ACE Evidence: Electricity Interconnection and Storage

ACE response to the:

National Infrastructure Commission Call for Evidence

8 January 2016

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About ACE

As the leading business association in the sector, ACE represents the interests of professional consultancy and engineering companies large and small in the UK. Many of our member companies have gained international recognition and acclaim and employ over 250,000 staff worldwide.

ACE members are at the heart of delivering, maintaining and upgrading our buildings, structures and infrastructure. They provide specialist services to a diverse range of sectors including water, transportation, housing and energy.

The ACE membership acts as the bridge between consultants, engineers and the wider construction sector who make an estimated contribution of £15bn to the nation's economy with the wider construction market contributing a further £90bn.

ACE's powerful representation and lobbying to government, major clients, the media and other key stakeholders, enables it to promote the critical contribution that engineers and consultants make to the nation's developing infrastructure.

Through our publications, market intelligence, events and networking, business guidance and personal contact, we provide a cohesive approach and direction for our members and the wider industry. In recognising the dynamics of our industry, we support and encourage our members in all aspects of their business, helping them to optimise performance and embrace opportunity.

Our fundamental purposes are to promote the worth of our industry and to give voice to our members. We do so with passion and vision, support and commitment, integrity and professionalism.

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For this response, ACE has drawn heavily on its report, Electricity Market Reform: Generating Results, published in July 2014.[1]

Q1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
- Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
- Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

On tariffs, ACE found that rises continue to be of concern with the average dual fuel household bill rising from £1,057 in 2011 to £1,232 in 2012. These rises have been against a backdrop of low wage rate growth, employment uncertainty, and a general lack in consumer confidence, fuelling affordability concerns.

ACE's research found little evidence of regional pricing by the 'big six' companies, however, when analysing the differences between tariffs. In addition, it was also found that the benefits of switching are relatively limited over time, with direct debit customers being the main beneficiaries. Looking at the rationale behind price changes, our research found that the price reductions felt by consumers for direct debit tariffs are as a result of company's pricing policies and not simply inflationary changes.

ACE also found that over time there has been a shift towards short term, 'spot' trading with increased volatility and cost owing to the higher price that can be demanded on a short term transaction. These costs have then been passed onto consumers with little explanation from the energy companies or the regulator as to why increases in this kind of activity have been allowed to occur. Policy makers can no longer ignore such a shift, given the implications this has for affordability. As such, intervention is required to encourage more competitive, longer term trading on an open and transparent market.

There is also an increasingly vague view as to what the energy mix in the UK will be, creating uncertainty and holding back the investment the country needs. Whilst in theory, with the government remaining technologically neutral, competition should be encouraged. In reality it has created a situation where only the most certain of projects (those with the lowest financial, political and planning risk) progress, with all others prevented from progressing while investors continue to seek the right signals.

[1] *Electricity Market Reform: Generating Results* (2014), Association for Consultancy and Engineering, http://www.acenet.co.uk/electricity-market-reform-generating-results/746/12/1/8

Our research also considered the Consolidated Segmental Statements of energy companies and found that the costs and earnings of the generation arms of companies vary more significantly than that of their supply businesses. Economies of scale and efficiency are generally cited in favour of vertical integration in the energy sector, yet the analysis in this report called into question whether the actual benefit is passed through the system to the consumer.

In some circumstances the results even suggest that costs move in opposite directions for the different divisions of energy companies (e.g. generation and retail/supply), demonstrating that pricing signals are not efficient and the system is not responding to them as would be expected. Part of the reason behind this may be that companies are responding to media pressures and attempting to control costs at one end of the system. This, however, fundamentally undermines price and investment signals within the market.

The analysis also calculated the 'earnings' premium that is applied as prices pass through the system. That is to say that if generators charge more to suppliers, suppliers in turn charge more to consumers. For every extra £1 a generator earns in profit, a supplier is also able to make an extra £0.57p, making a total increase for consumers of £1.57. Given that more than 'base' costs are passed onto consumers the case for vertical integration and the efficiencies it brings within the market appears uncertain.

The correlation between generators' and suppliers' weighted average costs shows that as the former's average costs increase the latter's average costs do not change significantly. This suggests two possible scenarios, the first being that the average weighted cost of generators has no bearing on suppliers' average costs. Alternatively, supply businesses are able to hedge prices forward so effectively that they can absorb variations in generators weighted costs with little effect on their own. The second scenario is, however, questionable given the shift towards short term spot trading where it is more difficult to offset cost volatility.

The ACE report suggests a way forward which attempts to balance the needs identified within the EMR framework, including:

- The need for a policy which will secure a reasonable baseload and invest in solutions which can 'store' energy;
- The need to address capacity issues without radically reforming policy again and therefore increasingly delay and uncertainty which is a major problem for investors;
- Ways to improve and implement effective competition in the generation market by creating a secure base that lowers costs and allows technologies to compete where appropriate;
- The need for increased transparency within the market, allowing the retail side to access and buy from a number of sources.

This report proposes that five Generation Investment Vehicles (GIVs) with a combined value of £8bn are created to ensure that in the short to medium term project finance is secured. In order to secure medium to long term investment to 'lock' long term cleaner energy into the UK's generation system, this report also proposes that three Tidal GIVs (TGIVs) with a combined value of £21bn be created.

These vehicles could be used to finance for any type and combination of projects, for example:

- Six CCGT plants at an approximate cost of £3bn (providing approx. 7,500MW).
- Eight waste to energy plants at an approximate cost of £4bn (providing approx. 575MW).
- £21bn of funds towards the building of tidal/lagoon assets (providing approx. 2,000MW to 3,000MW).
- A £1bn fund for community projects, where money would be raised via crowd sourced funding.

The three £7bn TGIVs for example could finance:

- The roll out of either smaller tidal schemes or more economically the construction of a Severn Barrage (with a target price of 16% below the current £25bn estimated cost) to lock in lower cost long term electricity not only for this generation but also the next few.

Introducing a secure supply has to be accompanied by increased transparency and ultimately improved competition within that part of the market where competition for variable electricity demand takes place.

This paper proposes a Priority Auction Mechanism (PAM) where:

- A new structure of two open market traded exchanges where government has to purchase 50% of the capacity put forward in the first round, 75% in the second round, and all remaining capacity then having to compete OTC.
- The first round of purchasing will be on contracts longer than 24 months, while the second will see providers enjoy contracts of longer than 12 months' duration. This will have the dual impact of providing certainty of revenue for generators and encourage future investment whilst also encouraging a transparent and efficient pricing mechanism for the electricity market.

Q2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

The biggest barrier to the development and deployment of energy storage capacity is often the siloed way that infrastructure more broadly is considered, both at government and industry level. ACE's main recommendation in this area would be that future projects need to be considered much more in the round and questions as to whether there are possible energy storage angles must be asked and answered.

There is a significant need in the UK for substantial new infrastructure in the coming years, from housing, rail projects, road investment, and new water storage facilities. Government and industry must ensure that it works together to enable these schemes to adequately consider the possibility of incorporating energy storage techniques into their design and construction.

With the scale of housing required by the UK to meet demand, for instance, consideration should be given to incorporating technologies that allow for the charging of electric vehicles, as well as the ability for them to act as battery storage that can be used to supply power back to the house at various times. This will encourage take up through reduced bills, assist in meeting our climate change targets, and reduce reliance on the grid.

Additionally, there are plans for new reservoirs to be built, especially in areas of the country that experience water shortages at certain times of the year such as London and the South East. It is possible that this infrastructure can also be fitted with technology that allows for storage of energy that can be deployed at peak times when required then replenished during off peak times.

ACE's members are often at the forefront of innovations such as those mentioned above and others, and are keen to incorporate new thinking on projects they are asked to work on. The key barrier though is often a reluctance to consider the projects beyond their specific purpose, an attitude that should be resisted in the future if our infrastructure is to be fit for purpose.

Q3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?

ACE does not have any comment to make on these questions.

Q4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

ACE’s research into the international market found that the UK sits around 40 per cent above the IEA median for energy prices excluding taxation, and over 10 per cent when they are included.[2] This is important as a key component when comparing the UK with other global energy markets is price, and particularly the relationship between the amount being charged and the taxation being levied on top.

When the amount of taxation is benchmarked against the other IEA members, the UK is found to be leveraging only 5 per cent in taxation, well below the IEA median of 24 per cent. This perhaps indicates that the UK might not be proactive enough in reallocating resources from market which are inefficiently accounting for the effects of climate change, pollution, and volatile prices towards a more stable and sustainable long term solution.

Electricity prices in the UK on the open market (not including taxation) are some of the highest amongst the countries analysed. This is likely to be due to a lack of strategic planning as no one company considers investment in the UK as a whole at the macroeconomic level. As such, any investment outcome from the sector will favour individual companies’ investment strategies and not one that is efficient for the UK as a whole.

ACE’s research found that countries with higher energy taxation are often better insulated from rises in wholesale energy prices. We concluded that this was probably due to their improved ability to promote new technologies and a broader energy mix through better redistribution of capital via subsidies, tax breaks, or other funding mechanisms.

[2] *International Domestic Energy Prices* (2015), Department for Energy and Climate Change, https://www.gov.uk/government/statistical-data-sets/international-domestic-energy-prices

The Association for Decentralised Energy

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Bringing Energy Together

Response to National Infrastructure Commission Call for Evidence 8 January 2016

Context and Summary

The Association for Decentralised Energy (ADE) welcomes the opportunity to respond to the energy infrastructure section of the National Infrastructure Commission's Call for Evidence.

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

Our members include industrial energy users which generate their own energy on-site, local authorities which operate their own local energy generation, in addition to energy service providers and demand response aggregators.

We welcome the Commission's focus on energy infrastructure, particularly its focus on ensuring that existing and future infrastructure are used as productively and efficiently as possible.

Infrastructure should be developed with a clear aim – to deliver the best consumer value in the transition to an affordable, secure and low carbon economy. To do so, there are two key principles that should apply to reviewing infrastructure policy and investment:

- We should control consumer costs by using existing infrastructure more effectively to deliver a better value and more secure energy system. There are major infrastructure opportunities to cut waste from the energy system that remain untapped.
- New energy infrastructure investments should be considered holistically, as part of the wider energy system. There are major interactions with potential conflicts and synergies between heat, power and transport. To ensure the best value for energy users, the synergies need to be understood and exploited and conflicts mitigated. This cannot be achieved with the current siloed approach to energy policy.

By addressing these two principles, the Government could move towards more productive, better value energy, low-carbon infrastructure, for consumers' benefits.

We see the six key opportunities to deliver on these principles.

1. **Control consumer costs by using existing infrastructure more effectively**

   1.1. **Support demand side response, including load shifting and local generation.** Demand response enables users to take control of their energy and be rewarded for helping to maintain a stable energy system. Committee on Climate Change analysis identified nearly £7 billion of reduced infrastructure investment costs as a result of seizing demand side response in a low carbon energy system. Current policy is failing to tap this value and fails to value avoided infrastructure investment almost entirely.

1.2. **Drive network productivity.** Analysis of DECC data reveals that UK power network efficiency has improved by only 2% since 1990. If UK transmission and distribution losses were equivalent to those in Germany[1], the best in Europe, customers would save £605 million a year, the equivalent of £23 per household[2]. However, regulators' funding to cut network losses is small at only £6.4m a year over the next five years.[3]

1.3. **Retain and build on the key principle of 'cost reflectivity'**. The network charges applied to users and generators should reflect the costs they impose or reduce. As the energy system becomes more decentralised, is it vital we retain the value generators receive for not using the power transmission system, known as the Embedded Benefit.

2. **Build new energy infrastructure to deliver best consumer value**

2.1. **Invest in heat infrastructure to capture wasted energy.** The UK power generation system wastes enough heat for every home in the UK. District heating networks in densely populated areas are an ideal way to collect waste heat and move it to the points of use. This cuts unnecessary energy waste, boosts security of supply and reduces emissions.

2.2. **Look to today's energy storage solutions.** Energy users want energy services (mobility, warmth, computing), not the energy itself. Energy storage solutions should focus on the services needed. Thermal storage is far less costly than power storage. Holistic analysis of system energy needs will ensure we build the right type of energy storage rather than being enthused with the latest technology.

2.3. **Bring energy production and use nearer together**. This cuts network losses and enables wasted heat from power generation to be captured. Combined heat and power is up to 90% efficient compared to 50% for normal power generation, but needs to be located near to points of demand, such as industry.

Heat network infrastructure

The Infrastructure Commission has not addressed the potential for heat network infrastructure in its Call for Evidence, but we believe this offers a vital area for its future consideration.

Any time we make or use energy, we lose some of it as heat. Power stations, the industrial sector and cities like London all waste heat, and together they waste more heat than is used by every home in the UK. By building heat infrastructure, also known as district heating, in densely populated areas we can collect waste heat and move it to the points of use. It is by investing in this form of low carbon infrastructure that we can cut unnecessary waste from the energy system and reducing emissions at the same time.

Analysis by a number of research and Government bodies, including Stratego, the Energy Technologies Institute[4] and DECC[5], show district heating is a key form of cost-effective network infrastructure as part of the low carbon network transition. DECC has indentified a cost-effective potential for heat networks to meet 14% of UK heating demands by 2030, a seven-fold increase from today.

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[1] The World Bank data, based on the International Agency Statistics (OECD/IEA) 2012. Electric power transmission and distribution losses in Germany represent 4% of the electrical output, and it is 7.9% for the UK and 7.1% for Denmark
[2] Values each lost unit of electricity at the wholesale market price.
[3] Ofgem, 2015. *Losses Discretionary Reward Guidance Document.- Change in response to March 2015 consultation.*
[4] ETI, 2015. *Heat Insight – Decarbonising heat for UK homes*.
[5] DECC, 2012. *The future of heating: meeting the challenge*.

With the support of the Government's Heat Network Deployment Unit (HNDU), more than 150 local authorities are now investigating local heat infrastructure investments, with a value of more than £2 billion. These innovative schemes capture waste heat from power stations, industrial sites, and tube stations to make our energy system more productive and alleviate fuel poverty.

Government has now committed £300m to heat network development over the course of this Parliament. This investment is welcome and will help bring a number of schemes forward. However, a longer-term regulatory and market framework will be necessary if the UK's full heat infrastructure potential is to be reached.

Unlike gas and power networks, heat networks do not have an investment and regulatory framework underpinning them. The absence of such a framework excludes potential investors as the risks around district heating investment are considered to be significantly higher than for other network infrastructure projects. Government can take steps to reduce investment risk for this network infrastructure and secure larger, better-value schemes into development at low cost to taxpayers.

Bring energy production and use nearer together

Currently 54% of the energy used to produce electricity is lost by the time it arrives at a UK home or business. This lost energy is worth £9.5 billion a year to the UK economy. Put another way, it is the equivalent of £354 per household. It also represents carbon emissions equivalent to every car in the UK.

Combined heat and power (CHP) is a form of energy production infrastructure which produces energy close to customers, providing them with both heat and electricity. By producing electricity closer to its demand, CHP cuts network losses. If half of current centralised thermal generation was instead directly connected at the distribution level near demand, the avoided transmission losses would save energy users £135 million annually[6].

CHP also enables wasted heat from power generation to be captured and used by manufacturers, businesses and homes. CHP is up to 90% efficient compared to a maximum of 50% for normal power generation, but needs to be located near to points of demand, such as industry. The cost effective potential for CHP is more than three times the current capacity[7], and the potential captured heat could be worth more than £2 billion a year[8].

Currently the Capacity Market incentivises new power generation infrastructure that is largely inefficient and does not capture its heat. In the 2014 Capacity Market auction, nearly 2.6 GW of new generation included only 3 MW of new CHP capacity but about 800MW of gas and diesel engines which waste their heat. With limited new CHP capacity participating in the 2015 auction, results are not likely to differ significantly.

Responses to consultation questions

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

If the UK is to be successful in cost-effectively balancing supply and demand, a transparent, accessible electricity market is essential, shifting away from subsidies to market-focussed measures. A more market-based approach would decrease political uncertainty and enable

[6] See lesswastemoregrowth.co.uk/report
[7] Ricardo-AEA, 2013. Projections of CHP capacity and use to 2030. Report for DECC. Cost effective potential based on a discount rate of 15% over 10 years.
[8] See lesswastemoregrowth.co.uk/report

market participants to construct sensible economic models to justify new investment when the market deems it cost-effective to do so. However, any changes made to the electricity market must recognise the economic value of distributed generation and demand response in reducing system costs by reducing the necessity for costly network infrastructure.

Three key changes need to be made within the electricity market to ensure that supply and demand are balanced, while minimising cost to consumers, over the long term. These changes are to ensure that:

- Business energy users who provide demand side services can access and receive value from the wholesale and balancing markets.
- Demand response and on-site generation are treated fairly in a simplified, more user-focussed Capacity Market
- Balancing services are made more user-focussed, easy to navigate, and support the most cost-effective solutions, including generation, demand response and storage.
- Protect cost reflectivity for distributed generation and DSR in network charging

All three of these areas need to be addressed if the UK's full demand response potential is to be reached. Unfortunately, to date the UK's approach has been to address each of these three areas in silo. The DECC Energy Security team designs the Capacity Market, National Grid designs balancing services, while Ofgem and DECC design the wholesale and balancing market arrangements.

We see an opportunity for the National Infrastructure Commission to draw all three of these areas together into a comprehensive and cohesive policy to fully unlock the potential of distributed generation and demand response. We have outlined the key measures needed in each of these areas in further detail below.

Access to wholesale and balancing markets

Currently distributed generators, energy demand users, and aggregators are not able to access either the balancing market or the wholesale market. This creates two barriers which limit demand side management.

The first barrier is that the dispatch of a customer's demand response by a third-party aggregator changes the supplier's balanced position, creating costs or benefits for the supplier depending on their position.

The second barrier is that demand side services can only receive value for the demand response in the wholesale market if the energy user or their aggregator have a contract with the customer's licensed supplier. This currently limits the growth of the demand response market and adds a significant transaction cost and barrier for demand response providers.

These issues are addressed in further detail on Page 7 in response to the question: *Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?*

Fair participation in the Capacity Market

The Capacity Market was largely designed for large, centralised generators, and this has limited the competitiveness of distributed generation and demand response.

The Government's commitment to reform the Capacity Market to ensure it brings forward new gas power plants carries a significant risk that the reforms unintentionally damage both on-site generation and the growing UK demand response market.

It is important that the Capacity Market increases, not decreases, fair treatment across different technologies and approaches. This includes equal contract lengths between all Capacity Market participants, as currently new build generators can receive 15 year contracts while existing generators and demand response participants are limited to one year. This difference in contract lengths results in very different support levels for different capacity types, and results in uncompetitive outcomes.

The focus on new build generation may risk missing the already sizeable potential capacity from existing resources. For example, while 4 GW of CHP and autogeneration successfully cleared the Capacity Market in 2015, there is more than 7 GW of autogeneration capacity listed in the Digest of UK Energy Statistics. These figures indicate that more than 3 GW of existing generation did not participate in the Capacity Market. In addition, as addressed later in this consultation, the potential demand response market is several gigawatts. Therefore measures to facilitate the participation of existing generators and demand response are arguably just as important as measures to stimulate investment in the Government's preferred technologies.

Access and participation in balancing services

There are a number of hurdles which can commonly arise and prevent demand response from providing the balancing services that are procured by National Grid. These include over-sizing minimum bids, requiring fixed quantities to be available for long periods, activations that are too frequent or have unnecessarily long maximum durations, and requirements for symmetric bids.

The launch of National Grid's Power Responsive campaign in 2015 was a positive step in bringing attention to how the System Operator can facilitate a cost-effective demand response market through its balancing services. Current work by National Grid to develop both a new Demand Turn Up service and a new demand response service are very welcome progress, especially as the only dedicated demand response balancing service currently available is the recently-introduced Demand Side Balancing Reserve, which is expected to end by 2018.

However, over the longer term there will be a need for National Grid to look at its suite of balancing services in the round and ensure they are simple, customer-led, and focussed on securing least cost services, whether from generation, demand response or storage. This will include considering whether the common barriers outlined above can be mitigated or removed across its balancing service offers.

Protecting the embedded benefit and the principle of network 'cost reflectivity'

Key to keeping costs low for consumers is to ensure 'cost reflectivity' that is the prices charged to users and generators should reflect the costs they impose or reduce on the system. Without such signals there is a significant risk that overall costs for consumers will rise. There are two areas where cost reflectivity is a current issue:

As distributed generators do not use the transmission system, they do not pay for its use. This recognition is termed the 'Embedded Benefit' and allows generation to avoid the cost of Transmission Network Use of Systems (TNUoS) charges. National Grid reviewed the Embedded Benefit in 2013 and decided to retain the Embedded Benefit following a clear response from every major energy association that the proposals would make the energy system less cost-reflective and risked overall higher costs for consumers.

In those cases where increasing local generation causes electricity to 'spill upwards' onto the transmission networks, new infrastructure investment may be needed[9]. It is right for National

[9] This is termed an 'exporting grid supply point (GSP)'

Grid to ensure cost reflectivity extends to this issue, but it must implement changes so they recognise the future more actively managed local network. As such it will be important for National Grid to consider the future distribution system in its consultation.

What role can changes to the market framework play to incentivise this outcome:

Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

We recognise there is a conflict of interest within the current arrangements, where the System Operator is also earning a return from investments in system assets. We would agree with the benefits of having an independent system operator to ensure consumers do not pay for unnecessary infrastructure investments.

However, we are unconvinced the creation of an independent system operator is the most urgent step at this time, with a number of other more vital changes to the UK electricity market and network arrangements. There is a substantial risk that the creation of an independent system operator distracts Government and regulators from making these important changes. We also think it important to recognise that the current balancing services offered by the System Operator are some of the only avenues available for most demand response providers to secure revenue for their services.

The increasing management role for distribution networks

Current energy security policy and operation is approached from a national, centralised perspective, rather than a local one. National Grid is not able to model overall the optimal investment in the electricity supply system, or the optimal location of generation. There are future cases where there could be a surplus of supply on one local area and its distribution network, while other areas have a shortage. The Capacity Market's focus on securing national electricity supply without regard to local demands exacerbates this issue.

As the energy system becomes more localised, with local generation meeting local demand, there will be more of a need for local network management solutions. Ofgem recognised this year that to achieve a more flexible, responsive system it will be important to see Distribution Network Operators transition become Distribution System Operators. Therefore either the Infrastructure Commission or an independent system operator would need to consider both the transmission network and the distribution networks, and an independent system operator at a national level must support innovation at the distribution network level to deliver more localised active management solutions.

Consideration should be given to the distribution network's planning standard, known as P2/6[10]. The Energy Networks Association is leading a revision of this planning standard[11] which will determine the approach distribution networks take to new infrastructure investments. It will be integral this review is ambitious in supporting and driving innovative solutions in distribution networks to reduce the cost of distribution infrastructure to consumers.

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[10] P2/6 defines the required levels of security of supply in terms of the time to restore supplies to customers affected by a circuit failure.

[11] http://www.dcode.org.uk/assets/files/Working%20Groups/May%201%202015/DCRP%20P2%20WG%20Wider%20Stakerholder%20Enagement%20Workshop%20presentation%201%20May%202015%20FINAL%20FULL.pdf

Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

Yes. Under the current GB market framework the dispatch of a customer's demand side response by a third-party aggregator changes the supplier's balanced position, creating costs or benefits for the supplier depending on their position. Since the trigger for the change in balance position is based on external actions, the supplier should neither be penalised nor rewarded for the change in their position. The demand response action may also risk changing the supplier's energy position, where they purchased a certain amount of electricity for a half hour period which they now did not sell.

The solution to this problem is to allow for the settlement of the energy position between the aggregator and the licensed supplier. The aggregator would therefore buy the sourced, but not consumed, energy in the case of demand reduction. By doing so, the balancing position of the supplier will be corrected and the supplier will receive fair payment for their open energy position.

However, we would caution that just reforming the treatment of imbalances created by demand side actions is insufficient to secure increased demand response in the GB market.

The current electricity market arrangements do not allow direct access by energy customers to the market, and this issue is the critical barrier to the development of demand response. There are no provisions for a market participant who is not a supplier or a generator to participate in the balancing or wholesale market, and it will likely require a new category of participant to be defined with proportionate requirements.

Therefore, under current market arrangements, a customer or their demand response aggregator must have a contract with a supplier to access the wholesale market. This currently limits the growth of the demand response market and adds a significant transaction cost and barrier for demand response providers.

Energy suppliers can give customers the ability to provide generation and demand side services, but this approach requires a customer to both receive supply and provide demand response through one agent. This limits competition by preventing the customer from shopping around separately for the best, supply and demand response deals separately, even if it is more economic to have different agents for each service (purchasing supply and providing demand response).

The evidence from other energy markets shows that, for these services to be successful and lead to market growth, it must be possible for consumer flexibility to be unbundled from the sale of electricity: markets with mature levels of demand-response participation have all unbundled the purchase of demand-side flexibility from normal supply. In fact, the evidence indicates it is not possible to reach efficient levels of participation without doing so. The examples are the large US centralised markets, such as PJM, the Western Australian capacity market, and the New Zealand ancillary services markets.

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

The Association for Decentralised Energy is currently developing a bottom-up analysis of the potential for demand side measures and embedded generation to increase flexibility of the electricity system. We expect our analysis to be completed by March 2016.

It is important to note that there is already a significant amount of demand response and embedded generation in use in the UK contributing to flexibility. The Digest of UK Energy Statistics lists nearly 7 GW in autogeneration in 2014. Currently, there is currently estimated to be 1 GW of demand response in the Industrial and Commercial sectors (defined as an action to reduce a customer's metered consumption)[12].

Almost all of this existing embedded generation and demand response is located in the industrial, commercial and public sectors. However, we still see a significant potential energy resource from these sectors. For example, there is a total of 30 GW[13] of industrial and commercial peak demand. Securing 10% of this demand, as occurs in other international markets such as Belgium and the US, would result in 3 GW in demand response capacity.

A 2014 Imperial College and Element Energy study for the Committee on Climate Change found that by deploying smart voltage regulation and demand-side response around on distribution networks, £5 billion of reinforcement costs to enable decarbonisation could be avoided. This is in addition to £300m in avoided transmission infrastructure costs. A September 2015 analysis of the UK's demand response potential produced for DECC showed that there is currently more than 18 GW of peak demand which could participate in demand response, given the right market and regulatory framework.

2. What are the barriers to the deployment of energy storage capacity?

Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

We agree with the Commission's focus on the importance of energy storage, but would caution that a systems approach to new infrastructure can ensure that we are able to take advantage of synergies between heat and electricity, specifically in securing cost-effective energy storage. Fossil fuel systems, such as coal and gas, can store significant amounts of energy, and a move to a more renewable system will require that such existing energy storage to be secured in other ways.

Thermal stores are a large version of a household hot water tank, and heat is cost effective to store. Thermal stores can reduce the cost of balancing the electricity system, and heat network efficiency. These both cut consumers' bills. When the electricity grid is over-supplied (e.g. high wind and solar), instead of paying turbines to stop thermal stores can turn on electric boilers absorb the electricity and release it as heat when customers need it. When the electricity grid does not have enough power, a heat network or home can use highly-efficient combined heat and power to generate electricity and store the heat for when users need it.

Analysis by the UK Energy Research Centre (UKERC) found that heat networks supplying 100,000 heat customers with large-scale heat pumps could provide the equivalent of 8 GW battery storage. Their analysis also found that heat storage costs as low as £25/m^3, which translates to the equivalent of £31/MW of electrical storage capacity[14]. European analysis has found that the price differential between gas and liquid storage; thermal storage; and electricity storage is

[12] National Grid, Future Energy Scenarios 2015 and associated tables
[13] ADE analysis based on NG data for overall power demand in 2014 and peak power demand profile
[14] Eames, Phil, et al, November 2014. The Future Role of Thermal Energy Storage in the UK. UK Energy Research Centre.

1:100:10,000. This means that while thermal storage is 100 times more expensive than gas and liquid storage, thermal storage is also 100 times cheaper than electricity storage[15].

Despite being available today, thermal storage struggles to participate in an electricity market designed for large, centralised generators. Such challenges are also faced by battery storage. The market failures and barriers faced by storage technology providers are similar to those faced by other distributed generators and demand response providers. These include:

- Limited ability to access and receive value from the wholesale and balancing markets.
- Difficulty accessing the Capacity Market due to complicated and unfair scheme design.
- Ensuring balancing services are customer-focussed, easy to navigate, and support the most cost-effective solutions, including generation, demand response and storage.

What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.

The determination for the most appropriate scale for energy storage technologies should be based on cost-effectiveness, allowing market solutions to come forward. This will likely result in a mix of solutions at the industrial and commercial scale, as well as at the network scale.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

The ADE has no comment.

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Switzerland is the best case example of a European country on delivering cost-effective balancing of supply and demand. Demand response aggregators are 'Balance Service Providers' (BSP) and contract directly with the Swiss Transmission System Operator to access the market. The Neither aggregator as BSP or the supplier as a 'Balance Responsible Party' (BRP) are charged for imbalances caused by load curtailment, and any commercial loss to the BRP is reimbursed.

For further examples, we would recommend *Mapping Demand Response in Europe Today* by the Smart Energy Demand Coalition.

For further information please contact:
Jonathan Graham, Head of Policy
[email address redacted]

[15] EU Heating and Cooling Strategy Consultation Forum Brussels, 9 September 2015, "Issue Paper IV Linking heating and cooling with electricity".

Response to the National Infrastructure Commission Call for Evidence: Electricity interconnection and storage.

January 2016

The following response provides the thoughts of the Association of Directors of Economy, Environment, Planning and Transport (ADEPT) in the area of energy as requested by the Call for Evidence.

About ADEPT

ADEPT represents local authority county, unitary and metropolitan Directors who manage some of the most pressing issues facing the UK today. Operating at the strategic tier of local government, we are responsible for delivering public services that primarily relate to the physical environment and the economy, but which have a significant impact on all aspects of the nation's well-being.

ADEPT is submitting a response to this call for evidence within this context. At the local level, our members, with our wide-ranging responsibilities and cross-cutting professional knowledge, have a unique understanding of the opportunities and barriers facing their respective places. Because we start from a place-based approach, we automatically join up policy areas that in Whitehall are spread across a number of different Departments. We therefore see ourselves as having a key role in supporting and helping to deliver sustainable economic growth and quality of life and are keen to work with Government, business and the community and voluntary sector to make the most of the opportunities available.

As one of the key organisations representing officers in local government whose areas of responsibility cover energy and climate change we would welcome the opportunity to work closely with the Commission in its deliberations.

1. What changes may need to be made to the electricity market to ensure that supply and demand is balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

ADEPT believe that the system operator function should remain with National Grid (NGET and NGG), and that any dilution of this would be counterproductive. The incentives currently, related to cost factors, should remain however there should be a greater range of incentives covering storage capacity and the stimulation and delivery of demand reduction within the system.

The balancing market should be shifted to ensure that the most is made of renewable energy generation, on a local level[1], so that transmission losses are reduced to a minimum. The inefficiency in the electricity distribution network, due to transmission losses, needs to be addressed, and significant inroads into this will greatly increase energy security, and reduce the costs for consumers. This is particularly for consumers in rural and remote locations where renewable and storage can provide an important part of the future energy infrastructure. The approaches of some islands in Scotland are beginning to demonstrate what can be achieved through community generation and storage. A greater level of investment in innovation in business and universities through, for example, Innovate UK, can help drive this area of the economy and provide potentially increased productivity in local economies through the commercialisation of solutions for the UK and export markets.

The new energy infrastructure thought needs to ensure that it enables the transition to a low carbon economy. While this needs to be mindful of the costs to the consumer the cost of not transitioning will be greater to the consumer and other parts of the economy. The transition, for which the energy sector is pivotal, needs to be based on the needs of the UK as a country and not through the pure lens of a market derived solution. The transition while offering many opportunities for business and the country will also require challenging existing vested interests. The Commission will need to make some difficult choices and there will be a need for further research, to understand when we need to make significant step changes, to position the UK ahead of its competitors. If we are not to miss out on export possibilities and maintain and grow any productive advantage for UK innovation and development.

In this light our future infrastructure needs to be flexible so that it that does not penalise renewable technologies, for periods when the wind does not blow or there are low light levels. We would argue that the growth of renewable energy is only part of the renewable solution. Energy storage, as power or heat, or its use in power to gas solutions provides the whole of the renewable technology offer, to date renewable have been seen in isolation from their complementary technologies.

Therefore it is the development of storage that is key to smoothing out fluctuations in generation, and this is where investment and market balancing

[1] http://www.ukcec.org/our-vision-community-energy-2020

should be targeted. There needs to be greater research into the potential for domestic, community and city level energy storage to support local renewable generation but also provide storage for energy produced in excess of what is needed from nuclear and gas so it can be used in periods of high use. It should also be considered how this can be built into new developments funded through Government and European programmes to provide a more joined up solution. We need to future proof economic development and housing infrastructure for the future so that we can deploy “plug and play” energy solutions be they district heating or sub-national energy storage.

The Commission, we would suggest, needs to consider undertaking research in how the new infrastructure should be financed and, how and, if there should be separate funding and incentives regimes for different levels of investment and technology at national, city, community and domestic levels. There also needs to be a better understanding of how the internet of things can support this transition and the potential costs[2].

We would agree with the publication by Green Alliance[3], and comments made by the Energy and Climate Change Select Committee, that the Government should create a FIT mechanism for demand side reduction as part of a comprehensive transition finance package for domestic properties and businesses.

The current demand reduction pilot needs to be expanded, and represent better value for money for businesses and have greater flexibility.

The Government also needs to ensure that the emergency capacity market does not create strange anomalies where diesel generators can out-compete more low carbon options on price without regard to the carbon impact.

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other ‘balancing’ technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

The lack of investment in energy storage capacity at sub-grid level and research, which has the potential to be a significant area for growth and export, lags a long way behind where it needs to be. If we are to achieve the ambitions in the Low

[2] http://www.techthefuture.com/technology/the-hidden-energy-cost-of-networked-devices/

[3] The Power of Negawatts Green Alliance October 2012 http://www.green-alliance.org.uk/resources/The%20power%20of%20negawatts.pdf

Carbon Transition Plan then we need to increase the development and deployment of the current small scale storage industry including investment in non vehicle based hydrogen fuel cell storage, thermal and electricity storage. The Government and system operators need to see renewable technology as an integral part of the mix with storage enabling the smoothing out of fluctuations in generation and increasing resilience.

However at present the cost of domestic, community and city scale storage is unaffordable and does not represent value for money at anything but large scale deployment by DNO's. The Government needs to provide market mechanisms to reduce the initial cost of storage options, and grow the market place and reduce cost in the long term. The FIT for renewable generation, as mentioned above, should be deployed as has been done in Germany[4]. Homes and offices that generate energy, but have a surplus, would be better storing it for use at peak times, thus supporting peak demand reduction as well.

The transition to an electric/ hydrogen economy in domestic and transport use requires a significant increase in domestic, community and city storage.

The UK should consider the generation and distribution of energy on a more district heating ethos. In other words, local generation used locally. While we will still need a national generation and distribution network, we need to maximise the benefits of local network storage, to reduce costs for the consumer and increase resilience.

As the energy network of the future needs to be more distributive, then investment must come from Government, National Grid and the DNO's to stimulate the market. The current regulation framework does not appear to incentivise this.

There is the potential for energy companies to develop Power Purchase Agreement solutions for its customers, to increase the spread of single property and community level storage. The current energy system incentivises large scale single point storage, we need to diversify this to increase energy security, and make the most of UK local generation and reduce interconnector dependencies.

The Government needs to set out a national energy storage policy, and target to stimulate the market and put appropriate incentives in place. The storage should be for both power and heat. There also needs to be a clear policy steer on the role of the hydrogen economy, and how power storage and surplus energy, is used for this emerging part of the economy.

[4] The Energy Storage Market in Germany Factsheet: Germany Trade and Invest Issue 2015/16
https://www.gtai.de/GTAI/Content/EN/Invest/_SharedDocs/Downloads/GTAI/Fact-sheets/Energy-environmental/fact-sheet-energy-storage-market-germany-en.pdf

The reduction in FIT has had a negative impact in particular, on the potential for community generation in off grid rural and urban locations, we feel this is unfortunate of the Government and runs contrary to localism, devolution and the Community Energy Strategy. For those communities that are off grid in particular, renewables provide potentially the only option to reduce the significant costs of energy, and when these are linked to storage options can create greater energy security and cost reduction for these communities.

This needs to be detailed consideration of the climate change vulnerability of current and future energy generation and storage facilities and locations. The floods over the last ten years have shown how vulnerable energy infrastructure is and the events in Cumbria in 2015 show that even protected assets are still vulnerable. The climate adaptability of our infrastructure is just as important as what infrastructure we should have. It must not be seen as an optional extra but built into the design, location and costing of our future network. There is the opportunity with the current reviewing of the Climate Change Risk Assessment[5] and National Adaptation Programme[6] to address these concerns.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current ‘cap and floor’ regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?

There is a concern that a reliance on greater interconnectivity will leave the UK subject to uncertain energy cost increases from other national governments. There is also a concern about the distance electricity can be transported before the energy losses through transportation defeat the objective.

While there is certainly a need for a European interconnector energy system based around the North Sea, because of the potential from offshore wind energy, we need to consider how we can store energy from UK generation to reduce the need for taking supply from interconnectors. There also needs to be an assessment of the vulnerability of energy generated from countries we are connected to in terms of how climate change will affect their ability to generate and supply surplus or dedicated energy to the UK.

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[5] https://www.theccc.org.uk/tackling-climate-change/preparing-for-climate-change/climate-change-risk-assessment-2017/

[6] https://www.gov.uk/government/publications/adapting-to-climate-change-national-adaptation-programme

The cost of energy from interconnectors should be cost competitive with that from renewable and other low carbon technologies. Further any energy delivered through interconnectors should only come from low carbon sources. We would not wish to see the UK low carbon transition undermined through carbon intensive interconnection sources.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

It is important that the new energy infrastructure acknowledges the important part that will be played by non-traditional infrastructure at local and city level. While we need a national generation and distribution network we need to invest in and develop more distributive energy networks such as those in Scandinavia and Germany to deliver zero and near zero carbon production. The continued investment in HNDU is welcomed but there is still a significant knowledge gap in local authorities who are the prime instigators of this approach nationally. Funded training for knowledge transfer to local authority officers involved in district heating would be welcomed so that we can ensure that the public sector obtains the best value for money.

We would suggest that the Commission speak to the author and futurologist Jeremy Rifkin who has a significant insight into the energy infrastructure transition that needs to take place. He has advised the European Union, Angela Merkel and Francois Hollande as well as the Chinese Government and numerous cities globally[7].

Contact details
If you would like to get in touch with ADEPT, please contact the Association's Secretariat who will direct your enquiry to the appropriate person.

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[7] Jeremy Rifkin The Third Industrial Age http://www.thethirdindustrialrevolution.com/

7 January 2016

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energyevidence@Infrastructure-Commission.gsi.gov.uk

Dear Sirs,

National Infrastructure Commission: call for evidence on improving how electricity demand and supply are balanced

Age UK is delighted to put some brief suggestions to the Commission as it considers these initial issues in the energy sector. The Charity co-signed a letter to the Chairman before Christmas proposing that there is merit in looking at energy efficiency programmes in general as a means both to manage demand more effectively and support consumers (especially the most vulnerable) to reduce consumption, and thus reduce their likelihood to be at risk of fuel poverty. Since this would amount to a major home retrofit and refurbishment programme, our argument was that it should be seen as a legitimate infrastructure project, recognising the savings that could be made in new generation capacity as well as the various economic and social benefits accruing from increased employment and better health outcomes. We highlight some of these benefits towards the end of this letter, and are still keen to see the Commission take a view about this wider vision.

However, this submission recognise that the Commission has defined its enquiry more specifically, so our suggestions are confined to that narrower agenda. In particular, we have noted that the Call for Evidence is primarily about the demand for electricity, so we have eschewed any comments on gas usage, and the use of gas for space heating, where there are significant potential savings from a more widespread investment in the upgrading of heating systems and the improvement of domestic insulation.

Below we outline our key points, which we would be happy to expand on and discuss.

1. **Scrappage schemes**
   Government policies can have a big influence on consumer and market

response. The boiler scrappage scheme is a case in point; it helped significantly to stimulate demand for new, efficient boilers. That scheme, plus the rules for scoring energy savings outcomes in the Energy Company Obligation, weighted the choices offered by ECO strongly in favour of boiler replacements (which, for the fuel poor, would have been an unaffordable capital expense, by definition). As with old boilers, there must be thousands – perhaps millions – of ancient and inefficient fridges and freezers operating wastefully in domestic homes. There must be scope for similar scrappage schemes, and, as ECO is being reshaped pending its renewal from Spring 2017, for its outcomes to be reappraised, in order to promote the deployment of more efficient electrical goods.

2. **Domestic generation and storage**

Domestic generation of electricity triggered by feed-in tariffs has been a startling success, and led to a dramatic fall in the cost of photo-voltaic installations. But this momentum must be retained despite the well-publicised changes to the feed-in tariff regime, and the clue here probably lies in battery technology. Domestic batteries, which store the energy generated for later release, are now much more effective and efficient, but not yet available at scale in order to see their installation costs falling. There is a case for stimulating the domestic battery market with a time-limited subsidy or an incentive in the same way as the original concept of the feed-in tariff envisaged.

There may also be a case for a similar subsidy for battery schemes at a greater scale, linked to wind and solar generators in order to smooth their input of power into the grid.

3. **Reforming Green Deal and ECO**

The Green Deal was a massive disappointment, and one reason was probably that it was developed for individual households in the hope that they would individually and separately appreciate the concept and opportunity it offered and buy into it in isolation from the wider community. Similarly ECO has hitherto been largely focussed on individual households, some of which have shown little appetite even for a cost-free scheme when weighed against the disruption, mess and distrust of the work proposed.

However, where different programmes have been implemented at a community level, and encouraged neighbours to work together and provide mutual support and re-assurance, take-up levels can improve dramatically. The benefit goes beyond take-up and installation; neighbours compare notes on how the new scheme is working for them, and how they are making savings and using the benefits to best effect. ResPublica (amongst others) has done useful research into how behavioural change messages are amplified if they can be embedded in common conversation in a neighbourhood or community.

The emphasis in a new Green Deal and a re-shaped ECO must be to offer a wider array of options for community based schemes. Simple templates would curtail the administrative uncertainty for any neighbourhood or community group contemplating going down this route, and it could work with battery provision included too. And of course there is scope for incentives and other stimuli to be part of the package, such as reductions on Stamp Duty or council tax.

4. **Smart meters**
The ramping up of smart meter installations this year and through to 2020 is intended (inter alia) to prompt a new interest in energy usage and consumption. The role of Smart Energy GB is primarily to drive a consumer engagement programme, and create a conversation where householders compare notes on what they are discovering from their new meter, and what it is prompting them to think about in order to save on fuel consumption and costs. Possible actions they may consider taking may lie in some of the paragraphs above, but we need to convert 'possible' actions into 'probable' ones. That requires facilitation on two fronts. First the capital costs of installing new equipment or housing adaptations need to be underpinned by an offer of soft loans (or grants and other incentives). Second the finding and commissioning of suitably trained and qualified installers, with credible complaints routes and appropriately guaranteed outcomes, is an important support service. The Bonfield Review is looking at this latter consideration with vigour. The Infrastructure Commission may want to engage with this work by offering recruitment and training support.

5. **Making consumer action more straightforward**
The installation of smart meters is one potential trigger point to raise consumer awareness about energy usage and possible savings. It is also a one-off opportunity to engage with every household in the country: everyone will be visited by a skilled energy engineer, whose visit should prompt a short discussion about using the information provided by the meter to manage their energy better. The engineers must be careful not to push the sales of energy upgrades, new appliances and other services, but it would be a colossal missed opportunity not to offer information and to make informal suggestions about improving energy consumption and to suggest lines to explore. But leaving the premises without comment about the likely cost of those improvements and how to access funds to act on them would be equally inadequate. There needs to be some mechanism whereby people can be referred to a neutral advice agency which can take the householder forward to the point of action.

   Interestingly, the National Institute of Health and Clinical Excellence published a Guideline (March 2015) calling for precisely that, so that medical professionals, who suspect that a patient's health could be in jeopardy as a result of living in a cold home, could signpost a route forward. The Guideline suggests that non-medical professionals, such as these visiting smart meter engineers, could access the same service. The Infrastructure Commission may wish to consider how to stimulate a development along these lines.

   A service of the kind envisaged does exist in a number of local areas, but seldom under an identifiable household name. Some are statutory, but most are a mixture of voluntary and commercial interests: there is no generic name to build on to promote awareness of the service: their skills are not monitored and few can offer professional indemnity cover. But there is a rudimentary system to build on.

6. **Energy Performance Certificates**
Energy Performance Certificates were originally intended to provide a better map of the energy efficiency of our housing stock. Since they are only mandatory when a property is sold or rented to a new tenant, their penetration has only extended to about half the national housing stock. There is no reliable update

procedure – for example when people have undertaken home improvements. They do not give the householder a menu or shopping list of potential steps they might consider taking to improve their homes. Overall, they are rather superficial and fall short of being fit for purpose.

The Bonfield Review is looking at how they might be improved and turned into a more useful tool for helping a householder to manage energy more effectively, but inevitably there is a national investment called for in implementing a better system. But taken together with some of the other suggestions tabled above, there could be merit in seeing EPCs as an important part of the infrastructure architecture, and thus a legitimate concern for the Commission.

With the exception of point 2 (supporting the development of battery technology), our focus is on managing demand by promoting more consumer awareness about energy usage, and making it easier for consumers to reduce their consumption. Investing in effective consumer awareness will be key to achieving the needed demand-side responses.

Age UK is willing to provide more detail and supporting material. We are impressed by the modelling work done by Cambridge Econometrics and Verco, which shows the potential of a national programme aimed at supporting all low income households to achieve at least EPC Band C by 2025, and helping all households to achieve that by 2035. This could lead to outcomes including:

- GDP increased by £3.20 on a Government investment of £1.00;
- Tax revenues increased by £1.27 on a £1.00 investment;
- A 23.6MtCO2 reduction per annum by 2030;
- Total energy savings of £8.6bn – over £400 per home;
- 108,000 new jobs (net) per annum over the period 2020-2030;
- NHS savings of 42p for every £1 invested in reducing fuel poverty.

Overall, we ask the Commission to consider the merits of adopting energy efficiency as a key priority to reduce energy demand from our growing population of older people, many of home live in cold homes and put pressure on health services.

Yours faithfully,

Mervyn Kohler

External Affairs Adviser
Age UK
[email address redacted]

National Infrastructure Commission:
Call for evidence

APM background
The Association for Project Management (APM) is a registered charity with over 21,000 individual and 550 corporate members making it the largest professional body its kind in Europe. APM is committed to developing and promoting project and programme management through a wide range of activities including membership, qualifications, events and enhancing standards and knowledge in the profession.

About APM's call for evidence and background of respondents
APM held an online survey which was open to members and the wider project management community. Responses came from a wide variety of business sectors such as transport and logistics, consultancy and construction as well as a broad spectrum of roles including project managers, academics and company directors. The timing of the call for evidence reduced the opportunity for the fullest consultation, so this document presents an informal synthesis of responses received, rather than a formal statement of APM policy.

NIC Call for evidence

1 Connecting northern cities

1) To what extent are weaknesses in transport connectivity holding back northern city regions (specifically in terms of jobs, enterprise creation and growth, and housing)?

Respondents felt that weaknesses in transport connectivity are currently playing a major role in holding back the development of enterprise creation and growth in northern cities. Job creation was also an area of concern in terms of connectivity with respondents noting that connectivity played some extent in regards to this issue. Housing was not a great issue amongst respondents, with most believing that connectivity had little or no impact on the northern housing market.

2) What cost-effective infrastructure investments in city-to-city connectivity could address these weaknesses? All transport modes are open for consideration.

Some respondents noted that road users could be reduced by expanding the Manchester Metrolink into Cheshire which would primarily serve to support the Cheshire hinterland around Manchester. It was felt that Manchester Airport railway station has a useful range of services but the lack of parking, very limited pick up and no bike facilities, means it is impractical for many would be travellers particularly locals who have not flown into Manchester Airport. A railway link from Manchester Airport south connecting into the Manchester- Chester line, would considerably improve the access to the Airport from Chester and surroundings. Modern electrified rail services with fast and reliable commuter services are desperately needed throughout the north of England, both between and within cities. Rail connection to airports such as Leeds and Manchester are essential. Rail networks should also consider more reliable goods transport to take heavy goods vehicles off the road thus rail development should be prioritised over building new and enhancing existing roads.

All respondents felt that, although road transport will continue to be highly important, is important to note that it is only one form of communication and is currently close to maximum capacity. Respondents noted that by including on-line and virtual communication methods when considering infrastructure investments, it would be easier to identify the essential from the nice-to-have. It was felt that a policy of nationally driven localisation would create the capability for regions to identify and resolve their own transport needs which would speed up action and create a greater focus on sustainable regional needs.

In terms of funding, respondents believed that the current regulated privatised system in key transport modes exposes the taxpayer to all of the downside risk and the private sector to all of the upside risk. They considered whether it would be possible to run a multimodal tender where private and public sector bid on the same basis. It was felt that running a tender like this, with all costs truly pushed up front, allows for the different bodies real risk appetite to be shown, ensuring that a true cost can be identified and assessed appropriately.

3) Which city-to-city corridor(s) should be the priority for early phases of investment?

Respondents considered a number of potential corridors which they felt should be considered as priorities for early phases of investment. These included:

- The expansion of the Metrolink into Cheshire
- Hull and Grimsby (docks) to Leeds
- Leeds to Birmingham
- Leeds to Newcastle
- Manchester to Birmingham
- Manchester to Liverpool

4) What form of governance would most effectively deliver transformative infrastructure in the north, how should this be funded and by whom, including appropriate local contributions?

It was suggested that a strategy of regional empowerment could involve some type of pan-northern political body to make the decisions. This could potentially be headed by Ministers and include northern MP's and Councils with oversight from central government to ensure that national interests were not compromised when achieving only local gains. The advantage of such an approach would be centralised information and idea sharing which might stimulate growth with sustainable solutions conceived by the areas impacted by change. It was also felt that local employers should have a voice and thus involved in the funding solution.

Funding could be from a combination of central and regional potentially supported by fairer distribution of existing subsidies, possibly away from London, and by reducing road infrastructure development in favour of rail and by private contributions from rail operators as well as government capital and borrowing.

5) What are the key international connectivity needs likely to be in the next 20-30 years in the north of England (with a focus on ports and airports)? What is the most effective way to meet these needs, and what constraints on delivery are anticipated?

Respondents believed that both Leeds-Bradford and Manchester airports had the potential for expansion but require enhanced rail links and more long distance flights in order to reduce the need to travel to airports in the south east. All respondents noted that northern ports have an important role to play in terms of international connectivity over the next 20. Sunderland, Grimsby/Immingham and Hull were cited as potential models which would serve to support UK import and exports and hopefully help support a northern powerhouse built around engineering and advanced manufacturing. Success at these ports may also open the way for Newcastle or Middlesbrough ports to be further developed to respond to changes in demand and volume.

2 London's transport infrastructure

1) What are the major economic and social challenges facing London and its commuter hinterland over the next two to three decades?

Nearly all respondents believed that the UK is overly reliant upon London and the South East which has led to over-crowding, inflated property prices and increasing pressure upon its infrastructure and services.

Many also felt that this 'London centricity' fuelled unnecessary travelling into London whilst creating a lack of investment in the northern cities and elsewhere. Most respondents felt that incentives are needed to encourage people to move to other parts of the country to utilise the available resources and capacity in other UK settlements.

2) What are the strategic options for future investment in large-scale transport infrastructure improvements in London - on road, rail and underground - including, but not limited to Crossrail 2?

Respondents only offered limited guidance in answering this question but many felt that large scale infrastructure developments could be diverted from London to northern cities.

3 Electricity interconnection and storage

1) What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Many respondents noted that in the short term, local generation though wind and solar energy should be encouraged and supported, with some local storage and less reliance on the national grid. Demand management can only be assisted by improving housing stock and price incentives. Participants noted that the UK faces a major power supply shortage with poor resilience, lack of generating capacity and poor distribution. Most of the market questions cannot be addressed adequately until secure supply is achieved.

2) **What are the barriers to the deployment of energy storage capacity?**
Much household demand could be for low voltage, such as can be generated by solar energy and stored in batteries. Respondents suggested that new housing might have a low voltage distribution network for lighting and electronic items. For higher voltage storage, options were limited.

3) **What level of electricity interconnection is likely to be in the best interests of consumers?**
Respondents believed that one of the main issues is the fragmentation of the market which makes it impossible to coordinate interconnection. Participations considered that a larger grid may not be required if there were more localised generation and storage.

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January 2016

Alderney Renewable Energy response to National Infrastructure Commission call for evidence on delivering future-proof energy infrastructure, January 2016

Alderney Renewable Energy (ARE) is a renewable energy developer in the Channel Islands, focused on two projects.

Firstly, and of particular interest to the Commission, is the FAB Link electricity interconnector (France, Alderney, Britain Link). This will be a 1400MW interconnector that will facilitate lower prices for British consumers and improve our security of supply by broadening potential sources of power generation at peak times. This includes access to renewable energy from our associated tidal array project, as well as cheap French nuclear power.

FAB Link was referenced in the government's National Infrastructure Plan 2014 and has now been granted an electricity interconnector licence and a cap and floor regime in principle by Ofgem. Independent analysis by Pöyry, commissioned by Ofgem, found that, using a baseline case of future market projections: "FAB Link presents large benefits to GB consumers."

FAB Link is progressing well but it is essential that policymakers continue to provide a stable and positive policy environment that reflects the importance of FAB Link and interconnection more broadly for UK consumers and in addressing any potential imbalance between energy supply and demand.

Alongside this, if the UK is to ensure future energy security and a balance in supply and demand, it is essential that the government supports integrated energy projects. ARE's second project is a tidal array in the fast waters of the Alderney Race that will 'plug in' to FAB Link. Unlike many forms of low carbon power, tidal provides 12 hours of reliable and completely predictable power output each day. The tidal flows of the Alderney Race could provide c3GW of predictable renewable energy. However, in order to take forward our tidal array project we need stability in the UK's support mechanism for renewable energy and to be given the opportunity to access Contracts for Difference (CFD) support for an initial 300MW array.

We would note that the development of predictable renewable generation may help the UK's energy system in the long term, as larger volumes of unpredictable generation come on stream.

This will provide the support necessary to bring the technology to scale and subsequently undertake the additional arrays; as well as enabling the marketisation of a technology that has not yet been given the opportunity to establish itself. This would have significant benefits not only for the UK's decarbonisation targets but also security of supply and in bringing about lower costs for consumers.

The integration of the tidal array with the FAB Link interconnector offers an exciting solution to a potential imbalance between energy supply and demand. It will provide the UK with access to predictable, renewable tidal energy as well as cheap French nuclear power. This will be a vital contributor to security of supply. However, unless the government provides the support needed to take the tidal array forward, this potential will not be realised.

As the Commission takes forward its work on electricity supply in the UK we hope it will consider the potential, beneficial role that predictable power generation projects such as tidal arrays can have for the UK, particularly when combined with interconnection. This combined project allows the UK to access tidal power for 12 hours a day, and affordable French nuclear for the other 12 hours, bringing significant new supply to the UK at a blended cost that is highly affordable.

[JK2]
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For the attention of

energyevidence@Infrastructure-Commission.gsi.gov.uk

8 January 2016

Dear Sir/Madam

NIC Consultation – Energy interconnection and storage

For this topic area, we have not attempted to answer each question as set, however, we would hope it may be helpful to contribute some remarks that might inform the process and suggest a direction toward future lines of enquiry.

Electricity interconnection and storage

The foreword refers to 'Improving how electricity demand and supply are balanced' and then sets out highly detailed questions at a level of granularity which seems to indicate that the direction of thinking within the Commission may already be rather advanced in terms of specific options in certain areas.

Without trying to second guess current or future work streams, it may be useful to flag other areas of focus where the NIC could exert influence where little or no coordination currently exists. This could be fertile ground for future review and research.

For example, the NIC is well-placed to examine opportunities in areas where energy from any number of sources interfaces within other significant infrastructure environments, such as cities, transport or water. Although the question you raise refers to electricity, taking a more holistic view of the broader energy landscape will perhaps provide more useful insights in the medium and long-term development of the market.

This is partly because interconnection and energy storage are developing in new ways to form what will likely be key elements of the future energy landscape. To date, they have had a somewhat challenging genesis on account of the fact that these elements do not easily conform to the regulatory and policy frameworks that were set up for a linear, one-way supply-to-demand energy system.

However, the trend is certainly real and it raises a great many challenges such as the inclusion of disparate sources; tenure in the Capacity Auction; and network connection charges, which currently do not reflect the benefits they bring.

Analogous to the energy system at large, there is also the increasingly critical issue of storage to consider. Storage is very likely to become an integral element of future networks. Storage will be required centrally and locally, covering a range of fast and slower response rates, and with higher and lower capacity. Innovations are developing fast across a number of areas from pumped hydro storage to molten salt or hydrogen.

All these opportunities require deeper consideration and may need support to drive innovation and implementation, perhaps with direction from the Commission.

It is already clear that there is no single solution that will define the future energy market. Rather, we will see a range of appropriate solutions evolving. Storage of electricity, thermal storage and potentially hydrogen as a storage vector, all ensure both diversity of supply as well as integration and full life use of existing networks.

In all these areas, the NIC could be a powerful advocate for innovation.

By contrast, there are areas where perhaps the NIC might be advised to consider whether there is a pressing need to take a lead given the potential for regulatory overlap and the risk of creating mixed messages in the market.

For example, large-scale electrical interconnection is making great strides at present through the efforts of National Grid and other developers in Europe and elsewhere. Although broad NIC support may be valuable in terms of engendering support for the UK-Icelandic interconnector for instance, in general terms, electrical interconnection is proceeding well and should perhaps not be a primary area of focus for NIC.

At the same time, interconnection and storage form part of a much broader physical and virtual energy system. These elements must be deployed in a manner that is balanced with the anticipated policy and regulatory framework for all the components of the overarching energy system, including renewables for example. These mechanisms do not operate in isolation. Neither should the determination of interconnection and storage. And here, the NIC could make a valuable contribution.

In particular, regulatory certainty and a willingness to take a broad, holistic view of all the key elements of the energy system will be the key to future success in creating a balanced energy market that meets the needs of energy security, sustainability and affordability. The NIC could drive this thinking.

Equally, demand side measures must also come into consideration. Leveraging elements such as microgrids and, indeed, micro-generation, will have a significant role to play in driving the future supply-demand balance equation. The increasing prevalence of virtual mobilization of existing assets will combine with the development of new physical assets to create ‘virtual’ opportunities to balance supply and demand. This will form an increasingly important component of the UK energy mix and the NIC should be at the vanguard.

This approach could be more productive than adding to the risk of potentially overlapping with the current roles of the Department of Energy & Climate Change, Ofgem and National Grid. If the NIC adds to that already complex regulatory and policy mix, while at the same time loses the opportunity to explore the full potential of future energy infrastructure systems and how they interface and interact, then that would be a lost opportunity indeed for the UK.

The industry as a whole very much welcomes the advent of the NIC. Sensible planning and prioritisation for long-wavelength infrastructure investment simply must be considered on a time horizon that stretches beyond single Parliamentary terms. The success of the Commission's work will undoubtedly translate into success for UK plc and Arup will stand ready to support the vital work of the Commission as and when required.

Yours faithfully

James Kenny
Head of Global Affairs, Arup

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National Infrastructure Commission call for evidence: Submission

About the Association for the Conservation of Energy

The Association for the Conservation of Energy was formed in 1981 by major companies active within the energy conservation industry, in order to encourage a positive national awareness of the needs for and benefits of energy conservation, to help establish a sensible and consistent national policy and programme, and to increase investment in all appropriate energy-saving measures.

We welcome this opportunity to provide a short submission to the National Infrastructure Commission's call for evidence.

Submission

We were delighted that, when the Chancellor launched the new National Infrastructure Commission on 30 October last year, he announced that one of the three key areas on which the Commission would initially focus was: 'energy, particularly exploring how the UK can better balance supply and demand'.

Improving our energy efficiency and thereby reducing demand is the most cost-effective way of delivering on the UK's energy policy objectives, and should therefore be at the heart of any serious appraisal of how better to balance supply and demand.

We were therefore somewhat disappointed that the Commission's full terms of reference appeared to exclude consideration of how to *reduce* overall demand, focusing instead solely on the *management* of existing and anticipated demand through storage, interconnection and demand side response. While these are clearly very important issues to tackle, we would consider it a serious missed opportunity if the Commission did not, at an early stage of its existence, investigate fully the pressing case for making energy efficiency an infrastructure priority.

We are a long-standing member of the core steering group of the Energy Bill Revolution campaign, whose key ask is that energy efficiency be recognised as a UK infrastructure priority and have funding committed to it accordingly. We therefore have pleasure in attaching for the Commission's consideration the Energy Bill Revolution/UKGBC briefing paper, into which we have had considerable input.

It is not our intention to rehearse here again the content of that briefing, but we would echo wholeheartedly its central thesis – namely that the fabric of our existing housing stock is one of the most crucial elements of our infrastructure and that the Commission should therefore conduct a full consultation, similar to the current one, to investigate this huge, untapped infrastructure opportunity. While the Energy Bill Revolution ask is focused on residential energy efficiency, ACE also advocates that a similar investigation of non-domestic energy efficiency be undertaken.

Were such a consultation to take place, we would be keen to play the fullest possible part in it.

Balfour Beatty

National Infrastructure Commission
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Balfour Beatty's submission to the National Infrastructure Commission (NIC) inquiry into delivering future-proof energy infrastructure

1. Introduction

Balfour Beatty is a leading international infrastructure group. With 20,000 employees across the UK, we provide innovative and efficient infrastructure that underpins our daily lives, supports communities and enables economic growth.

Our Power Transmission and Distribution teams work with regional, national and international electricity network owners and operators to provide technical engineering solutions. With experience and expertise across the full spectrum of the electricity grid, including overhead lines, cable tunnels and distribution networks, we deliver a range of proactive and reactive services which support a reliable and safe supply of power flowing to millions of homes and businesses around the world.

From scoping and feasibility, to design, construction and on-going maintenance, our in-house experts and industry-leading innovations support clients in the development of ambitious power transmission and distribution projects. We have worked on a range of high profile, complex energy projects, from installing the high voltage electricity cables for National Grid's London Power Tunnels project, ensuring London's electricity needs continue to be met; to Sellafield and soon Hinkley B nuclear facilities; and reinforcing our leading position in the growing offshore transmission market through our work on the £317 million Greater Gabbard project, the high-voltage transmission system located off the coast of Suffolk in the UK.

We recognise that the energy sector is going through a tremendous transformation and faces significant challenges over the next few years:

- coping with increasing demands for energy;
- moving to a more broader combination of energy sources and making sure the UK's power network is ready to connect to them, including the new generation of nuclear power plants;
- playing its part in helping to meet the 2050 carbon targets and the 2020 renewable energy targets whilst maintaining security of supply;
- becoming more flexible and innovative in order to keep pace with the speed at which the energy system is changing.

We are keen to use our expertise to help the country meet these challenges and opportunities and to continue to shape the future energy landscape.

2. Overarching thoughts on future energy infrastructure

Having a resilient energy system is vital for a growing economy[1]. However Britain has historically underinvested in its infrastructure[2], including its energy networks. In order to make up for this, the government estimates that it spent £45bn on electricity generation and networks between 2010 and 2013[3], investment which Balfour Beatty welcomes. However we believe that, in order to rise to the challenges outlined above, more will be needed. The government's own calculations are that up to £100 billion of further investment could still be needed to 2020[4]. We are therefore keen to see delivery of the projects in the National Infrastructure Plan, which outlines that energy projects currently account for around 60% of the UK's total infrastructure project pipeline, totalling over £200 billion[5].

As well as maintaining the existing system, developing energy infrastructure that is fit for the future is a significant challenge. Part of the challenge is ensuring that new power sources, whether from nuclear or wind and other renewables, are connected to the electricity transmission network in order to move the electricity to where it is needed. In England and Wales, much of the new electricity generation will be in remote locations such as on the coast, or offshore, where there is little existing transmission infrastructure, so additional transmission capacity will be necessary to transport the energy to towns and cities. It will also be necessary to carry out work on existing areas of the network to upgrade and reinforce it to make it fit for these new low carbon sources of electricity.

As the UK transitions to a low carbon economy, it is likely that electricity supply and demand variability will increase, driven by changes in the electricity generation mix; an increased in the proportion of variable renewable generation such as wind, solar and tidal, and a decrease in the proportion of flexible, conventional generation likely to be fuelled by gas. In terms of variable renewables, the output from wind and solar generation for example, can often be unpredictable. To ensure a reliable supply of electricity, it will be necessary to ensure that reserves can be held. There are a number of ways this could potentially be resolved, including greater exploitation of conventional generation and energy storage. Electricity storage could be revolutionary in terms of balancing electricity supply and demand if it is possible to find a way of doing it cost-effectively (more detail below).

The UK's transmission and distribution networks are limited in the investment that they can make to accommodate increasing amounts of distributed generation. As such, bottlenecks in the capacity of the networks are stifling the investment in new generation.

The funding mechanism for the network operators is partly to blame, as the funding is focused on the cost of the transmission and distribution networks rather than the cost impact on the whole electricity market. These issues are partly the cause for the current crunch in capacity and are drivers for the introduction of the Capacity Mechanism.

These issues could potentially be addressed through the use of a reopener mechanism for the distribution networks, to cover additional costs. This could be similar to the Strategic Wider Works[6] funding mechanism for the transmission network operators and could be used to develop economic solutions to accommodate increased distributed generation. Use of a reopener mechanism would

[1] OECD, Egert, Kozluk and Sutherland, 2009
[2] RSA City Growth Commission, Connected Cities – The Link to Growth, July 2014
[3] DECC, Delivering UK Energy Investment, July 2014
[4] DECC estimates based on EMR Delivery Plan modelling
[5] HM Government, National Infrastructure Plan
[6] Ofgem, Strategic Wider Works mechanism https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works

also mean that grid connections could be more readily available, particularly if the network operator is funded only for reinforcement or refurbishment work required to accommodate the new connection and the generator is required to fund the connection, either through higher use of system charges or a lump sum up front fee.

The UK's electricity infrastructure is limited in its ability to balance the network without over-supply of generation, due to the losses in the transmission and distribution networks and the ability to quickly drop generation to respond to a drop in demand. There are a number of solutions that could improve this situation and reduce oversupply. These include the installation of more undeviating (via high-voltage direct current or alternating current) infrastructure to link generation more directly to demand for example, by linking onshore wind generation in Scotland to demand in South East England using the planned Eastern bootstraps.

Alternatively a requirement for distribution networks to take a more active role in their system's management and balancing, together with an obligation to procure a capacity of storage to support demand centres – similar to the requirement in California – could create a more efficient and balanced electricity system. These solutions could also reduce the environmental impact of developing the network to be low carbon, particularly if network operators are encouraged to upgrade existing infrastructure or utilise existing network corridors.

In addition if network operators are encouraged to take the lead on developing energy storage solutions, this could have a positive impact on the cost of electricity by reducing the price-time differentials. Increased energy storage at distribution and transmission level could also have a positive impact on the environmental impact of the electricity infrastructure through reducing the number of 'peak' power plants which are required to support demand and by ensuring that low carbon generation can be stored to meet demand.

The biggest challenge for the network operators in achieving a low carbon network is the limitation of their funding. Although schemes like the Low Carbon Network Fund (LCNF) have shown the possibilities for innovation in network design and management, in our view, the cost of implementing these schemes en masse is too high. When the cost challenge of the RIIO[7] regime is added into the mix, it is easy to see why network operators are looking to low cost contractors to support them in the maintenance of their networks. Whilst this may be cost effective in the short run, it stifles innovation within their supply chain and reduces the ability of the network operators to use more competent contractors to work together to identify opportunities for innovation as part of the development of the networks or deliver innovative solutions in construction.

Ofgem incentivises the network operators fairly well to develop innovation, but often they are forced to choose a single solution from a sole supplier to progress for funding support.

Investment in energy networks

Britain is at its highest risk of power cuts, shortages and price spikes for more than 60 years[8], with available electricity capacity in April 2016 calculated to be 52,360MW, falling short of National Grid's 2015-16 winter electricity demand forecast of 54,200MW. We need to invest in our energy networks across the UK: significant funds will be needed to ensure that the UK's electricity infrastructure is resilient and fit for the future. These will not be forthcoming without investors being confident in the policy landscape.

[7] RIIO is Ofgem's framework for setting price controls for network companies
[8] Centre for Policy Studies, The Great Green Hangover, November 2015

Investing in energy infrastructure projects is not without complexity. Energy projects take years to plan, design and build, as well as significant investment. The consenting process alone can span governments. A stable and predictable planning and investment environment is critical. A good example is electricity generation, where credible commitments over the long term to measures such as carbon pricing are required to support private investment in new, efficient low carbon generation capacity.

There are many points investors will consider before developing key energy infrastructure. These include:

- Clear political and financial commitment from government to a sector
- A clear, predictable source of income. This protects the value of an investment whilst mitigating revenue risk
- A coherent strategy that fits into wider, global goals for energy
- Cross party consensus on the direction of travel for the energy mix
- Clarity on how the government will implement and fund the plan
- A predictable and stable subsidy regime for nascent technologies

The actual funding approach is secondary to these key concerns. For example, the recent change of direction on subsidy for renewable energy (onshore wind and solar) calls into question the value in further development and investment in any renewable sector.

Other points

- The largest blockers to private sector investment are the timescales and risks associated with consenting, the lack of long term commitment to both the energy strategy and funding of that strategy and clear routes to income to recover investment costs.

- Without a clear 5 - 10 year road map with cross party support, the risks involved in investing in major energy projects may be difficult to justify. This will drive up expected returns from such an investment and add cost to the consumer. Frequent changes of direction or lack of commitment to the "greening" of our energy mix will lead to stagnation in development.

- Much of the investment in UK infrastructure is undertaken by international businesses which have a choice of markets and projects for their scarce capital. These businesses will naturally choose those jurisdictions with effective policy frameworks which provide certainty over the longer term over jurisdictions which do not.

  The UK has recently lost its place in the top ten markets for clean energy according to the Renewable Energy Country Attractiveness Index[9], as investors have taken up opportunities in markets overseas. We therefore urge an end to the recent sudden changes in direction in energy policy in favour of a financial and regulatory regime that is stable and predicatble, in order to maintain investor confidence.

- There are currently a number of agencies involved in decision making and enabling development:

  - DECC controls the subsidies required for new technology
  - The Crown Estate controls critical development space for marine energy

[9] EY, RECAI Issue 45, *Renewable energy country attractiveness index*, September 2015

- The Treasury controls (and changes at short notice) budgets, local government control planning and consenting on land
- Various agencies control marine consents and environmental consenting etc.

It would be helpful if these gatekeepers were coordinated and perhaps the planning and consenting pathways were simplified and related timescales accelerated. One example is marine consents. If there were a precedent for a given area, then perhaps the next consent should only have to deal with the incremental differences rather than repeat the entire consent process.

Procurement models

More broadly, it is Balfour Beatty's view that the model of procurement should fit to the type of project being considered. Where there is a critical need with a limited opportunity to develop such a project, we believe that PFI/PF2 should be considered.

For example, the development of Tidal Lagoons should be centrally planned and procured. Such projects lend themselves to a PFI/PF2 type model due to the resource limitations required and scarcity of sites for implementation.

In our view, it makes little sense having numerous parties "reserving" areas of the country for the development as they do at the moment, by publicising plans and consulting publicly when there is no guarantee they can implement the plans. The current approach also leads to the risk of multiple consents on the same site or within the same region and no clarity as to who will eventually be able to implement their plans. This leads to confusion and potential failure of all plans.

There are also resource and capacity limitations relating to the build of major infrastructure in the UK market. For economically viable Tidal Lagoons, the quantity of material required would be enormous. This would need a "one at a time" approach so as not to cause material shortages and drive cost upwards.

Open competition with clear, committed funding would reduce the costs, risks and invite competitors into the market.

3. Responses to specific questions outlined in the inquiry

Questions 1. and 2. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term, and what are the barriers to the deployment of energy storage capacity?

In our view, in order to ensure supply and demand is balanced at the lowest cost, the regulation around energy storage needs to be addressed. The current definition of energy storage is not robust in that it varies from country to country across the EU. In Italy, the regulator has interpreted the definition in such a way that the system operator (SO) is able to own and operate storage, whereas the current UK interpretation prevents this.

If the definition of energy storage could be clarified – preferably to enable the SO to own and operate storage – as well as defining regulation for energy storage for generators, suppliers, Transmission Network Operators/Distribution Network Operators and the private sector in order to prevent double charging for generation/transmission/distribution, it would be possible to create a market for energy storage which will help renewables integrate into the network. This could reduce the level of network investment required and ultimately drive down costs for consumers.

Importantly, the market should not be subsidised or subject to any price mechanisms which could prevent the market from developing organically.

Balfour Beatty believes that any support for energy storage should focus on the development of technologies, in order to support UK industry. Different storage technologies also have different benefits, from the speed with which they can be dispatched, through to the duration of supply. No single technology is a 'silver bullet': they should all be considered as complementary and viewed based on their individual merits.

Any regulation needs to consider the speed of dispatch, storage capacity and the duration of supply for technology, rather than focusing on a single variable – size is not the be all and end all of storage. Storage should also be considered under the capacity market, as it has the potential to provide electricity during peak demand (peak shaving) which could reduce the need for (fossil fuel powered) peaking plants.

In our view, the most appropriate scale for energy storage is a mixture of transmission, distribution and domestic level, as well as storage at the point of generation. Storage across the network could provide much greater demand reduction and, through coordination of the transmission and distribution storage, provide balancing services for all parts of the network. Enabling storage at the point of generation would enable intermittent renewable generators to limit their generation when required, without losing revenue or requiring curtailment payments to compensate them.

Finally, we believe that the regulatory regime for Distribution Network Operator funding should be reviewed in order to consider how the regime can be an enabler for connecting renewable generation, rather than a barrier. At present, the regulation prevents the network operators from being able to connect some distributed renewable generation to their network as there is limited capacity in their network and the cost of the wider works required to facilitate the connection is considered too high.

If the regulatory regime allowed network operators to apply to Ofgem for funding for the wider works – on the basis that in the long term it will provide a greater socio-economic benefit and help drive down costs – then it would be possible to recover a proportion of the funding for these works from the saving made on capacity market contracts or short term supply agreements made by National Grid. Particularly if the network operators deployed storage.

Skills and training

Designing, constructing, operating and maintaining the transmission and distribution infrastructure which supports the electricity market requires specialist skills and experience. In order to support the balancing of supply and demand it is important to ensure the UK develops and retains the required level of skilled resource.

Balfour Beatty welcomes and supports the government's ambitious plans to create 3 million more apprenticeships by 2020. We invest in apprenticeship programmes across a broad range of disciplines, employing over 150 apprentices each year in the UK in addition to the 320 currently under training in a diverse range of roles across the business[10]. We employ around 700 more young people on graduate and part-time higher education / degree schemes. We are also members of the

[10] http://www.balfourbeatty.com/index.asp?pageid=364

5% Club, and are committed to the aim of ensuring that 5% of our UK workforce are apprentices, graduates or sponsored students on structured education programmes within the next five years. We recognise the valuable contribution our apprentices make to our business and as the pipeline of future talent. By investing in growing numbers of apprenticeships, we believe that we are not just helping young people build productive careers and successful lives, but also making a sound investment in our own future.

However, we do not believe that the apprenticeship levy alone will be enough to meet the shortfall in skilled workers the infrastructure industry needs.

- Business needs confidence in the quality of the pipeline in order to ensure it has the skilled staff for some of the specialist roles in energy projects. This is especially the case where new skills are required, for example in new nuclear build. It can take a decade from starting an apprenticeship for someone to gain all the skills they need to work in this area. Early, firm decisions are needed to enable us to invest in the people we need.

- The NIC could help drive investment in skills across the industry, in both contractors and network operators (transmission and distribution), by promoting a requirement to include minimum training requirements within OJEU tenders.

- The NIC could also work with the regulator (Ofgem) and network operators to look at how they can manage workflow across the sector. Recognising the specialist nature of the skills required in the industry, it is possible for the skilled operatives from the industry to find work abroad when the workload drops in the UK. This 'brain drain' means that when work increases, it is often challenging to find the number of skilled staff needed. This results in higher costs that are subsequently passed on to consumers.

- To ensure that costs are kept low for consumers, training requirements across the industry need to be clearly shared, and network operators should (where possible) ensure that they provide a steady flow of work for contractors and the industry needs to be encouraged to and supported in developing the skills needed to support the networks.

Question 3. What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnection has significant benefits for balancing supply and demand in both the UK and across Europe. Greater interconnection from the UK to Europe will have significant long term benefits in terms of balancing the networks and reducing carbon emissions across Europe. In our view, capacity should be developed in line with the current cap and floor regime as a minimum.

There may be a case for developing interconnection at a higher rate beyond 2020 if projects in North Africa (Morocco/Egypt) and parts of Europe (Spain/Portugal/Ireland) provide low cost, reliable generating capacity, but bottlenecks in the existing (onshore) system prohibit the UK from accessing this generation. In this case the current regime may be prohibitive to the development of these projects, as the window for applications is not frequent enough. A continuously open window for applying to the cap and floor regime would allow projects to be brought forward for assessment sooner than the current programme.

Question 4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Balfour Beatty highlights the following international examples:

- California – encouraging storage.

  The Californian energy market regulator has set a requirement for the distribution network operators to each develop 1325MW of storage capacity by 2020 in order to provide network balancing services as they integrate renewable generation into the system.

- Uruguay – decarbonising without subsidies.

  In Uruguay the country has managed to shift electricity generation to 94.5% renewable sources without the use of subsidies. Renewables now make up 55% of the country's overall energy mix (including transport fuel) compared to the global average of 12%[11].This has been facilitated by a supportive regulatory environment and strong partnership between the public and private sector.

- India – developing solar without subsidies.

  In India, the government has set out an ambition to develop 100GW of solar by 2022 – which is half of the world's current installed capacity. The government is not providing any subsidies for solar, instead they are relying upon the fact that the cost of the technology has fallen sufficiently to make it competitive with coal. In the UK, the subsidies for solar have hidden the true cost of solar, so as the cost has fallen, the benefit of having the subsidies increased. But once the subsidy was removed it created a false fall in the returns from investing in solar.

Contact

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[11] http://www.theguardian.com/environment/2015/dec/03/uruguay-makes-dramatic-shift-to-nearly-95-clean-energy

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National Infrastructure Commission
1 Horse Guards Road
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19th December 2015

Dear National Infrastructure Commission,

RESPONSE TO NATIONAL INFRSTRUCTURE COMMISSION CALL FOR EVIDENCE

Please accept this letter as London Borough of Brent's response to the National Infrastructure Commission's (NIC) call for evidence on the following three issues:

1. Improving connectivity between cities in the north of England
2. Large-scale transport infrastructure improvements in London
3. Improving how electricity demand and supply are balanced

Brent appreciates the opportunity to contribute towards the NIC's work and the Borough supports the process currently being undertaken by the Commission. The following response has been prepared based on the questions put forward by the NIC for each issue.

ISSUE 1: IMPROVING CONNECTIVITY BETWEEN CITIES IN THE NORTH OF ENGLAND

Brent has no comment on the issue of connectivity between cities in the north of England. We support Local Authorities in the north of England who wish to comment on this issue.

ISSUE 2: LARGE-SCALE TRANSPORT INFRASTRUCTURE IMPROVEMENTS IN LONDON

Q1: What are the major economic and social challenges facing London and its commuter hinterland over the next two to three decades?

Brent is facing many of the same economic and social challenges as London and the United Kingdom as a whole. Sustained high population growth is a challenge across many policy areas, including housing, transport and employment. Brent's population is projected to grow by 24% to almost 390,000 over the period from 2012 to 2036 compared to 22.5% growth London-wide over the same period[1]. This growth will place greater pressure on housing and services which are already straining to cope with record populations and usage, such as transport. In addition, it's a continuing challenge for the borough to support employment growth within the borough to provide jobs and economic stimulus for residents.

In recent years, the dynamic of these challenges has also changed, with greater focus on sustainable development. This trend is likely to continue in the future, with an increasing focus

[1] Office of National Statistics, 2015, *ONS 2012-based subnational population projections*, [Sourced from London Datastore] http://data.london.gov.uk/dataset/ons-2012-based-subnational-population-projections/resource/dfdd7444-ea66-4a27-91ff-a95fdc9fe611#

on car-free development and localised employment and services, thus reducing the need to travel, along with the provision of sustainable transport options, such as walking and cycling in addition to public transport.

In order to deal with these challenges, significant investment is required in local transport infrastructure, including resolving existing maintenance requiremennts on local road networks. At the same time, investment is also required in large both new large-scale infrastructure (such as the Crossrail/West Coast Main Line link) and the modernisation of existing infrastructure (such as the Bakerloo line modernisation).

Q2: What are the strategic options for future investment in large-scale transport infrastructure improvements in London - on road, rail and underground - including, but not limited to Crossrail 2?

Brent believes that the greatest opportunity for investing in transport infrastructure in London is not in the strategic network, but in the local network. It is local transport networks which are currently suffering from deferred maintenance and lack of investment due to funding cuts, while additional funding is being made available for strategic transport networks, which, while important, do not carry the vast majority of vehicles (either passenger or freight) and can not support economic growth without a well maintained local network. At the same time, we recognise that funding must be provided to the strategic network as well. We do not see the demands of the different networks as an 'either-or' scenario, rather investment must be directed towards both networks to ensure the delivery of high quality national transport networks which support economic growth and improve peoples' wellbeing.

At a strategic level (both nationally strategic and regionally strategic), there are a number of major schemes which Brent supports:

<u>West Coast Main Line / Crossrail link:</u>
This project is Brent's highest priority transport project, on the condition that Crossrail trains call at Wembley Central Station. This project will support substantial regeneration in Wembley, along with providing high speed, high quality access for residents and businesses to Central London, Heathrow and the rest of the nation via the Old Oak Common Interchange.

Brent continues its work with Transport for London (TfL) on this issue and we would encourage Central Government and any other stakeholder to support it.

<u>Upgrade and extension of the Bakerloo Line:</u>
In addition to supporting growth in southeast London, the Bakerloo line currently has the oldest rollingstock on the London Underground network, dating to 1972. These trains are in considerable need of renewal, in addition to the need to modernise track and signalling along the route.

An upgrade of the Bakerloo Line, completed in conjunction with an extension in southeast London would improve access to public transport, reduce car usage and associated emissions and congestion across northwest London. The extension would support regeneration in Wembley, South Kilburn and Old Oak Common / Park Royal, improve journey times and provide better connections, improving public transport capacity and passenger satisfaction along the length of the Bakerloo Line.

<u>High Speed 1 / High Speed 2 link:</u>
While this project has been excluded from the HS2 Hybrid Bill, currently before parliament, Brent believes it is essential towards achieving a comprehensive national High Speed Rail network in the future. At the same time, the previous proposal via the North London Line in Camden, impeded the capacity of this route and would have had a detrimental impact on local communities.

An improved solution needs to be developed now, so that other projects do not jeapodise the practicality and deliverability of this link in the future.

Electrification of transport networks (road and rail):
Brent supports the electrification of transport networks (including both road and rail vehicles) for both freight and passenger services. While rail electrification works are planned with lengthy lead-in periods, the electric vehicle market is less certain, and as these vehicles become cheaper and more widely spread, there is a risk that domestic energy consumption could rise considerably for these vehicles. This could potentially require additional infrastructure to support these vehicles.

Increasing the uptake of electric vehicles in commercial fleets and household vehicles is predicated on having sufficient charging infrastructure to give people the confidence to switch to a hybrid or fully electric vehicle. Domestic infrastructure, coupled with nation-wide charging infrastructure is essential to ensuring that the nation's homes, offices businesses are prepared for zero-emission vehicles of the future.

Freight transport networks:
An essential requirement of any strategic infrastructure is the provision for freight to utilise the network. Pursuant to this, where possible, Brent strongly supports the relocation of freight from road haulage to rail, given the impacts on local amenity of poor air quality, traffic noise and safety risk of freight vehicles. We also support maintaining and/or improving access in the form of service slots and sidings for freight to rail networks, such as the West Coast Main Line, Dudding Hill Line and the Midland Main Line.

Cycling infrastructure:
While cycling infrastructure has generally not been considered to be strategic infrastructure, with the addition of high-capacity cycling infrastructure currently being constructed and/or planned across Greater London, along with the demand for greater cycling provision means the scale of infrastructure and popularity of cycling is increasing. The greater number of cyclists will generate additional demands on strategic road networks and for regional cycling infrastructure. These considerations should be taken into account both for strategic planning and in assessing individual traffic schemes.

Resolution of London's air capacity issue:
In February 2015, Brent Council wrote to the Davies Commission to recommend that of the three options being considered to increase London's air capacity, Brent's preferred option was the Heathrow Northwest Runway. The Davies Commission agreed with this and recommended the government move forward with this option. A final decision on how the government will proceed has been delayed several times. Ongoing uncertainty regarding whether an additional runway will be built at Heathrow or Gatwick Airports, or not at all affects the planning and transportation decisions being made by Brent, other Local Authorities and TfL. Resolution of this issue needs to be a priority in consideration of national infrastructure.

Q3: What opportunities are there to increase the benefits and reduce the costs of the proposed Crossrail 2 scheme?

Brent understands that Transport for London has already undertaken considerable work to evaluate and increase the benefits of the proposed Crossrail 2 scheme. In spite of not being located on the route for Crossrail 2, Council officers have been kept abreast of the project's evolution as there are potential long-term impacts for the borough in relation to connections to Crossrail 1 (at Tottenham Court Road) and HS2 (at Euston), along with the interchange between these two projects at Old Oak Common.

Given that the opportunities for increased benefits will come with greater demands on local authorities along the route, Brent will reserve contribution on this question to those authorities.

Q4: What are the options for the funding, financing and delivery of large-scale transport infrastructure improvements in London, including Crossrail 2?

Brent supports the funding arrangements for Crossrail 2, as currently outlined by TfL. We believe that it is fair and reasonable that large-scale, transformative infrastructure projects (including Crossrail 1 and Crossrail 2) should be funded by a combination of Central Government funding, Greater London Authority (GLA)/TfL funding, S106/Community Infrastructure Levy development contributions and localised business rates supplements for beneficiaries of the scheme.

A key consideration of equity which must be addressed for Crossrail 2 and future regional schemes such as this is the disparity of power for enforcing localised contributions between local authorities under the GLA and those located in the Home Counties. It certainly is achievable to come to negotiated settlements on funding agreements with these local authorities, however the Mayor of London does not have any authority to enforce them outside of the terms of the agreement. This will be of particular concern for Brent in support of the Crossrail / West Coast Main Line link, which will travel through the London Boroughs of Brent and Harrow, before continuing through Three Rivers District, Watford, and Dacorum Councils, which are all located outside of Greater London.

Q5: How have major metropolitan areas in other countries responded to similar challenges and priorities? Are there any lessons to be learned and applied in London?

No specific comments on this question.

ISSUE 3: IMPROVING HOW ELECTRICITY DEMAND AND SUPPLY ARE BALANCED

We have no specific recommendations for action on this issue, however we would note our concern regarding the challenge of ensuring continuity of electricity supply (across both the high voltage and low voltage networks) given projected population and employment growth, particularly in areas designated for regeneration, such as Old Oak/Park Royal. Of interest to the Council is how these services will be accommodated; particularly where they are proposed within the public highway and may affect transportation networks, other services or potential infrastructure improvements. In addition to this, Brent would be interested in opportunities for data to be shared, and upgrade works to be coordinated between utility providers so as to minimise disruption to residents and businesses.

I trust this response has been of some assistance, however if you have any questions, please feel free to contact our Transport Planner, Chris McCanna, on [Phone number redacted].

Thank you for your consideration.

Yours sincerely,

Tony Kennedy
Head of Transportation

7th January 2016

To: Sir John Armitt, Commissioner of the National Infrastructure Commission

From: Angus Macdonald, CEO British Solar Renewables

Re: Call for Evidence

Dear Commissioner,

I am responding to your call for evidence, launched in 2015, on Electricity and Storage.

I am proud to lead British Solar Renewables, the largest integrated developer and operator of PV systems in the UK. Since our inception with three employees in 2010 we have developed, delivered and now operate 400MW of PV capacity, representing an investment of around £500m in that period.

Our view is that while the UK faces significant challenge in the energy "trilemma", the advent of new technology offers huge opportunity. Our fear, based on experience, is that the speed of technology and business innovation will far outstrip the ability of traditional central-generation thinking, network management and regulation.

BSR has specialised in delivering large scale projects, including 130MW on government property at RAF Lyneham and RAF Wroughton. We have procurement and joint-development links into China, including with CNBM (China National Building Materials), with whom we are working on the integration of energy with housing and commercial property on repurposed brownfield land.

With Western Power Distribution we are in the process of delivering what we believe will be the UK's first demonstration of a grid-integrated PV and battery storage system under the Network Innovation Allowance scheme. We are also working very actively with a number of UKplc customers on the development and integration of "behind the meter" generation and storage.

Two themes which commercial customers are bringing to us are their concerns about the rising cost of grid power, and the risk of grid outages or very high peak pricing.

We believe that those concerns are real, and that we have an unusual perspective on the energy market because:

- All of our projects have been developed and delivered very quickly relative to their operational life and level of investment; we nevertheless to achieve over 99.5% availability on all of our sites
- We have had to build strong working relationships with the major DNOs and understand the technical, financial and regulatory constraints within which they work
- We work with the major suppliers of PV and Storage worldwide, and are increasingly engaged in project delivery outside the UK
- We have developed a deep understanding of the drivers of the cost of grid power in our engagement with commercial customers, frequency response aggregators, and funders of embedded generation and storage

I hope that our views are useful to your Commission's work. We would be delighted to engage further in what we see as a vital part of developing the UK's economy and competitiveness.

Yours sincerely,

Angus Macdonald

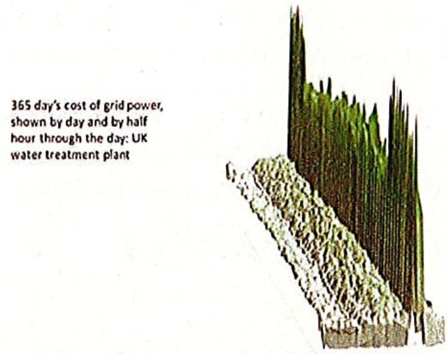
1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

<u>Underlying Drivers</u>

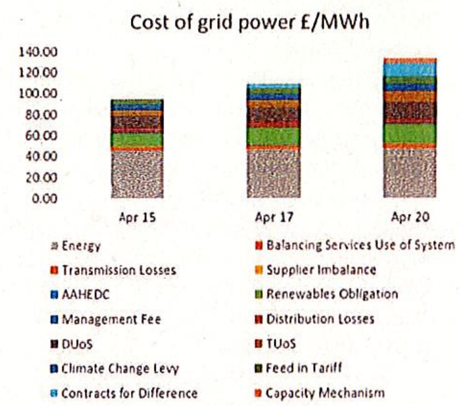
We believe that to answer this and subsequent questions it is first important to understand the drivers of change in today's energy market and systems.

We identify the following:

- The cost of energy generation and supply will continue to be driven by the cost of peak periods (see chart)



- The cost of delivered grid power will rise, not just to 2020 but also beyond, and will increasingly be biased towards 'system' charges (tax, TNO & DNO charges) and away from the underlying cost of generation



- The cost of distributed generation and storage will continue to fall to the point where subsidy of PV is not required; commercial battery storage is a fundable proposition today without tariff support
- Falling costs for distributed generation, rising charges for gird power and the fear of supply failure will spur the widespread adoption of embedded (behind the meter) generation, especially by the commercial sector who face larger impacts from loss of supply
- Reducing levels of fossil-fueled, rotational generation will bring a rising need for frequency management across the grid

Given that background of on-going change, we strongly support the objective of reducing the cost of managing the energy system to consumers through long-term planning and evolution of the system.

We strongly advocate the deployment of new energy technologies, and adapting regulation to encourage technical innovation and to enable a level playing field. We believe that the energy industry can achieve a balance between central planning and de-regulated delivery which is optimal for consumers.

Limits of Regulation and Central Governance

Having managed our business through four years of tariff support, we are however very familiar with how rapidly the changing cost of technology can outstrip the ability of central regulation to respond. We believe that the risk of over-investment in stranded, centrally governed assets is very significant (for example, over-investment in TNO-connected storage, as explained below).

We also believe that the current system of network and supply governance is prone to entrenched interests and is resistant to change. This underpins our support for development, for example, of a DNO type-testing facility at the Berkley College

Extract from submission for funding:

1. The UK is undergoing very rapid change in its mix of energy supply. As a de-regulated energy market and an early adopter of un-schedulable renewables, the UK market is now potentially in the vanguard of countries developing the technologies to deliver ever-lower carbon intensity.
2. This change is being forced onto a system of National Grid and Distribution Network Operators who are supplied by a relatively small pool of equipment suppliers: many global energy equipment businesses have focussed on HV (132kV, 400kV) generation and Transmission equipment, and have moved away from lower-voltage (11kV, 33kV) Distribution equipment supply.
3. The suppliers who have remained in the market have over time established scale and other barriers to entry, including operation of their own test facilities. The UK does not currently have a supplier-independent test facility for DNO voltage equipment.
4. Many of the changes to our grid systems will principally impact and will require investment in the DNOs' networks:
    a. PV is already DNO biased and will continue to grow at this level as it is installed on commercial and domestic roofs
    b. Battery storage and the charging of electric vehicles will follow the same pattern
5. Systems which we can anticipate being needed by grid operators, or demanded by consumers, include:
    a. Advanced switchgear (or cheaper versions of existing equipment)
    b. Storage-integrated DC:AC inverters (paired with PV generation)
    c. Rapid electric vehicle charging stations
    d. Distributed demand and storage management systems (linking multiple homes and commercial sites)
    e. DNO integrated and secure data capture and control systems (SCADA)
6. Because of a limited supply base for DNO grid equipment, the UK is faced with delay, a lack of innovation and higher prices for these types of equipment. It also faces, potentially, losing the opportunity to establish standards and export systems, equipment and expertise to the many countries worldwide (including the Commonwealth) whose electrical systems are very similar to those in the UK

The UK has successfully navigated a similar fundamental and technology-driven change in its infratsructure in the recent past, in the deregulation and digitisation of the telecommunications industry.

We take three lessons from the telecoms revolution:

- Embracing technology can yield huge dividends: growth of the de-rgulated City of London was dependent on (also de-regulated) digital telephony and data networks
- Telecomms systems are regulated by interface protocols, which maintain service while allowing separation of the roles of carriers (similar to energy networks), service providers (similar to generators, storage operators) and network administrators (DNOs, TNO, SO)
- The telecoms system in the UK has become increasingly complex and now offers levels of connecitivty and service which were never anticipated when the original interfaces between the above players were established; nevertheless the same structure has survived and service has been maintained (although the interface protocols have themselves changed beyond recognition)

<u>Answers to questions</u>

- What role can changes to the market framework play to incentivise this outcome:
    - Q: Is there a need for an independent system operator (SO)?
    - A: A large proportion of the changes to our system are and will be driven by changes in the cost and scale of generation and storage. These are DNO-level changes, as new capacity will be connected to the grid on the consumer's side of the meter while fossil-fueled central capacity is retired. The role of a System Operator should be to:
        - Project the rate of change of demand, and of the deployment of new technologies
        - Establish clear boundaries, and develop the roles and responsibilities (for frequency management, imbalance, generation) between DNOs and TNOs
        - Monitor and administer performance at those boundary points
        - Encourage minimum cost solutions, innovation and new technology adoption
    - The SO should not seek to guide investment, but should allow network operators to incentivise the deployment of technologies on their networks, providing a clear business case is demonstrated and services such as generation or frequency management can be delivered on a commercial basis. Cases for investment by TNOs should be compared with those presented by DNOs.
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- The balance of investment in for example storage should be on DNO networks as embedded batteries can provide a greater range of services, and therefore realise greater value, from the lower end of the system
- A role which is lacking in the current framework is the near-medium term projection of demand patterns and generation capacities. In an environment where embedded, deregulated generation is expanding, storage is rising and new loads such as electric heating and transportation are rising, network operation is out-stripping regulation. As a first step toward more effective regulation and as a guide to investment, a regularly revised view of where power is coming from, how it is being used, the volatility of balancing would be extremely powerful. This can be seen as an evolution of the existing pathways work, recognising that we are some way down the path to transition already.

- Q: How could the incentives faced by the SO be set to minimise long-run balancing costs?
- A: We do not see that a SO is best established as a commercial entity, rather that the SO role is an evolution or a replacement of existing system administration. We do see that a broader range of experience, not biased towards 'legacy industry' experience, is important in embracing change and overcoming obstacles through innovation as opposed to over-investment.

- Q: Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- A: Imbalance between supply and demand is a cost to all consumers. It may be appropriate, given rising levels of distributed generation, to extend imbalance management to smaller scale generators on a transparent basis. Aggregation of distributed generation, for the purpose of imbalance management, would be one way to encourage new approaches from asset operators.

- Q: To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?
- A: We see widespread adoption of embedded generation and storage within the next 5 years, as costs fall and prices rise. That brings huge scope for the expansion of these services. If encouraged in the near-term, we see that adoption in turn encouraging innovation and development of new technologies and business models, with potential for export worldwide.

2. What are the barriers to the deployment of energy storage capacity?

- Q: Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- A: We can identify three barriers to adoption:
    - Entrenched interest in existing technologies and relationships
    - Lack of clear standards (protocols) for interconnection and operation
    - Lack of opportunity to monetise the services which embedded storage can provide to DNOs, TNOs
- As an example there is a risk that the TNO, driven by traditional thinking and a desire to expand its asset base, over-invests in under-utilised storage and as a result kills the market for services to be provided by embedded storage.
- Any investment by monopoly players (TNOs, DNOs) in equipment such as batteries for Fast Frequency Response, should be tested (via open contract tender or another mechanism) against the open market/deregulated business case for investment

- Q: What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)
- A: We reference the work of Professor Goran Strbac at Imperial College London in quantifying the difference in value between distributed and centrally-connected storage and believe that embedding storage is by far the cheapest way of enhancing our energy system.
- We do understand that multi-purpose batteries are potentially more expensive than single-application batteries but believe the world market for storage will continue to drive down costs for the most valuable equipment.
- We anticipate rapid adoption by Industrial and Commercial customers, together with rising adoption by domestic consumers over time

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Q: Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- A: We believe that interconnectors should be developed, but that they should not receive favourable funding or support relative to other means of achieving the same goal.
- Q: Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?
- A: We cannot answer this question.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

- A: We believe the parallels between the management of change in telecommunications within the UK offers a strong guide to the management of:
  - Roles of players in order to encourage innovation and competition
  - The power and interests of incumbent players
  - Advancing technologies and evolving consumer needs

BSA – The Business Services Association

Response to the National Infrastructure Commission Consultation

January 2016

Improving how electricity demand and supply are balanced

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

In August 2015, the BSA produced a policy paper which called for the publication of a National Energy Security strategy to act as a sub-section of the National Infrastructure Plan[1]. This will allow for better understanding of the government's approach to energy security. Such a strategy would allow a clearer comprehension of where the government plans to invest in energy generation. With a significant proportion of the UK's power generating capacity due to come offline within the next ten years, clarity on future supplies is crucial to maintaining a healthy balance between supply and demand.

The UK needs a range of solutions with a diverse energy mix in order to increase the reliability and stability of its power supplies. Nuclear, particularly with the government's planned developments at Hinkley Point, Bradwell and Sizewell can provide a baseload of power supply. Beyond this, the development of renewables should be encouraged, with a focus on bringing down their price and improving their reliability.

2. What are the barriers to the deployment of energy storage capacity?

The lack of a clear, codified, long-term energy security strategy and stalling construction of new generating capacity presents a barrier. If the market doesn't know where and when future supply capacity is due to come online, it subdues confidence that it is worth investing time, money and skills into the deployment of storage capacity. Energy storage will become of increasing importance, especially as the renewables share of the energy mix increases in the short to medium term. As such, government guarantees may be required to boost market confidence and encourage investment in this vital piece of infrastructure.

Specifically, there is a need to review the regulatory demands on the providers of large scale energy storage as the current system is clearly not designed in a way that supports new provision. At present, energy storage deployment requires a generation licence whilst also being treated as a consumer.

To make a meaningful impact, the BSA considers that deployment should be at a transmission network scale. However, this scale of development will often require consent through the National Strategic Infrastructure Planning regime. This, therefore, points to the importance of a strategic plan for investment and deployment as opposed to a series of urgent demands resulting from reduced capacity in the system.

Energy storage assets in the UK are treated as generators under current regulations. One of the key opportunities for deployment of energy storage is to enable providers to defer or avoid network reinforcement costs. This can help alleviate the high capital costs associated with the construction,

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[1] http://bsa-org.com/uploads/publication/file/185/BSA_-_Energy_Security.pdf

operation and maintenance of energy storage facilities. Increasing the provision of battery storage should be explored as costs have declined 50% since 2010 and are expected to see another 50% decline by the end of the decade. The structure of the Capacity Market should be examined as well to all storage onto a more levelled playing field rather than locking in 'old world' solutions.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

The deployment of electricity interconnection offers benefits in terms of security, by adding an alternative source of energy supply to the grid. However, the UK runs the risk of losing control over its energy supplies if we become overly-reliant on foreign energy sources. Interconnection should not be seen as an alternative to the construction of new sources of energy generation so that improving the reliability of energy supplies remains primarily under domestic control.

Another potential advantage of further interconnection with Europe is that the associated emissions remain in the country of generation. Therefore the displacement of emission neutral imports from the continent would also help to meet carbon and other environmental targets. Despite this and despite interconnector developers having access to the 'cap and floor' regulated regime, the UK is still set to miss its 2020 EU target of 10% interconnection. It appears that the main hurdle to achieving this target is securing finance. The Green Investment Bank could be seen as an option for providing funds and partnership on future interconnection projects.

4. What can UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Given the complex and often expensive nature of balancing energy supply and demand, nations which are open to innovation, including from business, are more likely to see encouraging results. The Netherlands, for example, has demonstrated the 'Energiesprong' programme, which manufactures and fits energy saving solutions for both houses and businesses offsite and within three days. Solutions such as these offer a more holistic and less piecemeal approach to reducing energy demand. The Smart Meter programme offers an additional means of further reducing energy demand and the BSA encourages its deployment as soon as is feasibly possible.

BuroHappold Engineering Response to NIC call for evidence

Electricity interconnection and storage

Introduction

With the urgency of both the need for national energy independence and the need to make significant progress on avoiding climate change, several European countries have made commendable progress in terms of balancing supply and demand within an agenda for a low carbon future. Denmark has pioneered wind generation and integrated city energy infrastructure, over many years France has set in place extensive nuclear and hydro infrastructure, Germany has new bold plans for its energy transition or Energiewende. Spain and Italy are making progress too. A number of these countries are now not only addressing their internal energy issues but also are in fact exporting their resilient energy products and experience.

The UK has one of the best national carbon reduction commitments in the form of the 2008 Climate Change Act, which is further strengthened by the outcomes of Paris COP21. This act of law commits the UK to achieving an 80% reduction in CO_2 emissions from 1990 levels by 2050. This is tough, but it is founded on what needs to be done to limit global temperature rise by 2°C. This dictates carbon free power and heat by 2050 if not before.

There have been some quick wins, the 'dash for gas' in the 1990's cleaned up power generation to a certain degree until North sea gas production dwindled and prices rose. The last recession also helped to reduce demand. But the hard yards lie ahead. Renewable incentives in the form of Feed in Tariffs, Renewable Obligation Certificates and Renewable Heat Incentives have driven the implementation of renewables but: bio fuels, carbon capture, nuclear, energy storage and smart grid infrastructure are all technologies that take time to implement. In particular technology such as carbon capture is a pre-requisite in justifying long term investment in shale gas and redeveloping the abstraction of coal, but predicting when this can be successfully deployed is proving difficult and therefore cannot be relied upon in long term planning.

This is the Achilles heel, whereas other countries have strong strategy the UK energy strategy is weak, indecisive and heavily biased towards protecting the incumbent large scale generators rather than encouraging individual and community participation in local renewable power generation, a cornerstone in energy policy within several European countries.

The strategy vacuum forces bodies like the Energy Technologies Institute (ETI), National Grid and DECC to talk in terms of scenarios. For sure demand forecasting is subject to many variables, but one of those variables should not be trying to second guess national energy strategy!

The ETI boils its scenarios down to two; Clockwork, assuming that a strong top down energy strategy will emerge quickly and Patchwork which assumes that central strategy will remain weak and it will be local ground up action that will push us down the carbon reduction curve. The ETI states both are affordable in GDP terms but that patchwork is possibly more costly than clockwork.

If the UK is to hold true to the Climate Change Act there is a growing realisation that it will be local and regional patchwork activity that will get us there.

BuroHappold Engineering is a multi-disciplinary consulting engineering practice whose energy consulting group recently partnered with the Eden project to organise the Energy Island workshop. The goal was simple, to explore whether a collective approach to Cornish energy which makes the most of Cornish natural resources could significantly enhance economic benefit to Cornish people. The workshop involved over 150 experts and stakeholders and we have used this as our basis for evidence, we think that an island within an island would be a key study for further testing, and we are actively seeking partners, including government, to take this further.

Cornwall already generates 20% of its energy by renewable means. But the Energy Island workshop also highlighted the issues of a weak national energy policy. One of many examples that emerged over the two day workshop was that on sunny summer days Cornwall produces over 50% more electrical power than it consumes. To keep the grid stable this must be exported over the grid to meet demand further afield. Grid reinforcement to meet this transient power flow is extremely costly and time consuming (planning applications for new overhead lines can take over ten years). These costs must be met by seeking high connection charges for future solar power generation which in turn provides a degree of regulation of the deployment of solar power. Why can't these costs be used to incentivise an increase in seasonal demand?

It may sound counter intuitive to increase demand to lower emissions but perhaps diverting this investment by making cheap power available for seasonal industry or to increase the use of electric vehicles or to deploy greater storage could solve the infrastructure problem and enhance the performance of the local economy. The problem is right there, our regulated utilities are bound to minimise cost to the consumer, and stitching together sensible local solutions does not compute in the bureaucratic world of utility regulation. It creates a gap between the clockwork and patchwork strategies.

Significant structural and market reform in the energy sector is a necessity and it looks like it may well be the cities and regions, like Cornwall, who will demand and drive this change for the sake of their local economies.

The Cornwall Energy Island project identified the following relevant points:

Vision: Stories are powerful, and this story should be told consistently by Cornwall Council, the LEP, community energy groups, businesses investing in the region, and others, in the media and through publications and public speaking opportunities. This is relevant at a national level particularly when seen as part of a bigger economic regeneration initiative

Coordinated Leadership: There are many people leading the creation of Cornwall's energy future, as is the case across the UK. The involvement of a diversity of stakeholders, and the distributed nature of leadership is a strength, but greater data sharing and coordination is valuable. Coordination activities should be valued and resourced.

Infrastructure planning: Develop a detailed understanding of a future energy system in Cornwall to incorporate demand management, storage, generation and distribution. This study will inform a strategic plan alongside detailed research into the future management of these systems such as funding, legislation and ownership to address the issues of the status quo.

Funding: Ensure availability of development funding, address the cost of capital, interest levels on loans, and support small projects to access larger pots of funding through aggregation.

Policy and regulation: Remove barriers which drive distributors to undertake network reinforcement rather than storage solutions when faced with rapid increases in transient distributed generation and ensure future incentives are flexible and able to adapt in a predictable manner in the face of rapid changes in technology.

This response to the call for evidence is structured in the following way:

For each question, an introductory paragraph summarises our perspective. Below this, a series of paragraphs provide further detail explaining our analysis of the challenges faced by the current system, followed by bullet points outlining our recommendations for how to approach this.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The electricity market needs to achieve all three pillars of the energy trilemma: sustainability, affordability and resilience. This means low carbon, as well as affordable costs to consumers and balancing of supply and demand. Minimising costs to consumers over the long term will include energy efficiency, and the electricity market can contribute to this through tariff structures that incentivise investment in efficiency. This could include time of use tariffs and rising block tariffs. with a focus on sustainability and low carbon, as well as affordability and security. Additionally, the electricity market needs to take into account the long term impacts of other parts of the energy system, including heat and transport, as these become increasingly electrified. Domestic heating and hot water systems can provide an electricity market role through storage of energy as heat in hot water tanks and the fabric of buildings. This can make a substantial impact in peak electricity demand and the ability for demand side management to provide flexibility. Multi-vector energy planning is therefore needed, not isolated electricity market planning. Implementing building and behavioural changes requires action by many individuals and local activity, and devolution provides an opportunity for local authorities and community energy groups to make a substantial contribution. The design and deployment of smart metering should support this, to ensure maximum effectiveness of embedded generation and demand-side management measures.

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

1. **Multi-vector energy planning is needed for greater flexibility.** Conversion of energy between different forms will be of growing importance to meet the challenges of balancing supply and demand in an efficient manner, including through demand side flexibility. The electricity market should therefore be considered in the context of multi-vector energy planning, including heat, gas (including natural gas, synthetic methane, and hydrogen as a means of storage), chemical energy (in fuels and batteries) and transport fuel. This requires systemic thinking. Heat is on the way to being electrified which will cause significant changes to the electricity market driving up prices. Electrifying heat will lead to substantial seasonal variations in demand, tripling loads on the electricity system which will need to be sized to deal with a few cold days per year - quite the opposite to better balance between supply and demand. Transport is also being electrified, with similar consequences to heat.

- Ensure that regulation of energy markets supports optimisation of use of different energy vectors, through systemic thinking.
- Energy efficiency, electrification of heating and transport, use of gas, heat and other energy vectors and demand response are interrelated with electricity market. The development of the electricity market should therefore support effective uses of the interfaces between these.

2. **Use of more innovative tariff models[1]:** Currently tariffs are structured so that domestic customers do not pay for the cost of balancing supply and demand. With the installation of smart meters there is an opportunity to change this. Local and social tariffs could also be used to support the business case for investment in energy efficiency whilst ensuring affordability for vulnerable consumers. Tariffs currently provide cheaper electricity to those who use more, and more expensive electricity to those who use less. This could be changed with rising block tariffs, which are used in many countries around the world. .
    - Explore the potential for tariff structures to incentivise demand reduction (e.g. rising block tariffs) and demand response (time of use tariffs, critical peak pricing), whilst ensuring affordability of basic energy needs e.g. warmth, lighting and cooking.

3. **Demand response and smart meters**: The current capacity market favours emergency generation (diesel generators) over demand response. The roll out of smart meters provides an opportunity for
    - Use capacity market mechanisms to incentivise new and low carbon forms of balancing capacity, through demand response at all scales, and electricity storage, rather than to support diesel and existing fossil fuel generators.
    - Accelerate deployment of smart metering and facilitate market in terms of incentivising intelligent demand management
    - Encourage the demand response aggregator market, learning from the US market.
    - Encourage domestic demand response through domestic aggregators combined with time of use or similar tariffs.

    Maximise the effectiveness of smart meters by designing new buildings to be 'smart-grid ready' - through existing Building Regulations, considering the interfaces between electrical and heating systems, including dual fuel heat, gas and heat networks with heat and electrical storage capacity.

4. **Devolution and electricity market flexibility:** this provides an opportunity for integrated delivery of multiple energy services at a local level, where local energy markets could make use of flexibility in heat, transport, gas and electricity systems to achieve balancing in each. Integration of local energy system delivery can also include demand response, network investment, and community engagement. Local ownership through devolution provides an opportunity to experiment at a local scale, with innovation resulting from diversity of initiatives across the country, particularly if supported by peer to peer knowledge sharing and learning.
    - Local energy markets: provide regulatory space for regional and local experimentation in energy markets, e.g. in Cornwall building on the foundation of the Cornwall Energy Island project. This should be an energy market that includes all energy vectors, and the potential to manage heat, transport, heat networks, electricity generation, storage and demand management within one locality. Local market mechanisms would allow a variety of local stakeholders to participate, including SMEs, social enterprises, national businesses, community energy groups and the local authority.
    - Area based smart meter deployment is needed to provide the technical foundation for local energy market innovation[2].
    - Smart meters should be designed to support third party access to data, and facilitate community energy initiatives. Community projects can substantially increase people’s engagement with demand response and energy saving[3].

2. What are the barriers to the deployment of energy storage capacity?

Storage of electricity is essential to enable greater integration of renewable generation, and balancing of the increased electricity demand peaks which would be caused by electrification of heat and transport. Ownership and operation of storage should be considered systemically so as to optimise deployment and viability of renewable generation, grid

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[1] https://www.cse.org.uk/downloads/reports-and-publications/policy/pub1111.pdf

[2] https://www.cse.org.uk/downloads/file/towards-a-smart-energy-city-maping-path-for-bristol.pdf

[3] http://smartcommunities.org.uk/

reinforcement, interconnection and demand response. Storage also needs to be considered in relation to multi-vector energy management: storage of heat in domestic hot water tanks and the fabric of buildings can make a contribution alongside electricity storage technologies. Regulation does not currently support deployment of storage, wrongly classifying it as generation. Storage is required over a number of timescales and geographical scales, leading to potential conflicts between different demands on storage facilities. These need to be better understood in order to make efficient use of storage.

Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

1. **Classification of storage as generation:** electricity storage does not have a separate regulatory classification, and is classified as a generation asset by default. Additionally, DNOs are required to avoid distortion of competition in generation and supply, which restricts buying and selling of electricity as part of operation of storage, making the business case more complicated as third parties need to be involved[4]. DNOs are well placed to own and operate storage for the purposes of ancillary grid services, and in Cornwall WPD would be very keen to take on storage assets, which could release grid capacity for further connection of renewable generation.
    - Regulation should create a new category of energy storage, so it is not classified as generation
    - DNOs should be allowed to buy and sell electricity to charge/discharge storage, and invest in storage without requiring complex third party commercial and contractual arrangements.

2. **Potential conflict between different services provided by storage:** electricity storage could provide services at multiple timescales and geographical scales, and to multiple parties: to DNOs, to TNOs, to suppliers, to generators. Business models for electricity storage require revenue from multiple services, but there may be conflicts between requirements of different parties at certain times. The extent to which this is an issue is not well understood, and should be tested. Dialogue between parties relying on storage services, and regulation of priority levels may be required to ensure grid reliability is not compromised by conflict between different requirements for storage.
    - Invest in modelling and piloting of use of electricity storage to provide multiple ancillary grid services, to better understand the extent to which there can be conflict.
    - Facilitate dialogue between different parties using storage facilities to support

3. **Multiple geographical scales are required:** including domestic, distribution network and transmission network scale. These need to be operated in such a way that activity at each scale supports the needs of other scales: e.g. domestic operation of storage should be operated to minimise negative impacts of distributed generation and demand peaks on the local distribution network, and local distribution network operation of storage should be operated so as to enable greater deployment of distributed generation, electrification of heat and transport, and support national balancing of supply and demand. The Cornwall Energy Island project considered the potential for nested optimisation of generation, storage and demand at the local, Cornwall and UK levels (see Figure 1).
    - Design tariffs and distributed generation incentives to maximise self-supply and local (domestic or demand side) storage operation to serve distribution and transmission requirements
    - Enable innovation and experimentation at the local level through devolution and geographically specific implementation of storage by local area. This could be supported by allowing local energy market development, including whole-system approaches (storage, smart meter deployment, generation and supply) to be trialled at a local level.
    - Make it easy for commercial customers with generation assets across multiple sites to 'self supply' and benefit from balancing their own supply and demand in real time through some form of licensed supplier status or 'net portfolio metering' e.g. many local councils operating heat networks and CHP / solar have energy consuming assets.

[4] http://poyry.co.uk/sites/www.poyry.co.uk/files/smarter-network-storage-lcnf-interim-report-regulatory-legal-framework.pdf

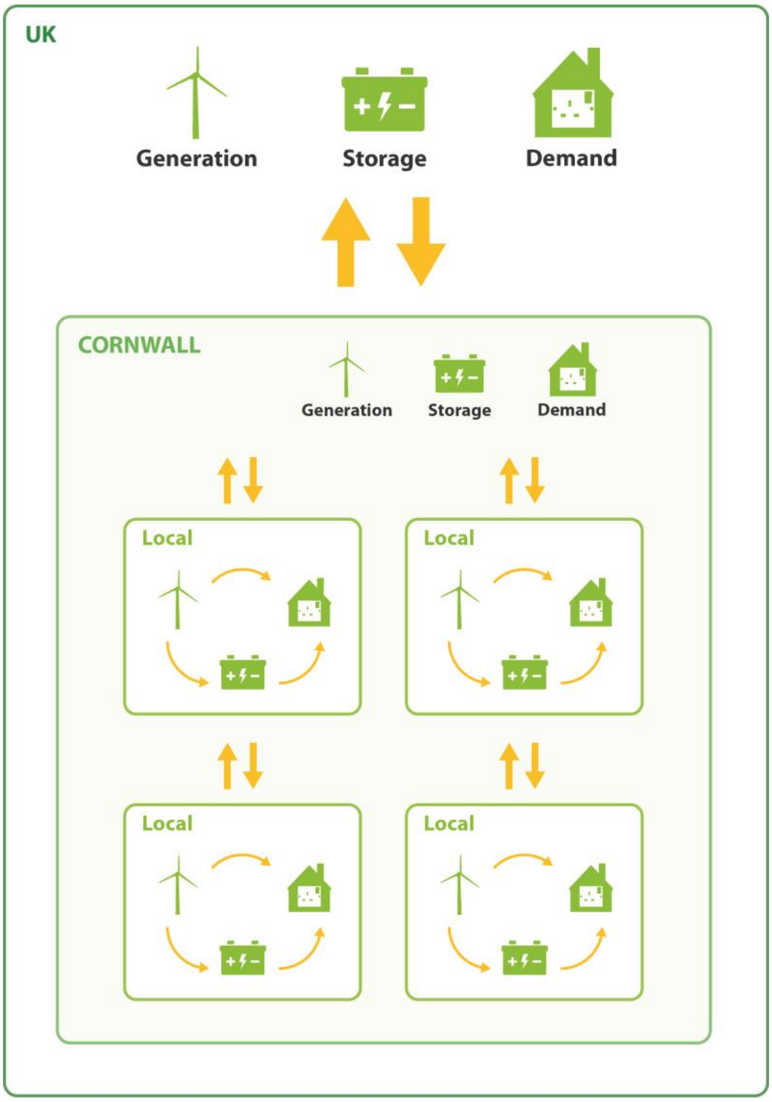

Figure 1: Nested optimisation of generation, storage and demand management at the local, Cornwall and UK levels

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnection can support balancing of supply and demand of electricity in a number of ways: through making use of geographical differences in natural energy resources (e.g. pumped storage, compressed air storage, variable and dispatchable renewable energy generation), differences in weather over larger distances increasing the balancing of wind and solar power, and differences in timings of peak demand between countries. Interconnection also has a role in enabling export of power. The UK is particularly well placed for offshore and onshore wind power, as well as marine energy technologies. Interconnection can ensure that these resources can be exported to benefit the UK economy.

Network development within the UK is also important. The Cornwall Energy Island project imagined the national grid connections from Cornwall to rest of England as 'interconnectors', which need to be reinforced so that the Cornish economy can benefit from export of electricity to the rest of the UK, and contribute to the wider goals of the UK Climate Act and EU renewable energy targets.

Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

1. **Systems thinking:** Interconnection should be understood as part of a whole energy system:
    - Use of interconnection to increase UK electricity resilience, with a focus on export and ability to be independent rather than reliance on other countries for balancing the UK system. Internal energy supply should be prioritised before relying on interconnection.
    - Existing interconnectors are operated according to market signals, and it is therefore difficult to rely on existing usage to model the potential contribution of interconnectors to balancing and energy security[5]. This requires research.

2. **Long term framework:** infrastructure investment should consider the long term:
    - Invest in interconnectors ahead of demand as enabling infrastructure to support long term investment in Atlantic and north sea wind generation

3. **Nested model:** Consider interconnection internationally as analogous to connections between regions within the UK.
    - Regions such as Cornwall can be operated to be as self-sufficient in energy as possible locally, whilst contributing to the wider UK system
    - In particular, electricity infrastructure development should consider the evolving roles of the rural and urban areas, which have changed since the electricity network was initially designed, with the rise of high rural generation of renewable energy, as well as urban distributed generation, increased demand, and potential for demand response.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Planning to balance supply and demand must involve consideration of demand reduction and management. Future sustainable energy scenarios in the UK and internationally rely on ambitious demand reduction to achieve balancing[6], a finding supported by our regional level work in the West of England and Cornwall, which modelled a 50% reduction in demand to achieve an energy island. The UK has the least energy efficient building stock in northern Europe. Energy efficiency should be established as a national infrastructure priority, and the business case for investment in demand reduction should be supported through appropriate pricing and tariff arrangements. The rate at which technology is changing, particularly in the area of decentralised generation is forcing reactive change in both physical infrastructure and incentive programmes, for example the rapid reduction in cost of solar PV since the introduction of the Feed in Tariff. The implementation of relatively mature technology such as thermal insulation, smart metering and demand management should be accelerated. The development of 'game changing' technology such as economically viable bulk storage and carbon capture appears difficult to predict. The use of Shale Gas should only be developed with a strong commitment to renewables and low carbon technologies[7].

1. **Stable and clear energy policy goals:** UK energy policy is currently moving against the global trend to distributed generation as costs for wind, solar and storage continue to fall whilst costs for large power stations, continue to increase well above the rate of inflation, leading to higher costs for consumers. Having a clear and consistent policy direction in Germany, with the Energiewende, has driven innovation and activity. The Climate Change Act 2008 puts the UK in a potentially strong position by setting out very clear goals with respect to CO_2 emissions reductions, but recent policy changes have reduced investor confidence and the ability to respond with agility to changes in technology.
    - Make a clear commitment to a direction of travel that is low carbon, resilient, and affordable.
        i. minimising dependence on fuel imports (including nuclear?)
        ii. Clear statement on nuclear
        iii. Informed long term planning with respect to Climate Change Act

[5] http://erpuk.org/wp-content/uploads/2014/10/52990-ERP-Energy-Storage-Report-v3.pdf

[6] http://www.demandenergyequality.org/2030-energy-scenario.html

[7] https://www.taskforceonshalegas.uk/news-and-events/task-force-on-shale-gas-launches

   iv. Cost/medium term viability of carbon capture and storage as a prerequisite for shale gas development

- Assess long term impacts on bills of infrastructure investment (grid reinforcement) and renewables (long term fuel-prices etc.), taking into account impact of existing tax breaks and subsidies for fossil fuels.
- Prioritise affordability of basic energy access for households, particularly those in fuel poverty
- Address the impacts on energy costs of:
   i. Future fuel price instability
   ii. Decreased load generation load factor arising from increasing proportion of non-dispatchable generation (which may change if storage situation improves)

2. **Demand reduction:** the UK has the least energy efficient building stock in northern Europe. Building space heat demand remains a dominant energy demand with its seasonality adversely affecting energy generation and transmission load factor. If space heating is electrified as part of energy system decarbonisation, this will further exacerbate the impact on plans to balance supply and demand for electricity. Green deal has not been successful, but the goal of improved thermal performance of domestic buildings remains an infrastructure priority, and progress in other countries has demonstrated that significant demand reduction is practical with current technology. More broadly, other countries have taken a strategic approach to encouraging building energy efficiency and demand reduction as a key element of energy systems planning:

   Performance-based incentives - these have been used to encourage technical innovation in the energy efficiency market whilst being flexible about how the target is met. Good examples include the NABERS scheme in Australia or the domestic energy efficiency market in Germany where the availability of low cost loans was linked to the specific targets being achieved.

   Investor confidence - UK investment in energy efficiency and small scale renewables has been undermined by abrupt changes to the policy regime (e.g. FIT, ECO, Zero carbon Homes) resulting in dramatic collapse of the supply industries (e.g. Mark Group, Climate Energy) and undermining of confidence for investing in this sector or the development of new business units within established companies. Other countries have encouraged businesses to invest their own capital in developing new technologies and business models through providing long term investor confidence.

   Low cost finance - other countries have provided financial support mechanisms that are technology-neutral but sufficiently long term and low cost as to stimulate a range of technologies and projects to emerge. Good examples include low interest energy efficiency funds from the German Development Bank KfW and revolving retrofit guarantee funds in Hungary. Whilst the Green Investment Bank has an important role to play in crowding in finance and recycling capital for target sectors (e.g. energy efficiency, waste, offshore wind), state aid limitations have prevented it from achieving the same impact that KfW has managed to achieve.

   - Establish energy efficiency as a national infrastructure priority - Government should invest in energy efficiency as a national infrastructure priority and realise the strong macroeconomic benefits that have been clearly articulated in reports by reputable experts including Cambridge Econometrics. These include tax returns to the exchequer, job creation, regional economic growth, reduced spend on health, improved energy security and cost-effective achievement of carbon targets.
   - Create a demand reduction roadmap - Establish a clear road map for supporting demand reduction and energy efficiency including targets, milestones and support mechanisms.
   - Reform energy pricing within other European countries suggest pricing can be raised through taxation to both incentivise demand reduction and fund demand reduction programmes focussed on those in energy poverty. Tariff structures such as rising block tariffs could further support this.
   - Develop clear policy and structural incentives to stimulate investment in energy efficiency. The UKGBC consultation response on “Reforming the business energy efficiency tax landscape” provides a good reference point for the qualities that need to be achieved, including:

i. Transparency – the final policy mix should make it easier for participants and external stakeholders to understand how their energy performance compares to their peers and to invest accordingly
ii. Visibility – the drivers for action under the new landscape must be clear and visible, so that they attract the attention of senior decision makers
iii. Consistency – as stated above, creating a new regime that is has longevity is absolutely critical. It should be consistent with the UK's long-term climate and energy needs, to avoid the risk of near-term changes disrupting investment.
iv. Ambition – as stated in the consultation document, the final landscape must improve the business case for investment in energy efficiency if we are to deliver a more productive, efficient, low carbon economy. It is extremely unlikely that simplification alone will achieve that aim.

The UKGBC Retrofit Incentives task group evaluated a series of potential mechanisms for the non-domestic sector including variable Stamp Duty, Council Tax and Grants.

3. **Heat supply:** heat networks predominate in many Northern European cities. They are a long term investment, and although the argument can be made that thermal transmission losses negate efficiency benefits in central heat generation, they allow: flexibility to change heat generation to suit: evolving technology; tightening carbon reduction targets; and periods of surplus energy production – e.g. wind energy to heat; as well as access to waste heat sources and reduction in seasonal electrical demand.
   - Increase support for public (through local authority) development and ownership of integrated utility distribution networks (particularly heat)
   - Repurpose bodies such as the Green Investment Bank to provide competitive finance for publicly owned distribution networks

4. **Bulk energy storage vs carbon capture and storage** – the development of these technologies appears slow and is under supported in the UK. Other northern European countries do not predicate the success of their medium term (10-20 year) energy strategy on the success of this technology. This partially due to a desire to limit dependence on fossil fuel importing but nevertheless significantly greater emphasis is being placed on integrated bulk energy storage in other countries.
   - Set required deployment dates for bulk energy storage and carbon capture and storage against Climate Change emission reduction.
   - Set in place decision dates at which point deployment of an alternative approach is necessary if evolution of required carbon capture and storage or bulk energy storage technology appears unable to meet target deployment dates.

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National Infrastructure Commission
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8 January 2016

Dear Sir,

I am aware that you are currently looking at aspects of the energy sector and write to highlight some of the concerns we have around the current market design.

We are also members of Energy UK and have fed into their response, but thought it worth pointing out some of our particular concerns too.

As an overview I think it fair to say that the results of the second capacity auction have confirmed the fears of many. The interventions of recent years, including the fundamental design of the capacity mechanism itself, have created a market that is not stimulating sufficient investment. Any investment that is forthcoming, is focused on generation types inconsistent with Government and EU policy objectives.

We believe there are several areas that need to be scrutinised to get us closer to being an efficient and fair market conducive to investment, as had originally been intended. At an overview level, we believe that Government policy must aim to create a long-term, stable environment based on market-based mechanisms that will address the 'energy trilemma' by creating proper market mechanisms that allow these objectives to be met.

We are encouraged by the initial commitment of the new Government to move to a less intervention, more market-based approach and are keen to help them address the current challenges. In particular, we believe the following aspects need urgent attention:

Market design

- The current capacity market design is generally accepted as being flawed and is characterised by vested interests seeking bespoke solutions. As a result, it fails to encourage new build of the type required by the market (ie new CCGTs) and, more worryingly, is failing to give meaningful incentives to existing CCGTs to remain open.

- The in-built distortion between new build and existing capacity, the artificial encouragement of coal stations to refurbish and the failure to address how the capacity market interacts with other distorting incentives for embedded generators have left a market that is encouraging new build diesel generators over CCGTs and failing to stop existing CCGT stations from closing.

- The capacity market needs changing radically and urgently if the UK is to avoid a capacity crisis. We are encouraged by the Government's latest consultation in this respect, but would urge that any design changes focus on providing a market that allows a proper pricing of firmness and flexibility across all generation types, and that minimises the subjectivity available to the system operator.

Interconnectors

- Whilst we understand the desire for greater inter-connection across Europe, this must be done in a way that does not distort price signals to other generators. Unfortunately, due to artificial 'subsidies' such as the absence of carbon pricing and distortions around transmission charging, inter-connectors are not competing on a level playing field with other types of generation.

- This naturally makes the market far less attractive for new investment in conventional gas generation. As an example, new-build interconnectors can bid into the capacity market in direct competition with new build CCGTs, whilst the certainty of energy output that they provide at key times is clearly different as energy through an interconnector will flow in either direction depending on price signals (so could actually deliver negative generation at times of crisis). This should be compared to the generation certainty provided by existing or new CCGTs.

Flexibility

- Demand side and embedded generation provide many opportunities for increasing the flexibility of the system but there should be a level playing field across all technologies and additional impacts, such as grid costs borne elsewhere, must be included in any cost benefit analysis.
-
- In addition, one form of generation should not have access to sources of revenues that others can't compete with (eg triad avoidance, STOR contracts, etc) whilst then competing in the same capacity market. Given these distortions, it should come as no surprise that new diesel engines are winning capacity contracts ahead of new CCGTs, despite the fact that they have a much higher average running cost and produce far more pollution. This same effect is also suppressing the clearing price of the capacity market, threatening the sustainability of existing, efficient CCGTs.

Storage

- The barriers for storage appear to be mostly technical and economic and we don't believe that subsidies in any form are warranted, as any UK subsidies will have minimal effect and are likely to give negative returns for the UK tax payer due to the global nature of storage development.

I hope that these points will help with your thinking and would be happy to discuss them further with you, or one of your team, should you find that useful.

I can be contacted at [email address redacted] or on [phone number

redacted]. Yours faithfully

Kevin McCullough
CEO
Calon Energy Limited

Electricity Connection and Storage – Submission to the National Infrastructure Commission from the Cheshire and Warrington Local Enterprise Partnership

Cheshire and Warrington Local Enterprise Partnership

The Cheshire and Warrington Local Enterprise Partnership (LEP) is a private-sector-led partnership charged with driving the economic growth of the Cheshire and Warrington Sub Region and is one of 39 LEPs in England. Established in March 2011 it covers the three Unitary Authorities of Cheshire East, Cheshire West and Chester and Warrington, an area of approximately 871 sq. miles.

Summary

The Cheshire Warrington Local Enterprise Partnership is keen to respond to the Call for Evidence issued by the NIC, however we acknowledge that the questions posed are, on the whole, very specific and technical in nature. As such the LEP does not have the level of expertise to answer these in its own right, however the Cheshire and Warrington Sub-Region is home to a number of nationally significant energy-related companies a number of whom we have consulted with through the Cheshire Energy Hub (http://www.cheshireenergyhub.co.uk/).

One of the lead partners in the Energy Hub, EA Technology, has responded to the Call for Evidence in its own right and we have restated their response as **Appendix A.** Further information is included below in respect of the barriers to deployment of energy storage.

In terms of key points we would wish the Commission to 'take away' from the evidence submitted, these would be: -

- Continued investment in the development of energy storage capability and technology will be critical in ensuring energy security and continuity of supply. Having a reliable, affordable energy supply is crucial for many of the key industrial sectors based in Cheshire and Warrington and without out such security future investment in new products and facilities could be at risk.
- Supporting the development of SMART Grid technology will be an important element of enabling creation of a more responsive, flexible energy market.

Context

Strategically located between the Core Cities of Liverpool and Manchester and with close to a million people our Cheshire and Warrington is one of the most successful economies in the country. Generating in excess of £23 billion of GVA per year, our sub-region has a workplace GVA per head consistently above the national average and around 30% higher than any other economy in the North of England.

Based on latest 2014-2015 economic data, Cheshire & Warrington is:

- ***A major economy with a large cohort of world-leading firms****, with an annual Gross Value Added (GVA) of over £23bn, and 430,000 work-based employees. The C&W economy is equivalent in scale to cities such as Birmingham and Leeds. The sub-region's key firms include Bentley Motors, Tata, Vauxhall and Barclays, and there are distinctive sectoral specialisms in advanced, high-value engineering, energy, and professional and business services as well as growth potential in food, agri-tech and biological engineering.*

- ***A diversified and internationally-oriented economy****, with around one-fifth of employment in Cheshire and Warrington in export-intensive industries, the third highest of any LEP area across England. Cheshire and Warrington has a consistently strong record in attracting new inward investment compared to the national average, with the area offering a diverse range of investment locations for investors: in urban centres, in and around attractive market towns, and in high-quality, yet accessible, rural spaces.*

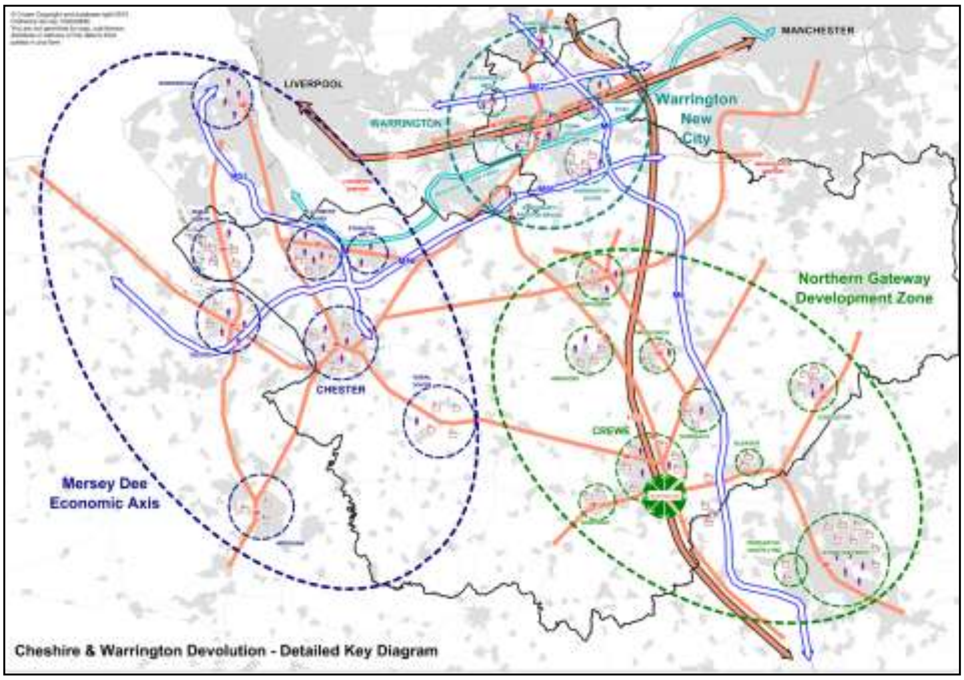
- ***A private sector-led and knowledge-rich economy****, with a high density of private sector jobs relative to its population, one of the highest outside of the capital. The area boasts a large private sector business base, with business density rates well above the national average; the business base contains a well-defined mix of high profile international companies, well-established and substantial medium-sized companies, and a dynamic and growing small business base.*

- ***A connected economy****, with long established linkages to Manchester and Liverpool and their city centres, higher education, and innovation assets, as well as strong economic links to North Staffordshire and the 'Potteries', and across the border to North Wales. Our people and businesses benefit from key strategic transport infrastructure – the West Coast Main Line, the national motorway network, the M6, M62, and M56 axis – and proximity to international transport linkages at Manchester and Liverpool airports, and the Port of Liverpool, but it is recognised that current capacity limit, resilience and journey times connecting to this key infrastructure remain poor.*

Our current Strategic Economic Plan forecasts economic growth of some £12 billion by 2030 and we are in the process of revising this to target a £50 billion economy by 2040. **We would therefore stress the importance of not restricting consideration on transport connectivity to city regions. Important as they are, our big cities are not the only source of economic growth in the UK**.

Helped by the proximity to key air and sea gateways and trade routes, Cheshire and Warrington LEP has developed three interconnected spatial proposals that will increase and accelerate growth, enhancing the sub-region's economic impact within the Northern Powerhouse and UK.

These spatial proposals are fundamentally driven by enhanced connectivity and strategic transport investment and are shown in terms of their spatial locations, and spatial interactions with surrounding Core City Regions and adjacent LEP's in the figure below.



Key Growth Areas & Existing Transport Connectivity

Northern Gateway Development Zone

The primary aim of the Northern Gateway Development Zone is to capitalise on Crewe's current and future connectivity through the arrival of HS2, delivering high speed connectivity to the Northern Powerhouse 7 years earlier than otherwise planned.

This will help maximise the benefits and growth opportunities as the "Gateway to the Northern Powerhouse", supported by productivity critical improvements in term of access to/from the HS2 hub, by all modes.

Across this area as a whole there is the potential to deliver 120,000 jobs and over 100,000 homes by 2040, with supporting, and required transport investment to consolidate early-HS2 benefits across the North.

Mersey Dee Economic Axis

C&W is building upon collaborative links with the Mersey Dee region to unlock a number of growth employment sites in Chester, Ellesmere Port, North East Wales and Wirral. These opportunities have the potential to bring forward:

- Over 700 hectares of employment land; and 1 million sift of prime city centre commercial space; and
- Deliver 54,000 new jobs and 41,000 new homes by 2040

Cheshire Energy Hub, based in Ellesmere Port is supported by a number of leading International energy systems companies based in Cheshire and Warrington including Atkins, Boulting Group, C-Tech Innovation, CNS (Capenhurst Nuclear Services), EA Technology, Electricity North West, National Nuclear laboratory, Storegy UK and Scottish Power.

Thornton Science Park includes The University of Chester's Faculty of Science and Engineering which is fast developing into a major energy-focussed research and innovation hub including development of a Smart Grid systems demonstrator.

There are strong social and economic links in to North Wales and the next generation of nuclear power station at Anglesey Energy Island.

Warrington New City

Warrington's connectivity will be reinforced in the future as it sits at the intersection of HS2/ West Coast Mainline and TransNorth Networks.

The Town's strategic position is at the heart of the M6, M56 and M62, benefitting from significant growth potential at Port of Liverpool and the string of ports along the Manchester Ship Canal.

Warrington New City, and associated development proposals is anticipated to deliver 26,000 new homes, and 55,000 jobs; with additional transport infrastructure to enhance strategic connectivity, enhance resilience of key Pan-Northern and Trans-European networks, and unlock capacity constraints preventing local growth.

Warrington is home to one of Europe's most significant clusters of nuclear-related companies including NNL (National Nuclear Laboratories), AMEC Foster Wheeler and Rolls Royce Nuclear, providing engineering and consultancy services and research and development activity.

Responses to Specific Questions Raised by the Commission

The Cheshire Warrington Local Enterprise Partnership is keen to respond to the Call for Evidence issued by the NIC, however we acknowledge that the questions posed are, on the whole, very specific and technical in nature. As such the LEP does not have the level of expertise to answer these in its own right, however the Cheshire and Warrington Sub-Region is home to a number of nationally significant energy-related companies a number of whom we have consulted with through the Cheshire Energy Hub (http://www.cheshireenergyhub.co.uk/).

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Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

2. What are the barriers to the deployment of energy storage capacity?

Cheshire is location for the UK's largest onshore gas storage facility, one of a number of such assets which utilise the vast salt caverns found under the sub-region. Strategically it allows security of supply in case there are disruptions to production, transport or supply. These could be due to commercial reasons (e.g. somebody else has paid a higher price for the gas), political reasons or an outage. Gas storage is also important in balancing seasonal variations in consumption where the winter demand is greater than the summer usage. It can also cover peak demands such as weekday evenings. It can also enhance the effectiveness of gas transport and production, where it can be stored locally to where it is being used.

However there are limited areas where the geology is suitable for underground gas storage and as such this means that such facilities could be located a significant distance away from where demand for the gas actually is.

In addition to possible financial barriers, there are also Technology barriers to energy storage to consider. Market failures preventing investment in energy storage are mainly centred on the cost to develop technologies alternative to existing storage capacity. The dominant technology is pumped hydroelectric, with around 99% of installed capacity. The possibility to expand this capacity further is limited, and is in any case not suited for flexible deployment to reinforce the grid in an effective and cost-neutral manner. A further limitation is its slow response time. The dominance of pumped-hydro is due to its low cost, typically 100 €/kWh, which is a proven target that any new storage technology must approach to be commercially viable. The next most widely deployed storage technology is compressed air (CAES). CAES is also cost effective, but again limited by the availability of suitable locations and is typically deployed at a scale of 100s of MW.

The remaining electricity storage technologies are based on electrochemical systems. Sodium-sulphur (NaS), lithium ion and lead-acid batteries are the major contributors to current capacity. NaS systems are exclusively produced in Japan and the ability of European companies to enter this market is limited by the extensive IP protecting this technology. Lithium ion batteries remain expensive, and due to their high power density, are most suited to smaller scale applications such as electric vehicles and portable devices. Long term, the use of lead-acid batteries will be limited by the supply of lead and its perceived negative environmental implications. Other technologies, including flow batteries, are mainly at the development scale and unproven, with prohibitively high capital costs (>€1000/kW).

Whilst many energy storage technologies remain within the realms of academic research, aside from Li-ion, the number of industrial organisations involved in deploying these technologies remains relatively low. The lack of financial incentives in the way that feed-in tariffs benefited the renewable generation market, and a lack of understanding of how storage should be integrated into existing distribution networks are clear barriers to wide-scale deployment of electricity storage. Investing in these areas will help raise awareness of the capabilities of new and existing storage technologies, and create interest and investment for wide-scale deployment.

The most likely scenario for future energy storage is likely to be a combination of many technologies, with solid state batteries and supercapacitors being widely used for short-term energy “power-hungry” domestic applications (<10’s kWh). For longer term energy requirements (100’s kWh – MWh), redox flow batteries (RFB’s) have the flexibility to decouple power from energy, and therefore capacity can be scaled up without the need for additional battery hardware, significantly reducing costs when compared to other battery technologies.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current ‘cap and floor’ regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

APPENDIX A – EA Technology Submission provided to NIC.

Electricity interconnection and storage

The following response has been provided under the National Infrastructure Commission's call for evidence, published 13 November 2015.

EA Technology has a strong heritage working with the owners and operators of energy networks to increase their reliability or make them more cost-effective. We have a rich technical knowledge base and are passionate about using this to deliver economic benefits to our customers, and the customers they ultimately serve. We have pioneered world-leading developments ranging from intelligent investment planning software, to electrical energy storage, through to running large scale projects on electric vehicles.

We therefore focus these responses on the **electricity interconnection and storage** consultation on how changes to existing market frameworks, increased interconnection and new technologies in demand-side management and energy storage can better balance supply and demand.

For more details please contact: [email address redacted]

Changes to the electricity market to ensure that supply and demand are balanced

Domestic energy consumers – representing approximately 40% of UK consumption[1] – are not currently exposed to half-hourly balancing costs. There is currently therefore little or no incentive for individual customers to modify their demand to reduce these costs. The reasons for this lack of exposure include:

- legislation enacted to simplify tariffs means that electricity supply companies cannot easily offer variable half-hourly tariffs (i.e. political constraint);
- the market demand for variable half-hourly tariffs is still to emerge (i.e. economic constraint), although fixed-time tariffs such as Economy 7 remain popular and account for 25% of domestic consumption; and
- the smart meters necessary for half-hourly billing are not yet widely deployed in the UK (i.e. technical constraint).

For non-domestic energy consumers – representing approximately 60% of UK consumption – the situation is different as approximately 70% of demand is half-hourly metered. Therefore 42% of UK electricity consumption is potentially exposed to half-hourly balancing costs and could therefore be incentivised via tariffs to ensure supply and demand are balanced. In practice, consumers do not like the variability that this entails and so they will generally look for a tariff arrangement that limits their exposure to this variability.

The result of this is that electricity consumers in the UK currently have very little incentive to ensure that supply and demand are balanced, even if it were beneficial for them to do so. As a result, balancing costs will inexorably rise (in the absence of any other controlling factors). This situation represents a market failure.

[1] https://www.gov.uk/government/collections/sub-national-electricity-consumption-data

The need for an independent System Operator

The above market failure can be addressed in a number of ways. The debate is often framed in terms of a dilemma between the two following choices:

1. should consumers and generators be exposed to balancing costs (thereby applying free market mechanisms to keep balancing costs down), or
2. should the task of minimising balancing costs be entrusted to an independent System Operator (thereby limiting the exposure of consumers and generators to balancing costs)?

EA Technology does not have a strong preference for either option.

We believe that Option 1 would, ultimately, produce the best outcome (i.e. the lowest costs to consumers, over the long term). However, all the political, economic and technical constraints described above would need to be addressed beforehand in order for this market to function. Furthermore, the current half-hourly market (on which all electricity trading is based) may ultimately be much to slow to reflect the real-time nature of balancing costs, especially as the generation mix becomes ever more intermittent (see Figure 1). Moving to real-time electricity trading would be a massive, unprecedented undertaking and not a decision to be taken lightly.

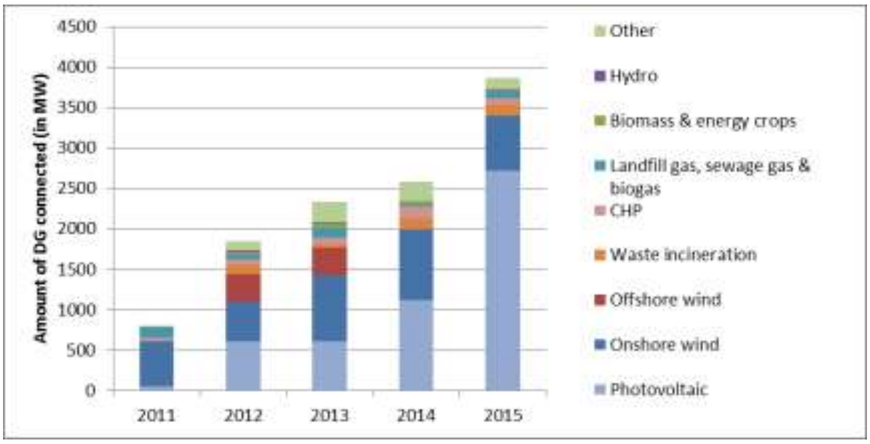

Figure 1 Increase in in intermittent, non-despatched generation connected to the UK distribution network

Option 2 represents a more pragmatic approach, in that an independent System Operator would undoubtedly drive incremental reductions in balancing costs over a realistic timeframe. Our concern is that this approach will not, ultimately, produce the best outcome. The System Operator may have only limited authority over the real-time behaviour of generators (especially distributed generation) and will have little or no control over consumer behaviour (unless the political, economic and technical constraints are addressed, as above). Therefore, rather than influencing generator and consumer behaviour to minimise balancing requirements, the System Operator is likely to respond to balancing issues through costly infrastructure investments and changes to operational procedure – over timescales measured in years. This is very different from being driven solely by a desire to reduce balancing costs. In this light, it is hard to conceive of an appropriate set of financial incentives for the System Operator that would – somewhat perversely – need to offer greater rewards as its services are needed less and less.

Interconnection versus balancing

On a small highly islanded electricity network, balancing is a real-time, technical imperative. Without balancing, the lights go out. Instantly.[2] Keeping the lights on can result in very high balancing costs.

On a heavily interconnected network (with the necessary robust transmission infrastructure)[3], balancing costs are less of an issue. Generators generate, consumers consume and the market takes care of the energy pricing. Local system operators manage power flows as best they can, but can (generally) fall back on the backbone transmission system as needed. This results in very low balancing costs.

There is therefore an opportunity to reduce balancing costs by increasing interconnection.

A market opportunity

EA Technology believes there is a strong case for using market mechanisms to minimise balancing costs to consumers over the long term.

However, EA Technology does not believe that an electricity market based around half-hourly energy prices is the right market mechanism to reduce balancing costs. Even with significant reform and investment, it is hard to imagine how variations in half-hourly pricing can achieve the desired outcome; if energy consumers are exposed to sudden price spikes, the outcome is likely to be anger and dissatisfaction directed at "those in charge" rather than any meaningful change in behaviour.

On the other hand, consumers are more likely to change their behaviour if offered a direct reward for any change they make. If inflexible generators (and network operators) are exposed to significant balancing costs, they may well be willing to pay consumers directly to help them reduce these costs. If this were a direct payment – outside of any half-hourly trading mechanism – then this would immediately address the three constraints identified above:

- there would be no change to domestic energy tariff arrangements between consumer and supplier;
- demand would be created by the offer of a payment to those able to change behaviour to address balancing costs; and finally
- the implementation of this market framework would not necessitate smart meters.

We believe that a new 'direct balancing market' mechanism that exposes market participants in the following way would produce the desired outcome:

1. System Operator sets the balancing price for a specified period
2. Flexible generators adjust their output during this period to minimise balancing charge
3. Inflexible generators either pay the remainder or pay flexible consumers to help minimise it
4. Flexible consumers modify their demand in return for payment from inflexible generators
5. Consumers who choose to remain inflexible do not benefit from such payments

Only those consumers participating in balancing activities need to have a measuring device or other mechanism to confirm participation. This would offer far more opportunity for innovation over what can be achieved using a typical domestic smart meter e.g. use of smartphones to provide monitoring and/or evidence of behaviour in return for payment. Furthermore, because there would be an active market in influencing behaviour to minimise balancing costs, together with a clear financial advantage for flexible generation over inflexible generation, any dependence on the independent System

[2] http://www.independent.com.mt/articles/2014-01-09/news/widespread-power-cut-3641016320/
[3] http://www.entsoe.eu

Operator to manage these costs is reduced. The System Operator merely needs to set the balancing cost and let the market take care of the rest.

The effectiveness of Demand Side Management

Demand Side Management is sometimes referred to as demand side response. This alternative term recognises that demand isn't something that can easily be "managed". However, it may be possible to shift useful amounts of demand using appropriate signals and incentives, at the same time as ensuring that customers retain overall control over their electricity consumption.[4]

The understandable concern about this more voluntary approach is that it may be ineffective: what if consumers are unwilling (or unable) to shift demand in response to these signals? Won't this lead to significant imbalance?

Such concern is well-founded. There is relatively little deferrable load currently in consumer premises: other than cooling and heating, most existing load (such as lighting and cooking) cannot be deferred for long. However, this rather pessimistic outlook ignores the fact that there are very significant changes occurring (and about to occur) in electricity usage patterns. The most significant changes include:

- The connection of photovoltaic (solar) generation to domestic premises (3kW-10kW+)
- The use of heat pumps for heating (3kW-15kW+)
- The charging of electric vehicles (3kW-10kW+)

These new electrical loads all share some interesting characteristics:

- They are all significant – often much bigger than existing domestic loads
- They are all becoming increasingly commonplace
- They are all controllable and/or deferrable to some degree

The Transform Model® developed by EA Technology has shown that demand will change significantly moving forward with the electrification of heat and transport and the proliferation of small scale generation (and potentially, small scale storage). Furthermore, recent work by National Grid with Element Energy[5] has indicated that, by 2030, the contribution of such deferrable loads could provide over 80% of GB's requirements. This is because loads such as electric vehicles are plugged in for an average of 8 hours per day, but only require 3 hours to draw charge, meaning the window within this load can be managed is significant.

The opportunity is there for these new loads to play a significant and increasing role in minimising balancing costs. The technology is already available: EA Technology / SSEPD's My Electric Avenue electric vehicle project[6] has shown beyond doubt how its Esprit managed electric vehicle charging can deliver significant shifting of electric vehicle loads without detriment to the customer experience. What is currently missing is any market mechanism to enable adoption of such technology. This is the opportunity currently available to the UK and we urge the National Infrastructure Commission to play a key role in realising this outcome.

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[4] Koliou, E.; Eid, C.; Hakvoort, R.A., "Development of Demand Side Response in liberalized electricity markets: Policies for effective market design in Europe," in European Energy Market (EEM), 2013 10th International Conference on the , vol., no., pp.1-8, 27-31 May 2013
doi: 10.1109/EEM.2013.6607403

[5] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Technology-reports/

[6] http://myelectricavenue.info/

Barriers to deployment of energy storage

The existing energy market and balancing regime considers "generation" (with one set of rules) and "demand" (with another set of rules). Storage technology is unique, in that it can be both generation and load. Distributed storage is often able to switch from one mode to another in a very short space of time – yet this is not recognised by the traditional market. The developing UK Balancing Services market (especially STOR[7]) provides one model to address this limitation, but unfortunately the minimum generator size (3MW) is prohibitively large and the frequency of balancing requests (~70 p.a.) much to infrequent to encourage commercial deployment of storage technologies.

Storage operators therefore need to operate two supply contracts – one for demand, one for generation – with limited opportunity to optimise between them: even if the electricity supply contract recognises that the storage unit can reduce its demand to zero at any time, it will not be able to recognise that it could also become a generator (i.e. negative load) at times of high demand. Likewise for the generation contract, which will not be able to recognise that the storage unit could become a load (i.e. negative generation) at times of excess generation. Both of these capabilities would enable storage to contribute effectively to balancing services, but cannot be achieved through conventional energy trading mechanisms. As a result, the positive contribution that storage can make to balancing at all voltage levels cannot currently be recognised.

There is another aspect of storage that is often overlooked: such technologies often make use of heat energy (e.g. phase-change heat pumps, compressed air storage). Unlike electricity, heat is extremely difficult to transport over long distances and so for these storage technologies to be cost effective, they must be in a geographically suitable location. The economically ideal location for storage would contain a synergistic mix of local heat and electricity demand that can be balanced off using the storage unit. Heat energy is not regulated and can be traded locally; unfortunately the same is not true for electrical energy. If storage operators want to make use of the local electricity grid, they can only do so by trading through the energy market – which, as described above, does not recognise the contribution that storage can make to balancing services.

EA Technology believes that two changes to the existing market would enable greater uptake of storage capacity:

1. The enabling of "Storage" connection agreements and tariffs, instead of requiring storage operators to hold both "Generation" and "Supply" contracts.
2. The enabling of electricity to be traded directly between third parties over the local electricity network (via contract with the local electricity network operator), without requiring participation in the national electricity market.

It is realised that the above proposals would represent a radical shift away from the national half-hourly trading regime and we recognise that such market freedom may be somewhat risky of adopted on a large scale. However, we think there is a case for trialling these freedoms with small scale storage units. Not only would this remove a significant barrier to the uptake of storage, but also the behaviour of these smaller units could be closely observed with a view to further relaxing national trading arrangements as more is learned about the contribution that storage can make to balancing.

Such wider uptake should also drive down the price of storage technology – an issue that must be addressed if storage is ever to make a significant contribution to balancing service.

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7 http://www.thinkinggrids.com/ancillary-services/stor-provides-short-term-generation-support-and-cost-62m-in-2014-2015

Appropriate level of electricity interconnection

As described above, increased interconnection leads to reduced dependence on balancing services. In EA Technology's view, the economic case for increased interconnection should always be weighed up against the economic case for reducing the requirement for such interconnection through demand side response. The optimum mix of interconnection and demand side response will change and develop continually. We believe this mix should be determined though market mechanisms wherever possible.

The 'cap and floor' regime provides a useful mechanism to encourage the building of interconnection. Our primary concern is that such market "distortions" might encourage building of interconnection when it is not needed (if the floor is set too high) or discourage the connection of necessary interconnection (if the cap is set too low). There does not appear to be any reflection in this mechanism that the actual need for interconnection may change over time. Given the significant changes expected in electrical demand patterns that is expected over the lifetime of these 'cap and floor' contracts, we think there is a high risk of an eventual mismatch between the level of required interconnection and the level that is actually built.

The ideal approach would be to expose interconnection, demand side response and storage to the same market drivers – given that they all contribute to the same outcome i.e. a balanced system. We would encourage further discussion and analysis on whether the 'direct balancing market' proposed earlier in this response could be usefully extended to interconnection providers as well.

International best practice

An example of allowing consumers to participate in the market via a mechanism other than through smart metering tariffs is that provided by Powershop in New Zealand.[8] This is a model whereby customers have the option of purchasing different 'packs' of electricity units at different prices in advance of using them. In this way, customers can purchase units at a saving compared to the standard tariff. The interface is accessible via an app on the customer's phone or tablet, putting them in control of their energy purchase, and allowing them to monitor their consumption. This model is soon to be brought to the UK via partnership with RWE npower[9].

[8] http://www.powershop.co.nz/

[9] http://www.npowermediacentre.com/r/5298/rwe_npower_and_meridian_energy_limited_enter_into

Capita Response to the National Infrastructure Commission's Call for Evidence

Electricity Interconnection and Storage

Q2. What are the barriers to the deployment of energy storage capacity?

CAPITA

2 What are the barriers to the deployment of energy storage capacity?

Introduction

The National Infrastructure Commission is to carry out independent and unbiased assessments of the UK's long-term infrastructure needs, including a specific study on how the UK can better balance electricity supply and demand. Below is Capita's response to one set of questions relating to the barriers to the deployment of energy storage capacity.

Capita Plc is interested in supporting the development of a low carbon economy in the United Kingdom. Capita is already heavily involved in the UK energy industry, primarily by running the top-level control software behind the UK's largest existing battery storage facility in Leighton Buzzard and establishing and managing the smart metering data and communications infrastructure for the GB roll-out of smart meters. Capita has an active CSR policy and has been recognised and listed in the FTSE4Good Index for 14 years.

The NIC is interested in ensuring the energy market and operators manage an effective supply, but they are also tasked with assessing how the UK will remain competitive in this area in comparison to other G20 countries. This means that the key characteristics of the national electricity supply can be described as the following:

- Secure, stable and safe from failures
- As low carbon as possible
- Available at low cost to consumers
- As far as possible self-sufficient (as per the remit for the NIC)

To reduce its carbon footprint, the UK is investing significantly in renewable energy, which causes some new difficulties for maintaining system stability. Due to the reduced control over the energy source (wind and solar) and reduced system inertia provided by these generators, a greater proportion of renewable energy generation is making system balancing more difficult. This will be seen in a decrease in frequency stability in the electricity signal. In order to pursue the low carbon economy, it is important to invest in technologies such as energy storage that enable the effective use of more renewable energy sources. At the same time the cost of batteries has reduced sufficiently, which means it is now possible to build Grid scale energy storage capacity that can respond very quickly to imbalances in supply and demand, providing the potential for frequency response services that have previously been unavailable. The lower costs of energy storage technologies open up the possibility of building assets dedicated to providing balancing services, rather than balancing activity purely being an ancillary service for an asset built primarily for a different purpose. Such assets can offer a high availability, providing a greater certainty for system stability. They also have an advantage over the use of Interconnectors, because it can help the UK be more self-sufficient and competitive amongst the G20 members.

Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

Pricing structures & uncertainty

There is currently limited price information available for balancing-only services, which makes investment decisions for constructing purpose-built assets more difficult. Generally, the business cases for non-purpose-built assets are not predicated on balancing service prices, and so they have already made investment decisions based on more predictable revenues. This isn't possible for investing in dedicated assets, so to take advantage of the greater speed of response and availability these new technologies can offer, there should be greater transparency on expected market prices.

Part of the issue is that the value of fast response balancing services is not clear; no exhaustive end-to-end business case is available that describes exactly the intention for its use. Being able to respond to imbalances quickly should support a more stable network better than slower responses, but it is not yet clear if such a service would replace existing services or be additional to them. The uncertainty of the future demand adds risk to the investment of these assets. Moreover, the value of the generation/absorption capability of energy storage might change under different conditions, but it is unclear if the price will change to reflect this. For example, in low demand periods, generators are paid to constrain their output, but instead, an energy storage asset could absorb excess energy and then use it in high demand periods. This would likely save the consumer money, but the price might not reflect this system benefit. It would help to improve the visibility of potential price-points and mechanisms.

Contract lengths

The last major 'balancing technology' facility built in the UK, the Dinorwig hydro-electric facility, was a multi-hundred-million pound investment made by the state on a business case with a long payback period. Currently, there is a call for more investments to be made nationally, but for contracts that are being let only for short periods. Since the predictable revenue period is so much shorter than the life of the assets being built, capital expenditure will be amortised over the contract term, meaning the short contract durations will artificially inflate costs significantly. In order to address this, longer-term contracts should be let.

Regulation & charges

Energy storage investments face significant regulatory uncertainty around charges and obligations, particularly for larger scale facilities. This is one of the most significant market barriers that is solely in the control of regulators and network operators, and should be addressed with urgency. National Grid and Ofgem should be supported in fast-tracking the update of regulation, but also in providing clarity on short term exemptions for assets to be built within the next two years.

Some mandatory requirements set out within the existing regulation are counter-intuitive for the new technologies providing new balancing services. For example, assets with a large generation capability are required to provide continuous output through a wide range of system frequencies. This makes sense for a generator sourcing its energy from carbon-based materials, but a battery will have a finite capacity before needing to recharge. Enforcing this requirement would require the batteries to be oversized, adding unnecessary cost to the consumer. The new frequency response services are also described differently to mandatory frequency response criteria, but it is not clear if the service description supersedes the regulation.

Battery storage technology will also respond to high frequency (generation higher than demand) in a different way to traditional FFR suppliers, in that instead of reducing output, it absorbs energy from the grid and acts like an increase in demand. Even though the facility would only be storing energy to be released later, under existing regulations, the facility would become a consumer of energy, requiring it to pay both for the supply of electricity, but also consumption tariffs such as use of system charge, the climate levy and feed in tariffs These are not required to be paid by traditional suppliers, and causes an unnecessary barrier on energy storage. As these charges will also be paid by the end consumer, this will lead to a double recovery and artificially increase the operational cost of storage facilities. In summary, frequency response criteria designed quite sensibly for generators, aren't necessarily appropriate for such fast response, short-duration facilities.

It is particularly worth exploring the application of the climate levy more fully. Energy storage facilities are to be built specifically to enable the UK to move towards a reduced carbon footprint and reduce the human impact on the climate, and yet because they currently need to fit with existing regulation, they would be charged as an end user. It is counter intuitive to place a charge designed to reduce the UK's carbon footprint, on technologies that also reduce the carbon footprint. This creates an unnecessary barrier, and increases the cost to consumers for this development.

Planning permission

Another area of uncertainty is on obtaining planning permission for these investments. There is no current definition of asset class for energy storage, so these facilities risk being classed as large scale generation in spite of the characteristic differences. In particular, for battery-based technology, there are no large chimneys releasing by-products, the noise levels are lower and the equipment could largely be contained, and look less 'industrial' than a large generator. A balancing service is also of a national benefit that is being requested with some urgency, and so a national fast-tracked planning process would be a significant benefit. The NIC should look at ways to speed up the planning approval process for large scale storage projects.

Site availability

But even before seeking planning permission, there is a limited availability of suitable sites for large storage facilities. This is driven by both the physical land requirement and also the capacity of the electricity network local to the intended connection point. Mothballed generators, often designed to use carbon-based fuels, are included in calculations to understand network capacity, meaning they can prevent other assets connecting even if they are not expected to use the capacity allocated to them. Energy storage can be provided by new technologies, meaning it is appropriate for new companies to enter the market, but they won't necessarily own existing land near connection points. Owners of that land are not incentivised to sell, and so suitable sites could remain unused. Given the national interest in energy storage, the NIC could look into ways to develop a "use it or lose it" approach to plots that meet the criteria for new balancing services.

What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

One of the important factors of developing and investing in new technology is ensuring best value for the consumer. The requirement for a national balancing service capacity could be satisfied by multiple small storage assets or fewer large storage assets, but at Capita we believe smaller storage devices would represent poor value to the consumer. Using fewer larger facilities would benefit from significant economies of scale, particularly by reducing the cost of grid connections and sites.

Energy storage provided by battery technology can be used for multiple services, and when connected at a distribution level, it can be deployed to provide stacked services that can benefit local priorities as and when required. However, to support the national system stability through frequency response services, it is advantageous to connect onto the transmission network, as this improves availability and alignment to national priorities. Distribution Operators could choose to prioritise local requirements over national requirements at any given time, which risks diminishing the value of the assets employed to the National Grid. Equally investors may choose to stack services when connected at the DNO level to drive maximum ROI, supporting DNOs with specific local challenges through services such as peak shaving and voltage support. This could further limit the reliability of balancing services for National Grid

Distribution Operators have expressed concern over installing fast responding balancing assets near consumers, as they could cause high rates of change of voltage. This could at best cause a DNO to limit the use of the asset for frequency response to protect local security of supply, or at worse could cause inconsistent supply for a consumer. This issue is reduced if the asset is connected at a transmission level, due to the increased distance from consumers and the higher network voltage at the point of connection.

While we recognise that domestic services will play their part, wholesale changes to the UK energy landscape will be required. The UK will need to rollout smart metering, time of use tariffs and have more intelligent customer interaction before domestic balancing services will be fully viable. Only when smart metering is rolled out will we be able to determine if they change consumer behaviour. Along this path, there will likely need to be better understanding on how to regulate domestic services, before they can be designed into the national balancing strategy.

In the near future a large scale energy storage facility (potentially 100MW+) connected to the transmission network delivering dedicated balancing services would be valuable in securing resilient and cost-effective infrastructure. This should be complemented by smaller scale (~10MW) facilities on distribution networks providing non-dedicated services, and supporting local requirements. It is difficult to determine the scale required in the future, however it is generally agreed that the amount of storage on the network will need to increase significantly to meet some of the challenges on in the near future such as decreasing system inertia and larger potential infeed losses.

From: Martin Crane [email address redacted]
Sent: 08 January 2016 23:51
To: EnergyEvidence Infrastructure-Commission
Subject: Value of district heat to electricity networks

My experience is in district heating so will confine my comments to this area.

The economic opportunity for DH is in area of high heat density eg city centres, where individual renewable energy solution are not practical eg limited roof space for solar and air source heat pumps. Potentially DH could also work in small rural centres. Both these applications of DH would be displacing the use electricity for heating – so the there is an immediate reduction in electrical demands and most probably peak electrical demands.

The heat sources that DH uses can have significant benefit electricity networks. Gas CHP installed with thermal storage (large hot water tanks) can respond to price signals so it generates at times of high electrical demand and is off at times of low demand. A well designed UK new build DH scheme with CHP will have sufficient thermal storage to make the time of electrical generation independent of the times of heat demands over the period of 24 hours. Typically the thermal store size will supply all the overnight (the off – peak electricity period) heat demands on the DH scheme. In Denmark the electricity price signals have led to thermal storage on gas CHP schemes being sized such that the CHP does not need to operate at the weekend (as the electricity price is lower). With the correct price signals CHPs could be sized larger and thermal stores sized bigger to allow the CHP generation to be focused into smaller higher price portion of each day. This is all tried and tested, bankable technology. Price signals should be easy to set up to incentivise optimal CHP operation. An SSE DH scheme I have helped design will when fully built out to serve 4000 new flats in London will generate 2200kW – just over 0.5 kW per flat, this generation should be operating through all the winter evenings when the grid demand peaks. The annual CHP electricity generation per connected flat is 2.6MWh per year (equivalent to the electricity demand for heating / DHW in a similarly size new build electrically heated flat, or 2 heat pump heated flats). There will across a fleet of CHPs connected to DH and Heat pumps in dwellings a high correlation between them operating – the CHP operating hour matching the heat pump operation (except where the price signals has got the heat pump operation moved to the off peak periods).

There is a clear benefit from gas CHP, and I would suggest that gas CHP is one of the most beneficial uses of gas, the electrical efficiency at 37% (gross) vs 52% (gross) for a CCGT is lower but the use of heat can lifts the overall efficiency up to 85% (gross) if supplying a well-designed (Danish standard) DH network, the current UK design practices means only 78% efficiency is achieved at best and with higher heat distribution losses. This crude efficiency analysis overlooks the fact that the extra electricity from the CCGT could be more valuable than the heat from the CHP, but to the CHP's credit is also overlooks the flexibility and potential speed of response of gas CHP with a start up time of a few minutes and that the CHP is at the demand end of the distribution network so reducing losses and reducing the need for grid reinforcement. The network loss reduction is greater than the average network losses as the CHP will tend to be operating at times of higher network loads which are times of higher losses.

Thermal storage can also help at times of surplus electricity, again look to Denmark to see that district heating operators (responding to straight forward price signals) are installing heat pumps and even direct resistance heaters to use surplus electricity – eg at times of high levels of wind generation. So the thermal store on the DH allow this electricity to be usefully consumed. At other times of low power prices the boilers would operate rather than the CHP so not adding to the generation at time of surplus / lower power prices.

Benefits of DH post natural gas, DH allows the use of the all the heat that most 'Energy' from Waste plants in the UK currently throw away – so this will reduce future electricity demands. DH networks with thermal storage can use heat pumps in place of the CHP and use the thermal stores so the heat pumps operate at the time of cheapest electricity availability, or DH could be heated from biomass or from CHP fed from AD plants or geothermal or solar thermal…. The benefits of DH is the flexibility in that one plant change can change the main heat source for a whole town – which is somewhat easier than a number of thousand of individual changes of heating plant. DH also allows the use of heat generation solutions that are not possible on a small scale eg AD, EfW, or are less efficient at a small scale eg gas CHP. DH could take heat from large scale thermal power stations – it just at the moment no UK DH network is large enough for the economics of connecting to a large power station to be viable.

Question 1
DH with thermal storage and CHP can provide significant benefits to the electricity system. As can DH with thermal storage to usefully soak up excess electrical generation.

Question 2
Very pleased to see the question phrased as 'energy storage' not 'electricity storage'. DH and the storage of heat can offer scope for CHP to operate when network needs power and for heat pumps and direct electricity heating to operate when there are power surpluses. The scale of DH means these operations would be undertaken by a relatively small number of DH operators in the UK, potentially easier route to demand management than solutions on for example thousands of domestic properties to achieve the same demand response.

Question 4
Look at Denmark to see what district heating offers to both reduce peak electrical demands and balance electrical supply and demand.

Martin Crane CEng MEI

CCN COUNTY COUNCILS NETWORK	Consultation Response National Infrastructure Commission Call for Evidence January 2015

Introduction

1. The County Councils Network (CCN) represents 37 English local councils that serve counties. CCN membership includes both upper tier and unitary councils who together serve over 25 million people across 86% of England. CCN develops policy, shares best practice and makes representations to government on behalf of this significant proportion of the country. CCN is a member-led organisation which works on all party basis and seeks to make representations which can be supported by all member councils. CCN welcomes the opportunity to respond to the consultation, and would also direct the National Infrastructure Commission (the Commission) to the responses submitted by our individual member authorities.

2. CCN councils account for 41% of England's GVA, a combined output of £527bn. Reflecting this county areas are also the nation's most significant contributors to the Treasury. County economies represent a very healthy mix of occupations – they have above average levels of skilled trades, managers and senior officials and private sector employment. Additionally the largest proportion of active enterprises in the country can be found in counties, the total number of which currently amounting to well over a million. To ensure that these opportunities are maximised we argue that the National Infrastructure Commission (the Commission) and government must work with county areas, alongside cities, to develop national infrastructure strategy and secure investment.

3. Within this submission CCN express our disappointment that the work of the Commission, leading into the 2016 Budget, will focus on London and big city regions. We set out a number of recommendations which would give a broader basis for the work of the Commission, to ensure that vital economic opportunities presented by county areas play a key role in national strategy.

The remit of the Commission – investing in counties and cities

4. Ensuring the right strategic infrastructure is in place will be key to the future economic health and competitiveness of the country. CCN therefore welcome the formation of the independent National Infrastructure Commission (the Commission) as a permanent statutory body. Government has an important role, working with local areas, to prioritise nationally important schemes, make capital available, encourage private and international investment and enable areas to raise investment in innovative ways.

5. The overarching role of the Commission is described as carrying out 'independent and unbiased assessments of the UK's long-term infrastructure needs … to give clear strategic direction to industry and government and provide a firm basis for planning and investment.' The Chancellor has asked that the Commission undertake this role through five yearly National Infrastructure Assessments (NIA). In support of the first NIA the Chancellor has asked the Commission to propose some initial schemes for in-depth analysis in early 2016.

6. CCN welcome the introduction of NIAs, as they should ensure greater certainty for private investors, and provide greater assurance to local authorities and the development industry that

growth is deliverable in a sustainable manner, supported by existing and planned infrastructure. **We strongly suggest that the Commission thoroughly engage with the robust and evidence based priorities of counties in drawing up their NIA, and in making initial proposals for in-depth analysis in early 2016. CCN would be happy to facilitate and support such engagement.**

7. Additionally the Chancellor has written to Lord Adonis, Interim Chairman of the Commission, explaining that the Commission should concentrate its initial focus on three key areas; northern connectivity, London's transport infrastructure, and energy. As these are considered by central government to be the most pressing for the national economy, and these initial investigations will influence the 2016 budget. The Chancellor has issued the Commission detailed terms of reference for these first three projects.

8. CCN would like to express their disappointment that the work of the Commission has been so limited in the scope of its initial investigations, which will inform investment and priorities of the 2016 Budget. These initial inquiries focus entirely on London and the northern cities, without any regard to the rest of the country, except through references to 'commuter hinterland'.

9. We suggest that limiting the scope of these inquiries in such a way is not in the best interests of unbiased assessment of the UK's long-term infrastructure needs. We argue that strategic infrastructure investment is as pressing in county areas as it is city areas, that cities and counties function together, and that county regions represent substantial economic opportunities which must not be overlooked. These points are explained in further detail through this submission.

10. To address these points **we strongly recommend that the Commission takes a comprehensive, country-wide approach in making recommendations through its initial investigations, to inform the 2016 Budget. We urge the Commission to carefully consider the evidence put forward by CCN members to these initial inquiries, and broader evidence established through Strategic Economic Plans and other mediums to help inform this.**

11. **We also suggest that the Commission commit now to undertaking specific detailed inquiries into investment in county infrastructure as part of its next tranche of analysis and recommendations.**

Achieving our shared devolution goals

12. CCN share government's goals to devolve functions and financial freedoms, to bring decisions closer to the people and business they affect and to stimulate economic growth. To support this we must ensure that the Commission takes a localist approach and does not inadvertently centralise powers and decisions. Equally we must ensure that the work of the Commission and of government considers the economic opportunities in all areas and does not disenfranchise swathes of the country.

13. We note that government consider regional transport partnerships / Sub-National Transport Bodies to be an important stakeholder in the work of the Commission. We believe that in principle this is supportive of the devolution agenda. For example we are pleased to note that in its inquiry into infrastructure in the north the Commission will work closely with Transport for the North (TfN) to establish and evaluate options for investment.

14. We are also pleased that Sub-national Transport Bodies will involve joint decision making between the local elected representatives and businesses, the Department for Transport, Highways England and National Rail. These factors represent meaningful devolution and public service reform, which we hope will evolve over time.

15. To ensure that the best value is derived from these approaches **we strongly suggest that where counties wish to be a part of regional transport partnerships / Sub-national Transport Bodies they are encouraged to do so, and that government publically commits to promoting and listening to the important voice of counties alongside cities within these arrangements.**

16. In summer 2015 the Chancellor stated that TfN would be underpinned by 'devolving far reaching powers over transport to the North's Mayor-led city regions to deliver fully integrated public transport systems'. We must evolve this approach and ensure that the important economic and logistical hubs represented by counties are equally empowered, and able to contribute to regional growth. **We strongly suggest that transport and growth powers and budgets are devolved to counties where there are rigorous and appropriate governance measures in place and without a pre-requisite for metro mayors.**

17. In this context we are pleased that there has been a broadening of the membership of the TfN Partnership Board in recently months, beyond a city region focus to involve more county partners in the area. We would expect to see the role and voice of counties in such arrangements to growth over time, and would expect the Commission to fully consider the views of counties in its engagement with Sub-national Transport Bodies and individual areas.

18. **Where formal regional transport partnerships / Sub-national Transport Bodies are not in place, we still suggest that the Commission strive to engage groupings of local areas to help establish and appraise investment options put forward to government. CCN would be happy to facilitate such an approach.**

Counties role in sub-national transport and infrastructure governance

19. Counties are ready to take a lead role in driving sub-national transport and infrastructure, with local, national and international partners. Beyond the TfN example above counties have also been heavily involved with their city partners in the creation of Midlands Connect. This initiative has been promoted by Ministers and the Chancellor as a vital aspect of the 'Midlands Engine' for growth. We believe that Midlands Connect will play a key role in the infrastructure, transport and growth of the area, and would expect the Commission to engage with the board, in the same way they will engage with TfN.

20. Elsewhere in the country counties have come together to found England's Economic Heartland partnership. It is intended that this partnership will drive innovation in the area, as well as effective transport and infrastructure strategy. Forums such as this would be the logical point of contact for the Commission going forward, and help ensure that infrastructure opportunities from all parts of the country are considered.

21. In response to the national infrastructure, Sub-national Transport Body and devolution agendas more groupings of counties, counties and cities, or large county areas may begin to formalise sub-national transport arrangements. We must ensure that a one size fits all approach is avoided and that all areas have the chance to take on powers and influence national strategy.

The importance of county economies

22. To give a sense of scale, counties cover 86% of the landmass of England, they represent 47% of the country's population and are responsible for 70% of maintained roads. The combined population of counties now stands at 25.5m, and has grown 2.6% between 2010 and 2014, compared to 2.5% in metropolitan boroughs. It is estimated there are 10.6m households in CCN member councils, which is projected to rise 18% to 12.8m by 2037.

23. Using the latest data (2013) the economies of the areas served by the 37 CCN councils accounted for 41% of England's GVA, up 1% from the previous year, with a combined GVA of £527bn. This is strong performance compared to other areas of England. Further analysis of GVA growth since the recession shows that outside of London counties have seen the largest growth - 36% of GVA growth compared to 13% in the Core Cities. Equally county areas are the nation's most significant contributors to the Treasury. The latest breakdown of income tax receipts show that county populations contributed £66.4bn, which is 49% of all income tax in England and contributed 41% of all residential stamp duty.

24. County economies represent a very healthy mix of occupations – they have the highest levels of skilled trades in the country, above average levels of managers and senior officials and are only behind London for levels of technical jobs. Outside of London CCN members also have the highest levels of private sector jobs, and in counties the proportion of private to public sector jobs is steadily growing over time.

25. Additionally the largest proportion of active enterprises in the country can be found in counties, the total number of which currently amounting to well over a million. Outside of London counties hold by far the largest number of businesses created per 10,000 of population. There are countless FTSE 100 company headquarters based in county areas, to name a handful BAE Systems in Hampshire, National Grid in Warwickshire, Next in Leicestershire and Experian in Nottinghamshire.[1] Underlining this the Independent Commission for Non-metropolitan England stated 'Internationally mobile firms overwhelmingly choose non-metropolitan areas, not conurbations, as their base if they don't choose London'.

26. We argue that securing the national economy must take a broader view than simply connecting city regions together. Evidence is showing that county regions are growing faster than city regions and that the scale of business undertaken in counties is substantial. Equally evidence is showing that county areas are some of the most innovative[2] and that specialisation can be equally, if not more, successful outside of big city areas.[3] We must ensure that infrastructure links cities and counties across sub-national areas and that business and commuting links for counties are built into infrastructure plans.

27. Rural areas, the majority of which can be found in counties, are set to become ever more important to the national economy according to DEFRA. A report of late 2014 found a net migration from urban to rural areas in England, stating 'whilst in many OECD countries there has been a trend towards greater urbanisation, the UK has been experiencing net migration from urban to rural areas'. This strengthening of the rural economy is associated with innovation, knowledge-based industries and a strong entrepreneurial make up. DEFRA conclude 'if harnessed, these trends could help drive significant growth in productivity, employment and output … for the UK economy' and 'could offset aging demographics … in such areas'.[4]

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[1] The Independent Commission for Non-metropolitan England, Devolution to Non-metropolitan England : Seven steps to growth and prosperity, Final Report of the Non-metropolitan Commission, March 2015

[2] DEFRA, How increased connectivity is boosting economic prospects of rural areas, December 2014

[3] Respulica, The Missing Multipliers: Devolution to Britain's Key Cities, September 2014

[4] DEFRA, How increased connectivity is boosting economic prospects of rural areas, December 2014

28. Echoing these points the Independent Commission for Non-metropolitan England stated that 'non-metropolitan areas' high skills base positions them well for a world where trade is increasingly blurring the line between goods and services. They have an edge in knowledge intensive sectors, where getting people around the globe easily can be as important as moving goods … Future transport investment decisions will be informed by local and global connectivity, including the role of regional airports in accessing global markets'.[5]

29. Many ports, freight routes, airports and logistical hubs sit within counties. These gateways to international markets must play a central role to infrastructure strategy and not just an afterthought as means of moving goods in and out of cities. Logistical hubs and routes present important economic opportunities in their vicinity, alongside their broader reach.

30. Alongside cities English counties have strong identities, commodities and brands which attract international attention. This is borne out by the number of FTSE 100 companies based in county areas, but has huge potential to continue to grow. Counties are iconic to British life and business; they represent the land and the mix of business and lifestyle opportunities which are attracting big business. They have the high value skills base and growing track record of innovation and specialisation to service start-up, growing and international business – we must ensure that physical and digital infrastructure keeps pace with this and helps the nation grow.

Capacity for improved productivity and growth

31. Despite counties' strong and vibrant economies delivering growth, employment and taxes for UK Plc, productivity remains a long-term weakness. Figures for counties show that their average productivity is 91, compared to the UK 100 Index. This is considerably below the London average of 122, and also the Core Cities average of 94.

32. A key factor in addressing this productivity gap is the right strategic infrastructure interventions. With this in mind central government and the Commission should work with county areas to secure investment in infrastructure priorities and devolve growth, infrastructure and transport powers. CCN have calculated that if counties were enabled to raise their productivity to the national average, this could contribute an additional £100bn to the UK economy.

The ability of local areas to invest in infrastructure

33. Alongside the devolution of transport, infrastructure and growth powers and budgets mentioned earlier in this submission CCN strongly suggest that national and sub-national growth will be maximised by equipping all areas with the fiscal tools they need to invest in infrastructure.

34. Greater London, and now Greater Manchester are able to raise a region wide CIL to fund strategic infrastructure projects. Equally the Chancellor has proposed that those areas with a metro mayor are able to increase Business Rates. CCN strongly argue that such powers must be extended beyond big cities, and must not be arbitrarily connected to the mayoral model of governance. **We strongly suggest that county areas are equipped with a full suite of fiscal freedoms, so that their businesses and residents are able to decide what measures are put in place to invest in strategic infrastructure projects.**

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[5] The Independent Commission for Non-metropolitan England, Devolution to Non-metropolitan England : Seven steps to growth and prosperity, Final Report of the Non-metropolitan Commission, March 2015

05 January 2015

CCSA response to:
National Infrastructure Commission call for evidence

The Carbon Capture and Storage Association (CCSA) is pleased to respond to the Open consultation on the National Infrastructure Commission (NIC), in particular the remit of the NIC in relation to the delivering future-proof energy infrastructure.

The CCSA brings together a wide range of specialist companies across the spectrum of CCS technology, as well as a variety of support services to the energy sector. The CCSA exists to represent the interests of its members in promoting the business of Carbon Capture and Storage (CCS) and to assist policy developments in the UK, EU and internationally towards a long-term regulatory framework for CCS as a means of abating carbon dioxide (CO_2) emissions.

Although the consultation document does not explicitly ask questions about different electricity generation technologies, CCS on coal, gas and biomass power stations has the potential to deliver large volumes of clean, dependable (reliable) and affordable energy to UK consumers. On this basis, and given the specific infrastructure requirements of CCS projects, the CCSA has provided some high-level comments in response to the consultation and would welcome further engagement with the NIC as it further develops its thinking.

<u>The value of CCS to the UK electricity sector and wider economy</u>

CCS is unique amongst low carbon technologies in its ability to reduce emissions from fossil fuel electricity generation and thereby provide dispatchable[1], low carbon electricity. Recent reports from the ERP and the CCC have found that with an increasing amount of renewable technologies on the system there is a growing need for zero carbon firm capacity (such as Carbon Capture and Storage (CCS)) in order to deliver an affordable and secure electricity system that contributes towards the fulfilment of UK carbon budgets.

Energy systems analysis from across the world has consistently demonstrated that CCS has an important role to play as part of a diverse energy mix and that it has the greatest potential to reduce the costs of meeting climate objectives to consumers of any low carbon technology. The Intergovernmental Panel on Climate Change (IPCC) found in its Fifth Assessment Report that the costs of meeting 2 degree climate objectives could more than double without CCS (increasing by more than 138%)[2]. By comparison, the same study found that 2 degree objectives could be met without any new nuclear capacity with a cost increase of just 6% and with only limited solar deployment at a cost increase of just 7%.

A similar conclusion has been reached for the UK through energy systems modelling conducted by the Energy Technologies Institute (ETI), Energy Research Partnership (ERP)

[1] Electricity supply that be turned on or off rapidly and ramped up and down according to supply and demand.
[2] Fifth Assessment Report: Working Group III: Mitigation (IPCC, 2014)

and the Committee on Climate Change (CCC). The ETI, for example, finds that without CCS the costs of meeting UK climate targets could more than double, costing an additional £32 billion per year by 2050[3]. Analysis conducted by Cambridge Econometrics for the CCSA and TUC translates this value to approximately £82 per household, per annum in 2030[4]. The recent CCC 'Power sector scenarios for the fifth carbon budget' report further highlights that *'CCS is very important for reducing emissions across the economy and could almost halve the cost of meeting the 2050 target in the Climate Change Act'*.

The initial investment costs of First of a Kind CCS projects in the UK may appear high (thought to be in the region of £150 - £200/MWh for the first projects that build out infrastructure) but this will rapidly reduce below £100/MWh as infrastructure is shared, economies of scale are achieved and the cost of capital comes down[5]. CCSA analysis has suggested that a CfD Strike Price of less than £100/MWh can be achieved with just 2.5GW of installed capacity[6]. In addition, CCS infrastructure (CO_2 pipelines and geological storage sites) can also present opportunities to reduce emissions from the industrial heartlands of the UK, preserving existing- and attracting new jobs, and unlocking new opportunities for innovation, for example decarbonised hydrogen production. This value is currently not captured when the costs of CCS are compared to those of other low carbon generation technologies.

Due to its flexibility, the longer term value of CCS to the UK energy system is estimated to be more than £200 billion by 2050. The recent Government decision to withdraw £1 billion from the UK CCS Commercialisation Programme (Competition) has dealt a significant blow to the CCS industry and risked significantly delaying its deployment, in-turn putting at risk the considerable economic benefit CCS has to offer the UK. Government justified its decision on the basis of affordability and (short term) value for money but maintains the position that CCS will be important to the UK in the longer term. If the UK is serious about wanting access to CCS in the future then it is essential that policy focuses on commercial-scale deployment and developing CO_2 transport and storage infrastructure. To this end, the NIC should ensure that the electricity market is able to support investment in CCS-equipped electricity generation whilst also working with DECC and the Oil and Gas Authority (OGA) to consider how the UK can most cost-effectively deliver CO_2 transport and storage infrastructure.

Q4.1 What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The electricity sector is transitioning to one where all future electricity supplies will be from low carbon energy sources. In order to balance supply and demand in the future, significant investment in low carbon generation is required now. With a widespread increase in deployment of intermittent renewables, thermal generation plants, including those fitted with CCS, are likely to be increasingly used as back up generation. Although thermal generation plant are expected to operate at reduced capacity in the longer term future they will be vital for providing firm and dispatchable electricity and ensuring security of supply. When fitted with CCS these plant can also provide low carbon electricity and make a significant contribution towards reducing the emissions intensity of the power sector and therefore their development and operation should be incentivised appropriately.

[3] Carbon capture and storage Building the UK carbon capture and storage sector by 2030 – Scenarios and actions (ETI, 2015)
[4] The economic benefits of carbon capture and storage to the UK (CCSA, TUC, 2014)
[5] CCS Cost Reduction Task Force Final Report (2013)
[6] Delivering CCS (CCSA, 2015)

To bring forward new low carbon thermal plant policy measures are likely to be needed to provide revenue certainty in light of uncertain operating hours. In the 2011 EMR White Paper[7], DECC introduced the concept of a 'flexible CfD' that combined elements of a capacity payment with a payment for low-carbon output. Although this idea has yet to be developed further by Government, the CCSA believes the concept of a flexible CfD has merit and warrants further consideration as the UK energy system becomes increasingly reliant on intermittent and inflexible generation.

In addition to an appropriate investment framework that rewards both low carbon electricity generation and availability, there is a need for additional measures to support investment in CO_2 transport and storage infrastructure. Investment in this infrastructure (e.g. in advance of commercial operations commencing) should be an immediate priority given that the development of stores, or construction of new pipelines can take between 5 and 10 years before a generation/CO_2 capture project begins operating. The Zero Emission Platform – advisors on CCS to the European Commission – published a report in 2014, which outlined the market failure for investment in CCS infrastructure and recommended a 'market maker' type approach be adopted, based on a public private partnership to enable investment and reduce risk[8]. Such an approach may need to be considered in the UK to secure the necessary investments and warrants further consideration by the NIC, in conjunction with DECC and the OGA.

Recommendations for the National Infrastructure Commission

Given the significant value of CCS to the UK economy and the unique challenges facing the public and private sectors in its commercialisation, the CCSA believes that the NIC could make an important contribution towards the delivery of early CCS projects. It could do this by:

- Building on existing research and evidence to report on the likely infrastructure needs relating to CCS deployment in the UK, particularly the CO_2 transport and storage requirements necessary to meeting climate objectives at least cost.
- Working in conjunction with the DECC and the OGA to support development of a strategic CCS infrastructure plan for CO_2 storage in the UK Continental Shelf (UKCS).
- Considering and reporting on the need for a strategic CO_2 transport delivery body, in particular consideration of a Regulated Asset Base approach that could deliver right-sized infrastructure and enable economies of scale to be realised.
- Supporting CCS policy development in relation to infrastructure, particularly whether there is a need for Government intervention to support development of CO_2 transport and storage solutions. This issue is also being considered by a Parliamentary Advisory Group on CCS being led by Lord Oxburgh.

[7] EMR White Paper (DECC, 2011)
[8] Business Models for Commercial CO_2 Transport and Storage (ZEP, 2014)

National Infrastructure Commission call for evidence

Response from the Chief Economic Development Officers Society (CEDOS)

CEDOS

1. This Memorandum of evidence is submitted by the Chief Economic Development Officers Society (CEDOS). The Society represents Heads of Economic Development in upper tier local authorities throughout England. Membership includes county, city and unitary councils. The Society carries out research, develops and disseminates best practice, and publishes reports on key issues for economic development policy and practice. Through its collective expertise, it seeks to play its full part in helping to inform and shape national and regional policies and initiatives.

OUR OVERALL VIEWS

2. We welcome the creation of the National Infrastructure Commission as a new, independent body which will look broadly at long-term infrastructure needs and provide impartial advice to ministers and Parliament. However, we note that detailed work on the purpose and structure of the Commission, its economic and fiscal remit and its relationship with Government has still to be completed. We welcome the fact that these fundamental aspects will be the subject of future consultation, which we will be pleased to engage with.

3. In the meantime, as a national organisation we would like to take the opportunity to respond to this call for evidence issued by the Commission, notwithstanding the fact that it focuses on three very specific areas for which terms of reference have been set out for the Commission, two of which are limited geographically:

- future Investment in the North's transport infrastructure;
- London's transport infrastructure;
- delivering future-proof energy infrastructure.

4. In providing evidence we would like to emphasise the importance of the purpose of the National Infrastructure Commission as set out in the Government's Autumn Statement, to "enable long term strategic decision making to build effective and efficient infrastructure for the UK"[1]. We recognise that the three areas referred to above were stated as the Commission's initial focus, when it was launched in October 2015[2]. At the same time, the facts are: that the Commission is required to report on these three areas with recommendations by Budget 2015; that it is expected to deliver a long-term plan and assessment of national infrastructure needs early in each parliament, setting out what a government is expected to do over the next five years[3]; and that the Government intends to publish a National Infrastructure Delivery Plan

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[1] *Spending Review & Autumn Statement* HM Treasury November 2015

[2] *Infrastructure at heart of Spending Review as Chancellor launches National Infrastructure Commission* HM Treasury news release 30 October 2015

[3] *Chancellor announces major plan to get Britain building* National Infrastructure Commission & the Rt Hon George Osborne MP news release 5 October 2015

next spring, setting out in detail how it will deliver key projects and programmes over the next five years[4].

5. We support the need for action on infrastructure but the reality is that the Commission will need to consult and take evidence much more widely if it is to make a realistic assessment of national infrastructure needs to enable Government to put in place a comprehensive National Infrastructure Delivery Plan to meet the needs of this country as whole. The current limited focus of the Commission and the timescale to which it is required to operate are hardly consistent with the Chancellor's intention that it will "calmly and dispassionately assess the future infrastructure needs of the country"[5].

THE SPECIFIC AREAS BEING CONSULTED ON

Transport infrastructure

6. As a national organisation our evidence concentrates on the one area that has a UK wide focus - delivering future-proof energy infrastructure. Nevertheless, on transport we would make the point that important though improving connectivity between cities in the north of England, and transport infrastructure in London are, the shortcomings of transport infrastructure in the UK are by no means confined to these areas. The Commission and indeed the Government will not need reminding of the commitment to the Midlands Engine, where, for example, the relationship between the Port of Immingham (the largest in UK by tonnage) and major manufacturing areas across the Midlands should not be underestimated.

7. Equally there are significant infrastructure needs in many other areas. An example that has been highlighted in the soundings we have taken with our members is the proposed re-instatement of a rail link between Oxford and Cambridge as a key part of *East West Rail*, a major project to establish a strategic railway connecting East Anglia with Central, Southern and Western England. These and other essential projects need to be addressed if the strategic aims of achieving consensus and building effective and efficient infrastructure for the UK as a whole are to be achieved.

Delivering future-proof energy infrastructure

8. It is evident from feedback we have received from our members that an imbalance between electricity demand and supply is a major issue in many areas of the country. It is constraining residential projects, wider business development and growth and is holding back the use and development of renewable energy projects. For example, we have been told:

- "There are real issues around poor and unreliable electricity supplies constraining growth and deterring further business investment. This affects urban fringes, towns and rural areas" – Dorset;

[4] *Spending Review & Autumn Statement* HM Treasury November 2015
[5] *Chancellor announces major plan to get Britain building* National Infrastructure Commission & the Rt Hon George Osborne MP news release 5 October 2015

- "The mismatch between electricity demand and supply is a massive consideration which plays out at local levels as well as on a national scale. We have met several businesses recently whose growth is constrained due to a lack of power supply. The cost of installing a new supply is the responsibility of the first business that uses it and it would be helpful if the Commission could explore ways of spreading the cost with developers or with potential users over several years" – Lincolnshire;

- "The distribution network is now at capacity and in some parts of the county, particularly around the Greater Cambridge area, renewable or other energy projects cannot be connected to the network without paying significant grid reinforcement costs, which render most smaller scale renewable energy projects unviable" – Cambridgeshire.

9. There is a particular issue, which is being experienced in a number of areas, around the high cost of providing supply when the network is at capacity. As this is falling on a single user, it is making developments unviable. The Commission should consider mechanisms to allow for the forward funding and planning of new energy infrastructure.

The importance of all essential infrastructure

10. We recognise that in this consultation the Commission has had to focus on the specific objectives set for it. However, in delivering an overall assessment of this country's infrastructure needs it is essential the Commission looks at infrastructure more broadly and does not concentrate exclusively on transport and energy supply, important though they are. The soundings we have taken with our member authorities have also highlighted for example, water supply constraints on industries such as food production in some areas; and the fact that limited access to digital technology in particular superfast broadband remains a barrier in too many areas.

11. On the subject of superfast broadband, as we said in our evidence to the recent Inquiry into the digital economy by the House of Commons Business Innovation and Skills Select Committee[6], digital connectivity is essential for our economy to adapt, innovate, compete and grow – globally and locally – but as the Government's recently published Productivity Plan acknowledges, although our digital infrastructure is improving, "there are still too many businesses hampered by slow connections"[7]. In CEDOS' view superfast broadband should be regarded as a fundamental infrastructure in much the same way as electricity, water and transportation networks are.

12. The Commission must also seek to align with the wider National Infrastructure Planning Processes, in particular the Planning Inspectorate, to ensure that the critical planning and consultation processes required for nationally significant infrastructure are considered as part of the wider delivery process. Further details of how the Commission will operate with the Planning Inspectorate are needed.

[6] *Evidence to the Business Innovation & Skills Committee Inquiry into the digital economy* CEDOS October 2015
[7] *Fixing the Foundations – Creating a more prosperous nation* HM Treasury July 2015

NATIONAL INFRASTRUCTURE COMMISSION CALL FOR EVIDENCE
ELECTRICITY INTERCONNECTION AND STORAGE
Executive Summary - key points of our response

The UK faces an unprecedented challenge in meeting electricity demand in the coming years

- National Grid estimates that UK electricity capacity is at its tightest level for a decade. Coal stations are closing; the UK's nuclear fleet is ageing with only Hinkley C (earliest start-up 2025) agreed; and old gas-fired power stations are coming offline.
- Renewables have grown, but remain intermittent.
- Against this backdrop the UK can balance its electricity needs by supporting larger power stations that provide capacity; smaller peaking plants as well as other balancing services. Specifically measures would include:
    - Increasing support for gas power stations to maintain existing sites and encourage new build;
    - Facilitating interconnection with Europe, whilst recognising that interconnectors already benefit from a number of incentives and cannot be relied upon during times of system stress;
    - Supporting and growing Demand-Side Response (DSR) services and Distributed Electricity Resources (DER), which can help to manage peaks in electricity demand;
    - Support battery storage technology, which could help manage peak demand.

Gas is a more certain source of security, but currently interconnectors receive more support

- Interconnectors can play an important role in balancing the UK electricity system, but they cannot be relied upon for security of supply (as they can export as well as import) and new electricity interconnectors are already strongly incentivised as Table 1 highlights.
- Evidence suggests that interconnectors such as IFA (France-England) cannot be relied upon to flow consistently to Great Britain (GB) in cold winter periods when French electricity demand for heating may also be very high.
- We believe there is greater incentivisation for interconnection than there is for gas-fired generation in GB, which is distorting the market and there is evidence that greater encouragement of interconnection would further damage the economics of domestic gas investment. If not addressed this imbalance is likely to make the achievement of government policy objectives for gas a major challenge and could potentially threaten UK security of supply.

Table1: Incentives and Costs for Combined Cycle Gas Turbines (CCGTs) and Interconnectors showing disparity

Market conditions/rules	Gas Generation	Electricity interconnectors
Commodity market prices	Low clean spark spreads	High geographical spreads
Merchant risk	Substantial	Limited (cap/floor regime)
Transmission charges	Both TNUoS and BSUoS	Subject to neither
Carbon pricing	UK Carbon Price Floor	EUA (ETS price) only
Capacity market	Participates	Participates (from Dec 2015)
Locational incentives	Yes, via transmission charging structure (known as TNUoS)	No locational price signals apply

The Capacity Market is the correct instrument to support gas, but needs reform

- The GB Capacity Market (CM) is an essential instrument for maintaining security of supply; supporting existing power stations and incentivising new-build gas. We believe it is generally well-designed, but there are concerns it has procured too little capacity and in two years has not yet delivered any viable, new CCGTs.
- Amber Rudd's 'Energy Reset' speech in November 2015 supported a switch from coal to gas power stations by committing to the phase out of coal by 2025 and reviewing mechanisms for supporting new-build gas. We believe that coal stations are on a glide path to closure by 2025 and as more stations close, the economics for gas will improve. However, this improvement in economics for gas may not be sufficient to support new investment until 2019/2020 when significant levels of coal have been phased out, which could significantly threaten security of supply.
- The CM should be the mechanism to ensure there is sufficient gas to meet the phase out of coal. Government has rightly initiated a review of CM arrangements ahead of the forthcoming 2016 auction for 2020/21. In our view the following adjustments would ensure the CM is fit for purpose:

- review the 'de-rating' applied to certain types of capacity (e.g. wind and interconnectors);
    - introduce tougher incentives (penalties) and collateral requirements for new-build plant, with a view to ensuring that contracted capacity actually gets built;
    - bring forward some of the earmarked 'T-1' auction capacity in to the main CM auctions 4 years ahead to encourage new investment now; and
    - procure more capacity to ensure security of supply is maintained as margins tighten.
- We are also concerned that the Capacity Market may not be strongly enough incentivising reliable capacity. The future of the only new build CCGT project, Trafford, which received a contract in 2014, is uncertain and a number of the contracts awarded are short term. The Government should assess ways to ensure more reliable plant that can contribute in the longer term receives contracts, by: incentivising more new-build projects; considering lowering the investment threshold for existing 3 year refurbishment contracts; strengthening the penalties for generators that do not deliver their contractual requirements and assessing whether the current contract length and structure is providing adequately for long term security of supply.
- Electricity balancing and cash-out arrangements have recently been reformed and generally appear to be robust. There is, for example, a risk that significantly higher cash-out prices disincentivise ownership of generating assets, as opposed to buying in the market, due to an increased outage liability.

Distributed Energy and Demand-Side Response can smooth peak demand problems

- The future electricity system will need more flexibility services to manage times of the day when electricity demand peaks. Distributed Electricity Resources (DER) (generation and supply connected directly to the distributed networks) and Demand Side Response (DSR) (reductions in the amount of electricity consumers use) can achieve these aims cost effectively and should be encouraged further by the Government.
- As DER/ DSR become more important in the future system design and operations, it is essential that the national and local electricity systems are aligned and coordinated. With more electricity being generated at the distribution level there is a risk of making the balancing of the national system more challenging. It will be important for the Transmission System Operators (TSOs) and Distributed System Operators (DSOs), who manage these systems, to coordinate their work.
- We believe this work should be done before considering whether SO (System Operator) independence is sufficiently assured. But it is important that the TSOs and the DSOs act as neutral facilitators when providing connections, assessing flexibility services (e.g. DER/DSR) and communicating. They also need to be transparent and act in a non-discriminatory way - neither the TSO nor the DSOs should be active as commercial service providers.
- Policy incentives should consider the desired mix of embedded plant, making use of existing back-up diesel plant on industrial and commercial sites and flexible open-cycle gas generation to manage peak demand – without unduly incentivising new-build diesel ahead of other embedded generation types.

Battery Storage will make a major difference to the design of transmission and distribution

- Battery storage will likely bring benefits in a number of different areas. Battery storage will allow more efficient use of renewable energy and will have a significant positive impact on the grid's ability to balance and manage pressure at peak times. To help enable this product to come to market, battery storage should become eligible for Enhanced Capital Allowances.

The UK is a world-leader in balancing decarbonisation with affordable and secure supply

- There is much that the UK can learn from international experience, but in our view there is as yet no superior 'blueprint' model of international best practice and in some respects (e.g. the design of the CM and steps taken to reduce the level of unabated coal capacity on the system) the UK has been ahead of many other countries. The European Commission's updated 'Target Model' for EU electricity seeks to integrate renewable generation into the wholesale electricity market in a way which is already taken as a 'given' in the UK.
- The UK's carbon tax approach to carbon pricing is an important part of the policy framework and should be supported. Its market-based approach helps to create a simpler energy system and has the ability to create a market signal in favour of decarbonisation.

Our full consultation response

1a. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Overview

The CM is an essential instrument for maintaining supply security in today's market conditions. It is generally well-designed, but it has procured too little capacity overall and deferred volume to 'T-1' which new CCGT can't access. The incentive structures do not yet support sufficient investment in new-build gas generation.

Electricity balancing and cash-out arrangements have recently been reformed and generally appear to be robust. The future electricity system will need more flexibility services to maintain security of supply.

The market needs to facilitate the growth of Distributed Electricity Resources (DER) and Demand Side Response (DSR) to deliver this cost-effectively.

Capacity margins in the GB wholesale electricity market are currently very tight and this is expected to remain the case for several more years. National Grid issued a NISM (Notification of Inadequate System Margin) on 4 November and has indicated that more NISMs should be expected in an average 2015/16 winter. This does not mean an imminent threat of 'the lights going out' but it does signal to the market an exceptional need to make additional supply available and/or manage demand.

Partly due to the growth of intermittent renewables with very low variable costs, gas generation has seen lower utilisation in recent years and clean spark spreads (a measure of operating profit margins) have also been squeezed. Gas generation has become non-viable on the basis of the traditional energy market alone and Centrica's gas fleet made a 2014 operating loss of £120m (and £133m the year before). Gas generating capacity is vital to ensure a satisfactory level of supply security, including the provision of back-up generation when wind and solar generation are low. The CM has a key role to play in supporting existing gas stations and incentivising the development of new gas stations. Existing gas and nuclear stations require significant ongoing investment, and the CM is a key revenue. The CM is an important part of the revenue available for non-subsidised technologies, providing a lower cost and less volatile capacity in comparison to some intermittent and subsidised capacity. Therefore the CM should continue to include existing plant as well as new-build.

We supported the introduction of a market-wide, technology-neutral CM auction which excludes only those low carbon facilities already in receipt of subsidies. Unfortunately, experience with the 'T-4' auctions held to date suggests some major flaws:

- The government has not procured sufficient capacity to encourage the development of new-build CCGTs; the auction for 2018/19 cleared at £19.40/kW/a, which is far from sufficient incentive.
- Moreover, the weak incentive structure applicable to new-build plants encouraged some projects to remain in the auction and accept a capacity price which is less than they appear to need to justify a Final Investment Decision. The large 1.6 GW CCGT at Trafford Park secured a 15 year contract but has not yet gone into construction.
- The auction for 2019/20 cleared at a slightly lower price of £18/kW/a. Contracted new-build capacity was dominated by small embedded diesel plants rather than CCGTs.
- The set-aside of 2.5GW of the required volume to the 'T-1' auction precludes new CCGT from bidding for this as the 1-year lead time is insufficient for new plant; bringing this volume forward to 'T-4' would provide a better opportunity for new plant to be successful in the CM.

The Government has stated they will review arrangements for 2020/21, but gas stations currently face major challenges and without greater support there could be risk of companies being unable to develop new stations and struggling to maintain existing sites. We believe the Government's announcement of a phase out of coal-fired power by 2025 could improve the economics for gas in the coming years, but we are concerned that this trajectory is unlikely to improve the market for gas until 2019/2020, causing capacity challenges.

We are also concerned that the Capacity Market may not be strongly enough incentivising reliable capacity. The future of the only new build CCGT project, Trafford, which received a contract in 2014, is uncertain and a number of the contracts awarded are short term. The Government should assess ways to ensure more reliable plant that can contribute in the longer term receives contracts, by: incentivising more new-build projects; considering lowering the investment threshold for existing 3 year refurbishment contracts; strengthening the penalties for generators that do not deliver their contractual requirements and assessing whether the current contract length and structure is providing adequately for long term security of supply.

The move to a low carbon economy introduces large volumes of intermittent renewable generation. These make balancing supply and demand more difficult, and also introduce operability challenges for the network, impacting its resilience to faults (i.e. reduced system inertia and resilience).

Electricity balancing and cash-out arrangements have recently been reformed and generally appear to be robust. The future electricity system will need more flexibility services to maintain security of supply. The industry has just completed a long-running Significant Code Review led to an Ofgem decision to reform these arrangements to enhance supply security. These reforms are split into two phases, the first of which took effect from 5 November 2015 and the second of which is scheduled to be implemented in 2018.

We generally supported these reforms, which should allow markets to operate more effectively to preserve supply security. They will mean 'sharper' (higher) cash-out prices when capacity margins are tight in order to incentivise appropriate responses from market participants, including as regards demand-side response. We still have reservations around the proposed move to 'PAR 1' in 2018, particularly around the risk that competition in setting very 'marginal' cash-out prices may not be sufficiently robust. This will need to be monitored carefully, to balance the potential gains to supply security against the increased risk and cost to market participants and consumers. There is, however, a risk that significantly higher cash-out prices disincentivise ownership of assets, as opposed to buying in the market, due to an increased liability.

Growth in DER DSR is needed to provide the GB electricity system with the flexibility it needs to evolve from a conventional centralised generation system to one that has significant contributions from intermittent sources of generation.

DER and DSR can be used in a number of ways to provide numerous benefits:

- They allow the TSO to balance electricity supply and demand both on short timescales, for frequency response services, and longer term, in Capacity Market to ensure periods of high demand can be met.
- They can reduce the demand peaks on the Transmission and Distribution networks.
- Suppliers may also use DER/DSR to reduce wholesale costs for consumers or reduce exposure to imbalance charges.
- DER/DSR can also improve choice by increasing market competition between these services.
- DER/DSR can also provide a source of value for consumers e.g. rewards changing consumption behaviour as load shifting reduces the costs of electricity.

1b. What role can changes to the market framework play to incentivise this outcome?

Overview

We would emphasise again (as stated above) the important role gas-fired power generation will play as the country switches away from coal. It is important to ensure the sector is incentivised both to maintain the existing gas generation fleet and build new gas as soon as possible to meet the potential capacity shortfall.

As DER/ DSR become more important and services increase, it is essential we have aligned positions and processes between system operators to ensure the networks can be managed effectively.

The separate uses for DER/DSR identified above have different requirements, location may be important, the notice period to initiate the DER/DSR, the duration of the service and frequency of events will all impact availability. Whilst some DER/DSR may be better suited to certain uses, others can supply multiple uses. As a result there may be conflicts or synergies for the TSO (and/or DSOs) in managing their deployment.

TSOs have overall responsibility for system security while DSOs have responsibility for the secure operation of their distribution networks. This means TSOs will need to continue to have the leading responsibility for national balancing, frequency control and system restoration, whereas DSOs will maintain their responsibility for congestion and voltage management on their networks. As an increasing share of electricity generation connects to DSOs, one of the major operational challenges for the TSO will be maintaining overall system security. Scarcity of system services will become more acute in the future meaning new operational arrangements between TSOs and DSOs to unlock the capabilities of DER and DSR and maintain security of the distribution and transmission networks.

The TSO and the DSOs will both have a responsibility for providing information and support to market participants at their respective network levels. They must act as neutral facilitators when providing connections, assessing flexibility services (e.g. DER/DSR) and also need to be transparent and act in a non-discriminatory way. Neither the TSO nor the DSOs should be active as commercial service providers.

1c. Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

Overview

We do not believe now is the right time to address this issue. The first priority should be to establish the right set of SO roles and responsibilities across the system so that transmission and distribution system operators can work effectively at a time when balancing the networks is becoming more challenging. There is probably a case for longer duration SO incentives (provided that these are not over-generous) and in future it will also be important to incentivise the proactive management of 'smarter' distribution systems.

The SO has recently taken on new roles as the Delivery Body for the CM and the CfD auctions and plays an increasingly important role within the GB electricity system. An independent SO, with a dedicated board focused solely on electricity system issues, could be beneficial.

However, we do not think that these are current issues, and to date business separation arrangements appear to have worked well. Hence, any decision to separate out the SO business from NGET would need to balance the costs (and risks) with the benefits it could bring. For example separation could require the division of and/or investment in new information systems, increasing costs for consumers and potential disruption to the industry.

As outlined above, the GB electricity system is undergoing fundamental change and getting this right, is more important than establishing an independent SO. We have concerns that separating out the SO at this critical time would be a distraction and could introduce uncertainty when the industry is trying to encourage more DER and DSR. The first priority should be to define an appropriate set of SO roles and responsibilities across the electricity system as a whole (including the interfaces between transmission and distribution) and then to consider how best to ensure the independence of the system operator(s).

Finally, it is important to consider how the SO or SOs can best be incentivised to carry out their roles efficiently and invest where necessary to reduce the longer term cost of system operation to consumers. In particular:

- Current TSO incentives tend to be at most two years in duration. It is for consideration (a) whether this is long enough to incentivise the right investments, in some instances and (b) whether the risk/reward balance is appropriate from a consumer point of view. Longer duration incentives could be beneficial, but care would be needed to ensure that these are not over-generous.
- In the medium-long term, as DER and DSR continue to expand, there will need to be further incentives for pro-active system management at a distribution level. This will become a major issue by the time the current electricity distribution price controls come to end in 2023, but in the meantime the interim review to take effect from 2018 may provide an opportunity to begin to address this point.

1d. Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

Overview

The Balancing Markets will need to evolve to take account of the need for more flexibility services; the number and range of balancing players; and to solve operational constraints of TSOs and DSOs which may conflict.

The TSO is currently responsible for forecasting national electricity demand and undertakes operational planning from year ahead to day ahead to match generation and demand with an appropriate level of security margin. It has to take into account generation availability, the transmission systems capability and outages.

All system users are then responsible for balancing their own electricity "contractual" positions with their counterparties (through Elexon). These positions are fixed at gate closure, one hour ahead of real-time. The TSO, as the "residual balancer" must then ensure that electricity generation and demand are balanced across the GB transmission system on a second by second basis in real time. It does this by procuring a wide variety of Balancing Services to balance the power flows around the electricity transmission system and is responsible for contracting short term generating provision to cover demand prediction errors and sudden failures at power stations.

Distribution networks are currently largely passive and do not have any material balancing operations. This approach is starting to be challenged by the growth of DER, smart metering and DSR. The future development of 'smarter' distribution grids which can adapt to more complex and unpredictable electricity flows will in time require both new incentives and a different organisational 'mindset'.

Looking forward the balancing market will need to be responsive to the changes identified in this paper and evolve over time. A few of the principles and features we believe will be necessary are provided below. We do not believe wholesale reform is absolutely necessary; an evolutionary approach which engages all stakeholders will be less disruptive and create less uncertainty for the market.

- The TSO will need more visibility of all the DER/DSR connected to the distribution network (and the deployment of emerging technologies such as electrical vehicles and storage). Visibility will help the TSO maintain security of supply, lessen demand forecast errors and limit increases in reserve margins driven by growing uncertainty, which will benefit consumers by increasing cost-efficiency.
- The DSOs must avoid creating exclusive, fragmented markets in their respective areas as this will impact the ability for DER/DSR resources to maximize their economic potential at scale and could ultimately impact the efficiency of the market and overall effectiveness of system operation.
- DER/DSR sources should be able to sell their services where it is the most profitable for them (e.g. balancing, system services, valuation in the energy market, congestion management, contracts with DSOs or TSOs as an alternative to grid reinforcement, etc.)
- TSO and DSOs cannot be on both sides of the market as both the market facilitator and service provider. If they are demanding or buying a system service, then this service cannot be provided by them as well.
- DER/DSR should be integrated into the market on equitable and transparent terms with those offered to generation and storage. This will require opening all markets to DER/DSR on a non-discriminatory basis and creating suitable products and services to allow markets to deliver appropriate price signals and incentives to develop DER/DSR.
- Barriers to DER/DSR aggregation should be removed so consumers can aggregate their services with third parties, regardless of their connection points. However, suppliers will need to be protected from imbalances created by third party aggregation of their consumers.
- Markets need to be left to deliver appropriate price signals and incentives to develop DER/DSR in the system. Network companies should focus on efficient grid operation and should not be playing a role as commercial intermediaries as this is better fulfilled by market participants subject to competitive commercial pressures.

2a. What are the barriers to the deployment of energy storage capacity?
2b. Are there specific market failures that prevent investment in energy storage that are not faced by other 'balancing' technologies and how might they be overcome?

Overview
The cost of battery storage needs to fall to become commercially viable, which the Government could support. There has, until now, been a 'missing market' in frequency response and other forms of flexibility within the GB electricity sector. This will be required increasingly in the future to maintain system stability and security in the face of the growth in intermittent decentralised generation.

Partly through the impact of subsidies, there has been a very rapid growth in 'embedded' intermittent generation connected to distribution networks. This includes c. 9 GW of solar plant, of which most is free-standing rather than installed on residential customers' roofs. Such developments are starting to create system stability issues for the electricity networks, which are required to keep system frequency within narrow tolerances. There has also been a sharp reduction in the costs of solar power, which is encouraging, but this now needs to be complemented by the development of cost-effective energy storage.

Battery storage is an emerging market, which has made significant steps in recent years. Battery storage will allow us to use renewable energy more efficiently and will have a significant positive impact on our ability to balance and manage pressure on the grid at peak times.

While we do not believe there are any specific market failures, the costs of battery storage mean that it is currently not a commercially viable proposition. To help enable this product to come to market, we would like to see battery storage added to the Enhanced Capital Allowances list. This would allow businesses to realise financial benefits immediately, improving the payback period. It also has the benefit of not being recovered through energy bills, so avoids a regressive impact on bills.

It is interesting to note that National Grid is launching a national tender for rapid frequency response which is expected to take place in Q1 2016. Battery storage is ideally placed to provide these services and existing 'brownfield 'generation sites with good existing grid connections will be among the most suitable locations for it. Together with partners, we intend to participate in this auction which represents a first move to create the 'missing market' in flexibility which we mentioned above.

2c. What is the most appropriate scales for future energy storage technologies in the UK? (i.e. Tx network scale, Dx network scale or domestic)?

Overview
We believe that battery storage will bring benefits in a number of different areas. There are a number of different types of battery storage, with different technical and operating characteristics, which we consider further in the answers to this response.

These technologies have the potential to help businesses manage their energy usage more effectively, particularly where they use on-site renewable generation, such as solar and wind. Companies with solar PV that currently export some of their generation during the day will be able to store excess generation to use later in the day such as at peak times of demand, known as network red periods. It would also allow companies to import excess during low cost HH periods such as early morning or early afternoon and then use that power in high cost Triad and red periods.

They will allow homes to do the same, shifting the power generated from solar PV to more useful times of the day such as the evening maximising consumption and minimising less valuable export. In the longer term, this could further be supported by dynamic time of use tariffs.

They will also deliver whole system benefits, by removing pressure from the grid and reducing peak demand. Battery storage also has an important role to play in National Grid's Enhanced Frequency Response.

3a. What level of electricity interconnection is likely to be in the best interests of consumers?
b. Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
c. Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

Overview
The development of new electricity interconnectors is already strongly incentivised, including via a transfer of market risk and onshore transmission reinforcement costs to GB electricity consumers. We believe there is greater incentivisation for interconnection than for new gas-fired generation in GB. If not addressed, this imbalance is likely to make the achievement of government policy objectives for gas a major challenge.

The GB wholesale power market is currently characterised by a relatively low level of cross-border interconnection, at around 4 GW, equivalent to c. 5% of installed generating capacity. In part, a lower level of interconnection (by Continental European standards) is explainable by the much higher cost of constructing sub-sea cables as opposed to conventional onshore electricity transmission lines. For example, the 750 km NSN link under construction between Norway and northern England is reported to have a total capex cost of €1.5-2.0 bn, i.e. well in excess of £1 bn.

However, partly in response to the 'cap and floor' regime more projects are now going ahead: two further projects (with a combined capacity of 2.4 GW) have now begun construction and it seems likely that further Final Investment Decisions will follow in the next few years. Several factors are incentivising the development of interconnectors:

- There are currently large electricity price differentials between GB and various Continental markets. German power for 2016 is trading at €30/MWh, whilst UK power is priced at close to £40/MWh.[1] In Germany renewable generation with very low variable costs is displacing thermal generation in during off-peak periods and driving wholesale power prices at such times to very low or even negative levels.
- The EUA carbon price under the European Emissions Trading Scheme is around €8-9/tonne (c. £6), whilst UK generators are also subject to a carbon tax of £18/tonne.
- Interconnectors are exempt from National Grid's Balancing Services Use of System (BSUoS) charges which apply to GB generation and supply, the latest 2015/16 forecast being just over £1.80/MWh.
- Interconnectors are exempt from electricity transmission charges (known in GB as generation TNUoS) from which National Grid expects to recover just over £600m in total during 2015/16. Many Continental generators do not appear to face these similar charges.
- New interconnector projects are able to benefit from a supportive 'cap and floor regime'.[2] This has two particular effects:
    - First, the 'floor' on ROCE (return on capital employed) is generally set at the cost of debt – thus providing debt service assurance to providers of finance and allowing owners to take advantage of low borrowing costs by 'gearing up' the project balance sheet.
    - At the same time, since the floor applies to the whole of capital employed (and not just the debt portion), it also limits the extent of downside equity risk.
- In current market conditions, interconnector projects operating under this regime may expect to earn returns much closer to the cap than the floor, but the 'cap and floor' combination provides protection against future changes (such as a reduction in the carbon cost differential), as well as providing encouragement to any subsequent interconnectors with more marginal project economics.
- Finally, a number of interconnector projects are expected to benefit from EU subsidies, since they have been classified as 'Projects of Common Interest' (PCIs).

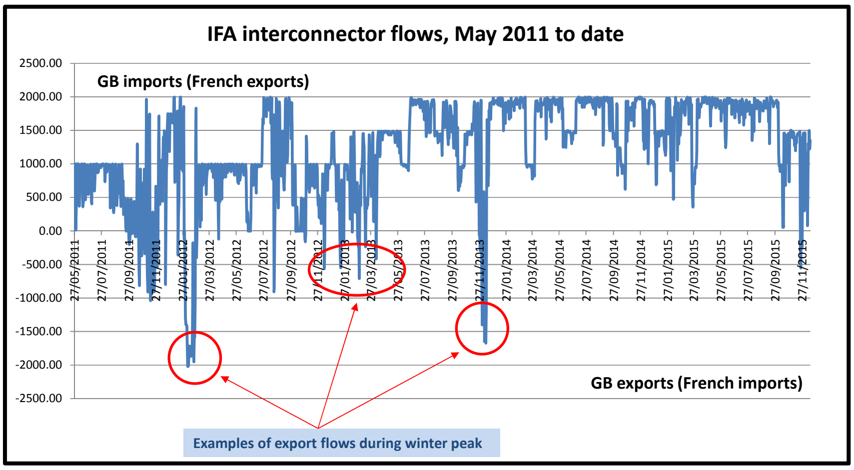
The Secretary of State set out in her November energy speech that building new gas-fired power stations would be a key priority. However, providing support for interconnection and gas-fired power stations could create challenges. The impact of more interconnection on the economics of gas-fired power is three-fold:

1. By driving marginal GB (gas) generation out of merit, it will tend to reduce the average level of wholesale power prices in GB. There is likely to be a similar impact on clean spark spreads, which are a key indicator of viability for gas-fired power stations.
2. Increased interconnection capacity operating at reasonably high load factors and mainly in the GB import direction will also reduce the average utilisation of GB gas-fired generating plant, perhaps by c.2.5% for each additional GW of interconnection.
3. Finally, interconnection bidding into the Capacity Market will tend to push back demand for GB generating capacity and thus reduce the amount of GB gas plant which secures Capacity Market contracts. It may also reduce the level of Capacity Market exit prices, at least in some periods.

[1] This does not mean that retail energy prices are lower in Germany; in fact they are significantly higher than in the UK, in large part because the rising cost of renewable generation subsidies more than outweighs the lower wholesale electricity price.
[2] Exceptionally, the proposed 1 GW Eleclink project from France to GB via the Channel Tunnel is planning to operate on a merchant basis, exempt from regulated third party access rules.

In reality, therefore, any artificial 'over-promotion' of electricity interconnector investment is likely to damage the incentives for investment in GB gas-fired generation which the government wishes to see. Although GB interconnectors with the Continent will tend to flow in the UK import direction during most hours under current market conditions, it cannot be assumed that they will always do so and the benefits to GB supply security may thus be lower than is sometimes portrayed. This was noted in the European Commission's state aid report on the GB capacity market (para 119), which stated "*…for the hours of highest GB system stress (i.e. where capacity margins are below 10%) interconnection flows have not consistently helped and have sometimes worsened capacity margins in GB.* "

To illustrate this point, we show in the chart below the daily electricity flows on the 2 GW IFA (France-England) interconnector in the period from 2011 to 2015. Flows have mainly been in the GB import direction, but there have been peak winter periods (in 2011/12, 2012/13 and again in 2013/14) during which the IFA was exporting. In a number of instances, this took place even though wholesale electricity prices in GB were above those in France. When the weather is cold, French heating demand can increase sharply and electricity which would otherwise have been exported to GB is retained within France itself.



For these reasons, interconnector capacity is typically 'de-rated' (reduced) for the purposes of GB capacity market participation. This suggests that around half the nameplate interconnection capacity can be relied up to contribute to GB supply security in peak hours. However, we suggest that the extent of de-rating should be reviewed ahead of the next 'T-4' CM auction, in the light of the above flow patterns and other relevant evidence.

The development of further interconnection at the expense of new GB gas generation is likely to erode the level of government tax receipts from the UK carbon price floor and other sources. The Carbon Floor is an important element of the UK's decarbonisation policy and is a sensible market-oriented approach to this policy aim. Therefore any move to harmonise UK carbon pricing with its neighbours should be by raising the latter's (most likely through reform of the EU ETS), not by eroding the UK's Carbon Floor. However, as it relates to interconnection, there is a disparity that distorts the cross-border economics.

Finally, we note that GB gas generation is incentivised under transmission charging arrangements to locate in 'deficit' regions which need the additional supply; this also allows the best use to be made of existing transmission infrastructure – thus helping to defer the need for additional capacity investment. By contract, there are no such locational investment signals applicable to interconnectors and as a result interconnectors may trigger material transmission grid reinforcement which will fall as an additional cost on GB electricity consumers. We believe interconnectors can play an important role, but we do not believe there is a need for further incentives, or a removal of existing barriers. We believe developing gas-fired generation should be the priority.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Overview

There is much that the UK can learn from international experience, but in our view there is as yet no superior 'blueprint' model of international best practice and in some respects (e.g. the design of the Capacity Market and steps taken to reduce the level of unabated coal capacity on the system) the UK has been ahead of many other countries.

Gas-fired power generation has recently been struggling for viability right across much of the EU. Gas plant utilisation has typically been lower in recent years than it was in the period to around 2010, in part due to reduced demand and (even more so) the rise of renewables. In some Continental markets, such as the Netherlands and Germany, there has also been construction of new, unabated coal or lignite capacities. Nevertheless, gas generating capacity is often vital to maintaining supply security at those times when intermittent renewable generation (whether wind or solar) is significantly lower than average.

Several other EU Member States (e.g. France) which are facing similar challenges to the UK already have their own capacity markets. A number of others have capacity payment mechanisms, of which some (including Italy and Ireland) have plans to move from capacity payments to a proper capacity market. As mentioned above, the UK has been ahead of many European states in this respect, but there is longer-running experience of capacity markets in several US jurisdictions.

The UK could learn the lessons of countries like Germany and Ireland in terms of integrating high volumes of intermittent renewables, which will be a key challenge for the networks in the coming years:

- In Germany, most wind capacity is in the north of the country whilst the early shutdown of existing nuclear stations has particularly affected the south. There are severe north-south transmission constraints which require (otherwise economically non-viable) thermal plants in the south to remain open. At a local level, there are also capacity issues on the local electricity distribution system in areas (such as Bavaria) where there are very high amounts of installed solar PV, with output typically concentrated in a relatively few hours per day and annual load factors of the order 10%.
- In Ireland, the rapid growth in onshore wind on a relative small power system has led to a very considerable escalation in transmission constraints and constraint costs. Partly in order to comply with EU legislation, a decision has also been made to replace the existing Single Electricity Market based on a mandatory Power Pool with a revised market design (I-SEM) which will provide for a balancing market and support intra-day trading across the electricity interconnectors. (These features are already provided for in the GB wholesale market design.)

It will be important for the UK to be prepared to handle growing issues of intermittency and regional imbalance. The very rapid recent growth in UK solar capacity to around 9 GW is already giving rise to distribution network constraints (e.g. in SW England) and issues around controlling frequency (system stability) in some parts of the electricity network. (See our answer to qu. 2 above re the role which energy storage can potentially play in helping to provide frequency response to the grid.)

In the USA, there is a somewhat different set of issues there are also significant differences between the different US regions. Given low wholesale gas prices, gas generation is more competitive in North America that it is in Europe.

North America is also the world leader in carbon capture and storage (CCS) applied to power generation. One Canadian CCS/coal plant is already in operation, with a pre-combustion coal facility in Mississippi and a post-combustion coal plant in Texas under construction; these two plants are expected to be on-stream at some point in 2016. In North America, CCS economics are somewhat enhanced by the scope to use CO_2 for enhanced hydrocarbons recovery in onshore oil and gas fields, which is not yet envisaged in either of the first two candidate UK CCS projects. However, the capital costs of these “first of a kind” projects are extremely high. In our view, these costs would have to come down very dramatically before CCS could play a material role.

Centrica’s downstream business in North America, Direct Energy, has seen considerable growth in energy technology in recent years. One key area has been battery storage, which is increasingly used to manage pressure on the grid. Battery storage in North America is further along the commercialisation curve than the UK. Market conditions, such as volatile demand and an increased amount of renewable generation have contributed to this, but incentives have also been put in place to speed up commercialisation. Government may want to consider this when looking at the role battery storage can play in the UK.

Introduction

Over the past decade we have seen infrastructure creep up the agenda to a point that it is now firmly placed at the heart of the political debate. With investment in major transport, energy and utility projects increasing to record highs and the development of the National Infrastructure Plan to set out key Government priorities, we have reached a stage where infrastructure is a nationally significant issue that transcends party political ties.

The formation of the National Infrastructure Commission last year was greatly welcomed by the industry and provided a great level of confidence in the deliverability of major projects and enables the current Government and future administrations to speed up decision-making on vital transport, energy and housing programmes that Britain needs to continue to grow its economy.

CH2M is a global engineering and programme management company that works in the areas of areas of water, transportation, environmental, energy, facilities and defence. With over 2,500 people employed in the UK, CH2M is currently working on some of the most iconic infrastructure programmes including Crossrail, High Speed 2, Thames Tideway Tunnels, Crossrail 2, the decommissioning of Dounreay and was one of the leading partners in CLM, Delivery Partner to the ODA for the London 2012 Olympic & Paralympic Games.

Given our experience of working on the development and delivery of major UK infrastructure projects, we felt it may be helpful to share some of our thoughts around the points laid out in the NIC's call for evidence in order to share the lessons learned for the efficient delivery of future infrastructure priorities. In particular, this document presents our views for regarding Electricity Interconnection and Storage. We have made separate submissions outlining our views for infrastructure priorities for London and Northern Cities.

Electricity Interconnection and Storage

Q1 – What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long term?

As large quantities of electricity cannot be stored easily, the key function of the system operator is to balance generation and demand to ensure a reliable supply of power to consumers and prevent damage to infrastructure such as power lines, transformers and generation plant. Within this context, National Electricity System Operator (NETSO), as the system operator for Great Britain (GB), has an obligation to balance the GB transmission system. Ofgem, the regulator of the GB market, operates a Balancing Services Incentive Scheme (BSIS) to incentivise National Grid to act economically and efficiently in performing its balancing role.

There are two broad categories of balancing actions available to the system operator (SO):

- Energy imbalance actions address overall mis-matches between generation and demand at a national level across the settlement period as a whole.
- System imbalance actions tackle local or regional constraints in the capacity of the transmission network, or short-term variations between demand and supply within a settlement period. Constraint actions can result in compensation ('constraint payments') for generators which lie behind a constraint barrier.

A recent assessment by the National Audit Office confirmed that the total cost of balancing services has considerably increased since 2010. The assessment concluded that this increase in cost of balancing services was predominantly due to growth of constraint costs. The increase in constraints was attributed mainly to unavailability of some transmission assets due to ongoing investment programmes of transmission owners in Scotland and elsewhere. In addition, the introduction of the 'Connect and Manage' policy, which allows certain types of generation to connect ahead of the required increase in transmission capacity was also identified as a driver for growth in constraints.

The 'Connect and Manage' policy was developed to facilitate a step change in renewable deployment across the GB market, by removing barriers for connection. Although largely successful in achieving this objective, in some isolated cases the policy has resulted in connection agreements for intermittent generation in areas where the transmission network is weak. Such agreements could result in further increase in constraint costs and impact adversely on balancing costs for the GB system. Considering the growth achieved in renewable generation capacity over the past decade (as well as additional Connect and Manage capacity expected to get connected in the coming years), and the typical lead times for implementation of major transmission upgrades, there is a need to closely monitor that the ‘Connect and Manage’ is achieving its objectives without adding disproportionately to constraint costs. If necessary, there may be merit in reshaping the policy in the future.

Given the emissions target and forecasts for carbon prices, the GB market is likely to see a significant reduction of thermal fleet. This could result in tightening of the capacity, which can have further impacts on system balancing costs. A significant proportion of this capacity is likely to be replaced by inflexible nuclear or further intermittent transmission connected and embedded generation, posing further pressures on system balancing. The recently introduced capacity market auctions provide a way tackling some of these pressures. However, as identified by the National Audit Office, there may be merit in reviewing current arrangements for balancing services as a whole fit for purpose in the light of current and future developments (including the growth of intermittent and embedded generation).

The System Operator already plays a critical role in the capacity auctions. It also monitors the impact of ‘Connect and Manage’ policy on constraint costs. However, an independent SO (ISO), if necessary, could play a vital role in redesigning a forward looking 'Connect and Manage' policy, which could minimise the GB consumers’ exposure to constraint costs. Equally, an ISO with greater authority could more actively transfer certain costs of imbalances in the system to respective players in the market, than it currently does. Furthermore, with extensive knowledge of the system, an ISO could facilitate creation of zonal markets to manage inefficiencies and reduce constraints. Equally, an ISO or an enhanced SO (ESO) could facilitate competition and ensure cost efficient and timely implementation of non-build solutions (e.g. demand side response) and new transmission assets, further reducing the GB consumers’ exposure to system balancing costs. Both ISO and ESO could also play a critical role in facilitating the development of necessary cross border interconnection, which supports greater efficiency in system balancing costs.

The current incentives for system balancing costs, which are based on profit or loss sharing, are more suitable for a joint transmission ownership and system operation licence. Such incentives may continue to be suitable for an ESO, whose liabilities are borne by the parent transmission owner. However, considering the critical nature of the system balancing function, there may be merit in reassessing the caps on profit and loss sharing arrangement. On a different note, the current package of incentives will not be feasible for an ISO, who will predominantly be performing a revenue based public service.

Q2 – What are the barriers to the deployment of energy storage capacity?

Under current arrangements within the GB electricity market, storage is considered as a ‘generator’ like any other non-synchronous fuel types. However, unlike all other intermittent generation, net production based asset utilisation of storage plant is affected through the market prices. In particular, such units generate revenue and profit through price arbitrage based actions within the market (unless they are directly linked to a cross border interconnector). Hence, under current market arrangements they are not incentivised to operate in a manner which could deliver economic externalities such as reduction in energy prices and improved efficiency in system balancing costs.

This inability of the market to extract economic externalities from energy storage demonstrates the market failure. Furthermore, storage has the potential to act as an alternative to significant transmission investment. However, the GB market’s current arrangements limit transmission companies from development and ownership of storage assets under most network conditions, as they are considered as ‘generation’.

The GB market currently has less than 4 GW of transmission connected storage capacity. If incentivised through income guarantees which fully recognise their potential for delivering the basket of economic impacts and go beyond the current arrangements, the existing storage capacity has potential to deliver some reductions in GB’s electricity costs as well as system balancing costs. However, the size of the impact could be noteworthy if such new market mechanisms were also offered to attract new private sector investments, which could deliver a critical mass of strategically planned transmission connected storage. Furthermore, there may be merit in considering a review of licence arrangements for transmission ownership, such that existing transmission owners and any new entrants to the market, can deliver additional storage capacity as an alternative and / or complementary to new transmission assets.

Smaller scale storage, based on technologies such as batteries, is less advanced. Subsequently capital costs of such developing technologies are not economically efficient yet. However, such storage technologies have good potential at micro level such as domestic use. In particular, they can complement the growing critical mass of embedded generation, facilitate demand management at distribution level and subsequently make further impact on the market's energy prices. However, there may be merit in considering some upfront capital support for households and small and medium enterprises for the short term, until the costs become economically efficient.

Q3 – What level of electricity interconnection is likely to be in the best interests of consumers?

The Barcelona agreement in 2002 set a non-binding aspirational target of interconnection of 10% of installed capacity for all member states. The European Commission (EC) is currently reviewing this position and determining more appropriate objectives to ensure the correct level of interconnection. This is not least because interconnection between member states is considered as a key driver for EC to implement the Single Energy Market (SEM) policy across Europe, which aims to maintain affordability of energy, whilst ensuring security of supply and delivering target levels of renewable generation and reduction in carbon emissions.

There is currently 4 GW of interconnection between Great Britain (GB) and other European electricity markets (including All Islands Irish market). Considering approximately 75 GW of installed capacity in the GB[1] in 2015, this equates our market's interconnected capability of some 5% of the total installed capacity. The five interconnectors which have been awarded Cap and Floor support (IFA2, Fablink, NSN, Viking and Greenlink) over the past twelve months along with Eleclink and NEMO (interconnector projects in advanced delivery stage which are being developed as merchant projects) will increase GB's interconnected capability to 11 GW. If all this interconnected capacity is delivered by 2020, it will momentarily increase the GB interconnected capability beyond 10% of our installed capacity. However, with increase in generation capacity between 2020 and 2030, our interconnected capability will drop again below the 10% target.

Interconnectors currently generate revenue through market arbitrage and subsequent trading of their capacities. Their current economic function from the GB consumers' perspective is predominantly to deliver socio-economic welfare externality, defined as reduced energy prices in the GB market. This is primarily due to the prevailing energy mix within the GB market and the GB specific price of emissions, which typically results in higher per unit cost of electricity compared to markets in continental Europe.

Depending on the future mix of GB's generation capacity, which will be influenced by both top down national policy drivers and supporting mechanism and bottom up activities in the market, this primary economic function of interconnectors may change. For example, any reduction in deployment of renewable generation from current levels due to lack of funding or technological issues, would result in continued disparity between electricity prices in GB and European markets over the foreseeable future. Greater levels of interconnection under such a scenario will continue to offer the above mentioned socio-economic welfare externality.

In comparison, persisting with current policies and mechanisms such as increasing carbon emission prices and financial support for renewable technologies, will lead to greater continued deployment of intermittent renewable generation. This is likely to result in some cannibalisation of prices between the GB and certain continental European markets in the medium term. However, increasing levels of non-synchronous generation will lead to considerable system balancing issues (summer minimum and winter peak demand), which are not currently common to the GB market.

A critical mass of interconnection, under such a scenario, can deliver notable system operation benefits such as black start capability, frequency response and reserve response. If their location on the GB network is planned strategically, in light of the recently implemented pan-European Capacity Allocation and Congestion Management (CACM) network code, new interconnectors can support notable reduction of system balancing costs or even displace major transmission investments. Active participation of interconnectors in services which are considered as ancillary to their price arbitrage based primary revenue stream, would expand their economic function towards ensuring security of supply, increasing system flexibility and improving efficiency in system balancing costs. Introduction of interconnectors in the capacity market auctions will be a step in the right direction.

Furthermore, increased level of direct and indirect support for renewable generation coupled with maturing technology and subsequent reduction in equipment costs, can lead to even greater level non-synchronous generation. This, coupled with aggressive decommissioning of nuclear and lignite fleet in across European member states, may lead to lower prices in the GB compared with most European markets in the medium to long term. Under such a scenario, although the socio-economic welfare benefit for GB consumers would diminish, the role of interconnectors in providing ancillary services would expand significantly.

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[1] Source: Europe's Ten Year Network Development Plan - Scenario Development Report, produced by European Network of Transmission System Operators of Electricity (ENTSO-E) in November 2015.

The revenue streams for interconnectors' ancillary services are poorly developed at present. Although attempts were made to establish the potential scale of GB consumer benefit of such ancillary services as part of the recent round of Cap and Floor by the System Operator, there continues to be a lack of clarity around how interconnectors can draw 'steady' income from provision of such services over the long term. Inability of the interconnectors to extract long term income from delivery of ancillary services based products, which lead to economic externalities such as security of supply, increase system flexibility and more efficient system balancing highlights the current market failure for new interconnector projects. In particular, further intervention is required to main stream an interconnector's long term revenues derived from ancillary services. This could also reduce the burden borne by the GB consumer through a new interconnector's Cap and Floor support.

Equally, there is need for strong leadership from the regulator and the system operator to ensure that appropriate products as part of CACM which will allow interconnectors to participate in system balancing activities are developed and operational soon. There may also be merit in considering improvements to enhance the planning of new interconnection projects which go beyond the recently announced Network Options Assessment for Interconnectors, by taking in account both socio-economic welfare and ancillary services benefits, as well as facilitate transfer of financial reward to interconnectors for outcomes such as increase in capacity of a major transmission boundary through formal contractual arrangements between transmission owners and project developers.

Q4 – What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Our response to the above questions already draws upon international good practice approaches such as the role of an independent SO, use of storage and interconnection for ancillary services (including constraint management), role of storage and interconnection in managing electricity prices within a market and creation of zonal markets for improving efficiency in system balancing costs.

We can provide further case study based evaluation on such specific issues to assist the evidence building exercise currently being undertaken by the National Infrastructure Commission.

From: Yates, Chris [email address redacted]
Sent: 08 January 2016 09:50
To: EnergyEvidence Infrastructure-Commission
Subject: response to consultation
Attachments: pei201512-dl.pdf

Question 1: What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome: Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs? Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- Apart from crude 'economy 7' tariff mechanisms there is very little to motivate grid users to demand shift. Smart metering that can deliver 'Real time tariff' information to large consumers will help them demand shift more effectively.
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?
- There are a number of large scale borehole thermal energy schemes (Churchill hospital Oxford, Karolinska Hospital Stockholm). We should rethink district heat and coolth as a means of tapping into low carbon electricity for recharging hot or cold boreholes whilst simultaneously unloading grid excess generation. As we know, the earth is the biggest capacitor – both electrically and thermally.

Question 2: What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- The current regulations make it difficult to operate storage. See this article on page 26 of attached.
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)
- Heat network scale. Heat networks could enter arrangements with individual wind farm operators to recharge their boreholes when the wind farm would otherwise be furling its turbines.
- Heat rejection networks also make sense in London (Victoria circle has set a precedent in this)
- **Alarmingly, most heat networks that are being put in place at present are not optimised for heat pumps (90degC and greater flow temperatures). This flies in the face of a lot of advice, including the recent CIBSE/ADE Code of Practice for Heat networks: CP1.**
-

Question 3: What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- I don't understand this.
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

Question 4: What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?
Look at Germany, Sweden + Denmark

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Call for evidence: National Infrastructure Commission

Submission from the Chartered Institution of Building Services Engineers

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About the Chartered Institution of Building Services Engineers (CIBSE)

CIBSE is the primary professional body and learned society for those who design, install, operate and maintain the energy using systems, both mechanical and electrical, which are used in buildings. Our members therefore have a pervasive involvement in the use of energy in all types of buildings the UK. Our focus is on adopting a co-ordinated approach at all stages of the life cycle of buildings, including conception, briefing, design, procurement, construction, operation, maintenance and ultimate disposal.

CIBSE is one of the leading global professional organisations for building performance related knowledge. The Institution and its members are the primary source of professional guidance for the building services sector on the design and installation of energy efficient building services systems to deliver healthy, comfortable and effective building performance.

This response is concerned with the third national challenge highlighted in the National Infrastructure Commission's call for evidence, *improving how electricity demand and supply are balanced.*

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

1.1 It must first be noted that reducing demand is a more time and cost effective approach than investing in new generation and distribution capacity. Improving energy security and reducing consumer bills are positive outcomes of a greater focus on energy efficiency, and would benefit from a coherent overall approach. Reducing energy demand in existing buildings (domestic and non-domestic) is an effective way to reduce consumption and costs and therefore to reduce demand on the national electricity infrastructure. This will then free up funds to be invested in other pressing types of national infrastructure, such as those highlighted in this call for evidence.

1.2 We have the experience and knowledge to improve the performance of building stock, but need Government to provide an appropriate policy and legislative infrastructure to support and implement this on a national scale.

2. What are the barriers to the deployment of energy storage capacity?

2.1 There are a number of publicly funded research projects which look into this issue. For example, Understanding the Balancing Challenge produced by Imperial College London analyses the merits of, and the interaction between, alternative balancing technologies (interconnection, flexible generation, storage and demand side response) in minimising the costs of balancing the system in short and long-term. It also considers the key barriers to achieving the efficient deployment of and investment in alternative balancing technologies.

2.2 Combined Heat and Power (CHP) and District Heating (DH) with large thermal storage could play a major role in balancing supply and demand. Large thermal storage can be used to smooth/prolong heat demands so that CHP can generate more in peak times. The lack of regulation in this area has created a barrier that prevents investment in heat energy storage. Adding heat storage into infrastructure can act as a balancing mechanism to assist the grid both at a local and a power station level. Storing heat is practical, feasible and reasonably cheap. The Institute of Mechanical Engineers highlights the issues around heat energy infrastructure in the report Heat Energy: The Nation's Forgotten Crisis.

2.3 There is a vibrant district heating sector with a number of towns and cities either doing feasibility studies or installing plant. These localised (often city wide) heat networks provide the opportunity for connecting local CHP and renewable technologies such as water source heat pumps. These systems almost always include large heat storage capacity that can help buffer the energy supply system and the generation capacity can act as a spinning reserve for the electricity grid. Examples include Southampton, Birmingham, Leicester, Sheffield, Kings Cross, the Olympic Park and Citigen in London and many more. The scheme at Pimlico includes 3MW electrical output combined heat and power (CHP) and three 8MW gas fired boilers and has the largest thermal store in the UK with a capacity of 2,500 m3 of water.

2.4 Another barrier is the lack of a systems thinking approach when it comes to energy infrastructure. For example, using rejected heat from power stations. Also, taking into consideration the rise of heat pump technology and the effect on our electricity infrastructure. Cooling is another forgotten part of the UK's energy infrastructure, electricity consumption for cooling is increasing and renewable forms such as water source heat pumps should be considered.

2.5 CIBSE has produced, with others, Codes of Practice on both Heat Networks and Water Source Heat Pumps to help raise standards across the supply chain and overcome the barriers of poor coordination and quality management in these areas.

2.6 There is a pressing need for greater systems thinking in the planning and design of energy and electricity related infrastructure to deliver energy in the most cost effective and secure manner in a given set of circumstances.

2.7 The most appropriate scale depends on the specific circumstances of the case – this is one aspect of the lack of systems thinking which we face. In some circumstances domestic scale may be cost effective, especially in isolated areas. In other circumstances, such as the Elephant and Castle regeneration programme, a district level solution is likely to be appropriate. It is least likely that storage at network level will be as efficient as more localised solutions.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

3.1 Interconnection is a tacit admission of inadequate local supply. Investment in local energy demand reduction measures would reduce the requirements for interconnection to supplement local supply, would reduce aggregate demand and promote security of supply and would be a more robust overall solution for the UK.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

4.1 Thermal storage has been used with District Heating Networks for more than two decades, for example, in Denmark, large-scale thermal store systems have been deployed to take advantage of liberalised electricity market and now almost all DH systems with CHP plant include heat storage[1].

4.2 In a number of European countries, heat networks are planned in a strategic way to integrate them into wider infrastructure. The City of Copenhagen’s district heating system is one of the world's largest, oldest and most successful, supplying 97% of the City with clean, reliable and affordable heating. Set up by five Mayors in 1984, the system simply captures waste heat from electricity production - normally released into the sea – and channels it back through pipes into peoples' homes. The system cuts household bills by 1,400 EUR annually, and has saved Copenhagen district the equivalent of 203,000 tonnes of oil every year - that's 665,000 tonnes of carbon dioxide[2].

[1] The potential for thermal storage to reduce the overall carbon emissions from district heating systems, Tyndall Centre for Climate Research

[2] For further details see, C40 Cities

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- **What role can changes to the market framework play to incentivise this outcome:**
  - **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**
  - **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**
- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

In our view, the key to ensuring that supply and demand are balanced at reasonable cost over the long term is stable policy and the use of market mechanisms and price signals to drive down costs. Some stimulus - subsidy - may be needed in addition of this to develop new technologies in order to meet low carbon targets but it should be tightly focused, restricted to only what is needed, and should supplement the market rather than replacing it. Policy should always prioritise the most cost effective measures, choosing lower cost options where these are available.

Those ideals are very far from what the current market framework currently delivers and this needs to change. Recent policies, in particular the Electricity Market Reform package embodied in the Energy Act 2013, have seen Government intervention in the electricity market become pervasive to the point where no power production technology can be brought forward without some form of public subsidy, whether low carbon (through contracts for difference or feed in tariffs) or high carbon (through the capacity mechanism). This dependence on policy stimulus rather than market signals distorts the market and creates investor signals to chase the investment that provides the greatest guaranteed return from Government rather than that which delivers the greatest benefit to society. Government in turn has adopted contracting procedures which are inefficient both in terms of prioritising higher cost measures where lower cost ones are available, and in failing to adequately introduce competitive stimulus into its procurement processes. The Competition and Markets Authority ('CMA') has suggested that the decision to award a majority of (existing) CfD funding 'outside the competitive process under the Final Investment Decision Enabling for Renewables scheme is likely to have resulted in higher costs to customers of approximately £250-£310 million per year for 15 years,'[1] building on similar criticism already expressed by the National Audit Office.[2] The CMA's energy market inquiry has also provisionally concluded that the Government's ongoing methods of allocating CfDs give rise to an 'adverse effect on competition,' expressing considerable concern that DECC is not supporting its decisions around the allocation of budget into funding pots for different technologies with robust evidence.

In its first CfD auction round, DECC allocated 80% of the available budget to the less established (eg more expensive) technologies pot. This trend to favour the most expensive technologies has since embedded further, as the Government has subsequently announced its intention to preclude new onshore wind projects from receiving CfDs and that the next CfD allocation round will see budget allocated exclusively to the less established technologies pot.

The consequences to consumers of banning cheap technologies and prioritising the procurement of expensive ones are potentially highly material. We commissioned NERA Economic Consulting to model the results of low carbon generation auctions both with and without onshore wind.[3] Its exclusion imposed significant costs on electricity consumers - around £0.5 billion over the term of the CfD auctions awarded in a single auction round. Because auctions may be repeated over a number of years, the eventual costs to consumers could be much higher. We also asked NERA to model what savings could be achieved if the technology pots were merged - eg that low carbon auctions simply focused on buying the cheapest low carbon generation it could. Applying that approach reduced consumer costs by around £1 bn, again, only in relation to a single auction round.

The absence of financial discipline in generation procurement decisions is coming at a significant cost to consumers. Given a budget during the last Parliament rising from £3.5bn this year to £7.6bn by 2020 to build new clean energy generation, DECC is already forecast to spend £9.1bn.[4] This overspend has forced DECC to scale back a range of policies during summer/autumn 2015 with consequential negative effects on

[1] 'Energy market investigation - provisional findings report,' CMA, 2015. http://tinyurl.com/hust94g
[2] 'Early contracts for renewable electricity,' NAO, 2014. http://tinyurl.com/h5uygwx
[3] You can find the results of its modelling on our website: http://tinyurl.com/zwr4o5n
[4] 'Written ministerial statement to the Lords on the Levy Control Framework,' 22 July 2015. http://tinyurl.com/q2jkqnd

investor sentiment and confidence in policy durability. This boom/bust approach is a lose-lose situation for both consumers and investors.

In our 2015 report, 'Generating Value', we analysed the effectiveness of current and recent past policies to stimulate low carbon generation and came forward with a range of recommendations for how policy could be improved to keep the lights on and meet carbon targets at lower cost to consumers. We recommended:

- The government should allocate the majority of CfD funding to the most currently cost-effective technologies.
- Instead of barring onshore wind from CfD allocation completely, government should instead lower the cap on strike prices (for example, by changing the previously set administrative strike price cap on auction clearing prices) to a level equivalent to the cost of new build gas generation.
- Any future decision to allocate funding to the less established technologies pot must be accompanied by a rigorous value for money assessment. DECC needs to start demonstrating the value (if any) of keeping the more expensive technology options open. If it cannot, they should not be funded.
- The criteria used to assess bill-funded low carbon deployment should be consistent across impact assessments. They should be heavily weighted towards reducing emissions at the lowest cost. Government can and must do more to quantify currently uncosted externalities given the size of investment it is committing to at consumers' expense.
- If job creation is the principal, or a major, consideration in the government's decision to stimulate a new project or technology, it should fund the job-creating proportion of any needed deployment support from general taxation.
- Where DECC proposes to award a substantive contract that has been bilaterally negotiated rather than competitively procured, it should publish a full impact assessment for consultation.
- As well as ensuring full impact assessments are carried out in future, the CMA should also demand full publication of terms in existing contracts that affect consumers' liabilities.
- The government should set an upper limit for subsidy per MWh as a stop-loss policy. It should degress over time. A medium term target trajectory should be published to allow investors to have confidence that they understand the terms on

which support will, or will not, continue. Competitive procurement processes for new low carbon contracts, such as auctioning, should continue in order to encourage developers to beat the degression curve and not simply to match it.

- Low carbon generation deployment and energy efficiency programme costs should be transferred from levies on bills into tax-funded programmes.
- Re-establishing energy efficiency policy in the wake of the cancellation of the Green Deal should be undertaken as a matter of urgency. Efficiency policies will be essential to mitigate the bill impacts of decarbonising generation. This should include targeting the successor to the ECO scheme towards fuel poor households, and designating energy efficiency as a national infrastructure priority.

We append that report to our submission and suggest that it provides a good starting point for informing your work on how to cost effectively stimulate new generation projects. [5]

We are open-minded regarding proposals to introduce an Independent System Operator ('ISO') function. In principle, we can see theoretical benefits in keeping the System Operator ('SO') and Transmission Owner ('TO') functions of National Grid bundled as they currently are. This is because we see some natural interactions between the two - TO is what you build, SO is how you use it. Trade-offs must exist between the two: eg investing in (TO) capacity (or not) should affect (SO) system constraint costs. As a consumer, one would want those trade-offs to be made in a way that reduces total costs and divorcing these functions into separate bodies could preclude or frustrate those trade-offs from being made. In practice, we acknowledge that theoretical benefit to keeping these roles bundled has not been as manifest as it could be in practice. While TO and SO functions are both price controlled they are subject to separate price controls which may impede the extent to which regulation drives efficient totex trade-offs. In addition to this, while the SO function is at GB level, TO is separated between England & Wales (also National Grid) and Scotland (Scottish Power and Scottish Hydro) which may constrain the synergies.

We think much of the current debate on whether or not there should be an ISO is driven by perceived conflicts of interest between National Grid's role as the EMR Delivery Body and as an advisor to government on issues like volumes to be procured through the

[5] 'Generating Value,' Citizens Advice, October 2015. Also available on our website: http://tinyurl.com/hl8zvmg

capacity mechanism, and the potential that government decisions made on that advice, or delivered through that role, could impact on its bottom line. If these perceived conflicts of interest were to crystallise, this could potentially have an adverse effect on the extent to which the market ensures that demand and supply are balanced at minimised cost. While we do not see evidence that the potential for conflicts of interest is occurring in practice, we recognise the arguments being made here and that this perception could affect investor, political or consumer confidence in the UK market.

We think that alongside consideration of whether there should be an ISO it may also be worth considering whether system balancing should remain the preserve of a single body acting at transmission level, or whether there is a role for distribution networks to take on such a role too - is it enough to have a TSO, or do we also need to develop DSOs? Volumes of (distribution) embedded generation have increased sharply in recent years, and much of the potential for demand side response and storage is also distribution rather than transmission connected. These changes mean that the balancing assets available to keep the lights on in future may not be transmission connected as they were in the past. While a single remote SO may be able to continue to call on such assets through new products and services, there may be a case that the distribution network they are connected to has a better view on how to operate those balancing assets in such a way that the total costs to consumers are optimised. Should DSOs be able to bid in to the balancing mechanism? Should they be able to procure balancing services in the same way that a TSO - whether independent or not - can?

While your consultation briefly mentions demand side management it only does so in the context of ‘new technologies’ and energy efficiency is not mentioned. This may suggest that you are only interested in new and novel demand side management technologies such as active demand side response and energy storage, and not more established markets like demand reduction through energy efficiency. We think this would be a mistake as energy efficiency has a potentially huge part to play in ensuring supply and demand are balanced at minimum cost. Energy efficiency has proven highly effective in reducing demand in recent years. Weather corrected domestic electricity demand dropped by 13% between 2008 and 2014, with a larger drop still in gas of 19%.[6] Much of this demand reduction will have been through measures that are far less cutting edge than those you are considering - loft insulation, boiler replacement etc - but they are also

[6] DECC Digest of UK Energy Statistics. http://tinyurl.com/pf9vrqv

low cost (when compared to subsidising large new power stations), low regrets and can deliver significant social benefits through helping to tackle fuel poverty and cold related illnesses. Energy efficiency is also essential if you are going to pay for large upstream infrastructure projects through bill levies - because reducing the volume of energy consumers use can counteract some of the inflationary pressures that subsidising power stations will put on unit prices. But government ambition here is low. The Conservative manifesto committed it to making one million homes more energy efficient in the 2015-20 Parliament - but this is a very significant drop on the deployment rate from the last Parliament.[7] The Green Deal has been scrapped and ECO2 is largely delivered with no replacement yet in place. In combination we are currently left with an unambitious energy efficiency target and a lack of credible policies to achieve even that limited ambition. The National Infrastructure Commission could usefully play a role in setting out a more ambitious pathway for UK energy efficiency policy to keep the lights on while minimising consumer costs. Ultimately the UK's buildings are its biggest single infrastructure asset - at the end of 2013, dwellings accounted for 61% of the UK's £7.6 trillion net worth[8] - it would be perverse if the NIC's work ignored our largest asset.

2. What are the barriers to the deployment of energy storage capacity?

- **Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?**

The market for gas storage is considerably more functional than the market for electricity storage. Gas storage assets built under the British Gas monopoly and since unbundled, combine with North Sea production, the gas interconnectors and expanding LNG import infrastructure to provide a robust security of supply environment. This has occurred largely absent any specific policy incentives or mandates for storage nor supply diversification. In particular, it has avoided the risk of 'oversupplying' storage. Consumers have not had to bear the costs of construction and operation of unneeded storage facilities, yet consumers' needs for reliable gas supply has been met, even during times where gas supplies in Europe have been disrupted. We see no reason for the government to change this market-driven approach to gas storage in upcoming years.

[7] For example: 860,000 major measures (boiler replacement, loft, cavity wall or solid wall insulation) were installed between October 2011 and March 2012. 'Left out in the cold,' Energy Bill Revolution and the Association for the Conservation of Energy, February 2015. http://tinyurl.com/pkue7en

[8] ONS, 'National Balance Sheet: 2014 estimates' http://tinyurl.com/gtetnbb

Electricity is very different. The technologies that can store electricity are either very new and expensive (including most prominently batteries but also more esoteric storage methods such as flywheels and power-to-gas storage), or very old and expensive (such as constructing pumped-storage hydro facilities).

The electricity market has evolved largely on the basis that electricity cannot be stored, or at least can only be stored at high cost and with low efficiency. The possible emergence of new technologies that can supply electricity storage much more cheaply, especially the reducing costs of large battery systems, fundamentally challenges many of the assumptions and market structures that currently exist. The commercial viability of proposed applications, such as arbitrage between periods of peak renewable energy supply and peak demand, under existing market arrangements is unclear.

The focus of policy should be on enabling efficient and cost-effective investments in storage, and not trying to push investment at any price. As is the case with gas storage, it is not simply that more is always better. Given the uncertainties around future costs we agree that the initial focus of policy assessment should be on removing barriers rather than developing additional funding mechanisms whose need is as yet unknown.

While we are not in a position to provide a comprehensive assessment of all such barriers, some examples may prove instructive.

For example, following unbundling initiatives at a UK, and subsequently at the EU level, network operators have been restricted from operating generation and supply assets. As costs of storage come down, there may be instances where it is cheaper for a DNO to add a storage system to a constrained network than to reinforce it in the conventional way. Yet present regulatory arrangements may preclude this. (There are other ownership models that may allow a storage facility owned by a third-party to provide an equivalent function, but it is unclear whether the current remuneration arrangements for DNOs would provide any incentive for them or a third party to participate in this way.) It is our understanding that these restrictions are under review in Brussels, with the European Commission and ENTSO-E considering the next round of electricity market legislation. The UK Government and Ofgem may also want to consider whether current unbundling arrangements would interfere with cost-effective deployment of storage options. A regulatory regime analogous to the one now in place for interconnection may facilitate the development of storage by networks but outside their regulated monopoly business, or under a cap-and-floor style regime that limit networks' ability to use their monopoly position to drive excessive profitability in a non-monopoly storage business.

Another instance where the regulatory treatment of storage could potentially dissuade new entry is in the charging for balancing services (BSUoS) charges. Storage operators face BSUoS charges twice - once when drawing from the grid to fill up storage, and again when supplying to the grid emptying storage. Conventional load or generation would only face one of these charges.

- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

It is too early to judge the scale that energy storage technologies could interact with the electricity system. It is quite plausible that it could play roles at all the levels suggested, working alongside wind farms and other intermittent generation on the transmission network, being used to avoid distribution grid constraints or reinforcements, and in household applications with electric vehicles, or in combination with solar PV.

At this stage in their evolution we see little merit in government trying to close off any of these options, or trying to steer deployment towards any particular application. Rather, the first stage in ensuring policy is ready for cheaper electricity storage should be to assess whether there are any regulatory barriers that would currently impede any of these applications, or which would distort incentives, such as those described in the response to the previous question.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- **Is there a case for building interconnection out to a greater capacity or more rapidly than the current ‘cap and floor’ regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**

- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

Interconnection can provide a valuable tool to the UK economy and to its consumers. As intermittent generation comes to form a higher proportion of total generation both within our borders and in neighbouring countries it can help to provide both with a balancing tool and a route to markets. Where the cheapest megawatt, or negawatt, is outside our borders interconnection can provide a route to deliver this benefit to UK consumers. Conversely, it provides export opportunities for our most efficient producers. Interconnection should also help to create deeper, more liquid wholesale markets, reducing total consumer costs. It is hard to see how a single european market could be completed without the integration of markets facilitated by interconnectors.

Notwithstanding these benefits, we are unconvinced there is either a need to prescribe a certain amount of electricity interconnection or a case to conclude that current arrangements will leave us short of the interconnections we need. It is often pointed out that the UK has lower levels of interconnection than the European average, and than the EU's (non-binding) 10% target, but this in part simply reflects a wider trend that is driven more by physical or political geography than market (or policy) signals. Low levels of electricity interconnection are a characteristic of the geographically peripheral EU states - of the 11 EU Member States who fall below the 10% interconnected capacity target, four are islands (the UK, Ireland, Malta, Cyprus), three are peninsular (Italy, Portugal, Spain) and another three are largely physically separate from the rest of the EU (Estonia, Latvia, Lithuania). A flat (10%) aspirational target is never likely to represent the geographical practicalities of individual member states.

According to the European Commission, interconnectors accounted for 6% of the UK's electricity capacity in 2014.[9] There is 4GW of current UK interconnector capacity, of which 1.5GW (37.5%) has entered service in the last 5 years (a 1GW link to the Netherlands and a 0.5GW link to the Republic of Ireland).[10] Another 7.3GW is planned by 2022. It is possible, perhaps likely, that not all of those prospective projects will come to fruition but if even half do the UK should meet the 10% target. This large volume of interconnected capacity either

[9] 'Achieving the 10% electricity interconnection target,' European Commission, February 2015. http://tinyurl.com/j55xmg2
[10] 'Electricity interconnectors,' Ofgem. http://tinyurl.com/jodw2nk

recently built, or in the near term pipeline, suggests that current market arrangements and policies are not a deterrent to interconnectors coming forward. This does not signify that arrangements are perfect and the NIC may be able to identify incremental improvements to the regime. But we would caution it against starting from a position that assumes major reforms are needed to bring forward new interconnection; it is not clear that the evidence supports such a view.

While not necessarily a deterrent to new interconnections - indeed, it may actually stimulate them because it may create arbitrage opportunities - it is worth being aware that the UK's decision to impose a unilateral carbon floor price may distort cross border electricity trading. UK power generators face a higher carbon price than those in our interconnected markets in Ireland and mainland Europe. This may give generators outside our borders a competitive advantage compared to indigenous generation and may undermine the case for investment in UK thermal generation. This problem may get worse if the carbon floor price ceases being frozen and returns to the year-on-year 'escalator' that was envisioned for it on introduction.

"4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?"

No comments.

National Infrastructure Commission call for evidence, November 2015

Memorandum from the City of London Corporation
Response to Question 4: Electricity interconnection and storage

Introduction

1. This submission provides the City Corporation's views on the need for greater regulatory flexibility and more targeted investment and calls for better planning of the delivery of capacity in the system. The submission concludes with a suggestion for a new approach to the capacity problem.

2. The City Property Advisory Team at the City of London Corporation works alongside developers, utilities and telecoms providers in ensuring that the Square Mile provides the optimum environment for existing and new businesses. It is in the context of the City's role in promoting the Square Mile as a world leading hub for business, that the City of London Corporation makes this submission.

3. The Square Mile directly competes with other cities to be the premium destination for global business. One part of the City's, and London's, attractiveness to international business is the ability to provide the highest quality commercial buildings and services. A significant factor working against London's position is exemplified by a recent World Bank Report which placed the UK as the 62nd out of 184 countries for getting an electricity connection on time.

4. The City of London's area has the largest electrical footprint (over 600 megawatts) in the UK and demand for electricity in the Square Mile has greatly increased in recent years, owing, for example, to the widespread use of power intensive IT equipment and cooling systems.

Lack of Capacity

5. UK Power Networks (UKPN) is the District Network Operator (DNO) for London. It is clear that its network in London does not have available spare capacity to cope with future demand. This poses risks to future development and refurbishment cycles because developers and property owners are unable to be sure of the availability of electricity capacity. Further uncertainty results from the fact that it can take up to 3 years for substations to be reinforced and installation works completed so as to have sufficient capacity to supply a new building.

6. Given that Ofgem's existing regime does not incentivise investment ahead of need, new connections generally occur on an ad hoc basis, responding to immediate demand. The difficulty of creating such new connections at the last minute is hampered by the physical characteristics of the City (such as utilities congestion under the highway. This is a further factor that creates uncertainty and results in a lack of capacity in the system.

Resilience and Security - Generation

7. Recent research[1] undertaken by the British Council for Offices has outlined that the forthcoming closure of the UK's legacy generation plant and lack of available new sources of generation has increased the likelihood of blackouts from 1 in 3,307 years in 2012 to 1 in 12 years in 2015. Moreover, the sector's regulator, Ofgem, does not incentivise DNOs to modify and improve aging network assets. The City Corporation is concerned that a possible "black start" - where supply is suddenly unavailable across the whole of a network and needs to be restored - would severely affect the Square Mile and its ability to continue to operate as a business centre. We are also gravely concerned about the effect that such an event would have on London's reputation.

Network Resilience / Power Network Distribution

8. As a regulated monopoly, UKPN is obliged to carry out a price control review every 8 years, which involves submission of their business plans to Ofgem, to determine future investment plans, and the overall revenues that UKPN is permitted to recover from customers. Under the latest price control review process, UKPN is required to consult with stakeholders and ensure that their views are represented in the final business plan. As part of UKPN's consultation, the City of London provided information to UKPN on likely forthcoming developments. After considering the draft business plan produced at the end of this process, the City concluded that UKPN's investment plans for the period 2015-2023 (which included the reinforcement of 6 existing substations serving the City of London). Whilst UKPN received considerably less funding than expected from Ofgem's final determination, it is understood that the planned level of new capacity will be sufficient to support forthcoming development activity in the Square Mile for the next 10 years. It is therefore the timing of investment that remains key.

9. The City Corporation is concerned that Ofgem's reduction in UKPN's proposed funding could affect UKPN's plans for investment in greater network automation enabling the provider to switch power between substations and thus avoiding loss of supply to businesses and residents. Investment in such automation would do much to provide a more robust network for Central London.

10. In a further aspect of its final determination of UKPN's business plan, Ofgem has reduced the amount of expenditure that UKPN will be allowed to make in installing deep level tunnels to house critical 132kv transmission cables. These operate at high voltage and deliver power to substations from the National Grid. If, because of Ofgem's determination, UKPN is required to take the cheaper route and install such cables under the public highway, there would be a serious negative impact on traffic across London. In addition, placing such heavily powered cables under the public highway could pose

[1] http://www.bco.org.uk/Research/Publications/Britains_Energy_Gap.aspx

considerable risk of catastrophic district wide network outages should one of the cables be disturbed by any of the many utilities companies that regularly dig up the highway.

11. Following UKPN's final determination, it is understood that new investment in central London has recently been constrained due to an appeal lodged against UKPN's 2015-2023 settlement by a third party energy provider. This matter needs to be resolved as soon as possible to avoid any impact on delivery of energy supplies to key strategic development sites across central London.

Size of Connection

12. The planning process for large developments can take many years. In an ordinary case, for example, it will take about 3 years. During the planning stage for large office buildings in central London, there are often difficult negotiations with UKPN over the availability of power supply to the building. These negotiations arise for two reasons: (i) there is very little spare capacity in the system; and (ii) the work required to reinforce a substation such that it is able to supply the required amount of power often takes longer than the design and build of an office block.

13. A separate problem arises because there appears to be an unknown amount of reserved capacity on the network which is currently unused. Some of the larger buildings in the Square Mile are now requesting up to 15MW, enough electricity to power a small town, which is largely to cater for trading floor operations. Developers (whether in relation to new build or to refurbishment) are likely to request large amounts of capacity because, given the difficulty of obtaining supply in a timely manner, they cannot sure what type of tenant is likely to occupy the building and so hedge their bets. The additional cost of reservation charges is borne by the business because they regard it as a way of mitigating the severe difficulty and uncertainty surrounding a future request for the supply of electricity.

14. UKPN has confirmed to the City Corporation that UKPN would consider a scheme where capacity could be sold by a building back to UKPN for use elsewhere on the network. UKPN maintains, however, that it is constrained from progressing this idea because the existing regulatory regime prevents it from engaging in such arrangements.

15. The City Corporation considers that, given the scarcity of available capacity in substations serving the Square Mile, UKPN should be permitted to take an active role in policing the size of the connections which developers and occupiers are able to retain when it is beyond their requirements.

16. UKPN should adopt the model used by Consolidated Edison, the electricity network operator for New York City, whereby developers are told what size connection they are allowed based on industry standard formula (10Kilowatts per sq m), and the amount of capacity taken is therefore dictated by a calculation of watts per square metre of the whole building. Developers are

able to reserve extra capacity for future expansion, if they agree to pay the cost of additional power at the start. Network capacity is, however not reserved, and Consolidated Edison will agree to invest in the network to create the additional capacity at an agreed point in time, providing the developer exercises the option for additional power at a contracted point in time. If the developer does not exercise its option, Consolidated Edison retains all monies paid by the developer and the capacity is released for use by other customers.

Investment ahead of need / timing of investment

17. The scenario set out above leads the City Corporation to conclude that there is a failure in the regulatory framework that prevents DNOs investing ahead of need. The City believes that in an area with the largest electrical footprint in the UK investment ahead of need should be permitted.

18. The City of London, London First and the City Property Association commissioned the "Delivering Power" study[2] in April 2012 which found that UKPN is not incentivised to invest ahead of need under Ofgem's current regime. The existing system promotes a "just in time" approach. The failure to allow investment ahead of need constrains developers' ability to ensure network capacity for new developments. Consequently, businesses and developers suffer from uncertainty in crafting their business plans, delays to new developments and risks to their business.

19. Together with Westminster City Council, GLA, City Property Association, Westminster Property Association and London First, the City Corporation has engaged with UKPN to feed into their business plan and called for central London to be allowed greater flexibility in investing in spare capacity.

20. In August 2013 the City submitted to UKPN's business planning consultation details of forthcoming developments in the Square Mile. The timing and distribution of the investment remains key - to ensure that capacity is delivered in a timely manner so that it does not pose risks to the delivery of new development. There must be better predictability of UKPN's investment path. The City Corporation's planning policy, in its 2015 Local Plan, requires developers to engage with UKPN as soon as possible. Developers must include the building's likely electricity footprint in the planning application so that this information can inform UKPN's future demand modelling for network upgrading. This approach can make, however, only a limited impact on the overall problem.

21. Engagement, by the City Corporation and others, with developers has shown that they are willing to pay more if it means that their connections will be delivered faster. In certain cases developers are prepared to pay for full reinforcement of substations, despite only using a fraction of the new reinforcement and accepting that refunds (calculated on subsequent use by other parties) may be paid at a much later date. This highlights how desperate

[2] http://www.cityoflondon.gov.uk/business/economic-research-and-information/research-publications/Documents/research-2012/Delivering%20Power.pdf)

developers are to secure electricity supplies for their building. It is therefore likely that developers would support any future developer-funded proposal to facilitate investment ahead of need.

22. Ofgem has argued that DNOs can invest ahead of need under Section 22 of the Electricity Act 1989. This provision allows developers to act as a consortium which may be effective on brownfield sites where there are 3 or 4 major developers, but it would not be practical in areas such as the City of London or other urban areas where there is a high level of continuous growth and with, for instance, over 70 developers operating across 120 development sites with varying timescales and developers requiring electricity connections at different times.

23. The City Corporation supports the Mayor of London's representations to Government on investment ahead of need, which led to Ofgem's "Quicker and more efficient connections" consultation in March 2015. This consultation brought forward good suggestions for addressing the issue of investment ahead of need. Whilst the City broadly supports incentives which could allow DNOs to make investment ahead of need in areas where there is an expected high level of development growth, some of the proposals required UKPN to seek Ofgem approval and for Ofgem to publicly consult on the location and level of investment being made. This is likely to be a protracted and cumbersome process for developers to manage, (for whom time is key). It is therefore unlikely that any developer would await the outcome of a public consultation to find out whether they have sufficient electricity supplies for their development as it would present too big a risk to their project. For this reason, the model would only be suitable for developments in areas where there is no spare network capacity in (or plans to upgrade) any of the surrounding substations and no other obvious immediate connecting customers in the surrounding area. It is highly unlikely that this model would be able to be adopted in the City of London given the continuous cyclical nature of development and differing timescales of developments which would mean that the need for consultation on investment would be too time consuming and present too many risks to timely investment and delivery of power supplies.

24. The consultation also suggested private investment in the form of a "DevCo" proposal that would be able to investment in new capacity. The City of London felt that this arrangement would give the DevCo inappropriate powers and the DNO onerous responsibilities in selection of development types which could benefit from reinforced infrastructure. The proposal would cut across the existing regime for planning new infrastructure (through the Community Infrastructure Levy), which considers a wide range of factors in consideration of the types of schemes which are appropriate in a given location, and would be inappropriate. DNOs in particular could be seen to be acting outside of their remit given that they are bound by existing regulation to not discriminate between those requesting connections.

25. The City of London welcomes Ofgem's findings from this consultation, however the starting point for the verification of any case for investment

ahead of need will be a clear overview of available DNO substation capacity in areas of high development growth. Regrettably this data is currently unavailable. Ofgem and the Government should ensure that DNOs make this information publicly available. It would be important to consider this data alongside information from developers, market details and Local Authority information (in London at the GLA level as well as at borough level) in determining appropriate areas. The City, for example, has robust information on the timescales of forthcoming developments.

26. The City has met with Ofgem and suggested that the link between local authorities and DNOs should be restored to allow UKPN to be able to compare future investment with local authorities' development projections, to coordinate connection works more effectively, and install spare ducts in areas of expected need. Areas such as the Square Mile benefit from high levels of continuous development growth and the City maintains a development pipeline that can pinpoint where large loads will occur. Based on this suite of information it can be argued that there will be a very high utilisation of investment in capacity ahead of need in such areas.

City of London Corporation
January 2016

The Prince of Wales's Corporate Leaders Group

National Infrastructure Commission – Call for Evidence

The Prince of Wales's Corporate Leaders Group is pleased to provide a response to the call for evidence. Please find a short introduction to the Group followed by our response, concentrating in particular on the third challenge to improve how electricity demand and supply are balanced.

The Prince of Wales's Corporate Leaders Group (CLG)

The CLG is a select club of European business leaders working together, under the patronage of The Prince of Wales and with the support and advice of the University of Cambridge Institute for Sustainability Leadership, to advocate solutions to climate change to policy makers and business peers at the highest level, both within the EU and globally.

The CLG members are committed to working towards business models that are compatible with the global emissions trajectory required to keep cumulative emissions below one trillion tonnes of carbon from manmade CO2, thus striving to limit global temperature rise to 2°C. CLG members are committed to playing a leadership role in securing a just, low carbon transition, both in terms of changing their own businesses and sectors, and advocating change in the wider economic and political context. At a minimum the CLG supports the goal of achieving net zero emissions globally well before 2100, and "at least" 40 per cent emissions reductions overall by 2030 and at least 80 per cent by 2050 EU-wide.

The CLG seeks to deliver its goal through bringing European business leaders together to advocate for policy change in relation to climate change and a low carbon transition, drawing on high-level convening, thought leadership, business innovation and new partnerships as required.

The CLG is composed of major companies including market leaders and household names that are representative of the majority of EU member states. It is deliberately composed to represent a broad cross section of business sectors, including service providers, retailers and consumer goods companies, infrastructure operators, energy generators, energy producers, energy intensive industries, advanced manufacturing, and technology suppliers.

The Prince of Wales's Corporate Leaders Group (CLG) is an initiative of the University of Cambridge Institute for Sustainability Leadership (CISL). CISL is not a member of the CLG but provides the secretariat to it[1]. For further details on the CLG's activities and plans please see http://www.corporateleadersgroup.com/ .

[1] Decisions of the CLG do not represent the policies or positions of CISL or of the wider University of Cambridge

Consultation Response

Over the next 15 years nearly £60trillion will be invested in global infrastructure in urban, land-use and energy systems. Resource efficiency, infrastructure investment and innovation are key drivers of a new low-carbon growth model.[2]

As business leaders, our interests are aligned with the future of the UK economy, and we believe that the future could be bright. The UK has world-leading expertise and capacities in innovation, engineering, finance, and business that provide the foundation for leading the global transition to a sustainable, resilient and low carbon economy that would create jobs, prosperity and growth. As major UK businesses, we are playing our role by investing in new resilient, low-carbon infrastructure, goods and services, but a new economy will only by realised if government actively works with us to deliver this transformational change. This means a strong and stable policy framework, consistent rhetoric, and making the right choices about the infrastructure we plan to build, the way we intend to run it, and the incentives faced by business.

We believe there are four key characteristics of a prosperous and sustainable economy:
1. A secure, efficient and decarbonised power sector
2. A resilient, efficient and low carbon built environment
3. An integrated and secure transport system that enables ultra-low carbon choices
4. Sustainable consumption patterns that are supported and encouraged by policy frameworks, business models and supply chains.

The Corporate Leaders Group would like to emphasise the need to embed resilience to extreme weather and climate change into UK national infrastructure, all plans must look to reinforce and actively compliment UK decarbonisation in line with long term climate goals.

[2] 'Better Growth, Better Climate', The Global commission on the Economy and the Climate, September 2014

National Challenge 3

The future of UK energy infrastructure will be defined by a broad range of national and international trends and risks including: the Carbon Budgets; the EU Energy Union; European grid interconnection; the falling cost of renewables; resource price shocks; the Post-Paris international climate change regime; the electrification of transport and heat; and political pressure to control or reduce prices.

We advocate that advancing efforts to address this challenge will need the Commission to ensure that it invests in its ability to exploit synergies across technologies, sectors and national borders, that it remains alert and flexible to opportunities and that it empowers those who control demand to be able to decide on relevant infrastructure. Future UK electricity and energy systems should be considered with a holistic infrastructure view, not contemplating electricity, heat and transport as separate and unconnected systems. Integration of these energy vectors is a necessary step towards decarbonisation; infrastructure development has to recognise this assimilation.

The UK Climate Change Committee (CCC) develops common, consistent and robust scenarios to underpin all infrastructure planning. Bodies such as UK Foresight show how complex and uncertain trends and technologies can be assessed in an open and participatory way so as to inform a comprehensive strategy.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The CLG recognises that in efforts to balance supply and demand in the long term whilst minimising costs to consumers the Commission should recommend reforms that are likely to correct predicted imbalances in the 2020s at the lowest costs. Responding to these predictable future uncertainties requires an ability to understand and manage demand, integrate across infrastructure systems, build-in flexibility and preserve optionality.

The CCC's lowest cost decarbonisation scenario through to 2030 shows interconnection, demand response and storage deployment significantly increasing system flexibility. They have demonstrated that the lowest-cost trajectory to the UK's legally binding carbon targets requires that the carbon intensity of power generation decreases from around 450 gCO_2/kWh in 2014 to 200- 250 g/kWh in 2020, and to below 100 g/kWh in 2030[3]. Under this lowest-cost trajectory low-carbon generation reaches a total share of around 75% of generation by 2030. The CCC's analysis shows that the demand side has an important role in increasing the flexibility of the power system, alongside interconnection,

[3] Committee on Climate Change, Sectoral scenarios for the fifth carbon budget – Technical report, November 2015, https://www.theccc.org.uk/publication/sectoral-scenarios-for-the-fifth-carbon-budget-technical-report/

storage and flexible back-up capacity; supporting the Commissions initial focus on lowest-cost balancing[4].

Recent policy changes have removed all public investment in carbon capture and storage (CCS) development and deployment creating a very significant barrier to lowest cost balancing which the Commission should address in its recommendations to Government. The Department of Energy and Climate Change and the CCC conclude that a major deployment of carbon capture and storage (CCS) technology in the first half of the 2020s will drive down costs by reducing the requirement for low-carbon new generation. The Commission should draw on the expertise of the CCC and the Department of Energy and Climate Change to insure that it is addressing current and future balancing challenges rather than those that have already passed. If the Government chooses to ignore the changes to the UK energy system predicted in its own scenarios, and specified in its legally binding Carbon Budgets in order to simplify decision making today there is a high risk of policy failure; policy designed to address the balancing challenge of today will fail to address the very different challenges of the 2020s.

- *What role can changes to the market framework play to incentivise this outcome:*
  - *Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?*

  - *Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?*

- *To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?*

The potential for consumers to respond to price signals and adjust demand is currently unknown but may be a very significant and cost-effective alternative to achieving system balance through supply side measures. The Commission should consider initiating or recommending a fundamental review of the issue of consumer engagement in the context of maximising the potential for demand flexibility and the decarbonisation of heat. The current market is based on the presumption that consumer engagement should be driven by price and price alone. Whilst there is likely to be a proportion of consumers, particularly those that are large or sophisticated, that will respond to price, many will not despite the low levels of effort required.

[4] 'Flexibility is important. To maximise the value of these investments and ensure security of supply it will be important to improve the flexibility of the power sector. That will require investment in flexible gas-fired generating capacity alongside expansion of international interconnection, flexible demand response and potentially electricity storage. The costs of these measures are included in our assessment of intermittency and system costs.' Committee on Climate Change, Power sector scenarios for the fifth carbon budget, p7, October 2015, https://www.theccc.org.uk/publication/power-sector-scenarios-for-the-fifth-carbon-budget/

2. What are the barriers to the deployment of energy storage capacity?

- *Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?*

At present, energy storage does not provide the most efficient means to help balance the energy system when compared to demand side response, interconnection or generation. Energy storage systems are currently technically immature but have the potential for significant cost reductions over the coming years and decades.

Driving forward these technical developments requires new and additional R&D investment but also a programme of deployment to deliver 'learning by doing'. This, in turn, might require system operators, both at transmission and distribution level, to take a long term perspective on the potential benefits for cost efficiencies. These considerations must therefore be included within the relevant regulatory and incentivising frameworks.

- *What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)*

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Evidence suggests the UK is currently under-connected with its neighbours and significantly greater levels of interconnection would be in the interests of consumers. The current wholesale price of electricity in the GB market is double the price of the German and Nordic electricity markets. Greater interconnection should lead to greater price convergence, including lower costs for GB consumers.

UK interconnection capacity represented only 6% of installed generation capacity in 2014. This puts the UK 21st out of 28 member states. In 2002, the European Council (including the UK) agreed a target for member states to reach interconnection capacity equivalent to 10% of installed generation capacity. The UK is unlikely to meet this level until 2021, 19 years after it was first agreed.

Interconnection is a strategic system resource. It plays four key functions to support the interests of UK consumers:

- First, greater interconnection between GB and European markets can enable optimal use of existing generation assets, meaning the most efficient plant are used first – lowering costs to consumers
- Second, interconnection across European markets can enable new generation (and/or demand) to be sited in the most optimal locations – for example for wind power to be located in the windiest regions and solar PV to be located in the locations with the most solar irradiation.
- Third, interconnection can act as a flexibility resource, to facilitate the integration of variable renewable generation.

- Fourth, interconnection can support energy security across asset replacement cycles – meaning the UK can import power when margins are low (as at present) and have the potential to become an electricity exporter in the future.

In this context, determining the best value interconnection level for consumers requires an assessment of the full system benefits, including enabling role interconnection plays in the energy transition - not just price differentials.

Interconnectors are long-term infrastructure. In a rapidly changing electricity system with major shifts to both generation and demand, the UK is unlikely to have completely optimal interconnection capacity at every moment in time. However, given the role of interconnection in creating system options and managing risk, underinvestment in interconnection may be more damaging to UK consumer welfare than overinvestment.

In recognition of the value of interconnection in developing the internal energy market, in October 2014 the European Council agreed a target for countries to achieve 15% interconnection capacity by 2030. This target helps to provide forward certainty for the industry as well as adding a political focus on moving investment forward. The 15% target should be seen as an appropriate minimum level of interconnection capacity for the UK to achieve by 2030, with further interconnection capacity developed if needed.

- *Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?*

The 2020s will see the continuing convergence of investment in building efficiency, electricity and gas infrastructure, and the beginning of the integration of electricity and transport systems. It will be impossible to make a credible case for future energy investment without a clear assessment of the impact of regulation and public investment on future demand. This must include assessment of international power resources as the UK grid will be increasingly balanced at European scale, drawing on Norwegian hydroelectric, Irish wind and Spanish solar power[5]

[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/68816/216-2050-pathways-analysis-report.pdf

- *Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?*

Interconnection faces specific barriers and challenges that are not faced by other balancing technologies. It is cross-border by nature, which means dealing with multiple jurisdictions and plays multiple roles in the energy system beyond system balancing alone.

Realising the benefits from more coordinated and strategic grid planning and interconnector system balancing requires the Commission to make significant political and regulatory reforms.

- Political reform can be achieved by refocusing political engagement with neighbouring countries to explore opportunities to co-operate on energy system planning and low carbon resource sharing. This should include bi-lateral discussions with key neighbouring countries and placing a strong mandate on the North Seas Countries Offshore Grid Initiative to exploit the opportunities associated with developing an offshore network.
- Regulatory reform requiring Ofgem to reform the regulatory system for onshore and offshore networks and interconnections to ensure effective co-ordination across the regimes as well as realising the full value of creating options to manage future uncertainty.

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Lord Adonis
National Infrastructure Commission

4th January 2016

Dear Lord Adonis,

Home energy efficiency infrastructure opportunity

I am writing to add my support to the briefing which has been submitted by Energy Bill Revolution and the UK Green Building Council. Their briefing paper titled 'Fixing the roof while the sun is shining' highlights the home energy efficiency infrastructure opportunity which is presented by the country's move towards decarbonised heat.

Community Energy Plus is a charity and social enterprise providing services to help householders and communities in Cornwall to enjoy warmer, more energy efficient homes. Up until 2014, a significant focus of our charity's work was centred on the delivery of energy efficient home improvements and we are proud to have installed loft and cavity wall insulation and heating improvements in over 25,000 Cornish homes.

We believe that the government has previously taken a 'one size fits all' approach to the design and delivery of energy efficiency initiatives which have failed to meet the needs of rural housing stock. Successive schemes have focused on delivering the most cost effective measures and have not tackled the problem of improving the energy efficiency of homes with solid walls, which account for 35% of the Cornwall's housing stock.

Cornwall currently ranks as having the twelfth worst problem with energy affordability in the country due to a combination of low incomes, a high number of homes with solid walls and high proportion of properties which are not served by the gas network which are reliant on expensive forms of heating. The latest report on fuel poverty in England has shown that 14.4 percent of households in Cornwall, which is almost 35,000 homes, have above average energy costs.

Community Energy Plus strongly believes that energy efficiency needs to become a UK national infrastructure priority and be allocated sufficient funding to make cold homes and fuel debt part of our history, with assistance prioritised to the most vulnerable in our society.

I would therefore like to take this opportunity to echo the call made by the Energy Bill Revolution and the UK Green Building Council for the National Infrastructure Council to carry out a full investigation as soon as possible to investigate the opportunity to improve the energy efficiency of the UK's housing stock as a crucial part of the infrastructure that is required to de-carbonise heat.

GREEN DEAL APPROVED Assessor* Reg No. STRA10151 *Domestic

Yours sincerely,

Dr Tim Jones
Chief Executive
Community Energy Plus

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8th January 2016

Dear Andrew

National Infrastructure Commission call for evidence - Delivering future-proof energy infrastructure

I am writing in my role as portfolio lead of the Core Cities Low Carbon, Energy and Resilience Policy Hub.

First of all, on behalf of the Core Cities, I want to welcome the establishment of the National Infrastructure Commission. It comes at a critical time in unlocking future investment to enable our UK economy to plan, grow and deliver sustainable and inclusive growth over the long term.

Our Cabinet members would be keen to meet with you and other members of the National Infrastructure Commission to help inform both the current and future stages of work and consider the vital role that Core Cities (and wider City Regions) can play in the delivery of the Commission's objectives.

The Core Cities Cabinet will be meeting in Sheffield on Tuesday 26th January, which we would be delighted if you could attend. If this is not possible, then please advise if there is another suitable date.

Our response below sets out our view on delivering future proof energy infrastructure, recognising also that the separate Transport for the North Board will respond to the challenge of improving connectivity between Cities in the North of England.

However, we would also like to make some more general points with regard to future infrastructure investment that we feel are critical in terms of enabling long term planning and ensuring future resilience; also taking into account the discussions and commitments made at this year's COP21 deal in Paris. These include:

Ensuring climate resilience is assessed and included in all planned investment – Following on from the recent flooding in the North of England and elsewhere, as well as the number of disruptions to transport during a number of extreme weather events in 2012, 2013 and 2014; the National Infrastructure Commission needs to embed climate change adaptation appraisals as part of its investment approach. The Parliamentary Office of Science and Environment cited in 2014 that estimated annual damages from flooding were in the region of £1.1bn a year in England alone. Failing to account for climate change when seeking to rebalance the economy risks undermining the very ambitions we are working towards for the long term.

Transport for the North of England – The Department for Transport's resilience review identifying and addressing a range of transport issues to build a more reliable and resilient transport system. Globally, cities are recognising that there is a need, wherever possible, to encourage sustainable transport options to reduce carbon, but they are also inherently more resilient. Greater investment and co-ordination of transport offers strong opportunities to manage extreme weather better, but needs an enabling framework which places this need for a climate resilient transport system at the heart of transport policy. Additionally (going forward from this initial phase), we would like to see this extended to **Support for all UK pan-city region transport projects** that are sustainable, affordable and provide real economic, social and environmental benefit at both a national and local level.

Balancing Energy Supply and Demand – In a similar vein to transport, the transition to a low-carbon economy will inevitably involve a diversification of supply and demand. Our energy sources will comprise a range of renewable and low carbon sources, as well as technologies to manage them, such as smart grids and storage. In essence this creates a broader resilience, allowing the grid to manage disruption from extreme weather. . However our current energy management structures, regulations and organisational frameworks need to be reviewed to ensure that they are fit to deliver a long term planned approach to national, regional and sub-regional supply and demand.

In recognition of the general direction of travel towards greater devolved powers for local government and the benefits of a more holistic approach, we would like to suggest that Core Cities should have the opportunity for involvement in the decision making process around current/future infrastructure policy and service delivery, including at City Region level and through for example a duty to co-operate. We would be happy to elaborate on this and any other points in any future discussion.

In the first instance, our views, specifically in relation to delivering future proof energy infrastructure are set out in the attached appendix.

We look forward to the opportunity to discuss this further.

Yours sincerely,

George Ferguson CBE
Mayor of Bristol
Portfolio Lead for the Core Cities Low Carbon Energy and Resilience Policy Hub

Appendix

Overview

The Core Cities strongly support the establishment of the independent National Infrastructure Commission and the inclusion of the energy infrastructure as one of the first priorities. However, we believe that energy infrastructure also needs to be seen and considered in a holistic way. At a local government level we see and have to respond to the outcomes of the various interconnected elements, as the following three examples demonstrate:

- Vulnerable households living in inefficient homes, which they cannot heat, or power. This creates additional demands on health and social care services and reduces quality of life for residents.
- Failure to invest in low carbon / decarbonised transport systems at the pace that we need within cities and their natural hinterland and between cities, leading to the associated economic and health consequences.
- No requirement for the statutory utilities to link their infrastructure investment with our economic growth plans, leading to the associated economic and social consequences.

Therefore, while we have responded to the detailed questions as asked in the consultation report later we would like to set the context of the Core Cities approach to sustainable growth and reducing social inequalities, and the infrastructure investment and approach that is needed to enable this is happen.

Resilience

The development of new infrastructure should be undertaken with a full resilience audit, not limited to but including; how the new infrastructure will meet the challenges of climate adaptation, i.e. more frequent extreme weather events, how the new infrastructure will support the UK resilience to geo-political events, e.g. not relying on security of supply from unstable regions or governments and how the new infrastructure will support the UK resilience to terrorist attack? Consideration should also be given to current existing energy assets, such as electricity sub stations, many of which were previously built in areas with high level of flood risk.

All these questions suggest a more decentralised, embedded and diversified form of energy production, storage and interconnectedness; not only geographically, but also between systems; heat, electricity, transport, water, waste and digitally and between regulatory entities especially at the city region level to ensure efficiencies in the investment provision and decision for infrastructure construction.

Efficiency

The development of infrastructure should be considered in the context of efficiency. The Core Cities strongly support the UK Green Building Council's response to the National Infrastructure Commission's call for evidence. We suggest that energy efficiency investment in UK homes should be seen as an infrastructure investment. In addition to the UK Green Building Council's well evidenced response for a wide-scale and deep retrofitting of energy efficiency measures to homes, the Core Cities would like to see a national infrastructure approach to the provision of heat networks. The provision of heat networks allows the delivery of heat to be undertaken in the most efficient and low carbon manner, while improving the overall efficiency, resilience and capacity of the UK energy system through the increased use of combined heat & power plants on heat networks.

Environmental standards

The provision of the infrastructure as outlined in the National Infrastructure Plan 2014 amounts to £466bn, in addition this call for evidence is likely to increase the level of investment by many further tens of billions.

The Core Cities advocate that during the design and construction phase whole life-cycle environmental impacts assessment are undertaken and that high environmental standards are built into the tender and design specifications. The opportunity to achieve high environmental standards on the design, construction and ongoing usage on such a scale of investment will impact positively on developing the necessary UK industries, skills and knowledge about how society will live in a very low carbon / decarbonised world. This is a set of skills and knowledge that the UK can export across the globe.

Interconnectedness

The provision of the future infrastructure that will ensure that the UK can compete in the global economy, contribute to reducing climate change emissions and be resilient to the future local and world extreme events, suggests that the various strategic infrastructure investments be coordinated. Currently this does not happen successfully in the UK and is invariably ad hoc.

As an example, the provision of increased demand side management of the electricity network at a local level, through the provision of smart metering and in-home management systems could also support the development of smart city improved transport management, waste management and heat and electricity storage and capacity solutions. However, because the UK has system regulators; Ofgem, Ofcom, ORR, Ofwat, Environment Agency, Natural Resources Wales, central and local government, this makes the coordination difficult. Core Cities have long advocated that we can take the local lead, responding to the local circumstances of each of our cities and its region. However, currently we have no mechanism to enable this to happen; if we did have a mechanism we suggest that we would enable the provision of more interconnected diverse future proofed infrastructure investment quicker.

Response to Consultation Questions (Energy section 4.1)

1. ***What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?***

   - *What role can changes to the market framework play to incentivise this outcome:*

     - *Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?*

     - *Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?*

   - *To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?*

Response Q1

With regard to the question: What role can changes to the market framework play to incentivise this outcome?

We consider changing the market framework to ease coordination could have a positive impact. As previously mentioned we would strongly argue that there should be a duty to cooperate on other infrastructure providers to ensure that their investment plans interface with the growth and economic plans of the city region.

With regards to the second bullet point; Core Cities recognise that we can and could play a significant positive approach to assisting the development of demand-side measures on the local electricity network and increasing the take up of embedded generation systems.

Demand side management and embedded generation will be key to a flexible and robust electricity system in the future. Micro generation at the local or community level will form part of the energy mix underpinned by a centralised base load of gas/nuclear generation when required. Wherever possible embedded generation linked to energy storage will be able to increase the length and frequency of demand side management, allowing the National Grid to increase the flexibility of the energy system.

Set out below is an example of where we are currently doing this and with further support and access to infrastructure funding and local mechanisms, this could be accelerated.

Bristol City Council Community Energy Fund

To assist local embedded generation, Bristol City Council, supported by DECC, has developed an approach with community groups and social investors to enable them to invest in installing embedded generation on Bristol City Council's land and buildings, or investing in Bristol City Council's energy generation projects. One of the key aspects to the project is the requirement for the project to negotiate a Power Purchase Agreement with Bristol Energy, a 100% Bristol City Council owned licensed energy supplier.

In addition to the example above, Liverpool, on behalf of the Core Cities, have been working with Government and their network operator over the last eighteen months regarding the strategic role that we could play in ensuring that the electrical infrastructure investment is undertaken in a coordinated manner which both supports economic growth and meets the needs of the distribution network operator. DECC and Ofgem have now committed to explore further Liverpool City Region's proposals on how innovation and collaboration can enable a more coordinated approach to network investment, in order to meet growing network demands. To deliver this, Ofgem commit to considering proposals put forward by the Liverpool City Region and the DNO as part of the 'Quicker and More Efficient Connections' project.

2. *What are the barriers to the deployment of energy storage capacity?*

- *Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?*
- *What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)*

Response Q2

With regard to the market failures/barriers question we believe that there is strength in tying together generation and storage, otherwise there can be little incentive to install energy storage if you have to 'pay' to then fill it. Without clear links between the two, energy storage by itself will have limited appeal in wide scale deployment. There is a lack of clear and stable incentive mechanisms to give confidence to the market for it to invest in meaningful energy storage and management systems.

While the National Grid does provide incentives for players at scale (3MW+) to participate in demand response (DR) for frequency control purposes - this can only be seen as a small scale solution with limited returns for companies to participate should the numbers of DR events increase (currently typically 10 - 30pa) due to coal being phased out and renewables offering a variable mix. While it is likely that many of these players participating in DR will have redundancy plans in place to ensure that they are not adversely affected by these events, the next logical step would be to incentivise them to invest in (or increase their) energy storage solutions as well, in order to allow them to withstand a higher frequency or increase the duration of events.

Equally as DR technology and energy storage becomes easier to implement and aggregate into the domestic market, large portfolio owners (such as Housing Associations) will be able to be offer DR aggregation at scale to the Grid, providing a new set of partners the National Grid can work with to peak shave demand. If energy storage is coupled with renewable generation & DR technology then there are opportunities for estate owners moving towards self-sufficiency, reducing demand on the Grid.

With regards to the second bullet point, Core Cities would strongly advocate that all the scales mentioned in the question are appropriate for future energy storage technologies. Technologies employed at the transmission and distribution levels will provide additional levels of redundancy and contingency scales and allow the Grid to balance the energy mix at times of stress. The domestic scale will be able to benefit hugely from localised energy storage, which depending on type – battery, hot water or both – will allow householders to have a level of energy independence which when aggregated nationally can be used to shave peak demand where required.

New smart metering and digital technologies and software will enable each of the scales to "talk" between each other and also between technologies. It is imperative that as we move to a more decentralised, embedded and diversified form of energy production, that the large scale centralised approach that has served the UK well for the last 60 years, allows for a more pluralistic approach to meet our energy challenges and opportunities.

Therefore, we would advocate that if any future funding approaches are being devised, that they are open to non network operators to make applications and in addition, that a proportion of funding is allocated for each of the three scales.

Currently a number of Core Cities are exploring, or have in demonstration, the following distribution network or domestic storage options:

- Electrical battery storage in properties linked to solar PV generation (in demonstration).
- Installing solar power (canopies and domestic) for electricity (as part of FIT), with further future potential for any surplus electricity not required in the house being directed to the immersion heater in the hot water cylinder to support further energy conservation.
- Cryogenic liquefied gas electrical generation from waste heat (in discussion).
- Phase change material heat storage from waste heat arising from electrical generation (in discussion). This approach improves the overall electrical system generation efficiency.
- Use of Dimplex quantum storage heaters and immersion heaters with smart controls throughout several tower blocks as a means to aggregate peak shaving (in discussion)
- Liquid Air (compressed when electricity is plentiful) as a transport fuel (funding application submitted)
- Connection of solar PV, electric vehicle charging, heat pumps, heat network and smart control technology in a holistic system configuration (funding approved commencement February 2016).
- Energy Storage test bed at Newcastle University.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- *Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?*
- *Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?*

Response Q3

We currently do not wish to make any comment regarding question three.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Response Q4

Previous EU Green Capital Cities such as Copenhagen, Stockholm, Hamburg have all set their own ambitious climate targets (Copenhagen to be carbon neutral by 2025 and Stockholm to be fossil fuel free by 2050) and can provide key learning in terms of balancing energy supply and demand.

In addition, forums such as the Covent of Mayors, the Compact of Mayors and Rockefeller Resilient Cities provide global learning and commitment to tackle climate change (including through reducing energy demand and finding more efficient and cleaner forms of energy supply) including the most recent learning and commitments made at COP21, which Bristol supported as part of its year as EU Green Capital 2015 - the Paris City Hall Declaration and the 'Under2' Memorandum of Understanding.

Japan has a very strong track record of research and investment in this field through their 'NEDO' (New Energy and Industrial Technology Development) Governmental arm which is running a number of ground breaking pilot on energy storage and demand side response technology in pilots across Europe including Greater Manchester.

The UK is also making its own progress in other areas with innovative and collaborative work across our different sectors such as on the development of Ultra Low Emissions Vehicles, Marine Energy Accelerator programmes and longer term energy storage.

<u>ENDS</u>

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8th Jan 2016

Dear recipient

Our comments below are in response to the question of future energy

https://www.gov.uk/government/consultations/national-infrastructure-commission-call-for-evidence/national-infrastructure-commission-call-for-evidence

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The electricity market allows benefits to accrue to different stakeholders in a seemingly fragmented way resulting in the 'broken value chain' problem. This is especially relevant in constraining smart grid development. An independent system operator can be influential in deciding when and how to use flexibility (DSR – Demand Side Response) for system balancing vs local network congestions. All existing actors will want to guard their own benefits whereas an independent body might ensure maximisation of overall system benefits. Risk evaluation cannot be conducted easily for all actors in the current regime and risks can be taken blindly leading to uncertain investment outcomes.

Large scale batteries are too expensive and frequency support for batteries applies not for DNOs but for large scale renewable generators but because they pay for connection capacity. This effectively doubles the amount energy they can sell[1], see for example. Energy storage particularly at micro level is very expensive although it avoids distribution costs. Renewable generators might benefit from energy storage, for example for large PV operators in northern England.

- What role can changes to the market framework play to incentivise this outcome:

[1] Koch, S. "Assessment of Revenue Potentials of Ancillary Service Provision by Flexible Unit Portfolios" in Energy storage for smart grids", editors Du and Lu.

- Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
- Is there a need to further reform the “balancing market” and which market participants are responsible for imbalances?

Regulatory changes allowing energy storage would help DNOs. It would help to better regulate the use of energy storage by DNOs by resolving constraints (e.g. overloaded assets, frequency problems and disconnect DNO from energy market) and for TSO (Transmission Service Operator – National Grid) balancing purposes. The TSO has a larger interest and so can draw from broader geographical range. The DNO would be using storage to resolve problems in local areas. There would need to be rules prioritizing between DNOs and TSO.

Engaging in and purchasing energy, charging and dis-charging at different price points, is not supposed to happen but does and leads to profit-making. Current policy is to segregate the market and to have non-overlapping load for each player.

- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Flexibility is the ability to accommodate unexpected demand and supply in the short term, see Lund et al (2015)[2]. The Falcon project suggests that DSR does not improve flexibility. Similar findings are suggested by the Smart Networks work-stream 7 project. DSR does not create capacity. Traditional reinforcement for example creates capacity.

Two approaches to building capacity are possible thereby creating flexibility. First, an evolutionary approach is suggested in Falcon to deal with adaptation and increase flexibility. Starting with the current network and modifying it using new approaches based on comparison of value to existing approaches, adopting the fittest solution, allows the network to evolve. Second, a top-down planning approach can be taken, starting with an aspiration targets, such as 2050 carbon targets, and then back-casting, or forward-planning to reach the end point/goal. For example CASCADE plans for 2050 targets by increasing renewable penetration thus meeting anticipated demand for electric vehicles (EV) and heat pumps, etc.

Flexibility is needed because in an electricity system especially in an energy system with renewables meeting base load, peak demand would be at different points from peak generation. It may be possible to de-charge car batteries in the day to create flexibility but the electricity charging infrastructure would need upgrades for de-charging, e.g. 3.7 lithium ion 2.5 to 4.2 depending on state of charge, 36-96V - close to sequential batteries, so power electronics quite expensive. A decay in the state of charge of battery 5% per day for lithium

[2] Peter D. Lund, Juuso Lindgren, Jani Mikkola, Jyri Salpakari, Review of energy system flexibility measures to enable high levels of variable renewable electricity, Renewable and Sustainable Energy Reviews, Volume 45, May 2015, Pages 785-807, ISSN 1364-0321, http://dx.doi.org/10.1016/j.rser.2015.01.057.

ion is suggested, and efficiency would decrease with the distance travelled from de-charging to use.

Embedded generation such as PV, Combined Heat and Power (CHP), or diesel provide short-term assistance. On a daily basis it could be 10-20 times more expensive than traditional approaches. The problem is with reliability. Embedded generation could compete against traditional re-enforcement provided there are strict reliability controls, to provide "n-1" functionality above 1MW. If customer has more than 1MW capacity, then should be able to supply to the customer. The implications for the regulator in operator mode is that networks need to be over-designed. "n-1" is probabilistic, and so may not happen for years but the system needs to cope in the event it occurs. If distributed generation is present the DNO is not paying for it and it is possible to use the capacity of firms to cope with "n-1" and specific voltage over-loading conditions, but both are very rare. Contracts would be needed with social infrastructures, such as hospitals, and with businesses. Even with contracts, reliability would be a problem. Testing would be needed not only of the hardware but of the links and networks to companies. Falcon found only 50% despatch reliability and in the second phase of published trials with one week advance notice to predict when generation needed results 90+% reliability.

DSR at the distribution level is challenging as there is minimal industrial participation. There are no mechanisms in place, manual, contracted, nor automated. There is the potential for some UPS aggregation providing potential business opportunities.

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

A key issue is that currently DNOs are not allowed to own storage because storage is defined as generation. The regulatory framework needs to change. However, would storage at the DNO scale be best placed for national system balancing or to resolve network congestions at local level? To overcome the national balancing problem, city or region balancing could be considered especially as meso-level solutions such as the Swansea 320MW tidal barrage come on line with improved predictability of renewables contribution. Trading could occur between lower scale operators who have excess capacity which can be sold to the market.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond

2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?

Given the expectations concerning the future generation portfolio, the growth in electricity demand and a CO_2 price, the cross-border transmission capacity expansion by 2025 expected by ENTSO-E will reduce dispatch costs by 1%. However, the impact of cross-border transmission investment on the electricity bills of the European consumers will depend on the impact of the investment on electricity prices (not necessarily related to dispatch costs) and on the capital costs of such investment.

A higher renewable energy sources penetration causes higher variability in the supply curve and therefore increases the demand for arbitrage in the system. In a future generation scenario with doubled wind and solar installed generation capacities than expected by ENTSO-E, the demand for hydro pumping decreases with higher cross-border transmission capacity. The reason for this behaviour is that cross-border transmission and pumped hydro storage are partly substitutes. Cross-border transmission can spread fluctuations in supply geographically, thereby reducing the impact per system, but because it does not offer inter-temporal arbitrage its potential to flatten residual load is limited.

The expected expansion of cross-border transmission capacity by 2025 has a limited impact on unserved load in the face of the expected low growth rate of electricity consumption in Europe (0.9%). However, if demand grows at the historical rate of 2%, the expected development of cross-border transmission will be needed to maintain the current level of security of supply in 2025 by avoiding 20 TWh of unserved load in Europe. Moreover, statistics of 18 European countries since 2002 show that as the normalised sum between remaining margin and import capacity increases, the frequency of major fault events in a European network between 2002 and 2011 decreases considerably.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

In countries with high renewables penetration, such as Germany with close to 30% of power on an average basis, some peak days, solar and wind supplied close to 80% of peak power demand at specific times of the day. In the near future, the UK is targeting a 20% average share by 2020 and a 50% average share by 2030.

The most important reasons on why Germany has a stronger position to accomplish EU goals are: (1) the existing strength of its power grids; and (2) flexible operation of coal and nuclear plants (and to a lesser extent gas and pumped hydro). In addition, Germany has managed quite well because of: (3) better design of the balancing (ancillary) power markets, to make them more effective, faster, and open; (4) better system control software and day-ahead weather forecasting; (5) modest technical improvements to local-level distribution systems; (6) exports of power to neighbouring countries; and (7) solving the “50.2 hertz” inverter problem.

A number of issues remain unsolved for the future, and will play a role in the future, but have not yet significantly to the ability to integrate and balance supply and demand today.

Capacity market or payments. Some coal and gas plants are required by the regulatory authority to remain operating, even if they generate very little power. These plants have been determined to be necessary for covering regional bottlenecks or seasonal variations. These plants receive “capacity payments” to cover their costs of operating at zero output.

Demand response. This is still small relative to the potential for providing flexibility and balancing, WPD Innovation had proven that creates more flexibility than operational capacity in the system. Some large power generators are selling this flexible demand into the balancing markets. Some generators are integrating demand response with their coal plants to give them economic flexibility for selling into the balancing market. Some system operators (ISOs) have also been contracting directly with large demand response providers on a pilot basis. However, the regulator does not explicitly include demand response in its planning, or set rules specifically for demand response. (See the California and Denmark cases for more on demand response.)

Curtailment of wind power output. Curtailment is when wind power output must be shut-down to balance the grid, resulting in economic losses. Strict curtailment rules have been instituted for ISOs, which have to curtail wind power output if transmission bottlenecks appear. Curtailment may become a bigger issue in the future, depending on progress with transmission upgrades and planning. (Germany, California and Denmark cases for curtailment are different approaches to discuss.)

Storage. Energy storage has played almost no role in the UK’s integrating and balancing mechanisms so far. Many do not expect storage to play a role in the coming decade, or at least until the share of renewables goes above 40%. There is interest in household-level storage in conjunction with the “self-consumption” economic model for distributed solar PV.

Yours sincerely,
Liz Varga, Jesus Nieto Martin, Nazmiye Ozkan and Eugene Butan

From: [email address redacted] on behalf of Alister Scott [email address redacted]
Sent: 21 December 2015 09:55
To: EnergyEvidence Infrastructure-Commission; Emma Bridge; Philip Wolfe
Subject: Infrastructure and energy efficiency

To Infrastructure Commission

I am writing to commend that you adopt energy efficiency as one of your key infrastructure opportunities and targets. I commend to you the idea of "Negawatts" as most recently put forward by The Green Alliance but going back many years to the time of electricity privatisation.

An LED light bulb that uses 90% less power is infrastructure - but how do we incentivise its use?

Beyond this, many new developments such as Smart meters and grid, energy storage and the internet of things provide huge opportunities for us to change dramatically the way we produce and use energy - away from the old style centralised "build and supply" model to a more demand responsive and interactive model.

This is not a problem that government has ever got to grips with and it needs a group of bright and influential people like you to do it.

Please take this opportunity.

With thanks,

Dr Alister Scott
Chair, Cuckmere Community Solar

Electricity Interconnection and Storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
    - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
    - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Local authorities have little or no direct influence over the electricity market, connections or managing supply and demand. Local authorities have more influence over areas such as energy efficiency/housing, planning, health and issues around fuel poverty. These issues whilst not directly linked are affected by connectivity and market variations in electricity/heating costs.

However, there is potential in Cumbria for the county to make a significant contribution to increasing national energy security through nuclear new build at Moorside, and the potential for other large scale projects such as the Solway tidal lagoon and the extension to Walney offshore windfarm. Increasing generation and connections through these sources will have a significant impact on the domestic market.

A large percentage of Cumbria's population is off the mains gas grid. A lot of housing, particularly in the most rural areas, relies on expensive and inefficient heating oil. The cost of heating oil is more volatile than gas, making budgeting utility costs more difficult and less predictable. Many Cumbrian homes use electricity to heat their homes which is also expensive and often less efficient. As a result the rates of fuel poverty in Cumbria are well above the national average.

Microgeneration is a potential growth sector for Cumbria. This sector could move further into the energy mainstream with the right support, offering consumers affordable, and cost-effective low carbon energy products.

Community scale generation can also reduce reliance on the grid and make rural communities less susceptible to price fluctuations and contribute to the achieving the right energy balance. As well as delivering economic benefits, this will give consumers and communities much greater opportunity to generate their own renewable heat and electricity, and play their own part in tackling climate change.

The Government has a Microgeneration Strategy – do the electricity market reform objectives support the objectives contained in the Microgeneration Strategy?

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

The operators and generators will be in the best position to offer feedback on this question on technical matters. From a Cumbrian perspective, sparsity means that storage at the community and domestic scale is the greatest hurdle but also the area for greatest growth opportunities. This links to a wider need to support microgeneration and local grids to promote more sustainable and secure supply to the most rural areas of the UK, as well as improved connections through the North West Connections Project with investment from the National Grid.

This supports the aims contained in Cumbria's Strategic Economic Plan that seeks to develop the low carbon economic sector in Cumbria. The SEP seeks to promote the most efficient and sustainable use of energy generation capabilities found in Cumbria's natural environment. Delivery will be enabled through investment in the following four work programmes:

- Energy excellence – delivering Cumbria's renewable energy potential through Britain's Energy Coast and locally led low carbon energy projects.

- Access and support for innovation – developing current and emerging entrepreneurship in clean technologies.

- Energy and resource efficiency – business advice to SMEs to reduce costs, consumption and to enable business to fully utilise low carbon technology and investment in energy efficiency programmes.

- Market development – promoting existing technologies and innovation both locally and through export.

Cumbria would look for support to these objectives through the electricity market reform process.

Support should also remain for large scale electricity storage projects, to continue the demonstrations which have been financed under the Low Carbon Network Fund, the DECC Innovation Fund and through other agencies. This is needed in the short term, in order to provide continuity of projects and to overcome the challenges of financing project investment when there are uncertain forecasts for the income streams accessible to electricity storage projects under present market conditions.

There are some barriers that could prevent cost-effective interconnection being realised, such as:

- The ability of increased interconnection to reduce energy costs, lowering bills for consumers at a national level.

- Whether or not new connections are an effective method by which to improve security of supply, and

- The overall economic impact on the UK of a greater degree of interconnection, opening new markets and promoting renewables and microgeneration.

There may also be local and project-scale barriers to the future delivery of new connections and storage facilities. Areas like Cumbria can be at a disadvantage due to the long distances to existing grid connections (although this will be improved following delivery of the North West Coast Connections project) but this provides an incentive to consider community scale decentralised generation.

Energy efficiency is a fundamental element in the progression towards a future low-carbon economy. Actions to increase energy efficiency can make a significant impact in squaring the circle between an increased demand for energy and environmental protection, ensuring a move towards a more sustainable energy future.

There is a strong business case for energy efficiency. It enables consumers to save costs, businesses improve their competitiveness and overall productivity. There are also opportunities to develop new businesses that enhance efficiency across regions and sectors.

The Government published the Energy Efficiency Strategy in April 2014. This strategy places energy efficiency at the heart of government policy and the long term energy and climate change plan for low carbon growth.

The strategy is designed to refocus efforts on energy efficiency, establishing a common framework and driving the necessary action to help the EU achieve its 20% energy saving target for 2020.

Energy efficiency needs greater recognition and investment as a way of reducing reliance on energy imports, reducing demand and maintaining a safe margin of reserve power. Currently the long term benefits of improved energy efficiency are often regarded as less certain. Consequently, energy efficiency is undervalued relative to other investment options.

Are the measures contained in the Microgeneration Strategy, Energy Efficiency Strategy and Electricity Market Reform mechanisms aligned and compatible?

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

The UK needs to change how we prepare for, and manage, uncertainties in the future patterns of generation and demand. We also need to better consider how we develop and bring forward new technologies, especially renewables. This will it turn require innovative approaches to new networks and connections taking a holistic view on future energy security.

In Cumbria it will be important to develop the major projects in new nuclear, tidal and offshore wind that will support increased national energy security. In tandem with this, support is needed for the microgeneration supply chain to ensure it is properly equipped to cope with any rise in demand, as well as creating and sustaining jobs in Cumbria and more widely across the UK.

Government has shown some commitment in previous annual energy statements to the roll out of a smart grid. A smarter local grid could facilitate connectivity for power from microgeneration. It will also provide better visibility across the network and the means to integrate distributed low carbon generation into a broader low carbon electricity system.

The first step to a smart grid is the installation of smart meters which are currently being rolled out across the country. Some companies have already trialled new ways of operating the network through the Low Carbon Network Fund which closed early in 2015. The Electricity Market Reform process could seek to build on this work and maintain the continued stimulus to champion the development of local grids.

The Electricity Market Reform process does not appear to make explicit reference to support for community energy and local grid connection. The application and current models of feed in tariffs have not supported community scale decentralised power generation as they have either been applied to domestic or commercial scale generation.

Cumbria is particularly exposed to oil price volatility and many properties are heated using expensive and inefficient electric systems. Cumbria is well placed to benefit from a smarter approach to decentralised energy, generated, used and owned by householders, local businesses, community groups, housing associations and councils. A fixed feed-in tariff for all scales of generation would help to make this happen and give the market the certainty it requires.

To help increase the use and supply of renewable and low-carbon energy, government could recognise, through the reforms the responsibility on all communities to contribute to energy generation from renewable or low-carbon sources. National policy should have a positive approach to the promotion of energy from renewable and low-carbon sources. At a regional and local scale planning authorities should be encouraged to identify suitable areas for renewable and low-carbon energy sources and supporting infrastructure.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

New technologies in the form of renewable energy systems are beginning to increase in terms of generation capacity. There is a growing consensus globally that the growth of low carbon energy generation is essential for a secure and sustainable energy future.

Countries that are moving most quickly towards lower carbon generation tend to frame their overall energy strategy around long term cuts to emissions. The UK has a legally binding set of carbon budgets in place driven by the Climate Change Act so should be well placed to put in place the right kind of long term energy policy.

Perhaps a key question therefore should be: 'What is the impact (or potential) of renewables and low carbon generation on energy security and supply?'

Energy security and diversification of the energy mix is a major policy driver for renewables and overall energy diversification. Use of renewables can also reduce fuel imports and insulate the economy to some extent from fossil fuel price rises and swings. This certainly increases energy security. However, concentrated growth of variable renewables such as wind and solar can make it harder to balance power systems without the right investment in new types of local grid connections. In line with this, Cumbria will benefit from the North West Coast Connections project to upgrade the existing network.

The low carbon energy sector in the UK is demonstrating its capacity to deliver cost reductions but only when the right policy frameworks are in place and enacted. Costs are decreasing and a portfolio of renewable energy technologies has become increasingly cost-competitive in a wider range of circumstances, particularly established technologies that have received initial support or where resources are favourable, technologies such as onshore wind. Economic barriers do remain in many cases. In general, costs need to be reduced further. Fossil fuel subsidies and the lack of a global price on carbon are significant barriers to the competitiveness of renewables.

Response from

Professor Elizabeth Shove, DEMAND (Dynamics of energy, mobility and demand) Centre/Sociology, Lancaster University, LA1 4YD

Electricity interconnection and storage

4.1

In line with the published terms of reference, the Commission is seeking evidence on how changes to existing market frameworks, increased interconnection and new technologies in demand-side management and energy storage can better balance supply and demand.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- *What role can changes to the market framework play to incentivise this outcome:*
    - *Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?*
    - *Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?*
- *To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?*

A first step, in responding to this question, is to clarify the meaning of 'demand' (www.demand.ac.uk). In many discussions, demand is equated with current levels of consumption. This is the benchmark and the point of reference in terms of which strategies of 'supply' are arranged. In this context, demand side management techniques represent a means of ensuring those current, taken-for-granted levels of consumption can be delivered.

Although very widespread, these assumptions overlook the longer histories both of provision and of consumption (Hughes, 1993 [1983]; Nye, 1999; Forty, 1986). In effect they assume that demand, in the sense of a 'need' for electricity is simply there: waiting to be met: hence the challenge is one of meeting need – whilst minimising cost to the consumer and meeting carbon emissions targets.

In fact, demand and the use of electricity is in large part an *outcome* of systems, technologies and institutions of provision and supply. As is widely known, but also routinely forgotten, current levels of consumption (and their timing) reflect concerted and systematic efforts to build demand in ways that suit the 'needs' of generation – for profit, to cover the cost of past investment, to operate efficiently, and to cater for domestic and industrial markets. Classic accounts of this refer to the role of electricity companies in selling home appliances to help build demand during the day, or of promoting night storage heaters as a method of peak load management. These are not just historical curiosities. Demand, in this sense, is continually reproduced and 'built' in just the same way today.

If we think of demand in this more fundamental sense – not equating it with current levels of consumption, but taking it to be an expression of what electricity is used for in society (Shove and Walker, 2014), of the social practices that have become 'electrified', and of how these develop and change over time, we would come up with a very different 'reading' of the question outlined above, and would provide correspondingly different answers.

From this point of view, the 'flexibility' in the energy system is inextricably tied into the 'flexibility' (or not) of the social, spatial and temporal ordering of practices that have come to depend on electric power. Peak loads are thus an outcome of what is called 'societal synchronisation' (Shove, 2009): these being points in the day, the week or the year when many people are engaged in similar energy demanding practices at the same time. The likely outcome of initiatives like real time pricing are consequently filtered through a mesh of social/institutional arrangements which define and determine the scope for shifting 'demand' (i.e. energy consumption) in space and time.

A further obvious point is to notice that the scale of the challenge of balancing supply and 'demand' in the sense of current consumption, relates to the overall scale of demand itself. If total consumption was less, if it occurred at different places and times, the task of meeting it would be different. Again it is critical to recognise that demand – in this more fundamental sense - is itself dynamic. It should be recognised that new investment in electricity infrastructures means making decisions about building the future of demand as well as of supply.

2. What are the barriers to the deployment of energy storage capacity?

- *Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?*
- *What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)*

In thinking about this question, it is important to realise that people do not use 'energy' as such: they use the services it provides. These take different form, and it is this which matters for the temporal relationship between generation, 'storage' and use, broadly defined. If we were to think about keeping warm at home, as a service, it is apparent that this can be configured in different ways, and with an array of technologies some of which arguably 'store' energy: e.g. the fabric of the home itself. Again the question posed above would be interpreted and responded to very differently if we accepted that buildings, and potentially clothing, were included in the energy system (Walt Patterson, http://www.waltpatterson.org/mewfinal.pdf), being also implicated in delivering energy services.

A second unorthodox issue to consider is again the relation between the timing of generation and consumption. Large scale policies of storage, especially relating to renewables, suppose that whilst the timing of generation/supply is unpredictable, and fluid, the timing of demand is not. Again this has not always been the case. For example, there may be scope to move the timing of significantly energy-demanding activities to periods when renewable energy is in good supply, thus avoiding the need for storage. In the

Netherlands, only millers were allowed to work on Sundays, an exception that was made to allow them to grind grain whenever the wind happened to blow. See: http://www.lowtechmagazine.com/2009/10/history-of-industrial-windmills.html.

There are modern equivalents to this strategy that could and perhaps should be developed further.

Third, and again illustrating the complex relation between timing, practice and energy demand, the potential for using EVs as storage systems for domestic power depends on related temporal and spatial patterns of mobility and on the scheduling of activities which structure the when and the where of energy consumption. The key point here is that space and location are as important as time and timing. Further, the organisation of 'storage' which can be of resources (fuels), as well as of power is closely linked to systems of provision and to the supply chains involved. More decentralised systems imply different distributions of storage as is evident in quite unrelated cases, such as the use of wood-fuel (Jalas and Rinkinen, 2013).

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- *Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?*
- *Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?*

Responding to this question depends, above all, on how one interprets 'the best interests' of consumers, in the UK and elsewhere, now and in the future. Concepts of 'the consumer' and of 'their interests' are necessary, but also necessarily abstract, figures in such discussions. At a minimum, it is important that any response to the seemingly technical question of markets/interconnection etc., is explicit and reflective about the idea or image of 'the consumer' on which they depend.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The UK is not alone in building energy demand, and in organising related systems of provision. Rather than supposing models of predict-and-provide, it would be useful to learn from planned or unintended situations of decline (e.g. in some parts of France), in which the entire electricity system is 'shrinking'. There are other parallels in the water sector, e.g. in Berlin (Moss, 2009; Moss, 2000). Networked systems – also including gas – are often predicated on delivering certain levels of supply. It is rather unclear how these systems might work, technically, financially or institutionally, should demand decrease substantially, or in specific parts of the system. Issues of scale (both of demand and supply) are critical also in more 'decentralised' systems (van Vliet et al., 2005).

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From: Les King [email address redacted]
Sent: 07 January 2016 20:22
To: EnergyEvidence Infrastructure-Commission
Subject: Doosan Babcock submission to the NIC Open Consultation

Please find below Doosan Babcock submission to the Consultation Process.

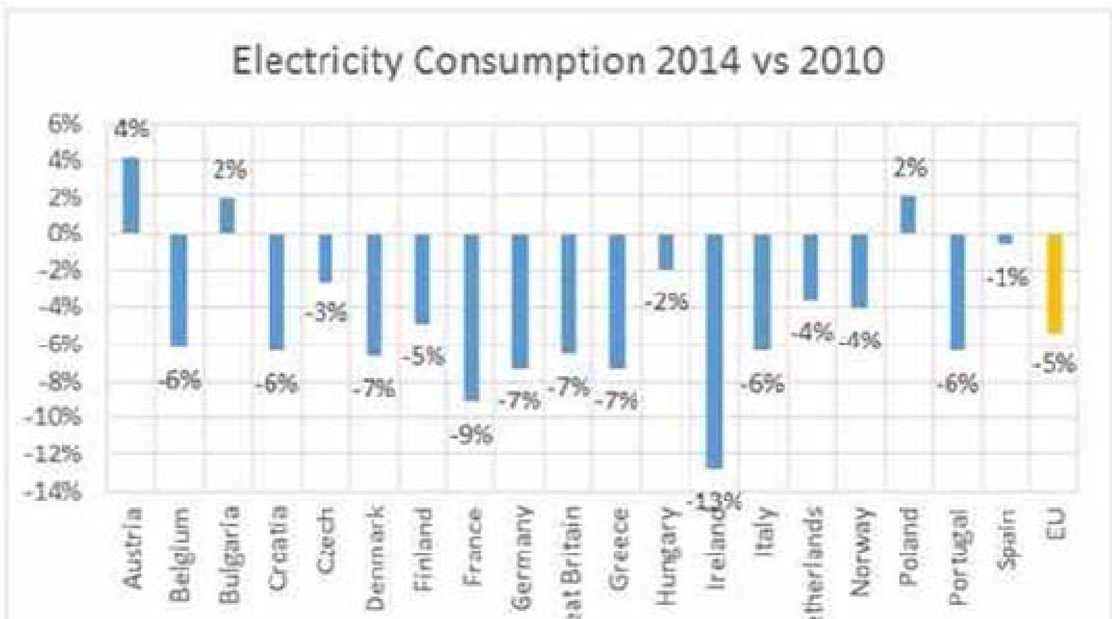
Doosan Babcock is pleased to respond to the Open consultation on the National Infrastructure Commission (NIC), in particular the remit of the NIC in relation to electricity interconnection and storage.

Doosan Babcock is part of a powerful combination of companies united under the Doosan Group to deliver complementary technologies, skills and value to customers the world over. *We are a specialist in the delivery of engineering, aftermarket and upgrade services to the thermal power, nuclear, oil and gas, petrochemical and process industries. Using best-in-class technical expertise and an industry-leading project management capability, the company builds, maintains and extends the life of customer assets worldwide.*

In our view, if the UK's overall CO2 reduction requirements are considered together with the growing trend towards distributed generation (moving away from centralised generation) then to consider only the electricity generation system independently of the UK's total energy system requirements is not the best option from a UK perspective.

As part of our ongoing electricity market reviews, Doosan Babcock has recently updated its scenario modelling exercise looking at the future of the UK electricity and energy systems. The output from this modelling exercise has further emphasised the need to consider total energy requirements with a holistic infrastructure view, as opposed to considering the future demands and infrastructure associated with electricity, heat and transport as separate unconnected systems.

Energy consumption is falling across the EU, see figure below, partly due to the financial situation and partly due to increases in energy efficiency. It is expected that this trend will continue, as increased energy efficiency in the residential and commercial buildings is implemented.



Current incentives for the electricity industry in the UK, whilst having been beneficial in a number of aspects, seem to be leading to unanticipated outcomes e.g. the recent capacity auction enabled diesel generators, despite the technology displaying poor air *quality and efficiency characteristics. The CfD approach, whilst encouraging new technologies, now seems to be encouraging the retention of large central power plant, a characteristic which appears perverse in an era of declining electricity demand and the move towards decentralised power.*

Integration of the power, heat and transport energy vectors is a necessary step towards decarbonisation, and this in itself implies infrastructure development which recognises the integrated systems. Energy efficiency across all sectors should be the number one priority, with for example improved residential and commercial building standards, local as opposed to central generation of electricity with the use of CHP as a matter of course, at both micro and macro level, being recognised and appropriately incentivised.

Whilst some form of energy storage may be required, interconnection with Europe as envisaged in Energy Union will help optimise the use of renewables across Europe. Against the backdrop of energy demand reduction and interconnection it is difficult to estimate the energy storage capacity required, if any, or the particular energy vector under which the energy should be stored.

It is recognised that the development and implementation of such an integrated energy infrastructure will take time, and that the existing supply means will require maintenance and potential upgrade in the interim period. However for the Infrastructure Commission not to consider now what an integrated energy system infrastructure should look like, and to set the initial steps in motion, will seriously jeopardise the UK's ability to deliver on its 2050 environmental commitments. In order for infrastructure projects to be investable, the National Infrastructure Commission should have a clear climate change remit to ensure future projects are compatible with the UK's long term climate goals.

Doosan Babcock would be happy to share, and elaborate further on, the ideas expressed above at the request of the Committee.

Regards

Les King
Director Technology, Policy and Liaison

Doosan Babcock
Porterfield Road | Renfrew | PA4 8DJ

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Web: www.doosanpowersystems.com

please consider the environment before printing this e-mail

To whom it concerns,

Please find below Dunelm Energy's response to the National Infrastructure Commission's call for evidence, Section 4: Electricity Interconnection and Storage.

Dunelm Energy was set up by Ian Marchant after he left SSE (CEO 2002-2013). The company provides advice, assistance and connections to companies and individuals involved in the disruptive changes in the Energy Industry (http://www.dunelmenergy.co.uk/home.html).

Response: (embolden text highlights key messages)

Executive Summary

The physical nature of our energy system is changing, rapidly. As we decarbonize, not only do we drastically reduce the **flexibility** and **resilience** within the system (by removing existing energy storage in the form of fossil fuel stocks), we simultaneous increase our demand for electricity (through electrifying heat and transport). The situation exacerbates - we increasingly demand more flexibility and resilience from the very system within which it is rapidly reducing. **Instead of continuing to see the system as supply side driven, we need to appreciate the importance of demand-side management and energy storage, particularly at the distributed residential scale.** So far we have only scratched the surface in terms of using available assets. We must put needs before technology – assessing our current and future needs for resilience and flexibility, and then deciding how, at what level in the system and which approach/technology is most appropriate.

Key concepts included here:

- Negative capacity market
- Quantifying the extent to which demand-side management and energy storage, located at the residential level, can dramatically reduce the nation's peak electricity demand.
- Energy efficiency feed-in tariff
- Demand side merit order
- Smart voltage appliances
- Restructuring the ownership model of the ISO, eliminating the need to set incentives at all and encouraging long rather than short term strategy

Introduction

We don't realise the vast extent to which energy storage currently, and always has, played a role within our energy system. If we look in some detail at what these ***existing*** **forms of energy storage** are – see Figure 1 – we can see that the amount of latent energy storage already in use is not only **colossal** but overwhelming dominated by **fossil fuel stocks** (primarily in the form of coal, petrol and gas stocks).

It is this that has and does provide the electricity system with **flexibility** and **resilience**. We believe that it is useful, indeed necessary, to define energy storage in conjunction with providing these two services. Society wants flexibility and resilience, and *uses* energy storage to deliver these two requirements.

Traditionally the relationship between *electricity* demand and supply (often the focus of the energy ecosystem) has been almost **entirely managed by the supply side**, through the ability to produce it on command; generators are called upon to alter output and are able to respond by simply feeding more or less fuel into their power stations. The UK system relies upon this approach to provide back up, fast response capacity, removing the need to store electricity and instead physically stock piling the original fuel source required.

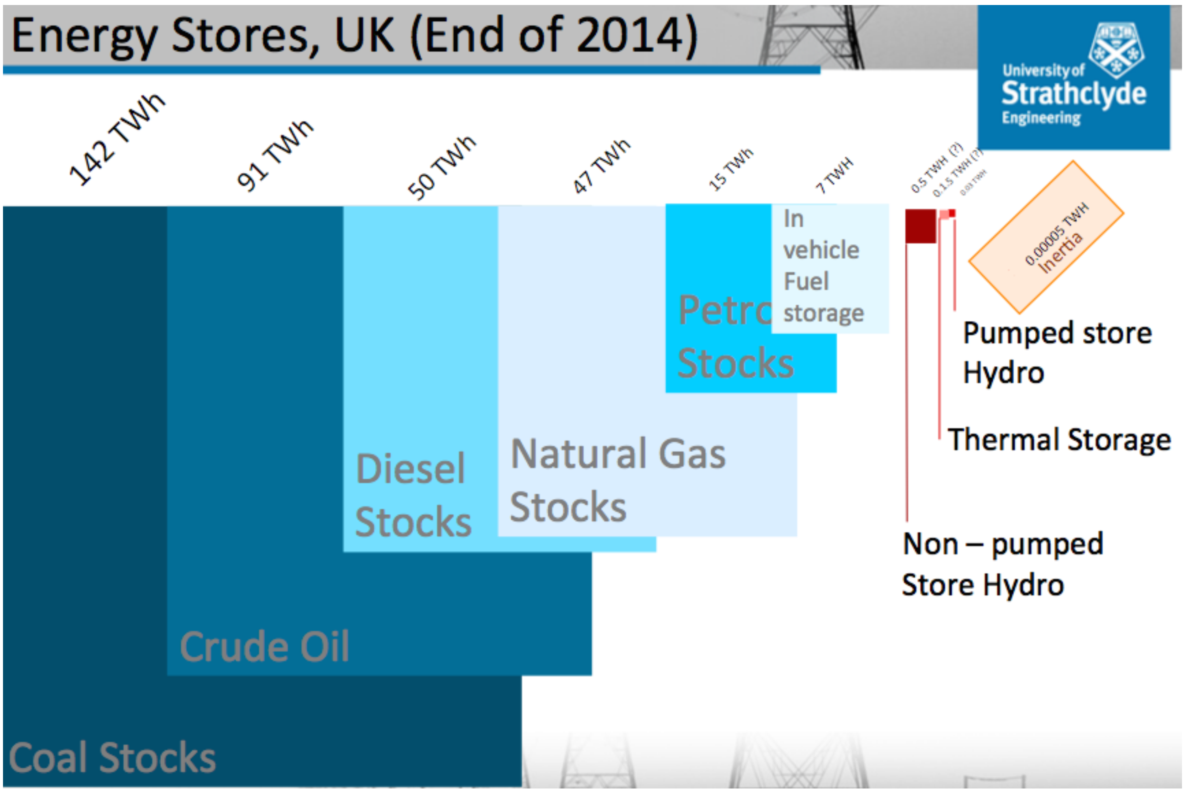

Figure 1 (Simon Gill, CEP, Strathclyde University)

The physical nature of our energy system is however **changing, rapidly**; with the exception of biofuels and to some extent hydropower, low carbon energy sources do not allow the level of energy produced to be dictated. As we **decarbonize**, not only do we drastically reduce the flexibility and resilience within the system (by removing existing energy storage in the form of fossil fuel stocks), we simultaneous increase our demand for electricity (through electrifying heat and transport). This **exacerbates the situation** as we demand more flexibility and resilience from the very system within which it is rapidly reducing; we will be faced with less of what we need, just when we start needing more. What will happen, for example, when our electric car battery needs to be recharged at the same time as our heat pump needs to work and we want all our lights and gadgets to function, but it is a still calm night?

Demand-side management and energy storage are ways of addressing and alleviating this.

Thus far short term tactical reactions have characterised the response to balancing electricity supply and demand. For example, both the capacity market and more recently enhanced frequency response has failed to address strategic questions, such as how much energy (all energy, not just electricity) we will actually need, what resilience we should expect in the provision of that energy and how much flexibility we will demand. This analysis should take a long term view of between 10 and 30 years, and will need to consider the degree of electrification that may occur.

As we face the challenge of future-proofing our energy infrastructure, we suggest three steps:

1. A **strategic assessment** of **long term needs**
2. An Independent System Operator that thinks long rather than short term
3. A realisation that the demand side is nearly entirely missing (inefficient scheduling of demand does not count). Why efforts are not being made to make sure it is considered on an equal footing to the supply side baffles us. Why is there no negative capacity market for example?

Demand-side management

Instead of continuing to see the system as supply side driven, we need to appreciate the importance of the demand side. **So far we have only scratched the surface in terms of using available assets**. This must be expanded, eventually giving the demand side an equal footing to the supply side. Otherwise the best options will not be selected, nor the best solutions implemented. Costs certainly will not be minimised, especially in the longer term.

Appendix 1 illustrates that equipping and incentivising just ~345,000 households to shift 1.7kWh of electricity consumption (15% of average daily demand) from the evening peak to other parts of the day can reduce *national* peak demand by an incredible 10%. We estimate that the total private cost of doing so equates to ~£52m/yr (with a kWh/yr cost of £89). Comparing this to the £1.53bn forecast to be spent on improving the network per year between 2013-2021, this clearly shows that the equivalent of a very small proportion of spend (3.4%) could be directed towards a very manageable and targeted amount of DSM.

DSM can be realised through (1) **informing** behavioural change, (2) **controlling** and/or (3) **automating** assets.

The Green Alliance's *Getting More for Less: realising the potential of negwatts in the UK electricity market* report is an excellent piece of analysis, that proposes the implementation of a new support mechanism for energy efficiency. Please take the time to look over the document (attached), which suggests that a new strategy should seek to enable the development of business models based around **aggregating the delivery of energy efficiency measures rather than assuming that their cost effectiveness is a sufficient motivation**. The implantation of a feed-in tariff (FiT) is recommended, such that suppliers are paid per kilowatt-hour of avoided use. While DECC is wary of FiTs given the difficulties controlling spending within the existing scheme, an auction mechanism like contracts for difference, rather than demand-led pay-outs, would prevent runaway spending. It is estimated that the total cost of an energy efficiency FiT would add around £1.1bn to the Levy Control Framework by 2030, but it would reduce demand by 6.4GW and therefore lower electricity bills by £4.8bn overall. The report states that, even with the conservative assumption that, of the potential savings by 2030, an electricity efficiency FiT resulted in just half being realised by 2025, this would still represent a net saving of £2.4bn off consumers' bills by that time. This would take the net impact of the LCF to only £6.6bn on customers' bills by 2025, as opposed to the £9bn already recommended by the CCC. Further, levelling the playing field in the capacity market by "generating" negawatts would, by the report's calculations, save almost £4bn in capital investment. There would also be additional savings from avoided operation costs and deferred investment in transmission and distribution infrastructure.

Producing a **Demand Side Merit Order**, just like we have with the supply side, is another suggestion – a long held view on how to improve the balance of electricity demand and supply. As energy economists are already familiar with the Levelised Cost Of Electricity produced for base/mid merit/peaking plant in £/MWh, adopting the same approach to cost the equivalent Levelised Cost of Electricity *shifted/stored* at consumer/distribution/transmission level in £/MWh should be investigated further.

Energy storage

Debate about energy storage tends to get dominated, right from the start, about technology; be it batteries, phase change material or pumped storage hydro. Instead, and foremost, we need to separately **assess our current and future needs for resilience and flexibility**, *then* **decide at what level in the system that need can most efficiently be meet** and only then determine the choice of technology. **We must put needs before technology**.

We see 4 levels at which energy storage can be deployed:

1. Household
2. Community / local substation
3. Generator
4. Grid

We believe there is **too much focus on large scale** (third and fourth levels). It is **increasingly possible to position energy storage at the smaller**

distributed end, rather than relying on fewer centralized schemes. Of course the need for aggregation is introduced here, but it need not be as daunting as some clearly find it. The following bullets explain how both resilience and flexibility can be achieved at the smaller end of the scale:

- **Variable voltage appliances** – the influence of digit and smart technology is a key enabler. Introducing a simple regulatory measure such that all appliances must be fitted with a variable voltage chip could provide the electricity system with an enormous amount of **flexibility**. DECCs *Towards a Smart System* report already highlights that automated voltage control through the use of power electronics can play a key role in increasing flexibility of our existing network infrastructure cost-effectively. We illustrate (in simple terms) that if grid voltage dropped and as such current increased proportionally, a smart kettle could prevent this by increasingly the time taken to provide the same amount of energy to heat a fixed volume/temperature of water. If for example the voltage dropped by 10%, the time for the kettle to boil would increase by a similar proportional amount ~3:20 rather than 3mins. Ultimately, the appliances could have variable voltage performance (dynamic rather than fixed response) providing real-time active support to the system rather than adding to the system inertia, that would hardly be noticed by customers.
- We estimate that 5 – 6kWh of energy storage is required to give the average household 24hrs of effective electric energy **resilience**[1]. Appendix 1 explains that installing 2.5kWh of energy storage capacity in ~233,000 households, at a direct private cost of ~£76m/yr (£130/kWh/yr) could reduce *national* electricity peak demand by 10%. Installing a 7.5kWh unit in ~83,000 properties would deliver the same result at a similar cost of ~£79m/yr (£136/kWh/yr). Comparing this to the £1.53bn forecast to be spent on improving the network per year between 2013-2021, again shows that the equivalent of a very small proportion of spend (~5%) could deliver very significantly at the grid level. It is worth highlighting that this analysis uses the current cost of battery technology available on the market – as seen in the solar PV market over the last 5 years costs can dramatically reduce, especially with mass roll out – it is reasonable to expect costs of energy storage to do the same.
- **Society is already comfortable with certain forms of distributed energy storage** – unfortunately this does not yet apply to electrical or thermal energy storage. Transport is a particularly striking and familiar example – the average car in the UK stores sufficient energy to meet 2-3 weeks use[2]! Indeed, if we knew there was a supply crunch most would probably stretch this to a month or so. Given there is already inertia for this scale of energy storage, we suggest it is harnessed and directed towards helping to balance electricity supply and demand.

We also need to consider whether we *care* about the level at which energy

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[1] Assumptions: 4115 kWh/yr = 11kWh/day = 5.6kWh storage (if consumption halves in light of supply constraints)

[2] Assumptions: 14 gallons/vehicle, 31 miles/gallon = 434 miles/vehicle, 162 miles/week = 2.7 weeks of storage

storage is located – whether we want the energy storage to provide additional services/address ancillary issues such as fuel poverty for example. **Modeling and "system thinking" is thus required.**

Finally, we would like to highlight that one of the key challenges that must be addressed is the fact that not only is energy storage **charged twice**, for both providing and using electrons, the **value** of doing this at times when it can then provide flexibility and resilience is **not rewarded**. Having never been an issue previously, this needs addressed.

Independent System Operator

There is most certainly a need for an Independent System Operator (ISO). We suggest however that the current **ownership structure** is not as effective or efficient as it could be, especially with regards to minimising long-run costs.

When an ISO is owned by the *same company as the transmission assets* (TSO) (as is the case with National Grid in England and Wales) this creates **conflicts of interest**. Additionally, when it is owned by a single *commercial* organisation, as is currently the case, this gives rise to **incentive problems** and reduces the visibility of cost and effectiveness. We suggest that mutualising the ISO is both a practical and attractive step; restructuring such that it acts as a not-for-loss company for the benefit of the whole electricity network and its users. It could be jointly owned by the state, TSOs, generators and suppliers. This structure would enable the profits of efficient ISO operation to be shared by the public and the taxpayer, and so instils clear objectives to maximise social welfare *and* system efficiency. Moreover it unites the aims and roles of owner and customer, in turn allowing the ISO to focus on customer service. Ultimately it will be far better equipped to proactively plan for developments and changing needs within the industry, whether they originate from generators, suppliers or consumers.

Incentive scheme: **Adopting a mutualised structure removes the need to set incentives at all**. It goes to the heart of the issue and solves from there, as the interests of the industry and consumer are aligned. The ISO will no longer have any incentive to maximise the apparent costs of system operation on to customers in order to outperform a short term incentive. It will be able to seize longer term opportunities to improve the efficiency of the whole network. Furthermore, the conflict of interest that currently exists due to the fact that NG acts as the ISO as well as the TSO for England and Wales (i.e. the same entity both operates and owns the network) is removed[3].

Statistics 2013/14: Currently the ISO is buried within National Grid's large UK transmission business so it is difficult to assess its current performance and value (illustrating part of the problem). Turnover in 2013/14 seems to have been £132m with an operating profit of £48m, of which £26m was derived from out performing the incentive scheme. **This huge amount of money could be better used to minimise long-run balancing costs**.

[3] While there is no evidence of inappropriate behaviour, the incentive to recommend a bigger network for example, which in turn increases revenue, exists.

It is important to note that **this approach (mutualisation) does not suggest starting from scratch**, which would be extremely daunting and likely unadvisable. Rather, it takes both the existing skills and expertise within NG (the current ISO) as well as maintaining NG as a part owner, and **fundamentally restructures the model**.

A new, genuinely independent ISO could also be responsible for additional functions such as administering the Capacity Mechanism, the CfD mechanisms and other centralised functions currently undertaken by National Grid and Ofgem. It would place the ISO at the heart of the industry and truly enable it to take on the role of system architect if desired.

Giving evidence to the Energy and Climate Change select Committee in January 2015, Dermot Nolan (Ofgem CEO) stated that he sees a "strong case" for establishing an ISO to replace National Grid's current position as transmission operator and asset holder[4].

Appendix 1

Please see attached excel document for detail of calculations and data sources. Please feel free to flex the parameters/assumptions to further analyse the data.

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[4] http://www.cornwallenergy.com/News/Features/Ofgem-evaluating-benefits-of-ISO-model & http://utilityweek.co.uk/Error/AnoymousSubscribe/ofgem-%E2%80%98strong-case%E2%80%99-for-iso-to-replace-national-grid#.Vg0qfY9Viko

E3G RESPONSE TO NATIONAL INFRASTRUCTURE COMMISSION CALL FOR EVIDENCE

Critical challenge 3: improving how electricity demand and supply are balanced while minimising cots to the consumer over the long term

The Commission is well placed to advance existing efforts to address this challenge. Balancing of UK supply and demand at lowest cost must be seen in the context of requirement to transform to a near zero carbon electricity systems by 2030 and zero carbon economy before 2050. Successful delivery will depend on the Commission's ability to:

(1) exploit synergies across technology types, sectors and national borders;
(2) develop common, consistent and robust scenarios to underpin infrastructure planning without foreclosing options; and
(3) shift infrastructure decision making down to those who can control the level of demand at a city and regional level to build-in flexibility and preserve optionality.

If the Commission's recommendations deliver on each of these three points then a transformative reduction in the cost of electricity balancing will become inevitable within this Parliament.

Global decarbonisation – accelerated by the recent Paris Climate Agreement – has stimulated new waves of technological innovation in clean energy, efficiency and storage which are converging with parallel trends in "smart systems" and big data to expand the options available to the UK to meet its long term energy service needs at least cost. Making best use of these innovations will require fundamental reform of how the electricity system is managed and how it relates to the infrastructure for heating, cooling and transport each of which are likely to be significantly electrified over the coming decade.

In this changed landscape regulatory and market governance should aim to achieve economic efficiency by:

- ensuring a level-playing field for investment and purchasing of all types of demand side, supply, infrastructure and storage solutions to energy service provision taking into account their full-lifetime costs over a realistic range of future demand, technology and fuel price scenarios;
- ensuring a level-playing field for centralised and distributed energy solutions;
- avoiding unjustified discrimination between use of UK domestic and international electricity sources, capacity, storage and flexibility; and
- ensuring funding for RD&D and early stage deployment to potentially strategically important technologies such as CCS, storage, demand flexibility etc is adequate and timely to deliver their optimal potential contribution to reducing system costs.

The current UK system fails to deliver any of these objectives and in many areas is significantly underperforming against global and European best practice. These failures risk over investment in a new generation of costly energy infrastructure which will not be capable of delivering the UK's security or decarbonisation goals. Specifically the Committee should address the following barriers to lowest cost balancing:

- Under investment in cost-effective flexibility and energy demand reduction.
- Failure to stress-test the economic performance of UK energy infrastructure choices under the full range of likely scenarios resulting in low levels of economic resilience.
- Failure adequately take into account the implications of electrification of heating and transport which will result in the increasing integration of electricity, gas, transport and building infrastructure choices.
- Under investment in interconnection with other European countries which will cost UK consumers when ample lower cost capacity exists in Europe.
- Discrimination against decentralised and distributed energy solutions which have lower access to affordably priced capital than in many other European countries.

- Underinvestment in CO2 infrastructure - failure to bring forward viable CCS technology for gas before 2030 could lead to stranded gas assets and a crash programme of renewable build out to meet the UK's legal carbon budgets, both increase costs to consumers.

The response to the questions below address each of these areas in detail and present potential solutions to remedy these problems and achieve lowest cost security of supply in the context of the move to a zero carbon UK energy system. These responses are based on extensive research and modelling at UK and EU level which is referenced below and can found at: http://www.e3g.org/showcase.

The experience of world class bodies such as UK Foresight and the Climate Change Committee shows how complex and uncertain trends and technologies can be assessed in an open and participatory way to inform a comprehensive energy infrastructure strategy. The Commission should draw upon expertise in bodies like the Climate Change Committee to develop common, consistent and robust scenarios to underpin all infrastructure planning. **The aim must not be to try and predict the future but to ensure that the future is not being wilfully ignored in order to simplify decision making.**

The Carbon Budgets

The UK is on track to meet the Second (2013-17) and Third (2018-2022) Carbon Budgets but recent policy changes have undermined investor confidence[1] and in the UK energy market and Government's plans to meet the Fourth (2023-2027) and Fifth (2028-2032) Carbon Budgets[2].

The Committee on Climate Change (CCC) have demonstrated that the lowest-cost trajectory to the UK's legally binding carbon targets requires that the carbon intensity of power generation decreases from around 450 gCO_2/kWh in 2014 to 200- 250 g/kWh in 2020, and to below 100 g/kWh by 2030[3]. Under this lowest-cost trajectory low-carbon generation reaches a total share of around 75% of generation by 2030. The CCC's analysis shows that the demand side has an important role in increasing the flexibility of the power system, alongside interconnection, storage and flexible back-up capacity; supporting the Commissions initial focus on lowest-cost balancing[4].

➔ **The Commission's recommendations and future work should be informed by the CCC's conclusion that the 2020s are a crucial decade for the future of the power sector.** Their findings show that onshore wind and ground-mounted solar deployment should be the priority in the first half of the decade, and nuclear, offshore wind and potentially carbon capture and storage (CCS) in the second half of the decade.

➔ **The Commission should address the risk that, instead of delivering this essential transformation, current policy will result in no deployment of additional onshore wind and CCS and only a limited deployment of offshore wind[5]**. Department of Energy and Climate Change *Energy Trends* data shows that this risk to low carbon deployment could present a significant barrier to balancing supply and demand as a generation gap of over 100TWh is set to open up in the mid 2020s rising to 200TWh by 2030 (see Figure 1 below).

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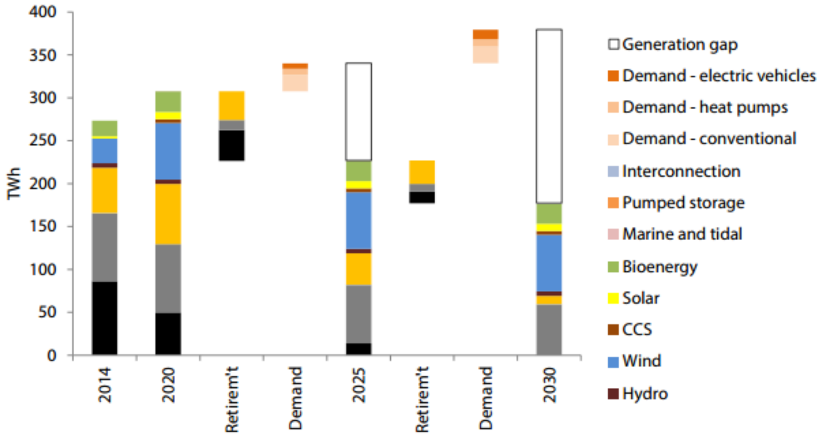
[1] Ernst&Young warned in September that "The lack of clarity and direction around UK energy policy may undermine investment" and concluded that "At best it may be a case of misguided short-term politics getting in the way of long-term policy. At worst, however, it's policymaking in a vacuum, lacking any rationale or clear intent." (EY, Renewable Energy Country Attractiveness Index -Issue 45 - country focus – UK, p35-37 http://www.ey.com/Publication/vwLUAssets/RECAI-45-September-15-LR/$FILE/RECAI_45_Sept_15_LR.pdf#page=35

[2] The Committee on Climate Change warned in September that "[t]he uncertainty created by changes to existing policies and a lack of replacement policies up to and after 2020 could well lead to stop-start investment, higher costs and a risk that targets to reduce emissions will be missed." (A letter from Lord Deben, Chairman of Committee on Climate Change, to The Rt. Hon. Amber Rudd MP, Secretary of State for Energy and Climate Change, 22 September 2015, https://www.theccc.org.uk/publication/letter-clarifying-the-direction-for-low-carbon-policy/)

[3] Committee on Climate Change, Sectoral scenarios for the fifth carbon budget – Technical report, November 2015, https://www.theccc.org.uk/publication/sectoral-scenarios-for-the-fifth-carbon-budget-technical-report/

[4] 'Flexibility is important. To maximise the value of these investments and ensure security of supply it will be important to improve the flexibility of the power sector. That will require investment in flexible gas-fired generating capacity alongside expansion of international interconnection, flexible demand response and potentially electricity storage. The costs of these measures are included in our assessment of intermittency and system costs.' Committee on Climate Change, Power sector scenarios for the fifth carbon budget, p7, October 2015, https://www.theccc.org.uk/publication/power-sector-scenarios-for-the-fifth-carbon-budget/

[5] PWC warned in May 2015 that 'Policymakers must be mindful of industry's need for sufficient long term certainty to support the investment decisions necessary to maintain an appropriate balance between security of supply, decarbonisation and affordability' State of the renewable industry: Investment in renewable electricity, heat and transport, May 2015, http://www.pwc.co.uk/industries/power-utilities/insights/investment-in-renewable-energy.html



(Figure 1. Committee on Climate Change (2015) Power Sector Scenarios for the Fifth Carbon Budget, p32)

The falling cost of decarbonisation

Over the past five years the cost of solar PV has declined by 50%, onshore wind by 18% and offshore wind by 11%. Global markets in efficiency are now larger than new investment in supply side power production[6] whilst the cost of electric vehicle batteries has fallen by 55% and the cost of LED light bulbs by 84%[7].

More co-ordinated and strategic grid planning across onshore, offshore and cross-border regimes could save between £1.5bn and £10bn by 2030. Whilst sharing of system balancing resources with neighbouring countries can save a further £3bn each year by creating a more flexible system that has the effect of 'firming' the output from variable renewables and reducing the need for investment in low carbon generation capacity[8].

Solar generation in the UK has grown from less than 1GW in 2010 to 5GW by end of 2014. Current capacity may double by 2020 depending on government policy changes. These investments were largely unanticipated. In 2011 the Committee on Climate Change expected negligible amounts of solar power in the UK by 2030.

The UK's clean energy policy is not sufficient to meet its Paris Commitment, and needs to be consistent with a lowest-cost pathway to meet the tougher long term targets agreed in Paris. This will require stronger policies to support renewable energy, energy efficiency, low carbon heating, smart grids, clean vehicles and European interconnection.

Electricity consumption and the electrification of transport and heat

Electricity consumption is currently falling as goods like computers and fridges have become much more efficient due to advancing technology and European product regulation. The electrification of transport and heat is expected to add an additional 30TWh of demand by 2030[9]. To improve how electricity demand and supply are balanced the Commission must ensure that the electrification of transport and heat reduces balancing costs. This will require domestic efficiency improvements and a smarter grid that can transform homes and cars into an additional storage resource.

If the electrification of domestic heating is combined with significant improvements in domestic energy efficiency and demand response our housing stock could deliver thermal storage infrastructure at a scale that would significantly reduce the challenge and costs of balancing electricity supply and demand (see section 1c)

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

➔ **To balance supply and demand in the long term whilst minimising costs to consumers the Commission should recommend reforms that are likely to correct predicted imbalances in the 2020s at the lowest costs. Responding to predictable future uncertainties – or "known unknowns" – requires an ability to understand and manage demand, integrate across infrastructure systems, build-in flexibility and preserve optionality.**

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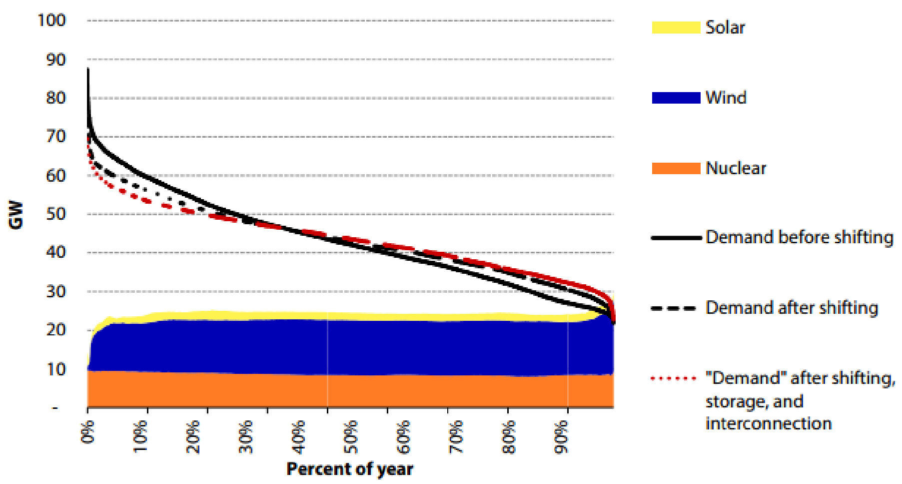
[6] https://www.iea.org/Textbase/npsum/EEMR2014SUM.pdf
[7] US Department of Energy, Solid State Lighting Research and Development Multi-Year Program Plan, 2014
[8] Transmission Planning and Regional Power Market Integration: UK Oportunities (2015), Simon Skillings and Goran Strbac, http://www.e3g.org/library/transmission-planning-and-regional-power-market-integration-uk-opportunitie
[9] Committee on Climate Change, Sectoral Scenarios for the Fifth Carbon Budget, 2015, p41, https://www.theccc.org.uk/publication/sectoral-scenarios-for-the-fifth-carbon-budget-technical-report/

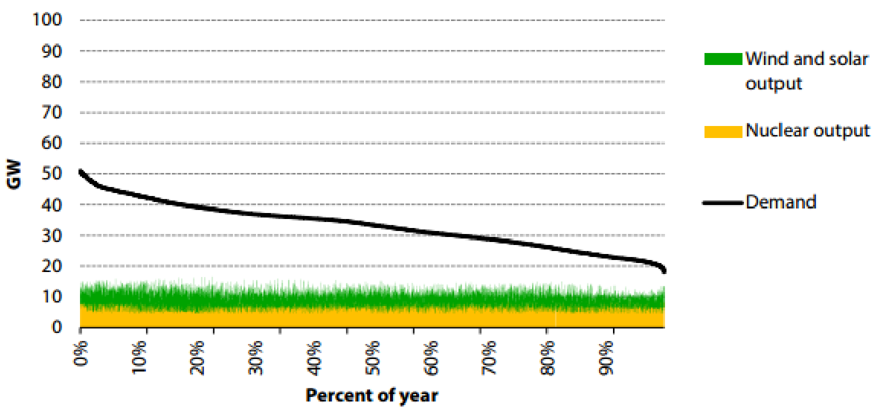
The CCC's lowest cost decarbonisation scenario through to 2030 shows interconnection, demand response and storage deployed and significantly increasing system flexibility. Figure 2 (below) shows how the deployment of flexibility infrastructure lowers peak demand during periods of reduced low-carbon output (on the left) and increasing demand at periods of high low-carbon output (on the right).



(Figure 2. Contribution of wind and solar to meeting demand in hypothetical 2030 scenario (reaching 100gCO2/kWh) with system flexibility deployed[10])

The CCC's findings demonstrate the timeliness of the Commissions emphasis on the system flexibility that interconnection and storage are capable of providing. They also highlight the challenge of delivering a balanced system in 2030 that does not exceed 100gCO2/kWh. Recent policy changes have removed all public investment in carbon capture and storage (CCS) development and deployment creating a very significant barrier to lowest cost balancing which the Commission should address in its recommendations to Government. The Department of Energy and Climate Change and the CCC conclude that a major deployment of carbon capture and storage (CCS) technology in the first half of the 2020s will drive down costs by reducing the requirement for low-carbon new generation.

➔ The Commission should draw on the expertise of the CCC and the Department of Energy and Climate Change to ensure that it is addressing current and future balancing challenges rather than those that have already passed. Figure 3 below shows the gap between current demand and low-carbon output – in 2014 demand was always higher than the combined output of wind, nuclear and solar.



(Figure 3. The combined output of wind nuclear and solar compared to hourly demand data in 2014. CCC calculations based on Gridwatch (2015) Elexon BM Report data for 2014 and Aurora Energy Researh, EOS Data Analytics Platform (2015) data[11])

Ignoring changes to the UK energy system predicted in the Government's own scenarios, and specified in its legally binding Carbon Budgets, in order to simplify decision making today results in a high risk of policy failure; policy designed to address the balancing challenge of today will fail to address the very different challenges of the 2020s. Figure 4 (below) shows that with the higher deployment of wind and solar through the 2020s, the combined low-carbon output (including nuclear) will often exceed demand.

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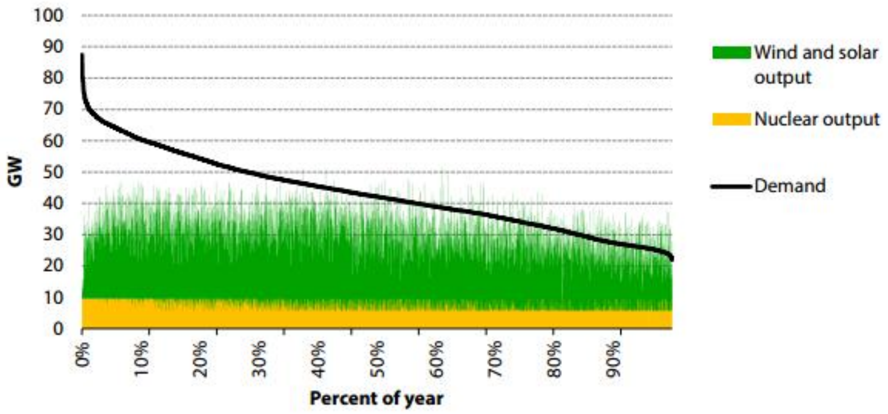
[10] Committee on Climate Change estimates based on Imperial College London modeling (2015)

[11] Committee on Climate Change, Sectoral Scenarios for the Fifth Carbon Budget, 2015, p65, https://www.theccc.org.uk/publication/sectoral-scenarios-for-the-fifth-carbon-budget-technical-report/



(Figure 4. The combined output of wind nuclear and solar compared to hourly demand data in hypothetical 2030 scenario reaching 100 gCO2/kWh, Imperial College London modelling (2015))[12]

(a) Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

An independent systems operator (SO) and reforms to deliver resilient electricity market should be immediate infrastructure priority for the Commission.

The system operator has two key roles: firstly to ensure the least cost and secure operation of the system through design and implementation of a balancing mechanism and contingency measures and secondly to act as the delivery body responsible for central procurement of resources (e.g. low carbon technologies, capacity or flexibility resources, ancillary services to ensure compliance with statutory system operation targets).

It is necessary for the Commission to decide three things: the preferred nature of ownership, the requirement for unbundling and the method of incentivisation for the system operator. The current structure of transmission system operation is a legacy from the early days of liberalisation when there was concern that secure operation of the system required a detailed understanding of the network infrastructure and its maintenance schedules. However, it is now clear that this concern was misplaced and independent system operation has proved viable not only in many overseas markets but also in Scotland (for more information see Annex 1).

Independent system operators have become a standard feature of electricity markets around the world. The increase in complexity of market operation and the need to ensure resources (generation, network and demand) are employed optimally suggest that the time is right to establish a GB ISO, with an eye toward regional integration of system operation. Apart from ensuring that generation, network and demand resources are treated on a level playing field, an ISO can work closely with neighbouring system operators to ensure resources are used efficiently across a larger geographical area. This could be the first step towards creating a regional SO charged with the efficient operation of the market at a regional level.

(b) Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

➔ **Transformational benefits can be obtained through increasing the availablility of low cost balancing resources. The Committee should focus on the challenge of maximising the availability of flexible demand resources and ensure the interconnection of markets allows the full sharing of balancing resources between countries.**

Market reforms over the past 25 years have been based on the presumption that the most efficient outcomes are achieved by allocating imbalance costs where possible and leaving the move to organised trading as late as possible. The 'balancing market' actually comprises three elements:

- Future imbalances resolved through bi-lateral trading
- Future imbalances resolved through organised trading
- Current imbalances resolved through contingency actions

Imbalances arise for both energy and system reasons. Energy imbalances involve those that can be predicted ahead of time and actions that can be taken to restore balance and those that can't be predicted where contingencies need to be put in place to allow recovery. System issues involve locational constraints that are relatively constant and those that cannot be predicted and require various services to maintain system integrity.

The two key choices facing market designers involve the extent to which the costs of imbalance should be allocated between market participants and the point at which organised trading takes over from bi-lateral trading (see Annex 2). Renewable intermittency generally

[12] *ibid*

arises through changes in weather conditions and, therefore, is predictable several hours in advance. Experience in other markets with high levels of variable renewable generation has demonstrated that future output is most easily predicted on a system wide basis, rather than by individual operators, as the impact of weather systems moving across a country can be forecast. This suggests that the system operator is best placed to manage the risk of renewable intermittency since they will have earlier warning of imbalance and access to a wider range of remedies. This would need to be achieved by moving to organised trading several hours ahead of real time.

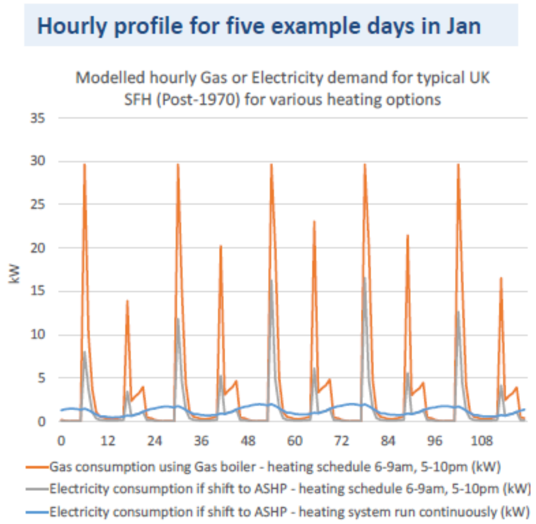
Balancing market design is an extremely complicated issue that has remained contentious despite several decades of attention from regulators and trading experts. It is broadly accepted that the costs of imbalance arising for energy reasons should be allocated to those parties out of balance. However, there are a number of important questions that remain to be resolved:

1. Is the calculation of imbalance cost appropriate in terms of predictability and magnitude?
2. Could imbalances arising for system reasons (long term constraints, reserve costs) be allocated?
3. Is it more efficient to allow intermittent renewables to resolve imbalances through organised trading several hours ahead of real time?

➔ **Above all, it is important to realise that any benefits that may, or may not, be achievable through addressing these questions of detailed market design are likely to be small in comparison to the benefits that can be obtained through increasing the available of low cost balancing resources. In particular, it is important to maximise availability of flexible demand resources and ensure the interconnection of markets allows the full sharing of balancing resources between countries.**

c) To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

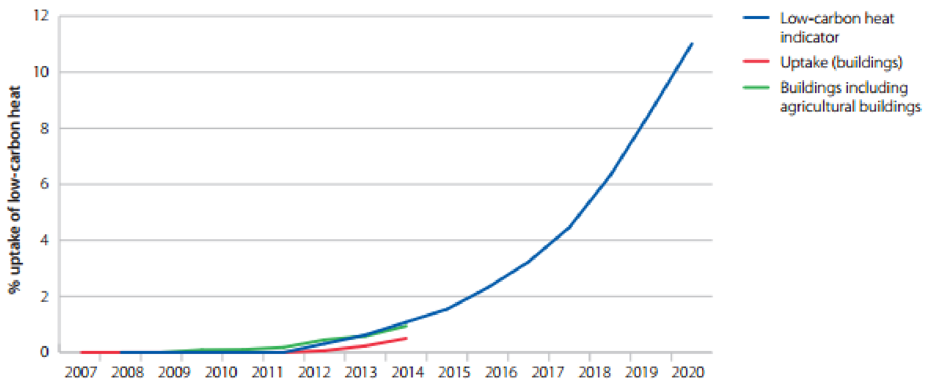
The potential for consumers to respond to price signals and adjust demand is currently unknown but may be a very significant and cost-effective alternative to achieving system balance through supply side measures. A transformational impact on system balancing could be achieved by combining the electrification of heat with domestic energy efficiency (see Figure 5).



(Figure 5. Element Energy for CCC – Research on district heating and local approaches to heat decarbonisation[13])

➔ **The high likelihood of policy failure on heat electrification poses a significant risk to lowest cost systems balancing. The Committee should recommend the delivery of domestic energy efficiency and heat electrification as an infrastructure priority.**

[13] Element Energy for CCC – Research on district heating and local approaches to heat decarbonisation https://www.theccc.org.uk/publication/element-energy-for-ccc-research-on-district-heating-and-local-approaches-to-heat-decarbonisation/



(Figure 6. Uptake of Low Carbon Heat in Buildings from DECC 2014 energy consumption statistics, CCC calculations)[14]

The current market is based on the presumption that consumer engagement should be driven by price and price alone. Whilst there is likely to be a proportion of consumers, particularly those that are large or sophisticated, that will respond to price, many will not. Experience in the supplier switching market suggests that the majority of customers will not engage, despite low levels of effort required and benefits that are far greater than are likely through offering demand flexibility.

A lack of consumer engagement might be acceptable if it was simply a matter of failure to switch supplier since potential impacts on resource efficiency are limited. However, the provision of demand flexibility has real and material potential benefits for overall resource costs that could significantly reduce prices to all consumers. Moreover, widespread engagement in the energy market is an essential prerequisite for the decarbonisation of heat since this will involve significant changes to individual premises.

➔ **The Infrastructure Commission should initiate a fundamental review of the issue of consumer engagement in the context of maximising the potential for demand flexibility and the decarbonisation of heat. In the meantime, momentum must be maintained in promoting market access for those consumers who are prepared to respond to a simple economic incentive.**

2. What are the barriers to the deployment of energy storage capacity?

(a) Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

At present, energy storage does not provide the most efficient means to help balance the energy system when compared to demand side response, interconnection or generation. Energy storage systems are currently technically immature but have the potential for significant cost reductions over the coming years and decades.

Driving forward these technical developments requires new and additional R&D investment but also a programme of deployment to deliver 'learning by doing'. This, in turn, might require system operators, both at transmission and distribution level, to take a long term perspective on the potential benefits for cost efficiencies. These considerations must therefore be included within the relevant regulatory and incentivisation frameworks.

(b) What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

➔ **Transformational opportunities for energy storage can be delivered as part of the electrification of heating (see section 1c) and transport.**

The Commission should include in their next inquiry specific questions to establish a more detailed understanding of the energy storage possibilities from the mass distribution of battery storage through electric vehicles. The effect of zero emissions vehicles on the system balancing challenge will largely be determined by whether or not Government can encourage strategic investment decisions that ensure an orderly transition. With a large disruption to the light vehicle market now considered likely[15], failure to intervene could undermine other interventions to improve energy balancing.

The levelised cost of solar PV has fallen by 78% since 2009 and is increasingly cost competitive with fossil fuels[16]. Solar generation in the UK has grown from under 1GW in 2010 to 5GW by end of 2014. The new tariff for domestic-scale solar of 4.39p/kwh means it now makes sense for

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[14] Reducing emissions and preparing for climate change: 2015 Progress Report to Parliament: Summary and recommendations https://www.theccc.org.uk/publication/reducing-emissions-and-preparing-for-climate-change-2015-progress-report-to-parliament/ p80
[15] http://www.goldmansachs.com/our-thinking/pages/new-energy-landscape-folder/report-the-low-carbon-economy/report.pdf
[16] http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf

household to store what they generate in a battery at home rather than export it for the low tariff. Current trends in distributed generation will be reinforced by the proliferation of newly available battery storage systems for homes and large-scale commercial business, such as the Tesla Powerwall.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

The UK is currently under-connected with its neighbours and significantly greater levels of interconnection would be in the interests of consumers. The current wholesale price of electricity in the GB market is double the price of the German and Nordic electricity markets. Greater interconnection should lead to greater price convergence, including lower costs for GB consumers.

UK interconnection capacity represented only 6% of installed generation capacity in 2014. This puts the UK 21st out of 28 member states. In October 2014 the European Council agreed a target for countries to achieve 15% interconnection capacity by 2030. This target helps to provide forward certainty for the industry as well as adding a political focus on moving investment forward. The 15% target should be seen as an appropriate minimum level of interconnection capacity for the UK to achieve by 2030, with further interconnection capacity developed if needed.

➔ **Interconnection is a strategic system resource. It plays four key functions to support the interests of UK consumers:**

- First, greater interconnection between GB and European markets can enable optimal use of existing generation assets, meaning the most efficient plant are used first – lowering costs to consumers
- Second, interconnection across European markets can enable new generation (and/or demand) to be sited in the most optimal locations – for example for wind power to be located in the windiest regions and solar PV to be located in the locations with the most solar irradiation.
- Third, interconnection can act as a flexibility resource, to facilitate the integration of variable renewable generation.
- Fourth, interconnection can support energy security across asset replacement cycles – meaning the UK can import power when margins are low (as at present) and have the potential to become an electricity exporter in the future.

(a) Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

The Cap and Floor regime is an improvement on the merchant-only model but remains deeply suboptimal from a system perspective. While there is a strong pipeline of interconnectors planned over the next 7 years, the current regime alone is unlikely to lead to an optimal level of interconnection for British consumers. There are three core reasons for this:

- The Cap and Floor model – like the merchant model – relies primarily on congestion rents based on price differentials to fund new investment. However, as interconnection approach the optimal level from a system point of view, price differentials will fall and may not be sufficient to support new investment.
- As the only model of its type in the EU, the Cap and Floor adds regulatory complexity to projects and additional barriers when connecting with other countries (who tend to operate more straightforward regulated investment models).
- Unlike onshore transmission, there is currently no 'system architect' for interconnection, meaning interconnection development tends to be fragmented and incremental. Owners of existing interconnection built under a merchant model have a perverse incentive to avoid new interconnection development.

A new, more forward-looking perspective is needed. Transformational cost reduction and security improvements are available through a regional system architect empowered to make anticipatory investments. In any future with a greater level of interconnection significantly less infrastructure is needed to deliver a secure, balanced and low-carbon energy system.

The 2020s will see the continuing convergence of investment in building efficiency, electricity and gas infrastructure, and the beginning of the integration of electricity and transport systems. It will be impossible to make a credible case for future energy investment without a clear assessment of the impact of regulation and public investment on future demand. This must include assessment of international power resources as the UK grid will be increasingly balanced at European scale, drawing on Norwegian hydroelectric, Irish wind and Spanish solar power[17].

As more physical interconnectors are built, the costs to UK consumers of ignoring the opportunities to share resources with European neighbours will become too large to ignore[18]. It is expected that investment in onshore, offshore and cross-border transmission capacity will reach £23bn–£50bn by 2030, which is considerably greater than the entire current Regulated Asset Value of existing GB transmission assets (< £13bn)[19].

[17] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/68816/216-2050-pathways-analysis-report.pdf
[18] http://www.e3g.org/docs/E3G_Electricity_Market_Reform-_Unfinished_Business_Simon_Skillings_120515.pdf
[19] Transmission planning and regional power market integration: The opportunities for UK Energy Policy (*Simon Skillings and Goran Strbac*) H:\ECF market integration paper - draft (2).docx

Any improvements in the network planning process therefore have the potential to deliver considerable savings in the cost of the network infrastructure as well as significantly reducing the costs of a major offshore wind deployment program. Moreover, more integrated operation of the power system with neighbouring countries has the potential to deliver further savings:

- More co-ordinated and strategic grid planning across onshore, offshore and cross-border regimes could save between £1.5bn and £10bn in the period out to 2030,
- Whilst sharing of system balancing resources with neighbouring countries can save a further £3bn each year by creating a more flexible system that has the effect of 'firming' the output from variable renewables and reducing the need for investment in low carbon generation capacity.

(b) Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

Interconnection faces specific barriers and challenges that are not faced by other balancing technologies. It is cross-border by nature, which means dealing with multiple jurisdictions and plays multiple roles in the energy system beyond system balancing alone.

Realising the benefits from more coordinated and strategic grid planning and interconnector system balancing requires the Commission to deliver institutional, political and regulatory reform. Institutional reform can be achieved by establishing an Independent System Operator (SO) as the institution responsible for coordinating network development requirements and evaluating the implications and opportunities of market integration.

The Commission should make a clear recommendation to Government to ensure that the Internal Energy Market reform process currently being undertaken by the EU Commission focuses on two key issues of significant potential benefit to the UK:

- ➔ Firstly, a system of financial transmission rights trading should be introduced, since this will enable the UK to fund renewable energy projects in other countries and directly benefit from the energy produced.
- ➔ Secondly, a mechanism for the inter-state trading of flexibility products and corresponding allocation of interconnection capacity, since this will create a more flexible power system and reduce the quantity of low carbon generation that is required to meet decarbonisation targets[20].

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The National Infrastructure Commission can significantly improve energy infrastructure delivery by adapting best practice examples from UK and EU cities, international cities and other EU member states.

Responding to predictable future uncertainties – or "known unknowns" - requires an ability to understand and manage demand, integrate across infrastructure systems, build-in flexibility and preserve optionality. Taking advantage of digital smart technologies and the opportunities of convergence of infrastructure systems requires careful integration at the local level of consumer markets, physical systems and planning choices. Pioneering approaches to managing integrated infrastructure can be seen in New York and Berlin in electricity systems and to an extent in London on managing climate adaptation.

Under the Covenant of Mayors – a political movement of mayors that has proved to be one of the most successful instruments of EU energy policy – some 6500 cities have made climate commitments to 2020, and have produced over 4600 city/regional delivery plans, known as Sustainable Energy Action Plans (SEAPs). Many of the commitments in these SEAPs are more ambitious than the EU and national climate and energy targets: signatories have committed to an overall average of 28% GHG emission reduction by 2020 compared to the EU target of 20%3, and have just endorsed an at least 40% CO2 emission reduction target by 2030.

The Smart Cities Forum has defined additional capacities that cities would need to deliver modern infrastructure projects, particularly the need to improve capacity for project development and innovative finance. Moving to a fully devolved system will require stronger delivery support institutions to work with cities, including financial support from the Green Investment Bank.

The Investment Plan for Europe ("Juncker Plan"), which includes the creation of the European Fund for Strategic Investments (EFSI), is supporting increased investment in low carbon projects but the volume of projects coming through is currently low. A significant barrier at the city level has been that energy efficiency financing counts as debt in cities' budgets, and that many EU cities have strict debt rules in line with the national and EU frameworks. Cities are reluctant to increase their level of debts, creating additional uncertainty for energy efficiency investment. As an example, Paris had to look for alternative financing tools for its energy efficiency retrofitting in schools because traditional finance tools such as Energy Performance Contracting (EPC) required public authorities to list the payment as debt in its books.

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[20] Transmission planning and regional power market integration: The opportunities for UK Energy Policy (*Simon Skillings and Goran Strbac*) H:\ECF market integration paper - draft (2).docx

- Re-classifying energy efficiency expenditure as infrastructure capital spending could help overcome these barriers**.** Designating energy efficiency as an infrastructure priority and ensuring that public subsidies and financial support mechanisms in favour of energy efficiency are counted as capital spending, would give greater security and certainty to energy efficiency schemes. The Scottish Government has made home energy efficiency insulation an infrastructure priority.

Progress on deploying these innovations is accelerating as new forms of electricity market governance are pioneered across the world, led by sub-national jurisdictions such as New York[21] where the state Public Service Commission has launched one of the most extensive electricity market reform efforts in the world.

- This could provide valuable insights for the UK. Under New York's Renewing the Energy Vision (REV) new technologies including demand management, energy efficiency, distributed generation and storage are to be used as key tools in the planning and operation of an interconnected modernized power grid. The reform effort underway involves changes to the role of distribution utilities in enabling market-based deployment of distributed energy resources as well as to the current regulatory, tariff, and market designs and incentive structures to better align utility interests with achieving policy objectives. In particular, the NY Public Service Commission (PSC) has recognised the greater role that distributed energy resources can play in system balancing.

Annex 1 – Independent System Operator

The important advantage of independent system operation is that it ensures that all resources are treated equitably and there is no preference, explicit or implicit, for approaches that improve returns for the transmission (and interconnections) business. This is important and can be introduced through well-enforced business separation or full ownership unbundling.

It is also extremely important that the system operator is effectively incentivised, to ensure lowest costs to consumers (current and future). Equitable treatment of resources is only part of this challenge since it is also necessary to have a clear time-horizon over which costs are minimised. In particular, certain resources, such as those on the demand side or storage (see below) may be technologically immature and require some short term support to deliver long run efficiency.

Developing a sufficiently robust financial incentive for a for-profit system operation business is likely to be extremely complicated (the existing system operator incentivisation mechanism already suffers from complexity and lack of transparency). In most international energy markets, the preferred structure is, therefore, for a Government-owned independent system operator operating under statutory mandate.

A Government-owned independent system operator is the preferred way forward in the UK. Apart from the advantaged described above relating to the efficient procurement and dispatch of resources, it would also present the opportunity to rationalise resources currently residing in Government and Ofgem that are involved in resource procurement and market surveillance.

Annex 2 – allocating costs for energy imbalances

Market reforms over the past 25 years have been based on the presumption that the most efficient outcomes are achieved by allocating imbalance costs where possible and leaving the move to organised trading as late as possible.

The process of cost allocation for energy imbalances involves a number of subjective judgements. Firstly, the cost has to be calculated and this depends on the pricing algorithm adopted in the organised trading mechanism and the extent to which the costs of contingency reserves are included. Secondly, imbalances will often arise through some combination of energy and system reasons that cannot be separated.

The pricing algorithm adopted within the organised trading mechanism is not only important in defining the magnitude of the costs to be allocated but its predictability is also critical in determining the efficiency of the forward trading market. This latter point is particularly relevant for demand response where actions often need to be taken ahead of real time to prepare for reduced consumption. This requirement will diminish as more automation is introduced and a response can be delivered to a price signal almost immediately.

Currently, there is no attempt to allocate the costs of imbalance that arise through system reasons. However, long term locational constraints could be represented effectively through locational marginal pricing and a system of financial transmission rights and this approach is adopted in some international markets. Also, the costs of contingency reserves arise through unexpected loss of power plant (or rapid changes in demand driven, for example, by TV schedules) and the costs are particularly high as a result of power plants with high unit capacity (e.g. nuclear).

[21] See New York's Reforming the Energy Vision at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

Electricity interconnection and storage

The following response has been provided under the National Infrastructure Commission's call for evidence, published 13 November 2015.

EA Technology has a strong heritage working with the owners and operators of energy networks to increase their reliability or make them more cost-effective. We have a rich technical knowledge base and are passionate about using this to deliver economic benefits to our customers, and the customers they ultimately serve. We have pioneered world-leading developments ranging from intelligent investment planning software, to electrical energy storage, through to running large scale projects on electric vehicles.

We therefore focus these responses on the **electricity interconnection and storage** consultation on how changes to existing market frameworks, increased interconnection and new technologies in demand-side management and energy storage can better balance supply and demand.

For more details please contact: [email address redacted]

Changes to the electricity market to ensure that supply and demand are balanced

Domestic energy consumers – representing approximately 40% of UK consumption[1] – are not currently exposed to half-hourly balancing costs. There is currently therefore little or no incentive for individual customers to modify their demand to reduce these costs. The reasons for this lack of exposure include:

- legislation enacted to simplify tariffs means that electricity supply companies cannot easily offer variable half-hourly tariffs (i.e. political constraint);
- the market demand for variable half-hourly tariffs is still to emerge (i.e. economic constraint), although fixed-time tariffs such as Economy 7 remain popular and account for 25% of domestic consumption; and
- the smart meters necessary for half-hourly billing are not yet widely deployed in the UK (i.e. technical constraint).

For non-domestic energy consumers – representing approximately 60% of UK consumption – the situation is different as approximately 70% of demand is half-hourly metered. Therefore 42% of UK electricity consumption is potentially exposed to half-hourly balancing costs and could therefore be incentivised via tariffs to ensure supply and demand are balanced. In practice, consumers do not like the variability that this entails and so they will generally look for a tariff arrangement that limits their exposure to this variability.

The result of this is that electricity consumers in the UK currently have very little incentive to ensure that supply and demand are balanced, even if it were beneficial for them to do so. As a result, balancing costs will inexorably rise (in the absence of any other controlling factors). This situation represents a market failure.

[1] https://www.gov.uk/government/collections/sub-national-electricity-consumption-data

The need for an independent System Operator

The above market failure can be addressed in a number of ways. The debate is often framed in terms of a dilemma between the two following choices:

1. should consumers and generators be exposed to balancing costs (thereby applying free market mechanisms to keep balancing costs down), or
2. should the task of minimising balancing costs be entrusted to an independent System Operator (thereby limiting the exposure of consumers and generators to balancing costs)?

EA Technology does not have a strong preference for either option.

We believe that Option 1 would, ultimately, produce the best outcome (i.e. the lowest costs to consumers, over the long term). However, all the political, economic and technical constraints described above would need to be addressed beforehand in order for this market to function. Furthermore, the current half-hourly market (on which all electricity trading is based) may ultimately be much to slow to reflect the real-time nature of balancing costs, especially as the generation mix becomes ever more intermittent (see Figure 1). Moving to real-time electricity trading would be a massive, unprecedented undertaking and not a decision to be taken lightly.

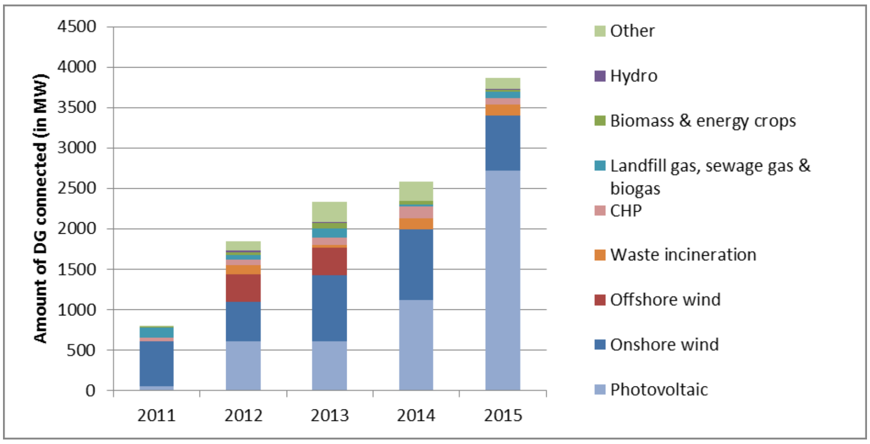

Figure 1 Increase in in intermittent, non-despatched generation connected to the UK distribution network

Option 2 represents a more pragmatic approach, in that an independent System Operator would undoubtedly drive incremental reductions in balancing costs over a realistic timeframe. Our concern is that this approach will not, ultimately, produce the best outcome. The System Operator may have only limited authority over the real-time behaviour of generators (especially distributed generation) and will have little or no control over consumer behaviour (unless the political, economic and technical constraints are addressed, as above). Therefore, rather than influencing generator and consumer behaviour to minimise balancing requirements, the System Operator is likely to respond to balancing issues through costly infrastructure investments and changes to operational procedure – over timescales measured in years. This is very different from being driven solely by a desire to reduce balancing costs. In this light, it is hard to conceive of an appropriate set of financial incentives for the System Operator that would – somewhat perversely – need to offer greater rewards as its services are needed less and less.

Interconnection versus balancing

On a small highly islanded electricity network, balancing is a real-time, technical imperative. Without balancing, the lights go out. Instantly.[2] Keeping the lights on can result in very high balancing costs.

On a heavily interconnected network (with the necessary robust transmission infrastructure)[3], balancing costs are less of an issue. Generators generate, consumers consume and the market takes care of the energy pricing. Local system operators manage power flows as best they can, but can (generally) fall back on the backbone transmission system as needed. This results in very low balancing costs.

There is therefore an opportunity to reduce balancing costs by increasing interconnection.

A market opportunity

EA Technology believes there is a strong case for using market mechanisms to minimise balancing costs to consumers over the long term.

However, EA Technology does not believe that an electricity market based around half-hourly energy prices is the right market mechanism to reduce balancing costs. Even with significant reform and investment, it is hard to imagine how variations in half-hourly pricing can achieve the desired outcome; if energy consumers are exposed to sudden price spikes, the outcome is likely to be anger and dissatisfaction directed at "those in charge" rather than any meaningful change in behaviour.

On the other hand, consumers are more likely to change their behaviour if offered a direct reward for any change they make. If inflexible generators (and network operators) are exposed to significant balancing costs, they may well be willing to pay consumers directly to help them reduce these costs. If this were a direct payment – outside of any half-hourly trading mechanism – then this would immediately address the three constraints identified above:

- there would be no change to domestic energy tariff arrangements between consumer and supplier;
- demand would be created by the offer of a payment to those able to change behaviour to address balancing costs; and finally
- the implementation of this market framework would not necessitate smart meters.

We believe that a new 'direct balancing market' mechanism that exposes market participants in the following way would produce the desired outcome:

1. System Operator sets the balancing price for a specified period
2. Flexible generators adjust their output during this period to minimise balancing charge
3. Inflexible generators either pay the remainder or pay flexible consumers to help minimise it
4. Flexible consumers modify their demand in return for payment from inflexible generators
5. Consumers who choose to remain inflexible do not benefit from such payments

Only those consumers participating in balancing activities need to have a measuring device or other mechanism to confirm participation. This would offer far more opportunity for innovation over what can be achieved using a typical domestic smart meter e.g. use of smartphones to provide monitoring

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[2] http://www.independent.com.mt/articles/2014-01-09/news/widespread-power-cut-3641016320/

[3] http://www.entsoe.eu

and/or evidence of behaviour in return for payment. Furthermore, because there would be an active market in influencing behaviour to minimise balancing costs, together with a clear financial advantage for flexible generation over inflexible generation, any dependence on the independent System Operator to manage these costs is reduced. The System Operator merely needs to set the balancing cost and let the market take care of the rest.

The effectiveness of Demand Side Management

Demand Side Management is sometimes referred to as demand side response. This alternative term recognises that demand isn't something that can easily be "managed". However, it may be possible to shift useful amounts of demand using appropriate signals and incentives, at the same time as ensuring that customers retain overall control over their electricity consumption.[4]

The understandable concern about this more voluntary approach is that it may be ineffective: what if consumers are unwilling (or unable) to shift demand in response to these signals? Won't this lead to significant imbalance?

Such concern is well-founded. There is relatively little deferrable load currently in consumer premises: other than cooling and heating, most existing load (such as lighting and cooking) cannot be deferred for long. However, this rather pessimistic outlook ignores the fact that there are very significant changes occurring (and about to occur) in electricity usage patterns. The most significant changes include:

- The connection of photovoltaic (solar) generation to domestic premises (3kW-10kW+)
- The use of heat pumps for heating (3kW-15kW+)
- The charging of electric vehicles (3kW-10kW+)

These new electrical loads all share some interesting characteristics:

- They are all significant – often much bigger than existing domestic loads
- They are all becoming increasingly commonplace
- They are all controllable and/or deferrable to some degree

The Transform Model® developed by EA Technology has shown that demand will change significantly moving forward with the electrification of heat and transport and the proliferation of small scale generation (and potentially, small scale storage). Furthermore, recent work by National Grid with Element Energy[5] has indicated that, by 2030, the contribution of such deferrable loads could provide over 80% of GB's requirements. This is because loads such as electric vehicles are plugged in for an average of 8 hours per day, but only require 3 hours to draw charge, meaning the window within this load can be managed is significant.

The opportunity is there for these new loads to play a significant and increasing role in minimising balancing costs. The technology is already available: EA Technology / SSEPD's My Electric Avenue

[4] Koliou, E.; Eid, C.; Hakvoort, R.A., "Development of Demand Side Response in liberalized electricity markets: Policies for effective market design in Europe," in European Energy Market (EEM), 2013 10th International Conference on the , vol., no., pp.1-8, 27-31 May 2013
doi: 10.1109/EEM.2013.6607403
[5] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Technology-reports/

electric vehicle project[6] has shown beyond doubt how its Esprit managed electric vehicle charging can deliver significant shifting of electric vehicle loads without detriment to the customer experience. What is currently missing is any market mechanism to enable adoption of such technology. This is the opportunity currently available to the UK and we urge the National Infrastructure Commission to play a key role in realising this outcome.

Barriers to deployment of energy storage

The existing energy market and balancing regime considers “generation” (with one set of rules) and “demand” (with another set of rules). Storage technology is unique, in that it can be both generation and load. Distributed storage is often able to switch from one mode to another in a very short space of time – yet this is not recognised by the traditional market. The developing UK Balancing Services market (especially STOR[7]) provides one model to address this limitation, but unfortunately the minimum generator size (3MW) is prohibitively large and the frequency of balancing requests (~70 p.a.) much to infrequent to encourage commercial deployment of storage technologies.

Storage operators therefore need to operate two supply contracts – one for demand, one for generation – with limited opportunity to optimise between them: even if the electricity supply contract recognises that the storage unit can reduce its demand to zero at any time, it will not be able to recognise that it could also become a generator (i.e. negative load) at times of high demand. Likewise for the generation contract, which will not be able to recognise that the storage unit could become a load (i.e. negative generation) at times of excess generation. Both of these capabilities would enable storage to contribute effectively to balancing services, but cannot be achieved through conventional energy trading mechanisms. As a result, the positive contribution that storage can make to balancing at all voltage levels cannot currently be recognised.

There is another aspect of storage that is often overlooked: such technologies often make use of heat energy (e.g. phase-change heat pumps, compressed air storage). Unlike electricity, heat is extremely difficult to transport over long distances and so for these storage technologies to be cost effective, they must be in a geographically suitable location. The economically ideal location for storage would contain a synergistic mix of local heat and electricity demand that can be balanced off using the storage unit. Heat energy is not regulated and can be traded locally; unfortunately the same is not true for electrical energy. If storage operators want to make use of the local electricity grid, they can only do so by trading through the energy market – which, as described above, does not recognise the contribution that storage can make to balancing services.

EA Technology believes that two changes to the existing market would enable greater uptake of storage capacity:

1. The enabling of “Storage” connection agreements and tariffs, instead of requiring storage operators to hold both “Generation” and “Supply” contracts.
2. The enabling of electricity to be traded directly between third parties over the local electricity network (via contract with the local electricity network operator), without requiring participation in the national electricity market.

[6] http://myelectricavenue.info/

[7] http://www.thinkinggrids.com/ancillary-services/stor-provides-short-term-generation-support-and-cost-62m-in-2014-2015

It is realised that the above proposals would represent a radical shift away from the national half-hourly trading regime and we recognise that such market freedom may be somewhat risky of adopted on a large scale. However, we think there is a case for trialling these freedoms with small scale storage units. Not only would this remove a significant barrier to the uptake of storage, but also the behaviour of these smaller units could be closely observed with a view to further relaxing national trading arrangements as more is learned about the contribution that storage can make to balancing.

Such wider uptake should also drive down the price of storage technology – an issue that must be addressed if storage is ever to make a significant contribution to balancing service.

Appropriate level of electricity interconnection

As described above, increased interconnection leads to reduced dependence on balancing services. In EA Technology's view, the economic case for increased interconnection should always be weighed up against the economic case for reducing the requirement for such interconnection through demand side response. The optimum mix of interconnection and demand side response will change and develop continually. We believe this mix should be determined though market mechanisms wherever possible.

The 'cap and floor' regime provides a useful mechanism to encourage the building of interconnection. Our primary concern is that such market "distortions" might encourage building of interconnection when it is not needed (if the floor is set too high) or discourage the connection of necessary interconnection (if the cap is set too low). There does not appear to be any reflection in this mechanism that the actual need for interconnection may change over time. Given the significant changes expected in electrical demand patterns that is expected over the lifetime of these 'cap and floor' contracts, we think there is a high risk of an eventual mismatch between the level of required interconnection and the level that is actually built.

The ideal approach would be to expose interconnection, demand side response and storage to the same market drivers – given that they all contribute to the same outcome i.e. a balanced system. We would encourage further discussion and analysis on whether the 'direct balancing market' proposed earlier in this response could be usefully extended to interconnection providers as well.

International best practice

An example of allowing consumers to participate in the market via a mechanism other than through smart metering tariffs is that provided by Powershop in New Zealand.[8] This is a model whereby customers have the option of purchasing different 'packs' of electricity units at different prices in advance of using them. In this way, customers can purchase units at a saving compared to the standard tariff. The interface is accessible via an app on the customer's phone or tablet, putting them in control of their energy purchase, and allowing them to monitor their consumption. This model is soon to be brought to the UK via partnership with RWE npower[9].

[8] http://www.powershop.co.nz/

[9] http://www.npowermediacentre.com/r/5298/rwe_npower_and_meridian_energy_limited_enter_into

Evidence

National Infrastructure Commission call for evidence - Electricity interconnection and storage

EDF Energy's response to your questions

Q1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Market framework and investment challenge
The generation mix will have a significant impact on the costs of operating the system. This is shown clearly in National Grid's recent System Operability Framework (SOF) publications which highlight the differences in system costs arising from different generation mixes. Although it may be possible to mitigate these cost impacts to some extent through storage, demand response and interconnection, we believe that an important first step is to ensure that there is a sensible generation mix. Government should regularly publish and consult on its view of the key constraints and parameters for the generation mix, taking account of deliverability, whole system costs and operability, including the implications for transmission infrastructure; it should take this analysis into account in the design of support schemes.

The Electricity Market Reform (EMR) package has provided the right framework to deliver the transition to a low carbon generation mix and to maintain security of supply at an affordable cost to consumers. Key elements of EMR are the Carbon Price Floor to provide an appropriate carbon price signal to electricity generators, a market-wide technology neutral Capacity Market to support investment in new and existing capacity to safeguard security of electricity supply and the Contracts for Difference (CfD) mechanism to support investment in new low carbon generation.

However, further evolution of the market framework is required to address outstanding challenges, both in the short and longer term. The UK needs to replace and upgrade energy infrastructure. Specifically in power generation, over 40% of the capacity operating in 2012 will have closed by 2030, falling into three main categories:

- Around 8 GW of coal-fired plant has closed since 2012 driven by restrictions imposed by the Large Combustion Plant Directive with the remaining 18 GW expected to close before 2025, some of it imminently, due to further environmental limitations coming from the Industrial Emissions Directive and the Government's intention to close all remaining coal generation by 2025;
- Moreover, over 6 GW of older less efficient gas-fired plant has closed since 2012 with further plants at risk of closure in the next few years;
- Over 7 GW of EDF Energy's Advanced Gas Cooled Reactor (AGR) nuclear plant is expected to close as it reaches the end of its scheduled life by 2030.

We need to replace this capacity to deliver a balanced energy mix that will include new and existing nuclear, gas-fired plants (replacing coal generation as it closes) and renewables, each of which has different characteristics. We must achieve the required scale of investment, delivered when needed through a combination of extension of existing asset lives and construction of new capacity. This investment challenge is exacerbated by low commodity prices making investment in low carbon generation uneconomic. CfDs provide the right mechanism to support investment in new low carbon generation. Investment in existing low carbon generation is also required; EDF Energy invests £600m per annum in its existing nuclear stations, including in , life extension and outages. It is important that this is supported by access to capacity market revenues and strong carbon price support.

The capacity market provides the right framework to support investment to ensure security of supply; it must remain technology neutral to deliver the best value for consumers. It has been widely commented on that first two capacity market auctions have not delivered new CCGTs. This is unsurprising as we have been coming out of a period of over-capacity. However, we are reaching a time when new gas-fired generation will soon be needed, but the clearing price for the first two auctions would not deliver new capacity. Some further development of the capacity market is necessary including:

- Measures to ensure that new assets securing capacity agreements are delivered, including effective pre-auction checks on project financing (DECC has recently consulted on this issue);
- Ensuring that adequate capacity is procured in T-4 auctions through prudent assessment of capacity requirements, and a review of volumes set aside for procurement in T-1 auctions;
- Consistent methodologies to calculate de-rated capacity provision.

In addition, action should be taken to address market distortions arising from embedded benefits that do not reflect the costs and benefits arising from embedded generation. These embedded benefits are currently distorting outcomes in the capacity market by giving an unjustifiable cost advantage to embedded generation compared with transmission-connected generation, such as CCGTs.

National Grid is right to use Supplemental Balancing Reserve (SBR) as an interim measure until 2018. It is important to ensure that it continues to provide consumers with value for money during this period. SBR will not provide signals for new investment and therefore must stop when the CM becomes operational in 2018.

Efficient price signals
The development of an efficient system, where supply and demand can be balanced cost effectively, relies on efficient price signals. There are three areas where this needs to be addressed: carbon pricing; pricing intermittency and network charging.

Carbon pricing:
It is important to maintain strong carbon pricing to provide the right economic signals to meet decarbonisation goals. This would ideally be achieved through the European Emissions Trading Scheme (EU ETS). However, to date this has failed to provide the price signals necessary to support investment in low carbon generation. Until it does so, it is vital that the UK continues to maintain a strong UK-wide Carbon Price Floor through the 2020s. Continuation of the Carbon Price Floor at a level which stabilises the current level of wholesale price impact will provide a clear price signal to encourage investment in decarbonisation and a source of tax revenue to the Government and will support decarbonisation at least cost to consumers. More specifically, it will support the Government's objective of phasing out coal

generation and replacing it with new, efficient gas-fired plants and it will also support the refurbishment and life extension of existing low carbon generation, including existing nuclear power stations.

Pricing intermittency:
Intermittent plant imposes additional costs on the system because it requires additional capacity to provide back-up when it is not available at peak demand times, it leads to additional investment requirements on the transmission system and, as the volume of intermittent generation grows, it will increasingly result in the production of surplus wasted energy at times of low demand. Therefore, intermittent plant should bear the cost it imposes on the system; it is important to develop clearly agreed solutions to deliver this.

There are two possible approaches which may not be mutually exclusive. One would be to make changes to market rules and charging arrangements. The other approach would be to provide clearer incentives to intermittent generators through two changes to the design of the CfD mechanism.

- Firstly, new CfDs for intermittent generation could be struck against the baseload reference price: this would greatly improve incentives for market-supportive outage planning, as well as more accurately allocating at least some elements of the costs created by intermittency.
- Secondly, paying CfDs on the basis of availability rather than output would remove incentives to generate when not needed and help to avoid distortions to near-term wholesale and balancing markets, and consequential distortions to incentives for investment. In our modelling we have quantified the additional cost of suboptimal dispatch introduced by this distortion as being in excess of 20% of the total cost of providing response, or around £65m a year. We are happy to share this modelling with the National Infrastructure Commission.

Network charging:
A comprehensive review of networking charging arrangements is required to ensure that they remain fit for purpose and effective in promoting economic outcomes to ensure that the energy system develops at least cost to consumers. A significant example of concern is the favourable treatment of embedded generation through the transmission charging regime; this has contributed to the success of embedded generation in the Capacity Market auctions at the expense of transmission-connected capacity (e.g. new CCGTs) for reasons that do not reflect economic fundamentals.

Embedded generation gets a double benefit from the transmission charging regime because, firstly, it does not pay for generators' Transmission Network Use of System (TNUoS) charges and, secondly, it derives a benefit because suppliers can net embedded generation off their TNUoS charges. This approach had some justification in the past when transmission charges were largely driven by the need for investment to meet increases in demand and the relatively small volume of embedded generation served to reduce the need for this transmission investment. However, transmission investment is now largely driven by changes in the generation mix, not by demand growth, and new embedded generation will bring little or no benefit to the transmission system.

There is a similar charging treatment of Balancing Services Use of System (BSUoS) charges which means that, for example, although embedded solar photovoltaic (PV) generation requires National Grid to hold more reserve to cover rapid changes in its output, it pays nothing towards the cost of this reserve but instead derives a benefit through an offset against charges on suppliers.

It will often be the case that solar PV on a consumer's premises will make no contribution to reducing the peak capacity requirement driving the need for distribution network investment but it will reduce the distribution charges paid by the consumer. Other charges, e.g. for the capacity market, are also levied on net demand volumes. With increasing embedded generation this needs to be reconsidered.

Demand Side Response (DSR) and Embedded Generation
Existing market arrangements provide price signals that indicate to consumers when electricity is most costly to provide and when it is cheapest, and we support the continuing development of these signals.

- Two-thirds of electricity consumption is settled on the basis of half-hourly meter readings and so exposed to the wholesale market time-of-use signal. This provides an incentive for large business consumers to shift their load to periods when it is cheaper.
- Charging for access to the transmission and distribution networks is on the basis of consumption during winter peak hours that signals the additional cost of meeting peak demand through investment in new network capacity. This provides an incentive for large business consumers to avoid consumption when overall electricity demand is highest[1].
- For the domestic residential sector and the smallest commercial premises, historically the only significant flexible load has been electrical heating. The various Economy 7 tariffs have been effective at providing an incentive to take this demand overnight.
- Smart metering will enable these consumers to be settled on the basis of half-hourly meter readings, along with existing half-hourly meters. This means the entire market will be half-hourly settled, and exposed to time-of-use incentives.

Therefore, the arrangements for DSR participation in the wholesale market already exist, and the smart metering programme is completing the picture. It is right to ensure that the market framework does not impede the development of cost-effective DSR. At the same time, efforts to stimulate artificially a "market" for DSR outside the wholesale market would risk undermining the economic efficiency of these arrangements.

There are circumstances in which it is appropriate for the SO (for the transmission network, and, potentially, in the future, for distribution networks) to procure DSR outside the wholesale market, as it does with generation: within half-hourly periods; in specific geographical locations; or with specific technical characteristics (inertia, reactive power provision etc.) Where a demand-side provider can offer these services most cost-effectively then that is to the benefit of all consumers. Equally clearly, it is not to the benefit of all consumers that the SO should pay "over the odds" for demand-side services – there is no additional social benefit that would justify this.

[1] This is known as "TRIAD avoidance".

Modelling work was undertaken in DECC / Ofgem's Smart Grid Forum[2] workstream on the 2030 distribution networks, to analyse the potential for DSR to be used outside the wholesale market for management of the local network. The results show that "smart solutions" may help to postpone necessary reinforcement work, and are relatively quick to deploy, but cannot avoid indefinitely the need to put new distribution infrastructure in the ground. Based on this and similar analysis, we consider that the most cost-effective application of DSR is through the wholesale market, not via network operators. Therefore, we would like to emphasise the importance of having a clear route to market for DSR, to enable all consumers to satisfy their consumption needs at least cost. The current proliferation of overlapping special and one-off schemes obscures the opportunity rather than stimulating it.

In parallel with consideration of the market arrangements for DSR, we are also keen to counter the frequent exaggeration of the potential volume of domestic residential DSR. A mistaken sense of the ease with which the load curve could be "flattened", and the value of a flat load curve compared with a peaky one, has fuelled inappropriate refinements to the market arrangements.

Since 2010, we have undertaken detailed modelling to create an hour-by-hour breakdown of electrical load by application. We have used this breakdown to assess the potential for flexibility of DSR, and used our fundamental dispatch models to determine the value of enhanced flexibility across a range of scenarios. The modelling approach complements the experimental approach undertaken in a series of trials by the distribution networks, in which we have also been involved, funded under Ofgem's Low Carbon Networks Fund (LCNF)[3]. Together, these trials create a valuable resource of data on the real-world reaction of domestic and other consumers to incentives for load shedding and shifting.

Based on our modelling (which we are happy to share with the National Infrastructure Commission on request) and LCNF trial results, evidence is accumulating that there is little value creation resulting from shifting the volume of load that is flexible in typical household consumption. Frontier Economics' analysis of Northern Powergrid's Customer-Led Network Revolution[4] trial shows the *annual* value of interrupting tumble dryer load is up to £4 for a typical household. Other (smaller) loads, including washing machines and dishwashers offer around half that potential. Larger value, up to £15, is available for households with electrical heating – though the number of these households is small, as the majority of electrically-heated homes already utilise night storage heaters (to benefit from Economy 7 tariffs).

In our modelling we have also reviewed scenarios for future changes in load, especially resulting from the electrification of heating and transport, driven by cutting carbon emissions in these sectors. It is clear that electric vehicles (EV) in particular could dramatically increase peak load, assuming consumers recharge their vehicles on arriving home in the early evening. Projections for the speed and extent of EV roll-out vary widely, but we calculate savings from flexible EV charging could be significantly higher, around £150 for the first mover (i.e. assuming all other consumers charge their EV as they wish, there is a saving of £150 available for anyone willing to be flexible; though as more consumers shift their consumption to take

[2] UK Smart Grid Forum Portal: http://uksmartgrid.org/
[3] LCNF: https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund
[4] Northern Power Grid: http://www.networkrevolution.co.uk/

advantage of the saving, the saving will fall to around £90). For this reason, we believe the assessment of the benefit of half-hourly settlement for smart meters should take note of the latest projections for EV uptake.

Finally, we would like to emphasise that a distinction should properly be made between genuine load-shifting / shedding and embedded generation. The capacity market design does not distinguish between "true" DSR and "behind the meter" embedded generation; we believe that there are essential differences. Embedded generation can provide an appropriate response at peak times in the same way as DSR but it has impacts on carbon and other emissions and so it is important that the right controls are in place to manage any consequential environmental damage. Therefore, in the interests of transparency and to assist future policy development, the operation of the capacity market and the procurement of flexibility products should identify clearly whether providers are providing DSR or embedded generation.

Independent System Operator

The System Operator (SO) has a key role to play in ensuring that the system is balanced cost effectively both short- and long-term. National Grid's role is evolving as it enhances its SO function by acquiring greater responsibility in system planning. We do not believe that the case has yet been made for a fully independent SO and there are risks that need to be carefully considered if such a proposal is implemented. However, we believe that it is appropriate for there to be a review its role, which should encompass SO incentives, National Grid's role in providing visibility on system costs, and potential conflicts of interests, particularly in relation to National Grid's interconnection business.

<u>SO incentives</u>

Ofgem sets a range of incentives on National Grid that are designed to deliver financial benefits to the industry and ultimately consumers by reducing the cost and minimising the risks of balancing the system. The SO incentives are generally set over short time periods (1 or 2 years) and partly due to uncertain future projections of costs, and so focus on minimising short-term costs. With an evolving, fast-changing energy mix and the need to develop innovative solutions to address new or growing issues, a different incentive framework is needed. Developers of new services need longer-term certainty to allow investment. Whole system costs also need to be considered which go beyond the current artificial transmission/ distribution boundary. Incentives are needed to ensure that processes and systems are developed to plug this potential gap.

We believe there is scope to set more effective SO incentives for National Grid that could minimise cost to consumers over the longer-term while balancing the need to keep short-term costs and risks low. This is important area needs significant attention during 2016.

<u>System costs</u>

It would be helpful if National Grid could do more to provide visibility of the system-related costs of different generation mixes. We believe this could be achieved through further development of their Future Energy Scenarios (FES). The status of the FES has increased over recent years. They are now used across the industry to determine capacity requirements, allocation of CfDs under the EMR framework, as well as the general development of longer term energy policy. Given their elevated status it is important to review the checks and balances in place to minimise conflicts of interest and ensure that these FES represent an independent assessment of the potential range of future outcomes. The FES forms the basis of the System Operability Framework (SOF). It would be helpful if National Grid could do more in the FES to provide evidence of the likely costs of operating the system under different future energy mix scenarios.

Conflicts of interest
Finally, we believe it is important to ensure there is no conflict of interest between National Grid's SO role and its ownership of a commercial interconnection business. There is a risk that National Grid's ownership of an interconnector business could compromise its ability to provide independent advice in its role in supporting Ofgem's interconnector cap and floor assessments. It is important that the SO can make an objective assessment of more interconnection, and take that into account in its views about system development. We recognise that National Grid has put some measures in place to manage potential conflict. We believe it would be valuable to review whether these measures are sufficient to ensure that no conflict of interest could arise.

Balancing Market
We do not see a need for further reform of the balancing market itself at this stage. The outcome of Ofgem's Electricity Balancing Significant Code Review to address long-standing concerns on electricity balancing arrangements[5] began to be implemented in late 2015. It is important that these changes are given time to have effect. In parallel, European Market initiatives to harmonise markets are in development which may lead to further reform of the GB balancing market and lead to a broader balancing market.

One area where development is needed is ensuring that the balancing market arrangements are applied effectively to all parties who may be responsible for energy balancing. There are already new market participants getting involved in providing balancing services, e.g. aggregators, and the potential for further innovative business models. With increasing innovation it is important that imbalance arrangements cater for new types of parties to ensure incentives to balance are maintained.

Q2. What are the barriers to the deployment of energy storage capacity?

Energy storage plays a huge role in GB's energy infrastructure at present. Coal is stockpiled at power stations; petrol is stored in quantity throughout the supply chain; and natural gas is injected throughout the summer into vast underground caverns, and withdrawn to fuel consumption in winter. Fossil fuels are cheap to store. The challenge for a low-carbon energy mix is to replicate the flexibility that this storage provides, without the fossil fuels. The most significant barrier to using electricity storage to provide this flexibility is simply its much higher cost per unit of energy.

Due to the high capital costs, to date electricity storage has only been economically viable with pumped hydro, which can cycle on a daily basis. Through technological innovation, the costs of battery storage are decreasing rapidly, and are no longer orders of magnitude higher than pumped storage. It is therefore becoming commercially viable to deploy batteries for applications with very high frequency of cycling, e.g. for second-to-second management of the transmission grid; and as costs continue to fall, we expect these applications to become

[5] Concerns included cash-out prices not creating the correct signals for the market to balance, which could increase the risks to future electricity security of supply and undermine balancing efficiency, unnecessarily increasing costs

broader, to include other reserve services (requiring longer response duration) and potentially playing a daily cycling role similar to pumped storage. At residential scale, for example, this would enable daytime solar generation to be used in the evening. On a transmission-level scale, daily cycling of storage could help to accommodate intermittent wind generation; on the distribution level, storage with reliable daily cycling potential can help provide security of supply to the local DNO.

These applications are dependent on continued strong cost reduction, by perhaps as much as an order of magnitude, which is not guaranteed. Moreover it is inconceivable that costs could fall to the point where batteries (or any other electricity storage) could play a role in accommodating seasonal variation in demand or supply. So a "solar plus storage" model will only work in GB in the summer months to utilise daytime solar power in the evening. It does not have the same potential in GB as in other parts of the world, for example California, where hours of sunshine are more evenly distributed through the year.
It will be important to support further cost reduction in storage via R&D as this is the key barrier to its deployment. In addition, addressing some of the distortions in the market already mentioned will help to facilitate storage development by ensuring there are efficient price signals. This includes National Grid providing more visibility about the system costs of different generation mixes, and the future value of balancing services and flexibility.

Q3. What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnection has a valuable role to play in an efficient European electricity market, and EDF Energy supports increasing the current level of interconnection. We believe that there are clear long-term benefits from increased interconnection such as lower GB consumer prices, a wider pool of electricity balancing providers, diverse contribution to security of supply and efficient use of European resources. However, we believe there are also implications for the GB market that need to be considered further; there could be conflicts of interests with National Grid's interconnector business that need to be reviewed.

We do not agree that there is a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020. We consider that the current cap and floor regime has flaws both in design and implementation that risk over-supply of interconnection.

The "cap and floor" regime sets a floor on returns at the cost of debt. We consider that this is too generous such that it minimises risk to investors. In addition the floor protects the developer from technical risk, e.g. continued availability of the interconnector, as well as market risk. For longer interconnectors with challenging sea bed conditions where risk of cable failures may be higher, ultimately this risk is being covered by consumers.

Given the regime is developer-led; it is likely to lead to projects coming forward that are not necessarily optimal. There is no check as to whether these are the best interconnectors and this is an area where a demand led approach may lead to inefficient outcomes. While in the short run new interconnection reduces consumer costs due to market differentials, in the long-run, it will increase costs for consumers as such projects will deter capacity that could have come forward at lower cost. Lowering the floor would expose the equity providers to appropriate market risk and is likely to optimise the level, location and design of new interconnection.

In Ofgem's assessment of the case for a cap and floor regime, they do not consider all the costs that will be incurred by GB consumers and they base their analysis on the market differentials rather than the long-term fundamentals. For example, lower GB wholesale prices due to a new interconnector will increase CfD payments which are ultimately recovered from consumers. Ofgem do not assess this impact which will become material during the 2020s. In addition, the current large price differential between the GB and European market is largely driven by Member State policy interventions, e.g. renewable support schemes in Europe or the Carbon Price Floor in the UK. It is not clear that these differentials will endure through the 2020s as there is likely to be a convergence with time, e.g. strengthening carbon price via the EU ETS and potentially with the introduction of carbon price floors in other member states. Furthermore, if differentials between Member States reduce faster than expected, consumers may be exposed to the costs for stranded assets under Ofgem's cap and floor approach. Therefore, it is important that Ofgem's assessment is based on long-term fundamentals to avoid the risk of future stranded assets and increased costs to consumers.

Q4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

There are two French initiatives which have sought to adopt changes in energy technology when planning to balance supply and demand.

The first initiative seeks to encourage storage technology in order to manage intermittent renewables and balance supply and demand. The French regulator CRE is organising tenders in order to grant feed in tariffs to renewable energy providers in the "non-interconnected zones" typically in the French islands. The successful projects need to be compliant with a set of rules in term of output. Mainly, the generated power needs to be "smoothed" reducing its variability and enhancing its forecast. This is usually met by adding storage technologies to the project. This scheme contributes to "facilitate" supply and demand balance end hence better integration of intermittent renewable technologies into the mix. At this stage it cannot be applied to GB as the current subsidies regime does not take into account the variability and the predictability of the generated power. However, this initiative should be consider if the UK Government were to review further the subsidies for intermittent generation.

The second initiative is a DSR scheme for residential consumers; France has a high proportion of homes with direct electrical heating. Management of peak load has been an important feature of residential tariff design for many years. Consumers on the Tempo tariff[6], for example, are notified day-ahead of up to 22 peak days – designated "red" days, on which the rate charged is a 5-fold multiple of the average annual price. In return, the rate charged on normal "blue" days is around 12% cheaper than the average price. This achieves a peak demand reduction on red days of around 200 MW, compared with normal "blue" days.

[6] Tempo is a demand response option of a regulated tariff for residential customers with a minimum contract of 9kVA. It is based on a horo-seasonal pricing method: the day is split in peak and off-peak hours (10pm – 6am); the year is split in blue, white and red days (from the cheapest to the most expensive tariff).

This initiative suggests that DSR from the residential domestic sector in GB may not be great. The magnitude of the incentive (i.e. the ratio of peak to normal prices) needs to be very high to achieve consumer engagement; it is difficult to believe that such ratios are cost-reflective in GB. The achieved response is a small fraction of France's 75,000 MW peak, even in circumstances in which direct electrical heating is widespread. By contrast the majority of electrically-heated homes in GB have night storage heaters.

EDF Energy
January 2016

Fixing the roof while the sun is shining

A briefing for the National Infrastructure Commission

on the home energy efficiency infrastructure opportunity

Introduction

The National Infrastructure Commission (NIC) has been asked by Government to investigate the UK's infrastructure needs and has issued a consultation on several Government priorities, including transport infrastructure requirements in London and the north of England and how best to balance electricity supply and demand.

These investigations are welcome, but there is a gaping hole at the heart of the National Infrastructure Plan that must be fixed. That most crucial element of infrastructure – the fabric of our existing housing stock – is missing from the Government's list of infrastructure priorities.

On 25th November 2015 the Government set out its plans in the Comprehensive Spending Review for investing £120 billion of public capital funds in infrastructure projects[1]. This included £10 billion of investment in new housing infrastructure and regeneration and £20 billion for building schools[2]. But no infrastructure funds were allocated for a retrofitting programme to make UK homes energy efficient.

Yet our existing UK housing infrastructure is in poor condition. As a result the UK has one of the highest rates of fuel poverty and Excess Winter Deaths in Western Europe[3]. Our homes are also responsible for over a quarter of the UK's carbon emissions and these emissions must be almost entirely eliminated in the first half of this century. These challenges simply cannot be addressed without making UK homes energy efficient. To achieve this means recognising home energy efficiency as an infrastructure opportunity.

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1 Treasury, Spending Review Nov 2015
2 Treasury, Spending Review Nov 2015
3 ACE, Cold Man of Europe Update, Oct 15

This is entirely appropriate as domestic energy efficiency can be classified as infrastructure[4]. A public investment of approximately £49 billion is required to make the UK housing stock energy efficient, bringing 21 million homes up to at least Band C on an Energy Performance Certificate. The investment required is on average £2.5 billion / year if it was spread over the next 20 years.

Following the Spending Review the Government is committed to spending only £650 million each year on energy efficiency measures, raised from the Energy Company Obligation. This means an additional investment of £1.85 billion is needed each year. Given that over the next 5 years the Government plans to spend £24 billion every year on capital projects[5] this would represent only 6.6% of the capital infrastructure budget.

In this briefing we highlight evidence showing that such an investment is not only affordable, it is also an extremely good investment for UK plc.'

We call on the National Infrastructure Commission to launch a consultation on how best to make the existing housing infrastructure energy efficient and de-carbonise our heating infrastructure in the most cost effective way.

The poor condition of existing housing infrastructure

All UK homes need to be brought up to Band C or above on an Energy Performance Certificate in order to make them energy efficient and so minimise fuel poverty and meet our carbon budgets[6]. There are 26 million existing homes in the UK and **21 million UK homes have a poor standard of energy efficiency, rated below EPC Band C[7]. This means that approximately 80% of UK homes need their energy efficiency to be improved.**

The Association for the Conservation of Energy (ACE) analysed the latest official European Commission data to compare the state of the UK housing stock and fuel poverty levels with 15 other European countries. They found that:

- The UK has amongst the lowest energy prices, with the lowest gas price, but ranks 14th out of 16 on the affordability of space heating[8].
- The UK ranks 14th out of 16 for fuel poverty[9].
- The UK ranks 12th out of 16 for households reporting that their home is in a poor state of repair[10].
- In terms of energy efficiency, out of 11 countries for which data is available, the UK's walls are ranked 7th, roofs are ranked 8th, floors are ranked 10th and windows are ranked 11th[11].

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[4] Frontier Economics, Energy Efficiency as Infrastructure, Sep 2015
[5] Treasury, Comprehensive Spending Review, Nov 2015
[6] Cambridge Econometrics and Verco, Building the Future, Oct 2014
[7] ACE, Cold Man of Europe Update, Oct 15
[8] ACE, Cold Man of Europe Update, Oct 15
[9] ACE, Cold Man of Europe Update, Oct 15
[10] ACE, Cold Man of Europe Update, Oct 15
[11] ACE, Cold Man of Europe Update, Oct 15

ACE concluded that no other country of the 16 comparable European countries assessed performed as poorly overall as the UK across the range of housing indicators[12].

Reducing Energy Demand – The first energy infrastructure priority

Reducing energy demand is the most cost effective way to free up additional energy capacity and this is why it has been described by the International Energy Agency as *'an invisible powerhouse'* and the *'world's first fuel'*[13].

The Climate Change Committee estimates that to comply with future carbon budgets under the Climate Change Act the power sector will need to largely decarbonise by 2030, to an average grid intensity of around 50-100 gCO2 /kWh[14]. This challenge is all the greater because the Committee on Climate Change projects that the significant electrification of the heat and transport systems will be required[15].

It is essential to be aware that much more energy is needed to provide space heating and hot water to our residential and commercial buildings than to provide power and other services. In residential buildings 83% of energy is used in this way and in commercial buildings it is 64%[16]. It is therefore essential to decide on the projected energy performance of the built infrastructure, in order to optimise the methods of heat generation and distribution as well as to understand the impact on future electricity needs.

Total current levels of heat consumption in the UK are approximately 750TWh pa. Approximately 20% of this is attributable to the industrial sector, but about 600TWh is needed to generate space heating and hot water in residential and commercial buildings[17].

Most energy system scenarios to meet the UK's carbon budgets assume that heat pumps will be the main replacement for gas[18]. **But even meeting 20% of demand for heat using heat pumps would almost double the peak electricity demand by 2030 unless overall demand can be reduced**[19].

That is why, under all major energy model decarbonisation scenarios analysed by UKERC, a reduction in heat consumption of buildings of 20-30% is required by 2030[20].

To reach this heat reduction target by 2030 requires a significant infrastructure investment programme in the energy efficiency of existing buildings. To achieve this, approximately 1 million properties per annum will need to be treated[21], roughly equivalent to the peak deployment levels under previous schemes, such as CERT, but with a wider and deeper range of measures in each property.

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12 ACE, Cold Man of Europe Update, Oct 15
13 International Energy Agency, Energy Efficiency Market Report 2014
14 Climate Change Committee, Power Sector Scenarios for the 5th carbon budget Oct 15
15 Climate Change Committee, Power Sector Scenarios for the 4th carbon budget 2014
16 DECC, Energy Consumption in the UK, 2014
17 DECC, Delivering UK Energy Investment, 2014
18 UKERC, Which Energy Scenario? Time to Decide, 2015
19 Sansom, The Impact of Future Heat Demand Pathways, 2012
20 UKERC, Which Energy Scenario? Time to Decide, 2015
21 UKERC, Which Energy Scenario? Time to Decide, 2015

At the moment the Government has a target of insulating 1 million homes in the next 5 years, or 200,000 homes per year. One energy efficiency measure per home has been delivered under ECO. If this rate is continued it would take 250 years to make all UK homes energy efficient[22].

The Energy Company Obligation programme is funded by a levy on energy bills. Although the Government has recently announced that some form of supplier obligation will continue up until 2022, the Government only plans to fund home energy efficiency via such an obligation, with no public funding support. This will be the first Parliamentary term in the last 30 years that there will have been no public funding in England for home energy efficiency.

Due to concern about the impact of levies on energy bills, the Government has cut the rate of this levy from £56 / consumer / year to £26 / consumer / year[23]. But this means there is not enough investment available in home energy efficiency to meet the 4th carbon budget or to meet the obligation in the UK's fuel poverty strategy to get all fuel poor homes up to EPC Band C by 2030.

A key part of the infrastructure programme to deliver a low carbon energy system, including balancing electricity supply and demand, therefore has to include making the UK building stock energy efficient, using public infrastructure capital to provide the long term revenue stream to help fund it.

The building blocks for an energy efficiency infrastructure programme

There are three key elements of an energy efficiency infrastructure programme:

A long term goal: Firstly, the Government needs to set a long term home energy efficiency goal, to give confidence to investors in the infrastructure pipeline and help facilitate a clear delivery plan. To meet carbon reduction targets and fuel poverty obligations, a commitment is required to make all UK homes energy efficient by 2035, within 20 years. A target to bring 1 million homes up to EPC Band C each year is needed.

A strategic infrastructure delivery programme: A devolved approach would work best, allowing local authorities to plan an area based scheme. Low income areas would be the primary focus for improvements, with support also provided to vulnerable households outside these areas. This is the basic approach undertaken in Scotland and is recommended by many leading businesses, fuel poverty groups such as ACE and NEA and the leading consumer group Citizens Advice, as the most effective[24].

Infrastructure investment: The Government has set a cap of £650 million / year to be raised from the Energy Company Obligation to support the delivery of energy efficiency measures[25]. For a programme to bring all UK homes up to EPC Band C within 20 years, a public investment of approximately £2.5 billion is required each year to cover both grants for low income households and subsidised loans for the able to pay[26].

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22 Energy Bill Revolution: 2015
23 Treasury, Comprehensive Spending Review, Nov 2015
24 Citizens Advice, Closer to Homes, May 2015
25 Treasury, Comprehensive Spending Review, Nov 2015
26 Cambridge Econometrics, Building the Future, Oct 2014

That means that on the assumption a supplier obligation continues at the same level, the energy efficiency investment level in existing buildings needs to be raised by £1.85 billion per year on average if the investment was to be evenly spread over the next 20 years.

This means that the current level of investment in domestic energy efficiency set by the Government is only a quarter of the annual investment required and it has only been agreed to 2022. So the investment is neither large enough nor long enough. This is a direct consequence of the Government failing to adopt a long term infrastructure vision to make the entire UK housing stock energy efficient at the scale and speed required to meet carbon budgets.

The Economic Case for Energy Efficiency as Infrastructure

The home energy efficiency market can stimulate both construction and manufacturing industries. Over 135,000 people are currently employed in the energy efficiency industry[27]. By improving all the UK's existing homes, business opportunities would be spread across the country and the investment has the potential to boost local employment and regional economic growth[28]. Up to 108,000 extra jobs could be created across the economy[29].

A building programme to make homes energy efficient has the advantage that many projects are 'shovel ready' unlike many other infrastructure projects that have to go through major planning processes. There is already a pent up funnel of projects which could be aggregated and delivered quickly if the infrastructure funds were made available.

The energy efficiency sector has enormous potential to attract investment and provide a major source of additional income for central Government. For every €1 of public funds spent on the KfW Energy-efficient Construction and Refurbishment programme in Germany in 2010, over €15 were invested in construction and retrofit, and more than €4 went back to the public finances in taxes and reduced welfare spending[30].

Exports from the UK's energy efficiency sector were already worth over £1.8 billion in 2011-12[31]. Establishing a domestic energy efficiency market delivering at least 1 million deep retrofits a year would place UK industry in a prime position to further increase the export of knowledge, skills and products to other countries.

There are two major reports by two of the UK's leading economic consultancies which have examined the economic impact of making home energy efficiency an infrastructure priority. Both use different methodologies for estimating the net benefits but both conclude that those benefits are substantial.

a. **Frontier Economics: Energy Efficiency as Infrastructure**

Frontier Economics published a report in September 2015 examining the case for energy efficiency as infrastructure. They reached the following conclusions:

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27 Department of Energy & Climate Change, Energy Efficiency Strategy: 2013 Update, Dec 13
28 Department of Energy & Climate Change, Energy Efficiency Strategy: The Energy Efficiency Opportunity in the UK, Nov 12
29 Cambridge Econometrics, Building the Future, Oct 2014
30 KfW, Impact on public budgets of the KfW promotional programmes, 2011
31 Department of Energy & Climate Change, Energy Efficiency Strategy: 2013 Update, Dec 12

- There is a strong case for Government to make home energy efficiency an infrastructure investment priority and to develop an infrastructure programme to deliver it[32].
- Examination of academic and official citations of infrastructure demonstrates that energy efficiency investment can be classified as infrastructure. Domestic energy efficiency investment can free up energy sector capacity just as effectively as delivering new generation plants, networks or storage[33].
- Energy efficiency investments provide public services, by reducing carbon emissions and improving health and wellbeing. They also provide option value in the fact of uncertainty over future energy sector conditions – eg uncertainty over future fuel prices.
- An energy efficiency programme would meet the criteria HM Treasury apply for determining their top 40 infrastructure requirements. It would also fit with the eight characteristics of infrastructure identified in HM Treasury's valuation guidance. In addition, classifying energy efficiency as infrastructure is consistent with the way energy efficiency is considered by a range of international organisations such as the European Investment Bank (EIB) and the International Energy Agency (IEA)[34].
- Energy efficiency investments provide value for money. Analysis of Government Impact Assessments shows that they have comparable benefits to other major infrastructure investments. In fact, a programme to make British buildings more energy efficient would generate £8.7 billion of net benefits[35]. This is comparable to benefits delivered by the first phase of HS2, Crossrail, smart meter roll out or investment in new roads. This finding holds, even without quantifying many of the key social benefits of energy efficiency measures, including health and wellbeing improvements[36].
- An infrastructure programme to deliver energy efficiency measures can overcome key barriers to delivery. The market failures around energy efficiency provide a strong case for Government intervention. As part of a broad energy efficiency programme there are benefits to delivering a coordinated area-based scheme under a directly funded approach. This could be used to target the consumers who would benefit the most[37].
- The incremental nature of energy efficiency investments means that strategies can be changed as new information comes to light. This flexibility is not possible with more lumpy capital investments such as nuclear power plants.

b. Cambridge Econometrics: Building the Future

This report, published in October 2014, undertook detailed modelling to assess the economic, fiscal, and environmental impacts of bringing all UK homes up to EPC Band C with grants for the fuel poor and low interest loans for able to pay households. It captured broader macro-economic benefits than the Frontier analysis which was focused on Government micro-economic modelling. It concluded the following:

[32] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2016
[33] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2016
[34] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2016
[35] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2016
[36] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2016
[37] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2016

- **The economic case for making the energy efficiency of the UK housing stock a national infrastructure priority is strong.**
- **£3.20 returned through increased GDP per £1 invested by government[38].**
- **0.6% relative GDP improvement** by 2030, increasing annual GDP in that year by £13.9bn[39].
- **£1.27 in tax revenues per £1 of government investment**, through increased economic activity, such that the scheme has paid for itself by 2024, and generates net revenue for government thereafter[40].
- **2.27 : 1 cost benefit ratio** (Value for Money), which would classify this as a "High" Value for Money infrastructure programme.
- **Increased employment by up to 108,000 net jobs per annum over the period 2020-2030**, mostly in the service and construction sectors. These jobs would be spread across every region and constituency of the UK[41].
- **£8.61 billion per annum in total energy bill savings** across housing stock, after comfort take (including energy price inflation)[42].
- **Net benefit of £4.95 billion per annum** from the total energy bill savings across the housing stock (after able-to-pay energy efficiency loans have been repaid)[43].
- **23.6MtCO_2 reductions per annum by 2030**, after accounting for direct, indirect, and economy-wide rebound effects. This is roughly equivalent to cutting the CO_2 emissions of the UK transport fleet by one third[44].
- **Improved health and reduced healthcare expenditure**, due to warmer and more comfortable homes, and improved air quality. For every £1 spent on reducing fuel poverty, a return of 42 pence is expected in National Health Service (NHS) savings[45].
- **A more resilient economy**, less at risk of shock changes in gas prices, as the economy becomes less reliant on fossil fuels**. Investment in energy efficiency in the domestic sector could result in a 26% reduction in imports of natural gas in 2030, worth £2.7bn in that year**[46].

Increase Energy Security

Energy efficiency can improve the UK's energy security and reduce our reliance on imported gas. Reducing domestic energy demand through energy efficiency is vital to ensure there is sufficient supply to meet the UK's energy needs. Demand reduction is critical to guaranteeing a secure energy supply and stable prices, and minimising the costs of new generating capacity and imported fossil fuels. Investing in energy efficiency is a more cost effective approach for meeting the UK's growing demand for energy than building additional energy generation infrastructure. Energy saving

38 Cambridge Econometrics, Building the Future, Oct 2014
39 Cambridge Econometrics, Building the Future, Oct 2014
40 Cambridge Econometrics, Building the Future, Oct 2014
41 Cambridge Econometrics, Building the Future, Oct 2014
42 Cambridge Econometrics, Building the Future, Oct 2014
43 Cambridge Econometrics, Building the Future, Oct 2014
44 Cambridge Econometrics, Building the Future, Oct 2014
45 Cambridge Econometrics, Building the Future, Oct 2014
46 Cambridge Econometrics, Building the Future, Oct 2014

measures cost less on average per unit of power than large-scale power generation[47]. Through cost-effective investment in all forms of energy efficiency, the UK could be saving 196TWh in 2020, equivalent to 22 power stations[48].

Meeting energy needs through demand reduction will reduce our dependence on imported fossil fuels and increase national security. In 2004 the UK ceased to be self–sufficient in gas and in 2012 net imports of gas accounted for just over 40 per cent of gas use[49]. By 2020 the UK is expected to import more than half its oil and gas[50]. The UK could reduce its reliance on imported gas by 26 per cent in 2030 by making UK homes more energy efficient, saving £2.7 billion in gas imports per year[51].

Reduce Carbon Emissions

The Climate Change Act 2008 commits the UK to reduce carbon emissions by 80 per cent by 2050. Carbon budgets are set for each five year period up to 2050 in order to track progress towards this reduction target. Binding EU targets also require carbon reductions of 20 per cent by 2020 and 40 per cent by 2030. Achieving these significant levels of carbon reductions will require a complete transformation of the UK's existing homes to dramatically reduce domestic emissions. **The speed of the cuts needed is also likely to increase following the Paris Agreement that has set a goal of limiting the global temperature increase to 'well below 2C' and pursue efforts to limit warming to 1.5C.**

85 per cent of the UK's existing homes will still be standing and in use in 2050, presenting a significant low carbon refurbishment challenge[52]. To meet carbon reduction targets all UK homes will have to be made energy efficient within the next 20 years.

Reduce energy bills and fuel poverty

Domestic energy efficiency is the best way for households to gain control of their energy bills and insulate themselves against future price rises. By installing insulation measures households can reduce their heating use by up to 40%, saving £6 billion in heating costs nationally each year[53].

4.5 million households are classified as being in fuel poverty in the UK, based on the two different definitions used across the UK. In England there are 2.5 million households in fuel poverty[54]. The only permanent solution to fuel poverty is to retrofit the existing housing stock to a high level energy efficiency.

Improve Health and Well Being

Energy inefficient homes are not only expensive to heat but can also damage the health of their occupants. Cardiovascular and respiratory diseases are caused or worsened by living in cold

[47] Sustainable Energy Association, Clean energy measures in buildings are cheaper, Apr 14
[48] Department of Energy & Climate Change, Energy Efficiency Strategy: The Energy Efficiency Opportunity in the UK, Nov 12
[49] Energy Bill Revolution, Re-build Britain; June 14
[50] Department of Energy & Climate Change, The Carbon Plan, Delivering our low carbon future, Dec 11
[51] Cambridge Econometrics, Building the Future, Oct 2014
[52] Federation of Master Builders, Strategy for low carbon and building refurbishment market, May 13
[53] Energy Bill Revolution, Re-build Britain, Jun 14
[54] ACE, Cold Man of Europe Update, Oct 15

conditions. Children living in cold homes are significantly more likely to suffer from chest problems such as asthma and bronchitis[55]. Fuel poverty also adversely affects mental health. More than 1 in 4 adolescents living in cold homes are at risk of multiple mental health problems compared to 1 in 20 adolescents who have always lived in warm housing. Cold homes negatively affect children's educational attainment and emotional wellbeing[56].

An estimated 43,900 excess winter deaths occurred in England and Wales in 2014/2015[57] and around 30 per cent of these are likely to be due to cold homes[58]. The UK has one of the highest excess winter death levels in Europe despite our moderate climate, with deaths in the coldest quarter of housing almost three times higher than in the warmest quarter[59]. Many of these excess winter deaths could be prevented through warmer housing[60]. Investing in energy efficiency can help protect the health of residents and offset health spending on treating preventable illnesses.

NHS expenditure has been reported to rise by 2 per cent in the cold months[61]. Age UK has calculated that the annual cost to the NHS in England of cold homes is £1.36 billion[62], as well as the associated cost to social care services, which is likely to be substantial.

Conclusion

Fixing the UK's existing, leaky housing stock is a huge infrastructure opportunity. Not only does the government's own economic data show that it would deliver comparable economic returns to other major infrastructure projects, but it is an essential investment to strengthen energy security, end fuel poverty and meet our carbon budgets.

The Government has recognised in its infrastructure plan that new buildings must be included. But now is the time to include a retrofitting programme to eliminate energy waste in our homes. It is one of the most widely supported infrastructure solutions in the UK today, with over 200 major businesses, cities, unions and charities in support[63], including the CBI, Age-UK and Citizens Advice.

We call on the National Infrastructure Commission to launch a consultation on how to make our existing housing infrastructure energy efficient and de-carbonise our heating infrastructure in the most cost-effective way.

Now is the time to make our homes fit for the 21st century.

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55 Marmot Review, The Health Impacts of Cold Homes and Fuel Poverty, May 11
56 Marmot Review, The Health Impacts of Cold Homes and Fuel Poverty, May 11
57 ONS, Excess Winter Deaths, England and Wales, Nov 15
58 World Health Organisation, Environmental burden of disease associated with inadequate housing, 2011
59 Marmot Review, The Health Impacts of Cold Homes and Fuel Poverty, May 11
60 Public Health White Paper, 2010
61 Marmot Review, The Health Impacts of Cold Homes and Fuel Poverty, May 11
62 Age UK, Cost of the Cold, Nov 12
63 http://www.energybillrevolution.org/whos-behind-it/

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elementpower

ELEMENT POWER RESPONSE TO NATIONAL INFRASTRUCTURE COMMISSION

JANUARY 2016

Introduction

Element Power is pleased to respond to the National Infrastructure Commission's call for evidence of 13th November 2015. Element Power is an established global renewable energy developer that develops, acquires, builds, owns and operates a portfolio of wind and solar power generation and interconnection projects in several countries. Currently present in 8 countries, Element Power is actively developing a pipeline of c.3,000 MW, is contracted to manage nearly 100 MW of third party assets and operates 20MW of our own onshore wind and solar PV assets.

Among Element Power's current projects is Greenwire, a proposed strategic renewable energy interconnector between the UK and Ireland which holds existing grid connection contracts to construct up to 2.5GW of interconnector capacity between the two countries, linked to new renewable generation capacity. Greenwire has potential to provide Great Britain (GB) with up to 9TWh of clean electricity per annum, making a substantial contribution to UK energy security and low cost decarbonisation. The project is being developed in partnership with General Electric.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

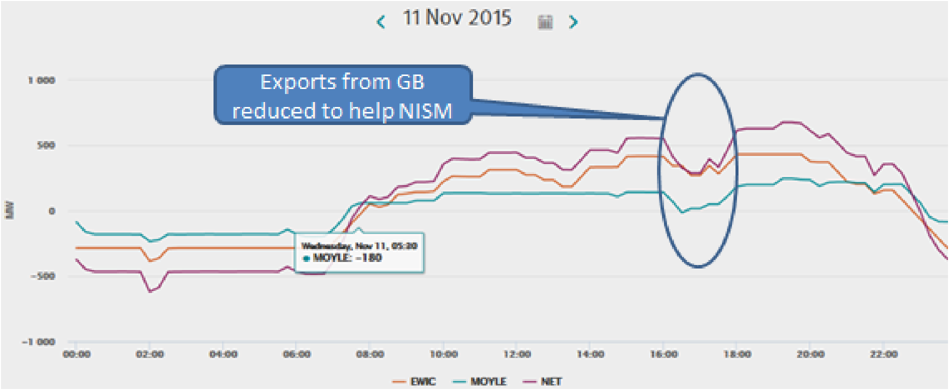
Generation capacity imported through interconnectors between Britain and other land masses could help balance supply and demand. The geographic dispersal of renewable energy sources reduces their variability as increased physical separation reduces the correlation of weather systems and therefore power outputs are "smoother". Extending the Contracts for Difference support scheme (including subsidy-free support) to generators located outside the United Kingdom, e.g. in Ireland, will reduce the variability in the renewable generation portfolio, increasing security, reducing carbon emissions and the reducing costs of back-up generation for consumers.

There are two aspects to this question.

a) Ensuring sufficient capacity to meet customer demand especially at high / peak demands and those high demands when renewables are not generating.
b) Balancing supply and demand on a short-term basis due to the mismatch of generation and demand.

In relation to a)

In the British market electricity suppliers are responsible for meeting the demands of their customers in each half hour settlement period. If their generation and supply are not matched they are out of balance and suffer the risk and penalties of the balancing market. Interconnectors can provide power at times of system stress, especially links to Ireland (which are often exporting to Ireland) can be reversed to bring power into GB at times of system stress. This behaviour was seen on the afternoon of 11th November 2015 when National Grid issued a NISM – Notice of Inadequate System Margin – due to unexpected breakdowns and shortfalls of fossil fuel generators.



In relation to b)

Providing better short-term matching of supply and demand to keep the system stable can be achieved in a number of ways including adding inertia to the system (rotating mass) and providing enhanced and faster frequency response. Interconnectors can provide such fast frequency response as was identified in National Grid's submission to Ofgem's cap and floor regime "SO submission to the Cap and Floor", (16 December 2014).

Element Power approved of the decision to include interconnectors in the 2015 Capacity Market auction as part of its efforts to increase interconnection capacity. As well as delivering routes to market for strategic interconnection, the Government should consider prioritising energy markets for interconnection which are economically and geographically desirable in order to increase the likelihood of it making a significant contribution to capacity. The company behind this submission would want Ireland to be included as a strategic priority for interconnection.

2. What role can changes to the market framework play to incentivise this outcome:

- ***Is there a need for an independent System Operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?***

An Independent SO (ISO) would have merit in being clearly independent of any network asset owners. An ISO would not have any incentive to build transmission and could judge each proposed transmission and interconnector project on its merit. It could also assess the options for interconnectors to reduce transmission constraints, e.g. flowing energy from Scotland to Northern Ireland and from southern Ireland to Wales creating north-south flows in Britain without needing additional transmission assets.

There are two facets to balancing costs faced by the SO.

a) Costs faced in balancing the residual and instantaneous supply and demand which has not been balanced by suppliers
b) Costs faced in managing generation because of transmission constraints.

It is tempting to believe that constraint costs should be eliminated, however it is important that an appropriate level of costs is maintained, otherwise there will be a massive over-investment in new infrastructure to avoid these costs.

- ***Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?***

We would make the following comments:

- Moving to shorter term settlement periods (e.g. 15 minutes) to reduce averaging of over and under supply by suppliers which can occur in the current 30 minute settlement period would be expected to help reduce balancing needs and costs.

- Smaller players have proportionately more imbalance than larger players as it is diversity in a large portfolio that reduces imbalance of any individual player. This in part explains the development of the "big 6" in the British energy market.

- With renewables, the forecast error on a single wind turbine will be very high, on a wind farm smaller, on wind in a region even smaller and on the whole GB wind fleet the forecast error is very small. It is important therefore that the forecast error of the whole GB wind fleet is considered in any imbalance of wind, not the forecast error of a small part of that wind fleet.

- ***To what extent can demand-side management (DSM) measures and embedded generation be used to increase the flexibility of the electricity system?***

- DSM needs strongly variable pricing to be worthwhile. This is achieved in parts of USA with locational marginal pricing (LMP) which creates large price spikes and troughs. The GB market is at the opposite end of the spectrum to LMP with one price zone for the whole market. A halfway house is exampled by the NordPool market with a similar volume to GB but with 14 price zones.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

As Ofgem noted in a 2014 report (Pöyry, Dec 2014), interconnectors help lower electricity prices when there is a higher share of renewables in the generation mix. This is due to the equalising or 'smoothing' effects of exchanging renewable power between jurisdictions at times of varying weather conditions.

Such infrastructure would lower the overall cost to consumers of the transition to low carbon generation.

- ***Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?***

There is a case for building more rapidly than the cap and floor regime can deliver. The cap and floor regime requires sufficient market price differences between the connected markets to provide financial certainty to investors many years ahead. It takes ~5 years to develop an interconnector and ~4 years to build it, and the investors are relying on forecasts for 10-20 years after that. This high risk approach can drive interconnection where there is a severe shortage, but will result in a sub-optimal level of interconnection once that severe shortage is reduced. Under the cap and floor regime investors will only invest under such long-term and high-risk conditions against a very strong forecast revenue stream. In addition, future changes to market price zones (e.g. under CACM) could create or destroy value overnight. Interconnectors should have the option of being fully regulated as is the case for onshore transmission assets.

Even where price zones in two markets are mostly coupled (i.e. equal) there can still be value in interconnection as the lowest cost way of overcoming transmission bottlenecks. For example we already see different percentage flows and even directions on EWIC and Moyle which connect the British BETTA and Irish SEM markets. These flows indicate that the interconnectors are being utilised to solve transmission bottlenecks on the island of Ireland or in Great Britain.

Historically interconnection has been much more expensive than reinforcing onshore transmission networks, however we now see that trend reversing due to the difficulty of building new overhead power lines on shore. For example National Grid and Scottish Power are increasing British north south capacity by the offshore subsea Western Link (West Coast Bootstrap) at a cost of over £1billion. With development of subsea cables and HVDC technology and markets relative costs for interconnection are falling compared to other onshore reinforcement options.

Reinforcements across Transmission Operators (TOs) are facilitated by the regulatory regime with, for example, Kintyre, Beauly Denny, and Western Bootstrap. National transmission reinforcements are prioritised and treated differently to interconnectors. An SO independent of any transmission or interconnector asset ownership or development would help identify and assess new assets for development and funding. Ofgem has created cap and floor to put risk on developers; however developers will not be able to bring projects forward if that risk is not rewarded. A completely independent

SO would help give Ofgem greater confidence in assessing new interconnector proposals and giving those projects a regulated financial regime.

Onshore TOs are paid for developing onshore transmission assets (they are reimbursed their costs from consumers) including shared assets between TOs (such as the Western Link). There is currently no such cost recovery for interconnector developers and therefore a reducing incentive over time to develop new projects.

- ***Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?***

- The Capacity Mechanism should reward interconnectors. Interconnectors that are often exporting from Britain or at float are far more valuable in addressing system emergencies and imbalances than interconnectors that are importing. Importing interconnectors cannot increase their power into Britain if there is an emergency, such as a large power station trip, breakdown, fire or fault. However exporting interconnectors can reduce exports or start importing and hence support the British system at times of stress or crisis. Therefore interconnectors with Ireland which are often exporting or float should receive capacity payments. This supporting behaviour was evidenced during the NISM event on 11th November 2015.
- Long-term capacity payments are required over 15 years to provide the certainty to enable financing interconnector projects. Making annual payments will not provide sufficient certainty to finance new interconnector capacity using the capacity mechanism.
- Interconnectors have much longer lead time than most generation projects due to the HVDC technology and dealing with permitting regimes in at least 2 jurisdictions. The Capacity Mechanisms should be able to contract years ahead for interconnectors so that new interconnectors can be financed, accounting for these benefits to UK consumers.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

In Denmark about 15 years ago there was a problem with an excess of generation when the wind blew and the system operator was having to dump surplus power into neighbouring markets. This situation arose because the many local Combined Heat and Power (CHP/CoGen) schemes were also running to generate power and heat when wind generation was high. By reforming the market with real time pricing it became cost effective for most of these CHP schemes to stop generating at these times, to increase heat storage and for many to install electric heating elements so that they could utilise cheap electricity to top up their heat demands. The result of the market reform was a much improved match of supply and demand taking account of variable renewables.

For additional details on this submission, please contact Leana Dos Santos [email address redacted]

By email to energyevidence@Infrastructure-Commission.gsi.gov.uk

National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

8 January 2016

Dear Sir/Madam

National Infrastructure Commission call for evidence

ELEXON Limited is the administrator for the Balancing and Settlement Code (BSC). We are responsible for managing the electricity balancing and settlement arrangements as set out in the BSC. We are independent of any part of the electricity industry and not for profit. The views expressed in this response are those of ELEXON Limited, and do not seek to represent those of the BSC Panel or Parties to the BSC.

You have asked for evidence on how changes to existing market frameworks, increased interconnection and new technologies in demand-side management (DSM) and energy storage can better balance supply and demand. We believe that to fully deliver the benefits of these new technologies new market arrangements are required.

ELEXON, under the BSC, has been investigating and implementing improvements to the existing settlement arrangements. One aspect has been to consider what changes are needed so as to unlock the benefits of new technology and innovation. For example, with the rollout of smart meters and more granular meter data (half hourly intervals) is available. This can be used to remove the estimates for customers' electricity usage (by settlement profiles) though more accurate metered data, thus improving the accuracy, timeliness of settlements arrangements. This leads to a more efficient and effectiveness market and can also start to realise the benefits of DSM, say through dynamic time-of use tariffs. The most recent work has been undertaken by the Settlement Reform Advisory group reporting to the BSC Panel (SRAG).

A further area for investigation of this SRAG group was to identify how improvements to the BSC could support innovation and technology change. This was to consider how settlement could develop to support new technology and innovation, including demand side response, local energy schemes, storage and virtual balancing. This work was due to commence shortly, however, in light of Ofgem's Open letter (17 December 2015), we are proposing that this work be included under this Ofgem planned activity. We will be supporting Ofgem in this area.

In the longer term for DSM, we believe the benefits of DSM to 'GB plc.' are very significant (potentially tens of billions), see ELEXON's response to 'Creating the right environment for demand-side response' consultation, 28 June 2013. Therefore, new market arrangements need to be developed in a timely manner with the right settlement processes at the heart of these. We suggest that a work programme is established which develops and implements new DSM trading arrangements (to deliver DSR benefits to customers).

The new market arrangements must recognise the need for coordination between the many different actors (customers, suppliers, aggregators, Distribution Network Operators (DNOs), Transmission System Operators and any new stakeholders). These different actors will have varied and potentially conflicting interests in utilising DSR. Efficient use of DSM should be facilitated by having a single DSM market framework and settlement arrangements where all these interests can be aligned and supported by an agreed common approach across the country. A centrally co-ordinated approach will be more efficient than, say, a bilateral contracting or Distribution Network area specific (or Transmission System Operator) approach, due to the interactions between parties. It should also incorporate any findings from existing trails or studies.

We have also been in discussion with various parties and providing expertise to Ofgem on their Smarter Markets work areas on areas of settlement reform, demand side flexibility, embedded generation, storage, community energy and next day switching. We understand the need for changes to the market arrangements to help support new technology, such as energy storage.

With regards to storage we believe that consideration should be given to facilitate distribution businesses operating in the balancing market. This would require new arrangements and pricing controls. In our discussions with a number of companies, who are seeking to innovate in this arena, there seemed benefits in aggregated small scale storage, if these were co-ordinated, as most providers are experiencing difficulties getting to a scale which can be useful to the system. We understand that larger scale transmission or distribution network level storage options are more viable in the short term.

I would be very happy to discuss my comments. Please contact me either by phone on [phone number redacted] or via email [email address redacted].

Yours sincerely,

Justin Andrews
Head of Design Authority, ELEXON

National Infrastructure Commission Call for Evidence

Electricity Interconnection and Storage

Introduction

Energy Networks Association (ENA) represents the "wires and pipes" transmission and distribution network operators for gas and electricity in the UK and Ireland. Our members control and maintain the critical national infrastructure that delivers these vital services into customers' homes and businesses.

Since privatisation the energy networks have managed to maintain a high level of security of supply at value to money for customers.

- Network costs are now 17% lower than they were when at the time of privatisation.
- The stability of the regulatory model has ensured consistent investment. Between 1990 and 2020, £80 billion will have been invested in the gas and electricity networks.
- This investment has delivered UK energy networks which are amongst the most reliable in the world. There has been a reduction in power cuts of 30% since 2002. The reliability of the transmission networks and gas distribution network is over 99.9%.

In order to maintain this strong record, the networks are adapting to meet the challenges of the UK's low carbon transition in a secure and affordable way.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The traditional role of the networks in the energy market has been relatively passive; taking energy in one direction, from generation to consumer with predictable levels of supply and demand.

The growth of intermittent renewables connecting to the electricity distribution network and the possible electrification of some sources of heat and transport will profoundly impact on the nature of electricity demand and supply with implications for electricity network infrastructure and the role of Distribution Network Operators (DNOs).

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DNOs have connected 11.5 GW of generation to the networks since 2005. This includes almost 4GW in the last year[1]. The growth of Distributed Generation (DG) has outstripped expectations in recent years, with solar PV connected, already close to the levels previously expected by 2030[2]. The electricity distribution network has been able to connect this new generation with little need for reinforcement; therefore not impacting significantly on customer bills. In the same period, demand has fallen as a result of energy efficiency measures, meaning that the net change in generation on DNOs' networks is even greater.

As a result of the changing nature of supply and demand associated with the transition to a low carbon economy, energy networks will play a more active role in the market to maintain security of supply, deliver efficiency and keep the cost to consumers low.

DNOs are already meeting the challenges of increasing DG and changing demand patterns by deploying new smart technologies on the networks. The distribution network is moving away from the traditional, passive role and is being run in a more intelligent and active way so that the operation responds in real time to demand and supply. This trend will continue as smart network technology advances, with an increasing number of network areas managed in this way. These active networks will play a crucial role in reducing the need for investment in traditional network reinforcement, while maintaining network reliability in a low carbon energy system.

We are already seeing the development of new technologies on the networks, with advances in data monitoring, communications technology and automation enabling the network to operate in a more sophisticated and efficient way.

New technologies are enabling networks to look at market solutions to challenges associated with a low carbon energy system, for example by entering into commercial arrangements for demand side response, energy storage, reactive power and voltage support.

Whilst frameworks are in place to provide sufficient technical governance to meet the above challenges, changes to the energy market to facilitate active management of the network at distribution level will deliver benefits to customers in terms of security of supply, improved efficiency and costs:

* **<u>Evolution from DNO to DSO</u>**

[1] Taken from Ofgem and DNO slides presented at 2015 DG Fora

[2] As above

The move away from a centralised energy system to one with increased DG, bidirectional energy flows and more active networks at lower voltage levels will see DNOs transition to become Distribution System Operators (DSOs).

DSOs with more information about and control over their networks will be able to offer new services and seek market solutions to the challenges they face. Low carbon innovation projects are already delivering the technical learning required for network operators to offer such services, including demand side response, voltage control and embedded storage.

In order to facilitate the DNO-DSO transition the regulatory framework will need to evolve in the coming years to reflect the new technologies on the system and offer services which will deliver benefits to customers.

* Distributed Generation and Balancing Costs

At present, balancing costs are increasingly driven by intermittent generation, a large volume of which is connected to the distribution network. This type DG needs to sell its output whenever it is producing (i.e. when it is windy or sunny.) There are often power purchasing agreements in place with suppliers to provide a guaranteed price for electricity whenever DG can produce.

The cost to the system operator of balancing supply and demand on the electricity system is paid for by customers and market participants through Balancing Services Use of System charges (BSUoS). Increasingly, many of these costs are posed by intermittent DG.

As most DG does not pay BSUoS, it does not contribute to the cost associated with the impact of intermittent generation on balancing charges. Therefore, there is a lack of incentive for these generators to reduce the balancing costs they impose. Consequently, the parties driving balancing costs have no incentive to reduce those costs and are effectively cross-subsidised by larger generators which do pay BSUoS. If DG customers were more exposed to these costs, it would provide a stronger incentive on them to install storage (behind the meter) so that they only exported onto the network when the costs of doing so were lower. Without exposure to these costs, they have no incentive to do this.

* Ongoing Work

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There is significant ongoing work across industry in GB addressing the challenges associated with developing a flexible market, for storage and other demand side response participants.

ENA's members have undertaken to efficiently facilitate rapid developments in storage and other demand side response mechanisms. There is significant innovation in the networks industry in both trialling and developing solutions that can ensure long term efficient costs to customers, while also facilitating other market participants. Additionally, maximising the benefits of smart meters to customers through working with suppliers and DECC is a key focus area for our members in enabling flexible solutions both in the medium and longer term.

Examples of these areas of collaboration include:

- ENA Transmission Distribution Interface Steering Group
- ENA Low Carbon Technology Group
- ENA Shared Services Working Group
- ENA Demand Side Response Working Group
- Smart Metering Steering Group

The networks also look to share this knowledge through the Smarter Networks Portal.[3]

In addition, the Ofgem/DECC Smart Grid Forum provides a platform for industry, government and other key stakeholders to engage on the significant challenges and opportunities posed by GB's move to a low-carbon energy system, particularly for electricity network operators.

National Grid's work in developing the Power Responsive program is another example of a platform for businesses, suppliers, policy makers and others to shape the growth of demand side response.

Outside GB, there is large volume of work ongoing at EU level on demand side response and ensuring electricity markets are working effectively. The European Commission led a Smart Grid Task force which, among other things, looked at the design of markets to encourage demand side response. ENA fed directly into this work and a final report was published in January 2015[4]. Many of the concepts within this report are being taken forward at European level. The ENA attends the so called TSO/DSO platform[5] meetings, where network operators and system operators are

[3] http://www.smarternetworks.org

[4] https://ec.europa.eu/energy/sites/ener/files/documents/EG3%20Final%20-%20January%202015.pdf

[5] http://www.geode-eu.org/uploads/GEODE%20Germany/Stellungnahme/2015/V%20-%20TSO%20DSO%20platform%20.pdf

coming together to agree high level models to improve how demand side response can be co-ordinated. They are producing a report for the European Commission later in 2016. This work is helpful in agreeing high level principles and potential roles and responsibilities which can then be applied at national level. ENA is using the work quoted below to help feed in a GB view to these debates.

2. What are the barriers to the deployment of energy storage capacity?

Storage on the electricity distribution network can play a role alongside other solutions in meeting the challenge of increased intermittency from renewable generation.

Through innovation funding mechanisms established by Ofgem in 2010 network companies are trialling new technologies and smart grid solutions, including the potential of battery storage to deliver benefits to customers. For example SSEPD's NINES project in Shetland has included the installation of a battery which will provide learning regarding the operation of MW scale batteries on a constrained distribution network. A 2MW battery has also been installed to help balance the grid and support renewable generation in Orkney, where total annual output from renewable sources exceeds annual demand from customers on SSEPD's network.

UK Power Networks is trialling how to integrate at 6MW battery into the distribution network. This is the largest of its kind in the UK and one of the largest in Europe. The project is trialling how energy storage could be used to provide benefits to consumers by deferring traditional network reinforcement and evaluating additional benefits that can be gained to maximise value. In order to achieve these additional benefits, the storage will be used for a range of other system-wide services, to benefit other electricity system participants, and test both the technical and commercial aspects of these applications.

Further details and learning from the trials of storage are available via the Energy Storage Operators Forum Good Practice Guide.

The findings from innovation projects are being transferred to business as usual, and DNOs are testing the market for the deployment of smarter solutions such as battery storage. For example, SSEPD's Constraint Managed Zone initiative is inviting interested parties to provide services such as energy storage, embedded generation and demand-side management/response to reduce the need for traditional reinforcement of the network. This process will not benefit from any innovation funding and is therefore a commercial test of the ability for new smart options to compete with conventional solutions.

The cost of storage on the network must be considered against the cost of conventional reinforcement of infrastructure to ensure value for money for customers over the long term. The cost of battery technology is falling, and is projected to further reduce in the coming years. However, large scale battery storage is not currently justifiable against the cost of traditional solutions. The projects and initiatives referred to above will therefore play an important role in both improving the technical understanding of storage and exploring commercial arrangements; facilitating an increased take up of the technology and a further reduction in costs.

Storage is seen as a potential solution to many of the congestion issues which companies are seeing on the networks. Consequently companies are keen to embrace storage technology and ensure that connection policies and commercial frameworks actively encourage storage to connect where it can provide most benefit for the network and save money for customers. As a result, companies are considering how they could adapt the current common charging methodologies to provide these incentives to storage parties. Network operators are also considering the types of contracts they offer, to see if they allow storage providers to ‘stack’ value across different vendors.

In order for battery storage to play a role in the balancing of the network in a low carbon future, there needs to be further clarity on which parties can own and operate storage and how it is treated from a regulatory perspective. This barrier to grid scale storage has already been identified by the Smart Grid Forum. There is ambiguity within the existing framework as to whether DNOs can own and operate storage assets where that involves buying and selling energy into the market. Clarity on this from Ofgem or DECC would be welcome along with guidance on the regulatory treatment of any income earned from the market.

In addition to battery storage there is also potential for energy storage within the UK’s gas network to play a role in balancing intermittency from wind generation. ‘Power to Gas’ technology takes excess wind generated electricity and converts it to hydrogen gas through electrolysis. Hydrogen can then be stored in the gas network and help meet demand for heating, cooking and transport. National Grid estimate that the gas network currently has up to 650 GWh of storage, and even if all the UK wind generation were to be stored in this way it would use only 5% of the grid.

3. What level of electricity interconnection is likely to be in the best interest of consumers?

Interconnectors will be important in enabling renewable energy by providing a solution to renewable intermittency. They also add diversity to our electricity mix and strengthen security of supply. For consumers the ability to link electricity supplies from the rest of Europe is good for competition in the market and will generally help to keep prices competitive. Doubling UK interconnector capacity to meet the European benchmark of 10% could save UK consumers up to £1billion a year.[6]

Existing and future interconnectors will also allow for the provision of services which are required for future system operability. Appropriate interconnectors can provide frequency response, black start, reactive power capability, and constraint management that may be at the most efficient cost to consumers.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The UK is establishing itself as a world leader in smart network technology, and the regulatory framework which has been put in place to encourage innovation is being considered in other countries. We consider that is leading the way in terms of identifying how to integrate new markets and technology in an energy system where generation, transportation and supply are treated as separate businesses.

In parts of the United States, such as California, there is a fast growing market for battery storage technology due to the explicit incentives which have been put in place for storage.

In Australia the role of manufacturers and equipment providers is helping stimulate smart grid development. The Government has mandated that electricity intensive products have an 'eco' mode which can be activated by DNOs when demand on the network is very high. This is something which could be of use in the UK if and when we see greater penetration of energy intensive technologies in households.

[6] National Grid, "Getting More Connected" (2014)

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8th January, 2015

National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

Evidence for the Electricity Interconnection and Storage Study for the National Infrastructure Commission

Dear Sir/Madam,

Please find below our evidence for the Electricity Interconnection and Storage Study for the National Infrastructure Commission.

To give some background, EnAppSys is an energy consultancy and energy data and analysis provider. We specialise in the development of tools and analysis that allow market participants to optimise their positions in the energy market and in particular in the short term, intraday and balancing market. We are currently supporting developers of energy storage projects and new entrant peaker plants which are both gas and diesel fueled. This support includes valuing opportunities in the balancing market, forecasting future prices and system requirements and supporting developers in raising finance and equity.

Our feedback for the consultation below is derived from the ongoing analysis and realtime monitoring of the GB market. We would have liked to provide detailed quantitative analysis to support some of the points we have made below but analysis of the GB Market is complex and time consuming and we need to manage our resources carefully. If you would like us to expand further on any of the points made please contact us.

Please find below responses to the questions you raised.

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**
    a. **What role can changes to the market framework play to incentivise this outcome:**

Changes to the market framework for managing supply and demand in the GB system has a significant ability to drive reduction of balancing costs and deliver the energy infrastructure that is required to keep the lights on, reduce environmental impact and keep costs affordable.

We believe that at a high level changes should be implemented to reduce the System Operator's intervention in balancing supply and demand and move the onus to the market where it is able to deliver more efficient solutions.

Ultimately it is suppliers who should bear the responsibility for ensuring that their customer's security of supply is ensured. Customers of suppliers sign a contract and within a market based approach it is necessary that any suppliers unable to ensure stability of supply must be sufficiently penalised to encourage compliance.

The changes implemented on the 5th November, 2015 to move to Single System Pricing were a step in the right direction and Imbalance Pricing is an ideal means to ensure that supply and demand match up, however the new system pricing calculation mechanism that offsets high price 'offer' actions by the lowest price 'bid' actions has resulted in more benign system prices than we believe was the intention.

The result is that GB imbalance prices may not send sufficient market signals for suppliers to balance and developers and traders to deliver technology and products that enables suppliers to better achieve balance.

Higher system prices result in a strong commercial driver to avoid imbalance and provide high payments to the system that ultimately results in a higher excess imbalance charge which through the recycling provisions (RCRC) rewards those parties that are better at managing imbalance. This is an effective mechanism but its effect is diminished if the penalties and returns are low.

An argument in the market is made that extreme system prices create an unacceptable risk that cannot be reasonably managed. One of the reasons of this is that the GB market 1 hour gate closure period prevents market participants being able to trade out imbalances just prior to the delivery period. This is a valid point and any changes to deliver higher system prices for imbalance should be part of an overall mechanism that enables market participants to trade their way out of imbalance closer to delivery time or else hold and operate their own or contracted standby generation assets. Short gate closure periods are used on the Continent and we understand these result in more self-balancing.

Higher potential imbalance prices and the ability for market participants to buy and sell power closer to the delivery period should result in increased intraday market volume and prices that provides a larger and more liquid market for flexible demand side reduction and generators to participate in. These strong market signals should encourage the building of assets the system needs.

We believe that moving the onus on balancing from the system operator to the market will ultimately result in lower cost of balancing and create more demand from market participants to build and/or own and/or contract flexible assets. Overall inefficiency in the system will be reduced, resulting in lower bills.

b. Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

We do believe that there is merit in the System Operator being fully independent. There is the potential that a System Operator who also operates the network sees network and transmission infrastructure as the solution to the challenges we face. Even if this is not the case it is hard for market participants to not perceive that the System Operator will have a bias against non-network solutions to system operation problems.

An example of this that is relevant to the other aspects of the consultation is that the solution being implemented to deal with constraints in Scotland is increased transmission. It is not clear if an economic evaluation of the option of large grid connected energy storage as an alternative was looked at.

How could the incentives faced by the SO be set to minimise long-run balancing costs?

We would suggest that incentives set for the SO are based on a levelised cost calculation using a forecast model to predict balancing costs forward based on past performance with a reward for beating the model year on year.

c. Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

The balancing market(s) as a whole seems to be functioning well but it is over complicated. There is a tension between what is deemed by observers to be "acceptable costs" of balancing and the prices required to justify a power station to be available to meet the intermittent needs of the system for power.

Due to its very high level of transparency high prices achieved in the balancing mechanism are used as examples of gaming and become politically sensitive. In our view as long as those high prices are borne by the party causing the imbalance then it is positive. It drives those imbalancing parties to avoid imbalance by better forecasting, building flexible generation or else improved asset reliability and encourages those assets that can bridge the gap between supply and demand to do so as the rewards are there.

When the capacity mechanism comes into effect in 2018 it will be interesting to see how the cost of balancing is impacted. Also the introduction of the TERRE replacement reserves market in 2017 may also impact the cost of balancing. It would be unwise to undertake a change to the balancing market before the impact of these other changes has been understood.

It is also useful to understand that the cost of the “balancing mechanism” is only around a third of the overall cost of balancing services. Sometimes there are interactions between different balancing services that result in undesirable consequences. For example moving assets from STOR to the balancing mechanism, to Firm Frequency Response or to SBR. National Grid has many different balancing markets which compete with each other for limited resources.

There are also asymmetries in information between different balancing tools used by the System Operator with some having exceptional visibility (the balancing mechanism) and others being very opaque (some of the non-tendered services). This means that market signals are obscured leading to inefficiencies for existing players and are a disincentive to new entrants.

a. **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

Demand-side management is going to be a necessary part of decarbonising the electricity grid. However, for demand-side management to occur on a larger-scale the connection between wholesale power prices and consumer’s power prices needs to be made. Regulatory interventions to reduce the number of tariffs provided to consumers are not helpful if a supplier wants to come up with more sophisticated time of use tariffs. Smart metering may help connect the engaged consumer to the variable cost of power.

Currently the system is heavily oversupplied during periods of high wind overnight resulting in the loss of low carbon power and very low power prices. However, since consumers are paid on a static rate they are unable to benefit from these periods resulting in a net cost upon the system as wind farms are paid not to generate and as low carbon power is not able to be used by the system.

If a connection can be restored between wholesale and consumer power price on an hourly or half-hourly basis, this opens up opportunities for businesses to provide consumers with solutions that allow them to benefit from generation surpluses and provide large scale-demand response.

On a smaller scale demand-side management gives an extra option in managing the system, but needs to be scaled to be truly effective.

Embedded generation can be effective in reducing the requirements for transmission to be built and should be rewarded for doing so, but only in cases where generators are providing real transmission cost savings. Otherwise embedded generation should be treated like transmission connected assets.

2. What are the barriers to the deployment of energy storage capacity?

a. Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

Storage assets typically have high capital costs that will be recovered by operating in the market at a premium. These assets have a high probability of recouping their costs as their risk of not being able to be profitable in the market is particularly low since they are almost certain to be able to buy cheap power and sell it later at higher prices.

However, these assets can have difficulty proving that they will be able to secure sufficient revenues in the market to justify investment since with higher capital expenditure, payback is longer and hence regulatory change risk is greater.

These storage assets therefore benefit from regulatory certainty and we would argue should be somehow incorporated into low carbon incentive mechanisms. This will promote the construction of new build as the ability to timeshift renewable generation and the speed of response of energy storage allows zero carbon power to be used to balance the system as opposed to being lost due to constraints.

Storage assets also allow transmission costs to be reduced as they can time shift renewable generation. The large build outs of onshore wind in Scotland are constrained in generation by the size of the transmission network. The current solution is to build more wires. Perhaps investing in storage may be a more cost effective means of smoothing renewable generation output. The saved cost on transmission is not recovered by the current market structures.

b. What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

There are numerous benefits of storage at distribution network scale in areas with high levels of renewables, such as regions with large solar farms that at peak output might oversupply the grid yet leave it undersupplied overnight. Such installations will reduce transmission costs.

However, building at distribution network level imposes restrictions on size that may encourage projects that rather than being the best projects are simply the most optimal for the current regulatory framework.

A better outcome may be achieved by treating storage as a whole as a unique asset with unique benefits for a grid beyond those rewarded by a market system through valuing the deferred transmission costs.

c. What level of electricity interconnection is likely to be in the best interests of consumers?

At a high level we believe that in the current market system the more GB interconnection is built the lower the average wholesale price will be due to the overall excess of generation capacity across a connected Europe reducing margins and prices. There is evidence of this in the UK market as interconnection has come on line.

The negative side of this is that the cost of the capacity mechanisms of each European country will rise as the revenue needed to keep capacity available to keep the lights on at times of system stress will increasingly come from these mechanisms. If the European Union does not centrally manage reserve capacity then the schemes will compete to attract capacity to be located in their country. The countries that lose this competition could see significant risk of power outages as country interests and capacity mechanism rules prevent electricity flowing to the area of highest price and hence highest demand.

Interconnectors allow the pooling of markets. The current situation in the GB market means that transmission costs are asymmetric with those on the continent meaning that energy flows into GB reducing the options for GB generators. Prices in the SEM in Ireland are typically higher than those in GB encouraging flows of power into the SEM providing opportunities for GB generators.

Taking the above considerations into account the level of interconnection can be allowed to find its own commercial level if there is a level energy market playing field across Europe with the premise that electricity flows will follow market price. Different regulatory regimes in different markets will result in interconnector investment being driven by regulatory asymmetries.

Modelling of UK electricity supply stability using probabilistic simulation of the loss of interconnectors either due to failure or system stress events in mainland Europe versus projected scenarios of UK installed capacity and reserve capacity will be required to ensure that we benefit from possible lower wholesale energy costs whilst keeping the lights on.

d. Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

See above.

e. **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

Interconnectors currently do not operate as balancing assets, but instead provide power via trading in the day-ahead market or via the purchase of capacity along interconnectors. There is a regulatory trajectory from Brussels to move more of the interconnection capacity to day ahead markets and then within day markets and finally balancing based on the principle of net social welfare. The TERRE market currently being finalised will provide for dispatch of replacement reserves balancing services across the interconnectors.

The technology used in the interconnections to the GB, CSC HVDC, is currently not suited to participating close to realtime in short term balancing services such as frequency response or short term balancing. Newer VSC HVDC technology provides more opportunities for provision of ancillary services but as this is new technology to the GB market it will take some time to understand how this technology will work in practice.

3. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The technology landscape is moving too fast for regulatory regimes and large utilities to keep up. Falling solar and onshore wind costs along with battery storage costs decreasing rapidly mean that designing markets to "pick winners" is dangerous.

The best international practice is technology agnostic, procuring the required services rather than the technology.

If the selection criteria for procuring balancing services is drafted to not pick technology winners, then the best solutions will come forward and the industry will be incentivised to find and deliver these solutions and not second guess what technology the UK government will support or want.

R&D support and competitions can ensure early support for new technologies to ensure innovation is nurtured to produce the next generation solutions.

Regards,

Phil Hewitt

8 January 2016

Energy Saving Trust response to National Infrastructure Commission call for evidence

Energy Saving Trust is the leading, impartial sustainable energy organisation. We work on behalf of governments and businesses across the UK providing services in the area of data, assurance, consumer engagement, advice and grant administration.

For the Department of Energy and Climate Change (DECC) the Energy Saving Trust delivers the Energy Saving Advice Service in England and Wales. We also undertake other research and awareness-raising work for DECC on a project-by-project basis – particularly field trials and studies to understand the impact of home energy technologies. EST has also worked with National Grid and other businesses to help them understand the impact of sustainable energy technologies – particularly in homes – on the wider energy system.

In Scotland Energy Saving Trust is the principal delivery partner of the Scottish Government for home energy efficiency. We run comprehensive local and national advice and support programmes. The Trust is also the lead partner for Local Energy Scotland on the "CARES" community renewable energy programme. This programme includes a challenge fund supporting innovative grid integration for community renewable energy projects including energy storage and demand side management initiatives.

The Energy Saving Trust Foundation supports the development of a strong and vibrant community energy sector in the UK through research and support projects including convening cross-sector roundtables on the role of community energy alongside energy storage and smart technology.

Since 2011 Energy Saving Trust, on behalf of OLEV, has advised over 200 organisations on where they could utilise plug-in vehicles in their fleets, and carried out a number of electric vehicle charging infrastructure mapping projects for Transport for London. This has given us a broad view of the practical issues involved in the large-scale roll out of plug-in vehicles. Our involvement in the Innovate UK-funded *Ebbs and Flows of Energy* project means we are also at the vanguard of the emerging vehicle to grid market and seeking to understand how this will change the electricity market

Electricity interconnection and storage

Key response points:

- Energy efficiency is one of the most cost effective ways to reduce electricity demand and reduce energy bills and as such should be an infrastructure priority
- Load balancing at a local level could be significant to improve the flexibility of the energy system
- Energy storage, along with renewables, could play an important role in balancing supply and demand, with storage important to alleviate grid capacity issues
- There are currently various barriers to the adoption of energy storage, many of which can be reduced by effective policymaking
- Households represent a substantial energy storage market building on uptake in the business sector
- Community energy groups are often willing to try innovative and untested business models and technologies, and could therefore be useful partners to deploy energy storage and smaller scale balancing technologies

There are a number of EST projects and studies to which we would like to refer you and about which we would be happy to provide more information:

- Energy Demand Archetype Model (EDAM). This energy model - designed for engineers - creates best estimates of what demand changes will look like in the future as new technologies are installed in the home.
- Scottish Government Challenge Fund for Community renewables and storage
- Recent round table events with government, academia and industty on the potential for community energy and storage

Question 1:

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Energy Saving Trust response:

One of the most significant steps to help reduce electricity demand is through improved energy efficiency in homes. It represents a huge cost-effective potential to reduce energy use and carbon emissions from homes, at the same time lowering energy bills for ordinary households. Energy efficiency achieves a number of important government objectives and there seems to be little disagreement that retrofitting the UK housing stock is crucial to achieve our decarbonisation targets, ensure better energy security and keep energy bills down. Nonetheless government action to date has not been sufficient with a lack of stability, clarity and with no clear roadmap in place on how to improve the energy efficiency of our homes. The Committee on Climate on climate change – for instance – stated in its 2015 progress report[1] that:

"[…] the policy landscape is complex and in places inconsistent. Our assessment of existing policies is that some of these are at risk of failing to deliver, either due to design and delivery problems, or because they are currently unfunded. Even if these policies delivered in full, there would be a policy gap to achievement of the fourth carbon budget (2023-27) and the cost-effective path to the 2050 target."

As such we are calling for energy efficiency to be set as an infrastructure priority – for reasons that are set out in the recent paper published by Frontier Economics[2]: *'Energy*

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[1] 'Reducing emissions and preparing for climate change: 2015 Progress Report to Parliament- The Committee on Climate Change. June 2015. https://www.theccc.org.uk/publication/reducing-emissions-and-preparing-for-climate-change-2015-progress-report-to-parliament/

[2] 'Energy efficiency: An infrastructure priority'- Frontier Economics. September 2015. http://www.energysavingtrust.org.uk/sites/default/files/reports/Energy%20efficiency%20as%20infrastructure%20September%20Final.pdf

Efficiency: an infrastructure prioirity'. And we would like to see NIC priorities and planning for the energy system to reflect this.

Load balancing at a localised level will play an important role in improving the flexibility and resilience of the energy market. In turn, energy storage and batteries (in EVs for instance), along with microgeneration, represent a clear opportunity in localised load balancing. In certain parts of the country where there are grid capacity issues storage could allow the installation of more solar PV without having to upgrade infrastructure and help load balance.

Energy Saving Trust data suggests there are over 6 million houses in the UK with south facing roofs. This does not include blocks of flats with flat roofs or non-domestic buildings. Even allowing for the fact that some of these may not be suitable for solar PV this still represents a significant opportunity. Considering this tremendous potential, having to restrict the growth of the industry because of excessive pressure on the grid is a missed opportunity.

We understand that there are various market-based solutions that are being looked at and one example of this that Energy Saving Trust is involved with is the 'Ebbs and Flows Energy System (EFES)' project: it is looking at creating a local energy system that can help address the electrical needs of the UK through utilisation of plug-in vehicle to grid technology to reduce demand on the National Grid (NG) at peak demand times. The project aims to demonstrate the development, impact and business potential of a Virtual Power Plant (VPP) integrating; building energy management, renewable electricity generation, electric vehicles and battery storage systems.

In addition, in Scotland the Scottish Government Challenge Fund, which runs alongside the CARES (community renewable energy systems) The fund supports *"projects looking to develop innovative energy distribution and storage solutions that have an overall aim of creating more local value and benefit."* Applications have included integration of energy storage and demand side management alongside community renewable energy. A similar fund would be useful for the rest of the UK. Although Ofgem has the Low Carbon Networks Fund this is not generally accessible to stakeholders other than Distribution Network Operators. Bringing in a wider range of stakeholders alongside DNOs could greatly increase the potential for innovation.

Finally, local authorities and community energy groups could have a significant role in supporting and facilitating the development of smart-grid approaches through their ability to draw together broad partnerships around local energy projects (e.g. area-based energy efficiency and local renewable energy projects). Energy Saving Trust Foundation has identified significant support for smart grid approaches, demand side management and energy storage within these sectors through a series of roundtable events and workshops we have facilitated with government, academia and industry. These focused on locality-based approaches to smart-grids alongside community-ownership models and had attendance from a wide range of organisations including:

- The community energy sector, alongside local authorities, could be a strong ally for this work on the basis of shared goals around energy efficiency, security of supply and carbon emissions reduction.

We would be happy to offer more information about these events and their outcomes if the commission wanted it. If so please get in contact.

Question 2:

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

Energy Saving Trust response:

In a recent roundtable event on community scale energy storage (and domestic to an extent) bringing together stakeholders from different backgrounds (academia, industry, community energy groups) a number of different challenges were identified:

- Capital cost of energy storage systems needs to be reduced
- Energy storage could have multiple income streams (including selling balancing services and increasing revenue from local generation) but in practice these can be difficult to realise as the market is not yet mature. Piloting new approaches could help to address this.
- A stable policy framework is needed for community energy and energy storage
- Social enterprise models for energy supply could help to unlock the potential of community-scale energy storage
- Deployment of more pilot projects is needed to demonstrate the viability of energy storage and test different business models

This list is not exhaustive and it should be noted that understanding the barriers to energy storage is complex.

Energy storage will become much more economically viable once the true environmental impact of alternatives is taken into account. Although storage forms part of the capacity market auctions, in comparison to diesel and coal generation it plays a relatively minor role at the moment. One of the difficulties quoted for energy storage is that there needs to be greater deployment of the technology, not only to help bring costs down but also to demonstrate the viability and explore the different potential business models that could be built around storage. The Capacity Market mechanism could be used to promote and develop energy storage to a much greater extent and help overcoming this hurdle. If, for instance, a greater emphasis on the environmental impact was taken into account in the

Capacity Market then energy storage would emerge as a more attractive option than diesel storage Given the potential future role of energy storage in reducing carbon emissions and providing secure supply through addressing the intermittency of renewable energy generation and balancing supply and demand, this would appear to be a much better investment than diesel generation.

Energy storage technologies are applicable for deployment at various different scales and we believe that businesses, communities and households all have an important role to play. Households often receive the bulk of the attention when energy storage is looked at, however as businesses work on a larger scale and have greater capacity it may be easier to focus on them first. Industry deployment could be a useful precursor to domestic rollout, particularly as they are already experimenting with demand side reduction supply contracts which provide additional financial incentives for embracing flexibility.

We also believe that community energy groups could play a leading role when it comes to this as they are frequently driven by social and sustainability concerns. In addition, community energy groups have shown themselves to be willing to try innovative and relatively untested technologies and business models.

Generally there seem to be few mechanisms in place to incentivise uptake of domestic storage; without half-hourly settlements and as the feed-in tariff does not offer financial incentives to store electricity, households currently have little financial reason to install storage.

The domestic sector represents a tremendous market. The single most significant change to get domestic energy storage on its feet would be half hourly settlements. The value of energy storage at a household level would increase substantially at this point as households and community groups would be able to charge their batteries during the daytime (off peak) and use or export the stored electricity during the evening (peak demand times). At present there is little financial value in storing electricity because the export tariff is the same regardless of the time of day, as is the cost of the electricity. Although we understand that Ofgem will introduce a time of use tariff in 2017 we are as yet unclear whether this will be the trigger for the domestic markets and to what extent this will incentivise the uptake of energy storage.

Of potential interest to the Commission is the modelling tool that Energy Saving Trust helped develop for National Grid - Energy Demand Archetype Model (EDAM). This energy model - designed for engineers - creates best estimates of what demand changes will look like in the future as new technologies are installed in the home. EDAM works with user-set assumptions regarding the uptake of various energy saving measures and low carbon or renewable energy technologies, although this does not currently include energy storage there is no reason why it could not be included if necessary. EDAM covers the domestic sector and the most recent version EDAM II includes both the domestic and non-domestic sector.

Finally, as pointed out by the Institute for Chartered Engineers[3] *"The key point is not to look at individual technologies or responses in isolation but rather consider the electricity system as a whole."* Although energy storage has a lot of potential to help balance supply and demand it is more important to look at ways that demand management and other systems can improve the flexibility of the system as a whole – including, for example, home energy efficiency Looking at the system in a holistic manner is important in this regard and we would encourage looking at models that can be scaled up, interact and incorporate a variety of technologies into them. There is no "winning" technology that policy should be focussed on, instead developing a smart system for consumption, generation and network management that can adjust to include different technologies as they become available is needed.

[3] In their written response to the inquiry into Low Carbon Network Infrastructure by the Energy and Climate Change Committee. 17 November 2015. http://data.parliament.uk/writtenevidence/committeeevidence.svc/evidencedocument/energy-and-climate-change-committee/low-carbon-network-infrastructure/written/23817.html

Question 3:

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current ‘cap and floor’ regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?

Energy Saving Trust Response:

As the Energy Saving Trust’s focus is on domestic and community level engagement, interconnection is not one of the areas that we work on. Our response to this question is therefore simply that the value for money of interconnection needs to be carefully looked at, investing heavily into expensive interconnection should be weighed against other, potentially less expensive, alternatives. Another point is that it is arguably better to keep the economic benefits of low carbon electricity generation in the UK economy by supporting development of our own industry in their area, given that this will be one of the most important global industries of the twenty first century in the wake of the Paris agreement.

Question 4:

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

No response.

Energy UK

The voice of the energy industry

Energy UK response to National Infrastructure Commission call for evidence

8 January 2016

Introduction

Energy UK is the main trade association for the energy industry, with over 80 members; representing energy generators and suppliers of all sizes. Our members supply gas and electricity and provide network services to both the domestic and non-domestic market. Energy UK members own over 90% of energy generation capacity in the UK market and supply 26 million homes and 5 million businesses, contributing over £25 billion to the UK economy each year. The industry employs 619,000 people across the length and breadth of the UK, not just in the South East, contributing £83bn to the economy and paying over £6bn annually in tax.

This paper was produced in consultation with Energy UK's members following the call for evidence issued by the National Infrastructure Commission on 13th November 2015 and seeks to address the questions posed in the 'Improving how electricity demand and supply are balanced' section.

We welcome the opportunity to respond to this consultation and engage with the National Infrastructure Commission more broadly on the challenges as we transition to a low carbon system. Flexibility is one of the key topics of development within the industry and the National Infrastructure Commission's work in this area, alongside that undertaken by Ofgem and DECC, is welcome in ensuring that the system can be managed efficiently and at lowest cost to consumers

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

There is a set of market and system operation arrangements to ensure that demand is balanced with generation at all times, including:

- Generators and suppliers use of bilateral trading or power exchanges to buy and sell power in the forward, day ahead and spot wholesale electricity markets. All transactions are notified to the System Operator. After 'gate closure' the System Operator is the residual balancer with generators and suppliers participating in the Balancing Market to help balance the system.

- National Grid in its role as System Operator has a number of Ancillary Services at its disposal which can be used to balance and manage the system.

Wholesale electricity market trading arrangements function well in terms of ensuring that suppliers or large consumers are able to purchase the power they need to meet their customers' demand. Clearly the uncertainty increases closer to real time but liquid day ahead and spot markets largely ensure that changes in circumstances, such as plant failure, or variability in weather conditions, can be mitigated.

Balancing Market

The Balancing Market ensures that any imbalances in the system can be resolved. In 2012 Ofgem launched a Significant Code Review of the electricity balancing arrangements which concluded that imbalance pricing (or 'cashout') did not reflect the cost of actions taken by the System Operator to balance the system and the cost to consumers of the system being out of balance (Value of Loss Load, or VoLL). Ofgem proposed a suite of reforms to make cashout prices respond more sharply to system imbalances to incentivise parties to improve balancing and reward providers of flexible capacity which can help balance the system. Following publication of its final policy decision in May, Ofgem instructed National Grid to raise two modification proposals to the Balancing and Settlement

Code to implement changes to the cashout regime. Implementation is staggered with some of the changes going live on 5th November 2015, comprising a Pricing of the VoLL at £3,000/MWh, a single cashout price; making cashout prices based on the average 50 most expensive actions taken by the SO, rather than 500 previously (PAR500 to PAR50); and inclusion of a Reserve Scarcity Price. Further changes to be implemented in November 2018/19 will raise the value of VoLL to £6,000/MWh and move PAR50 to PAR1.

Energy UK supports the principles behind changes to cashout, as efficient balancing is in the interests of consumers and the reliability of the system. The changes should ensure that flexibility is better valued in the Balancing Market, which benefits flexible generation and demand side response, including storage, to the extent that they have access to the Balancing Market. The new cashout arrangements have, however, also introduced new risks to market participants, particularly those more at risk of being out of balance. It is therefore important that the cashout changes are monitored closely and the impact properly understood before making any further changes. We note that some Energy UK members also advocate moving gate closure closer to real time e.g. 15 minutes, to minimise those risks. Others identify that this could present risks to System Operation. We suggest that this should be subject to further investigation in order to better understand the costs and benefits.

It should also be noted that there are changes taking place at a European level which will impact GB balancing arrangements. In the future we should expect to see a strong push from the EU to align the fragmented national balancing markets. In particular the EU Electricity Balancing Network Code (NC EB) will become a legally binding piece of EU law within the next 2-3 years. The NC EB aims to move Europe from the current situation in which most balancing is carried out on a national level, to a situation in which larger markets allow the different resources which Europe has available to be used in a more effective way. It will promote greater integration, coordination and harmonisation of electricity balancing rules in order to make it easier to trade cross border resources. This will allow the Transmission System Operators (TSOs) across Europe to use the resources available more effectively, resulting in reduced costs to the consumer and enhance security of supply.

As there are relatively few examples of large cross-border balancing markets in Europe today, TSOs and market players will need to work closely as markets evolve and existing national arrangements (including industry codes and contractual frameworks) will need to be updated. The development of a truly European balancing market will require more changes to existing rules. Energy UK supports in principle that alignment of balancing markets should bring efficiencies and benefits. As there are different levels of harmonisation it is vital that a thorough Cost Benefit Analysis is undertaken to ensure that the benefits outweigh the potentially substantial costs.

Ancillary services

The market for ancillary services is set to grow, as the number and volume of services required by the SO to operate the transmission system increases, particularly with high penetrations of intermittent renewable generation. National Grid's System Operability Framework sets out predicted future system requirements under the various Future Energy Scenarios.

There are currently varying levels of transparency in the way the different ancillary services are tendered for and utilised by the System Operator. Many of the services are also designed with more of a focus on traditional generation provision, as was the case in the past. National Grid has undertaken a positive campaign, Power Responsive, to encourage more demand side participation, and is also reviewing and making changes to services. Ancillary services should be designed in a holistic manner to avoid unintended consequences for the wider system. Examples include coordination needed across Transmission and Distribution Networks; the interaction between DSR aggregation participation and supplier imbalance positions; and ensuring that providers of multiple services can meet their obligations.

Transparency and a full market approach are also important and we believe there would be merit in looking at international examples of ancillary service markets. For example, dynamic procurement, such as half-hourly spot market, could be explored to allow co-optimisation of the dispatch of energy and reserves.[1] This would aid development of DSR, where the quantity of service that can be provided depends on the level of consumption by customer loads, which does not remain constant. Requiring participants to provide a constant level of availability for days or weeks at a time was a harmless simplification when only generators were providing the services; continuing with this approach causes an unnecessary barrier to customer participation.

Future system needs – energy, capacity, flexibility

The GB electricity system is changing which presents new challenges to system security. Large, dispatchable thermal generation is being replaced by low carbon, smaller, and largely intermittent generation. Managing the system is no longer handled solely through the energy market (wholesale and balancing) and ancillary services. A technology neutral Capacity Market has been developed to address the energy market failure to ensure that availability of capacity is sufficiently remunerated ('missing money' problem[2]). Markets for flexibility are being developed.

The flexibility challenge is one facing countries around the world which are on a transition to a lower carbon power sector - how to ensure that sudden changes in generation, and its knock on effects on system stability, can be managed through a combination of flexible generation, demand side response, interconnection and storage. The Committee on Climate Change has found that increased flexibility is a low-regret option reducing the overall cost even in a system that is less decarbonised, with savings of at least £2.9bn per annum out to 2030.[3]

DECC and Ofgem are both undertaking work on flexibility, which Energy UK is supportive of. One of the key aspects of this is to look at how the potential of demand side response can be unlocked given that it in theory should provide a lower cost solution than building new power stations and network capacity, much of which would have very low utilisation in the longer term.

Demand Side Response

Demand Side Response (DSR) and embedded generation are just two sources of flexibility, which as with the other forms (interconnection, large scale flexible generation and storage) have pros and cons. Energy UK supports a balanced, market approach to flexibility solutions. The emphasis should be on removing barriers and enabling equitable market access rather than putting in place special arrangements.

DSR addresses balancing constraints by adjusting energy consumption with the aim to mitigate over or under-supply. It does so by:

- Reducing / increasing consumption;
- Shifting consumption; and
- Optimising back-up generation or storage onsite.

By changing the profile of demand and increasing the flexibility of the demand side, DSR can assist the electricity market to adapt to the availability of increasingly intermittent supply and fluctuating demand. DSR encourages customers to undertake short term shifting of demand, i.e. to increase as well as to decrease consumption (referred to as valley filling and peak shifting respectively), to increase export or to take excess energy from the electricity network.

DSR could generate value for the GB system in the following ways:

- **Introduction of greater efficiency** with regard to system capacity (i.e. capacity required at times of system stress or peak demand) and guaranteeing adequate security of supply at potentially lower costs than thermal generation.

[1] New Zealand has such a market for for 3 services: Fast Instantaneous Reserves, Sustained Instantaneous Reserves, and Frequency Keeping: http://www.systemoperator.co.nz/market/ancillary-services/overview
[2] The 'missing money' problem is when scarcity periods are unpredictable and investors are not confident about being able to recover fixed costs either due to the lack of sufficient scarcity rents or concern that regulators or governments will intervene to cap prices or act on perceived market abuse.
[3] https://d2kjx2p8nxa8ft.cloudfront.net/wp-content/uploads/2015/10/CCC_Externalities_report_Imperial_Final_21Oct20151.pdf

- **Reduction in wholesale electricity prices** by driving down the average generation costs. By reducing demand at peak periods DSR can lead to lower peak prices which can be passed on to customers via lower energy bills.

- **More efficient investment in transmission and distribution networks**: A reduction in net-demand at peak times on the transmission and distribution grid can reduce grid reinforcement costs for the network operators, and increase asset utilisation across all parts of the system.

- **Reduced GHG emissions** by reducing the demand for high emission peaking plants to balance the system. This is particularly important in the future in the context of the UK's move to a low-carbon economy where there system will be constrained by intermittent generation. Additionally, more efficient utilisation of plant helps reduce GHG emissions and resource consumption.

Barriers to deployment of DSR include market structure, the perception of DSR, economics and market and regulatory arrangements:

- **Market Structure:** Until recently, the supply market has been relatively stable with the existence of predictable and manageable levels of generation; predictable fluctuations in demand through investment in flexible thermal generation; and grid re-enforcements. The distribution network is currently built with sufficient network capacity to accommodate peak flows. Consequently, there has been no need for network operators to actively manage their networks. Given the increasing penetration of renewables with distribution networks and continuing decline in industrial and larger scale demand, the system requires further investment in flexibility which DSR can provide. DSR could be one potential solution but needs the evolution of a flexibility market and commercial arrangements to encourage the engagement of suppliers, aggregators and consumers. National Grid's Power Responsive campaign; the System Operability Framework process and DNO trials are a good start. The main type of engagement at present lies in Triad Avoidance[4] and low levels of participation from in-house demand management to reduce energy costs, mainly from Energy Intensive users. Work still needs to be done to engage SME and Domestic sectors on the benefits of DSR.

- **Perception of Complication:** Traditionally only energy intensive users have had half hourly metering installed. SMEs and domestic consumers have been metered on sector averaging profiles and have little knowledge or experience. With the advent of smart meters, and the support of their supplier / aggregator, consumers will become more aware of their ability and potential value of proactively managing their demand.

- **Economic Barriers:** Consumers require a financial incentive to change their patterns of electricity consumption. This requires investment of both money and effort by customers. It also exposes them to risk: if they are unable to deliver the service for which they are contracted, they will be liable for penalties. For participation to be attractive, the benefits must outweigh the costs and risks. Aggregation of DSR can help here, as aggregators can build portfolios of customers who together can reliably meet system needs, while managing risks on those customers' behalf.

- **Regulatory arrangements:** The energy policy of the UK government has been mainly focusing on permanent demand reduction with measures such as Green Deal and Energy Saving Opportunity Scheme (ESOS). DSR aggregators have seen an increased role in the ancillary services, as that is the only market open to it in the absence of the opportunity to participate in wholesale or balancing markets. Most demand-side response does not currently have access to the Balancing Market. When a customer reduced demand at a time of system stress, it is their supplier that benefits, so only that supplier is motivated to buy this flexibility from the customer. This precludes the involvement of independent aggregators, who are responsible for the majority of demand-side participation in the

[4] The triad system is the way National Grid charges businesses for the cost of the transmission network. By reducing load and increasing generation when national demand is at its highest, customers can save or earn money.

Capacity Market and in ancillary services. To remedy this, flexibility needs to be unbundled from supply arrangements, by creating a role for aggregators under the BSC, independent of the supplier role. As discussed earlier, ancillary service product design could be optimised to make it suitable to DSR. DSR requires equitable participation in the various market open to generation. The inability of demand-side participants to access the wholesale and balancing markets and their limited ability to access ancillary services markets (due to poor product design and procurement arrangements) has knock-on effects on the Capacity Market. DSR participants are not competing on the same basis as generation resources, which can access wholesale and balancing market revenues.

Future System Operation requirements

The rapid, ongoing evolution of the GB energy system means the role of the System Operator and the distribution networks is becoming increasingly complex, and will continue to do so with developments in embedded generation and distribution level storage solutions and the drive towards integrated energy markets across Europe. We, therefore, believe it would be appropriate for Government to consult with industry, both the large established generators, smaller entrants and distribution and transmission networks, on an appropriate future framework for system operation that will ensure secure, efficient and stable network operations are maintained.

There are many areas to assess such as how best to co-ordinate system operation across both Transmission and Distribution Networks given the amount of renewables on the electricity system and growth of embedded generation. Only once sure about the issue to be addressed, then the various roles, responsibilities and interactions can be assessed. Whatever the outcome, a robust Cost Benefit Analysis will be required to ensure that the costs of moving to a different model will result in long term improvements to system operation and ultimately not increase the cost to consumers. The Federal Energy Regulatory Commission has undertaken such an exercise in the U.S. to understand the costs and benefits of introducing an ISO.

Cost reflective charging arrangements

Cost reflective charging should be part of the future market arrangements. This will ensure correct incentives on market participants to locate appropriately on transmission and distribution networks and encourage effective competition in the market. Currently the system is not cost reflective, for example between distribution and transmission connected generation. This is impacting competitive dynamics in electricity markets. Industry will work with the transmission, distribution and system operators and Ofgem to ensure that the future system is cost reflective and facilitates competition.

2. What are the barriers to the deployment of energy storage capacity?

Electricity storage is widely regarded in the sector to be the single most important technological breakthrough likely to happen over the period to 2030 and a complete ‘game changer’ in the way that the power system operates. Views are varied on when storage will be commercially viable either at a consumer level, or at a grid level.

Electricity storage can potentially be used for meeting long-term system balancing requirements, e.g. inter-seasonal shifts in demand and supply. Batteries are less well-placed to fulfil this role, and this therefore is a role better suited to pumped hydro, Compressed Air Energy Storage (CAES) and thermal storage. Power to gas technology also has potential given the gas infrastructure already in place in the UK, subject to gas quality considerations.

Because storage acts as both generation (when exporting) and demand (when importing electricity) there is a need to consider whether the market framework and regulatory mechanisms currently in place properly incentivise the development of electricity storage, predominantly at grid-level but also at small-scale. It should be noted that gas storage is exempted for certain network charges in recognition of the benefit storage brings to the system and to acknowledge that storage is not the end use of the gas. Ofgem is currently looking at this issue as part of their flexibility work and we encourage the National Infrastructure Commission to support it as appropriate.

Additionally, investors in large-scale storage assets, such as hydro-pumped storage, face the same challenges as investors in generation, such as long-term price uncertainty (due to technology, market and policy risk), long asset lives and high upfront capital costs. These are considerations within the scope of the European Commission's market design work to assess options to help deliver in large-scale storage assets that are on the European Projects of Common Interest (PCI) list.

Energy UK believes that the electricity storage market will be able to develop without subsidy, although we note the argument that some kind of deployment grant for household storage may help encourage the market. It has also been suggested that longer term Capacity Market/ancillary services contracts for large-scale storage should be investigated.

Various electricity storage technologies currently exist, at varying levels of development. Table 2 sets out some of the key characteristics of different storage technologies and estimated technological maturity.

Table 2: Electricity storage technologies

TECHNOLOGY	MATURITY	COST ($KW)	COST ($KWH)	EFFICIENCY	CYCLE LIMITED	RESPONSE TIME
Pumped Hydro	Mature	1,500-2,700	138-338	80-82%	No	Seconds to Minutes
Compressed Air (underground)	Demo to Mature	960-1,250	60-150	60-70%	No	Seconds to Minutes
Compressed Air (aboveground)	Demo to Deploy	1,950-2,150	390-430	60-70%	No	Seconds to Minutes
Flywheels	Demo to Mature	1,950-2,200	7,800-8,800	85-87%	>100,000	Instantaneous
Lead Acid Batteries	Demo to Mature	950-5,800	350-3,800	75-90%	2,200 – >100,000	Milliseconds
Lithium-Ion	Demo to Mature	1,085-4,100	900-6,200	87-94%	4,500 – >100,000	Milliseconds
Flow Batteries (Vanadium Redox)	Develop to Demo	3,000-3,700	620-830	65-75%	>10,000	Milliseconds
Flow Batteries (Zinc Bromide)	Demo to Deploy	1,450-2,420	290-1,350	60-65%	>10,000	Milliseconds
Sodium Sulfur	Demo to Deploy	3,100-4,000	445-555	75%	4,500	Milliseconds
Power to Gas	Demo	1,370-2,740	NA	30-45%	No	10 Minutes
Capacitors	Develop to Demo			90-94%	No	Milliseconds
SMES	Develop to Demo			95%	No	Instantaneous

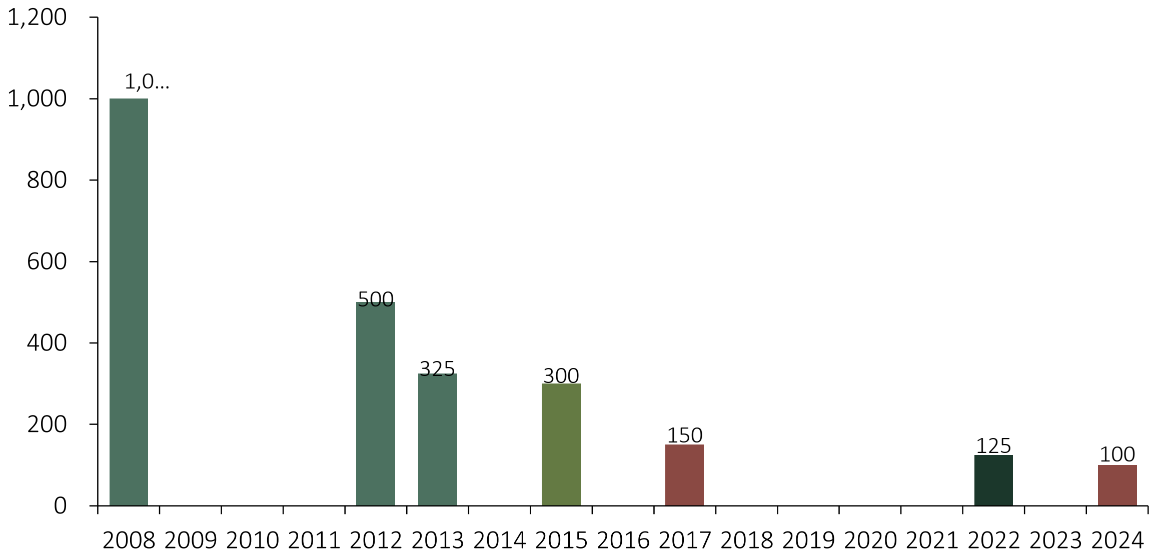
Source: Deutsche Bank, https://www.db.com/cr/en/docs/solar_report_full_length.pdf

There is potential for household-level batteries to open up the market for small-scale distributed systems in GB. In its recent position paper on system flexibility, Ofgem wrote that "[w]hile storage has been providing flexibility in other countries, and pumped storage has historically played a strong role in GB, the potential of battery and other forms of storage to smooth intermittent generation or contribute to local balancing has not yet been fully realised in the UK".[5]

A number of recent announcements have generated heightened public interest in battery storage technologies, particularly at the household level. Earlier this year 2015, technology company Tesla announced it will be releasing its domestic energy storage unit the 'Powerwall' in GB from late 2015-2016.[6] Priced at US$3,000 for a 7kWh model with an efficiency rating over 92%, Tesla's Powerwall product is expected to bring about a shift in the household storage market. Tesla is also due to release its utility-scale product the 'Powerpack' at approximately US$250 per kWh.[7]

Recent reductions in technology costs, combined with improvements in scalability, have increased the potential for commercial deployment of battery storage. Fig 2 below shows estimates by Deutsche Bank for reductions in battery prices from 2008 to date and estimated reductions to 2024.

Figure 2: Historic battery prices in the US; DOE/ Tesla targets



Source: Deutsche Bank, https://www.db.com/cr/en/docs/solar_report_full_length.pdf

Many in the industry believe that battery prices will continue to fall. Table 3 shows company forecasts for their battery storage products. The US Department of Energy also expects the trend of falling costs to continue, with an estimated 58% reduction by 2022 on 2015 prices. Tesla anticipates costs to half by as early as 2017 compared to 2015.

Table 3: Falling battery prices in the global market

	Technology	Current	Forecast
USD/kWh			
Aquion Energy	Sodium-ion	$500	$250
Eos Energy Storage	Zinc Air		$160
Primus Power	Flow – Zinc Halogen	$500	
EnerVault	Flow – Iron Chromium		$250
Imergy Power	Flow – Vanadium	$500	$300
Redflow (Australia)	Flow – Zinc Bromide	$875	$525
Enstorage (Israel)	Flow	$738	$307

Note: Selected companies shown. Deutsche Bank sources were also obtained from GTM and Energystorage.org
Source: Deutsche Bank, Crossing the Chasm, February 2015

[5] https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/flexibility_position_paper_final_0.pdf
[6] Tesla Energy, Press release on Tesla Powerwall, http://www.teslamotors.com/en_EU/presskit
[7] Forbes, Why Tesla Batteries are cheap enough to prevent new power plants, http://www.forbes.com/sites/jeffmcmahon/2015/05/05/why-tesla-batteries-are-cheap-enough-to-prevent-new-power-plants/

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Energy UK is supportive of more economic and efficient interconnection between GB and other countries, which will facilitate the benefits of the EU internal electricity market. There are a number of benefits that interconnection can bring to the GB electricity system and consumers if developed efficiently, such as cheaper electricity, enhanced security of supply and flexibility. However, it is not straightforward to establish what level of interconnection is in the best interests of consumers for a number of different reasons.

GB is currently under interconnected with only 4GW of capacity compared to the EU target of 10% of installed capacity. However, the EU targets are based on an arbitrary number and is not supported by Energy UK members. Interconnection will be built where there is a strong market case for doing so. The relative benefits of each interconnector depends on where it is connecting to and also the number of existing interconnectors with that market.

Ofgem's development of the Cap and Floor regulatory model has been successful in helping to address barriers to additional interconnector investment. Ofgem's Cost Benefit Analysis has supported the GB consumer welfare case for approving several new interconnectors supported through the Cap and Floor regulatory regime. This is dependent on a number of key assumptions. There are credible alternatives which show minimal or negative benefit to GB consumers. Whilst the short term benefit of new interconnection is not contested due to the current price differential between GB and other European markets, this is more uncertain over the longer term. The price differential, and therefore GB consumer welfare benefit, is largely driven by the UK carbon tax uplift, as well as higher network charges faced by GB generators compared to most European counterparts. As long as interconnectors import and provided that the level of interconnection is efficient, they would be expected to have a positive impact for GB consumers, including lower wholesale prices. This would not be the case in the case of persistent exports. The sensitivities in the cap and floor CBA demonstrate this so further independent scrutiny of the CBA is needed to ensure that only the interconnectors which deliver best value for consumers are developed.

An inefficient amount of interconnection may lead to higher costs than necessary. For example, increased interconnection is likely to lead to closure of GB generation and less new build generation as a result of displacement in the energy and capacity market merit order. It would be difficult and costly to reverse this if that extra plant is subsequently found to be needed because in their totality interconnectors are not importing at time of need as expected. This demonstrates the huge importance of developing regional adequacy assessments which can then inform consistent and more accurate de-rating factors.

It should be noted that increased interconnection bring increased policy and regulatory risk, as more interconnection requires more market harmonisation to ensure a level playing field for generation. While some differences in market structure are desirable and necessary for a number of reasons including fuel mix, security of supply and investment support, the National Infrastructure Commission should consider the long term impact of a more interconnected GB system with intra-market differentials in network charges (e.g. transmission) and taxes, on investment in GB electricity generation, storage and other forms of flexibility.

Various consultancies have undertaken work on the topic of interconnection, including Poyry[8], Redpoint[9], and a forthcoming report to be published by Aurora Consulting. Energy UK would welcome further independent analysis on this topic by the National Infrastructure Commission.

[8] https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/791_ic_cba_independentreport_final.pdf

[9] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The French electricity market provides a good example for encouraging Demand Side Response participation in the market. DSR can participate in all markets (day-ahead, intraday, balancing, ancillary services, reserve, and capacity). Demand Side Aggregators are able to participate in the Balancing Market in France.

Some of the states within the U.S. and Canada have had an ISO for a considerable amount of time and therefore provide good examples of the pros and cons of adopting an ISO.[10]

For further information, please contact Christopher McDade at Energy UK [phone number redacted].

[10] We recommend an academic paper by Michael Pollitt, 'Lessons from the History of Independent System Operators in the Energy Sector, with applications to the Water Sector', August 2011, http://www.econ.cam.ac.uk/dae/repec/cam/pdf/cwpe1153.pdf

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The Rt Hon Lord Adonis PC
Interim Chair
National Infrastructure Commission
1 Horse Guards Road
London SW1A 2HQ

Submitted by email

8 January 2016

Dear Lord Adonis,

Response from EnerNOC to the Commission's call for evidence on improving how electricity demand and supply are balanced

EnerNOC is grateful for the opportunity to contribute to the Commission's consideration of how to future-proof the nation's energy infrastructure.

EnerNOC provides energy intelligence software and services to commercial and industrial energy users and to utilities. As well as helping users manage their energy usage and costs, we work with them to offer their demand-side flexibility into wholesale capacity, energy, and ancillary services markets and utility programmes. In the UK, we employ 26 people and have commitments to provide demand-side flexibility both to National Grid and in the capacity market.

These comments are informed by our experience of providing demand-side flexibility in twelve countries, under a very wide range of market designs. Before addressing the relevant questions in the call for evidence, we first explore the changing nature of the UK's electricity system and clarify what we mean by demand-side management.

1 A brief primer on power system planning

Power systems have traditionally been planned by predicting demand, and making appropriate supply-side investments to meet that demand. These days, markets are preferred to central planners, but the principles are similar.

A key consideration is the expected maximum level of simultaneous demand there will be – this, plus a reserve margin to provide adequate reliability in the face of likely contingencies, determines the total capacity needed.

It is also important to consider how often particular levels of demand will be reached, as this is what determines which technologies are appropriate.

There is a trade-off between fixed costs and variable operating costs:

- Capacity which will be needed most of the time is best provided by the generators with the lowest short-run marginal costs (£/MWh), even if those are expensive to build and maintain (£/MW/year). These are typically called "baseload" resources, such as nuclear, coal, and combined-cycle gas turbines.
- For capacity which is needed less often – "peaking capacity" – the short-run marginal costs become less important, as the fixed costs tend to dominate. The lowest total cost is achieved by using technologies which have lower costs to build and maintain, such as open-cycle gas turbines, gas- or diesel-fired engines, or demand-side management.

The-load duration curve is a helpful tool for understanding what is needed. Figure 1 shows (in black) the level of demand for each half-hour of 2014, sorted in descending order of demand.[1] It shows that peak demand was 51 GW. Of this demand, 27 GW is present for 80% of the year – we will call this "baseload demand".

In the absence of a central planner, it is the role of the capacity market to procure the total amount of capacity required at lowest cost, and it is the role of the wholesale energy markets, balancing market, and ancillary services markets to provide the price signals which determine what sorts of capacity become attractive to investors.

2 How is the job of the UK's electricity system changing?

Intermittent renewable power sources such as wind and solar photovoltaics provide energy at the lowest short-run marginal costs. The electricity system should therefore use whatever energy these sources provide in preference to any other.

This means that the job of the controllable energy sources is to supply the residual demand: what is left after intermittent renewables have supplied what they can. The blue line in Figure 1 shows a load-duration curve for this residual demand in 2014.[2] The peak residual demand is still 51 GW, but baseload residual demand is 24 GW.

National Grid's most recent Electricity Ten Year Statement shows that the amount of wind generating capacity is expected to double in the next three years and quadruple in six years.[3] The pink and red lines in Figure 1 show approximations to the residual demand with such increased levels of intermittent generation.[4] In

1 Data from EnerNOC analysis of FUELHH data published on the Elexon Portal.

2 The FUELHH data set only covers large generators and interconnectors. Solar and most smaller wind generation appears in this data set simply as a reduction in apparent demand. Hence, in calculating the residual demand, we have only subtracted out the contribution of the large-scale wind generators that were present in the original curve.

3 National Grid, *Electricity Ten Year Statement 2015*, November 2015, Appendix F.

4 Again, since only large-scale wind generation output is present in the data set, we have only doubled or quadrupled this contribution. We have effectively assumed that demand patterns and small-scale wind and

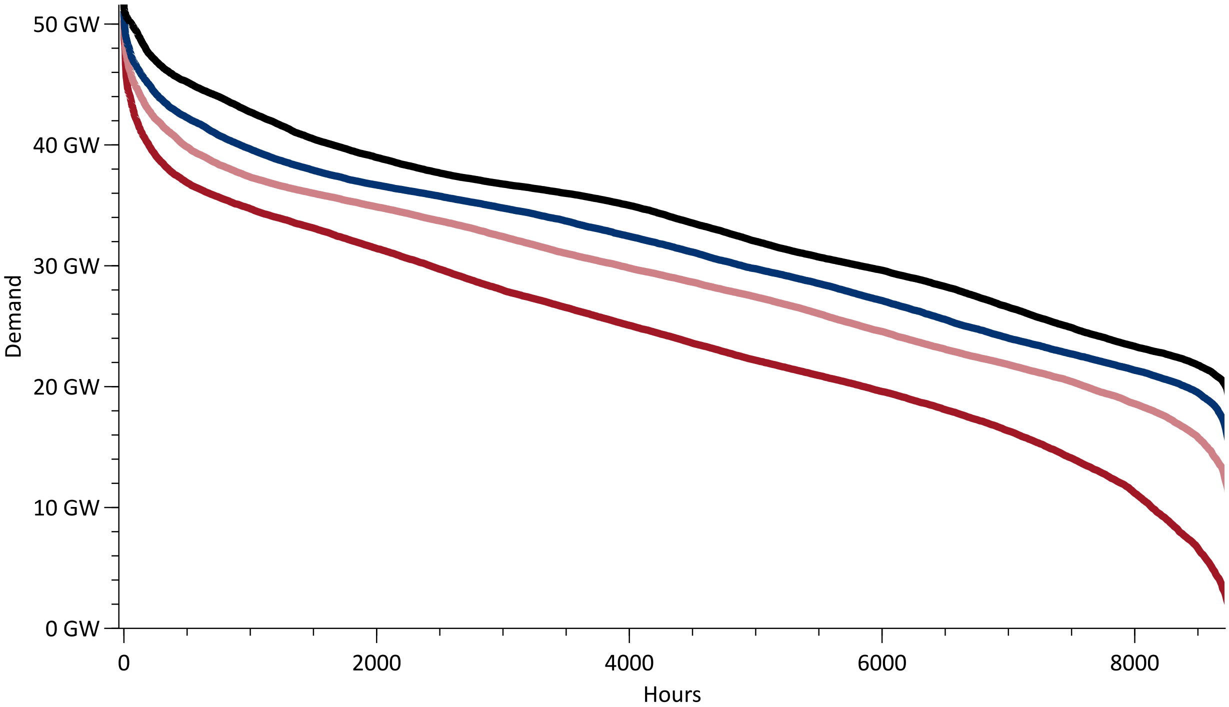

Figure 1: Load-duration curve for 2014, showing total demand (black), residual demand after removing wind (blue), 2x wind (pink), and 4x wind (red).

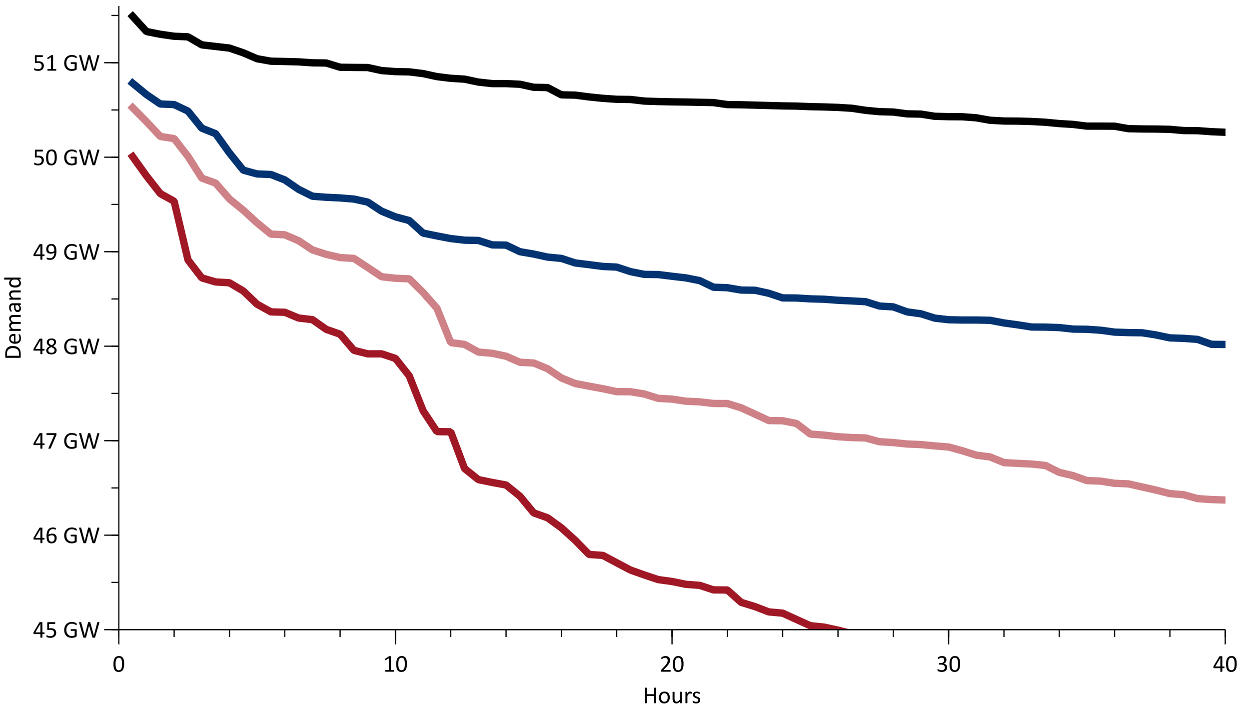

Figure 2: Top 40 hours of load-duration curve.

solar generation levels remain unchanged. This means we are probably understating the change.

these scenarios, peak residual demand barely changes, but the baseload residual demand falls to 22 GW and then to 16 GW.

This anticipated substantial fall in baseload residual demand means that we should not expect to replace retiring baseload capacity with new baseload capacity one-for-one. If we were to do so, the new baseload capacity would be underutilised.

If we look more closely at the top end of the load-duration curves, we see an even more dramatic shift. In Figure 2, we can see that 2 GW of residual demand in 2014 occurred for less than 24 hours of the year. We should expect this to increase to 3 GW when wind capacity doubles, and to 5 GW when it quadruples.

It would be extremely wasteful to build conventional peaking plant that will be used so little. Demand-side management is the most cost-effective means to address this issue.

3 What do we mean by "demand-side management"?

Demand-side management is about controlling demand in response to price signals or system needs. This contrasts with the traditional approach where demand is treated as an exogenous input – something that can only be forecast, not controlled.

There has been an unfortunate tendency for UK policymakers to consider everything that is not a transmission-connected generator as "demand-side" – even large peaking plants, if they happen to be connected via a distribution network.

We believe that a more helpful distinction is the involvement of electricity consumers. Demand-side management is about making additional use of existing customer-owned assets – i.e. plant that is there because it is associated with the customer's demand for electricity. This contrasts with the traditional supply-side approach of building new dedicated assets to serve the electricity market.

Using this definition, we would count as demand-side management:

- A customer reducing (or increasing) their demand.
- A customer shifting their demand forwards or backwards in time.
- A customer transferring load onto an embedded generator on their site, if the primary purpose of that generator is something other than electricity market participation.[5]

[5] For example, a hospital or data centre might install backup generators for use in emergencies. If the asset already exists, or is going to be built anyway, then it makes sense to use it in a way that benefits the wider electricity system. Most generators have to be run for a certain number of hours per annum so as to operate reliably; it is better for these to be hours when the supply is helpful to the system, rather than simply at times that happen to be convenient for maintenance staff.

- A customer transferring load away from a generator in a co-/tri-generation scheme, so as to increase the load seen by the grid at a time when the system has low demand and an abundance of supply.

- The use of battery storage, where those batteries have been installed for some other primary purpose.[6]

This means that we would not consider the following to be demand-side management:

- Generators – regardless of technology or network connection – that are built primarily for electricity market or network operator use.

- Generators that do not respond to market price signals or system or network operator needs – e.g. cogeneration systems that run continuously, or rooftop solar installations.

- Storage that is installed primarily for electricity market or network operator use – even if it is small and sits "behind the meter" on a customer's site.

4 Is there a need to reform the balancing market?

Yes.

Although there have been recent reforms to the balancing market to provide much sharper price signals, these signals still do not reach the right participants in some cases.

Specifically, a customer's supplier has balancing responsibility for that customer's demand.[7] The supplier procures supply to meet their prediction of the level of consumption, and they are exposed to imbalance prices ("cashout") on any errors. This could be a cost or extra revenue, depending on the direction of the error and whether the system is short or long at the time.

If the customer is participating in demand-side management through a third-party aggregator, they will occasionally be dispatched to change their consumption pattern in response to system or network operator needs. This unforeseen change puts the supplier out of balance, exposing them to the imbalance price.

There are two problems with this:

1. The supplier did not cause the dispatch, so it makes no sense to expose them to imbalance price for the dispatched volume. This could either be

[6] For example, telephone exchanges and most data centres have batteries to maintain uninterrupted supply between any failure of the mains supply and the starting of emergency generators. Similarly, electric vehicles' batteries could be used while they are connected to their chargers. In both cases, the assets have been installed for some other purpose, but can provide benefits to the wider system if appropriate price signals are provided.

[7] A few very large and sophisticated customers take responsibility themselves, or have it passed on to them by their supplier. This is a minority sport, and it not practicable for smaller customers.

an unjustifiable penalty, or a windfall gain, depending on the circumstances.

2. The third-party aggregator *did* cause the dispatch, so they should be exposed to the imbalance price for the dispatched volume.

The second issue is particularly important: the purpose of sharper imbalance prices is to provide a price signal to stimulate investment in flexible resources. Demand-side management is a highly capable and cost-effective source of flexibility. However, this issue prevents third-party aggregators from participating in the balancing market, so they are not exposed to the price signal.

This has a knock-on effect in the capacity market.

Most demand-side management comes from third-party aggregators,[8] whose capacity does not have access to the balancing market revenue stream, even though it is highly suitable for responding to the balancing market's price signals. This demand-side management capacity therefore has to be offered in the capacity auction at a price which is high enough to make up for the fact that it will not earn energy revenues.

Generators do have access to the balancing market revenue stream, so they can offer their capacity at a lower price, which puts them at a competitive advantage in the capacity market auction.

This tilting of the playing field means that more generating capacity and less demand-side management capacity will tend to clear in the auctions, and capacity prices are be higher than they need be. It takes the system away from the optimal resource mix.

This issue has been resolved in many other electricity markets, in various ways, allowing third-party aggregators to participate in the balancing market (or the local equivalent). The common principle is that, during a demand-side management event, the supplier should be responsible for the normal consumption of the customer, and the third-party aggregator should be responsible for the deviation from the normal consumption pattern.

Within Europe, this has been resolved in France and Switzerland and partly in Belgium.[9] It should be resolved similarly here.

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8 This seems to be the case in all markets where independent aggregators are allowed to compete to procure flexibility from customers. For example, in PJM, over 80% of demand response capacity is offered by independent aggregators; for ISO-NE and NYISO it's over 70%; in Western Australia it is over 60%; and in New Zealand it is around 50%. We suspect this is because successful aggregation requires a very different skill set from that normally found in a supplier or retailer, and suppliers often have conflicts of interest because large-scale demand-side management reduces the value of their generation portfolio.

9 See Smart Energy Demand Coalition, *Mapping Demand Response in Europe Today*, October 2015.

5 To what extent can demand-side management increase the flexibility of the electricity system?

To a very large extent.

The current level of demand-side management is quite modest, and much of it does not provide particularly useful flexibility.[10]

We will consider three routes to market for demand-side flexibility: the capacity market, the balancing market, and ancillary services markets.

5.1 Capacity market

Systems with mature capacity markets which properly integrate demand response can have much higher levels of demand-side participation than we currently see in the UK. For example, in the United States, 10.2% of peak demand in ISO-NE and 7.4% of peak demand in PJM can be controlled through wholesale demand response programmes.[11] In Western Australia, the figure is 12.0%.[12]

These successful demand response programmes provide the system operators with a dispatchable resource which they can use as necessary to balance the system. This contrasts with the UK, where the capacity market design fails to provide the system operator with a dispatchable resource, and so only provides a crude form of flexibility. We think it may be unique amongst the world's capacity markets in this respect.[13]

The level of demand-side participation in the capacity market could be improved in two ways:

1. By opening up the balancing market and ancillary services markets to participation by demand-side resources, so that they are not entirely reliant on capacity market revenues.
2. By simplifying and reducing the cost of capacity market participation by demand-side resources.

We will discuss the first point in the following sections. On the second point, issues include unnecessary complexity and cost in metering arrangements,

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10 The bulk of what is typically counted as demand-side management in the UK consists of customers reducing their demand speculatively in an attempt to avoid Triad charges. While this does reduce the peak demand experienced by the system, it does not do so in a way which provides the system operator with a predictable, flexible resource.

11 Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering*, December 2015, Table 3-3. Quoted figures are for 2014.

12 EnerNOC analysis of data from the Western Australian Independent Market Operator for their 2013-14 capacity year.

13 Since capacity market resources are paid to be available, you would expect that the system operator would be able to issue dispatch instructions to them, specifying what response it needs to balance the system. Instead, the system operator's only recourse is to issue a "capacity market warning", after which each capacity provider will determine whether they think a system stress event is likely to occur, and, if so, they will estimate level of response they will need to provide to avoid a penalty. The system operator only finds out the size and timing of each response when it happens. There does not seem to be any appetite amongst policymakers to improve the design in this respect.

requirements for excessively frequent tests, lack of flexibility in portfolio formation, and no provision for portfolio maintenance. Generally, these issues seem to have arisen from the market having been designed with large, centralised generators in mind, and provision for aggregations of small demand-side resources having been included as an afterthought. Reforms to fix these issues have been proposed to DECC and Ofgem, but it is not clear that they will be implemented.

5.2 *Balancing market*

Demand-side management resources should be given access to the balancing market, as previously discussed. At present, customers can take responsibility for their own balancing, either bypassing the normal supplier arrangements or using a pass-through arrangement. However, this approach is only practicable for the very largest, most sophisticated energy users.

To achieve broader participation, it is important that the procurement of demand-side flexibility be unbundled from retail supply so that independent aggregators can compete for customers' business. We are not aware of any electricity market that has achieved reasonable levels of participation without such unbundling.

5.3 *Ancillary services markets*

National Grid procures a range of balancing services to help it manage the system. Unfortunately, the way that National Grid has designed the ancillary services products it procures, and the tendering arrangements through which it procures them, show an unintentional bias towards arrangements which are suitable for large centralised generators but unsuitable for aggregations of small demand-side resources.

Demand-side management resources are capable of meeting many of the system's technical needs highly cost-effectively, and, in other markets, they do so extensively. It is unnecessary details of the product designs which preclude, or severely restrict, demand-side participation.

The exact issues vary between products, but examples include:

- Requirements to offer constant quantities for days or weeks at a time, or quantities fixed a long way ahead of real time. This is convenient for a generator of fixed capability, but severely constraining for demand-side management resources, where the quantity of a service that is available varies with the demand patterns of the participating customers.

- Telemetry requirements which may represent a reasonable trade-off between cost and performance when applied to a large power station, but are prohibitively expensive when applied to hundreds of smaller customer sites.

National Grid seems to be becoming aware of the issues through its “Power Responsive” campaign. However, a significant amount of work is required to remove these barriers.

PJM and New Zealand are examples of what can be achieved when ancillary service product and market designs are right. In New Zealand, over 80% of their “Fast Instantaneous Reserves” frequency management service comes from demand-side resources, freeing generation resources for energy production.[14]

6 What are the barriers to the deployment of energy storage?

Energy storage is not limited to batteries. In fact, much of what is normally called demand response is really a type of energy storage, and can provide the same services to the system as a battery can. For example, a cold store stores energy in thermal form, and can adjust its consumption up and down as needed, within limits.

Battery storage is likely to be deployed as many small resources on different customers’ sites served by different suppliers. As such, it will suffer the same barriers as other demand-side management capacity: inability to access all the potential revenue streams, and unsuitable product design.

7 What is the most appropriate scale for future energy storage technologies?

Nobody knows.

Policymakers should not try to guess, as picking winners rarely ends well. Instead, the best approach is to remove barriers, and to make sure that the appropriate price signals are available to all possible technologies and scales.

8 What can the UK learn from international best practice?

We have cited examples of best practice in other jurisdictions above. However, in summary:

- New Zealand and PJM provide examples of best practice ancillary services markets.
- France has fully integrated demand-side management into all aspects of the market.
- PJM, NYISO, ISO-NE, and Western Australia have integrated demand-side management into capacity markets on a large scale.

[14] EnerNOC analysis of cleared market offers in the NZ FIR market, 1 July – 19 October 2015.

I would be happy to provide further detail on these comments, if that would be helpful.

Yours sincerely,

Dr Paul Troughton
Senior Director of Regulatory Affairs

England's Economic Heartland
Programme Office
c/o Buckinghamshire County Council
County Hall
Walton Street
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HP20 1UA

8th January 2016

Dear Sir,

National Infrastructure Commission: call for evidence
Response of England's Economic Heartland Strategic Alliance

The Strategic Alliance is a non-statutory partnership whose participants share a collective ambition to realise the potential of England's Economic Heartland. Its participants are committed to looking beyond current success and, through collaborative working to a common purpose, raise levels of productivity to match, and where possible exceed, those of global competitors by addressing the identified barriers to economic growth.

As an Alliance of strategic authorities and their constituent LEPs, the partnership represents almost 3.5 million people from:

- Oxfordshire
- Buckinghamshire
- Northamptonshire
- Milton Keynes
- Luton
- Central Bedfordshire
- Bedford
- Cambridgeshire

It is an expressed aim of the Alliance to seek to become a statutory Sub-National Transport Body. The Alliance partners are also committed to developing a strategic infrastructure plan whose scope reflects that of the Commission: a recognition by the partners of the critical importance that strategic infrastructure has to play in supporting planned growth.

Given these ambitions, the proximity of the Heartland to London, the Midlands and North and our shared issues with connectivity, London transport infrastructure and energy supply, the Alliance looks forward to working closely with the Commission as it looks to advise Government on future infrastructure investment priorities.

<u>Connecting Northern Cities</u>

1. To what extent are weaknesses in transport connectivity holding back northern city regions (specifically in terms of jobs, enterprise creation and growth, and housing)?

2. *What cost-effective infrastructure investments in city-to-city connectivity could address these weaknesses? We are interested in all modes of transport.*

3. *Which city-to-city corridor(s) should be the priority for early phases of investment?*

4. *What are the key international connectivity needs likely to be in the next 20-30 years in the north of England (with a focus on ports and airports)? What is the most effective way to meet these needs, and what constraints on delivery are anticipated?*

5. *What form of governance would most effectively deliver transformative infrastructure in the north, how should this be funded and by whom, including appropriate local contributions?*

The Alliance makes no response to these questions but raises the matter that the success of economic initiatives in the North are in no small part dependent upon the infrastructure connections through and across the Alliance area, particularly through improved radial and orbital movements from London and the South Coast by road and rail.

London's transport infrastructure

1. **What are the major economic and social challenges facing London and its commuter hinterland over the next two to three decades?**

London and its commuter hinterland face significant economic and social challenges in the short, medium and longer term. Unless drastic changes are made over the next two to three decades, congestion will have a severe impact on the economy and people's daily lives, with many journeys being effectively impossible. Forecasts show that additional transport capacity is required across the wider South East but this should not necessarily be through continued emphasis on focusing exclusively on radial connectivity. New or improved strategic road and rail infrastructure across the wider South East will change travel patterns thereby supporting economic development in the wider South East and at the same time provide some relief to the demand on traditional radial corridors serving London. In addition to giving rise to wider beneficial impacts for London and England's Economic Heartland, such an approach would be consistent with the Government's ambition to rebalance the economy.

It is clear from our engagement in the emerging London Plan, that the economy will continue to be over-heated in the city and there will be difficulties in meeting the housing demand that comes with this. It has also been accepted that the South-East supports London growth by delivering homes to meet the current and planned growth through our own housing allocations. A sub-national approach to strategic planning will be needed to avoid offsetting this economic growth by extending radial links outward to bring labour to jobs; rather there needs to be a shared aim to re-balance the economy across the South East (and indeed to the north as well) and seek to reduce the need for journeys through/to London by providing much needed infrastructure to support economic growth in the wider South East. This will allow London to meet more of its own need whilst supporting a more balanced economic approach.

Some of the fastest-growing towns and cities in England are located in a belt to the north of London which already enjoy some strong, albeit well-used, links which support London. England's Economic

Heartland – with an economy worth £90bn but with the potential to grow another 20 per cent - clearly has the potential to help offset some of the over-heated economic impacts on London so that existing radial networks can more efficiently serve in and out-commuting to meet demand. The economic potential of the Heartland area reflects its competitiveness in global markets, driven by its leadership in the digital economy. Our approach to investment in transport infrastructure must avoid reinforcing traditional patterns of movement when economic growth derives from the new economy.

England's Economic Heartland sits on the busy road and rail transport corridor between the south coast ports, the Midlands and the north and enjoys easy links to London and the West Midlands via the M40. However, it suffers a lack of east-west connectivity, in particular to the high-value growth areas around Milton Keynes and Cambridge, and also in terms of access to/from the international gateway at Luton Airport (including business aviation needs arising from businesses in the Heartland area operating in the global market).

There are currently no direct rail connections between the centres of Oxford and Cambridge and to the areas in between (forcing commuters to travel into London in order to come out again), while travel by road involves cross-country single-carriageway routes or use of the M25 around London. Improving the connectivity on this corridor – through East-West Rail and the Oxford to Cambridge Expressway projects - will place the authorities in the Alliance at the centre of the south-east orbital corridor as a key hub for south-west to north-east transport. As a result, England's Economic Heartland would realise further improvement in agglomeration opportunities for jobs, growth and innovation, with its vastly-improved road and rail links to these high-value centres of the UK economy.

2. What are the strategic options for future investment in large-scale transport infrastructure improvements in London - on road, rail and underground - including, but not limited to Crossrail 2?

The focus for investment to help London should not solely be within London. Existing radial routes, much the focus of current and previous national investment, serve to provide vital lifelines for labour supply to meet London's booming economy. While the Heartland area has good radial connections into and out of London, the service level on transport connections across much of the area - for example, including between major economic hubs such as Oxford, Cambridge, Aylesbury, Milton Keynes and Luton – is notably poor, a consequence of existing high levels of economic activity and travel demand already looking to avoid the need to transit the London area.

The lack of transport for people and freight between these areas creates an artificial barrier between hubs of knowledge-based growth. This area was recently recognised as being the most innovative part of the UK - connectivity between this area, and particularly north London, will not only reinforce London's and the UK's attractiveness in terms of investment, but as the area also links very well to the North West and North East, it provides a good platform for linked innovation growth in the Midlands and Northern Powerhouses.

Pushing forward with plans to complete East-West Rail and the Oxford to Cambridge Expressway (including vital links to the A34 linkage to the South Coast ports) provides a critical and long overdue outer-orbital that complements growth in London by reducing the need for traffic to transit through it, supports the Alliance partners to realise the potential of England's Economic Heartland, as well as enabling the logistical needs of the national economy to be supported.

- ***How should they be prioritised, taking account of their response to London's strategic transport challenges, including their impact on capacity, reliability, journey times and connectivity to jobs?***

East-West Rail will reconnect Oxford to Milton Keynes and Cambridge by rail, and direct rail access from the west into Heathrow. This is due for completion in Control Period 6, post 2019 and must not slip any further in delivery.

In addition, work on the Oxford to Cambridge expressway is underway and we are working with Highways England to develop a route based strategy linking Southampton and the East Midlands, which will include improvements to the A34 and the development of an expressway to connect the two growth centres, linking up major economic hubs along the way (i.e. Milton Keynes, Aylesbury, Luton). England's Economic Heartland will put forward an initial statement of investment priorities in autumn 2016 as part of the input into the review of the Road Investment Strategy (due to be reviewed in 2017) and the related review of the rail infrastructure review.

- ***What might their potential impact be on employment, productivity and housing supply in London and the southeast?***

Work to date has demonstrated that improvements in economic productivity across the Heartland area would generate an additional 20% GVA per annum – equivalent to c£10bn per annum. Just as important, a failure to invest in the Heartland will result in the level of service on existing infrastructure declining making existing business activity increasingly uncompetitive in global markets. A decline in economic performance would reduce the Heartland's net contribution to the Exchequer, thereby reducing the scope for investment by Government across the UK.

3. ***What opportunities are there to increase the benefits and reduce the costs of the proposed Crossrail 2 scheme?***

No comment.

4. ***What are the options for the funding, financing and delivery of large-scale transport infrastructure improvements in London, including Crossrail 2?***

- ***What is an appropriate local and regional contribution - given the potential distribution of benefits to business, residents, transport users and the wider economy - and how could this be achieved?***

If there was to be evidence of a proper regional distribution of investment and growth in support of London, then regional contributions to the solutions would be defensible and fair. The uplift in growth realized through delivery of both East-West Rail and Oxford to Cambridge Expressway will be significant and would need to be reflected in some way. The Alliance members already have a well-established partnership in support of East-West Rail contributing over £45m to its delivery. Furthermore, the likelihood of such an arrangement would be improved should the Alliance be successful in its attempts to become a Sub-national Transport Body as provided for in emerging legislation.

- ***What innovative funding mechanisms could be considered to support delivery of key schemes?***

Notwithstanding the potential to deploy innovative financing mechanisms to deliver key schemes, the cost of those schemes will ultimately have to be met from one of three funding sources – the user or beneficiary of the infrastructure, local sources of funding (council tax payers or local businesses), or central Government investment.

5. How have major metropolitan areas in other countries responded to similar challenges and priorities? Are there any lessons to be learned and applied in London?

No comment.

Electricity Interconnection and Storage

The responses in this section are based on our experience of the grid or distribution network in Oxfordshire, however they are reflective of the challenges faced across the Heartland area. The Alliance partners commitment to develop a strategic infrastructure plan reflect a recognition on their part that the issues need to be addressed at a sub-national scale

The questions below assume that the installation of renewable energy generation is proceeding unhindered so as to provoke the need for balancing of supply and demand, including deploying energy storage. Unfortunately, this is not the case.

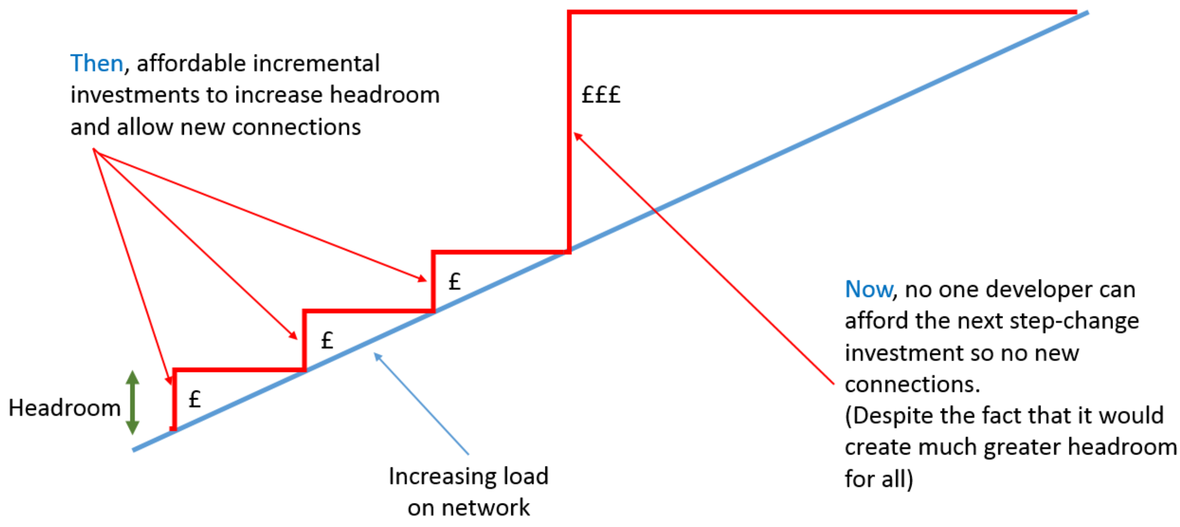
It is worth pointing out that there are two fundamental issues:

- There is an acute need to invest in renewable energy to diversify and add to current supply to meet demand; and,
- There is a need for additional capacity full stop to support large scale economic/housing growth.

The local market for connecting new renewable energy schemes to the distribution network has effectively failed. All of the sub-stations operated by Scottish and Southern Energy Power Distribution (SSEPD) across Oxfordshire for example, are constrained by fault levels. So, in practical terms, there will be no new large installations (above 50kW) in Oxford for the foreseeable future. In Bicester, there will be no new renewables, nor allocation of new supply connections until 2019 at the earliest. There are similar examples from elsewhere in the county: In November, a £240k solar PV scheme in Chipping Norton, Oxfordshire, was recently quoted a connection cost of £437k with a delay of two years, making the scheme unviable.

As elsewhere across the Heartland area, Oxfordshire's local grid needs significant investment to make it fit for the 21st century. It needs to move from a centralised energy system designed to distribute electricity in one direction to the smart system needed to manage embedded generation and storage, as well as the increasing up-take of electric vehicles. At present, this is funded by individual developers as they request a connection. We have reached the point where no one individual developer can afford the cost as shown in Figure 1 – The Investment Hurdle

Figure 1 – The investment hurdle



We also believe there is a significant information failure in this market: scheme developers are unaware of each other, making it difficult to pool resources. The Distribution Network Operator (DNO) reacts only to firm requests to connect rather than taking a strategic view based on the much wider range of information available. The Alliance suggest that the regulatory framework within which the 5-year investment plans are prepared by the operators (and approved by the Regulator) must be required to take into account the strategic growth identified by local partners. We feel the most efficient and effective way of doing this would be at a sub-national level reflecting the reality that networks extend beyond individual local authority boundaries.

The current approach is inefficient thereby increasing costs to developers – in re-scaffolding when limits on schemes size are relaxed or in abortive costs when schemes turn out to be financially unviable because of the high cost of connection.

To develop as it should, the energy grid needs mechanisms to facilitate funding in advance of a connection request, based on a strategic vision of the development of the grid. There may also be a 'public good' argument for investment in the grid, analogous to investment in other infrastructure such as roads and broadband.

The strategic vision needs to be owned by local stakeholders as much as the DNO. This requires much greater dialogue between planners, the DNOs and major users to avoid pinch-points blocking development, as is happening in Bicester with knock-on impacts on Oxfordshire's economic growth.

The Alliance suggests that an obligation should be placed on the DNO to work with sub-national bodies to identify the longer term strategic needs for additional installed capacity – and then a requirement on the regulator to take that into account when agreeing to specific 5-year investment plans. The Alliance partners are keen to work with the Commission to develop its thinking in this area with a view to shaping the remit of the Commission moving forward (and ensuring future legislation is fit for purpose).

We would also like to see greater use of the Ofgem innovation funds to help support the area's long term innovation and growth strategies. Exploring smart solutions to fault-level constraints is key as is supporting the innovative work we are doing in the electric car market which impacts on the grid and could provide a balancing function. In this example, the electric car is part of the storage chain and adds a wider value to the energy use/storage cycle without the need for wider storage investment. This presents a huge opportunity, so reinforcing the point that forward planning must improve.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Investors need a secure and equitable investment environment with clear long-term signals within which to plan multi-year projects that have investment and construction timescales that extend well beyond the timeframes associated with regulatory reviews. The recent reviews on rail infrastructure investment have noted the difference in terms of cost and efficiency of large scale investment schemes handled outside the 5-year regulatory framework (i.e. Crossrail and Thameslink) with those handled as part of the regulatory framework (i.e. GWML electrification) – if Government is sympathetic to shifting more strategic schemes outside of regulatory frameworks then one could see a similar approach being applied to other sectors. The Alliance wants to work with the Commission to explore this opportunity further.Without this environment, new energy supply projects will not come forward at the rate needed

At the local grid level, for example, Oxfordshire's thriving community sector is already demonstrating balancing projects which have significant potential:

- Project **ERIC** (Energy Resources for Integrated Communities) is an initiative bringing solar PV power and smart energy storage to up to 100 homes in Rose Hill, East Oxford. Project ERIC is led by Moixa Technology and Bioregional and is part-funded by Innovate UK. Using domestic Maslow batteries and a new software platform, Project ERIC aims to demonstrate how distributed storage in a community can be managed to reduce average peak grid load by 65% and increase self-consumption of local PV energy across the community by twofold[1].
- The award winning **Energy Local** project aims to use smart technology systems to pool community demand so that members can access the time of day tariff and locally generated renewable power directly, adjusting demand to reflect local generation[2].

The market needs to facilitate local initiatives such as these by minimising the cost and resources needed to participate. Whilst they will initially contribute to local balancing, they can of course contribute to the national balancing market at scale, which is the long term intention.

What role can changes to the market framework play to incentivise this outcome:

- ***Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?***

There is a major need to upgrade the local grid in Oxfordshire so that it facilitates new approaches to the generation, storage and use of electricity rather than blocking them as at present. Such an upgrade will also require a change in the role of the District Network operator (DNO) to an

[1] https://localisedenergyeric.wordpress.com/
[2] http://www.energylocal.co.uk/

independent system operator, if not a new operator. The incentive scheme should encourage the strategic rather than reactive management of the network in partnership with local stakeholders. It could also remove the barriers in the current system which mitigate against long term strategic investment.

- ***Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?***

As above

- ***To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?***

Oxfordshire has shown that community energy initiatives, such as ERIC and Energy Local, can make a significant contribution to both demand-side management and embedded generation. In particular, the Low Carbon Hub has demonstrated that there is a strong demand for local investment opportunities. It must be recognized though that this is only part of the supply offer to meet what will be significant growth in the Alliance area.

At present, this is held back by fault level constraints and by the failure to develop a smart grid in the county.

2. What are the barriers to the deployment of energy storage capacity?

- ***Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?***

Battery-based storage is still expensive. Further government investment in battery innovation, testing and de-regulation are required for example to meet the challenge of creating a step change and shift away from carbon-based engines. The Alliance area is at the forefront of this and needs continued investment to succeed.

Some energy storage devices, such as batteries, can contribute to fault levels. At present, fault level constraints in Oxfordshire and the consequent market failure limit the roll-out of such devices at scale. This basic issue needs addressing as described above.

- ***What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)***

  All scales are appropriate to make the best fit with the technology and source of funding eg pumped storage will work at the transmission network scale. In contrast, businesses, schools and households will invest in small-scale battery storage which in aggregate will make a significant contribution.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- ***Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?***

- ***Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?***

We assume these questions relate to interconnection at the level of the transmission network and therefore have no comment.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

How best to roll out and use a smart grid to make more efficient use of the grid asset.

The Alliance partners look forward to working closely with the Commission as it discharges its functions. If you need any further information in response to this submission please contact me on [email address redacted]

Yours sincerely

Martin Tugwell
Programme Director

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Bringing energy to your door

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8th January 2016

Dear Sir/ Madam,

National Infrastructure Commission call for evidence: Published 13 November 2015

Thank you for the opportunity to contribute to your studies of the three national strategies set out in the consultation paper. Electricity North West owns, operates and maintains the North West's electricity distribution network, connecting 2.4 million properties, and more than 5 million people in the region to the National Grid. Our network covers a diverse range of terrain, from isolated farms in rural areas such as Cumbria, to areas of heavy industry and urban populations including Manchester. Our response is therefore focused on your third challenge, "Improving how electricity demand and supply are balanced" and the specific issues which may impact on electricity distribution networks. Our responses to the questions published on this challenge are given below.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- **What role can changes to the market framework play to incentivise this outcome:**
    - **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**

    The Transmission System Operator (TSO) role has been established for some time and is clearly distinct from the role of transmission owners. In addition to the three major transmission owners of NGET, SSE and SP, there are now multiple owners of offshore transmission assets and, in addition, Ofgem is looking to increase competition in the ownership of onshore transmission assets. In this context is does not seem appropriate that the role of the TSO should be in the same ownership structure as the dominant transmission asset owner. We would therefore support the role of TSO being independent.

    We do not suggest that NGET, in performing this role currently, is in any way acting improperly, however this will remove any perceptions of bias in favour of incumbent infrastructure providers. The TSO can then be incentivised to minimise long-run balancing costs without any incentive to consider associated potential financial impacts on other businesses within the same ownership group. This becomes particular important as new technologies emerge which could act as game-changers in the way that networks are operated and balanced. For example, we are currently working with NGET to deploy Customer Load Active System Services (CLASS), a technology developed in one of our Low Carbon Network Fund Projects. This project has proven the ability for DNOs to provide balancing services to NGET by using innovative voltage control on DNO networks. This has the potential to significantly reduce the cost of providing balancing services with huge benefits to energy consumers across Great Britain. The project has recently been extended to model the wider market impacts of such a deployment. Other such developments are likely to emerge and an independent TSO will have the right incentives to stimulate, facilitate and embrace such developments.

In terms of distribution networks, the role of the Distribution System Operator (DSO) is not yet clear or defined, particularly in GB, as DNOs currently have no system balancing duties. This may need to change as more distributed sources of generation and storage are deployed on distribution networks. The DSO role should be developed within the existing DNOs, at least until the DSO duties and obligations achieve a more mature state, as is with the case of transmission.

- **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

  The "balancing market" should not embed current ways of doing things. Our CLASS project, outlined above, has the potential to be a disruptive technology, changing how services such as frequency response are provided. The balancing market should not inhibit such deployment in favour of existing technologies and incumbent providers. New markets must be allowed to evolve as alternative technologies become established, and the lack of an existing 'market' must not inhibit deployment of such technologies where it can be demonstrated that the approach is likely to bring long term benefits to customers.

- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

  We believe that demand-side management and embedded generation have significant potential to increase the flexibility of the electricity system as demonstrated by the CLASS project referred to above. It is important that technologies connected to distribution networks are managed at a distribution level to ensure that the effects across the whole electricity system are considered and thereby maximise benefits to consumers. For example NGET's recent request for Enhanced Frequency Response services, which was primarily aimed at storage providers, could potentially increase reinforcement costs on distribution networks. A better model could be for NGET to only procure services from network users connected directly to its network. Embedded services could be procured through DNOs and aggregated from DNO connectees to ensure that more localised infrastructure issues are also considered and all the potential costs to customers are considered in solution evaluation and decision-making.

2. What are the barriers to the deployment of energy storage capacity?

- **Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?**

As mentioned above, it is important for a whole system approach to be adopted to ensure that the benefits of storage are maximised through the system giving storage providers access to value across the whole energy supply chain. As discussed above, NGET's requirement for balancing services currently requires unconstrained connections. For service providers connected to distribution networks this may result in high connection costs and hence make deployment uneconomic. A more flexible approach, with DNOs co-ordinating an aggregated response on behalf of a number of users of their networks, may make better use the available infrastructure and allow more of this technology to be deployed. Consideration also needs to be given to allow DNOs to utilise storage to manage constraints on their networks where this will not affect the wider energy balancing mechanisms. Storage providers should also be able to contract with multiple parties including energy retailers and a mechanism to ensure all contracting parties have visibility of the other commitments needs to be considered. These issues were considered carefully in the work of the 6th workstream of the Smart Grid Forum and we commend the final report of this workstream. In this report a wide range of stakeholders from across the electricity industry have identified the key actions required to facilitate the efficient deployment of storage technologies and the removal of barriers to the efficient development of the electricity system.

It will also become increasingly important, where DNOs offer managed connections to facilitate lower connection costs, that they have the ability to modify these over time. This may become necessary to facilitate further new connections or to reduce operating costs. Whilst this could impact some providers and slightly increase their risk, it is important that DNOs have flexibility in how they deliver their statutory obligations to provide an efficient network.

- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

  It is too early to say at this stage. As a DNO our approach is to facilitate the development of technology and not to favour or inhibit particular approaches. It is likely that different sizes of storage devices will be able to provide different solutions to meet a range of emerging needs. We do advocate cost reflective charging, as it is not our role to provide subsidies to particular technologies. Such charging will highlight challenges and facilitate the deployment of efficient, value-adding solutions including storage where it is competitive.

I hope these comments are useful and please do not hesitate to contact me if you require further information.

Yours faithfully,

P R Bircham
2016.01.08
13:55:24 Z

Paul Bircham
Networks Strategy & Technical Services Director

National Infrastructure Commission Call for Evidence
Response by E.ON SE Group

Executive Summary

- Ofgem has recently implemented major reforms to the balancing market and will be reviewing the effectiveness of this before proceeding with further changes in 2018. We do not believe further reforms need to be considered at this stage.

- The requirement for flexibility is growing. We strongly believe that this provides an opportunity to reset the market framework for ancillary services such that it treats all sources of flexibility; demand side response, storage or generation equally.

- Interconnectors have a role to play in the GB market and should be built to an economically efficient level, but we should avoid intervention which specifies a target by a set date. Instead the market should be left to choose the most economic options.

- There needs to be a much greater emphasis on tackling the energy efficiency challenge of the nation, which will help to deliver a more permanent reduction in energy usage. In particular there remain over 7 million solid wall homes without insulation, and will need to be tackled if we are to meet our longer term legally binding carbon emission targets as set out in the Climate Change Act. This should be a major infrastructure priority for the nation.

Questions

Q1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Is there a need for an independent system operator (SO)?

1. We note that one of the questions behind seeking evidence on this issue is around the merits of having an Independent System Operator (ISO). Since the industry was privatised, National Grid has shown that it is able to operate the system in a way which has been effectively independent from its transmission asset owner responsibilities.

2. Our biggest concern with the current structural arrangements is more around whether GB transmission companies should continue to be able to own generation and supply businesses. As a developer of generation assets, we have to negotiate connection agreements with these companies and are arguably competing for resources and connection time slots with their own respective generation interests. Additionally, with the state aid requirements allowing interconnector owners to bid into the Capacity Market, some of which will have an equity interest from the owner of the System Operator (SO), there is at the very least a case to consider in respect of making the Delivery Body role within Electricity Market Reform (EMR) wholly independent of National Grid.

How could the incentives faced by the SO be set to minimise long-run balancing costs?

3. The aim with setting mechanisms to assist in minimising the long term balancing costs, that are ultimately paid for by customers, should be to enable the SO to make trade-offs between short term operating actions and longer term investment decisions.

4. However, setting incentive schemes for a sufficiently long time is challenging. The incentive parameters assumed in the first instance, will from time to time need to be re-opened, especially when the assumptions turn out to be fundamentally flawed. Market participants who are exposed to the costs of those schemes end up being exposed to uncertain cost adjustments which they could not predict. This therefore lends itself to setting incentive mechanisms that are relatively shorter term in nature, typically two years, than they would be in an ideal world, and is perhaps something worth evaluating to see whether the risk/reward balance is set appropriately.

Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

5. Over the last few years, the industry has been working closely with Ofgem via the Significant Code Review process to undertake major reforms to the balancing arrangements. A key element of the reform is to move to a system whereby all trades that are out of balance with their respected contracted positions are treated equally, commonly known as the 'single cash-out' price option. Other reforms include sharpening the cash-out price significantly via the use of a Value of Lost Load (VOLL) which is included in the calculation, along with moving in two stages to a marginal cash-out regime.

6. We welcome the two stage approach to reforming the imbalance price calculation, which is designed to guard against unintended consequences. The first stage of moving only commenced in November 2015. We fully support this approach including the decision of Ofgem to undertake an interim review before the second stage is implemented in 2018. We should allow this process to be completed as opposed to considering now whether further reforms are required.

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

7. The increasing penetration of variable renewables such as onshore and offshore wind along with inflexible new nuclear generation coincide with the closure of some existing conventional coal and gas generators that have in the past provided flexibility to the SO for balancing the system on a second by second basis.

8. However, the market is changing: the requirement for flexibility is growing and new sources of flexibility are emerging which may be able to provide services to the SO more cheaply in the coming years. We strongly believe that this provides an opportunity to reset the market framework for ancillary services such that it treats all sources of flexibility equally and is open to new, distributed and smaller individual sources of flexibility to compete alongside traditional sources; this ensures the best possible deal for customers. Open and transparent markets are key design principles that would enable the SO to procure the most efficient products for delivering these services, be that from the demand side - including load shifting, embedded generation and battery storage – or the more traditional supply side transmission connected generators.

9. There is no technical reason why the demand side cannot contribute to the wider range of sources of flexibility. Indeed batteries for example are well placed to provide frequency response to keep the grid frequency within the required tolerance limits in a matter of seconds. What is therefore important is making sure the market is not distorted and designed to drive a particular technology outcome. There is no need for specific, targeted subsidies for any particular technology. The transmission SO (TSO) and perhaps even more sophisticated distribution SOs (DSO), should specify the services they need and procure them through an open and transparent process where newer sources of flexibility can compete. SOs should avoid bilateral or opaque pricing wherever possible.

Q2. What are the barriers to the deployment of energy storage capacity?

Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

10. The ancillary services market has been designed for a world in which there is relatively low wind penetration, with conventional generators typically providing flexibility services to the SO. These services, such as frequency response and fast reserve, have been typically provided via the use of bilateral agreements. This makes the market opaque and difficult to value when considering possible investments in alternative demand side products, including load shifting, onsite generation and battery storage. Addressing this issue via the use of greater standardisation of the products and procuring this via regular open auctions, as some other markets have adopted, would provide fairer access for all.

11. However there are other barriers that need to be considered, some of which are more relevant to storage.

    a. Definition of storage
    b. Creation of a Distribution System Operator market
    c. Enhanced Frequency Response

<u>Definition of storage</u>

12. The lack of a definition of storage complicates the way storage is treated at different points in the energy system. It is currently defined as a generation asset, which does not recognise its true role in the energy system as an enabler of flexibility. This makes it difficult to address storage as a separate entity in regulations such as grid codes. It also means that stored electricity is often liable for payments under the Contract for Difference (CfD), Feed-in-Tariff (FiT) and Capacity Market regimes twice: both directly (when importing electricity to store) and indirectly (when a customer consumes the stored electricity), resulting in double charging for using energy.

13. A fair definition of storage would have to include a number of things:
    - A focus on the temporal aspect of storage, not on the import and export of energy (as this can lead to double charging/locational dependence issues);
    - A recognition that with all forms of energy storage comes an efficiency loss (so that more efficient technologies are more favourable than less efficient alternatives); and

- An appreciation that the role of storage in an energy system should be as an enabler of flexibility.

Creation of a Distribution System Operator (DSO) market

14. Energy storage could offer constraint management services to network operators, helping to defer the investment of replacing copper cabling, but there is no market in which to offer these services. This greatly reduces the opportunities for storage projects.

15. We welcome Ofgem's recent commitment to engage with Distribution Network Operators (DNOs) and other stakeholders in clarifying their future role, including work to remove any barriers to DNOs transitioning to DSO functions and the nature of their interactions with the Transmission SO.

Enhanced Frequency Response

16. National Grid has introduced a new Enhanced Frequency Response product in order to increase inertia on the system which is currently reducing as larger conventional power stations close. It is currently the main value stream for Lithium-ion batteries in the GB market. However National Grid has found it difficult to specify the exact requirements for battery performance within this product.

17. As highlighted above, we believe the long term aim should be for an open and transparent market setting out requirements for services that the SO requires, without any particular technology in mind. However, until this aim is reached we believe there are three aspects of the Enhanced Frequency Response product that need to be addressed to maximise the flexibility that can be provided by energy storage.

    - Delivery duration - the current definition of 9 seconds needs to be clarified with an explanation of exactly what is required in the case that a frequency deviation lasts longer than 9 seconds.
    - Extended service - clarification is needed on exactly what is required in the case that the battery is essentially bid in to the primary and secondary response markets.
    - Availability - an appreciation that the 95% availability is not in line with other products because of the longer contract, and therefore a relaxation on this availability constraint.

What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale?

18. It is not clear at this stage where the most appropriate scale will be, especially as innovation is likely to continue for the foreseeable future. This is why it is imperative that the underlying market signals do not skew the market in any one particular direction, especially since each segment has the capability of providing flexibility into the market place.

19. In the short term, however, our expectation is that battery storage will initially be targeted at grid scale and industrial and commercial customers. But there is no reason why over time the market cannot support the domestic market if the propositions are sufficiently compelling, which in part will be driven by the scale of cost reductions that the industry is envisaging.

Q3. What level of electricity interconnection is likely to be in the best interests of consumers?

Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

20. The market framework should be designed to bring forward the most cost effective solutions for delivering the intended policy objectives, for example, in delivering a specified security of supply standard. We would therefore be extremely concerned if a specific target for new interconnectors was set for the GB market. Similarly some of the current underlying distortions to the market need to be addressed which are arguably in favour of interconnection over competing options, such as the UK's unilateral carbon price floor which interconnectors do not have to pay when supplying energy from the continent.

21. Interconnection needs to be built to an economically efficient level. These are not cheap investments to make particularly for an island network such as the UK and have a significant environmental impact with large converter station facilities at either end. We recognise that they can provide access to surplus capacity which becomes available in other markets and in this context can provide additional value, although it is not clear interconnectors can provide reliable capacity during times of system stress which is caused by adverse weather conditions that if affecting large parts of North Western Europe.

22. There is clearly a limit to this kind of benefit, and investment should not be encouraged beyond this, this is why it is crucial that investment is market driven rather than regulated. The cap and

floor regime has some critics as it is based on a forecast of this benefit with the risk underwritten by customers rather than investors. Nevertheless it does attempt to analyse this overall benefit, which we are supportive of. We would therefore not be supportive of moving to a system which further encourages interconnection, but rather focus effort on making sure that a robust cost-benefit assessment is conducted to mitigate the risk of over investment that is ultimately paid for by customers.

23. The risks of underinvestment in interconnectors is likely to be asymmetric, in so far as it may result in a few years when energy or balancing costs are higher than they would otherwise have been in an optimal system. In contrast, over investment in interconnectors means much longer periods of time over many decades that customers are paying for large capital projects which should never have been built in the first place.

Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

24. No. Interconnectors in our view already receive preferential treatment which other providers of services do not receive, such as avoidance of the carbon price floor and other charges such as transmission use of system charges, as well as benefiting from a cap and collar regulatory approach which provides a stable investment environment.

Q4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

25. As an island, it is important to recognise that these characteristics are somewhat different to continental Europe today where energy systems are generally much more interconnected. It is therefore difficult to find other regions that are similar enough to the GB system to draw useful conclusions. Our neighbour Ireland has perhaps an energy system that most resembles the GB market, but it is much smaller in size, and therefore market arrangements adopted may not necessarily be directly applicable to the GB market.

26. But if we focus on Ireland, it is interesting to see what has been achieved; in particular, Ireland has been able to integrate a significant ramp up in renewables capacity over a short space of time. System Operators have traditionally favoured a gradual change in the makeup of the system, but Ireland has demonstrated that in terms of balancing the system on a second by second basis, the SO needs to have the right tools at their disposal. This is why EirGrid has

proposed a number of new balancing services to accommodate the changing nature of their energy system, and are exploring a fairly large redesign of their electricity market.

27. A key lesson we would therefore draw from Ireland is to ask the question of whether the SO has all the available tools at its disposal to meet the challenges of the evolving energy system, and to be able to procure those tools in the most efficient way. Our belief is that whilst there are some short term measures that can be introduced in order to highlight to the market the new opportunities as we transition to a lower carbon energy system, a more fundamental redesign of the market(s) for flexibility (predominantly the existing ancillary services markets) appears inevitable if we are to efficiently and securely balance supply and demand.

Additional Points:

28. We believe a smarter energy system supporting a greater penetration of flexibility, including DSR and Storage will help deliver a better deal for customers, by reducing the need for new generation, optimising the existing amount of generation on the system particularly for technologies that are less flexible in their operating regimes, helping to avoid significant reinforcement of our energy networks and delivering a lower cost for balancing the system.

29. But there are other areas of the energy system where there is, or needs to be an infrastructure focus over the next decade and beyond. The UK government is already committed to the Smart Meter programme which will not only help to make it easier for customers to take greater control over their energy usage, but also support innovation in the market, which could create new opportunities for domestic DSR and Storage. However we also strongly believe that there needs to be a much greater emphasis on tackling the energy efficiency challenge of the nation, which will help to deliver a more permanent reduction in energy usage, thereby improving the productivity of businesses and the affordability of energy for households. In particular there remains over 7 million solid wall homes without insulation, which will need to be addressed at some stage if we are to meet our longer term legally binding carbon emission targets as set out in the Climate Change Act. This in our view represents a major infrastructure project in its own right.

E.ON SE Group
January 2016

National Infrastructure Commission: Electricity interconnection and storage

The Electricity Storage Network is the UK's industry association for the promotion of electrical energy storage. Current members include electricity storage manufacturers and suppliers, developers of electricity storage projects, users, electricity network operators, consultants, academic institutions and research organisations.

The Electricity Storage Network works on behalf of its members to respond to and address issues affecting the development and utilisation of electricity storage within the UK power system. This includes special interest meetings, liaising with the media, responding to consultations, providing a unified point of contact for those interested in electricity storage and promoting the value of storage within the UK power system.

We strongly support UK energy storage solutions for the UK electricity system and by promoting local innovation in electricity storage we support wider UK industry.

Introduction

The National Infrastructure Commission seeks views on how the nation can deliver the infrastructure that is will create the electricity system we need now and in the future, while retaining secure energy supplies and delivering the fit-for-purpose future system in the most cost effective way.

Essentially we are moving from a centralised, top-down system, to a more distributed and integrated approach to electricity. This is particularly the case for low carbon generation, which, in the case of solar generation, is often installed at the domestic level, on the distribution system. However many of the entities in our system, such as National Grid, large generators, suppliers and Elexon, are not moving rapidly enough to accommodate the decentralised system that consumers and communities want. There is an over-arching desire to retain the outdated business models and processes of the past and without fundamental change we cannot empower the consumer to take control of their energy needs.

The current model for our electricity system is that demand is almost completely unconstrained and generation is modified to meet this varying demand. This approach is no longer appropriate when a proportion of generation is variable and not always able to match demand. While large-scale thermal plant (non-nuclear) is able to respond to changing demand, it is high carbon and does not address climate change. This type of plant is being removed from the system. Nuclear plant, while providing carbon dioxide free electricity is not flexible, so does not meet the needs of system approach that is demand-centric. In addition new nuclear is not likely to be on the system before the loss of significant high carbon thermal plant. This means there is an increasing need for flexibility in our electricity system.

Flexibility can be provided by interconnection, demand-side management and electricity (energy) storage. This response will focus on the potential role for electricity storage in providing that much needed flexibility, but will also address the potential role for other sources of flexibility.

Electricity storage technologies are able to provide a broad range of different services and able to be deployed at various levels in the GB electricity system, from the transmission level, distribution level, community level and in household, behind the meter. Critically electricity storage supports a system with a significant deployment of renewables, while supporting even greater deployment of renewables and providing the necessary system services to ensure security of supply. Additionally there are a number of UK companies with innovative ideas and products for electricity storage that have the potential to create business and jobs in the UK.

General Comments

There is a great deal of interest in the potential for electricity storage in the UK and a very widespread recognition at all levels that storage is essential for stable operation of the electricity system. Electricity storage on the distribution network has an important role to play in supporting novel connection approaches on a constrained network and allowing communities and householders to use their low carbon generation more efficiently. By incorporating energy storage into the distribution network, both electricity storage and heat storage (behind and in front of the meter) local generation can be used locally reducing the need to transport electricity great distances from centralised large-scale generation, typically high carbon, and reducing line losses that currently amount to about 10 % of all electricity generated. Since peak demand is ~50 GW, these line losses represent 5 GW or about 5 large-scale centralised power stations.

Until there real change in the way we operate the electricity system we will be forced into a less than ideal "solution" based on the incumbent centralised models and processes, which favours large-scale high carbon plant and high-carbon reserve plant.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Significant changes have already been made to imbalance costs to incentivise suppliers to better manage their position (November 2015), however at the moment the tools a supplier has to minimise their imbalance costs, but being in balance, are generally market based. There may be an opportunity for suppliers to use electricity storage to manage their position and there are a variety of business models for this approach. One such model currently being tested is the Ofgem Low Carbon Network funded UK Power Network "Smarter Network Storage" (SNS) project, which amongst other things, allows a supplier to access the 6 MW battery at Leighton Buzzard.

However the supplier has indicated that the unintended consequences of the taxes to fund the low carbon generation incentives (Climate Change Levy (CCL), Feed-in-Tariff Obligation and Renewable Obligation) mean that an operator, not just suppliers, of an electricity storage device are double charged on this taxes. For the SNS project it means the battery is uneconomic for the supplier to operate outside of the winter season. This is because electricity storage was not defined as not being an "end user" when these taxes were set. For the SNS project HMRC have taken a pragmatic approach on the so that the tax is levied once at the _final_ end user. This ruling needs to be available to all future electricity storage projects. However Ofgem administer the other taxes and have not yet agreed to resolve the problem, but are assessing the issue. This could be resolved rapidly and would make a very material difference to the investability of electricity storage project on the GB system.

- **What role can changes to the market framework play to incentivise this outcome:**

Half hourly settlement for all participants in the GB system (including domestic customers) would allow the full value of providing demand-side response to be realised by the party providing that response. Because domestic loads are small, the potential income from shifting that domestic load is also small and may not represent sufficient incentive, particularly if the less than ideal current settlement arrangements do not allow that small value to flow to the service provider. Even when domestic loads grow with the addition of electric vehicles, one DNO has estimated that it would only be worth about £40 year to shift an individual household's load up to 15 times in that year(Customer Led Network Revolution (CLNR), (2013), Initial Load Profiles from CLNR Intervention Trials, Northern Power Grid).

National Grid, in a recent innovation study (http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Technology-reports/), indicated that a householder may gain up to £25 per year for direct control of the charging of an electric vehicle to provide frequency response (it should be noted that the £25 does not take into the account the probable costs of reinforcing the distribution network to ensure that such a direct control service could be accessed).

Additionally a UK Power Network project, Low Carbon London (UK Power Networks (UKPN), (2014) Residential Demand Side Response for outage management and as an alternative to network reinforcement, UK Power Networks Holdings Limited, London, UK [available at: http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-%28LCL%29/]), has indicated that demand-side response from domestic customers is expensive to procure and expensive to keep customers engaged (up to £2000-4000 per kW of flexibility). Therefore the focus is on industrial and commercial providers, with National Grid launching their "Power Responsive" programme in mid-2015 (http://www.powerresponsive.com/), to explore ways to support more I&C demand-side response onto the system.

- **Is there a need for an independent system operator (SO)?**

  Is not National Grid as the Transmission System Operator (TSO) not already independent? Do we need an _unregulated_ independent TSO? Or do we need an independent "system architect" to oversee the development of the system (which is more of a _network_ operator task)? The IET have suggested that the UK needs an independent system architect, but we do not need yet other large entity (like Elexon and National Grid). Determining the future of the _network_ could be a role for the National Infrastructure Commission, since the electricity system already falls within its remit and the electricity system is clearly a vital piece of national infrastructure.

  If National Grid is not our independent TSO then we certainly need one. National Grid occupies a very large space (electricity (system and network operator), gas (system and network operator) and interconnection, plus activities in the USA) in the UK energy space and there is some argument that the SO functions should be more obviously separated from the wider and more commercial of National Grid's operations. The 2015 Future Energy Scenarios (FES), published by National Grid (TSO) in July 2015, certainly had a key role for National Grid's gas transmission business and an increasing role for gas – this is clearly good for National Grid businesses, but not necessarily good for achieving a low carbon energy system. The FES has been seen a semi-independent and much valued forward look at the energy system, but it is clearly now a vehicle to support National Grid's wider commercial aims.

  It will be essential in the very near future that Distribution Network Operators (DNOs) transition to Distribution System Operators (DSOs), with a function for not just maintaining and managing the wires in their network, but also managing and balancing the energy flows. This represents a real challenge to the current TSO, but is the only way to effectively and efficiently manage our more distributed system. DNOs are keen for this transition but have just started a new price control period that locks them in to a regulator approved business plan until 2023 (RIIO-ED1). The transition to DSOs needs to happen well before then.

DSOs will need to purchase local services for balancing and this will develop novel business models and local supply opportunities. It is a radical shift from the way we currently operate our system and one that will need careful thought and planning.

It should be noted that National Grid are already actively seeking to have more control down to the meter, rather than the Grid Supply Point and as the current only purchaser of services is in a position to make it very difficult for DSOs to purchase their own services.

The Energy Network Association had a "Shared Services" group that was exploring how the DNOs/DSOs and the TSO would share services, since a single asset on the distribution network could provide services to both. This group and its activities appears stalled, but setting up these arrangements (which may need to be codified) will incentivise the development of both electricity (energy) storage and demand-side response services.

- **How could the incentives faced by the SO be set to minimise long-run balancing costs?**

The SO is currently incentivised to mimimise balancing costs. This requirement, to exclusion of all other incentives, such as balancing the system at _lowest carbon emissions_, does not help to develop the low carbon balancing services we will need on our future sustainable electricity system. If "lowest cost" is the only motivator then diesel generator farms will continue to sprout across the UK.

While accepting that the future electricity system needs to also be cost effective as well as secure and sustainable, there are way to achieve this that does not rely on small- and large-scale high carbon plant. The approach taken in the USA and in California in particular, which requires utilities to install electricity storage on their networks has shown that 1 MW of electricity storage displaces 3 MW of peaking high carbon plant and is able to support and balance the system without carbon emissions. Large-scale thermal plant now operates in the UK as "peaking plant" rather than continuously running "baseload". This changes the economics of operation of such plant and because the plant is part loaded it is likely to be running inefficiently and producing more emissions. In this way distributed electricity storage can replace centralised large high carbon plant and support the development of a decentralised electricity system, which is likely to be more resilient in the face of bad weather and system problems.

o **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

Imbalances costs were recently reformed (November 2015) and it would seem unfair to increase the imbalance costs further without giving participants the tools to manage imbalances. The only tools available currently are market based.

Sources of imbalances are many and varied – forecasting wind and solar generation, particularly the latter, is tricky and while great progress has been made for wind forecasting, forecasting solar remains problematic. This is an issue for the TSO as much as suppliers/generators. Domestic demand is becoming increasing mobile as use of electricity and small devices increases. Aggregators are currently unregulated, and this possibly helps them to be innovative, but means that there is no requirement for them to notify the "system" when they take an action. At the moment the loads are relatively small (in system terms), but as industrial and commercial demand-side response increases, suppliers may find themselves increasingly out of balance. The Ofgem Flexibility project is actively assessing the role of aggregators and whether any future regulation is required, but another issue is the role of smart meters and the potential implications of Consumer Access Devices (CADs), which, while the devices are registered with the Data Communications Company (DCC), the actions taken using that device are completely independent of the DCC, since communications with the device do not pass via the DCC. An energy action made via CADs (via the internet/mobile network) will not be notified to the system in any way and the first thing a supplier will now, is that they are out of balance. This is not only a problem in terms of imbalance costs, but could also mean that a supplier takes an action to correct that imbalance that then invalidates the original demand-side response action (providing a system balancing service) and causing more system issues. This is a problem that was raised with the DECC Smart Meter specification team by Workstream 6 of the DECC and Ofgem Smart Grid Forum, but has yet to be resolved.

- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

Demand-side response will be an important tool, particularly at the industrial and commercial scale where the size of potential loads, understanding of energy and potential financial benefits to the provider will incentivise involvement. Demand-side response at the domestic scale is currently expensive to procure and maintain and because the loads are small (and even in the future when loads are larger) the value is small on a household by household basis. The cost of smart appliances to the householder is not currently factored into the cost of providing domestic demand side response and it would be very helpful to see a technical study on the true costs and benefits of domestic demand-side response.

Embedded generation, where it meets low carbon goals, has an important role in providing system flexibility and system support. Embedded electricity (energy) storage also has an important role in managing energy at all scales. Intelligent behind the meter domestic energy storage has the potential to manage roof-top solar generation, but if the domestic storage is unconstrained and "dumb" it may well have reached full charge (maximum temperature, if heat storage) before peak solar generation, which causes significant system problems. The benefits of industrial and commercial scale behind the meter (embedded) storage should not be underestimated and can be achieved through managing heat and cold and through uninterruptable power supplies (UPSs). UPSs are designed to provide electricity during a mains failure and potentially have the opportunity to provide system services (to the TSO and the DNO/TSO) as well as take a demand off the system at times of system stress. UPSs are a low carbon solution to providing back up power, for short duration situations and may be a reasonable replacement for diesel generation.

2. What are the barriers to the deployment of energy storage capacity?

- **Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?**

The issue of double charging of environmental levies has been covered earlier and this a specific market failure than affects only electricity storage.

The fact that other low carbon (generation) assets have received support, while electricity storage has not has dis-incentivised the deployment of storage. There has never been any requirement in the GB for connecting variable generation to be dispatchable or provide system services. This has led to a "connect and forget" approach from developers and we are now trying to resolve the issues of variability on the system.

Like low carbon generation, electricity storage has high up-front costs and low operating costs. We accept that our industry will not receive deployment incentives, but we would ask that the market place reflects the need for low carbon balancing and the development of services such as National Grid's Enhanced Frequency Response, is welcome. Although far more consultation with industry and the DNOs should have been made prior to seeking expressions of interest as DNO connection teams are creaking under the load of multiple connection applications for storage on already constrained networks.

In general there is a complete lack of interaction between the TSO and the DNO/DSO, which leads to delays and problems.

Connecting storage to networks needs to be resolved as it is currently connected on one side as demand and as generation on the other, requiring two connection methods and charging regimes. This is largely the result of an energy Act (1989) that does not define electricity storage as an activity and may unintended consequences flow from this omission that prevent easy deployment. DECC and Ofgem are actively working on these regulatory issues, but clarity is needed soon as Natation Grid would like the Enhanced Frequency Response service to be available in mid-2017 and the tender is due in April 2016, which means potential developers will have to tender into an uncertain regulatory regime and this is not helpful for investors.

Access to connections is not only a problem for electricity storage by renewable generators. The approach to connection applications, offers and agreements does not work, with the current approach "sterilising" connections when projects do not actually go ahead. For instance, the National Grid Enhanced Frequency Response service attracted 64 expressions of interest (the industry is more than ready and keen to deploy), with a total capacity of ~1.3 GW. Several DNOs are dealing with < 2 GW of storage connection applications, with only 1.3 GW to connect. This means individual projects are making multiple connection applications in multiple geographic regions. If they accept all their offers, then connection capacity will be tied up indefinitely, reducing access to any other connecting project (storage or generation). This situation needs to be resolved urgently and one option is a time limit on offers, so that connections become free if not activated within a certain time and to limit the number of applications any one asset can have.

Also DNOs are not currently able to signal where they feel storage would best support their network (usually in constrained locations, which may not suit the service specifications of the National Grid service, but this is where consultation would have helped). This ability would mean that a storage provider could have access to another business opportunity (supporting the DNO) that would strengthen the investment case for the storage developer.

- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

While there will be a limited amount of transmission connected electricity storage, it is most likely to connect (where connection is possible, see above) at the distribution level and behind the meter, but not limited to the domestic scale, as there is the opportunity for behind the meter industrial and commercial scale storage.

Care is need to ensure that behind the meter storage coupled with solar generation does not create more system issues than solar generation alone does (the "duck curve"). Solar generation is seen by the TSO as low demand (because demand is being met by local generation). Low demand causes significant system issues since there is "must run" generation plant (nuclear and some high carbon thermal) and in summer 2015 the TSO had pay wind generation to come off the system to accommodate the "must run" plant. This cannot be a sensible or long-term approach if we want to meet our carbon goals. In summer 2014 low demand saw 13 consecutive settlement periods with negative prices for generation (a very common problem in Germany, with much more solar generation), essentially generators paying for users to take its electricity. So behind the meter storage will not necessarily support the wider system.

We would like to see more distribution connected electricity storage either through the DNO or through partnerships between renewable generators and storage developers or through community owned energy storage. The DECC community Energy Strategy has remained quiet, but storage coupled with either community owned generation or with domestic roof-top solar is an alternative to behind the meter electricity storage that allows a larger asset to be managed more effectively (by energy experts, rather than the householder – managing a mobile telephone battery is tricky enough, let alone a household battery) and wouldn't necessarily need aggregation to provide system services (earning income). There are many potential business models for community storage, including partnerships with DNOs/DSOs and this is a natural fit as both are more likely to want security of supply over commercial gain.

Currently there are regulatory barriers to DNOs owning and operating electricity storage due to is default definition as "generation". Electricity storage should have its own licence and be a specific defined activity. DNO ownership and operation of electricity storage is not contrary to EU rules, just local legislation. We see the DNO as a critical market for services (in the first instance) and deployment of electricity storage and facilitating this approach should be a priority.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- **Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**

While interconnectors are a source of flexibility, they are a market based tool, that is, flows of energy are governed by the market and so are not reliable, given the cross-border trading and negotiations required (Department of Energy and Climate Change - Pöyry, (2010), Demand Side Response: Conflict between Supply and Network Driven Optimisation.). Additionally interconnectors do not come without system impacts when they "swing" from full import to full export and this has to be managed carefully using other system balancing tools.

Interconnectors are considered as a possible option to help secure the system during a persistent winter high pressure (very cold, low winds). However it is possible that our northern European neighbours, who would rely upon to provide interconnection support (importing) may also be impacted by the same weather system and be unwilling to export their electricity. The issue of how an interconnector operates in times of system stress and how this relates to national energy security needs more thought. As interconnectors are a market driven approach, it may be that the country prepared to pay the highest price secures the electricity needed.

There are other tools to better match demand and supply that are likely to be more cost effective and in the national interest.

- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

No response.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

There are some interesting examples from the USA and the Ireland-Northern Irish approach and the Irish situation is a foretaste of what the GB system is likely to experience in the near future. Learning from our nearest neighbour presents a great opportunity (http://www.soni.ltd.uk/Operations/DS3/).

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[phone number redacted]

From: Ralph Bakker [email address redacted]
Sent: 31 December 2015 07:06
To: EnergyEvidence Infrastructure-Commission
Subject: A TW-accu by ET3

Dear Commission,

For your three projects:

- Improving the Northern transport infrastructure - especially East-West,
- Future, large-scale investment in road, rail and underground London transport infrastructure and
- Nationwide delivery of N-2 (future-proof) powerinfrastructure with maximumcapacity based on cryocooling (CERN), that balances supply and demand;

we surprisingly have one answer called ET3. Let me first explain that with the scientific word 'high' in "high temperature superconductivity" we actually mean cryocold exactly - 200 degrees Celsius and use of HTS-NanoTape; practically the most precious substance on the Planet. All advisors will tell you that superconductivity is 'not ready yet' and they are wrong - partly because VERY few people understand the exact physics in vacuum. This is our very expertise by which we can transport the most powerful DC current (http://www.hts-powercables.nl/wp-content/uploads/2015/08/Long-distance-HTS-HVDC-cables-final-1-2.pdf) and the most powerful AC current (www.hts-powercables.nl). Our cables are the only one in the world that are the most effective, cheapest in both construction and operation and at the same time meet the most strict safety norms in magnetic radiation for children (international norm: max 0,4 microtesla).

Our transport through vacuum and precision quantum-locking the eLimosine, the vehicle, through precision magnetic suspension (HTSM) is actually so effective, that by the photonic, interactive onboard screens with both facial scanning and irisscanning inbuilt - our system carries less germs and virusses than any other mode such as shipping, metro, bus, train, plane and any car. Interaction is by swipe movements IN FRONT OF the screen vs touch, on-screen. The same screens will be in our portal guiding people to their next available eLimosine of choice. Only licensees (www.et3.net) will have access to our portal (and medical personnel; no police and no customs in our portal ever). Since we promise our licensees the utmost privacy outlined in our privacy policy here http://www.et3.com/privacy-policy, we deliver our own security and friendly service by local, multilingual artists whom we train and monitor continuously and daily. Since we can transport cargo, utilities and passengers a mile higher or lower in altitude within a matter of minutes, we ALWAYS adjust the airpressure during the trip to the level of the destination access portal. Because of safety standards we deliver people in the destination access portal in the temperature according to the outside temperature. Should our portal be part of an airport, rail- or metro/underground station, access is ONLY by a passenger airlock beyond which we apply our own security, hygiene and safety so as to be absolutely sure to not only deliver fastest transport at 1G always during any acceleration or decelleration - for which we have our own patented max regenerative braking - but also be sure to deliver only 100 % safety as also meaning safety healthwise and virussafe. We offer point-to-point transport of garbage, power, sewage, cadavers, corpses, cargo such as flowers, dairy, newspapers, data, mobileholo's and are the only technology that offers a second choice in offgrid, 100 % safe & secure datatransport by not using the existing internet. Thus we supply the Kingdom a new net of datatransport even up to all islands of Scotland that are inhabited. By connecting to underground ET3 (2 meter in diameter of tunnelling only), they have access to internet with a maximum delay of hours.

Only the ET3-system, because of its various unique worldwide patents including patents by our licensees such as the Chinese government and experts in composities, magnetic suspension, cryocooling, HTS-tape, HTS-wire, ultrahighperformancebeton, photonic irisscanning (userscreen) and developing ET3-holo by mobile phone can deliver this level of safety because we fully automate transport and are hackersafe because we do NOT exchange information on internet. Any information to secret intelligence we exchange only after their legal department buys a corporate license one-time fee $ 500 and we will then deliver the required and requested information via our own patented technology in hackerfree transport of data - 100 % safe even virusfree.

A deep underground ultraspeed track 2 meter diameter only can hold a TW of power at night. That will be enough to power entire London at night and power the next morning untill sunrise with 100 % or N-2 security while transporting power to the edges of the Kingdom as well. Any metropole in the UK can afford to build such a deep, underground ring ET3 and thus provide a second or third totally independent system. The reason that no millionaire or billionaire has ever wired us a penny is because nobody ever explained it in as much detail as I do here based on the most generous invitation to send in max 10 pages. I must request the liberty of including all data in attachments, plans, calculations, links and proof we have supplied on et3.com, et3.eu, et3.nl, quantumtrain.com and hts-powercables.nl. I also submit the PDF on www.metavisionpublishing.nl to remind bankers of the EU approved method of financing largescale continental most modern (underground) transport including superconducting powercables and ultraspeed, superconducting maglevtrains by goldcollateral. The Treasurerer that I would not know but you surely do of the HSBC is absolutely aware of this possibility that goes up in £ trillions. The reason being that most banks refuse to publish ownershipcertificates of gold they claim to hold in their vaults. And when they are finally published and made available to journalists and the international press to study, gather and compare, we will probably see that banks own much less gold than the general population imagine. This means all the while more goldasset is available for independent, ECB-approved goldcollateral financing of large scale ultramodern and ultrasafe infrastructural projects that have the same timeline as you are speaking about.

The remainder of the max of 10 pages I may submit, I would like to humbly draw your kindest attention to the films I made not excluding: https://www.kickstarter.com/projects/493781514/44115705?token=d094058b and published for free on above sites. More detailed movies about e.g. Glasgow or London would be as per subscription and our own licensing as crowdfunding. I should not end before indicating our friendship has to continue via http://et3.eu/shopping-cart.html because the information presented in this email-proposal, the links on my sites and the texts of our combined pool of patents is extremely vast and requires weeks to process. I have a businessplan for 3000 kms length. Costs of construction will be matched by yearly revenue upon taking in function.

As I said; almost nobody on Earth masters the precise mathematics of physics in vacuum but we do. Your invitation was very cordial. London outperformes all other metropoles because you invite every stateholder to voice their deepest concerns and the deepest concerns that people have are with:

- inherent corruption
- lack of objective data as to the only two benchmarks that really matter namely A. Cost per person per mile and B. Cost per pallet per mile. This in the 50 year timeframe that you are allowed to take and you will quickly calculate that after ET3, place number two and place number three are empty.

But as proposal for Part III Energy Evidence I herewidth submit the DC and AC HTS-powercable.nl.

Most sincerely,

Ralph Bakker, MBA
Acting-president ET3 Global Alliance Inc.
CEO ET3 Europe, ET3 Netherlands, QTI bv, Hts-powercables.nl, MetaVisie X bv
[phone number redacted]

Consultation Response
8th January 2016

EUA response to the National Infrastructure Commission call for evidence

This submission is from the Energy and Utilities Alliance (EUA) a not for profit trade association that provides a leading industry voice to help shape the future policy direction within the energy and utilities sector. Our association comprises 5 divisions: Utility Networks, the Heating and Hotwater Industry Council, the Hot Water Association, the Manufacturers Association of Radiators and Convectors and the Industrial & Commercial Energy Association (ICOM).

We welcome the formation of the National Infrastructure commission and the call for evidence on the three target areas. We are particularly pleased that energy is being recognised as an important UK infrastructure project.

We would urge the commission to ensure that when compiling the final recommendations attention is paid to the gas grid and how gas consumption in the UK is a cost-effective and sustainable option for the future. Heat currently accounts for approximately 50% of total UK primary energy demand and 40% of UK Green House Gas emissions (estimates based on figures from DECC's Energy Consumption in the UK statistics).

To deliver heat at peak times of demand, on an all-electric basis, has a significant impact upon power generation, transmission and distribution. Typically, heat is demanded at times of the day when marginal grid carbon intensity is at its highest (in terms of carbon emissions). Without significant expenditure on zero-carbon electricity generation or exceptionally efficient electric heating systems, the electrification of heat is at odds with the UK's climate and carbon abatement commitments. Furthermore, the power transmission and distribution network would need to be significantly upgraded in order to cope with higher peak demand. To avoid this infrastructure expenditure, which would lie idle for much of the year, the existing gas grid should be acknowledged as playing a major role in supplying energy to the UK into the foreseeable future. As such, it should be recognised as a key part of the UK's national infrastructure.

The graph below (sourced from Grant et al; 2013) shows the nature of the challenge, with massive variation throughout the year in gas demand (heat) compared to the fluctuations in electricity demand (power). Even with a massive energy efficiency retrofit programme (which we would support), our climate is a major determinant of such variation.

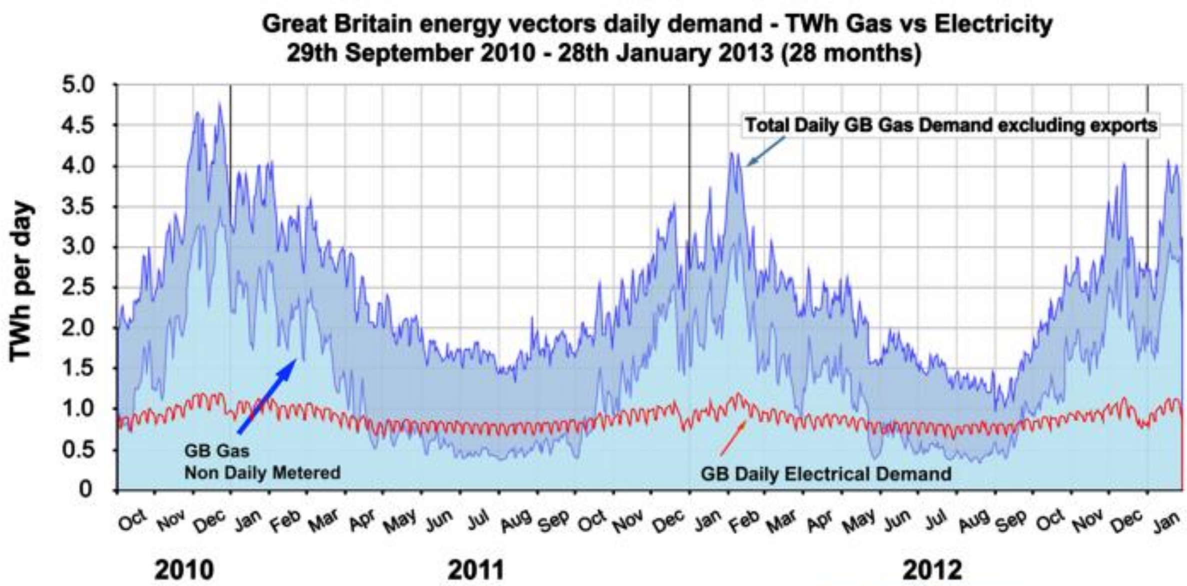

Fig. 1. Daily GB Gas and Electricity Demands (TWh). Data sourced from National Grid website (NGDIE, 2013; MHHED, 2013).

Analysis of the Future Energy Scenarios conducted by National Grid, suggests that gas can still be used when meeting our 2050 climate change obligations. More recently, low carbon gas – biomethane, synthetic natural gas and hydrogen – all have an important role in keeping the gas grid distributing fuel to our homes, when it is needed. Potentially, gas powered HGVs - supplied via the grid - could also bring about reductions in carbon emissions using known and proven technologies and at little or no extra cost to the transport sector.

Notwithstanding this, demand for electricity will increase in the future and its generation and distribution needs to be planned for. Population change and switching to products such as electric cars are just two causes of this demand increase.

To help provide the flexibility on power generation, to meet demand patterns and supply variation, we believe gas has an important role to play. To this end, gas storage, therefore, is a key component of the UK's energy infrastructure now and is set to play an increasing role in the future. For the past 40 years, the UK has benefitted from a huge gas storage facility, the UK Continental Shelf, with its ability to increase gas flows where necessary. Our increasing dependence on gas imports going forward brings sharply into focus both the strategic benefit in terms of security of supply but also the price smoothing function played by gas storage. Part of the review should examine whether the UK has sufficient gas storage levels, as our evidence suggests in does not compared to our European counterparts. Gas storage needs to have both the ability to deliver short-term balancing to the system but also longer-term benefits in security of supply.

Whilst UK shale reserves offer potential for homegrown supply, the amount of recoverable gas and the associated flow rates are as yet unknown. We would recommend that the shale reserves are investigated in order to determine the amount of recoverable gas. A decision can then be made based on quantity and the economic viability. If there is as much shale gas as has been estimated then it reinforces the case for retaining and investing in the UK's gas network.

If the Commission would like us to expand on any of these points we would be very pleased to do so.

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Eurotunnel submission to the National Infrastructure Commission consultation – Energy

Eurotunnel welcomes the opportunity to respond to this consultation, having long been aware of the need to ensure that infrastructure projects in the UK are delivered rapidly in order to support economic growth. This response focuses on our experience delivering energy infrastructure projects, to support UK energy security and resilience, through the ElecLink interconnector,

Overview

Groupe Eurotunnel (GET) manages and operates the Channel Tunnel Fixed Link between Britain and France, providing the infrastructure for Eurotunnel's own Shuttle services and for international freight and high speed passenger trains. Completed in 1994, the Tunnel was financed entirely from private sources at no cost to the taxpayer.

In addition to operating the Tunnel, GET is partnering with STAR Capital Partners to develop the ElecLink interconnector project to join the electricity systems of the UK and France. This will allow up to 1,000MW of surplus energy to be transmitted between the two countries via the Channel Tunnel. The interconnector involves a €400m capital investment in existing infrastructure and will play a key role in helping meet the UK's future energy needs by enhancing the capacity and efficiency of the electricity market. Critically, the scheme involves no capital risk to consumers as ElecLink will be financed privately and independently of the major electricity operators in the UK and France.

Response

Eleclink is an excellent example of an initiative which maximises the efficiency of infrastructure projects by diversifying their uses. The Channel Tunnel not only provides capacity for freight and leisure travel from the continent to the UK, but has also provided the opportunity for energy transmission between the UK and France helping to tackle Britain's lessening capacity for power generation and the risk of shortages in supply. Analysis from Frontier Economics in 2011 suggested that laying the interconnector using the service tunnel within the Channel Tunnel could result in a 25% cost saving when compared with laying the interconnector across the sea bed. Additionally, it minimised construction disruption, including through the protection of marine life.

As with many large projects of this nature, there were barriers to its successful completion when certainty was required to deliver the investment. Negotiations with UK and French regulators featured as part of the process, with arguments around whether levies should be charged on revenues rather than the profits generated by the project. Additionally, there was a need to negotiate exemptions from the EU's Third Package Electricity Directive's unbundling requirements, in order to make the project deliverable.

Eleclink is a vital project in protecting the UK's energy supply, also contributing to: decarbonisation; the development of a single European market in electricity; and a greater diversity of energy supply through the combination of thermal dominated generation capacity with France's nuclear dominated capacity. It is a good example of an international project relating to energy supply, highlighting the barriers and successes that international collaboration can bring.

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8th January 2016

National Infrastructure Commission call for Evidence

Submission from Catherine Mitchell, Professor of Energy Policy, University of Exeter, Energy Policy Group

Questions asked by the National Infrastructure Commission (NIC)

Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers over the long-term?
2. What are the barriers to the deployment of energy storage capacity?
3. What level of electricity interconnection is likely to be in the best interests of consumers?
4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Summary

We, the Energy Policy Group of the University of Exeter, welcome the NIC's investigation. We argue that the fundamental problem for GB energy infrastructure and the balancing of supply and demand within markets is that the current GB governance system is not fit for purpose. IGov, a project within the EPG, has put forward an alternative governance framework (as shown in Figure 1, 2 and 3). We believe if this governance framework were put in place, competition between the various energy resources – whether they be demand side or system capabilities, such as interconnection or storage – would be improved, as would operation, security and environmental outcomes. We would also see this as the long term cost minimisation strategy to meet the GB carbon commitments. The transformation to an energy system capable of meeting the environmental, security and social goals – and the infrastructure and market needs of that – should be overseen by an Independent and Integrated System Operator (an IISO), as the technical executor of Government policy. It should be a state owned not for profit IISO created from the SO functions of National Grid. This alters the balance of power between institutions in the GB energy system. We do not believe that Ofgem

should continue with multiple competing Duties. It should revert to being an economic regulator. These two institutions should be on the same level of institutional hierarchy. The IISO should implement the required energy system transformation from the CCC recommendations, and the economic regulator should regulate it. Both of them would be working to a Strategy and Policy Statement (SPS) from an Energy Policy Committee (the executor of, and advisor to, the Secretary of State) and DECC. We think this will go a long way to help overcome the barriers of storage, but at the moment a central barrier to a 'smarter' energy system are data flows. Until there is a fundamental re-structuring of those flows and who 'owns' that data, it is difficult for storage (and many other capabilities) to capture its value to the energy system. Also, there is no right answer to the amount of interconnection there should be. This is something the IISO will re-assess at regular intervals as the energy system develops. Finally, there is a great deal of international best practice the GB should learn from. IGov's work falls squarely in the area of the NIC exploration. IGov itself has been investigating international best practice in this area (Denmark, Germany and the US) and would welcome more detailed discussions of the issues.

Introduction

I am currently a Professor of Energy Policy at the University of Exeter and an 'Established Career Fellow' with an EPSRC project on Innovation and Governance for a Sustainable Economy www.exeter.ac.uk/igov (IGov), which funds a small team and lasts from. 2012-2016. With respect to the four questions above, our IGov work falls squarely with Q1 and Q4, although of course, Q2 and Q3 are part of that. Because of this, we welcome your investigation and consider our work extremely relevant to it.

IGov considers governance both as the 'rules of the game' (ie policies, institutions, rules and incentives), and the politics and decision-making processes of how those rules are implemented. It is a comparative study of GB with Denmark, Germany and three US States in particular: California, Texas and NY.

At root, we argue that GB energy governance (including of interconnection and storage) is not fit for purpose. We are slowly developing an energy governance framework which we consider would meet the regulatory and infrastructural challenges of energy.

This submission is laid out in the following way: the next section sets out our arguments for GB governance change. The following sections then answer your 4 questions above.

GB Energy Governance for a Whole System

Energy is a whole system and needs a governance system which reflects that. If something is done to it in one place, there will be an impact in another. It is therefore insufficient to think narrowly about what changes need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers over the longer-term. The governance framework has to be set up to up to do this - and this would include markets, networks, the system operator, distribution service providers, Codes, Data bodies, market monitoring and so on.

IGov wrote a couple of introductory papers to explain GB's governance problems, and then what needs to be done in order for them to be overcome. Although they are now a year old, they are both useful for explaining the issues in full. The first paper set out what we see as key issues for governance in GB. The second paper is a high level explanation to what we called Public Value Energy Governance [now changed to Output Based Regulation] which was a straw- proposal for necessary governance change in GB.

In this latter paper, we argued that there are three fundamental issues of our current regulatory process which needs to be dealt with:

- the lack of legitimacy within our energy policy process, which has developed because of the changing nature of the challenges that the energy system faces
- the lack of nimbleness in its decision-making, which means that there is a gap between the removal of regulatory barriers and technology take-up, so that practice change is slow; and
- the way that its rules and incentives suits the characteristics of fossil technologies and their related business practices, thereby undermining new business models and competition and perpetuating the current system and current ways of thinking

We have now developed an overall governance framework as shown in Figure 1 below. We argue that the roles and relationships between the GB energy institutions need to change to:

- an energy policy committee (EPC), which both advises the Secretary of State but also executes the Secretary of States decisions, thereby bringing in more legitimacy to decision-making;
- an integrated and independent system operator (IISO) which is the body tasked with energy system transformation (ie to ensure system capability of meeting the carbon reduction targets for 2030, 2040 and 2050 as set out by the Committee of Climate Change); ensuring security; and combining complementary market and network functions;
- that Ofgem be restructured so that it becomes an economic regulator

We think the IISO and the Economic Regulator should be overseen by the EPC and that they are both on the same level of hierarchy.

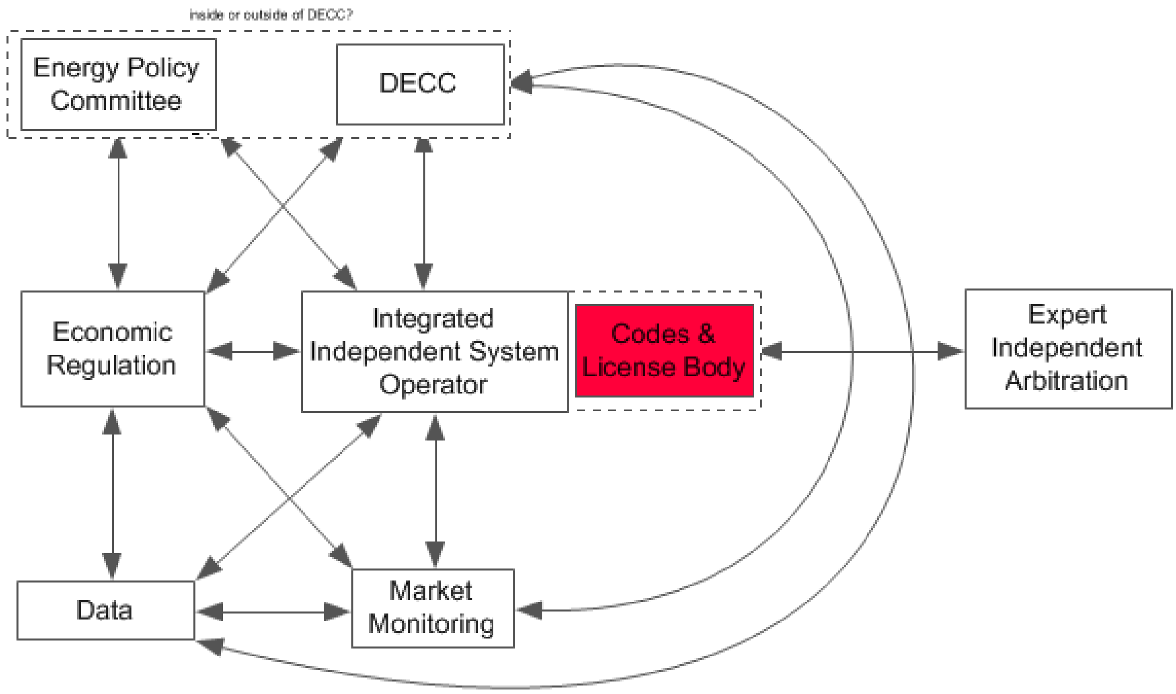

Figure 1

In the same way that we think the transmission system operator role needs to be transformed, we think distribution network operators (DNO) should also alter their role. We think that this is best done by means of new regulation which alters the incentives received by the DNO. Transforming DNOs into market facilitators has been discussed as far back as the Embedded Generation Working Group in January 2001. Currently, there is a spectrum of possible roles that the DNOs can transform into – and these options need to be discussed fully.

At one end, the minimal change is that DNOs are regulated in a different way from currently. At the other end, DNOs are transformed into Distribution Service Providers, as envisaged in the New York Reforming the Energy Vision regulatory transformation (NY REV) , which facilitate fully formed local markets for energy. Somewhere in the middle, are DNOs transformed into distribution service providers / market facilitators but where local markets, if they exist, are ad hoc arrangements which buy and sell into a national market. It seems to us that DNOs need to transform. We also like the idea of local markets because of the arguments put forward by the NY REV and because of the (already) increasing interest from places of different sizes in GB to develop local markets (eg Bristol and Wadebridge).

Figure 2 below sets out how we see the transformed distribution service provider interacting with other energy institutions such as the IISO, markets, customers, data and so on. Please also see Figure 1 for how this fits into the IGov governance framework which has been developed so far.

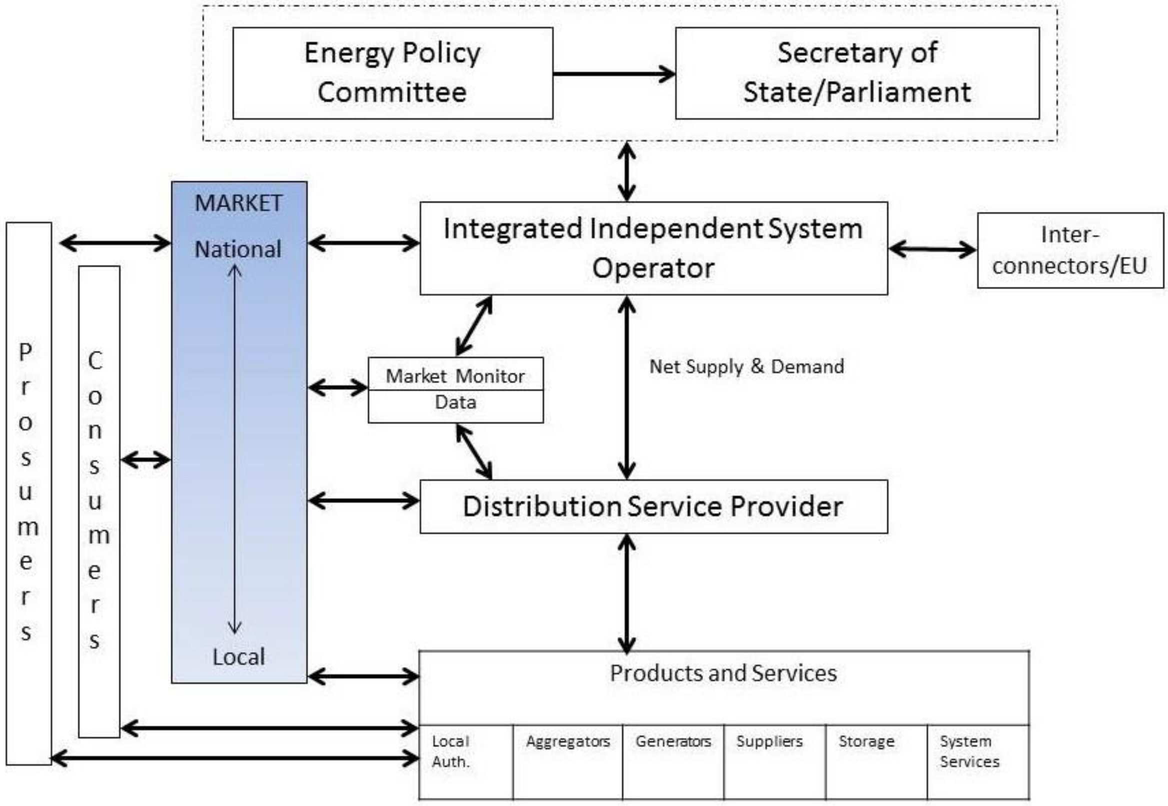

Figure 2

Codes

Codes and Licenses are the legal basis of energy system operation. The current governance of Codes and Licenses needs root and branch restructuring – both with respect to text, process and institutions. Codes (and data flows, discussed below) are actually central blockers to a new energy system. Policy and regulation can change, but before they are implemented the relevant Codes have to be altered. The process for Code change is entirely unfit for purpose, and this is something which has been taken up by the Competition and Mergers Authority (CMA). IGov has set out its governance framework for Codes within a Working Paper and here, and show in Figure 3 below.

IGov has participated very actively within the CMA investigation in general – including arguing that the CMA investigation should increase its theories of harm from four to five to include the governance framework as a potential of harm – which they accepted. Our specific recommendations for Code Governance change to the CMA can be found here.

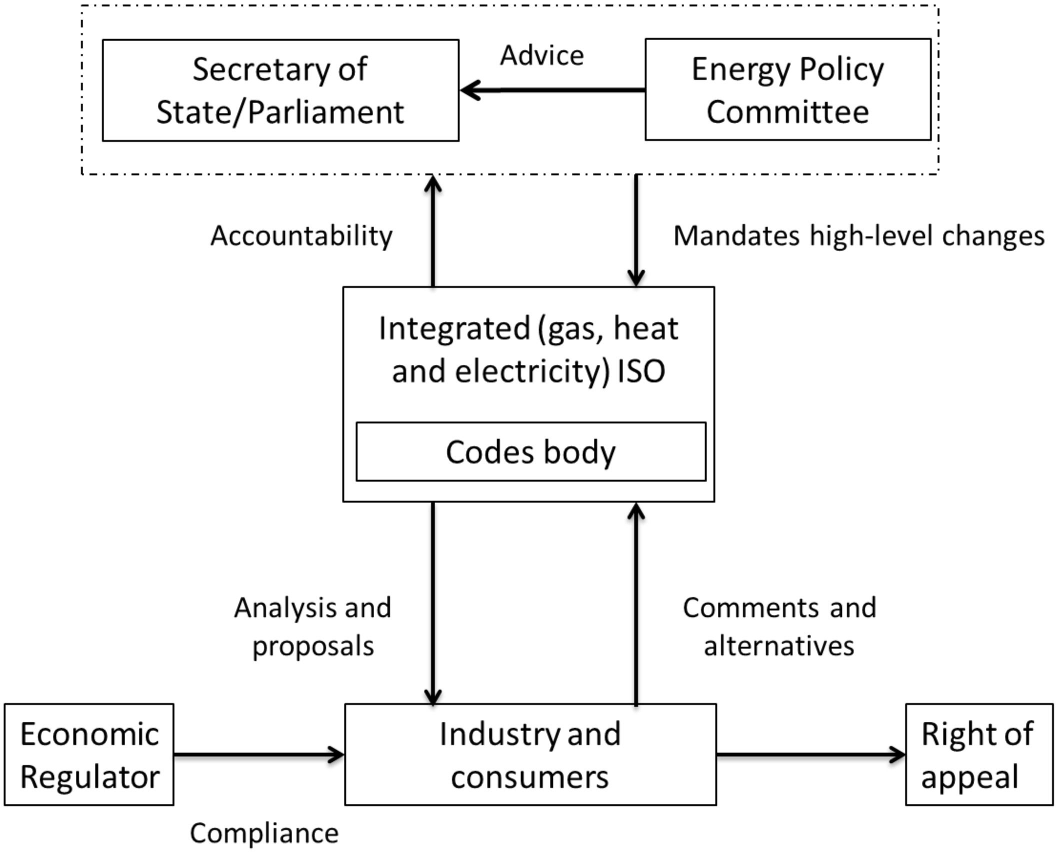

Figure 3

Data
Data is another underpinning requirement for appropriate competition, market and network interactions, and GB's process for data flows are also not fit for purpose. As with Codes, which requires getting rid of the basic principle of self-regulation, so data flows has to move beyond suppliers as the institution with customer to a central data body, as DataHub in Denmark.

Strategy and Policy Statements
We argue that the governance framework should have Strategy and Policy Statements (SPSs) between the institutions so that while their individual roles may differ, they all have the same goals. Ultimately, we argue, that the Minister gives authority to the EPC to execute energy policy. There should be SPSs between DECC, the EPC and all the institutions – the economic regulator, the IISO, the Data Cody, the market monitor, the Code Body and so on. The current model of SPS leaves Ofgem to handle the trade-offs, which leaves too much of the political aspects of energy in their hands. The EPC would be handling the political aspects of policy decisions, including trade-offs, which would be the basis of advice to the Minister. While our model still has concerns, we argue it is more legitimate than the current model.

Denmark as a useful example
Our GB governance framework has drawn on governance examples from elsewhere, in particular Denmark but also various States in the US. Please see a recent Working Paper on Danish energy governance, and the NY REV update link for distribution governance above.

Answering the Questions

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers over the long-term?
2. What are the barriers to the deployment of energy storage capacity?
3. What level of electricity interconnection is likely to be in the best interests of consumers?
4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers over the long-term?

As I am sure you know, the EU currently has a consultation on electricity market design, and individual Member States are working out their preferences for how their own markets are designed, including how they interconnect with other countries (eg Germany) and how they establish the value of a multitude of capabilities within the market which is needed to keep an energy system running securely.

We argue that there are a few central issues for this.

Firstly, that market reforms are part of a wider restructuring of the governance framework set out above. Secondly, that it is recognised that markets and networks are inextricably linked, which is why the IISO should be responsible for both system and market operation, and why distribution service providers enable greater involvement of local supply and demand. And thirdly, markets need to be set up to suit the characteristics of variable power, and their system needs. IGov produced a blog series called No resource is 100% reliable which endeavoured to explain that while different technologies and fuels have different characteristics, they are all in their different ways unreliable. The important point is that markets should be designed to maximise their flexibility, which includes a capability market as opposed to a capacity market. One argument is that markets have to value energy and capacity. We would argue that capacity is only one capability which needs to be valued. All the different capabilities of system operation – such as rapid ramping etc – need to be able to be valued within a newly designed market for a no-regret energy policy so that it can 'reduce, flatten and flex'.

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

GB can learn a lot from international best practice – as set out in the various links above. Denmark as a country, whilst small, has created a very interconnected energy system – this is not just from Denmark to other countries, but also within Denmark between resources (such as heat and electricity) and between local and national markets. Other countries, in particular many US States, have been very successful in developing capacity markets which include the demand side. As explained more fully in the link, The Federal Energy Regulating Commission (FERC) publishes an annual Staff Report which sets out what US State or market has done in the last year to their CMs, and why. Over 10% of peak capacity is provided by DSR in PJM, while DSR averages 6% of peak across the US. This translates to between 5-8% reduction in wholesale prices averaged across the year, although this is a whopping 90% cut for the peak time price. As set out above, the NY REV is endeavoring to establish an energy system governance process which will enable a more efficient energy system operation, at lower cost to customers.

The intention of IGov is to bring this best practice to GB, and we would welcome discussions about this.

What are the barriers to the deployment of energy storage capacity?

At the moment, storage is not cheap enough to be incorporated into the energy system without any changes to its governance. Moreover, the energy system market as set up and discussed above, does not value capabilities such as flexibility - which storage provides. The current capacity market is far too narrow in what it provides value to, and needs to be rethought so that flexibility (and its different capabilities) can be included. The US markets are the best examples currently of that (see links in section above), although Germany is moving towards that now.

Thus, for the appropriate amount of storage to come forward, the GB governance system has to alter. At the moment, it is a system based on competition but set up to suit the characteristics of fossil fuels. It needs to alter so that it enables 'better' competition by getting rid of the de facto pursuit of fossil fuels but also to enable better direction to meet carbon reduction targets cost effectively. We believe that the IGov framework will enable an appropriate process for doing this – and within that the barriers for storage would be removed, and the appropriate amount of storage would come forward.

What level of electricity interconnection is likely to be in the best interests of consumers?

There is no 'right' answer to this. We have an energy system at the moment. We would hope, with appropriate governance change, as set out above, that the energy system transforms into one capable of meeting our environmental, security and social goals.

Because the energy system is a whole system, it is never possible to say that X amount of interconnection is correct. Interconnection is a very important function of a secure and flexible energy system, as shown by the Agora study of Denmark. The EU makes a recommendation for about 15% of supply to be available from interconnection – some countries have well above that, and GB is still well below that.

We argue that the IISO is the body which is responsible for energy system transformation. So, for example, if we need X million electric vehicle chargers by 2040 to ensure Y carbon reduction, then the IISO would make that recommendation, ensure that the market rules were in place, and the economic regulator would regulate for that. As the GB system develops, it will have a certain amount of flexibility – which will differ depending on its development. The IISO may take the view that we need more interconnection. They should then be able to tender for that through a targeted strategic capacity mechanism – a mechanism with different properties from that in place at the moment.

We therefore do not think the NIC should worry about the 'right' amount of capacity or storage. More, the NIC should recommend a governance system which enables better system wide decision-making, as we recommend.

Conclusion

We, the Energy Policy Group of the University of Exeter, welcome the NIC's investigation. We argue that the fundamental problem for GB energy infrastructure and the balancing of supply and demand within markets is that the current GB governance system is not fit for purpose. IGov, a project within the EPG, has put forward an alternative governance framework (as shown in Figure 1, 2 and 3). We believe if this governance framework were put in place, competition between the various energy resources – whether they be demand side or system capabilities, such as interconnection or storage – would be improved, as would operation, security and environmental outcomes. We would also see this as the long term cost minimisation strategy to meet the GB carbon commitments. The transformation to an energy system capable of meeting the environmental, security and social goals – and the infrastructure and market needs of that – should be overseen by an Independent and Integrated System Operator (an IISO), as the technical executor of Government policy. It should be a state owned not for profit IISO created from the SO functions of National Grid. This alters the balance of power between institutions in the GB energy system. We do not believe that Ofgem should continue with multiple competing Duties. It should revert to being an economic regulator. These two institutions should be on the same level of institutional hierarchy. The IISO should implement the required energy system transformation from the CCC recommendations, and the economic regulator should regulate it. Both of them would be working to a Strategy and Policy Statement (SPS) from an Energy Policy Committee (the executor of, and advisor to, the Secretary of State) and DECC. We think this will go a long way to help overcome the barriers of storage, but at the moment a central barrier to a 'smarter' energy system are data flows. Until there is a fundamental re-structuring of those flows and who 'owns' that data, it is difficult for storage (and many other capabilities) to capture its value to the energy system. Also, there is no right answer to the amount of interconnection there should be. This is something the IISO will re-assess at regular intervals as the energy system develops. Finally, there is a great deal of international best practice the GB should learn from. IGov's work falls squarely in the area of the NIC exploration. IGov itself has been investigating international best practice in this area (Denmark, Germany and the US) and would welcome more detailed discussions of the issues.

NATIONAL INFRASTRUCTURE COMMISSION CALL FOR EVIDENCE: Electricity interconnection and storage

This response is from Flowgroup. Please contact Geoff Barker, Business Development Director at [email address redacted]

Flowgroup is a leading UK-based technology developer and independent energy supplier employing 200 people. The company's vision is to see UK households generating their own low cost, low carbon electricity at home, replacing conventional heating system with micro combined heat and power (mCHP). Flowgroup's mCHP unit is about to launch in the UK market. The company will be launching its mCHP product as part of an innovative energy supply proposition that is capable of revolutionising the UK retail energy market by empowering consumers and reducing costs.

Flowgroup's business model has the potential to:

- Disrupt the UK retail electricity market dominated by few vertically integrated utilities by delivering great value in energy supply and related use products and empowering consumers to generate their own electricity at home;
- Offer a lower carbon alternative to conventional condensing boilers, a market currently dominated by few established players;
- Support electricity generation at the point of use and at times of winter peak demand, reducing the strain on transmission and distribution systems, deferring the need for infrastructure upgrades and displacing high carbon emitting power plants.

Flowgroup is working closely with its global manufacturing partner Jabil to achieve a low cost, sustainable mCHP product. As an early stage technology, significant capital cost reductions can be achieved at scale. A policy framework that reflects the wider value of mCHP for the energy system and allows the consumer to capture some of this value is key for the eventual success of our novel business model.

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

MCHP is a maturing technology, currently manufactured in low volumes, which leads to a relatively high starting price with steep cost reduction potential. The technology is ideal for the development of business models that can inject enhanced competition in the entrenched boiler and electricity supply markets benefiting consumers and the energy system.

In order to access the benefits delivered by mCHP, Flowgroup recommends implementation of half-hourly settlement for customer profile classes 1-4. Half-hourly settlement would allow customers to access the full benefits of onsite electricity production by improving accuracy in the allocation of energy and network costs across suppliers. Implementation of half-hourly settlement could in turn reduce the actions that the System Operator needs to take to balance the energy system.

Flowgroup is supportive of DECC Smart Meter Programme which is considered as key enabler of a smart energy market. The rollout of smart meters for all consumers regardless of their size is set to play a key role in enabling deployment of new demand-side technologies that could open up opportunities for local trading and for third-parties to take a more active role in flexibility markets.

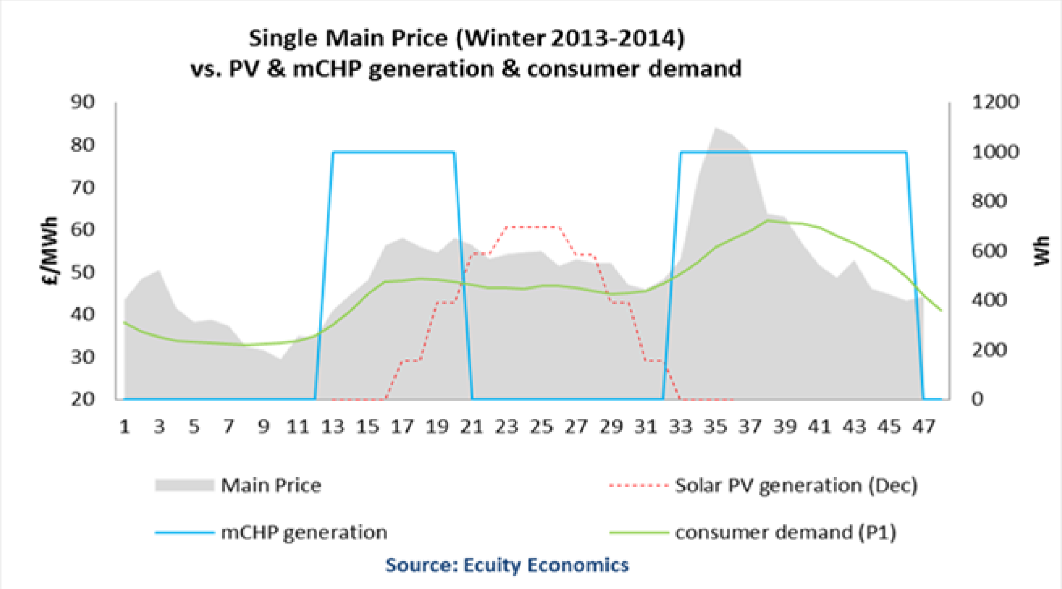

Figure 1. mCHP generation vs. System Main Price

- **What role can changes to the market framework play to incentivise this outcome**

Under current market arrangements, consumers are unable to access the full benefits of onsite electricity generation. At present, most consumers do not have meters capable of recording half-hourly consumption data and are settled using estimates of their energy usage. Introducing half-hourly settlement for profile classes 1 to 4 would result in suppliers being charged for the electricity their customers have actually consumed (as opposed to using estimates) so that changes in electricity demand will be attributed to customers making the changes and the value could be tracked.

- **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**

NA – welcome views from energy business

- **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

NA – welcome views from energy business

- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

Heat led mCHP, unlike other distributed technologies such as solar PV, tends to generate more power at times of peak demand (e.g. winter evenings) and so deployed in volume would reduce the need to operate, or maintain, fossil-fuelled peaking power plants. This creates substantial economic benefits for the wider energy system from avoided capacity, energy, network and emissions costs. The electricity generated by mCHP can address a significant part of domestic needs and reduce rising consumers bills. Surplus electricity can be exported to the grid. In addition, heat-led mCHP would normally generate during winter peaks and therefore displace costly and fuel-based power generation delivering economic benefits to the wider energy system.

MCHP is also the solution that allows the most cost effective use of gas at the domestic level for heating purposes. The technology is a heating solution that is flexible in terms of fuel type utilisation; therefore renewables, in the form of renewable gas, should not be overlooked as the eventual fuel of preference for mCHP over the medium term. Renewable gas fuelled mCHP would allow the technology to become part of the portfolio of renewable heating solutions utilising existing infrastructure to attain full decarbonisation of heating by 2050.

2. What are the barriers to the deployment of energy storage capacity?

- **Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?**

N/A

- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

N/A

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- **Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**

N/A

- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

N/A

Consultation on National Infrastructure Commission call for Evidence.
Section 4, Electricity Interconnection and Storage.

Response from Friends of the Earth England, Wales and Northern Ireland.

Introduction
Friends of the Earth England, Wales and Northern Ireland (EWNI) represents more than 100,000 members in the UK, and is part of a Europe-wide network representing 30 national organisations. Worldwide we have more than 2 million members. We welcome the opportunity to submit views on the National Infrastructure Commission.

While there are others who will make more technical comments, we are happy to be able to submit thoughts on the general scope and direction of the Committee's investigations into electricity interconnection and storage.

General comments

In 2015 the Prime Minister David Cameron, speaking at the International Climate talks in Paris said: "instead of making excuses tomorrow to our children and grandchildren, we should be taking action against climate change today". Friends of the Earth agrees.

In light of this, and the UK's commitment to keeping global temperature rises to 'well below 2 degrees' it is **crucial that the National Infrastructure Commission places decarbonisation and environmental protection at the very core of its function and purpose**.

This is not only environmentally necessary, but economically logical.

The UK is in the midst of a transition to a low carbon economy. This will require large scale deployment of low carbon technologies, particularly renewable energy.

Two of the oft-cited options for tackling decarbonisation and security of supply in the UK – a large scale shift to natural gas (potentially 'fracked gas') as a 'bridge', and new nuclear – can be discounted in the medium term.

By 2030 the Committee on Climate Change estimates that the carbon intensity of the UK electricity supply should be reduced to around 50gCo2/kWh to avert dangerous climate change. The carbon intensity of natural gas, while significantly less than coal, is still around 350-400gCo2/kWh, meaning that unabated natural gas cannot form a large proportion of the electricity supply if we are to decarbonize by 2030.

It is unlikely too that there will be any new nuclear in the UK before 2025, or that there will be large amounts available in the time frame required before 2030. Given the falling costs of renewable energy (most already require less support than new nuclear ten years early) nuclear power is also unlikely to be the cheapest option.

For similar reasons, new nuclear and fracked gas, which will not be available at scale for perhaps 15 years, cannot play a significant role in any medium term security of supply issues.

Friends of the Earth believes that to decarbonize to the level recommended by the CCC, renewable electricity will need to account for around 80% of electricity generation in the UK by 2030.

Alongside larger systems such as offshore wind farms or large solar installations, decentralised renewables like rooftop solar, small wind, hydro and other micro-renewables technologies can play a vital role in generating low carbon electricity, promoting community engagement or efficient onsite generation and the fostering of innovation and invention in low carbon products and services.

For these reasons it is vital to have grid infrastructure which prioritises decarbonisation through renewable energy. This will mean an energy storage and management system which works to facilitate and incentivise the large amounts of variable but predictable renewable energy onto the grid, as well as looking to match demand more closely to supply through enhanced use of demand side management systems. This should be the focus of any future changes to the grid operation and structure – to facilitate decarbonisation through interconnectors, small and large scale energy storage and demand side measures.

Capacity market

While they are eligible to apply for support, energy storage and demand side management are dis-incentivised through the capacity market. The majority of payments through the capacity markets are being made to *existing* coal, nuclear and gas power stations, and to new but very cheap and polluting diesel power.

In 2019 alone, the UK will spend at least £942 million through the Capacity Market, of which £851 million will be used to support existing generation. Just £8 million will be spent on demand response, compared £139 million on old coal power and £136 million on existing nuclear, which cannot provide flexible back up.

Subsidy of existing coal power stations, and non-flexible nuclear power stations, places emerging technologies such as energy storage using batteries or flywheels, or demand side response, at a significant disadvantage. Similarly the fact that new generation may bid for 15 year contracts in the capacity market but storage and demand side measures appear unable to do so is a clear barrier to new energy storage.

Finally, failure to account for the environmental costs of technologies incentivised by the Capacity Market is at odds with the UK's commitments to tackle climate change, and is something which should be rectified.

CONTACT DETAILS:

Alasdair Cameron; [email address redacted]

FREIGHT on RAIL

Freight on Rail response to Call for Evidence to National Infrastructure Commission:

This is the Freight on Rail response to the National Infrastructure Commission (NIC) call for evidence on the terms of reference listed.

Freight on Rail, a partnership of the rail freight industry, the transport trade unions and Campaign for Better Transport, works to promote the economic, social and environmental benefits of rail freight to local, devolved and central Government in the UK and to the European Commission, Parliament and Council of Ministers.

Summary

In addition to the terms of reference, covered in our sections A, B & C, we would like to make key general points, which are not only relevant to all three NIC terms of reference but also to the vast majority of NIC future infrastructure schemes.

NIC needs to take into account the socio-economic benefits of rail compared to HGVs which impose high external costs on society which are not internalised. Government policy, as a whole including the NIC, should set equitable transport policy across the modes which takes into account these market distortions. (See section 6)

Our response is comprised of key general points with headings below, explained in detail in sections 1-7 followed by our response to your terms of reference in sections AB & C.

The general points are covered under the following headings below:-

Growth of rail freight and its importance to UK PLC
Infrastructure Commission should make using rail a planning condition
Road and rail complement each other as part of the logistics solution
Rail's role in delivering to cities and transhipping to last mile low emissions deliveries
Land use planning
Lack of a level playing field between modes
Upgrading key rail routes can significantly reduce road congestion on key strategic corridors

1. **The growth of rail freight and its importance to UK PLC**

Both the Secretary of State for Transport, Patrick McLoughlin and the Rail Minister Claire Perry have voiced their support for rail freight. In June 2015 Claire Perry commented on *'the* *remarkable rise of rail freight'* at the *Rail Engineers Forum* conference in June 2015. She highlighted rail freight's excellent record to date and its forecasted growth in two key market sectors saying that the Government wants to work with the rail freight industry to remove barriers that inhibit that growth.

On December 9th 2015, the Secretary of State endorsed her statement saying "*that the story of our modern rail industry is amazing and freight is a key part of that. We want rail freight to grow much further because demand to going to keep increasing".*

Consumer traffic has grown by 30% since 2006/7 and grew 5% in the last full year14/15. Construction traffic increased by 17% in 2013/14 and 10% last year with 2.5 per annum growth forecasted. The decline of coal traffic has been largely anticipated and forecast although the scale of the decline was sharper than expected; coal traffic was down 61% in the first quarter of 2015/16. So the Government and devolved bodies need to work together with the industry to provide a network which can cater for more consumer rail traffic and construction traffic, both forecast to expand, to replace the coal traffic.

Industry Forecasts show intermodal rail traffic will quadruple by 2034

Consumer rail traffic is forecast to quadruple by 2034. Construction traffic 2.5% annum growth forecasted. But forecast are dependent on upgraded network and existing market conditions. Retention of the mode shift benefit grants are important to overcome the lack of a level playing field between HGVs and rail. See section 6

2. **Infrastructure Commission should make using rail a planning condition** during construction phase of infrastructure projects for the delivery of raw materials and removal of spoil because of its lower external costs than road freight. The nearest railhead should be used whether building roads, rail, power stations or airports, using nearest railhead. The Olympics, Crossrail and Terminal 5 are good case studies of demonstrating the benefits of this approach.

3. **Road and rail complement each other as part of a logistics solution** by each playing to its strengths. As well as its bulk commodity markets, rail is well placed to offer the long-distance

trunk haulage for consumer traffic, as demonstrated its 30% growth since 2006/7 and its sustained 33% market share for the past few years, including in 2014/15.

4. **Rail's role in delivering to cities and transhipping to last mile low emissions deliveries**
   A growing number of cities in the UK need to reduce air pollution to comply with EU regulations as seen by the Supreme Court ruling on London's air pollution violations. By 2020 Leeds will not be compliant with EU NOX regulations. Rail has far lower NOX emissions and lower particulates which are the key air quality problems. Two separate Colas Rail trials with TNT and Stobbarts into Euston have proved that specialist freight trains can come into the heart of cities where the cargo can then be discharged into low emissions vehicles. Similarly, if rail connected consolidation centres are set up on the edge of conurbations rail can be part of the logistics solution by transporting the goods long-distance and then transhipped to low emissions vehicles for final urban deliveries.
5. **Land use planning**
   We believe the NIC needs to be cognizant of the importance of land use spatial planning in delivering national infrastructure .Without coherent and integrated spatial and transport planning, the NIC , TfL and TfN will find it difficult to deliver the required rail upgrades. TfN can set the overall spatial planning framework for the North and direct local authorities to safeguard suitable sites and rail alignments for potential rail use in their Local Development Frameworks. For rail freight, it is crucial that local and regional authorities protect suitable sites for terminals for future potential use because there are a limited number of suitable locations which have the necessary rail and road connections. The Government's National Network National Planning Policy which includes the Strategic Rail Freight Interchange policy would support applications for SRFIs nationally significant infrastructure projects in the planning system.

6. **Lack of a level playing field between modes**
   All levels of Government must take into account the scale of subsidy given to HGVs and the level of external costs unpaid by the sector in their transport planning; HGVs impose almost ten times more external costs on the economy and society than rail freight. The latest research carried out

for the Campaign for Better Transport[i] using DfT values, found that HGVs pay less than a third of their costs, such as road congestion, road collisions, road damage and pollution which equate to an annual subsidy of around £6.5 billion. These conclusions are in line with a MDS Transmodal study in 2007 which found a very similar amount of underpayment: £6billion. The Government needs to recognise HGV costs in discussion about rail freight costs so that policy implications can then be understood in both directions with road and rail being examined across the piece. The level of HGV subsidy makes a compelling case for supporting rail, which imposes much lower costs on society and the economy, equivalently.

7. **Upgrading key rail routes can significantly reduce road congestion on key strategic corridors** Research commissioned by CBT looked at specific routes which typically tend to be more congested because of more long-distance HGV traffic, particularly to ports. Its key findings were that:
   a) Some parts of road network have more long distance HGV traffic which could be carried by rail
   b) The impact of additional traffic in already congested conditions is far greater than a simple increase in pcu or vehicle kilometres suggest – it rises exponentially.
   c) In congested conditions each single per cent increase in traffic causes several percentage increase in congestion. In fact, Department for Transport figures state that a modest decrease in traffic of around 2%, results in congestion falling by 10%. DfT figures show that on congested parts of the network, congestion could be three to four times the percentage reduction in overall traffic levels, using a simple low congestion impact multiplier of 3-4.

The research found that in key corridors, such as the Trans- Pennine, London to East Midlands, Felixstowe to the North, Southampton to the North, Yorkshire and NE including M1 and A1, which all suffer severe congestion at peak hours the transfer of freight to rail could be significantly alleviate road congestion by removing HGVs.

http://www.bettertransport.org.uk/sites/default/files/research-files/Freight%20mode%20switch%20report%20d6.pdf

Importance and strength of rail freight as part of the logistics solution.

- Rail freight generates more than £1.6bn a year in economic benefits for UK PLC through improved productivity, reduced congestion and wider environmental benefits.

- Rail freight transports goods worth over £30bn a year, ranging from high end whiskies and luxury cars to supermarket products, cement and coal. Rail moves one in four of the containers entering the UK and half of the fuel used in electricity generation.

- The Hendy Review, which was tasked with reviewing the status of the Network Rail enhancement projects, acknowledged rail freight schemes deliver very high value for money. It stated that the average benefit cost ratio for rail freight schemes is between 4 to 5[ii], which demonstrates that rail freight upgrades offer significant socio-economic benefits to the UK. Targeted infrastructure interventions work; the gauge enhancements out of the port of Southampton resulted in rail's market share increasing from 28 to 36% within a year of the completion of the work.
- **Terminals help regenerate local economies**
  Local and regional authorities and LEPS therefore need to take into account the fact that rail freight terminals bring local re-generation benefits. Strategic rail freight interchanges (SRFI) can employ large numbers of staff directly. Daventry SRFI now employs around 5000 staff which will rise to 9000 when current expansion is finished. There is scope for terminals of all sizes which need new road/rail works.
  For example, LEPs could help fund new roads to SRFIs and rail connections to the network for terminals through the Local Growth Funds.
- Rail freight industry has invested over £2bn since the mid 1990s

Rail freight's socio-economic benefits to society and the economy

- Rail freight is safer than road freight, HGVs are more than 6 times likely to be involved in fatal accidents than cars on local roads. *Source: Traffic statistics table TRA0104, Accident statistics Table RAS 30017, both DfT*

- Transfer to rail can reduce road maintenance costs as HGVs have an adverse impact on road infrastructure. The heavier HGVs are 160,000 times more damaging to roads than the average car- Source 4th Power law. This was shown by the high HGV charge for the M6 toll road, a private venture.

- Congestion benefits of rail freight - road congestion is now costing around £24 billion per annum according to the Freight Transport Association; the heaviest freight train can remove a 160 long distance HGVs from our roads – *Source Network Rail June 2010 Value of Freight.*
- UK rail freight produces 70% less Carbon dioxide emissions than the equivalent road journey- *Source DfT Logistics Perspective Dec 2008 P8 section 10*

- Energy efficiency of rail
  A gallon of diesel will carry a tonne of freight 246 miles by rail as opposed to 88 miles by road – *Source Network Rail July 2010*
- Rail freight produces almost 90% less PM10 emissions than road freight and up to fifteen times less NOX emissions – DfT Logistics Perspective Dec 2008 P8 paragraph 10
- Damage and costs of main pollutants from transport
  Road transport is the source of 80% of NOx in problem areas which rail can help reduce[iii].

C. Delivering future-proof energy infrastructure

Make using rail a planning condition for transportation, where practical, to reduce adverse impacts. Rail is currently used in the biomass and nuclear industry.

Philippa Edmunds Freight on Rail Manager January 2016

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[i] *Addendum to Metropolitan Transport Research Unit MTRU 2014 report February 2015. Heavy Goods Vehicles – do they pay for the damage they cause 2014*

[ii] *Ref 28 Hendy Review*

[iii] *NOX costs the UK 6576 euros per tonne, in urban areas PM2.5 costs 194751 euros per tonne. Source Ricardo-AEA et all - Update of the handbook on external costs of transport 2014 using figures for 2010.*

fsb Experts in Business

Lord Andrew Adonis
Chair
National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ
energyevidence@Infrastructure-Commission.gsi.gov.uk

7 January 2016

Dear Lord Adonis

Electricity interconnection and storage

The Federation of Small Businesses (FSB) welcomes the opportunity to respond to this National Infrastructure Commission consultation.

FSB is the UK's leading business organisation. We exist to protect and promote the interests of the self-employed and all those who run their own business. FSB is non-party political, and with around 200,000 members, we are also the largest organisation representing small and medium sized businesses in the UK.

FSB has engaged frequently with both Ofgem and the Competitions and Markets Authority (CMA) as they have both seek improvement in the energy market. FSB persuaded the CMA to look specifically at microbusiness issues as part of their wider investigation into the market. We have been particularly concerned about tariff transparency, unfair terms and conditions and the role of Third Party Intermediaries (TPIs).

FSB has long been concerned that small businesses are prevented from getting a fair deal in the energy market. A third of FSB members say energy costs have a significant impact on their business. It is important, then, that they can access the market and understand where and how they can save money on their energy bills.

That said, FSB has stopped short of dictating what the cost of energy should be or what percentage of energy retailer sales margins should be allocated to infrastructure investment, profit, customer service and staff (although it is right and proper that these continue to be scrutinised). The "fair" market we seek is unlikely to ever make energy costs universally insignificant for customers. So customers must be empowered to make wise choices. The transition to a low carbon economy – something which FSB fully supports – will require unprecedented investment in our energy infrastructure and the cost of this will, ultimately, fall on bill and tax payers. FSB's role is to represent the interests of smaller businesses – both as customer and investor – to ensure that the costs of this transition, and the opportunities that it will undoubtedly bring, are allocated fairly.

It is in this context that we approach the National Infrastructure Commission.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

It is clear that the transition to a low carbon economy will place massive pressure on the national grid, both through the large number of additional connections that will need to be enabled and, subsequently, through managing the potentially steep peaks and troughs of daily generation and usage.

FSB's view is that Government should focus investment in new technology and innovation that takes pressure off the national grid. Energy storage is discussed in more detail below, but it is clear that a suite of measures will be required to manage supply and demand.

FSB believes that **microgeneration** and community energy schemes will play a critical role in this, particularly if they are incentivised to sell directly to their neighbours rather than to the grid itself.

Energy efficiency will also play an important role in managing grid capacity. For smaller businesses, it is also the single best way of reducing energy bills. FSB has engaged with Government around how best to promote efficiency among businesses. However, if you cannot monitor usage, you cannot manage it. As smart meters are rolled out across the UK, FSB remains concerned that this new infrastructure may not lead to real energy reduction without a clear strategy for ongoing customer engagement and empowerment. The implementation of smart metering must also enable the introduction and promotion of management and intervention technology, without which they cannot achieve their aim of reducing and managing energy use.

Demand Side Management in the UK energy market needs radical development. **Time of use tariffs** will undoubtedly take on increasing importance as grid infrastructure becomes more stressed. Some businesses are already accustomed to time of use charges, but many smaller firms will not be. Going forward, their ability to take advantage of these charges will be dependent on the equipment they rely on, the development of new technology and smart appliances, and the degree to which they can introduce flexibility into their day-to-day activities. It is clear that some businesses will be more able to take advantage of time of use charges than others, depending on the nature of their operation. FSB also raises caution that many businesses operate on different cycles to the average domestic customer. So a one size fits all approach to time of use charges will not work. In order to drive behaviour change, the market will need to provide not only a price disincentive against using energy at certain times, but also a clear pathway for achieving this. For instance, it may be prudent to consider a recommendation for all users above a certain energy threshold to implement storage and management systems that allow them to run 'off line' at certain times of the day

In addition to cost indicators, **education** will play a role in managing capacity. In Italy, public education to reduce the use of large capacity equipment at peak times, or in combination with other equipment, has achieved success in reducing the risk of power cuts.

At a macro-scale, the **capacity market** is responsible for driving investment in technology that helps to manage supply and demand. However, it is clear that, in some areas, this framework can be a hindrance as much as a help. For instance, there is evidence of large-scale inefficiency in the way that Distribution Network Operators (DNOs) manage their reserve capacity, largely because of uncertainty about future availability.

Under current arrangements, capacity is reserved at vacant properties due to the risk of a lack of availability once the property is re-occupied. This process can distort the calculation about how much demand is required, or available, in a specific area. This is particularly important in a situation where a business applies to increase its capacity. Currently, if such a request would push the local substation over the total available capacity allocated, then that business would have to fund the upgrade cost to that substation. We believe this situation is unfair, particularly since such investment provides clear benefits to the wider community. However, setting issues of fairness aside, these costs are still particularly difficult to justify if, in reality, the available spare capacity has been deliberately under-estimated for the reasons set out above. The available capacity, as well as committed generation, should be available in real time, and should take account of planned re-enforcement works.

Neither the Distribution Network Operators (DNOs) or National Grid have moved at the expected level or pace that we expected, given that they are the first point of call for demand and load-based applications. There is a lack of clarity around responsibilities for aspects of planning, funding and implementation – and therefore where the delays are occurring – between DNOs, National grid and Ofgem. We would like to see improved clarity and delineation around these roles and responsibilities.

2. What are the barriers to the deployment of energy storage capacity?

Compared to other technologies, the Government has appeared reluctant to explore the potential of storage, highlighted by the lack of subsidies on offer to speed up investment in research and development in this area. Storage has traditionally been seen as overly-expensive or too under-developed. Yet, in a low carbon future, storage will be the key to enabling the UK's renewable technologies to flourish.

Some technologies have developed more quickly than others. Battery Storage costs are reducing by 8 per cent a year. Hydrogen fuel cell technology is being used widely in places like Germany and has shown potential for providing base load and reducing pressure on the national grid. Hydrogen appears to have a number of advantages over other technologies, including scale, seasonal range and versatility. By transferring "power to gas", excess capacity from the grid can be used to produce hydrogen via electrolysis, which can then be stored. This is an example of where new technologies can take pressure off the grid, rather than add to it. Many of these technologies are tried and tested and scalable.

Other Questions

What is the most appropriate scale for future energy storage technologies in the UK (i.e. transmission network scale, the distributed network or the domestic scale)?

The scale of storage technologies must be appropriate for their specific location. For example, where there are bulk or industry users, CHP or Hydrogen (piped or tanked) may be a solution. However, for a small village with no industry, battery on a UPS level, supported by solar and wind may be more appropriate.

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

We would like to see a greater level of engagement between National Grid and DNOs in this country with their European counterparts so that common goals can be identified and addressed. There is little evidence of this happening currently.

I hope this helps to adequately clarify FSB's position. If you would like any further information or input from FSB, please do contact our energy policy advisor, Andy Poole, at [email address redacted]

Yours sincerely,

Mike Cherry AIMMM FRSA
Policy Director

Gaelectric Holdings Plc.

Response Paper to:

National Infrastructure Commission call for evidence

Relating to; 4. Electricity Interconnection and Storage

08/01/2016

Public

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1 EXECUTIVE SUMMARY

Gaelectric Holdings Plc ("Gaelectric") welcome the opportunity to respond to the National Infrastructure Commission's ("NIC") call for evidence relating the long-term infrastructure needs of the UK. Gaelectric's response related specifically to the NICs 3rd stated challenge; namely "improving how electricity demand and supply are balanced". Our focus in this response is primarily associated with the development of energy storage in the UK.

Our response focuses on the need to clarify the treatment of energy storage, and to explore potential for commercial and regulatory changes or incentives which would create a level playing field for energy storage. Gaelectric have previously engaged with Ofgem, National Grid and DECC relating to the need for energy storage and the barriers to entry that we perceive in our experience developing projects in the UK and Ireland.

Gaelectric are encouraged by the NIC, Ofgem and DECCs consideration of the need to understand the benefits of energy storage in an attempt to address the challenges in developing the business model for storage in the UK. Specifically we are following with particular interest the Flexibility Project launched by Ofgem in January 2015[1] and subsequently the report issued in December 2015 by Ofgem in relation to the Smart Grid Forum, specifically work-stream 6 which has identified a number of key enablers for energy storage and distributed generation[2].

There are a number of other workstreams ongoing which are encouraging the development and understanding of energy storage such as Smarter Network Storage Project which has identified a number of key challenges for energy storage in the UK.

Currently energy storage is not appropriately classified from a regulatory standpoint. Energy storage is neither a normal generator nor major load centre and should not therefore be treated as such. We believe that energy storage should have a distinct regulatory classification given its unique operating characteristics and benefit to the system.

The lack of direction in regard to the regulatory classification of energy storage has, in our opinion, led to inefficiency in the connection and operation for energy storage assets in the UK. Specifically Gaelectric have previously raised concern relating to double charging and commercial challenges to the operation of energy storage which prevent the emergence of a business model which remunerates energy storage for alleviating constraints and mitigates the need for T&D upgrades (either completely or by extending the life-span of existing infrastructure).

We believe a holistic approach is required to mitigate these concerns which encompasses direction for connection policy, review of ancillary service provision and their associated contractual arrangements and the treatment of the ownership model of energy storage assets.

It is clear that there is a considerable amount of work being undertaken at present to consider means to incentivise energy storage, which we fully support. We have been disappointed that over the last

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[1] https://www.ofgem.gov.uk/publications-and-updates/open-letter-facilitating-efficient-use-flexibility-sources-gb-electricity-system

[2] https://www.ofgem.gov.uk/electricity/distribution-networks/forums-seminars-and-working-groups/decc-ofgem-smart-grid-forum/workstream-six-ws6-commercial-and-regulatory-issues

number of years these work programmes have resulted in no significant investment in energy storage at commercial scale due to the apparent barriers to entry within the market. By way of example, the capacity market was developed to incentivise plants to stay online and for new plants to develop in order to manage the capacity shortage that was envisaged over the coming decade. Notwithstanding this, Trafford power station aside, no significant new entrants and no new energy storage projects have been in a position to clear the auction. It is widely considered that clearing prices (£19.40/kW 2014, £18/kW 2015) are too low to support new investment. We believe it is now critical that the research and development programmes designed to develop storage will lead to commercial signals to carry that development into investable programmes.

In summary of our response, we make the following points;

- Energy Storage requires a distinct regulatory classification as opposed to being treated as generation or end-user.
- Double charging of levies which are imposed on energy storage should not continue.
- Energy storage should be able to access flexible grid connections and be remunerated for provision of T&D deferral services.
- Co-location of energy storage and Government supported renewables must be accommodated.
- Long term contracts for energy storage are required to create a level playing field with incumbent service providers.

1.1 Introduction to Gaelectric

Gaelectric is an independent wind, energy storage, solar and biomass developer operating within the Republic of Ireland, Northern Ireland, United Kingdom and North America. To date Gaelectric holds approximately 175MW of generating assets across 9 projects in Northern Ireland and the Republic of Ireland, and a further 40MW of 'shovel ready' projects with grid connections and full planning approvals in place. Gaelectric's near term pipeline on the island of Ireland is circa 320MW with the expectation that the company will have 400MW of wind projects generating power by the end of 2017.

Our energy storage division is currently developing Project CAES, Larne NI ("Project CAES"), a Compressed Air Energy Storage plant with a capability of 330MW of generation and 250MW of demand, both sources providing inertia to the system.

Compressed Air Energy Storage is a commercially proven technology which has been in operation since 1978 in Huntorf, Germany and since 1991 in Alabama, United States. CAES has a strong technical ability and Gaelectric have shown that it is capable of providing substantial performance and flexibility in energy and ancillary services markets, being particularly proficient in the fast frequency response products.

PMCA Consulting has carried out an independent economic impact assessment of the likely economic and socio-economic benefits in respect of the implementation of Project CAES in Larne, Co. Antrim.

The analysis found that system production cost savings from Project CAES to the SEM would range between £32m - £52m per annum, depending on the rate of progress regarding the adoption of renewable energies on the island of Ireland[3].

Project CAES has been designated as a Project of Common Interest ("PCI") by the European Commission and further recommended for grant funding of up to €6.5 million under the Connecting Europe Facility[4]. The project is the only CAES PCI in Europe and the only electricity storage PCI on the island of Ireland, the UK and the Northern Seas Offshore Group of PCIs.

Gaelectric are further assessing the opportunity for the development of CAES in the UK with sites identified and analyses undertaken with respect to grid infrastructure and connection options. We continue to assess the commercial opportunity for such a project and hence look forward to engaging closely with all relevant stakeholders in addressing the barriers to entry for such a project.

Further to our development of Project CAES, Gaelectric and Tesla have announced the purchase and planned deployment of Tesla Energy's first battery power utility-scale project in Ireland, and we expect to develop MW scale demonstration project in 2016 in the Single Electricity Market (SEM) before expanding development throughout Ireland, the UK and Europe.

Both Project CAES and future battery installations will be designed in a manner which maximises ancillary service provision and can be utilised for flexible balancing of the system by TSOs, constraint management and the provision of capacity to the system.

[3] http://www.gaelectric.ie/wpx/wp-content/uploads/2015/09/107715-Galectric-FTI-Booklet.pdf
[4] http://www.gaelectric.ie/energy-storage-projects/project-caes-larne-ni/

2 CONSULTATION RESPONSE

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Gaelectric are of the view that more work is required to develop commercial incentives recommended in the assessment of projects such as the Smarter Network Storage Project and the Flexibility Project.

This includes the use of energy storage as a tool which can alleviate constraints and mitigate the need for costly T&D upgrades. We recommend therefore that assessment is made on the remuneration for energy storage assets which are connected to the system with a view to supporting T&D deferrals. The development of specific ancillary services is therefore integral. We echo the recommendations of the Smart Grid Forum (workstream 6) which identified that long term contracts for energy storage operators are required to create a “level playing field”.

In respect of the development of independent system operators, our concern mainly relates to the ability of system operators to contract with, and perhaps own, such assets and the regulatory barriers which exist for such activities.

In addition to the need for T&D deferrals, we believe that the flexibility of energy storage assets to provide fast acting balancing services should be strongly considered, and avenues to accommodate co-location of such assets with intermittent generation be explored.

Currently we understand that the co-location of renewable generation which is supported under a renewable support scheme is complicated by the potential impact of this co-location on the support provided to the renewable generator. The Smart Grid Forum also recommended that DECC and Ofgem produce guidance on the applicability of support renewables and storage to be co-located given the clear efficiency (in terms of both balancing and maximisation of capacity at grid connections).

2. What are the barriers to the deployment of energy storage capacity?

<u>Regulatory Classification</u>

Gaelectric have identified a number of barriers to entry to energy storage projects in the UK. Our primary concern relates to the regulatory classification of energy storage. Storage is neither normal generation nor a substantial load, and is not an end-user despite being treated as such.

The lack of clarification on the regulatory treatment of energy storage has resulted in the perverse treatment of the asset class in regard to charging, remuneration and contracting and ownership models.

The use of storage by Transmission/Distribution Network Operators is limited by the fact that storage is licenced as a generation activity as opposed to a storage specific licence. European Regulations prohibit DNOs from operating generation activities, however were storage to be licenced separately, this barrier would be removed.

Charging Methodology

Furthermore, under the current regime, the Balancing System Use of Service (BSUoS) charges represent a double charge (demand and generation) for energy storage. In addition, the Smart Grid Forum workstream 6 report stated the following;

"Electricity Storage may be double-charged for both import and export in terms of levies related to sustainability. A specific exemption for a single project has been issued by HMRC so that storage is exempt from paying the Climate Change Levy, but this approach needs to be standardised for all storage projects. Likewise there is double charging of the FiT obligation to suppliers (on entering storage and on leaving storage to the end user)"

And further;

"What is needed is the assurance that this ruling by HMRC is applicable to all future storage projects."

Double charging in effect creates an undue barrier to entry when energy storage is compared to conventional generation. We believe this is as a result of the treatment of energy storage as an end-user rather than a distinct regulatory activity. We recommend that the recommendation made above is acted upon and that the double charging of energy storage is no longer applied.

T&D Deferral Opportunity

Energy storage has been shown to alleviate constraints on electricity systems and can result in significant T&D deferral by supporting infrastructure in two ways;

a) By negating the requirement to build expensive infrastructure, or
b) By extending the life-span of the existing infrastructure.

Gaelectric therefore make 2 recommendations. Firstly we believe that flexible connection policies should be extended to include and consider energy storage such that energy storage can avail of flexible connections for the provision of a T&D deferral service or indeed to mitigate the need for generator cycling and manage peak shaving activities.

Related to this is the need to ensure that commercial incentives exist to remunerate storage operators for providing T&D deferral services. Currently there is no accessible revenue stream available to storage for providing such a service despite their being a very clear system benefit of doing-so. We recommend consideration of both the flexible grid connection policy and commercial incentives for the provision of T&D deferral services.

Co-location with Government supported renewable energy

As outlined in response to Q1, Gaelectric have identified concerns in relation to the co-location of energy storage and renewable electricity in receipt of government supports. The joint operation of energy storage and such renewables creates a risk of adverse effects on the support scheme for the renewable generator despite that this would often result in the more efficient use of grid capacity, minimising imbalances and providing ancillary services in key areas of the system.

Gaelectric

Ancillary Services Provision

It is a widely agreed position that new investment requires long term contracts in order for it to be able to compete on a level playing field with incumbent generation. This position is clearly understood by the Government given the use of 15 year contracts for capacity contracts and Renewable Obligation and Contract for Difference contracts.

Currently the ancillary service market, contracts are typically short term in nature and do not therefore support new investment. This issue is exacerbated by the fact that the capacity market has not created an incentive to support new energy storage and is widely considered as a market which will not support significant new capacity as will be required by the UK.

We recommend consideration of longer term contracts and transparent procurement of all ancillary services in the UK.

3 CONCLUSION

Gaelectric welcome the investigation by the NIC relating to energy storage and its assessment of the barriers to entry for such technology. We were encourage by Amber Rudd's comments of 18th November which she stated;

"We are also looking at removing other regulations that are holding back smart solutions, such as demand side response and storage."

The Smart Grid Forum has in its workstream 6 recommendations paper, made a number of wide ranging proposals which aim to break down the barriers to the development of energy storage and which assesses commercial incentives which can be progressed to create a level playing field for energy storage in the market. Gaelectric support such endeavours.

In our response we have highlighted a number of key areas which require immediate review including but not limited to;

- A requirement for appropriate regulatory classification of energy storage activities
- The need to ensure that double charging in levies is eradicated for energy storage
- The requirement to ensure that energy storage can access flexible grid connections which further compensate the technology for supporting T&D deferral.
- The need to support the co-location of energy storage and government supported renewables such that balancing requirements are reduced, system service provision is enhanced and the most is being made of grid capacity.
- Our assessment that long term contracts are required to ensure a level playing field in regard to ancillary service provision.

We look forward to engaging further with all relevant stakeholders in relation to the development of the business model for energy storage, primarily via the removal of barriers to entry which we have identified in this paper.

Should you have any queries in relation to this response, please do not hesitate to contact us.

GE RESPONSE TO NATIONAL INFRASTRUCTURE COMMISSION CONSULTATION, 8 JANUARY 2016

1. This response focuses solely on the energy policy questions in the Commission's call for evidence.

Context

2. In principle, GE favours a liberalised market approach, with, if necessary, time limited interventions to address clear market failures. We are also in favour of consistent policies across Europe, rather than a patchwork of conflicting national approaches, which create investment uncertainty and raise costs.

3. GE welcomes the Commission's focus on energy infrastructure. The GB electricity system is changing which presents new challenges to system security. Large, dispatchable thermal generation is being replaced by low carbon, smaller, and largely variable generation. As recent analysis by the Committee on Climate Change (CCC) has shown, the lowest-cost trajectory to the UK's legally binding carbon targets requires that the carbon intensity of power generation decreases to below 100 g/kWh in 2030, with low-carbon generation producing around 75% of generation. Managing the system will no longer be handled solely through the energy market (wholesale and balancing) and ancillary services. Flexible generation, demand side response, interconnection and storage will all be important. The CCC's analysis shows that increased flexibility is a low-regret option, with savings of at least £2.9bn p.a to 2030.

Questions

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

a) What role can changes to the market framework play to incentivise this outcome?
c) Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

4. The existing arrangements to ensure that demand is balanced with generation include:

   - **Bilateral trading or power exchanges**: generators and suppliers buy and sell power in the forward, day ahead and spot wholesale electricity markets. All transactions are notified to the System Operator. After 'gate closure' generators and suppliers use the Balancing Market to ensure that individual positions are balanced.

   - **Ancillary Services**: the System Operator (National Grid) has a number of ancillary services which can be used to balance the system.

5. We support the recent Ofgem reforms to ensure that cash-out prices respond more sharply to system imbalances. The changes should ensure that flexibility is better valued in the Balancing Market. However, it also poses risks to market participants, particularly those smaller players more at risk of being out of balance. It is therefore important that the cash-out changes are monitored closely before making any further changes.

6. We would support moving to shorter term settlement periods (e.g. 15 minutes) to reduce averaging of over and under supply by suppliers which can occur in the current 30 minute settlement period.

7. With renewables, the forecast error on a single wind turbine will be very high, on a wind farm smaller, on wind in a region even smaller, and on the whole GB wind fleet, the forecast error is very small. It is important therefore that the forecast error of the whole GB wind fleet is considered in any imbalance of wind, not the forecast error of a small part of that wind fleet.

European level

8. There are changes taking place at a European level which will affect the GB's balancing arrangements. The EU is expected to push for the alignment of national balancing markets, through the EU Electricity Balancing Network Code, which could become legally binding in the next 2-3 years. This will move Europe away from a position in which most balancing is carried out on a national level, which should bring down costs and enhance security of supply.

b) Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

9. Yes. An Independent System Operator (ISO) would have merit in being clearly independent or any network asset owners. An ISO would not have any incentive to build transmission and could judge each proposed transmission and interconnector project on its merit. It could also assess the options for interconnectors to reduce transmission constraints.

d) To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

10. Demand-side management needs strongly variable pricing to be worthwhile. This is achieved in parts of USA with locational marginal pricing (LMP) which creates large price spikes and troughs. The GB market is at the opposite end of the spectrum to LMP with one price zone for the whole market. An example of a halfway house is the NordPool market, which has a similar volume to GB, but with 14 price zones.

2. What are the barriers to the deployment of energy storage capacity?
a) Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
b) What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

11. Energy storage systems have the potential for significant cost reductions over the coming years, growing to be a $6 billion dollar global market by 2020. GE's energy storage solutions are already present in 25 countries with over 50 megawatt hours (MWh) of grid storage installed in a variety of applications (see more at: https://renewables.gepower.com/energy-storage

12. GE specialises in bringing technologies together to configure custom solutions for a variety of applications, including:
    - **Energy management**: peak demand reduction, back-up, photo-voltaic (PV) self-consumption, power quality.
    - **Transmission and distribution**: capacity management, asset deferral, frequency regulation, harmonic suppression, voltage support, and power quality.
    - **Microgrid applications**: grid management, PV integration, and grid enhancement.
    - **Thermal and renewable power generation**: virtual spin (no emissions), ramp rate control, frequency regulation, time shifting, voltage support, curtailment avoidance.

13. Energy storage is now becoming more accepted by the market. This has been helped by reasonable size technology demonstrators and electric vehicles, amongst others. But education of developers, transmission system operators (TSOs), distribution network operators (DNOs) and investors is still very much needed to keep this market acceptance growing.

14. In the UK, there appears to be a disconnect between NGET (National Grid Electricity Transmission) and potential developers as to where best to integrate energy storage systems (ESS). This is because NGET need active power from the ESS on to the transmission grid to support frequency. However, if the ESS is connected via the distribution network, there may be additional usage fees applied to the ESS by the distribution network operator (DNO). Furthermore, there are potentially times that the distribution network may be at full capacity, meaning that the ESS is not available for the EFR (error and failure resolution) services, leaving a question of who pays for unavailability. The DS3 process in Ireland covers a huge number of similar issues, though we understand that there are no formal discussions between EirGrid and National Grid at present. Perhaps this could be initiated in order to share knowledge?

15. If we look at the price for an ESS project, a large part of the cost is batteries. These costs are starting to fall; within three years, battery costs are expected to decrease by up to 30%. This means that larger systems can be considered. However, there are significant site and grid connection costs. As installations grow in size, the amount of equipment and the necessary cooling are best managed within a purpose built substation. NGET has suggested that a 50MW block is the largest they expect at any one location. But the substation and 400kV connection costs are almost the same as for a 200MW installation. This may be a problematic for developers and their business cases.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

a) **Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**
b) **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

16. Interconnection capacity was only 6% of the UK's installed capacity in 2014 (21st out of 28 EU member states). The UK is clearly under-connected with its neighbours and greater levels of interconnection would be in the interests of consumers. The exact level of interconnection should be left to the market, but we note that the European Council agreed a target for countries to achieve 15% interconnection capacity by 2030. That would seem to be a minimum level that the UK could achieve by the end of the next decade.

17. While there is a strong pipeline of planned interconnectors, the current regime alone is unlikely to lead to an optimal level of interconnection for British consumers. There is a case for building more rapidly than the Cap & Floor (C&F) regime can deliver. C&F requires sufficient market price differences between the connected markets to provide financial certainty to investors many years ahead. It takes around 5 years to develop an interconnector and around 4 years to build it, with the investors relying on forecasts for 10-20 years after that. This high risk approach can drive interconnection where there is a severe shortage, but will otherwise result in a sub-optimal level of interconnection. Under C&F, investors will only be tempted by to take long-term, high risks against a very strong forecast revenue stream. In addition, future changes to market price zones (e.g. under CACM) could create, or destroy, value overnight. Interconnectors should have the option of being fully regulated, as is the case for onshore transmission assets.

18. Even where price zones in two markets are mostly coupled (i.e. equal) there can still be value in interconnection as the lowest cost way of overcoming transmission bottlenecks. For example we already see different percentage flows and directions on EWIC and Moyle, which connect the GB BETTA and Irish SEM markets. These flows indicate that the interconnectors are being utilised to solve transmission bottlenecks in Ireland or in GB.

19. Historically, interconnection has been much more expensive than reinforcing onshore transmission networks. However, we now see that trend reversing due to the difficulty of building new overhead power lines onshore. For example, National Grid and Scottish Power are increasing north-south GB capacity through the offshore, subsea, Western Link (West Coast Bootstrap) at a cost of over £1billion. With development of subsea cables and HVDC technology, relative costs for interconnection are falling compared to other onshore reinforcement options.

20. Reinforcements across transmission operators are facilitated by the regulatory regime with e.g. Kintyre, Beauly Denny, and Western Bootstrap. National transmission reinforcements are prioritised and treated differently to interconnectors. An independent system operator – free from any transmission or interconnector asset ownership - would help to identify and assess new assets for development and funding. Ofgem has created C&F to put risk on developers; however, developers will not be able to bring projects forward if that risk is not rewarded. A completely independent SO would help give Ofgem greater confidence in assessing new interconnector proposals and giving those projects a regulated financial regime.

21. Onshore transmission operators are paid for developing onshore transmission assets (they are reimbursed their costs from consumers) including shared assets between TOs (such as the Western Link). There is currently no such cost recovery for interconnector developers, resulting in a reducing incentive over time to develop new projects.

22. Interconnection faces specific barriers and challenges that are not faced by other balancing technologies. It is cross-border by nature, which means dealing with multiple jurisdictions and plays multiple roles in the energy system beyond system balancing alone.

23. On specific market failures/barriers, we would highlight the following points:

- The capacity mechanism should be reformed to incentivise new interconnectors. Although interconnectors were eligible to bid in the recent auction, the clearing price was too low for new build. Long term capacity payments are required over 15 years to provide the certainty to enable financing interconnector projects. Making annual payments will not provide sufficient certainty to finance new interconnector capacity.

- Interconnectors have a much longer lead time than most generation projects due to the HVDC technology and dealing with permitting regimes in at least two jurisdictions. The capacity mechanism should be able to contract years ahead for interconnectors so that new interconnectors can be financed accounting for these benefits to GB consumers.

- Interconnectors with Ireland which are often exporting or float should receive capacity payments, as they are far more valuable in addressing system emergencies and imbalances than interconnectors that are importing. Importing interconnectors cannot increase their power into GB if there is an emergency, such as a large power station trip, breakdown, fire or fault. However, exporting interconnectors can reduce exports or start importing and hence support the GB system at times of stress or crisis.

24. In any future with a greater level of interconnection, significantly less generation infrastructure will be needed to deliver a secure, balanced and low-carbon energy system. As more physical interconnectors are built, the costs to UK consumers of ignoring the opportunities to share resources

with European neighbours will become too large to ignore. It is expected that investment in onshore, offshore and cross-border transmission capacity will reach £23bn–£50bn by 2030, which is considerably greater than the entire current Regulated Asset Value of existing GB transmission assets (< £13bn). Any improvements in the network planning process therefore have the potential to deliver considerable savings in the cost of the network infrastructure, while greater integration with the power systems of neighbouring countries has the potential to deliver further savings.

About GE

25. GE is the world's Digital Industrial Company, transforming industry with software-defined machines and solutions that are connected, responsive and predictive. GE is organised around a global exchange of knowledge, the "GE Store," through which each business shares and accesses the same technology, markets, structure and intellect. Each invention further fuels innovation and application across our industrial sectors. GE employs around 22,000 people in the UK. www.ge.com

Contact: [email address redacted]

From: Gilbert, Alyssa R [email address redacted]
Sent: 08 January 2016 16:12
To: EnergyEvidence Infrastructure-Commission
Subject: Submission from Grantham Institute, Imperial College London

Dear Lord Adonis,
As one of the world's leading science and technology universities, many of the academics at Imperial College London are carrying out extensive ongoing research that is relevant to the outstanding questions of the National Infrastructure Commission. In particular, we have several academics with pertinent work and views in relation to the questions posed in the current consultation on electricity interconnection and storage.

Unfortunately, we do not have research that has been designed to answer the precise questions raised in the consultation but we wanted to draw your attention to several bits of recently completed or planned research that will deliver within the timeframe of your investigation.

We would be very interested in sharing more information with you as you progress your investigation and study, and as our relevant work is finalised. We have identified a number of academics who we believe would be well-placed to discuss these issues further with you. We are happy to put you in touch with them, as relevant.

Professor Richard Green, Professor of Sustainable Energy Business, with ongoing research into the impact of low-carbon generation (nuclear and renewables) on the electricity market, and the business and policy implications of this.
Professor Goran Strbac, Chair in Electrical Energy systems has published a recent report for the CCC that is relevant to these issues and that can be found here https://www.theccc.org.uk/wp-content/uploads/2015/10/CCC_Externalities_report_Imperial_Final_21Oct20151.pdf
Dr. Rob Gross, Reader in Energy Policy and Technology, is in the process of undertaking a thoroughgoing meta-analysis of international evidence on the costs and impacts of intermittency (variable generation). This will update the benchmark UKERC (UK Energy Research Centre) review of the topic undertaken in 2006. The report is relevant to many of the questions in the enquiry, scoping note, further details and earlier work can be found at. http://www.ukerc.ac.uk/programmes/technology-and-policy-assessment/the-costs-and-impacts-of-intermittency-ii.html
Ajay Gambhir and Sheridan Few at the Grantham Institute for Climate change and the Environment, are carrying out extensive research on the current state of specific energy storage technologies, with varying scales of application. This work will be completed by May 2016 and could feed into your study.

We hope to be in touch with you further as your work progresses.

Best wishes,
Alyssa

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National Infrastructure Commission call for evidence

Written submission by Green Alliance, January 2016

Green Alliance welcomes the National Infrastructure Commission's call for evidence. In particular, we believe that new initiatives can help to ensure the UK realises the potential of electricity efficiency to reduce emissions cost effectively and to underpin a secure power system.

We furthermore welcome the recent acknowledgement by the Commission's interim chair, Lord Adonis, of the importance of public dialogue, when he pledged to "ensure that the Commission places the needs and views of the UK public at the heart of a long-term strategy and responds to the clear demand for a more strategic two-way conversation."[i] Bearing this in mind, we note that there does not appear to be any meaningful attempt to engage the public in this first set of activities by the Commission.

We question the scope of Part 4 of the call for evidence: the energy section focuses entirely on the objective of security of supply, with no mention of carbon constraints or environmental impacts. To achieve the UK's legislated carbon budgets and to ensure the UK plays its part in global efforts to tackle climate change, carbon considerations must be at the heart of all major infrastructure plans. Any new infrastructure that is built to last will have to facilitate a very low carbon economy.

Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Our work on electricity efficiency savings – negawatts – demonstrates that very substantial cost and carbon savings can be achieved by adopting tried and tested policies used in Texas, California and New England to incentivise the use of energy saving products and systems instead of constructing new power stations. If the government were to adopt these policies, it could reduce the cost of decarbonisation by more than £2 billion by 2025, and keep the UK on the least cost pathway to meeting its carbon budgets.

A key priority for the government should be to allow low cost demand reduction and response to compete with higher cost power stations in the electricity market. Yet current market biases create a perverse effect: the UK pays to keep polluting coal-fired power stations in operation, via the capacity market, and then pays again for low carbon technology to displace them, via contracts for difference for low carbon power. Previous approaches to incentivising electricity efficiency have failed to deliver significant results, primarily because they don't allow the demand side to compete with the supply side.

Meanwhile, the most effective existing approach, the European Ecodesign mechanism, has been slow to deliver electricity savings because it only applies to new products, so its uptake is necessarily limited by the natural replacement rate of products in the market.[ii] In the US, incentives to purchase energy efficient appliances have been used alongside product efficiency standards to good effect.[iii]

Obligations like CERT and CESP have had significant effects because they featured targets and penalties, and gave flexibility to suppliers about how precisely to find savings. However, suppliers have been very slow to reorient their business models towards delivering energy services, because they are unable to profit from their obligations. The result has been good delivery of measures, but limited innovation and competition. Our view is that a feed-in tariff, supporting efficiency aggregators to offer energy services, would overcome this weakness.

Enabling efficiency aggregators to seek out electricity savings from other companies would help to address the well known behavioural barriers that companies face, including the fact that "efficiency improvements are competing for management attention with other potential investments that also have powerful business cases, often in groups looking to allocate investment between different countries as well as different priorities. Energy costs make up less than five per cent of overheads for three quarters of companies; something more than price is needed to bring energy to the attention of those business leaders."[iv]

Permanent electricity demand reduction (EDR) measures are available at £30 per MWh, and can compete with new power stations, which cost a minimum of £76 per MWh.[v] But EDR measures are only currently procured via the EDR pilot, which is very small and can only incentivise a tiny fraction of the UK's technical potential for negawatts. The government's conservative estimate is that almost 39 TWh, around ten per cent of the country's total electricity demand, could be reduced by 2030.[vi]

The first mechanism we recommend, therefore, is a **negawatts feed-in tariff,** to be paid on the basis of avoided energy consumption, with recipients competing in an auction to deliver energy savings in homes and businesses at lowest cost. It would keep the UK on the least cost, long term decarbonisation trajectory by reducing electricity demand by 6.4 GW by 2030, equivalent to the capacity of eight 800 MW combined cycle gas turbine (CCGT) power stations. We calculate that the ensuing investment in electricity demand reduction alone could yield net savings to British consumers of £2.4 billion by 2025.

Alongside EDR, demand side response (DSR), which temporarily brings down power demand at peak times, can also play an important role in ensuring that supply and demand are balanced, whilst minimising cost to consumers. Evidence presented to the Energy and Climate Change Committee suggests that, if DSR were allowed to compete on equal terms, it would save bill payers up to £359 million in the first year alone.[vii]

The US experience proves that DSR is an effective means of keeping the lights on. In the PJM market on the east coast of the United States, a market with three times the electricity demand of the UK, 15 GW, or nine per cent of total capacity in 2015-16, will be provided by DSR. Demand response kept the lights on during the 2014 'polar vortex' in the US, when old coal-fired power stations stopped because their coal stacks had frozen solid. In New England, EDR and DSR have proved so reliable that the system operator was confident enough to avoid investing $260 million (£156 million) in grid upgrades.

In the UK, DSR and EDR measures are generally excluded from equal participation in the capacity market. Instead, they are required to meet additionality criteria that generation does not have to meet, and are only able to access short term contracts, unlike generators who can receive 15 year contracts. In contrast, in US electricity efficiency markets, co-ordinated by PJM and ISO-NE, projects only have to prove that they will reduce peak demand: that's what the capacity payment is for. The evidence from the US is that negawatts out-compete power stations on price, when they are treated equally with generation, and can access multiple sources of funding.

Our second recommended mechanism is therefore to **open up the capacity market,** to allow competition from demand side response and energy demand reduction on an equal basis with electricity generation. This could bring forward 6 GW of additional load shifting and reduction by 2023, covering most of the coal capacity deficit created by the prime minister's pledge to phase out unabated coal.

An electricity efficiency strategy incorporating the above recommendations could address major market distortions. As it stands, the UK market is skewed strongly towards creating new sources of electricity supply to meet demand. Energy companies can only really make money by selling more energy and therefore pushing up bills unnecessarily. Because energy saving services can't compete on equal terms, only a third of one per cent of UK peak demand is currently being met by negawatts.

A well designed strategy would enable innovative companies to develop new business models that aggregate the delivery of energy efficiency measures, and compete with power stations to deliver the energy services consumers want on the most cost effective basis. Aggregators, enabled to profit from selling negawatts in a market framework, would actively seek out efficiency opportunities from households and businesses.

Our recent report, *Getting more from less: realising the potential of negawatts in the UK electricity market,* presents evidence to support the above argument and discusses the recommendations in detail. Link: www.green-alliance.org.uk/getting_more_from_less.php

Contact

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Green Alliance is a registered charity number 1045395
Company Limited by guarantee, registered number 3037633

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[i] Lord Adonis, Foreword in *Independent survey of attitudes to infrastructure in Great Britain*, December 2015 http://www.copperconsultancy.com/wp-content/uploads/2015/12/20151203_Attitudes-to-infrastructure-in-Great-Britain-2015_FINAL-PDF.pdf

[ii] Green Alliance, *Cutting Britain's Energy Bill: making the most of product efficiency standards*, 2012, available from http://www.green-alliance.org.uk/resources/Cutting%20Britain's%20energy%20bill.pdf

[iii] Green Alliance, *Creating a market for electricity savings: paying for energy efficiency through the Energy Bill*, 2012, available from http://www.green-alliance.org.uk/resources/Creating%20a%20Market%20for%20Electricity%20Savings.pdf

[iv] EEF, *The low-carbon economy – moving from stick to carrot*, 2015, available from www.eef.org.uk/resources-and-knowledge/research-and-intelligence/industry-reports/the-low-carbon-economy-moving-from-stick-to-carrot

[v] The most recent study from Bloomberg New Energy Finance identified a cost of $115/MWh for new CCGT, converted to £76/MWh, exchange rate as of 6 October 2015, www.prnewswire.com/newsreleases/wind-and-solar-boost-costcompetitiveness-versus-fossilfuels-300154606.html

[vi] Green Alliance, *Kickstarting the negawatts market: How to make sure the electricity demand reduction pilot succeeds*, 2014, available from http://www.green-alliance.org.uk/resources/Kickstarting_negawatts.pdf

[vii] Letter to Rt Hon Matt Hancock MP, minister of state at DECC, from Tim Yeo MP, chair of the Energy and Climate Change Committee, 9 September 2015, www.parliament.uk/documents/commons-committees/energy-andclimate-change/Matthew-Hancock-090914-DSR-Cap-Market-letter.pdf

GREENPEACE

Submission to the National infrastructure Commission Call for Evidence

Improving how electricity demand and supply are balanced

Greenpeace has a longstanding interest in the energy system because of its widespread impacts, especially through climate change. We have written extensively about potential changes of new storage technology[1]. We welcome the fact that the newly formed NIC is looking at new opportunities for supply and demand balancing.

Demand Side response and system costs

We notice that sometimes this call for evidence is titled demand and supply balancing but at other times being principally about interconnection and storage as the major foci. We are very supportive of both storage and interconnection, but also believe demand side management is critical. All of these tools will be important in ensuring grid balancing. This is because there is a high likelihood that significant power sector decarbonisation (like the carbon intensity target for the UK of 50-100gCO2/kWh proposed by the Climate Change Committee) will be met substantially by renewable energy. The other key low-carbon technologies are struggling: Carbon Capture and Storage has suffered a major setback with a second competition for public funds being cancelled – meaning any further competition or mechanism for awarding funds is unlikely to be taken seriously – whilst nuclear power continues to be many years away and subject to substantial delivery risks as identified by Sussex Energy Group[2], National Audit Office[3] and other commentators such as the Financial Times[4].

Under circumstances of high renewables penetration, all forms of balancing are helpful. Specifically, the analysis that Greenpeace commissioned for UK demonstrates that DSR is an important tool for delivering power sector decarbonisation, alongside interconnection, some storage, and a proper integration of thermal generation with heating needs[5] – notably under these circumstances, a 2030 power system of 85% renewables is possible without new nuclear or CCS, and including substantial electrification of both heat and transport. Similar studies for the US have emphasised the role of

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[1] The solar storage energy revolution is arriving, Doug Parr, Greenpeace, April 2015 http://energydesk.greenpeace.org/2015/04/27/comment-the-solar-storage-energy-revolution-is-arriving/

[2] Whither Energy policy, Sussex Energy Group, Dec 2015 https://blogs.sussex.ac.uk/sussexenergygroup/2015/12/09/whither-uk-energy-policy/

[3] Over a third of major infrastructure projects branded 'undeliverable' or 'in doubt', report finds, Jan 2015 http://www.telegraph.co.uk/active/12083669/Over-a-third-of-major-infrastructure-projects-branded-undeliverable-or-in-doubt-report-finds.html

[4]Beyond Hinkley — the need for a plan B, October 2015, http://blogs.ft.com/nick-butler/2015/10/21/beyond-hinkley-the-need-for-a-plan-b/

[5] 4 ways the UK can get almost all its power from renewables – without Hinkley, Sept 2015 http://energydesk.greenpeace.org/2015/09/21/4-ways-the-uk-can-get-almost-all-its-power-from-renewables/
Full report: Greenpeace 2030 Energy Scenario, Sept 2015 http://www.demandenergyequality.org/2030-energy-scenario.html

DSR from both Stanford University[6] and Rocky Mountain Institute [7]. In the former, the key balancing agents for their 100% wind, water and solar system are hydrogen production and THERMAL energy storage (rather than power storage). Notably the conventional costs of this system, with supply and demand balanced over every 30 second interval for 6 years, are the same as a 'business as usual' approach to energy provision, but with huge co-benefits on avoided air pollution & climate impacts. The Rocky Mountain Institute study stated that DSR and wider connection is more important than storage in providing for high penetrations of renewable power.

A similar detailed study for the European power system[8] by McKinsey, KEMA and Imperial College showed that by 2030 interconnection and demand side response "shifting up to 10% of daily load in response to availability of supply, decreases the need for grid capacity by 10% and back-up capacity by 35% and thus helps in managing the risk of insufficient grid transmission. Demand response also reduces the volatility of power prices by better matching demand to available supply, reducing volatility by 10–30%".

In terms of overall system costs an earlier study by the same authors[9], again looking at costs across the EU by 2050, indicated that a combination of interconnection, demand side response and storage would deliver system costs at 40% renewables similar to that of 80% renewables. 40% renewables is not far off where we are headed, with renewables expected to contribute approx. 30% to UK system by 2020 and further expansion in wind and solar to take place in 2020s.

Note that both EU studies took place before the sharp drop in solar costs over the past few years.

Specific barriers do exist to DSR: the UK capacity market has been widely criticised as unfriendly to demand side response, even during its development[10]. The Belgian market allows DSR to compete directly with new plant and takes a larger share of the market than the one allocated to it in UK[11].

Innovation

The NIC call for evidence, quite reasonably, asks for evidence on costs. However it needs to be borne in mind that a number of new technologies are coming on stream with costs shifting all the time.

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[6] Low cost solution to grid reliability problem with 1005 penetration of intermittent wind, water and solar, Jacobsen et al, 2015
http://web.stanford.edu/group/efmh/jacobson/Articles/I/CombiningRenew/CONUSGridIntegration.pdf
[7] Is Storage Necessary for Renewable Energy?, August 2014
http://www.engineering.com/ElectronicsDesign/ElectronicsDesignArticles/ArticleID/8272/Is-Storage-Necessary-for-Renewable-Energy.aspx
[8] Power Perspectives 2030, European Climate Foundation, Nov 2011
http://www.roadmap2050.eu/attachments/files/PowerPerspectives2030_FullReport.pdf
[9] Roadmap 2050, European Climate Foundation, April 2010 http://roadmap2050.eu/project/roadmap-2050
[10] Criticism from NGOs: The Energy Bill: Matching supply to demand, Dec 2012
http://www.foe.co.uk/sites/default/files/downloads/matching_supply_demand.pdf. Criticism from Parliamentarians http://www.theguardian.com/environment/cif-green/2011/jan/14/energy-market-reform-plans. See also https://alansenergyblog.wordpress.com/
[11] How to generate 'negawatts' through demand response, Sept 2014. http://utilityweek.co.uk/news/how-to-generate-%E2%80%98negawatts%E2%80%99-through-demand-response/1048152#.Vo6ixvmLTIX

Any framework proposed by NIC should give ample scope for innovation and stress flexibility. Two examples would be:

A) power-to-gas plant. Here intermittent renewable power is converted to gas for storage or later use. Experimental facilities have been set up in Germany and lsewhere[12] and although costs are early stage, we are aware of at least one study in preparation that suggests high levels of cheap onshore renewables with power to gas plat provides cheaper baseload than nuclear[13]. Nor is it clear that power-to-gas plant will necessarily be large scale, as at least one company is looking at plant suitable for individual buildings[14]

B) Northern Power Distribution voltage control technology, which preliminary data suggest if applied across UK could reduce demand at peak times by approximately 4GW[15].

C) Innovation is not simply technology development. Again drawing on the possibilities from demand response, REGEN SW is looking to develop a tariff with Tempus Energy and Wadebridge RE Network to shift power usage to when solar is delivering. But the contractual relationships need to be worked out[16].

D) Business innovation may be delivering 'behind-the-meter' solutions in combinations of solar plus battery storage if low cost finance can be delivered. Here at North Star Solar[17] and Moxia Tech[18].

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[12] The story of storage — and where we go from here, Dec 2014 http://energydesk.greenpeace.org/2014/12/23/story-storage-go/

[13] Michael Freidrich, pers. comm.

[14] New Clean Power Powerhouse: Power-To-Gas Plus Software Defined Power Plants, Dec 2015 http://cleantechnica.com/2015/12/14/new-clean-power-powerhouse-power-gas-plus-software-defined-power-plants/

[15] Why your kettle could take longer to boil when the wind isn't blowing, Aug 2015 http://www.telegraph.co.uk/news/earth/energy/11799573/Why-your-kettle-could-take-longer-to-boil-when-the-wind-isnt-blowing.html

[16] Cornwall experiments with 'sunshine tariff' as possible alternative for UK solar, Oct 2015 http://www.pv-magazine.com/news/details/beitrag/cornwall-experiments-with-sunshine-tariff-as-possible-alternative-for-uk-solar_100021583/#.Vjhy4dSNBIc.twitter

[17] North Star Solar to test solar-plus-storage systems in London boroughs, Dec 2015 http://www.solarpowerportal.co.uk/news/north_star_solar_to_test_solar_plus_storage_systems_in_london_boroughs

[18] http://www.moixatechnology.com/case-studies.php

From: Crispin Dunn-Meynell [email address redacted]
Sent: 15 December 2015 15:25
To: EnergyEvidence Infrastructure-Commission National
Subject: Infrastructure Commission call for evidence

We would urge the Commission to make home energy efficiency an infrastructure priority. In the medium to long term this would both ensure and safeguard the future energy requirements of the UK whilst improving the wellbeing and health of the population.

Regards

Mr Crispin Dunn-Meynell
General Secretary

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NATIONAL INFRASTRUCTURE COMMISSION
CALL FOR EVIDENCE
HULL AND HUMBER RESPONSE

Kingston upon Hull, East Riding of Yorkshire, North East Lincolnshire and North Lincolnshire Councils and the Humber Local Enterprise Partnership welcome the opportunity to respond to the Call for Evidence issued in November by the Commission.

The following provides our joint response to the challenge of Electricity Interconnection and Storage which has a direct impact on economic success and development especially given the continued growth of the Energy Estuary and Renewables Industries in our area.

3. Electricity interconnection and storage

3.1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

It is strongly felt that the current system operator function should remain with National Grid (NGET and NGG), and that any dilution of this would be counterproductive. The incentives currently are related to cost factors, which should remain important, should also be moved to incentives that relate to storage capacity and stimulation and delivery of "negawatts" within the system.

The balancing market should be shifted to ensure that the most is made of renewable energy generation, on a local level, so that transmission losses are reduced to a minimum. The inefficiency in the electricity distribution network, due to transmission losses, needs to be addressed, and significant inroads into this will greatly increase energy security, and reduce the costs for consumers. This can be achieved through greater investment in innovation in business and universities through, for example, Innovate UK, and the creation of local distributive networks.

However, there needs to be flexibility that does not penalise renewable technologies, for periods when the wind does not blow or there are low light levels. This would create a perverse twist in the market and add additional burden to the development and deployment of renewables. The move to a low carbon economy needs to accept this intermittency in part of the energy mix, and storage can help with this. To penalise it, in the same way that would happen for fuels that are causing climate change, does not make any logical or clear policy sense. It is the development of storage that is key to smoothing out fluctuations in generation, and this is where investment and market balancing should be targeted.

We would agree with the publication by Green Alliance[1] , and comments made by the Energy and Climate Change Select Committee, that the Government should create a

[1] The Power of Negawatts Green Alliance October 2012 http://www.green-alliance.org.uk/resources/The%20power%20of%20negawatts.pdf

FIT mechanism for demand side reduction, this can be used to both incentivise business, and domestic investment in storage and energy efficiency investment. The current demand reduction pilot needs to be expanded, and represent better value for money for businesses. It also once the pilot moves to a more mainstream project, which we hope it will, should have more than one auction a year potentially every quarter.

The Government also needs to ensure that the emergency capacity market does not create strange anomalies where diesel generators can out-compete more low carbon options on price without regard to the carbon impact.

3.2. What are the barriers to the deployment of energy storage capacity?

The lack of investment in energy storage capacity at sub-grid level and research, which has the potential to be a significant area for growth and export, lags a long way behind where it needs to be. If we are to achieve the ambitions in the Low Carbon Transitions Plan then we need to increase the development and deployment of the current small scale storage industry. The Government and system operators need to see every renewable technology as an integral part of the mix with storage enabling the smoothing out of fluctuations in generation.

However at present the cost of domestic, community and city scale storage is unaffordable and does not represent value for money at anything but large scale. The Government needs to provide market mechanisms to reduce the initial cost of storage options, and so grow the market place and reduce cost in the long term. The FIT for renewable generation, and the proposed market mechanisms to encourage new gas generation, must also be deployed for storage as has been done in Germany. Homes and offices that generate energy but have surplus would be better storing it for use at peak times thus supporting peak demand reduction as well.

The transition to an electric economy in domestic and transport use requires a significant increase in domestic, community and city storage.

The UK should consider the generation and distribution of energy on a more district heating ethos. In other words, local generation used locally. While we will still need a national generation and distribution network, we need to maximise the benefits of local network storage, to reduce cost for the consumer.

As the energy network of the future needs to be more distributive, then investment must come from Government, National Grid and the DNO's to stimulate the market. The current regulation framework does not appear to incentivise this.

There is the potential for energy companies to develop Power Purchase Agreement solutions for its customers, to increase the spread of single property and community level storage. The current energy system incentivises large scale single point storage, we need to break this to increase energy security, and make the most of UK local generation and reduce interconnector dependencies.

The Government needs to set a national energy storage policy, and target to stimulate the market and put appropriate incentives in place. The storage should be for both power and heat. There also needs to be a clear policy steer on the role of the hydrogen economy, and how power storage and surplus energy, is used for this emerging part of the economy.

The reduction in FIT has had a negative impact in particular, on the potential for community generation in off grid rural and urban locations, we feel this is unfortunate of the Government and runs contrary to localism, devolution and the Community Energy Strategy. For those communities that are off grid in particular, renewables provide potentially the only option to reduce the significant costs of energy, and when these are linked to storage options can create greater energy security and cost reduction for these communities.

3.3. What level of electricity interconnection is likely to be in the best interests of consumers?

There is a concern that a reliance on greater interconnectivity will leave the UK subject to uncertain energy cost increases from other national governments. There is also a concern about over the distance electricity can be transported before the energy losses through transportation defeat the process.

While there is certainly a need for a European interconnector energy system based around the North Sea, because of the potential from offshore wind energy, we need to consider how we can store energy from UK generation to reduce the need for taking supply from interconnectors. There also needs to be an assessment of the vulnerability of energy generated from countries we are connected to in terms of how climate change will affect their ability to generate and supply surplus energy to the UK.

The cost of energy from interconnectors should be cost competitive with that from renewable and other low carbon technologies. Further any energy delivered through interconnectors should only come from low carbon sources. We would not wish to see the UK low carbon transition undermined through carbon intensive interconnection sources.

The development of the offshore renewables industry within Hull and the Humber provides a key opportunity to utilise the technology required to deliver integrated offshore networks which can reasonably be expected to be available, at the ratings required, by around 2020[2]. Hull and the Humber provides a key point of access into

[2] Integrated Offshore Transmission Project (East) – Final Report and Recommendations, 23 December 2015, National Grid,

the national grid along with the potential for greater interconnectivity. As noted in the December report, consideration of the development of the codes, frameworks and charging arrangements is required to facilitate such an approach is vital to maintaining integration as a viable design option, which should also reflect national, regional and local economic demands.

3.4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

We need to look to Copenhagen to see how a city can make the transition to a low carbon future and how this model can be developed within the UK.

For example the City of Hull is perfectly placed for hydrogen generation because of its proximity to the Humber Estuary and River Hull. However, there is no national programme that supports the development of the hydrogen economy, and the role of key port cities, which are ideally place for distribution as well as generation. We would welcome working with the Commission in developing this, as this is an integral part of the storage question and the future electricity generation and storage challenge.

The UK can also learn from Germany, together with the nascent work within the USA, on how to develop domestic energy storage market.

National Infrastructure Commission call for evidence: 'Electricity interconnection and storage'

Evidence submitted by the iBUILD Infrastructure Research Centre, January 2016

Introduction

The iBUILD (**I**nfrastructure **BU**siness models, valuation and **I**nnovation for **L**ocal **D**elivery) Infrastructure Research Centre brings together a multi-disciplinary team from Newcastle, Birmingham and Leeds Universities to improve the delivery of local and urban infrastructure. iBUILD is developing and demonstrating alternative infrastructure business models that: take a whole life cycle view of infrastructure systems; exploit technical and market opportunities from modern interconnected infrastructure; leverage economic, social, environmental, aesthetic and other values from infrastructure; identify changes in governance, regulation and policy to unlock improvements; and, use innovative financing and funding mechanisms.

iBUILD promotes a service and system-wide approach to local and urban infrastructure, believing that there are significant advantages to be gained from planning, investing and managing infrastructure on an interdependent basis. As the recent floods in Cumbria, Northumberland and elsewhere in the north of England demonstrated, long-term resilience has to be built into the UK's infrastructure sectors and systems. Otherwise, the potential economic and social benefits that can be derived from infrastructure investment will be marginal compared to the economic, social and environmental costs of repairing infrastructure that is damaged or destroyed by adverse (but increasingly regular) weather-related events.

The emergence of the National Infrastructure Commission (NIC) reflects the recent emphasis towards national scale infrastructure planning in the UK, and provides an important strategic context for the planning, development and operation of infrastructure. However, it is also important to consider the distinct role of local and urban infrastructure in driving local, regional and national economies. It is at the local and urban scales where infrastructure services are most dense and where the majority of people use infrastructure services in their everyday lives. Balancing growth across different geographical scales – from the local to the city/city-region – is vital to the long-term success of the national economy, as infrastructure drives local economic growth and job creation, as a consequence of construction and management activities as well as the enhancement and facilitation of other economic activities.

The response below first summarises key findings from our research programme that are relevant to all infrastructure delivery, before specifically responding to the consultation questions. Our response draws predominantly on new research identified during the iBUILD project, but also decades of research and experience in the iBUILD team. This includes engineering expertise in the Centre for

Earth Systems Engineering Research (CESER)[1] and the Institute for Resilient Infrastructure (IRI)[2], and the long-standing track record in local and regional development by the Centre for Urban and Regional Development Studies (CURDS)[3].

iBUILD focuses on all infrastructure sectors, not just transport, but our work has also drawn lessons from non-infrastructure sectors. Where our research is undergoing external peer review we cite working papers which, amongst other work, can be found at www.ibuild.ac.uk.

iBUILD Mid-Term Review and Policy Manifesto

In March 2015, iBUILD published a mid-term review and manifesto setting out thirteen evidence-based policy recommendations on how local and urban infrastructure business models could be strengthened in both design and in application. The key recommendations are elaborated in the full manifesto document which is available online.[4]

Research from across the iBUILD Centre has identified five priority action areas for government and industry. If applied to all infrastructure planning and decision-making, these action areas will help to challenge the "timid, uncoordinated, incremental, wasteful"[5] way the UK currently builds and manages its infrastructure, and help to develop a new approach to delivering infrastructure systems and their services that will enhance the health, wealth and security of UK citizens.

Priority Action Area #1: Have a broader, integrated appreciation of infrastructure
Infrastructure is not just tracks, tubes and trunk roads. Failure to consider the resources that flow along these, the services they provide and the people and businesses that depend on them, will lead to investments that don't deliver effectively. At the same time, it is crucial to understand how all these systems are interconnected; infrastructure depends on other infrastructure to work, not just technically, but also economically and socially. The UK's infrastructure is amongst the most mature and interconnected in the world and therefore has a pressing need to adopt a broad, integrated and sophisticated approach to infrastructure planning.

Recommendation 1: Infrastructure planners, financers, engineers and other stakeholders need to use a broad, but appropriately specified, definition of infrastructure if they are to identify the full range of opportunities from alternative business models.

Recommendation 2: Housing and 'hidden infrastructure', such as efficiency measures, should be considered alongside the large-scale capital investments with which they interconnect, within infrastructure and spatial planning processes

1 www.ncl.ac.uk/ceser
2 www.engineering.leeds.ac.uk/resilience/
3 www.ncl.ac.uk/curds
4 iBUILD (2015) Are you being served? Alternative infrastructure business models to support economic growth and well-being, iBUILD Manifesto and Mid-term Report, Newcastle University: Newcastle upon Tyne. The full manifesto can be downloaded from http://research.ncl.ac.uk/ibuild/outputs/
5 Infrastructure UK (2010) *National Infrastructure Plan 2010*, First NIP: October 2010, HM Treasury.

Recommendation 3: National reforms in policy and regulation are required to enable an integrated approach to local infrastructure planning that can identify, and has the capacity to exploit, synergies across infrastructure sectors.

Priority Action Area #2: Enable action at the local scale that connects with the national
Too much infrastructure planning is top-down, yet every piece of infrastructure has to go somewhere; it is inherently local. Top-down approaches to infrastructure development and management stop locally-led and innovative business models from flourishing and discourage innovation. It also risks the wrong infrastructure being put in the wrong place at the wrong time because of a lack of local knowledge, engagement and ownership. These issues prevent the UK from maximising returns from infrastructure investment. The UK must devolve an appropriate and sensible proportion of infrastructure investment and responsibility to local institutions so they can deliver infrastructure that better reflects the values and needs of the communities it serves, yet remain mindful of the national strategy.

Recommendation 4: National and local policy frameworks should be realigned to focus on delivering wider societal benefits and to enable local infrastructure business models to emerge that can provide local solutions that are complementary with mainstream systems.

Recommendation 5: Effective operation of local alternative infrastructure business models requires greater fiscal decentralisation, complemented by a stronger and statutory devolved role for cities and localities in the planning, development and delivery of infrastructure.

Recommendation 6: Provide support for a wider range of innovative local infrastructure financing mechanisms, including tax increment financing, municipal bonds, social impact bonds and crowd source funding approaches.

Priority Action Area #3: Capture long-term value of every kind
Infrastructure is not only about cash returns. Investment in infrastructure provides wider health, economic and environmental benefits for society; infrastructure converts financial value to social value. A new economic valuation system that recognises these long-term, whole-life benefits is essential to maximise the benefits. Infrastructure must also be built for minimum whole-life costs. This might mean paying a bit more upfront for something that will last – and serve– for longer without the need for frequent maintenance; a resilient and sustainable infrastructure.

Recommendation 7: Incorporate measures of social and environment benefit (and cost) into infrastructure appraisal frameworks to recognise the wider societal and environmental outcomes and ascertain the widest possible set of mechanisms to capture revenue and other values.

Recommendation 8: Implement a quantitative framework within the infrastructure appraisal process to assess the value of flexibility and resilience across the whole system over the long-term.

Recommendation 9: Local authorities and infrastructure owners should apply resource assessments as a matter of course to identify the potential of land and infrastructure assets to generate long-term, stable revenue streams and not just one-off, short-term windfalls from selling-off assets.

Recommendation 10: Employ a new approach to infrastructure economics that recognises the long-term and system-wide value of infrastructure provision.

Priority Action Area #4: Deliver more efficient planning, procurement and delivery
Approaches to project financing, funding and delivery should not be chosen for political reasons. Mechanisms must be adopted that can best deliver the desired economic, social and environmental values, regardless of their political flavour. Many of methods and tools to enable this already exist: the Project Initiation Routemap, Building Information Modelling (BIM) systems, life-cycle assessment, so they must be used. These approaches support more efficient planning and procurement, minimise costs and human effort, preserve the environment, and maximise the potential to reuse and recycle materials and components in the future.

Recommendation 11: Implementation of the Project Initiation Routemap has been shown to have many cost reduction benefits and should be made standard practise for all public funded projects.

Recommendation 12: Planning and design of infrastructure should consider the material and resource demands of infrastructure pipelines to identify opportunities for reducing waste in the construction and operation phases, whilst designing for end of life material recovery or repurposing of infrastructure.

Priority Action Area #5: Accelerate the uptake of innovations through practical action and demonstration
Action often speaks louder than words. Alternative approaches to infrastructure business models are emerging. However, to quickly identify the most successful approaches and encourage their wide uptake locally, nationally and internationally, a number of ambitious demonstrator sites should be established for integrated infrastructure planning and testing of innovative infrastructure business models.

Recommendation 13: Establish full-scale urban demonstrator sites for integrated infrastructure planning and testing of innovative infrastructure business models.

Improving how electricity demand and supply are balanced: Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?
   - What role can changes to the market framework play to incentivise this outcome:
   - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
   - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
   - To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?
2. Related to barriers to energy storage capacity
3. Related to interconnectivity
4. International best practise in relation to planning and balancing supply and demand

The nature of our evidence means that we contribute primarily to Q1, but our international review has identified lessons for Q4.

Key messages

- Distributed generation and energy efficiency measures (including those within buildings) should be considered as an integral part of energy infrastructure planning, equal to increased centralised supply (i.e. new power stations), as they can increase flexibility, resilience and security, and reduce demand and carbon emissions.
- The magnitude of demand reduction and the value of changes to the supply system as perceived by the consumer – two things inter-related by behavioural change – will depend on whether such changes are implemented via private, public or civic provision and financing.
- It is critical to consider these provision systems or value allocation options, when considering the options for the *physical implementation* of demand reduction and/or distributed generation. Local re-investment of the short-term profits generated from cost-effective EER measures into measure that promote long-term values and goals (e.g. achieving CO_2 emission targets, alleviating fuel poverty, increasing energy security), rather than allowing these profits to be appropriated by external financial entities, will increase the value and efficiency of the overall system for consumers, communities and UK plc alike.

Market frameworks - Business models for local electricity supply

At the city-regional to neighbourhood level inappropriate regulatory frameworks too inflexible to open up all opportunities for balancing supply and demand. What is needed is a supportive policy and regulatory environment to allow local balancing within distribution networks. This can be achieved by making space for business model innovation at the retail or 'supply' end of the market that integrates demand reduction and energy efficiency as key parts of the overall supply system. Government may wish to support a local supply market because it offers four key opportunities that national utility business models are unable or unwilling to capture or pursue owing to commercial and financial pressures:

- Better routes to market for local generation: the market for small scale power purchase agreements is constrained; support for local supply business models is needed.
- Fulfilling the potential of the demand side: the benefits of demand side management in the UK are being missed.
- Real energy efficiency gains: national utilities are not best suited to delivering energy efficiency programmes because they disrupt their business model. Local supply archetypes could be better suited.
- Re-localising energy value: energy value is 'leaking' out of local regions and the UK due to increasing international financialisation of supply utilities, or limited focus on delivering social value (e.g. alleviating fuel poverty).

The emergence of smart technologies and distributed generation create additional value propositions that may be best captured by local supply enterprises; such as demand response, and smart loads.[6,7,8,9] Increasing diversity of local generation and consumption patterns suggests local balancing could more efficiently optimise supply and demand within regions[10,11,12,13] and could complement/run in parallel to national balancing.[14] However, the UK electricity system is based on 'top down' control, directing energy from centralised generation to meet demand at any point.[15] Regulation and trading systems follow this centralised model which encourages increased sale of cheap units of energy, rather than increased efficiency of services provided – heat, light etc. – to reduce demand.[16] Energy trading arrangements assume organisations manage their physical position and achieve contracted balance nationally.[14]

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[6] Pudjianto, D., Djapic, P., Auinedi, M., Kim Gan, C., Strbac, G., Huang, S. and Infield, D. (2013) 'Smart control for minimizing distribution network reinforcement cost due to electrification' *Energy Policy*

[7] Ceseña, E. A. M., Good, N., Mancarella, P. (2015). Electrical network capacity support from demand side response: Techno-economic assessment of potential business cases for small commercial and residential end-users. *Energy Policy*, *82*, 222-232.

[8] Oren,S.S., 2013. A historical perspective and business model for load response aggregation based on priority service .In: Proceedings of the Hawaii International Conference on System Sciences. IEEE,pp. 2206–2214.

[9] Palensky, P., & Dietrich, D. (2011). Demand side management: Demand response, intelligent energy systems, and smart loads. *Industrial Informatics, IEEE Transactions on*, *7*(3), 381-388.

[10] Foxon, T.J. (2013) Transition pathways for a UK low carbon electricity future, *Energy Policy*, 52, pp.10-24. doi: 10.1016/j.enpol.2012.04.001

[11] Cornwall Energy (2014) *Creating Local Electricity Markets: A Manifesto for Change.* Cornwall Energy

[12] Cornwall Energy (2014a), Local tariffs and the BSC, July 2014 Nigel Cornwall. Evidence submitted to the Local Supply Working Group 2014.

[13] Cornwall Energy (2014b) Cornwall Energy information note [domestic supply market] (Figures up to 31.7.2014). Cornwall Energy

[14] Elexon (2014) Encouraging local energy supply through a local balancing unit. www.elexon.co.uk/wp-content/uploads/2014/08/Encouraging_local_energy_supply_through_a_local_balancing-unit.pdf

[15] Lockwood, M., (2014) Energy networks and distributed energy resources in Great Britain, IGov EPG Working Paper: 1406.

[16] Roelich, K., Knoeri, C., Steinberger, J.K., Varga, L., Blythe, P.T., Butler, D., Gupta, R., Harrison, G.P., Martin, C. and Purnell, P., 2015. Towards resource-efficient and service-oriented integrated infrastructure operation. *Technological Forecasting and Social Change*, *92*, pp.40-52.

iBUILD research[17,18] identified nine business model archetypes for local electricity supply. Each of these business models incentivises demand response and balancing of local generation differently. Table 1 shows each of these business models and how they variously incentivise: better routes to market for distributed generation, local balancing and demand response, energy efficiency and energy value retention.

Table 1: Archetypes of energy business models. Scale +++ = strong positive effect to --- + strong negative effect -/+ = neutral

Archetypes	Enabling Mechanisms	Opportunities/value propositions of local supply			
		Better routes to market for local generation	Fulfilling the potential of the demand side	Real energy efficiency gains	Re-localising energy value
Current Archetype	Full Supply License	--	-	--	---
Local White Labelling	Third Party Licensed Supplier Partnership (TPLSP)	+	-	-	-/+
Local Aggregator	TPLSP	++	+++	+	+
Local 'Pool and Sleeve'	License Lite with TPLSP	+	-/+	-	+
Municipal Utility	Full Supply License	+++	+	---	++
Municipal ESCo	Full Supply License	+++	++	+++	+++
MUSCo	Full Supply License	+++	++	+++	+
Peer to Peer	TPLSP	+++	-/+	-/+	+
Peer to Peer with Local Balancing Unit	TPLSP With local settlement unit	++	++	-/+	++

Source: Hall and Roelich 2016

[17] Hall, S., Roelich, K., (2015) *Local Electricity Supply: Opportunities, archetypes and outcomes*. Ibuild/RTP Independent Report. March 2015, Available online at: https://research.ncl.ac.uk/ibuild/outputs/local_electricity_supply_report_WEB.pdf

[18] Hall, S., Roelich, K., (2016) Business model innovation in electricity supply markets: the role of complex value in the United Kingdom, *Energy Policy*, Forthcoming.

Each of these business models has different challenges in market proliferation. Some of these archetypes are constrained by the regulatory environment, a lack of capacity/experience in a new sector, a lack of understanding of replicable models, and unclear risk frameworks. In response to these barriers[18] propose a set of short, medium and long term strategic activities that could be carried out at the national scale that would foster this sector and help to realise as yet untapped opportunities in the energy market. Each of these recommendations is evidenced more fully in [17] and [18]. However we call attention to medium term proposal 3, as this would create a geographic unit in settlement that would enable suppliers to optimise balancing within regions, making best use of distributed generation and geographically aggregated demand response. This is both the most market and technically efficient approach but is currently impossible within the national market structure. These proposals are:

- **Short Term Proposal 1: Local supply innovation fund**
  A substantial but time-limited fund of comparable size to the urban and rural community energy funds, explicitly aimed at testing local supply archetypes in the market
- **Short Term Proposal 2: A 'portal of power'**
  An online platform with clear policy and regulatory advice specifically generated by and tailored for local supply stakeholders
- **Short Term Proposal 3: Resource the Local Supply Working Group or similar forum**
  Continued resource to support the Local Supply Working Group which has progressed the understanding of local supply in the UK and will be needed to guide its future development

- **Medium Term Proposal 1: Clarify the requirement for national supply**
  New fully licensed suppliers are looking to exploit the benefits of focussing on particular geographies, but regulation is not suited to this. New frameworks and customer protections for geographic supply are needed.
- **Medium Term Proposal 2: Amend the requirement for fully licensed suppliers to offer only four tariffs for those areas operating local supply archetypes.**
  Fully licensed suppliers looking to partner with 'intermediary archetypes' that rely on this relationship are being penalised by the requirement to offer only four main tariffs. This has been facilitated by a temporary arrangement for the 'local white labelling' sector, but will need to be addressed as new local supply archetypes and intermediary relationships proliferate.
- **Medium Term Proposal 3: Allow for a 'local balancing unit' [Balancing unit allowable within a single grid supply point region].**
  This would allow new local business models such as aggregators and junior suppliers to maximise the benefits of local supply and demand management, offering benefits to suppliers, network managers and system operators.

- **Long Term Proposal 1: Investigate the opportunity to allow local ESCo or multi utility models which incentivise substantive efficiency gains to be exempt from supplier switching legislation.**
  As a longer term activity, the requirements on suppliers to ensure the domestic consumers' right to switch supplier need reviewing to make space for domestic energy performance contracting that

can be delivered where it is relevant. i.e. by being recouped through the household energy bill. This would unlock new opportunities for energy efficiency in deep retrofit, micro generation and appliance efficiency.

- **Long Term Proposal 2: Investigate the opportunities for demand reduction-centred business models and their treatment in regulation and policy.**
  Much more work is required to investigate how energy demand reduction can be incorporated into markets and incentives. The opportunities of demand reduction can be delivered by new aggregator business models. However to date demand reduction has been undervalued in favour of policy mechanisms aiming to reduce unit prices as opposed to final bills. Local supply options can deliver demand side services that reduce final bills, deliver benefits to distribution and transmission system operators and reduce the need for centralised generation investments across the system.

The Department for Energy and Climate Change has already used [17] to inform the update to the Community Energy Strategy.[19] This work has also fed into the Ofgem consultation on Non Traditional Business Models. However the NIC will find this work of particular interest as innovation in energy retail markets has the potential to deeply affect the need for new transmission and distribution grid re-enforcement, the need for interconnection and the capacity and utilisation of the existing thermal generation fleet. By optimising for balancing at the local level significant savings could be made on critical infrastructures. If this is a managed process these critical infrastructures have much less chance of becoming stranded assets.

Revolving fund financing and governance structures

The research assumes that the provision of demand reduction measures can offer systematic benefits by lessening the requirement for generation infrastructure and improving system flexibility and reliability.[20,21,22] We focus upon a particular class of demand reduction, namely that of the energy efficiency retrofit (EER) of UK buildings. The technical potential of such measures is well known, thus we consider instead how different modes of governance and financing arrangements may influence the extent to which such technical potential is achieved. Research results suggest that overall levels of EER provision, are highly dependent on the source of its financing and the contexts and conditions under which it is deployed and governed.

Different financing and governance arrangements are analysed with respect to various private, public and civic modes. Here these modes are considered in the context of a revolving investment fund for EER. A revolving fund recycles direct financial returns, (in the case of EER, fuel cost savings) from previous investments, to further funding in a specific investment area – thus helping to capture and retaining local value. Revolving fund structures are used currently to finance investment in EER in a

[19] Department of Energy and Climate Change (2015) Community Energy Strategy Update, DECC, Available at: www.gov.uk/government/uploads/system/uploads/attachment_data/file/414446/CESU_FINAL.pdf
[20] Washan, P, Stenning, J and Goodman, M. 2014. Building the Future: the economic and fiscal impacts of making homes more energy efficient. 2014.
[21] Mount, A and Benton, D. 2015. Getting more from less: realising the potential of negawatts in the UK electricity market. 2015.
[22] ADE. 2014. Invisible Energy: Hidden Benefits of the Demand Side. 2014.

variety of sectors, for example, the SALIX fund for public sector buildings and the HEFCE fund for Higher Education. The ring-fenced nature of returns are intended to act as a driving force for the achievement of ambitious targets for levels of provision, while drastically lowering initial investment requirements - a point of significant benefit in an era of austerity (see Gouldson et al 2015 for more on revolving funds). Our modelling assesses the potential of private, public and a civic revolving funds and suggests that the impacts – in terms of investment achieved, measures deployed, and energy saved – can vary dramatically depending on how EER provision is financed and operated.

Demand reduction (for both electricity and heat) via EER has much potential, with carbon emission reduction targets foreseeing a carbon neutral housing stock by 2050.[23] The achievement of this target will offer inherent benefits to system resilience, but will require the implementation of a wide variety of privately cost-effective and privately non-cost-effective EER measures. Policy mechanisms in the UK in the last 10 years have mainly targeted the most privately cost-effective measures. The Carbon Emission Reduction Target scheme (2008-2012), for example, was effective at provision of the most cost-effective measures. Measures that are equally necessary (for the achievement of long term targets) but not necessarily cost-effective in the short term, were largely ignored. The focus on the most cost-effective first allows the greatest bang for a limited buck, but creates a scenario where unlocking the remaining long-term, high-value potential becomes increasingly expensive.

Publicly funded schemes, such as the Green Deal Home Improvement Fund (2012 – present day) which have some focus on less privately cost-effective measures, have limited capacity in an era of fiscal austerity and limited public money. Alongside the CERT scheme they also have the drawback of offering a piecemeal approach to an issue which will require multiple measures in single properties in the long term. The support for individual measures, as opposed to overall energy saving attainment or a "whole house" approach, leads to inefficient implementation of a costly process and will only exacerbate issues with household disruption and lack of consumer buy-in.

Our modelling considers the impacts to overall provision of different hypothetical frameworks for provision. The private mode delivers significant investment and carbon savings in the short-term, focussing upon exploiting financially cost-effective opportunities. However, this often precludes the ability to implement more socially-minded modes of delivery e.g. using the savings from these cost-effective opportunities to deliver measures with low financial benefit-cost ratios that are nonetheless essential for delivering long-term goals such as meeting carbon reduction targets or alleviating fuel poverty. The public mode could achieve deep levels of EER deployment even when restricting investment to the cost-effective measures; provided that the potential public co-benefits of such investments (healthcare savings, improved tax revenues from net employment gains, etc.) are incorporated into the economic decision making process and the public benefit of EER is credited via subsidy. The civic mode, despite being assumed to have access to relatively limited levels of upfront investment, achieves high levels of EER deployment in the longer-term, on a par with that achieved by the public scheme. It does this by recirculating capital from early cost-savings into the measures with lower benefit-cost ratios, much more efficiently than a public subsidy scheme) via a number of

[23] CCC. 2015. Meeting Carbon Budgets - Progress in reducing the UK's emissions. 2015 Report to Parliament. 2015.

beneficial social and institutional arrangements that are characteristic of civic decentralised energy movements funding cost-ineffective measures with the returns from cost-effective measures and lower stipulated interest rates. The retention of local value by the civic fund is envisaged to encourage a more coherent approach to EER uptake, potentially limiting household disruption with a more multi-measure or "whole house" approach.

In summary, the private mode we consider requires little public investment, is fast (with respect to implementation), but is limited in scope and thus potentially very costly in the long-term (as privately cost-ineffective measures may be left requiring large subsidies). Comparatively, the public mode requires substantial public investment, but is also fast and foreseen to be both profitable in the longer-term (via increased tax returns and healthcare savings) and thorough in scope. The civic mode requires little (although not insignificant) public investment, is profitable in the long-term and thorough in scope, its benefits, however, are achieved more slowly.

Beyond the energy system: Alternative and integrated infrastructure business models

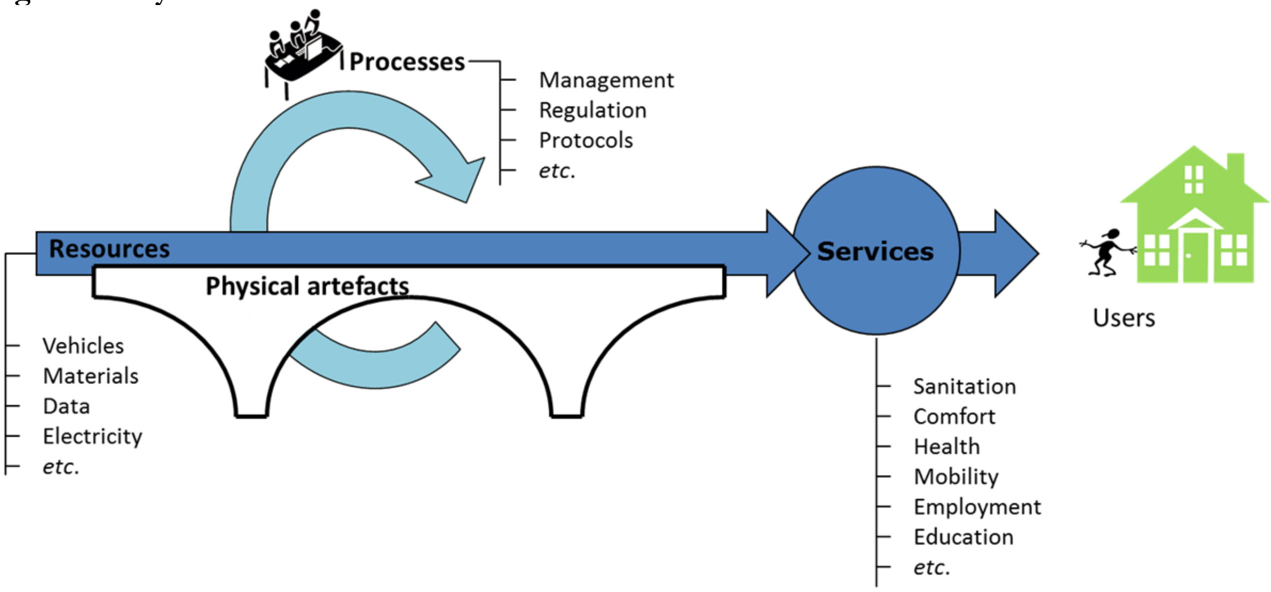
Business models take into consideration different governance, but must also consider the wider infrastructure system that comprises (Figure 1):

- *physical artefacts* – includes the physical links, nodes and components of infrastructure systems such as roads, bridges, pipes and cables;
- *processes* – includes actors, institutions, management, regulation, protocols and procedures that govern the infrastructure over its lifecycle;
- *resources* – includes people, vehicles, water, electricity and data that are conveyed by the physical artefacts and the materials used in the construction of the artefacts; and,
- *services* – such as warmth, mobility, sanitation, transportation, welfare services and communication that benefit a wide range of users.

Infrastructure is therefore the artefacts and processes of the inter-related systems that enable the movement of resources in order to provide the services that mediate (and ideally enhance) security, health, economic growth and quality of life at a range of scales.[24] Moving beyond a narrow or solely economic view and distinct from the world of more conventional goods and services, an infrastructure business model therefore describes how infrastructure systems create, deliver and capture economic, social and environmental values over the whole infrastructure life cycle.[25]

[24] Dawson RJ (2013) *Bridges n'that: An infrastructure definition for iBUILD*, iBUILD Briefing Note 1.
[25] Bryson JR, Pike A, Walsh CL, Foxon T, Bouch C & Dawson RJ (2014) *Infrastructure Business Models*, iBUILD Briefing Note 2.

Figure 1: A systems view of infrastructure.

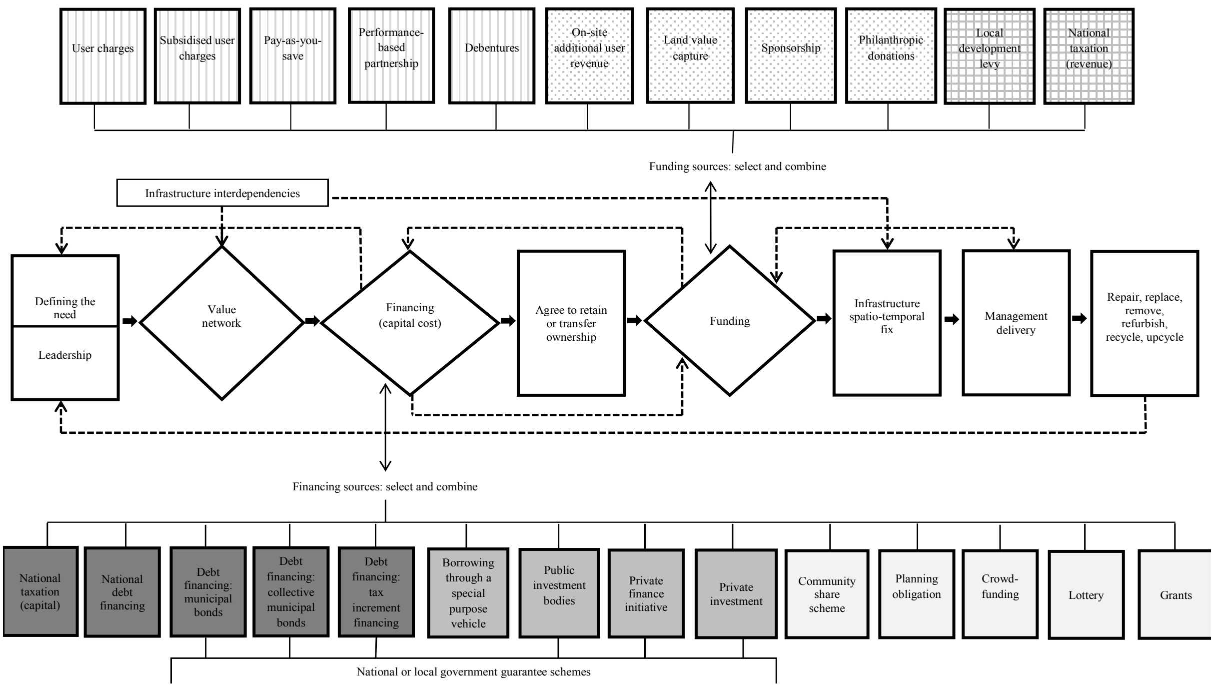


Source: iBUILD (2015: p5).

iBUILD has undertaken a review of over hundred UK and international local infrastructure business models, both traditional and non-traditional, across all infrastructure asset classes.[26] The business models are diverse. Value creation includes social, economic and urban regeneration outcomes as well as direct outputs in terms of service supply. International comparison has illustrated how the development of business models from niche to established mainstream models reflects the regulatory, political and socio-economic context.[27] For example, the success of municipal decentralised energy supply in Denmark and subsidy-supported business models for local energy supply in the UK.

[26] Currently online here: http://ceg-research.ncl.ac.uk/ibuildDemo/ (URL subject to change when site goes fully live)
[27] Bryson, Mulhall, Song, Loo, Dawson (in review) Conceptualising Local Infrastructure Business Models: The Spatio-Temporal Fix, *Research Policy*.

Figure 2: Conceptual Framework of Local Infrastructure Business Models



Source: Bryson et al. (in review).

Developing and implementing alternative approaches provides some benefits, but as noted above, our infrastructures are increasingly interconnected and some of the most promising opportunities are from thinking about delivering what people really require i.e. warmth, light, mobility etc. rather than electricity, gas, roads. This can help identify business models that deliver efficiencies across multiple 'traditional' sector boundaries. A rapidly emerging interdependence is between electricity and transport infrastructure – most notably uptake of electric vehicles (EVs). Coupled analysis of energy and transport systems models, has demonstrated that distribution networks could accommodate higher growth in electric vehicles than previous studies have suggested. Exploiting the geographic spread and different timings of EV charging can limit the impact on power infrastructure. Distribution network operators should collaborate with new market players, such as charging infrastructure operators, to support the roll out of an extensive charging infrastructure to make both networks more robust.[28]

A well-established demonstration of the value of integrated infrastructure thinking applied to an industrial park – now an industrial ecosystem – is the closing of material and energy loops locally with integrated infrastructure in Kalundborg, Denmark. Since 1972, this industrial park has evolved from a single power station into a cluster of companies that exchange materials and energy for mutual benefit as by-products from one business are often inputs for others. For example, treated wastewater from a refinery is used to cool a power station which in turn provides steam for the refinery and a pharmaceutical plant. Surplus heat from the power station is also used for warming nearby homes and businesses. This has led to substantial annual savings of resources and costs – for example, a reduction in water consumption of 3.3million m3/year, savings of $15m from resource sharing and far larger

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[28] Neaimeh M, Wardle R, Jenkins A, Hill GA, Lyons P, Yi J, Huebner Y, Blythe PT & Taylor P (in press) A probabilistic approach to combining smart meter and electric vehicle charging data to investigate distribution network impacts, *Applied Energy*.

savings by sharing infrastructure have been reported – highlighting how integrated infrastructure business models can produce substantial savings.[29,30]

There are many potential ways of organising and regulating such interactions to create efficiencies. For example, in 1887 in Indianapolis, local civic leaders established a natural gas company as a Public Trust, with an aim to "create the greatest long-term benefit for customers and communities". Today, the Citizens Energy Group owns and operates a large portfolio of physical infrastructure assets that deliver multiple services including energy, water and wastewater for 800,000 people and thousands of businesses in the Indianapolis area. This has provided community services that are entirely compatible with good financial management. The group was awarded a top rating (MIG 1) by Moody's credit rating agency in 2014, a reflection, in part, of the strength of the company's infrastructure business model.[31] By recognising the opportunities from the interdependencies of modern infrastructure, and explicitly designing this into our energy and other systems, this not only offers opportunity for alternative business models but also can be used to deliver flexible infrastructure systems that can enhance resilience.[32]

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[29] Chertow MR & Lombardi DR (2005) Quantifying Economic and Environmental Benefits of Co-Located Firms, *Environmental Science & Technology*, 39(17):6535 -6541.
[30] Chopra SS & Khanna V (2014) Understanding resilience in industrial symbiosis networks: Insights from network analysis, *Journal of Environmental Management*, 141:86-94.
[31] www.moodys.com/research/Moodys-Concludes-Review-and-Confirms-MIG-1-on-Indianapolis-Indiana--PR_302963
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ICE written submission to the National Infrastructure Commission call for evidence - Electricity Interconnection and Storage

Dear Lord Adonis,

Please find the Institution of Civil Engineers' submission to the National Infrastructure Commission call for evidence on Electricity Interconnection and Storage.

The ICE is a UK-based international organisation with over 86,000 members ranging from professional civil engineers to students. It is an educational and qualifying body and has charitable status under UK law. Founded in 1818, the ICE has become recognised worldwide for its excellence as a centre of learning, as a qualifying body and as a public voice for the profession.

ICE would like to thank the National Infrastructure Commission for the chance to take part in this call for evidence. We would welcome any opportunity to provide further insight at subsequent stages.

Yours sincerely,

Gavin Miller
Policy Manager

It is noted that this section of the NIC call for evidence is titled 'Electricity Interconnection and Storage', therefore the answers given below relate specifically to electricity rather than energy as a whole.

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

Implementation of Electricity Market Reform (EMR) including the annual Capacity Market auctions should continue smoothly with changes kept to a minimum.

Looking at the GB electricity market as a whole, there is a need to continue to ensure the competition between generators distinguishes between cost and cost-effectiveness. That is, what is achievable for the price. This will assist the development of supporting capabilities: the efficient delivery of energy infrastructure will require a cost-effective supply chain and skilled workforce.

EMR has generally established appropriate and effective mechanisms, in the form of Contracts for Difference and the Capacity Market, to deliver a low carbon, diverse and secure energy mix at lowest cost to consumers. EMR should be more capable of bringing forward the tens of billions of pounds of investment required at a lower cost of capital than previous policy instruments.

Nevertheless, it is important to remember that EMR is relatively new; established under the Energy Act 2013 but not fully implemented until 2014. As such, any changes to its continued implementation should be considered carefully from the point of view of investor confidence. Where alterations are required, early notice of future funding availability will reduce risk, enabling investors and developers to make informed decisions, as would greater emphasis on the longer-term contracts available for new plants through Capacity Market auctions.

In the short-to-medium term, this means further changes to EMR are the minimum necessary. Nevertheless, as part the planned review of the Capacity Market system, expected in 2018-19, consideration should be given to taking a more systems-based approach, for example assessing how the mechanism relates to, and works with, other schemes such as balancing services to deliver flexibility, responsiveness and security.

- **What role can changes to the market framework play to incentivise this outcome?**

The Electricity Act 1989 (as amended) is the main legislative component of the GB electricity system introducing privatisation and unbundling, and it remains central to the GB electricity market framework. However, the licensing regime it put in place now risks working against innovation and flexibility.

There will always be a need for bulk electricity generation, transmission and distribution as encapsulated in the 1989 Act (and which EMR has sought to improve). However, an effective and vigorous market at a local and national level seems to be desirable by current common consent, with local operators, generators, communities etc., able to buy and sell power and energy to solve local constraints on networks as well as participating in national energy balancing needs. The increasingly 'local' and disaggregated supply and demand of the GB electricity market also needs a response.

Technology, in terms of small generation equipment, smart domestic appliances, and the very likely near-term evolution of affordable storage, all point to a very different dynamic arrangement than was envisaged in the 1989 Act. Therefore, it is not clear, if the basic assumptions of the Act remain capable of allowing appropriate growth in local energy services, or if it risks stifling sensible innovation and development in the sector. A thorough review of the Act and its associated licensing regime should be undertaken: it might be that the objectives of the Act remain fundamentally correct but their implementation seems to be working against the growth of new local trading and services.

- **Is there a need for an independent system operator (SO)?**

Weighing up the need for an Independent System Operator (ISO) is largely dependent on what this term would mean in the GB context.

The GB National Electricity Transmission System is owned and maintained by three regional transmission companies: National Grid Electricity Transmission (NGET) (in England and Wales)**,** Scottish Hydro Electricity Transmission (north of Scotland), and Scottish Power Transmission (central and south of Scotland). NGET alone operate **t**he GB system as a whole, the single System Operator (SO).

For the purposes of this submission, the creation of an ISO is taken to mean a separation of the ownership/maintenance and the operational functions both currently performed by NGET in England and Wales. Therefore, a newly created ISO is expected to have responsibility for controlling the access to, and use of, the transmission grid by generators and maintaining system balance across GB but would not own, nor maintain the infrastructure.

As the Scottish part of the GB system is owned/maintained - but not operated - by Scottish Hydro Electricity Transmission and Scottish Power Transmission, it follows the electricity system within Scotland effectively already functions with NGET as an ISO (albeit one that is integrated into the GB system). Therefore, we assume that the breakup of NGET would - formally - only affect England and Wales, creating a set-up similar to that currently present in Scotland.

Looking at different parts of the electricity system, the main purported advantage of creating an ISO in England and Wales is that it should ensure – via regulatory design – that there is no inappropriate incentive for NGET to use its assets to undercut the market.

NGET does not own or operate generation or distribution assets. The licensing regime prevents it from doing so, so there are unlikely to be any conflicts of interest in these areas.

However, with the transmission network, as NGET has a dual position in England and Wales there is a potential risk it could recommend changes to the network to increase its own revenue streams (or possibly disadvantage the Scottish transmission owners and/or offshore transmission owners). Nevertheless, Ofgem have stated they know of no instances of this happening in practice[1]. As such, in terms of transmission, it appears creating an ISO would be about removing the suspicion of, rather than actual, favouritism.

Through wholly-owned subsidiaries, National Grid holds licences for interconnectors. Despite the formal separation of businesses, this twin role seems to drive criticism and suggestions that NGET should be broken up. That National Grid is both responsible for balancing the system and advising on the need for new interconnectors has been seen by some as a potentially inappropriate incentive, particularly as interconnectors can now participate in the Capacity Market[2].

If National Grid's ownership of interconnectors is the main impetus behind the creation of an ISO, then it is recommended consideration is also paid to the possibility of modifying the licensing regime to ensure transmission and interconnector licences are mutually exclusive in the same way as transmission and generator, and transmission and distribution licenses. This should have the effect of removing any potential conflict of interest.

It is further recommended that assessment is carried out of the functional relationship between Scottish Hydro Electricity Transmission **and** Scottish Power Transmission as owner/operators with NGET in its role as an 'ISO' in Scotland to ascertain if practical lessons can be learned from such a relationship within the GB context.

- **How could the incentives faced by the SO be set to minimise long-run balancing costs?**

Electricity SO incentives are designed to deliver financial benefits to the industry and consumers by reducing the cost and minimising the risks of balancing the system. Ofgem sets the incentives.

The SO incentive schemes currently establishes cost targets NGET is expected to achieve. For balancing, the key mechanism is the Balancing Services Incentive Scheme (BSIS), which covers energy, constraint and black start costs.

With BSIS, if NGET's costs come out below the level set by Ofgem, it retains a proportion of its savings (capped at £30 million) but if costs exceed the target, it faces a penalty. Since 2011, the scheme has been managed on a biennial basis with the current iteration in place until 2017.

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[1] Dermot Nolan quoted in Utility Week (2015) 'Ofgem: 'Strong case' for ISO to replace National Grid'
[2] Energy and Climate Change Committee (2015) 'Implementation of Electricity Market Reform'

While the BSIS two-yearly scheme is only in its third cycle and there should be a general wariness of altering mechanisms, if the intention is to improve long-run costs, consideration should be given to increasing the cycle length from two years to three or possibly even five years. Doing so could incentivise longer-term planning, for example in line upgrades or investment in new ancillary services technologies. However, such potential benefits would need weighing up against the current short cycle arrangements that allow Ofgem a degree of flexibility to manage changing objectives.

- **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

ICE considers the current balancing market does not fairly represent participants' roles in balancing the system, in particular the current set up unfairly penalises electricity storage.

As SO, under the terms of its electricity transmission licence NGET recovers the costs of its balancing activities through Balancing Services Use of System (BSUoS) charges. NGET applies BSUoS charges to large electricity consumers and generators to cover the costs it incurs in maintaining balance in the system, mostly through arrangements paying parties to either increase or decrease their generation/consumption.

The calculation of BSUoS charges are ex-post based on the volume of energy large users (i.e. those larger than 50 MW) takes from, or supplies to, the transmission system on a half-hourly basis. The charges are paid by the 332 parties to the Balancing and Settlement Code (BSC) and are split between generators and consumers. Ultimately, both sets of costs are passed on to business and domestic customers through their bills.

In 2013-14, more than 50% of the total cost of balancing services related to frequency response and reserve generation. Around 40% of total costs arose from instructions to generators to adjust their production because of local and regional constraints in network capacity.

Bulk storage facilities can be an effective means of balancing the network (see Question 2 for more detail). At present, the BSUoS regime works against their further deployment: storage acts as demand while charging and generation while discharging, so operators must pay BSUoS charges twice, affecting economic viability.

Therefore, ICE recommends that electricity storage's potential for helping to reduce imbalance in the transmission network should be recognised by reforming the balancing market through exempting storage operators from BSUoS charges.

Cost neutrality can be maintained by removing extraneous costs instead of providing a direct subsidy. Exempting *new* storage from BSUoS charges when they are acting to help balance the system would not result in National Grid losing money, nor would it add costs onto other electricity generators or customers[3].

Looking at balancing the system in a wider sense, consideration should be given how to manage smaller operators outwith the market. This will become of increasing importance as the prevalence of distributed, often intermittent, generation on the grid.

- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

More work needs to be done to ensure that active demand side management (DSM) develops in GB. All decarbonisation trajectories assume increases to near total electrification of heating and transport. With this comes the likelihood of creating a much larger peak electricity demand for which networks and generation will need to be sized to match.

However, improvements can also be made on the demand side through storage to allow time-shifting of consumption to more closely match the capacities of the electricity system[4]. The use of storage should also help to reduce the use of high emission diesel generators currently commonly used in DSM.

Embedded generation on the distribution network has grown dramatically over the past few years with around 11 GW connected since 2010. On the face of it, the shift to disaggregated generation would seem to increase the electricity grid's overall flexibility – rather than relying on a few, large generators with limited variability of output on the high-voltage network, the country is moving to many, smaller, more responsive facilities on the low-voltage system.

However, existing distribution networks and their regulation were not designed with embedded generation in mind. Rather, they were configured to manage one-way flow from the transmission grid to consumers with relatively passive controls. As such, the GB electricity system is getting to the point where the low voltage networks, DNOs and their regulation can hinder rather than enable increased flexibility.

Embedded generation has the potential to play an important role in smart energy networks. Here, real-time information on network operation and energy consumption are used to manage demand with new monitoring and control technologies making the network more flexible and reliable. However, for this to be fully realised it seems there is a need to shift from a DNO to a Distribution System Operator (DSO) model, where the low-voltage system as a whole, including generation,

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[3] It is noted that extending such an exemption to *existing* bulk storage operators would result in the storage operators BSUoS charges being picked up by the other BSC parties, marginally increasing their costs. However, as bringing new storage onto the system should improve system balance the storage exemption is also expected to result in overall BSUoS charges decreasing, therefore all BSC parties' costs.

[4] There is a significant work looking at these issues, in particular see Smart Grid Forum and Future Power System Architecture Project

demand and the technical and commercial interaction between them, is managed and operated on a regional basis.

2. What are the barriers to the deployment of energy storage capacity?

ICE considers electricity storage to be a key technology for the development of electricity networks to manage the transition to a low carbon economy. Markets and regulation do not currently recognise the potential of electricity storage and need to adapt if Britain is to take full advantage of the technologies on offer.

We have built a national electricity grid to deliver electricity from *where* it is generated to *where* it is needed. Electricity storage can help us in much the same way by moving electricity from *when* it is generated to *when* it is needed. With more and cheaper renewables, storage will become a crucial part of efficient future energy systems.

Storage's important role should be recognised and enabled through removing the red tape and regulatory barriers to its further deployment. We encourage the Commission to consider our recent report, 'Electricity Storage: Realising the Potential' in order to explore this further.

- **Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?**

ICE considers there are three key policy/regulatory barriers, the removal of which will facilitate further development and deployment of electricity storage:

1. *Exempt storage operators from Balancing Services Use of System (BSUoS) charges.*
   Storage's role in balancing the network should be recognised by exempting it from BSUoS charges. Currently the BSUoS regime works against the further deployment of storage as operators are 'double-charged'. This is because storage draws electricity from the grid when charging up and exports electricity to the grid when discharging. If these charges were to be removed, this would act as an economic incentive for operators to deploy new storage. Exempting new storage from BSUoS would not result in National Grid losing any money, nor would it add costs on to other electricity generators or customers.

2. *Clarify storage's position through establishing a separate regulatory classification.*
   Electricity storage does not have a licencing classification and is consequently often treated as a form of generation. DNOs' (and others') licences prevent them from operating generation and therefore, cannot control storage facilities. Classifying storage as a specific activity - one that all licence holders can participate in - would free up DNOs to improve their networks. Such cutting of red tape will effectively be cost neutral, as it would only involve minimal administration costs.

3. *Enable renewable electricity generation to match demand through encouraging storage.* Renewables operating with storage should be eligible for a feed in tariff (FiT) that tops-up wholesale electricity prices. The percentage premium FiT is designed to use market signals – tracking the wholesale price – to encourage renewable operators to use storage so as to export electricity at times of high demand. Under this system, decisions on whether, when and how much storage to build are guided by the market, enabling new storage to be built when there is a need and when it is economic to do so.

If the potential benefits of electricity storage in future systems are to be realised for GB, the Government, working with the regulator and industry should act to provide a clear statement on the future of electricity storage in the energy system setting out steps towards making the recommended policy changes.

Doing so will encourage investment in a sector with huge potential not just to improve energy efficiency and security but also position the country as a leading technology innovator. With the confidence provided by the certainty of direction on electricity storage, new technologies would develop to market and existing ones will improve their application and efficiency.

- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

There is no "most appropriate scale" for electricity storage. Rather, because the term 'electricity storage' encompasses a wide range of technologies with diverse capabilities suitable for application at different points on the network for different purposes, electricity storage can be deployed at a variety of scales, situations and sizes.

Storage is unique in the electricity system in that it cannot only supply, it can also absorb energy to export as-and-when required. This can be for frequency response to maintain the second-to-second balance between level of supply and demand (either through absorption or through discharge), providing reserve power or inertia, network congestion management and reducing the need for investment in system reinforcement.

Economies of scale will apply to storage just as they do to generation. However, it is the use of storage that will determine the scale: the MW by the local needs, and MWh by the owner's view of the appropriate capacity / cycle.

Transmission-level or 'bulk' storage can reduce generation investment costs and help ensure security of supply against unplanned outages and mitigate the need for inefficient ramping up and down of low load factor backup generation with low efficiencies and high emissions. In addition, they can 'firm–up' intermittent renewables generation by effectively shifting supply profiles to meet demand. If planned from a systems point of view such storage can complement or potentially offset the need for interconnection and transmission investment.

Currently there is a capacity of around 2.8 GW (or up to 25.5 GWh) of electricity storage capacity in GB. All of this bulk storage is currently from pumped hydro storage (PHS). In the main, PHS is expected to continue to be the main technology for bulk storage in the near future, however, there is also potential for newer systems such as liquid air and compressed air. There are at least five planned new bulk storage facilities in GB, all PHS three new plants in Scotland plus Glyn Rhonwy in Wales, and the proposed upgrade of Cruachan PHS. If all were developed to their planned capacity they could provide a further 1.8 GW (up to 69.6 GWh) of new storage**.**

For Distribution Network Operators (DNOs), managing the connection of an ever-increasing share of distributed generation combined with the electrification of heat and transport, and multiple, intermittent generation sources in the market will be a challenge. Networks will no longer be just from transmission to customers, but rather multifaceted networks with two-way flows. Here electricity storage will be particularly useful in avoiding local network constraints and reducing / deferring the need for line reinforcement. They will, therefore, be sized to match the local requirements, generally in MW/MWh but also including quite small installations possibly of only a few kW/kWh. Such installations can of course contribute to local, regional and national balancing opportunities.

There are two main reasons why co-location with renewable power - as opposed to network connected - generators is important, or at least valuable. The first is to avoid flows of energy that are too large for the local network, diverting the excess into storage, to be released later. This can also avoid the need to make constraint payments. Secondly, co-location allows the losses incurred from storage to be kept ‘on the same side of the meter’ - in other words, they are picked up by the storage operator unlike the cost of network loss costs that are spread across electricity suppliers.

If storage is working in concert with renewable generation, it operates as a form of pre-network helping to flatten the load curve and potentially facilitating predetermined generation profiles improving dispatchability and integration with the network. By releasing energy at a steady rate when most needed, storage co-located with renewable generation can smooth supply fluctuations and, as such, is expected to play a significant role for further integration of renewables onto the grid. It follows that this would also lead to less network constraint problems and assist in reaching renewable energy targets.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

If interconnection is displacing synchronous generation, the behaviour of interconnectors needs to compensate for the loss of the system inertia. It is also worth pointing out that alongside the benefits of interconnection in balancing the system, there is also increased risk to the GB system from transferring a serious problem on the continent by interconnection to the GB system. A simultaneous loss of more than one interconnector because of a widespread blackout (such as that which happened in 2006 on the continental system), could lead to serious system stress and frequency exertion on the GB system, possibly resulting in the tripping of demand in GB.

- **Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**

No response.

- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

Under the EC's Third Package's Electricity Regulation, interconnectors are defined as a transmission line. Consequently, interconnector flows are neither classed as production (generation) nor consumption (demand) but part of the overall transmission infrastructure facilitating the wider market and are therefore not liable for BSUoS. As such, it could be argued that interconnectors have an advantage over other 'balancing' technologies, most notably storage, which as noted above pay BSUoS twice.

4. **What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?**

No response.

ENDS

Written evidence submitted by the Institution of Engineering and Technology (IET) / Energy Systems Catapult (ESC) to the National Infrastructure Commission's Call for Evidence on Energy

Introduction

The IET is one of the world's leading professional bodies for the engineering and technology community and, as a charity, is technically informed but independent. This submission has been prepared on behalf of the Board of Trustees by the IET's Energy Policy Panel and takes into account input received from the wider membership, and the views of the Energy Systems Catapult.

The Energy Systems Catapult works with companies that are focused on exploiting the opportunities created by the need to transform global energy systems; not only playing a part in accelerating technology based solutions, but also engaging with Government to address the market mechanisms and business models that will be required to enable such solutions.

The IET and Energy System Catapult are working together to deliver the Future Power Systems Architecture (FPSA) project[1] which follows from the issues raised by the IET the document 'Handling a Shock to the System[2]. The FPSA project is referenced a number of times within this submission.

Summary of views on set up of National Infrastructure Commission

There is no natural market for electricity, or even wider for energy, the "market" is a creation of successive governments, and market mechanisms are used to deliver policy objectives. Investors in both supply and demand side therefore need clarity on long term policy aims, whilst recognising that technological and other change might require policy to be adjusted. The greatest potential benefit from the National Infrastructure Commission (NIC) would be to give a clear sense of direction to energy investors. Investors will generally be understanding of changes resulting from external circumstances such as new technologies, provided they are signalled appropriately, but find change arising from political decisions difficult to assimilate. Such change is seen as introducing arbitrary risk into investment decisions, which is very difficult to price.

Electricity is unlike other infrastructure in that a market is used to make strategic decisions. We do not expect a market to decide where we need a new road. That is something government decides and then we use competition to build (and on occasion finance and operate) that road efficiently.

For the NIC to have a beneficial impact on investment decisions in electricity infrastructure it must develop a track record for three things: **Expertise, Consistency, and Impact**. Without these the NIC will simply add another layer of uncertainty to the electricity infrastructure landscape.

Expertise: Energy issues are complex and interrelated. Electricity, heat, transport, supply and demand have complex relationships which are often poorly understood and caricatured in public debate. For the NIC to gain investor confidence it must somehow develop its own expertise, ideally by consensual working with DECC and industry. It would be badly served if it relies on a series of one off consultant reports into binary issues. A body of expertise is

[1] DECC Future Power System Architecture Project (FPSA)
[2] Handling a Shock to the System, the IET

being created within the Energy Systems Catapult (ESC), and it may be beneficial for NIC to work with and develop the ESC as its expert reference.

Consistency: The proposed five yearly reporting cycles for the NIC would be inappropriate for energy investors. Five years is a long time in energy and the inevitable jeopardy of a major course correction every five years would paralyse investment in some parts of the industry. We strongly advise that the NIC and DECC produce a rolling annual forward view of the expected / desired electricity mix covering near, medium and long term. The long term view would change gradually and be well signalled. The nearer term would be consistent from year to year with only minor changes. This would provide some currently missing confidence to investors.

Impact: If the NIC achieves both the above, ideally with a high degree of industry consensus, then it will make it more likely that future governments will act in line with its recommendations. Over time this will give confidence that the political risk to UK energy investment is low, resulting in lower cost of capital and hence lower consumer bills, and more investment in Britain's energy systems.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Ensuring flexibility services can be acknowledged and rewarded

In a normal market, price signals and high profit margins usually trigger new entrants and new investments however the long term nature of electricity investments and the inevitable political issues involved often makes this difficult. The requirements of the market are also changing given the rise of renewable energy sources, the potential electrification of much of transport and heating, and the transformation of energy usage, storage and production within consumer premises. This requires a much more flexible approach to production, storage and consumption than has been the case up to now, and the electricity market should be developed so that flexibility services can be acknowledged and rewarded. One way of avoiding larger peak electricity demand as heating and transport becomes increasingly reliant on electricity is to create ways in which the demand side can use its natural storage properties (e.g. thermal inertia, or specific energy storage say in vehicle batteries) to allow consumption to be scheduled to some degree to match the capacities of the electricity system. However, creating this capability has many technical and institutional challenges to solve.

A range of commercial and regulatory mechanisms will need to be further developed so storage and other innovative solutions are incentivised to offer products and services to the System Operator (SO) to balance the system. There is a significant volume of work looking at these issues; the following sources of information likely represent the definitive state of the art knowledge:

- Smart Grid Forum Work Streams (WS) 3, 6 and 7, particularly 6. The latest WS6 report addresses changes needed to the market framework to implement Demand Side Response (DSR) into the GB market.
- The IET's and Energy System Catapult's – Future Power System Architecture (FPSA) Project. This project is testing the IET's proposition that the current approach to planning and operating the power system in Great Britain may not be robust to the challenges it will have to meet. The project is carrying out this test by examining the fundamental functions that will be required to plan and operate the power system in response to new user needs.

- <u>What role can changes to the market framework play to incentivise this outcome:</u>

Wide adoption of time of use tariffs that incentivise generation at times of plant shortage and consumption at times of generation surplus

One significant issue with the current market is that the vast majority of demand consumers and small generators have a flat rate tariff and hence have no incentive to schedule their consumption / production to minimise the overall cost of the power system. This could be addressed by the wide adoption of time-of use-tariffs, say half-hourly, that incentivised generation at times of plant shortage and consumption at times of plant surplus. The national roll-out of smart meters is timely to support such a development. The extension of half-hourly settlement to all current profile classes is a prerequisite to Suppliers developing time-of-use tariffs.

The limitations of primary legislation

The electricity sector is governed by the 1989 Electricity Act – which has been amended a few times, although not fundamentally. The fundamental tenets of the Act are to secure reliable supplies of electricity to consumers, to protect consumers and the public from the physical dangers of electricity and to protect the commercial interests of consumers. It does this partially through a licensing regime. Although not explicitly stated, the defacto design assumptions for the Act and its licensing regime reflect the power system of the 1980s with a relatively small number of very large generators connected to the transmission system supplying the vast majority of the energy to passive consumers, with the only formal contact between small consumers and the industry being through suppliers, i.e. the energy retailers. The Act is absent of any notion of generation being local or consumers being active, and such generation or responsive demand trading locally. The assumptions in the Act drive the shape of the market and the licence obligations. Although licensing thresholds etc are in secondary legislation, and therefore in theory more easily changed, it is not immediately clear if this could be a sufficient remedy.

An effective and vigorous market at a local and national level seems to be desirable by current common consent, with local players, generators, communities etc, able to buy and sell power and energy to solve local constraints on networks as well as participating in national energy balancing needs. The technology in terms of small generation equipment, smart domestic appliances, and the very likely near term evolution of affordable storage all point to a very different and much more dynamic arrangement than was envisaged at privatisation in 1989. Additionally, increased competition across the power industry may well be desirable and the opportunities and challenges should be considered. It is not clear if the basic assumptions of the 1989 Act are capable of allowing appropriate growth in local energy services, and a thorough review should be undertaken of the Act and its associated licensing regime. The objectives of the Act are still, of course, completely valid but the way they are enacted risks stifling sensible innovation and development in the sector.

- <u>Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?</u>

Effective system operation and engineering integrity should be key to any governance model of the electricity system

The future electricity system is likely to be very different to today if we continue with current trajectories around decarbonisation, smart homes, smart grids and smart cities, and the greater participation of individual citizens and real and virtual communities of interests in the energy economy.[3] Whilst some aspects of this change will make tasks such as system balancing more demanding than currently, the change will also open many new opportunities to balance the system using resources not currently available, and potentially at lower cost. The Future Power System Architecture Project being undertaken by the IET and the Energy Systems Catapult for DECC currently is exploring the functionality required of the future electricity system, and the engineering implications of that functionality.[4]

It is important that whatever governance models are adopted to accommodate the future electricity system that there is facilitation of effective system operation and assurance of engineering integrity. This will help maximise the opportunities for innovation, by and for consumers, will help maintain system integrity and resilience, and will help minimise balancing costs.

There are both some advantages and disadvantages of moving to a true Independent System Operator (ISO) model and there are a number of options for how an ISO could be implemented. Broadly, the advantages relate to removing any potential for conflicts of interest for the System Operator. On the other hand, the disadvantages derive from separating asset risks and system risks/costs into different organisations, making it harder to balance the two effectively.

We understand that DECC is currently taking a whole system perspective when considering a possible ISO and very much encourage this approach, which is aligned with the IET and Energy System Catapult's thinking on whole system issues from an engineering perspective.

Provided an institutional and market environment is developed that delivers these outcomes we have a neutral view on its form, the extent to which government is or is not involved, and how the industry is organised to perform the roles required of it. However, delivery of these outcomes requires significant understanding of the underlying engineering of the whole system. We would be pleased to assist government in coming to this understanding, and would encourage government to work closely with the industry as well.

Further evaluation is required in order to determine whether a true ISO would be beneficial and if so, which specific approach should be pursued. This evaluation should include building an understanding of why the current SO incentive regime is an insufficient tool in the long term, recognising that Ofgem has the capability to modify it to achieve new objectives as they emerge.

- <u>Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?</u>

Adoption of time of use tariffs and consideration of severe imbalance prices is needed

There is a need for time-of use-tariffs to provide small players with an incentive to contribute to keeping demand and generation in balance. The vast majority of demand

[3] If these trajectories are not followed, and we follow a path of building more large dispatchable power stations, move away from smartness of electricity end use and local energy solutions, and move away from electrification of transport and heat, the future electricity system will change much less. In this case the arguments for change in how the system is operated soften considerably. Such a system could conceivably decarbonise electricity (with nuclear, gas or even coal with CCS and some renewable generation), but would require non-electrical low carbon solutions for heat and transport.

[4] DECC Future Power System Architecture Project (FPSA))

consumers and small generators have a flat rate tariff and hence have no incentive to schedule their consumption / production to minimise the overall cost of the power system. This could be addressed by the wide adoption of time-of use-tariffs that incentivised generation at times of plant shortage and consumption at times of plant surplus. While the smart meter roll-out could be a valuable facilitator here, suitable settlement systems would also have to be implemented. An alternative is that consumers are offered a lower cost flat-rate tariff in return for allowing a Supplier to exercise control over some of the consumer's appliances.

At present the balancing mechanism provides an incentive to contract ahead for expected consumption / production and then to deliver that contracted position. Given that the suppliers currently have few ways of influencing the outcome post-gate closure (and the metering system currently could not record it if they did) there is not a strong case for making imbalance prices more severe. Indeed, if System Buy Price was seen to be more of a risk than System Sell Price (or vice versa) the balancing mechanism would incentivise market participants to go long (or short) and tend to drive up overall system costs.

- <u>To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?</u>

The flexibility potential of demand side management measures and embedded generation is large however to leverage optimal flexibility from such sources, an in-depth understanding into their different characteristics will be required.

Both can provide considerable flexibility in operating the electricity system, both at distribution and transmission level providing they are fully understood, modelled and co-ordinated across the industry. The important factor is the ability to control the generation/demand in an acceptable way. If the generation concerned is a "flow" renewable (i.e. one relying on instantaneous availability of the input energy resource, such as wind, solar or run of river hydro), or nuclear (where there tend to be more costs than savings when output is varied) then it should only be used for balancing when all other options have been explored. Gas fired generation could provide flexibility provided that it was given the correct financial incentives and did not have its flexibility constrained by other factors – e.g. the need to deliver process heat in a combined heat and power scheme[5]. Turning to the demand side, consumers must either have another way of delivering the energy (e.g. dual fuel heating) or storage to allow the demand to be time shifted (charging an EV, hot water tank or thermal store for space heating). There is no incentive for a consumer to engage if they are on a flat rate tariff.

Smart technologies, communication networks, smart appliances and smart meters are key enablers to integrate these types of resources into the electricity system. Many projects and demonstrations have taken place in GB in recent years to prove their ability to provide flexibility; technically both approaches are possible and the evidence is growing that they can make a notable contribution to efficient running of the electricity[6]. We may see market entry from new suppliers in this area, with completely fresh ideas, which may be disruptive. Community energy, smart city developments, and the internet of things are potential catalysts here.

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[5] The same would not be necessarily true for a community heating application, where heat could be produced and stored for later use

[6] Smart Grid Forum Work Stream 7 - DS2030

We would suggest the commercial and regulatory aspects are examined with view to aligning them with these emerging changes. They are perceived to be the main barriers at present. Ofgem's consultation and review of non-traditional business models (NTBMs)[3] will hopefully begin to explore changes to market structures to enable new market entrants to develop new products and services utilising demand side resources and distributed generation.

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

Electricity and other forms of energy storage can play a range of roles in the electricity and wider energy system. This variety of roles is not always well understood outside the industry, and includes:

- The recognised role of storing energy when it is plentiful, and releasing it when it is scarce, over daily or longer cycles.
- Managing the load in a power network, by reducing peak current flows and hence avoiding the need to reinforce distribution systems, typically over a daily cycle, or by providing sufficient reserve capacity to enable supplies to be maintained in the event of an unplanned network outage.
- Providing a fault ride-through capability or covering a short term loss of generation – which tends to be a short term occasional requirement.

The current retail price of electricity is too crude a mechanism to incentivise storage. Not only does it fail to vary as system marginal prices vary, it also rolls up the fixed costs of the power station and transmission/distribution costs into a single kWh charge. This leads to many anomalies such as a small consumer with gas generation having an incentive to run it when there is renewable generation being constrained off in the balancing mechanism. Rather than focussing on how these issues play out for storage, it would make more sense to attempt to make the whole charging structure more cost reflective, whilst recognising issues of social equity.

A model for storage may be to mimic that of an interconnector, whereby a regulated entity owns and operates the facility under a regulatory mechanism (with performance incentives or a cap and collar mechanism) while 3rd parties and other market parties 'pay' for the capacity and use it for commercial purposes, such as energy arbitrage, balancing, frequency response, network support, etc.

High initial capital cost and an insufficient understanding of the impacts and value of storage to other parties

The high initial capital cost of designing, installing and operating a large scale storage system is a deterrent to potential investors. Furthermore, a reasonably high usage factor is required so that the fixed costs of the installation can be recovered while containing the cost per unit of energy delivered. To make such an investment, investors would typically need some certainty around revenue streams. In the eyes of the market, there are many competing technologies (DSR, interconnectors and new gas or diesel fired power plants), so the risk for any storage owner would be that of having a stranded asset. Other challenges for storage are:

- Insufficient understanding of the value streams a storage asset can capture and how they may be stacked to make a facility economic (especially when some of those revenue streams are regulated and some commercial).
- The benefits of a storage asset often accrue to many stakeholders, the market and regulatory structures currently do not reflect this, however work is underway to understand how they could be.
- A storage asset can act as generation or demand, potentially in aggregation or acting at a specific network point. This cuts across many regulatory frameworks and further consideration should be given to how storage is classified and how its value can me monetised.
- No clear way to value the flexibility storage offers to balance variable renewable generation to maximise low carbon usage on the system.
- The risk of a storage technology being supplanted quite quickly by a future storage technology with lower operating costs (eg through better round trip efficiencies).

- <u>What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)</u>

All three scales of storage have potential; storage has a diverse portfolio of applications for different sections of the electricity network. Storage technologies are developing in a way that suits particular applications. For large scale there are Pumped Storage, Compressed Air Energy Storage (CAES), Liquid Air and flow batteries, for distribution Lithium-ion and a range of other novel battery chemistries while at domestic scale the majority of products centre around Lithium-ion or the storage of heat. Typically for transmission-scale, storage would need to be of the order of 100MW+ and given the barrier mentioned above this is a significant challenge. Storage at this scale is significant infrastructure, tending to require bespoke planning and financing solutions.

Many network applications to date around the work have been in the 10-50MW scale and this is ideally suited to distribution system applications, but also as an aggregated distribution network connected source of frequency response for the System Operator. To date this appears to be the ‘sweet spot’ for early larger scale storage applications. The main driver for distribution network deployment is capacity enhancement and investment deferral. It is also deployed in conjunction with solar PV farms, as a means of managing network-related export constraints without curtailing production, and extending the export window beyond sunset when the market price might be more attractive. The economic case is very network specific and often it loses out to conventional reinforcement, DSR or smart commercial arrangements which curtail renewable output. There are other options at this scale, for example integrating community heat and power schemes so that heat is produced and stored when power is not needed, and the schemes switched to power production at times of high demand. Schemes such as this require systems thinking across energy vectors, but the incremental costs of the additional flexibility will be low.

At the domestic scale there are products available from Moixa, Tesla and Sharp to name a few. At present the economics at domestic scale are challenging, even for PV owners, although with reasonable reductions in cost as manufacturers gain scale such investment could become economic even on current Economy 7 tariffs. Further deployment at this scale at current costs would largely require a significant spread on time of use tariffs and/or the ability for homeowners to receive additional revenues from offering the asset to aggregators for balancing services. The system impacts could be large – a 5% market penetration of the

Tesla Powerwall product could roughly equal the capability provided currently by the Dinorwig pumped storage scheme in Wales.

It is worth commenting on the particular case of storing energy in an electric vehicle. This offers a greater pay back to the owner who avoid the purchase of heavily taxed petrol or diesel and prevents the associated GHG emissions. Whilst the energy is never returned to the electricity system, it does offer considerable flexibility regarding when the energy is supplied. For example, charging electric vehicles (and heating hot water tanks) could be a way of boosting electricity consumption at times when renewable generation would otherwise need to be constrained off due to a shortage of demand, albeit consideration would need to be given to any local network constraints. The benefits that can be realised require further study and analysis. It could be value to consider the returns that could be achieved from commercial fleets for example.

All three scales of application offer value to the electricity system and we would suggest barriers are looked at in each case and removed where possible to allow storage to compete with and complement other technologies. Ultimately, the trade-off between the economies of scale for large scale storage and the network benefits and cost reductions through mass manufacture of small scale storage are likely to dictate the outcome.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- <u>Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?</u>

Creation of a single European market for electricity using interconnectors creates opportunities to reduce costs to consumers by optimising the use of generation across time zones, weather systems, and geographic boundaries. It does however mean one needs to trust counterparties in other countries to meet their contractual obligations at times of system stress, if supply shortfalls are to be avoided.

The extent of interconnection desirability depends on the access to the new capacity it provides. Simply increasing the capacity connecting two generation-constrained power systems is probably unhelpful, whereas a diversity of interconnectors accessing a diverse range of generation sources could be in consumers' interest, if provided at reasonable cost.

A further opportunity through interconnection could be large-scale access to renewable energy sources from places like North or West Africa. Such sources have the potential, if developed, to export vast amounts of power to European countries, and could require interconnectors crossing Europe of vastly greater capacity than today. In principle this could assist UK decarbonisation and provide consumers with more cost-effective supplies. However there would be clear geopolitical risks to consider if relying to a meaningful extent on power from African renewables.

An interconnector affects two system operators simultaneously. Hence, a change requires the agreement of two controlling minds. In reality, this could be achieved by allowing/encouraging SO-SO trading post gate closure. However, other market players may not be comfortable with this limitation.

Conversely, interconnector users can (and do) schedule the interconnector to ramp as rapidly as possible to exploit small price changes between the markets. This can cause problems to the SO as the relatively smooth trajectory of changing demand is distorted for a few minutes by the rapid ramping of the interconnector. This causes costs in the balancing mechanism that are picked up by all consumers.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

A comparison of certain electricity systems similar to GB's is being undertaken as part of the IET/Energy System Catapult's FPSA Project. For a full understanding of these insights, we would encourage the NIC to view the final report from the FPSA project.

There are examples of other countries/regions adopting varying strategies in response to their changing generation mix. In most cases this has seen the acceleration of market and regulatory changes to bring flexible solutions to market to ensure system stability continues.

For example in California CAISO mandated 1.2GW of storage be built by the IOUs in a range of applications to support the development of the electricity system. Ireland has pursued a strategy of accelerating interconnection and smart solutions to deal with the challenges of falling system inertia as wind generation frequently makes up 50% of the capacity. PJM in the US has pursued a strategy of supporting demand side response programs along with some large scale energy storage.

It's clear a mix of these technologies will all help provide system balancing. It's not clear if there is an overall clear economic preference as the technologies have very different characteristics, and every power system is different. We would suggest the UK takes a whole-system approach to ensure that we have a suite of technologies that are well co-ordinated and integrated into networks to ensure it remains resilient to system events, integrates significant renewable generation and keeps costs as low as possible.

A whole-system approach will become increasingly important as the character of the national energy system continues to change. These changes are being led by factors such as increasing contributions from renewable energy, the growth of distributed generation and storage, new 'beyond the meter' devices and services, and a fundamental shift to greater consumer and community engagement and empowerment in energy. Many of these developments will need to be controlled using large and complex IT systems. It is likely that the resilience of these control systems will be an important theme in maintaining security of supply for energy in the coming years.

A whole-system approach requires issues to be addressed that are wider than technology alone: these include regulatory and commercial frameworks, industry change controls, governance mechanisms, and consumer awareness and behaviour. All are critical to facilitating practical changes in a timely way and encouraging innovation and entrepreneurial actions and must acknowledge any electricity future is likely to be significantly influenced by the choices we make about the interrelationships and co-dependencies between electricity, gas including heat (thermal comfort) and transport. We note here the need to view the relevant work being undertaken by the IET and the Energy Systems Catapult on the Future Power System Architecture project[7].

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[7] DECC Future Power System Architecture Project (FPSA)

Innovate UK

The Innovate UK response to the National Infrastructure Committee's call for evidence on Electricity Interconnection and Storage.

1. Innovate UK is the UK's innovation agency, a non-departmental public body sponsored by BIS. It is the prime channel through which the Government incentivises innovation in business. Innovate UK is business-led. Our governing board and executive team is comprised of experienced business innovators and experts. We work with people, companies and partner organisations to find and drive the science and technology innovations that will increase productivity and exports and grow the UK economy.

2. We are working to:
   - accelerate UK economic growth by nurturing small high-growth potential firms in key market sectors, helping them to become high-growth mid-sized companies with strong productivity and export success;
   - build on innovation excellence throughout the UK, investing locally in areas of strength;
   - develop Catapult centres within a national innovation network, to provide access to cutting edge technologies, encourage inward investment and enable technical advances in existing businesses;
   - turn scientific excellence into economic impact and deliver results through innovation, in collaboration with the Research Community and Government; and,
   - evolve our funding models to explore ways to help public funding go further and work harder, while continuing to deliver impact from innovation.

3. In line with our strategy[1] we operate across Government and advise on polices which relate to technology, innovation and knowledge transfer. We also support Government departments to become more efficient by supporting them in developing innovative solutions through harnessing the creativity that businesses can offer.

4. Innovate UK was established in July 2007 (as the Technology Strategy Board). We have committed more than £1.5 billion to date and independent evaluations have established that overall Innovate UK has created over £6 of GVA for every £1 it has invested and 7 jobs for every business it has invested in. Over the last 8 years this has added up to delivering a total of £7.5Bn and 35,000 jobs. The private sector more than matches that investment, doubling the power of public sector money, and we have directly supported over 6,500 companies. We work with nearly every University in the UK to stimulate the commercialisation of leading-edge academic research and innovation.

5. The energy sector has grown into one of Innovate UK's key priorities. Our aim is to help innovative UK businesses to take advantage of the opportunities that a rapidly changing energy system will present, both in the UK and in overseas markets. Over the last parliament we have invested up to £60m per year in support of hundreds of innovative businesses developing new products across the energy sector, from new supply technologies, through to new network-

[1] 'Concept to Commercialisation: A strategy for business innovation, 2011-2015'. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/360620/Concept_to_Commercialisation_-_A_Strategy_for_Business_Innovation_2011-2015.pdf

based products and energy use efficiency services. Our 2012 – 2015 energy strategy articulates our objectives in this sector.[2]

6. Innovate UK supports businesses in two main ways. Firstly, we provide funding to allow development of high potential, ground-breaking new technologies and products that are too early and too risky for the private sector to fund alone. Secondly we help businesses connect to the right partners, expertise, test facilities, financiers and influencers that can accelerate their route to market. Examples of this support are the Catapult centres, launched by Innovate UK to provide critical expertise and test facilities to businesses in developing new products. Two of these are in the energy sector; Offshore Renewable Energy Catapult in Glasgow and Blyth, and Energy Systems in Birmingham.

7. A growing part of our energy portfolio is in 'energy systems' (by which we mean the development of an optimised, flexible, reliable and cost-effective system of energy supply across electricity, heat and gases). The experience gained in funding projects in this field, alongside setting up the Energy Systems Catapult has provided a great wealth of knowledge about the possibilities that will be provided by new technologies, products and services in optimising and enhancing flexibility of the energy system in the near future. This submission is written through this lens, intending to ensure awareness of the art of the possible in enabling network flexibility.

8. In summary this submission makes the following points, illustrated by our experience and projects:
    - Storage, Interconnection and demand response are three methods of providing critical flexibility to the network at times of stress. They should all be evaluated and incentivised on the same terms and built out in the most cost-effective way. There is little benefit in establishing a storage target or an interconnection target without a full evaluation of these technologies against the flexibility that can be provided by demand response or other methods.
    - We see a very large potential for demand response to provide cost-effective balancing services to the network enabled by new technologies such as sensor and communications developments, digital trading and aggregation platforms, new power electronics and more local engagement in balancing distributed generation to enable energy resilience. There is a risk of over-investing in new high capital infrastructure if the potential of these new resources, products and methods is not taken into account
    - Enabling the widest range of actors to take part in balancing the grid can enable lower bills for users and minimise investment costs. There are barriers in regulation that stop this from happening at present.
    - New business models that provide value across the range of actors in the network, and serve the needs of the end user will be just as important in enabling these opportunities as new technologies. Disruptive thinking from outside the sector can help accelerate the development of flexible grid systems but need to be encouraged alongside flexible and innovative regulation. We are starting to see Ofgem understanding the importance of this.
    - The pace of change in this sector is rapidly increasing. We are seeing a very high demand for support in this area from businesses, and multinational energy technology companies starting to engage heavily in these new ways of balancing the energy networks. It is essential that infrastructure is planned with these emerging technologies in mind to avoid saddling energy users with higher bills than necessary for decades to come. Our detailed submission follows.

[2] Innovate UK energy strategy at https://www.gov.uk/government/publications/energy-strategy-2012-to-2015

Q1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

9. **Summary of Q1 key points:**
   - The goal should be an electricity market that provides for the needs of current market stakeholders but is also very flexible to allow for future innovative disruptive business models that are likely to emerge at very short notice from outside the traditional energy sector e.g. the digital/ICT sectors in particular.
   - Innovate UK has a significant role to play in bridging the gap between current/future innovators interested in this sector by working with stakeholders such as DECC, Ofgem, and Elexon.

10. Supply and demand balancing methods are extremely varied, encompassing both supply and demand side tools at multiple scales, with many different types of stakeholders participating. Providing future low cost balancing tools (such as increased demand response, of which storage is a subset) which meet the needs of all users in the system will require innovation and creativity to bring forward new business models and technologies.

11. Below are two relevant types of business model that are becoming visible through Innovate UK funded projects:
    - Local energy use, and business models that encourage locally sourced energy to be used locally, such as for community benefit (reduced energy costs) and network operator management of asset life (through reduced thermal stress, and therefore investment deferral). Current market mechanisms and network use charging methodologies do not encourage this.
    - Micro energy trading, the ability for the owner of a small-scale low carbon technology asset to trade their energy or capacity on an ad hoc basis to another party who may or may not be local. This effectively means that this asset owner is a micro "ad hoc" energy supplier, which some existing market mechanisms do not cater for.

    New business models are emerging rapidly that enable these kinds of demand response in reaction to local or national grid needs, enabled by data and communications technologies emerging from across the economy. Future infrastructure plans need to take account of the pace of change in these emerging areas to avoid building infrastructure that is not fit for the 2020s and beyond.

12. In some of the above business model scenarios, storage is just one (but not an essential) type of energy resource involved. Over the coming 18 months as the above projects conclude, we will have a much clearer picture as to whether innovations of the above nature will lead to a significant reduction in the energy costs for those involved, though they do align with strong community (and individual energy user) interest in taking more control of energy locally and personally.

13. Innovations of the above nature will drive the need for changes in the way the current supplier model works, potentially requiring changes to the financial transaction and cost recovery processes that underpin the current energy system. Such reforms are not trivial as the current mechanisms are already extremely complex and based on the current industry structure. This challenge is something recognised by Ofgem and DECC. Elexon are also an essential party to facilitate this change and are forming a new innovation working group in early 2016 to engage with this agenda, and Innovate UK will support this knowledge and innovation bridging process.

Q2. What role can changes to the market framework play to incentivise this outcome:

- **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**

14. Other parties are better positioned than Innovate UK to answer this question.

- **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

15. Innovate UK is currently running a number of innovation development and demonstrator projects that show that the current balancing market is able to bring in new market participants and offer end value for customers. If successful they could engage end users more effectively in energy use, and energy management (such as making use of demand response, time of use tariffs, encouraging local energy production and use), enabling end users to reduce their energy costs[3].

16. The transparency that provided by the current mechanisms effectively rewards energy efficient use, and conversely disincentives high cost or polluting energy use. While Innovate UK does not currently have specific balancing market reform recommendations to make at this time, anything that increases the degree of transparency or fuller access to market mechanisms is welcomed.

17. There is potentially great benefit in enabling as wide a range of actors to participate in balancing as possible. If time of use pricing were available to all users, they could take advantage of new technologies and business models that enable them to minimise energy use at times of high price and vice-versa. Innovate UK has recently funded Tempus Energy to develop their technology designed to enable this for small businesses and domestic consumers, delivering lower energy costs and a more balanced grid.

Q3. To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

18. **Summary of Q3 key points**
    - There are very significant opportunities in enabling demand response to deliver flexible network balancing resources by harnessing existing assets that are either unused or underutilised.
    - Catalysing new business models that enable fragmented benefits across the system to be aggregated to its full value is key to unlocking additional demand side and embedded generation capacity.
    - Using existing assets to provide balancing flexibility at key times of grid stress are likely to be much more cost effective, and therefore prioritised over build and operation of new assets, whether additional storage, generation or transmission.

19. Demand side measures
    Innovate UK believes there are significant opportunities to provide additional demand response capacity (DSR) using existing assets both to reduce system load when required but also to increase load (responsibly) when required. Evidence to support this:

[3] The list of projects in our localised energy systems programme is available at: https://interact.innovateuk.org/documents/1524978/14654581/Localised%20energy%20systems%20-%20a%20cross-sector%20approach%20-%20Competition%20results

- A recent DECC commissioned study[4] concluded that there is significant additional demand side response (DSR) potential in the future in many application areas. The study considers different future scenarios (based on the National Grid Future Scenarios modelling[5]) and given there are many uncertainties and variables the report makes it difficult to give a conclusive forecast.
- Below are some comparisons of asset capacities from Innovate UK sources that support that view. They are demand response/storage assets that are either currently completely unused currently, are only partially used or have significant future potential:

20. Assets currently unused for demand response
    - Hot water typically held in domestic hot water tanks where the sole heat source is electric immersion heaters – "in store" at any point in time = 23GWh approximately[6]. There will also be a hot water storage opportunity in commercial applications though this has not been quantified.
    - Distributed battery storage such as fork lift trucks.

21. Assets currently only minimal demand response capacity used
    - Cold stores/chillers.
    - Electric storage heaters. These are used in approx. 10% of UK dwellings[7]. Although many of these are aligned with Economy 7 tariffs, this is a passive use incentive system, not providing the active or dynamic value that such resources could provide if engaged in DSR, providing 3GW[8] of demand response load
    - Commercial building (e.g. air conditioning) and buildings heated by heat pumps (e.g. domestic). By treating the building effectively as a thermal battery short term by intelligently increasing or decreasing the activity of those systems over short (sub 30 minute) electricity network balancing can be achieved with effectively the same functionality an electricity storage asset. This opportunity will grow with the anticipated take up of heat pumps.
    - Industrial and commercial capability that is currently untapped or underexploited such as in the food and drink sector.

22. Future asset bases with demand response opportunity
    - Electric vehicle (EV) and plug-in hybrid vehicles (PHEV). The current electricity storage capacity of these vehicles on the UK roads 0.5GWh (based on Society of Motoring Manufacturers and Trader vehicle sales figures, assuming Nissan Leaf EV capacity for all EV, and Toyota Prius capacity for PHEV), rising to a capacity of 2GWh by 2020 and 4GWh by 2025 (assuming a year on year sales growth rate of 5). These figures are a very cautious minimum – the like for like 2015/2014 UK EV sales saw a 50% rise, and PHEV nearly 150% rise in sales.
        - This could provide significant capacity for demand response and Vehicle-to-Grid capability in the future with the right business models and infrastructure provision.

[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/467024/rpt-frontier-DECC_DSR_phase_2_report-rev3-PDF-021015.pdf
[5] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Future-Energy-Scenarios/
[6] https://www.reading.ac.uk/web/FILES/tsbe/Saker_TSBE_Conference_Paper_2013.pdf
[7] https://www.reading.ac.uk/web/FILES/tsbe/Saker_TSBE_Conference_Paper_2013.pdf
[8] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/467024/rpt-frontier-DECC_DSR_phase_2_report-rev3-PDF-021015.pdf

- The Ofgem Low Carbon Network Fund (LCNF) funded SSE project "My Electric Avenue[9]" project has highlighted this as a credible opportunity from the perspectives of both energy system operators and vehicle user (assuming optional participation).
  - The TSO has just completed a study of the potential for EV and PHEV battery use[10] for grid frequency support, concluding a very positive outlook for the value to the network for balancing services.
  - Innovate UK believes business models will emerge that will support this opportunity.
- Second life (end of vehicle life, but still functionally useful for other energy applications) batteries from electric vehicles (and potentially the smaller batteries in plug-in hybrids), will start to become available in the next 6-7 years and in progressively larger numbers as the rising population of vehicles on the roads ages. These have the potential for re-use as grid support storage assets.
- Forecast 30% minimum bus fleet conversion to battery electric by 2025 (Western Power Distribution data sourced in its Electric Boulevards project[11]) based on surveys of bus operators.

23. The majority of the above areas have "turn up" capacity potential as well as demand reduction, effectively offering the characteristics of storage.

24. Embedded generation measures
Commercial scale. At larger embedded generation sites, Network operators already operate curtailment of large scale distributed generation in some circumstances, agreed with the asset owners as a means to achieve lower connection charges and manage local thermal constraints. An example is the UK Power Networks LCNF funded Flexible Plug and Play Project[12] an approach which enables increased embedded generation connection at different scales and voltage levels with acceptable levels of curtailment. This affects commercial wind, solar, and CHP connections and is an arrangement that has the potential for more wide-scale deployment.

25. **Micro scale.** At this scale (typically on a customer side of the meter), management methods for generation output are being explored by a number of Innovate UK projects[13], either coupling micro generation with storage, or incentivising local energy use. Specific examples of Innovate UK projects that are developing new balancing demand response capabilities are:
- **Project Upside** – providing aggregation of a wide range of distributed energy assets including demand side and storage. One of the assets targeted in this project are uninterruptible power supplies, with an estimated 2GWh of storage accessible to the Upside business model
- **Project EFES** – providing local energy balancing with distributed micro generation and storage, balanced against local energy use

26. In the case of both of these, the challenge they are seeking to address is to aggregate fragmented small scale resources and monetise value that is also fragmented and spread across different stakeholders in the system. This is a key innovation opportunity area for Innovate UK, supporting entrepreneurs in finding ways to draw together these fragmented benefits in bringing creative new business models and technologies to market, liaising with the necessary policy and regulatory

[9] http://myelectricavenue.info/
[10] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Technology-reports/
[11] http://www.westernpowerinnovation.co.uk/Projects/Electric-Boulevards.aspx#FAQLink53;javascript:void(0);
[12] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/
[13] https://interact.innovateuk.org/documents/1524978/14654581/Localised%20energy%20systems%20-%20a%20cross-sector%20approach%20-%20Competition%20results

change processes in support, as well developing new supply chains for innovative solutions to be commercialised.

27. As an example of the business model challenge, in the aforementioned My Electric Avenue[14] project the effect of electric vehicles on the local low voltage grid infrastructure was studied. It estimated that the benefit "to the DNO" of time being able to time shift EV charging (e.g. into the middle of the night) as circa £20 per home per year to a DNO in avoided deferral. This alone is not felt to be a sufficiently compelling value proposition in its own to engage end users successfully or support a business model that delivers this functionality alone. However from a TSO innovation project[15] there is an additional opportunity to add in another piece of fragmented value that of providing grid frequency support services with Vehicle-to-Grid functionality, adding circa £25 per vehicle per year potential benefit for the vehicle owner/driver. The table below summarises the creative challenge of finding a business model that can aggregate and monetise these different types of fragmented value.

Function description	Beneficiary	Value to beneficiary	Benefit criteria
Remotely "managed" charging	DNO	Circa £20	This benefit is only applicable when the vehicle is charging (or needs charge) and is connected to a weak or thermally constrained part of the network, with the greatest likelihood that this would be called during the evening peak
Vehicle-to-Grid	TSO	Circa £25	This benefit could be realised at any time of the day and is generally not location-specific

Q4. What are the barriers to the deployment of energy storage capacity?

28. **Summary of Q4 key points**
    - Regulatory and market cost mechanism changes need addressing.
    - Successful creativity to increase DSR capacity using existing and emerging energy resources will reduce business case for dedicated "new" storage assets.
    - Battery technology costs will continue to reduce, forecast by circa 50% by 2020.
    - From an energy system functionality perspective network operators view storage as no different to DSR in their "tool box" for network balancing.
    - Justifying new storage assets for network balancing is likely to be a more capital intensive option than most other flexibility tools (interconnectors being the main exception).

29. Background
    - Transmission and distribution network operators do not envisage business as usual storage deployment within the current RIIO ED1 period from the perspective of thermal management or investment deferral. In the longer term it is very uncertain what the storage needs for the UK energy system will be, and the extent to which it will be needed. One of the objectives of the new Energy Systems Catapult is to inform this thinking.
    - There is currently very active TSO engagement with providers seeking new system frequency control capability, including many storage providers.
    - Storage is regarded functionally by distribution network operators as a means of providing demand response capability, and hence when seeking future additional demand response capability for thermal management they will be agnostic as to whether that capability is provided by storage or other means, For example contracting in the capability to reduce or

[14] http://myelectricavenue.info/
[15] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Technology-reports/

increase load in a particular locality they look for the least cost means of achieving this whether that be by customer demand reduction, customer demand increase, or storage.

The perceived barriers to storage are described in the following two sections:

30. Barriers to the use of existing/future storage assets in grid support
    In answer to question 3 we listed storage assets that are either not utilised for grid support or where there is only a limited amount of utilisation, the most significant being:
    - Electrically heated hot water tanks, both domestic and commercial.
    - Storage heaters.
    - Cold stores/chillers.
    - Electric and plug in vehicles for demand response and vehicle to grid.

31. The principal barriers to the deployment of the above opportunities are:
    - Less appetite/interest by innovators in thermal (both hot and cold) storage innovations. An analysis of the funding for research and innovation projects funded by both EPSRC and Innovate UK, showed the number of funding awards for electricity storage outnumber the number of funding awards for thermal storage by a ratio of 7:1. A common view in the innovation community is that thermal storage isn't regarded as exciting as electricity storage.
    - The above factor leads to a limited engagement in exploring technology/business models that exploit commercial opportunities where thermal storage might be controlled in a manner that provide grid support. That isn't to say there is no activity; there are some examples of healthy activity such as increasing use of DSR for the control of aggregated commercial refrigeration loads and the commercial building/facilities sector is starting to engage in this area.
    - Active funding support to encourage demonstrators and the formation of new business models is a barrier to progression in these areas and Innovate UK is now assessing this funding priority amongst its other funding priorities going forward.

32. Increasing the future exploitation of the above resources could be achieved if opportunities were taken early to future-proof thinking and solutions where possible. Examples are:
    - Given the potentially significant balancing resources that will be available from electric and plug-in hybrid vehicles the automatic provision of Vehicle-to-Grid capability in charging points should be considered at the earliest opportunity.
    - Remote control provision for all new storage heaters to enable future innovation and business models to take advantage of.

33. **Barriers to dedicated new grid support storage**
    Non-technical barriers
    The barriers to deployment of new storage vary depending on the location of deployment. For example for network operator owned storage the barriers are more regulatory (e.g. legal status of storage) whereas for micro storage on a user's property lack of availability of time of use tariffs are a barrier to market. Below is a list of the main non-technical barriers:
    - Availability of time of use tariffs (smart meters rollout is essential to enable this).
    - Network Use of Service (UOS) cost mechanisms are extremely complex and do not work in a way that easily enables or encourages local and self-use of energy.
    - Ability to stack services on a given resource (i.e. to use a particular asset to provide different types of DSR service to different stakeholders). Network operators (especially the TSO) need different levels of certainty for different types of demand response and so have traditionally required asset exclusivity for different demand response functions. It is fully

recognised by the TSO that this makes the business case for dedicated storage weak currently and that as it increases its confidence in different asset and service types, that this requirement will soften in time and so improve the business case for storage usage.

- Status of storage from a regulatory perspective. For network owned storage this is a barrier. Storage is currently classed as a generation asset in the current regulatory model, and therefore does not fit with the regulatory definition the network operators have to work within.
- Successful acquisition of more DSR capacity is a barrier, for example every 1GWh of DSR capacity that can harnessed for grid support reduces the need and weakens the case for storage.

34. **Technical barriers**

- Technology cost (a factor at all scales and for all technology types). Industry predictions regarding the rate of fall in costs for battery storage vary but costs are typically quoted to fall by 50% by 2020, driven largely by the growth in electric and hybrid vehicles.
- Use of storage incurs energy conversion efficiency losses. These vary depending on the storage technology used. The technology most commonly used for electricity storage is Lithium Ion batteries which in grid applications demonstrate round trip efficiencies reported of approximately 80% (Northern Powergrid CLNR Project report)[16]. Low loss power electronic devices would improve this but they are not deployed in these applications because of their cost (of the order of >10x conventional technology).
- With energy conversion losses above of 20% this loss manifests itself as heat, forced air cooling of the equipment is required. Network operator trials have highlighted noise from cooling as being problematic with local residents in the vicinity of larger storage installations.
- There are a number of alternatives to battery storage in other energy vectors such as flywheels, compressed air, hydrogen, liquid air but their technology maturity is generally weaker and costs higher than Lithium Ion.
- Internet of things (IOT) market development. The information connectivity that will come from smart meters and IOT data for example has the potential to make an enormous impact and enable network operators to draw on DSR/storage resources in ways that we cannot conceive. As a comparator, the iPhone App store had 5000 Apps on it in 2009 – it now has 1.5 Million. The sort of business model creativity that produced Airbnb, Uber, and Waze is therefore anticipated to be a key opportunity in creating business opportunities that support the needs of energy balancing and end user engagement.

Q5. Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

35. **Summary of Q5 key points**

- The principal economic barrier is cost/investment costs, which will inherently be more expensive than DSR control of an existing asset.
- Because of its technical origins the dialogue around storage has historically been one of "technology push". Now that the agenda is shifting towards one of anticipated future commercial deployment there needs to be a clear and methodical focus across the sector on the range of likely common usage case scenarios and the economic case for each. This will provide the most effective and structured approach to evaluating the comparative

[16] http://www.networkrevolution.co.uk/wp-content/uploads/2015/03/CLNR-G026-Project-Closedown-Report-FINAL-V2.pdf

economics with DSR and the clearest view of barriers and investment cases for each use scenario.

36. Market failures/barriers
    - As a demand response tool, deployment of new storage assets for grid support is disadvantaged in its business case compared with DSR of existing assets because of the investment cost and management cost inherent a new asset resource. Despite this and the other barriers identified above, a number of network operators have been approached by third parties in recent months interested in connecting storage at distribution level to provide frequency balancing services to the TSO, wishing to engage early in what they see as an attractive sustainable future growth sector.
    - There is poor clarity of the commercial viability of storage deployment given the range of potential applications, the different benefits and barriers case to each and the different technology options.

37. Overcoming the barriers specific to storage
    Building and addressing the last point above, Innovate UK believes that there is a need for the sector to focus on the market failure/barriers to storage in a different way to how it has done so to date. The following are observations and sector characteristics for background:
    - This part of the energy sector has historically been heavily driven by "technology push'.
    - There are many different application scales (we believe of the order of 10-12) generic deployment/usage scenarios for electricity storage ranging from storage operated at the transmission level through to micro storage (e.g. domestic) at the other end of the scale.
    - The benefits, barriers, business models and technologies for each scenario are different in all cases.

38. The result of the above is a very complex and confusing picture with dialogue frequently segmented into separate areas of technologies, benefits, barriers, trials, without a clear picture for understanding or communicating the current commercial viability or outlook for the aforementioned 10-12 scenarios. This lack of clear perspective is in itself is a barrier to progress because it is hindering successful engagement of broader stakeholders.

39. Innovate UK has recently been advocating with stakeholders that a move away from "technology push" thinking to a thought process and communication approach that focuses around the above common scenarios on an individual case basis, so effectively describing the commercial picture for each of the 10-12 scenarios. So for each scenario in turn this would include:
    - The benefits and beneficiaries.
    - The options for monetising the fragmented benefits from the beneficiaries.
    - The barriers specific to that scenario:
        - what actions are needed to break them down?
        - which barriers will fall away naturally with time and when?
    - The most likely appropriate business model.
    - The most favourable technologies.
    - An overall view of the strength of the commercial viability for that scenario.

40. As well as providing a focus and clarity for the storage sector such a "commercial case scenarios" approach would also aid the development of business models or monetisation methods for other balancing innovation opportunities with other types of DSR asset. Innovate UK has found stakeholders very receptive to adopting this focus.

Q6. What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

41. **Summary of Q6 key points**
    - Given the size, diversity and varied history of our electricity network, storage is likely to prove to be needed and economically viable at various system levels and scales. There is unlikely to be an 'ideal size or scale".
    - There are too many variables in take up of low carbon technologies and in the future energy source mix to warrant simplistic rules on the extent to which storage will be required or timing of need.
    - Scale and location of storage should be led by the need of the application, deployed as and when those needs arise or when needs are identified as part of normal network planning. In all cases, taking careful consideration of the future likely scenarios known at that time for that locality is essential in order to minimise unnecessary infrastructure cost and avoid locking in solutions or assets that subsequently create other problems or unnecessary costs downstream.

42. Commentary to support the above
    Network/commercially deployed storage
    It is not possible to predict when and where storage will be the best balancing solution to deploy because of the significant unpredictability of low carbon technology deployment, both in type, extent and geographic location, uncertainty of our future energy source mix and uncertainty to which other balancing opportunities are exploited. Having a wide range of energy balancing and network management options (storage being just one) that can be deployed very quickly on a needs basis is the best approach to minimise additional infrastructure cost, and therefore cost to customer, and provide the most reliable solution for their local need. The network operator LCNF innovation programmes demonstrate the breadth of solutions being trialled directly in support of this aim.

43. The UK network is extremely diverse in its nature, local design, asset age, scale, load profile. The network operators have installed storage 14 locations in different LCNF projects all at different power and voltage levels. The chart below shows their power and capacity distribution.

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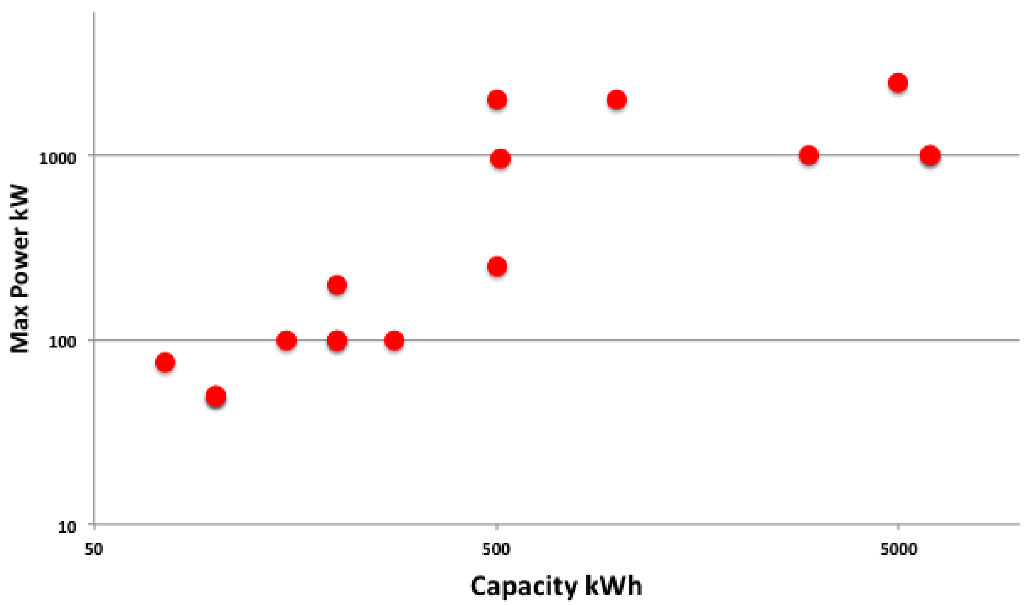

44. A common observation on the outcomes from such trials is that storage could have an appropriate network balancing role at a wide variety of voltage levels and capacities depending on the local need. Network operators may therefore in the future consider storage as a solution, at the scale and voltage level needed to suit the local circumstances as they arise, and balanced against other options for resolving those network constraints such as available conventional DSR.

45. The focus of many of Innovate UK projects is to aggregate smaller assets, including both utilisation of existing and new assets, with a portfolio of innovation projects currently in progress to evaluate the technical and commercial opportunity. The outcomes from these projects will be in the 9-18 month range. It is difficult to say how valuable the aggregation of these more fragmented assets will be from a system balancing point of view, although they certainly have other potential benefits such as energy user engagement. Innovate UK observes that many of the backgrounds and personal skill sets in these projects are from the telecoms and ICT sectors, who as newcomers to the sector, are demonstrating their ability to be both creative in terms of business model and to develop their propositions very quickly. It is important to mention that their ingenuity is focussed on providing sustainable business models that support balancing rather than storage deployment per se, but their creativity provides insight into the "art of the possible" both in terms of demand side system balancing but potentially supply side also.

Q7. What level of electricity interconnection is likely to be in the best interests of consumers?

46. The answer to the degree of interconnection required is dependent on the degree to which balancing tools can be achieved through other and lower cost means such as provision of additional demand response, take up of renewables, and improvements in renewables generation output forecasting.

Q8. Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

47. As described above, Innovate UK believes there is a great deal of potential for system balancing functionality that could be released by capturing the value of existing and forthcoming energy storage/demand response capable assets, and that deployment of these will benefit greatly from the digital sector, internet of things, and creative business models. Taking advantage of these anticipated "low investment" balancing tools should be considered as a first priority, and offset the need for high capital solutions such as interconnectors.

48. These "low investment", easy to achieve opportunities also frequently serve to engage end users very positively, and so contribute to improved end use efficiency, something that further interconnector capacity will not achieve.

49. The speed of change of many of the new business models emerging out of use of digital technologies and data means that new demand response opportunities are emerging very quickly. In this climate, it would seem poor use of public money to invest in high capital infrastructure faster than is needed, since the risk of building under-utilised assets is high.

Q9. Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

50. Please see the answer to the previous question.

Q10. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

51. With the exception of the US, the UK is probably one of the world leaders in the development of flexible energy systems. The circumstances in every country are different with different energy source mix, energy use profile, system architecture, legacy equipment and decarbonisation strategies. However, there are significant learning opportunities:
    - At the macro level there is potential learning regarding how other countries plan, and design their future energy systems, in particular the mix of generation technologies, cross vector solutions (e.g. power to gas, market structure) and energy system decarbonisation strategies
    - At the micro level there is likely to be useful value in understanding methods other parties have developed for policy and regulation, monetising and aggregating value streams for different parties with a view to understanding how these could help the UK creativity in terms of business models, and practical innovation solutions.
    - Innovate UK already has a relationship with our peers in France and Germany and will seek to increase this engagement going forwards. For example, France has a unique network balancing environment with its high proportion of nuclear energy generation, and Germany has significant geographical energy balancing issues with a large proportion of its intermittent renewable generation in the North with a large proportion of its industrial energy use in the South.

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RESPONSE TO NATIONAL INFRATRUCTURE COMMISSION CALL FOR EVIDENCE: ELECTRICITY INTERCONNECTION AND STORAGE

ITM Power
22 Atlas Way
Sheffield S4 7QQ

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

1. The value proposition to ensure excess renewable electricity is utilised rather than curtailed needs to be specified and made clear to all stakeholders.

2. A limit on the amount of excess energy that can be curtailed per year needs to be implemented, with associated incentives and penalties arranged within a remuneration framework, so that appropriate low-carbon balancing solutions can be implemented.

3. The electricity grid operator should be charged with achieving low carbon objectives in its operational/balancing practices; it should apply appropriate payment levels for balancing services pertaining to the conventional use of CO_2-emitting fossil power plant and the emerging use of non CO_2-emitting energy storage technologies and controllable loads.

4. The grid operator should be charged with achieving a 'carbon merit order' in the operation of the UK's power plant at all times and specifically for all grid balancing. The balancing market needs to be reformed to ensure operational practices are well aligned with maximising the year-on-year decrease in grid carbon intensity, within the limits of what the grid operator can achieve with the generators, energy storage facilities and load control options available in the year in question. The responsibility should rest with the electricity grid operator in its role to balance and achieve a greener power system.

5. The market framework needs to span both the electricity and gas sectors, to enable the transfer of excess energy from the power system into the extant gas grid by "power-to-gas" (P2G) systems. This will help limit balancing costs, electricity infrastructure upgrade costs

and also reduce the GHG emissions of the gas grid.

6. The value proposition to the gas grid to receive renewable energy from the power sector, in the form of hydrogen or synthetic methane, in order to help it decarbonise needs to be specified and made clear for all stakeholders.

7. The GS(M)R (Gas Shipping (Management) Regulation 1996) regulation which specifies the permitted hydrogen concentration in the gas grid needs urgent revision, so the UK adopts higher concentration limits that are similar to those applying already in other EU countries. In 2013 the GridGas study recommended to DECC and HSE that a volume concentration limit of 3% be adopted in 2015, but no associated adjustment of the GS(M)R regulation has yet been made.

8. DSM (Demand Side Management), embedded generation and energy storage are good methods for helping balance the electricity system. Clear remuneration arrangements need to be put in place if these are to displace the use of CO_2-emitting reserve power plant. However certain fundamentals should be kept in mind:

    a) Embedded generation can cause imbalances and require electricity infrastructure upgrades to manage voltage and reverse power flow during periods of low demand within the lower levels of the power system. Therefore an embedded generation plus storage approach is needed.

    b) The application of Power-In/Power-Out energy storage technologies follows the law of diminishing returns - as valleys in the load profile get filled and peaks get clipped by this form of energy storage, the economic justification for deploying further amounts of it decreases. Accordingly implementing a cost-effective remuneration mechanism for this type of energy storage is problematic.

    c) The application of Power-to-Gas energy storage does not follow the law of diminishing returns - as the power system de-carbonises, it can be utilised to mop up increasing magnitudes and durations of excess renewable energy from the power system as they occur without limitation, while simultaneously assisting de-carbonisation of the gas grid. Accordingly a remuneration mechanism can be implemented for this type of grid balancing, in the knowledge that the annual utilisation of a P2G plant can increase as the electricity system de-carbonises. It is important that the measures implemented appropriately motivate stakeholders in both sectors (i.e. the electricity and gas).

    d) DSM is useful but its ultimate potential is limited, because research shows that load shedding and load shifting soon infringe upon consumer/industrial behavior and end user expectations. Traditionally DSM has been applied successfully to reduce peaks in the load profile. However its application within a high Renewable Energy Source ('high-RES') power system requires loads to be operated at times of excess energy, which coincide with periods of low national demand (overnight for wind, summer afternoons for solar). The feasibility of legitimately shifting the operation of some loads to improve the flexibility of the electricity system needs to be weighed carefully against the shifting of other loads by users in an energy wasteful manner to access the remuneration mechanism (e.g. switching lights on all night unnecessarily in order to receive a balancing payment

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

9. The main barrier is the lack of storage targets and an energy storage policy for the UK to deal with the emerging operational issues of power sector decarbonisation (i.e. renewables integration and old fossil fuel plant closure).

10. The grid operator needs to identify availability and utilisation payments by energy storage technology type, or balancing services category, so that the requirement to use CO_2-emitting fossil plant for balancing diminishes and the use of energy storage increases.

11. Clarity is needed about the amount of excess renewable energy that is allowed to be wasted/curtailed per year as the power system decarbonises, in order to guide the deployment of energy storage.

12. A dedicated scheme is needed to encourage Power-to-Gas storage and make use of the sunk capital and hidden nature of the UK's capacious gas grid.

13. Clear distinctions need to be drawn between Power-in/Power-out storage and Power-to-Gas storage and policies adopted to achieve appropriate implementation levels for the UK.

14. The present GS(M)R regulation stipulating a maximum 0.1% hydrogen concentration limit in the UK gas grid needs to be raised to come in line with other natural gas grids in Europe (e.g. 10% in Germany, 12% in Holland), so that a power-to-gas market can commence here.

15. The HSE has expressed its support for Power-to-Gas in the UK and its belief that it will help demonstrate the safe use of an emerging and sustainable technology, provide an opportunity for HSE and other regulators to develop a template for enabling the safe introduction of the technology in support of the UK's 'growth' agenda, help to develop a sound evidence base for future changes to the permitted composition of natural gas transported in pipeline networks in the UK. In addition, adjustments to the GS(M)R regulations would support the future exploitation and use of 'unconventional gases' such as shale gas in the UK.

16. With respect to size and scale, energy storage is mainly needed to face onto and manage the effects of:

a) an increasing wind penetration, requiring multi-MW stores in the medium voltage and high voltage electricity networks,
b) an increasing solar penetration, requiring sub-MW and MW stores in the low voltage and medium voltage electricity networks,
c) a decreasing amount of system inertia due to the closure of traditional thermal power generating plant

The total amount of storage and number of plant to be realised in the UK depends on the requirement (in MW or GW) of each category of balancing service and on expected excess energy levels by target year (2020, 2030 etc.). There is a need to implement storage in a geographically distributed de-centralised manner to ensure the effects of distributed generation and the distribution networks (for gas and electricity) have appropriate levels of storage within each region.

17. Clear ownership/operator models for energy storage technologies need to be developed and introduced. Ownership and operation by the TSO, the DNOs, load aggregators, industrial third parties and consumers should be facilitated. Action on several fronts is desirable because energy storage should be applied at all voltage levels in a high-RES power system, in accordance with the balancing requirements of each level (which are driven by the associated amounts of embedded generation and demand profile). Pragmatic arrangements will be needed to achieve storage targets, because realisation will be restricted by the availability of storage technologies at the kW, MW, GW scale and the detailed feasibility of site implementation.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

18. Expanding interconnections with other national electricity grids will not provide a long term solution because each grid will produce excess energy from its power system which may not necessarily occur at a time when the neighboring grid can use it. Indigenous solutions are required for island countries like the UK.

19. Interconnection of the UK electricity and gas grids is needed to enable each to help the other to decarbonise efficiently. The power-to-gas approach affords an opportunity to help de-carbonise both the 300TWh flowing through the electricity grid and the 700 TWh flowing through the gas grid.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

20. Most countries have done nothing, they just curtail renewables or export the power across a land border when needed.

21. There are some good reports identifying the requirement and opportunities for storage. For example http://www.fch.europa.eu/publications/commercialisation-energy-storage-europe identifies that in 2050 Germany will incur 173TWh of curtailment (or nearly 30% of its projected electricity demand) unless storage is implemented.

22. There is a very low amount of storage in the UK electricity system, which is particularly unfortunate for an island nation, because islands face much greater balancing challenges than countries served by a large continental grid. We cannot look to mainland Europe for a storage policy solution.

23. The CPUC energy storage procurement targets set in 2013 for the three utility companies in California are pertinent (i.e. procure 1325 MW of new storage by 2020). The UK should set targets and base them on the principle of minimising the curtailment of renewables.

24. The incentivisation of consumers owning PV systems in Germany to deploy batteries in their homes via loans is an ineffective solution. Throughout much of the summer there is insufficient overnight demand to utilise the stored excess solar energy, so the battery cannot absorb all of the excess solar on the following day – it fails to provide an efficient storage solution so renewable energy is wasted.

25. Too often the focus here and elsewhere is placed on Power-In/Power-Out storage, but the UK has a very good reason to apply Power-to-Gas storage with its extensive gas and electricity grids. About 20 P2G plant are operating in Germany, where the injection of hydrogen and synthetic methane derived from renewable energy is being trialled. The technology is now at TRL 8/9, what's lacking is a remuneration framework to enable widespread implementation.

26. We are not aware of any policy framework in terms of international best practice for the UK to follow. The UK needs to lead the way in integrating storage to achieve an electricity system that can be balanced in a low-carbon manner.

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Lord Andrew Adonis
National Infrastructure Commission
1 Horse Guards Road
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6th January 2016

Dear Lord Adonis,

RE: National Infrastructure Commission Call for Evidence – Energy Evidence

Interconnector UK Ltd (IUK) is a significant gas interconnection pipeline between Britain and mainland Europe.

IUK welcomes the establishment of the National Infrastructure Commission (NIC) and its focus on energy infrastructure as one of its initial three focus areas. The NIC provides a valuable central authority that can evaluate Britain's infrastructure priorities and how the country can make the right choices to achieve a rational and optimum outcome. Having sufficient infrastructure is the backbone for the efficient operation of energy markets, and we believe that IUK is a good example of the benefits brought through strong interconnection.

We are responding to this consultation as we believe that, in delivering on its terms of reference, the NIC should consider the future of vital existing energy infrastructure assets such as IUK. We are grateful for the opportunity to highlight the specific issues relating to this critical piece of energy infrastructure.

1. IUK Overview

Operational since 1998, IUK is a sub-sea gas interconnecting pipeline between Bacton in Norfolk, UK and Zeebrugge in Belgium. We are the first and only physically bidirectional gas interconnector between Britain and mainland Europe, enabling gas to flow gas in both directions. We have substantial throughput capacity and are able to import over 25 billion cubic metres of gas per year, which would represent over a third of the UK's total gas demand. By way of comparison, electricity interconnectors typically have a capacity of up to 2GW, whereas IUK can import the equivalent of 33GW.

2. Economic benefits

IUK is a reliable and significant piece of energy infrastructure with an important function of connecting markets. We provide significant benefits to Britain, which are briefly summarised below.

Lower prices

In the winter, we provide considerable savings to British consumers by importing gas and keeping prices low. We estimate GB consumer savings of around £340m since 2010. We have also been instrumental in increasing gas market liquidity in Britain and thereby further reducing costs for consumers. Our analysis indicates consumer benefits of around £25m a year from this source.

Supply security

The UK currently has a diverse range of gas supply sources. This reduces the risk of a significant supply curtailment which would lead to price spikes or, in the worst case scenarios, restrictions on physical supply.

IUK has played a key security of supply role on various occasions in the past, responding to changing market and infrastructure conditions. For example, following a shutdown at the largest UK storage site in early 2006, IUK flows into Britain almost doubled. During the very cold weather in March 2013, IUK flows stepped up to record levels and the pipeline flowed at maximum capacity. Throughout the 2013 winter as a whole we delivered more gas than either LNG imports or Rough.

Energy demand and supply projections show a continuing need for gas in GB and for multiple options to supply it. Of course, this poses a challenge for a security of supply asset, specifically how to remunerate an asset whose utilisation is predicted to be low on average, but with occasional high peaks.

Increasing trade

As well as importing gas into Britain, IUK's export capability enables surplus gas in Britain to access (via Belgium) the German, French and Dutch markets. Over the last 5 years IUK has resulted in an average of £1.1bn per annum in cross-border trade from Britain to other European markets. These trade revenues provide economic benefits, including tax revenues and maintained jobs in gas production. IUK's export capability is also a factor in attracting new investment into GB gas production, targeting both conventional and unconventional resources.

3. The need for a holistic view, taking into account both new and existing assets

We believe that the narrow scope of the NIC's energy sector mandate is unfortunate and risks leading to sub-optimal or perverse recommendations and outcomes. There are two ways in which the focus is narrow.

First, the "stock" of infrastructure depends on maintaining existing assets, as well as new build. There can be perverse outcomes when favourable regulatory treatment is provided only to new assets, whereas existing assets are taken for granted. This can lead to the premature closure of old assets, to be replaced by new assets which the energy system would not otherwise require.

Second, to consider only electricity interconnection misses the important interrelationships that exist between the gas and electricity systems, including interconnection infrastructure. For instance, gas and electricity interconnectors are substitute means to supply the GB energy system.

The energy market has already been severely impacted by some asset categories receiving regulatory support and subsidies whereas others have not. In the case of interconnection, to achieve a least-cost balancing of demand and supply it is important to take into account the role played by gas interconnectors. For example, a narrow focus on just new electricity interconnection could ignore the possibility that an optimal least-cost outcome may be achieved by supporting new build Combined Cycle Gas Turbine (CCGT) plant in the UK (e.g. through the Capacity Mechanism) in combination with light-touch measures to ensure access to gas for this plant, either via LNG regasification capacity or through pipeline interconnection with the Continent.

This approach should be evaluated and compared against the costs and benefits to the consumer of multiple new electricity interconnectors, which may achieve the same outcomes (sufficient electricity supplies) but at a much higher cost to consumers.

4. Existing assets are not guaranteed

We believe that the NIC should evaluate ways in which critical existing infrastructure can be supported, as well as ways to promote new infrastructure. We note that economic studies sometimes make the assumption that existing assets will remain in place because they represent a sunk cost. However, we believe that this assumption is often invalid, especially where 1) assets need ongoing maintenance investment to prolong their viability; and 2) where a significant part of their economic benefits are societal and not necessarily rewarded in the market.

In IUK's case, we face a challenging environment from 2018 when our initial suite of long term contracts expire. We are also exposed to a form of market failure, in that we are subject to a more restrictive regulatory framework, providing less commercial freedom, than our gas flexibility market competitors. This is because we are classified as a Transmission System Operator (TSO), and therefore subject to very prescriptive European Network Codes which severely limit our product design and charging options. Our gas market flexibility competitors have a less restrictive regulatory framework and more commercial freedom through being classified as upstream flexibility, LNG regasification terminals or storage operators (SSOs). This is not a sound basis for market competition to get the best outcome for consumers.

To help us survive financially from 2018 and continue to make our capacity available to the market, we are seeking additional commercial flexibility of the sort that would allow us to compete in the gas flexibility market on a level playing field with other gas flexibility assets.

We have made these points to DECC and to our regulators (Ofgem in the UK and CREG in Belgium) and continue our dialogue with them whenever an opportunity arises. We have also raised these points with the European Commission and DG Energy. We would encourage the NIC and HM Treasury to support us in our requests for greater commercial flexibility, in the interests of promoting fair competition and maintaining an important piece of energy infrastructure for as long as possible.

5. Conclusions

In its wider infrastructure assessment role, we believe that the NIC should highlight the importance of maintaining valuable existing assets, especially when their social benefits are significant but the regulatory arrangements do not properly support them.

The NIC's focus on electricity interconnection and storage is understandable and reflects exciting new energy sector investment opportunities, but it should not lead to perverse outcomes. IUK would recommend that the NIC also uses its influence to make sure that related existing energy infrastructure is subject to an appropriate regulatory framework and is able to continue to provide its capacity and the associated energy market and societal benefits for as long as possible.

We would be very happy to explain further any of these points in person or to provide further written information if this would be useful.

With Best Regards,

Robert Sale

Regulation Director, Interconnector UK.

Kent County Council response to National Infrastructure Commission re Electricity interconnection and storage

January 2016

Q1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

KCC believes that the system operator function should remain with the National Grid and that any dilution of this would be counterproductive. However, there should be a greater range of incentives covering storage capacity and the delivery of demand reduction within the system.

The balancing market should be shifted to ensure we make the most of local renewable energy generation and reduce transmission losses to a minimum. The inefficiency in the electricity distribution network needs to be addressed as a priority. If this can be achieved it will greatly help to increase energy security and reduce the costs for consumers.

KCC considers the development of energy storage solutions has an important role to play. Future infrastructure needs to be flexible so that it that does not penalise renewable technologies when the wind does not blow or there are low light levels in the case of solar. Renewable technologies should not be seen in isolation from complementary storage technologies. Together, and with appropriate investment, they can play a key role in smoothing out fluctuations in generation.

There needs to be greater research into the potential for domestic, business and community level energy storage and to consider how it can be built into new developments. This is particularly important in areas like Kent where major growth is planned. We need to future proof economic development and housing infrastructure for the future so that sustainable and cost effective energy solutions can be easily deployed.

From a low carbon economy perspective KCC wishes to highlight the role that local businesses and universities can play in helping to drive through the commercialisation of solutions. A greater level of investment in innovation to support this potential would be welcomed.

Finally, the Government also needs to ensure that the emergency capacity market does not create strange anomalies where diesel generators can out-compete more low carbon options on price without regard to the carbon impact.

Q2. What are the barriers to the deployment of energy storage capacity?

The lack of investment in energy storage capacity at sub-grid level and research lags a long way behind where it needs to be. We need to increase the development and deployment of the small scale storage industry including investment in non-vehicle based hydrogen fuel cell storage, thermal and electricity storage. The Government and system operators need to see renewable technology as an integral part of the mix with storage enabling the smoothing out of fluctuations in generation and increasing resilience. The Government needs to provide market mechanisms to reduce the initial cost of storage options, and grow the market place and reduce cost in the long term.

The UK should consider the generation and distribution of energy on more of a district heating basis. In other words, local generation used locally. While we will still need a national generation and distribution network, we need to maximise the benefits of local network storage, to reduce costs for the consumer and increase resilience.

The Government needs to set out a national energy storage policy and target to stimulate the market and put appropriate incentives in place. The storage should be for both power and heat. There also needs to be a clear policy steer on the role of the hydrogen economy, and how power storage and surplus energy is used for this emerging part of the economy.

There needs to be consideration of the climate change vulnerability of current and future energy generation and storage facilities and locations. The floods over the last ten years have shown how vulnerable energy infrastructure is, even where protected. The climate adaptability of our infrastructure is just as important as what infrastructure we should have. It must not be seen as an optional extra but built into the design, location and costing of our future network.

Q3. What level of electricity interconnection is likely to be in the best interests of consumers?

One concern is that a reliance on greater interconnectivity will leave the UK subject to uncertain energy cost increases from other national governments.

KCC acknowledges that a European interconnector energy system based around the North Sea is advantageous. However, because of the significant potential from offshore wind energy around the UK coast, we need to consider how best we can store energy from this generation source to reduce the need to import via interconnectors. There also needs to be an assessment of the vulnerability of energy generated from countries we are connected to in terms of how it will affect their ability to generate and supply surplus or dedicated energy to the UK.

Q4. What can the UK learn from international best practice in terms of dealing

with changes in energy technology when planning to balance supply and demand?

We can definitely learn from the way Scandinavia and Germany have invested and develop more distributive local energy networks. These have the potential to help deliver zero and near zero carbon developments such as at Ebbsfleet Garden City in Kent. The continued investment in Heat Networks Delivery Unit (HNDU) is welcomed and KCC is benefitting from the Unit's support in evaluating the feasibility of establishing a district heat network in Maidstone. Notwithstanding this, there is still a significant knowledge gap in local authorities who are the prime instigators of this approach. Funded training for knowledge transfer to local authority officers involved in district heating would be welcomed so that we can ensure that the public sector is able to unlock local opportunities.

From: Jonathan Ducker [email address redacted]
Sent: 08 January 2016 10:01
To: EnergyEvidence Infrastructure-Commission Richard
Cc: Burnley; Adrian Pargeter; Richard Bromwich National
Subject: Infrastructure Commission call for evidence

Please accept below comments on behalf of Kingspan Insulation Ltd.

The National long-term infrastructure plan needs to include a requirement for improved energy efficiency, to sit alongside a lower carbon electrically heated future; an aim to prioritise reduction in future demand through improved energy efficiency measures for buildings should be a fundamental part of any infrastructure plan.

Making buildings energy-efficient reduces energy demand, stimulates economic activity, strengthens international competitiveness and creates thousands of jobs, mostly with small local businesses. It lowers costs for businesses and householders, and reduces the burden on the NHS. Improving the energy efficiency of buildings can be more cost-effective than increasing generation and can help to safeguard Britain's energy security.

In common with responses from the UKGBC, Energy Bill Revolution and others, Kingspan Insulation Ltd call upon the National Infrastructure Commission to launch a consultation on how best to make buildings more energy efficient and on how to de-carbonise our heating infrastructure in the most cost effective way

Best regards,

Jonathan Ducker
ENERGY ASSESSMENT MANAGER

direct tel: [phone number redacted]
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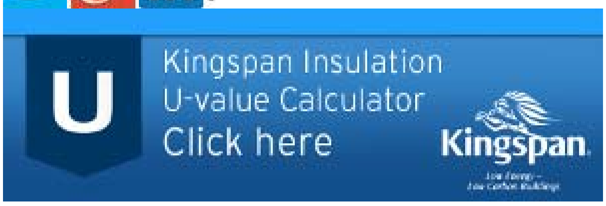

About KiWi Power

KiWi Power believe that the current approach to the UK electricity system is in need of greater reform than has currently been carried out. Therefore the company fully agrees with the need for a policy reset, as described by the government, and welcomes the infrastructure committee's interest in the space.

KiWi Power works in the field of Demand Side Response (DSR), the company is described as an aggregator. That is a company which engages industrial/commercial sites with small amounts of power generation capability, or enterprises that have the capacity reduce power at peak times. KiWi Power is then able to control the power use from these sites at peak times, selling flexibility back to the National Grid. KiWi Power specialises in dealing with the contractual risk involved in supplying balancing services to the National Grid, which means that its product is suited to both unsophisticated electricity users as well as the experienced companies. KiWi Power also advises companies on their energy management strategy.

KiWi Power builds its own software and hardware with assembly lines in the UK, and has a business model designed around giving the software away to the potential client without a charge. The client benefits from both hardware and software. The latter provides a service that can give them full visibility of their whole company systems. Therefore KiWi Power maintains a subsidy free business model, and currently operates internationally on this basis.

Overview

The DSR aggregators, as part of the electricity market, have two major stakeholders both of which could be described as 'clients'. On one side there is the industrial or commercial company that has been aggregated, and on the other is National Grid who pays for the service. In this document the phrase client will refer to the companies that KiWi Power aggregates, and the word customer shall mean National Grid as they are the ultimate customer in any transaction.

DSR Overview

The government's position was recently made clear by the Secretary of State, Amber Rudd, in the House of Commons[1] [Hansard 14 12 2015].

"Overall, this Government is absolutely committed to a low-carbon future that is value for money and constantly provides security to consumers and families."

The capacity market has failed, especially in the goal to deliver new gas. The first capacity market auction, December 2014, contains coal plant and therefore also perpetuates a high carbon energy offering. In addition, balancing market tools such as Supplementary Balancing Reserve (SBR), endorsed by the government and Ofgem, represent extremely bad value for money. KiWi Power notes that the cost of this SBR 'back up' capacity for next winter 2016-17 is in excess of £122m, and feels that this money could be better spent. Especially as this figure has increased substantially from 2015-16 winter price of £33m.[2]

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[1] House of Commons Hansard, Column 1297, 14 December 2015, Secretary of State Energy and Climate Change, Amber Rudd.
http://www.publications.parliament.uk/pa/cm201516/cmhansrd/cm151214/debtext/151214-0001.htm#15121426000582

[2] National Grid figures on SBR and DSBR auction procurement
file:///C:/Users/Spare%202/Downloads/Winter%202015-16%20Results%20of%20Tender%20Round%202.pdf

The structure of the current capacity market auctions also promotes a policy of building new build standalone diesel plants. On that basis alone, the claim of technology neutrality is debateable. At the very least an efficient policy should be spending capacity market funds on developing existing DSR sources of generation, rather than building new unnecessary plant with no capacity to lower carbon use. At the worst end of this policy failure, the capacity market has allowed for the unbridled development of new ‘diesel farms’. These new diesel assets will displace the incentive to fund, low or zero carbon, DSR alternatives derived from existing infrastructure.

KiWi Power suggest the following: that the government develop a facet within the policy process that guarantees some elements of any future policy, and that the current capacity market is reformed to provide a ‘level playing field’ for the whole market. Furthermore, government should acknowledge that embedded DSR could supply a large part of the UK balancing requirement, and lower the carbon content of the UK national grid at the same time.

If these issues are addressed in the right order, they will deliver a low or zero carbon alternative that can displace the remaining coal use on the system. In doing that they can also avoid the need for some of the costly new build natural gas thereby preventing a rise in electricity bills. Furthermore, they will do so in a subsidy free environment.

The key policy infrastructure pathways remain clear:

- Engage the ‘reset’ and amend system architecture in all future capacity auctions
- Guarantee a meaningful amount of DSR in T-1 auctions, and assure auction will take place
- Level the playing field for embedded DSR, and end displacement by new diesel farms

Questions:

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

<u>Investor confidence and a government guarantee</u>

In terms of successful infrastructure policy for embedded DSR this means doing something as simple as giving a government guarantee that all the T-1 auctions will take place with meaningful levels of DSR[3]. These auctions are vital to the future growth of embedded DSR, but also act as a key enabler to lowering the overall cost of the capacity market.

KiWi Power is expecting a substantial reset by the current government. Large scale gas fired power stations are seen as a requirement, and therefore it is expected that the government will be incentivised to make changes to future auctions.

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[3] The capacity market, the key UK government policy instrument for electricity delivery, is designed to work in four year time blocks. Provision of capacity is to be met at the end of a four year period. Hence, T-4 is for delivery in four years from the auction date. However, to make up for any unforeseen issues or shortfalls a smaller auction will also take place in the year just before delivery. This auction is called a T-1. It is a much smaller volume that the original T-4 auction. The point is that the KiWi Power and other DSR providers see these as key points of entry because there will be less involvement from traditional suppliers, who should have been more interested in the T-4 auctions.

New gas fired power has not been forthcoming, because neither of the two T-4 auctions delivered a high enough price. This outcome was driven by existing power stations bidding into the auction. These existing units do not require the expensive upfront building costs, and therefore they can outbid competition from a new build gas fired power station.

The capacity market also lacks a 'level playing field', and from a DSR perspective this is best demonstrated by the different lengths of contracts available to bidders. DSR, using existing infrastructure, is only allowed to bid using a 1 year contract. However, power stations are allowed to bid using a 15 year contract. This rule has perpetuated a rise in contract wins for so called 'diesel farms'. Embedded DSR finds it difficult to compete under such different conditions.

KiWi Power are of the view that the government will come up with a solution to this issue. However, it is imperative that when any solution is enacted for the T-4 auctions, it should also be mirrored in any future T-1 auctions. Thus both auctions can then avoid being flooded by existing power stations. Furthermore, this expected future change to the capacity market auctions must also make sure that the reset embodies the 'level playing field' required for successful DSR.

The government could add a level of certainty, and then work on gaining cross party support in the event that a future new executive could at least agree to keep policies in place with a right to review after 10 years from 2015. This would further help to build confidence that the UK was a place for long-term energy investment. This would then, in turn, further reduce the risk and therefore the cost of investment, which would mean there would be lower cost over the long-term to consumers.

What role can changes to the market framework play to incentivise this outcome:

- Is there a need for an independent system operator (SO) how could the incentives faced by the SO be set to minimise long-run balancing costs?

- Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

Reform

Creating an independent system operator or (ISO), is a near-term aspiration. KiWi Power currently feels that there are more important elements of the policy infrastructure that need to be amended. In terms of creating the level playing field an ISO should be developed as a final stage. KiWi Power, very much endorse the ADE response to this question as well.

In reference to the "balancing market", KiWi Power understands that the question refers to the half hourly settlement of supply and demand on a daily basis. As such DSR companies are not currently, at the time of writing, incentivised to access this market.

KiWi Power is not in a position to answer which market participants are most responsible for the imbalances, as it does not have the visibility or data to draw any conclusions. However, KiWi Power is aware that in the UK the traditional supply side of the industry, essentially the big six, are likely to see a significant change to their business model as customers become more efficient at power management. KiWi Power suggest that it is for the supply side to adapt to these changes, and feel that greater transparency will do much to allow old infrastructure to evolve. In particular, data sharing and communication between parties is to the benefit of all. This will also foster the creation of a visible 'real-time' second by second market settlement system.

- To what **extent** can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

KiWi Power's business model in the UK was predicated on the anticipation that up to 15% of daily load on the UK grid could be taken up by a mature DSR market[4].This would equate to between 6 and 9 gigawatts (GW), depending on the time of year. To put these figures in context a gas fired power station, with a build cost of approximately £8-900m, will deliver around 1.2GW. The UK's largest single power station which is Drax Power has a capacity of just under 4GW and the UK average daily capacity requirement is between 40-60GW.

Government figures indicate that DECC suggests the potential capacity is 2.5GW in 2018/19. Trilemma UK that points out that the figure should be taking into account what a developed DSR market can deliver.

"Indeed, the Government has assumed that up to 2.5GW of the demand side response (DSR) will ultimately contribute to capacity requirements in 2018/19 and evidence from regional capacity markets in the US suggests that demand response potential could be significantly greater than this."[5]

These sources of embedded DSR will stem from both turn up and turn down generation. However, the exact split between the two types and the total achievable carbon saving remain to be analysed. The overarching point is that the UK could avoid building at least 6GW of gas plant and possibly more, as this is a conservative estimate. It is also probably worth noting that this figure would almost cover the shutdown figure of coal fired power plants. This is on the basis that coal makes up around 20% of the UK energy mix[6].

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

Although not specified particularly earlier, KiWi Power has also been working with the development of batteries as a means of electricity storage. In terms of the future deployment of electrical batteries, local and national infrastructure should follow a deployment idea based on where the most need is required.

Batteries should also be placed on a 'behind the meter' basis. This means that they need to be embedded into the electrical infrastructure of a commercial premises. In the event that there is a supply shortage, or that frequency services are required, the site can run off-grid. However, the positioning will also be important geographically. Batteries should be placed in metropolitan areas of

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[4] Trilemma UK have put this figure at approximately 10% based on the Pennsylvania-New Jersey-Maryland Interconnection (PJM).

[5] Simon Skillings, Phil Baker, Alan Smart, Assessing the balance of risks associated with coal plant closure, Page 12, February 2015.
http://www.trilemmauk.co.uk/sitebuildercontent/sitebuilderfiles/assessing_the_balance_of_risks_associated_with_coal_plant_closure.pdf

[6] UK's coal plants to be phased out within 10 years, BBC News, 18 November 2015,
http://www.bbc.co.uk/news/business-34851718

the country where constraints exist on the district or national grid. Batteries clearly have a use at a domestic scale too, but they require a mass market business model.

In the best possible circumstances batteries will be placed in new developments, so they do not have to compete against sunk costs of existing infrastructure.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

KiWi Power, have chosen not to answer this question.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Using DSR to balance supply and demand is not a new technique. It has been prevalent between power stations and heavy industry since grid systems were first invented. The most mature market remains the US, and as a market it contains several independent system operators (ISO). The variety of these different participants have meant that most of the possible models, for DSR, have been tried and tested. PJM is often highlighted as the US system operator with the best formula for success. However, it's worth noting that even in America successful DSR policies are not found in all states. Using DSR to balance grids in Europe is also not a particularly new phenomena either. Market maturity is signified by using aggregation technology to collect smaller MW values, from previously less efficient sources. The volume of MW at which this can profitably take place, is a good measure of the maturity of a countries system. National Grid has recently commissioned a report looking at how DSR is conducted in other countries. The consultants, Baringa Partners, presented findings in November 2015 and isolated four challenge areas that related to the UK. These examined the different DSR schemes, the level of participation, market access, and baseline measurement techniques.

KiWi Power believes that the Baringa analysis contains many useful observations. Especially where the report describes the strengths of the American market infrastructure, and some of the pitfalls experienced in the German electricity markets.

PJM's market holds many of the answers to a better market infrastructure. The first is the level playing field, as mentioned before, is most starkly demonstrated by the length of contracts. PJM offers only one contract to all participants, and traditional supply side entities compete on a level playing field where contracts are 3 years in length. In the UK there were three different contracts in the first auction, with embedded DSR excluded from refurbishment and new build contract lengths of 3 and 15 years respectively.

The second important element is that in the PJM model, DSR participants are paid an availability charge, as well as the utilisation charge.[7] This payment is necessary as the aggregator's client has to be incentivised to provide the reduction. In some European cases where an availability charge is not paid, interest in DSR is driven by stipulating a minimum amount of activations in a given year.

Capacity auctions seem to be a relatively standard way of providing assets that might meet the requirements of STOR. However, some services provided by the demand side are considered 'ancillary', these might be frequency response and be responsible for very small second by second change to electricity infrastructure. It has been suggested that PJM has a very flexible approach to aggregation with the minimum asset size only 100KW. The UK has a requirement of 3MW, however this is not a critical difference. The level playing field is far more important in the short term.

The measurement of power reduction at a given site is also important as it is linked to payment and therefore different tariffs. This is often referred to as 'base line' methodology. A change by the NYISO to this measure resulted in a significant decline in participation, as less DSR was able to qualify under the new method. Baringa suggest that there was also poor communication between the ISO and the DSR participants. The system operator also used a day ahead scheme, in which only small energy quantities were scheduled.

In European markets some mistakes have been made which have prevented the smooth uptake of aggregated DSR. In particular, Germany has managed to create a particularly Kafkaesque system that requires several different parties to sign a contract before a site can be aggregated. These signatures include all the parties involved in the German electricity system. Whilst this process gives the supply side, TSO's, DSO's and federal electricity apparatus some visibility of an impending change to a sites electricity use, it also allows them to exercise too much control over the process. The volume of paperwork requires legal cost and time which means that the any potential site is incentivised to make arrangements with an existing supplier. This issue with excessive bureaucratic control was also picked up by the Smart Energy Demand Coalition (SEDC).

"While the German markets appear open, in practice, access is problematic due to a series of regulatory barriers."[8]

Further Reading

Europe Examples

- Demand response experience in Europe: Policies, programmes and implementation
- Mapping Demand Response in Europe Today – 2015 Smart Energy Demand Coalition (SEDC)

[7] Enernoc Frequently Asked Questions
http://www.enernoc.com/our-resources/brochures-faq/get-paid-to-reduce-energy-with-enernoc-demand-response-in-pjm

[8] Smart Energy Demand Coalition (SEDC)Mapping Demand Response in Europe Today – 2015 p.153.

Submission to the National Infrastructure Commission

Knauf Insulation Northern Europe, 8 January 2016

Introduction

The UK energy system is complex. To maintain a balanced, value for money perspective when considering interconnection and storage, as well as future generation projects, a whole system view should be taken.

On the supply and distribution side the need for robust gas and electricity supplies in industry has defined both the scope, and the reliability, of our national and local networks and generation infrastructure. On the demand side, the move away from coal towards gas in the 1980s has created one of the most integrated domestic gas networks in the world linking our homes directly to our gas requirements as a nation.

The move towards importing gas in 2004 has created pressures on the gas grid with new sources of LNG changing the flows within the system. For electricity, growth of consumer electronics in the home, particularly over the last ten years, has increased the amount of electricity we need. Renewable generation technologies – including an increase in 'embedded' generation, which is off the main electricity grid – add further system pressures and uncertainties.

The most significant energy use for individual households remains the amount of gas and electricity to heat their homes. This has stayed the same throughout.

On aggregate, in-home energy use makes up a very significant proportion of our national energy usage, more so when businesses are included. All avenues should be considered to maintain secure and affordable energy supplies, but silo based thinking must be avoided.

This paper sets out:

1. The clear definition of energy efficiency as infrastructure

2. Benefits for the UK, and for homeowners from improving this kind of infrastructure

3. A brief comparison of policy and market hurdles for energy efficiency:
    3.1. The lifespan of demand side and supply side assets
    3.2. Overview of supply side market interventions

The current asymmetry between supply side and upstream investment and demand side improvements, including our building stock, needs to be closely examined as part of future infrastructure investments. We are calling for a substantial consideration of demand side technologies as a UK infrastructure strategy is developed.

1. UK buildings: our most important infrastructure

The energy needed to heat our built environment is not fixed; it is wrong to see this as set in stone. Upgrading the infrastructure that we live and work within – namely the UK building stock – is an essential part of building a modern, workable, energy system.

In a recent paper, Frontier Economics, a consultancy, shows that energy efficiency fits clearly within each of HM Treasury's eight characteristics as defined by their valuation guidance[1].

Moreover, the research by Frontier emphasises that:

> *Domestic energy efficiency investments can free up energy sector capacity just as effectively as delivering new generation plant, networks or storage would. Energy efficiency investments provide public services, by reducing carbon emissions and improving health and wellbeing. They also provide option value in the face of uncertainty over future energy sector conditions (e.g. uncertainty over future fuel prices).*
>
> Energy Efficiency, an Infrastructure Priority – Frontier Economics, October 2015

When balanced against wider infrastructure investment, the Energy Savings Trust notes that a rollout of energy efficiency provides a comparable economic return to HS2[2]. This statement is drawn from work completed in 2014 by Cambridge Econometrics who looked at the rate of return for Government for every £1 spent on investing in a large scale energy efficiency rollout[3]. They concluded that such a programme would have a rate of return of 2.27 : 1 under standard benefit cost ratio (BCR) calculations. BCR calculations by the Department for Transport in making the case for HS2 begin at between 1.4 : 1 and 1.6 :1 and rise to 2.5 : 1 if wider benefits and later stages of the programme are included.[4]

2. Benefits for the UK energy system, and for homeowners

The economic underpinning for improved energy efficiency is solid, and some of the programmes used to improve building fabric have been successful. Government energy efficiency schemes have been shown to have an impact on UK gas usage between 2005 – 2013 where the UK managed to reduce domestic median gas usage by 30%[5]. This trend began before the global recession of 2008, making significant improvements to building fabric during this period a clear factor. In today's prices, that 30% represents at least £5 billion pounds in annual household bill savings. This is money that UK consumers are saving on energy bills which can be spent in the wider economy. Such a scheme would also create over 100,000 jobs.

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[1] Supplementary Guidance to the Green Book – HM Treasury, March 2015

[2] http://www.energysavingtrust.org.uk/blog/2015/09/are-we-failing-understand-wider-benefits-energy-efficiency

[3] Building the future – Cambridge Econometrics, November 2014: http://www.energybillrevolution.org/wp-content/uploads/2014/10/Building-the-Future-The-Economic-and-Fiscal-impacts-of-making-homes-energy-efficient.pdf

[4] The Economic Case for HS2: Value for Money – Department for Transport, January 2012

[5] National Energy Efficiency Database, Analysis report 2015 – Department for Energy and Climate Change

Previous schemes, including those referenced above, have often attempted to treat a social problem – that of fuel poverty and high energy bills – rather than working to upgrade building infrastructure. This means that money spent has been targeted, quite rightly, at people in need. But additional money to future proof buildings and bring the whole of our built environment 'up to par' has not been so widespread or successful.

It is of course essential for Government to work to help homeowners, without breaching the imperative that Homeowners have to manage their own properties as they see fit, and as suits their own lifestyles and needs. However, Government also has a duty to help ensure that people have access to new technology that can benefit them and save them money, without exposing them to unnecessary costs. Especially if these are avoidable costs from rising or unstable energy prices, or from economically sub-optimal Government programmes that restrict available options.

Change in the home is already happening

Smart meters are a new tool representing a significant infrastructure upgrade to every home. They will help to monitor, and ultimately manage, shifting pressures upon UK energy system requirements centrally and with an in home display, or connected computer, can help individuals understand how they spend their money. Smart meters are rightly one of the UK's infrastructure priorities, but in order to fundamentally master the energy that we use as a country, we need to help people to improve the fabric of the buildings that they live and work within. If smart meters are seen as a stand-alone solution with homes remaining under insulated, costs to bill payers will be higher than they need to be even if they switch supplier.

The continuous development of technology and the 'Internet of Things' has already led to in-home environmental management systems entering the market. Npower have partnered with Google to provide the Nest learning thermostat, British Gas have rolled out remote controlled heating systems through their Hive thermostat and app pairing. This kind of development will only increase, and it is essential for the UK infrastructure strategy to recognise the interconnection between these developments, and allow for these kinds of innovations to work with wider fabric improvements and policy incentives that help to reduce the heating requirements that homes have currently.

3. Policy and market hurdles for energy efficiency

3.1. Asymmetry of supply side and demand side assets

3.1.1. Supply side – Gas

Much of the heat we generate in the UK is fuelled by Gas. In 2004 the UK became a net gas importer. In recent years a number of tight supply margins have caused National Grid to issue warnings to the market as part of normal operating procedure, and prices have spiked to ensure that demand has been met in a timely fashion. Whilst there is no reason to assume that UK gas needs will not be met in the short or medium term, large manufacturers have expressed concerns about the degree of uncertainty that they face in these situations. They have also noted a number of price concerns over longer periods of time. In this context, recent investment to handle gas demand has been met by short, medium and long term investments in:

- LNG import facilities, such as the Isle of Grain which opened in 2005 and expanded in 2008 and 2010 to help meet growing UK gas demand;
- Fast cycle gas storage, such as Aldbrough in Yorkshire opened in 2011 and owned by SSE;
- Pipeline upgrades as stipulated by National Grid in their recent evidence for the RIIO-GD1 price control agreement;
- Commercial investments by National Grid in ventures such as BritNed, which opened in 2011 and connects with the Netherlands.

These are largely recent investments to handle growing demand and dwindling supply from the North Sea. It is important to ensure a secure and robust flow of gas, but it is equally right to balance these investments against what we can to do moderate our use as a country. Especially if it is more cost effective.

3.1.2. Supply side - Electricity

Infrastructure used to generate electricity lasts a long time. Recent changes to the UK electricity market have helped to overcome the ‘missing money problem’ which has held back some investment here. However, some of the main sources of electricity generation currently in use have an asset lifespan of fifty years or more. For example:

- Drax Power Station began ‘commercial’ generation in 1975, though it was generating from 1974. It is physically able to run much longer than the Government announced closure of unabated coal power in 2024, by which time it will have been running for 50 years.
- Hinckley point A began generation in 1965 and was decommissioned in the year 2000 after generating for 35 years.
- Hinckley point B began supplying electricity to the national grid in 1967 and is expected to run until 2023, a total of 56 years.

As noted above, part of our increased reliance on electricity is from growth in consumer electronics and the expected growth in electric cars. This paper does not look at these more predictable electricity loads. However, wider – reasonable – pushes to increase the use of electricity in heating homes to help to balance growth of intermittent renewables and to help to decarbonise heat need to be looked at in relation to building fabric. For example, we do not know how much ‘top up’ electric heating is used to account for poor insulation. The current policy environment reflects the fact that we are in an investment cycle for medium and long term assets such as the above. It is right for a long term plan to consider investment here against wider investments that could be made in demand side solutions.

3.1.3. Demand side – the UK building stock

The majority of the UK building stock has lasted for significantly longer periods of time than all generation and gas supply assets. As a country that commendably seeks to preserve our national heritage, this is very likely to continue.

- More than 55% of all UK homes were built before 1964[6]. The first significant thermal building regulations were brought in to effect in 1965[7] when the 'u-value'[8] was set at 1.7[9].
- 22% of UK homes were built before 1919[10]. Even though recent reports suggest these homes have continued to gain the most value due to build size, location and quality, these properties are often the hardest to insulate up to modern standards, requiring specialist investment.

New generation is being developed and it is right to modernise the way that electricity is generated so that we make best use of resources and maintain our global ability to compete. However, as you can see from the above, significantly more than half of the domestic demand side – particularly for heat – is already past the 50 year life span expected of generation assets. Moreover, the aesthetically desirable, and often most costly properties, are at least a century old, if not substantially older.

In an economic environment where cost effectiveness needs to be well considered, it is essential to make the opportunity to improve homes available to homeowners. Long term planning from a central body such as the NIC would also help to ensure that when investments by individuals or corporate bodies are made to improve buildings, thereby helping the UK as a whole, policy acts to make these improvements as economically efficient as possible.

In a recent speech[11], Amber Rudd noted that the new framework for funding could not see subsidy as part of a business model. She is entirely right. However, as acknowledged in the same speech, the constraints that are faced in the current investment cycle show that all technologies providing generation currently require some incentive to help manage the risks seen by investment committees.

The capacity market helps to ensure traditional gas generation is available for peak loads, contracts for difference create a clear incentive for renewable generation. Each of these address the 'missing money problem' that many see as hampering new investment. Upstream, tax incentives are being used to maximise exploitation of remaining North Sea oil and gas reserves alongside new incentives to boost UK domestic shale production.

It is right that all avenues be explored to maintain UK energy security. To do it cost effectively, a clear understanding of how demand is constituted and can be shifted also

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[6] English Housing Survey 2010 – Department of Communities and Local Government
[7] UK Building Regulations 1965, Statutory Instrument 1965 No. 1373.
[8] U-values measure the effectiveness of a material as an insulator in buildings.
[9] The U-value was improved to 1 in 1975 to help conserve energy in new build homes following the oil crisis of that year.
[10] English Housing Survey 2010 – Department of Communities and Local Government
[11] https://www.gov.uk/government/speeches/amber-rudds-speech-on-a-new-direction-for-uk-energy-policy

needs to be undertaken. This means a clear assessment of the UK building stock. At present, incentives are not well aligned to address this half of the energy system. A balanced infrastructure approach would help to resolve this.

3.2. Regulatory drivers for supply

The economic underpining for the UK energy system is formed from interlocking market arrangements. These were most recently tweaked by the electricity market reform package in the Energy Bill 2014.

In simple terms the electricity market, as currently constructed, seeks to match demand and supply levelling punitive costs upon market players that incorrectly predict the supply that is required – purchasing too little or too much and therefore being 'out of balance'. The costs extracted from those who are out of balance are used by National Grid to make real time adjustments to the system, maintaining system frequency and keeping the lights on throughout the day, night, month and year. A similar process takes place for gas.

Managing supply and demand in this short term manner way works well on a daily basis, but it does little to consider the long term health of the system. Moreover, these arrangements do not allow for wider benefits to the system to be recognised at all – particularly for electricity – if they can not be priced within the minute by minute, second by second, market framework that has been constructed.

In pursuit of clear and commendable national benefits – particularly energy security – the Government has recognised that long term pushes are needed that are external to the current market framework.

- The introduction of Contracts for Difference (CfDs) as part of a reform of the electricity market in the Energy Act 2014 has created a system of contracting that sets the price of electricity provided by low carbon generators. This creates clear, long term certainty for the delivery of large projects.
- The capacity market is an additional boost to supply, working outside of the current electricity contracting system, which allows providers to bid in to be available to provide capacity at set times of noted system stress. This is intended to provide money to ensure that ensures generation capacity is available – no matter if it is used – at times when the UK electricity system is under stress. Some demand side measures are being trialled under this system, but only as a reactive measure, not as a long term reduction.

Each of these mechanisms is designed to overcome the 'missing money problem' which has caused a lack of significant investment in energy generation due to insufficient market incentives and provide long term stability for investors.

Although able to provide additional security, there has been a noted absence of long term certainty over the same period for demand side investment. Following the Autumn Statement 2015, the Chancellor is to be commended for ensuring that the next iteration of the energy company obligation – which will focus specifically upon the fuel poor – will last for five years.

For the majority of UK homes, however, and especially those built before 1919, incentives to date have been constructed in such a way that the financial impetus to improve a property – although present – is too complex to pursue, or the payback is too long to be seen as a reasonable investment if not linked to a mortgage. Scrapping the Zero Carbon Homes policy – which had been in development for nearly ten years – has also not helped investor confidence.

Conclusion

If a cost effective route to a modern energy system is to be achieved, we need a more comprehensive approach to our national built environment is needed. We suggest that the national infrastructure strategy considers this in detail on an equal footing to supply side energy concerns in a near term dedicated investigation.

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Electricity Interconnection and Storage

Written evidence submission to the National Infrastructure Commission - Low Carbon

January 2016

A privately owned investment company, Low Carbon invests in, owns and manages both renewable energy developers and projects across a range of technologies including solar, wind, anaerobic digestion and concentrated solar power. Low Carbon has a strong management team with a proven track record in the development, construction, financing and management of UK solar assets, with more than 270MW funded and in operation today and a pipeline exceeding 2 GW in development. Low Carbon has a dedicated asset management team that currently manages assets on balance sheet and for third parties (unlisted and listed).

Low Carbon is the official renewable energy partner of the Land Rover BAR team, and has ensured that the team's America's Cup headquarters on the Camber in Portsmouth is powered by the very latest, high efficiency solar photovoltaic (PV) technology.

Low Carbon is also a major stakeholder in the TuNur project through its shareholding in Nur Energie ltd and is beginning investments in energy storage technologies.

1) **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

Balancing of supply and demand in the electricity market is a complex issue – unlike other commodities, electricity must be balanced on a second-by-second basis, but daily, weekly and seasonal variations mean that the scope of balancing actions required vary throughout the year.

The current regulatory framework in the electricity market is extremely complex, and is a barrier to both entry and innovation. As an example, the Balancing & Settlement Code requires signatories to comply with seven subsidiary documents – including relevant codes of practice, a balancing party will be subject to over 120 separate regulatory documents, totalling approximately 3,000 pages[1]. As well as being a barrier to entry and innovation, there is a considerable cost to the consumer, estimated to be over £635 million per year for energy administration[2].

[1] Howard, R (2015) Governing Power. Policy Exchange
[2] Ibid.

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The current role of National Grid has a number of shortcomings, highlighted by Ofgem[3] which are leading to misaligned incentives. A necessary first step to incentivise the System Operator to minimise long-run balancing costs should be to remove the misalignments caused by National Grid's multiple roles. It is our opinion that this is most easily resolved by the creation of an Independent System Operator.

In any change to the way electricity is balanced, consideration must be given to the UK's obligations under the Climate Change Act. In particular, the construction of significant volumes of fossil-fuelled generation capacity is not consistent with the need to reduce the carbon intensity of electricity generation to 90 g/kWh by 2030[4]. The Capacity Market regulations have been prepared without consideration of the UK's emission reduction obligations and this must be addressed.

2) What are the barriers to the deployment of energy storage capacity?

Energy storage is a collection of emerging technologies and business models, many of which are at the stage of initial commercial deployment. A significant barrier to that deployment is perception within government that energy storage is a "research and development" issue – this is the first issue to be addressed.

For significant deployment of energy storage technologies, the regulatory landscape must be clarified. There is currently a difference in approach between Ofgem & HMRC that causes energy storage projects to be exposed to some non-energy cost on charging, but not others (we understand that HMRC has ruled that electricity used for charging is not subject to CCL, but Ofgem has ruled that this electricity is subject to non-energy costs associated with ROC, FiT & CfD schemes). Similarly, it is uncertain how energy storage projects will be considered for business rates.

Government should undertake a review of the regulations related to energy storage at all scales to ensure consistency across the different organisations involved in electricity regulation. This review should also involve the Contract for Difference and Capacity Market regulations to ensure there are no unintended consequences of previous decisions that would impact the deployment of energy storage technologies.

One clear opportunity for energy storage is to defer grid reinforcements, but no regulatory mechanism yet exists to permit grid operators to pay a 3rd party to provide this service. This area represents a significant opportunity and should be investigated.

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[3] Strbac, G. et al (2013) Integrated Transmission Planning and regulation Project: Review of System Planning and Delivery. A report for Ofgem.
[4] Committee on Climate Change (2015) The Fifth Carbon Budget

It is likely that the first scale of energy storage technologies to deploy in significant volume will be at distribution and transmission (e.g. to provide Enhanced Frequency Response services to National Grid), but this should not be taken to mean that domestic scale deployment is not valuable. We expect that there is likely to be value in deployment at all scales.

3) What level of electricity interconnection is likely to be in the best interests of consumers?

We have no comment on the level of electricity interconnection.

4) What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Consideration should be given to a scheme similar to FERC Order 755 (known as "pay for performance") in USA, whereby better performance in providing frequency regulation receives greater compensation.

Appendix 1 - Energy

1. The Commission is seeking evidence on how changes to existing market frameworks, increased interconnection and new technologies in demand-side management and energy storage can better balance supply and demand.

2. The NIC have asked for responses to address the following specific questions:

(1) What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

3. The electricity market needs to be further liberalised in two areas. Firstly to allow small decentralised generators to more easily access the retail electricity market to realise the full value of their electricity. They currently receive lower wholesale prices. Secondly to allow SMEs and domestic consumers to participate in the demand side market and be paid for being flexible in their electricity use. The Mayor is active in both these fields:

4. Licence Lite: the Mayor is working towards being the first public body to operate a junior electricity supply licence buying electricity from local generators and selling it to local consumers. Licence Lite is about making the electricity market more open and therefore providing more choice for consumers. Further market reforms should address simplifying market operation for suppliers (particularly smaller suppliers) and making the provision of basic market services for licence lite by large scale suppliers mandatory.

5. Demand side response: the Mayor has supported two DSR (demand side response) SMEs to develop new market products. It would be highly beneficial to afford the same access to National Grid's ancillary services market for domestic consumers and SMEs as commercial and industrial consumers, assuming 'smart' technology is more widely available in the home (smart meter, home area network, smart appliances). Government and Ofgem need to do more to stimulate the availability of aggregation services for smaller consumers to enable them to benefit from their own DSR activities. The market currently incentivises aggregators to focus on larger electricity consumers.

(2) What are the barriers to the deployment of energy storage capacity?

6. Heat storage, in contrast to electricity storage, is a well-established, simple and cheaper way of storing excess energy, whether this originates from excess heat or electricity. Heat storage at scale requires the use of heat networks to connect heat production and storage to consumers. Heat networks are unregulated, unlike other utilities, and the Government should make more progress towards securing more public confidence and reduce the barriers to the installation of new heat networks. Particular issues include access by consumers to connect to heat networks, the interconnections between networks, and giving heat consumers more confidence in heat networks by introducing some regulation of heat price, recourse in the event of unsatisfactory service and making provision for heat suppliers of last resort to take over a network if a heat network operator fails.

(3) What level of electricity interconnection is likely to be in the best interests of consumers?

7. Electricity interconnectors are the physical links which allow the transfer of electricity across national borders. In the short-term, the GLA would support interconnections where this leads to a reduction in Londoners' electricity bills and its carbon content. More interconnections should:

8. Increase access to low carbon/zero carbon electricity and lead to a reduction in the carbon intensity of the grid mix, provided the electricity is affordable.

9. Reduce the peak demand on GB power stations (particularly given the timing differences between continental European peaks and our own), so reducing the level of capital investment required in peaking plant which is costly to consumers.

10. Decrease the need for back-up plant that needs to accompany the growth in intermittent renewables such as wind which is both expensive (thus undermining the economics of such renewables) and as peak plant usually carbon intensive.

(4) What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

11. In terms of energy planning, the GLA is working on the London Energy Plan that will provide a spatial map of London's energy supply and demand to 2050, identifying the locations and options for the required supporting infrastructure. It will include projections of heat and electricity infrastructure, retrofitting of the built environment to reduce demand, and electricity for transport. It will also identify the potential of 'smart' energy demand shifting. The London Energy Plan will identify the fraction of peak demand that is potentially 'shiftable' due to different types of demand side response and enabling technologies. Enabling technologies considered include smart meters, smart thermostats and additional thermal storage. Types of demand side response considered include static time of use tariffs, dynamic time of use tariffs and direct load control. The uptake of DSR (low to high) will be varied across different scenarios in order to demonstrate the potential effect of DSR in London.

CONTENTS

1 INTRODUCTION AND EXECUTIVE SUMMARY

Metrotidal Lower Thames Pool integrates new flood defences for London with energy storage, a multi-modal tunnel, data storage, utility wayleaves and enabling development for over 250,000 homes with corresponding employment. The integrated infrastructure provides economic growth without an associated increase in carbon audit. This green-growth is achieved through the integration of a flood defence system with a sustainable power plant that generates and stores zero-carbon energy for supply on demand. The sustainable energy offsets the demands of the new transport connectivity, led by rail, and the enabling development. The pool system includes energy-efficient data storage and distribution with an exceptionally low power usage effectiveness (PUE) and new utility wayleaves that serve the enabling development. The proposals also result in the construction of a valuable new deep-water dry dock on the Isle of Grain that is used to cast the Metrotidal Tunnel sections and the subsequent sections for the Sheppey Tunnel c2040.

The result is full-spectrum enabling development in which housing, employment, energy, transport, data, utilities and marine services are co-ordinated to generate green-growth benefits across the Greater Thames Estuary.

2 THE METROTIDAL LOWER THAMES POOL AGENDA

2.1 Integration Benefits

The combination of the separate initiatives into a single, well-integrated infrastructure project reduces the planning overheads, construction costs and environmental impacts while increasing the net economic benefits. Substantial integration benefits are realised by combining separate components for flood defence, sustainable energy storage, multimodal tunnel, data storage and utilities into an orbital network that supports growth across the Greater Thames Estuary region.

2.2 Flood defence

The Metrotidal agenda provides a new system of flood defence to protect London and the Thames Estuary from surge tides through to the 22nd century. The defences are provided in the form of a throttle working in tandem with flood storage capacity to reduce the level of an incoming surge tide. The throttle is located on the shipping channel and the associated flood storage is provided by a pool beside the Hoo Peninsula, with additional emergency capacity across the marshes to the Isle of Grain.

The throttle has a weir with deep-water flood sluices that admit water to the pool during an incoming surge and return it to the sea on the ebb tide. Existing monitoring systems provide over 24 hours' advance-warning of the storm surge. This allows the pool to be drained during the preceding low tide and the flood sluices closed to reserve the maximum flood storage capacity ahead of the surge tide. The variables of the incoming surge waveform and duration are recorded and analysed as the tide advances down the North Sea coast, enabling the most effective use of the available flood storage in the pool to be programmed before the storm surge arrives in the Thames Estuary. The level of the weir and area of the flood sluices are then controlled to suit the programme. If additional flood storage is required in an emergency a weir and flood sluices from the pool allow controlled flooding of the marshes beside the Isle of Grain.

The system is designed to allow the free movement of normal tides while restricting and limiting the incoming storm surge. The throttle and flood storage capacity of the pool then works in tandem with the capacity of the tideway upstream and the existing Thames Barrier to reduce the incoming peak surge. Accordingly, the system protects all the flood risk areas upstream from the throttle including the metropolitan areas and the existing fresh water habitats that remain at risk in the event of a surge tide under the current TE2100 proposals.

The flood defence proposals replace those of the TE2100 programme for which current budget is £1.5bn by 2034. The flood risk to very substantial property, infrastructure and habitat assets upstream is reduced, enabling the Association of British Insurers (ABI) to redirect a proportion of the premia raised under the new Flood Re agreement towards funding the flood storage system, so that government expenditure for the flood defence component will be less than the current £1.5bn budget. The flood storage pool impoundment doubles as a sustainable energy storage system and reduces the construction cost of the multimodal tunnel, consequently increasing the net economic benefits of the integrated system. The resultant net economic benefits are much higher than for the TE2100 investment programme, which addresses only the flood risks.

2.3 Sustainable Energy Storage

The Metrotidal agenda integrates flood storage and tidal power within the same impoundment, enabling the range within the impoundment to be pumped to treble the natural tidal range within the estuary. This allows the tidal power plant to increase peak output when required or store energy in the pool for delivery on demand. The energy for the pumping is provided by solar, wind and tidal power along with the forthcoming option of nuclear power from Bradwell in Essex. The solar energy is provided by floating arrays within the protection of the impoundment that generate up to 50MW per sq.km. The wind energy is provided from the London Array in the outer estuary and the tidal energy from the natural range at the throttle in the Thames generating power through turbines below the flood weir.

The combined solar, wind and tidal pumped-storage system can deliver sufficient energy to offset the energy demands of the multimodal tunnel and new rail systems, leaving surplus energy to be sold to the grid.

2.4 Lower Thames Tunnel and Sheppey Tunnel

The Metrotidal agenda includes a multimodal, D2T2 Lower Thames Tunnel formed from a combination of cut-and-cover and immersed tube tunnel construction techniques. The costs are reduced by maximising the proportion of cut-and-cover and minimising the length of the immersed-tube construction. For a Lower Thames Tunnel running between Leigh-On-Sea in Essex and Allhallows-On-Sea in Kent the pool impoundment reduces the cost of the tunnel by increasing the cut-and-cover approaches and reducing the length of immersed-tube tunnel across the remaining open tideway. The immersed tube tunnel sections are formed in a casting basin on the Isle of Grain, towed into position and sunk into a prepared trench across the open estuary. There is sufficient width in Sea Reach to maintain port operations during the immersed tube tunnel construction. The casting basin subsequently becomes a deep-water dry-dock to service shipping on the Thames and Medway Estuaries and provides the facility to cast the sections for the Sheppey Tunnel 2040.

The multimodal Lower Thames Tunnel completes a Crossrail Plus rail orbital and a highways outer orbital that together provide relief for the M25/Dartford Crossing and serve substantial growth across the Greater Thames Estuary region. On the north bank alternative Crossrail Plus orbitals can be completed via the C2C Basildon Line or the Southend Victoria Line to Crossrail at Shenfield. The rapid growth in population from Central London east along the Thames Estuary places priority on increasing capacity closer to the river hence the C2C route via Basildon is proposed as the initial orbital with the Shenfield orbital a subsequent option c2040.

2.5 Lower Thames Tunnel Connections

North Portal Connections

- new twin tracks alongside the C2C line from Leigh-on-Sea to Upminster, and dualling of the Upminster to Romford line for the extension of Crossrail services from Romford
- a subsequent option of a new connection from South Benfleet to Wickford and new twin tracks alongside the Southend Victoria services to Shenfield for the extension of Crossrail services from Shenfield
- a new passenger and freight chord at Shenfield to the Great Eastern Main Line
- road connection to the A13/A130 at Sadler's Hall Farm
- access to a new Southend Park-and-Ride bus service between Southend Eastern Esplanade and Leigh-On-Sea via the Pier, Western Esplanade, Chalkwell Esplanade and a new Leigh Esplanade that replaces the existing C2C tracks

South Portal Connections

- twin-track rail connection to the Isle of Grain Line, which is dualled from Lower Stoke to Hoo Junction for the extension of Crossrail services from Abbey Wood, with associated line improvements
- a twin-track chord from the Isle of Grain Line to the North Kent Line and Southeastern network services at Strood
- road connection to the A228/A229/A2
- rail connection to Sittingbourne and road connection to the A249 following construction of the Sheppey Tunnel 2040

2.6 Data Storage and Utilities

The Metrotidal Lower Thames Pool system generates and stores energy by moving large volumes of cool seawater between the pool and the sea. Data storage centres require reliable, sustainable energy supplies and efficient cooling systems. Modern Tier 4 centres secure alternative energy supplies for resilience and aim to achieve the lowest power usage effectiveness (PUE: total facility energy divided by the IT equipment energy). Data storage centres also require substantial cooling loads to maintain a steady-state environment for the IT equipment.

The seawater of the Thames Estuary maintains uniform temperatures throughout the year, suitable for providing a steady-state environment for the IT equipment and since the sustainable energy system moves large volumes of sea water this can be used to serve the cooling loads of the data centre, thereby achieving an exceptionally low PUE. The wide range of sustainable energy supplies used for pumping the pool provides additional resilience for the data centre supplies. The transport connections from the tunnel portals provide utility wayleaves for distributing the data across to the enabling developments across the Great Thames Estuary region.

Several existing utilities have key network connections that pass under the estuary not far from the line of the proposed tunnel. The immersed-tube tunnel cross-section includes passages for utilities with the benefit of access for maintenance and renewal. The transport corridors north and south of the tunnel provide routes for extending and connecting existing utility networks across the Greater Thames Estuary region. The utility way leaves (broadband, communications, electricity, gas, mains water and other private-sector services) contribute to tunnel revenues.

The Hoo Peninsula in Kent, one of the driest areas of the country, has a distant fresh water supply, pumped from the Medway Valley. The Lower Thames Tunnel opens a new water supply grid connection between South Essex and North Kent for a more resilient service with less pumping.

2.7 Tunnel Transport Services

Crossrail Plus: (C2C Basildon Branch) The Romford to Upminster single-track LTS Line is dualled and connected to new twin-tracks from Upminster to Leigh-on-Sea alongside the C2C Line, with 4-tracking through the stations at Upminster, West Horndon, Laindon, Basildon, Pitsea and Leigh-on-Sea, to create the Crossrail Plus orbital between Crossrail at Romford through Metrotidal Tunnel to Crossrail at Abbey Wood.

Crossrail Plus: (Shenfield Branch) The eastern limb of Crossrail to Shenfield in Essex is extended on a 4-tracked Southend Victoria Line to Wickford and a new twin-track connection to South Benfleet and so on to Leigh-on-Sea to create an alternative Crossrail Plus orbital route on the north bank from 2040, again serving the Greater Thames Estuary and Central London. Both orbital rail routes reconnect populations north and south of the Thames, with the existing and new stations becoming the foci for commercial and residential development.

Crossrail Plus connects with HS1 at Stratford and Ebbsfleet thereby providing convenient connectivity to Northern Europe without requiring access into Central London.

Crossrail Plus: (Halling & Peters Village Branch) A branch service of Crossrail Plus from Hoo Junction to Halling on the Medway Valley Line, with two additional platforms at Halling and/or Snodland providing a terminus that serves Peters Village on the east bank of the Medway

Pitsea-Isle-of-Grain-Strood Shuttle: A rail shuttle service that links the South Essex conurbation and the Medway Towns, with terminals at Pitsea, the Isle-of-Grain and Strood. The shuttle interconnects with Crossrail Plus at South Benfleet, Leigh-on-Sea, Allhallows-on-Sea, Stoke Harbour, Cliffe and Higham, the C2C services at Pitsea and the Southeastern

Network at Strood, with the option of a branch from the Isle of Grain Line via Hoo Junction and the North Kent Line to Ebbsfleet for access to the Javelin and HS1 services into Central London and the Continent. From 2040 the Isle of Grain line can be connected through the Sheppey Tunnel to extend the shuttle rail services through Queenborough, Swale and Kemsley to Sittingbourne.

Rail freight services: A rail-freight bypass to the east of London, via the new chord at Shenfield, opens a new long distance freight route between the Haven Ports, Thames Estuary and the Channel Tunnel. The Sheppey Tunnel opens an alternative freight route between Kent, the Thames Estuary and the Haven Ports.

Road connections: A new D2 highway between the A13/A130 at Sadlers Hall Farm and the A228/A289 on the Hoo, followed by a D2 connection to the A249 through a Sheppey Tunnel after 2040. The initial connection serves the enabling development across the Thames estuary region outside the M25 orbital and provides an alternative HGV road-freight route between Dover Docks and the Midlands that avoids the congested M20/M25/Dartford Crossing/M11. The current journey from Dover Docks to the A120/M11 junction northbound lane, via the A20/M20/M25/Dartford Crossing/M11 is 158km. The distance of the alternative route, via the A2/A289/A228/A130/A12/A131/A120/M11 is 179km. After the Sheppey Tunnel opens in 2040 the alternative route from Dover Docks to the Midlands via the A2/A249/A228/A130/A12/A131/A120/M11 is 163km. Improvements to the M2/A249 and A131/A120 junctions can reduce this to 158km, matching the existing journey, again without use of the M20, M25 Dartford Crossing or M11 up to the A120 junction.

Southend Park-and-Ride: a new shuttle bus service between Southend Eastern Esplanade and Leigh-on-Sea Station Carpark via the Pier, Western Esplanade, Chalkwell Esplanade and a new Leigh Esplanade that replaces the existing C2C tracks

2.8 Enabling Development

Residential Development: Growth-zones for over 250,000 homes, including the Shelter Wolfson Prize 2014 Housing Scheme on the Hoo Peninsula and Peters Village on the Medway, served by the stations of the Crossrail Plus orbital, the Pitsea-Isle-of-Grain-Strood Shuttle and the adjoining C2C and Southeastern networks.

Commercial Development: Office developments served by the stations of the Crossrail Plus orbital, the Pitsea-Isle-of-Grain-Strood Shuttle and the adjoining C2C and Southeastern networks.

Industrial Development: New industrial development on existing sites at the London Gateway Port, Basildon, Canvey Island, Isle-of-Grain, Kingsnorth, Hoo Junction, the Medway City Estate and Strood with convenient employee access provided by the Crossrail Plus orbital, Pitsea-Isle-of-Grain-Strood shuttle and the adjoining C2C and South-eastern networks. Additional connectivity for these sites, the industrial sites at Sheerness and Queenborough on the Isle of Sheppey and for the Swale, Kemsley and Sittingbourne in Kent after 2040 with the opening of the Sheppey Tunnel and the Shenfield chord.

Benfleet Esplanade: The existing station and rail tracks through Benfleet are replaced by a new 4-platform station and underpass beneath Benfleet Esplanade accompanied by commercial and residential development that restores South Benfleet to Benfleet-on-Sea.

Leigh Esplanade: The existing station and rail tracks through Leigh-on-Sea are replaced by a new 4-platform station and underpass beneath the existing station car park. This becomes the terminus of Leigh Esplanade, which runs on the line of the existing tracks through Leigh-on-Sea to Chalkwell, accompanied by commercial and residential development that restores Leigh to being on-Sea.

Southend Park-and-Ride: Mixed use commercial development over the new station and underpass at Leigh-on-Sea to receive visitors arriving via the tunnel and its connections and distribute them to the attractions of the Southend seafront via the Southend-Park-and-Ride service. Along with the enhanced rail access Leigh-on-Sea becomes a principal portal for visitors to the Southend conurbation thereby easing traffic on the notoriously congested A13 and A127 arteries.

The combination of one or more of the proposed East London Rivers Crossings upstream of the Dartford Crossing with the Metrotidal Lower Thames Pool downstream of the Dartford Crossing means that no work is required at the Dartford Crossing. The TE2100 proposals would be cancelled. Consequently, the budgets of £4.3-4.9bn for the Highways England LTC proposals and £1.5bn for the TE2100 to 2034 can be redirected to realising the Metrotidal Lower Thames Pool proposals, resulting in much higher outputs.

2.9 Counter-Cyclical Commuting-Capacity

The proposals enable the trains that would have terminated on the eastern limbs of Crossrail at Shenfield and Abbey Wood to continue around the orbital and return on the opposite sides of the estuary. The present radial configuration of Crossrail is designed to serve the diurnal radial commuting pattern into Central London, with trains running largely empty in the opposite directions during peak hours. The Crossrail Plus orbital system around the Thames estuary provides the same Central London diurnal commuter capacity but will also make full use of the counter-cyclical commuter-capacity to serve growth across the Greater Thames Estuary region. Journeys that would have run empty can now provide the rail capacity to serve settlements around the Thames Estuary without requiring journeys into Central London. Over 250,000 new homes and corresponding new employment across the Greater Thames Estuary region can be accommodated without increasing journeys into Central London.

Furthermore, the new orbital capacity will ease congestion and improve the resilience of existing radials by providing alternative routes into Central London. Basildon and the South Essex conurbation will have the option to travel south to Ebbsfleet and on to St. Pancras, while the Medway Towns can travel via the 4-tracked C2C and Great Eastern mainlines to Liverpool Street and Fenchurch Street.

2.10 Environmental Benefits

The environmental impact of the pool is assessed in terms of the impacts on intertidal and low-lying freshwater habitats. The area of St. Mary's Marshes to be occupied by the pool is already identified for managed retreat by the current TE2100 programme. The impacts on the remaining intertidal area occupied by the pool are offset by the benefits of protecting the intertidal areas upstream from tidal squeeze and from protecting large areas of low-lying freshwater habit from a storm surge. When the zero-carbon energy generated and stored by the system is taken into account the net environmental benefits are substantial.

2.11 Green-Growth

The integrated infrastructure provides economic growth without an associated increase in carbon audit. This green-growth is achieved through the integration of a flood defence system with a sustainable power plant that generates and stores zero-carbon energy for supply on demand. The sustainable energy offsets the demands of the new transport infrastructure and the enabling development. The sustainable pool system includes energy-efficient data storage and distribution with an exceptionally low power usage effectiveness (PUE) and new utility wayleaves that serve the enabling development. The result is full-spectrum enabling development in which housing, employment, energy, transport, data and utilities are co-ordinated to generate green-growth benefits across the Greater Thames Estuary region.

2.12 Agglomeration Benefits

New transport infrastructure creates an agglomeration benefit if the resulting economy exceeds the sum of the separate economies and the cost of the new transport links. Traditional agglomeration operates radially drawing satellite settlements into an ever-expanding urban nucleus. The Metrotidal Lower Thames Pool generates orbital agglomeration that spreads demand and capacity more uniformly.

The economic history of London can be seen as a series of agglomeration benefits, first from the Roman Bridge agglomerating the trade routes of the Thames Estuary with a radial road network spreading inland, accelerated by development of the regions, expanding sea trade, subsequent bridges, docks, warehouses and offices, all in turn rapidly increasing the urban economy and drawing in yet more investment. After WW2 the relocation of the port and trade from the Thames Estuary led to the contraction and separation of the economies in Essex and Kent. The Thames Estuary, for centuries the main artery of trade uniting the region into a single riparian economy from Central London to the coast, had become a barrier to growth. As a result, there are latent agglomeration benefits to be realised simply by re-uniting the economies north and south of the Thames through improved transport infrastructure. A relatively modest investment in new connectivity provides a large agglomeration benefit across the Greater Thames Estuary region. The Metrotidal Lower Thames Pool provides the new connectivity and enabling development, placing emphasis on orbital connectivity rather than extending existing radials. The congestion of Inner London arteries is avoided while full use is made of the counter-cyclical commuting capacity around the orbital, providing greater transport capacity for lower cost and higher agglomeration benefits.

The integration of the multimodal transport orbitals with flood defence, sustainable energy storage, data distribution, utilities and enabling development provides green-growth across the Great Thames Estuary region.

MW/March 2016

Response the National Infrastructure Commission's Call for Evidence 2015
from the Mineral Wool Insulation Manufacturers' Association (MIMA)

1. Introduction:

The Mineral Wool Insulation Manufacturers' Association (MIMA) is a trade body providing an authoritative source of independent information and advice on glass and stone wool insulation. MIMA actively promotes the benefits of mineral wool insulation and the contribution it makes to the energy efficiency of buildings and the comfort of their occupants.

We represent four of the leading insulation companies in the UK - Isover Saint-Gobain, Knauf Insulation, Rockwool and Superglass.

MIMA whole-heartedly welcomes the creation of the National Infrastructure Commission (NIC). It is hugely positive step to form a body able to make balanced, value for money decisions on how best to create a solid infrastructure base to support continued economic growth. The goal to link infrastructure delivery programmes to an independent assessment of projected future "need" is also to be commended.

The current consultation being conducted therefore represents an important development in the way that UK infrastructure is considered by government and we welcome the opportunity to submit our analysis.

The main focus of our response is on your third area of interest: "***Ensuring investment in energy infrastructure can meet future demand in the most efficient way***." We summarise why investment in building energy efficiency is an infrastructure priority, and more broadly answer how a national renovation programme of our aging building stock addresses the Chancellor of the Exchequer's questions:

- Does this increase the economic security of working people, or not?
- Does this enhance our national security, or not?
- Does this extend opportunity, or not?

2. Investing in energy efficiency is an investment in our national infrastructure

It has long been recognised that investment in infrastructure has a positive effect on economic growth by increasing productivity and attracting investment, as well as boosting employment in the construction and other industries. For example, building better transport links and energy generation capacity can have a strong positive effect on GDP per capita.

Visible, major construction projects, such as power stations and roads are most commonly thought of as infrastructure. Increasingly communications, connectivity and networks on a smaller scale and within local communities play just as big a role in ensuring our economy has the solid base needed to continue to grow. The inclusion of Smart Meters, which will be installed in individual properties, in the list of top 40 priority projects in the National Infrastructure Plan is evidence of our increasingly modern view of what constitutes infrastructure, and therefore what can drive economic growth.

The UK's building stock is part of our national infrastructure. Nationally coordinated investment in the quality and functionality of that stock - especially by making it more our 27 million existing homes more energy efficient – will drive growth and employment, just like most other infrastructure projects.

The reasons such investment can create growth are very simple:

- Energy efficiency reduces consumer demand for energy, freeing up energy capacity just as effectively as building new power stations, networks and storage.
- The work required to maintain and improve the building stock, including installing energy efficiency measures such as insulation, results in jobs and growth.
- Consumers living in energy efficient homes, and energy efficient businesses, have significantly lower energy bills, allowing them to spend money on other goods and services (particularly in the "able to pay" market).
- Energy efficiency provides a great range of public services, such as helping to protect consumers over the long-term from energy price volatility, from fuel poverty, and it substantially reduces the UK's carbon emissions.

Indeed, in terms of economic benefits alone, a recent report by Frontier Economics, sponsored by MIMA, found that according to the Government's own data, a large-scale energy efficiency programme for the residential and commercial buildings in Britain would provide a **net economic benefit of £8.7bn over 10 years and have a comparable economic impact to major road and railway projects, including HS2-Phase 1, Crossrail and new roads.**[1]

In terms of jobs, over 135,000 people are currently employed in the energy efficiency industry but major investment in energy efficiency could almost **double the number of jobs in the sector to 260,000**.[2]

The research by Frontier Economics also demonstrates that **energy efficiency fits clearly within each of HM Treasury's eight infrastructure characteristics** as defined by their valuation guidance:

> "*Domestic energy efficiency investments can free up energy sector capacity just as effectively as delivering new generation plant, networks or storage would. Energy efficiency investments provide public services, by reducing carbon emissions and improving health and wellbeing. They also provide option value in the face of uncertainty over future energy sector conditions (e.g. uncertainty over future fuel prices).*"

ResPublica built on these findings in 2015[3] by recommending that, in addition to classifying energy efficiency as a national infrastructure priority, there is a case to **devolve infrastructure spending** to the city or local level, which MIMA also supports:

"*As the Energy Bill Revolution and others have proposed, we advocate that energy efficiency should be made a national infrastructure priority: included in the top 40 priority infrastructure investments.*

But in keeping with our support to devolve powers and fiscal responsibilities to the lowest appropriate level, we also argue that Government should devolve infrastructure spending, where appropriate, to city regions."

When balanced against wider infrastructure investment, a rollout of energy efficiency provides a comparable economic return to HS2

[1] Frontier Economics, Energy Efficiency: An Infrastructure Priority, 2015. http://www.frontier-economics.com/documents/2015/09/energy-efficiency-infrastructure-priority.pdf
[2] UKGBC, A Housing Stock Fit for the Future, 2014. http://www.ukgbc.org/resources/publication/housing-stock-fit-future-making-home-energy-efficiency-national-infrastructure
[3] ResPublica, After the Green Deal, 2015. http://www.respublica.org.uk/wp-content/uploads/2015/05/After-the-Green-Deal.pdf

From an **energy security** perspective, the most secure energy system we can create is one which invests in supply, but also keeps demand as low as is cost-effective in smart, high quality, energy efficient homes. We must continue to support demand management for both electricity and gas.

Not only does demand management and energy efficiency **help to de-risk national supply strategies**, which could easily be thrown off track by changes in the global market, it is also one of the most effective ways to protect consumers from the full force of **energy price rises and volatility** in energy markets.

By way of example, analysis by the UKGBC in 2014[4] found that:

- The UK could **reduce its reliance on imported gas** by 19 per cent by making UK homes more energy efficient, saving £2 billion in gas imports every year; and

- Delivery of **energy saving measures costs less on average per unit of power than large-scale power generation**. Through cost-effective investment in all forms of energy efficiency, the UK could be saving 196TWh in 2020, equivalent to 22 power stations.

A report by Cambridge Econometrics in 2014 found that energy security could be enhanced further if all homes were to achieve an EPC rating of C by 2030. In that scenario we should see a reduction of gas imports of 26%, worth £2.7bn per year by 2030.[5]

Making building energy efficiency a public infrastructure priority has widespread support, including from other leading UK business associations and businesses, including the CBI. And in Scotland, the five main parties, including the Scottish Conservatives, have already committed to improving home energy efficiency through a "national infrastructure project". Such a move is also supported by core cities. Area-based programmes carried out by core cities are a natural fit with objectives to encourage resurgent cities and to support further devolution.

More than 200 businesses, charities and consumer groups are now calling for infrastructure funding to support energy efficiency, including Age-UK, Kingfisher plc, Co-operative Energy, the Energy Saving Trust, Keepmoat, Willmott Dixon and Worcester Bosch.

Energy efficiency of the building stock is an integral part of the energy system. By classifying energy efficiency of buildings as a national infrastructure priority, the NIC would be instrumental in creating the stable framework and strategic oversight required to attract the capital needed to deliver the necessary scale of works.

3. Why is there a need to invest in a national, long-term energy efficiency programme?

Reassuringly, between 2005 and 2013 UK homes saw a huge **30% drop in (weather adjusted) median gas consumption**, with gas consumption decreasing on average by 5% per year between 2004 and 2011.

A rough calculation at today's prices suggests **£5bn less per year will be spent on gas alone** across the UK's 27 million homes than if consumption had remained at 2005 levels (again, weather adjusted).

DECC cites one the reasons for this drop in consumption as being down to energy efficiency

[4] http://www.ukgbc.org/resources/publication/housing-stock-fit-future-making-home-energy-efficiency-national-infrastructure
[5] http://www.energybillrevolution.org/wp-content/uploads/2014/10/Building-the-Future-The-Economic-and-Fiscal-impacts-of-making-homes-energy-efficient.pdf

programmes, efficient boiler regulation and some austerity driven thermostat adjustment – however the trend started well before the 2008 recession.

This is a great **UK infrastructure success story** meaning we are already far more energy secure than we otherwise might have been. However, the job of retrofitting the housing stock is only half done.

Despite the implementation of a string of government programmes over recent decades, sadly, the **UK's housing stock still remains amongst the "leakiest" in Western Europe**. The energy being generated to power and heat our homes is being wasted through un-insulated walls and roofs.

Contrary to perception, there are still many millions of homes that haven't benefitted from insulation and energy efficiency upgrades. Only a very small percentage of the country's 8 million solid walls have been insulated, and around 5 million party walls are, as yet, un-insulated. The **estimated fuel bill cost to consumers from heat loss through party walls alone is around £465 million a year**.

Although more progress has been made on cavity walls and lofts, there are still millions which have not been treated or can benefit from being topped up.

Even worse, there are a growing number of examples of people from all over the country wishing to make their home more energy efficient, but being **unable to access the remaining support**, because government-driven delivery is now almost solely in the hands of energy suppliers, since other programmes and schemes were cut.

This has far reaching implications for consumers. For the average consumer, energy bills may be up to £300 per year more than they could be. For the 2.3 million households in fuel poverty, the decision to under heat their home to save energy and money is often their only option. Cold homes can put people's health at risk, especially in households with vulnerable people such as the elderly or very young. The ONS estimated there were just over 43,000 cold-related winter deaths in England and Wales in 2014/2015, more than double the number from the year before and higher than the average annual figure. The cost impacts of cold homes and fuel poverty on the NHS is an estimated £1.3bn per year.

In the future, as the population ages, many more people will fall into vulnerable categories, struggling to pay needlessly high energy bills or suffering the effects of living in a cold home. **Energy efficiency is one of the most cost-effective ways to protect vulnerable groups for the long-term.**

In terms of our climate change commitments and targets**, failure to deliver an ambitious energy efficiency programme is likely to make it more difficult and costly to meet carbon budgets**.

At present **more than a third of all energy used in the UK goes to heat either water or air** so that we have comfortable living and working environments. If demand side measures – particularly improving the fabric of UK buildings – are not fully considered as part of wider infrastructure choices, the UK risks being locked in to an inefficient energy system with an imbalance in long-term investment.

The Committee on Climate Change has, taking into account the uncertainty around the projections, estimated that there is already a shortfall against the fourth carbon budget (2023 to 2027) where our emissions are projected to be greater than the cap set by the budget.[6]

[6] DECC Updated energy and emissions projections: November 2015
https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2015

Analysis underlying the CCC's assumptions assumes certain levels of energy and carbon savings being achieved as result of government energy efficiency policies. There is cause for concern as, at present, the policies that would deliver carbon savings have either been cut or weakened, including the Green Deal, the Zero Carbon Standard for new homes, and the post 2017 Energy Company Obligation.

Why does incorporating energy efficiency into decision-making on infrastructure make a difference?

The reasons policies have not succeeded in delivering the technical potential (or even the cost-effective potential) are varied and complicated. But we would argue, it comes down to a **failure to deliberately and concertedly drive demand** for energy efficiency across the board towards an agreed target or goal.

We instead focused on piece-meal policies, often designed to remove barriers to uptake, such as the upfront cost in the case of the Green Deal. Such policies are more likely to be successful only in cases where consumers were already persuaded on the benefits of energy efficiency. Where there is latent demand.

Some steps were then taken by DECC and DCLG to rectify this situation. For example, the time-limited Green Deal Home Improvement Fund was introduced, as well as new energy efficiency requirements for the private rented sector. There is no doubt that the number of installations rose – but what resulted was a **boom and bust delivery profile** as DECC suddenly withdrew funding when the number of applications sky-rocketed, and then re-introduced vouchers in short stints.

Voucher and cash-back schemes can drive demand, but in an uncontrolled way and sometimes leading to perverse outcomes.

The ECO has proved to be more successful than the Green Deal, demonstrating that creating fixed targets e.g. to save a specified amount of carbon and making organisations responsible for driving sufficient demand to meet the target, works in terms of driving numbers – but in some cases, this has been at the expense of quality.

The **lack of a proper, long-term strategic framework** for the stock as a whole has had unwelcome consequences for the stability of the insulation industry. The building insulation market contracted by 22% in 2013 as the installation of cavity wall insulation fell by 46%, the installation of loft insulation fell by more than 87%, and the installation of solid wall insulation fell by 30%, compared with the number of measures installed under the Carbon Emissions Reduction Target (CERT) in 2012.

There is now a **clear opportunity for the National Infrastructure Commission and the Government to put in place the plan for improving the UK's existing housing stock through the infrastructure "architecture" to fully insulate our building.** We need to fully integrate energy efficiency into national infrastructure plans.

With energy efficient buildings classed as an infrastructure priority, and an appropriate long-term vision outlined, delivery can be implemented through a set of **coordinated policies designed to drive the uptake of measures**, including support for low interest loans, cost neutral stamp duty reform which rewards home owners with energy efficiency homes, and a programme of targeted capital investment in the homes of the fuel poor.

The UKGBC estimates that a national energy efficiency programme would need public investment of £3-4 billion a year to **address areas of market failures and leverage substantial additional**

private investment – just a small percentage of the £hundreds of billions of investment expected to be brought forward this Parliament.

4. Meeting future energy demand

One of the National Infrastructure Commission's primary areas of interest is to ensure "*investment in energy infrastructure can meet future demand in the most efficient way*". The key point we want to make in this section is that **no** matter what our future energy mix, **it always makes sense to invest in the fabric and energy efficiency of buildings**.

We must make solid progress on energy efficiency now as we work towards decarbonising the electricity grid over the coming decades, and a greater proportion of homes become electrically heated. Electricity is currently a more expensive and carbon intensive form of heating compared to gas, and even as this begins to change, we do not want to waste this clean heat.

Failing to insulate our homes properly means the **energy we pay for is needlessly wasted**. Heat is leaking through the walls. It is like paying out for energy to run a hot bath, only to have half the water go straight down the plughole.

Investing in the fabric of the building stock reduces the amount of energy needed to achieve the same levels of comfort in the home**. Energy capacity is then freed up**, potentially reducing the need for further investment in new infrastructure in other areas of the energy system. In doing so, **energy efficiency helps to de-risk security of supply strategies**.

Fabric measures can also help to **flatten morning and evening peak loads**. While only 2-3 million homes rely solely on electric heating, this still constitutes a significant part of peak UK winter energy demand. **Large numbers of gas homes are also meeting this peak demand with plug-in electric heaters** providing top-up heat which again likely coincides with peak times of the day.

Replacing inefficient appliances with the most efficient appliances is part of the answer, but making homes more energy efficient would also reduce for some of demand for electricity, such as for secondary heating, in the first place. 4.2 million English households currently have secondary electric heating.[7]

Similarly, when **smart meters** are rolled out, they could soon be followed by "time of use tariffs" which will aim to shave peak demand by setting higher peak prices. If this is not mitigated against, this could have a **potentially regressive effect on poorer households** pushing them away from peak use whether it's no longer cooking dinner at dinner time or heating their homes first thing in the morning or on their return from work. Ensuring fabric renovation options are available that will allow the home to retain heat means homeowners can comfortably move away from those winter peaks but still stay warm.

Looking ahead, we are increasing take up **microgeneration technologies** for heat and power such as Solar PV, Solar Thermal and Heat Pumps. It is of fundamental importance to ensure that we simultaneously insulate the fabric of buildings to minimum levels, otherwise risking the waste of renewable generation. This "fabric first" principle is a key tenet of energy efficiency policy and was reiterated in DECC's recent response to Feed in Tariffs consultation.

The move towards **smart homes** with clever tech which enables people to control their heating, hot water and appliances should also be matched with a quality building. Being able to precisely control when your heating comes on, in order to be comfortable and save energy, has much greater value

[7] Cambridge Architectural Research Ltd et al, Further Analysis if the Household Electricity Survey 2013. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/275483/early_findings_revised.pdf

and impact in a building which is not simultaneously leaking lots of heat. You wouldn't expect much from a cutting-edge GPS system installed into an old car with a broken steering wheel (even that is possible!).

Driving energy efficiency across the board - both electricity and gas – remains a wise choice. Around **80% of heat demand is currently met with natural gas.**[8]

To achieve the type of energy system needed we must address every aspect of heat and energy demand.

Currently, overall **energy demand is falling**. However, **it is expected to rise after 2025** as the impact of recent energy efficiency policies declines. In the absence of a major policy intervention, current levels of energy efficiency and the impact of fossil fuel prices may be insufficient to offset the impact of economic and population growth. Demand is expected to rise again.

5. Conclusion:

Gas consumption in UK homes has fallen by 30% between 2005 and 2013. Energy efficiency has been a major driver in this success story.

As a result, a rough calculation at today's prices suggests **£5bn less per year will be spent on gas alone** than if consumption had remained at 2005 levels.

It is not yet clear how we in the UK intend to continue to drive the remarkable benefits of energy efficiency, but the need is urgent. The UK still has some of the leakiest housing stock and amongst the highest excess winter death figures in Europe. The UK's current energy costs are some of the lowest in Europe, yet householder energy bills are amongst the highest.

Keeping the lights on is of course vital but so is providing the UK with a housing stock that is affordable to heat.

Driving the energy efficiency of the UK's housing stock to prevent energy capacity and investment being wasted must be central to our infrastructure, economic, energy and climate change policy. We desperately need a stable, long-term (at least ten-year) programme.

We urge the Commission to include the need to properly retrofit the nation's buildings in its up-coming assessment, and to make delivery of such a programme an infrastructure priority.

We also ask the Commission to urgently investigate and consult in detail on what our long-term energy efficiency targets and delivery strategy should be, and how these relate to and drive benefits in the wider energy system.

6. For further information, please contact:

Sarah Kostense-Winterton
Executive Director
Mineral Wool Insulation Manufacturers Association (MIMA)
Email: [email address redacted]
Tel: [phone number redcated]

January 2016

[8] Department of Energy and Climate Change (DECC): The Future Of Heating: Meeting The Challenge, March 2013 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/190149/16_04-DECC-The_Future_of_Heating_Accessible-10.pdf

About National Grid

1. National Grid's job is to connect people to the energy they use, safely.

2. We hold licences under the Electricity Act and Gas Act for:
   a) Electricity transmission, which includes both the system operation of the Great Britain transmission system and ownership of the high voltage transmission assets in England & Wales),

   b) Gas transmission (system operation and ownership of the high pressure pipelines in Great Britain), and

   c) Gas distribution network serving approximately 11million customers in England, across four networks.

   d) Under separate licences, and through, independent ring fenced companies, we have entered into Joint Ventures through which we also own and operate electricity interconnector assets between the UK and France and Holland and are developing projects with Belgium and Norway.

3. National Grid owns the high voltage electricity transmission system in England and Wales, which at 99.99995% is the most reliable network in Europe.

4. As System Operator we are responsible for real time balancing of supply and demand which is around 3% of total electricity [and gas] supplied.

5. In Great Britain, National Grid does not own any electricity distribution assets neither do we own any Scottish or offshore electricity transmission assets.

Context

National Grid sits at the heart of the UK's energy system, balancing the system second by second to meet the demands of energy consumers. We have a unique and privileged perspective of the issues facing the energy system. We are facilitating the drive towards a low carbon energy system and our focus is on enabling an orderly, economic transition that maintains security of supply, facilitates the achievement of climate change targets and provides a good foundation for further change required in the period to 2050 and beyond. Over the next decade, we plan to invest around £16-20 billion to ensure that our electricity and gas networks continue to provide safe and reliable energy supplies to customers

Exec Summary:

Changes to the market: Changing consumer behaviour and new technologies are driving fundamental changes in the nature of our energy system and how it is managed. This includes current changes both in technology and regulation. As such, there are a number of changes that we need to see in the energy market to support the delivery of efficient and secure energy supplies.

- Review of the capacity market
- Encouragement of Demand Side Response (DSR)
- Greater visibility of network connected assets

The System Operator structure: The structure of the System Operator (SO) function has been a topic of discussion for a number of years, with some parties favouring an SO that is integrated with a TO (or TSO) and some parties favouring an Independent System operator (or ISO). Our analysis suggests, based on international experience, that moving to an ISO would only deliver potential benefits to consumers if it was coupled with significant market reform (e.g. the introduction of locational marginal pricing (LMPs)) and broader changes to industry governance. It is not clear that an Independent System Operator is in the best interest of consumers and distracting the SO at a time when energy security is such a high priority would introduce an unnecessary risk. The focus for the SO should be on security of supply and ensuring the evolving market arrangements bring forward new generation to replace the capacity leaving the system from legacy plants.

Opportunities in storage: Technological advances have created opportunities for energy storage which has seen significant cost reductions over the last few years. There are three key barriers to the wider deployment of energy storage capacity on the system:

- High cost of technology compared to alternatives
- Accessibility of multiple revenue streams
- Lack of a policy definition of storage which means some companies are prevented from developing the technology

Interconnection levels: Electricity interconnection reduces costs to consumers by linking higher cost energy markets to those which have lower costs. Our analysis shows that Great Britain could unlock up to £1billion of benefits to energy consumers through doubling its interconnector capacity by 2020. As well as lower energy prices for consumers more interconnection would drive enhanced energy security, a cleaner environment and wider macro-economic effects. Failure to double existing interconnector capacity to nearer the 10% proposed by the European Commission could be equivalent to foregoing wholesale electricity price reduction of nearly £3million every day.

International best practice for the changing environment:
International experience has shown us that the requirement for particular system services or the provision of targeted subsidies to technologies has resulted in the penetration of new technologies. In this response we examine Italy, Belgium and Ireland and USA which have experienced growth in new technologies, particularly storage and DSR to understand how this has been achieved.

Questions:

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Review of Capacity Market

Renewable technologies such as such as wind and solar provide fluctuating levels of power over multiple time horizons, known as intermittent generation. This requires National Grid to have visibility of, and access to, flexible sources of generation to manage this intermittency and ensure supply meets demand.

The closure of large scale plants and the rise of new technologies and players such as smaller scale generators, storage, DSR (flexibility through management on the demand side) and interconnection changes the way in which supply meets demand. We are actively considering the impact of those closures on security of supply. We are supporting a DECC led review of the capacity market as there is a need to consider structural solutions to reduce uncertainty regarding future supply and demand-side technology mix to 2018/19.

Stimulate Demand Side Response

National Grid is actively pursuing the development of energy solutions such as storage, interconnectors and Demand Side Response (DSR). DSR is intelligent energy usage which financially incentivises consumers to lower or shift their electricity use at peak times. This in turn helps to manage load and voltage on the electricity network, and allows businesses and consumers to save on total energy costs and reduce their carbon footprint. Demand side response (DSR) is likely to be a significant contributor to system flexibility capability in the future.

We know that roughly two-thirds of national demand sits in the Industrial and Commercial business sector and so our initial focus is on developing DSR in this sector. To facilitate the development of DSR products we have developed a framework called Power Responsive which enables businesses, suppliers and policy makers to shape the growth of demand side response collaboratively. The aim is to deliver it at scale by 2020. To achieve growth in this area <u>there is a need for increased promotion of the opportunities in DSR and a simpler set of products with clear value for businesses</u>

Greater visibility of what is connected to the grid

On the distribution networks, system operation has become more complex as more community energy sources are being connected. Community or "Distributed" energy sources refers to electricity generating plants or users of electricity that are connected to a lower voltage local distribution network, rather than to the high voltage national transmission network. Some new technologies at consumer premises (e.g. Electric Vehicles) may increase demand on the system, leading the Distribution Network Operator to need to manage its system in a more active way[1] rather than increase its network capacity.

It is expected that there will be a requirement to balance the whole system (including distribution/local networks) in a much more active and dynamic way. Therefore there is a <u>need to ensure that all parties involved in system operation have full visibility and accessibility of assets that are connected to the distribution network</u>. In the interim, as we wait for greater visibility of what is connected to the grid, we are managing increasing system fluctuations by contracting with embedded generation to provide system flexibility.

[1] Increase or reduce demand rather than increase network capacity.

Is there a need for an independent system operator (SO)?
The structure of the System Operator (SO) function has been a topic of discussion for a number of years, with some parties favouring an SO that is integrated with a TO (or TSO) and some parties favouring an Independent System operator (or ISO). In Europe the TSO model is favoured and our current structure is TSO, whereas in the US an ISO structure is more prevalent and this is the case in our own territories in the North East.

This question has become very real in recent months in the UK with the advent of the enhanced planning role under Ofgem's Integrated Transmission Planning and Regulation (ITPR) project and with the increasing pace of change in the generation sector as it moves from larger transmission based units to more distributed generation, increased intermittency, demand side activity and storage. Given these developing challenges we have engaged some independent consultants (FTI Consulting) to explore the options regarding the future structure of the SO. This work includes consideration of the pros and cons of an ISO models as well as alternative models.

As result of the work we have done so far, we do not believe that an Independent System Operator is in the best interest of consumers. We believe the current focus should be on security of supply and ensuring the evolving market arrangements bring forward new generation to replace the capacity leaving the system (e.g. the closure of coal fired plant.) There is a risk that creating an ISO at this moment in time would be a distraction from focussing on security of supply matters. Our work with FTI suggests, based on international experience, that moving to an ISO would only deliver potential benefits to consumers if it was coupled with significant market reform (e.g. the introduction of locational marginal pricing (LMPs)) and broader changes to industry governance. Evidence suggests this would require large multi-year structural changes which risks reducing investor certainty in the generation market. This in turn could inhibit the connection of the new power stations required to deliver future security of supply.

Forming an ISO would entail significant set up costs and, would not be able to provide the strong incentives required for the role. Many of the benefits in ISO overseas are due to the market arrangements, rather than the structure of the SO.

It should be recognised that the integrated TSO model has delivered significant value to consumers historically, and there is real and material consumer value in maintaining the partially integrated SO model, which maintains the deep asset knowledge and SO - TO synergies that facilitate timely and accurate decision making that deliver system security and reduced overall costs of operating the system. We would be very happy to share our analysis on this and other aspects highlighted above.

Despite the obvious drawbacks of an ISO we do recognise the increasing need to provide confidence that any potential conflicts of interest between our TO, Non-Regulated Business, Business Development and SO are properly managed. We have a lot of experience operating in an environment where this is fundamental and legal requirement of our business.

An option that could be considered is a legally separated SO within National Grid, which would retain the majority of the benefits of the current arrangements (strong synergies between the SO and TO and strong financial incentives to deliver value to consumers) but also provide greater confidence to the industry around the management of conflicts of interest.

An alternative model which could go a bit further to introduce a new independent body, with National Grid reverting to just the system balancing activity, could also have merit (if the Government wishes to have a smaller role in energy matters, leaving more matters to industry experts,) and wishes to further address the management of conflicts of interest beyond a legally separated SO with National Grid.

Further analysis will be undertaken on the models in the New Year and we would be happy to share the work with NIC as they consider their recommendations"

2 What are the barriers to the deployment of energy storage capacity?

There are two key barriers to the wider deployment of energy storage capacity on the system. These are:

1. The high cost of storage technology compared with alternatives
2. The policy and regulatory framework

Technology costs: Energy storage has seen significant cost reductions over the last few years (e.g. lithium-ion battery costs have fallen by c. 60-70% since 2010[2]) yet does not compete equally with other flexibility providers. There are however promising efficiency improvements and cost projections for existing storage technologies. Storage will be cost competitive when the cost can be compared to other flexibility technologies such as interconnection for energy balancing, thermal generation or DSR for ancillary services, and traditional reinforcement for upgrade deferral. We anticipate those cost reductions to bring storage closer to compete with other flexibility providers, with battery capital costs forecast to fall by nearly 50% over the next 5 years[3].

The policy and regulatory framework: Though economic fundamentals account for slow deployment of battery storage to date we outline below additional five barriers which would depress deployment below the economically efficient level were they not to be removed:

1. Lack of clarity of the classification of storage: as acknowledged by Ofgem[4] the legal and commercial status of storage is unclear. This risks holding back network-led business models and so reducing investment in storage. It is noteworthy that the 2014 large scale storage project "Leighton Buzzard" required UK Power Networks (an electricity distributor) to gain special dispensation to proceed. Clarity on classification could provide the opportunity for a single storage system to provide a number of services, and therefore benefit from multiple revenue streams, which is critical to making a business case for investment. We recommend that this is done in a way which continues to prevent network owners from selling electricity in the wholesale markets.
2. Network Charging: due to its treatment as both generation and demand, storage can be 'double charged'. We recommend cost reflective charging for storage, as for other technologies. In most cases a cost reflective principle would lead to lower charges for storage, and so improve business cases for its deployment
3. Taxes: a similar issue exists where storage providers must pay environmental levies twice. Applying levies only to energy consumption would improve the business case for storage
4. Lack of half hourly settlement: The electricity settlement process places incentives on suppliers to buy energy to meet their customers' demand in each half hour of the day. At present, most consumers do not have meters capable of recording half-hourly consumption data. Instead, they are settled using estimates of their usage in each half hour. The roll-out of smart meters that can record half-hourly consumption and be remotely read presents an opportunity to improve the accuracy and timeliness of the settlement process. Wider adoption of half hourly settlement would accentuate temporal price differentials faced by end users and therefore the arbitrage benefits to be gained from storage (either through self-consumption or the wholesale markets)

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[2] SgurrEnergy, *The Market Opportunity for Battery Energy Storage*

[3] Lazard's *Levelised Cost of Storage* (November 2015) forecasts decline in capital costs between 2015-2020 of 47% for lithium-ion batteries and 38% for flow batteries.

[4] Ofgem, *Position Paper: Making the Electricity System More Flexible and Delivering the Benefits for Consumers* (September 2015)

5. De minimis restrictions: DNOs are restricted to investing no more than 2.5% of their share capital in non-regulated assets, which places a ceiling on DNO-backed investment.

National Grid are also reviewing the commercial services brought by the SO to ensure they are optimally designed to match the capabilities of emerging technologies (including storage and other flexibility tools) while continuing to meet traditionally high standards of reliability. Two key barriers being addressed are:

Service exclusivity: some SO contracts prohibit the provision of multiple services from a single asset, in order to guarantee availability when it is required. This makes it harder for storage assets to provide the service, as they tend to require the ability to benefit from multiple revenue streams to be economic

Little long-term certainty on ancillary revenue streams: the contract length for ancillary revenue streams is typically short (less two years) due to the SO's incentive regime, which makes it riskier for investors to develop storage, given the required longer payback period.

The opportunity:

The removal of these barriers would allow the full potential of storage to be unlocked. Our analysis of the whole GB market suggests there is significant opportunity for greater storage, equating to an extra 2-3GW by 2020 delivering over £100m p.a. of consumer value. This potential will grow strongly through the 2020s and 2030s as battery costs continue to fall, EV penetration drives increased behind the meter demand and the electrification of heat and transport creates need for network reinforcement.

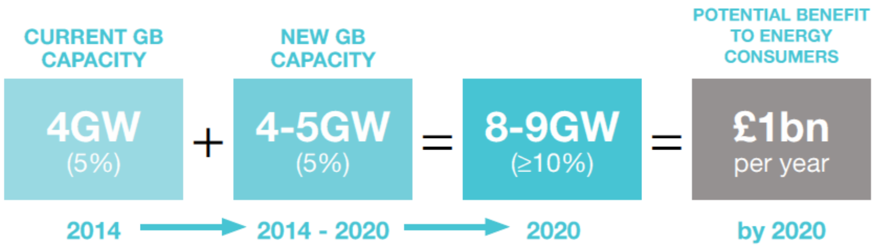
The first wave of additional storage is likely to be prompted by demand for frequency services. These can be provided by fast responding electro-chemical batteries (such as lithium-ion), flywheels and super capacitors. They can be provided from any location.

Over the longer term behind-the-meter models are likely to become economically viable, particularly following the wider adoption of smart meters and half hour settlement. This will see end users benefitting from self-consumption and/ or selling grid services via aggregators.

However, storage technologies are rapidly developing and it is not possible to forecast capabilities and cost with certainty. Furthermore, other emerging flexibility tools (such as demand side response and interconnection) can be used for many of the same applications as storage. Therefore we believe the market should remain open to accommodate future innovation and that a level playing field should exist for all flexibility tools. The changes recommended above will remove barriers which presently unduly hinder the deployment of storage

3. What level of electricity interconnection is likely to be in the best interests of consumers?

The benefit of increased Great Britain interconnection capacity for the energy market is clear with our analysis showing that Great Britain could unlock up to £1billion of benefits to energy consumers through doubling its interconnector capacity by 2020. Interconnection benefits include lower energy prices for consumers, enhanced energy security, a cleaner environment and wider macro-economic effects.



Electricity interconnection is a facilitating technology for reducing energy costs to consumers by linking higher cost energy markets to those which have lower costs; and over time aligning costs across the connected markets. Great Britain (GB) already has four of them, linking us to France, Ireland, The Netherlands and Northern Ireland. These links, totalling 4GW, represent around 5% of existing electricity generation capacity. However, this level remains low compared to the 10% benchmark proposed by the European Commission and there is strong consensus that this gap should be filled. Failure to double existing interconnector capacity to nearer the 10% proposed could be equivalent to foregoing wholesale electricity price reduction of nearly £3million every day.

The impact of increasing interconnection on the operation of the network is less clear. The way Europe manages interconnectors is changing with the introduction of the European network codes. This has a significant impact on how we manage GB interconnectors and presents both opportunities and threats. The opportunity is that we may get new, harmonised services across all interconnectors. However the threat is that we may lose existing capabilities as they are harmonised. Currently the network codes are at various stages of development and discussions are ongoing. Therefore the impact is unclear as the detail has yet to be discussed and agreed. The potential significant growth in GB interconnection increases the importance of achieving a satisfactory solution to the efficient management of interconnectors.

A merchant interconnector regime, such as that developed in GB, allows developers to build to an efficient level of capacity between markets, i.e. when there is no additional value to be realised between those markets. Such a position may be distorted if a developer has either generation or supply interests in either of the markets to be connected. The cap and floor regime (currently in place) provides an appropriate mechanism for remunerating developers. It allows them to have certainty of revenue recovery and ensures that the end consumer is protected and the wider benefits to the transmission system are realised. To that end each cap and floor arrangement needs to be set on a case by case basis.

Electricity interconnection requires the cooperation of multiple countries. This can itself form a barrier due to the different regulatory and legal regimes that exist between nations; placing additional costs and constraints to the development of interconnectors.

The on-going development and alignment of the electricity regulation regimes within the EU under the auspices of the Commission therefore has the potential to unlock more interconnection.

National Grid believes that a full understanding of the benefits of greater interconnection is important to inform the debate on an appropriate ambition to meet the country's need, and the timeframe within which it should be achieved. Significant progress has already been made in preparing for greater electricity interconnection. The UK Government and European institutions have provided strong support, Ofgem and its European counterpart has developed a new and innovative regulatory design, and multiple developers have come forward with proposed projects. With this regulatory and policy work we can unlock multibillion pound investment, and realise the benefits of interconnection.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

International experience has shown us that the requirement for particular system services or the provision of targeted subsidies to technologies has resulted in the penetration of new technologies. We examine those markets which have experienced growth in new technologies, particularly storage and DSR to understand how this has been achieved:

1. Case examples of provision of particular subsidies: **Italy**

The TSO (and DSOs) in Italy, can build and operate batteries under certain conditions. Italian network regulator (AEEGSI) passed a Decision on Provisions related to the Integration of Energy Storage Systems for Electricity in the National Electricity System (Decision 574/2014/eel of 10 November 2014) defining network access rules for energy storage.

It defines energy storage as a power generating system and makes them subject to certain obligations. Storage is required to pay connection fees in line with those for high efficiency CHP and power generation plants. Storage is also treated as programmable (dispatch-able) units if considered as single power generation systems, and as programmable or non-programmable units if considered as part of a group of generation systems, depending on the characteristics of the other units in the group (NERA 2014).

'Energy' project was launched with the 2011 Development Plan and envisages the construction of three storage systems in southern Italy for a total 34.8 MW capacity. The scope is to ensure significant flexibility is available in the management of renewable power plants, and to increment the transmission grid's capacity to absorb green power.

'Power' project approved in 2012, will install 40MW of energy storage capacity to increase security of electricity networks and develop smart grid applications. The first phase of the project comprises of 10MW Li-ion and 6MW of various other battery technologies for comparison purposes. Following positive initial results, phase 2 was announced, consisting of 20MW Li-ion battery and a 4MW sodium-nickel-chloride battery.

2. Case example of regulation aiding positive uptake of a desired service: **Belgium and Ireland**

Other international markets where the regulatory framework or the need for additional system services has driven the uptake of particular services, e.g. DSR includes Belgium where the TSO is active in contracting DSR for system balancing and Ireland which is introducing mandated Time of Use tariffs alongside its smart metering roll out.

3. Case example of using targets to achieve storage deployment ambitions: **USA**

One US example which has seen significant deployment of storage is California. In support of its renewable energy target, California Public Utilities Commission introduced storage targets in 2013 to enable renewables integration and efficient management of efficient management of networks. The three largest utilities (PG&E, San Diego Gas & Electric & Southern California Edison) are mandated to install 1.3GW of storage by 2020 (and have completed deployment by 2024). The program is weighted towards transmission connected storage although the networks have the flexibility to manage individual requirements.

We intend to work closely with the Ofgem, DECC and other parties to facilitate growth and uptake of particular technologies where needed.

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**National Infrastructure Commission, Call for Evidence:
Electricity Interconnection & Storage**

A response from National Grid, European Business Development (EBD)

EBD is a ring fenced division of National Grid, responsible for business development activities in line with our core capabilities and outside of National Grid's onshore regulated activity. We welcome the opportunity to contribute to this Call for Evidence and the work of the National Infrastructure Commission. In particular, to share our recent experiences from developing both our interconnector portfolio and other project opportunities in smart grids and storage.

We recognise that the UK electricity system faces considerable challenges over the coming decades, including the changing GB generation mix and the new patterns of demand. By 2020, according to UK Renewable Energy Roadmap[1], more than 30% of UK electricity demand will be met by renewable generation. To meet the government decarbonisation objectives, the electricity sector will also need to become increasingly decarbonised in the period 2030-2050. Without significant development in demand side response, introduction of more flexible generation, increased interconnectivity and the potential use of large scale volume of storage, the cost of providing energy to the consumers could increase significantly. We are responding to this challenge in several areas of our business development work.

One of our major areas of work is developing National Grid's UK Interconnector portfolio. We are developing several new interconnector businesses and exploring new ways to use interconnection to resolve the energy trilemma. Over the last five years EBD has worked closely with the UK regulator Ofgem, as well as project partners in Belgium, France, Norway, and Denmark, to support their development of a new regulatory mode and realise the next generation of investment in interconnection (the "cap and floor"). Today, we have a further 4.8GW of projects to mainland Europe and Scandinavia in development (IFA2 and Viking Link) and construction phase (NEMOLink and NSL). National Grid Group also operates two interconnectors (IFA and BritNed) that represent three quarters of the UK's 4GW of interconnected capacity.

We are using our interconnector expertise to open up the opportunity for offshore grids; supporting export of renewables and renewables trading. Through projects such as Icelink, we are exploring opportunities to harness the interconnector resource and relationships in innovative ways. EBD is also active in the area of Smart Grid solutions. We are exploring new business models and novel capacity products. We support the development of new and innovative markets that have the potential to reduce the total cost for the end consumer, as well as supporting system operation challenges across Europe.

This means we have a critical interest in the call for evidence from the National Infrastructure Commission, seeing it as an enabler of the longer-term transitions that the UK energy system needs and an important initiative that our project portfolio can play a part in delivering.

**Ian Graves
Director, European Business Development**

[1] HM Government, 'The UK Renewable Energy Roadmap', July 2011

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?
The challenge of balancing supply and demand is met by the UK System Operator, incentivised by the Balancing Services Incentive Scheme (BSIS), to efficiently manage balancing costs on behalf of consumers.

This challenge is set to increase in the future energy system, where intermittent renewable generation plays a greater role, and the distribution networks transform into active networks hosting two-way flows of power. The UK System Operator (SO) has suggested that the need for some system services will increase dramatically to meet this changing generation mix. For example, primary frequency response requirement could increase by 30-40% in the next 5 years, and by 2030 the response requirement will be between 3 and 4 times today's level[2]. Given this context, the UK needs new solutions to expand the diversity and breadth of balancing service provision.

Traditionally, these balancing services (such as voltage control, frequency control and constraint management) are provided by large, synchronously connected generators. As the energy industry is changing, many of these traditional suppliers look set to disappear e.g. due to plant closures. The new generating fleet is increasingly dominated by non-synchronous and/or embedded forms of power generation. This generation includes HVDC interconnection (bringing in power from neighbouring countries), wind and solar. These new sources of power, together with increasingly novel forms of demand-side management, facilitated by information technology progress, are potential new providers of Balancing Services.

This poses the question: Are the current market frameworks sufficient to incentivise appropriate service providers, including new entrants, to provide the balancing services our SO needs?

Our analysis, based on the experience of developing business models to support investment in interconnection, indicates that the market frameworks need adaptation to really incentivise the most efficient services to come forward. We note a lack of long-term investment signals in the relatively short-term Balancing Services contract as a barrier to making investment in interconnection as a balancing tool. This lack of price signal is also likely to impact investment in other technologies, such as storage, in the same way.

For example, the business cases for our interconnector portfolio are primarily based on the value associated with cross-border capacity used in energy trading in the Wholesale Energy Market. We are alert to new revenue streams and opportunities for our projects, to add additional value to the UK energy system. We regularly review whether we should specify additional components for our projects (for example, to provide reactive or overload capability for provision of enhanced voltage or frequency control services). As we cannot pinpoint the future value of the services, and our regulatory scrutiny drives minimisation of Capex (unless a robust business case can be provided demonstrating consumer value), this pushes us away from anticipatory investment and limits this kind of discretionary incremental capability.

To bring diversity in service providers that support system balancing at least cost to consumers, longer-term price signals are needed from the balancing market to support investment in new technologies.

2. What are the barriers to the deployment of energy storage capacity?
Because storage is both generation and demand, it does face barriers that are not faced by other balancing technologies. In EBD, we see two particular challenges:

i) The lack of clarity on the legal and commercial status of storage, particularly in relation to ownership of storage assets.

Components of the business case for storage are held by many different market actors and any one of them could be compelled to develop market opportunities in storage. Ultimately, a key outcome of

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

any intervention and decision on legal definitions should a strong marketplace enriched with a diversity of market participants, it should not unnecessarily preclude participants that are able to contribute to building a competitive marketplace.

ii) Insufficient incentive to invest because storage projects are underpinned by complex business models that rely on multiple revenue streams accruing to different parties, invariably governed by different regulatory or legislative regimes.

New business models supported by new regulatory and legislative frameworks are needed to catalyse market-led deployment of energy storage capacity. The regulator working alongside storage developers, the System Operator and Network Owners on specific projects and challenges is likely to yield results. In our experience, collaborative working on real pilot projects is the most constructive approach to create workable new frameworks; particularly where alignment of multiple objectives from multiple parties is needed (e.g. to capture maximum value for consumers and ensure an appropriate and stable investment framework for developers).

Our recent interconnector investment successes are an example of this – we worked side-by-side with our project partner Elia to support the development of the new regulatory regime for interconnection developed by Ofgem and their partner regulator CREG and piloted on NEMOLink. And we replicated this success, testing the new regime with a similar level of collaboration with partners, and interaction with Regulators and Government in the UK and Norway on NSL.

3. What level of electricity interconnection is likely to be in the best interests of consumers?
Following signing of multiple EPC (Engineer, Procure, Construct) contracts totalling over €2.5bn, the UK is getting two new power connections to Norway and to Belgium. These projects will realise significant benefits for UK consumers through lowering our electricity prices. This positive investment climate has been generated by the simple win-win of the consumer story, recognised by both the Regulator and Government with the development of a "cap and floor" regulatory regime and inclusion of interconnection in the UK capacity market.

Maintaining this momentum in investment and getting the right levels of cross-border capacity is the next challenge. UK consumers need interconnection built in response to market signals. Interconnection is infrastructure that complements home-grown generation, demand response and storage by providing access to support from the energy systems of the European Internal Energy Market. Interconnection is a new tool for the System Operator (SO) to provide much needed flexibility. To do this, we may need new markets to stimulate investment in additional cross-border capacity, and maximise the benefits to UK consumers of integration with the Internal Energy market (IEM).

Responding to this new challenge of maintaining momentum in investment raises several questions:

i) What are the benefits of interconnection?
ii) What drives more interconnection capacity and how much is optimal for the UK?
iii) What are the market failures stopping efficient and optimal new investment and how can we overcome them?

i) What are the benefits of interconnection?

Interconnectors reduce prices, make our system more secure, deliver flexible system operation services and facilitate renewables

Interconnection brings benefits to UK consumers through increasing the size of the market that they can access. This gives consumers access to lower cost generation, and new sources of renewable and low carbon generation. In addition, interconnection can make an important contribution to security of supply through providing links to energy networks in other countries.

As part of this, interconnection can also become an important tool in the System Operator's toolbox – supporting the management of the system in ancillary services through exchange of reserves between System Operators across Europe. Below, we give you some examples of how National Grid's existing and planned interconnector can provide these benefits now, and in the future.

Security of Supply:
Our two interconnectors to mainland Europe just participated in the UK capacity auction. Both cleared in the auction, acknowledging the value for money that interconnection can provide in delivering secure power to the UK system. The contribution of these links for 2019/20 will be:

Interconnector	Derated capacity
BritNed	828MW
IFA	1033MW

Interconnection also provides services to national System Operators (SOs) at times of system stress. On BritNed and IFA there is up to 3GW of capacity available in Emergency Situations to support the GB or neighbouring transmission systems. Our new links, NSL and NEMOLink will also provide these services through close SO to SO working.

For example, during the Solar Eclipse on March 20th 2015, there were concerns that a reduction in output from solar generation in Germany could cause problems. To help address this, capacity was made available on IFA and BritNed to help SOs in Mainland Europe manage the changing flows[3].

System balancing between SOs:
Interconnectors offer the possibility for National SO's to exchange balancing energy. National SO's can offer excess power to neighbouring systems or find more cost effective ways of accessing generator availability in other countries. This type of service is currently provided by IFA between Rte and NGET[4]. The European Network Code for Balancing promotes development of common cross-border balancing products, and has looked at the IFA solution as a template for others.

Provision of balancing and ancillary services:
As electricity cannot be stored, National Grid must balance supply and demand on a second by second basis to achieve a target frequency of 50Hz. Frequency response is one of the balancing services that National Grid procures to keep the frequency at the target level. Interconnectors can be an effective provider of frequency response. Interconnectors can react extremely quickly in response to a frequency deviation. BritNed currently delivers 100MW of this service to GB and through this has already provided significant operational security support to the GB system, as well as cost savings to the National TSO.

Energy market liquidity:
A fundamental of a healthy functioning market is liquidity in energy trading. This is improved by any measures that reduce barriers to cross-border trade, and increase competition. IFA and BritNed already make a positive contribution to these objectives.

The planned projects in our portfolio and in construction will make an incremental difference. For example, at 1GW IFA2 would represent an increase of 50% in the capacity available across the France-UK border, as will non-physical financial products associated with the interconnector flows. Any new players in the interconnector market will automatically increase the breadth and diversity of participants thereby improving competition in energy supply.

Integration of renewables:
Interconnection facilitates the deployment of renewables by reducing the costs of renewables integration.

A recent Imperial College / NERA Study for the Committee on Climate Change[5] found that the system integration cost of low-carbon generation technologies will significantly depend on the level of system flexibility; enhancing system flexibility would reduce system integration cost of

[3] http://www.telegraph.co.uk/news/earth/11433786/Solar-eclipse-to-disrupt-power-supplies.html
[4] http://clients.rte-france.com/lang/an/visiteurs/vie/contrat_angleterre.jsp
[5] https://d2kjx2p8nxa8ft.cloudfront.net/wp-content/uploads/2015/10/CCC_Externalities_report_Imperial_Final_21Oct20151.pdf

renewables *by an order of magnitude.*

For instance, the whole system cost disadvantage of wind generation against nuclear reduces from circa £14/MWh in a low flexibility system to £1.3/MWh in a fully flexible system achieving 100 g/kWh emission intensity. At the same time, the whole-system cost of solar PV reduces from being £2.3/MWh higher than nuclear to being £10.7/MWh lower than nuclear as the result of improved flexibility.

Interconnection is an important part of the mix of flexible options available (alongside more flexible generation technologies, energy storage, demand side response) and therefore essential in a future world with a higher renewables penetration.

ii) What drives more interconnection capacity and how much is optimal for the UK?

10% interconnection is "no regrets" for the UK, >10% is highly likely to bring additional benefits

We build interconnection to realise all the benefits described above. Depending on the energy mix in the UK and the countries we connect to, the signals to build more interconnection will come from different drivers and result in different levels of cross-border capacity.

Our work to establish the size of market opportunities for investment in interconnection has identified a no-regrets level of interconnection that is roughly equivalent to 10% of the installed generation capacity in the UK. Under our range of scenarios, this level of interconnection (equivalent to around 8-10GW of capacity) provides benefits to consumers of up to £1billion/year in wholesale energy -market price reductions from 2020[6].

The benefits of interconnection beyond this level are dependent on the underlying characteristics of the UK energy system, and those systems that surround us. Additional investment in interconnection could be viable and valuable for consumers beyond this level to:

1) Further reduce GB wholesale power prices (if UK prices remain materially higher than mainland Europe)
2) Increase security of supply and diversity of generation sources
3) Provide the System Operator with additional tools and capacity to operate the system efficiently and flexibly
4) Integrate greater levels of renewable generation in the UK, and provide a route to market for the UK renewable resource
5) Realise the objectives of the Integrated Energy Market in Europe and promote pan-European socioeconomic welfare benefits

Different scenarios would increase the value of cross-border transmission capacity beyond the 10% level. For example:

- **High levels of offshore wind generation and other intermittent renewable generation and a robust carbon price:** *greater levels of interconnection would allow UK renewables to be exported at times of surplus (rather than curtailed). Additional interconnection capacity would allow UK renewables to find new markets elsewhere in Europe. Additional interconnection also supports the economic and efficient outcome that sees renewable resources being supported in areas where the natural resource can be most efficiently harnessed – e.g. wind in the North Sea, and solar in southern Europe. Under this kind of scenario – our analysis indicates that UK consumers may benefit from more than 10% of our generation capacity being matched by interconnection to facilitate export of our renewable power at times of surplus. Evolving interconnection to offshore grids (i.e. meshed networks that connect offshore generation in to point-to-point interconnection) may bring considerable efficiency savings under high wind generation scenarios.*

[6] "Getting More Connected" (2014) http://www2.nationalgrid.com/About-us/European-business-development/Interconnectors/

- **Low offshore wind deployment coupled with increased demand response or a rise in the economic efficiency of storage technologies:** *this kind of energy future would see a focus into the distribution networks. Interconnection is still helpful and beneficial to consumers at the no-regrets level. Because new technologies and new players are more active in the market, UK consumers are not looking to non-GB generation for cheaper sources of energy. Interconnection may also become useful to allow for export for these new demand or distribution led services if similar transitions have not happened in other systems across Europe. Under this scenario – particularly if it is also correlated with low ambition in transmission connected renewable generation, we see little more than 10% of generation being matched by interconnection.*

- **High commitment to EU Member State cooperation to ensure secure and diverse supply of energy, maximising the potential for supporting the EU energy needs with resources from within the EU region:** *Considering world events, energy security is also impacted by our reliance on energy imports from elsewhere in the world. Interconnection offers a route to create greater physical connections between the EU member states that can dramatically improve system-system cooperation, and facilitate the development of an energy union that can work towards minimisation of reliance on external sources of energy resources through reliance on low-carbon and distributed energy resources as well as the natural resources found across the region. Greater political union and commitment to physical connection to promote energy security and stability could be a new driver of interconnection beyond the 10% level.*

iii) **What are the market failures stopping efficient and optimal new investment and how can we overcome them?**

The current regulatory arrangements and energy policy framework will support timely delivery of 8-10GW of interconnector capacity. New markets for balancing and reserves and enabling trading of renewable power across borders will support additional investment in interconnection.

With the current regulatory regime (i.e. Ofgem's "cap and floor") we believe that the UK can reach the no-regret, 10% level of interconnection to mainland Europe and Ireland. This can be achieved by completing NEMOLink and NSL, and realising projects like IFA2, ElecLink and VikingLink. A portfolio of around 8-10GW of interconnection would be both beneficial for UK consumers and investible under the current "cap and floor" regime.

Critical to this stable environment and realising these benefits is maintaining access for interconnection to the new capacity markets, and ensuring a fair representation of the value that interconnection brings to security of supply in the UK.

The European Network Codes and related legislation as part of the European "Third Energy Package" are important factors in achieving accurate price discovery and efficient operation of interconnectors in response to underlying system conditions. For example, removal of market entry and exit tariffs is a critical component required to realise the benefits of free-trade of energy across borders. In the UK, preventing layering of charges on cross-border trades has led to the removal of system charges on interconnector flows.

Achieving levels beyond 10% depends on the visibility of price signals associated with the drivers of interconnection investment. Currently, interconnector developers see signals from the Wholesale Energy Market and the UK Capacity Mechanism and will build new capacity on this basis. Value from balancing, offering system or reserve services is not so straightforward to capture and neither is value from import / export of renewables. The capacity mechanism and the development of a pan European Capacity Market will also play a part and potentially drive further investment as the value of cross border connections are realised in the context of security of supply.

We believe that the cap and floor regulatory regime is a helpful wrapper that can support investment under any scenario whereby the benefits of interconnection can be reflected in an accessible market framework. Currently, the cap and floor will deliver new interconnection that can be justified on the basis of more efficient generation dispatch and contribution to security of supply through the capacity market. Creating new markets e.g. for reserves and system services, or enabling cross border trading of renewables could allow the cap and floor to support additional investment.

Depending on the market developments and the underlying drivers for interconnection, adaptations to the cap and floor regime may be needed. For example:

1) to ensure that re-investment to realise novel services from existing interconnection is not disincentivised through the presence of a hard cap based on a pre-defined value for the regulated asset base.
2) to support hybrid structures of offshore networks that integrate the connection of offshore generation and interconnection, and may include some element of anticipatory investment.

Moving beyond point-to-point interconnection to create offshore grid networks also requires considerable commitment from the Member States Governments involved. For example, a UK-Iceland Taskforce has been set up to explore the feasibility of a connection between the two countries[7]. This kind of intergovernmental initiative is an essential ingredient of any complex cross border project integrating renewable power generation and interconnection. In particular, Government cooperation is required to integrate national support schemes for renewable generation and enable trading of renewable power across borders.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The European Network Codes are the starting point towards realising future benefits of a more integrated approach to balancing services within the European Integrated Energy Market. Much work remains to be done to bring this to life and will be driven by ENTSO-E and its various working groups. There is a considerable task to standardise balancing products, define co-ordinated balancing areas (ie. a stepwise regional approach to full integration) and work out pricing methodologies, settlement algorithms and implementation plans.

These steps will take time and are pre-requisites to fully realising the potential benefits of sharing balancing services across borders. We support the importance of this work and are participating in two pilot projects: BritNed frequency control trials (mentioned above) and project TERRE[8] (Trans European Replacement Reserve Exchange). These two initiatives will provide much of the experience and knowledge necessary before more widespread implementation is possible across Europe.

A further step along the journey will be cost-benefit analysis to ensure that reforms to balancing market/operational practices are only made where there is a strong expectation that the benefits will outweigh the costs. This is relevant in considering whether a portion of interconnector capacity should be withheld from the energy market for the purposes of providing balancing services in a real-time balancing market. There would be a positive case for reservation of a tranche of interconnector capacity for balancing, if the pan-European consumer welfare benefits of utilising capacity for (energy and balancing) are greater than the consumer welfare benefits if the full capacity was dedicated to energy alone.

The North Sea Link (NSL) interconnector connecting UK and Norway is exploring the opportunity to reserve capacity in this way to support SO actions on System Balancing. SOs in Scandinavia are already active in trialling different approaches and developing markets. A recent report from efforts on the Norway-Sweden border provides some insights in this respect that could provide help shape similar work in the UK market[9]

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[7] http://uk.reuters.com/article/uk-britain-iceland-power-idUKKCN0SN16G20151029

[8] Project TERRE (Trans-European Replacement Reserve Exchange) is an initiative set up by ENTSO-E to explore the possibility of increasing social welfare value by allowing TSOs to access cheaper balancing energy in other countries. Currently, the project consists of seven European countries and is in the design phase with completion expected by Q3 2018. The IFA interconnector plays a pivotal role in the initiative as it will allow the GB System Operator to access the TERRE platform and so reduce the costs of balancing the GB network.

[9] http://www.statnett.no/Global/Hasle%20report%20StGr_150317%20(3).pdf

Action for Warm Homes

National Energy Action (NEA) response to the National Infrastructure Commission call for evidence – Energy Priorities

Introduction

NEA is an independent charity which seeks to help an estimated 4.5 million low income households across the UK who can't adequately heat and power their homes[1]. As well as NEA's own work to influence and increase strategic action against fuel poverty at a national level, NEA also delivers practical solutions to improve access to energy efficiency products, advice and training and wider fuel poverty related services to UK households. NEA's supporters are made up of energy efficiency installers, manufacturers, utility companies, local authorities, housing associations, gas and electricity network operators, health agencies, community groups and other voluntary sector agencies. NEA and our supporters warmly welcome the creation of an independent National Infrastructure Commission (NIC) and the opportunity to respond to the call for evidence to identify the UK's long-term infrastructure requirements.

Specifically, NEA's response highlights several opportunities for improving how electricity demand and supply could be better forecast and balanced in the future. Within the response to the consultation questions NEA notes that exploiting these opportunities is predicated on ensuring all domestic customers have access to the benefits of domestic smart meters and, on an aggregated basis, much more accurate domestic energy consumption data will also help ensure supply is better matched to demand in any given area at different times of the day or year.

Whilst new technologies and approaches to demand-side management and energy storage can help facilitate some of this welcome innovation (and reduce the need for superfluous generation), NEA also stresses NIC, Ofgem and the Department of Energy and Climate Change (DECC) must also actively develop a new role for Distribution Network Operators (DNOs). The response notes that DNOs are best placed to co-ordinate these activities on their local distribution networks rather than relying on a central System Operator such as National Grid to perform these roles. As well as improving the efficiency and accuracy of how electricity demand and supply are balanced, this response also illustrates how encouraging DNOs down this path can also enable them to facilitate more efficient use of energy for households, which can in turn offset the need for electricity network reinforcement. NEA therefore highlights current innovation projects that are working towards these outcomes and asks NIC to help build on this good practice.

Finally, NEA's response also highlights that other organisations must be empowered to make a massive 'step change' in permanent reductions in total energy demand across the UK. By encouraging local authorities and their private sector partners to lead on city-wide domestic retrofit projects, NEA notes the NIC could be critical in galvanising this activity which could deliver substantial macro benefits. As well as noting how this will help to deliver the Government's stated vision for energy efficiency to play a central role in obviating the need to build new power stations or subsidise existing electricity capacity[2] (and therefore help reduce the cost to energy consumers of the transition to the low carbon economy) it is hoped the activities outlined in the response will complement current national energy efficiency initiatives and help accelerate the UK Government's fuel poverty commitments in England[3] over the next 14 years as well as support the other UK nations to meet their own statutory fuel poverty targets[4].

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[1] The time lag in publication of official fuel poverty statistics, generally around two years between collection and publication, means that the UK Government's estimates are not current. These statistics are taken from the *Annual Fuel Poverty Statistics Report, 2015, Department of Energy and Climate Change (DECC)*, May 2015.
[2] The Energy Efficiency Strategy: The Energy Efficiency Opportunity in the UK, DECC, November 2012.
[3] The *Fuel Poverty (England) Regulations 2014* are now law.
[4] The 2010 Fuel Poverty Strategy sets out a target to eradicate fuel poverty in Wales by 2018. The Housing (Scotland) Act 2001 requires the Scottish Government to eradicate fuel poverty in Scotland, as far as is practicable, by November 2016.

Enhancing current action & demand reduction as a 'first fuel response'

NIC's primary investigation considers the role of increased interconnection and new technologies in demand-side management and energy storage. Whilst the deployment of increased interconnection could help secure reliable electricity supplies cheaper than indigenous production (and demand-side measures can also help reduce peak demand for electricity), the call for evidence did not seek any specific evidence on how domestic energy efficiency can also contribute to these goals. NEA notes that this unfortunate omission has been made despite repeated calls for the UK Government to recognise home energy efficiency as a hugely important infrastructure opportunity and the Government's own analysis highlighting how cost-effective investment in all forms of energy efficiency could save the UK 196 TWh in 2020, equivalent to 22 power stations[5].

As a result, NEA highlights that the potential to join up the business case for action on energy efficiency will be a prominent theme within many responses to this consultation. The reason for this level of consensus amongst industry, academics and non-governmental organisations is that the benefits of enhancing energy efficiency are vast and are increasingly being quantified with the same precision as supply side measures. In particular, the International Energy Agency (IEA)'s report '*Capturing the multiple benefits of energy efficiency'* demonstrated the potential for energy efficiency to deliver new jobs and economic growth, reduce pressure on health services, improve energy security and reduce carbon emissions (at the same time as providing a long-term, sustainable solution to unaffordable fuel bills for all consumers). The report also found that that large scale energy efficiency programmes can lead to increases in GDP of up to 1.1% per year; can create significant employment (8–27 job years per €1million invested) and can have a benefit to cost ratio of 4:1[6].

This international evidence is also supported by extensive independent analysis of the macro benefits of enhancing domestic energy efficiency within the UK context. Building the Future: *The economic and fiscal impacts of making homes energy efficient* produced by Cambridge Econometrics and Verco, for example noted that an ambitious energy efficiency programme can return £3 to the economy per £1 invested by central government; help create a 26% reduction in imports of natural gas in 2030; domestic consumers could save over £8 billion per annum in total energy bill savings; increase relative GDP by 0.6% by 2030; increase employment by up to 108,000 net jobs and help reduce carbon dioxide emissions by 23.6MtCO2 per annum by 2030.

NEA contests that achieving these macro outcomes is a realistic prospect and the UK has historically been highly effective in reducing energy use and galvanising economic activity through this activity. For example, over 440,000 heating and insulation measures have been successfully installed to over 360,000 homes through NEA's Warm Zones[7]. NEA estimates this activity has helped reduce fuel bills by a total of £38 million per annum provided jobs and training for hundreds of unemployed people, provided major savings to the local health sector and stimulated local economies to a measure of £78 million each year. This activity was part of a broader improvement in the current housing stock that has seen millions of households already gain access to the benefits of energy efficiency measures[8]. Across the UK, this has helped cut energy use by c. 12% since 2000. However, in recent years this progress has now slowed with the introduction last Parliament of the incentive schemes, the Green Deal and the Energy Company Obligation (ECO) which have seen dramatic reductions in delivery rates[9]. In addition, low income households continue to live in less efficient properties than affluent households and currently, only 5% of fuel poor households in England live in the most energy efficient properties (EPC Band C or above) and well over one million live in least efficient properties, despite current and previous energy efficiency schemes.

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[5] Department of Energy & Climate Change, Energy Efficiency Strategy: The Energy Efficiency Opportunity in the UK, Nov 12

[6] Capturing the multiple benefits of energy efficiency, International Energy Agency, 2014.

[7] WZs is a community interest company which focuses on installing energy efficiency solutions to low income households in deprived areas using a wide range of funding sources and is delivered on a not-for-profit basis.

[8] At the end of December 2014, there were around 27 million homes in total in Great Britain, of which 23.9 million have lofts. Between March 2008 and December 2014, the number of homes with loft insulation with thickness greater than 125mm increased from 10.2 million to 16.7 million, a rise of 64 per cent. Around 70 per cent of homes with lofts have loft insulation thicker than 125mm. Since March 2008, the number of homes with cavity wall insulation increased from around 10.0 million to around 14.1 million in December 2014, a rise of 40 per cent. In December 2014 there were around 19.4 million homes with cavity walls, and therefore around 73 per cent of homes with wall cavities have cavity wall insulation. Between March 2008 and December 2014, the number of homes with solid wall insulation has increased from 65,000 to 294,000, more than tripling the level of uptake. In December 2014, there were 8.0 million homes with solid walls, of which around 3.7 per cent had solid wall insulation. There has also been an increasing trend for condensing boilers, replacing non-condensing boilers in households since 2005, partially as a result of a change in building regulations. In 2013, across all households, condensing systems can now be found in approximately 50 per cent of all homes.

[9] POST note: Number 503, 'Trends in Energy': September 2015, p2. The Parliamentary Office of Science and Technology states it produces independent, balanced and accessible briefings on public policy issues related to science and technology.

NEA also seeks to highlight that according to Department of Energy and Climate Change (DECC)'s own statistics[10] currently only c. 23,000 low income households are being brought up to EPC band C per year. Based on current delivery rates from the relevant components of the ECO scheme and Central Heating Fund (which will now expire at the end of March 2016), NEA estimates the UK Government could miss the fuel poverty target in England by 80 years and 1.8m FP households may still be living in homes below EPC band C by 2030. In addition, some fuel poor households could be waiting over 230 years to receive some insulation measures[11]. In addition, in November 2015 the Comprehensive Spending Review (CSR) stated that there will be deep cuts to the only GB-wide ECO energy efficiency programme from 2017. The overall spending envelope will be cut to c. £640m per annum which follows a similar previous reduction in 2014 when the budget was reduced by a third; from the original notional spend of c. £1.3bn per annum.

Prior to the announcement regarding these likely reductions, NEA had highlighted in both written and oral evidence to the Energy and Climate Change Select Committee that the UK Government's stated objective to ensure that as many fuel poor homes as is reasonably practicable have a minimum energy efficiency rating of Band C by 2030 was at risk of not being met. According to the Climate Change Committee (CCC)[12] and think tank Policy Exchange[13] current resources were less than half of what is required to meet these targets. It was therefore anticipated that the Government would ring-fence current levels of ECO resources on fuel poverty alleviation. The impact of this latest reduction in overall resources therefore cannot be understated. Whilst the new programme is likely to be more focused on vulnerable fuel poor households, it is now likely that fewer households will be helped with energy efficiency measures through levy funded supplier obligations than ever before. Without an intervention, it will also be the first Parliamentary term in the last 30 years that there will be no public funding in England for home energy efficiency in England.

The UK Government stated that the rationale for this was to reduce the projected cost of so-called green policies on the average annual household energy bill by £30 from 2017 and specifically noted that the bulk of these savings will come from reforms to the ECO scheme. Whilst levy funded resources can increase energy prices for struggling households who may not benefit directly from the programme in question, the ECO policy reduces total energy demand[14] and can obviate the need to build new power stations or subsidise existing electricity capacity. This decision was therefore short-sighted given the costs associated with this counterfactual. In the following sections NEA has highlighted how NIC can help redress this situation. Finally, NEA would stress this course of action is practicable and necessary, as in the future the burden of policy costs on bills looks set to increasingly be shouldered by domestic consumers as a result of the UK Government's plans to further extend exemptions for heavy polluters.

The role of local authorities and the Core Cities

The Core Cites are England's eight largest city economies outside London along with Glasgow and Cardiff. Collectively they account for 22% of the UK's energy demand and are responsible for 27% of England's carbon emissions. Within their Competitive Cities, Prosperous People: *A Core Cities Prospectus for Growth*[15] they highlighted that in order to be successful for the long term, cities need to help the most vulnerable in society and tackle fuel poverty, become more self-sufficient in terms of energy production, and reduce energy demand. They went onto highlight that with the right incentives it would be possible to harness the huge purchasing power of cities to drive new solutions leading to increased and competitive local energy supply, lower energy usage and carbon emissions, reduced fuel poverty, huge savings to the public purse and a stronger local business infrastructure.

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[10] *Annual Fuel Poverty Statistics Report*, 2015, Department of Energy and Climate Change (DECC), May 2015 p.18.
[11] NEA is happy to share our methodology for calculating these figures with the Committee however these figures are based on reported delivery rates using the Government's own ECO statistics.
[12] *Addressing fuel poverty and meeting carbon budgets go hand in hand* (CCC), 7 October 2014.
[13] *Warmer Homes - Improving fuel poverty and energy efficiency policy in the UK*, 2015, Policy Exchange
[14] Based on the figures provided to the EU Commission within *Communication of the United Kingdom's approach and analysis for complying with the requirements of Article 7 of the Energy Efficiency Directive*, Annex A - Final energy consumption savings by year from UK policies included for Article 7 policy plan, TWh [UK Government, June 2014] the ECO was assumed to have delivered between 4.7-6.9 Twh reduction in final energy consumption between 2017 and 2021. This figure will reduce substantially as a result of the proposed changes from 2017. It is also worth noting that the UK Government's Energy Efficiency Strategy made the case that improvements to domestic energy efficiency can reduce the country's dependence on imported fossil fuels and increase energy security. It highlights how cost-effective investment in all forms of energy efficiency could save the UK 196 TWh in 2020, equivalent to 22 power stations.
[15] Competitive Cities, Prosperous People: A Core Cities Prospectus for Growth, November 2013.

Table 1: Average Electricity Consumption of the Core Cities per household

	Mean consumption (domestic economy 7)	Mean consumption (standard tariff)	Mean consumption (all domestic)	Economy 7 meters (000's)	Standard meters (000's)	All domestic (000's)
Birmingham	5,178	3,667	3,872	300	1,348	1,647
Bristol	5,246	3,450	3,655	116	593	709
Cardiff	5,229	3,413	3,548	59	475	534
Glasgow	3,633	3,065	3,186	256	795	1,051
Leeds	5,256	3,530	3,715	192	1,076	1,268
Liverpool	5,851	3,341	3,485	71	668	739
Manchester	5,788	3,492	3,754	144	673	817
Newcastle	5,231	3,294	3,487	65	371	437
Nottingham	4,027	3,310	3,543	171	292	463
Sheffield	5,133	3,325	3,432	72	741	813

Table 2: Average Gas Consumption of the Core Cities

	kWh	No of meters (000's)
Birmingham	14042	386
Bristol	11934	168
Cardiff	12769	136
Glasgow	11799	246
Leeds	14034	302
Liverpool	12076	194
Manchester	12031	180
Newcastle	14234	109
Nottingham	12596	116
Sheffield	14009	220

Table 3: Fuel Poverty levels of the Core Cities in England [Low Income High Cost definition[16]]

LA Name	Region	Estimated number of households	Estimated number of Fuel Poor Households [LIHC]	Proportion of households fuel poor (%)
Birmingham	West Midlands	412401	78086	18.9
Leeds	Yorkshire and The Humber	327513	38133	11.6
Newcastle upon Tyne	North East	118362	15344	13.0
Manchester	North West	209159	31195	14.9
Liverpool	North West	210818	30567	14.5
Sheffield	Yorkshire and The Humber	234893	25509	10.9
Bristol City of	South West	191878	25379	13.2
Nottingham	East Midlands	128710	18050	14.0
England Average				**9.9**

[16] At the Spending Review in October 2010, the government announced that it would commission an independent review to consider the current fuel poverty target and definition. In March 2012 Professor Hills published the final report of his independent review of fuel poverty, making several recommendations for how fuel poverty should be measured. Professor Hills proposed a new measure: the Low Income High Cost (LIHC) indicator. This table uses both the 10 per cent indicator and Hill's low income high cost measure of fuel poverty. Under the LIHC definition a household is considered to be fuel poor where they have required fuel costs that are above average (the national median level) and were they to spend that amount, they would be left with a residual income below the official poverty line. The low income high cost measure consists of two parts, the number of households that have both low incomes and high fuel costs and the depth of fuel poverty amongst these households. Prior to the introduction of the Low Income High Costs indicator in England, fuel poverty was measured under the 10 per cent indicator. Under this indicator, a household is considered to be fuel poor if they were required to spend more than 10 per cent of their income on fuel to maintain an adequate standard of warmth. An adequate standard of warmth is usually defined as 21ºC for the main living area, and 18ºC for other occupied rooms. Northern Ireland, Scotland and Wales continue to use the 10 per cent definition and it is the basis of any respective statutory eradiation targets within these nations.

Who will deliver city-wide energy efficiency schemes and how would it work?

Because of their intrinsic understanding of their local areas and the fact they already have responsibility for affordable warmth strategies, climate change strategies and local development plans etc, city wide retrofits should be co-ordinated within that city region, local authority or unitary council. Generally trusted by residents, they will be able to foster local partnerships and involve/co-ordinate/contract with other local parties. As a result, in contrast to the current centralised model of delivery, this approach would also be able to leverage local employment and wealth creation opportunities.

Whilst the obligation to initiate and report on progress must rest with the public sector, delivery of the scheme can either handled in-house or by contracting with a private sector scheme manager. As with the local authority, this party would have the ability to tender for energy efficiency goods/services to carry out responsibilities such as coordinating home energy audits, project planning, technical support and feasibility studies and possibly installation and ongoing maintenance of any energy plant etc. This party may also be willing to carry a liability or contractual obligation as part of a defacto contractual standard. These principles are well established in contract energy management (CEM) or in the allocation of delivery risk under an energy services contract.

What would need to be undertaken locally to deliver a city wide vision?

- Identify areas with potential for District Heating or community energy schemes
- Identifying ward level areas of high fuel poverty, wider deprivation and poor housing. Using this information to target initial delivery at groups that are in most need
- Liaising with Local Enterprise Partnerships, local Health and Wellbeing Boards, energy and water suppliers, Electricity and Gas Network Operators to identify local co-funding sources
- Co-ordinate delivery of whole house audits (SAP assessment and a deeming pre intervention EPCs)
- A private sector energy auditor will check what approaches are necessary then prepare recommendations CO2 savings, cost of measures, projected energy bill reductions, provide a list of potential revenue streams
- Enforcement against landlords who rent out properties below EPC band E or are in category 1 or 2 hazard of excess Cold as determined by HHSRS

What role can NIC play nationally?

As a result of this analysis NEA's recommendations to NIC highlight the need for the UK Government to create a 'Warmer Community Fund (WCF)' within the current infrastructure budget. This new programme would run alongside the next supplier obligation and following pilots within the Core Cities, over time could emulate the Scottish area based schemes where all local authorities receive some ring-fenced funds to undertake the aforementioned activities with additional funding allocated to keener authorities (or their partners) via a 'top up'. NEA also notes local authorities, housing associations and other local agencies can help reduce public costs (like cold related morbidity) by improving housing standards. However, it is also critical they work more closely with a range of partners (Local Enterprise Partnerships, local Health and Wellbeing Boards, energy and water suppliers, Electricity and Gas Network Operators etc), to create local co-funding opportunities. These co-funding opportunities can ensure central Government funds lever in other resources from the private sector locally, strengthening the benefit to cost ratios for any investment. These opportunities are explained further below in response to the consultation questions. In addition, central Government must also support a systematic educational programme for relevant public sector professionals from local councils, procurement and planning officers so that all local authorities can identify existing and potential opportunities to support this new national policy.

Summary of recommendations

I. NIC should state that all domestic customers must have access to the benefits of domestic smart meters to facilitate more accurate domestic energy consumption data

II. NIC should recommend that Ofgem and the Department of Energy and Climate Change (DECC) actively develop a new role for Distribution Network Operators (DNOs) to become local System Operators (SO) rather relying on a central SO to perform this task

III. NIC must highlight to the Government that permanent reductions in total energy demand can also obviate the need to build new power stations or subsidise existing electricity capacity and reduce the cost of electricity network reinforcement. As a result, a deliberate policy intervention to make domestic energy efficiency a top infrastructure priority is justified and is a prudent course of action

IV. NIC must consult explicitly on how upgrading Britain's coldest homes can improve millions of people's lives whilst boosting the economy and creating local jobs. Specifically, in advance of the consultation, NIC should undertake its own analysis of the economic and fiscal impacts of making homes energy efficient and investigate the impact central Government resources can have in securing local co-funding from the private sector and the impact this has on the benefit to cost ratios for any national energy efficiency investment. This analysis should be compared to other infrastructure investments to ascertain value for money

V. NIC should highlight to the UK Government the opportunity for city-wide energy efficiency schemes and for this new approach to be piloted within the Core Cities. These pilots would be undertaken with a view to emulating (and enhancing) the current Scottish area based schemes

Responses to the consultation questions [Electricity interconnection and storage]

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

NEA welcomes the NIC's observation that by better balancing supply and demand, the UK can reduce costs to energy consumers and can help reduce emissions and fossil fuel imports. NEA believes that exploiting these opportunities is predicated on ensuring all domestic customers have access to the benefits of domestic smart meters and, on an aggregated basis, much more accurate domestic energy consumption data will also help ensure supply is better matched to demand in any given area at different times of day or the year. NEA does not however see how increased interconnection and new technologies in demand-side management and energy storage require changes to the electricity market. NEA believes these activities are already supported through a range of existing initiatives such as the capacity mechanism (in the case of interconnection) and existing Short Term Operating Reserve (STOR) contracts (in the case of demand side response).

However, as noted in the introduction, NEA does believe that NIC, Ofgem and the Department of Energy and Climate Change (DECC) must actively develop a new role for an agent to co-ordinate these activities. Given their detailed knowledge of large energy users and small scale embedded generators on their network, NEA believes Distribution Network Operators (DNOs) are better placed to co-ordinate these activities on their local distribution networks rather than a central System Operator such as National Grid (albeit co-ordination between both parties would clearly be required). As well as improving the efficiency and accuracy of how electricity demand and supply are balanced, encouraging DNOs down this path can also enable them to facilitate more efficient use of energy for households, which can in turn offset the need for electricity network reinforcement.

Ofgem has already stated that within the RIIO[17]-ED1[18] period Distribution Network Operators (DNOs) have an important role in enabling more efficient use of energy for households to offset the need for network reinforcement (or defer it) in a given part of their distribution area[19]. However, despite the innovation highlighted in the projects below, NEA believes this activity is taking too long to become BAU and conventional reinforcement in their networks may be taking place regardless of the opportunities to consider alternative investments in energy efficiency. There is therefore a pressing need for the NIC to clearly state to the UK Government that there is a need to ensure DNOs:

I. Identify ahead of time load related 'reinforcement hotspots' across their geographic territory
II. Obtain a forecast of the business as usual reinforcement costs
III. Establish an alternative cost-benefit analysis indicating which 'other actions' could be taken to either defer or mitigate the reinforcement need in an area entirely (through permanent electricity demand reductions, not demand shifting). This will require working with supportive agents to simultaneously assess the scale of electricity demand reduction potential within that area of the network and aggregate this potential
IV. Identify complementary domestic energy efficiency activity that is also currently being planned within this area and match the initial alternative investments to this existing or planned activity within that area and approach the delivery partners (this latter element is critical because the most valuable role DNOs can play is simply to provide capital to an existing or planned project, rather than starting a new one)
V. Grade the potential aggregation of electrical demand reductions by prioritising electrically heated **domestic** customers on the basis that there are positive social impacts and wider benefits (reduction in local health costs etc)
VI. Provide capital or develop projects which meet the 'Golden Rule' test set out below
VII. Produce annual reports on the aforementioned activity.

The alternatives to reinforcement that may be appropriate could be encouraging a DNO to help replace inefficient electrically heated systems, provide a contribution towards connecting a household to a modern efficient district heating or gas network, help fund solid wall insulation or provide capital towards lighting improvements or other low cost energy saving measures etc. However, in order for these alternative energy efficiency projects to occur, first they must be located in similar locations to those places where the DNO is planning to invest in network reinforcement alongside areas with relatively high population density, high deprivation and high penetration of electrically heated housing. This means the opportunity to invest in these projects will not be evident in every instance and this 'convergence' may only occur in a smaller number of planned reinforcements a DNO's may be planning on their network.

Another critical challenge for these alternative investments (and the key for delivering value to all energy customers, not just the direct beneficiaries of these measures) is that the contribution by the DNO to the cost of these projects would always have to be lower than the cost of the business as usual network reinforcement (the so-called 'Golden Rule' referenced above). However, complying with these criteria should not always deter a DNO from considering these approaches and taking a longer-term view of reinforcements to their network as potential exists for leveraging national or local energy efficiency programmes funds that can defray some of the cost of the in-house measures (should these exist)[20]. Where the 'Golden Rule' criteria is met this would ensure the investment in energy efficiency is more cost effective; benefiting all energy consumers whilst also providing a direct social outcome for the recipients of the energy saving measures.

[17] "RIIO" stands for Revenue = Incentives + Innovation + Outputs
[18] The RIIO-ED1 price control sets the outputs that the 14 electricity Distribution Network Operators (DNOs) need to deliver for their consumers and the associated revenues they are allowed to collect for the eight-year period from 1 April 2015 to 31 March 2023.
[19] *Strategy decision for the RIIO-ED1 electricity distribution price control*, Ofgem, 04 March 2013.
[20] In some instances, meeting the requirement to ensure the costs of an alternative project is always lower than the cost of the network reinforcement may not be feasible and therefore, justifiably, the aforementioned generic efficiency incentive would not provide a reward. This challenge may therefore result in DNOs being understandably reluctant to invest in any projects where the 'margin of feasibility' is tight. It is therefore important to understand how the regulatory regime incentivises a DNO to identify complementary energy efficiency activity that is already being planned or developed within an area. This is where the potential exists to 'piggyback' a DNO investment alongside 3rd party fund instead of making the investment entirely independently (albeit with the same intention of avoiding an unnecessary reinforcement of the network).

The *Low Carbon Network Fund (LCNF)* in particular provides results and information collected from various projects that have trailed some DNO-led projects aiming at reducing load as an alternative to network reinforcement. These projects (and others) have given network companies a better understanding of the opportunities and challenges of pursuing this model. A brief summary of these projects are provided below.

Solent Achieving Value from Efficiency (SAVE)[21]

Led by Scottish and Southern Energy Power Distribution (SSEPD) in the Solent and surrounding area, the project aims to establish to what extent energy efficiency measures can be considered as a cost effective and predictable by quantifying theoretical expectations with investigating actual customer responses to a range of different technologies. The trial will compare the effectiveness of four energy efficiency measures (LED installation, data-informed engagement campaign, DNO price-signals direct to customers plus data-informed engagement, and community coaching) and produce an investment decision tool that introduces the deployment of energy efficiency measures as a solution to network constraints.

Less is More[22]

Western Power Distribution partnered with the Centre for Sustainable Energy to help communities reduce their electricity demand, especially at peak times so that less money was spent on upgrading substations, to cope with rising demand. The project encouraged ten communities, "attached to" a monitored substation to consider their electricity use and find ways to reduce it and/or shift it to off-peak times, in return for up to £5,000. The project was presented as a solution to create savings for everyone, with reduced bills and reduced upgrade costs.

Energywise

The Vulnerable Customers and Energy Efficiency (VCEE) project also known as energywise is a partnership between ten organisations, led by UK Power Networks. The project is exploring how residential customers who may be struggling with fuel bills can better manage their household energy usage and consequently their energy bills by changing their behaviour. The project aims to recruit 550 households who may be struggling with fuel bills in the London Borough of Tower Hamlets and carrying out two trials. The trials will test different ways of helping households better understand and control their energy spending, enabling them to make changes which may save them money on their energy bills[23]. The project is rare in its scope as it involves a wide range of partners including UK Power Networks, NEA, British Gas, CAG consultants, Tower Hamlets Homes, Institute for Sustainability, Bromley by Bow Centre, Poplar HARCA, University College London and Element Energy.

Outside of the LCNF, there have been other projects which have provided insights which can support the development of this model:

Power Saver Challenge[24]

The project aimed to extend the life of existing network assets by working with customers to reduce the amount of electricity they use, in return of a reward. Electricity North West Ltd worked with NEA in Stockport on a proof-of-concept, gathering 10 teams in a competition, to aim for the challenge of a 10% reduction in winter peak electricity compared to the previous year, and with the help of advice and energy-saving equipment. The aim was explicitly to test the feasibility of avoiding investment in an urban primary substation and extend the life of the existing asset.

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[21] For more information visit: www.smarternetworks.org/Project.aspx?ProjectID=1325
[22] For more information visit: http://www.lessismore.org.uk/
[23] Firstly the project will explore if households benefit from smart metering solutions (smart meter and smart energy display) and from energy efficiency technologies such as energy efficient light bulbs, an ecoKettle and standby saver. Secondly understanding their appetite to change their behaviour by swapping to an 'off-peak' tariff.
[24] For more information visit: http://www.powersaverchallenge.co.uk

Supporting Local Energy Efficiency as an Alternative to Network Reinforcement[25]

In 2015, NEA and Agility ECO produced a report investigating the possibility to divert budgets currently allocated to load-related network upgrades into local schemes that improve energy efficiency for those who need it the most. In the report this concept is explained fully and is referred to as Alternative Investment Strategy (AIS). Specifically, the report looks to analyse the "Size of the Prize" on Northern Power Grid's network, the economic feasibility of investment in local energy efficiency and how this compares to conventional network reinforcement and practical feasibility.

To further highlight the value for money of expanding this innovation activity into BAU, DNOs are incentivised to deliver ED1 outputs as efficiently as possible. The effect of this regulatory framework should mean that where a DNO makes a saving in the cost of their investments (by implementing the new DNO model); they get to keep a proportion of the saving, with the remainder returned to consumers. As noted above, provided the contribution by the DNO to the cost of alternative projects is always lower than the cost of the network reinforcement, DNOs can then look to this mechanism to incentivise the installation of alternate heating technologies or in-home energy efficiency to offset the need for network reinforcement[26].

However, due to a range of non-financial barriers (such as distrust of new approaches or the need for many parties to work together to pull through this opportunity) and a lack of third party funds for domestic energy efficiency which would allow a DNO to 'piggyback' their investment alongside third party funds instead of making the investment entirely independently albeit with the same intention of avoiding an unnecessary reinforcement of the network, consideration of alternative investments in energy efficiency are still being overlooked. The consequence of this could be energy consumers paying for unnecessary reinforcement projects throughout the remainder of the distribution price control. NEA would therefore restate a pressing need for the NIC to clearly state to the UK Government the need to ensure DNOs undertake the aforementioned activities.

Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

As noted above, NEA favours Distribution Network Operators (DNOs) co-ordaining these activities on their local distribution networks rather than a central System Operator such as National Grid.

Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

As noted above, NEA believes these activities are already supported through a range of existing initiatives such as the capacity mechanism (in the case of interconnection) and existing Short Term Operating Reserve (STOR) contracts (in the case of demand side response).

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

NEA believes demand-side management measures and embedded generation are useful activities to balance and potentially lower demand however the extent to which they can be relied upon to provide these services when required is subject to a range of unknown factors including the predictability to save or dispatch known amounts of power at any given point. This is particularly the case for intermittent small scale embedded generation. In addition, as noted above, the options for permanently reducing energy demand through domestic energy efficiency also appear to have been overlooked in this context.

[25] For more information visit: http://www.northernpowergrid.com/downloads/1704

[26] Ofgem have also set out some clear requirements to improve the quality of information DNOs (or other parties) have access to about vulnerable consumers and request that there is a clear explanation of how this information will be used

What are the barriers to the deployment of energy storage capacity?

Given the remit of the NIC is consider the case for capital investment, NEA would highlight the main barrier to large scale storage is the upfront costs of the technologies compared to the unknown returns once it is in operation. In addition, NEA would highlight that energy storage can be construed at different scales and that the ability of a home to retain heat that is generated by an off-peak Economy 7 storage heater for example should be considered as a valid form of energy storage. Again, the main barrier to the mass deployment of homes capable of thermal retention is the upfront costs, particularly for solid wall properties. In December 2014, there were 8.0 million homes with solid walls, of which around 3.7 per cent had solid wall insulation. As noted above, NEA has estimated that based on current deployment rates some fuel poor households could be waiting over 230 years to receive this insulation measure.

What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

As stated above, whilst new technologies and approaches to demand-side management and energy storage can help facilitate welcome innovation (and reduce the need for superfluous generation), NEA also stresses NIC, Ofgem and the Department of Energy and Climate Change (DECC) must also actively develop a new role for Distribution Network Operators (DNOs) to co-ordinate this activity on local distribution networks.

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Many EU countries have prioritised meeting their energy needs through increased domestic energy efficiency and recognise this can reduce their dependence on imported fossil fuels and help to increase the European Union's energy security. An EU-wide building retrofit programme could cut gas use by an amount equal to circa 80% of imports from Russia.[27] NEA has also consistently highlighted that HM Treasury currently receive very significant sums through carbon taxes and VAT on domestic energy bills. Over the duration of this UK Parliament alone domestic energy consumers will contribute well over £14 billion to the Treasury[28], £30 billion over 10 years[29]. Even before the last General Election the Treasury raised an additional £500 million pounds creating higher energy bills[30]. NEA highlights that in common with thirteen other EU governments[31], channelling these funds (or equivalent non-levy funded resources from the infrastructure budget) would be a sound use of public money and as well as improving the quality of life of the poorest and most vulnerable members of our society, can also future-proof the economy and help reduce total UK energy demand by 50% by 2030[32]. These benefits can also be secured alongside stimulating low skilled labour and GDP growth, better air quality, reduced energy imports and carbon reduction etc.

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[27] E3G Briefing, Energy efficiency as Europe's first response to energy security by Ingrid Holmes, Luca Bergamaschi and Nick Mabey, June 2014.

[28] We estimate that £11.82bn will be collected in England, £1.33bn in Scotland, £690m in Wales and £190m in Northern Ireland).

[29] This analysis of the revenues the Treasury receives from domestic consumers is based on Government sources to estimate how much expected revenue they will receive from a) the European Union Emission Trading Scheme (EU ETS), b) the Carbon Price Floor (CPF) and c) VAT on an average electricity bill. We have then combined this with expected VAT revenues from domestic gas bills. These estimates are all based on the Government's own assumptions regarding energy consumption and this includes an unfounded assumption that EU products policy will increase the domestic energy efficiency of electric appliances substantially. However, what the analysis does show, regardless of the impact of various assumptions, is that both carbon revenue and VAT receipts help the Treasury yield large amount of money, which is collected regressively and without an intervention will further strain the finances of particularly low income households.

[30] This figure is the estimated income from the Carbon Price Floor 2015-16 compared to 2014-15. Source: Carbon Price Floor, 14 May 2014, House of Commons Library, p 10.

[31] According to a recent report: *The economic case for recycling carbon tax revenues into energy efficiency, Prashant Vaze and Louise Sunderland, February 2014:* 13 countries in the EU have pledged to return part of the proceeds from the EU-ETS auctions to climate and energy efficiency programmes.

[32] Policy proposals for the Liberal Democrat 2015 election manifesto: How to increase living standards, improve quality of life and future-proof the economy by David Boyle, Duncan Brack, Paul Burall, Fiona Hall MEP, Martin Horwood MP, Julian Huppert MP, Baroness Parminter, Neil Stockley and Mike Tuffrey, 2014 calls for an aim to reduce total UK energy demand by 50 per cent by 2030, including retrofitting 1 million homes every year, transform the Green Deal into an effective national programme to raise the energy efficiency standards of all Britain's households, eradicate fuel poverty, and provide funding by recycling revenue collected from the Carbon Price Floor and the EU Emissions Trading Scheme.

Response to National Infrastructure Commission's Call for Evidence on Electricity Interconnection and Storage

Introduction

This paper provides Northamptonshire Enterprise Partnership's response to the National Infrastructure Commissions' (NIC) call for evidence on electricity interconnection and storage. This has been developed with expert technical support from Peter Brett Associates and with significant input from business and public sector partners.

Specifically, this paper seeks to address four main questions posed by the NIC relating to, with each question considered in turn:

- Balancing of grid in terms of supply and demand;
- Barriers to the deployment of energy storage;
- Appropriate level of electricity interconnection; and
- Lessons learnt from international best practice regarding balancing supply and demand.

Northamptonshire has an ambitious and comprehensive growth strategy, with the aim of delivering approximately 70,000 new jobs and 80,000 new homes by 2031. The recent 'Utility Infrastructure Study' undertaken by PBA on behalf of NEP, established that energy security is critical to enabling Northamptonshire's continued growth. This can be achieved through a number of mechanisms not least enabling embedded generation and storage within the Northamptonshire electrical network.

The key limitations to industrial growth in the region are from a lack of available electricity infrastructure which is discouraging new businesses from investing in the region. For example, following the award of Enterprise Zone (EZ) status in August 2011, Northampton Borough Council undertook a programme of engagement with businesses within the boundary of the EZ. The results of the engagement highlighted a lack of power as the primary constraint to the expansion of several strategic businesses. As such, a bid was made into the Local Infrastructure Fund (LIF) and was successful in achieving a loan to install additional cabling into the EZ. The additional power has or will enable the expansion of existing large key businesses that will increase their workforces significantly. These expansions would not have been possible without the additional power supply.

It is not clear whether the planned delivery of energy will enable Northamptonshire to deliver on its plans for jobs and homes, or whether the existing infrastructure will cope with the increased demand placed on it.

There is a good 33kV network throughout Northamptonshire, however, following discussions with Western Power Distribution (WPD), two district/borough areas in particular will require upgrade and reinforcement works to accommodate the estimated demand in the near future, depending on specific location and time frames for delivery. These areas have a high number of housing planning permissions, the delivery of which may be inhibited by supply challenges.

Therefore in formulating these responses we have focussed on Northamptonshire's energy needs in order to consider how national policy can create a secure and balanced supply of energy within Northamptonshire and the opportunities for the area to profit directly from investment into generation and distribution.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Introduction

1.1 We consider that in order for the appropriate balancing of supply and demand, several key changes could be made to the electricity market which would have an overall economic benefit to consumers overall and specifically to the Northamptonshire region.

Strategic Position of Northamptonshire

1.2 Northamptonshire plays a strategic role in electrical interconnection as it acts as a lynchpin between northern/midland power generation and south eastern consumption. It therefore has the potential to act as a 'bridge' for geographically disaggregated generation and demand.

1.3 Regionally, Northamptonshire can maximise its location as it is "perfectly positioned at the heart of the country and the crossroads of the rail and road network, providing a premier location for inward and local investors".

1.4 The energy business sector is expansive and outward-facing in that businesses generally tend to sell services nationally, meaning that Northamptonshire's central location is ideal for companies working across England and the UK. The County also benefits from large infrastructure investment from key companies such as Cosworth, Carlsberg, and Travis Perkins. NEP in its role, working with government, can unlock Northamptonshire's growth potential to create one of the most entrepreneurial and fastest growing places in the country

1.5 The key to achieving this bridging role is by strengthening both power generation assets and networks within key areas such as Northamptonshire, thereby creating excess electricity and the means to export it. This could be achieved through new embedded generation as well as energy storage, and better management of demand side response. Our suggested mechanisms for removing barriers to these technologies are outlined in our responses to Questions 2 and 3.

1.6 The transmission losses associated with any export of power from an area such as Northampton to London would be significantly smaller than power transmitted over a larger distance (e.g. from larger power stations in Yorkshire). This would not only have benefits in terms of CO_2 savings from transmission losses, but increasing efficiencies could also drive down prices for consumers.

1.7 Sharing power more specifically across areas of higher and lower demand could be further incentivised by Government by formally recognising the role of places such as Northamptonshire, as being key to supplying energy in areas of high use (e.g. London) and directing further investment to strengthen power generation and networks assets. Although areas in the south east of the country and closer to centres of demand benefit from lower grid connection costs, these areas could be further prioritised in any future government or National Grid plans for future investment. Although, National Grid already shows areas in need of grid strengthening, these are based on current capacity, rather than on future growth plans. There is therefore a need for more proactive, rather than reactive, planning. Northamptonshire would not only be situated ideally to support centres of large demand (e.g. London and Birmingham) but also inward investment and its ambitious plans for growth.

1.8 These factors have attracted many large companies to the area (e.g. Travis Perkins and Booker Group PLC). Furthermore, a key ambition of the NEP is to substantially grow key industries such as logistics and high performance technologies. In turn these larger companies have large energy demands and therefore offer the potential for demand side response and more efficient energy management.

1.9 A low carbon energy opportunities and heat mapping study for local planning areas across the East Midlands was published in 2011[1], which reviewed the physical geography of the region for the deployment of renewable technology. The report highlighted that with the exception of Northampton, onshore wind forms the greatest technical resource potential. According to the report, key opportunities include:

- Onshore Wind: the greatest potential is found within Daventry, East Northamptonshire, Kettering and South Northamptonshire
- Biomass: Daventry, South Northamptonshire ,Kettering and East Northamptonshire – in particular potential from energy crops and agricultural arisings
- Small-scale hydropower- there are many potential sites in East Northamptonshire
- Northampton: as an urban authority, there is significant potential for EfW, sewage gas and waste wood

1.10 Despite this, a key constraint to the Northamptonshire area is the lack of suitability of the network to support generation. WPD advised that there are generation connections within Northamptonshire, but there have been a number of issues with the connections and flows back to the Primary Substations, and buffers needed to be used.

Role of an Independent System Operator (ISO)

1.11 An ISO could be beneficial for the UK electricity market, as well as for Northamptonshire. Adequate network capacity for Northamptonshire is critical to enable growth within the region if the ambitious plans for growth are to be realised. Information from WPD indicates that at least 2 areas in Northamptonshire are at capacity in terms of their 33kv network. One of the key areas limiting growth is the reactive nature, long timescales, prescriptive processed and often prohibitively expensive costs associated with reinforcement works undertaken by National Grid or the District Network Operator (DNO) – WPD. For example, information from WPD indicates that a new Primary

[1] http://www.emcouncils.gov.uk/Renewable-Energy-Study

Substation would be in the region of £5m and would take 2 to 4 years to install, which may include other time constraints beyond the control of a DNO.

1.12 33kV cabling can take months to install depending on whether there are 3rd party land issues, and the length of cable route. 132kV cabling can take 5 years to install depending on whether there are 3rd party land issues and the length of cable route. Overhead lines (33kV and 132kV) usually take longer due to public perception and 3rd party negotiations, and 132kV OHL cost approximately £1.2m per tower.

1.13 It is possible that the layers of complexity could be removed by an ISO. In terms of evidence in practice, the US uses ISOs to govern electricity distribution in several states. New York in particular has seen large economic benefits following the consolidation of the electricity market management into one ISO[2]. However, any ISO should promote the following:

- **Reliability -** The ISO responsibilities should include coordinating short-term operations such as reactive peaking plant to ensure reliability while supporting the competitive spot market.

- **Independence -** The governance structure and incentives for the ISO should be designed to ensure that no one subset of the market participants is allowed to control the criteria or operating procedures.

- **Equity -** Access to and pricing of services should be applied to all market participants without distinction as to customer identity or affiliation.

- **Unbundling -** Services should be unbundled when possible for acquisition from the competitive market and for utilisation by the market participants; and

- **Efficiency -** Operating procedures and pricing of services should support an efficient, competitive market for electricity. Attributable costs should be paid by the responsible parties. There should be no cost shifting to other parties – for example generators shifting costs to distributors. Joint costs should be allocated fairly with minimal impact on efficient incentives. Pricing and access rules should reinforce efforts to mitigate market power in generation. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints.

1.14 Despite this, to allow such an ISO would require a major rewrite of current guidance and would be a fundamental change in the way that the industry operates as a whole, and would not be a small or simple undertaking. In addition EU pricing rules would also need to be considered which could constrain the way ISO would operate especially in enabling early market trading in the UK when compare to the US electrical market. This could create more complications than the approach is trying to resolve.

1.15 Furthermore, issues encountered by DNOs are often related to a lack of up-front funding and pre-investment in assets, so they are unable to plan proactively for new development. Rather than the introduction of an ISO it might be beneficial for OFGEM, together with NG and DNOs to work more proactively and find solutions to pre-development investment.

Balancing future supply and demand

1.16 In order to achieve Northamptonshire' ambitious plan for growth, early engagement between National Grid, DNOs and Local Authorities is essential. This could be achieved through an ISO or alternatively, and probably more realistically (at least in the short term) through a nominated representative of the DNO.

1.17 Ensuring the ISO's functionality will need overseeing to ensure effectiveness. OFGEM's role in this would be critical.

1.18 There is a need for better forward planning from grid operators to enable a proactive and joined up approach to meeting the demands for new development, rather than reacting to each proposal in turn. In this way, National Grid (for large scale infrastructure requiring a 400kV connection) or the DNO (for smaller scale grid reinforcement) would be better prepared for a likely 'pipeline' of projects which are proposed in the area and could target infrastructure upgrades to selected key areas.

[2] http://www.ksg.harvard.edu/hepg/Papers/NYISO_Analysis_0307.pdf

1.19 There is a good 33kV network throughout Northamptonshire, however, following discussions with WPD, two areas in particular will require upgrade and reinforcement works to accommodate the estimated demand in the near future, depending on specific location and time frames for delivery.

1.20 It was also noted that the existing 132kV Overhead Lines (OHL) are currently at capacity and a new tower line from Grendon to satisfy demand requirements within Northamptonshire, may be required in the future.

1.21 Currently, Objective 3.5- Energy and Environmental Sustainability of the NEP Strategic Economic Plan[3] focuses specifically on the delivery of power to deliver sustainable growth. This outlines the need for funding to be provided to assist the development and reinforcement of power distribution in the county in relation to a number of specific issues. The SEP references key large-scale projects being developed by partners relating to energy including Kettering Energy Park, a CHP scheme within Northampton, and proposed Smart Grid trials.

1.22 Within Northampton Borough Council's development plan documents, consideration is given to strategic policies for steering and shaping development, together with strategic site allocations. There are also detailed supplementary planning guidance documents regarding e.g. five year housing land supply, and waste provision. Similar documents have also been prepared for other districts of the County. However, there appears to have been scant input from National Grid or DNO's as to how future strategic development would be supported in terms of grid capacity.

1.23 This is in contrast to e.g. waste policy in the borough, which has been planned with waste operators and alongside regional growth strategies and identified suitable areas for further waste provision and waste derived fuel. Waste provision is therefore written into local policy; just like electricity provision could be, given the right input from DNOs.

1.24 The WPD Long Term Development Strategy (LTDS) is in the public domain and illustrates WPD's proposed capital investment programme for the next 5 years.

1.25 Ultimately WPD will only respond to actual financially backed orders from developers and will rarely construct and forward fund new infrastructure for speculative development.

1.26 WPD are restricted by OFGEM and can only improve their network where there is a customer demand. Once a major investment plan has been agreed then the costs are shared between WPD and the developer/s.

1.27 For example, two areas in Northamptonshire have recently had upgrade works completed but this was customer lead and all additional capacity has been allocated.

1.28 One possibility for regulating this early engagement is through OFGEM, who could ensure that there is a 'Duty to Cooperate' put in place between DNO and the Local Authority. With this duty to cooperate clear open lines of communication should be achieved to ensure strategic growth plans are clearly monitored allowing resilience in the DNO's forward planning.

1.29 There is clear evidence that this does not happen at the moment, as stated above, WPD will only respond to actual financially backed orders from developers and will rarely construct and forward fund new infrastructure for speculative development. As stated in the introductory section of this report, this expansion of the EZ in Northamptonshire was only achieved through forward funding from the LIF. However, this is not unique to WPD, but a common issue with DNOs.

1.30 The advantage of this approach is that prospective developers coming into Northampton would not only have a clearly defined area for strategic development, but this would also benefit from DNO who is already primed to deliver the required network upgrades to enable development.

1.31 In addition this platform would also allow early infrastructure costs to be understood which could form Development Infrastructure Funds to be established reducing land development cost burdens.

[3]http://www.northamptonshireep.co.uk/resources/uploads/files/20131219%20Northamptonshire%20Final%20Draft%20SEP.pdf

The Benefits of Demand Side Response

1.32 NEP and partners have recognised the value of reducing energy demand across Northamptonshire as a key part of promoting economic growth.

1.33 Regional and local demand side response will release utility network capacity. In turn this will not only enable cheaper and faster connections for strategic land development growth but will also attract businesses looking for secure expansive grid capacity for their operations.

1.34 In addition demand side response also has the attractive proposition of reducing costs associated with buying energy in the first instance. This reduces domestic and commercial overheads and frees up money that would have otherwise have gone out of the region and to the national energy markets.

1.35 The above benefits are recognised at a national level with a range of regulatory measures set by OFGEM, DECC and CLG associated with energy demand reduction.

1.36 At a regional level, a challenge facing the Distribution Network Operator (DNO) Western Power is to balance the peaks from the generation of electricity supply with consumer demand peaks[4]. This issue is complicated by the increase of intermittent low-carbon renewable energy such as onshore wind and solar PV energy generation.

1.37 These techniques include 'smart grid connection agreements' combining monitoring and control supply and consumption, with additional active network management (ANM) if necessary. This will include connection offers with curtailment agreements during peak hours. Smart grids should also be used as a means of managing forecast in increased demand using existing electrical connection infrastructure to the best effect and minimum cost.

1.38 Whilst strictly speaking this is a supply and capacity issue, reducing demand on the grid network at peak periods to distribute energy will ensure the networks are balanced, allowing more effective future connection opportunities.

1.39 It is understood that connection of more sustainable energy generation[5] is a major strategic issue for WPD and Northamptonshire. The network is well equipped to deal with additional electricity demand; however for those wishing to generate electricity the opportunities are quite limited.

1.40 Trials of such DSR mechanisms, such as Southern Electric Power Distribution in partnership with local businesses in Bracknell, have shown as much as 20% peak grid demand can be released[6].

1.41 The University of East Anglia has also benefited significantly from DSR. They have installed a system which measures the local frequency of the mains across campus. When frequency is too low it can shed some of its load within two seconds. If frequency goes too high, then it can add load.

1.42 The system has an accurate electricity meter that is measuring everything so it can prove to National Grid that the event is really happening. National Grid then pays the University who are now actually generating a steady income, just for operating their utilities slightly differently[7].

1.43 Whilst there are clear advantages for demand side energy reduction, it is our view that demand reduction needs better regulation. It is currently only incentivised through negawatt (i.e. amount of energy saved) and therefore somewhat reflects focus onto the point the system fails. Currently, economics of demand reduction are not enticing enough.

1.44 A better approach could be to treat Negawatts as a commodity which can be traded. In this way large electricity consumers could see a direct benefit to the amount of energy saved. The value of Negawatts could be set higher for peak periods of electricity demand. This would encourage consumers to reduce their electricity use during peak periods through e.g. altering factory shift patterns. In addition potential subsidies or tax breaks could be added to the Negawatt regime to make the economics of demand reduction even more attractive.

[4] http://www.nnjpu.org.uk/docs/NN%20JCS%20PRE%20SUBMISSION%20IDP%202015.pdf

[5] http://www.nnjpu.org.uk/docs/NN%20JCS%20PRE%20SUBMISSION%20IDP%202015.pdf

[6] http://www.thamesvalleyvision.co.uk/our-trials/understanding/

[7] http://www.powerresponsive.com/viewpoints/where-dsr-is-a-matter-of-degree/

1.45 By reducing demand at peak times, the grid could benefit from a more steady state rate of consumption throughout the day, in turn leading to less stresses and less risk of 'brown outs'. It should be noted though that any demand side reduction mechanisms should not be taken out of the control and/or agreement of the use, which may cause detrimental economic impact on their business activities. A supplier led restriction on supply, for example, would impact economic competitiveness for a region.

1.46 Additionally, time of use tariffs could also be rolled out for smaller commercial and residential consumers. A concerned and more urgent approach to smart metering and regulation to enable Time of use tariffs could significantly impact demand profiles, reducing peak problems and enhancing the potential viability of local or regional storage solutions. British Gas is currently exploring the potential for rolling out these tariffs and the other 'big five' energy companies will likely follow suit.

1.47 However, despite this, as stated previously in this document, the evidence from Northampton is that the pressure is from growth on historic and outdated infrastructure.

1.48 The recent launch of the System Operability Framework (SOF) by National Grid has highlighted the vital role which DSR will play in the future UK energy market. Together with battery storage, and smart grids, they offer the potential for grid balancing and carbon reduction as well as cost savings for large businesses.

1.49 WPD are operating a smart grid at Corby, where there is a priority list of generation connections onto the network, and which has been successful in achieving a more balanced grid. However, they are unable to offer the availability of any further connections at the current time. Therefore, further network analysis must be undertaken to use DSR effectively without putting at risk existing operability.

Embedded Generation

1.50 Embedded generation also has a key role to play in balancing supply and demand. The role of embedded generation should be to ensure that the local distribution network benefits from additional capacity, particularly at peak times to maintain the position closer to existing operating margins.

1.51 Smaller peaking plan type generators (e.g. <20MW) outputting into the local distribution network reduce the need for the DNO to draw supply from the National Electricity Transmission System (NETS), helping to increase security of supply in the local network and reduce the risk of blackouts. This in turn supports the national grid.

1.52 It is National Grid policy to operate with a supply margin (i.e. supply capacity exceeding demand at all times). This margin is essential in seeking to eliminate, as far as possible, the risk of power shortages and blackouts, when there is an unexpected demand or sudden loss of supply. In common with many areas of the UK, a number of renewable energy schemes are operating or proposed in Northamptonshire, delivering intermittently to the local grid. Onshore wind is the predominant installed technology in Northamptonshire with a total of 8 projects and an installed capacity of 91.3MW. This is closely followed by solar photovoltaics, with 11 operational projects and a total installed capacity of 88.2MW.

1.53 In developing flexible generation assets (e.g. small peaking plants which can be rapidly started up or shut down) which connect directly to local or regional networks, local and regional consumption can be more easily balanced and stresses taken off the National Grid. Furthermore, with embedded generation usually installed at or close to a connection point (e.g. DNO 33kV substation) much of the transmission losses traditionally associated with exporting power from large power stations on the national 400kV network are significantly reduced, leading to greater efficiencies.

1.54 A major benefit of delivering embedded low carbon energy solutions is the ability for them to release capacity on the National Grid 400kv system. Releasing grid capacity will support economic growth both in terms of physical growth of towns but also offers significant attraction to high energy demand business sectors such as data centres. The opportunity to connect at a low price to a secure power network is extremely attractive to many sectors, which in turn will support the diversification of Northamptonshire's economy.

1.55 However, balancing and demand side response are tools for network management but not the end answer. They need to be strategically planned rather than openly incentivised otherwise we will see similar 'technology rushes' as with solar over the last 5 years. As a point of evidence, the recent round of capacity market auctions saw around 1.9GW of new capacity achieving a successful auction clearing price[8], Most of this new

[8] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/2015%20T-4%20Capacity%20Market%20Provisional%20Results.pdf

capacity was fast response diesel plant, which in turn has led to negative press surrounding diesel farms and the need for a re-think on how capacity is structured.

1.56 They also need to be backed up by strengthening of existing networks. It was noted by WPD in recent consultation that the network in Northamptonshire was not designed to take multiple isolated small generation sites, but for single large power stations that filter load down through the voltages and across the country. Therefore, the plant/assets connecting these isolated sites are not ideally located or sized to accommodate these generated flows.

1.57 Furthermore, a full network analysis with fault diagnosis to establish the appropriate degree of back-up to be provided is required. As the volume of embedded generation increases the current practice of matching it one for one with transmission back-up is no longer cost effective, and based upon probability of failure within the distribution network a lower proportion of back up will be appropriate. The actual figure will depend upon the type and number of embedded generation units on the system, the demand profile, any demand reduction possible, and the acceptable probability of a power failure in terms of occurrences or minutes per year.

2. What are the barriers to the deployment of energy storage capacity?

2.1 Energy Storage offers significant potential to reduce carbon emissions from generation by using more of the available energy from intermittent generation sources such as wind and solar. It also offers the potential to deliver a more balanced grid as power can be delivered as and when needed in order to 'fill gaps' when other technologies cannot generate or to reinforce the grid at times of peak demand.

2.2 Despite this, the technology is still in its relative infancy in the UK; especially for large scale applications (pumped hydro storage excluded which is very site specific). To date there are around 20 such installed systems in the UK. Though storage can provide numerous grid services, there are a number of factors that restrict its current deployment.

2.3 Probably the most significant barrier to deployment currently is high capital costs, particularly for larger scale geological storage systems. In comparison to other technologies used for grid balancing, such as embedded diesel fired peaking plant (around £500,000 per MW installed capital cost) and demand side response (£1000's per MW very low capital costs) the cost of storage at (£millions per MW on average) is significantly higher.

2.4 Potential storage owners are therefore reluctant to consider the deployment of resources until they can be assured a predictable revenue stream.

2.5 Currently there is a lack of clarity surrounding the functional classification of energy storage. If managed correctly, storage can be used to provide simultaneous services across different classifications of: generation; transmission; and distribution and discrepancies in market rules and regulations across a large number of differing markets.

2.6 At present, storage in the UK is classed as 'generation' and therefore is incentivised through open market trading, or scheme such as the Capacity Mechanism, where they are competing with traditional forms of generation, despite their wider potential application and benefits.

2.7 Furthermore, one of the main ways to maximise storage potential is by combining it with other intermittent technology types (e.g. wind and solar), or by developing storage capacity adjacent to substations – to maximise the available substation capacity. However, as storage is defined as 'generation', a DNO such as Western Power Distribution cannot own generation on their own network and so they cannot take responsibility for strategic grid management through their own assets.

2.8 Ultimately this could create a market failing as ultimately the DNO are in the best place to utilise electrical storage to balance their network, so therefore should really be in the position to dictate need and geographic preference.

2.9 Revenue compensation mechanisms in the different market environments present a barrier to the further deployment of energy storage resources. These mechanisms are oriented towards the evaluation of traditional power system technologies and may not appropriately compensate energy storage resources for the services they are capable of providing. Restructured markets base pricing on the generation costs of the marginal unit, which is appropriate for generators that have significant operating costs but creates a difficult situation for capital intensive and low operating cost resources like energy storage.

2.10 To overcome these issues it is suggested that storage should be treated as its' own category of energy and allow it to benefit from multiple revenue streams, which will both provide a more certain and stable income for investors and alleviate the high capital costs by providing greater returns. Any categorisation of storage could also remove the block on DNOs taking ownership of such projects.

2.11 Alternatively, mechanisms could be introduced which facilitate partnerships between DNOs and regional/local authorities to plan and structure storage within network and within Local Development Frameworks, then auction off as an asset. They will have a relatively high value as not only will need have been established but an element of planning security would be achieved through having the assets within a local plan.

2.12 A key aim of National Grids SOF is to roll out more storage projects and to test hybrid battery storage and renewable generation projects in an effort to further balance the grid. This could be a key growth area for Northamptonshire to maximise the generation potential of its existing renewable assets

2.13 At present, the most appropriate scale for implementing storage is at the local / regional level and a lot of this is likely to be through battery storage projects. This is simply because of recent advances in technology through increased efficiency and storage which has been somewhat driven by the electric vehicle market.

2.14 In terms of larger scale storage systems, the path to viability includes further research, development and testing before they can be considered as 'proven'.

2.15 At present, larger, national or international storage projects (excluding pumped hydro) are not viable in terms of capital investment, relative infancy of technology and transmission losses associated with exporting electricity over large distances.

2.16 This situation is set to alter slightly with greater advances in technology for MW scale battery storage.

2.17 Increasing local and regional storage capacity, alongside embedded generation will help with grid balancing and evening out peaks in energy demand.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

3.1. Increased interconnection is a clear goal of European energy policy. Typically, interconnectors are seen as positive infrastructure as they increase competition, reduce market reserve requirements and facilitate renewable energy as grids can be balanced over large distances with different weather systems and time zones.

3.2 Interconnectors derive their revenues from congestion charges. European legislation governs how capacity is allocated. It requires all interconnection capacity to be allocated to the market via market based methods, i.e. auctions. It also includes specific conditions on how revenues are used.

3.3 Despite this, factors such as different market structures, operational rules and market strategies of power suppliers have a significant influence on cross-border trading. Any expansion of interconnectors therefore requires harmonization of common technical standards codes or guidelines in the areas of Planning and Design, System Operation and Maintenance.

3.4 This is likely to require the cooperation between governments and other stakeholders in order to achieve maximum benefits from interconnection operation.

3.5 Furthermore, capital costs of interconnection are high, and in most cases are undertaken by specialist developers (e.g. National Grid Interconnector Holdings (NGIH)). Although the returns can be significant, the level of initial investment and rules on revenue streams means that it is often difficult for financial advantages to be felt outside of the specialist company.

3.6 Key to developing successful interconnectors is to generate a stable and predictable price for the consumer.

3.7 Any planned increase in international interconnections is likely to have a moderate benefit to Northamptonshire. Although it may increase security of supply, this will be true for the country as a whole. It is also unlikely to result in increases to local or regional electricity infrastructure.

3.8 The potential benefits of Northamptonshire forming strategic supply arrangements to the south east of the UK has been highlighted in our response to Question 1. Although this is not an interconnector by definition, this type of arrangement would be likely to result in more benefits on a regional scale.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

4.1 Although the UK has historically been one of the first to adopt new technologies in an effort to meet increasing energy demands, a better structured and more fixed, constant energy policy direction is required. This will in turn give confidence to developers and investors of consistent financial returns over the long term.

4.2 The majority of planning applications for energy developments last for 25 years, and represent a significant capital investment in planning and front end engineering design. However, the current UK position is that energy policy is subject to change over much shorter timescales. For example, within the last three years there have been significant changes to the Feed in Tariff (specifically affecting solar and wind farms), Renewable Obligation Certificates (specifically affecting biomass and wind farms), and the Electricity Market Reform (EMR).

4.3 The EMR programme contains a significant amount of complexity including rapid change in subsidy support for renewable energy projects and significant ambiguity on guaranteeing investment returns especially associated with the CfD.

4.4 It should also be noted amendments to the Renewable Obligation Order have also been recently tabled which has included the removal of onshore wind support through the RO from 31 March 2016, a year early than expected.

4.5 Further uncertainty has also been raised by mixed messages on fracking and the recent announcement by the Energy Secretary in support of more gas fired generation.

4.6 Therefore, although the government is providing a number of schemes to support renewable and non-renewable energy projects, the current lack of consistency creates an environment of long term investment uncertainty and complicates the ability of developers to accurately forward plan their projects and investments.

4.7 Other European countries such as Germany have a more committed long term energy policy.

4.8 Taxation on energy in Scandinavian countries is extremely high to support their federal electricity systems. Taxing unabated consumption is not necessarily a bad thing. Stable consistent energy pricing, even at a high p/kw allows business to plan effectively.

4.9 In Germany, security of supply is one of the cardinal objectives of the Government's energy policy, along with affordability and environmental compatibility. Section 1 of the Energy Industry Act (EnWG) establishes the principle of guaranteeing a reliable, attractively priced, consumer-friendly, efficient and environmentally compatible supply of electricity to the public that is increasingly based on renewable energy resources.

4.10 Under the amended Energy Industry Act (EnWG) (amendment dated 20 December 2012 and promulgated in the Federal Law Gazette. I p. 2730), new regulations aimed at guaranteeing the electricity supply came into force on 28.12.2012. These regulations offer solutions for sustaining the power supply in the short term without pre-determining the long-term roadmap for a workable future design for the electricity market to promote the energy transition and to facilitate the necessary integration of the renewable energies into the market. They include:

- an obligation to give 12 months advance notice of the intention to shut down any power plant and a ban on shutting the plant down before the end of the 12 months;
- the option of paying at cost price to keep power plants that are vital to the system on line;
- measures to ensure the operation of important gas power plants in the event of supply bottlenecks;
- A statutory instrument to systematize the existing practice of contracting for reserve power plants; it should also be possible to install new reserve capacities on a limited scale in justified particular cases.

4.11 The 2011 amendment of the Energy Industry Act obliges the German transmission grid operators to draw up a power balance and submit it to the Economic Affairs Ministry (BMWi) every year (Section § 12 para. 4 and 5). At the same time it entitles the grid operators to obtain the information they need for drawing up the power balance from lower-level network operators, power generators and end consumers.

4.12 The report officially submitted in September 2014 on the power balance presents the national power balances for 2013 to 2017. In the report the transmission grid operator predict an assured capacity surplus in the region of 8.8 to 10.3 GW in the years 2014 - 2017. Last year, too, there was adequate generating capacity available.

The surpluses mean that demand can be reliably met by the generating capacities available in Germany even in the potentially most critical situation of the year.

4.13 Within the last decade the construction of distributed generating installations has been increasing, especially as a result of subsidization under the Renewable Energy Sources Act (EEG) and the Combined Heat and Power Act (KWK-G). As the output from the major part of these low-capacity distributed energy resources (DER) cannot be controlled by the grid operators, there is risk even in the short to medium term of not being able to keep the grid system balanced. That means that in extreme cases situations can occur in which more power is being fed into the grid than is needed to meet demand and for exporting. In these situations, infeed from DER needs to be appropriately reduced by means of some sort of control feature.

4.14 Against this backdrop, the Economic Affairs Ministry has commissioned a consortium, made up of Consentec GmbH, Aachen, and Ecofys Germany GmbH, Berlin, to carry out "Studies into the need for more far-reaching system control to maintain the system balance." The study is intended to help assess whether and, if so, when construction of further non-controllable distributed energy resources, especially photovoltaic, heat-and-power co-generation and biomass installations, might lead to problems in balancing the grid.

4.15 Sweden is divided into four bidding areas from bidding area Lulea SE1 in the north to bidding area Malmö SE4 in the south. The price of electricity in each bidding area is determined by supply and demand of electricity and transmission capacity between bidding areas. In northern Sweden more electricity is produced than is needed, in southern Sweden it is the opposite. Therefore a large amount of electricity is transported from north to south Sweden.

4.16 Therefore, the power reserve consists of contracts with both electricity producers who can quickly increase production and large consumers of electricity who can temporarily cut back on consumption.

4.17 It is suggested that a similar system could be employed in the UK in order to balance supply and demand. As already set out in our response to Question 1, the role of Northamptonshire in any such ‘power trading’ arrangement is likely to be key given its strategic geographical location.

Conclusions

This report provides NEP’s response to the NIC call for evidence on electricity interconnection and storage.

Specifically, the following topics have been addressed:

- Balancing of grid in terms of supply and demand;
- Barriers to the deployment of energy storage;
- Appropriate level of electricity interconnection; and
- Lessons learnt from international best practice regarding balancing supply and demand.

Northamptonshire has an ambitious and comprehensive growth strategy over the next 15 years, which will bring an increased electricity demand and subsequent strengthening of both generation and transmission assets.

The key limitations to industrial growth in the region are from a lack of available electricity infrastructure which is discouraging new businesses from investing in the region.

Coupled with this, there is a current lack of collaboration between National Grid, the DNO and local authorities on delivering electrical infrastructure to meet growth plans, and instead, the DNO in particular is reactive to new development, rather than being proactive.

Within this response we have highlighted a number of ways in which this situation could be improved, including better regulation by OFGEM.

Furthermore, we have also suggested how changes in national policy regarding storage, grid balancing and interconnectors could benefit the Northamptonshire region as well as the UK as a whole.

Finally, we have provided examples of best practice from other European countries which could benefit the electricity market in the UK as a whole and in turn region such as Northamptonshire.

Network Rail

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8 January 2016

National Infrastructure Commission call for evidence; Improving how electricity supply and demand are balanced

Network Rail welcomes the opportunity to contribute to the call for evidence by the National Infrastructure Commission concerning improving how electricity supply and demand are balanced.

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

- **What role can changes to the market framework play to incentivise this outcome:**
- **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**
- **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**
- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

Network Rail is one of the UK's biggest purchasers of electricity and operates a large electrical power system in its own right. It is investing heavily in electrifying more of the network and our demand for and reliance on electricity will increase in the years ahead. We welcome market reforms that will deliver long-term price stability, security of supply and reduced emissions, and minimises the on cost of network provision.

Although we have not seen evidence that suggests the electrical system operator needs to be "independent" we welcome this debate. We wish to see a transparent relationship between participants, marked by clear incentives that are an efficient and sustainable balance between short-run and long-run costs and a coordinated forward view of investment.

We wish to see a more symmetrical operation of the balancing market that fosters greater participation from the demand-side and more opportunities for industrial, commercial and domestic users to participate. We would also welcome reforms that create a longer term market to aid price stability and risk management.

Further incentives are required to improve demand side management and to bring the heat and power markets together. The development of the Energy Systems Catapult in early 2015 is a welcome development. We believe increased deployment of distributed generation and combining heat and power schemes, active control schemes and integration with demand side schemes will inevitably improve flexibility and gain greater utilisation of assets across shared functions.

Coordinating or joint investment plans by aligning incentives between sectors and regulatory periods would provide an opportunity to reduce costs and improve performance and could also encourage scaling up of small participants and novel technologies.

2. What are the barriers to the deployment of energy storage capacity?

- **Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?**
- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

The current market reflects its historic roots and is built around large producers, bulk transport and a one way flow of energy. Industrial and commercial companies that can actively manage their own demand and energy systems should be encouraged to participate in the market to foster competition and choice. We recognise that National Grid has introduced new balancing and reserve products and industrial users are responding but in our view there needs to be more thought on more integrated solutions.

Infrastructure investments could also be more coordinated and integrated across sector or corporate boundaries in order to develop a more coherent infrastructure which would reduce investment costs. And these infrastructure investments may enable or assist in the business case for other sectors e.g. the scavenging of utilisation of multiple small storage, demand management or generation; or leveraging of aggregated battery storage from electric vehicles using non-utility power infrastructure and property rights.

Our view is that there is no one answer to the scale of energy storage and deployment across industrial, commercial, domestic as well as distribution and transmission will be required. Successfully deploying energy storage will enable other technologies such as distributed generation and more optimal asset investment to be facilitated, avoiding building network infrastructure for very peaky demand curves, increasing resilience.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- **Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**
- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

Network Rail supports measures to improve the security of supply and long-term investment in the UK's generation capacity and interconnection. We support measures that increase security of supply and that facilitate completion to reduce costs, increase innovation and effective response to climate change. Interconnection can enable this but electricity (and gas) interconnections increase the interaction between markets and territories as well as facilitating competition. We note historic interactions between European gas markets and territories that has had an impact on gas security of supply in the UK; and with low storage capacity for gas in the UK - and a potential move to increases in gas in the electricity supply mix - the market incentives and protections on interconnections should be considered carefully and the interactions between these principle energy supply markets in the UK.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

We understand that in Europe unbundling of private power networks is being investigated and synergies with transmission and distribution systems explored. The Polish and Italian railway operators already use their private power systems to serve external customers and in Germany this extends to power generation. Switzerland also has an extensive power system that operates alongside electricity utilities. This potential for integration between power and rail sectors and increased utilisation of cross sector power assets may provide insights in the integration of infrastructure.
We believe that future infrastructure investments should consider the economic and other benefits from integrated planning and investment across sectors such as transport and energy and also facilitate innovative or alternative ways of delivering energy.

Network Rail would welcome the opportunity to discuss the issues raised in this evidence submission further with the commission.

Yours sincerely,

Jo Kaye
Director, Network Strategy & Capacity Planning

Nissan response to the National Infrastructure Commission call for evidence

Energy

- **A stable environment for investment** is however crucial to making this work, and should allow for more energy supply making balancing supply and demand less critical.

- Additionally, **incentives should be available to large energy users** to offset some of the costs of peak energy usage. It is not economic for some large users to "switch off" during peak periods, and therefore these businesses suffer significant cost penalties. The costs of switching off far exceed the incentives currently offered. Some reliefs are currently available through the Electricity Intensive Scheme, but this is based upon a very high threshold.

- **Investment in the development of new energy storage systems, and better connections between private vehicles, the electricity grid, renewable energy generation and buildings' energy management systems.** Nissan's Vehicle-to-Grid (V2G) technology allows electric vehicles to be fully integrated into the electricity grid by improving grid capability to handle renewable power, and will make renewable sources even more widely available and affordable. V2G charging infrastructure and V2G-enabled electric vehicles give EV owners, and businesses with large EV fleets, the opportunity to create mobile energy hubs by integrating their vehicles with the grid. Technologies like Vehicle to Grid have the potential to transform energy systems. The integration of energy balancing mechanisms with electric vehicles is a cornerstone of the future of the electric system; with vehicles now much far more than mobility solutions. With increased pressure on the grid and an overreliance on fossil fuels, Vehicle-to-Grid implementation gives EV owners the ability to store and release green energy back into the grid.

  In the UK for example, where there are 37 million vehicles and where the current electricity generation capacity is 85 GW, a future where all vehicles on the road are EVs/PHEV, the grid integration of the vehicles could generate a virtual power plant of up to 370 GW (more than 4 times the national generation capacity). V2G is one of the innovations that can improve our life and make the world a better place for all people now and for the generations to come.

  Electrical power supply capacity would clearly need to increase as well to charge all of these vehicles, but managing supply and demand should become more economic.

The attached paper forms the response of NRG Management Consultancy to the National Infrastructure Commission's call for evidence in relation to electricity interconnection and storage.

NRG Management Consultancy provides commercial advice to start ups in the energy sector and contract management advice across the energy sector.

Nic Rigby 8 January 2016

Q 1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Q1.1 What role can changes to the market framework play to incentivise this outcome:

A number of examples where the UK electricity market is structured so as to constrain the provision of services such as storage and demand side response[1] are listed below.

Transmission/ Distribution Asset Avodiance
The nature of transmission and distribution asset ownership is such that monopoly or licensed ownership is a given. Ofgem's development of competition in asset ownership can be expected to increase transparency and reduce costs to consumers but this development will not directly address the impact of using non conventional services in place of transmission/ distribution assets. Non conventional approaches have benefited though from Ofgem's Low Carbon Network Fund. In order to ensure conventional and unconventional approaches to the provision of transmission/ distribution assets are treated equally the **Low Carbon Network Fund's role will need to increase.** The emphasis of Ofgem's treatment of the fund also needs to change to include detailed evaluation of the market benefits of non conventional approaches and **challenging those asset owners who continue to use conventional assets** in situations where non conventional arrangements have been shown to reduce costs to consumers. This approach is broadly consistent with Ofgem's proposal to develop Distribution System Operators rather than Distribution Network Owners.

Cost Reflective Charges
In a truly cost reflective and unrestrained market any non conventional service provider would expect to be able to create monetary value if their service can be provided at lower cost than existing providers.

Non conventional balancing approaches particularly location independent storage and demand side response are currently not able to monetise the value they can provide to consumers as a number of system costs are not fully imposed on the parties that cause them. Socialising some electricity market costs has the unfortunate side effect of dulling the incentive to buy alternative services. To encourage storage and demand side response users need to pay more realistic

[1] See Glossary

locational charges by **charging for time of day electrical losses**. The introduction of charges for losses should be done gradually and in a way that fits with Use of System charges.

The cost of drawing power at times of system peak also needs to fully reflect the **extreme costs associated with that extreme provision.** Ofgem have made strident efforts to ensure that both locational and system peak costs are levied on those who cause them but the lobbying for "socialisation" has been well organised and had support from more prominent politicians than the "cost reflective" case.

Demand charges being levied on parties (such as storage) that only draw demand at off peak periods is clearly not cost reflective and where this occurs (for example some DNOs levy these charges) they should be replaced by a more cost reflective mechanism.

Q1.2 Is there a need for an independent system operator (ISO)?

National Grid's approach to managing conflicts of interest is to utilise small isolated teams for sensitive roles such as the Capacity Market. Whilst this approach ensures focus and has to date generally delivered independent thought it is sub optimal as those small teams do not have the benefit of a complete management structure. For example access to lawyers and other specialist advisers are often constrained. This approach also mitigates towards the conventional. The expansion of the Capacity Market to include National Grid owned interconnectors before solving problems with storage (see 2.1 below) may or may not have been influenced by the positive impact on employee share save valuations but such perceived influences do not enhance an independent reputation. For these reasons the time has come to **adopt the Independent System Operator model** which should be established as a completely independent company with no links to National Grid/asset owners.

Q1.3 How could the incentives faced by the SO be set to minimise long-run balancing costs?
SO costs will be partly driven by the structure and location (see 4 below re crowded and windy islands) of each electricity market but as many other markets use the independent SO model comparisons will be easier once an ISO has been established in GB. As **all the employees of an ISO are dedicated** to the success of that business one would expect them to be more focused on the task of reducing costs to consumers with greater emphasis on innovative approaches that will produce long term value for the ISO and consumers.

Q1.4 Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

As set out in 1.1 additional cost reflectivity is required in all aspects of the power market and in particular the "balancing market" at times of peak demand as this ultimately reflects the cost of providing electricity or not at these times. Current Balancing Market proposals i.e. p305 are a step in the right direction. The proposal to charge VoLL at times of system stress may seem a blunt instrument but it is an essential part of charging the costs on those who cause them. Intermittent generation such as wind, solar etc are clearly a major cause of imbalance cost but imposing these imbalance charges also offers the benefit of encouraging innovative approaches to forecasting output and hence the level of imbalance. It may also be appropriate to consider **implementing an "information charge"** as well as system balance charges on those parties who incorrectly declare their imbalance in the most costly direction.[2]

Q1.5 To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Studies such as Element Energy and Strbac et al have demonstrated that demand side measures and storage can play a significant part in increasing the flexibility of the electricity system. Care should be taken though in promoting some forms of embedded generation. In those areas (particularly urban areas) where air quality is or could in the future be below appropriate standards **new diesel plant should not be consented nor should such plant receive Capacity Market contracts.** It is also inappropriate that money allocated to enable the transformation of the GB's energy system to reflect future environmental needs (EMR) is funding the installation of polluting diesel generators. To avoid this anomaly Capacity Market prices need to reflect the environmental credentials of each provider. A short term measure would be to **apply a price differential depending on the efficiency and environmental impact** of plant that wins Capacity Market contracts. An alternative approach is to split the Capacity Market where long term contracts are only offered to parties who can meet stricter eligibility criteria including environmental and flexibility obligations.

Q 2. What are the barriers to the deployment of energy storage capacity?

Q2.1 Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

The issues discussed in 1.1 (Cost Reflective Charges) and 1.4 above need to be addressed to ensure that storage can access all the value that it can create. In addition the Capacity Market has been established to fit conventional providers of support rather than considering all potential providers. This is a reflection of industry understanding and insufficient motivation to be innovative. Incumbents whose assets run the risk of being stranded clearly have limited motivation in relation to certain forms of innovation. The issue for storage is that it needs to be built with an optimum MW/ MWh capability. This allows for charging and discharging in relatively short periods typically 6 hours. There are occasions when the Capacity Market expects a provider to have capacity or generate over

[2] i.e. an information charge for under delivering versus notification at peak times and for over delivering versus notification at off peak times

periods of longer than 6 hours. Storage can meet the most valuable peak period when it will be discharging and can also be available in the pre peak shoulder but would expect to be fully discharged before the post shoulder peak. Storage would want to be discharged so that it can maximise its arbitrage revenue by discharging over the peak and being ready to charge at off peak times. Clearly the **Capacity Market** needs to reflect consumer needs but the service should be **designed around those peak needs rather than conventional providers**.

Storage can manage this situation by taking penalties but this approach does not fit with the concept of matching delivery to promise and cost reflective penalties.

Q2.2 What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

As the table in Appendix 1 sets out storage can access value from three distinct services. Some of these services are locational with optimum value when storage is located adjacent to consumers. This is because locating storage close to consumers enables the whole system from generator to storage/ consumer to run on an optimal basis. Storage located closer to the generator means that only generator to storage can be optimised leaving storage to consumer unoptimised. This suggests that the greatest value is available when **storage is located within the distribution network.** This is also supported by Strbac et al's analysis. Storage will though need to be capable of being accumulated so as to provide ancillary services at MW levels that are of value to National Grid. In time accumulation of domestic based storage should also be feasible which would then encourage storage to become optimal at domestic scale.

It is the co-existence of storage and intermittent generation that creates the arbitrage value stream. It is also the case that to access optimum value in terms of ancillary service provision and asset avoidance the storage needs to be co-located with consumers not generators. Hence co-existence does not lead to co-location. There will though be specific occasions when storage may add significant value alongside generation for example when the generation capacity is MW constrained.

Q 3. What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnection is as important as storage and demand side measures in terms of improving security of supply. It will also be particularly important in the next few years in lowering UK power prices so that they are closer to those in mainland Europe. Interconnection via under sea cable should though be subject to the same cost reflective market as all other technologies. There are a number of cost reflectivity issues in relation to environmental costs of electricity imports. The UK has taken a foresighted but lonely approach in terms of imposing a higher cost of carbon. By ensuring that the **environmental cost paid by electricity**

importers is at the same level as GB producers is unlikely to be popular and may not be possible but it does fit with the "polluter pays" principle.

Q 4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Deployment

UK and International studies make the case that significantly more demand side response can be utilised in the UK (see Element Energy, CEER and European Commission). Some regions in the USA appear to be leading the world in terms of MWs of demand side response. This is particularly unfortunate given that the UK was probably the world leader in this field prior to the demise of the electricity pool. In the case of storage it is probably too early to comment on UK versus world leading practice. It would be good though to see an **Office of Storage/ DSM Deployment within DECC** though, so as to give equivalent treatment to other technologies such as Nuclear.

Crowded and Windy Islands

As crowded and windy Islands the UK and our neighbour Ireland have particular opportunities and challenges in terms of managing security of supply. The UK transmission system is built and operated to a very high standard[3] but alongside that getting consent for new overhead lines is particularly challenging in the UK. The traditional response to consent challenges has been to underground cables. The developing energy system in these islands deserves better than "more of the same". Other ways of optimising transmission assets and how they interface with generation and demand need to be evaluated. This suggests that the **UK should be leading rather than following in terms of best practice.**

The establishment of the National Infrastructure Commission should be a wake up call and an opportunity for the UK electricity industry to:
- establish an ISO
- structure a truly cost reflective market
- remove the barriers that prevent the implementation of storage and demand side measures
- re-establish the UK energy industry as the world leader in managing change.

References and Glossary

Reference to "demand side response" is to the shifting of load from peak to off peak or shoulder periods. Shoulder periods are those immediately before or after peak periods when demand rises or falls respectively.

Element Energy, Demand side response in the non-domestic sector, Final report for Ofgem, July 2012

[3] GB Transmission operates each cable route to N-2 meaning that even if 2 cables are unavailable the remaining N cables can carry the expected load.

Strbac et al, Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future, Energy Futures Lab, Imperial College London June 2012

CEER Advice on Ensuring Market and Regulatory Arrangements Help Deliver Demand-Side Flexibility, 26 June 2015

European Commission, Commission Staff Working Document, Incorporing demand side flexibility, in particular demand response, in electricity Markets, 5 November 2013

Appendix I Sources of Value for Storage

There are numerous ways of describing the value of storage. To focus attention on the monetisation process the table below categorises these descriptions into three capabilities.

Arbitrage or time shift which is the capability to buy power (MWh) when it is cheap and sell it later when prices have risen.

Ancillary services (now known as Balancing services in GB) which are those services (other than power) required to keep power systems operating. There are three types of ancillary services reserve, voltage support and Black start. Reserve is further divided into three types instantaneous (and automatic) provision of MWh (primary frequency response), secondary frequency response which is provided with a short delay (30 seconds) or standing reserve which typically requires plant to be started (available within 10 minutes). Voltage support is achieved by providing MVarh (reactive power) and Black start is the capability to support start up of large scale generation.

The third service is asset avoidance where storage is used in place of transmission or distribution assets. Storage running alongside assets such as lines, switchgear and transformers which are usually subject to intermittent use can significantly improve the optimal use of those assets. The ultimate form of asset avoidance is the use of storage in an off grid installation.

In the UK there are constraints on parties who provide monopoly services. The most relevant for this discussion is the constraint on owners of transmission and distribution assets in terms of their ability to also own generation assets. Two transmission/ distribution companies Scottish Power and SSE are permitted to own both but they are allocated to different companies. The potential storage owners and buyer of services are set out for each of the three capabilities of storage below.

Service/ Capability	Technical constraint	Locational constraint	Buyer of service	Owner of capability	Notes
Arbitrage/ Time shift	Typically a daily cycle so 10 years = 3000 cycles. Size of storage MWh/MW typically optimised at 6 hours approx.	None	Any BMU registered party (generator or supplier)	Owner must either be a BMU or work through an agent that is signed up to BSC	Some parties ie DNOs may be constrained in terms of being owners of a BMU.
Ancillary Services	A party providing frequency response utilisation at all times will need to accept a large number of cycles could be 100 per day. Providers of capability can constrain cycles.	Reserve is less valuable if it is the wrong side of system constraints. Reactive power is locational.	National Grid, System Operator	Could be any party except National Grid. DNOs also effectively ruled out as they cannot sell energy.	Black start needs to be co-located with conventional generation and fully available at all times so provision alongside other services is severely constrained.
Asset avoidance	If working with other conventional assets, cycles can be restrained. If off grid discharge times may need to be longer. Also cycles likely to be several per day.	Locational and greatest value is as close to customers as possible.	End Users (off grid) and DNOs or Transmission Owner	As buyers of service but feasible to consider a DNO/ Transmission Owner as a service buyer but not asset owner.	

DNO = Distribution Network Owner
BMU = Balancing Market Unit
BSC = Balancing and Settlement Code

It should be noted that revenue from the three capabilities is likely to require storage to discharge at different times. For example frequency response could require discharging at anytime, arbitrage requires discharging at time of system peak demand whereas asset avoidance requires discharging at time of local peak demand. Hence on any particular day revenue may not be possible from all three sources.

The conclusion from the table above is that DNO or Transmission Owner participation is likely to be required in order to address the asset avoidance market. Off grid application prevents access to the other markets so is not considered in detail. The approach taken to date is for DNOs to be the lead owner but other owners provide access to market for the other capabilities. In future other monetisation approaches will need to be part of the regulatory landscape. These could include DNOs requesting bids for asset avoidance services, or DNOs buying asset avoidance capability on a transportable basis.

Written evidence submitted on behalf of the Power Systems Group at Newcastle University to the National Infrastructure Commission call for evidence's on "Electricity interconnection and storage"

Authors: Dr Pádraig Lyons, Dr Neal Wade, Professor Phil Taylor

Introduction

Power Systems Group, Newcastle University

The work of the group has a particular focus on the emergence and critique of 'smart' energy systems and seeks to understand how this relates to broader shifts in systems of infrastructure service provision. The research seeks to gain a deeper understanding of the extent to which 'smart' can assist in planning, managing and facilitating future energy systems that are flexible, complex and uncertain.

Lecturer, Dr Pádraig Lyons CEng

Dr Lyons joined Newcastle University in July 2013 having served a number of roles within industry and academia in the UK and Ireland. He was a senior smart grids researcher at Newcastle and Durham Universities where he lead the network flexibility trial design and analysis for the Customer Led Network Revolution (CLNR) which is the largest UK smart grid project thus far. Dr Lyons leads the development of the smart grid laboratory in collaboration with Siemens and also leads a number of smart grid projects including a collaboration with UTAR Malaysia under the British Council’s Newton Fund.

Senior Research Associate, Dr Neal Wade

Dr Wade is the project lead and researcher on a number of projects in the electricity distribution and off-grid power sectors. These projects are addressing the need to cost efficiently decarbonise the power sector over the next thirty years, by investigating the innovative network integration of new generation and demand technologies. Computer simulation, laboratory investigation and demonstration projects are used together to produce the new knowledge that delivers this need. He is an established researcher with ten years’ experience in numerous university research and teaching roles and previous experience working in the electronics industry. He works with team of research associates and supervises PhD and MSc researchers.

Director, Professor Phil Taylor CEng, FIET, SMIEEE

Professor Phil Taylor is Director of the Institute for Sustainability and Professor of Electrical Power Systems at Newcastle University. He is a member of the RCUK scientific advisory committee on energy, and a non-executive Director of Northern PowerGrid. Professor Taylor is an active member of the EC ETP on Smart Grids, and also works as a scientific advisor on energy to Singapore, Dutch, Norwegian, and Estonian governments. Professor Taylor was the academic lead for the Customer Led Network Revolution, a £54 million Low Carbon Networks Fund project involving Northern Powergrid and British Gas. Professor Taylor and his research team are behind EPSRC funded £2m energy storage test bed facility at Newcastle University.

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- *What role can changes to the market framework play to incentivise this outcome:*
    - *Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?*
    - *Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?*
- *To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?*

1. The design of the electricity market needs to consider not only the changes to the market itself, but also those in the overall electrical energy system, including other actors in the space, such as consumers, prosumers, aggregators, energy suppliers and community energy projects. Furthermore due to the increasing integration and reliance of the transport and heat sectors on the electrical energy vector, the role of an energy architect to consider the design and operation of the energy system including its associated markets, in a holistic way, is critical. Crucially, the architect could consider the energy system as a whole including customers, to build plans that resolve how heat, power, water and transport systems are all linked together at least cost to the overall energy system. This will enable delivery of a low carbon energy system, that provides the required security of supply, by ensuring that the supply and demand in the system are balanced, in real time and long term, along with sustainability at the lowest cost to UK PLC.
2. The decarbonisation of the UK economy will require a paradigm shift in the planning and operation of the energy sector, due to developments such as the widespread electrification of the heat and transport sectors, and electricity generation becoming increasingly reliant on intermittent renewables. This increased dependence on electrical infrastructure could significantly increase social and economic vulnerability; these potential vulnerabilities could arise from a reduction in the overall redundancy of the entire energy system, if existing design and maintenance approaches are left as they are. The distances between generation and demand, particularly urban zones, are forecast to greatly increase (for example, due to the increase in offshore wind generation). Increased reliance on ICT will require investment in these systems, as well as a new approach to operate, maintain and ensure security of the network.
3. To enable these changes and ensure that the future electrical energy network provides the reliability required to support a UK low carbon energy infrastructure, the electrical infrastructure will need: -
    a. To be intensively monitored, particularly at distribution network level, through network monitoring and smart meters, to enable network operators to operate and plan their networks effectively and economically now and in future scenarios;

b. To be flexible, dynamic and be able to quickly respond to changes in the network and have the capability to heal itself where appropriate to enable high levels of security of supply;
c. To integrate demand side response technologies such as vehicle to grid (V2G), real-time thermal ratings, energy storage and active distribution network management need to be part of business as usual in order to economically deliver a zero carbon electrical system which is the aim for 2050;
d. To ensure that domestic and commercial electricity customers to be fully engaged and financially benefiting from their local renewable generation and flexible load;
e. To have low cost energy storage commonplace and financially viable at domestic, commercial and network level (requiring regulatory and markets changes to enable the real value of this technology to be realised);
f. To have electrical energy infrastructure integrated with other systems such as transport, heat, gas and water such as the infrastructure proposed at the Science Central site in Newcastle-upon-Tyne

4. If the UK industry can be a leader in these fields, then the benefits could be felt both financially and environmentally. The projects run under the Low Carbon Network Initiative (LCNI) have already resulted in world leading progress, and it is important to continue to fund projects such as these for both the development of new solutions and technology, and moving the methods from previous projects into business as usual.
5. An ancillary service market at distribution network level is required to give clear price signals for the location of new technologies that can provide services to several energy system entities. Energy storage is a prime example of this; it can participate in operating reserve and frequency response markets for the TSO, defer or remove the need distribution network reinforcement for the DNO and participate in the energy market via Supply Companies. The DNO service is location dependent, the TSO and Energy Market services are not. DNOs have very limited means to give the locational signals needed to encourage energy storage developers to design their systems to support the DNO. The same issue exists with other technologies in the area of Demand Response.
6. Large quantities of energy storage and distributed generation embedded in distribution networks may reduce network could reduce the use of the distribution network assets and reduce a key revenue streams for DNOs. If DNOs or DSOs could sell ancillary services into transmission level markets this could provide them with a revenue stream that would incentivise them to facilitate the connection of energy storage.

What are the barriers to the deployment of energy storage capacity?

- *Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other ‘balancing’ technologies? How might these be overcome?*
- *What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)*

7. There is a lack of clarity on the future role of energy storage in the UK and consequently no regulatory framework for energy storage [1].
8. There are no specific licence conditions for ownership and operation of ESS, which is different because it functions as a load or generator. At present, energy storage in electrical networks to be considered a generator. This arrangement precludes transmission and distribution network operators from operating larger energy storage devices with a maximum power capacity of greater than 10 MW or greater than 50 MW if the declared net capacity of the power station is less than 100 MW.
9. There is no incentive for generation developers to invest in ESS as Renewable Obligation Certificates (ROCs) and Feed in Tariffs (FITs) reward renewable generators based on electricity output regardless of the impact they have on networks or the electricity market. They also have priority access to the grid.
10. In distribution networks where high amounts of distribution generation (DG) are anticipated, distribution network operators (DNOs) may need to reduce the real power export from DG, upgrade or reinforce their networks to maintain quality and security of supply. At the same time, under the security of supply standards (ER P2/6) which all transmission and distribution networks in the UK plan their networks under, DG is considered to be a non-network solution that contributes to system security. In contrast energy storage, which is generally considered as a possible solution to increase DG proliferation and improve quality and security of supply, is not recognised for its contribution to system security.
11. Other challenges energy storage faces in the UK are competition with cheaper, established fossil fuel based technologies, e.g. gas peaking power plants, for providing balancing and other ancillary services. In the electricity market, different contracts have to be agreed upon for the balancing and different ancillary services; this means energy storage owners need multiple contractual agreements to derive maximum benefits. There are also issues with long payback times when participating in the unpredictable electricity market. The two aforementioned factors greatly complicate the economic evaluation by energy storage owners and other stakeholders of the multiple benefits that can be provided from this technology.
12. Energy storage is not considered an asset for network or system operators, therefore they cannot recover the investment costs for energy storage as a regulated asset if used on their networks.
13. National Grid in the UK is responsible for balancing demand and supply, this limits DNOs who cannot actively manage the regional distribution networks or provide demand response. This is crucial in future scenarios which anticipate a large-scale proliferation of low carbon technologies such as electric vehicles and heat pumps; and renewables based generation, including solar and wind. These changes are likely to have large impacts on the capability of system operators, both on the distribution and transmission, level to predict load and generation and thus the power flows through their assets such as transformers, overhead lines and underground cables.
14. The conservatism of power sector stakeholders, particularly among transmission and distribution network operators, in adopting new technologies and the possibility of competition between the transmission and distribution network operators and generators when contracting for services provided by energy storage to manage the grid are also factors impeding the adoption of energy storage in UK networks.

What level of electricity interconnection is likely to be in the best interests of consumers?

- *Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?*
- *Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?*

15. Electricity interconnection provides another degree of flexibility within the electricity market and by extension the overall energy market. The level of flexibility required within today's electricity market is currently served predominantly by large, fossil fuel based generation plant. This scenario is likely to change in the future as we move away from the existing large centralised generation plant based paradigm and move to a more distributed approach with large quantities of renewables based generation on the system with limited centralised control available. The existing model will be put under further pressure by the anticipated electrification of the transport and heat energy vectors through technologies such as electric vehicles and electric heating. Therefore, the requirement for flexibility to the electrical energy system in the form of demand response, energy storage and interconnections become more valuable.
16. The level of interconnection required to best benefit consumers can only be evaluated if we view the operation of our future energy systems holistically. The most economically prudent option or options for UK PLC to provide this flexibility must enable a future energy system that is reliable, economically viable and environmentally sustainable.

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

17. Smart meters have formed part of the smart grid in a number of countries, for example Italy, rather than being used primarily as a means of reducing the cost of meter readers for energy suppliers. The data from smart meters will become more critical for Distribution Network Operators as the existing assumptions regarding the way energy is consumed and produced (microgeneration and distributed generation) become increasingly unreliable. Therefore, this data should be applied to mitigate the growing uncertainty in the operation and planning of asset replacement and refurbishment.
18. National level island grids have reported penetrations of renewable generation that has resulted in some renewable generation reaching 100% of energy production during peak wind periods, as has been demonstrated in Ireland. Therefore, realistic aspirations for penetrations of renewables can be high and should not be limited by inflexible fundamental system limits.
19. Voltage limits for low voltage networks could be lowered without causing problems for equipment supplied by these networks.

20. We need to learn from other countries e.g. Germany that have suffered with regard to the operation of their electricity system due to the large scale penetration of PV.
21. Demand side response can make a sizeable contribution to the operation of networks as shown for example the USA.
22. Community energy systems can work and could make a sizeable contribution in enabling the UK to reach its carbon emissions targets as has been demonstrated in a number of EU projects.

[1] O. H. Anuta, P. Taylor, D. Jones, T. McEntee, and N. Wade, "An international review of the implications of regulatory and electricity market structures on the emergence of grid scale electricity storage," *Renewable and Sustainable Energy Reviews,* vol. 38, pp. 489-508, 10// 2014.

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8 January 2016

National Infrastructure Commission
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RE: National Infrastructure Commission Call for Evidence

Open Energi welcomes the opportunity to contribute to the National Infrastructure Commission's call for evidence. As members of the Association for Decentralised Energy and in addition to contributing to the ADE response, Open Energi is responding to the energy infrastructure section of the call for evidence.

4.1.1 What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long term?

The UK is a global leader in demand-side innovation and National Grid has broken ground in developing competitive markets to enable dynamic demand. Having recognised the role of demand response in helping to build a smarter, more flexible energy system while cutting costs and carbon, National Grid is aiming to meet well over 50% of its balancing needs from the demand-side by 2030. This equates to 4.5GW of demand response, an increase of 1.7GW from today. Though National Grid is responsible for both transmission and system operation, Open Energi does not encounter any immediate conflicts in these roles. Rather than replacing the system operator, the market challenge is to implement demand response at scale over the next decade.

As identified in DECC's recent report on demand response, Industrial and Commercial (I&C) load shifting is ready to deliver on carbon and security objectives at least cost while domestic DSR is yet to overcome significant technical and market barriers. I&C consumes more than double the energy of domestic users while business, waste management and industrial processes drive close to a quarter of UK CO_2 emissions, outweighing the contribution of the residential sector. Up to 10% of I&C energy demand can be quickly and predictably shifted without any impact on business processes or operational performance. Open Energi and other demand response providers have demonstrated the role of I&C demand response in delivering UK CO_2 emissions targets, reducing consumer bills by up to £790m p.a. (NERA) and increasing energy security by directly displacing peaking power stations. With the objective of facilitating the scaling of I&C demand response, market reform could add value by;

- building in longer term incentives for the system operator, beyond the 2-4 years of the balancing services incentive scheme
- attributing value to the decarbonisation achieved by implementing demand response. Open Energi has measured that for every MW of service, 2276 tonnes of CO2 p.a. is saved from the electricity grid. Businesses respond to clear incentives and attributing value to this carbon would no doubt increase uptake among consumers.
- Ensuring, in principle, that balancing markets are technology neutral. With government in the short term focused heavily on the 'capacity margin', the potential of fast response demand-side management and energy storage remains nascent.

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4.1.2 What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

When considering the scale of energy storage it is important to bear in mind the different types of energy storage. Demand response which shifts consumption and reacts very quickly to imbalances is essentially an aggregation of small energy stores into one larger resource. For example energy can be stored in refrigeration, air conditioning, steel furnaces, bitumen tanks and water pumping into reservoirs.

With regards to the scale Open Energi believes that the distribution network or at large Industrial and Commercial businesses is the appropriate level. On the transmission network there are transmission losses to account for by the time the energy reaches the point of consumption and the battery can only be used for National Grid's purposes. On the domestic scale there are few economies of scale and reliability can be questionable for balancing. On the distribution network energy storage can used to solve local network issues as well as for Grid; there are economies of scale to make projects feasible and there are plenty of engaged customers keen to engage with the market.

About Open Energi

Open Energi is a UK company headquartered in London with a satellite office in Manchester. Our globally patented dynamic demand technology provides a dynamic frequency response service which is up to five times faster than thermal power stations. We have been providing this service to National Grid since 2011, fine tuning the consumption of over three thousand electrical loads on three hundred sites across the UK in real-time. We currently have >150MW contracted and are on track to have installed 25MW by the end of 2015, delivering revenue to companies including Sainsbury's, United Utilities, Aggregate Industries, NHS and many more.

Open Energi would be happy to offer a briefing on demand response for you or your staff or to arrange a site visit so that the innovation can be seen in action. Please do not hesitate to get in touch at chris.kimmett@openenergi.com.

Yours sincerely,

Chris Kimmett
Commercial Manager, Open Energi

National Infrastructure Commission Call for Evidence:

Energy Evidence

A Response by the Pensions Infrastructure Platform (PiP)

January 2016

Contents

Executive Summary

The issue of pension funds' investment in infrastructure cannot be looked at in isolation from the wider economy and, specifically, the role of defined benefit (DB) pension provision. Despite the gradual decline of DB pension provision in recent years, over a third of the UK's workforce is still accruing benefits in a DB scheme, with schemes themselves managing over £900bn of assets. It is therefore crucial that employers sponsoring DB schemes can meet their obligations to scheme members without facing undue impact on their ability to invest elsewhere in the economy.

In order to match their long term pension payment obligations, provide security for scheme members and reduce the risk of volatile cash contributions from scheme sponsors, pension schemes need investments that generate long term, consistent, low-risk, inflation-linked cash flow returns. Core infrastructure, including electricity generation, storage and supply, can be a great source of these long term, low risk cash flows. Unlocking institutional investment into infrastructure on a large scale would also be highly beneficial to the economy.

However, achieving increased investment into infrastructure depends a great deal on the predictability of the returns that will be generated over the longer term. For the energy sector, and electricity in particular, this predictability principally relates to the political and regulatory regimes energy projects will be operating under, the level of any subsidies that may be paid and the revenue that will be obtainable for any electricity produced, stored or distributed.

Predictability in these areas is needed from start to finish – from the initial stages of project consideration – to make it worthwhile for pension schemes to incur project development and bidding costs and to arrange long term funding – right through to plant operation.

Any reduction in long term predictability, whether real or perceived, increases the overall project risk for an investor, pushes up the level of returns required to reward the taking of that risk and therefore makes projects more expensive.

As the ultimate regulator, Government has the biggest influence in the perceived stability and predictability of the overall operating environment for energy related projects, and of their total lifetime cost.

We believe that the definition of clear long term goals which form the basis for a coherent long term plan is the best way to provide confidence to pension scheme investors, developers and operators. Such a plan should also include transparent and predictable mechanisms for evolution to reflect changes in the external environment and to facilitate responses to unanticipated market or technological developments.

Overview of PiP Response

Introduction

1. The Pensions Infrastructure Platform ("PiP") is the UK infrastructure investment business set up "by pension funds for pension funds". Its objective is to facilitate investment into UK infrastructure projects by UK pension schemes, by developing investment vehicles which meet their needs in terms of structure, returns and cost.

2. PiP was established in 2012 following the signing of a Memorandum of Understanding by the National Association of Pension Funds ("NAPF"), the Pension Protection Fund ("PPF") and HM Treasury. The development was supported by 10 of the UK's largest defined benefit pension schemes.

3. PiP's first investment fund was launched in 2014. It is managed by Dalmore Capital and invests in PPP equity. The second fund invests in small scale (sub 5MW) rooftop solar PV installations. This was launched in February 2015 and is managed by Aviva Investors.

4. PiP has also worked with Dalmore on the successful consortium bid to construct and operate the new Thames Tideway Tunnel (TTT). PiP was instrumental in £370m of equity contribution to the project by UK pension schemes.

5. Since its establishment, PiP has helped secure over £1bn of committed investment into UK infrastructure projects.

6. PiP has recently received FCA authorisation. Future pension scheme investments into infrastructure will be delivered through a regulated investment fund, operated and managed by PiP.

7. Pip will not be commenting on the technical questions posed in the call for evidence. We are not urban planners, we are not transportation specialists nor are we electricity market academics. What we are is a specialist equity and debt financier, working on behalf of UK pension schemes to facilitate, source and manage effective investment by them into UK infrastructure projects. We do this because we believe the stable long term, inflation linked cash flows that can be generated by core UK infrastructure projects is a good match for the long term pension payment liabilities within such schemes. This makes decision making easy for PiP because there is one fundamental criteria above all else that determines whether pension schemes will invest into infrastructure; will the entry price, the risk taken on and the returns to be generated over the full project life improve the ability of pension schemes to pay their members pensions in full when they become due?

   If this criteria is not met, there will be no investment since it would breach the basic fiduciary duty of the Trustees who are responsible for the financial security of the schemes they manage. No amount of political expediency, publicity or perceived "national interest" will overcome this basic requirement to safeguard the retirement provision for UK pension scheme members.

Background

8. When pension schemes assess investment into long term, illiquid assets, such as physical energy related projects, which typically will be bought and held for 20-30 years, a key consideration is the stability of the operating regime and therefore the robustness of the long term financial forecasts which need to be made. Political, regulatory, legal and subsidy environments are core parts of this stability assessment.

9. The perceived stability and predictability of the UK are real competitive advantages. Indeed, the reason why the UK has been so successful to date at attracting pension scheme investors into infrastructure projects is because it is viewed as having a very stable political, legal and regulatory environment. It is impossible to look forward to the potential for any future infrastructure investment projects without stating the essential precondition that the Government should NOT enact any retrospective legislation that would subsequently change legal contracts that have been freely entered into. Any such legislation would undermine the stability argument and severely damage long term investor confidence.

10. Where a system of subsidy payments forms a significant part of the operational economics of a project, it is equally important that these are predictable for the long term. This applies through the full project life from the earliest stages of investment appraisal, while funding sources are being secured and after project contracts have been signed.

11. Pension schemes have a fundamental obligation to pay accrued pension benefits to members, usually on a monthly basis. It is therefore vitally important that pension schemes have a reliable stream of income from their investment portfolios to enable them to fund their pension payments. This need for income imposes a finite limit to the proportion of every scheme's investment portfolio that can be invested into non-yielding assets, such as infrastructure projects which do not return any cash to investors during a construction period. In general, the longer the period of no income, the less attractive an asset is for pension schemes to invest in.

    The recent Ofgem proposals for Competitively Appointed Transmission Owners ("CATO's") under which revenue payments to the onshore transmission asset owners will only begin upon completion of construction, which will be up to 3 years, has, all other things being equal, made these assets less attractive to pension schemes.

12. We now turn to the specific questions posed by the consultation, focusing on those where we disagree with the current proposals.

Response to specific key questions

Question 1: What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long term?

Assuming current trends continue, over the longer term, the lowest cost of energy generation will be achieved by increasing the proportion of electricity produced from renewable sources such as solar and wind, where, post commissioning, there are no input costs.

This thesis depends on:

- A continuing decline in the cost of renewable generation technologies.
- An acceleration in the deployment of energy storage solutions capable of maintaining supply when the sun is not shining and the wind is not blowing.
- A continuing political desire to reduce global carbon emissions, and therefore a willingness to establish and maintain a level economic playing field with carbon and nuclear based alternatives.

Whilst not directly applicable to the electricity market itself, the following policies could be adopted to encourage renewable generation and greater deployment of energy storage solutions:

- Change planning rules for all new residential, commercial and public buildings to mandate installation of Solar PV generation on their roofs.
- Support the development of Solar PV roof tiles that can be installed as a direct alternative to existing clay, concrete or slate tiles.
- Revise the current capacity market auction process to incentivise utility scale energy storage solutions rather than short term, small scale, highly polluting, diesel generation.

Question 2: What are the barriers to the deployment of energy storage capacity?

We perceive the barriers to greater deployment of energy storage capacity are:

1. Technical
   Government R&D support should be provided as a matter of priority for the development and commercialisation of rechargeable battery technology.

2. Financial
   There is currently no explicit system of financial support or operational subsidy for energy storage technologies. This should be changed.

   The rules of the current capacity market auction system should be changed to encourage storage solutions for the provision of balancing capacity. Rather than effectively subsidising the installation of small scale and highly polluting diesel generators as in the December 2015 auction, such a rule change could provide financial incentives for the development and deployment of utility scale storage technologies.

The system of constraint payments should also be changed. No renewable generator should be allowed to receive payments for not generating electricity. The incentive for generators should be changed to encourage maximum generation with "excess" power being stored for future release to the grid. Battery storage systems should be installed at existing solar or wind generating facilities. The costs of these should be recoverable from capacity market/constraint payments.

We believe the most appropriate deployment of energy storage systems will combine both utility scale projects and distributed, domestic scale installations.

An integrated policy combining rooftop solar PV generation, adoption of electrically powered vehicles and installation of smart meters could transform residential UK into a mass distributed generation and storage system.

Question 3: What level of electricity interconnection is likely to be in the best interest interests of consumers?

We believe the long term priority should be the development and adoption of sufficient UK based renewable generation capacity, energy storage solutions and a smart grid, which combined with nuclear generation capacity, will be capable of meeting the UK's total energy demand without the continuing use of fossil fuel based systems.

We would view interconnector capacity as a short to medium term mechanism for reducing total electricity supply costs. If these reduced supply costs were combined with maintained costs to consumers, the surpluses could be used to finance renewable generation developments to achieve the long term goal.

The installation costs of interconnectors should be amortised over the period agreed for the achievement of the long term goal. Thereafter electricity supply via interconnectors should stop and the physical infrastructure simply be maintained for emergency backup use.

Question 4: What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The key consideration for investors in long life projects such as those for electricity generation or demand reduction, is certainty; certainty about regulatory regime, about political view, about revenue levels, input costs and inflation linkage for example.

The most theoretically correct and sophisticated energy market models are vulnerable to the real world reaction and ingenuity of entrepreneurial individuals and businesses.

The operators of the current Capacity Market Auction system failed to predict that it would incentivise entrepreneurs to import small scale and highly polluting diesel generators rather than the building of new CCGT generating plants.

DECC has consistently failed to predict the scale of Solar PV installations encouraged by the technology driven decline in panel prices compared to infrequent, step changes in subsidy levels. Smaller, more frequent and predictable changes to subsidy levels would better allow new industries to develop without excessive costs to consumers.

Further Information

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National Infrastructure Commission: Call for evidence

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Electricity interconnection and storage

4.1 What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The electricity market in the UK would benefit from the introduction of flexibility in how and when energy is produced and consumed. By modifying generation and consumption patterns in reaction to changing prices, the energy system can make sure the power being generated matches more efficiently the amount of energy used. This can result in a smarter electricity market that reduces energy generation and supply costs and satisfies its commitment to lower carbon emissions. Innovative ways to introduce flexibility into the electricity market include: implementing demand-side response (DSR), energy storage, and distributed generation. DSR is based on flexible tariff schemes for consumers in which electricity prices vary at different hours of the day. Flexible tariff schemes would encourage users to avoid the use of appliances during critical hours, thus shifting the peak demand of energy and balancing it with generation. Energy storage systems can help to save the surplus of energy when generation is abundant. This excess of energy can then be used at times when it is needed, thereby balancing the demand. Several technologies are available for this purpose including, but not limited to, battery banks and hydrogen storage systems. Distributed generation can produce clean energy locally at home or work premises and in this way contribute to the reduction of the cost of transmission.

4.2 What are the barriers to the deployment of energy storage capacity?

Because energy storage is a novel technology, it lacks tried-and-tested business models, the lack of which leads to a high level of risk aversion when it comes to procurement and initiation of energy storage projects. Another factor is that such projects face rapidly diminishing technology costs, which makes the timing of the investment decision important. In addition, the cash flows of energy storage projects would be heavily influenced by the price of energy and resultant policies around the capacity markets. One tool that can be useful in assessing capex-heavy investment in times of high uncertainty is real options analysis. Traditional project valuation potentially undervalues the worth of projects that have long payback and high upfront costs, like energy storage. Real options analysis can be used as a tool to model energy price uncertainty, and possibly policy risk, with regard to how energy storage systems would be treated in capacity markets in terms of compensation for offtake. Such models could be used to optimise time of investment and also to best examine the potential value of energy storage projects.

http://www.mdpi.com/1996-1073/7/4/2701/pdf

C. Partridge and F. Medda (2014) "Fuzzy Real Options Analysis Applied to Urban Renewable Energy Projects", Regional Studies Association Winter Conference 2014, London.

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8th January 2015

Response to NIC call for evidence - electricity interconnection and storage

Dear NIC,

Britain's electricity supply to business and homes will be less costly, more secure, and emit less carbon, if additional electricity storage is deployed. Current market barriers, legislation and a lack of clear government strategy have combined to deter most investors and storage companies from delivering these three desirable outcomes.

At Quarry Battery Company we are developing the first pumped storage to be built in the UK for 40 years, and the first to be built using private funds. It is at Glyn Rhonwy in north Wales and we aim to have it operational in 2019.

We want to see a fairer market and legislative framework around storage so that the sector can flourish, with different companies and technologies competing to offer storage solutions at all levels in the electricity supply grid so that British households and industry are the winners.

In our view Britain is only a few steps away from catalysing the build-out of a sustainable national storage fleet – perhaps without the need for subsidy or major legislative changes.

In the following pages we highlight barriers and offer solutions that would help any storage technology or developer equally.

Yours sincerely,

Dave Holmes
Managing Director
Quarry Battery Ltd.

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long term?

Quarry Battery is an energy storage company, and so our answer naturally focusses on this area of a smarter future energy network. We have written a short paper on this topic which shows that storage can help reduce costs to the UK consumer by enhancing the performance of renewable assets, in particular that a 10GW fleet of pumped storage with 31GW of Wind would deliver the same number of renewable MWh as a 40GW Wind fleet, while improving Wind load factor, reducing curtailment, improving flexibility and reducing costs; please see this link. However, there are many more benefits brought by storage than this paper shows. Various academic and industry commentators have shown similar results including Imperial College[1] Energy Futures Lab and the Carbon Trust[2].

The NIC call for evidence barely mentions carbon emissions. While we understand that Carbon considerations are perhaps not within the NIC's remit, it cannot operate in a vacuum and must be mindful of the legal framework surrounding carbon emissions in the UK. The third and fourth carbon budgets in particular look difficult to achieve. It will be highly regrettable if we fail to meet the forthcoming carbon budgets, particularly if significant potential decarbonisation, available from grid scale storage, has been neglected. Please see this link for a carbon payback calculation for our site in North Wales.

Storage is not a single thing. There are a number of different storage technologies, each in a different place on the spectrum of response speed, scale, geographic freedom, charge density, cost, reliability, maturity, longevity and environmental impact. This ecology presents useful options for storage solutions at every scale and in every place, but it also makes it potentially difficult to create policy that is perfectly focussed on consumer and UK benefits while treating all technologies at all scales in a transparent and accurate and free-market manner. The challenge for policy-makers is to unlock the value of storage without picking winners or losers or blighting its development with undue costs or uncertainty. For this reason aligning commercial and public interest by addressing market failures should be the first step.

Two logical moves have already been made. Firstly the Capacity Mechanism assists by identifying the value of energy security [at least in part] and providing a mechanism which supports those who can deliver services in a stress event. Secondly the move to PAR1 single pricing better reflects the extremes that the electricity market should reach in free-operation. In the past policy makers have been wary of high and low energy prices and this has suppressed a market signal that is now free. The PAR1 calculation still disguises the extreme highs and lows to some extent, but it is at least progress from the previous system. Both of these interventions support new storage by closing the gap between market signal and required economics and both leave electricity consumers as winners; improving security in the case of the CM and further reducing cost through greater efficiency in the case of the single pricing.

These interventions have evidently not been sufficient to stimulate the bigger players in the market such as SSE, who explain their reluctance to invest in the Coire Glas scheme as follows:

> *"…making a Final Investment Decision to progress the Coire Glas scheme will require overcoming a number of commercial and regulatory challenges. These include changes in the existing transmission charging regime for pumped storage and a satisfactory and supportive long-term public policy and regulatory framework."*

[1] https://workspace.imperial.ac.uk/energyfutureslab/Public/Strategic%20Assessment%20of%20the%20Role%20and%20Value%20of%20Energy%20Storage%20in%20the%20UK.pdf
[2] http://www.carbontrust.com/media/168551/tina-electricity-networks-storage-summary-report.pdf

The gap between the current economics of storage and its required economics is different at different scales and for different technologies. However there are further modest market and legislative changes that could be made to help close the gap. We believe it is sensible to focus on these. Major changes may take a long time to achieve and have the potential to create further uncertainty.

While storage has clear benefits in partnership with renewable forms of electricity, it is not only in a renewable UK that storage offers benefits to the grid; far from it. The existing pumped storage facilities in the UK were not built for renewable balancing and yet have been a very important feature of UK grid stability over the past half century. The maturity, reliability, efficiency, speed and longevity of pumped storage sets it head and shoulders above all other forms of energy storage at grid scale. It does not matter which mix of electricity generation we end up with, especially if we seek to electrify heat and transportation, storage will help us. The UK should strive to get it built and with a low carbon future on the horizon, and historically low costs of capital: now is the time.

Storage is currently considered to be “generation”. It is treated as such in the planning process, in the environmental impact regulations, in the way it connects to the grid, in the way it interacts with the market and in the way it is rewarded for the services it provides. Storage is a square peg in a round hole and market barriers and failures can be found in the gaps.

What are the barriers to deployment of energy storage capacity?

The core challenges facing storage are:

- Difficulty in raising funds to begin a storage business
- Lack of transparency in current market
- Complex revenue streams
- Uncertain future revenue streams
- Build finance hard to secure

All of these challenges are related to market clarity, stability and investor confidence. While we have one of the most transparent energy markets in the World, the majority of Balancing Mechanism contracts, especially at the fast response end of the BM, appear to be bilateral and opaque between National Grid PLC and the service provider. It is difficult to evidence the value of grid balancing and build a business case in such an environment. For now many “build and operate” investors struggle to see a suitable return without substantial low-cost bank finance, while banks don’t understand (or cannot see directly) the revenue stream and so are reluctant to make the required capital available at a reasonable rate. The complexity of trading behaviour required for a storage unit makes it difficult to communicate to all except energy traders, which rules out most of those able to provide the required finance.

The specific market failures are:

- Connecting
- Taxation
- Lost revenues/ External benefits
- Regulatory risks
- Transparency

Connecting

The problem - Academic commentators such as the Energy Futures Lab at Imperial College London, have shown how storage is bizarrely and unfairly penalised for bringing system benefits. A new power station causes stress on the local grid and increases distribution and transmission infrastructure costs. It rightly pays connection charges which help offset the cost of reinforcing the grid to handle its output. But storage is not a power station. It tends to absorb energy when there is too much and release it when there is too little. It therefore *reduces* pressure on existing infrastructure, *saving* grid reinforcement costs, and increasing its effective capacity.

The solution - Storage should not foot the bill to connect to the network. The DNO and SO benefit from storage in the form of reduced network reinforcement costs, so it is right that they should share some of that benefit with the storage developer. We suggest that the network operators should bear the cost of new storage connections. However we need to consider possible unintended outcomes; what if the storage facility never gets built, or it not operated for the full design life? The result in both cases would be that DNO or SO is left with a redundant asset. In yet another scenario a potential site for storage exists but it is so distant from a possible connection point that the cost of connection is simply uneconomic. It is clearly not in the public interest to force a DNO or the SO to pay for the connection in such a situation.

There is a middle path, which is that the storage developer pays the initial connection fee, but rather than facing an ongoing annual charge, the developer is gradually paid back the initial cost of constructing the connection, less maintenance fees. This could be worked out, say, on a 10% pa basis so that the developer has to perform a useful storage role for a considerable time in order to recover the initial funds. A worked example where a connection costs £10m and maintenance runs at £100k pa would run as follows:

Year of operation	Asset balance	Connection running costs	DNO Payment to developer
0	£10.00 m	£0.00 m	£0.00 m
1	£10.00 m	£0.10 m	£0.90 m
2	£9.00 m	£0.10 m	£0.80 m
3	£8.10 m	£0.10 m	£0.71 m
4	£7.29 m	£0.10 m	£0.63 m
5	£6.56 m	£0.10 m	£0.56 m

In this worked example the DNO gradually refunds the developer for the connection fees it paid, and after 20 years 86% of the cost of connection has been recovered, and the line has been maintained all along. This leaves the connection cost risks with the developer, while returning to the developer some of the externalised benefit the storage scheme has conferred upon the network.

For a sense of scale – connection costs at our site in Glyn Rhonwy are over 10% of the required CapEx, and this would make our scheme much more attractive to investors while not causing undue risks for the DNO.

Taxation

The taxation problem -

Energy consumption is taxed. But if a MWh of electricity is stored and then later returned to the grid it has not been consumed. Despite this simple fact, and despite assurances given by HMRC and Ofgem to DECC that consumption taxes would not be applied to storage, the reality is that they are. The Lithium Ion battery at Leighton Buzzard storage project currently pays consumption taxes because it operator did not receive adequate reassurance from HMRC and Ofgem that the taxes would not be levied.

The solution -

We do not propose the abolition of consumption taxes for storage. No storage is 100% efficient, so charge-discharge cycle losses mean that some energy is consumed, even if the majority is returned to the grid. Complete abolition of consumption tax would not properly encourage and reward cycle efficiency. We propose that rather than reading the import meter and applying taxes, the tax is calculated as the difference between import and export, which represents actual consumption.

A side consideration here is those storage technologies that can turn electricity to fuel such as hydrogen. The operator could choose to feed it into a fuel cell and regenerate electricity, or feed it in to the gas network. How should consumption taxes be applied in such a case? What if the hydrogen was used on site for some other process? Or put into a vehicle for transportation? Is this storage or consumption? We suggest that once an electrically-created fuel [or store of heat or cold or other potential energy source] is used for something other than to return electricity to grid, the energy used has been consumed rather than stored. The [import-export = consumption] formula follows this logic and seems a simple and clear way to proceed in what could quickly become quite confusing with significant bureaucratic overhead on any tax collection.

Lost revenues/ external benefits

Storage creates externalised benefits for the system. Capturing more of these benefits for the storage provider will help better align commercial interest with the public interest.

Curtailment

Curtailment is where a generator is asked to switch off as their electricity is not required. Fossil fuelled plant has long been curtailed, but curtailment is increasingly being resorted to for renewables. Because renewables are subsidised, operators will only curtail if paid the value of the subsidy to do so.

Storage is a cheaper and lower carbon alternative to curtailment, reducing the cost of electricity, increasing the efficiency/ load factor of existing renewables fleet, and boosting carbon reductions.

Avoided infrastructure – Grid

Storage lessens stresses on the grid, reducing the need for costly new network infrastructure or costly reinforcement of the existing transmission and distribution systems. Our suggestion on connection fees above would address this market failure.

Avoided infrastructure – Generation & interconnection

Renewables and interconnectors are funded by subsidy or subsidy-like mechanisms; the more we build the more it costs.

Renewables plus storage have a higher load factor than renewables without storage, and will cost Britain less. At QBC we have modelled how a 10GW fleet of new pumped hydro storage would enable a 31 GW wind fleet to produce the same amount of electricity at less cost as a 40 GW wind fleet *without* new storage (and with greater energy security and less carbon). If Britain builds renewables until the need and price signals for storage show the required incentive, and *only then* focuses on storage, the risk is suboptimal cost, impaired UK security and increased carbon emissions. It will also make the job of the SO job more difficult. This is the situation that Germany now finds itself in.

We believe it is better to build renewables and storage in step with one another and deliver a secure low carbon electricity supply at optimal cost. Portugal shows wisdom in linking renewable power to storage according to a 3.5:1 ratio. The identical ratio would not necessarily apply to the UK, but a formal recognition of a linkage would aid investor confidence, stimulate developer ambition and concentrate the minds of policy makers. California has made the link between generation mandatory. The ratio is one to first understand in the UK context and then to keep an eye on.

It is useful to the UK consumer to reduce, postpone or enhance CapEx spent on renewables by building storage alongside, while still delivering on our legally binding carbon responsibilities.

Sovereignty

While it allows international power trading, interconnection could also make the UK dependent on other countries for energy security. More storage would enable the UK to increase its security and self-reliance.

Trade balance

By storing excess power for later release rather than importing electricity Britain will improve its trade balance.

Flexible capacity

The problem –

The Capacity Mechanism rewards storage technologies only as generators. Following lobbying efforts from ourselves and others the CM rules were changed to give generators' obligations in the more dynamic and urgent Balancing Mechanism primacy over their responsibility in the less critical Capacity Mechanism. This avoided the trap wherein BM units would have remained static when the system most needed flexibility. However, the "BM trumps CM" rule only encourages the desired behaviour; it does not fully appreciate the fact that storage assets can work in both directions as generators and absorbers. In a stress event both abilities are desirable.

The solution –

Creating a new class of capacity that recognises the value of flexibility to grid stability would enable storage to be properly rewarded for its enhanced provision during times of poor grid stability. However the legislative burden of such a move and the risk of unwanted side effects might make such a suggestion unappealing. A similar result could be achieved under the existing system by adapting the de-rating factor for storage technologies. Each technology is "de-rated" according to its likely reliability in a stress event. Pumped hydro for example has a derating factor around 97%, meaning that a 100MW unit will be counted as a 97MW unit in the Capacity Mechanism. Since storage is not only generation, and a 100MW storage unit can in fact deliver a power range of 200MW [+100MW to -100MW] it is our opinion that the derating factors for storage should reflect this greater range of ability. The creation of a bespoke "mechanism" for flexibility, balancing or storage is one to consider if it is not felt that the Capacity Mechanism a suitable vehicle, or if desired changes to the UK generation mix are not coming to fruition.

It has been argued elsewhere that the CM is cost neutral to the taxpayer. This is because the CM revenue received by new build is expected to suppress the energy price by an equivalent amount. Provided the energy market is competitive the argument is not without merit. Increasing the CM de-rating factor for storage therefore should not have an adverse effect on consumer energy bills. In our opinion the jury is out on whether or not the CM adds costs to the taxpayer, and while it seems likely that energy costs would rise if the CM were suddenly removed from the market place, it is difficult for us to perform such an equation. Whatever the answer, the CM is unlikely to pass all costs on to the consumer and so could be seen as a low cost option. In the case of storage, tweaks to the CM would be good value for the taxpayer given the cost suppression, security and carbon benefits storage delivers.

BSuoS charging [Balancing Services use of System]

The problem -

Storage is a net contributor to grid stability, yet it pays the same charges levied on the generators, and transmission and distribution assets that fund the balancing mechanism – the system that keeps the grid stable. While it does not necessarily follow that all storage in all places and at all times will assist in stabilising the grid, it is generally uneconomic for storage to act otherwise since it makes its revenue by buying surplus power and addressing spikes in demand. The charge is therefore an illogical barrier to storage.

The solution -

Modify the BSuoS charging regime for storage. This could be done in a number ways, each with different outcomes. The current regime can be visualised as follows:

	Transmission	Distribution
Importing	£ BSuoS charges	£ BSuoS charges
Exporting	£ BSuoS charges	£ BSuoS revenues

For distribution connected storage above the meter, BSuoS charges and revenues interact and more or less cancel one another out. An efficient storage facility operating in a way that benefits the grid can reduce the charges or even turn BSuoS into a revenue stream. This is the case for our first project at Glyn Rhonwy, where BSuoS net revenues are around £100k pa, which is a welcome but relatively insignificant contribution to the overall economics. The more efficient storage is and the more it acts in the interest of the grid, the more it reduces charges and increases revenues.

For example:

	T	D
I	£	£
E	£	£

Do nothing… makes no difference to the costs of balancing the grid, and provides no change to the storage market signal.

	T	D
I	-	-
E	-	-

Storage immune to BSuoS… This has the effect of boosting transmission level storage, while not really changing the environment much at the distribution level, and in fact slightly harming our project at Glyn Rhonwy as described above.

	T	D
I	£	£
E	£	£

Reverse charges for transmission storage exports… This has the effect of neutralising BSuoS at transmission level, while having no effect on distribution level storage.

	T	D
I	-	-
E	£	£

Remove BSuoS import costs for all storage… this has the effect of boosting both transmission and distribution level storage, while not changing the landscape heavily.

	T	D
I	-	-
E	-	£

Remove all BSuoS charges… This boosts both transmission and distribution scale storage.

There are a number of permutations. Simple and logical regulatory tweaks to BSuoS can have a marked effect on storage price signals without adding additional cost to the UK consumer. We would recommend one of the last two options as a significant first step, and suggest that further adjustments might be considered as the build out of new storage develops.

At the distribution level, the "remove all BSuoS charges" option would boost revenues at our Glyn Rhonwy scheme from £100k pa to around £800k pa. Since this is a form of revenue banks can easily grasp and are prepared to rely on, it would be helpful in securing project debt finance.

At transmission level the "remove all BSuoS charges" option would boost the net profit of transmission owned pumped hydro by about 10%, as reported by the Institute of Civil Engineers in its recent report[3] "Energy Storage: Realising The Potential". The redistributed costs would increase the BSuoS charges for other parties by just 0.3%. The change could be applied only to

[3] https://www.ice.org.uk/getattachment/media-and-policy/policy/electricity-storage-realising-the-potential/ICE-(2015)-Electricity-Storage-Realising-the-Potential.pdf.aspx

new schemes, or for the first say 20 years life of new facilities, if an unnecessary windfall to existing schemes was to be avoided.

Regulatory risk

The risk of revenue streams diminishing or drying up altogether is a serious concern to developers, investors and debt funders alike. Just as the Bank of England has helped navigate the UK though a time of fiscal uncertainty by being clear about the interest rate, so too can policy makers be clear about what the direction of travel is, even if the detail is a little hazy. The CM and the PAR1 pricing mentioned earlier are excellent examples.

A suite of small positive changes, flagged early and often will send a powerful signal to investors. Large changes would need to be mindful of creating uncertainty and causing a hiatus to our first scheme, and perhaps look to bespoke support should such a situation arise. Economics would deteriorate for the builder of a single plant if there were suddenly another 10GW of pumped storage on the horizon, so the aspiration of government to build storage needs to match the incentives offered for investors to be confident of their decisions. In the words of one of our key investors;

> *"The profitability of PS plants will decline as additional plants are built out and compete in the various markets into which fast response electricity is sold. Accordingly, until the future size of the sector is capable of being estimated by investors, even if only approximately, it will not be possible to construct a convincing revenue model for any new project. The predictable consequence is that early stage investing becomes unacceptably risky, and the cost of capital too high for economic viability.*
>
> *What makes this uncertainty even worse is that we can't tell what factors will influence Government thinking on sector size. Does CO2 saving any longer count with this Government, the Chancellor, or now for the NIC under Lord Adonis, which is the Chancellor's creation? The Climate Change Act 2008 is the law of the land, and it sets very specific legally binding staged targets for decarbonisation. If not taken into account, this consultation will be legally flawed, and may be challenged. Yet the NIC's call for evidence contains no reference, direct or implied, to the Act, its imperatives, or whether decarbonisation will be a factor in the NIC's thinking on sector size."*

Transparency

The Balancing Mechanism is serviced by companies able to adjust their power output/ input quickly enough to be of utility to the System Operator in managing Grid stability. This service is procured in three ways: firstly through open processes such as the Fast Reserve tendering market, secondly ad hoc through bids and offers and thirdly through bilateral contracts between the SO and service providers. The opaque bilateral contracts unfortunately form the majority of contracts in the Fast Reserve end of the Balancing spectrum and this makes it difficult to evidence their value, frequency or contract length to investors or financiers. Increasing the independence and transparency of the SO would assist in resolving this issue in the long term.

Re-classification of storage?

We are aware the government is pondering a re-classification of storage to make it distinct from its current home in generation. This would fit well with our statement above *"Storage is a square peg in a round hole and market barriers and failures can be found in the gaps."* However creating a new regulatory home for storage does not necessarily change anything, since it is the regulatory detail that will deliver change. This document has therefore focussed on the current market and the specific detail of suggested solutions/ realignments. The question on reclassification appears to be a legislative one – is it easier or quicker to effect the desired change by tweaking the current frameworks or by inventing something new? We do not know the answer, however whether or not storage is re-classified we ask that the market failures and solutions presented here are considered.

Summary

In this submission we have identified modest market framework adjustments that we believe are sufficient to unlock investor money and stimulate the development of new storage schemes.

1. Return connection fees to the developer over time
2. Remove double taxation, applying the formula [consumption = import-export]
3. Make logical changes to BSuoS to enhance storage price signals
4. Improve CM de-rating factor for storage to recognise the enhanced role it plays during a stress event
5. Improve Balancing Mechanism transparency by removing the secrecy surrounding bilateral contracts, through making the SO independent or through other measures
6. Consider re-classifying storage if this helps enable better alignment of commercial and public interests

The changes suggested are storage technology neutral and we believe would not require major changes to legislation or add significant cost to consumers. We believe they would bring the energy market into better alignment with the public interest by allowing storage to capture a fairer reward for the unique multiple services it provides.

Response to the National Infrastructure Commission Consultation on Electricity interconnection and storage

Dr Jonathan Radcliffe, University of Birmingham and
Professor Peter Taylor, University of Leeds

January, 2016

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Market framework

Historically, the electricity market has balanced supply and demand primarily by adjusting supply through altering the level of flexible electricity generation from fossil fuels, plus some pumped storage and demand response at the margins. In the future, the proportion of fossil fuel generation will decline and its load factor will also reduce due to a combination of increased generation from variable renewable technologies (largely wind, with some solar) and greater variability in demand (across days and seasons due to the greater electrification of heat and transport).

Against this background, incentivising the build of new 'conventional' infrastructure (typically large-scale and capital intensive, with long life-times) now, according to the current paradigm, risks systemic lock-in or stranded assets – leading to unnecessarily high overall costs. An approach which considers the long-term direction of change within the electricity market is therefore needed, while retaining the flexibility to adjust to the details of developments.

For the UK to successfully decarbonise its energy system requires not just new technologies, but new market frameworks and ways of doing business. Improvements in ICT, together with energy market liberalisation, offer the potential for new business models that challenge the incentive to increase profit by increasing energy sales.[1] To enable this, markets need to evolve over the next decade to incentivise the provision of energy services, rather than the consumption of energy, and to consider the whole energy system, recognising heat as a critical component, while meeting the flexibility challenge.

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[1] See for instance Roelich, K. and S. Hall (2015) Local Electricity Supply: Opportunities, archetypes and outcomes. https://research.ncl.ac.uk/ibuild/outputs/local_electricity_supply_report_WEB.pdf

Measures for increasing flexibility

The precise role that can be played by different flexibility measures is still uncertain but, on the basis of recent studies, demand side management and energy storage (which can overlap technologically) appear to offer cost-effective ways of ensuring reliability in a low carbon energy system in the medium to longer term. The impact of embedded generation may be positive or negative, depending on its operation.

The current analysis, however, is limited, and there is an urgent need to investigate how new technologies can be integrated within future energy systems both technically and under different market frameworks.

Though the costs of energy storage technologies are expected to continue to fall, and its value to rise, the current commercial case is not strong in the UK. We conclude, therefore, that new mechanisms need to be put in place that recognise its potential role. Two options possible options (not mutually exclusive) are:

- Energy storage could be considered as a regulated asset. This might make sense for network-connected facilities that have public-good characteristics.
- Greater participation within the EMR framework, through the capacity market (with special auctions for new energy storage and demand side response technologies, that go beyond the current short-term transitional arrangements) or contracting flexibility through Feed-in-Tariffs (possibly alongside renewables).

2. What are the barriers to the deployment of energy storage capacity?

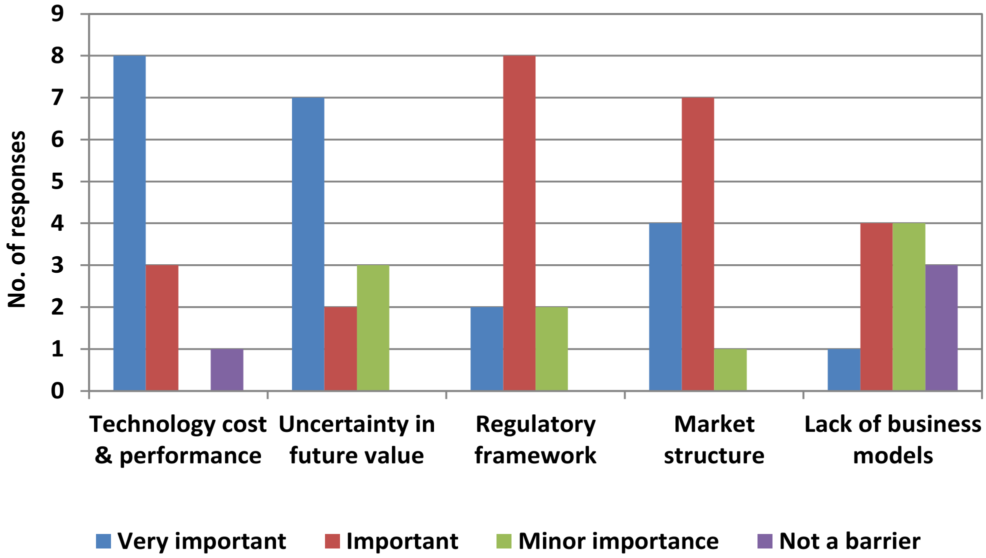
- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

The term energy storage encompasses a wide family of technologies with very different physical, operating and cost characteristics. Due to the different storage technologies available and the varying services that they can offer, it is likely that energy storage can play a role at all scales in the UK and potentially will therefore face different barriers.

We carried out some research during 2014 on these issues to understand the views of key stakeholders on barriers to energy storage and where storage was most likely to be situated on the system.[2] Below is a summary of our results.

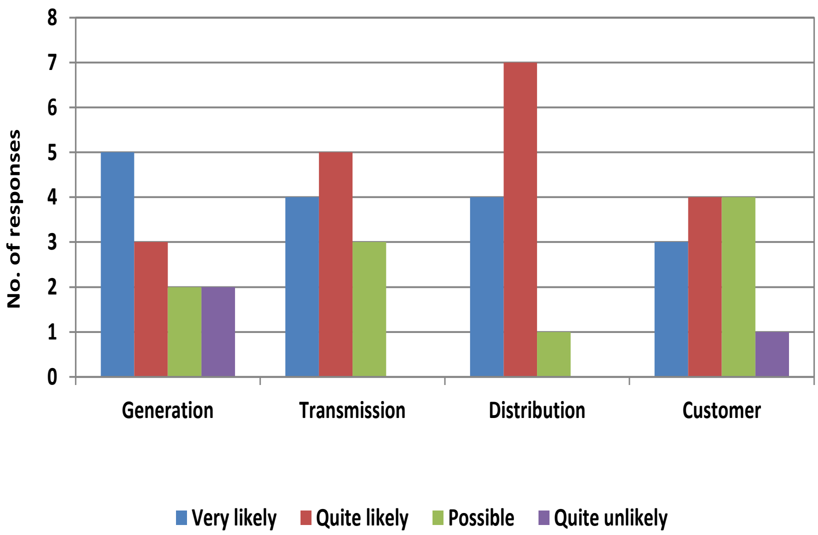
[2] See 'Energy Storage in the UK and Korea: Innovation, investment and co-operation', Appendix A4.2 (2014) Centre for Low Carbon Futures, for full details; available at http://www.lowcarbonfutures.org/energy-storage/korea.

How important are each of the following barriers to the deployment of energy storage over the next 5-10 years?



Technology cost and performance was seen as a very important or important barrier by all but one of the stakeholders, with uncertainty of future value also being highlighted as very important by more than half of respondents. A number of specific performance issues were highlighted by stakeholders in response to Question 9. The regulatory and market framework in the UK was also seen to be an important barrier. A number of respondents highlighted in particular uncertainty in the market and regulatory structure as a problem, rather than necessarily any need for further reform. The lack of business models was considered to be less of a barrier, with a number of respondents believing that business models would emerge if the commercial case was strong.

How likely is additional energy storage to be situated on the following parts of the system?



Locating storage in the distribution system was seen as very or quite likely by virtually all stakeholders. A number of reasons were given for this including that the small capacity size of some storage technologies were better suited to distribution rather than transmission, that the targets for distribution network operators could be easily realigned to drive storage uptake, that it could address grid constraints and that it was easier to have storage downstream in the value chain. Two-thirds or more also saw generation and transmission as likely or very likely locations for storage. In the case of generation the main role was seen as enabling the integration of variable renewables, such as wind farms. At the transmission level, the reasons given included economies of scale, the value of storage for fast response and dealing with volatility and the market to provide National Grid with system services. Customer-level storage was seen less favourably, but this option was still rated very or quite likely by more than half of respondents. Those in favour often highlighted the role of storage alongside PV systems.

From considering these responses from stakeholders, and other studies[3] we identify six key barriers affecting the deployment of energy storage:

1. Technology cost and performance: the current price of many energy storage technologies is too great to give a business model for deployment, even if the full system value could be extracted. Over time, the technology costs and performance of storage technologies are expected to improve, and the value of storage will rise as renewables are deployed.
2. Uncertainty of value: the value of energy storage is dependent on the energy system mix - uncertainty in deploying renewables could reduce the appetite for investing in options that can address their variability. Further, energy models have so far been limited in their scope and ability to include storage, so estimates of value are still to be refined.
3. Business case: an energy storage technology could access multiple revenue streams in different markets and across timescales of seconds to days. A business model which captures those income streams is currently difficult to establish, as the technology will cut across traditional business boundaries and potentially need to extract value from both regulated and competitive markets.
4. Markets: the current market framework, which now includes a capacity mechanism, does not require the total cost of energy generation to be reflected in the energy price (so called "missing money" problem). This results in lower energy price fluctuations (through lowering peak prices) and so reduces the opportunity for energy storage to provide a service (and extract value) through arbitrage. This might not matter, if there were not also barriers to energy storage participating in the capacity mechanism (see 5) below. More fundamentally, the future long-term value of storage cannot be

[3] Energy Research Partnership (2011) 'The future role for energy storage in the UK' http://erpuk.org/project/energy-storage-in-the-uk/; Centre for Low Carbon Futures (2012) 'Pathways for energy storage in the UK' http://www.lowcarbonfutures.org/energy-storage; Strbac et al (2012) 'Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future' http://www.carbontrust.com/resources/reports/technology/energy-storage-systems-strategic-assessment-role-and-value; UKERC (May 2011) 'The future of energy storage: stakeholder perspectives and policy implications'

recognized in today's market, with the consequence that other established technologies (i.e. thermal generation) crowd-out the space now, but lock-in future emissions.

5. Regulatory/policy framework: there are restrictions on network operators operating storage technologies on a merchant basis; and high network charges affect storage operators. The EMR process has continued to incentivize the provision of capacity and flexibility by established technologies, without sufficiently recognizing the longer term opportunities from new technologies.
6. Societal: large-scale deployment of energy storage could introduce new technologies at a local level, and larger scale facilities will need planning approval. Wider community acceptance is a pre-requisite if they are to be adopted, but little work has been done in this area.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Our work with Korea has demonstrated the value of Governments providing clear signals to the market in terms of expectations and preferred options, rather than taking a laissez-faire approach in which scenarios are merely presented as options and for which the government has no view of the merits or otherwise.

We can also see markets for energy storage emerging in the United States (especially in California where a minimum level has been mandated) and Germany (where incentives were introduced to reduce the cost of installing batteries with small-scale PV).

In recent years public RD&D funding for energy storage has increased significantly – and storage has been identified as one of the Eight Great Technologies. However, while this "technology push" is welcome, there is a distinct lack support to deliver the complementary "market pull". Government should provide greater certainty over what it sees as the role of energy storage in the energy system and consider introducing policies that will encourage investment in the technologies from industry and allow the UK to take a position as a leading innovator.

Without creating the full innovation ecosystem, the UK could see the value from early stage funding being captured elsewhere, as technology development and manufacturing migrate to emerging markets and eventually the UK could end-up in the situation where it needs to import the energy storage technologies for which it funded much of the basic R&D.

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RENEWABLE ENERGY ASSOCIATION

REA response to National Infrastructure Commission Call for Evidence

The Renewable Energy Association (REA) is pleased to submit this response to the above consultation. The REA represents a wide variety of organisations, including generators, project developers, fuel and power suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 750 corporate members of the REA, making it the largest renewable energy trade association in the UK and the only trade body covering power heat and transport.

We are particularly keen to work with the Commission and its Commissioners on energy storage and the value it can bring to the UK. The REA is working on a report with KPMG on the costs of storage and recommendations for supporting the market in the UK which we hope will assist the Commission and Government. Further detail will be provided in the report therefore we have not gone into details of prices and some other aspects in this response.

The REA believes the National Infrastructure Commission (NIC) should consider the following priorities:

- **Supporting new build energy storage projects**. Under the UK's legally binding climate change targets, there is a limit on the energy we can generate from fossil fuels, and this reduces steadily over time. Therefore the UK must design an energy system that incentivises large amounts of low carbon capacity and increased flexibility. Under the Committee on Climate Change's scenarios, we will also need to significantly increase electricity supplies as transport and heating are electrified. In this context, the Capacity Market (the only public contracts available for energy storage in the UK) should be reformed in order to support energy storage. This would enable storage companies to secure finance on the back of the mechanism, which they presently cannot due to the short term nature of support. Increasing flexibility in the system is a win-win situation and one which should not result in 'stranded assets' as the need for flexibility will always exist and increasing low carbon energy sources and new infrastructure, such as Electric Vehicle charging points, will significantly increase this requirement.
- Energy storage helps provide not only security of supply and other important technical support to the grid network, but also a level of stability to the power market and wholesale prices
- **Consider a carbon emissions test in new infrastructure considerations**. In line with the CCC's advice on meeting legally binding carbon budgets, the Commission should consider or require Government to consider, the carbon and environmental impact of new infrastructure projects, for example road projects.

<u>New-build energy storage: balancing supply and demand on the system</u>

New-build energy storage projects help balance the energy system and incentivise and enable low-carbon technologies. They help stabilise energy prices by enabling peak shifting. Many storage projects also strengthen the grid network, at a lower cost than building new overhead lines or underground cables. See Low Carbon Network Fund projects for more details[1]. Further benefits to the System Operator are illustrated by the fact that National Grid are currently running an auction process for support for 'frequency response' services, which is specifically targeted at battery storage providers due to the speed and scale at which they can respond.

These projects, due to the current regulatory and legal framework, and only short term nature of support currently available, often struggle to secure finance in the market. Our energy storage member companies tell us that if longer term support was available then securing finance would be eased.

Therefore we strongly agree that energy storage projects should be a key priority for the Commission.

Storage services

Energy storage technologies provide a range of services to the grid and the System Operator. These include:

- **Balancing electricity supply and demand**: storage technologies can respond within miliseconds (batteries) to signals to discharge to the grid. Other bulk technologies (pumped hydro) can still respond within 1-4 hours, and provide very large amounts of capacity.
- **Frequency response**: National Grid has recently launched a tender programme for capacity specifically to assist with regulating the frequency of electricity on the network, targeting rapid (seconds) response, for which battery storage is ideally suited. The system frequency must be kept within statutory limits to prevent damage to consumers and businesses, but frequency stability has reduced in recent years partly due to an increase in non-synchronous generation.
- **Voltage stabilisation**: Alongside the range of other services, energy storage devices can assist in regulating network voltage, another critical aspect of the grid system. Storage is typically more versatile than generators at providing this service.
- **Avoiding grid infrastructure reinforcement**: UK DNOs have used batteries as a substitute for upgrading overhead lines and in the right environment this could be commonplace. The Capital costs of the first demonstrator projects are already believed to have reduced in the roughly two years since they were commissioned, and have the potential to offer a significant cost saving to traditional circuit reinforcement upgrades.

By integrating energy storage into the UK's system we can reap the benefits of low carbon energy and reduce the costs associated with this transition. An Imperial College/Carbon Trust report into the benefits of storage discusses the net saving to

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[1] Low Carbon Network Fund, UKPN, Leighton Buzzard Battery, http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/

UK consumers of large amounts of storage on the system, for example a £2billion net saving from 5GW of storage capacity, which rises to £10billion by 2050 in a high renewables system[2].

Many other countries around the world have realised the benefits of energy storage, such as the US and Germany, and installations globally this year topped 1GWh or large-scale storage devices. See the REA's high-level Overview report for full list of other countries' energy storage projects, which can be read here[3]. The UK must develop its market now in order to avoid missing out on the supply chain and investment opportunities this global market offers. For example, some early stage companies are manufacturing in the UK, sometimes through contractors who are active already in other markets (for example Cumulus storage).

Costs of energy storage

The costs of storage are rapidly declining for most technologies. The REA is working with KPMG on a report into energy storage and decentralised energy that includes costs and cost reduction projections, and will send this to the Commission.

It is often stated that there are parallels to be drawn between solar PV and lithium-ion batteries, as costs are reducing at a similar rate. Lithium-ion batteries have come down roughly 16-18% in costs each year for the past five years, with the trend expected to continue. Solar PV costs have fallen by over 75% in the past five years.

The market expects grid scale battery costs to be roughly 50% lower in summer/autumn 2016 compared to the same time in 2015, as supply chains grow and learning rates increase. The REA-KPMG Report will clarify the cost reductions expected in the market.

Barriers to the deployment of energy storage

The Commission will be aware that DECC and Ofgem are examining barriers to energy storage in the UK and we understand the two organisations' work will be linked.

The REA and our members have identified a number of barriers and suggestions for improving the market for storage in the UK, which are summarised below:

Barriers to the development of energy storage in the UK:

- Lack of clear route to market for UK energy storage providers. There is only one public mechanism supporting storage in the UK, the Capacity Market (CM), yet this policy is failing to deliver new energy storage as the past two auctions have proven. We are calling for several changes to be made to the mechanism, which are detailed below.

[2] Strbac et al, 2012, 'Imperial College/Carbon Trust: Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future', https://www.carbontrust.com/media/129310/energy-storage-systems-role-value-strategic-assessment.pdf

[3] REA, 2015, 'Energy Storage in the UK: An Overview', http://www.r-e-a.net/upload/rea_uk_energy_storage_report_november_2015_-_final.pdf

- Application of final consumption levies to energy storage despite this being in clear conflict with the spirit of final consumption levies
- Lack of longer term contractual mechanisms(via either the CM or National Grid mechanisms) creates problems accessing finance, either being completely unavailable, or unavailable at economic rates.
- At the grid-scale level, DNOs are unsure whether they are currently prevented from installing and running energy storage due to the EU market un-coupling legislation preventing them 'putting power back down the wires' (effectively acting as a generator). This uncertainty may deter the development of the distribution network storage market. Consumers could be paying for unnecessarily expensive grid reinforcements when cheaper, more effective storage options exist.
- The position of storage within the UK legal and regulatory framework is unclear. This creates a perception of regulatory risk for investors. It also results in the absence of common terminology, which is a key tool in the development of appropriate market and network rules.
- There is a lack of a common terminology and knowledge in the wider market.
- There is no standard technical guidance or best practice, to prevent 'cowboys' entering the market and dangerous installations.
- No central tracking of installations (especially behind the meter) – this could develop into a problem for the DNOs as there is no central database of installations.
- CfD uncertainty and eligibility and design issues for hybrid systems

<u>Opportunities for overcoming these barriers and developing storage in the UK:</u>

- Provide signals of high-profile Government support to provide investor confidence, potentially in the form of a 2020 capacity target for storage.
- Reform the Capacity Market:
    - Energy storage projects should be eligible for longer term contracts – this should be the 15 years available to new build conventional plants, or at least of seven years in order to offer adequate options for finance. This will enable financeable contracts with lower equity costs leading to greater savings for consumers – enabling more capacity for the same amount of money.
    - Remove the restriction on 'stacking' revenues for energy storage projects – ie allowing these projects to receive income streams from multiple sources and therefore enable more to go ahead.
    - Clarify the time restrictions for energy storage and DSR providers, so they know how long they would need to supply power for. Associated fines for non-delivery should be capped at the minimum required period of supply. Storage projects vary in length in terms of how long they can store and discharge power for but they may not always be fully charged when a request from the SO comes to provide power back to the grid.

  - Storage projects could be further incentivised by allowing higher payments to projects able to provide quicker response times and additional services to the grid such as frequency response.

- Improve access to finance – eg through providing Green Investment Bank finance
- Government should shift their mindset from seeing storage as an collective industry at the R&D stage, to one capable of delivering at scale now via numerous technologies (although some are at other stages)
- Develop support for joint renewable energy / storage deployment. We would be happy to work with Government on policy proposals in this area.
- Set an agreed 'definition' for energy storage in legislation and clarify its regulatory position.
- Amend licence conditions to enable DNOs to install and operate storage
- Develop technical standards and consumer guidance for installing and using energy storage technologies – the REA is working on this at present with a number of partners
- Consider reforms to the CfD mechanism to enable storage and renewable hybrid projects

Conclusion

We look forward to working with the NIC on developing storage in the UK and can provide cost information and market knowledge we hope will be of use.

Energy storage can transition us to a low carbon energy system in line with Government targets and legally binding commitments as well as reducing net costs to consumers. As the price of the technologies reduce rapidly the costs of <u>not</u> taking advantage of the technologies becomes ever greater. If the UK acts quickly it can reap numerous benefits, which extend beyond the energy system, into the creation of new jobs, supply chains and Intellectual Property.

National Infrastructure Commission call for evidence

Regen SW response

January 2016

Summary

Regen SW welcomes the National Infrastructure Commission's call for evidence. This response addresses two of the 'Electricity interconnection and storage' questions.

In the Secretary of State's speech on 18 November 2015 on a new direction for energy policy, Amber Rudd commented, "locally-generated energy supported by storage, interconnection and demand response, offers the possibility of a radically different model." We agree.

Changes need to be made to enable a much more active role for Distributed Network Operators in balancing the system, to make half-hourly metering the standard approach to provide the data needed for smarter use of energy and to ensure price signals drive behaviour to make best use of our energy infrastructure – for example through storage and demand side response.

A more integrated approach to energy is also required through addressing regulatory barriers to enable flexibility on a constrained network to use 'excess' electricity to create another energy vector, such as heat, hydrogen or ammonia.

Many of the changes required are being trialled or worked on by Ofgem and market players. What is now needed is greater impetus and focus on implementing these changes.

Regen SW

Regen SW is an independent, not-for-profit centre of expertise on sustainable energy with frontline experience of working in the renewable energy sector in the south west. We are a membership organisation with over 260 business and local authority members, as well as a network of over 250 community energy groups in the south west and beyond.

Regen SW's response is based on experience of working on the ground with developers and community groups, as well as over a decade's worth of experience supporting the wider renewable energy industry. It also draws on the learning from being closely involved in Work Stream 6 of the Smart Grid Forum over the last two years; from managing a demand side response trial; and from supporting supply chain growth in the smart energy sector.

Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

DECC has set out why better system balancing will minimise the cost to consumers over the long term, including:[1]

- Deferring or avoiding investment in network reinforcement
- Reducing the need for a significant increase in reserve generation capacity

[1] DECC (2015) Towards a Smart Energy System. https://www.gov.uk/government/publications/towards-a-smart-energy-system

- Making the best use of our low carbon generation.

Better system balancing includes: smoothing demand; making renewable generation more predictable; and shifting demand away from peak times and towards times when renewables are generating. There are a number of barriers to the market responding to balancing opportunities. These include:

Access to demand side response (DSR) opportunities: The current market is limited to large scale DSR at the transmission network level. The Distribution Network Operators (DNOs) are not yet using DSR to balance the distribution network on a business as usual basis. And potential smaller DSR providers, such as renewable generators and community energy groups, do not yet have access to the market.

Multiple parties may benefit from DSR opportunities, but action is needed to enable value from DSR and facilitate commercial arrangements. Local flexibility markets are required to enable smaller providers to access opportunities. This would be best achieved by a move from a DNO to a Distribution System Operator (DSO) model. In the interim, we encourage the use of bilateral contracts between the DNO and the service provider. Support will also need to be provided to facilitate DSR providers' entry into emerging and established markets through developing appropriate contractual and product requirements.

Time of use price signals and cost-reflectivity: The full value of DSR is not visible or available to the customer without a time of use price signal. And effective time of use price signals require half-hourly settlement, which is currently not standard practice for domestic and small and medium sized enterprises. Half-hourly settlement will allow a shift in demand to be directly rewarded via the settlements system, whereas today the value is lost in the profile smearing process.

Innovative supply models: New and innovative supply models are required to enable consumers to engage in and benefit from flexibility markets. We have seen various new models come forward over the last year, many of which are at the trial stage and are facing regulatory and commercial barriers.

Local supply models that include local generation and balancing can reduce pressure on the networks and potentially enable more generation to be connected. Regen SW is working with Western Power, Wadebridge Renewable Energy Network and Tempus Energy to trial a Sunshine Tariff in Wadebridge.[2] The project aims to resolve network capacity issues in the local area by incentivising customers to use electricity between 10am and 4pm in the summer months. If the trial demonstrates that the Sunshine Tariff is reliable and consistent in shifting energy consumption to times when solar PV is generating, Western Power will consider enabling new renewables projects to connect to the network where it is technically at capacity.

Another example is the Community Energy Service Company (CESCo) model being trialled by Energy Local.[3] This enables a group of domestic customers to pool their local generation and net this off a single, aggregated demand curve. The aggregated demand is then settled half-hourly to enable them to benefit from moving their use of energy to cheaper times of day and matching it to local generation.

Both of these models are exploring the potential for localised distribution use of system (DUoS) charging and Line Loss Factors (LLF) to reflect that they are using a much smaller proportion of the electricity network. The potential reduction in charges would help incentivise customers to shift demand and provide balancing services. Work Stream 6 of the Smart Grid Forum also recommended that Ofgem explores the trialling of alternative DUoS charging methodologies for networks where there is a high percentage of local generation and local use.

Further work also needs to be done on the viability of local balancing of generation and demand as part of the settlement process. Elexon is exploring the potential for a Local Balancing Unit (LBU) and Energy Local is looking at alternative approaches.

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[2] http://wren.uk.com/sunshine
[3] http://www.energylocal.co.uk/

On a more general note, current trading arrangements generally assume that contractual positions for supply and demand will be achieved at a national or supplier portfolio level. This arrangement doesn't exclude local operators per se, but puts them in a weak position, compared with national operators. Furthermore, the costs associated with setting up and running a supply licence (even 'licence lite') are considerable and partnerships require a third party licensed supplier to deliver services on behalf of local suppliers. Further work needs to be done by Ofgem and DECC on how local supply models can be supported.

2. What are the barriers to the deployment of energy storage capacity?

There are a number of regulatory and commercial barriers that affect deployment of storage within the GB market:

Classification of storage: Storage is not defined in any legislation and is treated as an 'end user', which obliges any supplier operating storage to pay obligations and levies twice: once when electricity enters the storage and again when the electricity reaches the true 'end user'. It is also unclear how storage should be accounted for in Use of System (UoS) charges. UoS charges may be applied when storage charges and discharges, however it is not 'demand' or 'generation'. DNOs need to assess how current UoS charges impact on the viability of storage and whether charging specifically designed for storage is required.

Furthermore, storage is often treated as 'generation', this means that ownership and operation of storage by DNOs is not allowed in the generation licensing regime.

Technology costs: costs of storage, or at least the initial capital cost, are still high and without volumes of scale, costs will not fall. Support is needed in the short-term through the cost reduction phase.

Flexibility market: contracts for balancing services are currently available at transmission network level. However, they tend to be of short-term nature and so do not provide long-term certainty for potential investors. They are also only suitable for large scale or aggregated storage, which can rule out smaller schemes. Contracts at the distribution network level would support growth in the market. This may require a move to a DSO model, which would involve greater distribution system balancing and the introduction of arrangements to enable this to happen.

Multi-vector approach: One approach to providing flexibility on a constrained network is to use 'excess' electricity to create another energy vector, such as heat, hydrogen or ammonia. This is common in other countries such as Denmark where the amount of electricity generated by wind can reach 140% of demand and some of this is stored and used as heat through the countries extensive heat network system.

There are a number of barriers to this. Regulatory challenges include gas quality regulations that may block hydrogen injection into the gas network. It is also not clear whether a DNO could trade heat, hydrogen, ammonia or other vector under current licence conditions.

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National Infrastructure Commission
1 Horse Guards Road
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[08/01/2016]

Dear Sir/Madam,

Re: National Infrastructure Commission – call for evidence

RenewableUK is the leading trade association in the UK in the renewable sector, with over 500 corporate members across all parts of the value chain in the wind, wave, and tidal energy industries. Having the ability to connect renewable energy generation to the electricity network and being able to use those networks cost effectively is very important to our members. It is also very important for the UK's plan to transition to a low-carbon economy.

The electricity networks underpin every facet of modern life, and so when questions are posed which ask how the UK's national infrastructure will develop and operate, then considering the electricity infrastructure is of vital importance. Making the wrong strategic decisions at this point will lock the UK into a much higher carbon emitting future than will be possible to correct for as we move into the 2020s and beyond. A low-carbon future needs a decarbonised electricity sector, and this presents challenging problems when it comes to maintaining the balance between supply and demand.

The renewables which we need to make up the bulk of the decarbonised electricity sector are historically more variable in their output than conventional fossil fuelled generation. This is changing, with new offshore wind turbines forecast to operate at a capacity factor of 47.7%[1], and with onshore wind farms operating at above 30%, broadly in line with the capacity factors for gas plant[2]. Maintaining the balance between supply and demand on an hourly or on a second-by-second basis, however, will still require National Grid, as the GB System Operator, to have much more access to balancing and ancillary services. We support the development of these services from renewable sources in ways which are fair to both providers of the services and to consumers, who are ultimately paying for the services.

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[1] The Renewables Obligation for 2016/17, p. 7:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/464685/Renewables_Obligation_Level_Calculations_for_2016-17.pdf
[2] DUKES 2015 report, p.143:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/450302/DUKES_2015.pdf

4.1 What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising costs to consumers, over the long-term?

The UK has legislated for Carbon Budgets[3] via the Climate Change Act 2008, and it is clear that if we are to meet these targets, renewable generation will be a significant part of the generation mix for the foreseeable future. The Committee on Climate Change's recent paper on power sector scenarios up to 2030[4] shows contributions of renewables of 45-55% of the generation mix for the scenarios where the carbon intensity is under 100gCO_2/kWh, with the variable technologies of wind and solar making up 35-45% of the mix by themselves. It is therefore clear that the electricity network will have to operate in a radically different paradigm than the one in which the network was originally conceived and built. Balancing the system in the long run will mean the application of many different forms of technology than those used in the main today.

The challenge faced is two-fold: firstly, it is to have the right physical infrastructure, so that power can be generated, stored, transmitted, and shifted in the most efficient manner possible; secondly, it is to have the right legal and regulatory environment for the grid of the future, where charging and operation are fairly dealt with as the system evolves.

We believe that there is no need for the National Infrastructure Commission to propose any reforms to the Balancing Mechanism (BM), as the reforms to the way that imbalance prices are calculated in the BM, which were put in place by the Electricity Balancing Significant Code Review (EBSCR)[5], have yet to come fully into force[6]. These reforms, which are primarily to what is known as the 'cash-out' price, will have far-reaching effects on the actions taken by parties to maintain the balance between supply and demand.

The key outcome of the EBSCR reform is to begin a move, not yet fully implemented, to make the cost to a BM Party for being 'out of balance' against the system the same as the cost of the most expensive MWh which National Grid has to purchase to correct that imbalance. Prior to the EBSCR, the cost to BM Parties was the volume weighted average cost of the most expensive 500MWh which National Grid had to purchase through the BM to correct the system. This had the effect of diluting the cost of the most expensive – and therefore most critical – grid balancing actions, disguising the true value of the services which offer the needed flexibility to National Grid, an issue known as the "missing money" problem.

The transparent and market based price which will result from the full implementation of the EBSCR will be a key signal to those service providers who can most efficiently and cheaply increase system stability. We suggest that the effects of the EBSCR reforms should be allowed to run their course and to be tested in the market before any further market based reforms to the BM are initiated.

However, if the National Infrastructure Commission considers the term "balancing market" to encompass both the Balancing Mechanism and the set of Ancillary Services which National Grid procures for the purposes of ensuring system stability, then we support further reforms to the "balancing market". National Grid's recently launched System Operability Framework[7] has fired the starting gun on what will be a marathon race to develop and bring to market new and innovative solutions intended to balance the system. New solutions may very well require new market access routes to be opened up and will doubtless need an open mind on the part of regulators in order to accommodate technologies which may be round pegs for what are today square holes.

The renewables industry will participate as fully as possible with the developing balancing markets in order to access new and existing revenue streams from the provision of Ancillary Services. As the provision of flexibility through balancing services becomes as much a part of project revenue as the

[3] https://www.theccc.org.uk/tackling-climate-change/reducing-carbon-emissions/carbon-budgets-and-targets/
[4] https://www.theccc.org.uk/publication/power-sector-scenarios-for-the-fifth-carbon-budget/
[5] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review
[6] https://www.ofgem.gov.uk/sites/default/files/docs/2015/04/p305d_1.pdf
[7] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

provision of electricity, consumers will save money in a market which is more stable, which requires less network reinforcement, and which avoids the costs of building expensive and dirty peaking plant.

In order to manage the transition to an energy infrastructure in which flexibility plays as big a role as the electricity itself, we support the consideration of a move to create an Independent System Operator (ISO) role in the UK, which would have the responsibility to maintain system security.

We hold that the costs of Capacity Adequacy are not solely the responsibility of the renewables sector to shoulder. It is the case that an individual wind farm will be more volatile in its output when compared to a CCGT plant across a given period of time; however, it is also the case that system imbalances are caused by myriad factors, and the prevalence of renewable power on the system is but one of them. We call attention to three things which support the view that renewables do not disproportionately imbalance the system, and indeed they both play their part and are poised to contribute more to system stability:

- The first thing to note is the Notice of Inadequate System Margin (NISM) which was called by National Grid on 4 November 2015[8]. Whilst the system maintained its stability across the length of the NISM warning period, the volume of generating capacity to which National Grid had access over this time became very small, and with such a tight margin the safety valves, if not exactly opened, certainly had a tensed hand poised on the spigot. 35% of the coal fleet was unavailable to generate during the NISM, compared to the 12% which is National Grid's working assumption for such periods, and the IFA Link Interconnector was under repair during this time. The contribution of the wind industry to this particular tightening of margin was merely one component amongst many of that day's issues.
- The second thing to highlight is that the renewables sector is already fully exposed to costs in the BM, like any other generator. The costs of system and energy balancing actions fall on wind and other renewable generators in the same way as they apply to conventional plant. The renewables sector contributes to the operations which ensure system security in a fair and open manner.
- The third thing to note is that the costs of Frequency Response services are socialised across all market participants in much the same way that Capacity Adequacy costs are socialised across all market participants. National Grid must pay for access to a minimum volume of power in order to manage the risks to the system from the largest single in-feed loss. It is the scale of this largest potential drop-off from the supply side which drives the cost of procuring Frequency Response services, and these scales have long been set by nuclear and conventional generators. It is not the case, however, that these large generators shoulder the burden of the procurement of Frequency Response services – rather, the costs are shared amongst market participants. It is with reference to this state of affairs, therefore, that any considerations regarding the assignment of Capacity Adequacy costs to the Renewables sector must be framed.

4.2 What are the barriers to the deployment of energy storage capacity?

The electricity network has historically been about moving power from controllable, centralised plant to remote and passive consumers. This paradigm is changing radically, with a growing volume of our generation fleet dependent on the availability of natural resources such as wind and sunshine, with much of our conventional generation fleet aging and needing to be replaced in the near future, and with an increasing number of consumers playing an active role in the balancing of the system.

Renewables pose a particular challenge to the development of a modern grid as they are both further away from and closer to demand than traditional generators. The best renewable resources tend to be where people are not. For instance, commercial scale onshore wind tends to be built in Scotland, and offshore wind is built, by definition, some distance from population centres. On the other hand, as

[8] https://sandbag.org.uk/blog/2015/nov/5/coal-too-old-be-useful/

renewable resources are to an extent available everywhere, there can be installations where people live and work. Tidal lagoons, for instance, present an opportunity for reliable and long term renewable energy generation at scale close to population centres. The network of the future has to cater for the huge growth in Distributed Generation (DG) and 'prosumers'.

This leads to the need to invest both in large transmission assets, including interconnectors with other markets, and in the distribution networks, particularly in 'smartness'. Due to the technological and business change that is ongoing, it is not clear which investment route will be the optimal one, and so there is the possibility that we will overinvest in some assets. We should be clear that investing in networks which facilitate multiple options when we are not sure which options we will prefer is a rational approach, and therefore we should not be paralysed from action by the risk that some of these actions may lead to assets becoming 'stranded'. Assets can always be reused, and economic signals can ensure that any underutilised portions of the grid can become targets for new connection customers.

Storage will be a key component, alongside Demand Side Management and Distributed Generation, of the smart grids needed to manage the non-traditional flows of electricity on the grid of the future. To generate when the natural resources are most abundant, to store as much unconsumed power as possible, and to call on that stored power at night, or when the wind isn't blowing – this will be the new paradigm. It should be a simple proposal to install storage at or near to the sites of renewable generation, so that power can be fed onto the grid in a more constant flow, increasing and decreasing output as need arises with zero fuel cost, but it should be noted that this is only one of a myriad of different approaches to the use of storage.

However, storage is not a homogenous mass – there are many different types with many distinct characteristics. Batteries, tidal lagoons, and pumped storage – amongst others – may offer the ability to provide flexibility and ancillary services. The priorities of the codes and the legislation governing the electricity industry are not clear on the issue of storage, on how it is to be handled, on how it is to be charged, and how it is to be supported. For instance, only projects of a single technology class can bid at any one time for a Contract for Difference (CfD), meaning that a wind farm which installed batteries to store and deliver its renewable power to the market would be classed as being composed of two different technology categories and would be ineligible for support. Allowing hybrid projects to bid for CfD contracts would immediately open a huge market for storage facilities by facilitating innovation in and broadening the scope of technologies such as tidal or from the development of hybrid wind projects.

Work Stream Six[9] (WS6) of Ofgem's Smart Grid Forum recommended that the regulatory treatment of storage be clarified, and that National Grid investigate the scope for standard contracts for multiple service provision (services to DNOs, as well as to the SO). WS6 also recommended that the 'heat maps'[10] produced by DNOs to illustrate where their networks are stressed should contain more information in order to facilitate the creation of new services. An understanding, for instance, of the amount of available capacity in a locality could help to direct a nascent storage provider to the most appropriate, and most valuable, sites.

With regards to arranging for storage to connect to the grid, at present there is a risk that grid capacity will be reserved for either storage or generation, leading to only one being able to connect, when in reality they would use the same capacity and together provide more flexibility to the system. The actions of storage have yet to be defined by Ofgem, and 'behind the meter' actions should be fully integrated into the relevant subsidy mechanisms. Better recognition for the benefits of the capabilities of storage in the codes and regulations governing the electricity industry, and a fuller appreciation of where the value of storage lies in the subsidy schemes affecting the electricity industry, are the first stages to lifting barriers for storage in GB.

[9] https://www.ofgem.gov.uk/electricity/distribution-networks/forums-seminars-and-working-groups/decc-ofgem-smart-grid-forum/workstream-six-ws6-commercial-and-regulatory-issues

[10] For instance, Northern Powergrid's Generation Availability Map: http://www.northernpowergrid.com/generation-availability-map

4.3 What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnectors are a TSO–TSO operation, meaning that the right interconnection to the right extra-GB system can help to reduce network reinforcement costs in GB and help to reduce the need for building expensive baseload or peaking plant. As the volumes of interconnection rise, the GB electricity market will develop stronger couplings to the electricity markets of the Continent. When the wind is blowing and power is cheaper and plentiful in GB then interconnectors should facilitate access to a much larger market for that power. For the UK consumer, more closely coupled markets will increase competition and result in cheaper electricity when prices on the Continent are lower.

We are supportive of interconnectors for the following reasons:

- **Balancing wind output.** As a variable technology, the generation of electricity from wind will not always correlate with demand. Interconnectors allow excess wind supply to be sold when system or energy limits would otherwise prevent this.
- **Reducing price volatility.** The capacity to export could help to reduce the wholesale price depression associated with high wind output, which would benefit generators supported by the Renewables Obligation and Feed-In Tariff schemes and reduce the need for further (consumer funded) support for renewable generation through the CfD.
- **Reduction in cost of Transmission Reinforcement.** An interconnector from Scotland to Norway may be a better investment than transmission network upgrades along the East Coast of GB or elsewhere, considering the related cascade of upgrades such a reinforcement may require. Power would flow to where it could most cheaply and efficiently be either stored or used. Interconnectors may reduce, or in some cases obviate, the need for Transmission Reinforcement work.
- **Transmission bottlenecks might be avoided.** A connection from Scotland to Ireland and back again into England may be a better way to flow electricity around current north-south bottlenecks. Filtering energy into Continental markets, as a form of storage, may also be an efficient way to manage north-south bottlenecks.
- **Service Provision.** The Moyle interconnector is bidding into the Enhanced Frequency Response scheme. This serves as an illustration for the possible Ancillary Services which may be provided by interconnectors.

The correct level of interconnector development in the market will depend on the direction in which the GB electricity market wishes to take in the near future. Consumers in GB will best be served with the cheapest and most stable access to electric power. Weighted against transmission upgrades, investments in new capacity, and the need for greater flexibility, interconnectors should be considered as a viable option where they contribute to the more efficient use of carbon-free power.

It is clear that the benefits obtained by building interconnectors are not geographically consistent. For instance, constructing links to Norway will offer the UK access to qualitatively different forms of resources and will provide qualitatively different benefits than would another link to France. The value of an interconnector is related to the make-up of the generation in the connected market. The Norwegian market contains a lot of flexible hydro power resources, which would offer a convenient place to "store" electricity generated from renewables in the UK when demand is low and generation is abundant. The French market, on the other hand, consists to a high degree of inflexible nuclear generation, offering little of the flexibility which the UK market needs. We recommend that the Commission considers carefully the full range of benefits associated specifically with each new interconnector investment before investment decisions are made.

The use of interconnectors in the UK market also, it should be noted, puts European generators at a competitive advantage, as non-UK based generators are not liable for Transmission Network Use of System (TNUoS) charges. To take an extreme example, were 100% of UK demand to be met via interconnectors, then UK generators would still bear 27% of the costs of operating the networks transmitting that power, even though all the generation was happening abroad, by plant at a price advantage. UK based generators should not subsidise the systems costs for generators selling into the UK via interconnector flows. We recommend that this market asymmetry is addressed alongside any planned interconnector development.

It should be stressed as well that interconnectors should not be regarded as a method to reduce greenhouse gas emissions in the UK, and that they are not an inherently low carbon source of power. Whilst interconnectors have a place in the power industry, the power which they provide is not necessarily carbon-free, coming as it does from the interconnected Continental market in which many sources contribute to the power imported to the UK. Power generated in the UK is more efficient, facing less transmission loss, and creates greater economic value here. These beneficial physical characteristics possessed of local generation should be taken into consideration when developing new interconnector schemes.

4.4 What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The Single Electricity Market (SEM) which links Northern Ireland and the Republic of Ireland is a good example of a grid restructuring to accommodate renewables. "[It] is a small moderately isolated system in which individual power stations are large and lumpy relative to peak demand (up to 10%) and the system is being adapted to handle up to 70% non-synchronous wind penetration."[11] On a truly islanded grid, Eirgrid are creating a system which will handle the largest percentage penetration of variable generation in Europe. They are having to innovate rapidly in order to deal with system inertia issues, voltage instability, and Rate of Change of Frequency (RoCoF) problems with a large fleet of non-synchronous, non-inertial generation. Eirgrid are quadrupling their Ancillary Services budget, and by the start of the 2020s they expect around half of a generator's income to come from Ancillary Service payments and Capacity payments[12].

The UK and the SEM electricity markets are settled in 48 half-hourly settlement periods per day, this being the level of granularity available for most balancing services, and the level at which the Day Ahead Market can react to system conditions. Most Continental markets employ 15 minute settlement periods in their Balancing Markets, providing a greater level of flexibility in how and when services are able to dispatch to respond to system stress, though Day Ahead Markets are at hourly granularity. The Australian electricity market operates with 5 minute settlement periods, allowing greater flexibility still, and the Californian markets are looking at emulating this.

Denmark gets 37.5% of its power supply from wind, with this share expected to grow to 50% by 2020. The Danes have set a target of full conversion to renewable energy by 2050[13].The Danish Energy Agency posits that with long term planning and a stable and supportive policy framework, the implementation of large scale wind integration is feasible at both transmission and distribution level. The Danish Wind Turbine Certification Scheme[14] was established in 2008 to establish the technical specifications[15] of wind turbines which wish to connect to the Danish grid, in light of the fact that the increased volume of renewable power has displaced many large generators and thus the system services which such large stations typically provided. In GB, the Grid Code specifies the required capabilities of connected generators, but defining the requirements for storage, and opening the market in GB to DSR, will become increasingly important in the years ahead. Denmark uses interconnectors with Norway and Sweden to balance wind generation with hydro power availability. When the wind blows, power is exported along interconnectors, reducing the draw on hydro reserves, and when the

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[11] P.5 Missing Money and Missing Markets: http://www.econ.cam.ac.uk/research/repec/cam/pdf/CWPE1513.pdf
[12] See slide 49 of the System Operability Framework launch event slides, under 'SOF Launch Event': http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/
[13] Danish Energy Agency – Energy Policy toolkit on System Integration of Wind Power: http://www.ens.dk/sites/ens.dk/files/climate-co2/low-carbon-transition-unit/danish-energy-policy-toolkits/system_integration_of_wind_power.pdf
[14] The Secretariat can be found at: www.vindmoellegodkendelse.dk
[15] The technical specifications can be found at: www.energinet.dk

wind calms, the stored hydro power is exported back into Denmark. This is a model which the UK should pay more attention to, especially with the GB interconnectors due to double in capacity. Denmark's Energinet is also undertaking an R&D project aimed at demonstrating the potential for domestic heat pumps to store energy generated by wind sources at times when demand is low and supply is high[16]. The concept, a component of Energinet's 'Smart Grid' programme[17], serves to illustrate the potential for heat stores to manage wind generation.

The Australian National Electricity Market (NEM) has no concept of 'Gate Closure', with prices set every 5 minutes. Whilst there is an argument[18] that moving to a more transparent, close to real-time central dispatch model would bring about benefits to competition, such shorter imbalance periods would certainly open up the Balancing Mechanism to new players, such as DSR providers who could more fully participate by shifting demand for periods of time much shorter than the current 30 minute long periods of the BM. The similar experiences of ERCOT and Nordpool should also be considered here.

Yours Sincerely,

Eamonn Bell
Policy Manager – Networks and Systems

For further information please contact:

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Email: [email address redacted]
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[16] http://www.energinet.dk/EN/FORSKNING/Energinet-dks-forskning-og-udvikling/Sider/Fra-vindkraft-til-varmepumper.aspx

[17] https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/Forskning/Smart%20Grid%20in%20Denmark.pdf

[18] See paragraphs 22/23: https://assets.digital.cabinet-office.gov.uk/media/54f44a7be5274a145200000b/Wholesale_electricity_market_rules_working_paper.pdf

Appendix – Skills

RenewableUK supports the development of the skills needed for the UK to thrive and prosper into the 21st century and which will hasten the achievement of the Government's carbon reduction targets. Leadership at the Governmental level can drive the realisation of what should be a vital element in the development of our national infrastructure: talent.

If the Northern Powerhouse is to actually drive enhanced economic opportunity, and if the energy networks of the future are to live up to our expectations of how we will live in a post-fossil fuel world, then we strongly suggest that the National Infrastructure Commission takes the lead in incubating the talent and ability of our workforce as a central plank of the future productivity of the UK. In order to support the many thousands of jobs which the industry has the potential to support[19], RenewableUK proposes the following skills policy recommendations, on behalf of the industry, as outlined in the Skills Manifesto[20]:

1. A long-term vision for the sector's deployment to incentivise growth – the industry's ability to invest in long-term strategic skills initiatives requires confidence in Government's commitment to the future of the sector.
2. A national Government-led skills strategy – the Government should take a lead on skills initiatives by implementing a national, Government-led strategy to anticipate future requirements and opportunities. An underpinning national skills strategy is necessary for this.
3. Funding centrally channelled to meet needs – the Government should ensure skills funding is co-ordinated, planned, and based on evidence of need to ensure transparency, minimise duplication, and maximise opportunity for all.
4. Encouraging study in key areas through financial incentives – a reduced fee structure and financial contribution to academic institutions in recognition of the increased costs involved in providing key courses to reflect UK skills demand and help incentivise course uptake.
5. A flexible approach to visa restrictions – where national shortages of skilled employees exist, UK employers need the flexibility to import labour.
6. A consistent UK approach to funding – funding for skills initiatives should be consistent across national borders.
7. Attracting women into STEM subjects and careers – Government and industry should work to attract women to the workforce for the continued success of the sector.
8. Clarity on the wider anticipated skills supply – the Government should clarify and communicate future workforce resource to provide a picture of the wider cross-sector skills supply currently being nurtured.

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[19] Working for a Green Britain & Northern Ireland 2013-2023, September 2013, Cambridge Econometrics, commissioned by RenewableUK and Energy & Utility Skills:
http://www.renewableuk.com/en/publications/index.cfm/working-green-britain

[20] Skills Manifesto, September 2013, RenewableUK:
http://www.renewableuk.com/en/publications/index.cfm/skills-manifesto

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08 January 2016
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Dear Sir/Madam

RES Response to: National Infrastructure Commission call for evidence

RES is one of the world's leading independent renewable energy developers working across the globe to develop, construct and operate projects that contribute to our goal of a secure, sustainable and affordable energy future. RES has been an established presence at the forefront of the wind energy industry for over three decades. Our core activity is the development, design, construction, financing and operation of wind and solar PV projects and we are also active in electricity storage, DSM and transmission. Indeed, we have this week announced our first UK battery storage project, drawing on our experience in this sector in the US and Canada. Globally, we have built approximately 10GW of renewable energy generation, including approximately 10% of the UK's current wind energy capacity.

We consider ourselves well-placed, therefore, to comment on the important issues addressed in this consultation and welcome the opportunity to respond. We would also urge the NIC to consider, under its remit and in further consultations, a broader examination of the energy sector and how to stimulate the necessary investment in the generating infrastructure needed in the transition to a decarbonisated energy system. We hope you find our comments below of interest and will be more than happy to assist with any further information as required. The key points we would like to make are:

1. By allowing mature low-carbon technologies continued access to the electricity market, it is possible to balance supply and demand whilst minimising cost to consumers and achieving decarbonisation objectives. Based on the recent CfD Pot 1 clearing prices, onshore wind and solar, with system integration costs, remain the cheapest form of low-carbon generation technology and expected cost reduction will make them the cheapest generation options in the UK.
2. Further reform of the electricity market is required to provide a fair and competitive route to market for these technologies but the complexity should not be overestimated and this requires a clear strategy for a smooth transition.
3. Flexible demand side response (DSR), electricity storage and international interconnections are no-regret options for consumers and should be pursued aggressively, providing benefits of £2.9bn independently of the energy mix.
4. Rapid resolution of the barriers to market for storage is required in order to provide multiple routes-to-market; this includes facilitating commercial deployment of battery storage for ancillary services today.
5. Interconnector benefits significantly increase with regional cooperation on security of supply so without this the UK will not accrue the full value of the benefits of interconnectors, increasing the importance of alternative forms of flexibility (DSR & storage)

Yours faithfully,

Alex Coulton
Senior Policy Analyst, RES Western-Europe
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T : [phone number redacted]
M :[phone number redacted]

National Infrastructure Commission call for evidence

Framing the discussion

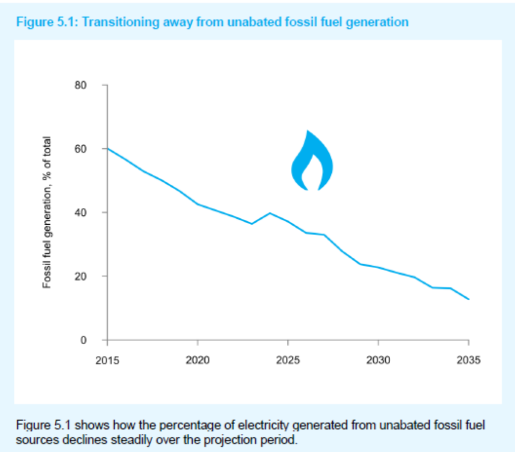
The government has committed to '*guaranteeing [consumers] clean, affordable and secure energy supplies*'. This creates two boundaries within which the government and its infrastructure policy and programme must operate:

1. Security of supply and the provision of uninterrupted energy to consumers
2. Decarbonisation, which is a decreasing carbon intensity of the power sector

Although a clear limit on decarbonisation is yet to be established through the implementation of the 5th Carbon Budget, it is emerging that the market is already accounting for decarbonisation risk. Indeed our internal estimates of unabated gas LCOE based on commercial commodity prices are in the range of £55-65/MWh. However, Trafford developers announced that they could not secure finance for installations with an LCOE below £72/MWh[1]. We expect that the impact of the decarbonisation agenda on plant load factors, operating life span combined with the expectations of competitive low-carbon technologies are now being factored into financiers' decisions. The recent COP21 only consolidates unabated fossil fuel generation limits and the risk of financing such plants.

In this regards, there is sometimes a fundamental misunderstanding from stakeholders that an increase in the LCOE of unabated CCGT plant is caused by variable renewables generators. Wind and solar PV deployment are an emergent property of our decarbonisation imperatives and it this the decarbonisation agenda that requires unabated fossil fuel generation to be reduced over time. Thus even in a heavy nuclear scenario, the utilisation rates and life span assumptions of unabated CCGT must decrease in as carbon emissions are squeezed out of the system.

Figure 1 provides an illustration of the implications of the decarbonisation boundary on fossil generation in the build up to 2020. Although the exact boundary illustrated here might be up for debate, the fact that a boundary exists is indisputable.



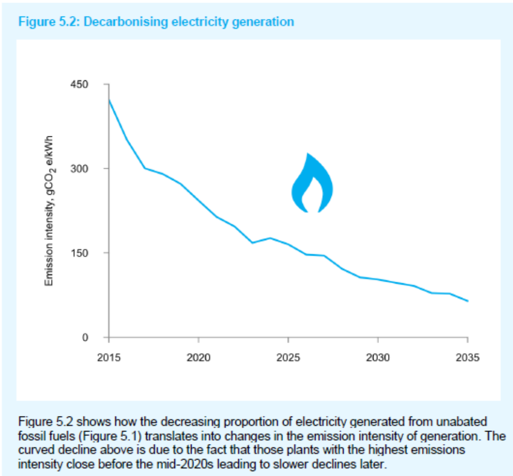


Figure 1 – Illustration of the implications of a 100g Co2e/kWh by 2030 target on unabated fossil fuel generation[2]

By 2030 the Committee on Climate Change (CCC) estimates that the UK will require more than 202TWh per year of new generation.[3] Of this,178TWh per year must come from sources other than unabated fossil fuel fired generators. Looking at the known cost data, we can build up a 'snap shot' of existing technology options for the UK, see Figure 2, that clearly highlights technology priorities required to deliver affordable power.

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[1] Blow to UK energy plans as new gas plant in doubt, the telegraph, 11/10/15 http://www.telegraph.co.uk/news/earth/energy/11925444/UK-energy-crisis-Trafford-gas-plant-in-doubt.html

[2] DECC's 'Update energy and emissions projections 2015' report, https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2015

[3] Power sector scenarios for the fifth carbon budget, CCC, 2015, https://d2kjx2p8nxa8ft.cloudfront.net/wp-content/uploads/2015/10/Power-sector-scenarios-for-the-fifth-carbon-budget.pdf

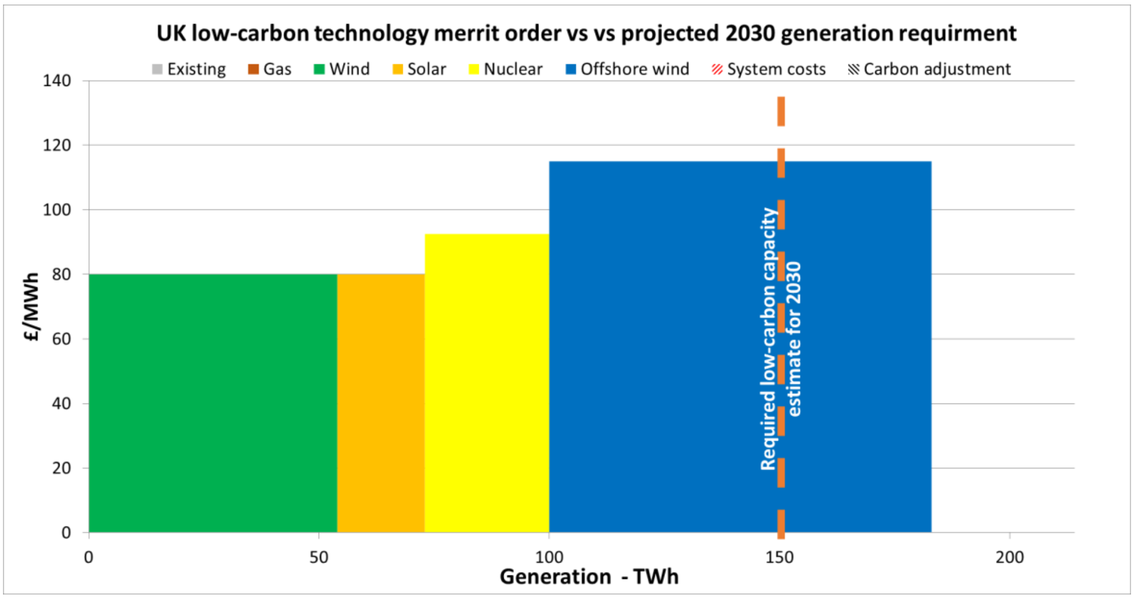

Figure 2 – Illustration of a snap-shot of the UK's low-carbon technology merit order respecting deployment limitations linked to site availability and system integration

Amongst the most affordable low-carbon technologies we can see significant levels of variable renewables. As we see, the inevitable retirement of traditional generators and the capacity adequacy concerns around the reliability of these technologies has increased. Part of this response therefore touches on the need for ongoing reform of the electricity market so that system integration costs can be better accounted for.

It is also important to highlight that increased flexibility on the system from flexible technologies[4] is a no-regrets option. Indeed, the CCC analysis highlights benefits of between £2.2bn to £2.9bn to the consumer exist even with limited decarbonisation ambitions. Importantly, benefits increase with greater variable renewable energy penetration, which makes the deployment of flexible technologies a priority.

4. Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The electricity market is not a single market but multiple markets and these are in constant state of flux in order to respond to changing policy imperatives and technological innovation and disruption.

Within the electricity market the wholesale market has been depended on as a generation dispatch mechanism as well as a mechanism to stimulate capital investment. Today the wholesale market is a demonstrably and exceedingly efficient dispatch mechanism, so much so that ongoing transformation of the power sector, from changes to the generation mix to the smart revolution, mean that it can no longer deliver the investment required for the scale of new-build generation the UK needs. It is widely recognised, including by government, that the wholesale price is not currently an adequate investment signal for the procurement of any new energy generating infrastrucure.

For the foreseeable future, the scale of new-build generation required to meet projected demand and replace retiring plant must therefore be procured by Government. To address market failures and deliver a more cost-efficient and cost-reflective electricity market the previous Government therefore delivered three critical market reforms: the Capacity Market, the Contract for Difference and the Electricity Balancing Significant Code Review[5].

[4] In this report flexible technologies is used to describe flexible demand response, electricity storage and International interconnections
[5] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review

Continuing the reform

We believe there is a need to move towards a truly technology-neutral competitive mechanism as soon as possible. This would meet government objectives of affordability, security, decarbonisation and also true competitiveness but requires further reform to the electricity market. For instance, different technologies have different system integration costs and carbon emissions and these real costs need to be taken into account in the design of technology-neutral auctions to achieve true competition. Critically, internalising the system integration costs to the cost of each generator means that all generation becomes reliable capacity and this creates an overlap between the CfD and CM mechanisms. As the CfD and CM overlap, reform will be required and it also becomes necessary to create a means to deliver investment in flexible back-up generation for variable renewables. At the moment, we feel this might be best achieved through adjustments outside the Capital Investment Market, see Figure 3 for an illustration of the transitional requirements.

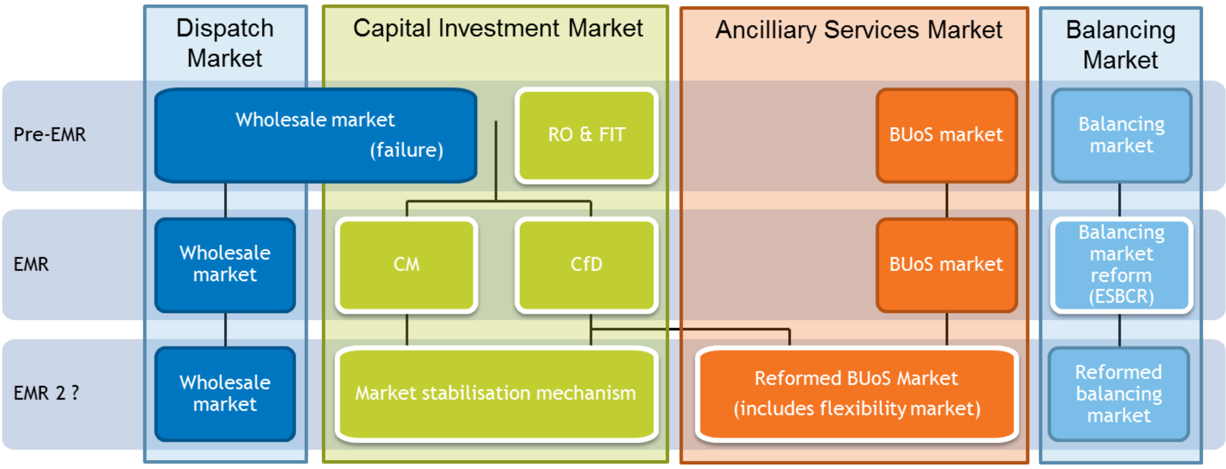

Figure 3 - Illustration of electricity market structure, recent reforms and possible future structure. The extent of reforms illustrated in the EMR 2 phase is significant and requires an extensive, structured and evidenced based policy development process with broad stakeholder engagement.

The complexity of such broad reforms should not be underestimated. With a concerted and cooperative approach we believe Government might be able to deliver these by the end of this Parliament and the RES group is willing to help champion this work to ensure as speedy delivery as possible.

Securing a cost-effective future

During such a complex and lengthy process, outcomes are highly uncertain and this is even more so because our proposed reforms does not fit simply within the European Commission's State Aid guidelines.

Government cannot therefore guarantee a rapid implementation that will support continuous investment, maintain a high level of investor confidence and support the evolution of market participants without clear transitional arrangements. Additionally the scale of the new low-carbon generation requirements to meet our 2030 ambitions should not be underestimated.

We therefore firmly believe that, in the name of cost-effective infrastructure growth and affordability, continued and controlled investment in mature low-carbon technologies must continue. Fortunately, the competitive CfD mechanism has proven to be effective at delivering new capacity at lowest costs. Broader electricity market arrangements are also adequate today to support controlled investment in mature low-carbon technologies without creating significant, if any, risk to or impact on consumers and broader government ambitions.

Because of the changed role of the wholesale market, we cannot understate that without a Capital Investment Market (see figure 3), continued investment necessary to maintain essential skills, experience and diversity within the mature low-carbon sector will be lost before the transition can be achieved and this will come at significant cost.

We believe the NIC therefore need to push for regular annual mature technology auctions to be announced as soon as possible, thus allowing stakeholders to focus policy and regulatory capital on EMR 2 reforms. We could potentially see a role for the NIC in the running of annual allocation rounds, thus allowing DECC to focus on these reforms.

Ensuring short-term cost effectiveness – the system integration cost (SIC) question

In order to continue investment under the current CfD framework it is important that we are certain of the real cost of different technologies so that the Government procurement decision through the CfD truly delivers to the Government's manifesto commitments of keeping bills *'as low as possible*' and '*cutting carbon emissions as cheaply as possible'*.

The conclusion of our analysis is that the burden created by variable renewables on the system is relatively small and mature renewables procured through the future CfD rounds will remain lowest cost. The Committee on Climate Change's 5th Carbon Budget power sector annexes provides the most up-to-date data on the SIC of low carbon technologies. This work correctly identifies that:

- The system integration costs vary with the energy mix and installed capacity of a specific technology.
- The only cost that is not internalised to the cost of generation is the cost of back-up generation.
- It is possible that other internalised costs, such as system operation costs (dealt with through the balancing and ancillary markets), might not be perfectly distributed.

This analysis does not, however, break down these various SIC. We understand that the majority of the costs are associated with the need for back-up generation and have therefore ignored this for now. Figure 4 is an extrapolation of the CCC's SIC data that illustrates the range and increase in SIC with installed capacity. This highlights that SIC remain below £10 per MWh penetration levels of solar below 20GW and wind below 40GW.

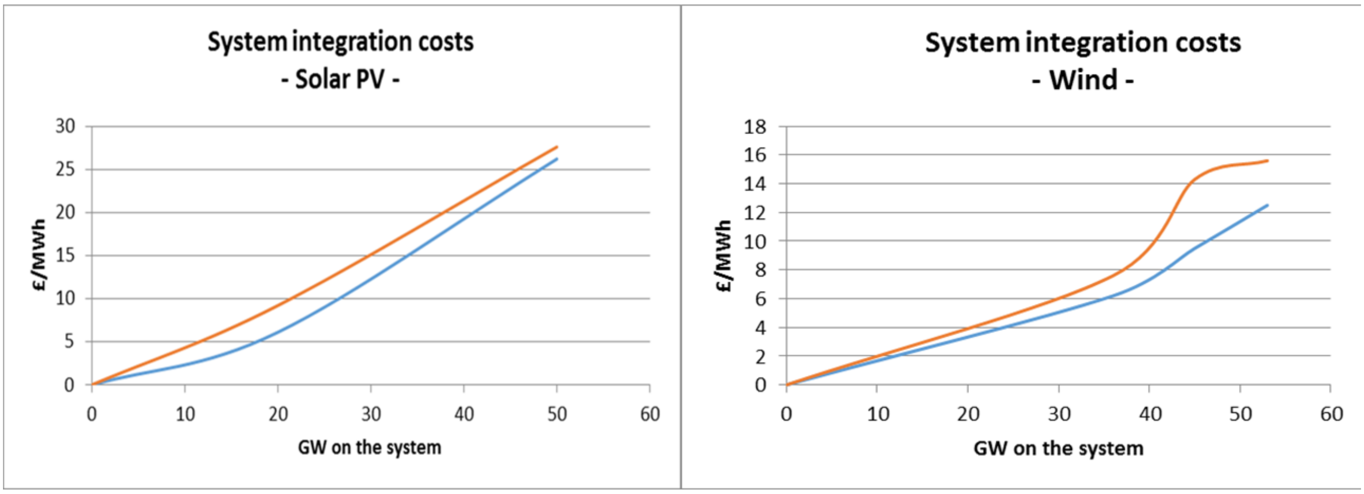

Figure 4 - Upper and lower boundary of SIC for different levels of penetration as defined by Table 3.1 in the CCC Power sector scenarios for the fifth carbon budget 2015.

In figure 5 we therefore investigate this by applying the SIC adjustment to the £82/MWh clearing price of the 1st Pot 1 CfD auction, including known lifetime benefits for consumers, resulting in a ~£85/MWh or additional ~£3/MWh above the clearing price.

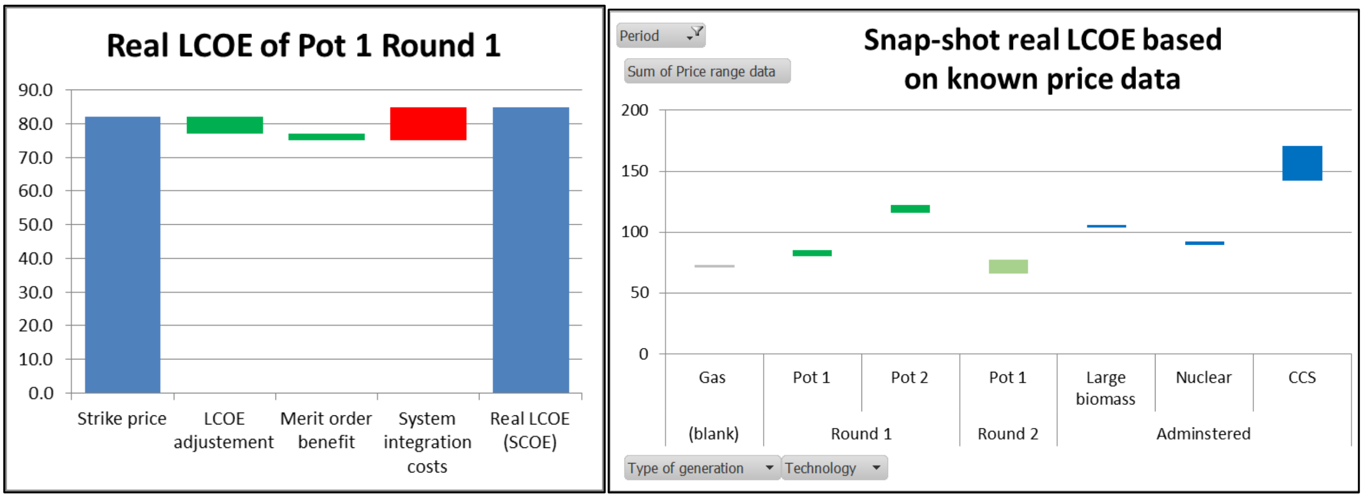

Figure 5 – On the left, adjustment of the pot 1 clearing price to get the real LCOE and on the left plotted against the real LCOE of known price data points, including estimates based on expected range for pot 1 round 2 clearing prices.

This evidence demonstrates that mature technologies allocated competitively through the CfD are the lowest cost low carbon generation technologies and represent no-regret investments for consumers. We also believe that another allocation round, that does not overlap the RO closure period, will yield clearing prices around £70/MWh which on a real LCOE cost comparison would make these technologies the cheapest available generation sources accessible to the UK and an invaluable benchmark to support any further procurement of nuclear power plants.

Figure 6 is an illustration of a snapshot of the entire UK's technological merit order reflecting 'real' costs and deployment limitations.

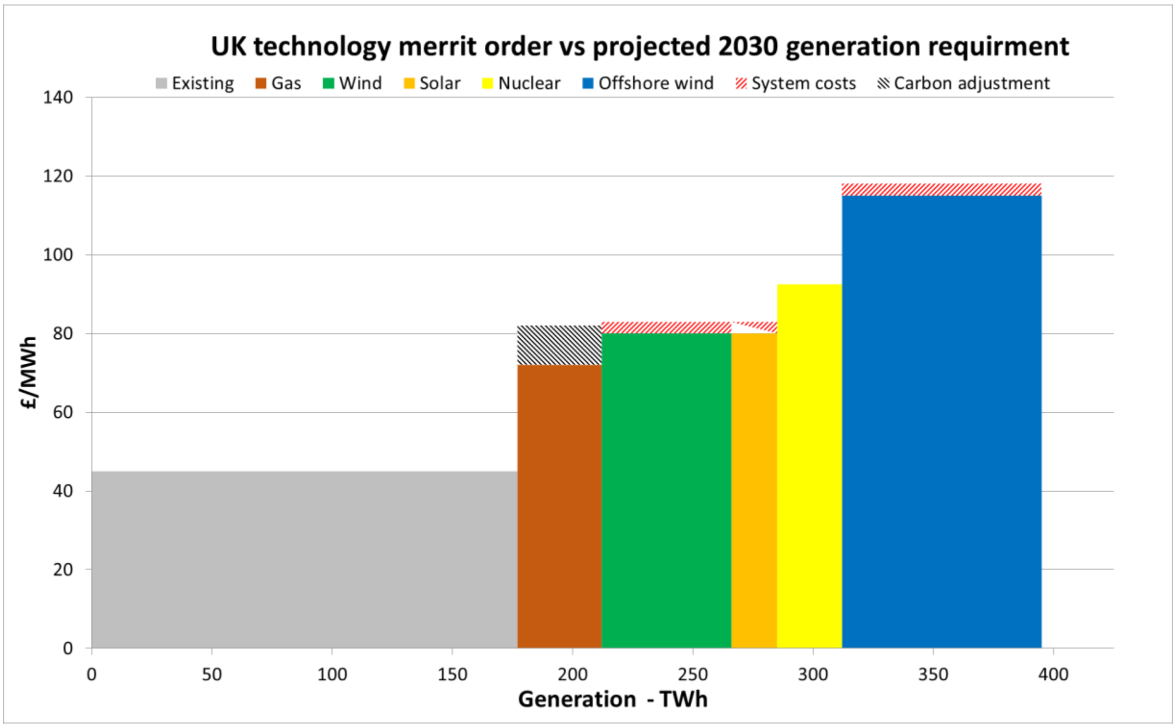

Figure 6 – Illustration of a snap-shop of the UK technology merit order based on known price information and adjustments for real LCOE against generation requirement data for 2030 in line with the CCC report

With minor tweaks to the current CfD framework today we therefore believe that limited allocation of Pot 1 CfDs can continue with no risk to consumers and meet Government commitments.

- **What role can changes to the market framework play to incentivise this outcome:**
    - **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**

We believe that the NIC has not quite pin-pointed the correct starting point for their investigation which feels influenced by large suppliers and generators.

The changes and reforms that have been undertaken and continue to be required are driven by the radical changes in the technologies that are fueling the energy transition towards a secure decarbonised power system. This transition is marked by two very distinct features:

- It takes place primarily at the distributed level not the transmission level.
- It includes significant penetration of variable renewable generation.

We believe the building blocks to an efficient decision around the status of the system operators are twofold:

- An investigation into the cost-effectiveness and adequacy of the ancillary services market in light of the ongoing and future changes to the market.
- The need for a Distribution System Operation role as both the level necessary to manage and facilitate distributed generation and demand side response.

We believe that the NIC must break with the traditional attitude towards infrastructure which is perceived as large centralised projects and consider what its role should be within a distributed system with as many market participants as there are generators and consumers.

  - **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

The regulated parts of the electricity market are continuously being reformed in order to deliver cost-effectiveness and cost-reflectiveness. The implementation of Cash-Out reforms in November are reforms that seek to make market participants more accurately responsible for their imbalances. These reforms are significant and developing a full understanding of their impact and success will take time and no further reform is currently justified. Ofgem and market participants are carefully monitoring the impacts of a process that will take the best part of 3 to 4 years. The processes that have led to these reforms are well established and effective in dealing with the balancing rules and we see no reason to diverge from these.

- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

It is commonly thought that flexibility is associated with the deployment of variable renewable energy technologies. However, solutions such as interconnectors, DSR and storage stand on their own merits providing the correct regulatory and market access can be facilitated.

The CCC report makes a very clear case that flexibility is a critical component of any future electricity system and can provide benefits to consumers of £2.2 to £2.9bn in 2030 even if the power sector only achieves an average grid intensity of around 200 gCO_2/kWh. Figure 7 is extracted from the CCC report and highlights the level of ambition (full flexibility) that we should be aiming for.

Benefits of a flexible solutions increase with the penetration of variable renewables which can consequently be increased providing additional option value to the UK generation mix.

Table B3.3: Flexibility deployment in Imperial/Nera scenarios

	No additional flexibility	Low flexibility	Medium flexibility	Full flexibility
Flexible plant	None	All new plant to have more flexible/efficient characteristics		
Interconnection	Current (4 GW)	Minimum of additional 3.4 GW (7.4 GW total)		
DSR (max 69TWh)	None	25% potential	50% potential	100% potential
Energy storage	Current (2.7 GW)	Additional 2.5 GW	Additional 5 GW	Additional 7 GW

Source: Imperial College (2015) *Value of Flexibility in a Decarbonised Grid and System Externalities of Low Carbon Generation* Technologies; Imperial (2012) *Role/Value of Energy Storage Systems in the UK Low Carbon Energy Future.*

Figure 7 - CCC flexibility assumptions

2. What are the barriers to the deployment of energy storage capacity?

As the UK has very few operational electricity storage sites, UK energy policy, market arrangements and network access and charging rules are not adequately set up for storage. This results in a number of unnecessary barriers to the uptake of electricity storage. In order to realise the value to the UK that storage delivers, these barriers need to be addressed. We consider that the four main barriers are:

1. Electricity market arrangements should be updated to allow the UK to take advantage of the benefits of electricity storage. Under current market arrangements, electricity storage is inappropriately penalised compared to other market participants. One key example is that of final consumption levies: electricity storage gets charged final consumption levies such as Feed in Tariff and Renewable Obligation recovery charges, even though electricity storage doesn't consume electricity and those fees are then paid by the true end consumer. This results in double charging and a discriminatory cost penalisation on storage compared to demand side management (DSM) and generators providing flexibility. One quick and beneficial solution to this final consumption levies issue would be for DECC and Treasury to confirm that final consumption levies should be applied on net import instead of gross import (netted over an appropriate period of time such as 24 hours). Overall, market arrangements should be updated to reflect that electricity storage is different and separate from consumers and generators so that it is correctly treated.

2. Network access and charging rules should be updated to reflect that electricity storage is different from consumption and generation. Network access and charging rules currently negatively treat electricity storage as both a generator and a consumer. In addition, the contribution electricity storage makes to network security is not correctly reflected and its contribution to system stability isn't considered at all. This means that storage is disproportionately charged for making use of the network and unduly delayed from connecting to it, even though it is a solution to network problems. Network access and charging rules should be updated to reflect that storage is a different category from consumers and generators so that the value of its contribution to the network and UK system is recognised.

3. The status of energy storage should be clarified in the UK legal and regulatory framework. At the moment storage is not a defined activity within legislation or the licensing regime. This lack of clarification:
    a. Is a barrier to making changes to industry codes as codes follow the principles set out in the governing licence (which are silent on storage), and there is no single commonly accepted definition of storage that can be used to develop code modifications; and
    b. Results in the perception of regulatory risk by investors and potential users of storage such as DNOs.

    A solution that can be implemented quickly and that provides a commonly accepted definition of storage should be sought.

4. A major benefit of storage is the versatile and valuable ancillary services it can provide to alleviate system and network challenges and so mitigate a number of the barriers to the move towards a low carbon future. Historically ancillary service contracts have been short length – typically one month to two years. These short

contract lengths are suitable when ancillary services have been provided by generators whose CAPEX investment is predicated on another revenue stream such energy generation. As we move to a future where the best value providers of ancillary services are dedicated service providers whose only revenue is from ancillary service income, contract lengths must be increased so that these projects are financeable in the first place. Longer contract lengths will mean that the cost of capital decreases and the same services can be offered at a lower price (as CAPEX recovery can be spread over a longer period). Longer service contracts will also give increased cost and network planning certainty to the SO and network companies who buy the services, so enabling better longer term infrastructure planning decisions. The regulator Ofgem should ensure that there are sufficient price control incentives on these companies to enable longer term incentives.

- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

The most appropriate scale for storage will be determined by its use case and technology type. Given ever changing technology costs, evolving service requirements, the development of new non-storage service providers (e.g. DSM), and that the potential uses of flexibility aren't fully understood, the best value technology and scale for storage cannot accurately be predicted and will likely change with time.

However looking over the next seven years, Distribution Network Operators (DNOs) have been awarded £39bn to invest in distribution networks within the current RIIO-ED1 price control period. This significant investment reflects the fact that most new load growth, an increasing amount of generation growth and an increasing proportion of network challenges will be on the distribution network. Given the high uncertainty about the exact magnitude and timing of load and generation growth, adding greater flexibility such as storage on the distribution network (either directly connected to the network or behind the meter) is a no regrets move. We believe that DNOs should be actively encouraged to deploy it now as it will deliver consumer benefits.

We have examined adding storage onto the transmission network and see it as important in the long-run to the integration of high levels of low carbon generation; however in the short to medium term it is unlikely to deliver the same benefits to consumers as distribution connected storage. Flexibility is useful on the transmission network, but flexibility on the distribution network has the potential to provide greater benefit – put simply, storage technologies connected to distribution networks could be used to manage transmission network constraints, but storage technologies connected to the transmission network can't be used to alleviate distribution network constraints. We have examined adding storage at the domestic scale and found that greatest cost benefit to network companies currently comes from having storage at the distribution scale.

However, in response to the inference of this question, we would be concerned if there were a central direction by a single entity as to where on the network storage should be located, as it is not possible to know at this stage where it will provide best value to the system and consumers. We believe a more beneficial approach to all parties would be to remove unnecessary barriers to storage and have clear price signals from network companies as to where it would be of benefit, so that it can be deployed at least cost to consumers and in the most valuable way to network companies and the system.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

We believe that increased interconnection will benefit the UK consumer and energy transition that is under way. There are, however, a lot of uncertainties and complex interactions with DSR, storage and interconnection all providing similar services and the optimum level of interconnection is difficult to pinpoint today.

It is also unclear to us whether or not all costs, benefits and risks associated with interconnectors are fully considered or can be fully capitalised upon. For instance interconnectors provide the opportunity to pool a number of ancillary services and reduce capacity margins with interconnection to different price zones around the UK contributing differently.

Additionally, the current approach of the UK government to security of supply means that the full benefits of interconnectors cannot be realised. Optimising interconnector use requires a regional approach to security of supply, for example regional capacity adequacy margins and regional shared ancillary services.

At the moment we believe that the voluntary 10% target by 2020 provides a no-regret level of interconnection and that development of further projects should be encouraged in light of very long development timelines and the option value associated with interconnectors.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Demand Side Management (DSM), also known as Demand Response (DR), is an underdeveloped source of flexibility in UK. The potential benefits of DSM are significant although difficult to quantify:

- A report commissioned by Energy UK synthesising public data suggested that 20% of peak demand (12GW) could be successfully shifted on demand.[6]
- A paper prepared by Sustainability First says the technical potential of demand management (capping) at system peaks is between 33% in winter and 29% in summer.[7]
- Based on a study prepared by DECC in 2014 assessing the total cost reduction impact of a Smart Grid, DSR could have an overall reduction potential ranging between 20%-30%[8]
- Other estimates vary, but many suggest a potential energy saving of over 10% of peak demand.[9]
- In 2013 in the USA just the additional revenue earned by customers from DSR exceeded $2.2bn which comes in addition to the avoided infrastructure investment costs as a result of DSR.46.

The efficacy of DSM in supporting the stability of the network is increasingly demonstrated through advanced communication technology that enables the management of demand on a minute by minute basis to align with generation. This has been shown in the New Brunswick / PowerShift Atlantic project in the US.

UK firms have the ability to take a technological lead in the most sophisticated DSM technologies. However, to do so the regulatory environment has to provide an appropriate platform and be responsive to the needs of innovative new entrants.

Key to this is the ability of companies that are focused on delivering flexibility to contract across the market and the barriers to entry removed to allow the innovations that independents would like to promote (such as virtual power plants) to come forward.

An example of how this innovation can be enabled is demonstrated by the French Market reforms where there are clear roles developing for DR aggregators to deliver both capacity services to the network operator and energy balancing and arbitrage services to the energy markets through a separate supply account and the NEBEF rules.

This contrasts with the UK where the DR market does not have the depth of definition to allow DR aggregators to deliver across markets. Rather DR aggregators can contract directly with the network operator for a limited range of services; however any arbitrage services and time value based services are captured in the supply account of the existing supplier. This limits the development of innovative products and the potential for new and innovative companies to enter into this area.

The key challenge, when bringing about increased demand side flexibility, is a regulatory and market design challenge. Once this has been resolved successfully, then the investment will follow.

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[6] Thermal Green Demand Side Response: UK Market Overview and the Potential for DSR
[7] Sustainability First, Paper 13: 'realising the Resource: GB Electricity Demand Project Overview, October 2014
[8] Smart Grid Vision and Routemap: Smart Grid Forum: February 2014
[9] SEDC, Mapping demand response in Europe today, April 2014

From: <email address redacted>

Sent: 24 November 2015 11:30

To: EnergyEvidence Infrastructure-Commission
Subject: Submission from <name redacted>

Attachments: Amber Rudd MP.docx

Dear Sir/Madam,
This call for evidence is seriously flawed and somewhat embarrassing to me because it is based on the erroneous assumption that electrical energy storage offers a long term 'solution'. There will be hardly any 'surplus spare' electricity to store in batteries if you are relying on expensive wind and photovoltaic electricity to charge them up. My suggestion would be to ask a more open question like, How can the UK generate all of its electricity 24-7-52 as firm capacity cheaply from renewable energy sources without burning ANY fuel at all and without using nuclear fission?
It so happens that I already have the answer and would be happy to gift it to the nation.
Please read the attached letter I recently sent to Amber Rudd carefully for some more background information.
If you are not interested and stay convinced that storing expensive random junk electricity is the solution then please let me know that my patriotism is misplaced as soon as possible. I can then approach some other government will benefit from my inventions and the UK will just have to play catchup - yet again.
Kind regards,
<name redacted>
<phone number redacted>

<address redacted>

Amber Rudd MP

Swallow House

Theaklen Dr

St. Leonards-on-Sea

East Sussex

TN38 9AZ

14th November 2015

Dear Amber Rudd MP,

This letter will be the most important letter you will ever read because it offers the UK energy security for ever more without being beholden to other countries for supplies of fossil fuels and uranium for nuclear fission.

I have sent this letter to your constituency office address in the hope that your agent has the good sense to let you read it. I would be grateful if you send me a personal note that you have received and read it carefully within two weeks of the date above.

The sad reality is that we have wasted over 40 years blundering down the wrong path i.e. generating tiny quantities of worthless intermittent junk electricity from a plethora of wind, wave and tidal schemes. In 1973, after the price of crude oil soared, Ted Heath put out a call for 'alternative ways of raising steam' in our thermal power stations other than coal, for obvious reasons then.

Unfortunately for us and our planet, scientists and engineers at that time completely missed the point and started to develop 'alternative ways of generating electricity' from wind and waves. Had these 'pioneers' actually did what was asked of them and converted the kinetic and potential energies in wind, waves and tidal streams to raise steam; this country would be generating all of its electricity from these 'cold renewables' without burning anything at all!

The UK government, and particularly you, could be remembered for the rest of time for saving the planet by stopping, yes, not merely reducing but stopping, the burning of all fossil and bio-fuels and reducing, over time, CO2 emissions to zero. All you have to do is to announce that you are no longer going to pay any more out in ROCs and FiTs for intermittent random junk electricity [MWh(rje)] but that you will pay one third of the current electricity rates for every MWh(thermal) going into thermal storage instead. It is from this stored heat secure firm electricity is generated.

Other counties will follow your lead because their politicians will realise quickly that their country's electricity will be very cheap because they no longer need to buy coal and gas from some pretty dodgy countries. All countries will be able to generate all their

I feel it is my patriotic duty to give my own government the chance to save our planet, to increase the prosperity of the nation by generating very cheap green electricity by using the UK's natural resources to provide alternative green heat sources for our existing fossil fuelled thermal power stations. You can elect to completely ignore this letter and continue to take advice from random junk electricity 'experts' that will say anything to get their hands on taxpayers' cash. One day in the next two or three decades when the temperature on planet Earth has risen in the order of >3°C coal exporting countries, realising that they are running out of coal, will hoard it for domestic use a leave the UK with the only option of converting the kinetic and potential energies in wind, waves and tides into and storing it – as heat.

The sooner we start converting all of our existing thermal power stations to run on renewable heat derived from the kinetic and potential energies of these 'cold renewables', the better. My fear is that you will pick up the phone and ask for advice from these so-called 'renewable experts' and they will ridicule the contents of my letter. Most politicians' eyes simply glaze over with 'technical jargon' but that is exactly what these charlatans want. You really need to be 'electrically savvy' and understand how electricity is generated and why talk of 'the energy mix' is just a load of nonsense.

The Generation of Electricity

The renewable industry has successfully conned politicians across the world into believing that the more intermittent junk electricity we generate is going to mitigate the effects of climate change. So how did they fool almost all of the people all of the time? They hijacked the term kilowatt-hour (kWh) which is a term used for the consumption of electricity (1 unit) and used it wrongly for its generation. The Scottish Government is happy to crow over meeting its targets it is not comparing like with like. Putting so many MWh(rje) in the numerator and so many MWh(e) in the denominator is mathematical nonsense. There is no 'energy mix'.

Over 93% of the world's electricity is generated thermally. This electricity is loaded onto the local utility grid as 'firm capacity' and it is this kind of electricity that keeps the lights on 24-7-52. The primary function of a thermal power station is to use its chosen heat source to raise steam to power steam turbine generating equipment. Heat sources include burning fossil fuels like coal, gas, oil, land-fill methane and other stuff like trees (aka bio-mass) and splitting atoms in nuclear fission power stations.

For the non-technical, it is useful to think of the National Grid as a big water tank filled to capacity at any given nanosecond in time. Imagine over 25 million capillary tubes at the bottom of the tank connected to our homes and businesses with 'water' flowing in line with our fluctuating demands. Obviously, provided that the 'water' flowing in to the tank matches what is flowing out, the system is balanced and stable and everybody gets all the 'water' they need on demand.

It our thermal power stations that generate what is known as 'firm capacity' to keep the National Grid's capacity to supply topped up sufficient to meet our demands. Every night when millions of us switch on our electric kettles during Coronation Street's commercial break the National Grid imports nuclear derived thermal electricity, as additional capacity, from France, to keep our lights on.

Raising steam by splitting atoms (nuclear fission) in a 'controlled thermo-nuclear explosion' has got to be the most expensive and dangerous way of boiling water ever devised by Man. I think we both know that the cost of building the nuclear power station at Hinkley Point with a strike price of £92.50/MWh(e) will at least double to over £100 billion pounds and this money could be better spent converting all our existing thermal power stations to run on a renewable heat source and raise 'green steam' instead.

With all of our existing thermal power stations running on 'green steam' and no fuel to buy and import the UK would be completely self-sufficient as the price of green electricity would drop to less than 10 pence/MWh(e) within the next 10 years – if we start now converting our thermal power stations to run on renewable heat without burning anything at all.

In Paris at the end of the month you can announce to the UN that HM Government is no longer accepting and throwing good money after bad for intermittent random junk electricity. It will only accept, and pay for every MWh(thermal) that is stored in large thermal accumulators. This is the *only way* of saving the planet from overheating by stopping, not merely reducing, the combustion of all fuels to raise steam.

Existing wind turbines can be easily converted to supply heat into storage and if the wind energy engineers do not know how to do this they are free to write to me and I will tell them how to do it gratis.

One day, when there is nothing left to burn, all electricity will be generated thermally converting stored heat into firm capacity electricity. Using renewable heat means that huge volumes of desalinated water can be produces as a by-product of the generation process. This very cheap water can be used for irrigation so that crops can be now grown in arid regions to feed the world's burgeoning population.

In Scotland, Fergus Ewing has surrounded himself with these 'renewable energy experts' and he has set up Wave Energy Scotland (WES) based on their advice to 'encourage private investment'. The poor man does not realise that he has been duped into spending around £150 million over the next 10 years and that at the end of the term there will still be no private investors. The problem is that Goldilocks' arriving at any fixed location off the west coast of Scotland, only occur for about 20% of the year so that 1MW Wave Energy Converter (WEC) that cost upwards of £200 million to build does not produce any junk electricity for 80% of the year. Wave derived electricity currently attracts 5 ROCs/MWh in Scotland and, of course, contributes absolutely nothing towards mitigating climate change. Also, it is worth pointing out that no fixed location wave machine has ever survived two winters anywhere in the world because they cannot get out of the way of storms like Abigail.

There is lot more but your eyes are probably glazing over – but you have it in your gift to be remembered as the politician who saves the world by actually taking the time to read this letter.

I am quite happy to come down to London outline how renewable heat without burning anything at all is the only way that we can stop global warming to 1°C. It is in your power to stop any more payments for useless junk electricity and if you do this I can gift you my British Patent gratis that will not only supply our beleaguered planet with electricity as firm capacity it will also provide trillions of tonnes of (flash) desalinated water to feed us all .

Yours sincerely,

<name redacted>

From: <email address redacted>
Sent: 08 January 2016 12:00
To: EnergyEvidence Infrastructure-Commission
Subject: National Infrastructure Commission call for evidence

The government should be placing much more emphasis on sourcing energy from renewables. Energy security can easily come from use of solar power and battery technology as well as wind-farms. The government should be seeking to expand it's infrastructure for harnessing renewable sources of energy for the good of the country, business and the planet. This government is too keen on listening to those lobbying from the fossil fuel industry within and does not appear to want to see community energy or renewable projects succeed. Long term planning on the basis of renewables is required as well as a public information campaign that encourages people to see energy as a precious resource not to be wasted. The government needs to consider that the long-term health of the planet and it's inhabitants is seriously effected by energy policy and should take precedence over short term monetary gain. Following the Paris talks they need to put their money where their mouths are and make some important choices to develop renewables.

Shame on Cameron and his self-servicing government that is trying to change legislation to mean that community's cannot resist development of fossil fuels. Resist we shall....my only hope is that this government is making itself so unpopular in its legislation that it will not survive the next election.

<name redacted>
<phone number redacted>

Summary

To support the cheapest and locally sourced form of low carbon electricity, onshore wind, this report recommends investing in strategically placed large scale pumped hydro, the cheapest form of storage. This will help National Grid to manage the intermittency of onshore wind, whilst the combined solution remains cheaper than nuclear electricity. As onshore wind continues to grow, pumped hydro can store this cheap, low carbon, renewable form of electricity at times of high wind and low demand, whilst releasing it at times of high demand and/or low wind.

The overall point that I make in this short report is that onshore wind combined with pumped hydro is cheaper and more secure than nuclear. For this reason I believe it should be given serious thought when considering infrastructure projects of national interest.

The objective is to highlight that renewable projects providing similar electricity volume and consistency to the National Grid as the proposed Hinkley Point C could do so at cheaper prices whilst providing more flexibility in output.

The table below compares some key variables, showing that onshore wind with pumped hydro is more cost effective than nuclear:

Parameter	Project consisting of onshore wind with pumped hydro – see next chapter for assumptions	Nuclear (Hinkley Point C)
Installed capacity	3,200MW pumped hydro and 7,000MW onshore wind	3,200MW
Annual output	25,000GWh	25,000GWh
Capital costs	£14,000m	£16,000m – £24,500m
Government subsidy (2012 money)	~£75/MWh for 30 years	£92.5/MWh for 35 years
Lifetime	30 years for onshore wind 60+yrs for pumped hydro	60 years
Decommissioning cost	Generally cost neutral	DECC currently spends £6bn/yr, committed for 80 more years to decommission current fleet
Fuel source	Wind – blows across land freely	Uranium – Main global supplier is Kazakhstan, followed by Australia, Niger and Namibia.
Amount of private investment in UK	£8bn - Over the last 5yrs onshore wind has received over £8bn of private investment in the UK	£0 – No UK nuclear power station has been built with private capital – last investment was in 1987 by CEGB, a Government quango.
Amount of capacity in UK	8,516MW onshore wind 2,860MW pumped hydro	8,883MW
% of generation	5%	19%
Amount of capacity worldwide	370GW onshore wind 127GW pumped storage	370GW
Worldwide electricity produced	599TWh wind	2,410TWh

Details of assumptions

In terms of the nuclear assumptions these have been taken from the EDF website on Hinkley Point C.

In terms of the assumptions for onshore wind, this is assumed to be one large onshore windfarm consisting of turbines at up to 200m tip and up to 150m rotor size. The windfarm would consist of about 800-1,100 turbines and cover an area of 70-100km2. For comparison this is equivalent to the following:

Bare land	Area km2	% needed
Bodmin moor	208	33%-47%
Dartmoor	954	7%-10%
Exmoor	692	10%-14%
North York Moors	1,436	5%-7%
Salisbury Plain	780	9%-13%
North Pennines	2,000	3%-5%
Cairngorms National Park	4,528	1%-2%

Please note that these large open spaces are used for illustrative purposes only.

For onshore wind a more realistic option would be to allow a large scale 'distributed windfarm' made up of many parts. This would be achieved by encouraging more sensitively placed onshore wind development across the UK. This would be more costly that a single large wind farm as there is not as much scaling. This solution would still be competitive with Hinkley Point C however. The UK National Grid enables all wind parks connected to it to act as one large powerstation. The pumped strorage would enable National Grid to match supply and demand.

In terms of pumped hydro the latest figures from National Grid have been used. The UK's largest pumped hydro station at 1.7GW, Dinorwig Powerstation in North Wales was built in the 1970s. It is still a cornerstone of the UK National Grid. Interestingly a large pumped hydro plant was planned in Exmoor back in the 70s/80s at the same time as this one.

Realistically most onshore wind capacity will be in Scotland going forward. Therefore a large scale pumped hydro station to work with these in the north of the island is probably the best option.

Onshore wind combined with pumped hydro provides the following to the UK consumer:

- Low cost electricity
- Low carbon electricity
- Energy security as it is home grown electricity – not reliant on foreign fuel imports

Answers to Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

My assumption with this question is that with cost the following is meant:

1. Minimising cost in terms of p/kWh to the end consumer
2. Minimising the cost of fluctuations by increasing energy security (reducing reliance on imported fuel)
3. Minimising costs due to climate change – therefore focusing on low carbon / renewable technologies

Onshore wind is top on all of the three criteria above. Storage is essential to the UK electricity generation as it enables more installation of onshore wind onto the grid. Pumped storage is still by far the cheapest form of energy storage for electricity at scale.

2. What are the barriers to the deployment of energy storage capacity?

No comment

3. What level of electricity interconnection is likely to be in the best interests of consumers?

No comment

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

No comment

From: <email address redacted>
Sent: 23 November 2015 13:14
To: EnergyEvidence Infrastructure-Commission
Subject: Energy

Dear Sirs,

As a professional in the energy field (primarily buildings and transport) I write to offer my comments to the commission.

The concentration on electricity is perhaps the most disturbing aspect of this evidence request; electricity is not a source of energy but a means of transmission, and only one of several available in theory. It is not even the largest energy 'market' in the UK; that is and seems likely to remain the provision of space heating (primarily natural gas), and transport fuel (petrol and diesel plus kerosene). The 70TWh or so of energy that gets transformed into electricity and shoved around the existing grid at some point in its use, annually in the UK, seems rather small beer in comparison to the picture as a whole. And is probably not the biggest energy problem we face as a nation.

So the narrowness of the energy issues placed up for debate must be the prime concern.

I will assume therefore that the person or persons who decided on a title for this commission, simply got things mixed up; what was meant was electricity supply via the national grid, not energy.

That being the case, there are a number of issues that the National Grid, a device set up over eighty years ago, now fails to address, of which the idea of an energy 'market' is probably the least relevant, even if it obsesses politicians. Briefly, they can be defined as 'fitness for purpose', 'long term usefulness', and 'thermal efficiency'.

Since the issue of efficiency - thermal that is - is probably the biggest one, I will deal with it first.

Overall thermal efficiency of the current grid, that is the energy outputs (as useful heat, light and power) compared to the energy inputs at the generators, is probably no more than about 30% overall. So the current energy supply via the grid contrives, in the doubtful guise of convenience, to throw away 70% of the - mostly fossil - fuels that it uses. That is on a par with the open coal fires of yesteryear, and rather worse than the town gasworks of my youth. On this basis the Grid is unsustainable. The only way to address this is to specify a minimal thermal efficiency - say 75% - for any new entrant wishing to put electricity in.

In terms of fitness for purpose, it has been clear for some time that the Grid is predicated upon large thermal power stations; it was designed for them and does not readily serve any other form of generation. Artificial, and potentially crippling, restrictions are in place to prevent the use of the grid for renewables, especially micro-renewables, where the Grid is not so much a long distance transmission system, but a local balancer of voltage and frequency, with the outputs being supplied to - and used - within the 33kV sub-grids of local extent. A major shift is required immediately to permit more renewable inputs, whose thermal efficiency is compromised from a very high base (90%+) by this archaic system. Many people wish to simply lean on the Grid's ability to balance voltages, not be dependent upon it for large numbers of amps, and simply want to swap a few kWh with their neighbours as convenient. Currently, the government see the 'market' as being for the 21st century equivalent of the 'Grand Allies' - where fortunes can continue to be made, by fair means or foul, as they were when coal was the only king of the castle. That attitude, in my view, needs to change.

The other principle heading under fitness for purpose is to address the issue of moving the grid from a national monopoly sucking the blood out of the users, to one where it serves everyone, not just the big battalions. A grid that sees everyone as a potential supplier and consumer, and whose prime purpose is to balance out those many millions of small supplies with the almost equal number of small users (even though 'small' may mean a factory using 2MW or more, and feeding it back in the right conditions). In short, a Grid where equality of access and benefit are its prime concern alongside security of supply. Perhaps key to this is the issue of storage.

Currently the grid has, de facto, almost zero storage. A couple of small hydro schemes, some capacity in the Scottish Highlands, a small hydraulic press in Tower Bridge. How the Grid develops a programme of energy stores (and bear in mind almost every dock installation in the UK had one in 1914), in terms of size and location, is one of the great challenges of the twenty first century. Which we needed a decade ago as part of the move to renewables, and which we presently have neither got nor look like getting any time soon.

The question of long term usefulness must, inevitably, be tied up with plans for the Grid. The issue of making people responsible for the energy they use is a key one; have your own micro-hydraulic accumulator in the garden or a shed at the back of the factory and you are acutely aware of how much it costs you and how much juice you have to run with. Pass the responsibility to the Grid and you can do what the rail industry in the UK does; use it without a care for how much or when. If HS2 had to build the 500MW station it will need to run it, then it would think very hard before letting 18MW into each TGV. That sort of responsibility would change fundamentally the electricity supply industry in the UK. The Grid as a supplier of big power may be a dinosaur about to meet a meteorite shower. As a supplier of balanced 220, 440 or higher voltage single and three phase AC its days may well be numbered; there are already ways of dealing with this on the scale that gives consumers power and responsibility for what they do.

At its best the Grid can only take energy made in one place and move it to another; allowing a completely safe nuclear station to be located a long way away from the customers, instead of at Battersea, for example, and knocking 5% off its thermal efficiency. On the other hand it could move onshore wind to the cities, or solar PV from schools after going home time, when their site stores are full. What you want the Grid to do depends on what you think its for; everyone, or only those with power to master it to their own ends.

That, in essence is a political, not an energy transmission, issue.

Yours Sincerely,

<name redacted>

<address redacted>

From: <email address redacted>
Sent: 26 November 2015 18:15
To: EnergyEvidence Infrastructure-Commission
Subject: Energy evidence

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

The future will see battery driven electric cars, a huge potential to store electricity if managed smartly
Electricity prices should be available at spot prices to consumers using smart electricity meters and availability of the electricity price over the next hours or night. (eg based on wind/sun predictions etc.)

Smart systems could enable cars to recharge when electricity is cheap automatically, using the excess capacity based on normal driving

With such short term price information and availability of these prices to the public, people can decide when to do washing etc. or smart boilers can heat water at time of low electricity prices

This will allow balancing out wind power / solar power variability and allow people on small budgets to buy their energy cheaply serving consumers and producer issues improving the reliabiity of the electricity supply (shrewd consumers could slash their electricity spend by half in my view)

This could be a private company initiative if these smart meters are available. So effectively storage and demand management will be at the consumers

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

Absence of spot pricing options for consumers to exploit(low electricity price for short term next hour or 8 hours

- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

Use Large water reservoirs for grid balancing (hydrolectric reservoirs in Scotland)
Combine wind turbines with water reservoir to pump up water when wind power isn't needed (old dutch plan called PLAN LIEVENSE)

Use consumer smart buying and consumer battery storage in future electric cars (Think Tesla car battery) to lower cost of electricity for the car owner and reduce variability in supply demand with renewables

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

If we go for Shale Gas and Shale Oil and resulting low cost electricity, it is in our interest to have minimal interconnectors to enable a lower electricity price in the UK compared to our competitors. Otherwise with open market we are shackled to high EU electricity prices

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

There used ot be a system in France where the electricity producers indicated the tariff with green yellow and red lights to indicate low medium and high teriff, where people postponed their washing etc. when tariff was red. A much more advanced option could be designed with smart phones etc.

From: <email address redacted>
Sent: 15 November 2015 22:19
To: EnergyEvidence Infrastructure-Commission
Subject: National Infrastructure Commission call for evidence - Energy - Submision by <name redacted>

Dear Lord Adonis and Committee

I spent many years in Electricity operation including a long period with
Operational Modelling.
In the current situation GB needs a co-ordinated approach to developing the Electricity, Heat and Gas mechanisms.

Since I retired I have been trying to get common sense into the areas of Renewables and Distributed Energy Management Integration.
My take on a practical approach to the Electricity, Gas and Heat strategy is below my signature. It refers to the initiative for Low Carbon Gas which also maintains Fuel diversity. Then getting the 'meaning of time and participation' into the Supplier to Retail customer area to encourage more and larger CCHP in large premises.

We have the trilemma of Cost, Emissions and Sustainability to deal with, including the issues of Fuel security and diversity as well as Generation capacity, basic fuel supply and Electricity system stability and security (fault resilience).
An odd note is that non-synchronous Wind penetration in any AC system is limited by the need to maintain adequate Synchronous plant for Intertial stability. Ireland has the largest proportion of wind in any AC system and has been stuck with a maximum instantaneous limit on non-synchronous infeed
(Wind, Sun, Import) of 50% for some time. Thus, even with flexing of the
large (to them) GB Interconnectors there is a limit on how much energy that can accept from renewables.
My ideas also attempt to address this issue.

I was interested to see the three strategies from the Infrastructure Transition Research Consortium, especially the approach to decentralised Energy.
I will be interested to see how they handle time series modelling of Electricity; a crucial factor in any evaluation and my specialist area over many years.

One point I would note, having dug into Electricity history and the mess GB got into by the early 1920's (and how we got out of it) is that managing lots of distributed (large premises) CCHP (use the Gas better) as I propose would be the biggest change to Electricity operational logistics since 1933!! However, we do have the communications and management technology; just need to put it together carefully to get the best result.

My webspace is at www.eleceffic.com on which you can find my 22 Articles on Future Power Systems - Basics (some not always well understood) through to Brave New World.
Each Electricity system is in fact a large machine, with the elements coupled together by Electromagnetics which are somewhat tetchy. Ours gets up to 60 million BHP at the Peak.

Best Regards

<name redacted> BSc(Hons) MIET MIEEE MEI Electricity Efficiency - APL 3454 www.eleceffic.com Retired, but still being a nuisance and open to contracts Ex CEGB and National Grid UK GB Electricity Operations - Generation, Demand, Fuel and Market modelling Contributor to EU Smart Grids Technology Programme WG 2 - Network Operations

<personal details redacted>

Sorry about the length of this but it is an engineering problem we have, now spanning Electricty, Gas, Heat and possibly Transport!!!.

Since retiring (for the first time!) from System Ops in 2003 I have been trying to get common sense into the integration of Renewables and Distributed Generation - the 'Big+Little' picture.
For 10 years I have been trying to push time band retail tariffs for half hour metered premises ('Simple Smart'), as the first stage in developing customer participation and to encourage more and larger CCHP. At two DG conferences a few years ago (parties at daggers drawn) I said the DNOs needed to get Smart (Grid) and the DG developers needed to understand
Participation. And that is happening.....

With our Coal plant shutting down (LCPD and IED) we need to use gas better but also maintain diversity of primary fuel input while trying to reduce emissions.

As John Loughhead said at a recent ETI event, Gas is highly versatile which makes it a difficult fuel to replace..... In fact the Power ramping capability of the Gas mechanism is awesome!!

Tony Day and Chris Hodrien (ex Brit Gas research) are promoting Low Carbon Gas by resurrecting the BG-Lurghi+HiCom Slagging Gasifier-methanator mechanism. "Eats" Coal, Biomass and Trash and produces Methane and CO2 at high pressure. Thus it is CCS ready - or perhaps we would combine with H2 (electrolysis from excess Wind) for more methane??.... Also gives us some diversity of primary fuel input to the gas system. A production scale BGL-HiCom system was in operation as Westfield up to 1992 when the Government cancelled the project, not appreciating of course that the CCGTs then coming in would increase Gas burn by 50% and advance the run down of UKCS (one reason for the Gasifier-methanator being developed in the first place).

The way I work on from that is to use the Gas better.... Large building plant room Engine based CCHP in cities with heat/cool connections to the immediately adjacent neighbours (inc flats etc). Internal Combustion Engine CHP + Absorption Chillers as at Leicester and the Nat Hist Museum; the latter also supplies heat and cool to the V&A and used to connect to the Science Museum and Imperial College.

Such large premises already have HHR electricity meters; @120000 retail connections with max demand > 100kW and the next tranche of non-domestic premises are being converted to HH metering. In total these premises consume @half the GB Electricity demand.

Predeclared Time period retail tariffs can be applied (Peak/Plateau/Trough Weekdays/Sats/Suns Summer/Winter) and Heat stores installed to get the Engines to run at the best times.... This also encourages larger installations as, with flat rate Import tariff and Export PPA, the present CCHP units are only sized for minimum Electrical and Heat demands .... The Nat Hist Mus Generator is 1.9MWe where their max demand is @4MW. I believe the Shard may have @1.9MWe of CHP but it's max demand is @12MW...

Then Community District schemes in Urban areas where the roads aren't as busy, again Energy Centre CCHPs which will be Half Hour metered.
Each site or area needs to be assessed on its individual merits; one size wont fit all...

As we get larger penetrations of variable renewables on the system we need to move on with the larger premises to more interactive communication - Tariff and bartering mechanisms. Need to make the smart interface flexible as regards Data Content (my FPS 21).

The existing Gas Distribution is in place to support more CCHP but the

Electricity Distribution is straining in Cities.
Thus CCGT/Wind+Heat Pumps/AirCon would need a large Electricity
infrastructure reinforcement alone (serious digging up of roads).....
Also, as I'm trying to research, Internal Combustion Engine CCHP with large flywheels for Inertia and declutchable Prime mover should help with stability and voltage control
(MVAr Export/Import) when the Engine is shut down. Inertia is of course an
overall system requirement and MVAr absorption/production is especially
important in cabled City networks. In fact Ireland, with the highest
penetration of renewables (mainly Wind) in any AC system is 'stuck' with a Power limit; instantaneous Wind + Import Power cannot exceed 50% of total
Generation Power (Demand + Exports). Hence we are helping them out by
letting them export over the Interconnectors (rather large in proportion to their system) overnight....

Now, as regards buffering large Wind variability, perhaps if we also produce
H2 from Electricity when the wind is blowing hard and combine it with CO2 from the Gasifier to produce Methane, that also leaves Electrical demand for the CCHPs to meet.

We also need larger CCHP to support the Peak capacity requirement and, as they run harder at the Peaks with time based tariff/PPA, that also relieves some Distribution loading. Mind you, as I said at the DG conferences a few years ago, the DNO systems need to get 'Smarter' (Smart Grid) and the DG developers need to understand Participation... which I see is happening.
The bigger CCHP systems would need larger Thermal storage to make the whole 'joined up' Low Carbon Gas + Time band tariffs + bigger CCHP' initiative work.
It was an integral part of my project proposal which would assess each Premises and Larger system (Microgrid up to community) on its merits.
Analysis, proposed facilities (Technology and Supplier/Distributor
interface) then installation if cost effective.
Horses for Courses, each premises and community system assessed on its merits and the various options; one size definitely dont fit all.

All in all we need a communication hierachy with Aggregation up and Dissemination down Premises - Microgrid - Grid Supply Point - DNO - TSO with cross links to the Suppliers.
We need standards for communication protocols but flexible data content as we learn what data needs to flow each way.

If we do end up with the Retail side buffering wind generation then the current industry methods of top down demand forecasting are rendered useless (FPS 20) We have to move towards bottom up 'bartering'....

If we can demonstrate that this strategy works then the IP sales potential is enormous... China is already trying to 'sort out' the impact of its massive 4bntpa coal burn (ours is @52mtpa) with over 900GW of Coal fired generation. It looks like they realise that Pithead (North & West China) Gasification and long Gas pipes would allow cleaner generation. The patents for the HiCom methanator are held by Johnson Matthey Davey and the BGL Gasifier is under a Chinese company.

On my webspace at www.eleceffic.com are the 22 articles on Future Power Systems - Basics (inc synchronous lock with the 'Biggest machines in the
World' comment) through to Brave New World.
FPS 21 looks at the Smart Customer, FPS 20 at the overall smart system and impact of Customer interaction and FPS 22 carries the requirements to evaluate the strategies to find the best one.
In FPS 1 I have a graph of Gas Power Generation and Demand which shows the effect of the massive internal storage (linepack).

On a more serious note there are fatal flaws in the modelling studies (my specialist area with CEGB/NG), run for the CCC by Poyry in 2010 for the
2030/2050 strategy (Big Nuc Big Wind, Big Heat from Electricity) flexibility analysis.

Hope that all makes sense... Brave New World, Here we come,

From: <email address redacted>
Sent: 19 December 2015 11:25
To: NorthernEvidence Infrastructure-Commission; EnergyEvidence Infrastructure-Commission
Cc: <email addresses redacted>

Subject: Northern Powerhouse and North Wales

Attachments: MAP.jpg

North Wales is only 8 miles from the City of Liverpool. Building a tidal power barrage across the River Dee between North Wales and the Wirral peninsula would generate enough electricity to power many thousands of homes and businesses:

- Include a toll road on top of it, to subsidise costs, although it would generate much revenue from selling the electricity.
- Include a commuter railway line on top of it.
- Most of the cost should be met by the Welsh Assembly, as the North Wales economy would see the biggest positive transformation as a beneficiary of such a scheme, largely due to them becoming closely and directly connected into the city centre of the great metropolis of Liverpool City Region and thus the Northern Powerhouse. There is also EU funding available for such projects.

The attached file contains a map showing 2 potential locations for the barrage and connecting roads and rail. Option A is 8 miles in total and option B is 10 miles in total. Both options connect to the M53 and into the existing 8 lanes of road tunnels, and the Merseyrail (Liverpool Underground) tunnel, under the River Mersey directly into Liverpool city centre.

The River Dee is one of 8 sites identified as optimum for a tidal barrage in the UK:

http://www.darvill.clara.net/altenerg/tidal.htm

Here is a video of one in France:

https://www.youtube.com/watch?v=NO1mFMQIMDg

Regards

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West Lancashire borough is only **2.5 miles** from Liverpool; Cheshire West and Chester borough is only **2 miles** from Liverpool; Warrington borough is only **5 miles** from Liverpool; North Wales is only **8 miles** from Liverpool.

From:	<email address redacted>
Sent:	16 December 2015 09:34
To:	EnergyEvidence Infrastructure-Commission
Subject:	Make our homes energy efficient
Attachments:	NIC_EE_Infrastructure_final.pdf

Hi,
in your call for evidence for national infrastructure programmes, I wanted to raise the issue of retrofitting our homes to make them more energy efficient. This would entail a nationwide infrastructure programme that raises the EPC of all homes to a minimum of C.
Work by the Energy Bill Revolution, Frontier Economics and Cambridge Econometrics shows that an infrastructure approach would be net positive to the UK economy, will help reduce NHS spending, reliance on foreign gas imports and improve our energy security.
With regards,
<name redacted>
<address redacted>

Royal HaskoningDHV
Enhancing Society Together

National Infrastructure Commission: Call for evidence

Royal HaskoningDHV Response

Delivering Future-Proof Energy Infrastructure

07/01/2016

Royal HaskoningDHV
Enhancing Society Together

1.0 Introduction: Setting the context for our response

Royal HaskoningDHV is an independent, international engineering and project management consultancy with more than 130 years of experience. Backed by the expertise and experience of 7,000 colleagues all over the world, our professionals combine global expertise with local knowledge to deliver a multidisciplinary range of consultancy services for the entire living environment from over 130 countries. By showing leadership in sustainable development and innovation, together with our clients, we are working to become part of the solution to a more sustainable society now and into the future.

In the UK, Royal HaskoningDHV's experience encompasses projects in several sectors including ports, flood risk, energy generation, transport, aviation and waste. Our collaborative approach means that our staff work outside, as well as within, sectoral silos and across geographic boundaries, ensuring that we identify opportunities or issues of mutual relevance to our clients and share project solutions from other sectors or countries. We firmly believe that working in partnership across sectors and disciplines delivers successful outcomes that cannot be achieved by those working solely within a sector.

We therefore consider that the sectoral and geographic split of the three initial challenges facing the Commission risks limiting the identification of links between these challenges (and others). The National Infrastructure Commission has a 'once in a generation opportunity' to seek to understand the drivers that shape the characteristics of the regions of the UK and how those drivers and characteristics interrelate. Transport and energy should be the facilitators of this grand vision instead of being pushed into the role of drivers of economic growth.

Royal HaskoningDHV is one of the UK and Europe leading energy consultancies with a particular interest in renewable energy.
Our track record speaks for itself.

- We have 40 years' experience in onshore wind development
- We have provided consulting and design services to over 500 projects
- We have provided services to 11GW of offshore wind consenting projects in UK and Europe
- We have successfully lead the EIA and consent process for 8 GW of offshore wind capacity and associated transmission assets in the UK since 2004
- We have provided design and consent services on 1300km of offshore export HV cables from North Sea offshore wind projects
- We have also consented and helped to optimise the route for over 200km of onshore HV cables and their associated substations
- We are the leading consultancy providing technical and project development support to the tidal sector principally in the UK.
- Active energy from waste projects in the UK
- Active Biomass and Anaerobic digestion projects in the UK
- Royal HaskoningDHV employs over 200 professionals in the UK focussed on the energy sector predominantly providing technical and engineering services to the low carbon sectors.

The UK currently has a very significant and global leading position in the low carbon industry particularly driven by the renewable energy sector. The level of investment in the UK planned by European utilities and investors, most noticeably in the offshore wind sector is very significant indeed. If the investment can be delivered we believe it can be transformative, enhancing society and communities in the north of the UK in particular. In order for the investment to be delivered investors require two main things; a market which will allow for long term investment with a reasonable rate of return; and more importantly long-term stability for the energy market, energy policy environment. . Our experience is that prior to December 2013 the cross-party support for renewables created the stability and confidence for developers and investors that allowed the UK wind and marine energy sector to surge ahead of the rest of the world. Whilst we accept reform in the market was required our primary call to government is to restore stability in the policy environment as well as the market.

In 2014 and 2015 we have seen the industry stutter and many major investors pull out of the UK due to losing confidence in the government's long term commitment. The COP in Paris last month and the governments very welcome response creates an opportunity for this National Infrastructure Commission to play a key role in delivering stable market arrangements that allow the transition in our energy generation infrastructure from centralised power stations to a model of a dispersed mix of generation linked into the European energy market.
We welcome and support the consultation and questions asked but urge the commissioners to look further and consider the changes made today in the context of the inevitable transition to the energy infrastructure and market the UK will need in 20 and 50 years' time. With this long term view clearly in mind the commission can set a clear direction for the UK's transmission market and system into the future.

2.0 What changes may need to be made to the electricity market to ensure that supply and demands are balanced, whilst minimising cost to consumers, over the long-term?

Royal HaskoningDHV would argue that the questions posed in the consultation are too narrow and miss the fundamental challenge that is upon the UK now. The UK energy generation and transmission sector retains much of its original model of centralised heavy carbon electricity generation with an associated demand-led national grid developed to deliver power where it is needed. The development of renewable energy generation capacity, particularly wind, has challenged this model but has been incorporated whilst preserving much of the original market paradigms. The challenge now for the NIC and UK Government is to recognise that the present model, handed down from the 1950s, is redundant and is increasingly inhibiting the transition to reliable, cheap and low carbon energy market needed in 21st century Britain.
We urge the NIC to consider reforms to the transmission market that will encourage the evolution (rather than revolution) of the transmission network towards one that will accept greater dispersed generation, flexibility and interconnectivity between the UK and our European neighbours. Key factors to consider are:

1. **Assurance of grid connection for dispersed generation projects**.

The standoff over Orkney and Western Isles connections has had a significant and detrimental effect on the development of renewable industry in these areas. Connectivity is a key risk for any project and its investors. There needs to be greater flexibility and incentives for The Network Operator (TNO) to allow, reward and proactively incentivise these enabling developments to occur. We would also seek to ensure that once a commitment is given by TNO to create a connection that it is held to a fixed timetable through penalties that reflect the consequential damages of delay.

2. **A long-term vision for the direction of the UK Grid development which provides assurance to project developers**.

The Grid development scenario approaches provided by National Grid are a helpful indicator but without a long-term vision, either set by or endorsed by the government. The risk is that we see a continuation of the same policies without any real movement towards the more flexible and integrated grid the UK needs.

Royal HaskoningDHV
Enhancing Society Together

3. **OFGEM Price Control to reflect low carbon policies**

The energy generation market is increasingly driven by the need to meet the goal of low carbon, reliable and cost-effective power generation. We do not see the same polices being actively implemented in the transmission price control or Revenue=Incentives+ Innovation+Outputs (RIIO) process. OFGEM mention a move to a low carbon economy but in practice we feel much more can and should be done.

It will be key for the future balancing of the transmission system, and to ensure the benefits of low carbon energy can be passed on to consumers, to ensure that the OFGEM price control systems for the Network operator properly reflect the UK's international obligations to reduce carbon emissions.

4. **Linking flexibility to the distribution and demand side**

As explained above the current grid system is primarily continuing to work to a centralised generation paradigm and so its systems and processes are set up in this way. It is clear that to meet our carbon emissions targets the UK needs to move towards an ever diversified energy generation market with large, medium and increasingly small energy generation and storage projects coming on line. In order to be ready for these developments we feel there is a need to ensure the transmission and to some extent the distribution grid is able to accommodate and support innovation and investment to ensure greater flexibility in the use of the grid.

3.0 What are the barriers to the deployment of energy storage capacity?

Royal HaskoningDHV have limited visibility of the energy storage sector however we are pleased to provide a broad summary of our views.

The technologies for energy storage are varied our view is summarised below.

Pump Power Storage systems

- Tried and tested technology used reliably for decades
- Tend to be large scale
- Capital cost very high, operational costs very low
- Location specific requirements exacting and tend to result in them being located away from the main markets

Battery Systems

- Comparatively new systems
- Low capacity of 0.2 – 5MW range
- Longevity (number of cycles per battery) is not well tested
- Can be used to 'trim' peaks in generation and so facilitate greater transmission capacity within existing infrastructure. Particularly useful to regulate and trim wind farm peak loads
- Technology developing quickly
- Capital cost is lower, operational costs variable.

Other systems such as flywheel or stored kinetic energy systems exist but we feel are mainly applicable to improving power quality by load levelling.

The barriers to deployment are very different between the two systems. The barriers to large scale pump storage systems (once environmental and planning concerns can be met) tend to be financial and business case uncertainties and the availability of technically feasible sites in strategically important locations.

The key barriers to deployment of more online and small scale, usually battery based, energy storage systems appears to be the lack of a market, or market supporting mechanisms for these third party services. Slow take up of storage technology risks creating a negative cycle where the potential value of the systems is not fully recognised. If energy storage systems are not adopted in a range of real-world situations, it is impossible to measure their value, and consequently monetizing their value will remain problematic.

We believe that the actions required are;

1. **Invest in energy storage to maximise transmission**

We feel there is a case to consider the use of energy storage systems as load levelling systems associated with the transmission network as a matter of urgency. Driving efficiency in the power network is far cheaper than the cost of upgrades. We feel with the strategic use of energy storage the capacity for more dispersed renewable energy generation can be enhanced. The use of energy storage would allow electricity transmission grids to operate more efficiently and cost effectively, allowing the system to be run at average load rather than the current maximum peak load.

Creating and supporting a market for the implementation of energy storage as part of the national grid network is a challenging but necessary step to monetizing the technology and ensuring effective investment.

Considering how such an investment can be paid for, many wind farm developers are looking at installing their own 'peak shedding' technology. It may be cheaper to have a more centralised system built into the transmission grid to accommodate a more diverse generation portfolio from multiple generators.

If undertaken effectively the energy storage could help end the absurdity of wind farms being required to close down on particularly windy days.

2. **A Vision of Smart Technology Across the Grid**

Initial opportunities lie at the transmission scale to ensure the system is operated far closer to average load than to peak loads. However what is required is a broader vision of both an energy transmission and consumer system where flexibility and the cost saving benefits of smart energy technology can be maximised.

Smart meters in homes are a good start and the consumer can now take advantage of remote and maximised appliance management to minimise cost (and so maximise efficiency). It is at the distribution network level that dispersed generation will need to be accommodated with increasing pace. Energy storage and buffering will play an important role in meeting increasingly episodic demand from consumers who self-generate most but not all of their electricity.

The picture is a complex one and getting more so, we welcome the National Grid's Future Energy Scenarios and would encourage them to be broader and to take the step beyond the scenarios to set a vision for the future with a suite of clear investment policies and priorities.

3. **What level of electricity interconnection is likely to be in the best interests of consumers?**

It is Royal HaskoningDHV position that the most beneficial level of electrical interconnection for the UK consumers to for the UK to become part of a wider interconnected European electricity network and taking part in an integrated European Electricity market process.
In simple terms the benefits of an integrated European Electrical distribution system are:

- Significant efficiency gains as market coupling allows generation capacity to be used far more efficiently and helps to avoid over generation of unusable electricity. Time differences between Europe and the UK mean peak demands rarely interact and the UK stands to be a significant beneficiary of such integration.
- Significant improvement in efficiencies of generation capacity and reserve energy management across Europe.
- Increased competition in the UK electricity market providing lower costs for UK consumers
- A single set of grid codes and a single market design and regulatory function
- The development of a European renewable energy strategy rather than a patchwork of National plans.
- Fair, transparent, and non-discriminatory access to the high-voltage transmission network for UK generators.

Further information

We would be delighted to engage with the Commission to provide further explanation and to participate in the discussion surrounding the challenges.

Our lead contact for delivering future-proof energy infrastructure is Alistair Davison. Alistair can be contacted via:

- o [phone number redacted]
- o [phone number redacted]
- o [email address redacted]

www.royalhaskoningdhv.com
Facebook: Royal HaskoningDHV – UK
Twitter: @RHDHV_UK

Royal Institute of British Architects response to National Infrastructure Commission Call for Evidence

The Royal Institute of British Architects champions better buildings, communities and the environment through architecture and our 40,000 members. We provide the standards, training, support and recognition that put our members – in the UK and overseas – at the peak of their profession. With government and our partners, we work to improve the design quality of public buildings, new homes and new communities.

1. The RIBA welcomes the decision to establish the National Infrastructure Commission (NIC) and the opportunity to respond to this call for evidence on the three initial projects the commission has been asked to consider.

2. The RIBA's response to this consultation is focussed primarily on the energy infrastructure and storage question.

3. However in addition to this we would like to offer the following comments relating to the other challenges identified by the NIC.

4. **Improving the transport infrastructure of the North of England must be a priority for the NIC.**

5. The failure of successive governments to address the infrastructure gap in areas of England outside London and the South East is a major cause of the widening gap between the regions of this country.

6. The knock-on effects are also putting additional pressure on London and the South East as economic growth and investment becomes increasingly focussed on these areas, putting infrastructure under strain and fuelling demand for new homes which the market has been unable to deliver.

7. We hope that the commission will be able to look in more detail at the economic impact of poor infrastructure and make the case for greater investment in areas of the country in which investment is currently lacking.

8. **Investment in London's transport networks is welcome, but without a more integrated approach, benefits will be lost and costs increased.**

9. A number of large infrastructure projects have transformed large areas of London over the past decades. The upgrading of the London Overground network has facilitated major investment in housing and job creation schemes by opening up previously underserved areas. However, a lack of joined up thinking means that opportunities to carry out large scale place making have been missed.

10. The creation of a number of housing zones in areas near the Crossrail scheme is a welcome start, we hope that this can be given greater consideration if Crossrail 2 is taken forward.

11. **An ambitious national energy efficiency scheme represents the best investment for achieving a sustainable balance between energy demand and supply.**

12. The RIBA is very pleased the Government has recognised housing as a key infra-structure issue. However, the only way to make our built environment fit for the future is to fully integrate built environment energy efficiency within the UK's Infrastructure Plan.

13. We hope that the NIC will use this opportunity to set out an ambitious national energy efficiency scheme of buildings to be embedded within the National Infrastructure Plan, which represents the best investment for achieving a sustainable balance between energy supply and demand.

14. No other investment can stimulate as much economic growth and create jobs in every constituency in the UK[i]. A programme to make UK domestic stock energy efficient would provide net economic benefits of £8.7 billion. This is comparable to the economic benefits of investments in HS2 Phase 1, Crossrail and new roads[ii].

15. Deploying infrastructure funds to support a national energy efficiency programme could create up to 108,000 new jobs, doubling the number of jobs in the sector to 260,000[iii]. Apart from generating significant economic growth in all regions of the UK, energy efficiency investment would also boost Britain's energy security by reducing gas imports by 26%[iv].

16. The benefits of investing in energy efficiency could go deeper and further than other more visible infrastructure schemes that are already being financially supported by government. The large net economic benefits outlined above excludes the added value of this approach through many of its social benefits, such as health and wellbeing improvements; and its critical ability to address national challenges of safeguarding energy security and tackling climate change.

17. The Energy Secretary Amber Rudd has called on industry and consumer groups to work with the Government to make new, stable policy and build a system that works for the longer term[v] . By investing in energy efficiency building stock, Government can substitute for expenditure on more visible elements of energy investment like power stations, energy storage and the grid, through more effectively reducing demand.

18. The private sector is already paving the way towards a low carbon future. The RIBA would like to see the implementation of a very successful large scale retrofit scheme in the UK based on the succesful Energiesprong model which is currently benefiting 111,000 properties in the Netherlands[vi].

19. The innovative whole house retrofit scheme helps homes achieve net zero energy levels through clicking on off-site manufactured building envelopes onto existing properties. It is a market driven initiative funded by savings delivered via a contractor-guaranteed energy performance contract. Plans are underway for housing associations and local councils in London, Birmingham and southern England to pilot the large scale carbon neutral retrofit of at least 1000 properties by January 2018.

20. Despite its knowledge, expertise, and established business models, the private sector is not able to implement large-scale roll out of energy efficiency measures without Government intervention. The success of

Energiesprong in the Netherlands relied on central Government starter capital which has helped develop economies of scale and enabled the business to work through any teething problems to achieve higher energy savings in energy costs than initial costs of the retrofit[vii].

21. Other reasons for Government intervention in driving a national energy efficiency programme are long-established. Many energy efficiency installations have a long asset life, while the private sector looks for shorter-term payback. Much of the private sector also does not consider externalities such as carbon benefits, and struggles to secure business without long term policy for energy efficiency.

22. Over £100 billion had been allocated to support infrastructure projects over the next 5 years under the Spending Review 2015[viii].The publicly funded investment programme should prioritise the upgrade of existing building stock, minimising the energy demand of new buildings through maximising fabric energy efficiency, and driving up standards and quality control to ensure buildings perform as designed.

23. Research has shown that if a refurbishment incorporates advanced energy-saving techniques, designed and administered by suitably trained architects, this has the potential to reduce overall energy usage in retrofitted domestic and non-domestic buildings by up to 90% with as little as 3% additional cost over a standard refurbishment that would have a relatively poor impact on energy use.[ix]

24. There's a clear case that energy efficiency delivers value for money and added value. By accepting and embracing domestic energy efficiency as infrastructure, and something that needs to be tackled as soon as possible, the benefits could potentially go further and deeper than those offered by more visible infrastructure schemes that are already being financially supported by government.

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[i] http://www.ukgbc.org/sites/default/files/A%2520housing%2520stock%2520fit%2520for%2520the%2520future%2520-%2520Making%2520home%2520energy%2520efficiency%2520a%2520national%2520infrastructure%2520priority.pdf

[ii] Based on Governments own economic analysis http://www.frontier-economics.com/publications/energy-efficiency-an-infrastructure-priority/

[iii] Based on estimate of 136,000 sector jobs in 2012 and the creation of up to 130,000 jobs by 2027 through recycling of carbon taxes: Department of Energy & Climate Change, Energy Efficiency Strategy: 2013 Update, Dec 13; Consumer Futures, Jobs, growth and warmer homes, Oct 1

[iv] According to Building the Future: The economic and fiscal impacts of making homes energy efficient, published by Verco and Cambridge Econometrics

[v] Amber Rudd speech to Conservative Party Conference, October 2015 https://www.politicshome.com/energy-and-environment/articles/news/amber-rudd-speech-conservative-party-conference

[vi] http://energiesprong.nl/transitionzero/

[vii] http://energiesprong.nl/transitionzero/

[viii] HM Treasury Spending Review 2015 https://www.gov.uk/government/publications/spending-review-and-autumn-statement-2015-documents/spending-review-and-autumn-statement-2015

[ix] https://connect.innovateuk.org/web/building-performance-evaluation/articles

Submission

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8th January 2016

National Infrastructure Commission (NIC): Call for Written Evidence

Introduction

RICS – Royal Institution of Chartered Surveyors - is pleased to respond to the above consultation. Intelligent infrastructure planning is vital to the social and economic health of the country, and the creation of the NIC to identify the UK's infrastructure priorities is hugely welcome. The Commission now needs to fulfill its potential, and our response sets out some of our ideas on how this can be achieved.

RICS is the leading organization of its kind in the world for professionals in property, construction, land and related environmental issues. As an independent and chartered organization, RICS regulates and maintains the professional standards of over 100,000 qualified members (FRICS, MRICS and AssocRICS) and over 50,000 trainee and student members.

It regulates and promotes the work of these property professionals throughout 146 countries and is governed by a Royal Charter approved by Parliament, and monitored by the Privy Council, which requires it to act in the wider public interest.

Since 1868, RICS has been committed to setting and upholding the highest standards of excellence and integrity – providing impartial, authoritative advice on key issues affecting businesses and society. RICS is a regulator of both its individual members and firms enabling it to maintain the highest standards and providing the basis for unparalleled client confidence in the sector.

RICS and Infrastructure

Our members are integral to providing the necessary project management and cost savings through the whole life of infrastructure projects. They use professional standards and relevant guidance, as well as benchmark data, to deliver projects on time and on budget. This ensures that infrastructure projects are considered, planned for, financed and executed appropriately, crucial to ensuring business and investor confidence. In addition, we can provide expertise on spatial planning and locational investment to equip the Commission to make effective strategic choices on the UK's infrastructure priorities.

We were at the forefront of calling for a National Infrastructure Commission to develop a long-term strategic approach to the UK's infrastructure needs, and the establishment of the Commission last year was a highly intelligent step towards achieving this. We are continually

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developing our activities in the infrastructure sphere and will work closely with the Commission to meet the UK's infrastructure needs.

We are unique amongst the professional institutions for the built environment in the breadth and depth of our understanding across land, property and construction. We also have strong working relationships with other organisations across the sector, and are uniquely placed to engage with the Commission to develop a holistic strategic approach.

It is in this spirit that we have launched the [Infrastructure Forum Steering Group], which is designed to give a voice to the best practice commercial delivery on UK infrastructure projects, and to lead a significant forum of professionals who seek to maintain and enhance value outcomes for lower levels of expenditure. The membership of this group includes leading figures from across the built environment, not just RICS members, and can be an invaluable source of advice, expertise and input for the work of the Commission.

Our President-Elect Amanda Clack plays a leading role in the infrastructure sector as Head of Infrastructure at EY. Her previous experience of working across land, property and construction for PwC gives her a unique insight into the issues involved, and she has written extensively on the challenges that need to be overcome if we are to deliver the UK's infrastructure requirements. Amanda has steered our infrastructure work and will continue to do so when she becomes President later this year. Her appointment as President will be another opportunity for RICS to support the work of the NIC and we look forward to continuing our collaboration.

This submission addresses a selection of the questions raised in the call for evidence. We have engaged widely across the sector in formulating the response, which is based on a large number of research papers, thought leadership pieces and other documents which can be provided to the Commission upon request.

Connecting Northern Cities

1. To what extent are weaknesses in transport connectivity holding back northern city regions (specifically in terms of jobs, enterprise creation and growth, and housing)?

Our members strongly perceive the lack of sufficient connectivity between northern city regions to be a severe constraint on economic growth and a threat to the realisation of the Northern Powerhouse. The 2014 Report produced to support the Higgins Review of HS2 – *Transport Constraints and Opportunities in the North of England* – identified many of the costs associated with the relative weakness of connectivity infrastructure in northern regions – specifically between the large city regions. For example, commuting between Manchester and Leeds is found to be 40% lower than would be expected given the size, location and socio-economic profiles of the two city regions[1]. This is largely due to prohibitive transport costs associated with such commutes, in the form of longer journey times and ticket prices. This has a real knock-on effect in terms of labour mobility, the flexibility of the housing market and business creation.

[1] Steer Davies Gleave, *Transport Constraints and Opportunities in the North of England*, 2014

The problem of connecting northern cities is particularly significant because, in common with all areas of the UK, the economic health of the region as a whole is dependent on economic growth within its largest cities. Urban areas benefit from the advantages associated with the concentration of jobs and enterprises within a specific area. Productivity is higher in urban centres, with output per worker 15% more than in rural areas. The five largest Northern cities of Manchester, Liverpool, Leeds, Sheffield and Newcastle account for 60% of the region's Gross Value Added (GVA), and for this strength to be leveraged for the benefit of the whole region, the transport infrastructure connecting them needs to be radically improved.

Infrastructure spending per head in the North is vastly lower than in London. For example, whilst the figure for London is £5,426 per head, the North West receives £1,248, Yorkshire and the Humber £581 and the North East a mere £233[2]. Whilst it is understandable that investment in the capital is very high, the disparity needs to be addressed if the government is to achieve its stated objective of rebalancing the UK economy and unleashing the potential of the Northern Powerhouse.

2. What cost-effective infrastructure investments in city-to-city connectivity could address these weaknesses?

The announcement in the Autumn Statement that HS2 will extend from Birmingham to Crewe 6 years earlier than initially planned was very welcome given the need for certainty and clarity over investment plans. Our members were also pleased to see the funding for Transport for the North (TfN) confirmed at £50 million as part of an overall transport budget of £13 billion.

The simple fact is that the Northern Powerhouse does not at present have any real meaning as a coherent entity due to the excessive travel times between its various regions. For example, a rail journey from Newcastle to Manchester takes 2-3 hours, whilst a journey from Liverpool to Hull takes 3 hours. This is in stark contrast with the south, where journeys of similar distances typically last less than 2 hours. To address these issues, the Manchester-Leeds transport corridor needs to be improved, and cities currently outside of major planned developments such as HS2 need to be better integrated into the system as a whole. Road transport should be similarly improved, as the motorway network currently suffers from many of the same shortcomings as the rail system.

It should also be recognised that there are significant gains to be made from improvements to the existing infrastructure – connectivity improvements between northern hub cities will not always necessitate entirely new projects. Too often infrastructure is seen as being synonymous with brand new schemes, and the benefits of maintaining and improving existing transport links should not be underestimated.

3. Which city-to-city corridor(s) should be the priority for early phases of investment?

[2] IPPR North, *Transformational Infrastructure for the North*, 2014

As is referred to above, the economic health of the North as a whole depends on stronger transport links between all of its core cities. Until connectivity between cities such as Newcastle, Liverpool and Hull is improved to create a single, coherent economic unit, there is no incentive for policymakers in any of these regions to agree to investment in improvements in other areas when their electorate or employees cannot benefit because travel times and fares put jobs there out of reach.

The concept of a HS3 corridor between Manchester and Leeds would be a good starting point, but it is vital that the concerns of other cities are also addressed. In particular, there is a perception in the North-East that cities such as Newcastle, Sunderland and Middlesbrough could be left out of the equation as the Northern Powerhouse agenda proceeds. These cities must be given careful consideration as the network as a whole is developed.

4. What are the key international connectivity needs likely to be in the next 20-30 years in the north of England (with a focus on ports and airports)? What is the most effective way to meet these needs, and what constraints on delivery are anticipated?

In terms of the North East of England, the joint report 'Faraway so close: the North East as an international gateway' from IPPR and NECC puts forward a well-argued case for the development of North East ports and airports to create a better international gateway on the eastern side of the country (http://www.ippr.org/publications/faraway-so-close-the-north-east-as-an-international-gateway). This would underpin the development of manufacturing in the region, which remains the only English region with a consistent positive balance of trade.

5. What form of governance would most effectively deliver transformative infrastructure in the north, how should this be funded and by whom, including appropriate local contributions?

A major threat to the delivery of a coherent and integrated transport system for the North is the fragmentation of governance structures. As has already been stated, the Northern Powerhouse is not (and arguably can never be) a monolithic entity. The region comprises numerous different cities and areas with different agendas and priorities; the creation of a successful infrastructure network serving the whole of the north requires that these disparate areas cooperate and coordinate with one another.

The establishment of TfN was a welcome step in terms of the strategic oversight it can provide for transport infrastructure in the north. It is vital that this body works closely with industry leaders and elected Mayors in ascertaining the needs of the region, and the RICS is willing to provide support and advice. At present TfN is very much public-sector dominated and it must work in close partnership with the private sector if it is to be effective.

The devolution announcements made by the Chancellor last year were a bold statement of intent with regards to shifting power from Whitehall to local authorities, and could be the start of a process that allows all regions of the UK to fulfil their potential. In practice, the delivery of City Deals now needs to ensure that fragmentation is avoided. For example, whilst directly elected

Mayors can provide effective local leadership in delivering infrastructure developments, they could also result in competing demands and conflicts of interest which hinder developments of regional and national strategic importance. Mayors will need to recognise the value of collaboration, and the NIC should make a compelling case for cooperation between cities when publishing its National Infrastructure Assessments.

The granting of powers over business rates to elected Mayors, giving them the power to increase the rate by 2% to fund major infrastructure projects (in agreement with local businesses) is a welcome incentive for Mayors to take ownership of development in their regions. By decoupling infrastructure spending from the vagaries of direct government grants, this should help northern cities take a more flexible and strategic view of long-term infrastructure requirements, and again this is an area where the recommendations of the NIC can add significant value. However, more clarity is needed on whether the increased funding from business rates retention and the power to increase rates will be sufficient to meet any shortfall from the reduction of direct grants. The final funding settlement needs to ensure infrastructure spending is protected.

London's Transport Infrastructure

1. What opportunities are there to increase the benefits and reduce the costs of the proposed Crossrail 2 scheme?

The Government's Construction 2025 strategy set ambitious targets to reduce costs by 33% and delivery times by 50%. For these ambitions to be met on large-scale strategic infrastructure projects like Crossrail 2, delivery needs to be significantly improved – around 75% of capital projects are still reported as going over budget. The surveying professionals represented by the RICS, particularly commercial managers and quantity surveyors, are indispensable to the achievement of cost savings on the scale required.

A key element of the Construction 2025 strategy is the creation of an infrastructure sector "underpinned by strong, integrated supply chains and productive long term relationships". To explore how this vision can be realised, RICS are currently working on a number of high-level Insight Papers to be published over the next year, across Building Information Modelling and Engineering, SME Engagement, Skills & Training, Team Building, Procurement, and Whole Life Cycle Costing of Rail Assets. The findings of these papers will apply to all rail projects, and will be especially applicable to the delivery of Crossrail 2.

The working hypothesis underpinning these Insight Papers recognises that the rail infrastructure industry is naturally fragmented but that better alignment could be secured through reaching a better understanding of enablers and measures (e.g. technology, policies, and training) and by focusing on ways of removing such barriers.

In addition, some of our members have expressed the desire to see stronger links between Crossrail 2 and Gatwick Airport as a way of improving access from across the capital and by extension, across the South-East more broadly.

2. What are the options for the funding, financing and delivery of large-scale transport infrastructure improvements in London, including Crossrail 2?

The past decade has seen some major strategic successes in the delivery of large-scale infrastructure projects in the capital, most notably on the 2012 Olympics and Crossrail. These achievements were made possible because they were based on a political consensus, a bold strategic vision, and they made effective use of innovative public-private delivery partnerships. Future infrastructure projects need to recognise what went right in these cases and where possible, replicate their experience.

The successful delivery of infrastructure requires both public strategic oversight and private delivery and funding mechanisms. The benefits of infrastructure for private investors are primarily the scale, longevity and certainty of long-term returns, and the NIC should assess how the full potential of private investment in the sector can be unlocked. We have already written to Commercial Secretary to the Treasury Lord O'Neill offering to convene a review of the barriers to infrastructure investment through collaboration across the built environment professions. Infrastructure cannot be entirely reliant on international investment and pension funds, and we are willing to work with the Commission to explore in-depth how funding can be obtained from other sources.

Electricity Interconnection and Storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The most effective way to minimise cost to the consumer is to ensure that as new forms of energy come forward, they are delivered in a technology neutral manner deploying the lowest cost generation mix. A mix of intermittent and base load needs to be delivered with the true cost of carbon being accounted for, coupled with the likelihood that currently all forms of new generation need some form of market support mechanism.

In the short term given the lack of new generation and investment coming forward, there needs to be certainty for investors in new generation, something that the ongoing changes to renewables and CCS funding have severely affected.

Balancing supply and demand will require the mix of generation types, whilst the meeting of climate change targets will require continued deployment of renewables alongside other new low carbon base load. In the short term the premature closure of existing thermal coal plants will adversely affect supply/demand and balancing if these plants are taken off line before there is a clear pathway to delivering fossil fuel plants with carbon capture and storage. If an SO can assist in achieving these objectives then it will be of benefit.

2. What are the barriers to the deployment of energy storage capacity?

The energy storage sector within the UK is immature and requires policy, regulatory and market support mechanisms to ensure that the long-term investment required can be delivered.

There is a need for storage technology at all of levels. For those that would work within the transmission network and distribution network scales, the investment will be significant and therefore needs clear government focus and support to ensure that new storage investment and technologies are able to come forward and work effectively within the current UK market mechanism.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnection plays an important part of the UK supplier/demand arrangements, but there appears to be an increasing over-reliance upon interconnection with mainland Europe rather than bringing new generation capacity on stream within the UK. There are a number of implications of this, including over reliance on non-UK generation at the time of tight capacity margins. They do nothing to stimulate investments into new UK-based low carbon generation, whilst adding to carbon leakage as emissions have the potential to become 'offshored'. For example, fossil fuel plant within the UK has to bear the significant extra cost of the UK's unilateral carbon floor price, whilst fossil fuel generation in Europe does not bear the same level of carbon taxation, and is able to export into the UK via interconnectors.

Yours faithfully

Lewis Johnston
Public & Parliamentary Affairs Officer, RICS
e. [email address redacted]

From: Garde, Howard [email address redacted]
Sent: 08 January 2016 16:24
To: EnergyEvidence Infrastructure-Commission
Cc: Clawson, Ronnie; Houghton, Barbara
Subject: Consultation Response

Dear Sirs,

We believe that it would be beneficial for the National Infrastructure Commission to carry out a consultation on how best to make the existing housing infrastructure energy efficient and de-carbonise our heating infrastructure in the most cost effective way.

The Government's own economic data shows that investment in energy efficiency would deliver comparable economic returns to other major infrastructure projects, but would also strengthen energy security, mitigate the increase in future demand on the electricity infra-structure and help meet national carbon budgets.

Riverside is a major provider of affordable housing in England and Scotland with over 52,000 homes in management.

Through our housing, care and support services, we enable people facing a wide variety of challenging circumstances to lead more resilient and independent lives.

Affordable warmth is one of the main challenges facing our customers and living in cold conditions is known to adversely affect physical and mental health.

Whilst Riverside has invested in improving the energy performance of our homes, the scale of required investment to bring all properties to an acceptable level is not possible without clear government policy to make energy efficiency a national infra-structure priority.

Yours faithfully,

Howard Garde
Energy Project Manager

Riverside, 2 Estuary Boulevard, Estuary Commerce Park, Liverpool. L24 8RF.
[phone number redacted] Riverside: 0345 111 0000
Follow Riverside @RiversideUK

giving nature a home

National Infrastructure Commission (NIC)

Response from the RSPB to the Call for Evidence

December 2015

Contact: Simon Marsh, Head of Sustainable Development, RSPB, The Lodge, Sandy, Bedfordshire SG19 2DL. Tel: [phone number redacted]. E-mail: [email address redacted]

SUMMARY

The RSPB welcomes the creation of the National Infrastructure Committee (NIC) and the opportunity that this provides to analyse and assess long-term infrastructure needs in a coordinated and strategic way.

Whilst we accept that '*better infrastructure is vital to improve the needs of British people*'[1], it is also vital – in order to achieve truly sustainable development – that this infrastructure is delivered in harmony with nature. Taking this approach would not only help to save nature, it would also provide a wide range of social and economic benefits,

Our recommendations are outlined below:

Green infrastructure

The NIC's remit should include consideration of the UK's strategic, long-term green infrastructure requirements as determined by the Natural Capital Committee. Such consideration must be designed to ensure that NIC recommendations complement, not undermine, the Government's 25 year plan to save the UK's biodiversity.

Taking a spatial approach

The NIC should:

- Recommend the creation – and lead on the development – of a 'light-touch', national spatial framework for the provision of key national infrastructure needs over the next 30 years.
- Undertake strategic environmental assessments of the UK's strategic infrastructure requirements.

Connecting northern cities

The NIC should ensure that its:

- Evidence base includes consideration of environmental impacts, particularly in relation to nature conservation designations of national and international importance.
- Recommendations on future investment priorities would result in no significant

[1] Statement from Chancellor George Osborne, launching the National Infrastructure Commission on 30th October 2015. https://www.gov.uk/government/news/infrastructure-at-heart-of-spending-review-as-chancellor-launches-national-infrastructure-commission

adverse effects on nature conservation designations of national and international importance.

London's transport infrastructure

The NIC should recommend that:

- The use of clean, excavated material - resulting from improvements to London's transport infrastructure – in habitat creation / flood risk management schemes should be classed as recovery, rather than waste disposal.
- Habitat creation / flood risk management schemes should be a primary option when considering how to dispose of clean, excavated material resulting from improvements to London's transport infrastructure.
- Infrastructure is provided to facilitate the transportation of excavated material – resulting from improvements to London's transport infrastructure - by train and by boat, including the provision of jetty facilities at coastal or riparian destinations.

Energy

The NIC should recommend that the UK's energy infrastructure needs be met in a way that:

- Reduces greenhouse gas emission by at least 80% from 1990 levels by 2050;
- Delivers a low-carbon energy sector by 2030;
- Maximises the use of renewable energy technologies and minimises reliance on fossil fuels;
- Is delivered in harmony with nature, resulting in no significant adverse effects and, where possible, delivering net-gains for biodiversity.

INTRODUCTION

The RSPB welcomes the creation of the National Infrastructure Committee (NIC) and the opportunity that this provides to analyse and assess long-term infrastructure needs in a coordinated and strategic way.

Whilst we accept that '*better infrastructure is vital to improve the needs of British people*'[2], it is also vital – in order to achieve truly sustainable development – that this infrastructure is delivering in harmony with nature. In particular, this infrastructure should be delivered in a way that:

- avoids adverse effects on our existing environmental assets, particularly those of national and international importance;
- delivers a net gain in biodiversity and contributes to establishing coherent and resilient ecological networks;
- contributes to people's health and wellbeing;
- mitigates – and facilitates adaptation to – the impacts of climate change.

Taking this approach would not only help to save nature, it would also provide a wide range of social and economic benefits (as outlined in the section on Green Infrastructure, below).

[2] Statement from Chancellor George Osborne, launching the National Infrastructure Commission on 30th October 2015. https://www.gov.uk/government/news/infrastructure-at-heart-of-spending-review-as-chancellor-launches-national-infrastructure-commission

In some instances, the natural environment can, itself, provide a cost-effective and sustainable alternative to expensive, 'hard' infrastructure, for example, through the managed realignment of coastal flood defences.

We understand that the Chancellor will consult further on the purpose and structure of the Commission and other matters. Our comments on green infrastructure and taking a spatial approach are relevant to the NIC's remit and therefore this further consultation, but are included here as they are fundamental to our view of the NIC's work and our response to the NIC's three key focus areas.

The NIC's terms of reference - and the questions that it poses in its call for evidence - currently give little emphasis to the principles above or to the related issues outlined below. In our recommendations, we identify how the NIC can potentially address these concerns.

GREEN INFRASTRUCTURE

Infrastructure can be defined as '*the fundamental facilities and systems servicing a country, city or area*'[3]. In the context of the UK's infrastructure needs, this is normally taken to mean the 'hard' infrastructure of physical structures such as roads, bridges, tunnels, water supply and sewerage systems, electricity grids, etc. However, in its broadest sense, it also encompasses what is commonly referred to as 'green' infrastructure – the network of green spaces and other environmental features that are integral to the health and quality of life of sustainable communities. It is based on the principle that protecting and enhancing nature and natural processes, and the many benefits human society gets from nature, should be consciously integrated into spatial and development planning.

This green infrastructure is central to the future of the economy and people's health and wellbeing. For example, it delivers essential 'ecosystem services' (life-support systems), such as capturing and storing carbon, flood protection and water purification. It enables contact with nature and active recreational use of natural green spaces, which contributes to people's psychological well-being and physical health. As such, it plays a crucial role in addressing the country's health crisis, which is being caused by spiralling levels of physical inactivity, obesity and mental health issues. It is also key in shaping the character and quality of the places in which people live and work. Finally, in many instances, it can actually provide a cost-effective and sustainable alternative to expensive, 'hard' infrastructure projects, for example, through the managed realignment of flood defences. The Natural Capital Committee's third report[4] makes a very strong economic and social case for the importance of elements of green infrastructure– such as green spaces, parks, green roofs, and sustainable drainage systems – to the future success of the country.

The wide range of benefits provided by green infrastructure makes it clear that it should be at the heart of any analysis and assessment of the UK's long-term infrastructure needs, both in the context of providing 'hard' infrastructure and in its own right.

[3] http://dictionary.reference.com/browse/infrastructure
[4]http://nebula.wsimg.com/272833c20f4e7f67e2799595a7f06088?AccessKeyId=68F83A8E994328D64D3D&disposition=0&alloworigin=1

25 year plan for nature

The Government has committed in its manifesto and subsequent statements to '*develop a 25 year plan to restore the UK's biodiversity*'. This provides an impetus to deliver green infrastructure at a strategic level, contributing to the Government's international obligations to restore biodiversity.

In 2013, 25 of the UK's nature conservation and research organisations came together to produce the *State of Nature* report, setting out the state of our wildlife[5]. The key finding of this report was that 60% of the 3,148 species that were assessed have declined in the last 50 years, and 31% have declined strongly. The follow-up report, *Response for Nature*[6], sets out 10 key actions that the Government must include as part of its 25-year plan to restore the UK's biodiversity.

The proposed Response for Nature actions are the responsibility of departments across government. Those of most relevance to the NIC are:

- **Set goals for nature and natural capital** - including a commitment to secure the effective management of a sixth of land for nature by 2020.
- **Defend and implement the laws that conserve nature** - including working to improve the implementation of the Birds and Habitats Directives and supporting the introduction of a low-carbon infrastructure plan.
- **Deliver an ecological network on land and at sea** - including creating a national ecological network and completing a spatial analysis of the ecological network.
- **Improve the connection of people to nature** - including a commitment to improve public health locally, by increasing the extent, quality and accessibility of natural green and blue spaces in all urban and rural settlements.

The NIC is not currently set up to deal with issues of green infrastructure. If our recommendation is pursued, consideration needs to be given to securing the relevant expertise from bodies such as Natural England, the Environment Agency and the NGO sector.

Recommendation:

- The NIC's remit should include consideration of the UK's strategic, long-term green infrastructure requirements as determined by the Natural Capital Committee. Such consideration must be designed to ensure that NIC recommendations complement, not undermine, the Government's 25 year plan to save the UK's biodiversity.

[5] Burns F, Eaton MA, Gregory RD, et al. (2013) *State of Nature report*. The State of Nature Partnership. https://www.rspb.org.uk/Images/stateofnature_tcm9-345839.pdf

[6] Response for Nature partnership (2015) *Response for Nature: England.* *http://www.rspb.org.uk/Images/responsefornature_england_tcm9-407740.pdf*

TAKING A SPATIAL APPROACH

The NIC is charged with offering unbiased analysis of the UK's long-term infrastructure needs and with holding government to account for its delivery. It will also be charged with beginning work on a national infrastructure assessment, looking ahead to requirements for the next 30 years.

The delivery of the UK's long-term infrastructure needs will, to a large extent, be spatial in nature (i.e. particular infrastructure will be delivered in particular locations). As such, strategic spatial planning should play a key role in the NIC's analysis and assessment of these infrastructure needs.

Whilst the local plan process can help to identify specific locations for specific local infrastructure improvements, this level of spatial planning is not sufficient to facilitate the delivery of national infrastructure needs. This will be true even where local authorities take a more co-ordinated approach to infrastructure provision, for example, through the devolution of powers to combined authorities. What is needed is a 'light-touch', national spatial framework showing options and proposals for key infrastructure provision over the next 30 years. This framework should complement related plans and strategies, such as the low carbon infrastructure plan proposed in our response on energy infrastructure (see above).

Strategic environmental assessment (SEA) should play a key role in this spatial planning process. SEA can be a particularly useful tool when considering the range of alternative options for future infrastructure provision, including consideration of different technologies and locations.

Strategic spatial planning and SEAs relating to the improvement of existing infrastructure, such as trans-Pennine transport routes, should be relatively straightforward. However, a more innovative approach will be required for other infrastructure issues such as the provision of a low-carbon energy system. The RSPB is currently developing a spatial framework that will identify how this low-carbon energy system can be delivered in harmony with nature. This has the potential to provide an essential tool for the NIC in developing its own spatial plan. The findings and recommendations of this project will be launched in 2016.

Further advice on spatial planning with nature in mind is provided in the RSPB / RTPI publication, Planning Naturally[7].

Recommendations:

The NIC should:

- recommend the creation – and lead on the development – of a 'light-touch', national spatial framework for the provision of key national infrastructure needs over the next 30 years;
- undertake strategic environmental assessment of the UK's strategic infrastructure requirements.

[7] RSPB (2013) *Planning Naturally: spatial planning with nature in mind in the UK and beyond.* *http://www.rspb.org.uk/Images/planningnaturally_tcm9-349413.pdf*

CONNECTING NORTHERN CITIES (Call for Evidence) / FUTURE INVESTMENT IN THE NORTH'S TRANSPORT INFRASTRUCTURE (Terms of Reference)

The RSPB does not seek to comment directly on the questions that have been posed in the NIC's call for evidence on the issue of connecting cities in northern England. However, we would like to comment on the NIC's terms of reference for providing advice to government on future investment priorities to improve connectivity between cities in northern England, particularly across the Pennines.

The NIC's terms of reference state that the NIC must first establish the evidence base and identify the options available. This must include evidence of the potential environmental impacts of the various strategic options for future transport investment. This should be addressed as a crucial issue by the NIC, given that several of the proposed trans-Pennine infrastructure improvements cut across sites of international importance for nature conservation (i.e. Special Protection Areas (SPAs) and Special Areas of Conservation (SACs)). Relevant SPAs / SACs - and the infrastructure proposals which could potentially have a significant effect on these designations - are outlined in Annex 1.

Under the Conservation of Habitats and Species Regulations 2010 ('the Habitats Regulations'), if any of these projects may have a 'likely significant effect' on the SPAs / SACs (either individually or in combination with other plans or projects), it must be made subject to an "appropriate assessment" of its implications for the site in view of the site's conservation objectives. This assessment is commonly referred to as a Habitats Regulations Assessment (HRA). **The projects may only proceed if they will not adversely affect the integrity of the site concerned**, unless the so-called 'derogation tests' apply. These include a test that there are no less-damaging alternatives to achieving the objectives of connectivity.

Recommendations:

The NIC should ensure that its:

- Evidence base includes consideration of environmental impacts, particularly in relation to nature conservation designations of national and international importance.
- Recommendations on future investment priorities would result in no significant adverse effects on nature conservation designations of national and international importance.

LONDON'S TRANSPORT INFRASTRUCTURE (Call for Evidence / Terms of Reference)

The RSPB's main interest in the issue of London's transport infrastructure is the use of excavated material deriving from improvements to this infrastructure. Our comments relate to Question 3 and 4 posed by the NIC in its Call for Evidence[8] and to the NIC's terms of reference on this issue.

Improvements to London's transport infrastructure result in the production millions of tonnes of excavated material that needs to be disposed of each year. Not only is this disposal

[8] Question 3. What opportunities are there to increase the benefits and reduce the costs of the proposed Crossrail 2 scheme?; Question 4. What are the options for the funding, financing and delivery of large-scale transport infrastructure improvements in London, including Crossrail 2?

potentially hugely expensive, but the transportation of this material also provides a significant challenge.

The Wallasea Island Wild Coast project provides an excellent example of how the benefits of such infrastructure improvements can be greatly increased and the costs significantly reduced. In this project, three million tonnes of excavated material from London's Crossrail project has been used to help create 670ha of new, tidal, wetland habitat. See Annex 2 for further details of this project.

One of the key factors that made the use of Crossrail's excavated material financially viable was that the Environment Agency classed this use as 'recovery' – as defined in Article 3(15) of the Waste Framework Directive (Directive 2008/98/EC on waste) - rather than 'waste disposal'. As such, the use of this material is subject to a much less stringent – and, therefore, much cheaper – regulatory regime than would be required for a waste disposal operation. The 'recovery' classification has also resulted in savings of approximately £200 million because landfill tax has not had to be paid for the disposal of this material.

However, the Environment Agency's decision to class the use of this material as 'recovery' has been somewhat controversial. For example, in a recent Court of Appeal case, the Environment Agency's legal representative '*argued that the EA* [Environment Agency] *itself had erred in law in granting a standard rules environmental permit (i.e. a recovery operations permit) in respect of the use of Crossrail waste spoil for the creation of a nature reserve in the Wallasea decision.*'[9]

Given the issues raised about Wallasea in the Court of Appeal case, it is by no means certain that a recovery permit will be granted for the use of excavated material at Wallasea, or for similar projects, in the future. If the use of this material is classed as 'waste disposal', it could jeopardise the completion of the Wallasea project (which still requires an additional seven million tonnes of material) and the delivery of similar habitat creation / flood risk management projects in the future. Last, but not least, it would also add hundreds of millions of pounds to the cost of improving London's transport infrastructure.

Recommendations:

The NIC should recommend that:

- The use of clean, excavated material - resulting from improvements to London's transport infrastructure – in habitat creation / flood risk management schemes should be classed as recovery, rather than waste disposal.
- Habitat creation / flood risk management schemes should be a primary option when considering how to dispose of clean, excavated material resulting from improvements to London's transport infrastructure.
- Infrastructure is provided to facilitate the transportation of excavated material – resulting from improvements to London's transport infrastructure - by train and by boat, including the provision of jetty facilities at coastal or riparian destinations.

[9] Tarmac Aggregates Ltd, R (on the application of) v The Secretary of State for Environment, Food and Rural Affairs & Anor *[*2015] EWCA Civ 1149http://www.bailii.org/ew/cases/EWCA/Civ/2015/1149.html

ELECTICITY INTERCONNECTION AND STORAGE (Call for Evidence) / DELIVERING FUTURE-PROOF ENERGY INFRASTRUCTURE (Terms of Reference)

The RSPB's main areas of concern relate to the NIC's Terms of Reference, rather than the questions posed in the Call for Evidence. In particular, we are concerned about the lack of any reference to (i) the Government's legally binding targets to reduce greenhouse gas emissions or (ii) the Climate Change Committee's recommendation to achieve a low carbon energy system (including a low carbon electricity network) by 2030.

Potential impacts of climate change

Climate change is the greatest single long-term threat to nature and to people, with one in six species at risk of extinction by 2100 if the temperature changes modelled by the Intergovernmental Panel on Climate Change (IPCC) come to pass[10].

The RSPB recently published a new report on the impacts that climate change is already having on wildlife[11]. For example, the 70% decline in UK kittiwake populations since the 1980s has been linked to climate change. Over the course of this century, impacts will only intensify and increase, particularly if action is not taken to limit climate change.

To avert these risks — and to enjoy the economic and social benefits of a healthy, natural environment — will require a transition to a low-carbon economy that takes place in harmony with nature.

Climate change targets

The UK marked itself out as a world leader in tackling climate change through the introduction of the Climate Change Act in 2008. It became one of the first countries in the world to set legally binding domestic climate change targets and, since then, many other countries have followed suit. These climate change targets set the UK on a trajectory to reduce its economy-wide greenhouse gas emissions by at least 80% from 1990 levels by 2050.

In order to keep on track for this 80% reduction, the Government's independent advisory body, the Committee on Climate Change (CCC) recommends that the UK needs to have reduced its emissions by 37% relative to 1990 levels by 2030. In order to achieve this, the UK needs a low carbon power sector that produces no more than 100 gCO_2/kWh. At present, our energy system has a 'carbon intensity' of around 450 gCO_2/kWh.

The CCC has said that while the UK is on track to meet its third carbon budget, there is concern about longer term progress. In order to meet the fourth carbon budget, 'significant action' will be required during this Parliament in order to keep the UK on track.[12]

An additional factor to be considered is the new evidence, published in the journal *Nature,* which has shown that, globally, the majority of fossil fuels will need to stay in the ground, if we are to achieve the global aspiration to keep temperature rises below two degrees[13].

[10] https://www.sciencemag.org/content/348/6234/571.full
[11] http://www.rspb.org.uk/natureclimate
[12] https://www.theccc.org.uk/wp-content/uploads/2015/06/6.737_CCC-BOOK_WEB_030715_RFS.pdf
[13] http://www.nature.com/nature/journal/v517/n7533/abs/nature14016.html [Globally, a third of oil reserves, half of gas reserves and over 80 per cent of current coal reserves should remain unused from 2010 to 2050 in order to meet the target of 2 °C]

Transition to a low carbon energy system

The UK's energy infrastructure has shifted towards a lower-carbon energy system in recent years, including increased levels of renewable energy and the proposed phasing out of unabated coal. However, recent cuts to support for energy efficiency measures, solar, onshore wind and carbon capture and storage (CSS) technology, as well as an ongoing enthusiasm for developing new gas infrastructure, including fracking, could all jeopardise the UK's trajectory to a low-carbon future.

It is critical that the UK Government sets out new support for the renewable and energy efficiency sector in order to drive investment in the infrastructure we will need over the coming years and decades to achieve this low-carbon future. With the costs of established renewable energy technologies in the UK (onshore and offshore wind, solar) falling all the time[14][15], we believe that renewable technologies, coupled with demand reduction and energy efficiency measures, are likely to meet our energy needs at costs similar to - or cheaper than a - higher-carbon pathway.

Delivering energy infrastructure in harmony with nature

The RSPB strongly supports the appropriate siting of all infrastructure, such that it avoids adverse impacts on the natural environment. The RSPB is currently reviewing evidence and modelling potential impacts of different levels of deployment of a range of energy technologies. We will be publishing our findings and our recommendations on how to deliver energy infrastructure in harmony with nature in 2016.

Recommendations:

The NIC should recommend that the UK's energy infrastructure needs be met in a way that:

- (i) reduces greenhouse gas emission by at least 80% from 1990 levels by 2050;
- (ii) delivers a low-carbon energy sector by 2030;
- (iii) maximises the use of renewable energy technologies and minimises reliance on fossil fuels;
- (iv) is delivered in harmony with nature, resulting in no significant adverse effects and, where possible, delivering net gains for biodiversity.

[14] http://energydesk.greenpeace.org/2015/09/21/4-ways-the-uk-can-get-almost-all-its-power-from-renewables/
[15] http://about.bnef.com/press-releases/wind-solar-boost-cost-competitiveness-versus-fossil-fuels/

ANNEX 1. TRANS-PENNINE INFRASTRUCTURE PROPOSALS & INTERNATIONAL NATURE CONSERVATION DESIGNATIONS

The designations of most relevance to the proposed trans-Pennine infrastructure improvements are the Peak District Moors (South Pennine Moors Phase 1) SPA / South Pennine Moors SAC and the North Pennine Moors SPA / SAC. Key habitats in these designations include European dry heath and blanket bog, which provide a wide range of ecosystem services, including carbon sequestration. Key bird species include golden plover (*Pluvialis apricaria*) and merlin (*Falco columbarius*).

The Trans-Pennine infrastructure proposals which could have an effect on these designations are outlined below:

(i) Improvements to the A628 (Manchester - Barnsley road): About 5km of the A628 road is straddled by the Peak District Moors (South Pennine Moors Phase 1) SPA / South Pennine Moors SAC, with an extra 1.5km where the SPA / SAC is on the south side only (i.e. 6.5km in total).

(ii) Viability study for a Trans-Pennine road tunnel between Manchester and Sheffield: The Woodhead Tunnel would use an old (double) railway tunnel underneath the Peak District Moors (South Pennine Moors Phase 1) SPA / South Pennine Moors SAC, so would negate the need for the passing lane on the A628 for the 6.5km of SPA / SAC mentioned in (i) above.

(iii) Improvements to the A57 between Manchester and Sheffield: About 5km of the Peak District Moors (South Pennine Moors Phase 1) SPA / South Pennine Moors SAC straddle the A57 on both sides.

(iv) Viability study for dualling of the A66 (Penrith - Darlington road) and A69 (Carlisle - Newcastle Road): About 1km of the A66 is straddled by the North Pennine Moors SPA / SAC, with an extra 5km where the SPA / SAC is on the north side only (i.e. 6km in total).

ANNEX 2. Wallasea Island Wild Coast Project

Wallasea Island Wild Coast Project is a unique partnership between the RSPB and Crossrail which brings together Europe's largest civil engineering project and Europe's largest intertidal habitat creation project. The project demonstrates how major infrastructure schemes can help to enhance nature and ‘future proof’ low lying coasts against sea level rise caused by climate change as well as generating economic growth.

The project will transform 670ha of levee-protected farmland – an area twice the size of the City of London - back to a wetland landscape of mudflats and saltmarsh, lagoons and pasture. It will help to compensate for the loss of such tidal habitats on internationally important sites elsewhere. Once the project is completed, Wallasea Island, which lies 8 miles north of Southend-on-Sea in Essex, will provide a haven for a wonderful array of nationally and internationally important wildlife and an amazing place for the local community, and those from further afield, to come and enjoy.

The challenges that the Wallasea project seeks to address are real and pressing. Four hundred years ago, the Essex coast was a wild and stunning place, a haven for wildlife – including 30,000ha of intertidal saltmarsh - and a source of livelihood for local communities. Sadly, today, less than one tenth (2,500ha) of this wild coast remains due to land claim for agriculture and accelerating coastal erosion. Across England, saltmarshes and mudflats are continuing to decline at a rate of 100 hectares a year. This rate of loss will accelerate with climate change as rising sea levels and more storminess steadily erode the precious transition zone between land and sea.

With much of the island lying 2-3 metres below sea level at high tide, it has become uneconomic to protect Wallasea with traditional, hard engineering flood defences (i.e. sea walls). The project demonstrates a more sustainable approach to flood risk management, using managed realignment. Current flood defences will be breached, allowing flood water to be let into the island in a controlled way in the event of a tidal surge. This will reduce the risk of an unmanaged breach and associated negative impacts, including disruption to navigation, erosion of adjacent sea defences and loss of built assets on Wallasea. The project will also help to mitigate the impacts of climate change by sequesting approximately 4 tonnes of carbon dioxide per hectare (i.e. over 2,000 tonnes across the whole site) per year.

The project requires the importation of 10 million tonnes of soil. 3 millions tonnes of this has been provided from the £14.8 billion Crossrail project, using excavated material from the 42km of Crossrail tunnels that have been dug under London. This represents half of the total amount of excavated material – 6 million tonnes (enough to fill Wembley Stadium three times over) – that has been produced by the Crossrail project. 80% of the excavated material has been transported by rail and boat, removing 150,000 lorries (and their associated health, safety and environmental risks) off the streets of London. The RSPB is currently seeking partners to provide the remaining 7 million tonnes that it requires to complete the project.

Planning permission was granted in 2009 and the first phase of the project - Jubilee Marsh - was completed in July 2015.The project is due to be completed by 2020, and will cost about £50m in total.

National Infrastructure Commission

RTPI Evidence On Energy

8 January 2016

Introduction

The Royal Town Planning Institute (RTPI) has over 23,000 members who work in the public, private, voluntary and education sectors. It is a charity whose purpose is to develop the art and science of town planning for the benefit of the public. The RTPI develops and shapes policy affecting the built environment, works to raise professional standards and supports members through continuous education, practice advice, training and development.

Consultation Questions and Answers

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The RTPI is not normally involved in energy regulation. However an issue of increasing concern to our members is the approach of the regulator to new housing development. At present the 5 year plans for electricity DNOs require that every housing development anticipated in the next five years has planning permission at the time that the DNOs' plans are submitted to OFGEM. This is a powerful constraint on housing supply. It assumes that the local planning process for housing development can be timed to fit in with OFGEM's plans, which is an extraordinary approach to take, given the multiplicity of infrastructure providers relevant to new housing development, all of which have their own plans and timescales (including gas DNOs under OFGEM's own purview).

The (in our view) over emphasis on "minimising cost to consumers" is holding back housing development. A more flexible approach is necessary to avoid long disputes between developers and electricity companies over who is responsible for financing additional upstream sub stations and cables. It is reasonable for developers to pay for immediate connections: it is not reasonable for them to have to foot the bill for wider demand, especially in cases where this is not solely due to their own development.

If it is acceptable for all water rate payers to pay for, for example, improving the quality of the river Thames, why is general population increase not a responsibility of a wider group than simply the purchasers of new homes?

The solution would either be for there to be a proper means of financing new development's impact on wider electricity distribution when this arises outside the very strict timetables set by OFGEM (alone, and with no reference to local authorities). Or, a more flexible approach needs to be adopted by OFGEM in regard to housing developments which are planned but not permitted. It is not acceptable to insist on the grant of planning permission before any funding of additional infrastructure is authorised in price settlements. It makes the local planning process rather redundant if draft or final allocation in a plan means nothing at all to the regulator.

IF OFGEM and OFWAT had "supporting housing growth" as part of their objectives set by ministers, it would be more helpful.

This evidence is prepared by Richard Blyth, Head of Policy:
[phone number redacted] [email address redacted]

RWE Response to National Infrastructure Commission Call for Evidence

8th January 2016

Introduction

This document is submitted on behalf of RWE's UK Generation and Retail businesses, RWE Generation UK Plc (RWEG), RWE Innogy UK Ltd (RWEI) and RWE npower Group Plc (RWEN), in response to the National Infrastructure Commission call for evidence.

RWE npower Group Plc is the retail energy supplier for around 5.1 million residential accounts and around 210,000 Small and Medium Enterprise business and Industrial and Commercial customers in the UK. RWE Generation UK Plc owns, operates and maintains a portfolio of gas, coal, oil and biomass stations together with a portfolio of smaller open cycle gas turbine and combined heat and power generation assets. RWE Innogy UK has an operational portfolio of over 2 GW, including wind farms, hydro plant and biomass generation. With a potential development portfolio of over 3 GW.

RWE is active within the energy storage market in Germany where already ca 20,000 – 30,000 domestic storage units have been sold, which are used in conjunction with domestic PV, although the motivation for the investment has been predominantly due to the customer's desire to achieve more energy independence.

In addition, RWE (through its network business) is trialling a 250kW lithium-ion battery to provide peak shaving services to offset high levels of PV feed in , as well as participating in the trials to assess the benefits of adiabatic compressed air storage systems and power to gas systems.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

(i) <u>What role can changes to the market framework play to incentivise this outcome:</u>

The Government has recently implemented a package of Electricity Market Reform (EMR) that is designed to keep the lights on, to keep energy bills affordable, and to decarbonise energy generation. The key elements of this reform package are:

- A mechanism to support investment in low-carbon generation: the Feed-in Tariffs with Contracts for Difference (CfD);
- A mechanism to support security of supply, if needed, in the form of a Capacity Market;
- The Carbon Price Floor – a tax to underpin the carbon price in the EU Emissions Trading System;
- An Emissions Performance Standard – a regulatory measure which provides a backstop to limit emissions from new fossil fuel power stations; and
- The institutional arrangements to support these reforms.

Electricity Market reform is supported by:

- Electricity Demand Reduction;
- Measures to support market liquidity and access to market for independent generators; and
- Effective transitional arrangements.

In addition, significant progress is being made towards establishing the Internal Electricity Market to achieve an integrated market for electricity in the EU. This requires the adoption and full implementation of the Network Codes developed since 2011, the efficient and secure integration of intermittent generation linked to renewables, and the implementation of a stable regulatory framework for the development of new trans-European network infrastructures.

We do not believe that there is a case for further reform of the GB electricity market.

In the event of further changes to the market framework, this should be subject to a thorough cost **benefit analysis to ensure that the benefits of any change outweighs dis-benefits for all credible scenarios.**

(ii) Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

National Grid as Transmission Owner, System Operator, EMR Delivery Body, Interconnector owner and Capacity Market Delivery Body plays a central role on the GB electricity system. During the development of the EMR package the potential for conflicts of interest between the differing roles undertaken by National Grid was acknowledged and safeguards in the form of special licence conditions were introduced to the Transmission Licence.

National Grid continues to play a pivotal role in the electricity industry and this will be enhanced with the implementation of the Energy Union, the integrated European energy market. We welcome the commitment of the Secretary of State to work alongside the National Infrastructure Commission with National Grid, Ofgem and others to consider how to reform the current system operator model to make it more flexible and independent[1]. In considering how to reform the system operator model, the scope of this review must include a review of how the Distribution Network Operators operate and how they integrate with the System Operator and the Transmission Owner.

(iii) Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

Ofgem recently completed a major reform of the "balancing market" through implementation of the recommendations of the Electricity Balancing Significant Code Review. From 5th November 2015 the imbalance pricing arrangements have been based on a single cash out price calculated from the most expensive 50MWh of bids or offers dependent on the direction of system imbalance (long or short). In addition, new arrangements for the treatment of reserve and demand control actions have been introduced such that cash out prices can rise towards the value of lost load (a price of up to £3,000 per MWh in a single half hour). These reforms will improve the effectiveness of the electricity market and address a "missing money" problem associated with the reserve procurement and demand control.

Whilst we welcome these amendments, the Supplemental Balancing reserve (SBR) continues to overhang the market and the recent announcement that coal units have been offered SBR contracts for winter 2016/17 serves to dampen prices since the long notice periods and run times mean that such units will need to be instructed well before an event develops.

[1] Amber Rudd's speech on a new direction for UK energy policy, From: Department of Energy & Climate Change and The Rt Hon **Amber Rudd MP**, Delivered on: 18 November 2015, Location: Institution of Civil Engineers, London, First published: 18 November 2015 at https://www.gov.uk/government/speeches/amber-rudds-speech-on-a-new-direction-for-uk-energy-policy

In order to provide value to consumers by enabling the recent balancing amendments to realise their potential to promote an efficient market, the SBR should be abandoned at the earliest opportunity

Implementation of the Energy Union and in particular the Framework Guidelines on Electricity Balancing and Electricity System Operation will have a major impact on cross border trading and electricity balancing. It is expected that these Framework Guidelines will improve reserve procurement and cash out arrangements, and the efficiency and effectiveness of the European electricity market.

(iv) To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Changes to the GB electricity balancing arrangements and implementation of the Energy Union will provide new opportunities for electricity market participants including demand side management and embedded generation. Improved price signals and reserve procurement will enhance cross border trade and deliver significant improvements for customers.

The extent to which demand side management measures and embedded generation can be used to increase the flexibility of the electricity system cannot be easily stated; although it is likely that its potential will be significantly constrained if policy continues to focus investment on the delivery of more generation capacity and network reinforcement before demand reduction and demand side response measures have been consistently and effectively supported and communicated to customers.

The recent DECC paper “Towards a Smart Energy System” contains a range estimates of the differing potential for DSR (for different customer segments) of between 1.2 – 4.4GW. However, despite the lack of agreement on the likely scale of the DSR potential, it is clear that DSR and embedded generation; if appropriately supported can provide essential sources of flexibility within a smarter energy system, with benefits for all consumers across the value chain.

The critical issue will be to ensure that the policy and regulatory frameworks are developed that provide sufficient clarity and incentive for all stakeholders to invest in these solutions. A key component to facilitate this development (and also for storage) will be to ensure greater exposure of the whole system costs (for both consumers and generators). As highlighted in our response to question 1, ensuring that the market can set the true costs for balancing the system would be a welcome first step.

2 What are the barriers to the deployment of energy storage capacity?

(i) Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other ‘balancing’ technologies? How might these be overcome?

In order to drive innovation and to minimise costs of electricity, it is important that storage is treated such that a competitive market emerges that can drive innovation, has the flexibility to access all markets and costs are minimised for the electricity consumer.

In doing so, it must be recognised that storage assets located at different locations within the distribution system, the transmission system, behind the meter or linked with generation assets will provide different services and derive revenues from different markets including energy price volatility, ancillary service provisions and avoidance of network reinforcement costs.

To encourage deployment:

Peak electricity prices need to allow for true value of scarcity to provide cost reflective price signals and to permit greater price volatility. Whilst recent reform of the “balancing market” is a positive step, there remain distorting effects of the SBR (as set out in detail in Q1) which serve to limit the realisation of scarcity pricing and hence undermine the case for investment in storage assets.

In addition, the threat of Regulatory and Policy changes have the potential to undermine investor confidence.

Treatment of Storage:

<u>Payment of system charges:</u>
It is essential that market mechanisms and regulations reflect the true costs and benefits of storage assets to provide appropriate price signals to enable the development and operation of an efficient and competitive market. In principle, the treatment of storage as both demand and generation is appropriate as this clearly reflects the operation of a storage asset and can be made cost effective and transparent.
The payment of system costs (and receipt of benefits) relevant to the storage asset’s location within the system and the time of charging or discharge is entirely appropriate

<u>Payment of energy taxes and levies :</u>
Again, treatment of storage as both demand and generation can be appropriate as this clearly reflects the operation of a storage asset and can be made cost effective and transparent as well as rewarding the use of high efficiency storage solutions.
The payment of consumption related taxes and levies (CCL, RO, FiT, and CfD costs) relevant to the storage asset’s location within the system and the time of charging is entirely appropriate **<u>provided</u>** the issue of double charging of these taxes and levies (ie the application of those taxes and levies on the energy used for charging as well as applying those charges on the of energy discharged from storage devices) to the final end-user.

We would welcome the opportunity to explore further detailed mechanisms such as longer term netting of imports and exports for the purpose of consumption based levies and taxes, and other options such as an examination of the Balancing and Settlement Code for the treatment of storage assets located on the grid could also be considered.

<u>Asset ownership:</u>

Energy storage technologies have the potential to participate in a wide range markets, delivering benefits to the electricity network (at both distribution and transmission levels) and its operation.

Whilst new markets will evolve throughout the life of assets, it is expected that storage can provide benefits including:

1. Reducing the need to reinforce distribution / transmission networks
2. Providing ancillary and balancing services
3. Providing enhanced frequency response
4. Providing peak capacity
5. Providing demand side response
6. Providing electricity price arbitrage
7. Enabling the more efficient use of electrical connections for intermittent generators (particularly renewable technologies)
8. Enabling the increase in self-consumption of energy from embedded generation

To efficiently deploy storage assets, asset owners must be able to access all of the potential markets relevant to the storage assets location within the System.

There are other potential barriers to utilisation by specific organisations such as Distribution Network Operators, Transmission System Operators due to the current classification of storage as a “generation” activity and the current rules preventing Transmission and Distribution Licence holders from also owning generation assets. However, we would caution against noting this as a specific market failure, given the clear need to ensure genuine unbundling within the market to ensure a market based mechanism that is both efficient, open and doesn't lock in actual or potential structural advantage or discrimination either for or against different market participants.

Whilst it is entirely appropriate for network and system operators to procure the relevant services from storage assets on a competitive basis, it is not appropriate for them to directly participate within these markets without losing independence and foreclosing competitive markets and hindering innovation.

One proposal that has been suggested (by ENA and others) is to treat storage as a distinct licensable activity, for which exemptions (by Distribution licence holders) could be made. Whilst this may enable more storage facilities to be developed,the issues would remain as to whether distribution licensees could or should be allowed to offer and procure additional services that extend beyond distribution system requirements.
If storage were to be classified as a distinct licensable activity (as has been suggested by several organisation) then it could remove the barrier to DNOs / DSOs from owning storage technologies which could help with grid operation / avoid grid reinforcement. However, this would solely be one use of the technology and would not enable the DNO / DSO to fully access the associated value of the storage technology – in particular the balancing and reserve services that can be provided to National Grid.
If such a solution were to be considered, it will be vital to ensure that DNOs and potentially the TSO’s are required to source associated services through competitive tendering (without DNO / TSO asset ownership), with the procurement managed in a fair and transparent way, to ensure other sources of flexibility (including but not limited to load management / DSR actions and additional distributed generation) are not discriminated against and unable to compete in a fair and transparent market.

We therefore support current structures that prevent direct ownership by Transmission and Distribution licence holders who are a natural buyer of a number of services. However, such entities must be able to procure services from the market.

<u>General barriers to entry:</u>

RWE notes there are some barriers that could prevent investment in energy storage, not least the <u>current</u> cost of the technology. We do expect that some storage systems (battery systems in particular) are likely to continue to benefit from the ongoing reductions in cost of ca 10-20% per annum. that have been experienced in the battery storage market, resulting in part through increased economies of scale , increased participation of automotive companies (which have developing battery storage for electric vehicles) and increased demand. There are however still significant differences in the cost of batteries (dependent upon size), with an expected cost of €700-€1000 per kWh for smaller storage systems, compared to average cost of €400-€700 for larger systems suitable for use by utilities.

The extent to which these barriers can be overcome will depend largely on the particular solution proposed and for purpose of the solution.

Impact of use of system costs

As storage can act as both supply and demand, there is a risk of uncertainty regarding the use of system charges and balancing system charges applied . There is also an additional risk that without a clear methodology for determining the type of storage (and its primary purpose (i.e. peak shaving, ancillary services to grid etc) that (as per generation) storage may be classed as intermittent (or non-intermittent) in a way that reduces the commercial benefits of investing in storage.

(ii) What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

We believe it is far too early to determine (or even consider) what the most appropriate scale for future energy storage technologies in the UK might be, given the current regulatory, and legislative uncertainty. Based on the experience of our parent company RWE, we believe that there will be sufficient opportunities for utilisation across the range. We note that in Germany, already ca 20,000 – 30,000 domestic storage units have been sold, which are used in conjunction with domestic PV, although the motivation for the investment has been predominantly due to the customer's desire to achieve more energy independence.

In Germany, RWE (through its network business) is trialling a 250kW lithium-ion battery to provide peak shaving services to offset high levels of PV feed in, as well as participating in the trials to assess the benefits of adiabatic compressed air storage systems. We believe that with a well-designed and regulatory approach that recognises the unique status of storage (both as a source of supply and demand) should facilitate the appropriate development and take up of the technologies without risking distortions to the competitive market across all scales, given the different commercial and behavioural motivations that exist. Storage must be treated equally (neither discriminated for or against) in relation to other technologies / sources of flexibility.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

(i) Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

RWE is supportive of efforts to improve interconnection between GB and the continent which will improve market liquidity, competition and security of supply. We expect interconnectors to play a growing role in the integrated European electricity market by enabling balancing of supply and demand as the impact of renewable generation increases.

As we stated in our response to the Ofgem consultation on the Cap and Floor regime it is important that the merchant approach towards DC interconnection is retained as the preferred route towards investment. However, we recognise that interconnectors form part of the transmission system in line with Directive 2009/72/EC. As such interconnectors must comply with all EU Regulations, guidelines and network codes. The cap and floor approach has a role to play in ensuring efficient and cost effective provision of vital infrastructure where such an approach can be properly justified.

As we stated in our response to the Ofgem consultation on the Cap and Floor regime it is important that the merchant approach towards DC interconnection is retained as the preferred route towards investment. However, we recognise that interconnectors form part of the transmission system in line with Directive 2009/72/EC. As such interconnectors must comply with all EU Regulations, guidelines and network codes. The

cap and floor approach may have a role to play in ensuring provision of vital infrastructure if such an approach can be properly justified.

However, these “arrangements could result in GB customers underwriting a significant degree of downside risk for interconnector investment (i.e. there is insufficient revenue from flows and customers end up funding the investment through the floor arrangements).

Whilst interconnectors can provide clear solutions in addressing the energy trilemma, we are aware of in increasing body of evidence that suggests that a large proportion of interconnectors provide no advantages with regard to carbon intensity, security of supply or affordability over and above domestic generation. We would therefore propose that the Cost Benefit Analysis, and the scope of the CBA is revisited before additional commitments are made.

> <u>(ii) Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?</u>

We do not believe that there are specific failures or barriers to prevent investment in electricity interconnection that are not faced by other balancing technologies. We note that under the European Union third package that interconnectors form part of the transmission system and are not considered to be a balancing technology in their own right. Consequently we believe that interconnectors provide a route to market for balancing technologies. In addition, interconnectors can facilitate cross border capacity markets, though further where work is required to ensure the cross border participation of power stations and demand side providers.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

From an internal review of EU and US energy market transformations, the New York Reforming the Energy Vision “REV” appears particularly relevant. Part of the NY REV seeks to meet existing grid objectives of low cost, reliability, universal access and enabling new technology. The efficient management of peak demand is a key part of this programme, and delivered by aligning demand with distributed generation, and demand side response.

Remuneration for services is based on the system value, as discovered through market mechanisms, potentially dependent upon location within the network. This transparency has been crucial to determine the value of energy efficiency, demand response, solar and storage and enables comprehensive cost-benefit analysis.

As a practical example, Con Edison’s Brooklyn Queens Demand Management Programme initiative highlights the potential of such an holistic approach where an original $1.1bn investment requirements was ultimately reduced to c$0.5bn through the use of the above mechanisms and targeting investment (by providing investment signals to market participants) in embedded solutions to mitigate the need for such an extensive investment in copper.

In addition, the California model provides an example of an effective Distributed System Operator which is a technically neutral market place coordinator. The DSO is itself limited to managing real and reactive power flows. Such a mechanism enables the full range of services to be developed in a transparent way. It is reported that up to 30 different services could be envisaged.

Both examples are particularly driven by a strong focus on cost & value and security of supply.

Common denominators are unbundling of services to enable efficient markets and a distribution service platform provider concept.

SCOTTISHPOWER

Rupert Steele OBE
Director of Regulation

Henry Shennan
National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

11 January 2016

Dear Henry,

NATIONAL INFRASTRUCTURE COMMISSION CALL FOR EVIDENCE

We welcome the opportunity to respond to this Call for Evidence. Balancing supply and demand cost effectively will be of the greatest importance as we transition to a low carbon electricity system. We therefore fully support the National Infrastructure Commission's work in this area, alongside that undertaken by DECC and Ofgem.

Our responses to the detailed questions in the Call for Evidence are provided in Annex A. We would, however, highlight the following issues in particular.

Independent System Operator (ISO)

We consider that recent policy changes have created increasingly deep conflicts of interest around the role of National Grid (NG) as the System Operator (SO). These turn on the fact that the SO is expected to hold the ring on policies such as transmission competition or the construction of interconnectors, while other parts of NG – as infrastructure investors – have significant interests in the outcome. By way of example, under the Ofgem process for determining the award of Cap and Floor support arrangements for interconnectors (which is an area in which National Grid Interconnector Holdings is a project developer), NG provides to Ofgem a quantitative assessment of the value of a range of systems services which interconnectors could provide.

The question of whether conflicts of interest can be managed through behavioural rules or whether ownership separation is required depends on how deep in practice the conflicts are. We consider that the conflicts cited above are sufficiently deep as to put the question of SO ownership (and the creation of an ISO) on the table.

Pumped Storage

We have the potential opportunity to expand our existing pumped storage site at Cruachan in Scotland. We believe that this would deliver good value for consumers for a storage technology at scale. However, the relatively high levels of capital, long investment lead times and future uncertainty result in significant barriers for investment.

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These are similar barriers to those which have affected the investment case for interconnectors.

We believe that these barriers could be overcome if a Cap and Floor mechanism (as used by Ofgem in respect of new interconnection projects) were available (subject to cost-benefit analysis) to transmission connected storage developments.

Interconnection

We are fully supportive in principle of the potential benefits arising from trade with Continental Europe through greater cost-effective interconnection. However, it is essential that this takes place based on a level playing field if the trading that ensues acts to create rather than destroy value. This is the principle benhind the efficient linking of markets to facilitate international trade.

In the case of the GB electricity market, we consider that there are number of dimensions of the charging and taxing regime, as well as the regulatory framework for interconnectors, that have the effect of distorting the market in a way that creates a fundamentally uneven playing field between domestic generation and foreign imported generation. Taken together, these various elements significantly disadvantage domestic generation in its competition with imported electricity from foreign generators – by around £11/MWh or over 25% of the wholesale price. These issues are further explored in the attached report from Oxera.

Capacity Market

Finally, whilst we believe that the market-wide Capacity Market (CM) is fundamentally the right mechanism for promoting investment and maintaining security of supply, we consider that there are a number of steps that the Government should take to ensure that the current CM Regulations and Rules provide a level-playing field for investment in all plant, including large-scale gas-fired power stations.

For example, embedded generation can currently benefit from Triad avoidance payments if it operates in the three highest demand half hours each year. This is, in effect, an additional capacity payment (equivalent to approximately £45/kW/year in 2019/20), which results in over-reward for embedded generation. We think that plants in receipt of CM payments should not be eligible for Triad benefits and have suggested to DECC how this could be achieved in the context of their consultation on possible reform of the CM.

If you have any questions regarding any aspect of this response, please do not hesitate to contact me.

Yours sincerely,

Rupert Steele
Director of Regulation

ANNEX A

NATIONAL INFRASTRUCTURE COMMISSION CALL FOR EVIDENCE

SCOTTISHPOWER RESPONSE

Question 1

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Outlook

In her recent speech setting out a new direction for UK energy policy[1], the Secretary of State outlined the need for significant investment in new large-scale gas-fired power, as well the phasing out of coal by 2025, to ensure security of supply and decarbonise the energy system.

It is critical, therefore, that there is an effective framework for investment in new capacity to replace the retiring capacity, particularly given the uncertainties around the timing of replacing the ageing nuclear fleet. Accordingly, we welcome the Government's commitment to reviewing the design of the Capacity Market (CM), the primary mechanism for achieving this objective.

Whilst we believe that the market-wide CM is fundamentally the right mechanism for promoting investment and maintaining security of supply, we consider that there are a number of steps that the Government should take to ensure that the current CM Regulations and Rules provide a level-playing field for investment in all plant, including large-scale gas-fired power stations. For example, embedded generation can currently benefit from Triad avoidance payments if it operates in the three highest demand half hours each year. This is, in effect, an additional capacity payment (equivalent to approximately £45/kW/year in 2019/20), which results in over-reward for embedded generation. We think that plants in receipt of CM payments should not be eligible for Triad benefits and have suggested to DECC how this could be achieved in the context of their consultation on possible reform of the CM.

Given long-term decarbonisation, it is clear that the electricity system will need to adapt over time. However, it is hard to predict precisely what the future system will look like. Among other things, this will depend on the pace and nature of change. Whilst it is possible that generation may become more distributed and more variable (though recent changes to the

[1] *Amber Rudd's speech on a new direction for UK energy policy,* 18 November 2015

small scale Feed-In-Tariff (FIT) scheme will have affected the rate of change), it is key that the appropriate infrastructure investments are made at a system level, as well as at a local level. This approach should ensure that the high levels of security of supply within the UK are maintained regardless of the nature and pace of future change.

Independent System Operator (ISO)

We consider that recent policy changes have created increasingly deep conflicts of interest around the role of National Grid (NG) as the System Operator (SO). These turn on the fact that the SO is expected to hold the ring on policies such as transmission competition or the construction of interconnectors, while other parts of NG – as infrastructure investors – have significant interests in the outcome. By way of example, under the Ofgem process for determining the award of Cap and Floor support arrangements for interconnectors (which is an area in which National Grid Interconnector Holdings is a project developer), NG provides to Ofgem a quantitative assessment of the value of a range of systems services which interconnectors could provide.

The question of whether conflicts of interest can be managed through behavioural rules or whether ownership separation is required depends on how deep in practice the conflicts are. For example, Ofgem and the EU commission found that the conflicts around ScottishPower's ownership of SP Transmission were minor and effectively mitigated by NG acting as SO. However, in the case of NG, we consider that the conflicts cited above are sufficiently deep as to put the question of SO ownership (and the creation of an ISO) on the table.

By way of example, under the Ofgem process for determining the award of Cap and Floor support arrangements for interconnectors (which is an area in which National Grid Interconnector Holdings (NGIH) is a project developer), NG provides to Ofgem a quantitative assessment of the value of a range of systems services which interconnectors could provide. While the information provided was interesting, it is very difficult to determine whether the analysis is robust and if the reported benefits are realistic. Also, we consider that the analysis should have weighed up the system benefits that the interconnectors deliver against the cost of foregoing the system benefits that could be delivered by a thermal plant that the interconnectors displace.[2] There is, therefore, a serious question about how appropriate it is for NG, as a developer, to be the central provider of the modelling on which Ofgem relies for its assessment.

Similar issues arise under Ofgem's ITPR proposals where NG as SO is meant to be preparing projects for tender, while NG's transmission business can be both a bidder and /or the host TO. NG's interests as TO are much bigger than their interests as SO and therefore there will always be a suspicion (whether true or not) that the SO may tend to act in the interests of its owner.

An independently owned SO could address these concerns. But it would clearly have issues of its own. It would need sufficient technical expertise and either it would need sufficient financial strength for Ofgem's current incentive process to be reasonable, or those incentives would need to be adjusted. We believe that the Government (working with Ofgem) is well-placed to consider these questions, including carefully weighing up any risks and timing questions. If the current arrangements are to endure, DECC and Ofgem will need to ensure that regulation provides for adequate business separation and transparency.

[2] We would also note that, for some of the interconnector projects assessed by National Grid, a large proportion of the benefits arise from system operation impacts. In two of the projects where National Grid Interconnector Holdings is a joint developer (IFA2 and Viking Link), the assessment of system operation impacts appear critical, accounting for 113% and 87% of total benefits respectively.

Balancing Market

As a package, we are broadly supportive of the recent cash-out reforms and the current balancing market. We believe that the current arrangements provide appropriate incentives for companies to balance as efficiently as possible. However, we do not underestimate the new financial risks now faced by our business during times of system stress.

For the EU's Internal Electricity Market to be successful, the fragmented national balancing markets across Europe will need to be better aligned. It is important that GB remains fully engaged in the process of producing the European Electricity Balancing Network Code which is set to be introduced in 2-3 years. As part of this process, it is vital to demonstrate that any harmonisation of European markets is in the interest of consumers.

Demand-side Management Measures and Embedded Generation

When considering the delivery of flexibility we think it is important not to be technology-specific, but rather develop functional specifications that can be met using various technologies. For example, 'flexibility' is about the rate of response and the magnitude and duration of response, rather than specific technologies such as energy storage, demand-side management or embedded generation. We also believe, when creating 'functional specifications', that it is important to consider likely additional future system requirements above and beyond flexibility; amongst others, this will include system inertia.[3]

Wind and solar PV have much lower inertia than conventional generation. Interconnectors also displace generation when importing, but are not currently configured to provide inertia. Therefore, frequency will deviate more quickly from the target value in times of unexpected imbalance. In this context, we welcome National Grid's work around its relatively new System Operability Framework. This work has begun to set out the future system requirements and may be used by the industry to better identify possible future demand for services.

It is also important that industry continues to share their understanding of the impacts that embedded distributed generation (DG) can have on the wider system and, where possible, identify solutions to mitigate these (as has been happening through the DECC/Ofgem Smart Grid Forum[4]).

The importance of Distribution Network Operators (DNOs) managing their networks more flexibly is likely to increase over time (though it is difficult to forecast the pace and nature of the changes). We will continue to support work on engaging with consumers to procure flexibility, and on clarifying the future relationship between the System Operator and a possible future Distribution System Operator (DSO) with greater involvement in local balancing.

[3] System inertia is proportional to the sum of stored energy in the rotating masses of machines (generators and motors) which are directly connected the electricity grid. (National Grid, *System Operability Framework,* November 2015.)

[4] https://www.ofgem.gov.uk/electricity/distribution-networks/forums-seminars-and-working-groups/decc-and-ofgem-smart-grid-forum

<u>Question 2</u>

What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

There seems to be growing recognition that as the UK electricity system decarbonises, building more power stations and cables to meet demand when renewable sources are unavailable may not always be the most efficient approach towards managing whole system challenges. In this context, it appears to be increasingly recognised that electricity storage has an important role to play in balancing the system, alongside other sources of flexibility such as interconnection and demand side response.

We consider below the potential for storage at three different scales (domestic, transmission connected and distributed) along with the potential barriers to uptake at these different scales.

Domestic Scale Storage

To ensure that potential future system benefits are not missed we are actively engaging in domestic storage trials. However, while domestic storage combined with solar PV may help alleviate localised problems with excess generation at summer lunchtimes, it may contribute to summer night excesses of generation and it is unlikely to make a useful contribution in the winter. We will use the data from our trials to calculate the average value from charging the battery during theoretically 'cheap' time periods and discharging during more expensive periods, and to inform a wider assessment of opportunities in this area.

Transmission Connected Storage

We have the potential opportunity to expand significantly our existing (440MW) pumped storage site at Cruachan in Scotland. We have applied for inclusion in the 2016 European Ten Year Network Development Plan (TYNDP) in order to leave open the opportunity to pursue status as a priority European project (Project of Common European Interest, PCI) should this be considered appropriate.

We consider that the further development of this storage technology at scale would deliver good value for consumers. We believe that pumped storage can facilitate the effective delivery of decarbonisation in an efficient and environmentally friendly manner.

However, the relatively high levels of capital, long investment lead times and future uncertainty result in significant barriers for investment. These are similar barriers to those which have affected the investment case for interconnectors.

We believe that these barriers could be overcome if a Cap and Floor mechanism (as used by Ofgem in respect of new interconnection projects) were available (subject to cost-benefit analysis) to transmission connected storage developments. The current approach to assessing Cap and Floor support based on a cost-benefit analysis should ensure that only cost effective projects are progressed.

Distributed Network Storage

The debate around the current classification of storage assets and whether this creates a barrier to entry is not new. Whilst we believe that bulk storage assets which deliver energy on a comparable basis to conventional generation can operate under the 'generation[5]' classification, we can also envisage instances where it may be more problematic for smaller scale resources[6].

In this context, we are supportive of the remarks made by the Council of European Regulators[7] noting that 'storage is considered, in principle, a market activity and therefore the role of DSO in storage should be limited to the use of specific grid-oriented services. However, energy storage cannot be used as a substitute for fully available distribution lines, but could be used to solve network constraints on a temporary basis. DSOs can use storage services, provided this technical solution is justified as the most cost-effective option and is sourced in a non-discriminatory manner'.

If any regulatory classification changes are to be made, then contestability and promotion of competition will, as always, be key. Any changes to the distribution licence should continue to encourage competitive and third party progression of storage wherever possible. Only in instances where third parties do not come forward on a competitive basis should DNOs be able to make capital investments themselves. In short DNOs should only be able to take on a 'provider of last resort' role.

To justify storage as the most cost-effective option to solve network issues, there is likely to be a need to demonstrate additional revenue streams over and above its application for network support. For this type of storage to be considered both successful and profitable, smart commercial agreements and services must be developed in such a way as to not distort existing competition. Such arrangements are explored in more detail in the recent work carried out as part of the Smarter Network Storage (SNS)[8] project - the aims of this project were to carry out a range of technical and commercial innovations to tackle the challenges and facilitate more efficient and economic adoption of storage.

For both domestic and grid distributed storage, the level of automated control, and availability readings may prove to be key if the storage is to be relied on, and full system benefits are to be realised. The control and operation of storage may, however, become complex where the storage has been deployed to solve network constraints, and is also used in other markets/applications.

[5] Electricity storage is not explicitly recognised under EU legal frameworks; storage is treated as a type of generation asset. It is not believed that this was a deliberate design choice.

[6] Classification of storage as a type of generation limits the involvement of DNO. DNOs can only participate in storage via the licence exemption route for smaller generation and the associated de minimis. However, even this approach is limited by the de minimis business restrictions placed on DNOs under their licence conditions (Standard Condition 29 places limitations on non-distribution activities. It restricts: total turnover from non-distribution activities to 2.5% of the DNO's distribution business revenue; and total investments in all non-distribution activities to 2.5% of the licensees share capital in issue, its share premium and its consolidated reserves.

[7] 'The Future Role of DSOs – A CEER Public Consultation Paper', CEER, 16 December 2014.

[8] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/Project-Documents/SNS4.6_SDRC+9.3+-+CA+for+IU+of+Flexibility_v1.0.pdf

<u>Question 3</u>

What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnetion that are not faced by other 'balancing' technologies? How might these be overcome?

We are fully supportive in principle of the potential benefits arising from trade with Continental Europe through greater cost-effective interconnection. However, it is essential that this takes place based on a level playing field if the trading that ensues acts to create rather than destroy value. This is the principle benhind the efficient linking of markets to facilitate international trade.

In the case of the GB electricity market, we consider that there are number of dimensions of the charging and taxing regime, as well as the regulatory framework for interconnectors, that have the effect of distorting the market in a way that creates a fundamentally uneven playing field between domestic generation and foreign imported generation. Taken together, these various elements significantly disadvantage domestic generation in its competition with imported electricity from foreign generators – by around £11/MWh or over 25% of the wholesale price. These issues are further explored in the attached report from Oxera.

A key aspect of this is the unilateral Carbon Price Floor in the GB (implemented through the Carbon Price Support mechanism), which is supplementary to the EU ETS regime. This in effect acts as a carbon tax applied to GB thermal generation but not to foreign generators who are supplying electricity to the GB market across the interconnectors. The effects of this tax are exacerbated by a system charging regime applying to GB generators (transmission, balancing and losses) that significantly deepens the overall market distortion. This is because the charging regime that applies to generators in most Continental EU countries is much less onerous than the one that applies to GB generators. Lastly, we would note that the potential costs associated with Ofgem's current Cap and Floor support regime for new build interconnectors is an additional cost burden that GB generators will have to bear.

Taken together, these various elements significantly disadvantage domestic generation in its competition with imported electricity from foreign generators. Whilst the level of distortion varies from country to country, depending on alternative tariff arrangements, the Table below provides an indication of the scale of this problem. In particular, the Table demonstrates the level of distortion between GB and countries that levy no or very limited system charges on generators, such as France and Germany.[9]

[9] Oxera, Impact of an uneven playing field for power generation in Great Britain and connected markets (research for ScottishPower), 17 December 2015

Additional costs faced by a typical GB CCGT as compared to equivalent plants in France, Germany and the Netherlands	£/MWh	% of 2016 Forward Wholesale Market Price (c.£40/MWh)
UK Carbon Tax (Carbon Price Support) (additional import support based on the additional value that feeds through to GB wholesale power price when compared to other EU countries)	6.4	16.0%
Higher liability for transmission network tariffs, balancing tariffs and transmission losses	4.5	11.3%
Total (approx)	**11**	**27%**

Moreover, the significance of this lack of a level playing field is not simply the unfair and distortionary impacts on existing GB thermal generators but, importantly, the fact that it creates a highly negative outlook for potential investors in new build gas generation in the GB market. This is particularly damaging for UK investment prospects given that the future projections for spark spreads, as is widely recognised, already make the environment for investing in new build generation a very difficult one. We consider that this is a critical issue taking into account the future challenges around security of supply, as well as the Government's stated ambition to develop a higher degree of energy autonomy by producing our own energy at home wherever we can do so cost-effectively.

Given the absence of a level playing field, we believe that the current regulatory framework could result in a higher level of interconnection than is economically optimal. Accordingly, we consider that the current discussions at an EU level around a possible 15% target should be focussed on an aspirational aim rather than a hard target. Moreover, it should be clearly recognised that a 'one-size-fits-all' target for interconnection does not suit all Member States, particularly island States.

Question 4

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The Energy Storage Operator Forum's (ESOF) work[10], which was supported by DECC, summarises some international policy developments that are being used to drive the uptake of electricity storage. It is noted that some of these policy developments have emerged to support reliability, grid operation and renewables integration in the context of the Government's decarbonisation ambitions as legislated for under the Climate Change Act 2008.

Whilst in Japan and Germany, subsidies are being made available to individuals and, in the case of Japan, businesses wishing to install energy storage, we consider that for larger scale assets which deliver energy on a comparable basis to conventional generation (and which can operate under the 'generation' banner), risk mitigating schemes, such as a Cap and Floor mechanism, would be more appropriate. Such a mechanism is already offered by

[10] http://www.eatechnology.com/products-and-services/create-smarter-grids/electrical-energy-storage/energy-storage-operators-forum/esof-good-practice-guide

Ofgem to a competing technology (interconnectors), and a Cap and Floor mechanism is a tool that could be used to procure additional system storage requirements on a competitive basis. A Cap and Floor mechanism could be designed to limit market distortions and unintended consequences whilst minimising complexity. In particular, it allows decisions on when to pump and when to generate to be determined by market signals (especially if the cap and floor are constructed 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 system.

In addition, whilst storage targets have been established in California[11], we consider that bottom-up delivery through properly designed and regulated markets should provide a better outcome for consumers in this country rather than top-down targets. If a Cap and Floor mechanism were to be introduced in the UK, we do not think that a storage target would be necessary. In this con text, the current approach of assessing Cap and Floor support based on cost-benefit analysis would be key in ensuring that only the most cost-effective projects are built to meet the UK's demand for future bulk storage.

Lastly, when considering distributed storage and generation, it is important to consider whether the economics are distorted by hidden subsidies. Where these exist, some developments that appear economic may in fact be negative in welfare terms. We therefore support the removal of hidden subsidies so that the most economically beneficial solutions, large or small, are deployed.

ScottishPower
January 2016

[11] In California the target level is set to be procured by 2020, with installation operational no later than 2024.

Submission to National Infrastructure Commission

18th December 2015

National Energy Infrastructure Commission

Submission by the Sustainable Energy Association.

To be sent to: energyevidence@Infrastructure-Commission.gsi.gov.uk

Closing date for submissions: 8th January 2015

Commission questions;

Prior to answering the questions raised by the Commission, the Sustainable Energy Association considers it important to discuss the context of energy services and infrastructure in a holistic context.

Section 1.2 of this call for evidence sets out the key intention of the Commission's regular National Infrastructure Assessment, which will identify: 'the UK's long-term infrastructure requirements and prioritise the most important projects…it will provide a firm basis for planning and investment.'

The SEA proposes that the National Infrastructure Commission considers the roll-out of domestic energy efficiency measures to be a National Infrastructure Priority.

Underneath, we set out why energy efficiency of households should be considered infrastructure, and secondly highlight the fact that it would represent one of the most cost-effective infrastructure schemes the Commission could pursue.

As discussed in the Frontier Economics report, *Energy Efficiency; A National Infrastructure Priority*, energy efficiency measures should be considered to be infrastructure.

Frontier Economics state[1]:

> ***"We conclude that domestic energy efficiency constitutes infrastructure investment.***
>
> - ***Domestic energy efficiency investments free up energy capacity for other uses, just as investment in new generation or network capacity would. In this way, they increase inputs to the production of goods and services across the economy.***
> - ***These investments also provide public services, by reducing carbon emissions and improving health and wellbeing."***

Not only is domestic energy efficiency infrastructure, should the Government invest in this class of infrastructure, it would be highly competitive with existing large projects, such as HS2.

[1] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2015

The NPV (£bn, 2014 prices) of an Energy Efficiency roll out would be: £8.7bn
The Smart Meter roll out is estimated to be £6.5bn. HS2 and Crossrail are £7.5bn and £7.2bn respectively, albeit for a different requirement, transport. The benefit-cost ratios for these projects are 1.5 (energy efficiency), 1.6 (smart metering), 1.4 (HS2) and 2 (Crossrail).

More detailed information has been highlighted by Verco and Cambridge Econometrics' report: *Building the Future; The economic and fiscal impacts of making homes energy efficient*. It highlights the benefits of energy efficiency, for example:

- £3.20 returned through increased GDP per every £1 invested by government
- An 0.6% relative GDP improvement by 2030, increasing annual GDP in that year by £13.9bn
- £1.27 in tax revenues per £1 of government investment, through increased economic activity, such that the scheme has paid for itself by 2024, and generates net revenue for government thereafter
- Increased employment by up to 108,000 net jobs per annum over the period 2020-2030, mostly in the service and construction sectors. These jobs would be spread across every region and constituency of the UK.[2]

Furthermore, there are three key aspects pertinent to this energy efficiency (demand side) roll out which the Commission should seek to investigate.

1. Energy efficiency decreases demand for gas & requirements for gas infrastructure investment. Gas is essential to flexible generation, and should be economically and frugally used at points of 'peak demand.' In this way, intermittent renewables can combine with use of gas plant to create the most efficient, low-carbon and secure energy network possible. The Commission should establish the optimal trajectory for combined use of multiple technologies to satisfy our energy needs- this ought to take a holistic view. By 2020, the UK could be importing nearly 50% of its oil and 55% or more of its gas according to DECC's document, *The Carbon Plan; delivering our low carbon future.*[3] Reducing the volume of required gas not only reduces outgoings, it also improves the energy security of the UK.

2. Balancing of supply and demand; the long term (middle path) trajectory identified by the Climate Change Committee identifies that one in seven homes require a low-carbon energy efficiency heating system in 2030.[4] This will have an effect on required investment in the electrical grid. The National Infrastructure Commission should investigate.

3. Storage; the commission will need to investigate to what extent is cost-reduction feasible and how much will in-house storage systems have to fall in cost before becoming competitive with supply-side energy solutions. The Climate Change Committee states: "the demand side also has an important role in increasing the

[2] Verco and Cambridge Econometrics; *Building the Future; The economic and fiscal impacts of making homes energy efficient.* 2014

[3] Department of Energy & Climate Change, *The Carbon Plan, Delivering our low carbon future*, 2011

[4] The Committee on Climate Change; *The Fifth Carbon Budge; the next step toward a low-carbon economy*. 2015

flexibility of the power system, alongside interconnection, storage and flexible back-up capacity”.[5]

As such, the SEA would recommend that, prior to any final decision on which infrastructure priorities being made, that the Commission does investigate fully the potential offered by energy efficiency as a National Infrastructure Priority.

The Sustainable Energy Association is considering further the questions raised in the call for evidence, and may provide a further submission as appropriate.

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[5] The Committee on Climate Change; *The Fifth Carbon Budge; the next step toward a low-carbon economy*. 2015

Sheffield City Region Response to the National Infrastructure Commission Call for Evidence

1. Executive Summary

1.1 Transformational investment into the North's existing transport and electricity network is absolutely essential to help assist business growth in the Sheffield City Region and help provide a step change in economic productivity and prosperity. Through dialogue with the Transport for the North Partnership, Highways England, Network Rail and HS2 ltd, there are a series of improvement to specific pieces of infrastructure and key corridors to unlock labour markets and increase economic interaction.

2. Section 3 - Electricity Interconnection and Storage

2.1 Energy consumption and generation is vitally important to the SCR and its businesses. The SCR has a large proportion of manufacturing companies which use, and rely on, access to large quantities of electrification and energy. Any change in the provision of electricity may force factory close downs which results in large business costs. In addition, the changing price of electrify means that production costs are not stable and this places vast amount of insecurity on business cost planning and long term investment. The SCR would therefore as part of this call for evidence, like to highlight the negative impact that the current electricity market places on the business environment, and this needs to be seen as a priority for change.

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

2.2 The use of transmission charges is a key concern for business as this is a direct result of mismanaging supply in relation to demand. The most significant of which is called the Triad charge, which is derived from National Grid data to identify the three biggest peaks in power demand across the November-February period. Industrial consumers are then retrospectively charged at a vastly inflated rate, based on their power consumption during these peak periods.

2.3 As a result of this, businesses seek to mitigate the impact of the Triad by switching off systems or closing down plants for several hours at a time whenever they suspect demand across the country is peaking. In seeking to avoid peak prices, plants close up to 30 times at short notice over the winter season, disrupting operations and suffering punitive opportunity costs. This is an unnecessary obstruction to business and in the SCR this is having an impact on business growth and employment rates. A consistent supply of energy throughout the year will help prevent these peak costs and provide more certainty for operational costs and overheads.

What are the barriers to the deployment of energy storage capacity?

2.4 One of the main barriers is the ability for Local Planning Authorities to seek investment and to allocate land for the use of storage and energy production. Many of the sites outlined for this type of development often require the provision of expensive enabling infrastructure such as, pipelines, cables and road access. This can make seeking planning permission and building the infrastructure economically unviable unless other higher value land uses can be developed alongside (employment and housing). Government Grants could be used to fund these projects and incentivise investment and development of these facilities.

2.5 In SCR, the DN7 project in Doncaster has a number of elements (Don Valley Power Project, Doncaster Energy and Technology Park and the Doncaster Energy from Waste Project) which when complete will be a major asset to national electricity production and storage. There will also be a significant benefit to the local area as these facilities will provide jobs and supply chain opportunities for supporting businesses.

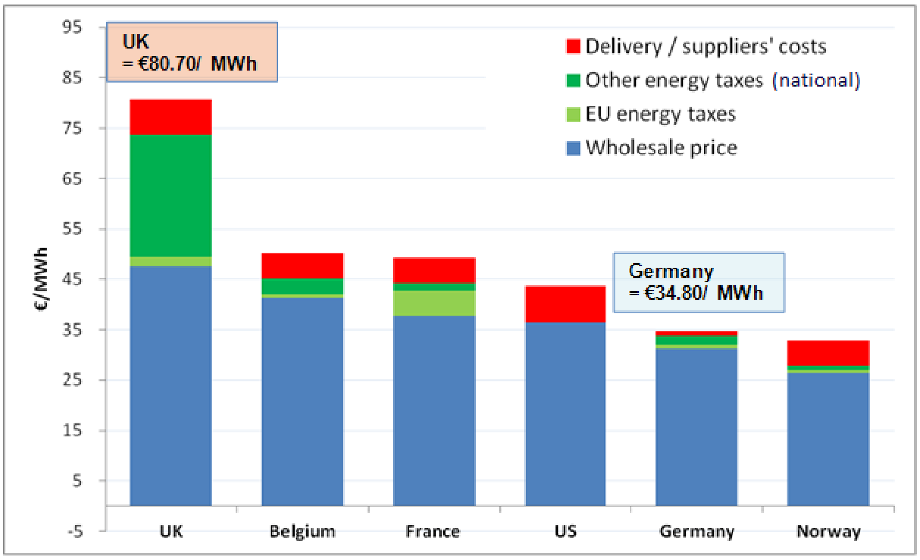
What level of electricity interconnection is likely to be in the best interests of consumers?

2.6 SCR recognises the benefits of the electricity interconnection and the potential increased interconnection will have on contributing towards energy security, consumer affordability and the ability to shift existing power production to decarbonised methods. On a national basis, this will also provide an opportunity to facilitate the single European electricity market, bringing more resilience, competition and economies of scale to the UK power market.

2.7 Evidence[1] published by DECC, shows that more interconnection is likely to be in the nation's interest. Through testing different investment scenarios, Great Britain consumers could see benefits of up to £9 billion by 2040. The evidence also stated that the security of supply would be enhanced by further interconnection. Any benefits in relation to costs or reliability of electricity will be supported by the SCR.

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

2.8 The below chart compares the €/MWh between various countries, with prices in the UK being substantially greater than the other compared nations. This demonstrates that the UK pays double what Germany pay, with most of the additional costs being 'other national energy taxes'.



6.9 The wholesale price is also radically different when compared to Germany and Norway. This would generally mean that in Germany and Norway, energy production is more efficient and the supply chain is more efficient with limited or managed peaks in demand. Although no specific examples can be pointed to in this response, SCR would recommend a closer look at the energy sector in Germany and Norway as this would help identify a series of quick wins for UK energy companies.

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[1] Department for Energy and Climate Change (2013), More interconnection: improving energy security and lowering bills, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266460/More_interconnection_-_improving_energy_security_and_lowering_bills.pdf

SHIRE OAK ENERGY

National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

8 January 2016

National Infrastructure Commission call for evidence:

4. Electricity interconnection and storage

Dear Sir/Madam

Shire Oak Energy ("SOE") is a UK based renewable energy development company focused on delivering innovative yet replicable energy solutions. SOE has significant experience in the development and delivery of renewable energy projects across the UK across different technologies. Through these development activities and within the wider context of an increasing volume of intermittent renewable generation in the UK energy mix, SOE has identified a significant requirement for additional flexibility in the UK electricity System (the "System"). In 2013 SOE began investigating the potential for additional Hydro Pumped Storage ("HPS") facilities in the UK. Over the last 3 years SOE has built up a portfolio of potential HPS projects ranging from 50MW up to hundreds of MW in capacity.

SOE welcome this call for evidence on delivering future-proof energy infrastructure and in debating the value of additional storage and interconnection to the UK System. Our submission focuses on the National Infrastructure Commission's key questions – our response will provide some context on how HPS could meet current and future System demands and our perspective on the current barriers and changes required that would facilitate the roll-out of new HPS plant in the UK.

Introduction

The current paradigm shift within the UK energy market (and indeed wider European markets) is being driven by a widespread move away from conventional, centralised, thermal, synchronous generation towards intermittent, embedded, non-synchronous generation. This change has various impacts on the overall stability and management of the UK System. An increase in intermittent generation creates a higher risk of imbalance, a reduction in thermal synchronous plant reduces overall system inertia increasing the risk of frequency based events due to a higher rate of change of frequency ("RoCoF"). An increase in distributed embedded generation creates visibility based management issues and amplifies regional effects.

National Grid is largely managing this change, which is happening now, through the procurement of additional flexibility from providers that are able to offer the services required to operate the System within the statutory limits set out in the System Security and Quality of Supply documentation ("SSQS"). Energy storage will play an increasingly important role in the management of this change due to its ability to mitigate imbalance risk in situations of over and under supply and in the provision of ancillary services required to operate the system with reduced inherent inertia and susceptibility to frequency based events.

4.1 What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

The introduction of UK and EU-wide renewable energy targets coupled with the implementation of financial support structures for renewable technologies has resulted in a widespread roll-out of renewable energy in the UK over the last 5 years from 9.2GW in 2010 to 24.6GW by 2014[1] with the largest change seen in solar PV. With such a rapid increase in the development of intermittent sources of energy, generally replacing baseload generators, the complexity of balancing supply and demand has increased significantly. Energy storage currently gives National Grid some of the tools necessary to help smooth out these disparities over a range of timescales, from days ahead to real time. HPS can also provide some of the ancillary services required to manage a network with inherently less mechanical and thermal inertia and a higher risk of increased RoCoF.

At a strategic level, there is recognition of the significance of HPS to the electricity market. The National Grid in Future Energy Scenarios (July 2015) states that electricity storage could be significant for the future balancing toolkit. Also, National Policy Statement EN-1 states that the only viable utility scale energy storage is HPS, and as there are only a limited number of these facilities in the UK, the development and deployment of these technologies is not yet at the necessary scale. The NPS also acknowledges that an energy pathway with a high level of renewables will require more storage into the future, which means that HPS will play an important role in a low carbon electricity system.

Furthermore, Houses of Parliament Post Note 492 (April 2015) endorses the role of HPS facilities to help the cost efficiency of the electricity supply by reducing the network capacity need. The Post Note states that a future energy storage sector could save UK consumers billions of pounds and also contribute further billions to GDP. The Carbon Trust in collaboration with Imperial College London showed that with the right development incentives, by 2050 energy storage could be delivering £10bn per annum in value to the UK consumer[2].

HPS is tried and tested – conventional HPS (which uses fresh water) currently provides 98.3% of the worlds installed energy storage capacity. The system uses electricity from the System to pump water from a lower reservoir to a higher reservoir. Pumping typically occurs during the night when electricity demand and price is low. During the day, the water is released back through hydro turbines to generate electricity again to meet morning and evening peaks and sudden spikes in consumer electricity demand. This cycle of pumping and generating generally repeats on a daily basis. Therefore, HPS is a way of storing electricity by turning electrical energy into stored (or potential) energy and back again. It is currently the only technology capable of providing significant levels of responsive storage at reasonable capital and operational cost (see Figures 1 and 2).

1 DUKES 2015: https://www.gov.uk/government/statistics/digest-of-united-kingdom-energy-statistics-dukes-2015-printed-version

2 Imperial College London: https://www.carbontrust.com/media/129310/energy-storage-systems-role-value-strategic-assessment.pdf

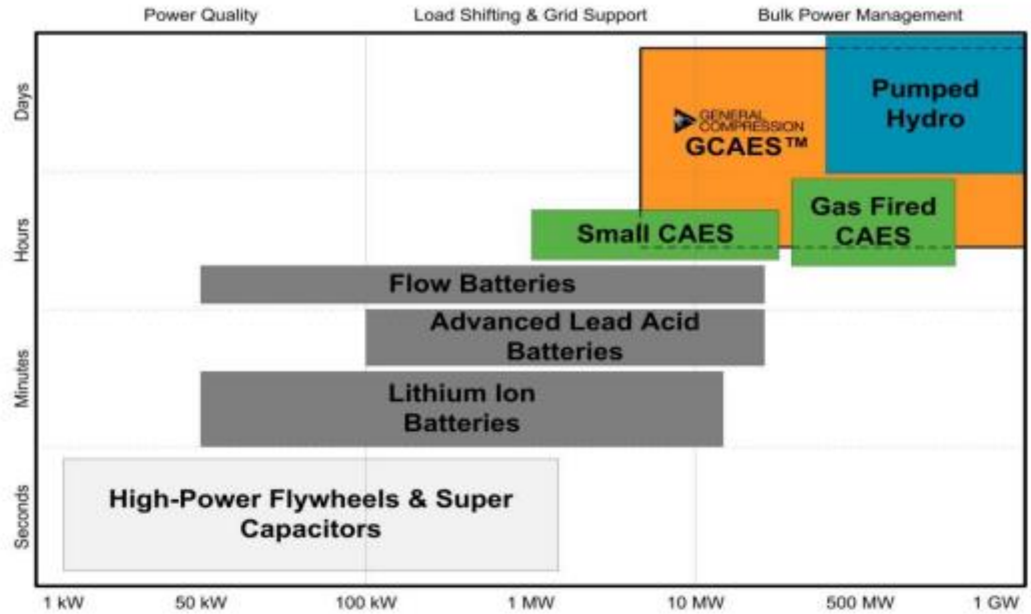

Figure 1: Energy storage technologies, applications and scale. Source; Clean Energy Council, 2015

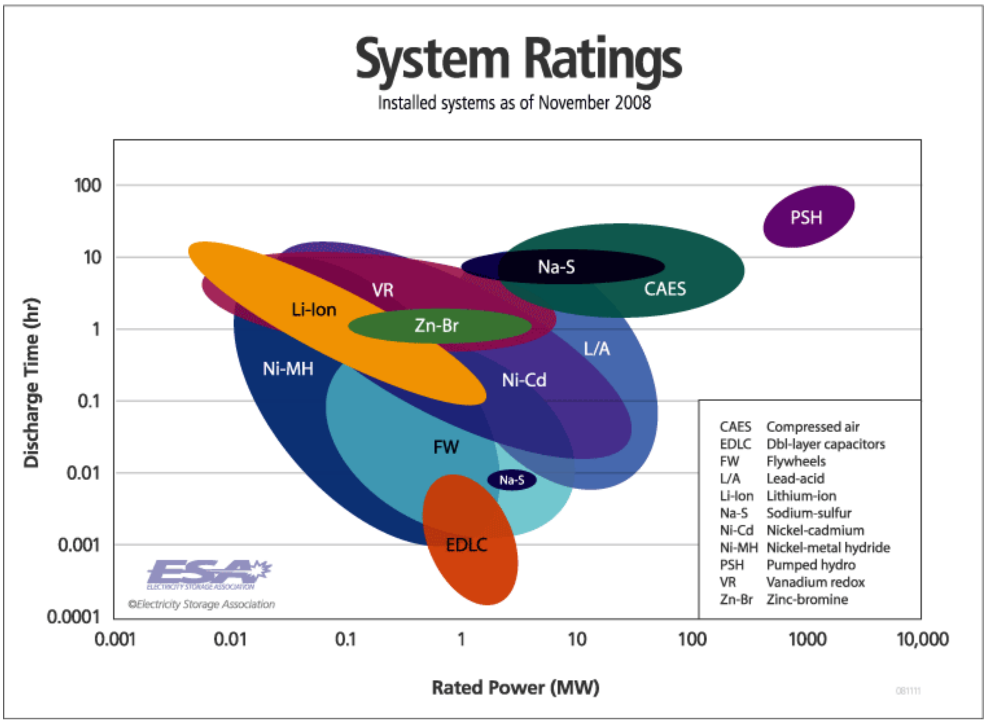

Figure 2: Current energy storage technology capabilities. Source: Electricity Storage Association

The UK has a track record in HPS though no development has taken place since the early 1980s; the following four conventional HPS plants are installed and operating in the UK:

Scheme	Location	Capacity	Operator	Completed	Cost (2012)
Dinorwig	Wales	1,728MW	GDF Suez	1984	£1,820m
Cruachan	Scotland	440MW	Iberdrola	1965	£273m
Ffestiniog	Wales	360MW	GDF Suez	1963	
Foyers	Scotland	300MW	SSE	1969	

More recently, planning permission was secured by Quarry Battery Company for a 49.9MW fresh water HPS scheme in the Snowdonia National Park. As Snowdonia Pumped Hydro, this developer is now seeking to increase the consented capacity of the project to 99.9MW through the Nationally Significant Infrastructure Project consenting process.

In addition to balancing supply and demand, HPS can also provide a series of ancillary services which contribute to the minimising of costs to consumers over the longer term, provide essential grid balancing services and support the stability of the System in an environment of increasing non-synchronous generation, reducing inertia and increased susceptibility of RoCoF events. There is a clear ambition at a national and international level to continue to improve the security, affordability and sustainability of the UK's energy mix. A robust energy storage network, at all scales, is vital to the successful deployment and management of a renewables-focused electricity network.

HPS provides further value to the UK consumer through the avoidance of expensive infrastructure upgrades that will likely be required to cope with the additional intermittent capacity connecting to the System. Energy storage provides the flexibility to manage supply and demand in real time and to buffer discrepancies between the two.

Many of the issues identified by National Grid are caused directly by factors in the Distribution Network rather than the Transmission System. There is a need for greater visibility and clarity to the System Operator over embedded generation and its performance which can currently only be observed and managed as a reduction in demand on the Transmission System. Whether this requires the creation of a new independent System Operator, an overhaul of National Grid's remit or the development of a Distribution System Operator ("DSO") model is debatable. SOE believe the mechanics of any new framework is more important than which particular body is responsible for operating the System.

HPS is generally connected to the Transmission System and dispatched by the System Operator. SOE is investigating the potential for Distribution Network connected HPS projects. The incentives and routes to market for this sort of scheme are not yet fully developed but SOE believe that the value of flexible plant within Distribution Networks, close to the source of significant embedded intermittent generation must be explored further. The efficient monetisation of embedded energy storage will rapidly incentivise a significant volume of development, managing the issues faced in the Distribution Network at their source without wider implications for adjacent Grid Supply Points or the Transmission System. A suitable market for embedded storage could have significant welfare benefits to the UK overall.

SOE believes that the current Balancing Mechanism, and the changes made through the recent Electricity

Balancing Significant Code Review to move to a single cash-out price for imbalance penalties, adequately captures and assigns responsibility for issues caused by imbalance. Transmission connected renewables are equally exposed to imbalance risk as conventional plant. Extending this concept to ancillary services, the main drivers for the level of frequency based services procured by National Grid is driven by the nature of conventional plant – large single generators that set the maximum infeed loss levels against which the System must be protected. Renewable units are generally modular and do not present such singular challenges to the System with the loss of single units.

Therefore, despite the strategic recognition and some policy support for electricity storage, and a track record for the technology in the UK, this is not translated to a market that functions to facilitate deployment of HPS. SOE believe that through reform of markets and innovation of technology, a new suite of potential HPS sites can be made available for development. We describe some of the barriers and considerations for resolving these barriers in response to question 2, below.

4.2 What are the barriers to the deployment of energy storage capacity?

Given the issues highlighted above and the potential cost savings to consumers available through HPS development, the UK has a time-limited opportunity to capitalise and facilitate a move towards a System with the necessary capabilities to transition to a low carbon energy mix over the next 20 years. Development of HPS projects takes 5-7 years from conception to delivery yet the drivers for HPS development are making their presence felt now.

The ability of the UK to increase renewable penetration and to be a global leader in the transition to sustainable, clean, affordable and secure energy production is dependent on the innovative development of a suite of energy storage facilities at all levels, from the domestic lithium ion battery scale to the Transmission System connected GW-capacity HPS scale. There is clearly already a disparity between the UK and other EU countries – Portugal has found the optimal ratio of energy storage to renewable capacity to be 1:3.5. This leaves the UK drastically under prepared with a current ratio of 1:8.7. This logic would see the UK increase its energy storage capacity from 2.8GW to 7GW immediately, without considering the possible doubling of renewable generation on the System by 2020.

Despite this clear and well-founded argument for increased development of energy storage there are still major barriers to new investment in this sector in the UK.

Short term nature of contracts and markets

The relatively high capital cost of large scale HPS projects requires long term debt financing. The lack of secure, long-term contracts with National Grid or through another mechanism has created a significant barrier for new investment into the storage market in the UK. Several developers in the UK have progressed HPS projects through the consenting process yet are unable to build out the projects due to a lack of bankability under current frameworks and contracts.

National Grid currently offer a maximum two year contract, leaving investors exposed to market risk beyond this timescale. Most new build HPS projects will be financed over 15-20 years creating a disparity between market dynamics and inherent risk.

Prohibitive connection and Use of System charges

HPS projects are liable for the same connection charging mechanism as conventional generators that are not providing System balancing and stability services. The cost of new connections reflects the additional capacity that the System in any particular region will have to cope with. HPS projects are operated in a way in which reduces System stress thus deferring the need for costly infrastructure upgrades with must be recovered through connection charges and Use of System charging.

As HPS imports and exports energy it attracts demand and generation Transmission System Use of System ("TNUoS") charges. These charges are levied by National Grid in order to claw back the cost of maintaining the infrastructure necessary to operate the System with the parameters of the SQSS. Given that HPS is generally taking actions to reduce System stress there is a valid argument for the exemption of HPS project from these charges.

Balancing System Use of System ("BSUoS") charging is also applied to HPS projects. These charges are levied by National Grid in order to recover the costs of imbalance in the System and the balancing actions that National; Grid has to take in each Settlement Period. The same argument is applicable to the levy of BSUoS charges on HPS projects given they are actively participating in the balancing mechanism as a tool for National Grid to reduce the impact of imbalance events on the System.

Triad generation benefits

Embedded generators are rewarded for providing energy to a distribution network during triads (loosely defined as the three settlement periods in which demand was highest). As HPS provides energy balancing and grid stability services it is highly likely that plant will be generating during triad settlement periods. However under the current framework Transmission System connected generators are not rewarded for generating or providing services during triads.

Development of alternative HPS sites

Conventional HPS makes use of mountainous landscapes with existing bodies of water with a significant difference in altitude between them but within a reasonable distance of each other. This tends to mean locations are limited to inland areas remote from settlements. To date, only one HPS scheme globally has employed the use of the sea as its lower reservoir, severely limiting the development of such schemes to a portfolio of fairly unique terrestrial environments. This limitation is due to a number of factors; the lack of knowledge and expertise (and therefore perceived risk) in the application of pump-turbines in alternative and marine environments; the cost of bespoke generators, drive trains and pump-turbines (where no standardization has occurred) and the perceived and real environmental impacts associated with the manipulation of the interface between marine and terrestrial environments and the safety concerns over the construction of artificial reservoirs near to conurbations. Innovation is necessary to overcome these barriers to greater roll-out of HPS facilities. For example, the development and demonstration of a seawater-based facility for the first time in the UK (indeed the EU) will stimulate the development of multiple comparable projects presenting opportunities for HPS facilities with lower economic, environmental and societal impacts in locations previously unconsidered by utilities, governments and developers alike.

Addressing the barriers

Investment in HPS need to be facilitated through changes to the existing routes to market and additional markets specifically devised to support HPS schemes. We would encourage further consideration of the following points:

- A storage-specific, technology-specific or new-entry specific capacity market auction with guaranteed long term contracts segregated from the wider auction where existing plant will always drive the clearing price down to a level that is unacceptable to new entrants, especially those with limited storage available, thus precluding them from other routes to market (the 2014 auction ended up at £19.40/kW, 40% of the CONE- cost of new entry, the 2015 auction settled at £18/kW). The current capacity market mechanism can only secure the longevity of existing and ageing gas, coal and HPS plant where there is little or no investment or operational modification required in order to benefit from the capacity market.

- Refinement of the capacity market auction process to allow HPS plant to compete directly with other technologies through its superior operational ability to respond quickly and to provide ancillary services.

- Further clarity on the role of embedded demand side response and storage. Also, increasing the responsibility of DNOs to manage their networks autonomously rather than passive role and reliance on National Grid to balance the system via the DSO model. This argument is becoming increasingly relevant as the volume of embedded generation grows. Mechanisms to allow embedded storage providers to work directly with DNOs ultimately decentralising the management and administration of the UK's electricity network should be discussed by industry and Government.

- Longer term firm frequency response contracts beyond 24 months to incentivise new entrants. The decreasing level of mechanical and thermal inertia on the system will create the need for further FFR providers in the future. HPS plant excels in this market and changes to the contracts with National Grid to provide more security and confidence in the market could incentivise new entrants.

- New ancillary services directly focused around the provision of synchronous inertia to the network.

- Dedicated contacts for difference for storage providers on a case-by-case basis (as is the case for nuclear), recognising the long-term value, energy security and sustainability that additional storage can bring to the UK.

- The development and implementation of hybrid-CfD structures that do not incentivise a purely volume based generation pattern. Structures that reward availability, response time and deferred investment in infrastructure.

- A request for National Grid, DECC, and regulators to give more guidance to the industry on what is required in terms of plant physical characteristics; storage capacity ramp-up and ramp-down times, response times, location, generation capacity.

4.3 What level of electricity interconnection is likely to be in the best interests of consumers?

The EU interconnection targets are a major driver to the development of new interconnection projects. These targets call for 10% interconnection by 2020 at a country level and 15% by 2030. The current pipeline has the potential to deliver up to 10GW of additional interconnection capacity in the UK.

In addition to a strong policy commitment, interconnection projects are provided incentives, EU subsidies and underwriting of minimum revenue streams, that results in interconnectors having significant competitive advantages over UK domestic generators and UK based storage. For instance, six of the eight interconnector projects proposed have been granted cap-and-floor structures by Ofgem.

Interconnectors are also exempt from the Carbon Price Support levy that would apply to UK domestic generators. Exemption from TNUoS, BSUoS and grid losses provide further competitive advantages to interconnector energy over domestic.

The effect of interconnection on UK welfare should be considered carefully. The impact of subsiding interconnection should be fully understood to inform the level of interconnection to the UK. It is SOE's view that the current level of interconnection to Europe in the UK could be sufficient to provide the required energy security alongside UK renewables and enhanced UK based storage and energy management solutions.

On the other hand, with appropriate pricing and volume controls to ensure a stable and fair market, the interaction between UK based HPS and interconnection could become increasingly important to the ongoing security and sustainability of supply. If UK based energy storage is integrated with interconnection, there is a balance to be struck in terms of opening a bigger and potentially more competitive market to support the HPS sector while ensuring that HPS facilities continue to support domestic networks at transmission and distribution scale. Interconnection alongside UK based HPS can both facilitate a move towards a more integrated and holistic management of energy, driving efficiencies in the best interests of consumers as we drive towards a low carbon economy.

4.4 What can the UK learn from international best practice on terms of dealing with changes in energy technology when planning to balance supply and demand?

Market and system reform

In the Republic of Ireland, Eirgrid have undergone a rapid and extensive operational overhaul driven by the development of large amounts of wind power. Ireland currently has 9GW of conventional plant and

3GW of wind power with a total peak demand of 6.8GW and a baseload demand of around 2.3GW. With only 1GW of interconnection to the UK, Eirgrid has developed operational frameworks that allow a high level of intermittent penetration while being able to operate the network securely and reliably. Eirgrid's DS3 system provides operational decisions to manage System Non-Synchronous Penetration of up to 55% with ambitions to increase this to 75% of the energy mix. This is an unprecedented level of non-synchronous generation penetration. DS3 has allowed the volume of wind penetration to increase rapidly while curtailment actions have decreased. This has been achieved by changes to RoCoF parameters, additional system services, revised operational policies and new control centre tools. This has seen a shift in revenue streams to generators moving away from energy payment dominated incomes to increased proportions of income from capacity payments and ancillary service provision. The availability of regulated tariffs fixed for five years and annual auctions with contracts for up to 15 years to encourage new investment have been pivotal in the changes seen in the Irish energy market over the last five years.

Independent Government backed studies facilitating investment

The roll-out of significant solar and wind generation in the USA also provides a useful source of learning for the UK in the net value of energy storage, in particular HPS which is currently the only technology capable of providing large volumes of energy over longer timeframes with fast response times at a reasonable cost. The USA Department for Energy has supported several detailed studies into modelling the value of advanced (variable speed) HPS in the United States. Led by Argonne Laboratories, the studies looked at revenue streams attracted by HPS projects in various locations through the provision of various balancing and stability services and through energy arbitrage (buying cheap and selling at peak). The analysis then went further to look at the displacement effect that the development of HPS would have on alternative services, plant and upgrades to the system infrastructure required to operate securely with increased levels of non-synchronous plant. A holistic analysis was then applied to the findings to reveal the overall system savings attributable to the development of HPS, thus illustrating the net welfare effect of supporting HPS development. These studies showed that under a base renewable scenario, California could expect to see a 3.36% cost saving with the development of fixed speed and variable speed HPS plant. Under a high wind development scenario this cost saving rose to 9.12%. The commitment from Government to support a holistic, in-depth analysis of the market, the dynamic effects, and benefits such as value for money, promoted targeting of investment and investor confidence to facilitate the energy storage sector.

Technological innovation

The Yanbaru Seawater Pumped Storage Power Station in Okinawa, Japan was commisioned in 1999 and provides valuable learning in terms of technology innovation necessary for greater deployment of HPS in the U, particulary utilisation of innovative landscapes and seawater based schemes. It has an installed capacity of 30MW and provides grid balancing and other ancillary services. Several innovative steps were taken to mitigate the operation of the pump-turbine in a seawater environment including corrosion preventative methods for parts of the pump-turbine through the use of paints, stainless steel and adjustable cathodic protection based on relative water velocities since corrosion is accelerated under higher water velocities. Similar protective techniques were devised for the wicket gates, gearing, turbine runner, shafts and draft tubes. Bio fouling issues were tackled through the monitoring of water velocities and the use of water repellent coatings.

Conclusions

- As part of a Europe-wide paradigm shift in the energy mix, the UK is seeing a rapid move towards non-synchronous, embedded generation both close to and far from demand centres. This represents a significant change from the centralised generation foundation that the UK System was designed and built upon. As such, major change in the operation and management of the System is required. The operational and market effects of these changes are making themselves felt now. The time to act is now.
- HPS is currently the only technology capable of providing large scale energy storage at reasonable cost with fast response times that are required for the safe and efficient operation of the System.
- HPS is a tried and tested technology and has been operational in the UK since the 1960s with four existing sites and potential for further development in alternative locations including industrial sites and seawater based schemes.
- The flexibility and System support services provided by HPS facilitates the continued take-up of renewable energy in the UK alongside conventional generation. The development of a suite of energy storage across the UK will reduce the overall cost to the consumer, improve UK welfare and enable the UK to meet its emission reduction targets.
- Significant barriers exist to the development of energy storage. A change to market frameworks to allow more flexible yet longer term contracting with National Grid, Distribution System Operators and/or a new independent Operator with visibility across the System, would encourage new investment into energy storage.
- Interconnection to the UK may improve energy security, but there is a balance to be struck to ensure that investment in UK based energy projects, and the UK energy market is not undermined.
- Ireland provides an excellent example of the innovation and change that is required to facilitate an increased penetration of non-synchronous plant into the System. Case studies in the USA have shown that significant cost savings can be achieved through the development of HPS on a system with a high proportion of renewable energy.
- SOE has a pipeline of HPS sites across the UK ready for development. An evolved market and regulatory environment could facilitate SOE to deliver significant storage capacity to the UK System enabling the transition to a low carbon energy mix.

Please contact me on [phone number redacted] or [email address redacted] if you consider, based on our submission, that further information or discussion will assist your considerations.

Yours faithfully

Michael Edge

Development Manager

Shire Oak Energy Ltd

Shropshire Council’s response to the National Infrastructure Commission consultation

Electricity Interconnection and Storage

Currently there are areas of the energy market that discourage the participation of small businesses, especially those hoping to provide competition through the development and direct sale of micro-generation energy. This is an area that has great potential for addressing some of the current issues in the energy market such as competition and consumer choice. An open market with a regulatory environment which encourages innovation and competition and new investment or access to flexible financing is required. However, we believe that small business plans to deploy micro-generation and renewable technologies are being frustrated by a number of difficulties connecting to the grid.

There is a lack of consumer focus by distribution network operators (DNOs), with consequential lack of quality service for small businesses wanting to connect to the grid. It is a bureaucratic and time consuming process. There is a lack of transparency of costs to small businesses connecting to the grid. Many of these costs are non-contestable and there is little evidence to show how they are calculated by DNOs. For works that are contestable – carried out instead by a private contractor – these costs could be significantly lower than those quoted initially by DNOs, especially if reliance on DNO services was reduced.

A small business has to pay the costs of connection up front, with no opportunity to phase the payments. We would like Ofgem to look at the potential for these costs to be paid over the life of an asset. We would like to see small businesses given an increased opportunity to supply energy to the grid, but also the opportunity to supply directly to customers locally. As it stands, a small energy generator may only make £0.04p kW/h exporting locally generated energy to the grid. However, by selling directly to a local smart grid (e.g. adjacent village/housing estate) at market rates they may make £0.11 kW/h. This would transform the viability of local energy generation without the need for public subsidy or green levy on energy bills, encouraging small businesses to invest in peak capacity beyond their own consumption. It would also provide a disruptive influence on the market overall.

There are a number of hurdles that need to be addressed in order to realise this micro-generation revolution:

1. Regulations restricting the direct sale of power from any power station below 50MW would need to be amended.
2. Ofgem would need to establish a light touch regulatory regime for sub-50MW retailers who would supply to local grids (FSB has already opened a dialogue with Ofgem about this).

3. There would need to be a separate category of light touch licence for community or business energy retailers selling to a defined local area with a limited number of customers.

Making it easier for small businesses to generate and sell their own energy will benefit our economy and establish a much needed boost to an otherwise stale energy market. We welcome the recommendations in the HM Treasury report, "A better deal: boosting competition to bring down bills for families and firms outlining the steps to help small businesses".

Further- more we would wish the consultation to note that with the de-commissioning of the Ironbridge Power Station in Shropshire the importance of the sub-station on the site for grid connectivity. Also of the site for energy intensive inward investment manufacturing for the whole of the West Midlands and the Northern Gateway given its excellent water and rail links.

Supply companies do not normally liaise with Local Planning Authorities on an area's development proposals and aspirations and factor these into their own business plans. Even though in Shropshire we use a very intense partnership approach to planning via Place Plans for each of our towns it still depends on willingness of utility companies to engage. A good example of this was in Whitchurch where only due to the pressure applied by Shropshire Council have these been finally taken into account in the investment plans of Scottish Power. Scottish Power now quote this as an example nationally of how this kind of relationship can make a difference. Private sector investing companies have much shorter timeframes and these do not sit comfortably with Electricity network company plans or with Local Planning Authorities development plans. For example Scottish Power has an 8 year business plan (2015-23) whilst the Shropshire Core Strategy is for 20 years (2006-26).

The additional problem however is that although sites are allocated there is huge uncertainty as to when development will occur .Companies want certainty that if they are to invest they will get a return. Where development proposals requiring electricity infrastructure investments such as district wide improvements the cost of these fall unfairly on the promoter to provide. This is due to the first-comer rule. This really must be looked at and a radical new approach found. As a result some commercial schemes (where development values are marginal based on costs) have not been implemented. Although other District Network Operators will provide private networks in other areas, this has been on the basis that the customer underwrites the risk if the actual amount of power used is below the estimated supply.

SIEMENS

Siemens plc response to National Infrastructure Commission call for evidence - Improving how electricity demand and supply are balanced

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Introduction:

This document forms part of Siemens' response to the consultation published by the National Infrastructure Commission (NIC). The response relates to the third part of the call for evidence: **Improving how electricity demand and supply are balanced.**

Siemens in the UK employs almost 14,000 people across the UK with 13 manufacturing sites and multiple other facilities. We are a major investor in the UK energy sector, both in the UK supply chain that serves the sector and in specific generation projects. We would like to do more here.

Siemens builds many types of electricity generation, electricity and gas substations and smart networks. We provide a range of energy services including meter operations and maintenance of energy infrastructure. We also invest both equity and debt into energy projects. This gives us a unique insight into the energy market as a whole.

Our UK energy businesses directly employ over 6,000 people. In the last 4 years we have created over 1,000 direct jobs and will add a similar number when our £310million joint investment with ABP in a wind turbine factory in Hull is completed in 12 months' time.

Response to Questions

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

We welcome the opportunity to respond to this call for evidence and a first chance to comment on the work and priorities of the NIC in this area, as set out in the terms of reference accompanying this consultation.

Affordable, secure and sustainable energy supply systems are a vital part of the UK's infrastructure. Energy issues are complex, interrelated and long term. Often the markets that govern them are subject to political changes. Too often government action or political announcements show evidence of lack of understanding of the industry and how things work in real world situations. Companies that invest in this infrastructure and its supply chain can be significantly impacted by such changes, or the lack of clarity that precedes them. Decisions to invest in UK jobs and infrastructure can be too easily impacted by short term politics. It is in the interests of all stakeholders that energy policy is evidence-based and properly considered.

As the NIC approaches this subject we urge you to follow the maxim "first do no harm". Wherever possible stay silent on a subject until you know you really understand it. And before announcing something check it for sanity with a range of industry stakeholders. We also urge the NIC to work collaboratively with the expertise within all parts of government, Ofgem and industry. Otherwise your actions will only add to the political risk faced by energy investors.

The TOR asked the NIC to consider "whether an appropriate institutional framework is in place." No framework is perfect. We would caution that the way such frameworks are deployed has at least as much impact as the statutes that underpin them. We suggest the NIC focus on how investment signals are given and the clarity of policy direction, rather than unpick the institutions.

We saw, for example, a lengthy hiatus in generation investment during the EMR process. Another such period of political jeopardy would damage investor confidence in UK energy policy and make it harder and more costly to achieve the infrastructure development required.

We note that "where possible, the Commission should aim to develop market solutions to these issues." We would like to point out that energy is unique among UK infrastructure in that it is the only type of infrastructure where there is any expectation that a market will decide what gets built. We don't use markets to decide whether to build a new railway. Government decides what it wants and we use competition to deliver it efficiently. In this case market or competitive solutions are useful for delivery but do not make strategy.

Similarly there is no natural market in electricity. It is a political creation, a set of levers with government on the other end of some of them. Investors in electricity infrastructure know this. Government rarely acknowledges the fact but it is the defining fact in industry behaviour.

Since privatisation 25 years ago we have had three markets, overlaid with various subsidies, codes, standards, licences etc. The idea is that if we can design a perfect market it will simultaneously dispatch the most economic generation in the next half hour and encourage the right mix of new projects. These projects will, after a decade of development and construction, build the right mix and quantity of generation to meet the as yet unknown future needs of electricity customers, and balance the trilemma of security, sustainability and cost over all time horizons. And this is before we consider engineering issues like stability, inertia, power quality etc. Or the interaction of electricity with heat, transport, or a range of other economic factors.

What happens in practice is that government creates a market that is programmed to deliver a particular mix. When this mix starts to emerge government decides it is not what was wanted and reconfigures some of the levers in the market to deliver something else.

Investors see this political risk and refrain from investing until government makes it worth their while. The cost of capital for all kinds of energy infrastructure is higher than it need be and the resulting stop-start market inhibits investment in UK jobs and delays cost reduction. At the same time no party is responsible for adequacy of the whole system.

Energy Policy

Recognition of the myth of the market is the first step to looking at what government can actually do to create a successful electricity industry. Some fundamental decisions always come back to government. By taking decisions in a timely and well informed way government can deliver real benefit for customers. By signalling the intent of future decisions it can increase investment in the supply chain.

EMR has given a set of levers which allow government to decide broadly on the electricity mix. Up to now, government has not said what mix it wants. This leaves developers and supply chain of all types with a level of jeopardy that puts up costs and inhibits investment in the UK.

Government can use existing levers to deliver a well managed electricity system. By signalling clearly the direction of travel, government can align the efforts of the industry with policy far better than hitherto. We suggest that governments stop trying to force all types of new build generation to compete in one single electricity market and instead run technology specific competitions to find the best projects of each type.

2. What are the barriers to the deployment of energy storage capacity?

Today's infrastructure is designed to transmit electricity generated in bulk from large power stations to large load centres. Decarbonisation was not a consideration in the evolution of the country's electricity infrastructure but, driven by the transition towards a low carbon future, we will see an increasing proportion of intermittent generation from renewable sources (both bulk and decentralised) and a growth in decentralised energy systems. This will result in the balancing of electricity supply and demand becoming more complex, an issue that is only likely to accelerate in the coming years.

There is broad agreement between industry, academia and governments that energy storage has a key and increasing role to play but that the application and leading technology will change over time. However, the current market does not incentivize the deployment of storage, nor does it adequately reimburse storage operators for the benefits their technology brings to the energy network. The market needs to properly recognize the value of storage, given the role it can play in maximising utilisation of intermittent renewable energy sources and existing transmission and distribution networks. As recognised by OFGEM, the current UK market also struggles to define storage: storage can be classified as "consumption" and/or "generation and/or "supply".

Energy storage can provide production, consumption and therefore balancing services. Siemens believes this lack of classification/recognition, combined with regulatory restrictions (e.g. a Distribution Network Operator cannot own generation assets) has a detrimental effect on potential solution providers' abilities to tender for storage solutions and services, as they will require revenue certainty over sensible contracted durations to guarantee returns, gain investor confidence and in time reduce costs.

Storage will become prevalent in a range of different forms. Types, scale and technology behaviour will vary according to local needs: there will be no single technology winner. Early winners may be network connected Li-ion bulk energy storage to alleviate short term network constraints; however, this could transition to sizeable grid scale storage solutions such as Compressed Air Energy Storage (CAES) and a much greater penetration of storage 'behind the meter' as EV rollout and levels of domestic distributed generation. Later, power to gas will become more prevalent as electrolyser technology improves or there are new developments in small scale combustion to support microgrids.

In the longer term, significant deployment of behind the meter storage could be a significant threat to distribution networks due to the issue of "Load Defection". Essentially, as prices of solar and storage technologies decrease, it could become more beneficial for end customers to install such technologies behind the meter. This could result in decreased revenues for the utilities as use of system charges are challenged, with the net result potentially being reduced investment in distribution networks. Due consideration should be given to these long term eventualities.

Siemens itself has a comprehensive research and development program focused on energy storage across a broad technology landscape and multiple use cases. Due to the long term potential for energy storage to maximise the utilisation of renewable generation capacity and address the complex balancing issues of low carbon networks, we would urge continuation of and consistent, innovation-focused financial support within the UK for storage projects to speed up the development, deployment and cost-effectiveness of storage technologies.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Others including Ofgem, DECC and the EU have identified that the UK and other countries would benefit from interconnection of at least 10% of national capacity, for both gas and electricity. Siemens has no expert view on an optimum level for the UK. We note that if all the proposed UK interconnectors were to be built they would add up to around 10%. It would be sensible to get on and deliver them all in the most cost effective way.

Siemens is a technology provider for interconnectors and we may provide some finance for projects but we do not regard ourselves as a developer. We have limited insight into the business models of projects but we do see how long they take to develop and how difficult they are to financially close.

The challenge for merchant interconnection (as for storage) is that project economics depend on a price differential between the systems to be connected. The nature of the connection, once built, is to remove the price differential. There are significant benefits to the country but not necessarily to the asset owner. If we finance interconnectors on a merchant basis this exposes the owner to market risks which they cannot control; pushing up the cost of capital. Most other countries choose to build interconnectors as strategic infrastructure assets. Indeed some of the existing UK interconnectors are merchant at one end and not the other.

The Cap and Floor approach aims to reduce the merchant market risk, whilst leaving the discipline of being exposed to some of it. In Siemens' assessment this is helping encourage projects to a more advanced state of development. However the system is new and as yet unproven and we believe further encouragement may be needed to deliver projects.

Cable supply for interconnectors is constrained and competes globally and with projects such as offshore wind and oil and gas platform connections. A single large interconnector, such as to Norway, can tie up European cable production for a long periods. The existing market approach leaves projects unable to commit to cable suppliers until final investment decision. There is a risk that this will result in a long period with no projects and then a number reaching this stage together, creating a bottleneck and pushing up the cost.

If the National Infrastructure commission were to propose a more planned approach to infrastructure delivery the supply chain could plan with greater confidence and both the delivery of cable and the cost could be smoothed. And even consider capital investment in additional manufacturing capacity.

The Cap and Floor approach gives a strong disincentive to anything that looks like a stranded asset. The linear nature of interconnectors and potential congestion at a limited number of landing sites make it sensible to plan for future capacity. In our experience the Cap and Floor approach discourages our customers from considering future expansion by making provision during one project for a future one. This may be as simple as designs that sterilise a future corridor, building ducts for future cables or even laying future cable sections that could be used as backup for the first project until incorporated into a future link.

We note the recent research on public attitudes to infrastructure by Copper Consulting et al which suggests public frustration at the lack of forward planning in infrastructure and a willingness to accept greater cost and disturbance once in order to avoid multiple and less efficient works.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Infrastructure investment is more straightforward where there is a clear long-term strategy and a relatively simple regulatory regime (or a state-backed utility.) Competitive processes work well when the goal is clear and companies compete on a like for like basis. All the efforts of competitors are focussed on the goal, not on second guessing what arbitrary weighting may be given to other technologies in some artificial single market.

We suggest that the National Infrastructure Commission should advise government on the broad mix of energy assets required and government should use competitive processes to deliver this mix in a cost effective way.

Further information:

If the Commission would like to discuss any of these subjects further with Siemens, please contact:

Matthew Knight, Director of Energy Strategy, [phone number redacted], [email address redacted]

Or

Steven Coventry, Government Affairs Manager, [phone number redacted], [email address redacted]

Siemens plc, 8 January 2016

About Siemens

Siemens AG (Berlin and Munich) is a global technology powerhouse that has stood for engineering excellence, innovation, quality, reliability and internationality for more than 165 years. The company is active in more than 200 countries, focusing on the areas of electrification, automation and digitalization. One of the world's largest producers of energy-efficient, resource-saving technologies, Siemens is No. 1 in offshore wind turbine construction, a leading supplier of combined cycle turbines for power generation, a major provider of power transmission solutions and a pioneer in infrastructure solutions as well as automation, drive and software solutions for industry. The company is also a leading provider of medical imaging equipment – such as computed tomography and magnetic resonance imaging systems – and a leader in laboratory diagnostics as well as clinical IT.

In fiscal 2014, which ended on September 30, 2014, Siemens generated revenue from continuing operations of €71.9 billion and net income of €5.5 billion. At the end of September 2014, the company had around 357,000 employees worldwide. Further information is available on the Internet at www.siemens.com. October 2015

National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

08 January 2016

Dear Sir/ Madam

National Infrastructure Commission call for evidence: Energy interconnection and storage

Scottish Renewables is the representative body for the renewable energy industry in Scotland, providing a united voice for more than 275 member organisations working across the full range of technologies delivering a low-carbon energy system integrating renewable electricity, heat and transport.

Our vision is for a Scotland that harnesses the full economic, social and environmental potential of all forms of renewable energy, in order to provide consumers with secure, low-carbon supplies of energy at the lowest possible cost.

The Committee on Climate Change estimates that 66 – 93GW of renewables will be required to deploy in order to deliver an electricity system in line with our 2030 carbon budgets - at least double today's operational capacity. Our energy infrastructure is central to this ambition and it is increasingly clear that providing more flexibility on that network will allow us to meet that target at lower costs to the consumer[1].

Interconnection and storage are both vital sources of this required flexibility and we welcome the commissions focus in this area. However, it is important to note that on the subject of 'system balancing' there is some concern that there is no definition of problem that the commission is seeking to remediate. It is our view that any proposal to alter the way that supply and demand is balanced should be supported by a clear 'needs case'.

We have set out or response to the questions provided below, and we would be happy to contribute to any additional work that arises from this consultation.

Yours Sincerely,

Michael Rieley
Senior Policy Manager: Grid & Markets

[1] https://d2kjx2p8nxa8ft.cloudfront.net/wp-content/uploads/2015/11/Sectoral-scenarios-for-the-fifth-carbon-budget-Committee-on-Climate-Change.pdf

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Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand is balanced, whilst minimising cost to consumers, over the long-term?

It is important to note that NIC's review comes after a number of completed and ongoing reviews of aspects of balancing arrangements. This includes over-arching work initiated by the regulator Ofgem, as well as narrower industry-initiated work as part of the industry code governance process. Including;

- National Grid's review of locational targeting of balancing costs (BSUoS), which was rejected by Ofgem[2]
- The Ofgem Electricity Balancing Significant Code Review (EBSCR) which recently completed and has targeted more cost reflective cash-out prices[3]
- Ongoing evaluation of the Capacity Market to establish any lessons and changes that may be needed to secure sufficient capacity during times of system stress
- A number of proposed changes to the System Security and Quality of Supply Standards (SQSS) triggered industry discussion on targeting higher costs of reserve onto users that trigger them[4]. This has been an issue for nuclear power and for large clusters of generation connected by a single radial connection e.g. offshore wind farms and island connections.

With this in mind, there is some concern that although it is clear that system balancing is a priority issue for the commission, there is no definition of problem that the review is seeking to remediate. Therefore, any proposal to alter the way that supply and demand is balanced should be supported by a clear 'needs case' building on this existing work and identifying where the current system could be improved.

Overall, it is our view that it may be too early to say how well current arrangements are working in the interests of consumers given the relatively recent introduction of more cost reflective 'cash-out' prices through the Electricity Balancing Significant Code Review (EBSCR). However there are issues that act as barriers for specific market participants including the development of electricity storage and distributed generators and we have set out our concerns in this area below.

Finally, given that any fundamental change to balancing arrangements would impose significant costs on market participants whose working arrangements, communications and IT systems have been purpose-built for the existing arrangements, we would welcome any clarity from the commission on how any changes, if identified, would be made.

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[2] .https://www.ofgem.gov.uk/publications-and-updates/decision-relation-use-system-charging-methodology-modification-proposal-gb-ecm-18-"locational-bsuos"

[3] https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review

[4] https://www.ofgem.gov.uk/sites/default/files/docs/2010/10/gsr007-ia-final_0.pdf

The NIC will presumably report to government with recommendations, but this need to be mindful that government typically intervenes to effect major changes via legislation, and the prospect of this will impact on the market.

Specific questions

What role can changes to the market framework play to incentivise this outcome:

- ***Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?***

Given the increasing set of market-wide responsibilities taken on by the SO, we believe the direction of travel is for an independent system operator, but we have no strong views on exactly when this should happen.

The Ofgem Integrated Transmission Planning and Regulation (ITPR) Project has already taken steps toward this by enhancing the role of National Grid as system operator in planning the electricity network.

If and when the SO becomes independent, its incentives need to be aligned with those of the TO's, in order to minimise overall network costs. Network investment can alleviate balancing costs and vice versa and it is important that drivers are consistent across the businesses.

- ***Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?***

All market participants are directly or indirectly responsible for their imbalances via the system of cash-out. As already noted, Ofgem has recently completed a review of cash out prices. These arrangements encourage participants to "self-balance" by submitting accurate Final Physical Notifications at Gate Closure, one hour before the trading period starts. Penalising imbalances between notified positions and actual positions helps to ensure that the information available to the SO is as accurate as possible.

While we understand that a case could be made for widening out balancing market participation to smaller parties not currently obligated to do so. At the moment, smaller parties can voluntarily participate in the balancing market, and as far as we know this arrangement is satisfactory. Therefore any benefit (such as providing National Grid more choice when taking balancing actions) would need to be set against the subsequent cost of smaller parties having to bid 24/7

However that there may be opportunities to better utilise intermittent generation and demand side response for the provision of services – and we would encourage the commission to consider this further.

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Demand-side management and embedded generation are already increasingly contributing to system flexibility. Embedded generators of a certain size face mandatory grid code obligations to help manage system frequency and reactive power and as noted generators and demand can voluntarily participate in the Balancing Mechanism.

Scottish Renewables strongly supports a Distributed System Operator (DSO) model where distribution companies actively manage generation and demand across their network areas and take overall responsibility for the interfaces with transmission. This effectively devolves some system operation responsibilities, and enhances the flexibility of actions available to balance the system. Under such a model, DSOs could aggregate the services of embedded generators and use these to support the operation of the transmission network.

2. What are the barriers to the deployment of energy storage capacity?

Specific questions

- ***Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?***

Cost is often viewed to be a key barrier to deployment of electricity storage. However, there is a growing expectation[5] that the capital costs of this technology will fall. In addition a number of projects taken forward under the Low Carbon Networks Fund have shown that it is possible to significantly improve commercial viability by realising the additional value that such technologies can add to the system[6]

In many ways, the drivers of this technology can be considered as analogous to that of interconnection.– driven predominantly by price arbitrage but deriving additional benefits across multiple network users – However, there is not yet a clear regulatory framework to underpin investment in storage assets.

Through the low carbon network fund some Distribution Network Operators (DNOs) have shown that they are well placed to realise many of these wider benefits. Yet, as it stands, there is some uncertainty around the ability of DNOs to do this given the commercial and regulatory definition of 'storage' and the restrictions around DNOs being active in generation or supply markets.

Overall, the regulatory position of storage needs to be clarified. In particular, storage is charged 'Use of Network' charges as both a generator and a load, which may not

[5] http://www.ey.com/GL/en/Industries/Power---Utilities/Renewable-Energy-Country-Attractiveness-Index---Storage---A-new-frontier-or-just-another-energy-asset
[6] https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/sns_progress_report_june_2015_v1.0_0.pdf

appropriately reflect the impact it has on network. There is also ambiguity over the application of the climate change levy for storage, as well as concerns that high BSUoS charges may discourage storage providers from offering balancing services at the times when the system needs them the most. A storage license, which is separate to generation and demand licenses, could be appropriate and may help resolve some regulatory issues. This would be analogous to the separate interconnector licence. However, we note that regulation for storage may be complicated by situations where generation and storage are co-located behind a single meter.

In addition there is some concern that when planning connections of storage to the transmission and distribution networks the standard DNO practice of looking at worst case scenarios for generation and demand will be applied. e.g. the energy storage will at worst case be generating at maximum during maximum generation minimum load conditions, and will be absorbing at maximum during maximum load minimum generation conditions. If networks are planned under such assumptions, this may lead to over-specification of the distribution network infrastructure required to accommodate storage.

Finally, it is our view that the capacity market has missed an opportunity to support storage, by taking a short-term approach of awarding largely one year contracts which are largely insufficient to promote investment decisions in assets with 10 – 20 year lifetimes.

- ***What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)***

There is an important role for all three – transmission, distribution and domestic. Large transmission storage has always played a valuable role, principally pumped storage which can respond quickly and flexibly to system shortfalls as well as absorb excess generation during periods of low demand. Distribution-scale storage is already been trialled as a means to support DNOs in operating more as DSOs. And on the domestic-scale storage can for example help avoid or mitigate expensive reinforcements (e.g. electric cars in remote areas to utilise local renewable energy generation).

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- ***Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?***

As it stands, interconnector development is largely driven by opportunities for price arbitrage. However, given the drive towards a single European electricity market, we consider that there is an increasing need for SO to SO engagement in identifying and planning long term interconnection requirements.

In some respects interconnection is treated favourably in the market arrangements, in so far as it is not liable for transmission charges, meaning non-domestic generation has a competitive advantage. The regulatory regime is also flexible to a number of interconnector investment models, facilitating merchant and merchant / regulated regimes – more so than domestic transmission investment models.

In other respects the regulatory framework is not helpful to interconnection, especially more complex arrangements which might incorporate offshore generation, and where it is not clear how the asset(s) should be treated.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

The GB market provides uniform balancing incentives across all technologies, irrespective of capability or any more considered assessment of whether this leads to efficient outcomes. For example, is it helpful to National Grid that intermittent generation is bundled up into a portfolio for notification and settlements on a half-hourly basis, or would it be more helpful if intermittent generation notifications were more closely aligned with National Grid's (separate to settlements) wind forecasting activities? There are a variety of international practices on balancing, somewhere incentives have or do differ for different technologies. We do not have any preconceptions of the right answer, but a review of international practices would inform the debate.

SSE response to the National Infrastructure Commission call for evidence, January 2015

About SSE

SSE (formerly Scottish and Southern Energy) is a UK-listed and based utility with a core focus on the energy markets in Great Britain, plus Ireland.

It is the broadest based energy company operating in the UK with interests in the production, transmission, distribution and supply of electricity and gas. SSE's core purpose is to provide the energy people need in a reliable and sustainable way.

SSE is one of the largest companies investing in the UK's energy infrastructure. In the five years to March 2018 it has plans to invest £5.5bn, net of disposals, in low carbon sources of energy and the infrastructure to support it. SSE's geographical focus is the markets in GB and Ireland, where it employs over 20,000 staff. The scale of SSE's investment and operations makes a significant contribution to the UK's economy; in 2014/15 independent research found that SSE made a contribution of £8.8bn to the UK's GDP.

SSE welcomes the opportunity to respond to the National Infrastructure Commission's (NIC) call for evidence.

Executive Summary

The UK requires significant energy investment in the coming years to ensure consumers continue to have access to the secure, clean and affordable energy supplies they depend upon. SSE welcomes efforts to provide energy investors with clarity and certainty and supports the aims that the NIC is working toward in its terms of reference. In this submission SSE addresses the areas of consideration in part four of the terms of reference, relating to energy infrastructure:

The case for large-scale energy storage in the UK's energy strategy

Storage technologies offer a broad range of benefits to the UK electricity system. The different characteristics and benefits of available storage types means there is no one type e.g. small-scale, bulk, or specific technology, that is most appropriate for all parts of the UK's electricity system e.g. at a transmission, distribution or domestic level. Different types of storage, at different scales, will be required.

Bulk energy storage will be an important part of this mix. It has the potential to play a crucial balancing role in the UK's energy mix, with the unrivalled volume provided by bulk storage technologies being particularly important when there are large shifts in renewable generation output.

However, the market framework does not currently support investment in new bulk storage. SSE therefore considers there to be merit in Government exploring how this could be unlocked.

Interconnection has a role but the cost/benefits must be considered

Analysis of the benefits and risks of greater interconnection to the UK has, to date, been limited in scope. SSE believes that without robust analysis interconnection may negatively impact the UK's efforts to encourage investment in other areas. SSE believes it is important that interconnection be viewed as access to capacity, rather than providing capacity itself, and that this is reflected in Government policy and support.

Market distortions in relation to embedded generation and demand side measures need to be addressed

While demand side response can increase flexibility of the electricity system it is important that a differentiation is made between true load shifting and embedded generation. The latter currently benefits from avoiding levies that support government policies (Capacity Mechanism, Renewables Obligation, Feed-in-Tariff, Contracts for Difference and Energy Company Obligation) and could displace more efficient transmission generation. SSE does not believe that the current distortions in favour of these resources are helpful from a societal and system-level perspective.

Independence of the System Operator

Some industry participants have expressed concerns that the way in which the System Operator (SO) is currently set-up within National Grid Electricity Transmission Ltd (NGET), part of National Grid plc, could create conflicts of interest, which could in turn impact on commercial decision making. Any perception that this is the case is likely to influence potential investors. Greater independence of the SO could help allay these concerns.

Other areas: the importance of the Carbon Price Floor in delivering energy investment

SSE has consistently been a supporter of carbon pricing, at both a UK and EU level, as the most efficient way to decarbonise the economy. SSE believes the Carbon Price Floor is the key plank in the UK's long-term energy policy. It underpins a number of existing policy mechanisms and has the potential to minimise future interventions by supporting the delivery of current government objectives, for example relating to the delivery of high efficiency new build CCGT, the phase out of coal-fired generation by 2025 and the economic case for increasing levels of interconnection and storage. SSE therefore believes that the NIC should consider the role and importance of the Carbon Price Floor in the delivery of cost-effective, low carbon energy infrastructure.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- **What role can changes to the market framework play to incentivise this outcome:**
  - **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**
  - **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

Some industry participants have expressed concerns that the way in which the **System Operator (SO)** is currently set-up within National Grid Electricity Transmission Ltd (NGET), part of National Grid plc, could create conflicts of interest. This was an issue that was also raised during the development of the Electricity Market Reform (EMR) programme, and NGETs role as the EMR Delivery Body.

These concerns ultimately stem from the fact that National Grid plc is a listed company with a requirement to maximise returns for investors. Whilst recognising that this must be done within the constraints of the Electricity Act and its licence obligations, this requirement will naturally drive National Grid and its subsidiaries to influence any arrangements to best meet that outcome. Potential examples include:

- National Grid is subject to incentive mechanisms on its electricity and gas TO and SO functions and gas DNO, where it is exposed to significant upside if it performs well. There is therefore a risk that decisions will be influenced to maximise overall incentive upside opportunity.
- In its role as the EMR Delivery Body National Grid could choose to favour transmission rather than generation investment through EMR; or try to skew parameters to bias transmission investment, particularly investment in mainland England & Wales.
- National Grid has a number of commercial arms, creating a risk that SO decisions could be to the advantage of NGET affiliated businesses. For example, following the conclusion in March 2015 of Ofgem's consultation on integrated transmission planning and regulation (ITPR), the regulator gave National Grid extra responsibilities including to appraise major investment options and assess the value of potential additional interconnection to other countries. National Grid has a significant commercial interest in interconnection, which directly competes with electricity generation assets both in the electricity market and the Capacity Market auction, which National Grid also sets the parameters for.

Looking forward, the increased connection of inflexible and variable generation (renewables/interconnection/nuclear) is likely to require new methods of balancing the system.

National Grid as System Operator has already proposed two new ancillary services to deal with these issues. It is important that interaction between the suite of ancillary services and other influences such as network charges and the Capacity Market are fully understood. In addition, National Grid's commercial arm has already noted its interest in owning and operating storage assets to balance the system if regulations are changed. This would mean National Grid could in effect tender itself as a provider.

SSE would emphasise that there is no evidence to suggest that National Grid has acted inappropriately in any way; and there are clearly a number of safeguards in place to prevent this from happening. However, the perception that there are conflicts of interest which could impact on commercial decision making is likely to influence potential investors. Greater independence of the SO could help allay these concerns.

The electricity market has recently been through a number of significant changes which will impact its operation, including the actions of market participants in the **'Balancing Market'**.

These changes, namely the Electricity Balancing Significant Code Review (EBSCR) and Electricity Market Reform (EMR), were developed over a number of years and involved significant consultation. The EBSCR is designed to ensure that market participants are fully exposed to the costs of imbalance, thereby sharpening the financial incentive for them to take appropriate balancing actions. This, in theory, will reduce overall system costs for consumers. The Capacity Market introduced through EMR, as well as the Supplemental Balancing Reserve (SBR), is designed to ensure secure electricity supplies at the lowest cost to the consumer.

However none of these mechanisms have yet been properly tested (with the EBSCR only formally introduced in November 2015), and their full impacts on the market and each other are not yet understood. SSE therefore believes it is too early to tell whether any further change is needed in this area. In addition it is important to note that the UK appears to on the right track to meet the criteria of the European Target Model.

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Traditionally Demand Side Management (DSM) has described the reduction of electricity demand at times of system peak, which usually occurs in the early evening. By reducing peak demand the use of expensive or carbon intensive marginal plant can be avoided, as can the requirement to reinforce distribution and transmission networks if their capacity is close to being reached. Since the 1970s DSM via off peak meters and tariffs such as Economy 7 have helped re-distribute significant electric heating load from millions of homes and businesses.

More recently, in line with the growth of variable renewable generation, Demand Side Response (DSR) has been discussed as a key demand management measure available to help balance the electricity system. DSR addresses supply and demand imbalances by actively:

- reducing consumption at times of supply shortage – this could include the DSM measures described above, or for example, it could include the use of behind the meter generation such as 'embedded generation' e.g. on site diesel back-up generators at large industrial sites;
- increasing consumption when inflexible and low carbon output is over-supplying – this could include charging hot water stores;
- fast switching to provide system frequency response – this has been demonstrated by using dynamically operated new electric storage heaters;
- shifting consumption to optimise the use of network capacity – SSEPD has created constraint Management Zones to incentivise localised load shifting.

SSE sees potential for DSR to operate at different levels of the electricity system, both as a provider of short-term system flexibility and within distribution networks where it can ease constraints. For example as a DNO SSEPD is exploring innovative solutions in the Assisting Communities Connect to Electrical Sustainable Source (ACCESS) project, which is investigating the dynamic capabilities of new electric heaters to track output from low carbon generation.

Despite the benefits that DSR can bring it is crucial that the full impact of different types of DSR are evaluated in order to ensure that unintended consequences are avoided and consumers are not disadvantaged.

For example, as embedded generation can lower net consumption on the transmission system it is often classified as DSR. Under the current market arrangements DSR derived from embedded generation is able to avoid charges which other forms of generation are exposed to. This benefit, according to Frontier Economics, distorted the result of the recent Capacity Market auction by providing diesel generators and reciprocating engines with an advantage over larger, more efficient forms of generation such as new CCGTs; and will ultimately cost customers an additional £50m.

Frontier Economics state that the key incentive given to embedded generation is in how transmission charges (TNUoS) are structured. Without the revenue from avoiding these 'TRIAD periods' it is estimated that embedded units would require £55/kW from the Capacity Market, over three times the last auction clearing price. The problem is that transmission charges are currently not cost reflective, for example they do not consider that the majority of network costs have already been incurred and are therefore sunk costs, rather than being avoidable.

When embedded generation is 'behind the meter' it also benefits from helping a small sub-set of largely industrial customers avoid levies that support government policies (including the Capacity Mechanism levy, Renewables Obligation, Feed-in-Tariff scheme, Contracts for Difference and Energy Company Obligation). Whilst this benefits a small sub set it raises costs across the board, as the policy costs remain the same but are paid for by a smaller pool of customers.

The current benefits available to embedded generation therefore create an un-level playing field with transmission generation; correspondingly the first two Capacity Market auctions cleared over 2 GW of new embedded capacity eligible for 15-years of payments. This represents well over 50% of the new build capacity cleared in the Capacity Market so far. Without changes to the regulatory framework this situation is likely to continue, to the detriment of new build CCGTs and existing thermal generation.

Despite owning embedded generators and being able to invest in similar new assets, SSE does not believe that the current distortions in favor of these resources are helpful from a societal and system-level perspective. SSE recommends an independent review is conducted into the interaction of charges and incentives that are afforded to different types of capacity.

2. What are the barriers to the deployment of energy storage capacity?

SSE is supportive of the deployment of storage across the electricity system. However SSE's main focus is currently large scale/bulk storage, and the detail below outlines its views on this area.

SSE owns and operates a 300MW pumped storage site at Foyers, and has planning consent for a new site at Coire Glas. This has the potential to provide up to 600MW capacity and 30GWh storage. The Coire Glas project is currently being considered by the European Commission for inclusion on the Projects of Common Interest list.

Currently the market does not provide investors with the necessary certainty to develop large scale energy storage capacity. Due to the existing market structure future revenues for large scale storage are extremely uncertain. Together with the large capital investment requirements, long lead times, and complex construction requirements this means projects are not currently viable.

In 2015 SSE commissioned Baringa to complete an assessment of the economic case for new pumped storage projects. This considered the potential for pumped storage to derive earnings from operating in the wholesale energy market and by bidding into the capacity and balancing markets. The report concluded that the revenue stream for new pumped storage plants is:

a) highly uncertain; and
b) there is a significant risk that potential revenues may not be sufficient to cover a plant's costs.

The uncertainty is amplified by the lack of long-term contracts in the ancillary services market; the fact that pumped storage projects often face substantial transmission charges; and that pumped storage projects are exposed to losses and BSUoS costs on both pumping and generation.

SSE therefore supports the Government's stated intention to work with Ofgem to consider how to best overcome current barriers to increasing deployment of energy storage capacity, including bulk storage.

SSE also supports the initial approach taken by the Government to establish what a 'least regret' level of energy storage for the UK's system would be; and how much of that capacity may be delivered through simple changes to the existing regulatory framework.

Looking further ahead at bulk storage specifically, it is likely that further work to overcome the issues of revenue uncertainty will also be necessary. In this context, SSE considers the investment case and characteristics of bulk storage to be similar to that of interconnection projects.

In terms of characteristics interconnectors provide a way to manage fluctuations in supply and demand and may provide opportunities for shared use of flexible, low carbon energy:for example a stated benefit of the proposed NSN link is that it enables access to bulk pumped-hydro storage in Norway. These benefits can also be delivered by the development of new bulk storage, but with the additional advantage that the UK could benefit from the wider welfare benefits that the development of large infrastructure projects brings. Just as many of the characteristics of interconnection and bulk storage are comparable, so too is the investment case, where for both the greatest barrier to investment is revenue uncertainty rather than absolute revenue expectation. However, there is not a level playing field for investment between the two technologies, with bulk storage being exposed to TNUoS and BSUoS charging and transmission losses, all of which interconnectors are exempt from. Furthermore the Cap and Floor Mechanism available to some Interconnector projects reduces the risk of investment.

SSE therefore considers there to be merit in Government exploring the potential for introducing a cap and floor arrangement for bulk storage in line with that which already exists for interconnectors. Such an arrangement can balance the requirement to provide greater certainty of investment to developers whilst also affording protection to consumers.

What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

Storage technologies offer a broad range of benefits to the UK electricity system including through:

- Increasing the effectiveness of renewables and other low carbon technologies through closer matching of supply and demand;
- Enabling more efficient system operability and supporting a diversified electricity system at a lower overall cost;
- Providing a range of balancing services to the System Operator (for example Frequency Response; Fast Reserve; Black Start; Reactive Power); and
- Facilitating the potential for avoided costs in, for example, developing additional peaking plant and additional network upgrade investment)All of these system benefits should also lead to lower overall costs for consumers.

The different characteristics and benefits of available storage technologies means there is no one type e.g. domestic, bulk, network connected, that is most appropriate for all parts of the UK's electricity system. Different types of storage, at different scales, will be required to achieve all of these benefits. SSE therefore recommends the government adopts a broad focus when looking at storage, and how it can best be deployed.

In terms of bulk storage specifically It is important to note that, at present, the volume and duration of storage provided by technologies connected to the transmission network cannot be rivaled by smaller units on an aggregated basis. By way of context, the maximum storage potential of Coire Glas (30GWh) is equivalent to the daily electricity demand requirements of approximately 350,000 UK homes. Given the core objective in developing storage is to maintain overall system adequacy, the ability of transmission connected storage to provide such significant storage volumes should not be overlooked. This will become increasingly important as deployment of renewable technologies increase and there are larger shifts in renewable generation output. Furthermore there are additional benefits in terms of overall system stability from the significantly longer run hours of large scale storage compared to other solutions.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

The European Commission (EC) has set a non-binding target for each member state to have at least 10% of installed capacity via interconnection by 2020. This is due to the perceived benefits they bring to Europe and the EC's desire to have an internal energy market[1].

Three main benefits are identified by the EC with respect to interconnection, which are:

- Increasing Europe's security of supply
- Providing more affordable prices in the internal market through greater competition and efficiency
- Helping sustainable development and decarbonsing the energy mix by accommodating more variable renewable energy

Currently the UK benefits from 4.2 GW of electricity interconnection with Ireland, France and Holland. Whilst this is less than the 10% target set by the EC, over 8 GW of new interconnection is either under construction or being considered by the Regulator OFGEM. If completed this would significantly surpass the 10% level.

The economic rationale for interconnector investment, whether projects are merchant or regulation based, is to take advantage of price arbitrage opportunities between jurisdictions, which should reflect the marginal cost of generation and differences in electricity demand. In theory this allows overseas capacity to directly compete with GB generation in order to lower consumer costs. However, interconnection enjoys certain economic benefits over GB based capacity. These include:

- Access to OFGEM's 'cap and floor' mechanism which underpins investment in interconnection by providing a consumer-guaranteed minimum level of return;
- The avoidance of a host of charges, including transmission (TNUoS) and balancing charges (BSUoS), which ultimately raises costs to other users.

As a result of the above there is not a level playing field in the wholesale electricity market, nor are there economic signals to ensure optimal system-wide investment. For example, the removal of TNUoS charges to interconnectors has meant there is no locational price signal; therefore an interconnector could be sited to the benefit of the developer, but lead to longer term increased customer costs.

Increased levels of interconnection have widespread impacts on the electricity system which need to be considered alongside the widely accepted potential benefits noted above. For example interconnection is now permitted to participate in the Capacity Market alongside 'firm', reliable capacity. This may reduce the costs of the Capacity Market for consumers, as interconnectors will generally be cheaper than new electricity generation. However, interconnectors do not provide firm domestic de-rated capacity and there is significant uncertainty of how reliable the capacity will be from interconnectors in future years. Furthermore, the levels of interconnection predicted for the 2020s is sufficient to replace GB's existing coal fleet; this undermines the investment case for new build gas-fired generation, as well as the economics of existing stations.

There is therefore a balance between the recently stated policy objective to encourage new build CCGT and the currently ambitious development of new interconnection, which is yet to be fully appreciated. This view was echoed by PA Consulting who recently stated that as the level of interconnection increases, fewer new thermal plants will be built.[2]

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[1] http://ec.europa.eu/priorities/energy-union/docs/interconnectors_en.pdf
[2] http://utilityweek.co.uk/news/will-more-interconnection-damage-uk-generation/1186753#.VozttfmqnWo

In particular SSE believes the current targets set for interconnection are somewhat arbitrary and a one size fits all approach across Europe is inappropriate given the different circumstances of member states. Going forward SSE recommends that an evidence based approach, which takes account of the full impacts of interconnection on the electricity system, is followed when evaluating the needs case for new interconnectors.

4. Further area of consideration: the importance of the Carbon Price Floor in underpinning the UK's energy investment strategy

SSE has consistently been a supporter of carbon pricing, at both a UK and EU level, as the most efficient way to decarbonise the economy. It was supportive of the introduction of the Carbon Price Floor, and continues to be a leading proponent of EU ETS reform.

SSE believes the Carbon Price Floor is the key plank in the UK's long-term energy policy. It underpins a number of existing policy mechanisms and has the potential to minimise future interventions by supporting the delivery of current government objectives. Examples include:

- The delivery of high efficiency new build CCGT
- The phase out of coal-fired generation by 2025
- The transition away from subsidies for low carbon generation to market based and/or cost competitive mechanisms
- The continued delivery of large volumes offshore wind at reduced cost

SSE therefore wishes to see the Carbon Price Floor extended beyond 2020. The instrument should also be designed in a way that sends out robust, reliable investment signals to UK energy infrastructure.

Summary

As a UK based utility SSE is seeking an energy investment environment that delivers the secure, clean and affordable energy supplies that homes and businesses depend upon.

This submission outlines SSE's views on the considerations in the NIC's call for evidence. It also highlights the importance of the Carbon Price Floor to the UK's energy investment strategy.

SSE invites further discussions with the NIC about this agenda and the contents of this submission.

January 2016

SOLAR TRADE ASSOCIATION

National Infrastructure Commission call for evidence - Electricity interconnection and storage

Response on behalf of the Solar Trade Association

About us

Since 1978, the Solar Trade Association (STA) has worked to promote the benefits of solar energy and to make its adoption easy and profitable for domestic and commercial users. A not-for-profit association, we are funded entirely by our membership, which includes installers, manufacturers, distributors, large scale developers, investors and law firms.

Our mission is to empower the UK solar transformation. We are paving the way for solar to deliver the maximum possible share of UK energy by 2030 by enabling a bigger and better solar industry. We represent both solar heat and power, and have a proven track record of winning breakthroughs for solar PV and solar thermal.

We welcome the opportunity to respond to the National Infrastructure Commission's call for evidence and look forward to working with the Commission on these areas in the future.

Respondent details

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Would you like this response to remain confidential?	No

Introduction

The Solar Trade Association welcomes the creation of the National infrastructure Commission and the priority that is being given to energy in this initial call for evidence. However, we would like to be assured that the Commission is working within national carbon budgets, which may be tightened following the international Paris Agreement. We are confident that solar energy can and will make a huge contribution to the UK's future energy demand. The costs of solar PV have fallen dramatically over the last decade and the technology has established itself as a leading source of renewable energy (indeed its capacity has recently overtaken that of onshore wind). Whilst cost reduction has been the major factor that has brought about this progress (coupled with the support available through government incentives), other key factors include the technology's scalability (from domestic to multi-megawatt), the speed with which it can be deployed and its popularity with the public – it consistently achieves top ratings (80%+) in DECC's quarterly opinion surveys. Furthermore solar PV generates power free of carbon emissions, has no moving parts and therefore high reliability and can be deployed in a wide variety of situations, from domestic rooftops to marginal agricultural land (where it can complement food production and contribute to biodiversity).

We firmly believe that, with a supportive policy framework, solar power will be able to compete without subsidy within 5 to 10 years. This will occur initially in the built environment, where solar self consumption competes with retail electricity – often known as socket or retail parity. Electricity from large-scale land-based solar is already one of the cheapest forms of renewable power and is expected to compete with new gas-fired power stations in the early 2020s.

For all its benefits, solar is often seen by the incumbent energy hierarchy as disruptive. By its nature solar is a variable energy source, generating at virtually zero marginal cost. It almost universally feeds into the distribution rather than the transmission system and therefore suppresses demand for central generation. Therein lies one of the main challenges, as the UK's grid has been designed for central generation feeding through the transmission then distribution systems to consumers. Accommodating distributed generation requires significant reconfiguration and investment, which should at least in part be socialised to encourage use of these valuable renewable resources.

In her 'energy reset' speech on 18 November 2015, Amber Rudd said the following: "*Some argue we should adapt our traditional model dominated by large power stations and go for a new, decentralised, flexible approach. Locally-generated energy supported by storage, interconnection and demand response, offers the possibility of a radically different model. It is not necessarily the job of Government to choose one of these models. Government is the enabler. The market will reveal which one works and how much we need of both*". Whilst it is true that the market will decide, the ways chosen by the government to enable growth of distributed generation will be crucial to the market's decisions.

Together with wind energy, solar has contributed to significant reductions in the wholesale electricity cost (known as the merit order effect), offsetting its cost to consumers through the Levy Control Framework[1]. Its logical role is to generate as part of a broad mix of technologies, including storage, interconnection and, in the short and medium term, flexible gas-fired generation.

Government has been surprised by the speed at which solar's costs have come down and market deployment has accelerated. Its reaction has been to limit deployment by reducing financial support. The STA published our Solar Independence Plan for Britain in June 2015, setting out solar's potential to achieve up to 25GW deployment by 2020 (from around 10GW now) as well as the policies for achieving that. We would welcome discussing our plan with the Commission as its contents are as relevant now as when it was published.

[1] See the recent report by Good Energy: http://www.solar-trade.org.uk/renewables-bring-down-the-wholesale-cost-of-energy-finds-new-study/

Response to the call for evidence questions

There is some confusion about how the Commission fits into the wider decision-making on electricity sector rules and regulations, which is already highly fragmented. While we would welcome the long-term perspective that the Commission could interject, the questions asked by the Commission on energy are highly specialised and technical and reforms in some of these areas are underway amongst a myriad of groups. There is also general concern about the current direction of UK energy policy in relation to meeting both EU renewable energy and national carbon targets, and which seems to lack understanding of the transformation new technology is enabling in power systems overseas. In general there is widespread concern about energy policy amongst the policy community, and Treasury's increasing involvement in decision-making appears to be taking investors away from a clear low-carbon trajectory. Similarly it is unclear whether the Commission is aligned to meeting UK carbon budgets. This is clearly essential for the credibility of the Commission and its recommendations.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Demand and supply are balanced effectively in the UK by National Grid as the System Operator. The balancing system is extremely reliable. Despite many hysterical headlines about blackouts, a recent ECIU report was able to identify only one outage over the past 10 years, which was caused by a thermal power plant. Faults in power supply typically occur locally in the local distribution networks as a result of strong weather events disrupting power distribution, like the recent flooding. In this regard it is surprising that the Infrastructure Commission has been asked to focus on such a specific market-regulatory area, rather than wider questions about the strategic direction of the power system to guide infrastructure investment. Strategic direction is sorely lacking in the UK. A modern, low-carbon electricity system particularly requires major changes to the business model of Distribution Network Operators to enable much more active management of local networks. This is the issue most frequently cited as severely holding back the modernisation of the UK power system and in our view this should be a key focus for the Infrastructure Commission. Please see our May 2015 internal discussion paper on the strategic needs of the grid, attached to this submission in confidence.

Balancing supply and demand is fairly cost effective. Latest Ofgem data shows that balancing adds only modest costs to a typical household energy bill. Keeping generation to contracted forecasts is not a perfect art for all generation types, but imbalances are small, leaving National Grid with a relatively modest cost for balancing services. These services anticipate the biggest risk to the system which is a single infeed loss, i.e. when a large thermal or nuclear plant suddenly comes off the system. The balancing system needs to be able to respond to this eventuality. According to ECIU there were 900 unplanned failures in coal and gas plant in the first 9 months of 2015. It is not possible for distributed solar output to change this rapidly – even the recent solar power eclipse had a much slower impact on power loss and is predictable years ahead.

Again, contrary to media coverage, where journalists rarely understand how the electricity system works, solar power has very high forward predictability. Because solar is generated on distribution networks, not transmission lines, it appears to National Grid as demand reduction. From discussions with network operators overseas, we understand wind is now forecast with 98% accuracy. Solar is in many ways easier to forecast as it has a more predictable generation pattern that ramps up with demand – i.e. during the day when demand is highest. Methodologies for forecasting solar output are improving in the same way that they have for wind, but they are already around 93-95% on the continent. National Grid has been surprised by the growth of solar and rather slow to adopt effective forecasting tools, but this should not prove problematic.

Certainly the ambient renewables entering the electricity supply require the system to balance supply sources more carefully, as well as balance supply with demand, but the forward predictability of ambient renewables is relatively easy to manage. EU markets have moved towards greater emphasis on day-ahead markets to ensure marginal cost renewables can be accurately forecast and dispatched. As variable renewables reach higher levels of penetration it is important that the system moves to value flexibility. Renewables can be considered the 'rolling baseload', since the merit order dictates that they will dispatch first. It is important that the system allows this in order to minimise prices for consumers and to minimise carbon, and that other generation can respond to remaining demand needs on the system. There is no evidence that systems are less reliable as result of variable renewables – quite the contrary; Germany and Denmark with high levels of variable renewables boast some of the most reliable electricity systems in the world.

The everyday onus to balance supply with demand is on suppliers who are expected to deliver as contracted and penalised if they fail to do so. In turn a supplier might contract with a solar generator under a Power Purchase Agreement. These can be long-term in nature so the supplier needs to form a view about the likely balancing costs for solar. In practice this premium is low for solar power (lower than for wind), again reflecting its predictable output. Ofgem last year changed the penalties under the Balancing and Services Code, so that there is now a single marginal cash-out price in place of the previous dual imbalance prices. Imbalance risk is set to increase given plans to implement 24 hour switching. There has been criticism of these changes favouring large vertically integrated companies over smaller players (they effectively meant a retrospective change for solar project income). This seems to be a trend under the Significant Review Code, which is monopolised by incumbent industry experts. As was pointed out, changes that disadvantage smaller players is to the detriment of competitive pressures which are in the interest of consumers. The UK electricity market is still characterised by relatively high volumes of positions locked in significantly ahead of delivery and which is still illiquid and lacking transparency.

National Grid has a wide range of tools it can draw on ensure that demand and supply are adequately balanced. There was a lot of coverage recently of the NISM event, which provides an indication to the market that either more demand reduction or more capacity is needed. However beyond this there are emergency measures that can be deployed such as via interconnectors, maxgen and voltage reduction.

The interesting questions for the UK balancing system are:

- how much more emphasis could be put on day-ahead markets
- how could the process around setting rules, as well as the rules themselves, be made fairer and more inclusive for smaller players in order to increase competitive pressures going forward

- how much of the centrally procured balancing services could be more cost-effectively left to the market. Experience on the continent suggests that there is far greater scope to let the market provide solutions, and evidence suggests that this has significantly reduced costs.

Interestingly the German Government, which has a much higher volume of ambient renewables than the UK (though also a higher level of interconnection), is not convinced of the need for a Capacity Market, with a discussion document last year suggesting that flexibility was best left to the market. This STA paper submitted to DECC in August 2015 on integrating solar into the networks may be helpful for your inquiries. This includes discussions with network operators on the continent who tell us they have more flexibility in the markets than they need, and it is extremely cheap to purchase this in the market. What is interesting is how they are merging market operations across countries to enable effective trading of power by whole regions. It is also interesting that they have moved to quarter hourly trading to help improve accuracy balancing supply and demand – this proved very helpful apparently in managing the solar eclipse.

An open market in UK balancing services in future?

The view of some utilities and power experts here is that the UK power market will develop in the same way as Germany's where balancing services have been opened up to the market, rather than being centrally procured by the system operator. This has created a market of aggregators and private balancing services which has significantly reduced balancing costs in Germany – indeed balancing costs have fallen by 50% in Germany since 2008. Denmark also operates a similar system.

Germany and Austria now have quarter-hourly trading products and gate closure for trading is 30 minutes ahead of real time. This means intra-day forecasting is very accurate. These markets were put to the test by the recent solar eclipse, which resulted in 2-4 times the normal variations in solar power output, yet markets proved able to handle this. Traders are now also 'bundling' regional markets in Denmark, Belgium, Holland, Switzerland and Germany, for very cost-effective inter-country trading. The UK is not yet taking part in this.

Traders and grid operators we spoke to in these regions said storage is 'completely over-estimated', even 'foolish', as they already have more cheap flexibility in the market than they need.

What role can changes to the market framework play to incentivise this outcome:

As above, it is likely that much more can be left to the market to provide flexibility instruments to enable cost-effective balancing of supply and demand. However, the Government has now introduced the Capacity Market, which will presumably limit options here. We understand the CM auctions were greatly over-subscribed and have resulted in considerable subsidies to existing coal, gas and diesel plant. While flexibility needs to be valued in the market, there are important questions to ask as to whether this is the most cost-effective, sensible, future-proofed and low-carbon way to deliver system flexibility and security.

Government has not made the decisions it should be making in relation to the extent to which it wants to use nearer-time markets, Demand-Side Response, smart networks, Time of Use Tariffs and interconnectors to better balance demand and supply, or indeed to incentivise a more efficient power system. It is inherently inefficient and expensive to require an entire national power system to be specified to a fleeting period of peak demand. Introducing the Capacity Market before having made these decisions seems unwise.

Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

We assume by this question, you mean whether National Grid should not be the system operator given much larger interests in transmission network assets. In theory clear independence seems sensible and this is consistent with the EU's Third Energy Package. There is uncertainty about how future networks will evolve and resistance in the UK to new technology. In our view, a modern system will place much more emphasis on active and smart local networks, with solar generation embedded at or near the point of use, which potentially provides considerable savings on transmission networks, particularly as storage becomes increasingly cost-competitive. Distributed power investments will increasingly be made regardless of central government policy, and government would be wise to recognise technology trends. Transmission assets, often reinforced to meet fleeting peak demand, are extremely expensive. Many country-wide analyses undertaken by the World Alliance for Decentralised Energy demonstrate that a much more distributed power system could yield very considerable overall system cost savings. The IEA has undertaken similar analysis. This is an important reason for taking a much more strategic approach to future network development and why we are interested in the IET concept of a "System Architect." A system operator that has vested interests in transmission assets may not be considered an objective stakeholder within a strategic review of system architecture.

However, in practice in our experience National Grid is an extremely well run and professional organisation, with not only a clear corporate responsibility goal to deliver low-carbon systems, but broader international experience of system transformation overseas. The Chief Executive of the National Grid has rightly recognised that solar is 'the new baseload for consumers'. We consider National Grid to be a high quality and responsible company. It is doing a robust job in managing the grid nevertheless intermittent renewables are making balancing and managing the grid more challenging. The STA has lead the way through its grid in initiating discussion, research and collaboration with National Grid. The STA and its members are keenly seeking to be part of the solution to these challenges. The NIC and DECC need to engage with and support these initiatives.

How to incentivise the SO to minimise long-run balancing costs is a regulatory question which we do not feel qualified to answer, however, above we have suggested ways in which this could be done, including through far more liberalised markets in balancing services.

Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

As above, the BSC has recently been reformed and in a manner which raises questions about how these decisions are made and ultimately in whose interests. All market participants are responsible for imbalances. Solar imbalances will reduce as forecasting improves. Solar will never be responsible for sudden large disruptions to power supply (barring eclipses), which are more expensive to correct. Interestingly in Germany, which has a lot of solar power, some solar runs below capacity so it can respond extremely quickly to market imbalances elsewhere on the system. The liberalised market itself is providing the incentive to do this, thus pricing the value of flexibility.

There is a difference between day-to-day imbalances and the need to ensure sufficient flexible generation capacity annually for short periods where variable wind and solar output falls short. It is important to recognise this distinction. In relation to managing this, there is a much wider range of tools that UK needs to be making use of including interconnectors, smart grids and DSM, ToUTs and load shifting (please see our longer briefing), rather than procuring more capacity through the CM.

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

This question is best answered by DSM providers. However, solar power can contribute to the inherent security of the power system. Solar does not leave the UK hostage to geopolitics or sudden fuel price spikes, by virtue of its highly distributed nature it cannot suddenly disappear off the system like a large thermal plant, and it is extremely reliable since there are no moving parts. Solar can also provide a wide range of grid services that have yet to be understood and exploited in the UK, adding to system efficiency and flexibility and potentially reducing the costs of some grid services. National Grid is beginning to recognise some of these opportunities – unfortunately we have had to cancel a joint workshop on this due to pressure of policy changes. Grid services solar can provide include voltage control, system inertia, frequency control, fast reactive power and reducing grid losses. Please see our paper for more details.

2. What are the barriers to the deployment of energy storage capacity?

We are optimistic that in the medium term (3-5 years) there will be a significant amount of innovation, cost reduction and entrepreneurial spirit that the solar industry is famous for applied to storage, in order to make storage a game changer for the energy industry. This view is similar to many other bodies, including the International Renewable Energy Association (IRENA)[2] UBS Bank[3], National Grid[4] and Deutsche Bank[5], who all believe that solar + storage is a future game-changer, but in the timeframe of the next 5 years rather than 6 months.

There are two key areas where storage can add a significant amount of value: at the consumer level and at the grid (distribution/transmission) scale. Both of these applications involve the storage of energy but they are completely different in terms of operators, owners and technology. They are highly complementary as they provide different services: for example, a domestic system could smooth out PV generation throughout a sunny day, while grid-scale storage could provide grid quality services such as fast frequency response or voltage control. Research in the US by the Rocky Mountain Institute found a very wide range of potential services that battery storage systems could provide[6], including grid, utility and customer services. The main conclusion was that additional value can come

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[2] https://www.irena.org/DocumentDownloads/Publications/IRENA_REmap_Electricity_Storage_2015.pdf
[3] http://www.theguardian.com/environment/2014/aug/27/ubs-investors-renewables-revolution
[4] http://www.energypost.eu/interview-steve-holliday-ceo-national-grid-idea-large-power-stations-baseload-power-outdated/
[5] https://www.db.com/cr/en/docs/solar_report_full_length.pdf
[6] http://www.rmi.org/electricity_battery_value

from providing multiple services, rather than just one. Batteries are only part of the solution – other technologies such as pumped hydro, flywheels and power to gas can provide similar services.

Research and development into storage is ongoing but it is now innovation in the shape of commercialisation and deployment that need to be focussed on to reduce costs and develop the market. The breakthrough in cost reductions for solar came from the supply chain, not research and development - innovation is not simply confined to a lab.

Other countries are actively developing the skills, markets and industries to be world leaders within storage: particularly Germany and the US. The UK has the potential to be a world leader in storage, with British companies innovating (Powerstation, Moixa, Sunamp). However, they need the right regulatory environment to flourish, otherwise other countries will win the race. The UK, with its old grid architecture, is a good candidate for storage to provide grid services either at the distributed or grid level.

Although financial benefits through subsidies may be one way of incentivising storage deployment in the short term, it is more important to set up **a clear legal and regulatory framewor**k to allow the market to innovate. The things that need to be done are:

- Storage needs to be a clear strategic sector for the NIC – future deployment of solar will depend on it. Start with a strategy building on the work of DECC and Ofgem.
- Clear regulation: storage is currently viewed as both a generation and a demand asset, so there needs to be a classification of storage specifically to stop this. Indeed there appears to be confusion on an EU-wide level as to exactly what storage's status is or should be and this is hampering progress throughout the EU. **Achieving a clear classification for electricity storage within EU legislation and regulations, that can then be transposed into UK regulations, would therefore appear to be the highest priority for the UK government.**
- Specific recommendations that seek to level the playing field for energy storage so as to realise its full value for the grid should be a key strategic focus for the NIC. It is believed that NG and Ofgem are already considering such changes.
- Turning DNOs into DSOs – currently DNOs are unable to procure balancing services as National Grid can, instead they are simply in charge of the operation of the distribution network. This means that they spend a significant amount on new wires and stations, even if by spending a lesser amount they could procure storage or other services that would mean the upgrades were not required. DNOs need to be empowered to be a part of setting up a decentralised energy network which is what the bodies described above are expecting to happen.

Within the Capacity Market, facilitating and incentivising generators to incorporate storage into the grid as part of hybrid wind/solar + storage plant should be an area of focus. Energy storage must be treated exactly the same as for example DSR and not be penalised when it imports power from the grid to charge in readiness for stress events or to peak shift power to the evening peak period. It should be noted that 450MW of DSR was enabled through the most recent CM auction. This, as applied to storage and other low carbon technologies, needs to be more fully encouraged within amended CM rules. CM rules could also be changed for all participating technologies by enabling shorter-interval discharges of storage during a particularly long stress event and ensuring these are not penalised (or at least more allowance given to hedge power so as to entirely fulfil the CM obligation).

These regulatory changes will set the groundwork for the industry to be able to innovate and develop over the coming years. The UK could potentially become a world leader in this area, but clear signals are required for the market.

There is also the potential for the NIC (or another body like Innovate UK) to sponsor monitored field trials of solar and storage. Some of these are already ongoing at a small scale, but large-scale commercial trials are also required. This could be a cost-effective way of kick-starting a storage market by providing hard evidence of the performance and economics of storage in a range of market applications.

Whilst we cannot comment on or endorse the contents, we would like to draw the NIC's attention to the following report published by UK Power Networks (funded under the LCNF): Electricity Storage in GB: Smarter Network Storage – Recommendations for regulatory and legal framework[7].

We are keen to meet with the NIC to discuss storage further and define how solar and storage can play a part in the future energy mix with a better balance of supply and demand.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Greater EU market integration reduces both the cost of balancing services and the need for reserve requirements since countries can draw on other grids to balance. The Impact Assessment for the European Electricity Balancing Market[8] estimates greater system integration will result in €3bn per annum of benefits and 40% potential reduction in reserve requirements, including €51m benefits from UK-France balancing. The most recent report for the European Commission recommends that the UK needs greater interconnector capacity[9]. For example, the UK can import just 5% of peak demand capacity compared to Belgium on 43%. The UK currently has 4GW of interconnector capacity, with an indicative target in Europe for members to reach 10% of peak capacity by 2020. We understand the 5 new interconnector projects in train would deliver a further 7.5GW of capacity. National Grid's most recent Future Energy Scenarios notes that the investment climate for interconnectors has improved. Government's own analysis shows greater use of interconnectors has the potential to save consumers £9billion to 2040[10]. Traders we spoke to said that expanding the market base through interconnectors is the key way to keep the costs of renewables expansion low. Power peaks in Germany, France and Norway do not coincide with UK peak demand, so there is good potential to securing peaking capacity this way.

Clearly improving interconnectors is in the interest of consumers and for the realisation of a low-carbon power system. This is why interconnectors are such a focus of the EU's new market design, which seeks to

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[7] http://innovation.ukpowernetworks.co.uk/innovation/asset/bfd24073-a7a4-44cd-b492-7cbb588e7bfO/SNS_ElectricityStorageRegulatoryFramework_SecondReport_v1.0+PXM+2015-09-30.pdf
[8] https://ec.europa.eu/energy/sites/ener/files/documents/20130610_eu_balancing_master.pdf
[9] http://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_unitedkingdom.pdf
[10] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266460/More_interconnection_-_improving_energy_security_and_lowering_bills.pdf

optimise value for consumers and take advantage of new technology. It is surely in the interest of British consumers to catch up with, and ensure consistency with, market reform across Europe. We understand further EU electricity market design proposals are expected later this year.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Please see the examples cited above and in our referenced paper. In addition to examples of more liberalised balancing markets in Europe there are growing examples of smart grids internationally e.g. in the USA, China, Korea, Mexico etc. We recommend the IEA's International Smart Grid Action Network: http://www.iea-isgan.org/?c=395/397

For a very long time electricity networks have been exceptionally un-innovative. For decades they have operated under Rate-of-Return regulations, which reward investment in passive system assets. Distributed solar power is transforming how electricity systems work and who owns generation assets. Solar enables consumers to be producers and, combined with developments in information technology, enables the development of local smart grids. While solar is perceived as disruptive by the incumbent industry, at the level of the local grid solar is a unifying technology that puts consumers, power, storage, IT and electric vehicles at the heart of the power system. Smart grids are now a key international area for technological innovation. Much of the UK's energy infrastructure is now aging and in need of replacement. This is therefore a critical moment to make strategic decisions about the future of the UK power system. We hope the Commission will recommend the UK adopts a clear strategic vision consistent with the rapid technological change climate change demands and with international best practice.

National Infrastructure Commission
Call for evidence on Electricity Interconnection and Storage

Written evidence submitted by Statkraft UK Ltd

January 8, 2016

About Statkraft

1. Statkraft is Europe's largest renewable energy company, with operations in over 20 countries. We have invested over £1.4 billion in the UK's renewable energy infrastructure since 2009 and we are among the biggest provider of power purchase contracts (PPAs) for independent renewable electricity generators in the UK.

2. We have over 500 MW of UK generation plant. We are majority owner and operator of three onshore wind farms (with a further one under development), a large hydropower plant and we are major shareholder in two offshore wind farms. Statkraft is a partner in developing the Triton Knoll offshore wind farm, and part of a consortium of four companies developing Dogger Bank, the world's largest offshore wind farm.

3. Statkraft is playing an important role facilitating the strategic energy partnership between Norway and the UK. A key element in this is the NSN interconnector that is being progressed by National Grid and the Norwegian transmission system operator Statnett. NSN will be able to provide low carbon energy for almost 750,000 British homes and, according to Ofgem, will save UK households up to £3.5 billion over 25 years by importing low carbon electricity from Norway.

Summary

4. Statkraft welcomes the opportunity to respond to this consultation. The overarching aim for any reform to energy infrastructure policy should be to establish energy security and ensure affordable carbon reductions to keep the world on track to keep future temperature rise below 2C. The National Infrastructure Commission's recommendations relating to this consultation, and its next areas of inquiry, should focus on how we meet these objectives.

5. Investment in low carbon technology is essential to meeting these aims. Interconnection and energy storage technology have an important role to play in the UK's long term energy mix. The UK particularly needs to do more to improve grid connections with Europe, which will enhance security, accelerate decarbonisation and can contribute to lower consumer bills. However, such developments are only one part of the solution, and should not be seen as alternatives to renewables investments, such as offshore wind.

6. Investors in low carbon energy infrastructure require certainty of policy direction. The National Infrastructure Commission has a vital role in ensuring long term policy stability is achieved.

What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

What role can changes to the market framework play to incentivise this outcome:

- *Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?*
- *Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?*

7. It is very important that the operation of the transmission grid is neutral, fair and efficient and that the operation and development of the grid is sufficiently independent of other business interests. There is a potential conflict between the TSO role as owner of transmission grid and the role as SO. National Grid also has other business interests where conflicts in principle may arise. Current business separation within National Grid seems to be working well, so we are not very concerned with the situation at the moment. We hence see no urgent need for a SO- reform. It is however important that the regulator closely monitors how well National Grid fulfils its critical role as TSO.

8. The balancing market has been through a number of reforms, like making balancing charges more marginal and the introduction of a single imbalance price. There is a need to consider the impact of these changes over some time before new significant reform should be considered. The recent changes have led to increased balancing cost exposure for generators, and increased interest in trading this risk. We are positive to introducing measures that could enable parties to better manage this risk, like trading closer to or post market gate closure.

To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

9. Demand side management and embedded generation are critical in an effective electricity market. To increase market flexibility, further market integration of such technologies should be encouraged.

10. Demand side management is less developed in the United Kingdom than in many other markets. We are however not aware of any major barriers to this with the exception that real-time metering has not been rolled out yet. Aggregation of demand side response should be possible, but in this case the aggregator should take over the balancing responsibility of such demand. We see no need to develop a mandatory framework regulating the relations between supplier-aggregator-consumer. The Government should not implement financial support mechanisms for demand side response that undermines the business case for developing flexibility through generation and interconnection.

What are the barriers to the deployment of energy storage capacity?

Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

11. Statkraft is at the forefront of developing energy storage technology in Europe, and is actively developing battery storage solutions in the UK. It is clear that the market design rules –like for trading, ROCs, ancillary services - are not designed with batteries in mind.

12. Batteries store energy when prices are relatively low and release energy when prices are higher. Treatment of storage as both generator and consumer in terms of charges like Renewables Obligation charges or transmission pricing might be a barrier to storage and might unduly worsen the business case.

13. The capacity market is designed for fuelled generators and not for storage as batteries. Participants are expected to keep generating for a long time, but storage like batteries run flat eventually. Still batteries will be very helpful in dealing with a temporary capacity crunch. Possible ways to address this is an 'x hour' capacity auction or a scheme where capacity payment would be stepped according to the time the storage can deliver capacity.

14. In this respect we will also point to that investments in small scale storage behind the meter tend to be incentivised by avoiding paying retail tariffs rather than being market driven. Such investments will hence tend to be artificially competitive and tend to increase system costs compared to market based solutions.

15. Research and development of energy storage technology needs to be supported through policy mechanisms. From a UK perspective, this could include investment in R&D funding through the budget of the Department for Business, Innovation and Skills.

16. Energy storage technology is fast advancing. However, once such technologies are commercially viable it should be left to the market to decide which technologies are most appropriate for commercial scale contribution the UK's electricity framework, rather than the Government "picking winners".

17. Storage (like generators) can provide grid support services to National Grid as well as to DSOs. However, TSOs/DSOs should not be allowed to own and operate storage facilities. TSOs/DSOs can contract such services from market parties. The regulatory framework should be such that TSOs/DSOs have the proper incentives to take efficient decisions choosing between network investments and contracting services.

18. Further clarification is required from National Grid and the Department for Energy and Climate Change on the relationship between the capacity market and energy storage technologies

What level of electricity interconnection is likely to be in the best interests of consumers?

Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

19. Statkraft is very supportive of increased interconnection between Great Britain and mainland Europe. Interconnectors will play an important role in helping the UK to achieve

security of energy supply. There is currently just over 4GW of interconnector capacity in operation but a substantial level of interconnector capacity in the pipeline, including 7.5GWs deemed eligible to partake in the cap and floor regime.

20. We welcome the European Commission's proposals to increase electricity interconnections between member states (to 10% of installed electricity generation by 2020 and 15% by 2030) and would like to see the UK Government drive this initiative forward. In particular, Statkraft strongly supports the development of further interconnection, particularly the NSN- link with Norway, which could enable both flexible and renewable capacity to enter the UK market.

21. There are a great number of advantages of linking hydropower with seasonal storage via interconnection with intermittent renewable sources in the UK market. Particularly, there is real potential for interconnections to be built in tandem with offshore wind developments, ensuring that intermittency is balanced as and when required. The combination of hydro storage and interconnection can provide both short term (fast response) flexibility as well as firm longer term back up e.g. in longer periods with scarcity due to high demand and low wind generation. It is for this reason that Statkraft is very supportive of the proposed North Sea Grid which has the potential to revolutionise the UK's energy market and security.

What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

22. After introduction of the single imbalance price which was an important step in the right direction, further progress could be made by allow trading closer to time of delivery.

23. Statkraft believes that a well-functioning balancing market should be open to both generators and demand side measures. All generators should in principle be responsible for balancing supply and demand, including smaller and intermittent generators. The UK balancing scheme is well progressed in following these principles, also compared with other markets.

24. In the UK the grid cost through the TNUoS charges are cost-reflective. Also imbalance charges are cost-reflective. This indicates that intermittent generators and generators far from centre of demand are charged for the cost they are imposing on the system. When it is appropriate that intermittent generators should pay their balancing cost and grid costs, we see no case for additional 'punishment' of intermittent generators. Given improvements in market design, increased flexibility through interconnectors and through the demand side, the electricity system will be capable of handling an increasing share of intermittent generation with less cost.

For further information, please contact Knut Dyrstad, Regulatory Affairs Manager, on [email address redacted] or [phone number redacted].

Tempus Energy Supply Ltd.
31 Oval Road
Camden NW1 7EA

National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

Dear Lord Adonis,

Please see below the **Tempus Energy Supply Ltd.** response to the National Infrastructure Commission's call for evidence.

About Tempus Energy

Tempus Energy ('Tempus') is a technology company and an innovative, new electricity retail supplier. Tempus was established to make energy systems more efficient through capturing the value of under-utilised assets using demand-side flexibility technology. Tempus has developed technology to shift real-time consumption patterns to optimise trading on the electricity market within each half-hour, leading to cheaper electricity prices for the company and its customers, while also helping to balance the overall electricity system. Importantly Tempus is demonstrating that through the use of demand-flexibility in liquid, transparent and competitive wholesale markets, where prices reflect actual scarcity and network stress, we can create a market-based approach to integrating more intermittent renewable energy onto the grid and therefore combat climate change through market-based solutions**.**

4. Electricity Interconnection and storage.

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

Achieving security of supply whilst minimising costs to consumers requires a paradigm shift in how we view and use the electricity system. The need to decarbonise the system, and the introduction of intermittent renewable generation technologies in particular creates new risks and opportunities. Our current system is not fit for purpose in a new world of smart infrastructure design, it does not mitigate those risks and maximise the opportunities.

A low-cost, flexible, and intermittent supply side requires a smart, flexible demand side. In order for decarbonisation and security of energy supply to be delivered in a manner that does not see energy costs spiral out of control, we need to find new ways of managing system imbalance. In essence demand flexibility is a way of managing imbalance risk by moving demand away from peak times into cheaper price periods where renewable generation is plentiful and prices are therefore lower. Building a flexible demand side which is able to utilise off-peak surplus renewable generation on the system also ensures better value for money for customers, and reduces the cost of capital for renewable generators. This allows us to make the most of our existing renewable generation and network infrastructure.

The alternative is to build a new fleet of fossil fuel peaking plant, which sits idle until called upon to balance the system when renewables are not generating and demand is high, which in reality will occur for limited periods. The latter option also requires continuous building out of transmission and distribution infrastructure to avoid grid constraints, at vast cost to consumers. This is more expensive, carbon intensive and inefficient.

The grid infrastructure needs to be built out to peak demand. Building generation, transmission and distribution to a peak that is occasionally reached without taking any measures to manage that peak means that we are paying for assets that are under-used for the majority of the time. By incentivising energy intensive users and network system operators to employ peak time load reduction, it is possible to address the energy 'trilemma' of decarbonisation, value for money and security of supply.

Those who are able to provide demand side services must be enabled to receive the value they are creating across the supply chain through both the wholesale and balancing markets. In order to achieve this it is imperative the customers are able to access Capacity market contracts on equal terms to incentivise this equal change, and get a fair deal. These markets must be transparent, open and liquid. The vertical integration of the largest market players means that the vast majority of power is traded through bi-lateral contracts. In order to create a liquid, competitive market that would ensure true cost-reflectivity that allows the value of demand-side to be unlocked, Tempus would be in favour of measures establishing everything over a megawatt to be traded on an open market. Once a level playing field has been established that allows the demand side to compete with generation for access to such a market, a secure, cleaner and cheaper energy system will be achievable.

1.1 Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

The GB energy market faces several barriers to become a fully competitive system that sparks the innovation that will bring costs across the supply chain down while maintaining security of supply and enabling the transition to a low-carbon system. Among the barriers to creating a more efficient and customer-centric market is the current bundling of both supplier and generators, an issue that Tempus believes is more pressing than that proposed.

However, Tempus would indeed be supportive of a move to create a truly independent system operator (SO) that does not own any of the transmission lines in order to avoid conflicts of interest. An ISO, as established in markets elsewhere such as PJM in the USA, will never be in a position to favour generation over demand to balance the system nor to favour investing in building up its asset base to keep receiving a regulated rate of return. Instead, the ISO will always be incentivised to balance the system at the lowest cost to consumers without over-investing in energy infrastructure.

The Federal Energy Regulatory Commission, in establishing ISO's under Orders 888/889 stated that an '*unbundled electric transmission service will be the centerpiece of a freely traded commodity market in which wholesale customers can shop for competitively-priced power'*. Arising over concerns around access to transmission, the Orders, established in 1997 recognised the inherent conflict of interest that occur when a system operator owns transmission assets.[1]

Any move to establish an ISO would have to ensure that that entity took Elexon and the responsibility for balancing the system with it, in order for the above to be realised. Moreover, OFGEM must set and enforce targets for the SO to meet in relation to the economical balancing of the system. A further detail that requires consideration is the relationship between an ISO and distribution networks. As the energy system becomes more localised, there will be a need for local network management solutions. An ISO must not neglect or distort this development, nor the innovation that will arise from it.

1.2 Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

In order to reduce costs to consumers over the long term, the ultimate goal must be to move ever closer to a market that balances itself hence minimising the role of the balancing market and completely avoiding the need for a capacity market.

Currently market signals insufficiently incentivise suppliers and generators to manage imbalance, with costs incurred by suppliers smeared on to customers' bills. Tempus welcomes the recent cash-out reforms that have gone some way to improving cost-reflectivity, but more must be done to ensure suppliers operate more efficiently and customers don't bear costs for inactivity on the suppliers behalf.

If suppliers and generators are incentivised to be balanced or alternatively penalised not to be out of balance, this will drive these players to invest in technology to keep themselves balanced, thus reducing the need for balancing and capacity markets. This capability would predominantly be delivered by half-hourly settlement ('HHS') meters capable of being read in real-time, and flexibility assets that can quickly ramp up or down, to ensure the system is balanced in each settlement period. This would ensure more efficient utilisation of our existing assets, and ultimately reduce the need to invest in expensive generating units, and indeed networks. Investing in both at vast expense, before efficiently utilising our existing assets does not reflect a sensible use of taxpayer's money.

The rollout of smart-meters will facilitate this transition universally but in the immediate term simply allowing demand side technologies to compete on a level playing field in the balancing market, be it

[1] Order No. 888, Federal Energy Regulatory Commission, Part 1, pg.11, 1997 (Link)

through balancing mechanisms or the capacity market will have a profound effect on how we are able to operate the system in the most cost-effective way. In order for this to be realised, the SO must improve their dispatch technologies. The current manual dispatch of demand side, opposed to the semi-automated dispatch of generation volumes would distinctly disadvantage demand side capacity.

Cost-reflectivity is key. The Capacity Market methodology is not cost-reflective and is therefore a missed opportunity in this regard. Smaller customers are not rewarded for avoiding peak times and hence the incentive to shift critical demand peaks (and therefore balance the system at peak times) is compromised. Any measures taken must also take a long-term, holistic approach acknowledging the cultural and business changes needed to unlock a flexible, low-carbon and cost-reflective demand side.

1.3 To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Demand side management measures can be used to increase the flexibility of the electricity system immensely. In the PJM market, a market with three times the electricity demand of the UK, 15GW or 9% of the total capacity in 2015-16 will be provided by DSR.[2] This capacity is inherently more flexible than generating units, and is more suited to being utilised in a dynamic way to address system stress and locational congestion. It makes economic sense to make full use of our existing assets before we invest in reinforcements, ultimately at the cost to consumers. Studies undertaken in the USA have found the average cost of 'negawatts', that being watts saved were £30/MWh, representing a massive saving from for example, a CCGT plant costing approximately £76 per MWh (LCOE).[3]

As previously discussed, demand side measures also reduce the need to invest in distribution and transmission infrastructure, at the expense of taxpayers money. In New England, 'negawatts' and DSR have proved so reliable that $260 million in grid upgrades were avoided.[4]

It is worth noting that it is important when unlocking this vast value, not to incentivise the 'wrong' kind of embedded generation. Diesel units, whilst being heavily pollutive also emit fumes that are now recognised as carcinogenic.[5] Any regime must be designed to minimise the uptake by diesel generating units and farms of the scale evidenced in the Capacity market. Any restrictive criteria that are applied need to apply on both sides of the meter (i.e. both generators and demand side capacity).

[2] 'Getting more from less: realising the potential of negawatts in the UK electricity market', Green Alliance, A. Mount & D. Benton, Oct.2015.
[3] Ibid.
[4] Ibid.
[5] '*Diesel engine exhaust carcinogenic*', International agency for research on Cancer, World Health Organisation, 12 June 2012, Press release No.213. (Link)

2. **What are the barriers to the deployment of energy storage capacity?**

2.1 Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

The development of energy storage capacity would be advanced by the formulation of an appropriate National Grid product in which storage could participate. Despite being currently able to participate in the frequency response services, the market proposition does not sufficiently support the investment required in energy storage devices. Energy storage capacity also face similar barriers faced by the demand side in the Capacity market. The products available to the market need to be genuinely technology neutral taking into account emerging sectors rather than using inherently generator-centric parameters that favour incumbents over innovative new market entrants.

The deployment of energy storage capacity could be accelerated through making the energy market more cost reflective, allowing storage and other flexibility assets to play a role in allowing end users to avoid expensive peak prices. This would greatly increase their value, therefore making them more viable.

2.2 What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

It is most important to facilitate a level playing field for energy storage to compete, allowing innovative technologies to compete to provide the most value at different stages of the system, rather than picking winners in advance.

More coordination is certainly needed between National Grid and DNOs especially since batteries need to be connected to the distribution network but ultimately provide a service to National Grid.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

3.1 Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

3.2 Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

Before considering what level of electricity interconnection is in the best interests of consumers, we should first ensure that we are using our existing assets to the maximum capability, before we invest in new assets be they generation or interconnectors at the expense of taxpayers money. As previously mentioned, a fully functioning demand side would dramatically improve our ability to do so. At the moment, valuable renewable generation is being thrown away at times of low demand, we should utilise this power before expecting consumers to pay for building new infrastructure.

In the event that further capacity is required, Tempus is of the opinion that interconnection is of more benefit than subsiding traditional generating units that are subsequently stranded assets. Interconnection increases liquidity into the wholesale market and can help security of supply efficiently. If our neighbours have spare capacity, it is much more efficient to use that rather than build more power stations just for peak demand. Being physically coupled with continental market is of benefit, and Interconnection along with demand flexibility should play a big part in meeting GB's capacity needs.

Interconnection requires a big up front capital expense so needs so far as possible, long-term regulatory certainty to be successful. If the current cap & floor regime does not provide the necessary investment certainty then it may need re-visiting.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

We cannot predict how technological advancements will alter the landscape of our energy system. Rather than hedging bets when new technologies are in their infancy, we should ensure a level playing field that allows new technologies to come forward and compete with the status quo. What is required is regulatory flexibility that allows the uptake of technologies that, in a technology neutral market, have proved their value. Innovation does not happen in a vacuum and we must ensure that our energy system and regulation is not so rigid so as to only protect the status quo.

Yours sincerely,

Sara Bell

CEO Tempus Energy Supply Ltd.

TIDAL LAGOON POWER

National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

8 January 2016

National Infrastructure Commission: call for evidence – delivering future-proof energy infrastructure

Dear Sirs/Madams,

Tidal Lagoon Power is driving a critical change in the UK's energy mix with the development of low cost, low carbon electricity sources that are sustainable, UK based and deliver long-term energy security for 120 years.

Overview

- Tidal lagoons offer low carbon, sustainable energy generation from a domestic technology with significant UK value and global export potential.
- Tidal lagoons deliver reliable, long-term predictable renewable energy to the UK System allowing balancing requirements to be identified well in advance.
- Tidal lagoons offer a source of low carbon energy without the inherent imbalance risk associated with other intermittent generators such as wind and solar.
- Tidal Lagoon Power is discussing with National Grid how to realise and optimise the benefit to the System from a portfolio of UK based tidal lagoons.
- Barriers such as current regulation and market structure mean that there is not at present a clear identifiable pathway for developing the system management potential of tidal lagoons.
- Tidal Lagoon Power welcome further engagement and discussion with the National Infrastructure Commission.

Introduction

Tidal lagoons represent affordable and sustainable infrastructure that can:

- generate domestic, low carbon electricity at scale;
- create long term UK employment;
- catalyse a long term UK hydroelectricity manufacturing and engineering industry;
- promote biodiversity;
- promote local community resilience and pride; and
- allow UK institutions and the general public to invest in and take long term ownership of our natural power assets.

Our first project, Tidal Lagoon Swansea Bay, establishes a scalable blueprint for our programme. Beyond this, we aim to develop, construct and operate a fleet of tidal lagoons to meet up to 8% of UK electricity demand - a significant contribution to the economy and to the decarbonisation of the energy sector. A report by CEBR[1] found that a fleet of 6 lagoons in the UK could contribute £27 billion to UK GDP, creating or sustaining 35,800 jobs on average and 70,900 jobs at its peak. Once operational, 6 tidal lagoons would contribute £3.1 billion per annum to UK GDP, creating or sustaining as many as 6,400 full time equivalent long term jobs. Also, because of the significant export potential, CEBR also reported that there was a potential to increase net exports by £3.7 billion per year (equivalent to 13% of the current trade deficit).

Smart infrastructure for a smarter energy future

Tidal lagoons are an innovative composition of the best established engineering, technology and development approaches, designed to generate predictable renewable energy for 120 years. Our main focus at this stage is to finalise the agreements necessary to start construction to deliver the Tidal Lagoon Swansea Bay project. This project will demonstrate innovative first of kind renewable energy technology, and unlock the potential for larger tidal lagoons in future.

A future portfolio of larger tidal lagoons will contribute domestic low carbon electricity at scale to the System. We also have an ambition to further understand the potential for a portfolio of tidal lagoons to provide flexibility and dynamic dispatching of power to the System.

We are engaged with National Grid to explore the potential ability of a future portfolio of tidal lagoons to provide solutions to current and emerging challenges to the Transmission System. Whilst one of the key characteristics of tidal lagoons (of relevance to system management) is their long-term predictability (a unique feature amongst renewable sources of energy), they also inherently involve a significant element of control and flexibility in their dispatch, attributes which have most potential through the development of a portfolio of larger future lagoons.

Tidal lagoons also have the capability to pump, thereby consuming energy (as well as the ability to generate). This capability could prove highly useful to system balancing needs in times of stress. The dual capability of future large tidal lagoons as a generator and a load, coupled with the ability to modulate the power level in both these operational modes (through the deployment of variable speed drives) is an attractive system management

[1] 'The Economic Case for a UK Tidal Lagoon Industry', Centre for Economics and Business Research, July 2014.

TIDAL LAGOON POWER

opportunity. As a fleet, tidal lagoons present a portfolio of highly predictable energy generation close to population centres, with the possibility of portfolio-wide frequency response, synthetic inertia and load.

There are barriers, including current regulation and market structure, which mean that there is not at present a clear identifiable pathway for developing the system management potential of tidal lagoons.

The key barriers preventing the realisation of benefits to the System from future tidal lagoons relate to current procurement approaches by National Grid, such as flexibility, and term of contracts and services. Current contracting requires fairly rigid availability windows (variable only between weekdays and weekends), which impedes the participation of tidal lagoons because operational parameters are largely governed by a tidal cycle (known long in advance). A move towards more flexible contracting designed around technology capability would be a welcome change.

Also, the maximum contract term for ancillary services is currently 2 years. If ancillary services become a key part of the suite of benefits offered by tidal lagoon technology, longer term contracts would be required in order to develop and finance this operational capability.

TLP would welcome the opportunity to discuss these barriers in further detail directly with the National Infrastructure Commission. We are keen to engage with work focused on future proofing the UK's electricity System as we believe that changes can be made to help realise the potential for tidal lagoons to offer system management capability in addition to significant low carbon electricity generation.

If you have any queries, or wish to discuss further, please contact me at [email address redacted] or [phone number redacted].

Yours faithfully,

Catrin Jones

Policy Manager

Tidal Lagoon Power

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Commission Secretariat
National Infrastructure Commission
1 Horse Guards Road
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8 January 2016

By e-mail to energyevidence@Infrastructure-Commission.gsi.gov.uk

Dear Sirs

National Infrastructure Call for Evidence

Thank you for the opportunity to respond to the above call for information. This letter should be treated as a consolidated response on behalf of UK Power Networks' three licensed distribution network operators (DNOs): Eastern Power Networks plc, London Power Networks plc, and South Eastern Power Networks plc. Our response is not confidential and can be published on your website.

UK Power Networks is one of the UK's largest electricity distribution businesses and we welcome the opportunity to respond to this inquiry. We are dedicated to delivering a safe, secure electricity supply to 8.1 million homes and businesses across London, the East and South East of England.

Our response therefore addresses only the questions raised regarding electricity interconnection and storage. Strong distribution and transmission networks will continue to be at the heart of delivering and affordable, secure, low carbon energy system. UK Power Networks has already been playing a crucial role in supporting the low carbon transition. In total, we have around 5,800MW of distributed generation (DG) connected to our networks. In the last five years we have connected 3,100MW of DG – this is enough to power 58 Olympic Parks and more than 20% of our combined network peak demand.

UK Power Networks also operates the UK's largest battery storage facility as part of our Low Carbon Networks Fund project Smarter Network Storage (SNS). The SNS facility now represents the first known battery storage facility to have been qualified and performing balancing services in the GB market. The reports produced by SNS, including our recommendations of the regulatory and legal framework for storage, are accessible through the innovation pages of our website

http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Smarter-Network-Storage-(SNS)/

With the rise of DG, we expect that we, and other DNOs, will need to take on the challenge of managing the intermittency inherent in renewable generation in order to meet the increase in demand. We are likely to see significant blurring of the boundaries and changes in the use of transmission and distribution networks. Government and Ofgem have a role to ensure that the legislative and regulatory framework will allow the transition to a low carbon network at the lowest possible cost.

Yours sincerely

Suleman Alli
Director of Safety, Strategy and Support Services
UK Power Networks

UK Power Networks response to the questions on Electricity interconnection and storage

Question 1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

DNOs have in the last years seen a shift in their networks as a result of Distributed Energy Resources (DER), such as DG, Demand Side Response (DSR) and most recently storage. As a result, DNOs have now started to consider how to best balance their networks to help the system as a whole and minimise costs to consumers. As energy resources become increasingly distributed, the market will need to develop to ensure that both transmission and distribution constraints are recognised and are visible to market participants so that the system operation and investment costs can be optimised to ensure the most affordable long term solution for customers. In the last five years we have connected 3,100MW of DG – almost the same capacity as the proposed new nuclear power station at Hinckley.

DER are emerging that play an active part in system ancillary services, for example storage providing short term operating reserve and enhanced frequency response, or demand response giving turn up/down capability. These resources can also provide services to both the transmission and distribution networks allowing the potential for active management of capacity, power flows and network voltage, maximising the use of existing assets. They also have the potential to allow more generation and demand to connect without reinforcement. Our Flexible Plug and Play project trialled a range of smart grid technologies and offered curtailment contracts to distributed generation customers to allow them to connect to our network at a significantly reduced rate in return for allowing us to reduce their output in the event of a temporary network constraint.

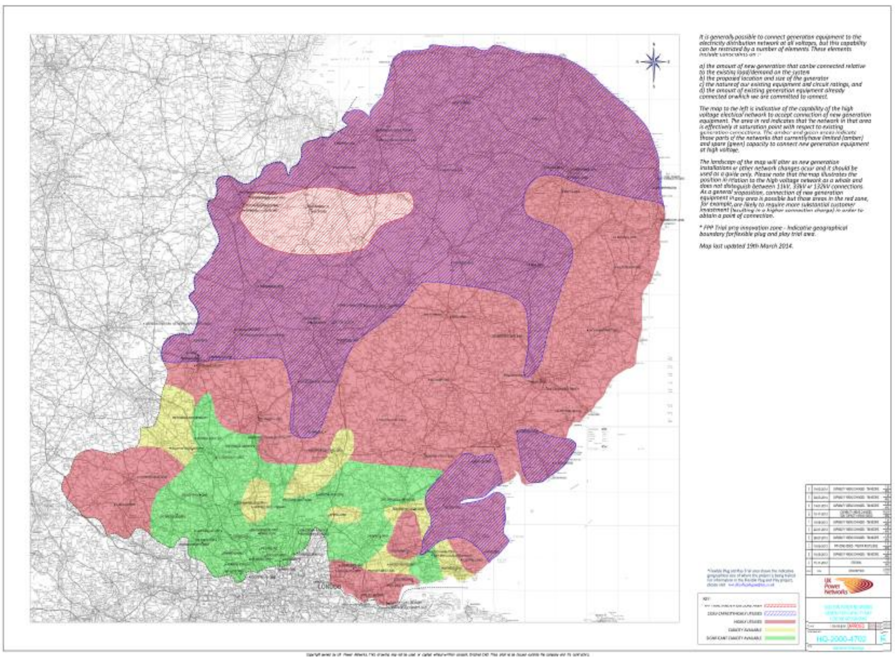
These services and resources make networks more dynamic and imply new capabilities for DNOs to address the challenges of a system operator. For example, DNOs may need to be able to actively manage DG export, providing network security and resilience, monitor the network in a coordinated wide-scale once smart meters are rolled out, to manage voltage within statutory limits and potentially use DERs to balance the system.

It has become apparent from the recent SO tender for enhanced frequency response services that the balancing market approach favouring high availability services may not be aligned with minimising the total system costs. For storage to provide frequency response services to National Grid, storage systems ideally require unconstrained import and export, as offered by most transmission connected generators. In their recent tender for enhanced frequency response National Grid do value different levels of availability, but the connection applications we have received are asking for unconstrained access to enable them to maximise their income. DNOs can provide this but such access is unlikely to offer distribution networks considerable benefits. The locations where unconstrained access is most economic are unlikely to be where there are high penetrations of embedded generation or where there are network constraints that could make use of the storage technology's potential. UK Power Networks has received over 1GW of connection applications for storage driven by this SO request, although we expect only a small proportion to proceed should the SO procure only 200MW of response.

It is also evident that the need for enhanced frequency response is driven in part by the impact of the intermittency and lower inertia of renewable energy sources. Storage would have the potential to address this at source by acting as a buffer to intermittent inputs whilst also providing the ability to store excess renewable energy where network constraints limit its export (and make use of it at an alternative time).

Intuitively the use of spare network capacity elsewhere on the network to provide access for fast responding storage devices to compensate for this intermittency creates the potential for higher overall system costs, be they the costs of connecting the additional storage or because subsequent demand connections experience reinforcement charges that otherwise would not have occurred as the additional storage has used this capacity. It is therefore important that the markets reveal and value these costs, providing the participants and network operators with the information and incentives to make the right long term choices to minimise system costs. This requires a consideration of both the balancing and wholesale markets to ensure they are working together to minimise costs.

Distribution networks in the UK communicate their constraints and investment costs through connection charges, where new users pay for some or all reinforcement costs, and ongoing capacity charges (with an element of peak time usage charges) for large customers (connected directly to larger substations). We publish capacity 'heat maps' (please see an example shown below) on our website to make visible the areas where network constraints affect the connection of generation.



Providing a framework where these embedded sources can provide services to all parts of the system will be a focus for the work the industry is conducting with Ofgem through the Energy Network Association's (ENA) Transmission and Distribution Interface working group and Ofgem's Flexibility programme of work.

We are actively looking to procure services as alternatives to reinforcement from embedded resources such as responsive demand, embedded generation and storage, where these are available. We are actively discussing in the ENA Transmission and Distribution Interface working group how these resources may also provide services such as voltage and reactive power support, and whether these should be procured by the distribution network operators, transmission network operators or the system operator. These discussions will consider what changes to existing regulatory frameworks this might require. Procuring capacity and potentially balancing services in conjunction with the system operator and other market participants such as aggregators is a new area for DNOs where greater knowledge of the markets and operations has to be developed. We are exploring how these services may be provided in our SNS project and are looking closely at the learning from Electricity North West's CLASS project.

We would support a stronger role for the DNOs in managing intermittency as the distinction between 'distribution' and' transmission' becomes increasingly opaque with greater generation capacity connecting to more actively managed distribution networks. We believe this will lead to an evolution from traditional DNOs to regional "Distribution System Operators" (DSOs). A DSO would undertake the conventional role of a DNO but would also make full use of smart techniques to create value for the wider electricity system e.g. by undertaking an element of regional balancing and providing reserve and frequency response services to the national system operator. Such services will become increasingly important to maintaining a stable balanced national electricity system as conventional 'synchronous' generation associated with coal and gas fired power stations gives way to higher volumes of intermittent renewables generation technologies.

Alignment of electricity market mechanisms to maximise whole system efficiency will require mechanism for code governance which is sufficiently inclusive, agile and flexible and considers integrated design and operation of both transmission and distribution networks to allow the system to innovate and evolve as these technologies develop.

Question 2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

The key issue for storage technology has been the cost, particularly of batteries. The economics of battery storage are changing rapidly with forecasts that the costs of battery capacity could fall by as much as 80%. The interest in battery storage for the enhanced frequency response tender is evidence that these improvements are likely.

Storage has the potential to provide many different services and may have advantages over other balancing technologies in being widely deployable and adaptable to multiple services. We believe energy storage, in various forms and scales, will form an important part of future low carbon networks. Storage can provide a key source of flexibility to the networks, enabling greater renewables uptake, reduced system operating costs and avoiding or deferring reinforcement. Energy storage systems are ideally suited to performing frequency response services as, once the frequency change is detected, they can transition from zero output to full power response in as little as 100ms, which means they can deliver a more significant stabilising effect to the system than a traditional generator which takes longer to ramp up to full output. At scale, this could allow National Grid to procure a smaller volume of MW response from storage devices, compared to that needed from spinning plant. Our SNS project is demonstrating these grid scale capabilities and allowing the network operators to understand how these devices can be integrated into networks.

The work being carried out by Ofgem on flexibility needs to consider if balancing services can be from distribution connected assets without the high availability normally associated with transmission connected assets. Whether it is economic to procure more potential services from a wider population of providers (either directly or through aggregated services) than from specific high availability assets is not yet clear but the market frameworks should not discriminate and allow such services to develop.

A cohesive framework of services from storage may provide a better approach than storage operators trying to optimise their revenues between the many opportunities. The system operator procuring balancing services, network operators procuring capacity and time of day pricing in the wholesale markets may optimise this over time but a clear framework for the services and the drivers would help all participants.

We are exploring the many services battery storage can provide though our SNS project. Our SNS system has undergone an extensive period of testing, including formal testing to prove that it is capable of performing beneficial wider system services, such as Short Term Operating Reserve (STOR). This has also provided valuable learning for the transmission system operator about the nature of storage devices, and the SNS facility now represents the first known battery storage facility to have been qualified and performing balancing services in the GB market.

As a network operator we are open to all scales of technology and work to identify the value that can be obtained through these technologies. It is likely that storage technologies will develop at all of these scales and these will need to be integrated. We are presently seeing storage enquiries with capacities in the range of 5MW to 50MW. Such energy resources are by their nature likely to connect to the distribution networks rather than transmission, but their effects are national, e.g. domestic storage could be aggregated and allow best use of domestic solar energy sources reducing stability issues at low load and also reducing system peak demand.

We are aware that a local DSO may be required to maximise the use of new technologies in local networks. We are engaged in DECC's Future Power System Architecture to identify the processes and systems that need to be developed to access these potential benefits and ensure that the networks are able to fulfil the role that is required.

Question 3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

As a distribution network operator we have no comment to make on wider interconnections to other systems within Europe.

Question 4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

We are following developments in energy markets around the world and particularly in the USA and Australia where similar issues for the local network impacts on markets are also being explored, to identify the best approach for distribution networks.

California is one of the areas with most storage installed capacity. This uptake has been driven by government incentives. Understanding the challenges and solutions to the balancing system should provide the UK insight to potential solutions to optimise the network, for example how to use long run marginal price signals should be considered in Ofgem's work on flexibility. However, vertically integrated utilities have different incentives for exploring these solutions and we need to understand how the learning can be applied to the design of UK markets.

In Australia there have been significant increases in solar PV installation since 2010. This has not been constrained by networks and as such the main benefits of the deployment of storage would be time of day arbitrage, with limited opportunities for value from transmission and distribution services.

Germany is another country that will continue to pursue the uptake of storage as their PV installed capacity increases.

ukpowerreserve
SUPPORTING A RENEWABLE FUTURE

National Infrastructure Commission
1 Horse Guards Road
London
SW1A 2HQ

8th January 2016

National Infrastructure Commission call for evidence: Electricity interconnection and storage

UK Power Reserve is an independent power generator with an extensive smart generation portfolio across England and Wales. Our primary business is to support the security of energy supply in the UK through our reserve supply services to National Grid. We are also committed to supporting the government's objective of decarbonisation through the flexible supply services we offer; unlocking the capacity for a flexible renewable energy infrastructure in the UK. To date, UK Power Reserve is the most successful and largest developer of new build gas-fired distributed generation in the Capacity Market, and continues to play a key role in shaping the future of the UK energy industry. UK Power Reserve welcomes this consultation and sets out our views to assist the National Infrastructure Commission in identifying the UK's long term energy infrastructure requirements.

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

Significant recent progress has been made to better position the UK electricity market to meet this objective, notably through the implementation of Cash Out Reform (P305) in November 2015 and the Capacity Market Auction in December 2014/2015. In combination these reforms will have implemented positive long-term changes toward ensuring security of supply, and incentivising efficient market behaviour in balancing electricity supply and demand.

The system operator role has shown to work very well to date and can boast one of the best operational records internationally. However, in order to achieve optimal performance at the minimum cost to consumers, we believe further attention is needed on the actions and costs incurred by the system operator.

Actions from the system operator

We have recently seen a significant increase in the complexity and number of commercial balancing services from what was already a complicated area of the market. Below is a table of the variety of commercial balancing services on offer from National Grid in 2014 and now in 2016 (NB: this does not include mandatory ancillary services such as Frequency Response and Reactive Power).

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Company no. 07385282
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2014	2016
Reserve - Short Term Operating Reserve (STOR) - Fast Reserve - BM Start Up Frequency Response - Firm Frequency Response (FFR) - Frequency Control by Demand Management (FCDM)	Reserve - Short Term Operating Reserve (STOR) - STOR Runway - STOR + - Enhanced optional STOR - Fast Reserve - BM Start Up - Demand Side Balancing Reserve - Supplemental Balancing Reserve Frequency Response - Firm Frequency Response (FFR) - FFR bridging contracts - Frequency Control by Demand Management (FCDM) - Enhanced Frequency Response

As shown in the table above, the number of commercial balancing services on offer has doubled. Whilst we are seeing the positive development of innovation in balancing services, it is consumers who ultimately bear the costs of these services. Although National Grid have a licenced obligation to balance electricity supply and demand at all times, and at the minimum cost to consumers; there is evidence to suggest that the system operator has not effectively procured balancing services at the most optimal cost. To highlight some examples;

Strategic Reserve procured via SBR/DSBR versus STOR

The introduction of SBR was procured at a total cost of £122.4m, for 3,577MWs (de-rated) equating to £34.21/kW for availability over the 2016/17 winter period[i]. In relation to a comparable existing product such as STOR, which has been procured at a firm cost of £12m for 1800MWs (de-rated) equating to £6.67/kW in 15/16 over a comparable winter period; this represents a five-fold increase in price paid for the same capacity over the same period.

We feel this highlights the need for additional scrutiny from the regulator and greater transparency from the system operator, which in this case we believe has resulted in additional costs to the consumer. In addition, this is further supported by the fact that consumers are exposed to 100% of pass-through costs under SBR, whereas STOR costs feed through the National Grid and Ofgem negotiated incentive scheme. Whilst the system operator has justified that SBR has been procured as a secondary reserve product to ensure security of supply, as opposed to a primary balancing service as STOR[ii]; both services contribute to the same objective of balancing supply and demand. We feel this also demonstrates how the current commercial arrangements designed by the system operator are becoming increasingly complex, and has created unintended market distortions due to the multiple ways of buying market volumes. Such distortions can already be seen in the shift of market volumes previously providing available capacity under STOR, then being attracted into higher value SBR contracts. This can ultimately result in a reduction of immediate supply in primary balancing services such as STOR, increasing the risk to utilise secondary reserve SBR capacity at a significantly higher cost.

Market behaviour in balancing services

We are increasingly seeing contracts awarded to capacity that have subsequently become unavailable to the system operator after being awarded a contract creating the 'Phantom MW'. The result of such market behaviour is the displacement of market capacity that would have otherwise been available to fulfil contracts. This also creates an unintended distortion where tenders can appear over-subscribed and more competitive than they actually are, which can in turn negatively impact bid prices in future tender rounds. Examples of this can be seen in the STOR market where there is significant evidence of volumes becoming unavailable once procured. Examples of over 800MW of STOR contracted volumes have become consistently unavailable, however their bid volume and price positions have been published in market data[iii]. In addition, up to 400MW of unavailable volumes have been committed contracts (reported in red as NBM_C_UNAVAIL), which should have otherwise contributed to an 1800MW target of committed STOR capacity for the system operator. This represents a 23% distortion of target procured volume to ensure daily capacity reserves are ready and available to the system operator to respond to daily supply shortages.

Market Transparency and awareness

Another example where we believe greater transparency is needed is in the bilateral contracting of capacity, of which the market is not made publicly available. Several bilateral balancing service contracts in the Bridging FFR product and STOR+ product were awarded by the system operator in 2015, of which there is little information available pertaining to the cost or volume of these contracts. These contracts have been awarded up to 24 months in duration covering the period 2016 – 2018. As information on cost or volume has still to be published, such volumes will have a direct impact upon other tenders for Firm Frequency Response (FFR) market and the system operator's volume requirements over the period. This again could have potential adverse effects on the market signal and competing participants bid behaviour at the ultimate cost to the consumer due to inconsistent levels of transparency.

Electricity Balancing System

Soon to be implemented is the new Electricity Balancing System (EBS) due to go live later in 2016. This new system should optimise replace National Grid current despatch decision processes with a new system taking into consideration all commercial and technical parameters available to National Grid closer to real time to ensure that the optimal commercial decisions are being taken whilst managing supply and demand. We would like to see the new EBS interface become demand/supply side friendly to enable supply side Balancing Mechanism (NBM) Units (BMUs) to access the post gate closure balancing market more readily to encourage more participation and competition. A BM for Non Balancing Mechanism (NBM) demand side capacity.

Independent System Operators

Whilst the current market arrangements with a national system operator have shown to have worked well for the UK electricity market it has been a sole buyer driven market which has shown signs of many distortions; and we believe there is a case for a system of localised operators to be explored.

The natural monopolistic position of the system operator has inherent issues pertaining to market competition and efficiency, often requiring intervention from the regulator to correct market failures. We believe a model of Independent System Operators at the regional level, in combination with a national system operator, could be able to manage the electricity infrastructure through greater visibility and direct control over the local Distribution Network, as well as the ability to create a more competitive market through multiple buyers of balancing and reserve services.

<u>Steps for the longer term</u>

We believe these services should be simplified where possible and procured using competitive processes on the basis of cost to ensure the efficient market operation for all technologies, including both generation and demand side response. The creation of new services has introduced more complexity and issues relating to transparency that arise from the monopolistic position of the system operator, who is able to take these actions with little cost to their organisation and at full pass-through cost to the consumer.

In the longer term to ensure best value for the consumer we would like to see;

- Greater scrutiny from the regulator, specifically in how National Grid procures balancing services including follow up on phantom MWs entering into balancing services.
- Greater transparency on National Grid's methodology in procuring balancing services
- Sign off for all bilateral contracts by the regulator accompanied by evidence that the best price for procured contracts has been negotiated
- Simplification of commercial balancing services frameworks to create a seller's market to ensure the end consumer is getting value for money
- Benchmarking of assessment for comparative balancing services (eg. SBR v STOR)

2. What are the barriers to the deployment of energy storage capacity?

Energy Storage faces the same barriers to entry as do all thermal generation technologies that do not receive long term subsidies, which translate into a higher level of risk. Battery storage in particular is currently at a relatively high cost in comparison to other technologies, combined with a shorter comparable asset lifecycle. The recent launch of the Enhanced Frequency Response has attracted interest in this area, and the tender process offering 4 year contracts from 2017 from National Grid should provide an opportunity that removes many barriers to entry for energy storage technologies, specifically battery storage. The introduction of the capacity mechanism should also complement other opportunities in the UK market that should further encourage investment in energy storage technologies, as long as they offer value for money and can compete with other technologies such as OCGT's, demand/load curtailment, standby/backup generation and interconnectors.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

Using National Demand as the sole measure we would see 10% - 12% of National Peak Demand (approx. 5GW – 6GW) would offer a balanced position to UK consumer whilst providing valued capacity to the UK and European power markets and flexibility to the National Grid to manage supply, demand and capacity margins.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Related to our response to point 1 above we see the best value in the longer term is ensuring that procurement practises being executed now pertain to best practise and are not isolated in their assessment of value when procuring for balancing services. We believe we should also start to examine the case for Independent or Regional System Operators, by looking at international examples such as the US, towards delivering a more efficient market. We believe a more robust market for balancing services can only be delivered if there are multiple buyers and sellers for services rather than a single buyer in the current market arrangements.

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[i] **National Grid SBR Market Information Winter 2016/17 p.4: Available at:** http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/SBR-Tender-Documentation/

[ii] **Demand Side Balancing Reserve and Supplemental Balancing Reserve – Supplemental Note #1. Available at:** http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/Archive/

[iii] **Monthly Balancing Services Summary – September 2015: Figure 2.3.3. Available at:** http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Services-Reports/

8th January 2016

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Unite note to National Infrastructure Commission Calls for Evidence

This note is submitted by Unite the Union. Unite is the UK's largest trade union with over 1.4 million members across all sectors of the economy including manufacturing, transport, energy and utilities, construction, metals and foundries, information technology, food and agriculture, financial services, health, local government and the not for profit sectors.

Unite is unable to respond to the three separate calls for evidence, not least on account of the tight timescale given - effectively eight weeks including the Christmas period. This is not a suitable consultation period.

However, we do want to make an important general point to the Commission.

The current crisis in the steel industry has highlighted the need for British steel to be at the heart of major infrastructure projects.

European rules give EU governments the capacity to award procurement contracts based on 'buying social', a principle which Unite supports. This allows governments to consider the social impact of contracts through the 'most advantageous economic tenure' in the award procedure which will enable governments to put more emphasis on quality, environmental considerations, social aspects and innovation, whilst taking into account the price and life cycle costs of goods being procured.

Government has amended procure guidelines, but the impact of these changes will not be apparent for a considerable time.

We note that this is a point picked up by the House of Commons Business, Innovation and Skills Committee in its report into the UK steel industry published just before Christmas 2015. [1] The Committee calls on the Government to "actively champion the use of domestic steel in large public infrastructure projects." More specifically, it recommends that:

> *"the National Infrastructure Commission looks closely at how the interests of UK steel industry and its supply chain can be considered in relation to large scale procurement decisions."*

We believe that major infrastructure projects should use British steel to support steelmaking and manufacturing in the UK, a key component of the UK economy.

Harish Patel
National Officer for Metals and Foundry
Unite

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[email address redacted]

Contact:
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8th January 2016

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[1] http://www.publications.parliament.uk/pa/cm201516/cmselect/cmbis/546/546.pdf (page 16, paragraph 20)

UNIVERSITY OF
BIRMINGHAM

College of Engineering and Physical Sciences
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Friday, 8th January 2016

National Infrastructure Commission
1 Horse Guards Road
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SW1A 2HQ

Dear Chair of National Infrastructure Commission:

In line with the Commission's call for evidence, I am writing to provide the evidence on how changes to existing market frameworks, increased interconnection and new technologies in demand-side management and energy storage can better balance supply and demand.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

The Independent System Operator or IS0 is the key actor in the various proposals for a deregulated, competitive electric power industry in the World. The IS0 has three major objectives: security maintenance, service quality assurance, and promotion of economic efficiency and equity. When the primary objective is to achieve of economic efficiency and equity of services, this is referred to as Minimized ISO. While the structure of UK's ISO is quite often referred to as Maximised ISO (Max ISO), which covers the objectives of security, service quality and economic efficiency together. In the meantime, National Grid is also the transmission system operator (TSO) in England and Wales. The current mixed ISO/TSO structure is quite often referred to as one of the popular models in the World. It has been known that it is not necessary to move from the current structure to establish fully independent system operator as the case of PJM in USA. We have such an argument because of the following issues associated with the fully separated ISO model:

1) *Efficiency*: Economically establishment of a fully unbundled ISO is not attractive as we will need to set up an independent organisation to perform similar functionalities being carried out by National Grid the moment. And in the meantime, National Grid will still need to keep the relevant departments performing the similar security, operation functionalities. The results of the established the fully separated ISO means that we will need to duplicate the most of the system operation departments that National Grid currently has.
2) *Conflicting operating objectives*: The fully separated ISO will create some technical challenges. The TSOs and ISO would have different objectives and incentives. The objective of ISO is to maximise the power flow transactions while TSOs want to reduce the maintenance costs of their networks.
3) *Risks of security*: In the real-time control and operation of power grid, there needs to a large amount of operational status information flowing between the ISO and the TSOs. This would inevitably affect the control performance of the power grids. In terms of emergency, the coordination between the ISO and the TSOs becomes difficult. These issues would result in potential risks of insecurity with the large scale integration of fluctuating renewable energy sources. Considering the potential cybersecuity issues, a separated ISO structure would create more problems rather than solve them.
4) *The challenges of coordination of planning, maintenance and expansion of the electricity networks*: As mentioned before, there will be duplication departments within the ISO and the TSOs, and this eventually brings inefficiencies of the investments. And in case there are disputes, the delayed engineering projects are very much expected.
5) *The barrier of innovations*: As the ISO and the TSOs may have conflicting operating objectives. The efficiency means different things for different entities. The costly disputes on innovative projects and contracts may create barriers for innovations in the system operations and investments. But I am sure that this fully separated ISO structure would create excellent job opportunities for lawyers and this means that significant payment to lawyers will be created!

Now actually the question becomes how to monitor and regulate the system operator's business in most efficient and effective ways rather than establishment of a duplicated entity ISO.

- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

The current assessment on the capability demand-side management measures and embedded generation to be used to increase the flexibility of the electricity system is very limited. Most of the studies were based on simple simulations with reduced order models of national electricity system. Although the demand-side management and embedded generation are in principle useful to increase the flexibility of the electricity transmission system in particular, and sometime the electricity distribution systems too, these distributed energy sources in the meantime may create unaccepted voltage profiles and power flow congestion in the electricity distribution networks. The current electricity distribution networks may not have the sufficient control resources to accommodate large amounts of distributed energy sources such as wind turbines, PV panels, electric vehicles and energy storage systems [1].

[1] X.-P. Zhang, et al, "Distribution Power & Energy Internet: From Virtual Power Plants to Virtual Power Systems", *Proceedings of Chinese Society for Electrical Engineering,* vol. 35 no. 14, 2015, pp. 3532-3540 DOI: 10.13334/j.0258-8013.pcsee.2015.14.007

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

There are three major issues related to the deployment of energy storage capacity, namely, viability of economics, ownerships, and business models under the market operation environments.

There are a few 'balancing' technologies (**in terms of active power reserve and frequency regulation**) available for the integrated national electricity system provided by:

1. Conventional large power plants
2. Distributed energy sources and demand side response
3. HVDC interconnectors from the other EU countries
4. Energy storage systems

Competiveness of energy storage: Normally we use technologies 1 – 3 with priority as these technologies are cheaper than energy storage systems. However, with the further integration of wind and solar energy into the electricity system, energy storage systems will be needed. Depending on the specific applications, energy storage systems may become profitable now. The viability of energy storage systems are very much related to the incentive schemes and real-time tariff being used. It has been widely accepted that for the time being HVDC interconnectors are more economic than energy storage systems.

A proposal for ownerships of energy storage systems: The very large scale energy systems should normally be connection with transmission networks and hence it would be more reliably and securely operated by TSOs. It is therefore more logic to propose TSOs to be the owners of these very large scale energy storage systems, and obviously such an arrangement would be helpful to ensure the effective use of energy storage systems against system blackouts in terms of emergencies. While the ownerships of middle sized to small sized energy storage systems are flexible, they could be owned by independent energy storage producers, which provide active power reserve for the system.

The current barriers for deployment of energy storage systems

1) there are appropriate strategies available to deploy energy storage systems for transmission networks, distribution networks, homes/buildings;
2) TSOs are excluded from providing energy storage systems, and this is going to adversely affect the development of large scale energy storage systems and subsequently this would delay the implementation of renewable energy integration targets;
3) There are no clear incentive schemes and legal framework available to encourage the penetration of energy storage into the distribution systems and homes/buildings.

- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

The capacity requirements of energy storage systems should be compatible with capacities of transmission network, distribution network and local network. At transmission network level, the required energy storage capacity could be at the level of GWh/100 MWh, 10 MWh/100 kWh, and 50kWh/10kWh for transmission network, distribution network, and homes/buildings, respectively.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

  Development of large scale HVDC interconnectors with the other EU countries is certainly in line with the policies of European Energy Union. The European Energy Union will ensure **secure, affordable and climate-friendly energy** for citizens and businesses. It will allow a **free flow of energy across borders** and a secure supply in every EU country, for every citizen. Using energy more wisely and fighting **climate change** is not only an investment in our children's future, it will also **create new jobs and growth**. By 2020, each member state should ensure that the interconnection capacity should be at least of 10% of its total installed electricity generation capacity.

  In smart cities, interconnected Gas/Heat/Electricity systems coupled with electrified transport and energy storage systems should be developed. It seems that the current policies for smart cities are mainly focused on ICT developments while the requirements for the effective management of energy demand of smart cities have been overlooked.

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At consumers' level, integrated management of Gas/Heat/Electricity/Electrc Vehicles/Energy Storage/Distributed Energy Sources (Wind/Solar) for smart homes/buildings should be developed.

There is a lack of big visions and right strategies in the framework of current energy system developments in terms of coordination and integration of electricity, gas, heat and transport at different levels. Such integrated electricity/gas/heat/transport systems could be better addressed in the framework of 'Global Power & Energy Internet of Everything' proposed by the University of Birmingham in 2011. For your information, I attached the PPT explaining the concept of 'Global Power & Energy Internet of Everything', which is a much broader framework than that of smart grids.

Should you require any further details, please do not hesitate to contact me. We are looking forward to welcoming you at the University of Birmingham.

Sincerely yours,

Professor Xiao-Ping Zhang
Professor of Electrical Power Systems

Wasting Opportunities: Veolia's case for placing waste management at the heart of the UK energy infrastructure policy mix

Executive Summary

Our key points as set out below are:

1. Minor infrastructure such as waste and water are just as critical as the big picture infrastructure, but waste in particular has a key part to play in plugging the gap of UK energy generation needs;
2. Indirectly, the circular economy helps this debate by saving carbon;
3. Because of this it is as important that the generation of this type of infrastructure can fall into the same category of infrastructure projects that have objective assessment to prevent lengthy delays in delivery.

Foreword

Infrastructure is fundamental to an efficient and successful economy. We welcome the creation of a National Infrastructure Commission which can take an independent long term view of the country's needs. Indeed its creation has been necessitated because much of the UK's infrastructure has not been renewed or enhanced as it should have been in recent years.

In 2014, the World Economic Forum ranked the UK 27th for the overall quality of its infrastructure in its report on global competitiveness, down a further 3 places since 2012. Despite being the world's sixth largest economy, the UK's infrastructure ranks well below that of some much smaller economies.

If the UK fails to address the state of its infrastructure, especially in relation to energy, then this will have a significant impact on the economy and the quality of life of our population. Further to this, investor confidence will continue to be undermined by political indecision and policy risk – we can already see this happening.

As the Commission moves forward and considers its terms of reference it will address the "bigger picture" in terms of the UK's priorities – but that should not exclude smaller but yet essential infrastructure, such as waste and water, from being considered as part of this bigger picture. We believe that means thinking beyond planes, trains and automobiles, and large scale power generation. Future planning must include how this country manages its most untapped resource – the waste we create but cannot recycle. We will only truly balance the UK's energy needs by using all the resources at our disposal, and using what we dispose of should be a part of that solution.

The UK lacks a clear strategic policy framework in this area, underlined by the fact this country still sends a third of its waste to landfill. Veolia wants to help move the UK away from a "take, make, dispose" model, and build a circular economy where we reuse or recycle everything we can, and harness the energy from what we cannot. For there will always be some waste materials that cannot be economically reused or recycled – this is the element we must start using more effectively as energy.

A circular economy is not about 'nice to have' green policies, it is about the vital management of the UK's resources. To do that we must:

- *Identify and address capacity gaps in the UK, based on facts*
- *Ensure the planning process is open and objective*
- *Look beyond municipal waste to include other waste streams; and*
- *Address negative perceptions of waste management by engaging with the public*.

The new targets set by the EU require the UK to recycle 65% of its municipal waste and 75% of its packaging waste, as well as reducing landfilling to a maximum of 10% of all waste by 2030. We are currently a long way off those figures, and only a radical approach will see the UK hit those targets. Why not meet our energy needs while we do it?

Energy from waste can effectively solve three problems in one go: an effective treatment option for non-recyclable waste materials, helping to meet the nation's energy demand and providing heat to local communities, whilst also reducing carbon emissions compared to landfill.

Identifying and addressing capacity gaps

All too often infrastructure projects have been subject to the short-term pressures of our electoral cycle rather than making decisions that will deliver a favourable solution in the long term. Infrastructure decisions are also largely focussed on the big 'set piece' projects, such as high-speed rail or nuclear power. But infrastructure should also be about effectively considering the 'small' together rather than simply thinking about 'big' projects.

The UK's infrastructure strategy should be underpinned by an independent evidence-based assessment of our infrastructure needs, and the new Commission will hopefully make a very positive contribution to ensuring we take a longer term view.

Lack of evidence in the waste sector and why the UK still doesn't have sufficient waste capacity
There are conflicting positions on infrastructure capacity being taken in reports such as Defra's '*Forecasting 2020 Waste Arisings and Treatment Capacity*', The Green Investment Bank's '*The UK residual waste market*', Eunomia's '*Residual Waste Infrastructure Review*' and Imperial College's '*Waste Infrastructure Requirements for England*'. There is a clear need for an independent evidence-based assessment of the UK's waste infrastructure needs over a 25-30 year horizon. Then the UK would have a clearer picture of how this could fit into the potential energy mix and be part of the solution. Given the EU targets, this review must be conducted with urgency.

Local versus national perspective
It is a fact that different parts of the country have different requirements when it comes to both waste management and energy. Different waste streams will require different approaches to treatment; much as the energy mix differs across the country. As an example, rural areas with large gardens will produce more 'green waste' and will have a greater need for composting infrastructure than densely housed urban areas.

To add up the capacity of each facility across the country and compare it to the total national waste arisings is to miss the point and hides the fact that some parts of the country will not have sufficient infrastructure to treat their waste effectively. It is therefore important that infrastructure planning takes into consideration these differences, and feeds them into a holistic view of how the country meets its energy gap. Energy from waste is a vital part of the local energy capacity matrix.

Generation under 50MW is under local authority control and given energy from waste facilities normally fall within that category they are often only considered at a very local level, which is not necessarily a bad thing for the communities concerned. However, is the country missing an opportunity? A more strategic approach to looking at these facilities collectively across the UK would not only benefit local communities through more recycling and recovery, but also ensure the wider national benefits of waste infrastructure to energy strategy (including energy security and renewable energy generation) are accounted for in decision making.

Utilising a valuable source of local energy
Our current export of Refuse Derived Fuel (RDF) illustrates the wasted opportunities in energy from waste. In 2014, England and Wales exported 2.37 million tonnes of RDF to Europe, which is sufficient to fuel a 250MW power station. The amount of RDF being exported has sharply increased since 2010, when the UK was exporting next to no RDF, and highlights the lack of capacity in the UK to meet the current demand and turn this valuable product into usable domestic energy. The UK lags far behind a number of other European countries in its current energy from waste capacity.

In exporting RDF, essentially the country is exporting a useful fuel at a cost (not only do we lose the money and the energy value by exporting RDF, but importing other fuels such as coal from far away costs huge sums of money) and is unnecessarily adding to its carbon footprint. Therefore, utilising energy from waste can help address two key problems of reducing expensive imports of energy and increasing renewable energy generation in the UK.

A significant proportion of our waste in the UK still ends up in landfill, which represents another missed opportunity. There is significant uncertainty in the future forecast for municipal solid waste and commercial and industrial (C&I) waste arisings and recycling rates, however even if Defra's optimistic forecasts are achieved there will still be some 7.5 million tonnes of biodegradable municipal waste being landfilled in 2020. This alone is sufficient to fuel a 750MW power station, yet the capacity is not being built in the UK to cover this amount of waste.

It is currently anticipated that the UK will fall short of meeting the EU target of sourcing 15% of energy from renewable sources by 2020 without further action. As such the UK needs to be far more ambitious in its strive for sustainable, low carbon, renewable energy from the everyday products we throw away in this country. Energy from waste has the potential to make a significant contribution to achieving the EU renewable energy target.

In summary:

1. Energy recovery, whether it be from waste, biomass or other, is a key contributor to power generation;
2. It's a key contributor to fulfilling the renewable obligation;
3. Most importantly, it's a key contributor, particularly through heat networks etc, on energy sustainability and reliability.

Ensuring the planning process is open and objective

Infrastructure planning decision making can be a significant blocker to the timely delivery of key infrastructure projects which are considered to be of economic and social importance. Thanks to an uncertain and evolving planning regime and policy framework, coupled with national political interference in local decision making, the UK's infrastructure requirements still remain acute and financially challenging.

It is important that such planning decisions are not mired in lengthy political disputes. Delays over planning decisions (see our Battlefield case study) and a changing regulatory environment (such as we've seen for ROCs and RHI etc.) send a negative message to investors. The result is often a stop-start approach to investment and a stagnation of development, which is in nobody's best interests.

We welcome the National Infrastructure Commission's ethos, which will bring more transparency and make the planning process less costly, both in terms of finance and time. Moreover, the work of the Commission would ensure energy infrastructure projects are subject to the same level of scrutiny and decisions would be made on a consistent and objective basis, allowing for long term investment in infrastructure projects that are in the national interest and without political interference.

A stable regulatory environment for resource management

Meeting the country's energy needs - by fully utilising waste as a resource - has suffered from a lack of clear direction and strategy from Whitehall. Today there are split responsibilities across the Department for the Environment, Food and Rural Affairs (Defra), the Department of Energy and Climate Change (DECC), and planning with the Department for Communities and Local Government (DCLG).

This is further exacerbated by differences in regulation within the UK between nations; it is clear that as debates around future devolution take place, the issue of waste resource management needs to be fully considered as part of energy policy. A more joined up approach to the infrastructural management of waste and its use as energy would create a more coherent national strategy. In essence a structured and secure framework would encourage investment in this area.

Looking beyond municipal waste to include other waste streams

When the nation talks about waste infrastructure, people are predominantly thinking about municipal waste – i.e. the bins outside our homes. However, municipal waste only makes up a fifth of the country's total waste arisings. The reality is that commercial properties, of almost all shapes and sizes, produce more waste than homes.

The drivers for the disposal of C&I waste are different from municipal waste. Cost is the key variable in how C&I waste is disposed of. The outcome is that commercial contracts tend to be much shorter than municipal waste contracts, which are typically for 10 years or longer. This makes it difficult when planning for energy from waste infrastructure since there is no long-term guarantee that there will be sufficient inputs for the facility to be efficient or financially viable. As a result, the C&I waste volumes tend to be managed via many smaller regional and local operators, which can hinder a wider strategic view of the nation's needs.

The challenge is therefore to attract infrastructure investment to a resource stream that, unlike the municipal waste market, does not have the benefit of long-term contracts that can underpin investment.

Addressing negative perceptions and engaging with the public

One of the most significant challenges that affects the waste sector, and the use of non-recyclable waste as energy, which indeed influences its treatment as part of national infrastructure, is public perception. The country's waste infrastructure requirements - as part of its energy needs - should be raised in the consciousness of the public beyond the immediacy of the bin collection round.

Waste infrastructure should be seen as vital infrastructure, just as roads, hospitals and water networks are, as they are all essential services. However, waste infrastructure is almost always viewed in a negative light, when it should in fact be considered in terms of its contribution to the energy mix.

People envisage smoking stacks, passing rubbish trucks and ugly treatment plants. This is an outdated view (see our Leeds case study) of a vital industry. We live in an age where waste is still seen as a bad neighbour development and where compensation for building a waste facility in a community is often seen as a requirement. However, there are many benefits associated with these types of projects such as job creation, training, lower home heating costs (from combined heat and power (CHP)) and cost savings to local authorities through landfill tax savings. Looking at the bigger picture, waste infrastructure projects attract inward investment, divert waste from landfill and contribute to energy security.

Industry and government must therefore strive to engage further with local communities to seek ways to encourage and promote acceptance of developments that communities need but do not necessarily want in their backyard. Currently, the public still frequently distrust the decision making process. Engaging with the public at an early stage of the planning process is essential; only by adopting this approach can the public's concerns be met and addressed.

Case studies: Both sides of the development coin

Energy Recovery Facility - Battlefield, Shropshire

True to its name the Shropshire site is an example of a facility that has ran the gauntlet of a battlefield through the planning process.

Veolia's planning application was submitted in 2009 but was refused in September 2010 by Shropshire County Council, against the planning officer's recommendation.

An appeal was lodged to challenge the decision, leading to a public inquiry in Autumn 2011. Final approval to go ahead with the project came on 10th January 2012, at a delay of three years and at a significant cost through the public inquiry process.

Operational since 2015, the new facility contributes significantly to reducing waste to landfill, helps to supply greater energy security for the UK and has created new jobs. Able to process about 90,000 tonnes a year of residual waste, the facility can generate enough electricity to power about 10,000 homes.

Recycling and Energy Recovery Facility – Leeds

Veolia's facility in Leeds has however had a much more straightforward development process, having been taken from proposal to completion in 4 years.

The facility is currently in the commissioning stage and is due to be fully operational in Spring 2016.

The facility will plug 11MW straight into the local electricity grid – enough to power around 20,000 homes.

With the environment at the heart of its design, it is one of the most significant wooden structures in the country and will feature the largest "Living Wall" in the UK, attracting local wildlife including bees and butterflies.

About Veolia

The UK leader in environmental solutions, Veolia provides a comprehensive range of waste, water and energy management services designed to build the circular economy and preserve scarce raw materials.

We're innovators committed to focussing on carbon reduction by preventing pollution, preserving natural resources, protecting biodiversity, combating climate change and raising environmental awareness.

Our new strategy is focussed on manufacturing green products and energy, helping our customers and suppliers to reduce their carbon impact by investing more than £1 billion in new infrastructure between 2012 and 2018.

We are committed to protecting the environment and improving the lives of the communities in which we operate and have been awarded a Queen's Award for Enterprise in Sustainable Development and received a Four Star rating in Business in the Community's Corporate Responsibility Index for 2014.

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21st December 2015

To Energy Evidence Team

VPI Immingham Response: National Infrastructure Commission Call for Evidence: Electricity Interconnection and Storage

VPI Immingham welcomes the opportunity to respond to the consultation, dated 13th November 2015. VPI Immingham is a combined heat and power (CHP) plant near Immingham, on the south bank of the river Humber. It is one of the largest CHP plants in Europe, capable of generating 1240MW – about 2.5% of UK electricity peak demand and up to 930 tonnes of steam per hour, which is used by the nearby oil refineries to help turn crude oil into products.

Set out below is our response to the National Infrastructure Commission's call for evidence regarding investment in energy infrastructure. We would be happy to engage bilaterally on any of the issues outlined below.

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- What role can changes to the market framework play to incentivise this outcome:
  - Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?
  - Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?
- To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

We believe that the current framework for matching supply and demand in the power markets works well, in that suppliers are able to procure power from generators from years in advance of delivery right up to the same day. Whilst there are, rightly, some concerns regarding liquidity within these markets, we believe that these are largely a result of external factors, such as increased levels of regulation, and they are not a reflection of fundamental issues with the design of the market.

We also believe that the current design of the balancing market is efficient and therefore it delivers good value to consumers, whereby power is procured by merit order, i.e. the generators with the lowest marginal costs are procured first. In addition, the recent changes by Ofgem in relation to the Electricity Balancing Significant Code Review, whereby charges for being out of balance are more reflective of the value during that settlement period should be sufficient to incentivise market participants to ensure that they are balanced within a settlement period. In the very least, with these arrangements less than two months old, the changes should be allowed to bed in before any further changes are made.

As a result, we do not believe that further intervention in and reform of the market is required

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currently. The correct market framework is in place to deliver the current objectives with competition being a fundamental part of the framework to ensure best value for consumers. Whilst some improvements may be required to the various elements of the framework, wholesale change and reform is not required.

However, we do think that further actions outside of the market itself may be required in the medium term to ensure that the balancing market remains fit for purpose. With the energy market expected to change fundamentally, with increasing deployment of embedded generation and less large scale despatchable generation, increased integration with the wider EU market, deployment of smart meters, increasing levels of demand side response, for example, then further reform may be required to ensure that the System Operator is able to manage the system on a day to day basis. This reform could take different forms from a review of the charges allocated to market participants or the introduction of additional products via ancillary services. We expect the requirement for these products to evolve over time without requiring explicit government intervention, as has happened historically.

To protect the integrity of the market, these products must be applied fairly and proportionally across all market participants – we favour the "polluter pays" principle whereby those parties responsible for the costs should pay accordingly. However, with huge amounts of investment required, reform must not undermine previous investment decisions nor should be it applied on a bilateral basis that could distort the market. Competition is the best approach to minimise costs to consumers, but it needs a long term view as opposed to short term, adhoc decision making to be truly effective.

In terms of demand side, it has an important role to play in the future. As the level of intermittent generation increases, demand side is one method of managing short term intermittency. It can also be used to reduce the electricity volume requirement at peak and hence reduce the levels of capacity required as well as reducing the investment required in the wider transmission system. As consumers become more engaged in the market, possibly by the roll out of smart meters, they should be correctly incentivised, via market mechanisms to shift their demand, such as via the introduction of time of use tariffs. However, it is important the DSR competes alongside existing technologies and remunerated at market rates to maximise competition and minimise costs.

National Grid in its current role as System Operator has the ability to develop and identify new balancing products, although these must be approved by Ofgem. However, we have concerns that a private company, concerned with protecting its own reputation and rewarding its shareholders, has such influence over government and regulator decisions regarding energy policy. Whilst there is no evidence of wrong doing from National Grid, there are clear conflicts of interest across the organisation, e.g. its role of EMR Delivery Body whilst its interconnectors are participating in the Capacity Market, its role of advising the government of procuring volumes whilst at the same time being responsible for keeping the lights on and the conflict of both owning the Transmission network and operating the system.

In addition, new products have been proposed and introduced by National Grid, although approved by Ofgem, despite clearly distorting the market and inflicting significant additional costs on market participants. These interventions must not be allowed to continue. For example,

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National Grid introduced the Supplemental Balancing Reserve to maintain healthy margins. This product pays generators that are to close to remain open in an emergency reserve. However, said costs are funded via BSUoS charges, i.e. by those plant remaining open. Our assessment of these costs is that these add approx. £0.15/MWh in 15/16 rising to £0.50/MWh in 16/17 to generators (total procurement cost divided by total expected generation). In addition, although only despatched in an emergency, plant dynamics are such that any despatch is likely to distort the market at the expense of the marginal generators.

As a result, we have a growing concern regarding the independence of the System Operator and believe that it is an appropriate time to review the role of National Grid, if nothing else but to re-instil confidence in management of the energy system. There are clear benefits to having a totally independent, autonomous System Operator overseen by Ofgem.

2. What are the barriers to the deployment of energy storage capacity?

- Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other ‘balancing’ technologies? How might these be overcome?
- What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

Whilst others are better placed to concentrate on the detail, it should be noted that large scale storage, in the form of pumped hydro currently exists in the UK and much of it has been successful in the two capacity auctions that have been run to date.

In terms of battery storage, we believe that the current main barrier to deployment is cost. It is only recently that batteries have been available at a domestic level and at current cost levels, payback is many years. With limited engagement in the energy market from the general public, it may be many years before costs are such that the proposition becomes attractive. As a result, any large scale roll out of domestic level battery storage in the short term would require form of government support which could have the consequence of distorting other areas of the market or “picking a winner”. We support the principle of technology neutrality and delivery at lowest cost.

Should any decision be made to support storage, it must be done on a fully costed basis with storage being made to compete with other technologies to ensure best value for consumers. Any such assessment of costs must look at the whole system cost of supporting energy storage, e.g. a concurrent review of Transmission charging may be necessary to ensure that the increasing costs of the Transmission network do not fall on a decreasing proportion of market participants.

Whilst, in general, we support the concept of increasing levels of energy storage, as it is a clear solution to the intermittency issues, any approach must be done on a competitive, market based way.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

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- Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?
- Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?

As an organisation, we support the principle of increasing interconnection to the United Kingdom – increasing levels of interconnection across Europe should reduce costs for consumers and increase the flexibility of the system. However, it is important that this increasing level of interconnection is supported by increasing harmonisation across European energy markets.

It would also appear that Ofgem's cap and floor framework would appear to be sufficient in bringing forward additional interconnection on the basis of the number of projects in the pipeline, with a further round due to open in 2016.

However, we have concerns regarding the impact on both existing and new UK generation and the potential for much higher costs in the future as a result of a lack of joined up thinking. We do not believe that interconnection alone will resolve any issues regarding security of supply and that their very existence undermines the case for investment in both new and existing assets. The combination of factors outlined below is likely to reduce investment in gas infrastructure, due to the reduced levels of return to be made and therefore any decisions to support increasing level of interconnection must look at the wider picture.

Areas that require consideration are:

- We do not think it is appropriate for interconnectors themselves to participate in the capacity mechanism. We understand that this is a "fix" to ensure State Aid approval conditions have been met. However, interconnectors are classed as transmission assets and therefore cannot in themselves contribute to security of supply and are not exposed to the same charges are generators resulting in their ability to bid lower than generators with no guarantee of security of supply.
- Cap and floor interconnectors are effectively regulated assets and yet are competing with merchant risk generators to deliver security of supply. The very existence of the floor means that any downside exposure as a result of capacity mechanism penalties is limited by the floor price (and underwritten by consumers), meaning that the capacity mechanism is all upside with little to no downside and interconnectors should be able to bid at a lower price, displacing UK generation. We also do not currently see capacity mechanism revenue reflected in the cap and floor assessments.
- Based on current forecasts, interconnectors are expected to reduce GB wholesale electricity prices and load factors by importing cheaper European power (largely driven by the UK Carbon Price Support levels). Whilst some imported energy is low carbon, UK generation may be displaced by more polluting imported power purely because it does not pay a UK carbon tax. Whilst this is of course good for consumers, combined with the reduction in capacity mechanism revenue as a result of interconnection participation, it would appear to be very difficult to make a return on investment in a new

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CCGT. Application of the UK carbon tax to imported energy or strengthening the European wide EU ETS would go some way to resolving these issues.

- With the flow of interconnection supposedly driven by market price signals, the direction of flow is very exposed to regulatory risk. Any policy decision that affects the wholesale market price may also affect the flow of power and impact the UK's security of supply. Currently the arrangements in Great Britain result in higher prices in GB than continental markets. However, changes to policy at either end could change this almost overnight. With each country having different charging regimes, such as for transmission charging, or tax regime, such as the UK's carbon price support, then it is unlikely that there will ever be a level playing field. It is therefore imperative the harmonisation proceeds as far as is possible.

We also have concerns regarding the potential cannibalisation effect of too much interconnection to one country, i.e. the impact of putting all your eggs in one basket. To take France as an example, with potentially over 5GW of interconnection possible by 2020, should something happen in France, driving high prices, such as issues with their nuclear fleet or a policy change that increases prices, then it is highly likely that these interconnectors will be exporting. With these interconnectors included in the capacity mechanism, should there then be a security of supply event in Great Britain, then the UK could be exposed and unable to rely on French imports. This situation could be further exacerbated by interconnection to neighbouring countries. Whilst we do not have a view on the "correct" volume of interconnection, we do believe that further analysis including more extreme, but possible, scenarios is required to ensure that there are no future unintended consequences as a result of the policy.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

We have no comments

We would be happy to discuss the content of the above response in further detail if required. For further question regarding any of the above, please contact:

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T: [phone number redacted]
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7th January 2016

Lord Adonis
National Infrastructure Commission
1 Horse Guards Road
London
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Submission from Westminster City Council to the National Infrastructure Commission

Dear Lord Adonis,

Westminster City Council is grateful for this opportunity to contribute to the work of the National Infrastructure Commission and, as the local authority at the heart of the UK's global capital, we hope that we can form a strong and constructive relationship with the Commission moving forward.

Central London is the engine of the UK economy: Westminster alone functions as a national and international centre for business, shopping, arts and culture and entertainment; houses over 600,000 jobs, 15% of all of London's employment; and generates 4% of UK GVA. Infrastructure is critical to maintaining and enhancing this contribution for the benefit of UK plc: it is essential that efforts to define strategic infrastructure priorities should properly reflect the national importance of the centre of London and that this is reflected in a locally responsive and sophisticated approach to infrastructure investment in the capital. The role of London boroughs, including Westminster, in steering this investment is critical.

This response is a brief contribution on the strategic options for future investment in large-scale transport, including public realm infrastructure improvements across London and energy supply and resilience.

This year, London surpassed New York in the Global Financial Centres Index, claiming the no. 1 spot.[1] However, of the ranking criteria London's infrastructure is rated as underperforming, potentially casting doubt on the perception that the city is serious about its growth ambitions.

Transport and public realm infrastructure are critical to enabling and facilitating the planned growth required across London. Devolution of Government finances and powers will play a key role in making this happen. Westminster City Council supports the significant investment being made in transport and public realm infrastructure in response to increasing residential and working

[1] The instrumental factors used in the GFCI model are grouped into five key areas of competitiveness (Business Environment, Financial Sector Development, Infrastructure, Human Capital and Reputational & General Factors) http://www.longfinance.net/images/GFCI18_23Sep2015.pdf

populations and London's continued global-city status. However, the future of London's transport infrastructure is not limited to high-profile, large-scale investments, but also depends critically on improving the way in which investment in existing infrastructure is prioritised, directed and delivered. It is essential that the planned reforms to the local government finance system, including the larger role envisaged for boroughs in the commissioning of capital projects, provides London with the fiscal autonomy to weigh up competing priorities and direct public and private investment in a way which maximises benefits relative to costs.

In particular, boroughs could significantly enhance the potential benefits of large scale infrastructure investment **if long-term, predictable and real financial incentives are made available**. Areas such as the West End of London, the economic and cultural heart of the capital, provide particular opportunities to leverage investment through innovative thinking. Westminster City Council is working with partners, including Transport for London, the Greater London Authority, the London Borough of Camden and the private sector, through the West End Partnership to provide greater strategic leadership and a common voice for the West End. We outline below some ideas on realigning growth incentives and leveraging investment in key infrastructure schemes in the West End, in conjunction with the opening of Crossrail 1 and the development of Crossrail 2, which we would be very interested to discuss further with the Commission.

Similarly, a secure, resilient and planned energy supply is a critical factor in London and Westminster's growth. The resilience and sufficiency of energy supply is a major reputational and practical risk to economic growth and performance in the West End in particular, with theatres and other businesses experiencing power outages and major constraints placed on future growth and development by insufficient energy supply. Over the past year, the Greater London Authority has worked with the Number 10 Policy Unit, HM Treasury, the Department of Energy and Climate Change, UK Power Networks and the Core Cities to develop potential new arrangements for the required investment, discussed further below.

An integrated approach to both these issues will be essential to meeting the economic, environmental and social demands of a rapidly growing global city. We look forward to working with the Commission on these challenges and we would be very happy to meet and discuss our response in more detail if it would be helpful.

In the meantime, if the Commission has any questions or would like more detailed information or analysis on any of the points touched on briefly below then please do not hesitate to contact me.

Yours sincerely,

Cllr Philippa Roe

Leader of Westminster City Council

Transport infrastructure in London

1. What are the major economic and social challenges facing London and its commuter hinterland over the next two to three decades?

The economic and social challenges facing London are well articulated in various strategic documents, including the Mayor's London Infrastructure Plan 2050 and Westminster City Council's City Plan. Key points include:

- The number of people who live and work in London is rising rapidly. In February 2015, the capital reached its highest population ever – 8.6 million people – and is set to grow to 10 million by 2030. Such significant growth means that large amounts of development will be required for the foreseeable future, including in areas such as affordable housing and transport.

- A clear set of policy approaches will also be required to address the socio-economic and environmental challenges that will be created or exacerbated by this rapid growth. These include the potential for a growing polarisation of the labour market and skills gap; addressing issues around air quality, climate change, heritage and residential amenity; and ensuring that investment – including foreign direct investment, on which London's comparative position has weakened in recent years – is directed to areas of need.

The density of activity and daytime population of central London means that it is particularly impacted by these points; at the same time, however, there is significant potential for well-targeted infrastructure investment in central London to help address these issues across the capital and beyond. In particular:

- Infrastructure will be required to alleviate severe overcrowding on London and the South East's rail networks including on Network Rail and London Underground services

- In central London, managing the dispersal of people from London Euston once High Speed 2 (HS2) opens in 2033 requires investment on the scale of Crossrail 2 (CRL2) as well as public realm investment to mitigate pedestrian pressures; similar measures will be required in light of a decision on airport capacity in the South East

- Inevitably, a city with a more diverse, older, population means that inclusion and accessibility will become increasingly important issues

2. What are the strategic options for future investment in large-scale transport infrastructure improvements in London - on road, rail and underground - including, but not limited to Crossrail 2?

•How should they be prioritised, taking account of their response to London's strategic transport challenges, including their impact on capacity, reliability, journey times and connectivity to jobs?

•What might their potential impact be on employment, productivity and housing supply in London and the southeast?

In central London, considerable growth will be accommodated within the Central Activities Zone (CAZ) and the City Council is working alongside the LB of Camden, the GLA/TfL, the private sector and development industry through the West End Partnership (WEP) to deliver significant investment in the West End to support and encourage that growth.[i] For example, at Tottenham Court Road £1bn of improvements are being delivered through the development of Crossrail 1 (CRL1), the biggest investment in the West End in recent times, which is fully supported both regionally and locally.

Large-scale transport infrastructure investment should be prioritised in a way which allows for alignment with identified development opportunity areas. For example, Paddington, Victoria and Tottenham Court Road are designated as Opportunity Areas (OAs) both within the Westminster City Plan (November 2013) and the Mayor's London Plan (March 2015) and are considered to have significant capacity to accommodate new housing, commercial and other development linked to existing or potential improvements to public transport accessibility. For example, the Victoria Opportunity Area is projected to provide at least 1,000 new homes and 4,000 new jobs from 2011 to 2031; similarly the Tottenham Court Road Opportunity Area is projected to accommodate at least 400 new homes and 5,000 jobs from 2011 to 2031. Victoria is changing from an area previously dominated by Government Departments to an area in which banking, finance and corporate HQ buildings wish to locate, while the Tottenham Court Road area has a more varied economy (including a world renowned creative sector in Soho as well as being a major tourist destination).

However, large scale infrastructure improvements will not, in themselves, maintain London's position as a successful global city. London already has well-established transport infrastructure and the prioritisation of investment should also seek to improve what is already in place. For example, some areas of London have good transport links but low levels of housing and commercial density.

An integrated, balanced approach to transport and development modelling and investment appraisal is needed in order to unlock sustainable development and address the effects of transport infrastructure on investment decisions, growth and productivity. This will need to be sufficiently sophisticated to balance a range of investment needs, including investment in walking and cycling facilities and public transport (such as radial routes in outer London and the proposed extension of the Bakerloo Line); social infrastructure and technological innovation such as greater uptake of electric vehicles in commercial fleets and private use. We strongly support the development of an integrated transport modelling framework, collaboratively with TfL and the London boroughs, to prioritise infrastructure investment for such a complex, historic and dense city. This includes looking across environmental and public health-related, as well as economic and transport-related, policy drivers in order to set out the right collective investments in current infrastructure, potentially including ambitious walking and cycling strategies to keep London moving.

3. What opportunities are there to increase the benefits and reduce the costs of the proposed Crossrail 2 scheme?

The City Council is a longstanding supporter of Crossrail 2 (CRL2). CRL2 presents an opportunity to help alleviate severe overcrowding on London and the South East's rail networks including Network Rail lines and London Underground lines. London's population is projected to reach 10 million by 2030 and supporting and maintaining a functioning, accessible and inclusive transport system for this population is a key priority for us.

However, we are currently seeking assurances that a proper assessment of the distinctive impacts and benefits for CRL2, and how these are mitigated or harnessed, will be undertaken at the various stages of the project, not just at its outset. Growth from CRL2 must recognise the need to improve existing situations as well as provide new opportunities. This should include a proper assessment of local impacts as well as route-wide effects to ensure that funding and delivery mechanisms for necessary mitigation or improvement measures are properly accounted for. Clear borough involvement from the outset in relevant governance mechanisms is critical in this regard.

Managed effectively and collaboratively, CRL2 can maximise its anticipated benefits, providing a vehicle for effective integration and planning of transport systems across London to enable major development and job creation:

- Through effective coordination of the delivery of CRL2, there is a significant opportunity to make better use of our current transport system and help relieve congestion on existing railway lines (including Underground lines) to reduce pressures across London. A key example is CRL2's role in managing the dispersal of people from London Euston once High Speed 2 (HS2) opens in 2033.

- There is potential to draw on the lessons of CRL1 to maximise the integration of public realm/transport interchanges and property development above and around CRL2 stations, including commercial, retail and residential development, delivered in partnership between the private sector, local authorities and other agencies (building, for example, on the new partnership arrangement between Transport for London and Network Rail for CRL2 itself). There are two CRL2 stations proposed within Westminster at Victoria and Tottenham Court Road, identified as having capacity for major housing growth, regeneration and job creation which should be supported by investment in public transport infrastructure. CRL2 is central to the West End Partnership (WEP)'s ambitions to integrate, coordinate and deliver £500m of improvements around Tottenham Court Road, including improvements to the public realm in and around the new CRL2 station entrance to create better pedestrian spaces and new walking routes. Understanding the role of property value uplift and how this can be used to maximise the benefits of investment will be essential.

- CRL2 presents significant opportunities for more employment across London, allowing for improved accessibility to employment as well as contributing to local job creation, including but not limited to construction works. Westminster's objectives in terms of employment include upskilling our resident population and removing barriers to employment for our residents, especially in the north of the city which has high levels of deprivation. Lessons should be drawn from Crossrail Limited's work with local employment brokerages, the Tunnelling and Underground Construction Academy (TUCA) and its role in offering opportunities to unemployed residents within boroughs along the route. To make this activity more sustainable, viewing employment and skills activity as an integral part of infrastructure investment packages has significant potential to unlock new models of investment and delivery, including the potential for the sharing of risk and reward between London and HM Treasury in order to reinvest savings from reducing unemployment into successful local programmes.

4. What are the options for the funding, financing and delivery of large-scale transport infrastructure improvements in London, including Crossrail 2?

•*What is an appropriate local and regional contribution - given the potential distribution of benefits to business, residents, transport users and the wider economy - and how could this be achieved?*

•*What innovative funding mechanisms could be considered to support delivery of key schemes?*

The main barrier to unlocking development opportunities is the availability of funding to implement projects and/or attracting sufficient private sector investment. Social infrastructure, such as housing, education and health facilities, will also be placed under more demand by a growing population – with an increasing number of older people – and will need to be addressed concurrently. In addition, the focus on capital and infrastructure operating costs should not obscure the importance of revenue spending required to manage and maintain public realm including maintaining heritage and cultural assets and facilitating services such as waste disposal, budgets for which are under severe and rising pressure.

Boroughs could significantly enhance the potential benefits of large scale infrastructure investment **<u>if long-term, predictable and real financial incentives are made available</u>**. Individual boroughs, and in particular Westminster, are in the best position to promote inclusive growth that generates direct benefits from London wide transport and infrastructure investment. There is a tremendous opportunity to bring together a number of different levels of public sector delivery of infrastructure by combining national, regional and sub-regional funding investment streams. Transport budgets for London, already partly made up from a proportion of business rates, could be further devolved and be part of a mix of other funding streams such as Tax Increment Finance, a more nuanced 'growth accelerator' financing model including broader economic targets such as reducing long term unemployment, a visitor levy or a share of climate change levy revenues. Such models could help create an incentive for growth in those areas that otherwise make no direct gain but incur new budgetary pressures. We would be interested to discuss this further as we believe that with the right financial package, Westminster through the West End Partnership, could unlock significant growth across the West End in coordination with the opening of CRL1 and CRL2.

5. How have major metropolitan areas in other countries responded to similar challenges and priorities? Are there any lessons to be learned and applied in London?

The Global Financial Centres Index, the Economist Units Liveability Analysis and the European Cities Monitor all provide useful perspectives on these questions. Ernst and Young track this form of competitiveness and there is now strong competition particularly from German cities. Lack of skills and the comparative costs of doing business are among the key challenges for London.

Germany has one of the world's largest and most sophisticated transportation systems. Whilst there a split between Government funding and Public Private Partnership funding, a national transport infrastructure funding agency (Verkehrsinfrastrukturfinanzierungsgesellschaft) was established in 2003 whose task it is to distribute the income from road tolls among road, rail and waterways and to support projects realised under a public-private funding scheme. Redistribution of cost and demand is something Westminster is particularly interested in and we would be keen for the Commission to explore this model in more detail.

http://www.internationaltransportforum.org/statistics/investment/Country-responses/Germany.pdf

We are also interested in exploring the other examples put forward in London Councils' response:

- PwC's Funding and Financing Study explores in depth international models for funding infrastructure, which have been considered for their applicability to London.
- Toronto, Canada, is responding to its city congestion problems with a two-stage investment in its transport system, focusing on bringing economic growth and job creation. It will build, extend and upgrade a series of light rail, underground and bus routes over a 25 year period.
- Paris is establishing a city-regional authority to improve its city transport connectivity with its suburbs. It is building a Grand Paris Express to link the centre of Paris with its airports and major economic areas in the greater Paris region.

Electricity interconnection and storage

1. **What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?**

   •What role can changes to the market framework play to incentivise this outcome: •Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

   •Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

   •To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Energy infrastructure is a particularly pressing issue for Westminster. Our work with UK Power Networks on their future Business Plan suggests an urgent need for investment of at least £400 million in electricity supply infrastructure in central London, and the Mayor is already aware that existing shortfalls are particularly constraining growth in Victoria and the West End, including causing power outages affecting theatres and other businesses. Given this we have taken a leading role in working with the Mayor to support the case for the provision of infrastructure in advance of development actually taking place, and have written to Ofgem to reinforce the case for the changes to the regulatory regime needed to achieve this.

We strongly endorse the move towards locally produced energy. There is a role for the Mayor in pushing for a regulatory regime more supportive of local decentralised energy provision. We also note that electricity demand driven by the decarbonisation agenda may rise dramatically. Therefore, carbon taxes will continue to be an important tool in ensuring a switch to lower carbon electricity and further investment into researching energy storage. Continued investment is also required in carbon storage capacity and technology, perhaps combined with subsidy for small scale electricity generation.

Over the past year, the Greater London Authority has worked with the Number 10 Policy Unit, HM Treasury, the Department of Energy and Climate Change, UK Power Networks and the Core Cities to develop new arrangements for the required investment ahead of demand. Two potential models emerged (see below) and we recommend that the Commission continues to develop these ideas as part of its review into these strategic challenges:

• One approach would be to allow distribution network operators to seek Ofgem's approval for increased investment in a specific area, but on the basis that the cost of the accelerated investment would be recovered from connecting customers as they emerge.

• The second option, which the GLA developed in conjunction with the Infrastructure UK team at HM Treasury, is based upon a private development company being established, potentially by a local or strategic authority in respect of any area, to fund up front investment. This would be done on the basis that the company recovers costs as connections are made by developers, with an additional premium to attract the required investment.

The London Electricity Infrastructure Review, a Technical Working Group Report by Ramboll, also makes several points which we suggest that the Commission also look at in detail:

- The essential change is for investment in London's electricity infrastructure to become more proactive. Infrastructure providers should have greater engagement in development strategies in order to fulfil a role that actively facilitates growth and anticipates demand rather than inhibiting by being reactive.

- The current application of the price control framework discourages proactive investment. A change in emphasis could facilitate such investment.

- The primary constraint in central London, physical space, will require co-operation by many public and private sector bodies in order to find a solution.

- Arguably, the initial phases of a strategic solution are partially underway with the reinforcement work being undertaken by National Grid in north London. This will pave the way for new bulk supply routes to new substations serving consumer voltages, as identified in UKPN's business planning for the next 10 years, but insufficient timely investment in the development of London's distribution network presents serious risks to London's economic growth, regardless of this current reinforcement work.

2. What are the barriers to the deployment of energy storage capacity?

> •*Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?*
>
> •*What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)*

Gas prices are a major determining factor in the cost of energy. Energy storage capacity, particularly in the form of alternative and "reserve" sources of energy, are exposed to the volatility of gas prices. Because of this dominance, the future scale of energy storage capacity will need to be large – however, a strategy that includes all three scales (transition, distribution and domestic) would balance the risk of a lack of technological progress in one area.

There is also a need for legislative change to require utilities to cooperate with boroughs' (and the Mayor's) strategic planning and to enable London level scrutiny and approval of utility franchises to meet these objectives. We welcome the steps the utilities have taken to work with the City Council and to recruit 90 local staff. In a recent response to Ofcom on broadband provision we called for a 'duty to cooperate' between utility companies and local authorities and believe this would be particularly beneficial in regards to energy provision.

Our work with partners in this area makes clear the need for all London stakeholders to accelerate thinking about the future direction of energy provision and infrastructure over the medium-to long-term, moving towards a “smart grid” to enable the most effective use to be made of existing (and help manage the need for new) infrastructure while providing choice and better value for consumers.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

•Is there a case for building interconnection out to a greater capacity or more rapidly than the current ‘cap and floor’ regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?

•Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?

One important market failure which we would highlight is a lack of clarity around return on investment. Investors are not clear on the longer term public sector appetite, or the market potential, for new technology. As part of its work the Commission could usefully consider how this could be addressed.

National Infrastructure Commission Call for Evidence

Woodland Trust Response

January 2016

The Woodland Trust appreciates the opportunity to respond to the National Infrastructure Commission call for evidence. We recognise the importance of a modern infrastructure system and as such are disappointed that the questions do not make any reference to the importance of green infrastructure and the need to design infrastructure in ways that respects the landscapes and habitats that have done so much to shape our national identity. We hope that our submission will show the Commission that green infrastructure, particularly irreplaceable ancient woodland and newly planted woods and trees need to be a key component in the Commission's considerations on long term infrastructure provision, as per the Government's manifesto promise to 'protect your countryside, green belt and urban environment'.

As the UK's leading woodland conservation charity, the Trust aims to protect native woods, trees and their wildlife for the future. Through the restoration and improvement of woodland biodiversity and increased awareness and understanding of important woodland, these aims can be achieved. We own over 1,250 sites across the UK, covering around 23,000 hectares (57,000 acres) and we have 500,000 members and supporters.

Ancient woodland is defined as an irreplaceable natural resource that has remained constantly wooded since AD1600. The length at which ancient woodland takes to develop and evolve (centuries, even millennia), coupled with the vital links it creates between plants, animals and soils accentuate its irreplaceable status. The varied and unique habitats ancient woodland sites provide for many of the UK's most important and threatened fauna and flora species cannot be re-created and cannot afford to be lost. As such, the Woodland Trust aims to prevent the damage, fragmentation and loss of these finite irreplaceable sites from any form of disruptive development.

Connecting Northern Cities

1. To what extent are weaknesses in transport connectivity holding back northern city regions (specifically in terms of jobs, enterprise creation and growth, and housing)?

No Comment.

2. What cost-effective infrastructure investments in city-to-city connectivity could address these weaknesses? We are interested in all modes of transport.

The Trust would prefer to see investment in public transport solutions rather than road building. Such an approach would minimise environmental impact.

3. Which city-to-city corridor(s) should be the priority for early phases of investment?

The Trust cannot comment on specific city to city connection priorities. But we would like to raise the issue of the importance of considering the natural environment from the outset. Whilst the Trust recognises that the development of infrastructure is critical to meet the needs of the growing population, we ask that it is done with due consideration of the natural environment. The Trust is concerned that the Commission's current approach is to consider hard infrastructure needs in isolation from the natural environment. This is reflected by the questions within this consultation. None of them make any reference to the wider environment, whereas the Trust believes the natural environment – both its protection and enhancing its ability to deliver vital ecosystem services to society - should be a starting point for all decisions on the infrastructure provision. This is essential to delivering the current government's manifesto commitment that 'we will build infrastructure in an environmentally sensitive way'

The Natural Environment White Paper (NEWP) published in 2011 must be at the heart of all infrastructure decisions. It outlines the Government's vision for the natural environment over the next 50 years and informs key areas of policy development in relation to conservation and biodiversity. This includes a Government commitment to "providing appropriate protection to ancient woodlands." In addition the NEWP confirms that "Departments will be open about the steps they are taking to address biodiversity and the needs of the natural environment, including actions to promote, conserve and enhance biodiversity."

The NEWP also says "We will move progressively from net biodiversity loss to net gain, by supporting healthy, well functioning ecosystems and establishing more coherent ecological networks."

The evidence on which the Government has based these key policies in the Natural Environment White Paper is found in the Lawton Review. This recognises the importance of habitat networks, and reducing fragmentation of habitats. The review also stated that the government must "provide greater protection to other priority habitats and features that form part of ecological networks, particularly Local Wildlife Sites, ancient woodland and other priority BAP habitats".

Careful ecological assessments and planning at an early stage can minimise damage and ensure that needed infrastructure and mitigation works are as effective as possible in enhancing biodiversity and public access.

The Trust seeks assurances that the Commission is taking these considerations into account at the earliest possible stage.

4. What are the key international connectivity needs likely to be in the next 20-30 years in the north of England (with a focus on ports and airports)? What is the most effective way to meet these needs, and what constraints on delivery are anticipated?

No Comment.

5. What form of governance would most effectively deliver transformative infrastructure in the north, how should this be funded and by whom, including appropriate local contributions?

To be truly transformative infrastructure must deliver green infrastructure integrated with grey infrastructure. It is critical that green infrastructure is considered beyond simply delivering screening but to consider the wide range of ecosystem services it can deliver - from reducing flood risk, improving biodiversity and providing valuable green space for local residents. Large infrastructure projects are an opportunity to view local green infrastructure needs strategically as part of wider development needs.

It is vital that the means of securing these new sites is embedded in a legal framework. Options for this include voluntary but nonetheless legally and financially binding “Conservation Covenants”, which have recently been the subject of a consultation by the Law Commission. These covenants can be undertaken between local authorities and private landowners, with a term of either perpetuity or a duration agreed between partners. For newly planted woodland to become established, develop a canopy and go through its first cycle of management, a minimum term of 50 years would be required. The recent A21 widening is a key example. The lack of a covenant has seen ancient woodland translocation works occur at the wrong time of year, with some translocation not occurring due to unexpected complications. The whole offsetting schemes was problematic with no financial commitment to mitigation, compensation or monitoring measures after the initial capital-funded 5 year period mentioned in the scheme proposals.

London’s transport infrastructure

1. What are the major economic and social challenges facing London and its commuter hinterland over the next two to three decades?

The London commuter hinterland is predominantly designated as green belt. The green belt offers an exciting opportunity for environmental enhancements on the doorsteps of vast swathes of London’s population. The green belt is coming under increasing development pressure, but the Trust would like to see its unique position close to both town and country capitalised on to make critical biodiversity links for wildlife as well as providing vital easily accessible greenspace for urban residents. In early discussions about the green belt, such as in an article by David Niven in 1910, emphasis was placed on the green belt being part of a park system with a focus on public access. With increased development occurring in the greenbelt it is critical that the remaining green belt is enhanced and the ecosystems services it provides capitalised upon. In 1914 in a speech to the London Society Aston Webb (architect of the Victoria and Albert Museum) said in his vision of London in 100 years time he saw ‘a beautiful sylvan line practically all around London’ with a certain amount of open spaces, pleasure grounds’. This is an opportunity to fulfil that vision and to create infrastructure and communities that are robust and resilient in the face of growing populations and climate change.

2. What are the strategic options for future investment in large-scale transport infrastructure improvements in London - on road, rail and underground - including, but not limited to Crossrail 2?

> •*How should they be prioritised, taking account of their response to London’s strategic transport challenges, including their impact on capacity, reliability, journey times and connectivity to jobs?*
>
> •*What might their potential impact be on employment, productivity and housing supply in London and the southeast?*

No Comment.

3. What opportunities are there to increase the benefits and reduce the costs of the proposed Crossrail 2 scheme?

No Comment.

4. What are the options for the funding, financing and delivery of large-scale transport infrastructure improvements in London, including Crossrail 2?

•What is an appropriate local and regional contribution - given the potential distribution of benefits to business, residents, transport users and the wider economy - and how could this be achieved?

•What innovative funding mechanisms could be considered to support delivery of key schemes?

No Comment.

5. How have major metropolitan areas in other countries responded to similar challenges and priorities? Are there any lessons to be learned and applied in London?

No Comment.

Electricity interconnection and storage

1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

> *•What role can changes to the market framework play to incentivise this outcome:*
>
> *•Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?*
>
> *•Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?*
>
> *•To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?*

No Comment.

2. What are the barriers to the deployment of energy storage capacity?

> *•Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?*
>
> *•What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)*

No Comment.

It is important that as the Commission consider electricity interconnection and storage, due consideration is given to future impacts on the natural environment. Ensuring that the delivery of all future provision takes in to account and works in harmony with our existing green infrastructure is vitally important.

The Woodland Trust has witnessed significant losses of irreplaceable ancient woods and trees across much of England due to the lack of consideration for impact on the natural environment. While new storage technologies and interconnection is something we do not object to, this must not come at the expense of irreplaceable habitats.

The Trust would also emphasise its support for the prioritisation of renewable sources and technologies in electricity provision.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

> *•Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?*
>
> *•Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?*

No Comment.

4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

No Comment.

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WWF response to the National Infrastructure Commission's call for evidence:

QUESTION 4: ELECTRICITY INTERCONNECTION AND STORAGE

January 2016

SUMMARY

1. WWF-UK welcomes the creation of the National Infrastructure Commission (NIC) and believes that it has an important role to play to provide a holistic assessment of the UK's energy infrastructure needs.

2. In partnership with the business and investment community, WWF-UK has set up the ***Renewables Taskforce*** (see Annexe 1) to examine how best to maximise the opportunities that renewables offer, including those that will arise as we find the best ways to integrate them into the energy system. The taskforce will soon publish its proposals, which we will be happy to share with the Commission. In the meantime, we wish to bring a major omission in the UK's infrastructure planning to the Commission's attention: **the fabric of our existing housing stock**. Any analysis of future electricity, interconnection and storage infrastructure should include consideration of the UK's buildings, a major consumer of electricity and a significant potential source of both distributed and large-scale energy storage. We therefore urge the Commission to **examine the potential to invest in the fabric of our building stock as an urgent priority.**

3. Failure to assess demand-side opportunities when making supply-side decisions risks policy objectives being achieved at greater cost than necessary[1]. Investing in the fabric efficiency of our buildings will help reduce overall energy demand, in turn helping to reduce the scale of investment required to balance the future energy system.

4. We therefore recommend that infrastructure funding together with progressive policy and regulation be used to **unlock private investment in domestic energy efficiency**, alongside existing funding for improvements in low income homes. As the following briefing shows, this would be a value for money investment and help the Government meet its objectives of reducing carbon emissions, improving energy affordability and security, and increasing economic growth.

5. **WWF-UK calls on the National Infrastructure Commission to examine how to make our existing housing infrastructure energy efficient and to examine how to de-carbonise our heating infrastructure in the most cost-effective way, and we encourage the Commission to come forward with progressive policy proposals to bring this about as soon as possible. The following briefing sets out why domestic energy efficiency should be considered under the NIC's remit.**

[1] Green Alliance (2015) Getting More From Less: Realising the Potential of Negawatts In the UK Electricity Market

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ROLE IN THE ENERGY SYSTEM

6. Our homes are a significant element of the UK's **energy infrastructure**, accounting for 36% of total UK electricity consumption and 52% of total gas consumption[2]. Heating homes has a significant impact on our electricity system**:** 12% of total electricity demand is used for domestic heating[3]. This is likely to increase in future, as electric heat pumps are one of the principle solutions for reducing emissions from heating[4], and electrifying 20% of heat demand would see peak electricity demand double from current levels[5]. Accompanying investment in low carbon heat with improvements to fabric efficiency will ensure that these costs are minimised[6].

7. Homes are also an opportunity to exploit low cost centralised and distributed **energy storage**. Hot water cylinders already provide low-cost load-shifting energy storage in homes equipped with solar photovoltaic panels. In future, phase change materials will allow domestic cylinders to store energy sufficient to meet space heating loads[7] (rather than hot water loads at present), which would help reduce the impacts of heat pumps at times of peak electricity demand.

8. Similarly, the expansion of **district heating**, supported by the announcement of £300m capital funding in the 2015 Spending review, will provide a significant opportunity to integrate our heat and power systems. District heat networks have a large energy storage potential, and coupled with flexible combined heat and power (CHP) and electric heating to exploit periods of excess renewable electricity, can provide balancing and flexibility services to the electricity system, as is already the case in Denmark[8].

9. However, the UK **existing domestic building stock** is old and we are in the bottom third for thermal efficiency when compared with our European neighbours[9] , with considerable potential for improvement through increased fabric efficiency. Failure to address this problem risks increasing the costs of balancing the energy system in future, as in many cases, energy efficiency can meet demand for energy services at a lower cost than supply-side measures[10].

10. **New buildings** are an another important opportunity to integrate new technologies and techniques (such as voltage optimisation, efficient lighting, demand side response) that will be needed as we move to a more integrated and flexible energy system. The Government must implement the requirements of the **EU 'Energy Performance in Buildings' directive** (that all new buildings have very low emissions) no later than 2020[11], and must take this opportunity to ensure that new-build regulations are compatible with future electricity system balancing needs.

11. It is therefore essential to decide on the projected energy performance of our built infrastructure, in order to optimise the methods of heat generation and distribution as well as to understand the impact on future electricity needs. The infrastructure programme to deliver a low carbon energy

[2] DECC (2014) Energy Consumption in the UK
[3] DECC (2014) Energy Consumption in the UK
[4] CCC (2015) Sectoral Scenarios for the Fifth Carbon Budget: Technical report
[5] Sansom (2012) The Impact of Future Heat Demand Pathways
[6] CCC (2013) Fourth Carbon Budget review, Technical report
[7] UKERC (2014) The Future Role of Thermal Energy Storage in the UK Energy System:
[8] Store-EU (2013) Overview of the Danish Power system and RES integration
[9] UK ACE (2015) The cold man of Europe
[10] Cambridge Economics (2014) Building the future
[11] 2018 for public buildings

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system, including balancing electricity supply and demand, must include making the UK building stock energy efficient.

STRATEGIC IMPORTANCE

12. Improving the fabric efficiency of our domestic building stock will help meet Government's three principle energy policy objectives: maintaining the affordability of energy supply, reducing carbon emissions and ensuring secure energy supplies.

13. **Carbon emissions:** Energy efficiency is one of the lowest-cost ways to reduce emissions as many measures such as loft and cavity wall insulation are cheap to install and will eventually pay for themselves in energy savings, going on to save on energy, emissions and bills for decades[12]. The Committee on Climate Change (CCC) recommends that a significant improvement in the fabric efficiency of the domestic building stock is part of the cost effective suite of measures to meet legislated carbon budgets. Current policies will not deliver sufficient emissions reduction to meet the fourth carbon budget (2023 – 2027) and the Committee has highlighted domestic energy efficiency as a priority for ensuring that this budget is delivered cost-effectively[13].

14. The CCC's deployment of domestic energy efficiency measures in its recommendations[14] is broadly equivalent to bringing all homes up to a Band C or above on an Energy Performance Certificate[15]. At present, 80% (21 million) of the UK's homes are rated below EPC Band C[16], and will therefore require upgrading if we are to meet carbon budgets cost-effectively.

15. **Energy affordability:** a programme of investment in the UK's housing stock would reduce average household energy bills by an average of £200 - 400 per annum[17]. Such a programme would also help reduce fuel poverty, whereby households are unable to afford to adequately heat their homes. This is a particular priority as the UK has some of the highest rates of fuel poverty, despite having some of the lowest energy prices in Europe[18].

16. **Enhanced energy security**: meeting energy needs through demand reduction will reduce our dependence on imported fossil fuels, increasing our energy security. It would also insulate the UK economy from global fossil fuel price volatility. In 2004 the UK ceased to be self–sufficient in gas and in 2012 net imports of gas accounted for just over 40 per cent of gas use[19]. The UK could reduce its reliance on imported gas by 26 per cent in 2030 by making UK homes more energy efficient, saving £2.7 billion in gas imports per year[20].

17. **Wider benefits:** as well as reducing carbon emissions, investing in domestic energy efficiency will provide significant wider benefits. The warmth and comfort of homes would be improved,

[12] Department of Energy & Climate Change, Energy Efficiency Strategy: The Energy Efficiency Opportunity in the UK, Nov 12
[13] CCC (2015) Progress report to Parliament
[14] CCC (2013) Fourth Carbon Budget Review Technical Report
[15] CCC (2015) Sectoral Scenarios for the Fifth Carbon Budget: Technical report
[16] ACE, Cold Man of Europe Update, Oct 15
[17] Cambridge Economics (2014) Building the future
[18] ACE (2015) The Cold Man of Europe
[19] Energy Bill Revolution, Re-build Britain; June 14
[20] Cambridge Econometrics, Building the Future, Oct 2014

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reducing incidences of excess winter deaths. It is estimated that 43,900 excess winter deaths occurred in England and Wales in 2014/2015[21] and around 30 per cent of these are likely to be due to cold homes[22]. Spending on energy efficiency would also provide a wider economic stimulus as spending is shifted from (increasingly imported) fuel to construction and labour, providing a manufacturing and construction sector boost. In the long term, reduced energy demand creates net savings which free up spending on other goods and services in the economy[23].

WHAT IS NEEDED?

18. The economic consultancy *Cambridge Economics* has modelled the costs and benefits of an ambitious investment programme in domestic energy efficiency to bring all homes up to an EPC certificate rating of C by 2035, which would modernise all of the UK's homes, help eliminate fuel poverty and deliver the carbon abatement necessary to meet carbon budgets.

19. A total of £100 billion of investment would be required over a 20-year period. This could be achieved by Government providing zero-interest loans to encourage householders to invest, or by **regulating minimum energy efficiency standards** at the point of sale[24]. The latter approach would require minimal public spending, and although would impose a cost on households these would be recouped in the long-run through lower energy bills[25]. This spending (on domestic labour and goods) compares to the £15 billion spent *every year* by UK households on increasingly imported gas for heating[26]. Public funds could be used to provide access to low-cost upfront capital, using the existing Green Deal pay-as-you-save framework.

20. This energy efficiency programme would meet the criteria HM Treasury apply for determining their **top 40 infrastructure requirements.** It would also fit with the eight characteristics of infrastructure identified in HM Treasury's valuation guidance. In addition, classifying energy efficiency as infrastructure is consistent with the way energy efficiency is considered by a range of international organisations such as the European Investment Bank (EIB) and the International Energy Agency (IEA)[27].

CURRENT POLICY

21. The programme outlined above would address a current gap in the Government's approach to energy and climate policy. The **current target of insulating 1 million homes in the next 5 years**, or 200,000 homes per year, is insufficient to meet out climate targets cost effectively. The commitment to a million homes will be delivered through Energy Company Obligation (ECO), but with the withdrawal of the Green Deal scheme there is now no policy to address efficiency in non-fuel poor homes.

[21] ONS, Excess Winter Deaths, England and Wales, Nov 15
[22] World Health Organisation, Environmental burden of disease associated with inadequate housing, 2011
[23] Cambridge Econometrics, Building the Future, Oct 2014
[24] E3G (2015) Taking back control: where next for household energy efficiency policy in the UK?
[25] Cambridge Economics (2014) The Economics of Climate Change policy
[26] ONS (2015) Quarterly Energy Prices
[27] Frontier Economics, Energy Efficiency as Infrastructure, Sept 2016

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22. The Government has set a cap of £650 million per year to be raised from the ECO to support the delivery of energy efficiency measures[28]. To deliver the programme outlined above, an annual investment of approximately £5 billion would be required. With little current private investment in energy efficiency (due to well understood economic barriers such as split incentives and high discount rates applied by householders to long term savings)[29], annual investment will run at less than a fifth of what is required to modernise our homes. This is a direct consequence of the Government failing to adopt a long term infrastructure vision to make the entire UK housing stock energy efficient at the scale and speed required to meet carbon budgets.

CONCLUSION

23. Fixing the UK's existing, leaky housing stock is a huge infrastructure opportunity. Not only does the government's own economic data show that it would deliver comparable economic returns to other major infrastructure projects, but it is an essential investment to strengthen energy security, end fuel poverty and meet our carbon budgets. As this briefing argues, infrastructure funding alongside regulation should be used to unlock private investment in domestic energy efficiency.

24. The Government recognised in its 2011 infrastructure plan that buildings must be considered[30], but no action on the housing stock followed. Now is the time to include a retrofitting programme to eliminate energy waste in our homes. It is one of the most widely supported infrastructure solutions in the UK today, with over 200 major businesses, cities, unions and charities in support[31], including the CBI, Age-UK and Citizens Advice.

25. **WWF-UK calls on the National Infrastructure Commission to examine how to make our existing housing infrastructure energy efficient and to examine how to de-carbonise our heating infrastructure in the most cost-effective way, and we encourage the Commission to come forward with progressive policy proposals to bring this about as soon as possible. The following briefing sets out why domestic energy efficiency should be considered under the NIC's remit.**

[28] Treasury, Comprehensive Spending Review, Nov 2015
[29] DECC (2012) Energy Efficiency Strategy
[30] HMT (2011) National Infrastructure Plan 2011
[31] http://www.energybillrevolution.org/whos-behind-it/

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TASKFORCE 'THE FUTURE OF RENEWABLES' ANNEX

1. WWF-UK has convened an industry-led taskforce on the Future of Renewables: the Market after 2020. The taskforce has a broad membership which comprises of energy generators, investors and transmission specialists. The taskforce will look at how to maximise the opportunities that renewables can offer and will investigate how the Government can best incentivise the modern energy system that is needed. Areas of focus for the taskforce are:

   - Building a more modern energy system and the policy mechanisms the Government can use to facilitate a move towards such a system.
   - Maximising the value chain of ancillary services.
   - Encouraging private sector investment in the low carbon economy.
   - The costs of different energy generation technologies

2. The taskforce will be publishing its recommendations in advance of the Budget and would be pleased to share these with the NIC.