Regulatory Challenges to Energy Storage Deployment

An Overview of the UK Market

Realising Energy Storage Technologies in Low-carbon Energy Systems

Working Paper 1

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Background

This working paper investigates how the UK is currently integrating energy storage technologies into its electricity markets, the regulatory barriers it is facing, and how it is responding to these challenges.

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The authors are solely responsible for all of the analysis in this paper. Any views expressed in this paper are the authors' and have not been endorsed by any of the organisations associated with the RESTLESS project.

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Overview

Current grid energy storage is supplied by pumped-hydro plants with an installed capacity of 2.7 GW and an energy capacity equalling a volume of 28 GWh. Pumped hydroelectricity accounts for over 99% of bulk storage capacity worldwide, totalling 127 GW.

Storage technologies can offer numerous services to the grid, including: electricity market arbitrage[1]; curtailment minimisation; primary, secondary and tertiary frequency control; a number of power generation services (e.g. alleviate technical restrictions, real-time generation planning, deviations management, complementary services for voltage control in transmission grids); demand-side management; transmission capacity investment deferral; contingency grid support; distribution power quality (e.g. voltage wave quality, power supply continuity); and black-start.

Energy storage could become a key enabling technology in the future to manage high levels of UK renewable electricity generation. System-wide savings of £2 billion a year could be achieved by 2030 deploying new energy storage technologies, in some scenarios.

The need for and value of storage will depend on the wider evolution of the electricity system, and on both UK and EU policy and regulatory regimes. Electricity demand profiles will be affected by the deployment of electric vehicles and heat systems. The potential role of storage in future will be partially determined by the development of counterfactual technologies, for example greater interconnection between EU networks and developments in demand-side management and smart grids. This means the focus of UK and EU policy has an important bearing on the value of storage. The most appropriate technology portfolio and deployment scale would be different if the European system were to evolve towards an 'energy superhighway', compared to if a strategy of local energy self-sufficiency were followed.

Current UK and EU electricity markets are not designed to incentivise the deployment of energy storage. Since energy storage has historically been more expensive than generation, markets are organised as day-ahead auctions that aims to achieve a cost-effective merit order. Since flexible generation technologies are currently cheaper than energy storage, this is unlikely to change unless clear market signals emerge.

The new capacity market is unlikely to remove barriers to most storage technologies. Suppliers have an obligation to pursue a load-following position in the market, with non-compliance leading to penalties. Since no defined time limit for the delivery commitment exists, the delivery obligation is effectively open ended, which is challenging for storage technologies since their discharge duration is always limited by the device capacity.

Energy storage is not currently recognised as either an activity or an asset class in the UK electricity markets. The unique contribution of storage is not recognised in the current RIIO regulatory frameworks. This has a number of consequences:

- Storage technologies may be required to pay transmission network use-of-system (TNUOS) charges twice, as both a generator and as a consumer, for the same electricity.
- In the absence of an official definition, energy storage is currently classified as generation, which means the ownership of storage by transmission and distribution network operators is heavily restricted. This is an important issue because storage complements or is an alternative to network reinforcement, whose value is best realised by being integrated into

[1] *Arbitrage* is the simultaneous purchase and sale of an asset in order to profit from a difference in price.

networks, but this is not likely to happen in the most cost-effective way when the network is barred from owning storage.

- The treatment of storage in the Climate Change Levy (CCL) is unclear, with renewable electricity exceptions not necessarily being passed on to storage providers.

Establishing a specific definition of storage might help to full realise the value of energy storage. A new definition would differentiate storage from generation and would facilitate the removal of barriers to the deployment of storage by treating it as an integral part of the electricity system, which complements transmission networks. However, a new classification would further complicate electricity system regulation and any confusion that might be unwittingly introduced through a change could act as a barrier against the deployment of other emerging technologies.

As a consequence of the EU's ownership unbundling requirements, transmission system operators (TSOs) are forbidden from controlling any form of energy storage. Since TSOs own and operate transmission networks as regulated businesses, this means that they have an incentive to use network reinforcement and international interconnection to balance supply and demand rather than storage. More fundamentally, TSOs are not incentivised to treat storage as an inherent part of the electricity system. Certification of TSOs occurs at an EU level, so changes to both UK and EU regulatory regimes would be required to address this issue.

Operation and ownership of storage technologies by distribution network operators (DNO) are largely constrained by the UK's *de minimis* restrictions. DNOs are not bound by ownership unbundling, meaning that they are allowed to own "small" storage that is exempt from the generation license. However, DNOs may own storage under strict conditions that effectively cap their revenue when dealing with regulated businesses. They are instead bound by legal, functional and accounting unbundling requirements which prohibit them from operating storage in order to ensure operational independence from other non-distribution activities in the system. If a DNO wishes to deploy storage assets, a third party must operate the asset independently and be named in the business case from the outset, which creates a further complication. Moreover, while larger-scale storage projects connected to high-voltage transmission grid may be classified as an EU Project of Common Interest (PCI), smaller scale storage projects connected to the distribution grid are not supported through the PCI framework, and are therefore not financially supported.

Lessons about energy storage can be learned from the natural gas market. Gas storage is an important part of the UK energy system and a sophisticated gas market has developed over the last few decades in which gas storage is treated as an independent activity.

The key argument in favour of promoting energy storage technologies in existing markets is to deliver more innovation and lower prices in the future. Most storage technologies in the UK are currently under development, in early commercialisation or in the demonstration phase. High costs are the largest barrier affecting deployment**.** All technologies are affected by their currently high costs and are likely out-competed by other generation technologies in virtually all grid applications in the short-term. Technological innovation is needed to decrease storage capital costs in the long-term, and this needs to be underpinned by deployment support in the short-term.

These issues mean that current initiatives in the UK are unlikely to fully realise and reward energy storage operators for the value of the services that they provide to the electricity system. Access to balancing markets for storage technologies could be widened and there is a lack of ancillary markets, which are key drivers of the success of storage business cases. There is a general absence of market signals to incentivise the deployment of new storage capacity.

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Renewables currently provide around 22% of the total electricity mix in the UK. As renewables assume an ever more important role in the power system, the frequency and magnitude of both supply and demand imbalances could greatly increase due to their intermittent nature and the likely electrification of the heat and transport sectors. Energy storage could be a key enabling technology for integrating high levels of renewable generation in the UK electricity system due to its ability to provide a number of different services. These include many services to the electricity and wider energy systems, including: the minimisation of wind curtailment, as well as primary, secondary and tertiary frequency control, a number of power generation services, such as improving the efficiency of existing generation assets by alleviating technical restrictions, improving distribution power quality, helping to meet decarbonisation targets and ensuring the security of supply. Currently, most power-to-power storage is supplied by four pumped-hydro plants, which provide an installed capacity of 2.8 GW. These facilities were constructed prior to the current market arrangements and compete with other generation for electricity provision and balancing.

Storage devices are categorised by size (medium or large) and by connection point (transmission or distribution). In England and Wales, storage devices with a power output greater than 50 MW are subject to different rules from those below that size. In Scotland, the threshold is 30 MW and 10 MW, and depends on location.

At present, the main argument in favour of deploying energy storage is to encourage innovation to reduce capital costs, which are an important impediment to competitiveness at present. In fact, there are a number of technological and economic barriers that makes their deployment very difficult. This report examines the *regulatory barriers* that prevent the integration of electricity-to-energy storage technologies in the UK modern power market.

Regulatory barriers: definition of ‘energy storage’

The categorisation of generators in the UK and EU was not designed to reflect the many potential roles and applications of storage. Regulations for generators were only designed to support electricity balancing. The Electricity Act 1989 defined the ‘generation’ class as ‘the generation of electricity at a relevant place’. In a similarly generic sense, the Electricity Order 2001 adds to the definition by stating that the technology ‘generates or is capable of generating electricity’. EU legislation (Directive 2009/72/EC) refers to generation as ‘assets that produce electricity’. Energy storage does not fit easily into either of these definitions, as although it is capable of generating electricity, it cannot do so without an external generator. Whereas both generators and storage devices are capable of exporting to the electricity system, storage is not able to generate a *positive* net flow of electricity, as the flows out are always the same or lower than the flows in due to round-trip efficiency losses. Although generation technologies share a number of characteristics with the ‘interconnector’ class, the two asset types do not share the same license, so there is a precedent for treating system balancing technologies differently from generation technologies. The “Electricity Directive”, 2009/72/EC, represents the most recent set of Directives that are most relevant to generation technologies; however, they do not mention storage.

Smaller-scale storage connected to the distribution system is eligible for exemption from the generation licence. Since the large pumped-storage assets provide balancing on a similar scale to conventional generators, they are effectively able to compete with these generators for balancing. Smaller storage devices can theoretically be licenced as a generation subset, which could be advantageous because the scale at which they can provide balancing is considerably lower.

However, exemption occurs on a plant-to-plant basis, causing potential delays. Exemption from the generation licence is provided if: output to the total system (GB transmission and distribution systems) is less than 10 MW, or if output to the total system is less than 50 MW while the declared net capacity[2] of the power station is less than 100 MW (henceforth, “small” storage). This exemption, which is obtainable for multiple projects, does not take into account the aggregate scale and cumulative impact on the market of all such projects. Therefore, if storage were to expand significantly in the coming years, the aggregate impact of all small-scale storage projects should be closely monitored to avoid adverse impacts of these technologies on the electricity market.

As a result of the EU’s post-market liberalisation ‘unbundling requirements’, storage technologies are required to pay charges for transmission network use both as a generator and a consumer. Participation in the market is influenced by location because it affects the Transmission Network Use of System (TNUoS) charges and the Distribution Use of System (DUoS) charges. This increases the costs of deploying the optimum amount of energy storage to support the electricity system and is arguably unfair, given the unique role of storage in the system.

Table ES1 – Network charges applied to electricity generators and energy storage technologies in the UK at each location and how they are regulated.

Location	Charges	Regulation of charges
Generation	Transmission entry capacity (TEC) payable via TNUoS by generators and consumers to National Grid and distribution use through DUoS.	▪ Paid at the generation TNUoS tariffs set by National Grid, which are charged on a maximum-capacity basis. This means that generators with 200 MW of TEC who only generated at a maximum rate of 100 MW during the year would still be charged for the full 200 MW of the TEC. ▪ Small (<100 MW in England and Wales) generators do not pay TNUoS if they do not significantly affect the transmission network. ▪ DUoS charges are payable by generators and suppliers to Distribution Network Operators (DNOs) for using the distribution network.
Distribution	DUoS paid by generators (and suppliers) to DNO for use of the distribution network.	▪ If DNOs suspect that the embedded generator may have a significant impact on the transmission network, they should contact National Grid, and will be liable to pay TNUoS. ▪ Distribution-connected small generators are liable to pay DUoS, or a charge levied by a DNO for the transmission of electricity through its local network, but not TNUoS.
Consumer	TNUoS payable by generators and consumers to National Grid if the device capacity exceeds 100 MW or if they significantly affect the transmission network.	▪ Different for half-hourly metered (HH) and non-half-hourly metered customers. Customers with sufficiently high peak demand are obliged to have a HH meter. ▪ Charges for a HH metered customer are based on their demand during three half-hour periods of greatest demand in evenings between November and February, known as the Triad, and equals average demand during the Triad periods multiplied by the tariff for their zone. ▪ Non-HH customers are charged for the sum of their total consumption between 16:00 and 19:00 every day over a year, multiplied by the zonal tariff.

[2] In this case, declared net capacity ‘of a generating station which is driven by any means other than water, wind or solar power is the highest generation of electricity at the main alternator terminals which can be maintained indefinitely without causing damage to the plant less so much of that capacity as is consumed by the plant’ (Pöyry, 2013).

As reported in Table ES1, the DUoS charges are payable by generators to Distribution Network Operators (DNOs) for the use of the distribution network and associated operation and management (O&M) costs. The TNUoS are paid by generators *and* consumers for transmission network access and relative O&M costs. Thus, in addition to DUoS charges, storage providers connected to distribution networks must pay double TNUoS tariffs for their role as generators and consumers, when operating in charge and discharge modes. If the power output is less than 100 MW, as in most cases for distributed energy storage, they are not liable to pay TNUoS but must still pay DUoS tariffs. TNUoS accounts for 2 percent of electricity bills, while DUoS accounts for 16 percent of electricity bills due to higher private costs (OFGEM, RIIO Factsheet, 2013).

Due to the differences in EU countries' approach to network tariffs, the cross-border trade of balancing and ancillary services involving storage is likely to be constrained. Current network fees encourage the deployment of a project in a certain member state that has more favourable rules in order to provide services in another member state with less favourable rules (WIP, 2013). Hence, the harmonisation of grid fees is critical to providing fair competition between storage providers themselves and with other generation technologies. Network fees should take into account the impact of electricity storage systems on the network. In fact, electricity storage facilities may choose when to absorb electricity from the grid and when to feed it back. In most cases, storage is used for balancing, which does not contribute to congestion but instead relieves it. Therefore, network fees could be calculated in such a way that costs are allocated more fairly to the players that are causing congestion, which is likely to reduce the operating cost of electricity storage systems, thereby positively affecting their viability.

One option for regulation would be to define energy storage as a separate asset, neither generation nor consumption. Such a definition (EASE, 2015) could take into account the net flow of electricity from the device, with the aim of setting a tariff that reflects the weighted sum of the generation and consumption tariffs. However, this approach could be seen by other market participants as providing energy storage with unfair advantage over other technologies, including foreign generators who provide balancing services via interconnectors.

In the UK, energy storage is currently not recognised as either an activity[3] or an asset class[4] by the Office of Gas and Electricity Markets (OFGEM), the UK electricity market regulator. Instead, storage technologies are categorised as electricity *generators*, giving rise to a number of potential issues and consequences. In contrast to the electricity system, gas storage is treated as an independent activity in the GB gas market. An important insight from the experience of gas storage in the EU is that regulations addressing the security of gas supply are considered to be insufficiently specific on required strategic stock levels, relative also to interconnection capacity and to local production (DG ENER, 2015). Similarly, energy storage capacity strategic stock levels could be taken into account when designing energy storage market governance. However, the potential contributions of counterfactuals such as interconnection capacity and local generation should also be considered in such an assessment, in order to minimise the cost of system balancing. The report also recommends minimising barriers that prevent the free flow of balancing and ancillary services between member states.

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[3] An *activity,* or *financial activity,* as defined in this paper, is an initiative undertaken by a business to fulfil economic objectives and maximise business profits. Financial activities may include buying and selling assets, such as natural gas, and issuing debt in the form of bonds or stocks to finance the firm. Gas storage is an activity which a business, such as a gas-fired generation firm, undertakes to increase revenues. In this case, the firm may buy a quantity of gas and store it to later sell it or use it to generate electricity when the price of gas is high enough over the cost at which the gas was initially bought.

[4] An *asset class* is a group of instruments which have similar financial characteristics and behave similarly in the electricity marketplace. The four broad asset classes of the electricity system are: utility generation, transmission, and distribution assets, as well as consumer systems. An example of an asset for utility generation is an electricity generator, such as a gas-fired generator, which transforms raw materials into a positive net flow of electricity. Energy storage technologies are currently recognised as generators, although they cannot produce a positive net flow of energy.

Regulatory barriers: ownership and operation

The potential for ownership and operation of energy storage resources by utilities is heavily restricted. ENTSO-E's Ten Year Network Development Plan (TYNDP) states that the issue of which players are allowed to own and manage energy storage systems is "an open question". TSOs are currently forbidden from both owning and operating storage, despite the potential contribution of storage to grid balancing and peak load shaving. Although DNOs are allowed to own but not operate storage technologies, their income obtained from business with other non-distribution firms is heavily restricted. In OFGEM's generation licensing scheme, operation and ownership of storage technologies by DNOs are largely constrained and plant sizes have an upper limit. DNOs are not required to abide to any ownership unbundling regulations. Rather, they have legal, accounting and functional unbundling requirements in order to guarantee the operational independence of distribution services from other activities in the system, if they serve under 100,000 connected consumers. If DNOs were allowed to operate storage, it would be very difficult to appropriately ring-fence them from engaging in anti-competitive behaviour. In contrast, they could offer a number of services to the grid, including the delivery of different ancillary services to the TSO. A cost-benefit and competition analysis under different DNO business and regulatory models would help to decrease uncertainty surrounding these issues.

The extent by which grid-scale storage is regulated depends on its interaction with regulated market players. Where storage technologies are applied to provide ancillary services or capacity expansion deferral, their revenue is largely affected by regulation. Instead, if the application of the storage device is intended to facilitate electricity management, a large share of its revenue streams would likely be determined by the unregulated market. Different locations in the system are associated with different stakeholders and would therefore affect the type of service that would be provided. This means that the relative sizes of the deregulated and regulated income streams is likely to vary both between and within networks.

While sources of value such as the deferral or avoidance of transmission capacity expansion represent potential services that the storage device could offer to the grid, these services are not provided through a market, meaning that owners of the device may not consider this a potential revenue stream. On the other hand, a DNO is more likely to access capacity expansion avoidance value, though not market value. While the scope for intangible, non-market based savings to be formally recognised is low at present, the cost savings potentially offered by energy storage are worthy of consideration.

Storage assets may not be operated by DNOs for balancing; however, a third party can operate storage technologies owned by DNOs. This is because trading by DNOs can impact on generation and supply, potentially creating a distortion in competition, which is the reasoning behind this restriction. The third party must be contractually-involved to directly handle electricity flows when storage is used for network purposes or for offerings to other players in the wider electricity system. The third party must be mentioned in the business case for the storage technology, which is an added complication for DNOs. This third party could either be an independent entity or another DNO that is appropriately ring-fenced from trading.

The distribution licence includes restrictive '*de minimis*' requirements for energy storage. These impose that: (i) total turnover from non-distribution businesses shall be one of 2.5% or less of total revenue of the DNOs from distribution and (ii) aggregate investments in non-distribution activities shall not be over 2.5% of the DNOs issued share capital, its consolidated reserves and it share premium. These precautionary measures derive from unbundling requirements for DNOs to prevent the distortion of competition in the generation and supply markets.

The assessment of activities by DNOs who own energy storage technologies is multifaceted and not well understood. If a DNO justifies its ownership of storage with an approach of either conventional asset replacement or reinforcement, its activity will be assessed against the least expected costs for the substituted type of asset, which will feed into its revenue and the regulatory asset value. However, such assessments are difficult to make at present because there is no benchmark against which they should be made. In addition, this assessment fails to consider other benefits to the wider system aside from those delivered to the DNO, such as deferring or avoiding investments in transmission capacity or improving security of supply. If a DNO were to deploy storage using a licence exemption today, it would be overspending over its capital allowance, but would receive only a small return on the investment as a result of the *de minimis* requirements. So while this treatment prevents the distortion of competitive markets, it does not encourage DNOs to reduce system costs through their storage technologies.

Business models

Current rules are designed to prevent discrimination by system operators in network balancing and these might be undermined if network companies were given the right to own and operate energy storage technologies. TSOs generally follow one of the three business models shown in Table ES2:

Table ES2 – Proposed business model specifications for TSO ownership and operation of storage assets (UK Power Network, 2013).

Ownership unbundling	This option requires full ownership separation in order to safeguard the independence of network ownership from potential interests in supply and generation.
Independent system operator (ISO)	An independent TSO free of interests in generation or supply operates the system is required. At the same time, ownership of the transmission network is allowed to remain within the transmission sector.
Independent transmission operator (ITO)	Ownership and operation of the asset are allowed to remain within the same sector; however, the ITO must be guaranteed to be operationally independent with stringent rules on ring-fencing.

The 'Ownership unbundling' and ISO models necessitate the separation of ownership between an entity that is involved in TSO activities and any activities that are related to the market. Such provision forbids the TSO from holding generation assets, and hence any form of energy storage technology. Instead, while the ITO model permits common ownership, currently disallowed, it must be accompanied by complete independence and ring-fencing from an operational perspective to avoid any distortion of competitive practices.

The DNO requires a third party to operate its storage devices in order to avoid distorting competition in the generation and supply markets. Business models for distribution-scale storage that have been proposed are listed in Table ES3.

Table ES3 – Proposed business model specifications for DNO ownership and operation of storage assets (UK Power Network, 2013).

Model	Description
DNO contracted	The DNO owns and has full operational control over the storage asset. Before the storage asset is built, long-term contracts are agreed for the asset's commercial control in certain periods of time.
Contracted services	The DNO offers long-term contracts for services at specific locations with commercial control in certain periods of time.
Charging incentives	The DNO sets the DUoS tariff to create signals that incentivise peak shaving to reflect the value of network reinforcement.
DNO merchant	The DNO owns and has full operational control over the storage asset.
'DSO' role	The DNO owns and has full operational control over the storage asset. In addition, the DNO is given a regulatory role in balancing and controlling aggregated demand and generation, taking on an active role as a Distribution *System* Operator.

These represent options for DNOs to realise the value of energy storage technologies. Most models have been suggested by DNOs and offer them partial or full control over the storage assets, which is disallowed by current regulations. It is as yet unclear whether any of these models will be made available to DNOs by UK and EU authorities. There is currently no consensus over which market players, including DNOs, should be given the ability to control storage devices (ENTSO-E, 2014).

For models involving DNOs as merchants and, more generally, DSO business models, a major concern is avoiding the distortion of competition in generation and supply and respect unbundling requirements. This is considerably less important for models concerning contracted services businesses because in these cases the distribution company has a much less important role in the operation of storage devices. These issues might be overcome by allowing distribution businesses to be actively involved in trading for balancing purposes, with appropriate restrictions that prevent speculative trading. Therefore, authorities could consider whether energy storage assets could be allowed to be operated by DNOs in this setting.

In models related to incentives to charge, such issues are less important as a third party would be involved in both ownership and operation. However, the DNO is less likely to invest in storage in this business model as the value of the asset to the DNO is more uncertain and it is prevented from operating the storage to realise its value. This suggests that the benefits to the DNO are not fully represented in this business case. Thus while the DSO models have regulatory challenges, the incentives models entail far higher commercial and security risk (UK Power Networks, 2013).

Market design

The current electricity markets, in which storage is treated as generation, are unlikely to realise the full value of storage to the electricity system. Creating a new category of energy storage would probably adversely affect other technologies, because the current electricity system has partly been developed with the current market design in mind. For example, it could greatly reduce market prices for ancillary and balancing services. Such a drop in prices could undermine business cases if large amounts of storage were deployed.

At present, the main argument in favour of storage is that it might encourage innovation to reduce prices in the future. Yet, this argument should embrace all emerging technologies to avoid creating unfair competition. This also suggests that smaller-scale storage, at least initially, could be built as an exception to current regulations, instead of placing well-established generators and immature storage technologies on the same playing field. While countries such as the UK address this issue by providing exemption to small-scale storage from the generation license, most other international markets do not. Moreover, it is crucial for licenses to be harmonised across Europe to enable the realisation of cross-border value.

The way in which storage is treated under the Climate Change Levy (CCL) remains vague and unclear. In the CCL framework, renewable sources of electricity are defined as those not derived from fossil fuels or nuclear, and include waste only if the fossil fuel content is less than 10% of the total. Renewable electricity receives a Levy Exempt Certificate (LEC). This statutory instrument requires the renewable generation to be calculated at the point where electricity is delivered from generation to a distribution or transmission system on UK land. However, if export of electricity from a storage device relies on the import of electricity (from a LEC-owning generator) and then the exporting of this electricity, the issuing of a new LEC at the point of export, since storage is considered a generator, necessarily implies a *double* LEC. Thus, an LEC must be allocated at the original generation point to avoid giving storage technologies a double LEC. It remains unclear whether or not storage devices should be eligible for LECs. While this issue needs to be clarified by authorities, it seems likely that double charges do not reflect a level-playing field.

The UK's Electricity Market Reform (EMR) recently introduced Feed-in-Tariffs (FiTs) with Contract for Difference to support investment in low-carbon generation and a Capacity Market to support security of supply, which could represent an opportunity for energy storage. However, the EMR could be altered to better reflect the value offered to the system by storage technologies because it currently limits their participation. In fact, low-carbon generators supported by Contract for Difference Feed-in Tariffs (CfD FiTs) and small scale (<5 MW) FiTs are ineligible for this scheme, at least while they receive payments, in order to avoid double payment. Smaller-scale (<2 MW) generators are ineligible if they are not combined with other capacity through the so-called 'aggregation' service. In addition, FiTs are not a market-based tool, thus is unlikely to yield an efficient and optimal allocation of storage resources.

A number of barriers could preclude the chance of storage providers to consider it a benefit to participate in the capacity market. UK electricity market policy aims to provide an equal playing ground for storage and other sources of capacity in the new capacity market. Storage may participate directly in the capacity market if its capacity is greater or equal to 2 MW, which clearly excludes storage devices with capacity less than 2 MW unless they bid into the market alongside other larger generators. Storage devices being awarded a capacity contract must commit to deliver a certain amount of electricity during periods of system stress. The main problem for storage is that there is no time limit over which delivery must be maintained, thus capacity can be requested at any time during the contract period. The delivery obligation is an open-ended one because there is effectively no defined time limit over which delivery must be maintained. This is clearly a problem for storage technologies since their discharge duration is particularly limited. So the storage device must remain fully charged for a long period and suffer energy losses, which could affect the profitability of storage projects. If the storage device were entirely discharged before the end of the warning period[5], its provider would be subject to a heavy penalty equal to the volume of under-delivery times a price that is directly related to VOLL (around £17/kWh) up to a cap of 100% of the annual capacity payment to the provider. Applying lower penalties to emerging technologies might be justified in cases where they are likely to decrease long-term system costs through innovation. It is possible to limit the provider's exposure to penalties if the provider offered less than its full capacity to the market, a practice known as 'de-rating'. However, this practice not likely to compensate for the barriers described above. A storage provider could participate in secondary trading to lower the penalty risk by buying the delivery obligation from another provider, but this is

[5] A warning period is issued in the capacity market at least four hours before an anticipated event of system stress, which is designed to give capacity providers a period of four hours in which to supply capacity.

unlikely to reflect the efficient value of storage since it is an expensive method due to the fact that the period in which this may occur is most often a tight market period. Relying on the secondary market is unlikely to represent an efficient solution to decrease non-delivery risk.

Current cash-out prices could, possibly unfairly, fail to reflect the value that storage technologies may offer to the system. If the system operator orders the DNOs to decrease demand through brownouts or blackouts in order to balance the system, these balancing activities are not included in the method for calculating cash-out prices, thus cannot increase during periods of market tightness because they fail to reflect balancing activities' costs. This barrier decreases the value of flexibility and reliability of generation, and hence the potential role of storage. Although it is reasonable for electricity imbalance arrangements to provide settlement for electricity that is produced or purchased without a binding contract, the methodology currently used for its calculation inhibits cash-out prices and could diminish the strength of the signals and incentives they could be able to deliver. OFGEM recently proposed the adoption of single cash-outs for the entirety of imbalances in individual settlement periods as opposed to the ongoing dual-price method, which could increase cash-out prices.

Policy initiatives

The UK's Electricity Market Reform (EMR) may better reward the value of storage technologies. While it provides payments to reliable sources of capacity through its capacity market, the contracts for difference scheme, which provides payments to low-carbon generators, could be an option for encouraging storage deployment. However, limitations affecting grid connection for smaller-scale storage is likely to keep many storage providers out of this scheme and may result in the loss of a significant portion of the overall value of these technologies to the system. Although the capacity market's open-ended obligation may limit the value of storage as a potential capacity provider, the UK's new capacity market could meaningfully contribute to the realisation of value by storage technologies. In fact, the capacity market has only very recently been introduced.

Clear signals that reflect the requirements for flexibility in balancing and ancillary services would potentially encourage storage deployment. Financial support for transmission infrastructure with storage, provided at an EU level though PCIs (ENTSO-E, TYNDP, 2014), is not currently a market tool and could distort market-based evaluations of storage projects (Sandia, 2013). Furthermore, the procurement of ancillary services is currently mostly based on bilateral contracts, but terms and conditions are not publicly available.

The option of allowing TSOs to own and operate storage could be given further consideration. Article 9(1) currently forbids UK regulated businesses (e.g. TSOs) from owning storage; however, there are a number of benefits that storage in the hands of TSOs could provide to the system, such as maintaining security of supply, providing back-up power and co-ordinating cost-efficient dispatch. However, Italian law Art 36, par. 4, decree 93/1, widely viewed as controversial, currently allows TSOs to build and operate batteries if justified with a cost-benefit analysis that shows the cost-efficiency of storage as opposed to potential substitutes. Belgium Article 9(1) similarly allows TSOs ownership of storage devices if such choice does not prevent the competitive functioning of markets.

EU regulations do not force national markets to provide an identical treatment of energy storage technologies when charging and discharging. Applying substantially different grid tariffs to storage technologies in different countries for charging and discharging modes could provide an inefficient and zonally sub-optimal allocation of storage resources across the continent. A number of member states (Czech Republic, Spain, Italy, Lithuania, Poland, Portugal and Slovakia) do not impose grid fees to storage plants while other states (Austria, Belgium and Greece) and Norway apply fees to storage for both charging and discharging. In addition, such treatment could act as a barrier to the cross-border trade of balancing and ancillary services between European markets. In fact, some markets avoid charging storage plants due to their withdrawal injection. However, there is a clear lack of common EU-wide legislation, which effectively leaves TSOs free to impose charging policies to different plants. A major issue with grid fees is that this regulatory heterogeneity encourages the deployment of a project in a certain member state that has favourable rules in order to provide services in another member state with less favourable rules. Harmonising grid access fees would probably provide fairer competition for storage technologies and other generators across transmission networks, so is likely to be viewed favourably by the EU and be the subject of EU initiatives in the future.

One of the main methods for funding energy storage innovation in the UK could be the OFGEM Low Carbon Networks Fund (LCNF), which provides funds for demonstration of innovative projects. The LCNF has invested £500m to support new technologies. This fund allows DNOs to recover a proportion of expenditure incurred on small-scale projects, and includes an annual competition for an allocation of up to £64m to help fund a small number of flagship projects. The largest allocation of funds through the LCNF is the Customer-Led Network Revolution (CLNR) Project (the UK’s biggest smart grid project) for £54m. The largest project devoted to energy storage that was funded with the LCNF is the Smarter Network Storage (SNS) project, through which OFGEM has awarded £13.2m to undertake trials to improve understanding of the economics of electrical energy storage.

Balancing and ancillary services give the opportunity for non-conventional generators to participate in these markets, possibly via an aggregator. In order for National Grid to provide balancing services in an economic, competitive and non-discriminatory manner, it expresses the services based on a series of parameters, including duration, speed, repeatability, reliability and scale of generation provision. The services can be realised in a portfolio mix that National Grid considers economical and appropriate to meet grid supply security targets. However, these services were linked to historical requirements and the various technical features of generation technologies used in a given historical period, so do not fully consider current system needs and the future deployment of technologies. For example, the historical observations for reactive power covered the period April 2005 to latest available data, and came from the Ancillary Services records against which Reactive Power utilisation is currently being paid (National Grid, 2012). New procurement principles enable flexibility for non-standardised services to be procured under bespoke contractual agreements. This could improve the integration of energy storage technologies since details of new contracts for a number of ancillary and balancing services may be negotiated.

National Grid is considering the introduction of an aggregate fast reserve service which should comply with the standard minimum service provision, which is 50 MW to be provided in 2 minutes. This would imply the enhanced possibility for non-conventional providers, such as storage, in offering fast reserve within an aggregated package. National Grid have also proposed revising the frequency response service. Among other points, they proposed the establishment of a week-ahead tender timescale, in order to avoid long-term forecast limitations, and aggregation. Indeed, both of these propositions have the ability of improving the participation of non-conventional providers, including storage. In addition, National Grid’s proposed Enhanced Frequency Response (EFR) tender could become a reliable source of revenue for energy storage technologies due to its potentially key feature of requiring the provision of 100% active power output at 1 second (or less) of registering a frequency deviation. Due to the fast-response nature of energy storage technologies, EFR is expected to become the most valuable service that storage may provide.

Conclusions

Current arrangements in the UK electricity market, in place to avoid the distortion of competition, and its design, reflect the system design prior to the introduction of renewables and the development of more cost-effective energy storage technologies. The current system contains a number of regulatory and legal barriers to the deployment and full value realisation of energy storage technologies. A key issue is the treatment of storage technologies as generation subsets, which creates a number of other uncertainties and additional regulatory barriers.

The value of storage is hindered by the inability of storage owners to capture value in multiple service markets. In order to accommodate storage technologies, authorities could consider creating a new category for energy storage in the electricity market regulatory framework. One reason why a pan-EU definition of storage is not available is because it is unclear how storage technologies differ from generators, in the current regulatory perspective. The potential impacts on the market of introducing such a definition is not well understood. It would be useful to consider what the best definition of a storage device would be in terms of market design.

Although the major argument in favour of storage deployment is to encourage innovation to reduce prices in future, it is currently difficult to justify deploying storage as both network reinforcement and flexible generation are substantially cheaper. The array of benefits that storage may provide to the system depends on a number of factors, including time-of-day, season, location, the available mix of resources and longer term electricity demand trends, which renders deployment particularly complex.

Policies could aim to recognise a larger number of technical services, including more balancing and particularly ancillary services, that emerging technologies can simultaneously provide to decrease system costs and increase system efficiency. Coupled with less restrictive rules to control financial interaction between market players and regulated businesses, emerging technologies would benefit from a friendlier market environment, thereby enhancing innovation and improving future systems. The UK is at the forefront of developing several energy storage technologies and these could become important exports in the future. However, it is unlikely that this will happen unless a route for the deployment of energy storage in the existing electricity system, at least at small scales, is made available.

1 Introduction

The importance of reducing greenhouse gas emissions rests with the premise of avoiding hazardous levels of climate change which induce major health risks, primarily as a consequence of extreme weather events (UNEP-WTO, 2008). The European Commission emphasised the need to reduce greenhouse gas emissions in order to comply with the Kyoto Protocol to the United Nations Framework Convention on Climate Change, as well as other similar commitments. The European Union (EU) therefore pledged its targets for such reductions to 20% below its 1990 levels, by 2020, with further advances in these set out for 2050 (EU 2050 Energy Roadmap). These objectives play a key role in supporting technological innovation. Different practices have been put in place since then. For example, by pricing each unit of carbon dioxide emitted in the production process, the European Union's Emissions Trading System (ETS), established in 2005, aims at limiting the consumption of polluting fossil fuels whilst promoting the use of renewable energy technologies and their innovation. To this extent, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 promoted the use of electricity from zero-emission, renewable sources and represents a breakthrough in current electricity politics. Renewable electricity generators and their development have been supported in various ways. For instance, feed-in-tariffs, green certificate systems, tendering systems and tax incentives are common practices in the EU to make sure that renewable sources are increasingly used.

As renewable electricity technologies become progressively more involved in our systems, and their innovation and role in current electricity markets advance ever more to meet environmental objectives, larger penetrations of renewable electricity in our grids imply major concerns. Among all, the uncontrollable nature of renewable electricity implies crucial risks to the security of electricity supply: the intermittency of power associated with technologies such as wind or solar power has for many years been a barrier to the development of a low-carbon electricity system. In fact, wind production generally peaks in the mid-afternoon, but demand collapses overnight, so excess wind mainly occurs at night; however, electricity during night hours is infrequently consumed. As more intermittent electricity is brought online, the grid is forced to reject ever larger amounts of power. For instance, in only 1.5 years since October 2011, the UK transmission system operator (TSO) was forced to turn down 224 GWh of potential electricity from wind farms alone (National Grid, 2013), which received a considerable fraction of the total curtailment and balancing services in 2013. This means that wind, or more generally renewable, generators are effectively paid for shutting down their output in order not to overload the grid. Increases in renewable electricity supply are therefore dismissed in favour of the steadier output produced by polluting coal and gas, and potentially perilous nuclear power plants.

The reason why electricity markets are so diverse from other markets is entirely due to a fundamental operational problem. The nature of the electricity product, namely the fact that it cannot be economically stored, is reflected by its particularly complex day-ahead markets and price behaviours. Price spikes are entirely due to the organisation of electricity supply into a cost-effective merit order which combines to recurrent, or seasonal, fluctuations in demand. Such price spikes could be avoided if electricity were able to be stored at low costs. Nevertheless, most energy storage technologies are currently not mature enough for deployment and batteries are unable to withstand high cycling rates, nor are they able to store large quantities of energy in their small volumes (Ibrahim et al., 2008). The excessive costs of storing electricity directly imply that precursors to electricity are stored rather than electrical energy itself, as the different types of generation are varied over time to continuously meet demand. The only exception to this practice is represented by pumped-hydroelectric generation which can produce large amounts of electricity for short periods, at a very short-notice. Pumped hydroelectricity accounts for over 99% of bulk storage capacity worldwide, or around 127,000 MW. Norway is the major producer of hydroelectricity worldwide and runs 937 hydroelectric power plants to serve electricity to a relatively small population of 5 million people, almost exclusively via its hydroelectric generation

(World Energy Council, 2015). Norway is therefore the major exporter of electricity in Europe, with European countries largely benefiting from their low-cost imports, and the European grid taking advantage of an improved security of supply. However, these large power plants are far from available as they require specialist sites, with mountainous areas in proximity of large plain spaces (Boekenkamp, 2014).

Our electricity systems are embarking onto a profound transition towards a low-carbon future and the role of energy storage is likely to change dramatically. The forthcoming low-carbon electrification of the transport and heat industries are likely to provide a largely seasonal demand profile and larger magnitudes of changes in electricity prices. The many technologies which are currently under development are designed to support the traditional view of the role of storage, or storing electricity when prices are low (excess supply) and using it when prices are high (excess demand). However, the valuable aspect of energy storage technologies is that some of these devices are able to support many other tasks within the electricity and energy systems, such as power-to-gas systems which can be used to produce gas for electricity generation, including other methods to store excess electricity from renewables as hydrogen, or heat, for use in other sectors. Other types of storage include: heat-to-heat, electricity-to-electricity, electricity-to-heat, and heat-to-electricity applications. Hybrid systems often maximise energy efficiency and represent an important value of storage within the energy system.

A wide range of technologies are currently available to store various forms of energy. These energy forms include chemical energy (solid, liquid, gas), potential energy (pumped hydro storage), sensible heat, kinetic and electrochemical energy. Such methods may have a variety of output and input forms.

In terms of system assessment and modelling, these stores of energy are classified according to the kind of energy they store (e.g. electricity) which can later be released to the wider system, including: thermal stores (e.g. sensible heat, phase change materials), electricity stores (chemical, pumped storage, kinetic) and chemical stores (hydrogen, ammonia, methane), which can be applied at different scales and in a variety of locations. A review of storage technologies can be found in different papers (including Hongois et al., 2011; Kucharski et al., 2011; Li et al., 2012; Moth-Poulsen et al., 2012; N'Tsoukpoe et al., 2009).

From a viewpoint of systems modelling, stores may not only be characterised by the forms of energy they produce and that they intake, but also by: the store's capacity (kWh), the efficiencies of output and input that provide the storage with throughput efficiency, the output and input maximum power (kW) and the standing losses. In addition, other factors may be considered, including: the store's mass energy (kWh/kg) and volumetric (kWh/m3) densities may be crucial in deciding the potential application of the storage, especially within the transport sector. Moreover, other important features to consider are running and capital costs, as well as environmental impacts of the store relating to its physical size (e.g. hydro stations), or to the energy loss they produce (Barrett and Spataru, 2013). Importantly, ancillary markets for storage and other fast-responding technologies must be technology independent and should enable storage to actively compete for the array of services it can provide to the energy system.

In fact, storage is widely regarded, due to its potential roles, as a key and enabling tool in system decarbonisation (EU Commission, 2012; Think, 2012; EAC, 2008; Kaplan, 2009; EPRI, 2010; Eyer and Corey, 2010).

Energy storage can be a main driver of the decarbonisation process and help the UK energy system achieve its ambitious decarbonisation goals. This is because it enables highly intermittent renewable electricity to integrate in the electricity system due to its quick energy conversion capacity, thus considerably increasing flexibility, and decreasing the role of conventional generation as well as their primary use as flexible power plants. The value of electrical energy storage is related to: the abilities to provide upward and downward adjustments to the system, its feature of being able to contribute to the consumption and production balance across a variety of time intervals, absorbing excessive or low-cost electricity production, replacing a low-productivity period or substituting high-cost electrical energy generation in consumption. The importance of the storage facility to the system, and thus its value relates to its technical features, especially its response time or power rating (Think, 2012).

The reason why storage technologies are not currently widely adopted are not only due to their high costs, expected to decrease as innovation persists, but is also largely dependent on present market designs, which do not reward energy storage companies for the value they could provide to the wider system. The value of energy storage lies in the option benefit that these technologies can produce and the service they are able to provide at different locations in an electricity system (Strbac et al., 2012). As with many emerging technologies, there is a need for incentives to encourage energy storage innovation in the short-term and investments that reflect long-term value. In addition, although feed-in-tariffs are supposed to incentivise consumers to adopt in-house storage technologies, the high costs of these technologies, coupled with current regulatory frameworks, could result in unfavourable conditions for such technologies to emerge.

The main challenges affecting storage are: technological, market and regulatory, economic, and strategic (DG ENER, 2013). Technological issues relate to the aim of increasing the capacity and efficiency of present technologies, the development of novel technologies for domestic, local, decentralised and centralised application, as well as market deployment issues. From a market and regulatory perspective, the main challenges are those of creating suitable market signals that encourage firms to build storage capacity and provide service to the electricity system, as well as the inherent differences between countries' electricity systems and thus their regulatory approaches, which is leading to a substantial inability in building a pan-European balancing and ancillary market. Importantly, there is a question of who needs the storage, who should own it, who should operate it, as well as what are the best locations for storage in the system. Economic barriers relate to the high capital costs of storage that are preventing deployment. Finally, strategic barriers are related to the development of a holistic approach to storage which incorporates technical, economic, regulatory and political considerations.

This report focusses on energy storage in the electricity system, and analyses the market and regulatory barriers preventing the mass deployment of these technologies in the UK. This entails an analysis of EU regulations, which lie at the basis of the UK electricity market. We provide an overview of storage technology regulation from the perspectives of generators, distribution and transmission owners, and discuss the issues of ownership and operation of storage technologies. The report begins by briefly presenting the main types of energy storage technologies, their potential uses for the different electricity market agents, and the methods used to assess the impact of storage technologies within the electricity system. Having provided this information, we proceed by discussing in detail the regulatory aspects of energy storage in the UK market and investigate the current barriers currently inhibiting the mass deployment of storage technologies, the UK and EU rules that are likely to decelerate the growth of the storage industry in the UK, and the initiatives that are being undertaken.

1.1 UK general energy policy

As one of the leaders in the EU-wide transition to a renewable pan-energy system, the United Kingdom is currently aiming at decarbonising its energy system in order to abide with the objectives set out in its Carbon Plan and the EU 2050 Roadmap, to meet the energy demand presently deriving from fossil fuels. With the likely prospect of an electrification of the heat and transport sectors, this process is likely to provide a dramatic change in the magnitudes of demand variations which, coupled with an increasing intermittency of supply, particularly from wind generation technologies, increases the uncertainty of security of supply in time frames of seconds to months. The use of energy storage technologies in the provision of electricity balancing is rivalled by their closest substitutes, or other methods used to provide system flexibility, including coal and gas power, increasing interconnection and demand response and management.

The delivery of the legislated 80% reduction in carbon emissions (compared to 1990 levels) by 2050 is expected to be accompanied by an increasing penetration of renewable electricity in the UK which, similarly to the EU as a whole, is supported almost exclusively by hydroelectric generation, whereas other forms of storage are absent on a significant scale. In the meantime, wind farmers are compensated for their ability to produce electricity when the UK grid is unable to absorb such electricity. A similar situation is the case of solar installations, currently subsidised irrespectively of their location and their ability to produce electricity. These examples illustrate the need for a reliable energy storage policy in the UK that avoids wasting existing flows of energy.

The key objective of securing reliable electricity supply stands on the flexibility of the system, implying that a plethora of different storage technologies are needed since some of these are able to be switched on in a matter of seconds (e.g. batteries), whereas others require more time, in the range between minutes and hours (e.g. hydroelectric). Clearly, the location on the grid, or off the grid, as well as their costs, are important factors to be considered when assessing the feasibility of any storage system, and the location of the device alters the system demand as well as the ways through which these technologies are organised and controlled. The opportunity to deploy storage will exist within a range of applications (e.g. electricity-to-electricity, electricity-to-heat etc.), scales (e.g. micro, meso, macro) and durations (i.e. seconds to months).

The main aims of the UK are those of understanding which types of storage are needed, how much of each technology is needed and at which locations in the system. In addition, the development of a coherent policy approach to energy storage must be finalised, along with methods that are able to stimulate governance and business models in order to enable rapid implementation (The Centre for Low Carbon Futures, 2012).

The following section discusses the current state of energy storage use in the United Kingdom, the pathways to 2050, the challenges to storage deployment, the potential roles of energy storage, energy storage R&D, demonstration, and deployment issues

2 Energy storage in the UK

In the first quarter of 2015, the UK electricity generation fuel mix was composed as follows:

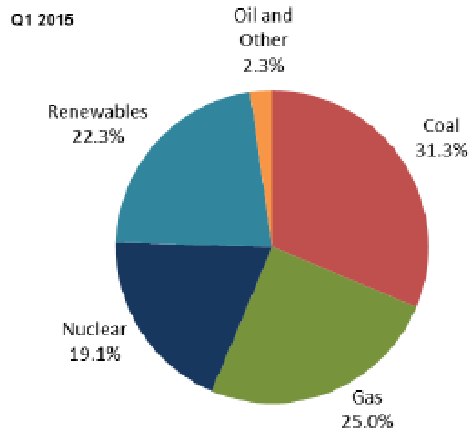

Figure 1 – UK electricity generation fuel mix (Source: Energy Trends – Electricity, Gov.uk)

Renewables provided 22% of total electricity generation, with a steadily increasing renewable share in total generation. Coal, gas and nuclear were responsible for 75% of electricity generation.

2.1 Current energy storage in the UK

Today, the majority of storage capacity is represented by stocks of fossil fuels, mainly coal and gas. It was recently estimated that the amount of electricity that could be generated from these conventional sources currently stands at 30,000 GWh and 7,000 GWh, respectively (Wilson, 2010).

As is the case in the EU and worldwide, *energy storage* in the UK is mostly supplied by hydroelectric power plants. They account for nearly the entirety of storage capacity, not accounting for fossil fuels, and are connected to the transmission system. The UK hosts four main such plants which are, however, more than thirty years old and provide a volume of 27.6 GWh, with an installed capacity of 2.7 GW. In addition, there are a small number of small-sized facilities for energy storage, mainly demonstration projects for battery technologies, which are connected to the distribution system in many parts of the country (BRE, 2007).

On the other hand, heat currently represents the main use of energy in the economy. In the UK, more energy for heating is used compared to transport and electricity generation, with annual spending required of £33bn in 2012 alone (DECC, 2012a).

Heat storage is largely involved in the UK energy system at a household or building scale, with almost 14m households operating hot water cylinders, providing around 80 GWh (Taylor et al., 2013). About 80% of heat in the UK is used in homes and buildings, and gas supplies this heat in 80% of cases, with the remaining 20% being mainly composed by heat from industrial processes. There is currently a rapid decline in the use of hot water storage and this may be attributable to the decline in gas boilers sales of 80%, in favour of new and more efficient combination varieties which do not require a hot water tank (RAE, 2012). Moreover, an increasing number of UK district heating schemes have water storage devices associated to them. Some district heating storage devices can be very large, and may store over 2,500m^3 of heat in a 3.4 MWth CHP plant, for example (UKERC, 2014).

Nowadays, heat networks still only characterise a very small part of heat demand in the UK (Pöyry, 2009; UKERC, 2014), thus only representing a tiny fraction of the European market. Nevertheless, as the UK government acknowledges this fact and aims at expanding its networks (DECC, 2012), it is expected that by 2050 heat networks may provide up to between 40-50% of UK heat demand. For this reason, recent scenarios supported by the government define heat network expansion as a likely future possibility. In scenarios of high renewable penetration (LCICG, 2012), district heating could be 200 TWh/year, representing 95 GW of installed capacity (Dodds and Hawkes, 2014).

Currently, most of the UK's heat is produced through fossil fuels, with the share of gas in this process representing an enormous 80% of total heat production. In fact, heat production accounts for one third of the UK's total greenhouse gas emissions (DECC, 2012). The 2011 Carbon Plan noted that if the UK were to abide to its international commitments toward reducing greenhouse emissions, buildings will need to emit virtually zero emissions by 2050, which emphasises the large efforts and, especially, the need for a completely transformed heating system (DECC, 2012). This changing environment in the heating industry, both in terms of production and use, is likely to diminish the exposure of the UK to fossil fuel price volatility, providing new opportunities and challenges. These include the possibility of the UK in supplying an increasing portion of the EU market for heat pumps which, in 2011, sold close to one million units (European Heat Pump Association Outlook, 2011). A diffused form of heat storage is represented by electrical storage heaters which use high-density bricks to store heat that is transformed from off-peak electrical current and released during the day. Around 1.6m properties currently use such heaters as their primary system for heating (BRE, 2007).

The UK government is keen in supporting clean heat. As is the case with feed-in-tariffs supporting renewable electricity generation, the UK's Renewable Heat Incentive, currently awards payments for the generation of low-carbon heat (DECC and Environment Agency, 2012).

2.2 Future energy storage in the UK

Electricity and heat storage may play a key role in the decarbonisation of the UK economy. This may be an enabling role, which could facilitate the continuous matching of supply and demand from intervals of seconds to minutes, hours and days. In fact, electricity and heat storage technologies are able to provide an intertemporal shift of demand and supply to meet the varying and increasing levels of both demand and supply. The key in this process may be energy storage technologies, which are able to provide enhancing services to other generation, transmission, distribution and end-use assets by improving their technical and economic efficiency and thus, the efficiency of the entire energy system. Nevertheless, this is subject to the efficiency of storage technologies themselves. However, as innovation persists and storage costs fall, system efficiency might improve.

It is likely that the future will present many challenges to the deployment of storage technologies in matching supply and demand, thus providing new opportunities to reinforce the role of such technologies in our electricity systems. These opportunities potentially vary depending on each component within the considerable range of applications that storage may provide to support a wide array of electric power system operations. Such opportunities also vary according to the different scales considered – namely from centralised storage (macro) to meso-scale and micro, decentralised storage – and durations, from seconds to months. However, the main challenges of storage technologies are represented by their duration, as well as their time scale, which matters the most when providing electricity, and heat, to any energy market agent (CLCF, 2012).

The opportunity to deploy storage in the UK will, depending on future innovation, also exist within a range of applications (e.g. electricity-to-electricity, electricity-to-heat etc.), scales (e.g. micro, meso, macro) and durations (i.e. seconds to months). The main challenges dictated by a rapid increase in renewable electricity generation can be met by an increase in storage capacity, as well as other means, such as the use of coal or gas, an increase in interconnection, or demand response. These challenges may be subdivided into different categories, depending on the response time of these technologies in relation to an increasing electricity demand.

2.2.1 Seconds

In the case there were a need for electricity to be injected into the grid in a matter of seconds, energy storage would be able to provide a reliable back-up service. Because most renewable supply is intermittent in nature, reducing the quality of supply to the system, an ultra-fast response rate of low-volume electrical energy is needed in case of failure from other generation units. Energy storage technologies, such as batteries, are able to compensate these low but quick bursts of power and may be associated to a variety of electricity market agents, namely distribution, transmission and generation (CLCF, 2012).

2.2.2 Minutes

Similarly, if electricity were required in a matter of *minutes*, energy storage technologies would be in the condition of enabling a fast response and can again be associated to the distribution, transmission and generation sectors. In such case, the main challenge is represented by the fast ramping up and down of power from renewable generators, mainly wind farms, which ultimately affects the power frequency profile, at least in one area of the grid.

2.2.3 Hours

When the system is analysed through a timescale of different *hours*, in the future case in which the heating and transport sectors are indeed electrified, daily peaks in electricity demand will be considerably larger. To this extent, high-power bulk energy storage may be used to supply mid-day peak electricity. In addition, distributed battery storage may be employed to evening peaks caused by people recharging their electric vehicles. Moreover, heat demand may be satisfied by household-, integrated building-, or community-level heat storage, or possibly by additional electrical storage technologies.

2.2.4 Hours to days

When considering a timescale of *hours to days*, it is possible that renewable electricity producers, mainly wind generators, are unable to provide a secure supply, with related generation needing back-up to smooth out overall supply or demand response frameworks. In this case, both large-scale and decentralised storage technologies are able to provide the needed back-up to the missing generation from wind farms. An additional challenge to be considered is the increased demand for electricity for heating purposes, which can potentially affect the system by increasing the variability of its daily and weekly demand electricity profiles. In this case, a potential for community- or building-level heat storage exists, or the use of combined heat and power (CHP) plants with storage are able to supply both heat and power.

2.2.5 Months

Finally, when the response time relates to months, assuming the electrification of the heating industry, it is very possible that the increased demand for electricity for heating needs, provides an ever more pronounced seasonal demand for electricity. Here, it is possible to employ large-scale interseasonal heat storage which may be useful to alleviate these seasonal peaks, if combined to CHP plant, or district heating schemes, to simultaneously provide heat and power. It is noteworthy to consider, once again, that energy storage technologies are not the only technologies capable of dealing with these challenges, which may also be solved by additional fossil generation, existing and new interconnection and demand management.

Importantly, all stores of energy imply energy losses, as well as high running and capital costs. Stores can only be profitable if they imply reductions in costs in other locations in the system that decrease the entire system's operational and capital costs, or if they can help in achieving renewable energy or decarbonisation targets.

To this extent, it is crucial to analyse how storage may reduce total system costs and shall be allowed to gain revenue accordingly. How can storage reduce system costs? It can in a variety of ways, including by: (i) storing excess renewable (or other short-run marginal cost) supply for those times in which such supply is not available; (ii) reducing peak flows and thus decreasing investments in system components such as transmission and generation capacities; (iii) decreasing our use of higher cost marginal supplies, most notably the unit cost of supply (£/MWh) which increases with supply power (MW); (iv) finally, by decreasing the demand variability which may be particularly costly for some kinds of supply, in particular electrical energy generation (Barrett and Spataru, 2013).

3 Factors affecting deployment in the UK

The degree of deployment of electricity and heat storage technologies largely depends on a plethora of technical, social, economic and regulatory factors. The main issues known to potentially affect storage in the UK are discussed in this section.

A major factor is represented by the way in which the UK energy system evolves. This may result in the system accommodating storage above other competing products that may provide the same services, as it may present the opposite situation. Ultimately, this will depend on the relative cost of competing storage technologies in specific grid and off-grid applications. For example, demand response programs, which are already widely adopted in certain areas of the UK, currently provide considerably lower costs compared to energy storage technologies which instead require comparatively high installation costs and a limited cycle life, rendering the adoption of demand response management much easier to apply compared to the use of energy storage. However, if cycle life and battery costs decrease in the coming years, they might provide more competition to such programs and result in these technologies being widely adopted.

In fact, research and development (R&D) both in the UK – which aims at becoming a global leader in energy storage technologies (Houses of Parliament, 2015) – and outside the UK, may provide encouraging downward cost and thus price trends, along with the necessary improvements in performance that may help displace other technologies. However, it may also be possible that these advancements do not develop at a rapid pace and that competing substitutes may prevail, at least for some applications. This may also entail the development of novel methods that may provide the same services as storage technologies and thus new alternatives.

Moreover, an additional important factor lies in the way in which the organisation of electricity market agents develops, which may boost the chances of mass deployment or decrease these chances. This really depends on the different market agents, such as generators, transmission and distribution operators, and consumers of electricity which, may or may not employ storage technologies in relation to other technologies which provide the same services. On a wider scale, such developments will translate in the creation, or destruction, of new business models promoting storage and, ultimately, will depend on the relative cost of the services.

Public attitudes represent a very important factor that may determine whether storage is widely accepted in the UK economy. The engagement of people with energy technologies, both from the demand and supply sides, has previously been identified as an important issue for the future deployment of low-carbon energy systems (Parkhill et al., 2013), but there is a substantial gap in knowledge with regards to energy storage (Whitmarsh et al., 2011). People may find different in-house technologies, or perhaps large-scale ones, more or less desirable to integrate in their lifestyles, or acceptable.

3.1 Pathways to 2050

The way in which electricity and heat markets evolve will have a very profound impact on the degree of deployment of energy storage over the next years. The decarbonisation of the electricity system, its pathways, scale and speed are to be the determinants of the degree by which storage technologies will end up being adopted by the different actors in the UK electricity system for the possible applications they can serve.

This section explores the pathways which have recently been revealed by the government in official publications (e.g. DECC, 2011; see also AEA, 2014). Following the 2008 Climate Change Act, the UK government has set out as its main objectives those of cutting emissions by a minimum of 35% by 2020 and 80% by 2050, below 1990 levels, according to the 3rd carbon budget (CCC, 2016).

3.2 Impact of decarbonisation on the electricity system

The UK policy aim of decarbonising the electricity system has clear implications for the deployment of energy storage[6]. This necessarily entails an unprecedented increase in renewable electricity generation, mainly wind power. Thermal power plants are shutting down, due to the UK's implementation of the Industrial Emissions Directive (IED) and the EU Large Combustion Plant Directive. Although generation is rewarded per MWh of low-carbon electricity, this type of generation is less dependent on such scheme than trading with market agents.

The integration of storage technologies into the electricity system, as with other countries, relies on market and regulatory arrangements and innovations which are able to incentivise new capacity toward market entry. The European Commission's Directorate General (DG) set out the importance of energy storage throughout its Working Paper of January 2013, focusing on the role of storage technologies in providing lower prices, security of supply and crucial balancing services to the electricity system (see also EC Roadmap 2050, 2011).

In addition to the latter, a more short-term indication by the Commission also implies the urgent need for storage capacity (EC Roadmap 2020, 2010). The Commission highlights the main energy

[6] This section focuses on *energy storage* and is based on Pöyry (2013).

storage projects, through Regulation 347/2013, with its guidelines for trans-European electricity infrastructure, mandating the subsidised deployment of storage infrastructure, by 2020, of at least 225 MW of installed, grid-connected capacity, which permits net generation of at least 250 GWh per annum. It is noteworthy that lower-scale storage capacity is *not* subsidised, although this important detail may be revised in the near future.

3.3 Scenarios description

Because the term ‘energy storage’ is a very broad one, it is impossible to generalise its meaning, thus the relative regulations. Energy storage incorporates a very wide range of different technologies which possess very different operational competencies, and are often able of providing multiple services simultaneously. Due to this crucial characteristic, it is useful to first consider the main potential scenarios of the UK’s possible pathways to 2050 to then provide a clearer description of the potential future uses of storage in the economy, as this strictly depends on the future generation mix[7].

The UK’s Carbon Plan (DECC, 2011) highlights these scenarios using the UK-MARKAL model, initially developed by the IEA. All scenarios display a large fall in the use of fossil fuels and a large rise in the use of renewables, with a steady increase in the use of electricity. The intermittent nature of renewable electricity (i.e. onshore/offshore wind, tidal/wave and photovoltaic power) implies the substitution of fossil fuel storage capacity with both electricity and thermal storage capacity. Nevertheless, the amount of storage and the applications for storage remain highly depend on the scenarios considered and are therefore uncertain. Whereas the increase in renewable generation and the possible electrification of heat are very likely to increase storage capacity, other policy aims, namely the need for flexible demand, for example via more demand response, will provide stiff competition to storage technologies and is expected to exclude storage from certain applications, such as balancing.

Overall, these scenarios show that the stake of fossil fuels within the primary fuel mix will decline from 90% at present to between 13-43%, depending on the scenario, in 2050. On the other hand, the share of renewable generation is shown to rise from 4% in 2011 to between 36-46% by 2050. Given the strict policy objectives, a strong trend arises already by 2030, where the UK generation mix is expected to be very different, with renewables composing 25% and fossil fuels 65% of the energy mix. Moreover, an important movement considered in the Carbon Plan (2011) is the electrification of transport and, more certainly, heat. The latter implies an even more seasonal demand for electricity. Overall, this would provide a much increased use of electricity, expected to rise from 18% of total final demand in 2011 to between 25-31% by 2030 and between 33-44% by 2050. As a result of these similar requirements to all simulations, efficiency is shown to considerably increase.

Currently, the large majority of the UK’s energy storage capacity is delivered by fossil fuels (e.g. piles of coal), as is the majority of electricity generated deriving from fossil fuels. With the share of these fuels lowering over the next decades, involving the transition to an increased share of renewables as the UK’s primary energy carrier and electricity as the second energy carrier, a considerably larger weight is likely to be given to electricity and heat storage.

[7] Section 2.3 is based on the arguments presented in Centre for Low-Carbon Futures (2012).

It is difficult to predict the very role that storage will undertake within the UK electricity system given the many uncertainties. Indeed, the main scenarios, summarised below, depend on the development of the entire energy system.

The main scenarios are represented by the increase in variable generation of electricity through renewable sources. These scenarios predict that the rate of renewable generation will increase from today's 5% to 15-26% in 2020, with the share of renewables in the UK generation mix peaking at 19-64% in 2040 and corresponding in the latter case to an installed capacity of 28-91 GW. In 2030, the report shows an increase in nuclear and thermal power with the stabilisation of, or possibly a slight fall in the share of renewables, occurring in all circumstances except those relative to the high renewables variant, because of the consequently greater importance of nuclear and CCS thermal plants in the mix. By 2050, the share of variable renewables slightly falls to 11-61%, which corresponds to an installed capacity of 20-106 GW. The latter implies an increasing need for more reserve and response capacity between 2020-2030, in addition to those already advocated by National Grid, or 3 GW (National Grid, 2011), some of which may be represented by storage. However, the report underrepresents the potential role of storage in covering this need.

Moreover, the Carbon Plan (2011) analyses additional scenarios as possible pathways to 2050, including differing generation mixes, degrees of electrification of heat and transport, and levels of demand growth. These scenarios include future higher renewables and more energy efficiency, future higher CCS and more bioenergy, and future higher nuclear, and less energy efficiency, among other scenarios.

A second most likely future occurrence modelled in the government's scenarios is defined by the electrification of heat. There is currently a minimal decrease in household heating lasting until end-2015 due to the retirement of electric heating systems. This is followed by a rapid increase, in all of the scenarios due to the introduction, as a consequence of more ground and air source heat pump systems. Furthermore, the proportion of households operating electrical heating is expected to be between 13-20% by 2020, with this share rising to 18-33% by 2030, reaching potentially all households in the UK by 2050, and varying between 48-100%. As pointed out by CLCF (2012), this has wide implications in terms of how peak demand should be supported, given that using a lower value than the lower bound of the latter range, or 40%, of UK homes will be swapping their gas boilers with 5kWe air heat pumps, this inducing the creation of an additional 50 GW of demand (Speirs, 2010). This possibly entails heat demand peaks coinciding with electricity demand peaks. However, it is possible to use a combination of heat pumps and thermal storage to reduce the burden on the electricity grid.

Another very important family of scenarios is represented by the future deployment of hybrid (HEV) and pure electric (EV) vehicles which are likely to drive a considerable portion of future demand for electricity. Already in use, up to 2040, it is likely that HEV will be the main battery vehicle. By 2025, HEVs are found to potentially account for 13-23% of all car-based transport, increasing to 32-38% by 2040 after which the share of HEVs stabilises or declines in all cases aside from the CCS scenario. On the other hand, the share of pure EVs is assumed to begin rising from 2020, again in all cases aside from the CCS scenario, finally providing 38-80% of total demand for car transport by 2050. The combination of HEVs and EVs will account for a share between 15-32% by 2025 and 63-80% by 2050. Once again, the implication in terms of total electricity demand could be enormous. As Strbac (2010) notes, if only all light-medium sized cars were to be replaced by similar electric vehicles, daily requirements of energy would reach 150 GWh. It is difficult to derive a precise estimation of the effect of the electrification of vehicles on the electricity market as they would impinge on consumer bills, although charged during low-priced night hours, but are also capable of providing balancing services to the grid via smart vehicle-to-grid, or V2G, connection.

Other scenarios are of course possible, for example regarding the rate of innovation, and therefore decreases in costs of storage technologies, and in terms of the degree of flexibility of fossil fuel generation. Whereas at present the most utilised power plants to provide flexibility backup services to the grid are open (OCGT) and combined (CCGT) cycle gas turbines and steam-cycle coal plants, all scenarios indicate that fossil fuels could comprise between 2-54% of total generation by 2050, with remaining generation composed by CCS.

It is important to note that if these shares do not drop definitively, fossil fuels are likely to out-compete and obscure the role of energy storage in providing reserve-response services to the market. The degree by which this may occur is contingent on a number of factors, including: the degree of flexibility of large fossil fuel plants when combined to CCS, as well as the economic and carbon emission costs associated with smaller polluting plants without CCS when operating at very low load factors, which in turn mainly depends on initial and fuel costs.

Furthermore, the deployment of CHP plants and district heating induce additional speculation regarding the potential future role of storage. Whereas it is widely thought that electrical heat pumps will become the main future source of heat, scenarios involving CCS imply a considerable increase in community-level CHP, with 19% of all UK households who could own electric heating by 2030 and 39% by 2050. Additional studies also conclude (e.g. Dodds and Demoullin 2013; Rhodes, 2012) that electric heating via heat pumps will be the primary heating method for end consumers and will replace natural gas (Hawkes et al., 2011; Rhodes, 2011; Dolman et al., 2012). As CLCF (2012) note, an increased use of CHP plant and district heating may lower the demand for electric heating and electricity demand more generally, potentially decreasing the demand for storage. However, this increased penetration in the system may also be combined with large-scale hot water tanks and additional storage at the same time.

In addition, the increasing demand for space cooling in the commercial and service sectors, coupled with the rapidly increasing demand for air conditioning systems at the household level, may induce additional challenges to the electricity system. The increasing demand for cooling could indirectly create more demand for storage capacity designed to operate both cooling and heating (e.g. phase change materials in building fabric).

At present, the UK is not well interconnected with other countries. In fact, it only has an interconnector linked to France (supplying cheap, nuclear-derived electricity – which could out-compete storage as a means of back-up) via a 2 GW direct current transmission line, in addition to a 1 GW interconnector with The Netherlands and a 0.5 GW line connecting Scotland and Ireland. As DECC (2011) notes, there are plans to provide further interconnection with Norway (in an attempt to use their cheap hydroelectricity, again, a direct competitor to UK storage), as well as Belgium, Ireland and an additional link with France. The Carbon Plan generally provides the result that interconnection could increase from the current 3.5 GW to 8 GW in 2025 and to 10 GW in 2050, increasing to 15 GW and 30 GW in the high renewables scenarios.

IEA (2014) and The Energy Storage Network (2015) argue that storage used solely as an electricity generation backup may destroy two-thirds of its value, thus it may be unlikely for storage to be primarily used in such way.

The extent of demand flexibility, achieved by shifting load in time, may be a key tool in the continuous matching of demand and supply and would be greatly eased by the mass disposition of smart metering (although this would involve strong public acceptability and political issues). The Carbon Plan (2011) focuses on the use of HEVs and EVs, which could solve short term and longer term flexibility issues, the latter being dependant on battery capacity innovation. In the Plan, the portion of all electric vehicles with these properties are set to range between 25-75% for EVs and 30-90% for HEVs. Moreover, the Plan also assumes a moderate degree of space and water heating flexibility. Strbac (2010) shows that the optimisation and coordination of demand response programs may result in a substantially increased efficiency of the electricity system thereby potentially decreasing the need for new transmission capacity, even for very little use of EVs and electric heating.

Overall, the Carbon Plan (2011) shows that the majority of considered scenarios indicate a substantial fall in fossil fuel use and an increasing reliance on renewable energy, as well as a largely increased use of electricity. As fossil fuel storage falls over the next years and heat pumps are ever more used for heating, both electricity and heat storage are likely to play an increasing role. Nevertheless, the degree by which storage increases remains unknown given the numerous applications that storage technologies can cover, as well as due to perspectives of competing services and relative costs. Moreover, the acknowledged role of electric heating in the future, alongside the electrification of transport, could entail a higher value for storage, including in the balancing market. Whereas the cost of competing services (e.g. natural gas for load following) are likely to out-compete storage technologies in certain applications, it is the relative price, due to innovation decreasing costs for both competing services, in certain specific applications, which will drive the effective value of storage. Therefore, the price of storage and methods to reward these technologies could be based on these relationships. Most importantly, the multiple roles of storage against their multiple competing substitutes could define the value of storage.

4 Regulatory frameworks impeding deployment in the UK

As DG ENER (2013) notes, regulatory frameworks could be adjusted to better integrate storage in the supply chain by creating an 'equal level playing field for cross-border trading of energy storage' and should be technology-agnostic, ensuring competition among the different types of storage and other technologies. Among other things, it should also ensure 'fair and equal access to energy storage' regardless of the size and location of the technology within the supply chain[8]. This section focuses on the regulatory barriers in the UK electricity system which are preventing the deployment of storage resources.

From an economic point of view, most technologies are presently either not cost-competitive or not yet available. As shown in Fig. 2, most of these technologies are currently under development, in early commercialisation or in the demonstration phase. In all circumstances, aside from most hydropower technologies and, more recently, CAES systems, this implies high costs and the likeliness for substitutes to out-compete these technologies in most applications. For example, the installation of storage capacity is considerably higher than the cost of an OCGT, i.e. €500–600/kW. Nevertheless, as R&D and deployment advance, costs are likely (although it is not guaranteed that any of these technologies has a cost-down profile (The Energy Storage Network, 2015). When this will happen is an open question and is likely to depend on a number of standard market factors, among which are regulatory barriers.

The current framework for the regulation of electricity markets in the UK is a combination of EU and UK legislation. Whereas EU rules on the operation of electricity markets represent the principal set of regulations, the UK is required to make more specific rules for market operations at the national level.

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[8] This section is based on the work in Pöyry (2013).

4.1 EU regulation

EU legislation presents different hierarchical layers within its regulatory framework, consisting of Treaties (binding agreements between member states setting out common objectives), Directives (legislative acts setting out binding goals for all member states, whereby national policies decide the methods to achieve these), followed by Regulations (binding acts) and Decisions (more specific binding regulation). The latter two are on par with the national laws of member countries. Finally, there are non-binding legislative instruments include Recommendations (lines of actions with no legal obligations) and Opinions (simple statements).

The key building block of the EU framework is the so-called “Electricity Directive” 2009/72/EC, also known as the Third Energy Package, or the most recent set of Directives that are the most relevant to the role of storage. This package promotes the liberalisation and competition of the EU internal energy market. A major principle of the package is the subdivided between entities active across both network and market services, the extent of which varies across the different network activities. A difference was made, for instance, between transmission operation and ownership, or between distribution and transmission activities. This feature of the package is particularly relevant for storage assets, which are required to have different entities operating and owning these technologies.

Current policy is driven by the long-term EU policy goals of an 80-95% reduction in greenhouse gas emission compared to 1990 levels by 2050 and by the EU’s 2020 climate change package whereby the main objectives for 2020 are those of: reducing greenhouse gas emissions by 20% (compared to 1990 levels), increasing energy from renewables to 20% and improving overall energy efficiency by 20%, these being collectively known as the 20-20-20 goals.

In addition, the Commission set out additional objectives to be achieved by 2030 to be those of reducing emissions by 40% (from 1990 levels) and raising the share of renewable energy consumption to 27%.

4.2 UK regulation

On the other hand, the UK’s legislation is composed of Acts of Parliament (primary legislation). Statutory instruments (secondary) are used to modify Acts of Parliament without going through Parliament. These instruments include: Council Orders, regulations, rules and orders. Beneath these are licenses, which grant permission to the owners of activities to perform such activities (unless exemptions are granted), and include: supply, distribution, transmission and generation. In addition, a new type of license has recently been established for interconnectors. On the other hand, energy storage is not considered as a licensable activity. Following the framework layer comprising licenses rests an additional one comprising individual industry codes and agreements, which list the relevant arrangements relative to each sector.

Principal UK legislation can be summarised as:

- *Acts of Parliament*

The main Act of Parliament concerning storage, and thus electricity markets, in the UK is the (amended) 1989 Electricity Act, which is responsible for setting out the electricity industry and defines its activities and rules. This remains the main component of UK legislation and additionally ensures that unbundling requirements in the Third Energy Package are respected. Moreover, the 2008 Climate Change Act enforced long-term greenhouse gas emission targets to be achieved by 2050.

- *Statutory Instruments*

The main statutory instrument in the UK concerning storage is represented by the 2001 Electricity Order which sets out “Class Exemptions from the Requirement for a Licence”. In addition, the 2015 Electricity Order, which came into act on 28th February 2015, does not mention storage, although it sets out additional requirements and grants exemption from the requirements of section 4(1)(a) of the Electricity Act 1989 (the latter prohibiting the generation of electricity for supply to any premise without a licence) to only one additional power plant.

- *Licenses*

These are individual asset-class based licenses setting out the main regulation for the activities of supply, distribution, transmission and generation (and now, interconnectors), but not storage. Storage is bound to the generation class with no advantageous exemptions which, as we will see later, clearly imposes stringent rules on such technologies.

4.3 Implications of EU and UK legislation for storage

Focussing on the current classification of storage and regulations regarding the ownership and operation of storage we present the main barriers that prevent the mass deployment of storage technologies in the UK.

The liberalisation process which resulted from the 1989 Electricity Act separated natural monopoly activities (T&D) from potentially competitive activities (generation and supply) to improve market efficiency and lower prices. The former was subsequently heavily regulated whereas the latter were left to be driven by market forces. The Act prohibits these activities without a license and was subsequently amended by the 2000 Utilities Act, the 2004, 2008, 2010 and 2011 Energy Acts. However, these do not impose particular constraints with respect to storage. This separation was then also adopted by the EC’s Directive 96/92/EC and Directive 2009/72/EC.

By the 1989 Electricity Act, the class ‘generation’ is said to refer ‘the generation of electricity at a relevant place’. In a similarly generic sense, EU legislation (Directive 2009/72/EC) refers to generation as ‘assets that produce electricity’.

Energy storage is not defined as an individual asset class or activity in either the EU or UK frameworks. On the other hand, ‘gas storage’ in the GB gas market is treated as an independent activity.

Although gas storage is currently recognised as an independent activity in the gas market, important barriers need be addressed when increasing gas storage capacities in EU member states. Present gas storage capacity is currently insufficient in most EU member states, although many of these have gas storage capacity obligations. Current cross-border use of gas storage capacities between member states is not active enough, especially in emergency supply situations. Regulatory barriers that hinder new gas storage capacity, especially in regions vulnerable to lack of supply, are particularly undesired. In fact, a major lesson to be learnt from the experience of gas storage in the EU is that regulations addressing the security of gas supply are recommended to be made more specific on required strategic stock levels, relative also to interconnection capacity and to local production (DG ENER, 2015). Similarly, energy storage capacity strategic stock levels must be closely monitored in the future if these will be realised, especially relative to potential competitors such as interconnection capacity and local generation, in order to minimise lack of balancing supply and to maximise the efficient use of resources. In addition, barriers that prevent the free flow of balancing and ancillary services between member states must be minimised.

The absence of a precise definition of storage in the electricity market means that storage is effectively treated as *generation* in the UK. Although large-scale pumped hydro storage facilities (e.g., Dinorwig and Ffestiniog) have generation licenses, instead smaller-scale facilities are eligible for exemption from the requirements in the generation license via the Electricity Order 2001. The Order enables a generator to be exempt if output is <10MW, or if it is <50MW with relative declared net power station capacity being <100MW[9]. This implies that, while the larger pumped storage facilities can compete with other generation technologies for electricity balancing, smaller-scale storage technologies are effectively unable to compete with conventional generation and must be aggregated to, and thus rely on, higher-marginal cost plants to provide balancing services.

The definition in both the UK and EU, presented earlier, are too general to encompass the role and applications of storage. Moreover, the Electricity Order 2001 adds to the definition by stating that the technology 'generates or is capable of generating electricity'; however, this still does not apply to storage. In fact, it could be argued both in favour and against of such definition by stating that either the technology: (i) is not able to generate electricity or (ii) it acts as if it were capable of generating electricity.

The new classification would entail a large amount of bureaucratic work and additional regulations, including those surrounding interaction with other market players. This also suggests that smaller-scale storage, at least initially, could be built as an exception to current regulations, which is how the UK is currently addressing this issue. By providing exemption to small-scale storage from the restrictive generation license, while most international markets do not, the UK is attempting to provide non-discriminatory energy storage policy. A new regulatory classification for storage could reduce the high transmission costs by treating storage as an integral part of the electricity system that complements the transmission system. In contrast, a new classification would further complicate electricity system regulation and any confusion that might be unwittingly introduced through a change could act as a new barrier against deployment of other emerging technologies.

With regards to smaller-scale storage connected to the distribution system, it shall be noted that exemption is granted on a plant-to-plant basis and to plants with output <10MW, or <50MW with declared net capacity being <100MW. The latter effectively places distributed storage within the "Small Generator" class, thus granting them exemption from a generating license.

Is storage really similar to a generator? Whereas both share some characteristics, namely that they are capable of discharging electricity, on the other hand, they are also very different, namely the fact that demand consumption for storage is greater compared to output potential due to its

[9] Within the Electricity (Class Exemptions from the Requirement for a Licence) Order 2001' the 'declared net capacity' of a generating station "which is driven by any means other than water, wind or solar power is the highest generation of electricity (at the main alternator terminals) which can be maintained indefinitely without causing damage to the plant less so much of that capacity as is consumed by the plant". However, storage technologies are not necessarily linked to alternators.

lower round-trip efficiency. Storage cannot provide a positive net flow of electrical energy. As pointed out by Pöyry (2013), although generation shares other characteristics with the 'interconnector' class, the two asset types do not share the same license.

As a result of the EU's post-market liberalisation 'unbundling requirements', storage technologies are required to pay charges for transmission network use both as a generator and a consumer. Participation in the market is influenced by location because it affects the Transmission Network Use of System (TNUoS) charges and the Distribution Use of System (DUoS) charges, as may be seen in Table 3. These charges are designed to recoup infrastructure costs from consumers and suppliers according to their level of use throughout the day. DUoS is banded by time of day, which offers an arbitrage potential for storage. TNUoS also offers potential revenue for storage by reducing peak demand during the Triads. However, this may unnecessarily and possibly unfairly increase the cost of deploying the optimum amount of energy storage to support the electricity system if storage is not controlled by a central operator, who can instead optimise the use of such technologies in the system. Consequently, users' imperfect close-to-real-time information about varying demand levels implies their inability to minimise private costs through storage. This suggests that the system operator is better equipped to control storage because of its higher likelihood in maximising societal welfare as opposed to individual users.

Table 3 – Network charges applied to electricity generators and energy storage technologies in the UK at each location and how they are regulated.

Location	Charges	Regulation of charges
Generation	Transmission entry capacity (TEC) payable via TNUoS by generators and consumers to National Grid and distribution use through DUoS.	▪ Paid at the generation TNUoS tariffs set by National Grid, which are charged on a maximum-capacity basis. This means that generators with 200 MW of TEC who only generated at a maximum rate of 100 MW during the year would still be charged for the full 200 MW of the TEC. ▪ Small (<100 MW in England and Wales) generators do not pay TNUoS if they do not significantly affect the transmission network. ▪ DUoS charges are payable by generators and suppliers to Distribution Network Operators (DNOs) for using the distribution network.
Distribution	DUoS paid by generators (and suppliers) to DNO for use of the distribution network.	▪ If DNOs suspect that the embedded generator may have a significant impact on the transmission network, they should contact National Grid, and will be liable to pay TNUoS. ▪ Distribution-connected small generators are liable to pay DUoS, or a charge levied by a DNO for the transmission of electricity through its local network, but not TNUoS.
Consumer	TNUoS payable by generators to National Grid if the device capacity exceeds 100 MW or if they significantly affect the transmission network.	▪ Different for half-hourly metered (HH) and non-half-hourly metered customers. Customers with sufficiently high peak demand are obliged to have a HH meter. ▪ Charges for a HH metered customer are based on their demand during three half hour periods of greatest demand in evenings between November and February, known as the Triad, and equals average demand during the Triad periods multiplied by the tariff for their zone. ▪ Non-HH customers are charged for the sum of their total consumption between 16:00 and 19:00 every day over a year, multiplied by the zonal tariff.

The DUoS charges are payable by generators to Distribution Network Operators (DNOs) for the use of the distribution network and associated O&M costs. Similarly, TNUoS are paid by generators *and* consumers for transmission network access and O&M costs. Thus, in addition to DUoS charges, storage providers must pay double TNUoS for their role as generators and consumers, in charge and discharge modes. If the generator is <100 MW, as in most cases for energy storage, they are not liable to pay TNUoS but will still have to pay DUoS. TNUoS accounts for 2 percent of electricity bills, while DUoS accounts for 16 percent of electricity bills due to higher private costs (OFGEM, RIIO Factsheet, 2013).

Grid fees could take into account the impact of energy storage systems on the grid. In fact, energy storage facilities may choose when to absorb electricity from the grid and when to feed it back. Storage used for balancing does not contribute to congestion, rather relieving it. Therefore, grid fees could be calculated in such a way that the cost is allocated more fairly to the players that are causing imbalances, which is likely to reduce the operating cost of storage systems, thereby positively affecting their viability. EASE (2015) suggests redefining energy storage as a separate asset, being it neither generation nor consumption. Such definition could perhaps take into account the net flow of electricity from the device, with the aim of delivering a tariff that reflects the weighted sum of the generation and consumption tariffs, albeit a single rather than a double one. However, this approach could be seen by other market players as providing energy storage with unfair advantage over other technologies.

5 Ownership and Operation: How are they affected by classification?

The process of liberalisation of the electricity market resulted in the creation of a variety of restrictions regarding the ownership and operation of the different activities in the vertical segments of the industry. Namely, there are currently restrictions on the possibility for network asset operators to be active in the sectors of supply and generation. In fact, both UK and EU frameworks are characterised by unbundling requirements which effectively separate network and non-network activities. The Third Energy Package implemented by the European Commission (EC) explicitly lists these requirements with the aim of avoiding risks of discrimination in network operation and little incentives for investment in the relative networks.

Unbundling requirements are applied to T&D system operators and are especially rigid for TSOs. TSOs are required to follow one of three possible models: ownership unbundling (requiring full ownership separation), independent system operator (requiring an independent TSO), and independent transmission operator (ITO, which allows asset operation and ownership but is subject to rigid ring-fencing rules).

Both the ISO and ownership unbundling models block entities involved as TSOs from intervening through any activity related to the market, effectively disallowing them from owning generation and thus storage technologies. Instead, while the ITO model permits common ownership, it entails full operational independence and ring-fencing.

On the other hand, DNOs are not required to abide to any ownership unbundling regulations; rather, they have legal, accounting and functional unbundling requirements in order to guarantee the operational independence of distribution services from other activities in the vertically integrated system. It is possible for exemptions to apply, however only to those DNOs with <100,000 connected consumers.

In more detail, DNO unbundling requirements are legal (from other activities unrelated to distribution), functional (in order to ensure independence from other activities), and accounting (use of separate accounts for independent compensation).

The amended Electricity Act 1989, via Section 7(2A), emphasises that *transmission* license holders are restricted from performing activities which require another licence aside from the transmission licence, effectively disallowing TSOs from providing generation and/or supply services (Standard Condition B6).

Similarly, in terms of *distribution* license holders (Section 6(2)), the Electricity Act not only disallows distribution businesses from providing generation or supply activities, it also prevents these entities, via the 'Independence of the Distribution Business' explained in Standard Conditions 42-43, from accessing operational and managerial confidential information. These conditions reflect unbundling requirements in the Third Energy Package.

Therefore, it is important to comply with these conditions by modelling a third party to manage the involvement of storage assets (e.g. Pöyry, 2013) within the electricity market, which effectively represents the mandated separation between the DNO's operation of the technology and its normal business activity. Yet, a license exempt generation is potentially possible for DNOs provided avenue for small storage.

5.1 On the possibility for DNOs to own storage

The unbundling rules in the UK require DNOs and TNOs to be independent from generation and supply. Given that storage is classified as generation, such companies are forbidden from owning and/or operating storage technologies which require such license, thereby acting as a barrier for network operators who could otherwise use them for network support or management.

Nevertheless, as stated earlier, exemptions to the generation license may be approved for small storage. Out of four possible exemptions[10], one of these is relevant for "small" storage if output of the total system (i.e. output from the entire GB transmission and distribution systems is: (i) <10MW or (ii) <50MW with the declared net capacity relative to the power station being one of <100MW.

The exemption for "small generators" is handed out on a case-by-case basis. What this implies is that such exemption is obtainable for many projects which are characterised by the appropriate size range, irrespectively of the aggregate scale and impact on the market for all projects. Thus, if storage were to increase over the coming years, caution must be applied to avoid distortion of competition in generation and supply.

Moreover, it is possible for power stations which do not apply to any of the four exemptions to individually apply to DECC for individual exemption seeking. In fact, it should be noted that those power stations that are able to export 50-100MW toward the entire system, and connected after 30 September 2000, are in most cases granted exemption this way.

In Italy, TSOs are permitted to operate battery technologies if the opportunity cost (for example, new transmission infrastructure) is shown to be more costly, via cost-benefit analysis, than storage (Art. 36, paragraph. 4, decree 93/11). Belgium allows DNOs and TSOs to some control over storage if they do not impede the normal functioning of competitive markets. More specifically, the conditions by which storage is allowed include if: electricity is only generated for balancing and not commercial aims, stored electricity is used as last resort, under the form of negotiated drawing rights and to the limit of the amount of power needed for ancillary service and in case the regulator

[10] Available in 'The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001'.

has previously approved the request to use such stored electricity (Article 9(1) of Belgian Electricity Act).

The previously discussed exemption which applies to small generators may imply the deployment of small scale storage technologies subject to operational separation requirements, which can be achieved with third partied managing the interaction of these technologies with the market, which occurs with Pöyry's (2013) SNS business models.

5.2 On deployment by DNOs

The generation of income using small-scale storage technologies by DNOs is possible but must face restrictions imposed by the distribution licence. More specifically, Standard Condition 29 on the 'Restriction of activity and financial ring-fencing of the Distribution Business' includes solid limitations on business associated with non-distribution activities. Most notably, the distribution licence provides the *de minimis* restrictions that: (i) total turnover from non-distribution businesses shall be one of 2.5% or less of total revenue of the DNOs from distribution and (ii) aggregate investments in non-distribution activities shall not be over 2.5% of the DNOs issued share capital, its consolidated reserves and it share premium.

Therefore, assuming these activities are even profitable for the DNO, their revenue and investments from storage would be significantly capped. Even more importantly, such licence inflicts additional restrictions on DNOs throughout terms regarding the avoidance of the distortion of competition in the supply and generation activities, as well as the avoidance of cross-subsidies.

The operation of storage technologies shall be considered in these terms; two methods are able to characterise storage flows, via: (i) unmetered flows and (ii) trading for buying (charging) or selling (discharging) related to the storage technology.

Although the net position is negligible due to high levels of the storage technologies' round-trip efficiency properties, the problem is related to instantaneous charging/discharging which provide a considerable footprint compared to that of any other network-related apparatus, including technical losses in cables/transformers or substation heating) or other individual unmetered connections (e.g. street lighting). Therefore, whether a DNO is willing to adopt either of the two approaches, they would need to show that they are not acting in ways that would provide market distortions.

In terms of *unmetered flows*, the impact of import/export flows affects losses in a non-transparent way, which in turn affects third parties; this clearly challenges the Third Energy Package which states otherwise (see Art. 25.3). This implies that unmetered flows both in and out of the storage device may represent a problem, in turn requiring for metered flows (by either the DNO or the affected third party) to be accounted for within the settlement procedure, supported by trading.

Consequentially, the DNO embarking in *trading activity for buying or selling electricity with the storage technology* may clearly affect the wholesale market. To this extent, it must be noted that trading does *not* require a licence, neither of the generation or supply kind, although a generation licence is anyway needed for small storage. In addition, charging/discharging does not imply that the DNO is either looking to "supply electricity to premises" (i.e. the definition of 'supply' under Electricity Act 1989), nor to be active in the sale or resale of electricity to consumers (i.e. 'supply' as defined in the Third Energy Package). Hence, whereas a supply licence is not required for trading in terms of charging/discharging the storage device, it is very possible that market distortions are created by trading through its impact on generation and supply competition. The latter is a clear barrier to the operation of the storage device in terms of balancing.

This means that, as regulation stands today, a third party contractually involved in the supervision of electricity flows is needed to manage the potential disputes occurring when storage is used on network-related grounds, or for global system offerings. The latter implies the need for this third party to be mentioned in the business case for storage, which further complicates the case.

Such party could either be an independent entity or an additional DNO which is appropriately ring-fenced from participating in these activities. This business should avoid potentially viable cross-subsidies between multiple activities and comply with the 'Independence of the Distribution Business' regime. Therefore, this issue may be managed using contractual arrangements. For example, under the 'DNO contracted' model, the DNO owns the storage device whereas the relative electricity flows are managed via contracts by a third party. The model shows that, in order for DNOs to realise the value of storage in terms of capacity expansion deferral, there ought to be a monetary flow from the third party toward the DNO, to be stated in the contract. In the 'Contracted Service' model, both ownership and operation are managed by the third party; in this case, the DNO does not benefit from capex deferral and the monetary flow is from the DNO to the third party for compensation relating to ancillary services (UK Power Networks, 2013).

On the other hand, as a TSO, National Grid is allowed in the trading of electricity for balancing, although its obligation remains to act in such a way to be economic, efficient and co-ordinated (see Standard Condition C16). In order to reach this goal, National Grid is allowed to buy balancing services, as well as trading electricity purely for balancing purposes. However, trading is disallowed for other purposes (see Standard Condition C2), including speculative trading. Nevertheless, the ownership and operation of storage devices by TSOs is not permitted due to unbundling requirements and the risk of a possible disruption of competition in generation and supply.

It might be possible that the mode of TNO operation can be adapted to also cover DNOs in such a way to allow DNOs to charge/discharge their storage devices to provide network services. Indeed, additional measures could be taken to avoid DNOs from exploiting their position for speculative trading. As the Third Energy Package implies, DNOs are certainly allowed to undertake a balancing role (Art. 25.6).

5.3 Storage investments and price controls

Assuming that DNOs own storage for network-related purposes, its treatment in price controls must be considered. In the case a DNO decides to use an approach of either conventional asset replacement or reinforcement, its activity will need to be assessed based on expected efficient costs for the substitute asset type, leading to efficient costs feeding into its revenue and the regulatory asset value.

Nevertheless, the way in which storage investment is treated as a substitute to conventional investment remains unclear. If today DNOs deployed storage using a licence exemption, it would be overspending over its capital allowance, but it would also receive capital throughout the *de minimis* rules. Both flows of capital in and out the regulatory account are visible to OFGEM, although they are not clear enough for OFGEM to make comparisons with similar projects in the case of mass DNO storage deployment.

The following issues could be considered: (i) there is little cost data for storage deployment to appropriately compare and assess their relative values. This is even more complicated by adding the plethora and diversity of storage technologies in terms of cost and maturity, and (ii) the assessment does not consider the whole set of wider benefits to the electricity system aside from those delivered to the DNO. The latter finalises the decision as to whether the investment is efficient and thus should be undertaken, therefore it could be clarified.

In order for investment in storage to be practicable, a defined methodology of assessment in the RIIO (Revenue=Incentives+Innovation+Outputs) framework is required. In this handbook, OFGEM provides the indication that business cases for storage can also be reinforced where the licence holders have considered alternative delivery solutions such as demand management and alternative assets. In any case, the assessment for investment in storage remains unclear.

In summary, the barriers that prevent UK network companies from adopting storage technologies are related to both unbundling requirements and licence restrictions based on the promotion of competition in the generation and supply sectors. TSOs are particularly restricted from owning and operating storage; on the other hand, it is possible for DNOs to own storage using the “small” storage facility option, which provides exemption from the generation licence. Nevertheless, the *de minimis* restrictions regarding the impossibility for them to earn more than a tiny amount from deals with generation or supply clearly undermines the profitability of their potential storage assets, potentially setting back investment opportunities. Moreover, DNOs are restricted from trading, therefore any operation of their storage technologies must be carried out via a third party, which should be a legally separate entity from the DNO itself. Investment in storage is not currently optimised partly due to how OFGEM’s assessment fails to consider the whole set of wider benefits to the energy system, aside from those delivered to the DNO. This implies that due to the present treatment of storage, it is impossible for storage to out-compete conventional network assets.

The current GB regulatory and legal frameworks may inhibit the adoption of storage technologies through a combination of UK and EU regulations, namely that: (i) the treatment of storage as a generation subset provides uncertainty and a variety of issues, (ii) the exemption to the generation licence provides flexibility in handling small storage devices to avoid issues related to unbundling requirements, (iii) the *de minimis* requirements restrict DNOs from deploying storage as it is classified as a generation asset, (iv) the use and operation of storage is clearly affected by restrictions used to ensure the avoidance of supply and generation competition distortion.

The arrangements in electricity markets, in place to avoid the distortion of competition, and its design reflect prior considerations before energy storage was even considered an issue. However, the system itself is providing clear barriers to the deployment of storage. Pöyry (2013) finds two main issues in the regulatory and legal framework that may contribute by preventing the mass deployment and a full value realisation for the technologies: (i) default treatment as a generation subset, which increases uncertainty and provides unnecessary issues – however, the generation exemption licence does provide flexibility for unbundling requirements; and, (ii) the *de minimis* restrictions place limits on the deployment by DNOs if storage is classified as a generator – however, the operation and application of such assets are undermined to ensure competition non-distortion in supply and generation.

These issues may have wide implications for business models entailing DNO operation and ownership and demonstrate that DNOs could potentially lead smaller scale storage projects. Yet, it is likely that the real value of storage will not be fulfilled if current regulations are to be maintained.

6 Market barriers to energy storage in the UK

The potential value of storage spans across a wide array of services, most of which are not fully rewarded at present. This is because the multiple sources of revenue that storage technologies may provide may include regulated sources (e.g. from transmission grid services, or from businesses regulated via contracts), which provide the firmest challenges, or unregulated and market activities[11].

The various storage technologies are classified by Pöyry (2013) in relation to their technical features, which determine their appropriateness for providing services in terms of: uninterruptible power supply (i.e. a secure and quality supply to final consumers), grid support (i.e. services that enable the management of network frequency, voltage and system restoration), power management (i.e. service to distribution and transmission operators in order to deliver stability manage and balancing services and peak load management), and electricity management (i.e. bulk electricity trading) (Elexon, 2015). The following figure provides a general introductory overview of how the many types of energy storage technologies and their applications classify within the electricity system, relative to the classifications of electricity market agents. This implies the degree of regulation for each application, denoted by the strength of the blue area depicted in the left hand side panel of the figure below:

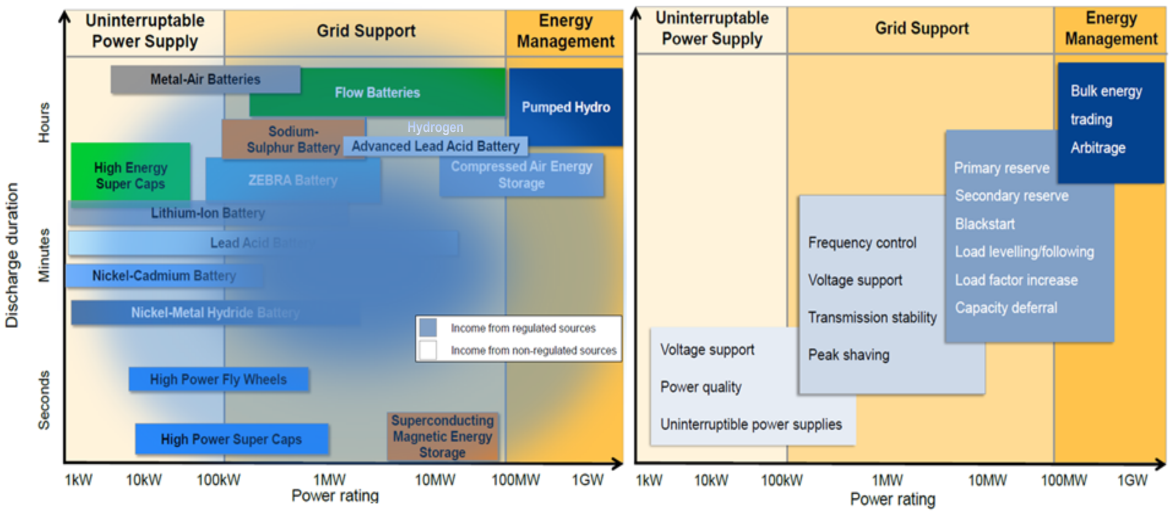

Figure 2 – Energy storage technologies and their applications in the electricity system, relative to the degree of regulation. Source: Adapted from Pöyry (2013), via Think (2012).

Fig. 2, reported above, shows that where storage technologies are applied to provide ancillary services or capacity expansion deferral, their revenue is associated with a high degree of regulation. Instead, if the application of storage is intended to facilitate electricity management, a large share of its revenue streams are determined by the unregulated market, although it must be noted that the activity of storage can well be affected by regulation to some extent. This extent depends on the *degree* by which storage activity is related to the grid.

6.1 Business case

The application of energy storage in the electricity system, thus its sources of revenue, and therefore the inherent degree of regulation, may directly affect a utility's business case entailing these technologies. This is likely to occur in the case that the technology were mainly used to provide services to regulated companies. In this case, it is appropriate for the underlying market rules to enable these technologies to capture enough value for these services to be feasible

[11] This section is based on the work in Pöyry (2013).

(Strbac et al., 2012). Similarly, where the storage project involves interaction with the competitive market for electricity or heat, then the technology must be accessible to the market and must be framed by identical rules as its competing technologies or participants in that/those service/s. In the combined case in which revenues to the storage technology derived from the provision of services to both a regulated and unregulated business, or where revenues are to be divided, the relative balance between non-regulated and regulated services must simultaneously allow the business case to hold and the services to be profitable. Moreover, due to the diverse applications that storage can provide, there is a need to create incentives, changes in the regulatory framework, and business models so as to cover each possible application (a method currently supported by both the EU and US) and stakeholder (Pöyry, 2013).

The economic and business cases strictly vary according to the application in question, and could depend on the storage technology's required location, i.e. at the level of generation, transmission, distribution or end-user. Furthermore, the benefits for operators and users is ultimately linked to the location of these technologies in the electricity system (DG ENER, 2013).

6.2 What are the business models?

The deployment of energy storage projects depends on the feasibility of the business models. The nature of business cases of storage technologies depends on the revenue from multiple value streams, including those possibly deriving from regulated businesses. In addition, they vary between projects by application, operator, owner and scale. As Elexon (2015) shows, they also depend on other present and forthcoming projects[12].

Grid-scale projects, in particular those relating to proof of concept demonstrations, simply concentrate on local network use; examples of these include power quality and voltage control, peak load management and reinforcement substitute. Other types of grid-scale projects aim at realising value from commercial applications in the electricity market. These include ancillary services, bulk electricity trading and arbitrage. Other grid-scale projects are instead a combination of local commercial applications and local network services. On the other hand, non-grid scale projects provide services to individual end-users, such as lower electricity costs (or peak shaving) and continuous power supply. Importantly, these services indirectly provide network services, reduce congestion and allow market participation. The projects in the following figure are those presently or prospectively implemented in the UK.

[12] This section is based on Elexon (2015).

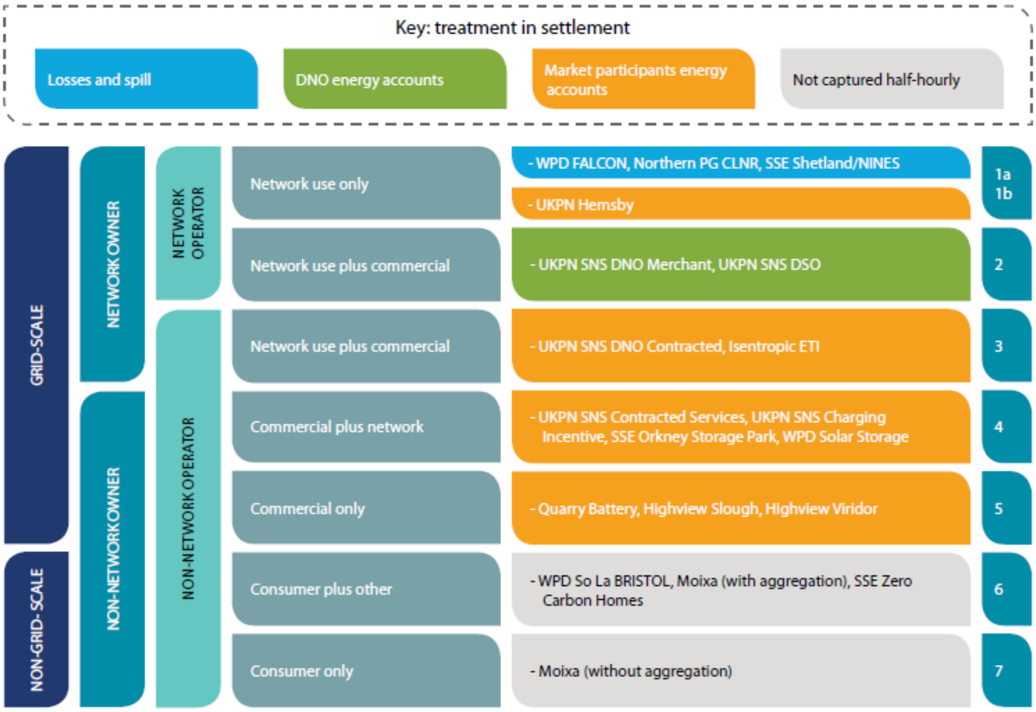

Figure 3 – Grid- and non-grid-scale projects in the UK. Source: Elexon (2015).

Business models may interact with the settlement procedure in four ways: (i) spill and losses – whereby electricity outflows and inflows are identified as network spill and losses and are therefore not counted for settlement; (ii) settlement occurs on a half-hourly basis in DNO accounts – here flows are directly included in the DNO account; (iii) settlement occurs on a half-hourly basis in market participant accounts – where flows are directly included in the participant's account; (iv) no settlement occurs on a half-hourly basis – in this case, flows are not settled on the usual half-hourly basis but feed into the accounts after reconciliation. These methods' feasibility and their repercussions can be assessed in the following ways (Elexon, 2015):

(i) The case in which s*pill and losses are not settled* is most probably an unsustainable resolution aside from initial demonstration projects. This is because of two main reasons: it provides additional costs to other participants in the market since the net position is included in the overall system losses; in addition, it jeopardises the business case for storage by not providing the service to the market, which would otherwise be a valuable income stream.

(ii) Current regulations prevent distribution companies from participating in the market and *DNO account settlement* is not possible as per the current UK regulatory framework. However, it would be possible to provide access to distribution businesses in the storage market by employing them as System Operators[13] in central settlement. In order for this to be possible, legal frameworks must revise the role of distribution companies.

(iii) Given present rules, the *market participant account settlement* option is the most realistic resolution for grid storage assets in the short and medium runs. In this case, network-owned

[13] This would be possible by using the National Grid model or also the standard market participant model (Elexon, 2015).

assets are allowed to provide market services to another party who is permitted to trade under OFGEM's Balancing and Settlement Code (BSC).

(iv) Finally, the case in which *no settlement occurs* (on half-hourly basis) represents the standard situation for both off-grid and also grid-edge storage. These technologies' operation is simply undetected in the market and not counted within the half-hour settlement process. The cost of this approach increases as deployment advances. Suppliers may want to make these assets more visible in the settlement code. In addition, asset owners may want to be provided access to the wholesale electricity market to realise the value of their technologies. If these conditions are not implemented, the value of storage and relative market efficiency will remain idle.

A number of business models for distribution storage have been proposed (Pöyry, 2013), including:

- DNO contracted: The DNO owns and has full operational control over the storage asset. Before the storage asset is built, long-term contracts are agreed for the asset's commercial control in certain periods of time.

- Contracted services: The DNO offers long-term contracts for services at specific locations with commercial control in certain periods of time.

- Charging incentives: The DNO sets the DUoS tariff to create signals that incentivise peak shaving to reflect the value of network reinforcement.

- DNO merchant: The DNO owns and has full operational control over the storage asset.

- DSO role: The DNO owns and has full operational control over the storage asset. In addition, the DNO is given a regulatory role in balancing and controlling aggregated demand and generation on its network in the spirit of a DSO's role.

The previously discussed regulatory and legal issues have implications for the way in which storage technology or storage-related business models should be supported, especially for those models involving the issue of ownership and operation of the storage asset. The latter, as previously discussed, stems from the need for DNOs to avoid distorting the competitive practices expected in the generation and supply (G&S) sectors.

For models involving DNOs as merchants and, more generally, DSO business models, a major concern is avoiding the distortion of competition in G&S and the need to respect unbundling requirements. This is considerably less important for models concerning contracted services businesses because, in these cases, the distribution company has a much less important role in the operation of storage devices. As Pöyry (2013) suggests, these issues may be overcome by allowing distribution businesses to be actively involved in trading for balancing purposes, where storage is operated in this context. The latter could be done in a way similar to National Grid and must place restrictions to avoid speculative trading. Moreover, in models related to incentives to charge, such issues are also less important given that a third party would be involved in both ownership and operation. However, these types of models present other incongruences, namely that the DNO is more uncertain as to whether the investment in the storage plant is feasible and will be made. The latter implies that benefits to the DNO are not fully represented as the business case now depends on the third party. Thus while the former type of models entails regulatory challenges, the latter two entail far higher commercial and security risk.

These represent options for DNOs to realise the value of energy storage technologies. Note that some of the above require full operational control by DNOs, which is disallowed by current regulations.

On the other hand, TSOs are faced with even stricter requirements and may only choose between three models:

Table 2 – Possible business models for Transmission System Operators.

Ownership unbundling	This option requires full ownership separation in order to safeguard the independence of network ownership from potential interests in supply and generation.
Independent system operator (ISO)	An independent TSO free of interests in generation or supply operates the system is required. At the same time, ownership of the transmission network is allowed to remain within the transmission sector.
Independent transmission operator (ITO)	Ownership and operation of the asset are allowed to remain within the same sector; however, the ITO must be guaranteed to be operationally independent with stringent rules on ring-fencing.

The ‘Ownership unbundling’ and ISO models necessitate the separation of ownership between an entity that is involved in TSO activities and any activities that are related to the market. Such provision disables the TSO from holding generation assets, thus any form of energy storage technology. Instead, while the ITO model permits common ownership, currently disallowed, it must be accompanied by complete independence and ring-fencing from an operational perspective to avoid any distortion of competitive practices (UK Power Networks, 2013).

6.3 Summary of business case barriers

Different studies (e.g., Carbon Trust, 2012; The Energy Storage Network, 2012; IEA, 2009, IEA, 2014) agree on the need for the UK to develop at least, or close to, 2,000 MW of energy storage by 2020. This requirement is additionally recognised by a number of developers, manufacturers and commentators (Elexon, 2015). This implies that system savings are derived from these minimum capacity levels (Carbon Trust, 2012), with a potential future need for more. System-wide savings of £2 billion a year could be achieved by 2030 deploying new energy storage technologies, in some scenarios (Carbon Trust, 2016). The installation of storage capacity is reflected in the additional amount of 2 GW of storage capacity for a total of 5 GW by 2020. At the present time, close to the entirety of the current 3 GW of installed storage capacity is delivered by large-scale pumped hydro, while the additional storage deployment will most probably be served by other means, including household-level and smaller-scale (e.g., community-level) distributed storage devices. The expansions of grid-edge and non-grid scale projects are also expected to play a significant role in future deployment and present business cases.

However, different regulatory and commercial issues are potentially hindering the development of these projects in the UK market. This currently hinders business cases by avoiding agents from realising the value of such technologies. These factors include: the classification of storage, the new ‘capacity market’ and current balancing service rules. The latter two are described in more detail below.

While the new *UK capacity market* could represent an opportunity for storage and an important source of revenue, instead its obligation to pursue an open-ended load following position in the market, or its otherwise exposure to penalties, clearly affects the feasibility of these projects;

Finally, *balancing services* represent an additionally valuable source of revenue for storage. Access to balancing markets is not adequately provided for storage technologies and strict requirements with respect to generation plants, i.e. storage technologies, are a main barrier to their provision of balancing services. Evolving system needs and new technology capabilities ought to be considered.

As previously mentioned, the fundamental challenges affecting storage are: technological issues (mainly relating to an increase in the capacity and efficiency of storage methods), strategic issues (supporting the development of a holistic, or whole-system, approach to storage), market and regulatory issues (involving the creation of apposite market signals that provide incentives to market agents to encourage the creation or adoption of new storage capacity) and, economic issues (which depend on technology costs, on which electricity market agent needs the technology, and its location in the system) (DG ENER, 2013).

This paper's focus lies between the latter two, focussing on the regulatory framework that is currently impeding such technologies from being widely deployed and used, including the barriers currently preventing storage from gaining market momentum.

Cost barriers and specific technologies

Technologies for energy storage can vary dramatically depending on their costs, which represent the primary barrier toward their deployment. The table below shows the different storage assets in relation to their typical rated capacity, nominal duration, cycle efficiency, electricity cost, power capacity cost, typical life, technology maturity and usual or anticipated scale.

Table 4 – Technology costs. Source: CLCF (2012).

TECHNOLOGY		TYPICAL RATED CAPACITY (MW)	NOMINAL DURATION	CYCLE EFFICIENCY (%)	ENERGY COST ($/KWH)	POWER CAPACITY COST ($/KW)	TYPICAL LIFE (YEARS)	TECHNOLOGY MATURITY	USUAL/ ANTICIPATED SCALE
PUMPED HYDROELECTRIC STORAGE		100-5000	1-24+ hrs	70-87	5-100	600-2000	30-60	Mature & Commercial	Large grid
COMPRESSED AIR ENERGY STORAGE		50-300	1-24+ hrs	70-89	2-120	400-1150	20-40	Commercial	Large grid
CRYOGEN-BASED ENERGY STORAGE		10-200	1-12+ hrs	40-90+	260-530	900-2000	20-40+	Early commercial	Grid/EV/ Commercial UPS
FLYWHEEL		0.4-20	1 - 15 mins	80-95	1000-14000	250-25000	15-20	Demo/ Early commercial	Small grid/House/EV
HYDROGEN STORAGE AND FUEL CELL		0-50	Seconds-24+ hrs	20-85	6-725	1500-10000+	5-20	Demo	Grid/House/EV/ Commercial UPS
BATTERIES	**Flow**	0.03-3	Seconds - 10h	65-85	150-1000	600-2500	5-30+ (200-12000 cycles)	Research/ Early demo	Grid/House/EV/ Commercial UPS
	Lithium	1-100	0.15-1 hrs	75-90	600-3800	400-1600	5-15 (4000-100,000 cycles)	Demo	Grid/House/EV/ Commercial UPS
	Metal-Air	0.01-50	Seconds-5 hrs	~75	10-340	100-1700	(100-10000 cycles)	Research/ Early demo	Grid/House/EV/ Commercial UPS
	Sodium-Sulphur	0.05-34	Seconds-8hrs	75-90	300-500	350-3000	5-15 (2500-4500 cycles)	Commercial	Grid/House/EV/ Commercial UPS
	Nickel	0-40	Seconds-hrs	60-90	800-1500	400-2400	10-20 (1500-3000 cycles)	Early commercial	Grid/House/EV/ Commercial UPS
	Lead-Acid	0-40	Seconds-10hrs	63-90	200-400	50-600	5-20 (200-1000 cycles)	Mature & Commercial	Grid/House/EV/ Commercial UPS
SUPERCONDUCTING MAGNETIC ENERGY STORAGE		0.1-10	Milliseconds-seconds	90-97+	1000-10000	200-350	20-30	Early commercial	Small grid/ Commercial UPS
SUPERCAPACITOR		0-10	Milliseconds -1 hr	<75-98	300-20000	25-510	8-20+ (25000-1 million cycles)	Early demo	Small grid/ House/EV

The above table (Table 4) reports performance details and costs relative to a variety of the main electrical energy storage technologies. Technologies with a large storage capacity, mainly PHS and CAES, are able to offer capacity to enable the smoothing of intra-daily fluctuations in supply. This may include the storage of electricity in excess from a wind farm or time-shifting the use of power from a solar technology during night time. At present, these represent the sole mature solutions that enable large-scale and long-duration applications because they depend on geographical locations and their capital costs are not comparable with technologies whose main advantages relate to scalability, portability and versatility of deployment. There is a concrete possibility for hydrogen storage systems and redox flow batteries to become commercially available for comparable applications. On the other hand, supercapacitors and flywheels are able to smooth short-term fluctuations such as those relating to transmission constraints (e.g. line faults, increasing or intermittent power from wind technologies) whilst at the same time decreasing the requirement for spinning reserve. To this extent, at present, spinning reserve is provided by conventional means (e.g. oil, gas, coal) which are required to run below their individual rated capacity, thereby decreasing total system efficiency. Furthermore, super conducting magnetic energy storage (SMES) is able to offer its service in a similar role though this is prohibitive at present due to excessive costs.

A variety of technologies exist which can serve as electrical (or heat) stores and these are diverse in their technical characteristics and their level of maturity. This report only discusses energy storage, as available in different output forms, rather than heat storage, which might be dealt with by different regulations due to their fundamental physical and operational differences. Given the plethora of possible applications, it seems improbable that a single solution might arise in the future. At present, the need for energy storage derives from firms who wish to provide frequency response correction and load levelling throughout higher power centralised systems. Pumped hydroelectric storage as well as CAES systems are currently commercially available and are also able to offer long-term and large-scale storage. Moreover, they might be provided with competition in such application by flow batteries, as well as hydrogen and CAES in the longer run.

In the case fast response services were required by the system, flywheels are at present commercial, although supercapacitors might soon be ready for deployment too. Nevertheless, there is an increasing need for distributed or decentralised systems and this can provide considerable benefits to such technologies and their prospective deployment. For distributed or decentralised applications, a plethora of battery technologies could have a prominent role, including sodium-sulphur and lead acid-nickel, which are the most likely to be deployed in the shorter term. On the other hand, metal-air could be deployed in the longer term. Additionally, second life lithium ion battery technology might also arise if transport is effectively electrified. Finally, although heat storage is currently not much considered it could well be the case that as heat storage will be available locally, currently a distant hypothesis, a large decrease in the quantity of electricity to be distributed across the system could arise, thereby paving the way for an increasing attention in technologies for heat storage.

7 Market design barriers

The multiple applications of energy storage technologies imply the potential for multiple sources of revenue. Hence, the business case for these technologies can be multi-layered and particularly intricate. In addition to the many applications that storage can be involved in, storage technologies can deliver a plethora of benefits to the entire electricity system, including valuable help in the progression of renewables and therefore the displacement of carbon-based generation. However, there is a lack of measures that rewards these technologies for services that can be crucial for grid development. The value of such technologies derives from the activities in which they are related, including the potential for wholesale market participation or the delivery of ancillary services to the TSO.

Moreover, the UK's Electricity Market Reform (EMR) may entail the delivery of value to storage technologies in two ways. Most importantly, the capacity market provides payments to reliable sources of capacity. On the other hand, the contracts for difference scheme, which provides payments to low-carbon generators over the market reference prices, may also be a source of value for storage, given that it is currently recognised as a generation technology. Nevertheless, limitations affecting grid connection for smaller scale storage could result in the loss of a significant portion of its value. While larger scale storage projects connected to HV transmission grid may be seen as a EU project of common interest (PCI), granting them particular priority, on the other hand, smaller scale storage projects connected to the distribution grid are not supported through the PCI European framework.

The value of storage is additionally related to the avoidance of the technologies' higher opportunity costs, such as avoiding spare capacity by peak shaving, as well as foregone network capacity expansion and possibly also displaced black generation. In addition to these, other means of accumulating value are: arbitrage opportunities, short-term operating reserve, frequency response and fast reserve.

As Pöyry (2013) notes, whereas the actual revenues from storage are mostly given by frequency response, its current costs may likely surmount them. However, they also note how, potentially, the benefits of storage facilities may enable considerable profits, with these potentially being provided through the avoidance of network capacity expansion.

However, it is clear that these sources of value are hardly accessible, as opposed to the realistic opportunity to capture *market-based* value. On the other hand, a DNO is more likely to access capacity expansion avoidance value, though not market value.

How can distribution-connected storage technologies expect to realise value? We look into this issue in the next section.

7.1 Wholesale market

The British Electricity Trading and Transmission Arrangements, which represents the British wholesale market, can be condensed into the following sections: (i) futures and forwards markets – allowing contracts to deliver electricity up to years ahead; (ii) spot markets – contracts to deliver electricity from one day ahead to one hour prior to delivery, or Gate Closure; (iii) the balancing mechanism, opening at Gate Closure, for the balancing of the transmission system; (iv) the settlement process, which enables the charging of market participants whose contract positions are not identical to the volume of electricity they consumed.

There are different ways in which market participants can trade power. These can be from a pure merchant approach, in which products are offered in the spot market throughout their in-house trading desk, to long-term, all-inclusive, bilateral offtake agreements, whereby a power off-taker takes on volume risk and provides the contracted pricing scheme, for all bundled products.

In between the two, there can be a variety of combinations which might involve more or less market commitment and thus more or less risk on the generator's side thus, ultimately, more or less value which may be realised. These are the possible 'routes-to-market', briefly described below:

Standard Power Purchase Agreements (PPA), which usually bind generators to suppliers, represents the normal approach taken by independent power producers in trading. These agreements may take different forms (e.g. fixed, floored, indexed prices), although under all forms the counterparty expects to be liable for at least a portion of the value of the contract due to the generator incurring in transaction costs and contract risks, thereby providing a margin.

The *trading services* approach relates to the outsourcing of trading activities to an external entity which participates in the market as a third party on behalf of the generator.

Own-account trading is an approach which is mainly used by large market players and utilities, which can take advantage of their economies of scale and their in-house trading platforms and experience. Under this strategy, the involved generator may face even higher trading, management and balancing costs, though it is in turn able to collect a higher value.

There is a trade-off between these options which mitigates the overall differences between the assumed overhead costs of participating in the market (e.g. the posting of credit to cover, industry code agreements or trading functions) and the lower price obtained due to trading outsourcing. Given the impossibility of DNO trading, if the DNO possesses a storage technology, it will have to trade indirectly through a third party, thus getting involved in the market through the other two options, using the previously discussed business models of operation. On the other hand, if the market participant owns the storage asset, then all three options are available for the individual.

7.1.1 Factors affecting inclusion in trading in the UK

The factors which may affect entry in trading arrangements in the UK are: Trading Parties and Balancing Mechanism Unit classification, discussed hereafter.

Trading Parties

In any of the discussed routes-to-market, the energy related to a storage technology must be considered in the settlement process. Under the UK's Balancing and Settlement Code (BSC), all entities who aim at physically trading power must be a trading party, thus should possess energy accounts. Holders of distribution licences are considered parties in the BSC, however not Trading Parties given they are not allowed to trade and therefore possess an energy account. Nevertheless, distribution license holders are not disallowed by the BSC from participating in the market. Instead, this occurs as a result of the distribution licence itself which requires the avoidance of any distortion of competition in supply and generation.

Balancing Mechanism Unit (BMU) classification

Trading parties possess two energy accounts, for production and consumption respectively, linked to the party's physical flows of the BMUs (i.e. the trade and settlement units representing the physical flows with high accuracy). In the majority of cases, large generation units are regarded as individual BMUs, whereas small generators, such as most storage technologies, are most often considered in a supplier's BMU.

On any day in the settlement process, BMUs have to be listed as either a consumption or production unit. This defines the energy account which a certain Unit's production or consumption of energy feeds into the system on the day of settlement. Different types of BMUs exist, with each of these standing for different parts of the system. The various types of BMUs can be: (i) directly linked to the transmission system, (ii) rooted within a distribution system, (iii) linked to an interconnector, or (iv) covering supply.

Also in this case, at present, there is no specific category for storage. The BSC treats storage technologies as generation units. Moreover, distribution network-connected storage would be treated as an embedded BMU.

7.1.2 Implications of trading measures for value of flexibility

The UK trading arrangements may not only affect wholesale market participation but also the value that storage technologies are able to realise throughout the entire electricity market. To this extent, the imbalance settlement arrangements represent a principal determinant of the value of storage. The electricity imbalance arrangements, or cash-out arrangements, serve to provide settlement for electricity that is produced or purchased without a binding contract. However, the methodology currently used for calculation is in place to inhibit cash-out prices and thus could likely diminish the strength of the signals and incentives they could be able to deliver. These calculations are briefly explained hereafter.

Currently, the primary imbalance price is given in consideration of the weighted average of the 500 MWh most expensive electricity trades that are required to balance the entire system. In this way, the method ensures lower cash-out prices because the costs relating to the more expensive balancing activities are eliminated via the averaging procedure. As a result, there is likely to be an incongruity between the marginal system balancing costs and the exposure to imbalance of parties who are out of balance. Thus, this approach could decrease cash-out prices, as well as the incentives and signals they are able to provide for those parties in need to balance their positions.

The current process by which short-term operating reserve (STOR) feeds into cash-out prices could likely deliver a negative effect on these prices. When utilisation fees are exercised throughout the Balancing Mechanism (BM), they directly feed into the cash-out price as accepted offers. However, the price level is fixed in the tendering procedure prior to delivery, implying that they are unable to reflect market fundamentals in a real-time fashion. When balancing supply is tight, the BM offers attached to STOR contracts will most probably displace other offers. This occurs when other offers are not cross-subsidised through an availability payment and are prospectively reflecting scarcity value related to system tightness.

In fact, utilisation fees attached to non-Balancing Mechanism STORs are, at present, not reflected in cash-out prices (Elexon, 2015). On the other hand, availability payments are indeed included in cash-out prices, however only in periods of historic utilisation of STOR throughout a Buy-Price Adjuster (BPA), which is an additional overhead to the cash-out prices due to other balancing activities and represents a misleading proxy for when reserve is effectively utilised and most valued.

In the most dramatic settings, the system operator may order the DNOs to decrease demand through brownouts or blackouts so as to balance the system. However, these balancing activities are not comprised in the methodology for calculating cash-out prices. Therefore, such prices are not given the possibility to increase during periods of market tightness because they fail to reflect such balancing activities' costs.

If these flaws are overcome, cash-out prices are allowed to increase, likely along with the incentives for balancing to parties. In turn, the value of flexibility and reliability of generation capacity (e.g. storage) will rise, thereby aiding parties in balancing their positions. The latter is acknowledged by OFGEM through its Electricity Balancing Significant Code Review (EBSCR), which directed toward the establishment of a proposed set of reforms regarding the procedure relating to cash-outs. In fact, their consultation stated their intention of: (i) providing a more marginal component to cash-out prices throughout the reduction of the amount of activities determining the cash-out price itself; (ii) ameliorating reserve pricing throughout an amendment regarding STOR activity prices within the cash-out price calculation methodology in order for them to reflect a newly defined Reserve Scarcity Pricing function; (iii) attaching a cost for voltage control brown-outs and black-outs for emergency balancing activities, within the cash-out rules.

Moreover, OFGEM has recently proposed the adoption of single cash-outs for the entirety of imbalances in individual settlement periods as opposed to the ongoing dual-price method. They suggest that such reforming of the cash-out method would provide increases in cash-out prices, thereby increasing the incentives for flexible capacity investments.

7.1.3 Implications for balancing services

In the UK electricity market, generators dispatch their electricity to consumers in order to accommodate the sales they have contracted. Yet, it is National Grid who ought to ensure the balancing of generation and supply at all locations and times using balancing and ancillary services.

The instruments they use are: (i) Frequency response – automatically increasing generation or reducing demand due to decreases in system frequency, which is further broken down into primary response (i.e. sustained output from 10-30s after a loss of 0.8Hz) and secondary response (sustained output from 30-1800s after a loss of 0.5Hz); (ii) Reserve – manually increasing generation or reducing demand over minutes to hours following an order from National Grid; and (iii) System Security – manually varying generation or demand to ease transmission constraints or security-related issues. To this extent, many of these services can be obtained from non-BM units, thereby providing the opportunity for non-conventional generators to participate, possibly via an aggregator.

In order for National Grid to comply with its Procurement Principles, it is mandatory for it to agree the provision of balancing services in an economic, competitive and non-discriminatory manner. For this to occur, they express the involved services based on a series of parameters, including duration, speed, repeatability, reliability and scale of generation provision. Moreover, the services can be realised in a portfolio mix that National Grid discretionarily considers economical and useful for grid security.

Importantly, these services were linked to historical requirements and the various technical features of generation technologies used in that historical period, thereby not considering system needs and the use of technologies at the decision time. Nevertheless, new procurement principles now enable flexibility for non-standardised services to be procured under present contractual agreements.

Another important point to consider is related to carbon emissions; to this extent, utilisation prices relating to providers of fossil fuels is inclusive of the ETS carbon price, though this still does not reflect the total carbon cost. Thus, it could be appropriate for the associated carbon cost to be considered in balancing service tendering assessment. Over the last periods, balancing services have developed to provide opportunity for non-conventional generators, including storage technologies.

STOR contracts can be agreed by both BM participants, usually being large transmission-connected electricity generators, and non-BM participants, most likely being small transmission or distribution-connected generators.

Non-BM participants of such services can offer a flexible service and are able to vary the number of hours and the timing of their availability, as opposed to the committed service of BM participants. The latter can be particularly useful for storage providers because of the technology's inherent charging and discharging durations.

Moreover, service providers below the minimum 3 MW capacity requirement may be amassed within a joint offer. In fact, the flexible service effectively delivers the STOR market toward many more possible providers. This improves the possibility of non-conventional capacity, including storage, to participate in the market.

Lately, National Grid proclaimed its consideration for the introduction of an aggregate fast reserve service by non-BM service providers, which must comply with the standard minimum service provision (50 MW to be provided in 2 minutes). This implies the possibility for non-conventional providers, including storage, in the offering of fast reserve within an aggregate offer.

Additionally, National Grid proposed to revise the frequency response service. Among other points, they proposed the establishment of a week-ahead tender timescale, in order to avoid long-term forecast limitations, and aggregation. Indeed, both of these propositions have the ability of improving the participation of non-conventional providers, including storage. It is crucial to consider how balancing services evolve over time to accommodate technologies such as storage, and their characteristics within the balancing scheme, thereby allowing storage technologies to potentially realise value.

7.2 Standards in UK energy storage regulation

In summary, with regards to storage regulation, the special case of energy storage is still unrecognised in the main legislation which covers electricity generation, transmission, distribution or supply. Furthermore, there are no specific licence conditions applying to the ownership or operation of energy storage technologies. In fact, energy storage technologies are at present not differentiated from other electricity generators. Nevertheless, there is much legislation presently covering electricity generation, supply, transmission and distribution, which mainly derives from the Electricity Act 1989 (and subsequent amendments in other Acts and Statutory Instruments).

In relation to grid connection regulation and standards, storage is effectively considered in the same way as other grid-connected technologies. To this extent, connections to the transmission system must comply with the Connection and Use of System Code (CUSC), Balancing Settlement Code and the Grid Code. On the other hand, connections to the distribution system must instead comply with the Distribution Code. Additional engineering requirements must be respected for technologies to connect to the distribution system, as defined by the distribution network operator.

In terms of market integration regulation, storage is at present not considered separately, thus is treated as any other participant in the market. Rules for market participation are based on power rating of generation (i.e. storage), and includes compliance with the Grid Code and the Balancing and Settlement Code.

With regards to UK incentive schemes and regulation, schemes of support for Low Carbon Networks currently provide funds for demonstration to the most innovative projects.

In terms of segmentation by application, segmentation in GB is directly related to the size of the storage device, defined as ‘medium’ or ‘large’, as well as the connection point (i.e. transmission or distribution). Within England and Wales, storage devices which are greater than 50MWs are subject to different rules from those below that size. In Scotland, the threshold is 30MW and 10MW and depends on location.

Finally, with regards to segmentation by location, at the distribution level some local schemes qualify as registered power zones with special incentives for innovation, although such incentive is now closed. Participation in the market is additionally influenced by location because it affects the TNUoS charges as well as the DUoS charges. In fact, storage technologies may be required to pay TNUOS *both* as a generator and as a consumer (DG ENER, 2012), thus making their deployment more difficult under these conditions.

7.3 What is the relevance of CCL for storage?

The way in which storage is treated under CCL remains vague and unclear. In the CCL framework, renewable sources of electricity are defined as those not deriving from fossil or nuclear fuel and includes waste only if the latter does not possess an energy content of 90% or more which derives from fossil fuel. This statutory instrument, however, also informs that the amount of renewable-deriving electricity ought to be calculated at the point where this electricity is delivered from generation to a distribution or transmission system on UK land. The latter reiterates what was previously mentioned, or that a LEC ought to be allocated at the original generation point. However, if export of electricity from a storage device relies on the import of electricity (from a LEC-owning generator) and then the exporting of this electricity, the issuing of a new LEC at the point of export (since storage is considered a generator) implies a double LEC. Therefore, it could be argued that storage should not be eligible for LECs.

7.4 Value realisation issues

The value of distribution-connected storage depends on participation in multiple activities in different regulated and unregulated markets. Many current rules may potentially prevent storage from realising its value, including: (i) distribution-connected storage may participate in the wholesale market, most probably via a supplier's portfolio. Nevertheless, the treatment of storage in the BMU and settlement are ambiguous. Moreover, the chance for DNOs to trade ought to be considered to allow for full value realisation; (ii) A considerable opportunity exists for storage to realise value by providing services to the balancing market. However, service requirements in the market are affected by historical specifications, clearly providing a barrier to the realisation of value; (iii) The CM provides an open-ended obligation and a clear exposure to penalties, thereby again undermining the potential value of storage.

Among the main initiatives that may potentially enable storage technologies to realise value are contracts for differences and the capacity market. While the former was discussed in Section 7, we now focus on the capacity market, a key innovation in the UK regulatory system.

7.5 The capacity market

The UK government's recent Electricity Market Reform (EMR) proposals are aimed at improving security of supply and increasing investments in low-carbon generation whilst minimising consumer costs. Among other measures, the establishment of the Capacity Market (CM) represents DECC's action to improve generation adequacy. The Capacity Market, is a system in which payments are offered to generators which can provide a commitment to deliver electricity in periods of market tightness, on the contrary receiving penalties for failure to deliver.

Contracts for the CM are allocated via auctions in such a way that a reliable capacity required to fulfil a load loss of three hours is achieved. The requirement is based on the obligation of technology independence across demand-side, generation (and thus, storage) providers, including interconnectors, and on the allowance for existent capacity and new capacity providers to participate in the market.

The clearing price in CM auctions is based on the capacity payment to the successful auctioneers. The first auction of the CM was set for 2014 with delivery in 2018-19 (subject to State Aid). Moreover, auctions for demand-side response will entail contracts for one year-ahead of delivery, running in 2015 for delivery in 2016-17, and comprises embedded generation, thus small storage.

The UK's fear for potential power shortages led to the introduction of a capacity market. As previously mentioned, with a centralised and encompassing design, the required capacity is determined by the government and is then bought on the market throughout an auction from the lowest bidder, and entails large penalties to the committed entity in case of failure to deliver. The first auction took place in December 2014 and entailed the provision of sufficient capacity in the winter of 2018-19, for a cost of £1bn. The UK government secured a capacity of over 50 GW with regards to the first period of delivery in 2018-19. The auction entailing the subsequent winter was set to take place in December 2015. Nevertheless, capacity markets could be prone to manipulation; in fact, the UK electricity market regulator OFGEM recently filed an investigation due to its suspicion that five companies have given incorrect and misleading information regarding their plans for new power stations. There is widespread criticism surrounding the scheme on the grounds that costs for consumers increased, as coal rather than gas stations have become the main beneficiary. In fact, opponents of the UK capacity market believe that little evidence exists that new investment is being encouraged (Clean Energy Wire, 2015).

7.5.1 Storage within the Capacity Market

Via DECC and through its EMR, the UK aims at providing an equal playing ground for storage in the CM as other capacity providers. Along with demand management, storage providers may bid in the year-ahead auction and the quadrennial-ahead capacity auctions. To this extent, storage may participate directly, if such technologies are equal or greater than 2 MW in capacity, or if their capacity is less than the *de minimis* requirement, via the aggregation method. With the aggregation method, storage is allowed to enter bids in the market to provide capacity alongside other technologies.

Nevertheless, it is important to note that storage can only offer export capacity to the CM. The possibility of storage technologies decreasing imports when charging may not presently be factored into capacity market agreements, thereby implying that payments from the capacity market cannot translate into revenue for full ‘swing’ capacity to storage providers (UK Power Networks, 2013). Yet, they can be compensated via over-delivery payments, by reducing imports during periods of market tightening or stress.

In the CM, those parties who successfully bid at the auction and are therefore awarded a capacity contract, are entitled to payments if they deliver the contracted capacity in periods of system stress and penalties for not doing so. Periods of stress are defined as settlement periods where controlled load or voltage control shedding needs are encountered for at least 15 minutes. In order for capacity providers to avoid being faced with a fine, the System Operator delivers a warning *four* or more hours prior to an anticipated stress event, with any unanticipated event occurring before the four-hour notice, resulting in no fine *in the relevant period*. To this extent, the period for which the warning applies is not defined at present and relates to either: (i) the end of the day of the warning’s issue in the case that a system stress did not occur on the same day as the warning, or (ii) the end of the day of the system stress and relative warning. The fact that no defined time limit for the delivery commitment exists, the delivery obligation is effectively an open-ended one. The latter represents a main challenge for storage technologies because their discharge duration is limited. If the storage is entirely discharged before the end of the warning period, its provider will be subject to a heavy penalty equal to the volume of under-delivery times a price that is directly related to VOLL (or ca. £17k/MWh) up to a cap of 100% of the annual capacity payment to the provider.

The latter is a considerable cost for storage and a barrier for such technologies from entering the capacity market as well as for technologies with smaller discharge durations. However, it is possible to limit the provider’s exposure to penalty if it offered less than its full capacity to the market, known as ‘de-rating’. However, this practice is likely unable to efficiently deliver the full value of storage. In addition, it is also possible for the storage provider to participate in secondary trading to lower penalty risk; this is done through the buying of the delivery obligation from a different provider. Yet, again this may not reflect the efficient value of storage, possibly wasting at least part of the overall value of storage because it is an expensive method due to the fact that the period in which this may occur is likely a tight market period. Therefore, relying on the secondary market cannot represent an efficient solution to decrease non-delivery risk (Pöyry, 2013).

7.6 Other initiatives

One of the main methods for funding energy storage innovation in the UK could be the OFGEM Low Carbon Networks Fund (LCNF), which provides funds for demonstration of innovative projects. The LCNF has invested £500m to support new technologies. This fund allows DNOs to recover a proportion of expenditure incurred on small-scale projects, and includes an annual competition for an allocation of up to £64m to help fund a small number of flagship projects.

The LCNF is aimed at exploring how networks can respond more flexibly to customers' needs by using more advanced voltage control devices, real time thermal rating and energy storage. A total of £500m over the five-year period was available. The First Tier (£2.35m to energy storage projects out of £16m a year), was spread across all DNOs to spend. The Second Tier, up to £64m a year, was provided to projects that win an annual competition. A discretionary reward totalling up to £100m over the five-year period, can be awarded by OFGEM for successful project completion and exceptional projects. The Smarter Network Storage project was awarded funding from OFGEM's LCNF scheme of £13.2m in December 2012 and will last until December 2016. It includes assessments of energy storage's capabilities to provide the range of services and their relative merits (OFGEM, 2016).

The main projects to have been awarded through the LCNF are:

- Customer-Led Network Revolution (CLNR) Project (the UK's biggest smart grid project) for £54m;
- FALCON project, a £16m OFGEM funded program to improve the industry's understanding of infrastructure needs in a low-carbon environment;
- The B.R.I.S.T.O.L. (Buildings, Renewables and Integrated Storage, with Tariffs to Overcome network Limitations) project is a £2.23m project which will be implemented in Bristol, and will investigate the potential for battery storage in conjunction with PV solar generation to be used within homes, schools and an office to provide network and customer benefits;
- The Hemsby project relates to a lithium-battery technology in a £1.8m partnership. The storage device has been installed at Hemsby in Norfolk;
- Through the Smarter Network Storage (SNS) project, OFGEM has awarded £13.2m to undertake trials to improve understanding of the economics of electrical storage.

Finally, National Grid's proposed Enhanced Frequency Response (EFR) tender could become a reliable source of revenue for energy storage technologies if correctly implemented. This service would require storage to provide 100% active power output at 1 second (or less) of registering a frequency deviation. Due to their high speed of response, EFR is expected to be the most valuable service that storage can provide. Since the contract is a 4-year one, it provides longer revenue certainty compared to other services (National Grid, 2016).

7.7 Levy Exempt Certificates

In April 2001, the UK government implemented the Climate Change Levy (CCL), an energy tax (rates are set annually via the Chancellor's Budget Statement), introduced through the Finance Act 2000, aimed at electricity, gas and solid fuels consumed by commercial and industrial users.

To this extent, renewable technologies and electricity deriving from renewable generation are qualified for an exemption from this levy and possess Levy Exempt Certificates (LECs), which apply to such generators for each MWh of electricity produced. However, hydro generators represent an exception with capacities over 10 MW. LECs are available to all technologies with Renewable Obligation Certificates (ROCs), as well as renewable generators from overseas when that electricity is imported and consumed in the UK. In addition, the exemption also covers the fraction of biomass in electricity produced from waste.

For renewable generators to gain exemption from CCL, they ought to: (i) sell their electricity to a non-domestic entity either directly or through a licensed supplier, (ii) possess a ‘paper trail’ in order to show that the amount of LEC electricity equals that generated, and (iii) submit generation data to OFGEM within two months of producing the electricity.

Suppliers of electricity are able to prevent payment of CCL by buying a LEC from a generator of renewable electricity. The value deriving from CCL exemption can be realised by trading LECs. Nevertheless, the LECs ought to be sold with and may not be unbundled from the electricity they are associated with.

8 Conclusions

Current arrangements in the electricity market, in place to avoid the distortion of competition, and their design, reflect prior concerns before the emergence of energy storage. However, the system itself could provide clear barriers to the deployment of storage technologies. There are different concerns in the UK regulatory and legal framework that may prevent the mass deployment and full value realisation for these technologies, among which are the default treatment as a generation subset, which increases uncertainty and provides unnecessary issues, and the UK’s *de minimis* restrictions, which place limits on the deployment by DNOs since storage is classified as a generator. The issues analysed in this report can have wide implications for business models entailing DNO operation and ownership and demonstrate that DNO can potentially lead small scale storage projects.

As the value of storage is hindered by the inability of storage owners to capture value in multiple service markets, including both regulated and unregulated ones, in order to accommodate storage technologies, authorities may need to consider clarifying and modifying the treatment of energy storage in the current regulatory framework by reviewing the definition of storage and its licence requirements.

Given the large number of benefits that storage assets may provide to the electricity system, new technologies such as storage must be encouraged since they may decrease future system costs. At present, the main argument in favour of energy storage is that providing market friendly rules might encourage innovation to reduce prices in the future. In fact, there are a number of technological and economic barriers that make their deployment very difficult.

In order to spur investment in such technologies, the role of storage is unclear in the current RIIO regulatory framework. An important step to fully realise the value of energy storage could be the establishment of a specific definition of storage. This would be an attempt to deliver an alternative to a generation (or other) licence and would be more likely to eliminate a number of other barriers surrounding the creation of value for storage. A new regulatory classification for storage could reduce the high transmission costs by treating storage as an integral part of the electricity system that complements the transmission system. Similarly, operation by Transmission Network Operators (TNO) can be adapted to also cover DNOs in such a way to allow DNOs to charge/discharge their storage devices to provide network services. In contrast, a new classification would further complicate electricity system regulation and any confusion that might be unwittingly introduced through a change could act as a new barrier against deployment of other emerging technologies.

The definition of storage leads to the major problem of grid fees in European countries applied to storage when charging and discharging encourages the deployment of a project in a certain member state that has favourable rules in order to provide services in another member state with less favourable rules. Furthermore, the harmonisation of grid access fees is critical to providing fair competition across the EU and enabling the competitive exchange of ancillary and balancing services among EU member states. At present, there is a profound heterogeneity in grid tariffs applied to energy storage in Europe given that such technologies are treated as generation or load (ENTSO-E, 2011). To this extent, Ruester et al. (2012) advocate the need for the harmonisation of grid tariffs across Europe, while Frontier (2011) showed the effects of these tariff differences by demonstrating how these provide serious comparative disadvantages to some countries.

Future electricity markets are set to be challenged by both demand and supply side issues, providing large pressures on prices. It is thus crucial to adapt market designs in order to enable the emergence of new technologies such as energy storage assets which could markedly decrease future system costs (Carbon Trust, 2012), whilst achieving decarbonisation objectives and safeguarding the system's stability and security of supply. To such extent, energy storage only represents one of the means available to us which could provide important services to the electricity system, including capacity accommodation and firming, frequency and voltage control, intertemporal arbitrage or back-up capacity, in addition to other competing means such as other flexible generation, demand management and interconnection.

Potential substitutes to energy storage in terms of flexibility all possess the required features to both respond to system necessities relating to downward or upward adjustment, and incorporate the ability to take advantage from intertemporal arbitrage. Their differences derive from the form of energy related to the accumulation and conversion processes. The main dissimilarities which are important to the services that these substitutes are able to offer to the wider system are mainly power rating, response time and energy rating. Thus, one form of flexibility is not essentially better than another. Moreover, the need for energy storage to facilitate the system's decarbonisation remains a question of technical and economic nature, one that requires the uncovering of the optimal technology flexibility mix that can enable minimum-cost services. It is thus crucial to improve market architecture and regulation and maximise the number of technical services remunerated by the system.

The value of storage must be analysed subject two main risks: the uncertainty of the direction, extent and timing of innovations in storage technologies and the unpredictability of the rate of change of both demand, generation and grid flexibility. This implies that the future of electrical energy storage will in principle not only be contingent on its technological development and cost patterns, but very importantly also on the way in which the power system evolves over time. It will be very different in terms of technology deployment scale and choice if the European system evolves toward an 'energy superhighway' or one of local energy self-sufficiency, implying the more extensive use of demand management and small-scale distributed generation (Think, 2012).

As far as the viability of business models in the future electricity system is concerned, at the heart of the energy storage model is the functionality of the storage facility in relation with the services to be provided, in terms of upward and downward adjustment and accumulation. A large set of studies have previously demonstrated that for only single applications, energy storage may not result as a profitable investment (e.g. Strbac et al., 2012). The major challenge such technologies currently face relates to aggregating multiple services and the maximisation of relative income streams.

The efficiency of storage business models and the choice of remuneration and procurement in ancillary services could be examined in a more general setting that considers the particular details and technical features relating to the underlying services. To this extent, an essential problem is represented by asymmetric information, which may be relevant to storage as its benefits most probably overlay with regulated businesses.

There is a question as to whether current design of electricity markets allow for the viability of today's business models. The services that storage technologies provide to the wider system or stakeholders are currently not appropriately identified and rewarded. These are due to ad-hoc peak load requirements which are implemented only in some markets and the observed inconsistency with regards to the mechanisms involved in price fixation within balancing and day-ahead markets, or their bidding requirements. Moreover, ancillary markets favour the marginal, or dispatchable, generator while technologies with low marginal costs (e.g. nuclear, wind) but high capital costs must operate at a disadvantage because they are unable to provide the required service with certainty at the required time

Various measures have been proposed to improve the current situation. The new rule set out in the Framework Guidelines on Electricity Balancing do not yet provide tangible balancing market design rules that can allow storage to compete. Market rules could be amended to apply minimum bidding requirements and rules imposing symmetric up and downward bids that are unable to prevent access for small, decentralised market players, such as storage (Think, 2012).

As for ancillary services, it is possible to accept the mutual existence of different varieties of remuneration and procurement on economic grounds, including spot markets, tendering, bilateral contracting and mandatory provision. Whether some options are more suitable than others will be contingent on the underlying service. Nevertheless, to substitute bilateral contracts with competitive tendering where this might be a possibility, could contribute to the realisation of value of storage and other flexibility tools. With regards to tendering, implementing source-neutral and performance-related arrangements that cover a wider set of technical services could be an important way to spur the profitability of these technologies. These actions could provide more efficient intracontinental ancillary service markets which could in turn provide a more efficient allocation of these services and their procurement in Europe. National borders as well as political boundaries should in principle disallow constraints on the flows of ancillary services.

The capacity mechanism is presently much discussed and disputed around many European countries. Nonetheless, its necessity, due to its sometimes advocated role of decreasing the possibility of long-term under-investment in peak generation capacity remains unproven. On the other hand, it is possible to address the reasons by which low investment incentives currently exist. This implies improving existing market signals, most importantly the quality of signals from balancing and ancillary markets.

The role taken by the EU Commission to guarantee a "level-playing field" (DG ENER, 2013) for all technologies to ensure competitive markets may prove to be detrimental to the emergence of new technologies such as energy storage assets. While the main argument in favour of storage is that it could encourage innovation to reduce future system costs and prices of these technologies, this report suggests that it will be very difficult to spur investment in these without a degree of regulatory flexibility. It is crucial to develop market friendly regulations for all emerging technologies in order to avoid placing well-established generators and immature storage technologies on an identical playing field, at least initially.

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