Energy storage race: Has the monopoly of pumped-storage in Europe come to an end?

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ABSTRACT

The rise of renewable energies has brought a new challenge in terms of the management of their intermittency. Pumped-storage hydroelectricity has served as the large-scale solution to the intermittency problem. However, flawed European spot markets and innovation are jeopardizing the future of this technology. This paper: 1) estimates historic revenues of 96 energy storage installations on 17 European electricity spot markets, 2) assesses how arbitrage revenue has evolved, and 3) compares the present value of new energy technologies (compressed air, batteries) with pumped-storage in energy-only markets. Results show that market openings to competition had led to revenue drops and convergence: all markets generate low income. Based on the findings: 1) energy storage requires revenue from other markets than spot ones 2) compressed air energy storage is competitive with pumped-storage, and 3) markets value daily pumped-storage installations rather than seasonal, where this technology keeps a technical comparative advantage. It means the current best pumped-storage installation design could not be the long-term one. We also highlight that further research should investigate if interconnection, a natural monopoly, competes with energy storage, which is open to competition.

1. Introduction

Electricity generation must match consumption at any given moment. Otherwise, it affects the frequency and may lead to blackouts. System operators must ensure enough flexibility, i.e. "the ability of a power system to maintain continuous service in the face of rapid and large swings in supply or demand" (Papaefthymiou et al., 2014, p.3). This is a challenging task, given that electricity generation fluctuations, especially in case of renewables. Photovoltaic panels stop supplying at night, wind turbines need specific weather conditions, and run-of-river hydropower relies on water seasonality. Therefore, increasing share of new renewable energy jeopardizes electric system reliability (Shafiullah et al., 2013).

The electricity system operator can address the intermittency problem using five main options (IEA, 2008). First, the energy generation can be reduced in case of an excess of supply, e.g. by braking turbines. This strategy is rarely applied where Feed-In-Tariff mechanisms guarantee a cost-based purchase price to renewable energy generation are in place. Operators have no economic incentive to stop their installations even during negative-price events. The second option is using backup technologies, such as gas turbines, which can generate electricity

quickly to ensure supply follows demand. Demand-side management, e.g. through the introduction of information and communication technology (ICT) and smart grids is the third option. Interconnection can be used as the fourth option to balance supply and demand. When a grid covers a small geographical area, it is subject to homogenous meteorological and climatic conditions. Through interconnections, an integrated system can be formed over a larger area as big as a continent (e.g. Europe). Then, the undesirable (e.g. windy) conditions in part of the interconnected system can be compensated by desirable (e.g. cloudy) conditions in another part. The last option, which is the focus of this paper, is employing energy storage technologies (introduced in the Section 2.1) (IEA, 2008). Storage technologies are charged during off-peak hours to generate energy during peak times. However, the profitability of energy storage technologies has become questionable with the experienced growth in renewable energy development.

Various specific case studies in Europe showed that renewable energy and storage energy may be complementary from an economic perspective (Gomes et al., 2017; Khalilpour and Vassallo, 2016; Mulder et al., 2013). Connolly et al. (2012) showed that pumped-storage is a cost-effective way of stimulating wind penetration in the Irish market. Zafirakis et al. (2013) conducted a similar study in Greece and

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investigated the option of storing energy by compressing air (CAES). This technology was found to be only profitable in the German market if wind energy represents a large share of energy generation (Swider, 2007). Anagnostopoulos and Papantonis (2012) looked at the implementation of a pump system in an existing hydropower plant in Greece. They concluded that PSES becomes attractive as intermittent energy sources become more propagated. Iliadis and Gnansounou (2016) conducted an analysis of a Swiss PSES installation. They considered revenue from both day-ahead and intraday markets. Connolly et al. (2011) assessed the profitability of generic PSES installations in 13 electricity markets.

It is important to understand how the mature PSES is being threatened by newer technologies (IEA, 2014). Numerous studies have compared energy storage technologies in Europe. Some contrast their technical characteristics and capital costs (IEA, 2014; Kousksou et al., 2014; Lopes Ferreira et al., 2013; Evans et al., 2012; Dunn et al., 2011), however, they do not assess revenue and investment. Lund and Salgi (2009) compared the results of various energy storage technologies for the Danish electric system from a social planner's perspective. They also showed that CAES with an arbitrage-only revenue model is not profitable on the Noorpool market. Loisel (2012) showed that compressed air energy storage (CAES) is unprofitable in France, although it holds a social value. Finally, Kazempour et al. (2009) show that PSES is more profitable than NaS battery in Spain.

These studies provide a good understanding of the electric system dynamics; however, none analyses a broad set of technologies at a European level. They lack a meaningful comparison of the various technologies with consideration of all European electricity spot prices. The case specific results presented above could be further expanded upon to identify regional trends to tackle policy issues at continental level, which is getting increasingly interconnected.

Our study aims to assess whether arbitrage revenues alone, can attract investment in storage in Europe, whether situations converge in every market, and whether operators capitalize on their ability to export their flexibility to neighboring markets. Furthermore, this study provides insights into the tradeoffs between round-trip efficiency and power. This information will facilitate the evaluating the benefits of innovation, which generally improves efficiency.

This study is carried out from a techno-economic perspective. We simulated the operations of 96 generic energy storage installations on 17 European spot markets. A numerical algorithm maximizes the annual revenue (archived on Zenodo, Gaudard and Madani, 2017) to identify historical trends. We also compute the Present Analysis and Modified Internal Rate of Return (MIRR) of the most common bulk storage technologies in order to assess their profitability.

All models, including our model, have simplifying assumptions that need to be considered when interpreting their outputs. Despite its limitations, out model helps us develop a better understanding of operations in a large area and provides a dataset that is versatile. It therefore contributes to the emerging literature on the topic with its original perspective.

2. Method and data

2.1. Energy storage technologies

Three main features characterize an energy storage installation. Firstly, round-trip efficiency is calculated by dividing the quantity of energy supplied by the quantity of energy consumed during a cycle. For example, 80% round-trip efficiency means that 20% of energy is lost in a charging and discharging cycle. Second, the energy storage volume represents the full amount of energy that can be stored. Third, the discharge duration is "the amount of time that a storage device can be discharged at the nominal power rating" (ESA, 2016). A device with a small discharge-duration will run out of charge in a few hours and benefits from intraday volatility. In contrast, devices with a long

discharge duration take advantage of weekly seasonality. For a constant energy storage volume, the lower the discharge duration, the greater the power of the storage device. Other technical characteristics matter and determine the type of services that can be provided, e.g. load level and power quality. However, such characteristics have little relevance to electricity spot markets.

Energy storage is provided through different technologies, with pumped-storage (PSES) installations being the major provider of energy storage to date. PSES is a mature technology that pumps water to an elevated position to generate electricity with a water turbine when prices soar (Guittet et al., 2016; Rehman et al., 2015) and provides 99% of the world's installed large-scale energy storage capacity. Compressed Air Energy Storage (CAES) is an attractive emerging alternative. This name encompasses various technologies, e.g. diabatic, adiabatic, isotherm, but all of which store energy by compressing air, i.e. in a mechanical form. The conventional diabatic system is reaching maturity, but it still requires natural gas to accomplish the necessary thermodynamic cycle and thus is not carbon-free. New technologies have been developed that do not require fuel, however, they still need further innovation before they become commercially viable. The scale of the devices goes from small decentralized plants to large plants that use underground natural or artificial caves as their reservoir (Kim et al., 2012). Finally, batteries store energy in an electrochemical form. The negative anode and positive cathode create a difference of potential. When the two electrodes are connected, the cathode attracts electrons and generates electricity. Lead-acid, Ni-Cd, Li-on batteries are mature and will be considered in our investment analysis (Mahlia et al., 2014; Dunn et al., 2011).

2.2. Optimization and investment analysis

We modified a hydropower management model (Gaudard et al., 2013; Gaudard, 2015) to simulate the 30-min charge/discharge operations. This model maximizes the annual revenues of any given energy storage device. It assumes that the operator is a price-taker, i.e. the installation is too small to affect the market price. The objective function is:

$$OF(b_{dis,t}, b_{char,t}) = \sum_{t=1}^{t=T} (b_{dis,t} - b_{char,t}) \pi P_t \, \Delta t \tag{1}$$

where T denotes the time horizon, $b_{dis,t}$ and $b_{char,t}$ are two binary variables which indicate the period of discharge and charge (see Eq. (5), below), π is the nominal power of charging and discharging [W], P_t is the electricity spot price [€W h^{-1}] or [£W h^{-1}] and Δt is the time step duration [hour].

The optimization problem is formulated as:

$$\max_b OF(b_{dis,t}, b_{charg,t}) \tag{2}$$

$$E_t = E_{t-1} - \frac{\pi}{\eta_1} b_{dis,t} \Delta t + \pi \, \eta_2 \, b_{char,t} \Delta t \tag{3}$$

$$0 < E_t < \epsilon \tag{4}$$

$$b_{dis,t}, b_{char,t} \in \{0, 1\} \tag{5}$$

where E_t denotes the energy stored at time t [W h], η_1 and η_2 are the efficiency of discharging and charging respectively, ϵ is the energy storage capacity [W h] (Eq. (4)), which is normalized to 1 kW h for all the results. The storage devices always start and end at mid-level storage volume. Contrary to large hydropower plants, this constraint insignificantly affects the results as energy storage observes many charging-discharging cycles in 365 days. The model assumes perfect foresight, i.e. the operator knows the prices in advance. While this assumption ignores the uncertainty that the operators face in practice and might result in overestimation of revenues, it has been an acceptable method in the literature (Francois et al., 2015; Madani and Lund, 2010,

2009; Tanaka et al., 2006)

A local search-threshold acceptance algorithm approximates the optimal 30-min management (Gilli and Schumann, 2012; Gilli et al., 2011). This algorithm modifies an initial random charging/discharging schedule and values the objective function. If it does not decrease by a defined threshold, the new schedule is recorded and the old one is discarded. The model adjusts the schedule during n steps, then reduces the threshold for m new rounds. We determined the value of each threshold with a data-driven procedure (Gilli et al., 2006; Winker and Fang, 1997).

A recent study by Ranzani et al. (2018) shows that the algorithm used here provides a reliable approximates of the actual operation in case of a storage-hydropower plant in Switzerland. Nevertheless, we remain unable to fully compare our results with operating installations because of the lack of data as operators are reluctant to sharing such data. We, therefore, validated the computational performance of the model by three means. The general optimum can be easily computed (without the optimization algorithm) if we discard volume storage constraints. We compared this outcome with those obtained from the local search algorithm with a discharge duration of 8760 h for two round-trip efficiency levels, i.e. 0.50 and 0.95. Our model error was below 1%, which we considered satisfactory. We also verified that no negative revenue was computed in all our results. Finally, we visually validated the daily and weekly patterns. In particular, supply must occur during peak hours, i.e. generally during the day, and pumping must happen during the night and weekends (off-peak hours). No relevant inconsistency was observed.

We considered 17 European electricity spot markets provided by Eikon (2018). We ignored other new markets, e.g. the balancing market (Hirth and Ziegenhagen, 2015; EPEX, 2016; NordPool, 2016), because it would have significantly shortened the price time series and limited the scope of our results. The revenue on these 'niche' markets has even tended to drop as they became mature and competitive (Hirth and Ziegenhagen, 2015). Spot markets remain the largest in terms of volume exchanged and the most attractive for producers in Europe (Schillinger

where B_t is the benefits at time t [€], r is the discount rate. C_t is the cost at time t [€] and I_0 is the initial investment cost [€]. I_0 is computed with Eq. (8), provided by Kaldellis and Zafirakis (2007), where c_p is the capital cost per nominal power [€W^{-1}] and c_e is the capital cost per energy storage capacity [€Wh^{-1}]. We used nominal values in our simulation, however the investment analysis considers real value annual revenue (year 2015 € equivalent), using the Harmonized Index of Consumer Prices (HICP) of the European Economic Area (EEA) provided by Eurostat (2016).

The discount rate depends on the risk taken. It is therefore interesting to complete the analysis with the Modified Internal Rate of Return (MIRR) (Quiry et al., 2011). This approach considers that the discount rate is an unknown variable. Therefore, the goal is to determine the discount rate that will make the present cost and present value equal. We considered the MIRR rather than the standard Internal Rate of Return (IRR) because the lifetimes of each technology differ. In this context, MIRR is more relevant.

This part of the assessment required further information. Energy storage data vary from a paper to another. We, therefore, decided to use the data provided by the latest available review paper written by Nikolaidis and Poullikkas (2018), see Table 1. We cross-validated this data with Lazard (2016), Kousksou et al. (2014), Lopes Ferreira et al. (2013), and Evans et al. (2012). They provide the same magnitude for all but the round-trip efficiency of CAES (Lazard: 75–79%, Kousksou et al.: 50–89%, Lopes Ferreira et al.: 50–80%, Evans et al.: 50–89%), and Li-ion (Lazard: 92–93%, Kousksou et al.: 85–90%, Lopes Ferreira et al.: 85–90%, Evans et al.: 85–90%). We only changed operational and management costs, because Nikolaidis and Poullikkas (2018)'s data were substantially different from the four above-mentioned references. Nevertheless, we acknowledge that energy storage characteristics evolve and some considered values might be inaccurate. We split the present cost of the present value in our analysis to make comparison with available data easier for the reader. The readers can also carry out the investment analysis with their technical characteristics by downloading our revenue series on Zenodo (Gaudard and Madani, 2017).

Table 1
Technologies considered and their characteristics. The investment analysis considers the values in parentheses.

	PHES	CAES	Lead-acid	Ni-cd	Li-ion
Round-trip efficiency[a] (%)	70–85 (80)	42–54 (50)	85–90 (90)	60–90 (75)	100 (95)
Discharge duration[a] (h)	10–100 (24,96)	2–100 (24)	1–24 (12)	h (6)	h (6)
Lifetime[a] (years)	30–50 (40)	30 (30)	5–15 (10)	10–20 (15)	5–15 (10)
Capital cost[a] ($/kW)	600–2000	400–800	300–600	500–1500	1200–4000
Capital cost[a] ($/kW h)	5–100	2–50	200–400	800–1500	600–2500
O&M cost[b] ($/kW-year)	2–4	1–2	16–22	16–22	5–11

[a] According to Nikolaidis and Poullikkas (2018).
[b] According to Lazard (2016).

et al., 2017). European practitioners confirmed that they generated most of their revenue on the spot markets. In the USA, market design differs, and the consideration of ancillary service markets would have been more crucial. The prices are given in euro (€) for all but the United Kingdom, which has its prices in pound sterling (£). The Eurostat (2016)'s annual exchange rate was used to convert the currency.

Based on the revenue data, we assessed the present value (PV) and present cost (PC) of six generic energy storage devices. The model considers the revenue over the lifetime of the installation as follows:

$$PV = \sum_{t=1}^{T} \frac{B_t}{(1+r)^t} \tag{6}$$

$$PC = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} + I_0 \tag{7}$$

$$I_0 = c_p \pi + c_e \epsilon \tag{8}$$

3. Results and discussions

3.1. Historic revenue evolution

Fig. 1[1] shows the annual revenue for a typical pumped-storage installation. An annual revenue of 0.4–3 € might seem very low. To better understand this figure, one can consider a Tesla powerpack with the following characteristics: energy capacity of 210 kW h, round-trip efficiency of 90% and discharge duration of 6 h. In this case, the annual revenue for 1 kW h was between 1 (Nordpool) to 11 (Ireland) € in 2016 (higher than observed in Fig. 1, because of the higher power and round-

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[1] Austria, AT; Belgium, BE; Switzerland, CH; Czech Republic, CZ; German, DE; Spain, ES; France, FR; Italy, IT; Ireland, IR; Netherlands, NL; Nordpool (Denmark, Estonia, Finland, Latvia, Lithuania, Norway, Sweden), NP; Poland, PL; Portugal, PT; Romania, RO; Slovenia, SI; Slovakia, SK; United Kingdom, UK.
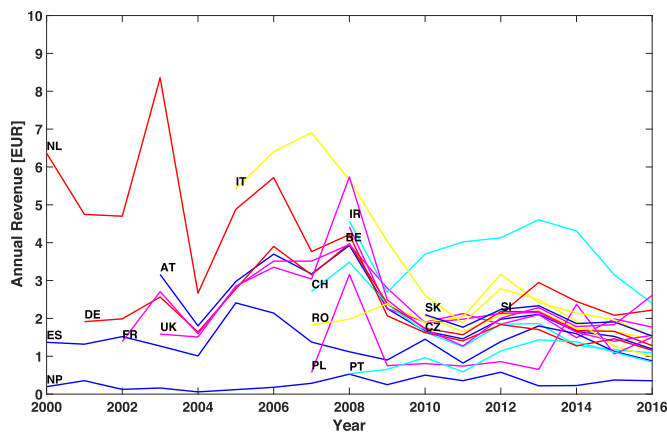
Fig. 1. Revenue of a normalized closed-loop PSES in the European Electricity Market from 01-01-2000 to 31-12-2016 (round-trip efficiency = 0.8, discharge duration = 24 h, energy storage = 1 kW h).

trip efficiency). Therefore, the annual revenue for this installation varies between 210 and 2310 €per year. Arbitrage alone cannot justify an investment in the powerpack (≈ 80′000 €, according to Lambert, 2016), but it shows that the magnitude of our results is reasonable.

In the beginning of the century, many European pumped-storage operators expected revenue growth following the introduction of intermittent energy. Fig. 1 shows that the opposite happened in most of the European markets. In contrast to electricity suppliers, the decrease in cash flows for storage operators is not associated with the drop in mean prices. The storage device owners' profits mostly depend on seasonality (daily, weekly and annual) and volatility of electricity generation. An installation with an efficiency of 0.8 must sell electricity at 1.25 times the charging price, otherwise it loses money. So, the profits mostly rely on the relative spread between prices rather than the mean price.

Fig. 2 shows the peak and off-peak prices in Germany in 2003, 2008 and 2016. We define 'peak' as the 84 highest hourly prices of the week and 'off-peak' as the remaining 84 cheapest hours. The revenue in 2003 (see Fig. 1) was higher than in 2016 despite the mean prices were similar, i.e., 29.4 and 28.9 €MW$\,h^{-1}$ respectively. The revenue also shored in 2008, when the spread between prices peaked.

Various studies investigated the impact of specific drivers of electricity prices (IEA, 2016; Genoese et al., 2015; PPC, 2014; Gaudard et al., 2014; Cochran et al., 2013). Based on their results, the rest of this section explains and discusses the trend observed in Figs. 1 and 2. We also identified some specific events, which support our analysis, in the 2008–2017 'Quarterly Reports on European Electricity Markets'
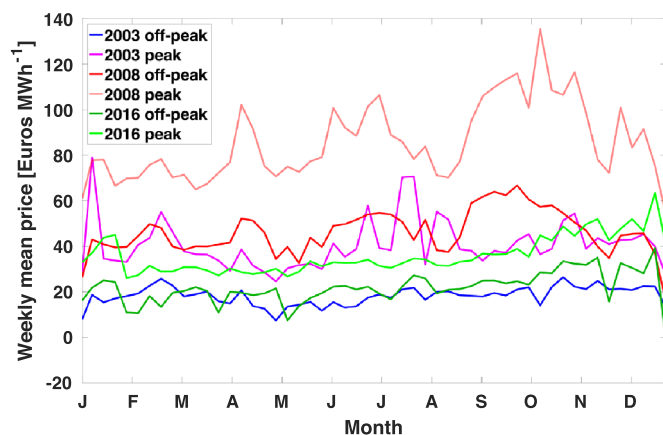
(QREEM) provided by the European Commission (Market Observatory for Energy, 2008–2017).

The high penetration of new renewable energies may increase the volatility of supply because of their intermittency. In some extreme cases, negative prices were observed, which is a bonanza for energy storage. The operators are paid to charge their battery. These events occurred when renewable energies generated a large amount of electricity. Renewable operators kept supplying because they earned income with the Feed-In-Tariff schemes. In contrast, it was cheaper to pay for consumption rather than stopping the inflexible base-load technologies, such as nuclear power plants. In January 2012, intensive wind energy generation, inflexible load and warm winter caused frequent negative prices (Market Observatory for Energy, 2012a). The energy storage revenue should have increased with the growing share of intermittent energy, but these events were still occasional and too short to compensate for other drivers. In 2010, the European Commission even noticed that intermittent energy deployment might not boost volatility (Market Observatory for Energy, 2010a).

Renewable energies themselves tend to reduce the gap between peak and off-peak prices, significantly affecting the energy storage revenue. In 2012, the peak price already felt below the baseload price because photovoltaic energy is generated during day hours when the consumption is high (Market Observatory for Energy, 2012b). The spread narrows, because conventional thermal power may stop generating during peak hours, as observed in 2014 (Market Observatory for Energy, 2012a).

The supply curve also relies on conventional technologies. The price of fuel and carbon emission allowance impact the mean price and the spread. As commodity markets are volatile, trends are hard to be identified. In 2012, coal power plants benefited from low resource and carbon prices (Market Observatory for Energy, 2012a), while in 2016, the coal price soared, boosting the competitiveness of and the electricity generation from natural gas plants (Market Observatory for Energy, 2016) However, one can expect that a high carbon price will tend to intensify the competition between the carbon-intensive coal and gas turbines, which must lead to a smaller spread.

Prices and volatility also soar when hydropower or nuclear power is lacking. A lower-than-usual hydropower reservoir level in Greece required higher coal and gas electricity generation, which boosted the peak hour price in 2011 (Market Observatory for Energy, 2011). Nordpool volatility also grew in a dry season at the beginning of 2015 (Market Observatory for Energy, 2015).

Energy demand also affects the spread (Madani et al., 2014; Guégan et al., 2012). Weather temperatures impact household consumption. During cold winter and hot summer, the price tends to peak. In July 2010, the Italian spread price rose to 12 € per MW h because of a heat wave, and then drop to 7.1 € per MW h (Market Observatory for Energy, 2010c). However, temperatures explain some inter-annual variability, not a trend, as climate warming occurs on a longer time horizon.

In contrast, economic growth increases industrial consumption. The 2008 financial crisis and European turmoil in 2010 mostly affected the industrial sector, rather than the domestic sector. At the beginning of 2009, cold weather stimulated household demand while industrial consumption diminished (Market Observatory for Energy, 2009). Most industries run during the diurnal weekday. Therefore, an economic slowdown mostly shaves peak demands. The economic recession narrowed the price range resulting in energy storage revenue shrinkage.

Surprisingly, the correlation between the economy and electricity consumption was observed in the late 2009, but disappeared while the economy restarted. Various QREEM reports in 2015–2016 highlight that the economic growth no longer boosts the electricity consumption. This is believed to be due to the fact that the economic crisis of 2008 has permanently affected the economic fabric and made the European economy less energy-intensive.

Finally, a significant trend-breaker was the opening of competition and the coupling of markets. Even in the period of economic recession,

Fig. 2. Weekly mean peak and off-peak prices in Germany in 2003, 2008 and 2016 throughout the calendar year (source: EEX, 2017).

liquidity increased, i.e., the share of electricity exchanged in the market grew, resulting in smoothing volatility. The latter further decreased with the coupling of the Central West Europe markets in 2009. The prices in each region became similar most of the time (Market Observatory for Energy, 2010b). In particular, the occurrence of reverse power flow almost disappeared; the price was no longer lower in the importer country. This market inefficiency may have increased the volatility of prices in the past. In 2014, the coupling was extended to the United Kingdom, Nordpool, and South Western Europe markets.

This coupling went with investments in physical interconnections. The cross-border flow has been growing over the years. Countries with surplus of flexible technology were able to export to neighboring countries (Midttun and Piccini, 2017; Ries et al., 2016). Fig. 1 shows that in addition to the drop in revenue, the variance amongst the markets tends to diminish for all but Nordpool and Ireland. The Scandinavian market benefits from a high share of flexible hydropower, which explains its lower revenue for storage. The latter increased from 2008, because they exported more flexibility thanks to the increasing integration with North-Western Europe. Ireland on the other hand, deployed renewable energy while decreasing its share of flexible gas turbines (SEAI, 2015). A large share of wind energy has increased price volatility (Market Observatory for Energy, 2014). As Ireland's low integration with the Great Britain and continental Europe prevented the country from using international trade to compensate for their lack of flexibility. Although this might not be a conclusive evidence, Fig. 1 shows that interconnection competes against storage devices (Lamy et al., 2014). By extending the spatial coverage, interconnection also softens the impact of supply intermittency (Mareda et al., 2017). For instance, wind turbines may stop generating in an entire country, but are unlikely to cease across one whole continental region, and this narrows the price spread.

While some trends were discussed in this section, they cannot be fully generalized due to the complex interaction of different drivers. Readers are referred to the 2008–2017 QREEM for further details.

3.2. Tradeoff between discharge duration and round-trip efficiency

Fig. 3 provides the mean revenue in the day-ahead European power market for the 2011–2016 period for different round-trip efficiency and discharge duration combinations. We weighted each country according to its share of the electricity generation in Europe, based on BP (2015)[2]. The figure shows the expected increase in revenue from increased round-trip efficiency. For example, for a 6 h discharge duration device, the operator's annual revenue can grow from 1 to 1.5 € by increasing the round-trip efficiency from 0.50 to 0.58. This kind of comparison can also help with quantifying the value of efficiency increasing innovations.

The figure also shows the growth of expected revenue with increased power capacity, i.e. lower discharge duration. For example, the revenue of a device with 0.8 round-trip efficiency can increase from 1.8 to 3 € if the discharge duration drops from 20 h to 10 h. This means doubling power capacity. Depending on the cost of power capacity, one can determine if buying more power is profitable for the installation. To sum up, Fig. 3 highlights that greater power capacity can compensate for lower efficiency.

3.3. Investment

Fig. 4 shows the present value for six standard energy devices, with their characteristics presented in Table 1. We only converted dollars into euro (1 € = 1.15$). The Nordpool market always represents the lowest present value. This area possesses abundant back-up power
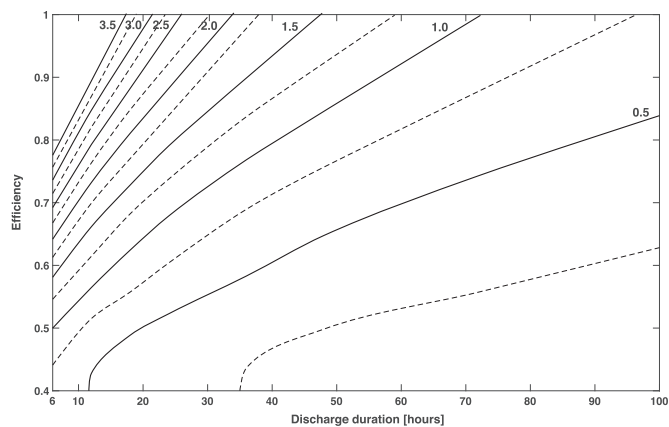
Fig. 3. Revenue tradeoff between round-trip and discharge duration (€ for 1 kW h of storage volume) for the European market prices from 2011 to 2016.
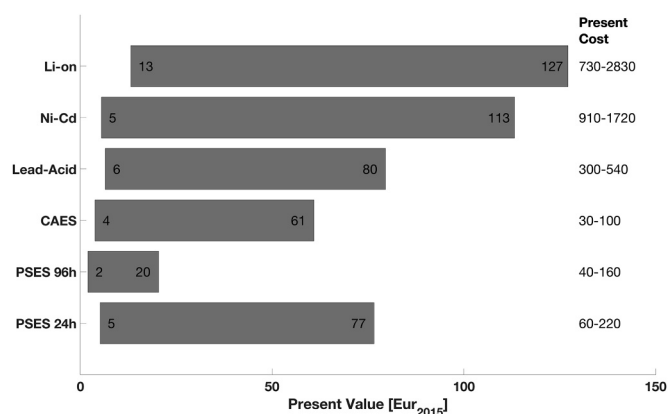

Fig. 4. Present value of future income and present cost of various standard energy storage technologies (for 1 kW h of storage volume), including PSES with two discharge duration (24 and 96 h).

capacity, mainly through hydropower plants. In contrast, all energy storage technologies are the most profitable in Ireland, closely followed by the Netherlands' present value for PSES with a discharge duration of 96 h and CAES.

We present revenue and cost separately. Indeed, the level of uncertainty of revenue is low, because it was computed with market data. On the other side, costs largely fluctuate between countries, projects, and change with innovation. The given numbers in the literature are not always consistent. Separating revenue from cost lets readers use their own cost data to make conclusions if needed.

If the present value is lower than the present cost, the spot market revenue does not justify investments. Fig. 4 shows that all technologies are barely profitable within an energy-only market. It becomes only profitable if CAES and PSES 24-h costs are in the lowest range observed in Table 1 and in the most profitable markets.

The profitability of PSES decreases with the discharge duration. Thus, utilities are inclined to invest in daily pumped-storage installations, rather than seasonal where this technology benefits from a comparative advantage. PSES maintains a technical advantage for weekly to monthly arbitrage by making long-term water storage possible. It means markets incentivize utilities to invest in PSES projects that are the most vulnerable to introduction of new technologies.

According to our data, CAES is becoming competitive with PSES. While 99% of worldwide storage capacity currently relies on PSES, this situation is likely to change in the near future. The comparative advantage of PSES can become less significant since it is the most mature energy storage technology. The cost of PSES will not decrease drastically whereas with new technologies are expected to become cheaper

by likely innovations. On the other hand, most PSES installations can take advantage of natural runoffs. This can represent a great advantage not reflected in our results.

A discount rate of 5%, considered here, might be lower than the rate applied in the sector (IEA et al., 2015). This rate could be relevant for PSES, but investing in a new technology means taking a higher risk. Thus, the investment analysis should consider a higher discount rate for CAES. This is why we also computed the MIRR (in parentheses) for the six generic installations: PSES 24 h (− 4.3 to 6.0%), PSES 96 h (− 5.9 to 3.6%), CAES (− 3.1 to 7.1%), Lead-acid (− 5.9 to 1.7%), Ni-Cd (− 8.9 to − 0.2%), and Li-on (− 8.1 to 0.7%). The numbers for CAES are comparable to, and even better than PSES. The increased risk associated with investing in this technology may explain why it has not observed greater deployment.

3.4. Limitations

By making certain assumptions, this paper provided a computationally cost-effective approach to analyze 17 European electricity markets. These simplifications that result in uncertainty that must be acknowledged when interpreting the results.

As confirmed by practitioners, arbitrage has remained as the primary source of revenue for the European energy storage operators to date. The European electricity markets grant considerable importance to the energy-only market, in contrast to the US market design. Our results provide a reliable first approximation, but do not consider all sources of revenue. We disregarded balancing and ancillary markets, because they concern a small volume of energy or power, attributed through auctions. Most past models of these markets have assumed perfect foresight, where the operator wins every profitable bid. This tends to overestimate the actual revenue and adds other uncertainties. To sum up, our results show that energy-only markets do not reward the full value brought by energy storage to the electric system, thus jeopardizing investments in storage installations.

Balancing and ancillary service markets are relatively recent in contrast to the day-ahead market. So, focusing on the energy-only market let us enlarge the time and spatial spans of the analysis. For example, German intraday market data is available since 2012, as opposed to 2001 used in our analysis. By limiting the analysis to spot markets, we could cover 23 countries over a period of up to 16 years without the need to develop models that are very specific to each market. This helped us develop a long-term continent-wide perspective. Nevertheless, there is a need and value for market-specific investigations in the future.

We also limited the analysis to an ex-post perspective, relying on a single scenario, i.e., the same pattern as the historical one, for the investment analysis. This helped us avoiding uncertain projections in the face of the evolving market design and energy policies evolve (Newbery, 2016), changing demands and prices (Madani et al., 2014), as well as volatility projections, that are relevant for storage technologies. While historical patterns are not expected to hold into the future, our analysis helps with better understanding the studied markets.

Additionally, we assumed generic energy-storage devices, represented by only three parameters, i.e., efficiency, discharge duration and volume of storage. As discussed in Section 2.1, other characteristics have a limited impact in the context of an arbitrage only model and their integrating could complicate the interpretation of outcomes. The calculated annual revenues can be used as the base approximation of the incomes in future in-depth studies.

Finally, this paper only considered the economic aspects. Nevertheless, energy design and operation decisions must also consider other factors such as safety, environmental risks, and social acceptance. Consideration of such aspects can decrease or increase the desirability of an economically attractive energy option (Hadian and Madani, 2015). Future studies can include additional factors to provide a more holistic evaluation of technology options to prevent unintended and

secondary consequences (Haghighi et al., 2018).

4. Conclusion and policy implications

This paper provided an overview of the current economic situation of storage technologies in Europe by looking at their revenue and profitability. It also shares a dataset of annual revenue of the storage device on 17 electricity markets that can be used to assess the revenue tradeoff between round-trip efficiency and discharge time. This helps comparing various storage devices or estimating the economic value of innovations aimed at improving efficiency.

The study results suggest that the revenue for storage technologies has dropped in most European markets. This justifies the lack of incentive to develop capacity in an energy-only market (Joskow, 2006). Our simulations can contribute to addressing this market failure (Cramton et al., 2013), as it quantifies the gap in income that hinders investment in six generic energy installations.

Our results show that the position of pumped-storage energy storage (PSES) has been jeopardized. The existing installations are unprofitable in the current market and PSES's comparative advantages could vanish in the near future, as some alternative storage technologies (e.g. compressed air) are emerging and benefitting from innovation. PSES's monopolistic position in terms of bulk energy storage is expected to cease, particularly given that current markets are deterring investment in seasonal storage services where PSES has a technical advantage. The modified internal rate of return (MIRR) highlighted which policy measures could spur investment in new energy storage technologies. New and revised policies are required to reduce the risks associated with CAES, e.g. offering guarantees and insurances. The MIRR of this new technology is comparable to PSES. Therefore, subsidies may not be justified, contrary to the other energy storage technologies, which have low to negative MIRR.

The historical revenue of energy storage devices in Europe tended to converge in time. This highlights that interconnection may represent a threat to storage and cause challenges for the regulator which sounds counterintuitive. Due to electricity transport being a natural monopoly, the transport system operator's strategy could conflict with the interests of the utilities. The lack of flexibility may promote further investment into interconnection, while deterring private companies from investing in storage capacity. This issue has not been highlighted to date, and further research should be conducted in order to investigate this specific issue.

As a primary state review study, this paper underlined the current issues rather than making projections and simulations to identify solutions. The fact that renewable energy tends to reduce the price spread should be addressed in the future. Beyond a large share of intermittent energy, one may expect volatility to increase, thus enhancing the profitability of energy storage. However, this issue requires further investigation. Revising the market design could represent part of the solutions, as investigated by others. Our paper highlights the value of such investigations.

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