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

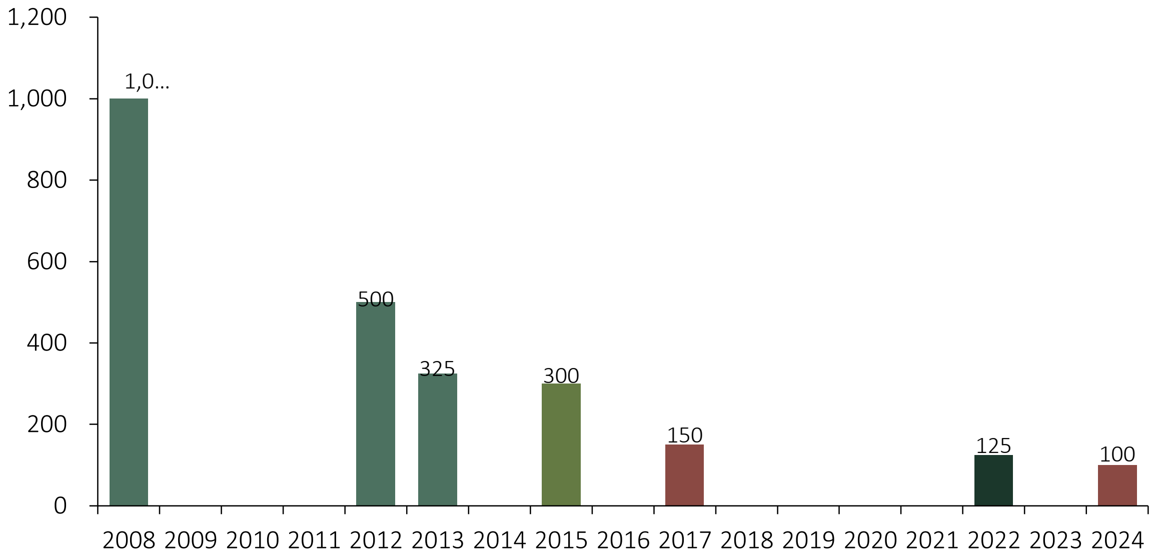
Source: Deutsche Bank, https://www.db.com/cr/en/docs/solar_report_full_length.pdf

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