SCOTTISHPOWER

Rupert Steele OBE
Director of Regulation

David Capper
Department for Business, Energy and Industrial Strategy
3 Whitehall Place
London
SW1A 2AW

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Dear David,

A SMART, FLEXIBLE ENERGY SYSTEM: A CALL FOR EVIDENCE

As the recent 'Smart Power' report from the National Infrastructure Commission (NIC) set out, new flexibility options could play an important role in achieving a cost-effective transition towards a low carbon energy system in the period to 2030 and beyond by helping limit the costs of managing and optimising a system with a significantly higher volume of intermittent renewable generation. The Government and Ofgem need to ensure that the right framework is in place to facilitate such a flexible system and we therefore welcome the opportunity to respond to this CfE. Our network business has provided a separate response on specific network issues relevant to its activities.

Our responses to the CfE questions are in Annex 1 attached. However we wish to highlight two key aspects that it will be important have at the heart of this project:

(i) the need to better understand the particular strengths and weaknesses of different storage or flexibility technologies when considering their potential contribution towards developing a smart, flexible energy system in a way that is both cost-effective and optimises the operation of the system; and

(ii) a continuing focus on ensuring that there is a level playing field across the range of technologies and that there are no hidden subsidies, double payments or over-reward arising from the complex interaction of revenue streams, the charging regime and policy mechanisms such as the Capacity Market.

Understanding and monitoring both of these dimensions is critical to delivering a robust analysis of the opportunities and possible barriers. In turn, this is vital to realising the potential consumer benefits and avoiding detrimental distortions to the market.

<u>Understanding the strengths and weaknesses of different technologies</u>

Storage is likely to play a critical role in helping to meet the challenges arising from the increased take-up of intermittent renewables. Requirements for storage are likely to apply on differing timescales: minute by minute to address short term fluctuations in supply or demand, and over a period of hours, to smooth out slower moving variations in supply or demand, typically within a day. At present, however, there is no storage option suitable for seasonal storage of electricity, because the quantities involved are so great and the only realistic option is modulation of generation volumes from conventional generation plant. In practice, this means gas because of the need to phase out coal, and the economics of nuclear generation which favour high load factor operation.

ScottishPower London Office, 4th Floor, 1 Tudor Street, London EC4Y 0AH
Telephone +44 (0)141 614 2000, Fax +44 (0)141 614 2001, Direct +44 (0)141 614 2012
rupert.steele@scottishpower.com www.scottishpower.com

In this context, pumped storage hydro-electric (PSH) and battery storage have very different characteristics and will have complementary roles in this future mix of flexibility assets. Both can provide a range of benefits including improved system operability, reduced network congestion costs, reduced CO_2 emissions and improved security of supply. However pumped storage can be deployed at scale, has an exceptionally long operating life and is particularly well suited to applications requiring longer discharge times. It is therefore likely that the optimal future mix will involve significantly more pumped storage capacity than is available at present and, if overall system costs are to be minimised, it will be important to remove barriers to the further development of PSH.

We consider the most promising approach would be to develop a Cap and Floor mechanism (similar to that already available to investors in interconnectors) to support investment in new PSH (and other large scale storage technologies). We explore this further in Annex 2.

<u>The need to ensure that there is a level playing field</u>

As the flexibility workstream progresses, it is vital that policy development and changes to the regulatory framework are taken forward in a way that ensures there is a level playing field for all technologies, avoiding inefficient distortions arising from “hidden subsidies”, double payments or overcompensation. Indeed, the outcomes of recent Capacity Market (CM) auctions have highlighted the importance of having a good overview of the market as a whole, including the possible interactions of charging arrangements and new revenue streams, so as to avoid over-reward to particular technologies that then results in sub-optimal outcomes. Thus, it is crucial to understand how System Operator tenders, CM payments, bespoke ancillary services contracts, research and development grants, and the network charging regime all interact.

It will also be important to promote due transparency around ancillary services contracts including black start, so as to facilitate fair and open competition for such services and optimal cost-effective procurement.

<u>Role of DNOs</u>

Beyond these two core themes, we think it is likely to be necessary to consider the role of DNOs and how they can most cost effectively facilitate these changes. This is often termed the “DNO to DSO transition”. It seems likely that use of storage and of network services beyond the simple firm connection will be needed, and it is essential that we have a coordinated and supportive regulatory regime to allow these DSO services to be provided without prejudicing liquid competitive markets. Given that DSO services and capabilities are likely to feature heavily in future price reviews, it is important that swift progress is made in developing thinking around technical, commercial and licensing aspects of the DSO model.

We look forward to working with BEIS and Ofgem as this important work is progressed. If you have any questions on our response please do not hesitate to contact me.

Yours sincerely,

Rupert Steele

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Director of Regulation

Annex 1

A SMART, FLEXIBLE ENERGY SYSTEM: CALL FOR EVIDENCE – SCOTTISHPOWER RESPONSE

Chapter 2: Removing policy & regulatory barriers – Enabling storage

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

The CfE identifies five main policy and regulatory barriers that may affect the development of storage: network connections, network charging, final consumption levies, planning and regulatory clarity. Whilst most of these are likely to be relevant to the development of battery storage, the CfE does not fully explore the important role in the overall flexibility mix that will be played by pumped storage, and the particular policy and regulatory barriers faced by investors in new capacity. We have provided additional information on the barriers facing pumped storage in Annex 2, and summarise the main points below.

Although we have focused on pumped storage, we would note that similar considerations may also apply to other large scale storage infrastructure such as compressed air storage, and it will be important to ensure that a level playing field is maintained between all such competing technologies.

Pumped storage

Pumped storage and battery storage have very different characteristics and will have complementary roles in the future mix of flexibility assets. Both can provide a range of benefits including improved system operation, reduced network congestion costs, reduced CO_2 emissions and improved security of supply. However pumped storage can be deployed at scale, has an exceptionally long operating life and is particularly well suited to applications requiring longer discharge times. It is likely that the optimal future mix will involve significantly more pumped storage capacity than is available at present and, if overall system costs are to be minimised, it will be important to focus on removing barriers to both battery and pumped storage. We would encourage BEIS/Ofgem to commission analysis and research to better understand the optimal mix.

There are a number of new pumped storage projects at varying stages of development, which if taken forward could transform the amount of available storage capacity in the UK. However, investment in such projects is characterised by long lead times for construction (5 to 8 years), early capital intensive commitments, long lifespans (50 years or more) and large uncertainties over revenues. Although it is likely that a number of different revenue streams may be 'stacked' (depending on the business model adopted by the pumped storage) so that the resulting project economics could present the potential for a reasonable return on investment, the key barrier to an investment decision in practice is the high degree of uncertainty over the likely long term returns of the various possible revenue streams. Moreover, the commercial timeframes associated with the most likely revenue streams are insufficiently aligned with project timeframes to support an investment decision. For example:

- **Capacity market:** agreements are available for a maximum 15-year duration up to four years ahead of delivery (meaning that a PSH project would be nearly half way through its construction phase before it could be awarded a Capacity Agreement);

- **Energy market:** liquidity exists to support trading activity only up to two years ahead of delivery;

- **Ancillary services market:** long-term agreements are not generally available beyond the two-year horizon of the System Operator's agreed incentive scheme.

Although some of these large scale storage projects may be highly positive for consumers, and the economics may be attractive to investors under many scenarios, the absence of bankable commercial agreements over aligned timeframes means that investment is unlikely to take place. We believe that this barrier to investment could be best resolved by offering similar Cap and Floor agreements to investors in new pumped storage developments to those which have already been offered to investors in interconnectors (with which pumped storage competes to provide flexibility).

Question 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.

Yes, with the exception of assessment and design (A&D) fees (see below), we agree that section 2.1.1 of the CfE correctly identifies the main issues regarding network connections for storage and areas where more progress is required. In particular,

- *Network security of supply standards.* The lack of clarity over how network operators should treat storage for the purposes of these standards is a key issue: the effects of storage may be positive (deferring reinforcement) or negative (requiring reinforcement), depending on its use, and further analysis is required to understand this.

- *Flexible connections*: While network operators can try to understand how the storage asset (which they are unlikely to own) is going to be used, given the pace at which the system and demands are evolving, this may change over time. Accordingly, we believe that appropriate use of flexible connections, in conjunction with Active Network Management (ANM)[1], could help strike a balance between unnecessarily reinforcing the system and making the most effective use of storage. (Then, if it can subsequently be demonstrated that a connection is restricting the battery owner's business activity, regulations or rules should be in place to ensure that it is addressed as a matter of urgency by the network operator.)

We do not believe there is a need to define storage as a separate asset class to address these issues. Network operators should offer what they believe to be the most cost effective solution(s) based on the specification of the generation plant (including storage) seeking to be connected, together with any other information provided by the applicant, such as that it is being built to perform a specific role.

<u>A&D fees</u>

The inability of DNOs to charge upfront assessment and design (A&D) fees for connection applications is resulting in a large volume of speculative connection applications and potential inefficiencies in the system. Currently connection applications are free to all customers and only those who accept the connection offer have to pay the DNO a fee, which reflects the costs of providing all offers. In the experience of our DNO businesses, the absence of upfront A&D fees has encouraged multiple and repeat speculative connection

[1] http://www.smarternetworks.org/Search.aspx?SearchOn=accelerating

applications by some applicants. These applications increase costs and cause viable applicants to cross-subsidise non-viable.

DECC issued a call for evidence in March 2016[2] concerning the possibility of allowing A&D fees to be charged up front so as to share this cost more fairly, and we would encourage BEIS to take this forward.

Question 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.

In general, we agree that consumers are best served by a level playing field between competing forms of flexibility – generation, interconnectors, DSR and storage – which provides fair access to the market and which recovers charges which reflect the costs imposed by each user of the network. Any exemptions from cost reflective charges or any preferential access to the market for an individual flexibility provider or technology classification inevitably results in distortions to competition to the detriment of consumers.

Given the growing complexity of the market and the different revenue streams available from various mechanisms or routes (eg NG tenders for EFR for batteries plus potential Capacity Market revenues), delivering a proper level playing field without distorting over-reward to some technologies is now more challenging than ever, and goes beyond ensuring cost-reflective charging (though this is also vital). Accordingly, we highlight below some of these wider issues.

<u>(1) Flexible connection agreements</u>

As per our answer to Question 2, we support the use of flexible connections in conjunction with Active Network Management (ANM). Moreover, we do not believe that there is a need to define storage as a separate asset class to achieve an effective outcome. The necessary outcomes can be achieved if storage continues to be regarded as a form of generation. For smaller storage units, which might not normally require generation licences, it may be appropriate to grant a simplified or modified generation licence in order to secure the appropriate treatment of input electricity, and consideration should be given to a suitable charging adjustment for domestic and other very small scale storage that forms part of an end user's installation.

Network operators should offer what they believe to be the most cost effective solution(s) based on the specification of the generation plant looking to be connected, and any other information provided, eg that it is being built to perform a specific role. We appreciate that there could be practical difficulties to be overcome in particular cases.

<u>(2) The need to address embedded benefits to deliver a level playing field</u>

One of the largest market distortions at present results from the transmission charging arrangements and the non-cost reflective 'embedded benefits' currently received by distribution-connected generation. This has the effect of a large hidden subsidy which makes distributed assets appear more cost-effective than they are and diverts policy attention away from transmission connected assets. Code modification proposals are being considered by Ofgem which would alleviate some of these issues. However, there is a need

[2] https://www.gov.uk/government/consultations/assessment-and-design-fees-call-for-evidence

to make further progress with this in a timely way so that investors and market players can plan accordingly, especially in the lead up to the pre-qualification process for the next T-4 Capacity Market auction in December 2017. Moreover, there is a wider problem associated with embedded generation located 'behind the meter'. It is also important that these 'behind the meter' distortions are addressed as a matter of priority.

We would also encourage BEIS/Ofgem to consider whether BSUoS charging arrangement may be placing transmission-connected storage at a disadvantage.

(3) The need to consider further the participation of batteries in the Capacity Market

We believe there is a significant issue with the disparity between the duration of each test within the Capacity Market's current testing regime, and the likely duration of a system stress event. If the Capacity Mechanism Units (CMUs) are not capable of providing power for the duration of a typical system stress event, then they would clearly undermine the fundamental objective of the CM, namely, procuring capacity to ensure the cost-effective maintenance of security of supply. Indeed, they would also represent very poor value for money for consumers to the extent that they could displace other CMUs bidding in the CM auction that could deliver for periods more aligned with the likely duration of system stress events.

We believe, to ensure that the intended level of security of supply is delivered and consumers receive value for money, that CMUs should only be allowed to participate at a level whereby they could pass a duration test of between four and eight consecutive Settlement Periods, the precise duration to be considered further.

(4) The need to consider further the participation of unproven DSR in the Capacity Market

Given that the market has had time to develop and that the majority of unproven DSR appears to be behind-the-meter generation, we no longer consider the category of unproven DSR and the limited level of detail that is required to qualify to participate in the auction as fit for purpose. If left unchanged, it will continue to support behind-the-meter generation that may also unduly benefit from hidden subsidies, and security of supply could be undermined by a high level of speculative projects that may never come to fruition. Indeed because of the way in which unproven DSR can pay out on virtually no evidence, there is a risk that the same behind the meter opportunity could be offered in the auction by multiple suppliers all of which would get capacity agreements; while this would come to light at delivery, it would be too late to deliver the intended security of supply.

Question 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.

We agree that network operators will increasingly wish to make use of storage to support their networks, eg to defer network reinforcement in appropriate locations. We also agree that as a general principle, network operators should not own or operate storage facilities, but that this should be left to the competitive market. However, we also accept that there may be circumstances where the market cannot deliver (and where it is not cost-effective for the DNO to establish a separate arms-length entity), and that in such cases it may be in consumers' interests for network operators to receive derogations to allow them to own and operate storage facilities within the regulated business, subject to appropriate safeguards.

In order to receive such a derogation, the TO or DNO should have to demonstrate that (a) it is an efficient use of resources to deploy storage (eg to defer re-enforcement of the network), rather than use other alternatives such as balancing services, and (b) that the inability of the market to provide has been demonstrated via market testing (eg a tender to procure the storage facility competitively from third parties has failed). Furthermore, (as has been suggested in the European Commission's 'Winter Package') such derogations should be subject to a requirement for periodic retendering, to check that the market is still unable to provide.

In such circumstances, the network operator should not be able to trade the asset in the competitive markets. Instead, trading could be done through a third party, with any value from the leasing of the asset to the third party (through a transparent competitive process) accounted for in any regulated income. It is important to maintain such separation to avoid distortion of competition with non-regulated assets which provide flexibility, such as generation, interconnectors, DSR and other sources of storage.

Although there are circumstances where DNOs could develop storage projects without a derogation (where the storage qualifies as licence exempt generation, where turnover and investment are below a *de minimis* threshold[3] and where the project does not distort competition in the generation or supply of electricity), a derogation process is likely to be required for larger projects, or for smaller projects once the *de minimis* threshold has been reached.

More generally, there is a need to develop remuneration mechanisms within price controls for the costs incurred by the DNO in purchasing services (e.g. for the deferral of investment at distribution). This needs to be implemented in a manner that is consistent across the UK network operators, provides price signals that truly represent lowest overall lifecycle costs for UK customers.

We believe our overall approach (described in our answers to Questions 1 to 4) appears practicable, limits interference with unbundling rules, is cost effective, and ensures that where it can be demonstrated that storage facilities would be in the interest of consumers, they get built. This approach also facilitates the achievement of a level playing field across all generation assets including storage, and cost-reflectivity of network charging, but this will only be achieved through addressing issues with the current network charging arrangements.

While we believe there is a role for National Grid to work with businesses, suppliers, policy makers and other stakeholders to make sure DSR regulations and opportunities are understood, we do not believe that it is appropriate for them to have a specific target to procure 30-50% of balancing services from demand-side sources[4], as this could bias behaviour. The provision of these services should be based on a level playing across all technologies and a transparent competitive tendering process.

[3] Condition 29 of the Electricity Distribution Licence requires that turnover from all de minimis activities must not exceed 2.5% of the distribution business turnover and investment in all de minimis activities must not exceed 2.5% of the distribution business share capital.
[4] http://theenergyst.com/national-grid-launches-major-demand-side-response-push/

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

The CfE suggests four (not mutually exclusive) approaches for the regulatory treatment of storage:

a. Continue to treat storage as generation for licensing purposes.
b. Define storage as a subset of generation in a modified generation licence (no primary legislation required).
c. Define storage in primary legislation as a subset of generation in the Electricity Act, with modified generation licence for storage.
d. Define storage in primary legislation as a new activity with separate storage licence regime.

We do not believe that storage needs to be regarded as a separate asset class, but instead can continue to be regarded as a form of generation with appropriate accommodation for the non-generation aspects (ie options (a) to (c) above, but not option (d). For smaller storage units, which might not normally require generation licences, it may be appropriate to grant a simplified or modified generation licence in order to secure the appropriate treatment of input electricity[5], and consideration should be given to a suitable charging adjustment for domestic and other very small scale storage that forms part of an end user's installation. Accordingly, we believe option (b) is the simplest approach, as a simplified generation licence could address these points without the need for primary legislation.

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

If there is a need to define storage, the most appropriate definition will depend on the purpose, eg whether the definition is for the purpose of planning rules, licensing or network charging. Without a specific purpose in mind, it is difficult to comment on the proposed definitions, but we would note that in general it is better to start with a broad definition of storage, which can then be further qualified in particular contexts. A broader (non-prescriptive definition) will be more future proof and avoids the risk that it may inadvertently restrict certain technologies and solutions (including innovation) or create a non level playing field.

On that basis we would generally support the ESN definition of storage as it is sufficiently broad to meet the needs of say the planning process. Any more prescriptive requirements, eg relating to minimum efficiency, could then be introduced in the context of relevant regulations or market rules. The Capacity Market (CM) rules provide an example of this approach. Despite there being a definition of storage within the CM rules, it is becoming clear that some rules will need to be specific to particular storage technologies. For example, we believe the approach to de-rating should reflect the high levels of reliability achieved by pumped storage plant and the potentially lower levels of reliability from battery projects (some of which have been plagued by operational issues). Indeed, we will be pursuing this particular issue further with the Capacity Market design team in BEIS.

[5] If the activity is licensed, it would be exempt from final consumption levies on the input electricity, provided that the input electricity consumption was for the purpose of licensed activity.

Chapter 2: Removing policy & regulatory barriers – Clarifying the role of aggregators

Question 7: What are the impacts of the perceived barriers for aggregators and other market participants? Please provide your views on: (i) balancing services; (ii) extracting value from the balancing mechanism and wholesale market; (iii) other market barriers; and (iv) consumer protection. Do you have evidence of the benefits that could accrue to consumers from removing or reducing them?

As a general observation, we advocate a level playing field for all providers of flexibility. Accordingly, existing price signals that are distorting the market, such as Triad payments, need to be addressed to ensure that the value of each market is cost-reflective. We support Ofgem's commitment to tackle behind-the meter technologies (which we believe is likely to lead to reform of Triad Payments) and look forward to supporting the effective implementation of the code modifications (CMP264/ CMP265) that sought to address excessive payments to embedded generators in the interim period.

The System Operator employs some balancing services which have qualifying criteria including minimum size thresholds for participation; this includes the balancing mechanism, which is currently open to BMUs only. We would be supportive of extending participation in the BM to aggregators, but it would be important to ensure that competition was not distorted by exemptions to obligations placed on other service providers, eg for electronic dispatch, continuously staffed control centres, etc. As these obligations can be too onerous at smaller scales, we consider that the lowering of the thresholds alone is unlikely to lead to a significant change to the number of participants in the balancing mechanism.

Increased participation may also be facilitated by the effective implementation of a Distribution System Operator (DSO) model. Such a model could adopt more cost-effective dispatch solutions for smaller providers and facilitate access to value provided by the balancing mechanism. The DSO is best placed to work with the SO to ensure optimum local balancing measures are used to deliver upon wider system requirements.

Similar contractual arrangements are available between service providers and the System Operator, as demonstrated by the turn-down Commercial Service Agreements (CSA) deployed by renewables generators in respect of distribution connected onshore wind and hydro plants.

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

Given the potential consumer protection risks associated with selling aggregation services to domestic households (eg the risk that vulnerable customers may enter into contracts that they do not properly understand and which may be significantly detrimental) we agree that consideration should be given to making the provision of aggregation services to domestic consumers a licensable activity. This would mean that provision of aggregation services could be subject to an appropriate set of licence conditions, providing inter alia an obligation to treat customers fairly and a route to redress when things went wrong.

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

We do not believe that an obligation on suppliers to sign bilateral agreements or standardised frameworks would necessarily address the issues highlighted, including requirements for locational visibility of demand reduction or generation in the balancing mechanism. Thorough cost benefit analysis of this option would be required to ascertain if the costs that obligated parties would face would be in the interests of consumers.

Given that aggregators only need to inform network operators of which Grid Supply Point (GSP) Group they are affecting and to what extent, this is unlikely to be sufficient to going forward. To realise the full potential of DSR would require the effective management of conflicts between local and national balancing needs, which could be done through an effective DSO model. It is our view that notification of aggregation activities at Grid Supply Point level could be sufficient in the initial stages of the DNO to DSO transition to avoid balancing conflicts.

Question 10: Do you agree with our assessment of the risks to system stability if aggregators' systems are not robust and secure? Do you have views on the tools outlined to mitigate this risk?

All things being equal, we believe that most DSR providers will participate in the capacity mechanism (CM). Information provided by participants in the course of applying to participate in the CM should be robust enough to ensure that the potential risks can be monitored and understood. However, to realise the full potential of DSR would require the effective management of conflicts between local and national balancing needs, which could be addressed through an effective DSO model.

<u>Providing price signals for flexibility - System Value Pricing</u>

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

The most important enabler is having transparent and accessible markets for flexibility and system operation services, and ensuring there is a level playing field between all participants. Such objectives should guide the design of the emerging markets for distribution system operation services, and reforms to the NETS SO procurement of longer term ancillary services contracts.

The challenge underlying the market design for such services is on the one hand, ensuring the various markets are sufficiently consolidated and coordinated to maximise the number of participants and liquidity whilst on the other hand, having robust rules to ensure only participants with a proven delivery capability are eligible and not remunerated more than once for each service.

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?

ScottishPower's liberalised business is an important provider of flexibility to the System Operator (SO) despite operating a smaller generation capacity and having a lower share of the supply market than many of its competitors - as evidenced by its historic performance in securing ancillary service agreements with the SO. This has been achieved by investing heavily in maintaining and improving the flexibility of our generation plants, developing a DSR proposition which is relevant to our customers' needs, through pro-active engagement with the SO, and by positioning our proposition competitively.

We stack revenues from the capacity, energy and balancing service markets in a dynamic manner, reflecting the changing risk-reward profiles each sector offers over time. We focus on both the near-term markets (balancing mechanism, spot market, day-ahead auctions, etc.) and the forward markets up to two years ahead of delivery (eg forward energy market and SO tenders for ancillary services such as frequency response, reserve, voltage and black start services). The absence of any opportunity to contract to provide longer term ancillary services (ie beyond one year) represents a considerable barrier to investment in refurbishing existing capacity or in developing new capacity.

The Capacity Market has been largely successful in delivering the cheapest capacity on behalf of consumers but does not, nor is it intended to, deliver the right capacity in the right location for system operability purposes. However, on its own, the clearing price from the Capacity Market is unlikely to result in investment in large scale storage, and stacked revenues from the ancillary service and energy markets will also be required. It is therefore imperative that an appropriate ancillary service market is developed to deliver this flexibility.

ScottishPower's DNO businesses have a potential future role in flexibility service provision. As set out in SP Energy Network's DSO Vision[6], we envisage DNOs as neutral facilitators of an ancillary services market. To achieve this goal there will need to be a transparent and fair mechanism to remunerate distributed energy resource providers when they are called upon to provide ancillary services.

13 If you are a potential or existing provider of flexibility is 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?

We consider that there are three key flexibility benefits which are not presently appropriately rewarded, stemming from shortcomings in current market arrangements:

a) **Inertia:** The SO benefits from the inertia provided by large transmission connected generation plants for which no payment is made. This helps stabilise the system using energy stored in the rotating elements of large scale generation plant. In the absence of reward and despite the service being required by the SO, such plants are liable to closure in the event of other stacked revenues falling short of the fixed costs of maintaining and operating such capacity.

b) **Voltage**: The SO benefits from the reactive power produced or consumed by generation plants in diverse locations of the network, for which payment is administered at a national rate. In the absence of a reward mechanism which reflects their localised value to the network, such plants are liable to closure in the event that other stacked revenues fall short of the fixed costs of maintaining and operating such capacity – which may not be efficient given their localised value.

c) **Black start**: Contractual arrangements are required in each zone of the network to adequately re-energise it in a black start event. The allowable revenues assigned to the target cost for the black start element of the Balancing Service Incentive Scheme (BSIS) reflect the costs of providing the service from ageing plants which are no longer economic and needs to be revised to incentivise new-build.

[6] http://www.spenergynetworks.co.uk/pages/dso_vision_consultation.asp

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

The single best change to market and regulatory arrangements to support efficient deployment of flexibility would be for the SO to be adequately incentivised through an amended Balancing Service Incentive Scheme (BSIS) to contract on a longer term basis for the various ancillary services it requires for efficient system operation.

Recent schemes have been limited in duration and incentivise the SO to contract only on a similarly short term basis. This has resulted in instances of inefficient outcomes for consumers whereby existing legacy plants have been awarded agreements when new-build options may have delivered a more cost-effective solution to consumers, had they been given an adequate opportunity to contest the requirement with sufficient notice (eg the black start deals awarded to coal generators in March 2016 at a cost of £113m).

An efficient outcome would be for short and long term auctions to be held by the System Operator to meet its ancillary service requirements, in a manner similar to the Capacity Market, whereby T-1 and T-4 auctions promote competition between existing and new-entrant service providers to the benefit of consumers.

As noted in response to Question 1, we would also advocate provision of a Cap & Floor risk mitigation mechanism to new pumped storage projects (and other large scale storage) similar to that which is already provided to interconnectors, with which pumped storage competes in de-regulated markets. (See Annex 2 for further details).

<u>Providing price signals for flexibility- Smart Tariffs</u>

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.

We believe the competitive market is best placed to discover what new tariffs and business models will work best for consumers. The focus for government and Ofgem should be to remove unnecessary barriers to innovation and put in place appropriate consumer protection measures, leaving the market to develop and introduce smart tariffs in response to customer needs. More direct Government intervention risks pushing the development of smart tariffs in a particular direction, precluding other products and services. Experience has shown time and again that the most successful products and services resulted from previously unforeseen market innovation.

Government intervention, thus far, has largely focused on delivering smart metering infrastructure and associated industry processes (such as half hourly settlement), and we think that this should remain its priority for the time being. The retail market is highly competitive, so we can expect the business models and tariffs needed to support the necessary transformation to evolve naturally as the infrastructure is put in place to support them. However, we think there is a need for more consumer education around the connection between smart energy, smart metering and smart appliances, and this combined message might best be delivered by Smart Energy GB.

Noting that this is a joint call for evidence from BEIS and Ofgem, we think it is worth highlighting the need for the clear demarcation of their respective roles in this area. It is particularly important that new participants entering the smart market are able to distinguish the functions of government and regulator.

With regard to Ofgem's role, we think it needs to ensure that licences remain fit for purpose, and that it acts swiftly to remove any barriers to the deployment of smart tariffs and/or new entrants.

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

It is important that the smart meter rollout places the customer journey at its centre if the levels of consumer engagement needed for smart tariff take-up are to be realised. Once smart meters have achieved a good level of market penetration (eg 50%), we would hope that a strong market pull for innovative products will begin to emerge.

We look to Smart Energy GB to help with this, but we believe suppliers will also play a central role in communicating the benefits of smart tariffs (and other smart-related products and services) in the course of normal market competition. Nonetheless, if consumer appetite does not prove sufficiently robust by that stage, there might be a case for the Government or Ofgem to add their weight to communicating benefits of smart tariffs - or allaying fears over any perceived risks.

It may also be useful for Ofgem to articulate to consumers the link between the deployment of smart tariffs and smart appliances and its initiatives in the area of network innovation.

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?

While we are aware that time-of-use tariffs are being considered for deployment as the default tariff in some jurisdictions, such as California, we have little evidence of the success of these initiatives. However, we recently deployed our own 'Power Up' tariff[7] based around a smartphone app which allows customers to buy energy in advance to cover an estimated number of months, weeks, or days' consumption, and which will be able to take advantage of smart meter functionality. A similar product launched in New Zealand[8] has consistently achieved exceptionally high customer approval ratings.[9]

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

We have not yet offered smart tariffs to larger non-domestic customers (profile classes 5-8), so do not have direct experience of the reasons as to why they may not be taken up. However the reasons suggested in the CfE (consumer preferences for simpler tariffs, supplier perception of limited value in consumer response to smart tariffs, trade-offs between reducing cost to serve and raising suppliers' costs of bill administration) seem plausible.

[7] https://www.scottishpower.co.uk/powerup
[8] http://www.powershop.co.nz/
[9] http://www.canstarblue.co.nz/energy/electricity-providers/

Providing Price Signals for flexibility –Smart Distribution Tariffs– Incremental Change

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

Historically distribution charging has been designed to average out costs across consumers and consumption profiles, and has generally assumed that electrical export flows are of benefit to the network. This approach was appropriate for passive radial networks but as distribution networks become more active, with increasing volumes of generation connected at all voltage levels, this charging approach is increasingly liable to subsidise unduly certain classes of network user whilst penalising others.

We are pleased to see that the initial Distribution Charging Methodologies Forum (DCMF) assessment identified a need to review underlying distribution network cost drivers to ensure DUoS charges remain cost-reflective for all network users. We believe such a review should also capture domestic consumers at the lowest voltage levels, to ensure the impact of present and future domestic generation and storage is captured in the relevant half hourly (red, amber green tariffs) tariffs. Finally, as flexibility providers including generators can be connected at any voltage, distribution charging should be compared with transmission charging to ensure there are no distortions between the two.

We recognise there is potential to reduce the complexity and transparency of the charging methodologies, for example the lack of a clear approach for the treatment of storage under the EHV Distribution Charging Methodology (EDCM) and Common Distribution Charging Methodology (CDCM), and we support the industry's commitments to resolve these issues.

We are fully supportive of a general review of network charging that would look at issues relating to storage, alongside a more comprehensive assessment of network cost drivers as discussed above.

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

Following a review of the factors outlined in our response to Question 19, we would expect amendments to existing tariffs to make them more cost-reflective. This may require the introduction of new tariffs and removal of credits for certain classes of user. The EDCM and CDCM statements may need to be revised to remove the complexity and improve transparency for storage providers.

21 How problematic and urgent are any disparities between the treatments 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.

We recognise that with the recent significant volumes of distributed generation and PV connecting to the network, there is a need to review the underlying cost drivers to ensure the charging methodology remains cost-reflective. We would expect all classes of uses to be reviewed alongside generation. Such a review should assess whether generator credits genuinely reflect network benefits attributed to the recipients. Similar considerations would apply to storage and other flexibility providers.

We believe it is equally important to examine any disparity that may exist between users connected to transmission or distribution networks and ensure they are treated on a consistent and cost-reflective basis.

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?

If the forms of flexibility discussed materialise in future in significant volumes, it is inevitable that the underlying cost drivers will have changed - but it is difficult to anticipate how this change will manifest itself.

It is more important that the charging methodologies are kept under review to capture the changing impacts on the distribution networks. We think such a review would be merited now, given the volume of distributed generation connecting in recent years. It is imperative that charges remain cost-reflective and do not unduly benefit or penalise different classes of user.

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?

One way to capture both long run and short run cost signals may be to have a combination of capacity and commodity charges, as suggested in this CfE.

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.

The costs and services associated with the DSO role are not material at present, but will increase as the transition progresses. The question will then arise as to how such DSO costs should be charged to users. For example, they could be incorporated into DUoS charges or, alternatively, separate charges could be developed analogous to transmission BSUoS charges.

Presumably a form of DSO charge could be designed to provide the kind of short run price signals anticipated in Question 23, but the complexity of such an approach would need to be weighed against the benefit from changes in user behaviour.

<u>Other Government policies</u>

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

This question raises questions across a very broad landscape and accordingly we have focussed on two key areas of existing energy policy, namely, the maintenance of security of supply through the Capacity Market and the delivery of renewables through support schemes.

Capacity Market

As we transition to a lower carbon and smarter energy system, it is essential that investment decisions are based on a level playing field for all types of generation so as to deliver progress cost-effectively. This requires having a clear overview around the interactions of various policies and possible revenue streams arising from those policies, the regulatory and charging framework and tendering exercises conducted by National Grid.

Thus, as discussed in our response to Question 3, the outcomes of the first three Capacity Market (CM) auctions have demonstrated the importance of taking action to ensure a level playing field for all types of generation in that market - and thereby minimise costs for consumers. In particular, we have seen levels of embedded generation succeed in the auctions (over 4 GW) that reflect a significant distortion of the market based on an unjustified over-reward through non-cost-reflective 'embedded benefits'.

Moreover, as mentioned in our response to Question 3, the CM auction in 2016 awarded Capacity Agreements to c.500 MW of batteries which may well be limited to 30 minutes generation duration rather than the typical duration of a system stress event, namely two to three hours. We believe that this issue requires further consideration with a view to improving the basis for participation in the CM in future. We will be pursuing these matters further with the BEIS CM design team and with Ofgem through its CM Rule change process.

Renewables support schemes

The Government has supported the extensive roll-out of small-scale renewable generation through the Feed-in-Tariff (FIT) scheme. Whilst this may have promoted technology cost reduction and a degree of consumer engagement, it is not clear that it has necessarily helped a cost-effective transition to a smarter energy future.

Indeed, it is apparent that decentralised small-scale generation is generally less cost-effective than large-scale generation. For example, the recent report from BEIS on electricity generation costs[10] shows that the levelised costs of small-scale onshore wind (<50kW), estimated at £220/MWh, are significantly higher than medium scale onshore wind (100-1500kW) at £124/MWh. And full size onshore wind installations are significantly cheaper still. This is important in the context of this workstream, as it may be that additional spend on smaller-scale renewable generation could be better spent on creating a smarter, more flexible energy system.

More generally, we would note that the use of storage alongside intermittent renewable technologies, such as wind, could possibly provide benefits for the system as a whole when compared to stand-alone storage (such as mitigating localised network constraints). It is important to note, however, that well sited stand-alone storage is likely to provide the greatest value for the system operator in terms of managing the system as a whole. We believe that any potential benefits of using storage alongside intermittent renewable technologies should be further considered and assessed by the Government as part of this workstream.

[10] available at www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016

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?

Please see our response to Questions 3 and 25 which highlights the need for steps to be taken to ensure a level playing field for all types of technology participating in the CM.

We would also response to Question 6 which argued that some of the CM rules and processes may need to be specific to different storage technologies. For example, the approach to de-rating should reflect the high levels of reliability achieved by pumped storage plant and the potentially lower levels of reliability from battery projects (some of which have been plagued by operational issues).

Moreover, any potential changes aimed at reducing barriers for newer forms of flexibility need to be fully tested to ensure that they do not create distortions in the market more generally.

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?

Whole-system cost of variable renewables in future GB electricity system

Last year, ScottishPower Renewables worked on a collaborative study with Imperial College, RWE Innogy and RES to quantify the total system costs and system integration cost (SIC) of low carbon technologies under certain energy mix scenarios. The work built on Imperial College's earlier study for the Committee on Climate Change, with a focus on onshore and offshore wind in the context of a future, largely decarbonised UK electricity system.

This study considered system integration costs such as increased balancing costs, necessary reinforcement costs and costs of increased back-up capacity. The findings of the report[11] show that credible scenarios to meeting 2030 decarbonisation targets involving increased deployment of renewables (onshore and offshore wind) with a moderate increase in system flexibility can substantially reduce the overall system costs.

Given the technical nature of the Imperial College report the sponsors selected E3G to compile a front end report in order to distil key messages and conclusions and provide a digestible summary for stakeholders.[12]

Utility of the Future

We would also draw your attention to a study by the MIT Energy Initiative on the 'Utility of the Future' published on 15 December 2016[13], which ScottishPower's parent company, Iberdrola, supported. This comprehensive study sought to address the technology, policy, and business models shaping the evolution of the delivery of electricity services. It examined several possible scenarios of the future of the electricity sector in order to inform utilities, regulators, policy makers, and new market actors attempting to navigate the rapidly changing industry.

[11] available at www.e3g.org/docs/Whole-system_cost_of_variable_renewables_in_future_GB_electricity_system.pdf
[12] available at www.e3g.org/library/plugging-the-energy-gap
[13] available at http://energy.mit.edu/research/utility-future-study/

Specifically, the report recommended that renewable or distributed energy support mechanisms should not distort price formation in the market. In terms of accounting for the costs and benefits of distributed generation on a smart system, the report argues that efficient network cost recovery may be comprised of three components: surplus from locational marginal prices (if any), a peak-coincident capacity charge, and a fixed charge to recover residual costs.[14] The study also found that the value from distributed energy resources (DER) varies widely depending on their location in the grid, and that any generic remuneration based on the value of DER should be avoided.

Chapter 4 – A System for the Consumer

Smart Appliances

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

Yes, we broadly agree with the four 'principles' or important facets for the use of smart appliances set out in the consultation document of interoperability, data privacy, grid security and energy consumption. However, we would make the following observations:

- **Interoperability** - open standards are always welcome in principle, subject to ensuring that the integrity of both energy networks and energy settlements is adequately protected. Achieving the right balance between proprietary standards that become *de facto* common standards and those laid down by Government is also important, with the greatest advantages often achieved through *de facto* common standards.

- **Data Privacy** – Given the relatively low financial incentives for domestic consumers to participate in flexibility services, barriers such as privacy concerns need to be minimised. It will be important that consumers feel they are in control of any data exchanged between their smart appliance and third parties, including clear consent procedures that enable them to make informed decisions. In the short term, existing data protection rules may well prove adequate, but if privacy concerns turn out to be a significant barrier to take-up, Government may wish to consider imposing additional restrictions.

- **Grid Security** – we agree that maintaining grid security must be at the heart of any programme for facilitating the use of smart appliances. The consultation document cites the example of simultaneous activation of loads following price signals: while we agree that the legitimate simultaneous activation of loads could pose an operational risk to energy network stability, steps could be taken to mitigate this through energy network operators, suppliers and demand aggregators collaborating effectively. It is also necessary to have plans in place to mitigate against malicious activation/deactivation of loads to cause system instability. This is particularly important when considering the range of cyber-security issues presented in today's world. A regulatory approach, such as that outlined in the National Cyber Security Strategy, 2016 will be important.

- **Energy Consumption** – we agree that in practice the additional energy consumption arising from the ability to respond to signals is likely to be negligible, and it is desirable (other things being equal) that this is the case; but we are not persuaded that this should be elevated to a 'principle'. Provided that the value of the flexibility services provided exceeds the value of the additional energy consumed, this should be sufficient. The key

[14] Ibid, page 116

objective of smart appliances should be to reduce the pressure on the electricity system at times of high demand, or high output by intermittent renewable generation, rather than to limit energy consumption as such.

Another important facet when considering the possible development and promotion of smart appliances is to consider the availability and suitability of such appliances across the range of consumers. In particular, it will be important to ensure that there is a proper focus on vulnerable consumers to ensure that any smart programme is taken forward in a way that avoids undue risks to such consumers.

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

We do not have any specific evidence in support of, or against, any of the three options set out. We note that the market may discover different and better approaches than those set out in any laid-down rules, and that regulatory options here can risk slowing innovation.

30 Do you have any evidence to support actions focused on any particular category of appliance? Please select below which category or categories of appliances you would like to submit evidence for, and use the text box/attachments to provide your evidence: •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)

We do not have any specific evidence to support actions focused on any particular category of appliance.

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

We think that the main risks or barriers around uptake are those identified in the CfE (limited financial incentives, technology lock-in, price, performance, autonomy and privacy) - with price potentially being the most significant.

Whilst appliance labelling and regulatory intervention could help to mitigate possible issues around data privacy and grid security risks, we think that they would do little to help tackle any cost barriers associated with uptake.

Nonetheless, we believe that Government has an important role to play in promoting generally the uptake of smart appliances among consumers.

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

Most of the risks identified will potentially affect all consumers, whether vulnerable or not. Vulnerable customers may be at greater risk if their ability to understand the agreements they enter into is impaired (eg agreements with a third party to control their smart appliance) or if the adverse consequences of having their devices controlled remotely are potentially more severe than for other consumers. In the near term, while the market is still evolving, these risks may be best addressed by education and awareness raising among the vulnerable and those who look after them. This could be followed by regulation if necessary.

Ultra Low Emission Vehicles in a Smart Energy System

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

Significant uptake of electric vehicles (EVs) could have significant implications for the electricity system, particularly local distribution networks, if there are high concentrations of EVs in any one area. Charging of these EVs will, therefore, need to be carefully managed and it will be important to strike the right balance between managing this charging through price signals and possibly an element of direct control by distribution network operators (DNOs).

Whilst the long term aim should be for consumers to be able to choose when to charge their EVs based on time-of-use price signals facilitated by smart meters, if EV usage growth strongly it may be necessary in some cases in the medium term to provide DNOs with the ability to have an element of direct control over these resources (possibly mediated by the supplier) so as to limit the need for (otherwise unnecessary) local network reinforcement. However, this clearly raises important issues in terms of consumer control and so we agree that this needs much further careful consideration including robust and widespread trialling evidence around what different types of consumers in different areas might or not might find acceptable. It will be important to monitor the impact of EVs on the electricity system over time as uptake increases.

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

We would expect the barriers and risks to be similar to those highlighted in our response to Question 31, though we are not in a position to provide detailed feedback on this question at this stage. It will be important for consumer confidence that customers who plug in their EV to be charged do actually receive a charge, so that they can drive when they intend to.

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

We are not in a position to comment - others will be better placed to respond to this question.

Consumer engagement with Demand Side Response (DSR)

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

We do not have any specific evidence as to how large non-domestic consumers currently find out about and provide DSR services, though we perceive that the National Grid's Power Responsive campaign would appear to have had some success in raising awareness amongst at least some of these consumers.

We have noted that a large proportion of DSR currently comes from generation located behind the customer meter.

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

The barriers outlined in the CfE appear to be a useful summary of the barriers that large non-domestic customers face in providing DSR. In our experience, overcoming customer concerns about the commercial implications of providing DSR (such as disruption to their operations or concerns over transferring control of assets to third parties) are often the most significant barriers that potential DSR aggregators or intermediaries must overcome.

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

As mentioned in our response to Question 36, National Grid's Power Responsive campaign appears to have had some success in raising awareness of DSR amongst large non-domestic consumers.

In this context, we would also note that the Capacity Market (CM) auction in 2016 also brought forward a significant amount of DSR, though as mentioned in our response to Question 3 above, it will be important going forward to ensure that this is true turn-down DSR and that its success is based on a level playing field in the CM. This means avoiding distortions to competition resulting from over-reward, whether from the network charging regime or from wider aspects of the market such as tendering exercises designed in isolation from the operation of the CM by National Grid. In particular, we believe that there is currently a significant benefit for DSR resulting from the non-cost-reflective system of embedded benefits in transmission charging, and that this is resulting in both unfair and sub-optimal distortions to the outcome of the CM auctions. Accordingly, we believe it is imperative that Ofgem takes forward its current work programme in this area so as to deliver a timely improvement in the position well before the next T-4 CM auction in December 2017, and that the Government works in step with Ofgem to ensure that true DSR (rather than behind the meter diesel engines) is being incentivised by the current CM design.

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

We think that this is something that needs to happen in tandem with the smart meter rollout. It will therefore be important to ensure that SmartEnergy GB has an effective role in this.

Consumer Protection and Cyber security

40 Please provide views on what interventions might be necessary to ensure consumer protection in the following areas: •Social impacts •Data and privacy •Informed consumers •Preventing abuses •Other

Social impacts

There is considerable risk that those consumers that are able to move effectively to a smart energy system will tend to be limited to particular socio-economic or age demographics. For example, the cost of smart appliances might be too high for some of the most vulnerable consumers to take advantage of the efficiencies, so leaving them comparatively worse off. This will require careful assessment and consideration by public policy-makers and regulators.

Data and privacy

We agree that data protection is very important and needs careful consideration on an ongoing basis. In this context, it might be that new consumer protection legislation in the specific area of smart appliances should be further considered in due course, if there is evidence that concerns over privacy impacts are creating a significant barrier to uptake. However, existing data protection legislation provides a strong overall framework, and it may be sufficient to provide guidance to industry as to how best to comply with it.

Informed consumers

We agree that the potential value of smart energy needs to be disseminated through a variety of channels. Clearly, Smart Energy GB has an important role to play in this context. We also agree that as we move towards a smarter, more flexible electricity system, there may be particular information needed by customers to help them understand the benefits available to them.

Preventing abuses

We think that the healthy number of supply licences awarded in recent years suggests that the licensing process is not unduly onerous, and that there may be a good case for licensing Third Party Intermediaries (TPIs) and aggregators. However, whatever course is taken by Ofgem in the future, we agree that it is essential to ensure that there is proportionate regulatory oversight of new market entities, such as TPIs and aggregators.

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

The design of Low Voltage (LV) networks in particular is based on certain assumptions about load diversity, which is implicitly based on assumptions about the independent behaviour of individual customers. This is a key element in the design of cost-effective networks. Smart technologies have the potential to create synchronised customer behaviour, which removes this diversity. An illustration of the impact of synchronised behaviour (though clearly for reasons other than smart technologies) is the surge in electricity demand during the advertising breaks of popular TV shows, or the switching of electrical storage heaters on the Economy 7 tariff. Whilst demand side response has the capacity to increase the efficiency of the system, it will also be necessary to include safeguard mechanisms to avoid unintended consequences, such as large-scale synchronisation of step changes of load or demand on the network which can have an adverse impact.

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

Increased levels of intermittent or inflexible generation along with the emergence of new low carbon technologies such as electric vehicles and heat pumps and the ever increasing complexity of the Smart Grid may create risks to the system which we are less familiar with. We will need to manage these risks effectively and achieve the right balance between risk and cost to consumers. Moreover, this process of assessment will need to occur in a way that is constantly alive to new challenges, especially around growing cyber-security issues.

The industry recognises the shift from traditional networks to a smarter grid and has begun the process of transitioning the network security standard (ER P2/6 – Security of Supply) to take proper account of flexible capacity, such as demand-side response and energy storage. This work began with a fundamental review of network security and considered a wide spectrum of review options ranging from "do nothing" to "remove the security standard completely". This work is ongoing, but aims to provide a sound foundation for future network security beyond the current ED1 price review period.

Roles and responsibilities

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

We think the figure broadly captures the issues emerging in many of the distribution networks across GB. SP Energy Networks (SPEN) has managed the connection of 3.3 GW of distributed generation (DG) to its two distribution networks and a further 3.3 GW of DG is contracted for connection. This has led SPEN to deploy innovative active network management (ANM) solutions to enable generators to connect in capacity-constrained areas of the network, for example in South West Scotland where SPEN is using ANM to actively manage capacity on the distribution network to overcome constraints from the local transmission network, and connect three renewable generators. Such experiences highlight the need to develop frameworks to enable greater coordination between the DNO, TO, NETS SO and other relevant stakeholders.

Such system requirements will inevitably become more pronounced if the potential of factors such as distributed storage, electric vehicles and the electrification of heat are realised and place greater demands on the distribution network.

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?

In the example cited in our response to Question 43, the adoption of the ANM solution resulted in a saving of around £12m of avoided transmission network reinforcement. This would suggest that, based on distributed generation alone, the impact on network reinforcement is likely to be significant.

Furthermore, as the CfE notes, there is an impact due to the greater volumes of DG connecting causing GSPs to export and increase the costs of transmission balancing by the NETS SO. That said, the overall impact may not be clear cut as it will depend on how and where generation and demand evolve across the distribution network. In some areas they may mitigate each other whilst in other areas they may place cumulative pressures on the network.

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

Operational co-ordination between distribution and transmission is at a nascent stage so it is difficult to quantify potential savings, but there would appear to be reasonable potential to realise material efficiencies in network reinforcement at all voltage levels in addition to reduced balancing costs.

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?

We agree that there is a clear need for a DSO role in the first instance, to facilitate the efficient connection of future distributed energy resources. Indeed, as noted in our response to Question 43, SPEN is already performing this role in areas of its distribution network where there is a demand for such services. We also agree with the need to develop a framework to facilitate co-ordination between DSOs, TOs and NETS SO. It is important that potential connectees encounter the same treatment across the country and at different voltage levels to ensure there is a level playing field for all flexibility providers.

In the longer term we believe there may be an economic case for broadening the DSO role to encompass balancing services (see our response to Question 46 below).

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 broadly agree with the assessment of the progress required in the coming year and the view that it is largely down to the industry to develop and deliver this. We would expect the DNOs to take responsibility for developing the DSO role, and we believe that appropriate incentives to facilitate this exist under RIIO-ED1. Bodies such as the ENA have a role in particular in developing the framework for greater co-ordination.

With regards to the development of markets, particularly for distribution services, we believe the onus in the short term will be on DNOs, TOs and the NETS SO to trial different approaches and share the results. We envisage that the development of formalised market arrangements will need to be in place towards the end of RIIO-ED1.

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

We have not identified any such barriers in the short term. In the longer term one barrier to address will be the regulatory treatment of the DSO function and associated revenues.

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?

It will be important that the market arrangement for flexibility services are transparent to providers and procurers, so that it is clear what services are required and where, in addition to the prices paid for them. Whilst such arrangements will be put in place for distribution, the existing transmission arrangements will need reforms to improve their transparency and accessibility, in particular for ancillary services. One of the main objectives guiding market development should be to maximise the value delivered in this respect. We support the concept of market stacking, allowing service providers to participate in as many markets as possible, whilst ensuring they are not remunerated more than once for provision of a particular service.

As noted in our response to Question 45, we believe the most efficient approach would be the development of a broad or full DSO role as articulated in SPEN's DSO Vision[15]. This would entail the DSO procuring services required to manage the distribution network in addition to managing balancing services for provision to the NETS SO. We envisage that DNOs would trial approaches and implement DSO service provision on a modular basis, ie targeting network zones where circumstances necessitate them. Alongside this, the industry would develop the required market arrangements. Once the DSO role has been sufficiently developed and associated markets have reached a certain volume, consideration will need to be given to the regulatory treatment of the DSO function and revenues, as it will no longer be possible to treat them as *de minimis* services. Given the current rate of progress, it will be important for Ofgem to put in place any new regulatory or licensing arrangements for DSOs ahead of the RIIO-ED2 price control.

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?

We think the CfE has identified the plausible range of models and approaches. Fundamentally, the choice would appear to come down to whether NETS SO has an enhanced role so it can manage the provision of balancing and operational services through the GSP and into the distribution network; or whether distribution companies could develop into a "full" or enhanced DSO role, procuring and managing services on the distribution network and on behalf of the NETS SO. In both cases, the SO or DSO could contract directly with flexibility service providers or via market platforms etc.

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

As noted in our responses to part a) the development of the "full" DSO role will require appropriate regulatory arrangement for the DSO function and revenues, and we believe there will be a need for these to be in place in time for the next distribution price control.

We believe the considerations we have outlined on market arrangements apply whatever model is adopted.

[15] http://www.spenergynetworks.co.uk/pages/dso_vision_consultation.asp

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

We believe the full DSO role is most likely to deliver the most efficient and effective approach for providing flexibility, balancing and other operational services at the distribution network and to the NETS SO through the GSP. The DSO requirements can evolve and be identified by DNOs as they deploy ANM solutions across their networks; this is a "no regrets" form of investment as it is required to manage current capacity issues and avoid network reinforcement.

With ANM in place, DNOs will have greater visibility of the real time operation of their networks and can deploy DSO services on a modular basis, responding to areas where they are needed; this is likely to be a more efficient approach than a blanket rollout. SPEN is adopting this modular approach by trialling DSO service provision in two zones – Dumfries and Galloway and Mid and North Wales – where generation significantly outweighs demand. Having trialled and refined its approach, SPEN can roll the model out to other zones as required.

An alternative approach would be for the NETS SO (or ISO) to provide the same service across the distribution network. However, given its current lack of visibility beyond the GSP, it is less likely to be able to adopt a modular approach and would need to resort to a blanket rollout - which is likely to be less cost-efficient overall.

Innovation

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

We think the RIIO innovation funding mechanisms such as the Network Innovation Competition (NIC) are a useful model in terms of governance, defined deliverables and shared learning that would maximise the value of the results of any funding.

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

Yes, these seem broadly sensible areas for innovation funding support. However, it is likely that over a five year period new technologies and commercial processes may emerge which would merit support, and the list should therefore be kept under review.

Annex 2

A SMART, FLEXIBLE ENERGY SYSTEM: CALL FOR EVIDENCE

BARRIERS SPECIFIC TO PUMPED STORAGE HYDRO

Introduction

1. The CfE identifies five main policy and regulatory barriers that may affect the development of storage: network connections, network charging, final consumption levies, planning and regulatory clarity. Whilst most of these are likely to be relevant to the development of battery storage, we argued in response to Question 1 that the CfE does not fully explore the important role in the overall flexibility mix that could be played by large-scale pumped storage hydro (PSH), and the particular policy and regulatory barriers faced by investors in new PSH capacity.

2. This Annex provides additional information on the role we see PSH playing in the future mix of flexibility assets, the barriers to investment in PSH infrastructure, and why we consider that BEIS/Ofgem should give serious consideration to measures to mitigate the market and regulatory risk associated with such investment - such as a 'cap and floor' regime similar to that which is currently provided to interconnector projects.

3. Although we have focused on pumped storage, which is of particular interest to ScottishPower (Box 1), we would note that similar considerations may also apply to other large scale storage infrastructure such as compressed air storage, and it will be important to ensure that a level playing field is maintained between competing storage technologies.[16]

Box 1 – Cruachan Pumped Storage Facility

ScottishPower (a wholly owned subsidiary of Iberdrola, the world's largest developer of renewables) has an existing pumped storage hydroelectric (PSH) station at Cruachan, near Oban, which was opened in 1965 and has an electricity generation capacity of 440 MW and a storage capacity of over 7 GWh. Cruachan is capable of delivering energy within seconds: it can go from rest to full load in two minutes, and from spin to full load in 30 seconds. Whilst Cruachan can generate at full load for up to 16.5 hours, it primarily runs for peak demand, and is a key provider of ancillary services to National Grid to balance the GB system.

We are considering a development proposal (known as Cruachan II) to expand the capacity of this facility, potentially increasing generation by up to 600MW (to 1,040 MW) and the water storage capacity by up to 10 million m3 (roughly doubling it). Because it is building on an existing facility this could be a highly cost effective way of significantly increasing the UK's PSH capacity, and would build on the experience of our parent company, Iberdrola, which recently completed a seven-year project to double the capacity of the Cortes La Muela pumped storage hydro plant near Valencia in Spain to 1,500MW.

[16] There is unlikely to be a need for such support for more scalable short lead time projects

The role of PSH in the future energy system

4. Storage is likely to play a critical role in meeting the challenges arising from the increased take-up of intermittent renewables. In the future, storage will not only help in balancing the system minute-by-minute (as the output from intermittent renewable generation varies) and meeting peak demand, but it will also play an increasing role in terms of storing electricity generated at times of low demand and high renewable output for use over extended periods of higher demand (not just peak times). Flexible generation, such as gas, could be used to meet demand at these times with curtailment of renewables at time of excess generation, but this is likely to be a higher carbon solution, Accordingly, we believe that a broad range of technologies will be required to optimise the use of intermittent low carbon generation technologies in the most cost-effective way.

5. PSH and battery storage have very different characteristics and will have complementary roles in this future mix of flexibility assets (Table A1). Both can provide a range of benefits including improved system operability, reduced network congestion costs, reduced CO2 emissions and improved security of supply. However, pumped storage can be deployed at scale, has an exceptionally long operating life and is particularly well suited to applications requiring longer discharge times. It is likely that the optimal future mix will involve significantly more pumped storage capacity than is available at present and, if overall system costs are to be minimised, it will be important to focus on removing barriers to both battery and PSH.

	PSH	**Battery**
Project characteristics		
Longevity	>50 years	circa 15 years (depends on technology)
Time to deploy	6-10 years	1-2 years
Typical scale	100’s of MW to GW	10s of MW
Main cost driver	Discharge capacity (MW)	Stored energy (MWh)
Service capability		
Inertia	✓	✓
Spinning reserve[17]	✓	n/a
Voltage control	✓	limited
EFR (<1s)	limited	✓
FFR (<10s)	✓	✓
BM (half hour)	✓	✓
Security of supply (hours)	✓	limited
Price arbitrage (hours)	✓	limited
Black start (hours)	✓	limited

Table A1 - Comparison of PSH and battery storage

6. As noted in Table A1, the main cost driver for PSH is the maximum generation capacity (MW), with the duration of discharge depending on the water storage capacity which can typically be increased at relatively modest cost. By contrast, the main cost driver for batteries is generally the energy storage (MWh), with only modest savings for reducing the maximum discharge power which depends on the capacity of the inverters. This is

[17] Spinning reserve services are typically provided by PSH and include spin-gen, spin-gen with LF relay, spin-pump, pump de-load, whereby units are synchronised to grid and in high state of preparedness to generate or consume to re-balance the system in the event of a major generator or network trip.

illustrated in Figure A1 which shows the capital costs of PSH and battery storage per kW, for different durations of storage.

7. In order to compare the relative economics, it is necessary to take into account the very different lifetimes of PSH and batteries. Once PSH installations are constructed they can generate for many decades with limited ongoing cost (Cruachan has been in operation for over 50 years), whereas the lifetime of batteries is around 15 years. Figure A1 also shows the cost of PSH adjusted to reflect the terminal value of the PSH asset at the end of 15 years (assuming a 5% discount rate), to provide a more balanced comparison. This suggests that batteries could be the optimal technology for shorter duration storage whereas PSH may be more cost-effective at longer durations.

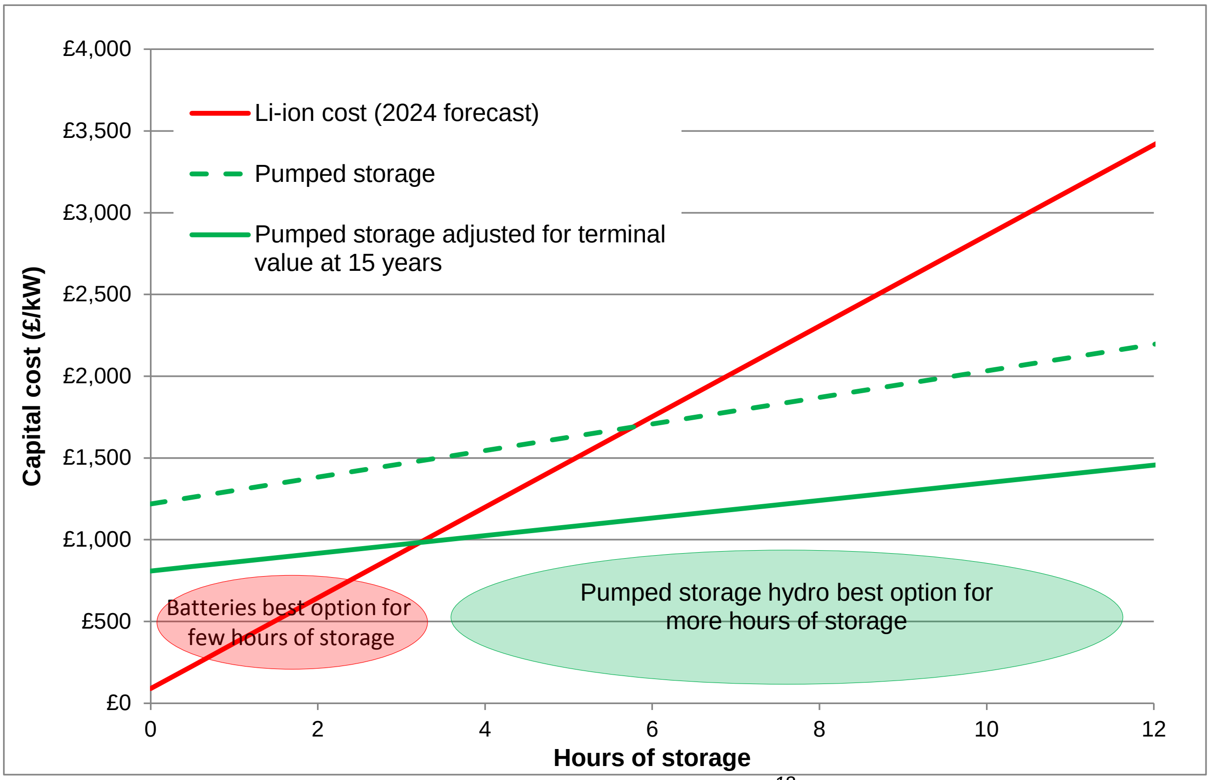

Figure A1 – Capex comparison between batteries and PSH[18]

8. Given the relative economics outlined above, the optimal amount of pumped storage in the future mix will depend on the level of demand for longer duration services. This is an area where further analysis and research is required, but we would note that:

   - the typical duration of a system stress event is around two hours or more[19], and this may be expected to increase in future with a higher proportion of renewables on the system;
   - Short Term Operational Reserve (STOR) contracts include a minimum two hour duration delivery requirement,
   - the CM Supplier Obligation is indexed to a three hour period (i.e. 4-7 pm on a working day from November to February).

[18] Source cost data in $ converted at £1=$1.23. Source for battery cost data is Bloomberg New Energy Finance, 'Central Scenario: Fully-installed utility-scale energy storage costs, 2015-24 (Real 2016 $/kWh nameplate capacity)'; PSH cost curve estimated by Iberdrola from data in 'DOE/EPRI Electric Storage Handbook in Collaboration with NRECA', Sandia Report, July 2013

[19] For example, the NISM/Electricity Margin Notices/Capacity Market Notices issued on the 4 November 2015 (2 hours), 9 May 2016 (2.5 hours) and 31 October 2016 (2.5 hours), all highlight the likelihood of system stress events lasting for between two and three hours

Wider socio-economic and environmental benefits

9. Socio-economic benefits from the construction and operation of PSH projects are not in themselves sufficient to justify a project. However, if value for money is otherwise achieved, PSH projects may have a number of positive socio-economic effects on the local, regional, Scottish/Welsh and UK economies. For example, in the case of Cruachan II, we estimate that during the peak construction period around 300 people could be employed and there may be opportunities for UK-based companies to win major packages of work (civils, components and assemblies). ScottishPower and Iberdrola have a good track record in awarding local content contracts in other technologies (for example it is leading the way with the East Anglia 1 offshore wind project with at least 50% of local content).

10. We note that the Call for Evidence states that PSH projects are big civil engineering works with high potential environmental and social impacts. In this respect, however, it is important to also note that as Cruachan II would be an extension to an existing facility, the environmental impacts would be limited. In terms of the comparison to batteries, we would also urge the Government to consider the lifecycle impacts of the two technologies, which will include those associated with the extraction of the raw materials needed in the manufacture of batteries and energy and environmental impacts associated with their safe disposal and/or recycling.

Barriers to deployment of PSH

11. As noted above, if overall system costs are to be minimised, it will be important to focus on removing barriers to PSH as well as to battery storage. There are a number of new PSH projects in the UK at varying stages of development (Table A2), including some with planning consent, which if taken forward could transform the amount of available storage capacity in the UK.

Scheme	Power (MW)	Energy Capacity (GWh)
Operational		
Dinorwig	1,728	9.1
Cruachan	440	7.2
Ffestiniog	360	1.3
Foyers	300	6.3
Planning consent achieved		
Coire Glas	300-600	30-40
Sloy (conversion from conventional hydro)	60	5-10
Glenmuckloch	400	To be determined
Proposed		
Glyn Rhonwy	100	1.2
Balmacaan	300-600	30-40
Cruachan (upgrade)	+400-600	To be determined
Muaitheabhal	up to 150	To be determined

Table A2 – Operational, Planned and Proposed PSH Schemes in the UK[20]

12. However, investment in such projects needs to take into account long lead times for planning (1-2 years) and construction (5-8 years), early capital intensive commitments,

[20] http://scottishrenewables.com/publications/benefits-pumped-storage-hydro-uk/

long lifespans (50 years or more) and large uncertainties over revenues. Although it is likely that a number of different revenue streams may be ‘stacked’ (depending on the business model adopted by the pumped storage) so that the resulting project economics could present the potential for a reasonable return on investment, the key barrier to an investment decision in practice is the high degree of uncertainty over the likely long term returns of the various possible revenue streams.

13. This is because the revenue streams in question are highly dependent on regulatory and policy decisions which are outside a developer’s control and there is insufficient long-term visibility around these matters to facilitate commercial decision-making. To put it another way, the commercial timeframes associated with the most likely revenue streams are insufficiently aligned with project timeframes to mitigate the risks. For example:

    - **Capacity market**: agreements are available for a maximum 15-year duration up to four years ahead of delivery (meaning that a PSH project would be nearly half way through its construction phase before it could be awarded a Capacity Agreement);

    - **Energy market**: liquidity exists to support trading activity only up to two years ahead of delivery;

    - **Ancillary services market**: long-term agreements are not generally available beyond the two-year horizon of the System Operator’s agreed incentive scheme.

14. Furthermore, aggregating or stacking these revenue streams can be difficult as there are complex interactions between them. This was recognised by the National Infrastructure Commission in their ‘Smart Power’ report in March 2016:

    ‘The complicated nature of storage, which could play a number of different roles in the electricity system and get revenues from each, means that it can be difficult for storage providers to develop a business case which relies on the stacking of these revenues’

15. Although some of these large scale storage projects may be highly positive for consumers, and the economics may be attractive to investors under many scenarios, the degree of regulatory and policy risk and the absence of bankable commercial agreements over aligned timeframes means that investment is unlikely to take place. A shortfall of investment in facilities required to achieve an optimal mix would represent a market failure, and in the next section we describe a form of risk mitigation intervention which we believe could address this failure.

16. Finally, although investment in battery assets is proceeding apace (with 200 MW of EFR contracts and 500MW winning CM agreements for 2020/21), this is may not be entirely due to the more favourable investment characteristics (shorter time to deploy and shorter asset lifetime). We believe that the investment case for batteries has also been assisted by the non-cost reflective embedded benefits available to small scale batteries and generation, and in the case of the CM auction, by a loophole in the rules which permits batteries with only 30 minutes storage capacity to compete. To the extent that PSH is in competition with battery storage, removing such hidden subsidies (and amending CM rules to require more appropriate discharge durations), will also help lower the barriers to PSH and allow it to better compete on a more level playing field.

The case for Cap & Floor support

17. Given the potential role of PSH in minimising the overall cost of future UK flexibility assets, Government needs to think innovatively about how these barriers to investment can be overcome. We believe the most promising approach would be to offer Cap and Floor (C&F) agreements to investors in new pumped storage developments (and other large scale storage technologies with long construction periods and operational lives) similar to those which have already been offered to investors in interconnectors.

18. A C&F agreement is a risk mitigation mechanism allowing consumers to share in the gains should revenues turn out to be above the cap, whilst limiting the risk to investors (and hence reducing the cost of capital) should revenues turn out to be significantly less than forecast. A C&F agreement could be used to help developers manage the revenue risks around additional storage, in the same way that it helps interconnector developers manage long term revenue risks. Any PSH project seeking a C&F agreement would be subject to close scrutiny by Ofgem to ensure that the overall project (including provision of C&F) is in the interests of consumers and has a positive impact on overall UK welfare, taking into account the range of different scenarios that may apply in future.

19. A C&F regime for PSH would also help level the playing field with interconnectors. Unlike other forms of transmission asset, interconnectors compete in liberalised markets for CM agreements, energy arbitrage and flexibility services, and are therefore in direct competition with PSH.[21] Furthermore PSH and interconnectors both have similar capital expenditure characteristics and therefore face similar investment barriers. In this context, we would note that Recital 39 of the EU Projects of Common Interest (PCI) Regulations[22] envisages that Ofgem could offer similar regulatory incentives to storage projects as they do to interconnectors.

20. The reason why existing support mechanisms for generation (CM, CfDs etc) cannot be used to overcome the investment barrier for PSH is that they do not effectively address the nature of the need for *risk mitigation* resulting from the long construction periods and lifetimes associated with PSH as well as the long-term uncertainties around the revenues. In particular, the 4 year ahead bidding horizon under the CM does not marry up with the typical planning and construction period for a new PSH project, contributing to revenue uncertainty; whilst CfDs appear to be unsuitable as they could provide a perverse incentive for storage to charge and discharge continuously thereby providing sub-optimal dispatching incentives.

21. A C&F regime, on the other hand, could provide the requisite structure for mitigating risks whilst being consistent with the continuing efficient operation of market incentives. Thus, it would allow decisions on when to pump and when to generate to be determined by market signals (especially if the cap and floor were designed so as to allow some remaining incentive when either the cap or floor is reached). This should ensure that the plant is deployed when most useful to the overall system.

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[21] Interconnectors and PSH currently provide a rather different mix of services, with interconnectors typically deriving much of their revenue from energy markets and PSH receiving more from ancillary services provision. However, this difference is largely driven by the ability of interconnectors to arbitrage the large difference in carbon taxation and network charges between the UK and the Continent, and the revenue mix might be expected to more similar if these distortions were to be removed.

[22] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure,
http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=EN

Conclusions

22. In conclusion, we do not believe it is possible for BEIS/Ofgem to identify where it should be focusing its attention without a better understanding of the relative contributions to the future flexibility mix of batteries and PSH (and indeed other large scale storage technologies). We would encourage BEIS/Ofgem to commission analysis and research to better understand the range of services that may be required in future and in particular the balance between shorter and longer discharge durations.

23. In light of such analytical work, we would also encourage BEIS/Ofgem to give further consideration to the development of a C&F regime for large scale storage technologies, in order to harness the considerable potential of such projects to reduce overall system costs and in order to provide a level playing field with interconnectors.

ScottishPower
January 2017