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RESTLESS

Realising Energy Storage Technologies in Low-carbon Energy Systems

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Regulatory barriers to energy storage deployment: the UK perspective

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Energy storage could make an important contribution to balancing a low-carbon energy system in the future for the UK, and the technologies have high export potential. A rapidly-growing family of technologies that can meet multiple system needs are in development. Innovation is required to reduce the costs of storage technologies, but their widespread deployment into electricity markets that is required to underpin this innovation is not occurring.

This briefing paper examines the regulatory barriers that power-to-power energy storage technologies are facing in the UK and in other major international markets. We consider that the creation of a new regulatory definition would facilitate the removal of barriers to the deployment of storage. Allowing transmission and distribution network operators to own and operate storage would enable its role in the system to be optimised, as long as competition concerns could be satisfied. However, some direct support for small-scale investments might still be necessary, perhaps using a similar approach to California. Many countries are facing the same challenge and initiatives to encourage deployment of energy storage are underway in Germany, Italy, Belgium and the United States. The value from investment in UK research efforts could be lost without similar action.

Contents

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1 Role of energy storage in electricity systems

Energy storage has been identified by the UK government as one of 'Eight great technologies' for the UK.[1] A wide range of energy storage technologies are under development with a range of attributes.[2] While different technologies are at very different levels of maturity, very few have yet achieved commercialisation (Figure 1).

At present, pumped-hydro storage (PHS) represents 99% of total storage power capacity worldwide, but some other novel technologies could have an important role in the future for balancing low-carbon, inflexible power systems, as more variable renewable generation comes online. High capital costs are the largest non-regulatory barrier affecting deployment. All novel technologies are likely to be out-competed by other generation technologies in virtually all grid applications at present.[3] Accelerated innovation is required to reduce these costs, which involves deploying technology into electricity systems in order to "learn-by-doing". This paper identifies some of the formidable barriers to the deployment of storage in the UK electricity system that arise from current electricity market design, and considers options for how these might be overcome.

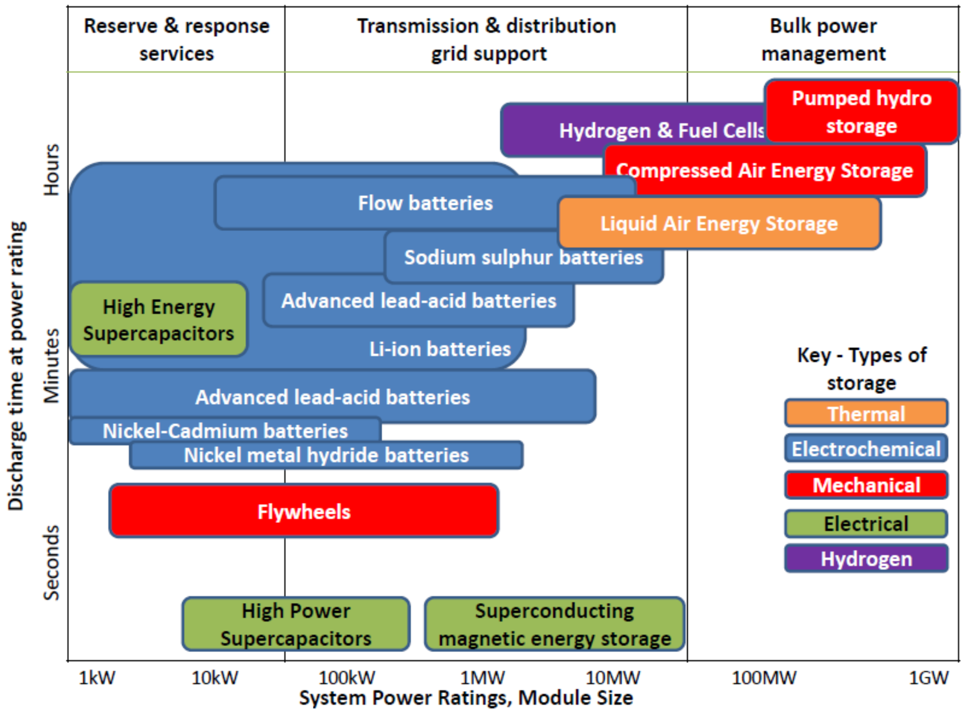
Changes to electricity markets to encourage energy storage would ideally aim for the optimum deployment that best reflected the value of storage to the system. The real value of storage is its whole-system value in improving energy system efficiency and can only be assessed with a technology-agnostic approach that also considers alternatives such as interconnection and demand side response.[4] One issue that hinders the development of storage technologies is the lack of understanding of the value of energy storage in likely future electricity systems. Moreover, most studies consider only power-to-power storage and do not examine alternatives, for example heat storage, that are integrated in the wider energy system. The potential role and competitiveness of energy storage in new markets is also not well understood, and the temporal resolution of existing market models needs to be increased to under one hour in order to understand the multiple benefits that storage might offer and to underpin business cases for new deployments.[5]

2 Regulatory definition of energy storage

In the UK, energy storage is not currently recognised as either an activity or an asset class. The absence of a regulatory definition of energy storage has led to its classification as a generation asset. Generation assets have a very broad definition in the Electricity Act 1989 as "the generation of electricity at a relevant place", and EU Directive 2009/72/EC similarly refers to generation as "assets that produce electricity". The Electricity Order 2001 expands on these definitions by stating that the technology "generates or is capable of generating electricity". Energy storage technologies can generate electricity so are undoubtedly described in the most literal sense by these broad definitions. However, energy storage cannot generate a net positive flow of electricity to the system, and classification as generation does not recognise the potential contribution of storage to moving electricity from periods of low demand to meet peak demands. A new definition that differentiated storage from generation would facilitate the removal of barriers to the deployment of storage by treating it as an integral part of the electricity system.

[1] UK Department for Business, Innovation & Skills, 2013, *Eight great technologies*
[2] Brandon *et al.*, 2016, *UK Research Needs in Grid Scale Energy Storage Technologies*, Energy SuperStore
[3] U.S. Department of Energy, 2013, *Grid Energy Storage Report*
[4] Strbac *et al.*, 2012, *Strategic assessment of the role and value of energy storage systems in the UK low carbon energy future*, Carbon Trust
[5] Minelli *et al., 2013, National Framework: Italy*, AlpStore

Figure 1. Key electricity storage technology options to support the system by discharge time (seconds to hours) and system power rating (kW to GW)[6].



Although large-scale pumped hydro storage (PHS) facilities are bound by generation licenses, the Electricity Order 2001 enables the exemption of smaller-scale facilities. While the existing large PHS facilities can compete with other generation for balancing, as they have only short-run costs, the high long-run costs prevent the deployment of new smaller-scale storage assets. Exemption from the standard generation licence is allocated on a plant-by-plant basis, imposing potentially significant delays on storage-related projects.

2.1 Implications of defining storage as a generator

Transmission Network Use of System (TNUoS) charges and Distribution Use of System (DUoS) charges are designed to recoup infrastructure costs from consumers and suppliers according to their level of use throughout the day (Table 1). Energy storage providers must pay double TNUoS tariffs for their role as both generators and consumers, when operating in charge and discharge modes, and also DUoS charges. If the generator is <100 MW, as in most cases for electricity 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.[7]

These doubled charges arguably do not reflect the complementary benefits of energy storage to the transmission network in balancing the wider electricity system – one moves electricity in time, while the other moves electricity across space. In most cases, storage is used for balancing, which does not contribute to congestion but instead relieves it. Therefore, it might be appropriate to apply lower network fees for storage that better reflect the role of storage in the electricity system.

[6] Taylor *et al.*, 2012, *Pathways for energy storage in the UK*. Report for the Centre for Low Carbon Futures
[7] OFGEM, 2013, *RIIO Factsheet*

The way in which storage is treated under the Climate Change Levy (CCL) framework remains unclear. The CCL is an energy tax aimed at energy consumed by commercial and industrial users. Renewable technologies and electricity derived from renewable generation qualify for an exemption from this levy via Levy Exempt Certificates (LECs). This statutory instrument requires the renewable-derived electricity to be calculated at the point where electricity is delivered from generation to a UK distribution or transmission system. However, if export of electricity from a storage device relies on the import of electricity (from a LEC-owning generator) and then the export 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, which currently represent a considerable barrier to the optimal deployment of storage resources.

Table 1. UK network charges by location and their regulation.

Location	Charges	Charging arrangements
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 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, suppliers, and major consumers for use of distribution network, to DNO.	If DNOs suspect that the embedded generator may have a significant impact on the transmission network, they should contact National Grid, and will 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 due to charging if device is 100 MW or greater and if they do not significantly affect the transmission network.	Different for half-hourly (HH) metered and non-half-hourly (NHH) 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. NHH 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.

2.2 Creating a new regulatory classification of energy storage

One option would be to create a new regulatory definition of an energy storage asset. Such a definition could take into account the zero (or negative) 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.

The regulatory definition of energy storage in the electricity system is quite different to that of gas storage in the natural gas market, which is treated as an independent asset.[8] Yet, experience from the gas market suggests that creating such a definition could be insufficient to meet the goal of realising the value of storage and other complementary technologies to minimise electricity supply costs. For example, the EU has raised concerns that

[8] Ofgem, 2015, *Guidance on the regulatory regime for gas storage facilities in Great Britain*

current regulations are insufficiently specific on required strategic stock levels to ensure security of supply, and that regulations should consider the relative roles of interconnection capacity and local production (DG ENER, 2015). Security of supply and system stability is a primary concern for electricity as well, and while this has concentrated on research capacity margins for generators in the past, a more encompassing approach that considered energy storage, interconnection, demand-side response, network reinforcement and flexible generation might help to reduce the costs of ensuring supply security in the future.

3 Ownership and operation of energy storage by DNOs and TSOs

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 Triad periods.[9] Whether these revenue streams can be realised, and storage use optimised, depends to some extent on how storage is controlled and storage services are sold within the electricity system. The system operator is best-placed to optimise the use of storage technologies to balance the system. If storage is not controlled by the system operator, it is likely that the imperfect information about electricity demands that is available to the storage owner means that they will be unable to sell storage services to fully realise the value that the storage technology could provide to the system, and this will over the long-term make storage less competitive and impede investments. There is a strategic regulatory question about the extent to which energy storage should be directly operated by the system operator.

In the generation licensing scheme, regulated by Ofgem, operation and ownership of storage technologies by Distribution Network Operators (DNOs) is restricted and limited to smaller devices. Transmission System Operators (TSOs) are not allowed to own or operate any form of energy storage (or electricity generation). Unbundling obligations in Directive 2009/72/EC of the European Union require the separation of entities in the vertically integrated system. DNOs are *not* required to abide to these 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 less than 100,000 connected consumers. Hence, they may own such technologies if they are exempt from the standard generation licence. The EU Commission is unsure about whether DNOs or TSOs should be allowed to own energy storage assets.[10] This creates considerable uncertainty for investments in storage technologies.

For DNO-owned storage in the UK, US, and other major world markets, a *third party* must handle electricity flows when storage is used to support the network or for the provision of broader system-wide services which involves business with other market classifications. The third party must be contracted and mentioned in the business case for the storage technology. This third party could either be an independent entity or another DNO which is appropriately ring-fenced from engaging in such activities. Such arrangements can be complex to arrange, leading to a barrier to entry for new storage technologies to the market.

[9] Triads are defined as the three half-hours of highest demand on the GB electricity transmission system between November and February each year. National Grid identifies peak electricity demand at these three points in order to minimise energy consumption and set charges for transmission system use (National Grid, 2015b, *Connection and Use of System Code. Applicability of sections and related agreements structure*).

[10] ENTSO-e, 2014, *2014 Ten-Year Network Development Plan*

If a DNO decided to deploy storage today using the generation licence exemption, it would be overspending its capital allowance, but would only receive little income via the restrictive *de minimis* requirements.[11] If a DNO used a 'standard' approach to justify its use of storage (i.e. conventional asset replacement, or reinforcement), its activity would need to be assessed based on the expected efficient costs for the substitute asset type, which would feed into its revenue and the regulatory asset value. This assessment reflects a key barrier to storage deployment in that it fails to consider the whole set of benefits to the wider energy system, aside from those delivered to the DNO itself.

4 Business models for DNO and TSO ownership of energy storage

A number of business models for ownership of distribution-scale storage have been proposed, and the most prominent are listed in Table 2. A major concern for the DNO Merchant and DSO business models is to respect horizontal integration unbundling in order to avoid distorting competition in the generation and supply markets. These issues are considerably less important in the DNO Contracted and Contracted Services business models since the distribution businesses would take a reduced role in asset operation under these models. However, they may be overcome by allowing distribution businesses to be actively involved in trading for balancing purposes, where storage is operated in this context. This could be done by allowing distribution businesses to trade for balancing purposes, in a way similar to National Grid; however, this may result in the distortion of competition. Therefore, restrictions would be required to avoid trading for any other purpose that does not directly involve balancing the system, thus activities such as speculative trading should be banned in such case.[12] These issues are less important in models with incentives to charge, given that ownership and operation would be devolved to a third party.[13] However, these types of models present other issues, such as that the DNO is more uncertain as to whether the investment in the storage plant is feasible and will be made, which might adversely affect system security. In this case, the business would depend on the third party, which could fail to appropriately recognise the investment benefits to the distribution business. Thus, while models such as the Charging Incentives model, and to a lesser extent the Contracted Services model, entail lower regulatory challenges than those arising from the DNO Merchant and DSO business models, they entail far higher commercial and system security risk.

DNOs could provide many services using energy storage, including: 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. services to distribution and transmission operators in order to deliver stability, provide balancing services and manage peak load); and, electricity management (i.e. bulk electricity trading). An appraisal of the benefits and potential concerns of these business models by national and EU regulators might remove some ownership barriers and encourage investment.

Across Europe, DNOs in Italy and DSOs in Belgium are allowed to own and operate battery storage. Italy allows DNOs to control batteries if such choice can be justified throughout a cost-benefit analysis showing that the storage system

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[11] The *de minimis* requirements are included in the distribution licence and require 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 (Pöyry, 2014, *Storage business models in the GB market*).

[12] Pöyry, 2013, *Storage business models in the GB market*

[13] Bradbury *et al.*, 2013, *Smarter Network Storage Electricity Storage in GB: SNS 4.7 Recommendations for regulatory and legal framework*

is the most cost-efficient way to solve the identified problem, as opposed to potential substitutes, such as building a new line. Belgium enables DSOs to operate batteries if they do not alter the competitive functioning of markets.[14]

TSOs have stricter regulations than DNOs and only the three business models listed in Table 3 are available in the UK. The 'Ownership unbundling' and ISO models require entities that are involved in TSO activities to be separated from all activities that are related to the market. This provision forbids UK TSOs from holding generation assets, and hence any form of energy storage, under the existing rules. While the ITO model permits common ownership, it is required to be completely independent and ring-fenced from an operational perspective to avoid any distortion of competition.

Italy and Belgium have more flexible approaches to TSO ownership than the UK. Italian law allows TSOs to build and operate batteries, if this can be justified with a cost-benefit analysis that shows the cost-efficiency of storage compared to alternatives.[15] Belgium similarly allows TSOs ownership of storage devices if this does not prevent the competitive functioning of markets.[16]

Table 2. DNO business models for distribution-scale storage[17].

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 on its network in the spirit of a Distribution System Operator's (DSO) role.

Table 3. TSO energy storage business models[18].

Model	Description
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.

[14] DG ENER, 2012, *The future role and challenges of energy storage*
[15] Italian decree law 93/11, Art. 36, par.4
[16] Belgian Electricity Act, Article 9(1)
[17] Bradbury *et al.*, 2013, *Smarter Network Storage Electricity Storage in GB: SNS 4.7 Recommendations for regulatory and legal framework*
[18] Bradbury *et al.*, 2013, *Smarter Network Storage Electricity Storage in GB: SNS 4.7 Recommendations for regulatory and legal framework*

5 Market design

At the moment, it is unlikely that storage investments could be economically-competitive if they offered only arbitrage services.[19] Ancillary and balancing markets currently favour dispatchable generators. Ancillary markets which provide a potentially significant portion of revenues to storage providers do not offer a number of services that storage could provide, including faster frequency response and transmission upgrade deferral or avoidance.

If the system operator orders a DNO to decrease demand to balance the system, these balancing activities are not included in the methodology for calculating cash-out prices, and this lack of monetisation means that cash-out prices do not increase as much as they would during periods of market tightness. Although electricity imbalance arrangements should provide settlement for energy that is produced or purchased without a binding contract, the methodology currently used for its calculation inhibits cash-out prices and diminishes the strength of the signals and incentives they would be able to deliver. If these activities were monetised, both energy storage and generation offering flexibility and reliability would become more competitive.

While a considerable opportunity exists for storage to realise value by providing services to the balancing market, the market design reflects the historical design of the electricity system, based primarily on fossil generation and without a high penetration of intermittent renewables, and this is a barrier to the realisation of the value of storage. Pricing is based on the production costs of the marginal unit, as with virtually all world markets. Technologies with low capital costs and high operating costs require a lower risk premium in such markets, which is why low-carbon technologies with high capital costs have required additional support to justify their business cases, whether through the Renewables Obligation or through strike prices for nuclear power. Energy storage technologies also have high capital costs and would require similar support, as hourly ancillary service market prices are similarly set by the highest-cost unit selected, which is the unit with the highest opportunity cost during that hour.[20]

While small-scale distribution-connected storage may participate in the wholesale market, most probably via a supplier's portfolio, the treatment of storage in the Balancing Mechanism Unit (BMU) and settlement remain ambiguous and market uncertainty could be reduced if this were clarified.

Although the new UK capacity market could offer an opportunity for novel energy storage technologies, it has an effectively open-ended delivery obligation as there is no defined time limit for the delivery commitment. This is a barrier for storage technologies since their discharge duration is limited. If the storage device were entirely discharged before the end of the warning period, its provider would be subject to a heavy penalty equal to the volume of under-delivery times a price that is directly related to the Value of Lost Load (VOLL) (around £17/kWh) up to a cap of 100% of the annual capacity payment to the provider.[21,22] To address this issue, lower penalties could be applied to emerging technologies; however, this could affect security of supply and be viewed as an anti-competitive measure. An alternative approach of establishing contracts for defined time limits might provide more secure revenue streams to storage providers and improve their integration within the system.

[19] Strbac *et al.*, 2012, *Strategic assessment of the role and value of energy storage systems in the UK low carbon energy future*, Carbon Trust
[20] Kirby, 2006, *Demand Response for Power System Reliability*, Oak Ridge National Laboratory
[21] 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.
[22] Ofgem, 2014, *The Electricity Capacity Regulations*

Capacity markets are fundamentally defined by mechanisms that most often reward peak generation plants and are not designed to directly compensate other flexible units such as storage. A number of countries have created capacity markets and storage has struggled to make inroads in virtually all of them, not least because double network tariffs for storage, for charging and discharging, make business cases less viable.[23] Although the storage provider may participate in secondary trading to lower penalty risk in the capacity market, this would likely lead to high costs for them in practice since the period in which they would buy would likely be a tight market period. In principle, lowering risks is possible by buying the delivery obligation from another provider. However, relying on the secondary market may not represent an efficient solution to decrease non-delivery risk.[24]

Little is currently known about the impact of deploying storage on the electricity market since very little storage has been deployed. The California ISO has mandated large increases in intermittent renewables, including wind and solar, which has translated into an increasing use of and need for storage.[25]

Accommodating higher levels of intermittency in the electricity system requires an understanding of the changes in the behaviour of net load created by high levels of generation occurring in a relatively short period of time, usually in the middle of the day. In order to make this possible, California and other U.S. markets have proposed to: shorten scheduling intervals, increase interaction across regions, and to create new market incentives for generator dispatch. Adding flexibility options can reduce the minimum generation needed from hydro and gas generation, thereby reducing renewable curtailments, which are highly prevalent in the UK. In a lower-carbon system, grid operators will need non-conventional resources to supply reserves and grid stability services. This requires system operators to have significant control of distributed PV, wind, storage, and load, and will likely require new market mechanisms that incentivise resources to participate in markets to provide grid services.[26] However, operational benefits from grid services, especially ancillary services, are currently very hard to quantify, which potentially restricts the role of storage. Hence, policies aimed at incentivising ancillary service provision could be a key factor in enabling higher levels of energy storage deployment.

6 Storage in international markets

Virtually all world markets, EU, Japan, China, Australia, and the United States, classify storage as generation. This approach reflects that there has not been a need for a separate classification previously, as storage devices were not economically viable (except large-scale pumped-hydro, treated as a special case), and because storage discharges electricity on demand like a generator. Most ancillary world electricity markets do not currently provide a number of technical services, including inertial response, governor response, black start and reactive power, which could make for a better storage business case.[27]

Due to the differences in EU member approaches to network tariffs, 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

[23] Kirby, 2007, *Ancillary Services: Technical and Commercial Insights*, Wartsila North America
[24] Bradbury *et al.*, 2013, *Smarter Network Storage Electricity Storage in GB: SNS 4.7 Recommendations for regulatory and legal framework*
[25] California ISO, 2011, *Renewable Integration Market & Product Review, Phase 2*
[26] National Renewable Energy Laboratory, 2015, *Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart*
[27] US Department of Energy, 2013, *Grid Energy Storage Report*

less favourable rules.[28] Harmonisation of grid fees would provide fairer competition between storage providers and with other generation technologies.

Several studies have examined the barriers to energy storage in the EU.[29] The major barriers to deployment, in order of perceived importance, are:

1. Absence of an approved definition and appropriate classification.
2. Absence of a verified need for storage.
3. Absence of a verified role(s) for storage.
4. Absence of verified benefits and lack of recognition of benefits.
5. Absence of ancillary markets.
6. Double or uncertain fees for grid access.
7. Absence of unified and conclusive EU legal and regulatory frameworks.
8. Distortions in national energy markets.
9. Incomplete, uncertain and complex licensing for storage.
10. Uncertainty regarding ownership of storage assets.
11. Lack of clarity regarding the operation of storage assets.
12. Absence of cost-effectiveness and efficiency of transmission planning.
13. Large dependency of storage on system development.
14. Lack of investment incentives.
15. Competition with other balancing and ancillary assets.
16. Public attitudes against storage.

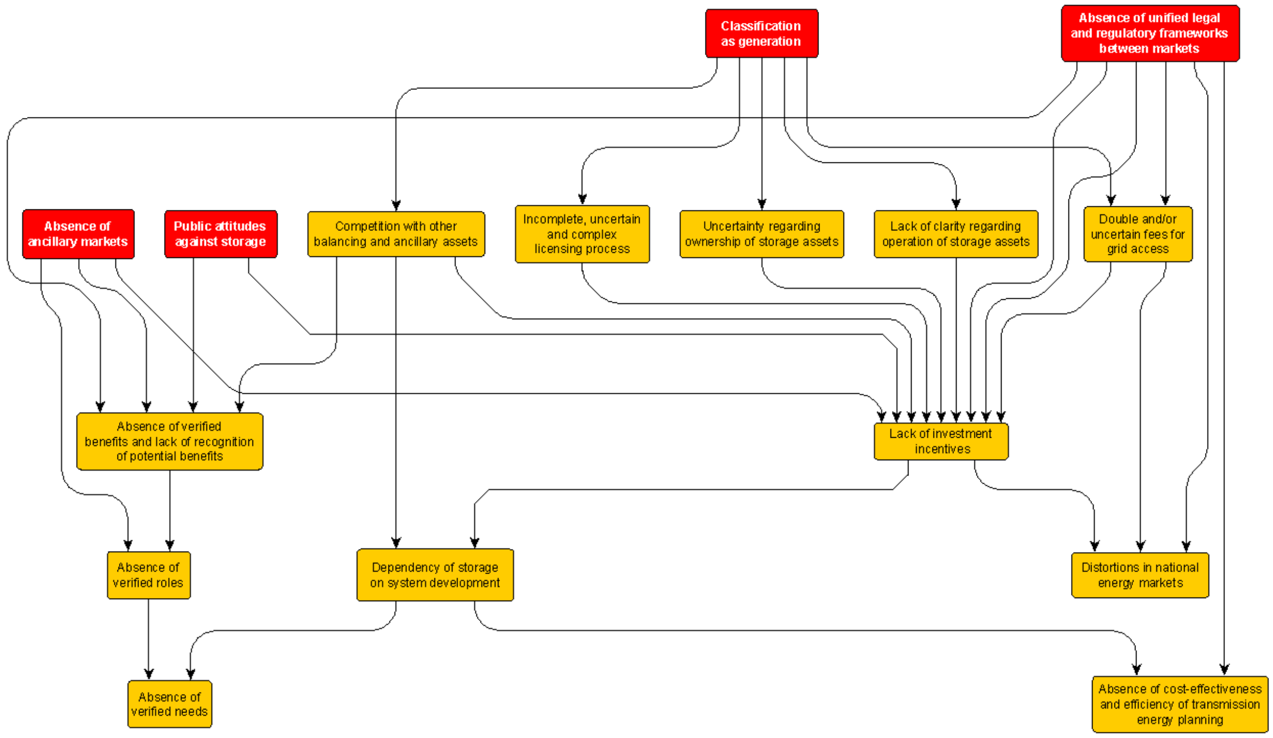
These barriers lead to cost allocation issues, distorted compensation mechanisms, lack of price signals and bureaucratic issues and delays.[30]

There are four principal ‘exogenous’ regulatory barriers to energy storage in EU markets that are unaffected by other barriers and can be categorised as restrictions due to: classification, differences in market rules between adjacent balancing and ancillary markets, lack of ancillary service markets, and public sentiment.[31] Figure 2 shows how these exogenous barriers are linked to the issues described above. This figure conveys three main messages. Firstly, barriers to deployment are highly interdependent, which makes sensible policymaking difficult by nature. Secondly, the four exogenous barriers can be considered essential issues because, if appropriately tackled, they can avoid a number of other barriers. Thirdly, the classification of storage contributes to the greatest number of barriers.

Public attitudes are a potentially 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, is a key and sometimes neglected issue that could affect deployment. People may find different in-house technologies, or perhaps large-scale ones, more or less desirable to integrate in their lifestyles or society.[32]

[28] WIP, 2013, *European Regulatory and Market Framework for Energy storage Infrastructure*
[29] Think, 2013, *Electricity Storage: How to Facilitate its Deployment and Operation in the EU*
[30] US Department of Energy, 2013. *Grid Energy Storage Report*
[31] Castagneto Gissey and Dodds, 2016, *Regulatory Challenges to Energy Storage Deployment: An Overview of EU and World Markets*, RESTLESS Working Paper
[32] Pidgeon *et al.*, 2010, *Creating a national citizen engagement process for energy policy*. PNAS 111, Supplement 4, 13606-13613

Figure 2. Relationship between barriers to energy storage deployment. Exogenous barriers are signalled in red colour.



7 UK initiatives

In order to accelerate the growth of flexible capacity, Ofgem recently proposed the adoption of single cash-outs for all imbalances in individual settlement periods. In contrast to the ongoing dual-price method, this reform could increase cash-out prices and incentives for flexible capacity investments, and hence potentially reward energy storage technologies.[33]

National Grid's proposed Enhanced Frequency Response (EFR) tender could be a reliable source of revenue for some energy storage technologies. This service would require 100% active power output within 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 4-year contracts have been mooted, there would be longer revenue certainty than for other services. However, it is unlikely that batteries would out-compete interconnectors at current costs.[34]

The design of UK balancing markets initially reflected the generation supply mix when they were introduced. New procurement principles now have flexibility for non-standardised services to be procured under present contractual agreements, improving the role of storage,[35] although *dynamic* requirements could lead to further improved allocation of resources.

[33] Ofgem, 2013, *Electricity Balancing Significant Code Review. Draft Policy Decision*
[34] National Grid, 2016, *Enhanced Frequency Response. Invitation to tender for pre-qualified parties*
[35] National Grid, 2015, *Balancing Principles Statement*

In addition to revising the frequency response service, National Grid are also considering the introduction of an aggregate fast reserve service by non-Balancing Mechanism (BM) service providers, meaning that storage could offer *fast reserve*. Storage technologies could comply with the standard minimum service provision of 50 MW to be provided in 2 minutes. However, this might only occur within an aggregate offer, with other generators, which would potentially distort to some extent the value of storage in offering this service. National Grid have proposed the establishment of a week-ahead tender timescale, in order to avoid long-term forecast limitations, and aggregation.[36] Both of these features could encourage the participation of non-conventional providers such as energy storage in these markets.

8 International initiatives

World markets are yet to undertake any significant regulatory reform that might enable energy storage technologies to capture value across regulatory classifications and between cross-border markets.

The United States has introduced a number of policies that might facilitate the integration of storage resources. The introduction of a *performance* payment (in the capacity market) is a cornerstone of modern US energy storage policy. The U.S. Federal Energy Regulatory Commission's (FERC) Order 755 imposes a two-part payment for the frequency response service, composed of a capacity payment and a performance payment. The capacity payment is based on a uniform market-clearing price, whereas the performance payment reflects a technology's performance accuracy in the provision of the frequency response service, which must be market-based. Importantly, the rule states that all markets with centrally-procured frequency response technologies must provide compensation for cross-product and intertemporal opportunity costs.[37,38] However, there is no mandate for a compensation methodology for capacity or performance payments, meaning that the process for these payments is determined by the different market operators; this has led to criticisms on the basis that a disharmonised market can fail to optimally allocate such resources across space. Moreover, the U.S. has recently opened its markets to storage resources, with FERC Order 719, which requires that Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) accept bids from demand response and storage technologies to participate in the provision of energy, balancing and ancillary services.[39]

The California market has been modified to encourage the deployment of novel energy storage technologies. California enacted a law in October 2010 requiring the California Public Utilities Commission (CPUC) to establish appropriate 2015 and 2020 energy storage procurement targets for California load serving entities, on condition that they were cost-effective and commercially viable by October 2013. Furthermore, specific storage targets were set by the CPUC for each electric utility and type of domain (i.e. transmission; distribution; end-user).[40] These initiatives are

[36] UK Power Networks, 2012, *Business model consultation*, Smarter Network Storage
[37] Sandia, 2013, *Market and policy barriers to energy storage deployment*
[38] A frequency response resource's payment for its cross-product opportunity cost reflects the cost of not participating in the energy market. The value a resource forfeits to provide regulation due to less flexibility to charge/discharge advantageously through the energy market reflects a resource's intertemporal opportunity cost. These two opportunity costs must now be payed to frequency response resources, which could make the business case for storage more attractive (California ISO, 2011, *Renewable Integration Market & Product Review, Phase 2*).
[39] Sandia, 2013, *Market and policy barriers to energy storage deployment*
[40] US Department of Energy, 2013. *Grid Energy Storage Report*

expected to decrease the risk that electric utilities face when investing in energy storage.[41] China and France have recently also implemented a similar obligation.

To encourage heat storage electric boilers and ice storage air conditioners, a preferential electricity price is applied to energy storage in China. Although such policy could certainly encourage the use of storage, it is unlikely that the more competitive EU markets would allow such a policy, on the grounds of maintaining competitive markets.[42] However, a similar policy could be developed that targeted a wider range of emerging energy technologies.

Although the European Union often advocates the usefulness of storage, no significant measures or policies have been taken so far to facilitate the deployment of energy storage technologies. In practice, new EU electricity market rules have targeted transmission networks and renewables, without placing particular emphasis on storage.

9 Conclusions

Energy storage technologies could make an important contribution to balancing low-carbon, inflexible generation. Effective innovation, underpinned by deployment into existing energy markets, is required to reduce their high capital costs so they can provide value to the system in the future. It is currently difficult to justify deploying storage as both network reinforcement and flexible generation are substantially cheaper. Furthermore, the array of benefits that storage might provide to the electricity system depends on a number of factors, including time-of-day, season, location, the available mix of resources and longer-term electricity demand trends. The potential role and competitiveness of energy storage in new markets is not well understood, which makes it difficult to demonstrate viable business cases. Moreover, there are a number of formidable barriers to the deployment of storage in the UK electricity system that arise from current electricity market design.

The absence of a regulatory definition of energy storage has led to its classification as a generation asset in the UK and in most other countries. A new definition that differentiated storage from generation would facilitate the removal of barriers to the deployment of storage. At the moment, any transmission and distribution tariffs are levied twice on storage as it is treated as both an electricity consumer and generator. These double charges arguably do not reflect the potential complementary benefits of energy storage to the transmission network in balancing the wider electricity system, and it might be appropriate to apply lower network fees to energy storage plants. There is a precedent in the gas markets for creating a unique asset definition for storage.

Ownership and operation of energy storage devices by TSOs and DNOs is forbidden or heavily restricted due to competition concerns, by both UK and EU law. Yet the system operator is in the best position to maximise the utility of storage in balancing the system, and deploying storage could reduce or delay the need for network reinforcement. A number of TSO and DNO business models have been proposed to enable storage ownership without introducing anti-competitive market behaviour. An appraisal of the benefits and potential concerns of these business models by national and EU regulators might remove some ownership barriers and encourage investment. In Belgium and Italy, network owners and system operators are already allowed to own and operate energy storage in some circumstances.

[41] Pollitt *et al.*, 2015, *Electrical Energy Storage: Economics and Challenges*, Energy World Magazine
[42] Hu *et al.*, 2013, *Integrated Resource Strategic Planning and Power Demand-Side Management*, Springer

It is difficult to envisage energy storage being able to compete with flexible generation in existing UK electricity markets. Low-carbon electricity generators with high capital costs have required subsidies to compete, in the form of generation quotas or strike prices, and energy storage technologies face similar challenges. Realising the potential value of storage to the balancing market has proven difficult, and even the new capacity market has features such as an effectively open-ended delivery obligation that affects the viability of storage in the market. Proposed market changes such as the provision of enhanced frequency response and aggregate fast reserve services could provide new opportunities for storage.

Key policies adopted by California and other U.S. markets to withstand increasing levels of variable generation were shown to enable greater utilisation of variable generation by reducing the technical and economic limits of thermal and hydro power plants to decrease or block generation, particularly in minutes to hours, during the central hours of the day. However, this requires system operators to have significant control of storage resources as well as new market mechanisms that incentivise such resources to participate in markets to provide grid services. The latter, in turn, requires an official methodology for the quantification of operational benefits delivered by such technologies.

Emerging energy storage technologies would benefit from a friendlier market environment. Energy storage is an important part of the UK's industrial policy and the UK is at the forefront of developing a number of novel energy storage technologies, with high export potential. However, the required innovation is unlikely to happen unless a regulatory path is created to facilitate the deployment of energy storage in the existing electricity system.