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POLICY AND REGULATION FOR ENERGY STORAGE SYSTEMS

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Policy and Regulation for Energy Storage Systems

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Abstract
We analyze the changes in the regulation of electricity systems required to adapt to the presence of energy storage. To that end, we begin by identifying different types of services provided by storage. As services have different economic properties, the economic mechanisms required to organize them will be different as well. There are two relevant "arenas" for storage services: i) buy and sell energy in different periods (including energy related to ancillary services); and ii) avoid the need to transport energy from one point to another, i.e. the need to use transmission and/or distribution networks. Consequently, this involves two kinds of regulatory challenges, because storage compete with different types of services. The first regulatory challenge is related to wholesale market design, because flexibility services can be sold in "competitive" wholesale markets (energy, ancillary services, etc.). The second regulatory challenge has to do with the regulation of energy networks, because storage services may avoid the use of "regulated" networks. Consequently, network rules should allow them to compete in a technologically neutral manner.

Keywords: Energy Storage Systems; Market Design; Network Regulation

JEL: D23; D82; L51; L94

1 Introduction

There is currently wide consensus regarding the fact that electricity systems in developed countries are being completely revamped and reshaped while moving towards a new setting. Although it is fair to say that this revolution is closely linked to the global need to tackle climate change, it would be misleading to believe that the latter is the only major factor at stake. Indeed, the current debate (e.g. proposed market design for the Energy Union) suggests that the change in the electricity system has been driven by four key factors.

The first factor is decarbonization, i.e. the dash for renewables. In fact renewable energy sources (or RES) excluding large hydro accounted for the majority of GW of new generating capacity installed in 2015 – for the first time ever: 53.6%, compared to 49% in 2014 and 40.2% in 2013. However RES, excluding large hydro, made up 16.2% of established power capacity and accounted for 10.3% of global electricity generation (UNEP, 2016).

Additionally, decentralization, i.e. a shift towards a decentralized system, is currently playing an increasingly relevant role. The «core» of electricity systems is moving «south»: e.g. prosumers, distributed generation, energy storage, smart grids, etc. Large and small consumers are taking over electricity generation while a single control area (TSO) is being replaced by a web of interconnected smaller control areas (TSO and DSOs); a key role will be played by Integrated Distributed Energy Resources (iDER) portfolios. This shift towards a more decentralized system is further enhanced by the developments of "internet of things", whereby increasingly every little electric device will be connected.

The third factor is electrification, i.e. the move from energy to electricity consumption. There is a revolutionary change in the paradigm, due to the further electrification of energy consumption. Such electrification mostly will occur at distribution level. The question is how this will affect the rate of growth of demand, with respect to impact of slower economies and lower energy intensity.

Finally, we are observing increasing convergence, i.e. the overlapping among ICT, automotive and energy industries. The new ICTs and digitalisation of almost everything open up the possibilities of smart energy systems. Batteries are becoming not just ways of powering vehicles (EV), but also storing electricity at home, while being remotely controlled by a smartphone.

The relative weights of these four drivers will be fundamental in defining the structure of the next electricity system in a particular geographical area (e.g., a more decentralized electricity system may be more suitable for a less densely populated country). However, it should be emphasized that these drivers have been triggered, for the most part, by the introduction of a set of "disruptive" policies: e.g. there would not be any decarbonization without the implementation of a renewable target[1]. Furthermore, these rapid changes taking place within the organization and structure of electricity systems, lead to a demand for new services.

In particular, the greater penetration of renewable-based generation, mostly of non-programmable type, in the European electricity system, in order to meet EU environmental targets for 2020 and beyond, clearly emphasizes the need for enhanced flexibility of that system. It is widely agreed that such flexibility can be provided by a set of specific technological solutions: demand side management, interconnections and smart grids, flexible thermoelectric generation and energy storage. The latter, in particular, is often indicated as a game changer for future electricity systems and, as such, has recently attracted a lot of attention from policymakers and regulators on one side and significant investments from both grid operators and grid users on the other one. Indeed a high penetration of intermittent renewables in markets such as California, Denmark, Germany and China is one driver of the ongoing changes in the electricity system that points toward rising opportunity for energy storage at the residential, commercial and utility levels.

Nevertheless, there is still considerable uncertainty with regards to which market design and regulation may actually provide the necessary framework so that energy storage can be adequately developed and thus contribute to increase the necessary flexibility and move towards a low-carbon electricity system. Indeed the evidence indicates that there is scope for policy interventions that could dramatically affect renewables adoption in two separate but connected ways. One is to provide subsidies for research and development in energy storage, whose progress would involve making renewable generation more profitable and eventually (and sooner than otherwise) sustainable without generation subsidies. Another is to tackle regulatory and infrastructural issues: indeed, with larger and better functioning wholesale markets and smarter electricity grids, installing storage capacity should come closer to commercial profitability on its own.

In this paper, we study the changes in the regulation of electricity systems required to adapt to the presence of energy storage. To that end, we begin by identifying different types of services provided by storage. As services have different economic properties, the economic mechanisms required to organize them will be different as well. There are two relevant “arenas” for storage services: i) buy and sell energy in different periods (including energy related to ancillary services); and ii) avoid the need to transport energy from one point to another, i.e. the need to use transmission and/or distribution networks. Consequently, this involves two kinds of regulatory challenges, because storage compete with different types of services. The first regulatory challenge is related to wholesale market design, because flexibility services can be sold in “competitive” wholesale markets (energy, ancillary services, etc.). The second regulatory challenge has to do with the regulation of energy networks, because storage services may avoid the use of “regulated” networks. Consequently, network rules should allow them to compete in a technologically neutral manner.

[1] Policy and regulation can not only trigger but also boost each driver: e.g. distribution tariffs supporting higher consumption levels, participation of storage facilities to capacity auction, more ambitious renewable targets, etc.

We will analyze the existing literature providing taxonomies of storage services and technologies. We continue by characterizing the various services according to their fundamental economic features. This characterization will in turn allow us to describe the fundamental regulatory and market design challenges that need to be tackled in order to coordinate these services. Equipped with this characterization, we provide a general analytical framework to deal with the previously identified challenges. Specifically, we will point at the challenges faced by the traditional logic for power market design (i.e. mainly based on centralized fossil-fueled generation) in the presence of energy storage systems. Finally, we analyze the Californian and German markets in that framework, because we believe the latter are the most advanced ones with regards to energy storage, and provide general lessons from the study of the two case studies.

2 Problem statement and literature review

Our starting point is identifying energy storage systems as providers of flexibility, as indicated in Figure 2. In that context, energy storage has long been seen a holy grail for renewable energy advocates because it would help wind and solar plants match conventional, but more polluting gas and coal-fired power stations that can generate electricity at will. According to AEE (2016), new installed energy storage systems for renewable energy integration are expected to grow from 196 MW globally in 2015 to 12.7 GW in 2025. At the same time, energy storage is emerging as an alternative solution to traditional sources of ancillary services, for voltage regulation and other types of grid supports.

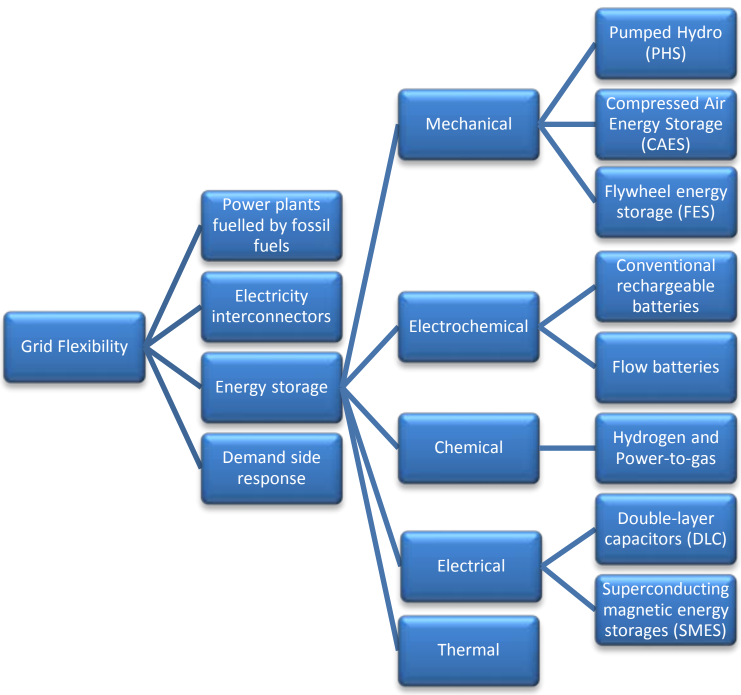

Figure 1 Technological solutions for grid flexibility.

Among different storage technologies, batteries seem to be the most promising ones, also because of its application to electric vehicles and thus to the possibility of decarbonizing the transport sector as well. Until recently the relatively high cost of batteries has put this goal beyond reach. However, with battery prices more than halving in the past six years, growing numbers of companies are starting to sell storage systems, notably in the US and Germany. Indeed, according to IEA's 2016 report on investments, in 2015 at USD 1 billion, grid-scale battery investment was ten times higher than in 2010 and was 10% of electricity storage investment, with the rest mostly from pumped hydro storage. The data also indicates that China, the United States, the European Union and India were the largest investors in networks.

2.1 What kind of services can energy storage provide to the system?

In this subsection, we analyze several descriptions developed in the literature of the services energy storage can provide.

2.1.1 The view of the energy industry

In Figure 2, we represent the classification provided by the European Association for Storage of Energy. It separates services according to each of the traditional segments (from generation to retailing). Note that services at the generation level are separated between those aimed at conventional generation and those aimed at supporting renewable generation.

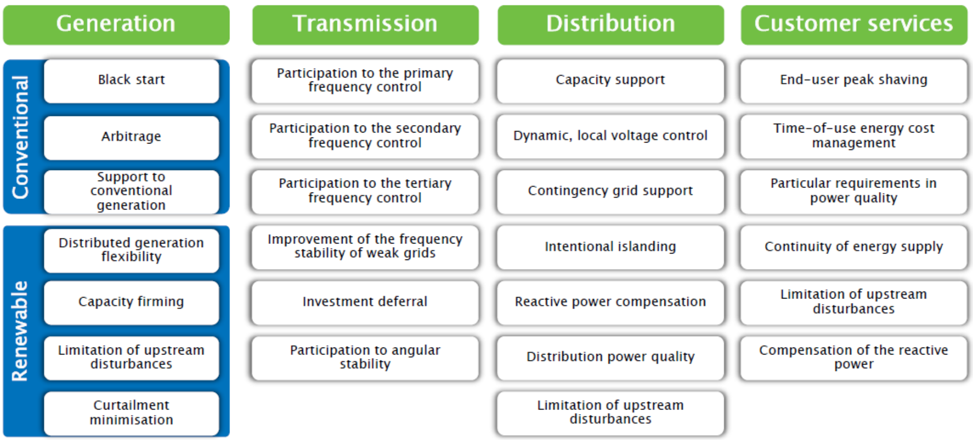

Figure 2. European Association for Storage of Energy (EASE).

2.1.2 The view of the European Commission

In DG ENER WP (2013), it is also highlighted the separation between traditional segments, but the type of use is also considered. In particular, it distinguishes between uses associated with centralized operation of the system, the ones associated with decentralized operation, and end-users' applications.

Storage applications	Centralised	Decentralised	End-use

Balancing demand & supply	- Seasonal/weekly fluctuations - Geographical imbalances - Variability of wind & solar	- Daily/hourly fluctuations - Peak shaving - Integrate with heat/cold storage	- Daily/hourly fluctuations - Integrate with heat/cold storage
Grid management	- Voltage & frequency regulation - Participate in balancing markets	- Voltage & frequency regulation - Defer grid reinforcement - Substitute existing ancillary services	- Aggregate to provide grid services
Energy efficiency	- Time shifting: off-peak to peak	- Demand side management - Integrate with district heating & CHP	- Increase value of PV& micro wind - Facilitate behaviour change

Figure 3. Classification provided in "The future role and challenges of Energy Storage" DG ENER WP (2013).

2.1.3 *The view of academia and think tanks*

In this case, classifications are more concerned with the technical aspects of energy storage, see (Palizban and Kauhaniemi, 2016). In Figure 4 we reproduce the technical classification provided by the Imperial College.

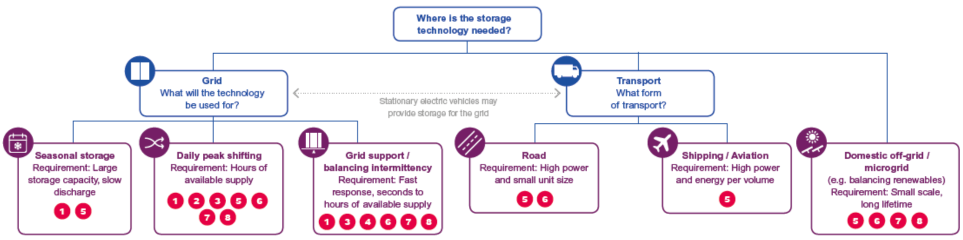

Figure 4. Classification by Imperial College London – Grantham Institute.

In Figure 5, we reproduce the classification developed by (Fitzgerald et al., 2015). We observe that, besides technical characteristics, services are classified according to the players in charge of coordinating the services provided by batteries.

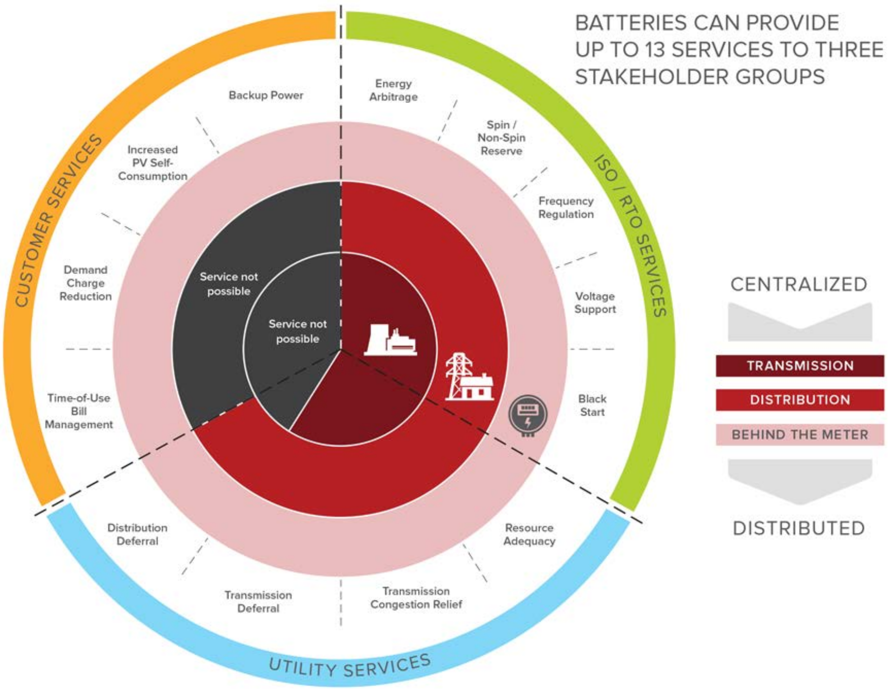

Figure 5. Different services by batteries (RMI, 2015)

2.2 Lessons drawn from the literature review: identifying regulatory challenges

Most of the studies that can be found in the literature analyze storage from a user's point of view (the kind of service storage provides). Moreover the analysis of such literature suggests different approaches providing a framework for the various services which could be provided by storage technologies, mostly batteries, as indicated in Figure 5. However from a market design point of view, it is important to analyze the question in terms of who offers storage services. From this standpoint, there are two relevant "arenas" for storage services:

- TIME SHIFT. Buy and sell energy in different periods (including energy related to ancillary services)
- LOCATIONAL SHIFT. Avoid the need to transport energy from one point to another, i.e. the need to use transmission and/or distribution networks

Consequently, this involves two kinds of regulatory challenges, because storage compete with different types of services.

The first kind of regulatory challenge is related to wholesale market design, because flexibility services can be sold in "competitive" wholesale markets (energy, ancillary services, etc.). Hence, markets rules should allow storage services to compete in a non-discriminatory manner with other services (e.g. utility-scale storage vs. CCGTs).

The second kind of regulatory challenge has to do with the regulation of energy networks, because storage services may avoid the use of "regulated" networks. Consequently, network rules should allow them to compete in a technologically neutral manner (e.g. utility-scale storage vs. transmission upgrades).

The next sections discuss these two sets of challenges.

3 Regulatory challenges associated with market design

Flexibility services may provide multiple services so we need to understand the economic properties of those services:

- **Energy services**, both short-term (e.g. day-ahead markets) and long-term (e.g. capacity markets[2]) – Commodity trading between two market players
- **Adjustment services** (e.g. intraday markets) – Trading of services to deal with imbalances; this also consists of trading among market players
- **Ancillary services** (e.g. re-dispatching) – Trading between SOs and market players in order to guarantee system integrity

In order to understand the available options, we need to consider the basic logic for the electricity market design. Differently put, in order to **choose coherently** the design that fits best to the new situation (including flexibility services), we need to understand the building blocks of the market design.

The most common spot market design is organized around a day-ahead auction, where producers place bids to sell the energy demanded in the system, the auction mechanism selects the cheapest ones, and a generation dispatch arises. The characteristics of this auction are, however, far from being standard and go beyond the theoretical results obtained by auction theory, see for instance (Milgrom, 2004). Day-ahead electricity auctions can be described as multi-unit (many different megawatts are purchased in each hour in each auction) and multi-product (the energy corresponding to the demand of several different hours are purchased at the same time in each auction, all of them different from the rest, but all of them inter-related).

3.1 Elements of electricity market design

3.1.1 Auction-based designs

A first alternative for implementing these day-ahead auctions is to design spot markets as simple auctions, ignoring the multi-product feature, so power producers would send bids specifying the price required for selling each possible quantity. In this context, there would be one simple auction to allocate the electricity produced at each hour, and all these auctions would be independent from each other. A simple auction only allows for the specification of a cost proportional to the units output and a maximum output constraint. However, the real conditions of generators in a unit commitment problem include several technical constraints (ramping limits, minimum output...) and non-linear costs (start-ups, shut-downs...), which make the cost structure more complex than the bids allowed in a simple auction. Besides, a

[2] In that respect it is useful to emphasize the recent (December 2016) results of a capacity market auction in the UK, whereby 500 MW of NEW storage projects (including a 49MW battery facility) won contracts to supply back-up capacity to National Grid.

number of these technical conditions have the effect of interlinking the different time periods, making the results of the auction in one certain hour depend on the results of the rest of them. Having a simple-auction market design results in the need for market players to internalize into their bids and offers the part of the costs that cannot be specified in the auction bids. For instance, they might place a bid for the quantity corresponding to their minimum output with a very low price, so that this quantity is always accepted in the simple auction and therefore always dispatched.

Bidding this way is quite a difficult task. For instance, in order to internalize minimum output constraints, producers must know when their plant will be online. This depends on the auction results, so it is subject to uncertainty when producers send their bids. Thus, the design of the bids requires not only the use of the technical data of the plants, but in addition the estimation of the auction results. If such estimations are not accurate enough, the bids will not be correct and the auction dispatch will not be satisfactory for power producers –e.g. the final unit commitment for some certain generator might not fulfill the ramping constraint and thus be technically infeasible. Hence, when a simple auction is implemented, there is a risk factor directly associated with the market clearing mechanism design, which translates into an additional production cost[3].

An answer to this problem is to allow for the creation of a number of additional markets, before and after the day-ahead auction, where generators can re-negotiate their positions and adjust their schedules, correcting the possible internalization errors, (Wilson, 2002). If arbitrage among the different markets works efficiently, the set of consecutive markets is equivalent to a single market with no internalization problems. This is the predominant scheme in Europe. Unfortunately, for adjustments that take place in time horizons shorter than the day-ahead market this arbitrage might be limited, so the consecutive markets solution allows for a mitigation of the bidding risk induced by the simple auction, but only partially. Actually, most EU markets have some bidding mechanism to manage this risk, which will be partly considered below as third alternative.

In many cases, the typical instance of the need of sequential auctions is the representation of start-up or online costs. But congestion is an equally valid example of the idea, and specific mechanisms have been designed to deal with this type of system constraint (e.g. market splitting or market coupling, (Marmiroli et al., 2006) or (Oggioni and Smeers, 2013). In general, they are forms of implicit allocation in simplified representations of the network. In the limit, one would have one price for

[3] Note that the problem is similar to the one described in (Vickrey, 1961). In the (Vickrey, 1961) context, the English and the Dutch auctions are equivalent under perfect information, but the English one is superior since it allows for truthful bidding and therefore avoids the need for internalization. In the day-ahead electricity market, the simple and complex auctions yield the same results when the information is perfect, but the complex one is superior since it does not need any information about the rest of the competitors to get to the optimal result. However, while in the (Vickrey, 1961) case the information is needed to optimize the strategic behavior of players, which might be questioned especially in a multi-unit context, in the electricity market the information is required to incorporate the cost conditions of the bidders, which would had also happened under perfect competition.

network node, as in the case of nodal pricing. It is important to distinguish these algorithms from the counter-trading algorithm, where the pricing zone is unique, and we deal with congestion within the zone.

An alternative solution is the complex auction, where players are allowed to place bids that specify additional conditions to the price-quantity pairs of the simple auctions. The block bids adopted in NordPool and EEX or the minimum-income conditions of the Spanish pool are examples of these rules. The corresponding market clearing, thus, must be found by solving some optimization problem. The pure complex auction is essentially a traditional unit commitment model, which is applied to clearing power markets, (Hobbs, 2001). This is the predominant approach in the US nowadays. The immediate advantage of these mechanisms, as of the iterative ones, is that they capture the inter-relation of the different hours and eliminates the need for internalization. On the negative side, their complexity makes their results difficult to explain and this may raise some credibility problems. Besides, eliminating the need for internalization of power producers means that the associated risk is borne by the auctioneer, which is typically equivalent to being borne by consumers. The auctioneers have more information than individual power plants about the system costs. However, the auctioneer must decide before realization of demand evolution over the next hours. The trade-offs associated with each solution are not clear and need to be investigated carefully.

3.1.2 Continuous auctions

The options described so far can be seen as different implementations of centralized trading. That is, generators participate in a simultaneous auction (that takes place at a particular point in time). The procedure is that generators offer to sell power (e.g. bid amounts of MW they are willing to produce every hour). The central auctioneer accepts the lowest bids, so that every hour, generators with accepted bids generate. As we have seen, tis general methodology can deal with a wide range of constraints, as demand-side participation, technical constraints on plant operation (e.g. maximum “ramp-up”), transmission constraints (losses and congestion).

The alternative to these centralized solutions is the continuous auction (bilateral trading). Under this alternative, generators sign contracts with retailers and large consumers to supply power, instead of participating in the simultaneous auction. The objective is to make power markets as similar as possible to other capacity markets. On the negative side, when compared to centralized solutions, is that technical constraints cannot be included in a straightforward manner, and hence the TSO’s actions become more relevant. That is, it is easier to trade in this kind of mechanism (transaction costs are lower) but efficiency is lower as well. In that view, transmission constraints may be dealt with by “physical transmission rights”.

We observed a trend to switch from centralized to bilateral trading in the 2000s (e.g. in England and Wales from the mandatory pool to NETA). Regarding trading rules, the preference for bilateral trading may be viewed as associated with concerns about “gaming” (observed for example in the GB pool prior to NETA). There was the belief that wholesale power trading would evolve to look like other forms of commodity trading (e.g. gas markets). This came with the acceptance of a risk of less efficient dispatch: traditional auctioneers could identify overall the most efficient way to meet demand, though bilateral arrangements needed to rely on the efficiency of the trading process. The main drawback of this approach is the risk of suboptimization of the short-term operation.

3.2 The rationale behind balancing mechanisms

In order to highlight the different uses for energy storage systems, let us begin by considering the case of power markets design with regard to the somewhat surprising diversity of spatial characteristics in US and EU markets. In particular, the market for Pennsylvania, Maryland and New Jersey (PJM) has more than one thousand day-ahead prices. The Spanish market, on the other hand, has one.

The idea is that the two implementations of market arrangements have different perceptions of the optimal trade-off between incentives and measurement, (Vazquez and Hallack, 2016). To illustrate this, note that in order to sell electricity produced at one node of the network to a buyer located elsewhere (i.e. at a different node), electricity needs to be transported through power lines. Such transportation is technically complex, involving many requirements for injections and withdrawals. Among them, consider the requirement that the power generator producing electricity needs to be rotating at a very precise velocity, synchronized with the rest of plants in the system (frequency regulation). This requires significant coordination efforts.

So let us consider the case where such coordination is done exclusively by network users (no central "network operator"). Consumers (all of them: residential consumers, industrial consumers, etc.) would need to measure consumption every few minutes, in order to send the information to distant power generators. In case adjustments were required, all users (generators and consumers) would need to reach an agreement in the actions to be taken, in the few minutes available. This is one very good example of the conflict situation that transaction cost economics refers to. That is, as conflict is going to be pervasive, decentralization of activities face more challenges than benefits, and hence aggregation of the decision-making process is a better solution. In that view, the designer cannot leave the decision to market participants.

It is interesting to note that another new technology, blockchain, might change the prospect of conflict and thus the reasoning associated with it. In fact, one may observe several instances of increasing potential for decentralization of very short-term decisions, (Codani et al., 2015).

Along the same lines, consider the choice related to the amount of locational signals given to users in the short run. Defining different prices for electricity at different nodes of the network improves the efficiency of the allocation. To solve the trade-off, market arrangements in power systems rely on a combination of markets and command and control allocations. Some spatial signals are given through prices, whereas frequency regulation is done outside markets by means of a "system operator"[4].

[4] A regulated agent in charge of the power network operation.

The question is how to decide the meaning of "some spatial signals"[5]. Using the designer's estimation of "prospect of conflict", the designer will implement prices only for the nodes of the network where the benefits of incentives are greater than the costs of measurement. For instance, if the values for electricity in two nodes are relatively similar (persistently, it is not enough that they are similar in just one particular hour or day), but measuring electricity at the two nodes is relatively costly for market players, the designer will decide to manage the flows outside the market, defining a single price for the two nodes. The allocation of the remaining services would be done under the responsibility of the system operator, and they are called in the power markets literature "ancillary services" and "congestion management" Note the difference between congestion resulting from the day-ahead auction, which is a market signal, and these network services to deal with congestion, which are TSO's actions and hence costs are socialized (they do not represent signals). This is the case of many Europeans systems.

A key element of this analysis is that the designer needs to estimate players' measurement costs ex ante. Not only does it imply an information problem, but also uncertainty about the real measurement costs. Consequently, it is sensible to expect different estimations depending on the designer. From that reasoning, US power market designers estimate low measurement costs for spatial characteristics whereas Spanish designers estimate large measurement costs.

In both cases, however, designers estimated some network services as prohibitively costly (as frequency regulation), and left them to regulated agents called system operators. In other words, in all cases the network was regarded as a monopoly.

3.3 Does energy storage opens the door for bilateral trading?

The basic message of this section is that balancing mechanisms are a required complementary tool to spot markets. System operators need to deal with the allocation of services that spot markets did not complete. Consequently, the more simplified spot markets are, the greater the amount of services to be allocated by the system operator. Differently put, when market players are responsible for few flexibility services in the power system, the electricity traded in spot markets is more homogeneous (closer to a typical commodity) but the amount of services controlled by the system operator is greater.

Flexibility services associated with ancillary services play a different role in each of the designs: the first one is concerned with optimizing the operation of the system; the second one uses ancillary services to facilitate market trading.

Historically, we observed a trend to switch from centralized to bilateral trading in the 2000s (e.g. in England and Wales from the mandatory pool to NETA). Regarding trading rules, the preference for bilateral trading may be viewed as associated with concerns about "gaming" (observed for example in the GB pool prior to NETA). There was the belief that wholesale power trading would evolve to look like other forms of commodity trading (e.g. gas markets). This came with the acceptance of a risk of less efficient dispatch: traditional auctioneers could identify

[5] The same analysis can be done with time characteristics.

overall the most efficient way to meet demand, though bilateral arrangements needed to rely on the efficiency of the trading process.

However, the combination of increased penetration of intermittent renewable generation and lack of significant storage capabilities implied an increased concern with short-term efficiency. In particular, there was a concern that bilateral trading and uniform pricing lead to inefficient use of transmission system. This motivated a shift towards more centralized system (e.g. market coupling) and more locational pricing (e.g. more than one price zone).

This choice is being challenged, as one of its main motivations (lack of storage) is changing with energy storage systems. That is, centralized trading are a solution for the lack of flexibility in the system in the presence of intermittency (because of the need of quick and tight coordinated answers to unexpected changes). However, what would be the market design with more flexibility coming from storage (but also demand response)? In a situation where markets do not need to be so "instantaneous", and hence closer to other commodities (e.g. gas), the choice between centralized vs bilateral trading may be modified or at least become less straightforward.

4 Regulatory challenges associated with network services

To motivate the framework proposed to identify the problem and hence the appropriate solution, it is useful to consider that, when building network capacity, the main tool to coordinate incentives among all parties involved is the long-term contract. Specifically, it shows the requisite commitment among investors and infrastructure users.

The simplest case to organize the investment is to let players located at different points in the network to negotiate their contracts with network owners. However, as infrastructure business are often characterized by large investment costs, the activity is typically subject to significant market power. Differently put, we are concerned with the dominant position of the transporter, especially if the latter has vested interest in generation assets.

A relatively direct solution would be to regulate the profits that the transporter is allowed to make in the contracts signed with network users. This is the solution chosen for the US gas system. However, path-based contracts are not technically possible in many power networks. Hence, the solution must consist in regulating the entire network, including how much network users pay. But regulatory concepts stem from the idea that more competition should be introduced into the core of network monopolies and that regulation is playing the role of a contract between network users and network owners. This general idea is expressed by describing the regulation of power networks as indicated in Figure 6.

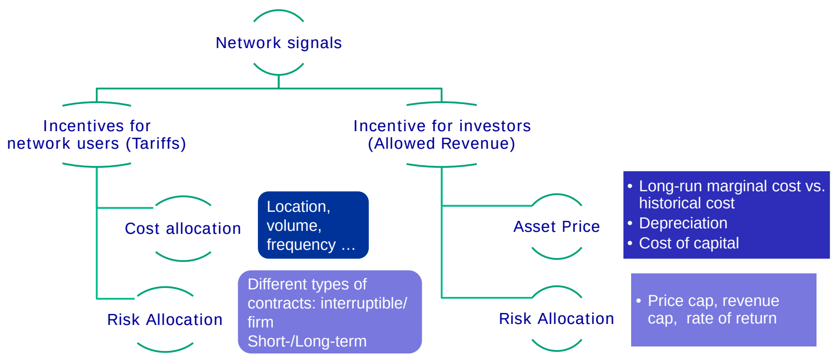

Figure 6. Representation of the elementary signals provided by network regulation.

We will next describe briefly the main ideas behind the definition of tariffs, as they provide incentives for network users, and in principle storage can be seen as a competing alternative for network users.

4.1 Overview on the definition of tariffs structure

We split the study of these signals into two main headers: the definition of the cost allocation among network users, and the definition of the risk allocation among network users. The former dimension deals with cost differentiation aspects. The latter deals with whether inter-temporal differentiation should be established. To put into context the challenge of defining tariff structures, let us begin by describing the steps involved in the process:

- Stage #1 – Define the transport services. This step is fundamental, as it is impossible to decide the price of a product that is not defined. This problem should be studied separately.
- Stage #2 – Define the allowed revenue. This is the total amount that will be recovered by tariffs. This problem was already analyzed in two previous topics.
- Stage #3 – Define mechanisms to allocate costs among network users. This gives a set of initial tariffs.
- Stage #4 – Make adjustments to include additional criteria that was not contained in the mechanisms to allocate costs. This gives the final network tariffs.

The following will describe stages #3 and #4. When defining tariffs, the regulator needs to decide whether to charge according to different uses. The trade-off is associated with whether cross subsidies are appropriate. In particular, there are several dimension where this decision needs to be made:

■ **Capacity/commodity** – What part of the allowed revenue should be linked to actual use (commodity, i.e. energy)? This will be an important element of the reasoning used below in the problem identification step.

■ **Location** – Should users using more km of power lines pay more? As in traditional power regulation commercial flows are decoupled from physical flows, cost socialization is a frequent characteristic of network tariffs. However, locational signals may play a relevant role to decide on investment in energy storage systems.

■ **Flexibility** – The main challenge behind this dimension may be summarized by the following question: should capacity used with flexibility be more expensive (e.g. a train ticket with flexible dates)? This will also be an important element of our problem identification step.

4.2 The need for revise tariff structures

In this section we analyze the basic dimensions identified above, in order to show how network regulation should be improved to provide adequate signals for energy storage systems.

4.2.1 Revision of capacity/commodity split

Let us consider first the technical characteristics of transmission: i) very high portion of the cost is investment cost with low operation cost; and ii) discrete investment sizes together with economies of scale, which cause capacity to be frequently in excess. These characteristics make a simple usage tariff (€/MWh) conflictive. First, if the tariff is set to the average cost of transmission, charges pay for the investments made but the excess capacity may be underutilized. On the other hand, if the tariff is set to the marginal cost of transmission (much lower), we have the opposite situation: we use existing capacity optimally, but not enough money will be collected and therefore no line would be constructed.

From an economic point of view, this problem would be solved by capacity reservation mechanisms (as in gas systems), where the access fee is charged on contracted network capacity. In power systems, where contracting is not frequent, the problem is solved using two-part tariffs. This may justified using nonlinear pricing theory, which shows that the efficient pricing solution consists of a fixed charge to pay for the fixed costs of the network (capacity charge) and a variable charge to pay for variable costs (commodity charge).

For wholesale markets, the issue is well identified and solved.

For retail markets, however, variable charges are in general much larger than variable costs. The traditional justification builds on the assumption that retail demand will change almost nothing upon changes in the access fee, which results in a kind of Ramsey pricing, i.e. higher than competitive pricing: those who consume more will pay a larger share of (distribution) grid costs.

The first assumption is challenged by the existence of energy storage systems, as well as other distributed energy resources. Actually, many distributed systems are being rewarded as if they could save network costs, but they do not actually save costs.

■ **Available options for revised regulation** – Access fees in retail markets should be revised in order to improve the capacity/commodity split. That is, variable charges in retail markets, according to the previous analysis, should be closer to variable network costs.

4.2.2 Revision of locational signals

We showed that network charges play two roles: i) Collect enough money to pay for the regulated investments; and ii) Provide economic signals to ensure efficient coordination with decisions potentially taken outside the network owner, such as investments in energy storage systems.

Next, we will consider two extreme logics to illustrate two extreme solutions for locational signals in tariff design.

The first extreme solution assumes that role ii) above (provide economic signals) is irrelevant. This exaggerated logic would be summarized by the following sentence: "There is no room for optimization since the influence of network costs on decisions is negligible". As the problem is reduced to cost recovery, the typical solutions are cost socialization among all network users (postage stamp) or Ramsay pricing.

The second extreme solution is considering that coordination is so important that any other consideration is negligible. The exaggerated logic may be illustrated by: "grid optimization needs to be enforced". This is equivalent to network planners taking all relevant decisions. That is, investment decisions would be taken by a central planner without coordination with other players (hence, without the need to define coordination signals in tariffs).

Let us consider these two extreme solutions in the following context: a certain distribution system needs to decide whether to invest in a wire alternative to expand the distribution system or to develop an energy storage system.

Within the context of the first extreme solution (grid optimization is irrelevant), network users install the storage system according only to market signals. That is, the investment decision is taken exclusively according to opportunities to sell energy in the market, without consideration of gains associated with deferring the need to develop wire-based expansions of the distribution network.

Within the context of the second extreme solution, as coordination is centrally done by the network planner, storage investment decisions would be taken by the DSO.

On the other hand, both extreme solutions face challenges. In the first extreme solution ("grid costs are negligible"), decisions are based on the siting of battery owners. Moreover, these decision are made considering just energy market signals (probably including ancillary services). In that context, the DSO will just adapt to exogenous decisions. There is a challenge in coordinating information regarding network needs and batteries installation. Specifically, deciding whether the DSO should expand the distribution network (by means of a wire alternative) or a market players should install storage to defer wire alternatives is extremely difficult.

The main limitation with the second extreme solution ("grid optimization needs to be enforced") is that there are elements that grid operators completely ignore. Without signals from network users it is difficult to know the needs for flexibility of the system. Differently put, if infrastructure is devoted to minimize network costs (for instance, to minimize investment), preferences of network users will be probably ignored. This problem is especially serious when network users' preferences are very heterogeneous. Figure 7 summarizes the example.

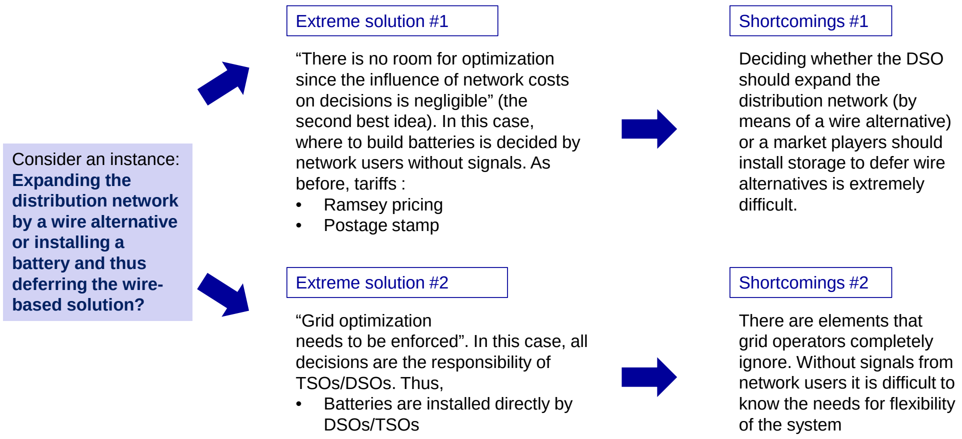

Figure 7. Examples of extreme solutions for cost allocation in power networks.

■ **Available options for revised regulation** – Use of an alternative strategy: "Define economic signals and let players decide" (Complex tariff design). That would consist at least in the introduction of locational signals. Ideally, tariff design would include also flexibility signals.

4.2.3 Revision of flexibility mechanisms

Grid tariffs are hop-on-hop-off tariffs, which means that today's costs are paid by today's users. The assumption behind that logic is that users will be stable (or growing) in time ("They have nowhere else to go")

This assumption is being challenged by the increasing potential to leave the market. Dismantling or mothballing of CCGT and self-consumption (solar, biomass) are becoming a pressing issue. Energy storage systems play a major role in this regard.

■ **Available options for revised regulation** – Ideally, connecting to the grid should imply a commitment to pay for all of the network costs caused.

Let us consider, just as an example, a typical scheme for a private regasification facility. In it, the access fee is charged on contracted capacity, which in turn implies a commitment for a fixed period of time, e.g. 10 years. How would this contract be managed? If the demand for gas transmission is stable, then reselling in the secondary market would be feasible with no loss. If the demand for gas transmission is reduced, then players should not leave without paying the network costs incurred for them.

Hence, the previous logic means that power markets, including retail markets, may need to move from two-part tariffs to charging access according to contracted capacity. Thus, contracts for distribution and transmission capacity would be needed.

In that sense, consider the following example: the allowed revenue of a certain wire investment in the distribution system is going to be recovered through two annual contracts (50% AR each). One is used by a flat network user (same consumption every day), and the other is used by a flexible network user (only uses the network during January). In this situation, the unit cost of the flexible contract is higher, because most of the time the capacity is not contracted. What can be done to avoid that?

- Option #1 – Reselling by DSO or by network user. The difficulty is that it requires a liquid secondary market
- Option #2 – Sell capacity only for peak periods. This solution is based on using short-term contracts. In that sense, we need to consider that, as long-term contracts bear larger risks, they may need lower prices
- Option #3 – TSOs sell more flexible capacity for every user. Under this solution, tariffs are equal for every user, but higher than before
- Option #4 – Sell different services with different tariffs, e.g. seasonal, storage... The last option would mean cost differentiation among different capacity contracts (each contract would imply different sets of network services)

From this point of view, the starting point of a tariff definition based on capacity reservation would be the definition of the network services that would be offered through contracts: different tariffs imply different services. In that context, flexibility would be one of the main dimensions. This includes both temporal and spatial flexibility. Besides, it would important to consider that risk allocation is an issue.

5 The Californian and German case studies

As shown in the following table, a series of relevant indicators pointed out to Germany and California as two key markets for storage to be investigated in the first place.

Key indicators	Germany	California
% of interconnection	5%	21%
Reserve margin	19%	25%
Intermittent RES capacity	13%	15%
Wind installed capacity	1st in Europe 3rd in the world (45GW)	3rd in the US 11th in the world (6GW)
PV installed capacity	1st in Europe 2nd in the world (40GW)	1st in the US 6th in the world (15GW)
Low-carbon policy	Wide and ambitious 55% RES by 2035	Wide and ambitious 50% RES by 2030
Energy storage policy	Only for residential	For utilities and DSO
Energy storage assoc.	BVES	CESA
Economy size	1st in Europe 4th in the world	1st in the US 6th in the world

Table 1 A quick comparison between Germany and California.

5.1 Germany

With respect developments to storage regulation and market design, the German electricity market represents a rather interesting case study. Due to the high penetration of wind and solar, energy storage is being seen as a very promising solution for the integration of intermittent RES in the German electricity market. In 2014 nearly 26% of Germany's power generation came from renewable sources (of which around 14% from wind and solar). In July 2015, renewable briefly covered 78% of German electricity demand. Also Germany has the largest amount of PV capacity in the world, both in absolute (38GW) and relative terms (58% of peak demand). Moreover it is the first electricity market to have introduced support mechanisms specifically targeting storage equipment when combined with PV: it has been estimated that 13,000 residential battery systems were installed in 2015 across Germany.

Above all Germany is currently developing the "electricity market 2.0.", whose aim is to support the country in achieving the targets[6] set in the Energiewende, (e.g. 80% of electricity supply from renewable energy in 2050), through a series of significant changes to its market design and regulation. Finally, the German wholesale electricity market is widely considered as one of the most competitive ones in Europe.

Since May 2013, the state-owned bank KfW has granted low interest loans with an aggregate value of €163 million for 10,000 energy storage projects combined with PV plants with a power up to 30 kW (45% of projects subsidized). The Government also covers 30% of the energy storage costs. Eligible PV systems should feed maximum 60% of installed capacity into the grid, with the rest stored. There are no direct subsidies specifically for large scale storage but financial support may be available through the use of other incentive schemes.

With regards to market design, energy storage provides relevant commodity services. Since RES are now responsible for generation forecasts and balancing solutions, energy storage will enable flexibility and more consistent production by providing energy and adjustment services.

Besides, energy storage may also participate in the balancing of the system, as it is allowed to:

- Provide capacity for the strategic reserve.
- Operate, if in excess of 1MW, within the non-discriminatory primary frequency response markets.

With regards to network services, energy storage might be used instead of traditional transmission investment, as part of the network expansion plans of network operators. However, no particular procedure is defined in order to ensure adequate coordination.

5.2 California

As much as Europe in the fifteen years has been widely recognized worldwide as a prime mover and a leader with regards to the deployment of variable renewable energy (thanks mostly to a more ambitious environmental policy), it is fair to say that **the US are rapidly taking the world leadership** when energy storage is concerned. One of the main reasons is that energy storage is transitioning from a

[6] There are no specific energy storage targets within the Energiewende.

large infrastructure market of pumped hydro and underground compressed air projects (i.e. much of the world storage capacity) to a technology-driven market, with rising scale and falling prices. Indeed, as indicated in IEA (2016), the global market for grid-scale batteries has grown ten-fold in the last five years, reaching over $1 billion in 2015. Furthermore, according to AEE (2016), global revenue from energy storage multiplied five-fold, from $462 million in 2014 to $2.1 billion in 2015. Above all, **the US energy storage market grew by 243% in 2015**, the largest year on record (+800% over 2011), with an estimated $734 million in revenue, a nearly 13-fold increase from 2014. Looking instead at future scenarios, annual deployments of utility-scale energy storage in the US are expected to increase from 184 MW in 2015 to 4.2 GW in 2025, and from 89 MW in 2015 to 2.6 GW of distributed systems (AEE, 2016).

Within the US market, the Californian one is also an interesting case study, since it displays both similarities and differences with the German one. Indeed both markets are characterized by a rather comfortable reserve margin (around 20%) and by a high penetration of non-programmable renewable energy (around 14%). Both markets have a considerable amount of network congestion, often due to the presence of large amount of renewables far from demand centres. Also both markets have been shaped in recent years by more ambitious renewable policies (e.g. RPS in California) than their neighboring ones.

However, there are also key differences between California and Germany. In California market trends and legislative actions have combined to create a rapidly growing market for both distributed and utility-scale energy storage.

California has **a specific policy for utility-scale energy storage**: in 2010 California's Public Utility Commission adopted a new energy storage mandate, which had been the first in the US; the mandate required California's investor-owned utilities (PG&E, Southern California Edison, and San Diego Gas & Electric) to develop 1.3GW of additional energy storage by 2020 expand their energy storage capacity (there are currently over 4GW of grid connected energy storage capacity over a wide variety of technologies). There is no official financial incentives for energy storage projects, although California is the largest residential market in the US for the installation of PV.

Also, if we focus on market design, whereby Germany wants to rely on an energy-only market based on uniform prices, California since 2004 has relied on locational marginal pricing (LMP), like many other US markets (e.g. PJM). There are also key differences concerning market architecture: in Germany there are four independent transmission system operators and one leading operator for the day-ahead market (i.e. Epex) whereby in California there is a single system operator which coincides with the market operator (i.e. CAISO).

With regards to market design, energy storage is allowed to provide a large set of energy services, according to relatively recent modifications of Californian power market. Currently, energy storage may be used for

- Daily, weekly and seasonal arbitrage.
- Operate in a number of balancing and ancillary markets through CAISO, although there are operational difficulties of combining revenue streams for multiple services.

As in the German case, it may be used instead of traditional transmission investment, although the particular procedure to decide that is not clear.

6 Conclusion

In this section, we summarize the analysis developed herein. In particular, we identify regulatory challenges for different market design choices, represented by the power markets in California and Germany.

In section 6.1 we analyze, using the Californian and German markets, the challenges described in section 3.3, related to the needs of market rules reforms.

In section 6.2, we focus on a first set of challenges associated with network regulation, which were identified in general in sections 4.2.1 and 4.2.2.

In section 6.3, we analyze the remaining challenges associated with network regulation, namely the ones identified in section 4.2.3.

6.1 Analysis of market design – Need for a choice between centralized vs bilateral trading

- US models are based on centralized trading (auctions), which requires standard products, including those to trade storage. The challenge is to be able to innovate quickly enough, or to rely on regulated businesses (as utilities) to build storage
- EU systems may rely more on bilateral trading. In that context, the need for standardization is lower, as market payers may adapt more quickly to innovation

6.2 Analysis of network regulation (Part 1) – Need to introduce cost-reflective tariffs

- US models rely heavily on utilities (especially distribution) in charge of batteries installation – No signals to markets (it might be viewed as the “extreme solution #2” of problem #1). Challenges are related to the difficulty of planning without all the required information.
- Germany relied heavily on incentives to costumers to install batteries (it might be viewed as the “extreme solution #1” of problem #1). This implies that suboptimization of grid expansion is the main challenge.

6.3 Analysis of network regulation (Part 2) – Need to introduce long-term commitments for network access

Neither California nor Germany is addressing problem #2, nor considering alternatives to current tariffs design to provide signals for coordination among all players involved.

Connecting to the grid should imply a commitment to pay for all of the network costs caused. The problem would be similar to the one associated with the access to other facilities. In particular, access fees may need to be charged according to capacity reservation. Consequently, contracts to define different preferences for capacity reservation would need to be implemented. Those contracts would have specifications on:

- Location in the grid;
- Use of the system (flexibility);
- Contract duration.

	Revised mechanism	Solution to what problem	Services competing with storage
Market design			
Storage as standard product	Including storage as player in all auctions (energy auctions and ancillary services auctions)	Storage cannot compete with other energy sources (including demand response)	Energy sources
Reduce need for standardization	Implement power markets based on bilateral trading, with reduced need for auctions and hence for standard products	Standardization is difficult when services and technologies are rapidly changing	Energy sources
Network regulation			
Capacity/commodity split	Network variable charges reflect variable costs	Many distributed sources are being rewarded as if they could save network costs, hence creating an extra cost for other sources as energy storage	Energy sources
Locational signals	Tariffs reflect the costs to the network associated with installation of equipment at different locations	Without economic signals, market players cannot decide the cost of storage when compared to wire network expansions	Wire network expansions
Grid defection	Grid connection represent commitment, so access fees are	Grid defection leads to higher tariffs, which	Wire network expansions

	calculated according to capacity reservation	leads to more incentives to defect	

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