The economics of electric energy storage and its interaction with the market rules

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Many claim that de-carbonization targets cannot be achieved without substantial development of electric energy storage (EES). However, the ever-growing interest in EES contrasts with a lack of commercial penetration in Europe. One reason may be that electricity markets, since their inception, have not evolved in a way that encourages flexibility either as a requirement, or as a means, including EES. This may obstruct innovation and development of flexible systems, which could significantly contribute to the reliability of future European power networks, characterised by a high share of intermittent energy production. This paper seeks to expose the interaction between the economics of EES and market regulation. An exhaustive investigation of relevant market regulations for the business of storage is conducted by examining (a) spot and futures markets, (b) ancillary services' procurement and (c) possible capacity enhancement. It is concluded that market regulation can be and should be improved in a number of ways to better recognize the value of EES.

The EU has committed to reduce GHG emissions to 80-95% below the 1990 levels by 2050 (EC, 2011). To this effect, European Industrial Grid set the objective to enable the integration of up to 35% of electricity from dispersed and concentrated renewable sources by 2020 and a completely decarbonized electricity generation by 2050 (EC, 2009).This implies the future power systems need to deal with increasing variability from both supply and demand side, but with less conventional flexible generations. This unprecedented challenge explains the revived interest on electric energy storage (abbreviated as EES hereafter), as one of the flexible means to provide various services (such as capacity firming, voltage and frequency control, back-up capacity, etc.) to ensure the reliability and stability of the system.

In fact, the pumped hydro storage has been operated in the European power system for nearly a century. Their main function was to provide flexibilities to the thermal power system. The total capacity is about 45 GW today in Europe (Prestat, 2010). Most of the investment was made before 1990s by the vertically integrated monopoly. As a result, the use of the storage plant could be coordinated internally through the whole value chain of the electricity business. However, the unbundling introduced by the deregulation reform makes this business model no longer possible. Actors in the regulated (transmission and distribution) and deregulated domain (generation and retail)

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pursue different objectives. New business model needs to be conceived to identify the most valuable services of EES and the most efficient way to deliver these services within the current market and regulatory framework. The market rules define the product/service exchanged as well as the way the price is fixed, thus having an important impact on whether the services that EES provides are adequately recognized and rewarded.

The existing market rules have been designed for conventional generation units. In an evolving scenario of power systems, these markets rules should also be adapted to account fairly the limits and the merits of EES in order to valorize the flexibility that EES introduces in the power systems to the fullest. This paper is aimed at enabling a profound understanding of the economics of storage and the market rules so that this flexibility asset could be better fit into the electricity market design.

In Section 1 the technical functions of EES are briefly introduced, explaining how EES delivers flexibility services to the power system. Section 2 discusses the plausible business models in the future power systems, distinguishing the regulated-driven and deregulated driven business model and presenting the main challenges associated. Section 3 seeks to identify the relevant market rules for the business of EES, analyzes their impact and proposes recommendations for improvement. The regulatory questions such as the ownership, the policy on renewable generators as well as ad-hoc incentive mechanisms for EES, albeit have profound impact on the business model, are not in the scope of this paper. Section 4 concludes.

1. Electric energy storage, a flexibility asset

In the broad sense, the basic energy-storage activity can be considered as "to take energy whenever and in whatever form it is available, convert it to whatever form is best for storage, and then reconvert it to whichever form is best for use at the time we need it" (Fink and Beaty, 1978). *Electric* energy storage, according to this definition, represents a sub-set of energy storage technologies, in which the energy injected in and withdrawn from is electricity. The basic functions of EES can be resumed as a "tri-able"; it is (1) able to *consume* electricity, (2) able to *accumulate* this energy; and (3) able to (re-) *produce* electricity.

Functions (1) and (3) contribute to the production/consumption balance in different timeframes, the former in absorbing excessive or low-cost electricity, the latter in covering a production deficiency or replacing high-

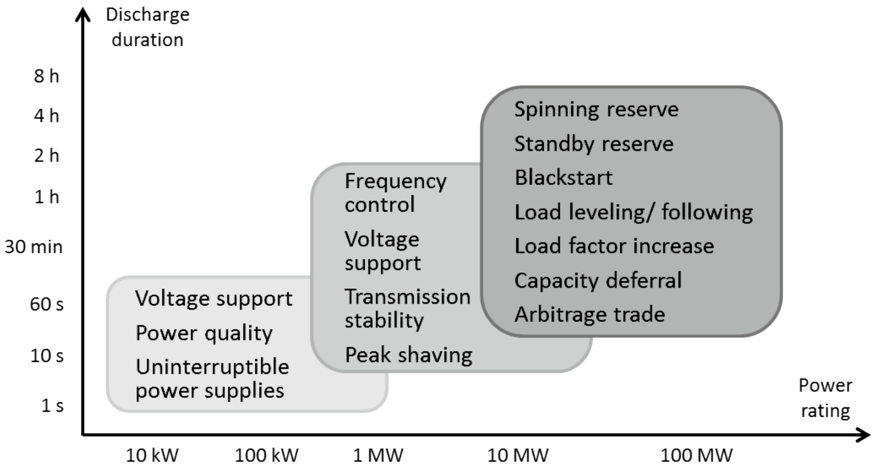

Figure 1: Selected services of storage according to power and energy ratings.

Source : THINK (2012)

cost electricity generation. The value EES can provide is related to the technical characteristic of these two functions, such as response time (How fast it can react [ms-s-min]?) or power rating (How much imbalances it can correct [kW-MW]?).

Function (2) is related to the accumulation of energy over time, giving rise to the possibility of inter-temporal arbitrage. The value of inter-temporal arbitrage action originates from better allocating production resources over time and is related amongst others to the energy rating (How long it can last [s-min-hours]?) as well as efficiency (how much energy is lost when storing [%]?).

These three functions can be valued by providing different services to individual actors or stakeholder group in the electricity system. Figure 1 displays selected services that represent different combinations of power rating and discharge duration.

The same vectors could be used to map different EES technologies as illustrated in Figure 2. Then one can match the desired services with the qualified technologies that provide them at different response time (ms, s, min), efficiency (%), power rating (kW, MW, GW), and for different time duration (s, min, hour, day), etc.

It is worth noting that the generation, demand-side flexibilities and even the network[2] can also provide the three functions, albeit they might differ in the form of energy conversion and accumulation, and in technical characteristics and implementation constraints. This suggests that the future grid might rely on a portfolio of flexibility means to ensure a reliable grid operation with the least costs. It is important to recognize that the often expressed requirement for EES is in fact the requirement for flexibility. EES is one of the means to meet this requirement. Hence, the search of business model for EES and the relevant market rules should also apply for alternative flexibility means.

2. Business model, matching the functions to the services

The three basic functions of storage, i.e. inter-temporal shift of energy and fast response (upwards and downwards) can provide various services to different actors in the power system. The business model is about how to extract the maximum value out of EES by matching its functions to the services. It involves both the operational and investment decisions. This section starts with a literature review on the

2. It refers to the use of networks devices such as FACTS, DC stations which allow a more flexible control of flow.

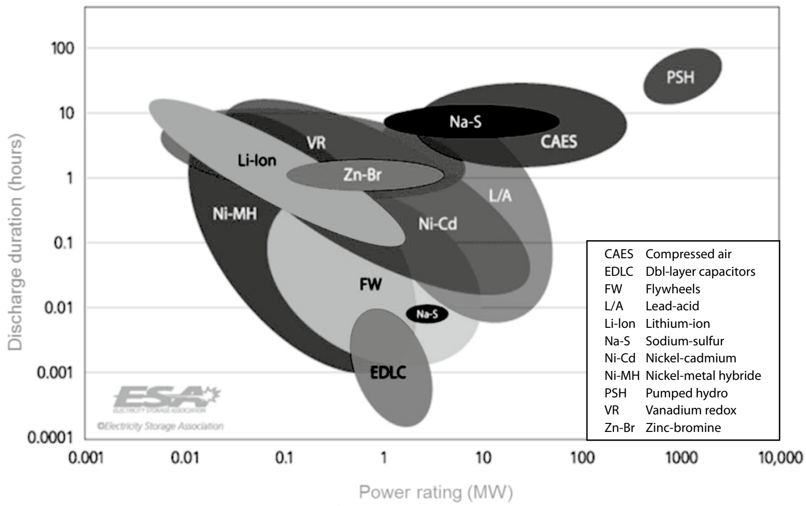

Figure 2: Mapping EES technologies by discharge duration and power rating.

Source: ESA (2011)

economic viability of different business models of EES. Afterwards, two plausible templates, namely the regulated and deregulated-driven business model, are distinguished and analyzed. Finally, the interaction between the operational and investment decisions is exposed.

A) Literature review

Numerous studies have been undertaken to assess the value of specific service of storage, including arbitrage in the electricity spot market (Lund *et al.*, 2009; Muche, 2009; Sioshansi *et al.*, 2009, Sioshansi, 2010), primary regulation services (Walawalkar *et al.*, 2007), generation portfolio optimization (Brown, 2004; Crampes and Moreaux, 2009; Yiannis and Emmanuel, 2007), congestion relief (Delille *et al.*, 2009; EPRI, 2006, 2007; Sandia National Laboratories, 2005, 2007; Silva *et al.*, 2008), wind optimization (Black and Strbac, 2006; Dufo-López *et al.*, 2009; Duque *et al.*, 2011; Fertig and Apt, 2011; Kapsali and Kaldelli, 2010; Korpaas *et al.*, 2003; Lipman *et al.*, 2005).

However, most of the analyses mentioned above do not show profitability of storage by providing only one specific service in the current market context. Indeed, most of EES technologies provide more than one services as depicted in Figure 1. The insufficient internalization of the externalities of EES on other actors might lead to the difficulty of payback. It could be expected that the combination of services could lead to higher value of EES, also to higher benefits to the whole system. Some studies have been conducted in this direction. Denholm and Sioshansi (2009) and EPRI (2004) studied the transmission-related benefits of combining wind and storage. Walawalkar and Apt (2008) combine the arbitrage in the spot market with the provision of the primary regulation. Delille (2010) proposes viable combination of services at different places of distributional grid; He *et al.* (2011a) proposes a systematic way to aggregate the services of storage by running an auction chain. He *et al.* (2011b) performs a multi-stream value assessment on a compressed air energy storage unit in the French market. These studies have shown that by combining the services and allowing third party access the value of EES could be substantially enhanced.

B) Analysis of viable business models for EES in the future power system

One can distinguish two types of business model that aggregate the services of EES, namely:

- Deregulated-driven business model (major part of the income originating from activities in electricity markets – “deregulated income streams”), and
- Regulated-driven business model (major part of the income originating from offering services to regulated actors with the procurement being realized via mandatory code or bilateral contracts, i.e. the price information is not accessible by third parties – “regulated income streams”).

The location of EES preconditions to a large extent that the most plausible business model is regulated or deregulated driven, as it often implies combination of most valuable services and determines the shares of income streams originating from competitive activities on the one hand, or from the provision of services not yet market based that are typically procured by the regulated actors (Figure 3). One can reasonably anticipate that relevant market rules and the need for regulatory intervention are different, too. In what follows, the main challenges facing the two business models are investigated.

Deregulated-driven business model

EES in its prevailing function here is used for competitive activities and remaining capacities might be used to provide services to regulated actors. The advantage of this model is that EES can provide regulated services without interfering with competition in competitive domains. The main concern is that the prevailing service is subject to many economic uncertainties, which results in an uncertain main revenue stream.

The major economic uncertainty is the evolution of market prices during the lifetime of the storage asset. The profit of the deregulated arbitrage activity strongly depends on the price spread, which decides both

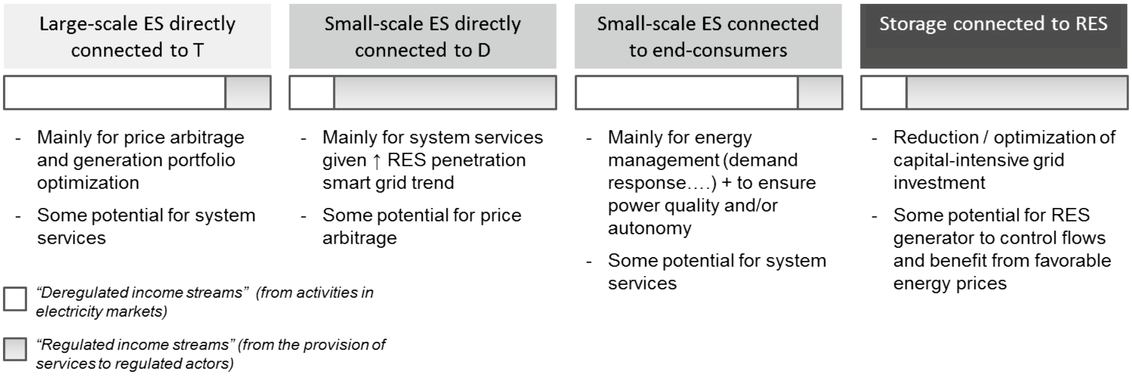

Figure 3: Location of storage against the most plausible type of business model today.
Source : THINK (2012)

"cost" and "revenue" of the energy transacted in the markets. However, the price spread is influenced by many exogenous economic and regulatory factors such as fuel prices, power mix, weather conditions, etc. Market integration of renewables is another sensitive issue as RES often have nearly zero marginal costs and their integration into the marginal price bidding system does inevitably depress the market price. This downward pressure of market prices affects the profitability of all generation means. Such effect is further exacerbated in cases where there are administratively fixed price caps and floors, which means that during peak periods, the price is not allowed to be set at the actual value of lost load if it would exceed the price cap, and during off-peak periods the inflexible base-load might not be allowed to offer negative prices (or prices lower than the price floor).

Moreover, the second step of the deregulated-driven business model, i.e. the valorization of remaining capacities with system operators, is not easy to realize either, as actual arrangements of system service procurement often do neither take into account the relative advantages of storage facilities nor the constraint of storage as an energy-limited source. In addition, the remuneration of these services is not fully market-based, which makes an estimation of the value of storage difficult. Controversies may occur in the method of evaluation (cost-based or opportunity cost based), in performance indicators, in the evaluation of fulfillment, etc.

It has to be noted that the viability of a similar business model can also strongly differ between alternative technologies. Pumped hydro, for instance, requires high upfront investment cost and furthermore is typically subject to long permitting (about 4 years for feasibility study, licensing, permitting, financing, etc.) and construction times (also about 4 years). Long-term investment security, thus, is a key factor especially for this technology. One also has to differentiate between existing and new storage facilities. Whereas a business model for new facilities obviously will include initial investment cost, existing assets might benefit from amortized assets.

Regulated-driven business model

In contrast, the regulated-driven business model implies that electricity storage in its prevailing function is used to provide services to regulated actors, and remaining capacities might be used for competitive activities. Regulated sources of revenue are guaranteed, but still a well-founded method of valorization is needed to justify the choice of storage instead of alternative means of flexibility. Mechanisms such as auctions for services, concession licenses, and capacity contracts would be considered as another way to evaluate electricity storage for regulated services, but on the same leveling fields as other competitive means of flexibility. It has been shown (Sioshansi *et al.*, 2009; Walawalkar and Apt, 2008) that some regulated sources of revenue are ranked as the highest revenue sources for electricity storage in US markets. In Europe, it seems that the key supportive argument for the regulated-driven business model, i.e. value quantification, is still missing because of a lack of data and transparent pricing mechanisms for system services procurement.

Another issue is how to combine the regulated and deregulated use of storage in an efficient way. In the regulated-driven business model, the regulated actor is supposed to have priority over the storage use. However, one should note that the need for system services is revealed only near real-time delivery, while the operating decision regarding competitive activities are taken more ahead of real-time, i.e. at different gate closures of electricity markets. The priority of the regulated actor would impose probably a guaranteed reservation of a bundled capacity of storage (charge-, energy storage-, and discharge capacity). This might lead to an underutilization of storage, because regarding the horizon of deciding on the usage of storage, grid operators should come at the last place (after forward, day-ahead, and intraday markets).

In summary, the differentiation between the regulated- and deregulated-driven business models helps to better understand what the most valuable services, electricity storage can provide, are, and if the current market design and regulation allow to reveal such values in a fair and credible way. In Section 3, a more detailed investigation of the interaction between the business model and the market/regulatory rules is presented.

C) Operational vs. investment decision

The operation of storage not only influences the operational benefits, but also optimal investment decisions. As well stated by CPUC (2010), EES tends to be an application-specific resource, therefore any generalized costs estimation are of questionable value. Given the modularity[3] of EES systems, the dimensioning of the EES can be adapted to the usage pattern of the unit in order to achieve higher return on investment. We can consider a simple example. For a given energy capacity, a storage unit can be dimensioned to have a high charge rate (short charge duration) and a low discharge rate (long discharge duration) or inverse.

3. Different EES technologies may present different degrees of modularity. For example, mechanic energy storage systems (such as Pumped Hydro Storage and Compressed Air Energy Storage) can use independent modules for charging and discharging the storage unit. In this case, energy storage capacity (MWh), charge rate (MW) and discharge rate (MW), can be configured separately. In comparison, conventional battery systems are characterized by a rather rigid input/output power ratio or power/energy ratio. But advanced flow battery technology can allow choosing the power/energy ratio.

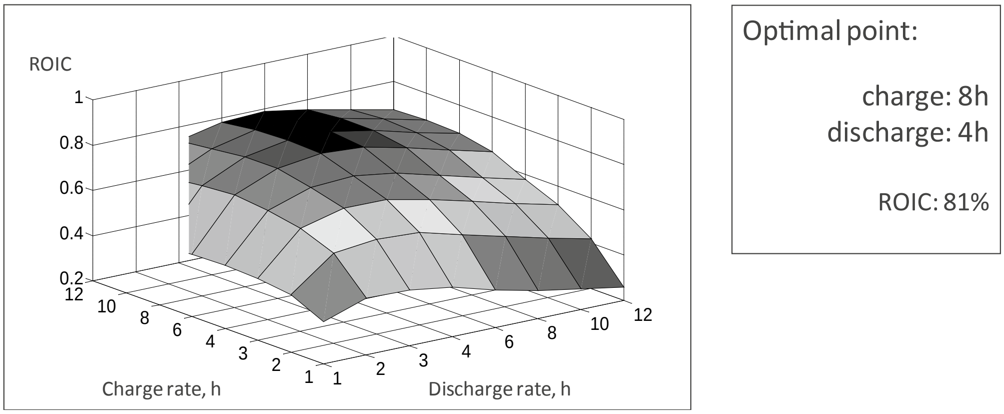

Figure 4: Sensitivity of arbitrage value with respect to different dimensioning of a compressed air energy storage system in Dutch power exchange APX 2007; ROIC refers to the Return on Invested Capital.

Source: He and Zachmann (2009)

These two configurations will entail almost the same investment cost but the second should lead to a higher profit by arbitraging in the spot market because low prices generally last longer than peak prices. He and Zachmann (2009) suggest that optimizing the dimensioning of an EES unit is as important as choosing the fittest technology. Figure 4 demonstrates impressively that the profitability of a CAES system is sensitive to its dimensioning.

3. Interaction between the economics of storage and the market rules

The economics of EES cannot be credibly assessed or anticipated without putting them into the context of market design. The availability of a defined product/service is a precondition to conceive relevant business models, and the credibility of market prices for such product/service affects the results of the business model.

Disregarding the actors[4], almost all services[5] that EES can provide are exchanged or contracted through, i.e. (a) spot and balancing markets, (b) ancillary services procurement, and (c) possible capacity mechanisms. The following analysis seeks to expose the interaction between the value of EES and market rules.

1.1. Spot and balancing markets

The day-ahead spot market is often considered as the main market place for the inter-temporal arbitrage of EES[6]. However, the credibility of the spot price cannot be evaluated without assessing its interaction with the balancing market. According to the market chaining effect, the prices in the balancing markets should cap the prices in the day-ahead spot market. The logic is simple: if it is cheaper to buy power near real-time, there is no incentive to buy at a higher price day-ahead. It is found that several market arrangements might cause price depression in balancing markets and the spot market.

1. *Ad-hoc peak load arrangements*. They refer to some kind of ex-ante capacity payment for peak load generation units, which enables them to bid into the energy market at a lower price. Such arrangements, though implicit, are quite common. For example, the Norwegian TSO implemented a reserves option market to secure sufficient resource bidding into the balancing market. Similar practices can be found in France, where the TSO remunerates a capacity payment for fast tertiary reserve to bid into the balancing mechanism. Such arrangements decrease the price level in the balancing market and cause asymmetric incentives for peak load generation and for EES, both capable of balancing the system.
2. The *price fixation mechanism*. The way that prices are fixed in the balancing market varies from country to country (Eurelectric, 2004; Vandezande, 2011). It is common that bids are selected according to the merit order of the bidding prices; however, it is not in every balancing market that the selected bids are remunerated with the same marginal price. Balancing energy instead may be remunerated based on pay-as-bid (e.g. Austria, Italy) or at average prices (e.g. France, Germany, or the UK). But such price fixation mechanism will drastically reduce or even eliminate any arbitrage possibilities.

   Moreover, the inconsistence regarding price fixation mechanisms in day-ahead and balancing markets could result in a misalignment of price signals of these two chaining markets. Average pricing or pay-as-bid remuneration in the balancing market could lead to a depressed level of the cost of purchasing energy at real-time, which would condition the price level in the preceding day-ahead market.

4. EES can provide different services for different actors. When enumerating these services, cautions need to be taken in two aspects. First, the services should be distinguished from the resulting benefits. For example, peak shaving is a service while the transmission investment deferral is one of the resulting benefits. Second, the same service can be called with different names if serving different actors. For example, the ancillary services are defined from the generator point of view while they are named as system services from the system operator's point of view

5. End user services are not included.

6. To date, the market of futures present an insufficient price spread for arbitraging while in the intraday market, the arbitrage opportunities are restricted by the limited exchange volume and liquidity.

3. *Market access and product specification.* Traditionally, only the balance responsible entities are allowed to bid into the balancing markets[7]. Minimum bidding units (often 1 MWh/h) are much higher than in the spot market (0.1 MWh/h). Pozo (2011) points out that automation of calling for bid activation would remove any disadvantage that small bids might have on the quality of regulation. Market rules, thus, could be modified such that they reduce minimum bidding requirements and allow separate up- and downward bids. Another solution could be allowing the aggregators to bid in the balancing market, who can group smaller-scale sources, including EES, to reach the minimum size required at wholesale level.
Furthermore, it is often required that balancing bids are symmetric, i.e. providing a symmetric up- and downward regulation power in case of need. It is also noted that the time step of activating the balancing product could be different from the time step of bidding. For instance, in the French balancing mechanism, the balancing bid must cover a 4 hour-period whilst it is activated with the time step of 30 minutes. However, an extended bidding time step brings difficulties to optimize the operation decision of EES since it is an energy limited resource (its production capacity is limited by the state of charge). A finer product specification with less constraint could make the market access easier for EES and other flexibility means, improving the market liquidity and reducing the cost of acquiring flexibility services.
4. *Administratively fixed price caps and floors.* They have been widely criticized as another reason for spot price depression in many power exchanges. While the effect of price caps on price depression certainly exists, it could be exaggerated as price cap is rarely attained (Hirschhausen, 2012). Negative prices are gradually permitted in different markets, reflecting the system's need for downward adjustments.

7. There is some on-going progress in certain Member States allowing market players not being balance responsible themselves but attached to certain balance responsible to propose bids in the balancing markets.

1.2. Ancillary service procurement

Ancillary services such as primary and secondary control, voltage support, or black start are traditionally procured by the TSO on a regulated basis. Several forms of procurement and remuneration co-exist, including mandatory provision, bilateral contracts, tendering or the use of the spot market, as presented in Table 1.

Tableau 1

Various form of ancillary services procurement

Primary frequency control	Mandatory provision (ES) Bilateral contract (FR) Tendering (DE, UK, SE)
Secondary frequency control	Bilateral contract (FR) Tendering (DE) Spot market (ES)
Voltage control	Mandatory for basic V-control (ES, DE, FR, UK, SE) Bilateral contract (FR, DE) Tendering (UK, ES)
Blackstart	Bilateral contract
Congestion relief	Bilateral contract Open season tendering

Source: based on THINK (2012)

All options have pros and cons. Mandatory provision does make sense for essential public services whose benefits are spread evenly amongst all parties involved. Bilateral contracts offer some degree of flexibility with respect to service specification, making the provision of ancillary services more tailored to the system operator's requirement as well as to the provider's ability or convenience. Tendering allows introducing more transparency compared to bilateral contracts and more competition for the provision of the service required. The spot market is an efficient way to procure standardized services or products at lowest costs through sufficient competition. It is clear that the suitability of procurement mechanism depends on the specificity of the underlined service and is conditioned by the number and diversity of the potential providers.

However, the mandatory provision might not allow to fairly recognize the value of EES in providing certain service. The bilateral contract, not accessible for a third party, creates difficulty for external investors, especially for those not being incumbent generators, to know the value of storage for providing the ancillary services. Heffner *et al.* (2007) provides an interesting study comparing selected European and non-European ancillary service markets, showing that there is a clear trend towards market-based procurement for ancillary services. It could be anticipated that replacing bilateral contracts by competitive tendering wherever possible could help enhancing the transparency and revealing the value of flexibility means, including EES. In the conception of tendering, it is recommended to adopt performance-based (i.e. source-neutral) remuneration schemes. This complies with the system operator's chief target to ensure the security of system operation, and also provides a level-playing field for all flexibility means able to deliver the required services.

1.3. Capacity mechanisms

A capacity mechanism currently is extensively debated in several European countries (Germany, France, Spain, Italy, etc.). The call for such an instrument is mainly based on the risk of long-term under-investment in generation capacity, especially peak power plants. However, there is no consensus yet regarding many key issues related to necessity and design of such mechanisms. An important concern about the capacity mechanism is it might jeopardize the price signals of the existing electricity markets and pose impediments towards the internal market building. Moreover, as far as the design of the capacity mechanism does not recognize possible contributions of alternative flexible means (including storage) in the capacity consolidation, the implementation of such a mechanism is likely to further penalize investments in storage as compared to peak generation units.

3. Conclusion

This paper has tried to expose the interaction between the economics of EES and the market rules, showing how the latter should be adapted in order to facilitate the market entry and to improve the evaluation of the flexible means, including EES.

It is emphasized that what the power system requires to deal with the variability challenge are the various services that flexibility means can provide, EES being one of them. These services are currently exchanged in various market places or centrally procured by TSOs. To our knowledge, there is no valid evidence that new flexibility service or ad hoc market design for flexibility is needed. However, our analysis has shown that the availability of market prices for the ancillary service are particularly important for the regulated-driven business model while the credibility of energy prices influences the viability of the deregulated-driven business model. An examination of the energy market, ancillary services and capacity market design shows that the market rules could be improved in many aspects.

First, a coherent chain between balancing- and day-ahead markets needs to be further improved. Heterogeneous national practices regarding peak-load arrangements might impede a level-playing field for all flexibility means across Europe. Second, balancing market rules such as minimum bidding requirements and symmetric up- and downwards bids should be relaxed in order to allow small, decentralized market players (including EES operators) to participate in these markets. Third, market-based approach should be introduced in the procurement of ancillary services where possible. The use of competitive tendering instead of bilateral contracts wherever possible could help to reveal and quantify the value of flexibility means.

In the end, the normalization and harmonization of the market rules among Member States would pave the way to exchange the flexibility services across the borders. This could allow a more efficient use of EES in a larger geographic scale. ■

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