charges can be changed by an order of magnitude by the actions of other existing and new users of the DNO system. As a case study, we set out these observations in a presentation to DCMF in January 2016 (minutes available from DCMF website[12]), which showed that the current charges are: i) <u>not</u> reflective of a user's impact on the network, ii) do <u>not</u> signal a user to operate in a manner useful to the network and iii) are <u>not</u> transparent, such that estimating a new site's charges in advance is practically impossible.

61. Secondly, the fundamental and significant clashes of methodologies applied at different voltages, principally from CDCM to EDCM (HV to EHV levels on a distribution network), from England to Scotland (132kV differential classification) and from DUoS to TNUoS (distribution to transmission); each of these provides a profound step-change in market signals which has led to inappropriate design. Non-optimal engineering solutions (fundamentally adding cost to the whole system) have been delivered in order for projects to navigate the gaping vagaries of present network charging rules. Holistic review of charging across levels is long overdue, as set out in our answer to Q22.

62. Another barrier is linked to the lack of price signals that result from distribution network constraints. Distributed intermittent generators are required currently to sign connection agreements in which they agree to unbound curtailment with no remuneration. In doing so the cost of network constraints is internalised to the cost of generation and no clear price signal emerges to inform network investment decisions, or in this case a price signal that flexibility providers could respond to. We believe that this is one of the changes to network management and charging that needs to emerge in a transition from DNO to DSO.

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

63. Holistic review of network charging across voltage levels is long overdue, as described in our answer to Q22. We would not here propose any short-term fixes, other than those already identified against chapter 2 (i.e. known barriers to facilitating electricity storage – chief amongst those an agreed and codified definition for storage).

64. Any incremental changes that are considered to reduce perceived distortions between distribution-connected and transmission-connected plant, must be mindful of the very different connection charging *boundaries*, which mean that distribution-connectees will have already contributed (on average) significantly more per-kW capital up-front (pre-energisation) to the network operator than transmission-connectees. This was evidenced in NGET's exporting GSP work[13] as an average cost *equivalent to additional network charges of* +£15/kVA/y.

---

[12] http://www.energynetworks.org/electricity/regulation/distribution-charging/distribution-charging-working-groups.html

[13] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/

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

65. Exactly as specified in answer to Q19: The fundamental and significant clash of methodologies at different voltages, principally from CDCM to EDCM (HV to EHV levels on a distribution network), from England to Scotland (132kV differential classification) and from DUoS to TNUoS; each of these provides such a step-change in market signals such as to drive inappropriate design, i.e. non-optimal engineering solutions (fundamentally adding cost to the whole system) are driven in order for projects to navigate the gaping vagaries of present network charging rules. Holistic review of charging across levels is long overdue, as described in our answer to Q22.

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

66. **Fundamental change in how distribution network costs are recovered is long overdue**. The electricity regulatory and charging framework has changed only piecemeal since the time of deregulation in the early 1990s; *None* of the fundamental precepts of that time (central generation, negligible DG, and different effective transmission boundary in Scotland) apply today and the charging framework in its entirety must be reconsidered to better meet the relevant objectives. Evidence is many and varied and contained in industry responses to such items as for example the EDCM Review, the exporting GSPs issue and subsequent Embedded Benefit review, and capacity market outcomes, amongst other network charging case studies.

67. On *how* charges should evolve: one **critical issue is the *perceived volatility* of future network charges**. As much as network infrastructure is a long-term investment, new power stations and other providers of flexibility may be making 20-year-plus investments, for which perceived volatility in DUoS is an extra risk which will adversely impact competition. This much has previously been acknowledge by Ofgem in its 2012 decision on EDCM for export[14] and must be central to any revised methodology.

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

68. As set out in the CfE, we agree that a hybrid of capacity-based tariffs (reflecting network infrastructure and related planning timescales) and dynamic ToU tariffs (signalling desired operational behaviour) is likely the best solution.

69. On capacity charges, CfE states at 22. [predetermined capacity charges] "…do not provide an incentive to reduce consumption below the agreed …capacity level" – we would disagree with this statement, they are an incentive to agree a *permanent* reduction, in keeping with slower network planning timescales. Under

[14] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=832&refer=Networks/ElecDist/Policy/DistChrgs

any hybrid DUoS model, *temporary* changes in use of the network would be reflected in the portion of charges recovered from dynamic ToU tariffs, in keeping with shorter operational timescales.

70. In analogy with transmission charging, we note there that TNUoS is determined so as to recover network spend, and has been in general a more stable signal (than DUoS) with at least some degree of longer-term visibility; whereas operational transmission network costs are recovered separately through HH BSUoS.

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

n/a

Other Government policies

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

72. We believe that the evidence presented clearly supports a shift away from the need for baseload generation in favour of flexible capacity that is compatible with the low-carbon technologies that that UK has access to. Recent evidence on the cost of renewables also highlights that these are the lowest-cost generation solutions in the build up to 2030 so long as even moderate levels of flexibility can be embedded into the electricity system in a timely manner (please see answer to Q27 for more evidence). We also believe that the evidence presented alongside the CfE by Carbon Trust supports an increase in use of storage, DSR and peaking generation over more traditional forms of generation capacity. This is broadly consistent with the outcome of the Capacity Market to date, albeit caveated with the environmental cost of contracts awarded to high emission diesel generators.

73. This CfE and our response cover a broad range of barriers and market defects that hamper the effective participation in the CM of smart flexible solutions. We support urgent action on these barriers and defects over any attempts to modify market arrangements to secure new-build CCGTs.

74. During this transition, there is a need for Government to provide visibility on medium to long term intentions for the CfD arrangements, to avoid further erosion of investor confidence and resultant damaging consequences to the infrastructure investment necessary to realise the benefits of increased flexibility.

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

75. We support the CM interim auctions that are dedicated to new-DSR capacity. This is because new DSR capacity, like storage, faces significant barriers to market entry in addition to an outdated regulatory regime and market arrangements.

76. We are however concerned by some of the CM Change Proposals that have been submitted relating to extending test duration times beyond 30min and sometimes to 4hrs with no detailed supporting analysis. These Change Modification proposals were also submitted outside the official window in the build-up to the auction; this combined with a lack of referenced analysis added considerable uncertainty and thus affects bidder behaviour. Whilst we support the need to make sure that the CM is delivering the desired capacity to maintain system security, it is important that due consideration is given by Ofgem and BEIS to the impact that any Change Modification proposals can have on bidding behaviour, and that any such proposals are pre-screened for an appropriate level of supporting evidence on a transparent basis.

77. Finally, on the issue of test duration, it is necessary that any change proposal includes quantified evidence on the probability and duration of events (particularly any longer than 30min) and their correlation with the level of demand.

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

78. Key evidence is the report available here: "*Plugging the Energy Gap*", 15/11/16 - https://www.e3g.org/library/plugging-the-energy-gap

79. This work on System Integration Costs of variable Renewables provides a high degree of confidence that, providing a moderate amount of flexibility is incorporated, increasing the proportion of energy delivered by

variable renewables by 2030 (evidence suggests that circa 45% is practicable) will deliver the lowest cost outcome for consumers.

80. Importantly it demonstrates that the additional System Integration Costs of variable renewables in the region of 45% of total energy generation remain small in scenarios with even moderate amounts of flexibility. However, additional integration costs in low- or no- flexibility scenarios could be extremely high.

81. This work takes a very conservative view on the Levelised Cost of Electricity (LCOE) of renewable generators and the System Integration Costs themselves – owing to inherent complexity there exists some unresolved double-counting in certain of the integration costs (such as network costs) – which means that the benefits of a high penetration of variable renewables are understated.

82. Within the context of CfD allocations, this evidence on System Integration costs of variable RES seems to indicate quite clearly that the merit order of low-carbon technologies compared to other solutions remains broadly unchanged and in line with the LCOE. Cost reduction in LCOE remains the main driver for shifts in what are the most desirable generation technologies for the UK.

83. Onshore wind that could be brought forward under a 2nd Pot 1 CfD Allocation round will be the cheapest form of generation accessible to the UK, *even when adjusting for the full impact of all System Integration Costs*, i.e. more cost-effective than traditional or baseload generation.

84. RES group supports market reform to ensure that all generation technologies are exposed, within reason and practicability, to the costs that they impose on the system. We believe it is important that BEIS launches as soon as practicable an official stakeholder engagement process on the future of the CfD, including how it can transition towards a more technology neutral mechanism and ensure best value for consumers, and how it can optimally account for such integration costs.

85. To facilitate a route-to-market for such renewables which represent the lowest-cost option of all new generation options, a 2nd CfD allocation round needs to be run as soon as possible. Indeed, renewables investment is otherwise projected to fall by as much as 95% cent between 2017 and 2020 without urgent action from BEIS.[15]

Chapter 4: A system for the consumer

n/a

[15] "*Investors are getting out of high carbon, but will government help them get into low carbon?*", Green Alliance, 06/01/17 - https://greenallianceblog.org.uk/2017/01/06/investors-are-getting-out-of-high-carbon-but-will-government-help-them-get-into-low-carbon/

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

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

86. We agree with the requirements identified and add one more. The issue of de-minimis (and associated *user-choice of..*) **security-of-supply**, i.e. the reliability of network access, should be given more weight as it has a profound impact on allocating network costs.

44. Do you have any data which illustrates:

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

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

n/a

45. With regard to the need for immediate action:

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

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

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

87. We support (with urgency) the need to trial models of DSO/TSO/independent system operation. By way of example this would include, but is certainly not limited to, the UKPN/NGET "TDI 2.0" project. These trials would be best placed to identify any regulatory barriers and the speed to which they need to be addressed.

46. With regard to further future changes to arrangements:

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

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

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

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

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

88. Better alignment of DSO/DNO and TSO/TO planning is a necessity to realise the benefits of flexibility outlined in the CfE. This will require a better alignment of the relevant planning standards. It is a product of history that engineering standards "P2/6" (as currently applies to DNO networks) and "SQSS" (TO networks) are so very far apart in principle and in application – better coordination on both the outputs and principles of network planning policies will be necessary. We are not saying whose role this should be, only that this coordination is a necessity.

APPENDIX A - The Waste Batteries and Accumulators Regulations 2009

Under SI 2009 No 890, The Waste Batteries and Accumulators Directive, any company buying industrial batteries from a foreign entity, and/or manufacturing industrial batteries in the UK, and placing them on the UK market for the first time, will be deemed to be a Producer. Batteries used for energy storage projects fall under the definition of industrial batteries. The UK's energy storage and depends primarily on battery suppliers outside the UK, therefore developers may in the near future be deemed a Producer. This would appear to be the case under Joint Ventures, EPC contracts or direct ownership of energy storage projects if batteries are imported from outside the UK.

Under article 16 (5) of Directive 2006/66/EC Producers are permitted to conclude agreements with alternative financial arrangements but the regulation states that registered Producers have to take back batteries, free of charge, if asked to do so under any of the following 3 limbs:

(i) on request, if a new battery is supplied to the end user within a calendar year.

(ii) on request, when an end user is not able to return waste batteries to his supplier (e.g. when not purchasing new batteries). This only applies to waste batteries that are of the same chemistry type as the new batteries being placed on the market and that which the producer has placed on the market in the calendar year in question or the previous three years.

(iii) If an end user cannot dispose of his waste batteries in line with limbs (i) and (ii) above (e.g. if an end user is no longer buying batteries and a chemistry hasn't been on the market for a number of years), they can contact any Producer to request a take back.

The risk posed by i) is quantifiable and proportional to the quantity of batteries a Producer may introduce to the market. Under ii) and iii) there is no relationship between the quantity of batteries a Producer places on the market and the quantity it can be requested to recycle.

In order to quantify the risk posed by ii) it is vital for industry to understand what is meant by the 'same chemistry type'. The regulation states 'chemistry type' means the type of the battery by reference to its main chemical constituents. In the case of lithium-ion batteries the various types, LFP, NMC, LMO, LTO etc., have different main chemical constituents but under the regulation lithium-ion may be considered one 'chemistry type'.

A producer may also be required to take back <u>an unlimited quantity of industrial batteries</u> regardless of origin or chemistry should an end user not be able to return their batteries to another producer/supplier under i) or ii). In order to understand this risk industry needs to further understand how to confirm limbs i) and ii) have been exhausted by the end-user before a take back is accepted, and how to ensure a fair distribution of battery take-backs under iii), limiting developers exposure.

Industry needs to understand the following:

- Which "chemistry types" should be considered the same under limb ii) ?
- How can a 'producer' be sure end-users have attempted battery take-back under i) and ii) before he accepts batteries for recycling under iii)
- How can 'producers' encourage its international suppliers to take on Producer responsibility under this regulation?

Fundamentally, the exposure to this risk could seriously damage the development of battery storage in the UK and a solution to limit individual 'producer' liability is desirable, not least because it is unlikely all the players that are in the process of entering this market will still be around in 10 or more years from now.