Market strategies of large-scale energy storage: vertical integration and stand-alone market models

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- *preliminary version -*

Abstract

The status of the energy storage is generally ambiguous, either generation, consumption, or both. This study evaluates the largest French Pumped Hydro Storage plant - Grand'maison, by means of an optimization dynamic algorithm of the plant hourly operation over the year 2017 as stand-alone market player. In this market model, the storage operator has myopic foresights of prices over the year but perfect information on the spot market price over one day for a daily storage provision; alternatively, it considers a weekly storage strategy, hence with perfect information within recursive weekly blocks. Results show that compared with the actual plant data in 2017, the storage operator does not fully capture the optimal market value, and partly confirm expectations that the storage economic model is not driven by the spot price, but it simply correlates with. Despite optimisation, the French price spread is not large enough to cover the investment costs (the NPV before taxes is of -34 M€$_{2017}$/yr or -23 €$_{2017}$/MWh). This further supports the design of contractual options for PHS as ancillary services provider and partly as stand-alone market player, or some forms of vertical integration, e.g. with the TSO or with nuclear or renewables generators. These revenue streams seem implicit today to the economics of PHS, and their value alone could justify the French regulator commitment to install new PHS plants despite unclear inhibiting business models. The main electricity market recommendation is against cumulating multiple contracts across wholesale, ancillary services and capacity markets, due to the complexity of markets, conflictual gate closure timelines, and high transaction costs. It rather suggests simple bundling with a complementary generator, directly or via the TSO, based on a metric which reflects the size of the storage, to soundly take into account the potential duration of the storage and the nature of the seasonality, e.g. short-run or long-run.

Keywords: pumped hydro energy storage, stand-alone market player, deterministic daily / weakly storage optimisation, perfect / myopic foresights, vertical integration

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1. Introduction

The specification of the role in power systems is complex as it depends on storage characteristics and the needs of frequency regulation from generators and TSO grid operator (CIGRE, 2019). Experience around the world power markets show that price arbitrage[3] on its own is not typically a profitable energy storage application, and arbitrage should be combined with reserves and ancillary services to stack revenue streams (Staffell & Rustomji, 2016). Despite the technological capacity of different storage devices to provide flexible and highly accurate services to different market segments, regulatory market structures, initially designed for conventional electricity systems, erect bariers to the storage operation. Anuta et al. (2014) show that, beyond the undetermined definition of the storage asset as generator or demand, difficulties in assessing the value of storage are due to unbundled electricity systems affecting the calculus of the full value of storage. In particular, transport and distribution being prevented from owning storages, can influence the value assessment, as in a vertical integration case it could give transparency of the direct beneficiary of the storage services.

The literature is rich in studies dedicated to large-scale storage evaluation, in particular Pumped Hydro Storage (PHS), and main trends are attempts to identify the share which should optimaly be addressed to arbitrage and to balancing (Staffell & Rustomji, 2016), the value of pumped storage in comparison with other large-scale technologies (Gaudard & Madani, 2019), the system value of pumped storage, beyond the project level revenue maximisation (Teng et al. 2018), the pumped storage design in terms of responsiveness time (Yang & Yang, 2019) and other than energy services provision, such as heat (Smallbone et al. 2017), etc. In short, this literature argues that in some cases compressed air energy storage is cost-competitive over pumped hydro storage, that supporting policies should be oriented towards financial risk reduction over subsidies, that variable-speed pumped storage would better handle the variability of renewables, and that the value of pumped storage increases with the market size, e.g. European-wide level over national level.

This paper is in line with the literature on pumped storage market evaluation, and it complements it with a different approach to identify the revenue streams where benefits to storage come from. It further aims at understanding the contractual forms which best fit the power system needs for regulation and the storage needs to cover the investment cost. To that is simulates the case where the storage operator acts independently on the power market, and selects as study case the French power system and its largest pumped storage plant such as to estimate the value on the wholesale market and the nature of its seasonality, e.g. short-term or long-term. It finaly sugests other than conventional indicators to compute the cost of storage based on energy-out only, since this one ignores the duration of storage which has led the literature to conclude that short duration storage has much greater value (Strbac et al. 2012).

The following Section 2 details the case study, Section 3 describes the model used in the simulation of the French storage plant. Section 4 presents and discusses the results, and finally, Section 5 concludes on main policy implications on the power market contractual forms.

[3] The Energy Storage Forum defines the energy arbitrage as wholesale buying and selling by grid operators, or from the demand side it is similar to time-of-use management. It is also comperad to a sort of load following or ramping up electricity supply as activity increases in the morning and ramping down as activity diminishes towards the evening. At: https://energystorageforum.com/energy-storage-technologies/applications-of-energy-storage

2. Case study

The pumped hydro storage in France has regained interest with the development of variable renewables. According to the French Multiannual Energy Plan in support to the Energy Transition Act, the target is to add 2 GW, by 2030, to the current installed capacity of 4.2 GW (PPE, 2018).

The current fleet is presented in EdF documents (EDF, 2011) as being meant to provide energy management such as pumping during low demand and discharging during demand peaks, which is different from a price arbitrage rational even if it finaly can be correlated with. PHS plants appear in this definition as being driven by flows instead of prices, as they belong to the EDF which makes the management of its diversified portfolio in a central manner. PHS plants are optimizing in this way the energy mix, they are mainly used during peak periods and supply both the wholesale and the balancing markets, for both negative and positive reserves. Table 1 gives a brief overview of plants.

Table 1. The description of the French PHS fleet

French PHS plant characteristics	Montézic	Revin	G. Maison	S.Bissorte	La Coche	Le Cheylas
Year of operation	1982	1976	1985	1987	1977	1979
Turbine, MW	910	720	1790	730	330	460
Pumping, MW	870	720	1160	630	310	480
Number of pumps	4	4	8	4	2	2
Discharge, hours	40	5	30	5	3	6

Source EDF (2015).

The PHS seems to cumulate services on different markets, which makes us having a closer look at the real-life performance of the French PHS fleet over one year (here 2017), at an hourly basis while pumping and discharging, and also for each individual plant out of the six PHS installations.[4]

The observation seaveals that there is a correlation between the spot price and the pumping and discharging modes of the PHS fleet, following the economic rational of pumping during low prices and discharging at high prices. However, statistics by plant show frequent uncorrelated operations: some plants are pumping while, at the same time, others are discharging. These events are far from being isolated over the year: their number is relatively high and volumes are significant. Fig. 1 shows several uncorrelated events over one week.

For orders of magnitudes, data are extracted for two PHS plants: Grand'maison (1,790 MW discharging/ 1,160 MW pumping/ 30h storage) and Super-Bissorte plant (730 MW discharging/ 630 MW pumping/ 5h storage). Uncorrelated flows are proportional to their nominal power: Grand'maison is discharging 191 GWh over the year when S-Bissorte is simoultaneously pumping 110 GWh, and it is pumping 316 GWh when S.-Bissort is discharging 66 GWh. The number of events amount to 627 and to 607 respectively, or 13% and 17% of the time when Grand'maison plant is operating in each discharging and pumping mode.

[4] RTE, 2017, http://clients.rte-france.com/lang/fr/visiteurs/vie/prod/production_groupe.jsp, accessed at 03/11/2019.

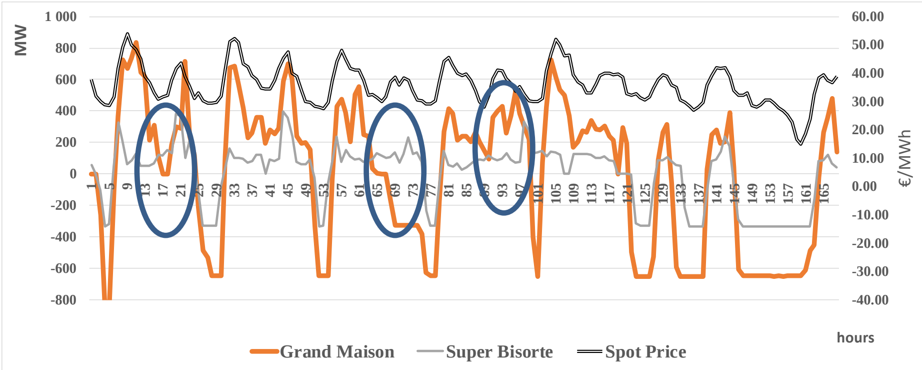

Fig 1. The operation of two PHS plant over one week in 2017

First intuition is that each plant follows different storage strategies that best adapt to their reservoir capacity (EdF, 2015): weekly energy storage for Grand'maison and daily storage for S.-Bissort. The two PHS plants being located in the same regulation area (administratively the two sites are in the same department, at a distance of about 70 km), we expect flows to have different duration, amplitudes and delivery time, yet correlated over one week; yet, in practice, flows are obviously conflicting. Next one PHS plant is modelled to understand the economic rational behind the operation on the wholesale market.

3. Methodology

For the model in this paper, two main classes have been identified to build assumptions on: models making the difference between short-term storage (around 4h) and long-term storage, around 700 h (Jülch, 2016); and models where storage operator makes price arbitrage assuming different foresights of future power prices (Staffell & Rustomji, 2016). The first class models simply assumes different capacities installed and different energy to power ratios for the same storage device. The later assumes perfect price prevision over months, as being revelant for seasonal storage. By contrast, in the following it is assumed that the same capacity is used for short-term storage and alternatively for long-term storage; and it implicitetly assumes that the future price evolution in weeks or months cannot affect the current storage decision in the French mix, due to the high market liquidity on both wholesale and balancing markets, with no prior reason to store the power over weeks.

The model is built to optimaly simulate the operation of a PHS plant such as Grand'maison, at two time horizons: the daily storage provision and the weekly storage for longer discharge. In the first case, the PHS operator supplies the spot market based on a perfect information of the spot price; while the later case consists of weekly storage delivery with perfect information on prices over one week. Longer this horizon, the information on prices and volumes is less accurate and the need to store bulk energy in well interconnected areas such as the French market seems questionable.

The model maximizes the operational revenue to charge and discharge the power under the economic constraint of hourly prices and under technological constraints such as the round-trip efficiency (80%), minimum load of reservoirs (10%), technology ramping, plant availability and nominal capacity of pumps/ storage/ turbines. The model is built by using the software Python, solver *scipy.optimize* (https://www.python.org). Dynamics is based on 8,760 time slices organized within 52 recursive dynamic blocks for weekly storage optimisation or 365 blocks for the daily storage. Within each block, the information on hourly power price is perfect starting with the first period of each week or day, and ending-up at the last hour of each optimisation block. Over the year, the information is said to be myopic given the sequential dynamics organized within blocks.

The model returns volumes of charging and discharging triggered by spot market prices, and outputs are extrapolated to the technical lifetime of the plant such as to reproduce the investors business model based on a representative year. The economics of the PHS plant is ultimately assessed by calculating the Net Present Value (NPV) of benefits and the Levelised Cost of Energy (LCOE).

Bold characters are used for endogenous variables, normal font is used for fixed values.

Eq1. Operational profit maximization (the objective function):

$$\boldsymbol{\pi_s} = \sum_{1}^{B_s} Max_{d,h} \sum_{\substack{h=1\\d=1}}^{\substack{d=t_s\\h=24}} p_{d,h} \cdot (\boldsymbol{PD_{d,h}} - \boldsymbol{PC_{d,h}})$$

Eq2. Dynamics of the storage reservoir:

$$\boldsymbol{R_{d,h}} = \boldsymbol{R_{d,h-1}} + \boldsymbol{PC_{d,h}} \cdot eff - \boldsymbol{PD_{d,h}}$$

Eq3. Minimum load condition (storage reservoir does not get empty) and maximum level of charging:

$$MinLoad \cdot K_R \leq \boldsymbol{R_{d,h}} \leq K_R$$

Eq4. Power discharged is lower than the power charged over the year:

$$\sum_{1}^{B_s} \sum_{\substack{h=1\\d=1}}^{\substack{d=t_s\\h=24}} \boldsymbol{PD_{d,h}} \leq \sum_{1}^{B_s} \sum_{\substack{h=1\\d=1}}^{\substack{d=t_s\\h=24}} \boldsymbol{PC_{d,h}} \cdot eff$$

Eq5. Power discharged does not exceed the capacity of turbines:

$$\boldsymbol{PD_{d,h}} \leq K_T$$

Eq6. Power charged does not exceed the capacity of pumps:

$$\boldsymbol{PC_{d,h}} \leq K_P$$

Eq7. PHS Net present value:

$$\boldsymbol{NPV_s} = \sum_{y=1}^{60} \left[\left(\boldsymbol{\pi_s} - c\_OM_y \right) / (1+r)^y \right] - INV_0$$

Eq8. PHS Levelised Costs of Energy:

$$\boldsymbol{LCOE_s} = \frac{INV_0 + \sum_{y=1}^{60} \frac{c\_OM_y}{(1+r)^y}}{\sum_{y=1}^{60} \frac{\sum_{h=1,d=1}^{h=24,d=t_s} \boldsymbol{PD_{d,h}}}{(1+r)^y}}$$

Index

y – years over the technical lifetime (1,60)

d – day (1, 365)

h – hour (1,24)

s – optimization strategy: daily or weekly optimization (s = {“*day*”, “*week*”}

t_s – time interval by optimization strategy: daily ($t_{\text{"day"}}$ = 1) or weekly optimization ($t_{\text{"week"}}$ = 7).

Bs – the number of recursive blocks over the year, by strategy: daily optimization ($B_{\text{"day"}}$ = 365); weekly optimization ($B_{\text{"week"}}$ = 52).

Parameters
eff – round-trip efficiency of pumping and discharging (*eff* = 80%)
MinLoad – minimum load of reservoir to remain filled in (10%)

Exogenous Variables (Inputs)
$p_{d,h}$ – spot market power price at hour *h*, day *d* (in €/MWh)
K_R – capacity of reservoir (in MWh)
K_T – capacity of turbines (in MW)
K_P – capacity of pumps (in MW)
r – discount rate (8%)
INV0 – PHS investment cost (in €)
c_OM – annual Operation & Maintainance cost (in €)

Endogenous Variables (Outputs)
π_s – yearly operational profit by strategy (π_{day}, π_{week}) (in €)
$PD_{d,h}$ – power discharged at hour *h*, day *d* (in MW)
$PC_{d,h}$ – power charged at hour *h*, day *d* (in MW)
$R_{d,h}$ – energy stored in the reservoir at hour *h*, day *d* (MWh)
NPVs – Net present value by optimization strategy (in €)
LCOEs – Levelised cost of electricity by optimisaiton strategy (in €)

4. Results

Optimisation results show that among the two storage strategies, daily and weekly, the one which best fits the actual behaviour is the daily storage (Fig.2). The result is not French-market specific, since the literature has already identified that markets promote daily pumped-storage installations rather than seasonal (Gaudard and Madani, 2019).

The contribution of this work is sizing, at a unit level, the hourly gap between the optimized operation and the actual one, revealing a missing market opportunity in both volume and money: over the year, the daily storage operator fails to capture 4.2% of the optimal profit of a virtual rational independent PHS market player, or a missing operational profit of 1.4 M€$_{2017}$. In volume, the energy supplied is 25% less important in the actual case than in the daily optimisation, which reveals that other constraints add to PHS stand-alone model triggered by the price spread only. Constraints could be internal related to the technology itself, but also external due to centralized dispatching of all power generators in the system, including exports and imports which punctually complement or substitute the PHS. A second point is more general and regards the lack of absolute profits even in a case of optimal operation on the day-ahead and infraday markets: despite optimization, the price spread is not large enough to cover the investment cost and the PHS operator records losses: the NPV before taxes is of -34 M€$_{2017}$ annually or -23 €$_{2017}$/MWh over the technical lifetime.

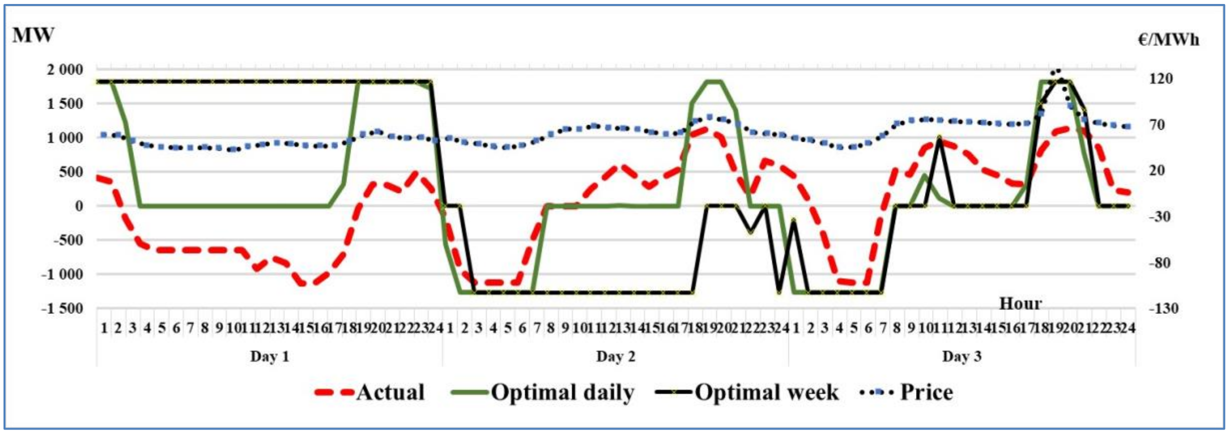

Fig 2. Operation of Grand'maison PHS plant over three days: Actual (real data) *versus* Optimal (model results)

Over the year, the graphical representation of the effective operation of the PHS Grand'maison plant is not constant, as the match between the historical behaviour in 2017 and the optimisation seems to alternate the weekly storage with the daily storage on an irregular basis. This partly confirms that the economic model of the PHS plant is not driven by the spot market only, but it simply correlates with (75% over the year). Hence other strategic options have been contemplated, mainly driven by the system operator by means of some contractual arrangements with other power plants.

At a glance, the gap actual-optimal operations reveals the provision of a service close to ramping energy blocks such as defined in Cigre report (2019) as being specific to systems exposed to high ramping. Corollary, four large nuclear power plants are located in the proximity of Grand'maison PHS plant and despite their commitment to meet a forecasted load profile, the anticipation of the rate of change is constantly subject to technological constraints of efficiency and safety. All french nuclear power plants are capable of load-following and they all provide flexibility and ancillary services to the grid. However, in case of requirements for faster response and longer lasting reserve, negative reserve in particular, operations could be limited by the reactor design in terms of ramping and minimum load safety requirements. PHS storage could be integrated within the nuclear facility, and naturally form a single entity as their both belong to the EdF operator.

Results show that seasonal storage results in larger volume supplied to the wholesale market than the daily storage, but at a lower price in average (47.8 €/MWh against 49.6 €/MWh). The factor use is more important in the long-term storage than in the short-term case (19% against 16% respectively), suggesting that long-term storage is not only a mater of storage duration but also a question of discharge term, with sales of energy blocks as probably support to a large-power plant, like a nuclear plant. The stock is also used differently, e.g. with more flows stored in the short-term than in the long-term (20.5% against 14%), suggesting a more dynamic use of storage for short duration operations.

The weekly storage is clearly less profitable than the daily storage, which means that the operators providing weekly storage have a missing market opportunity. This reveals to some extent that long-term storage cannot be the choice of a rational independent player, but rather a contractual agreement between the PHS plant and and a beneficiar which remains to be determined, either the operator system or a generator. Ultimately, the cost calculation based on levelized cost of energy supplied over the year seems restrictive to the flow out, as the indicator ignores the dynamics of the stock and the value of the long duration of storage. However, the higher factor use of turbines in the long-term storage leads to lower costs than for short-term storage (91 €/MWh against 108 €/MWh), yet with lower profits due to low spot prices over the discharge period as mentioned. To estimate the cost of storage, the literature is also using the indicator of levelized cost of energy or a modified indicator such as the cost of storage (LCOS - Jülch, 2016; Lazard, 2018), which is nothing but a simple application of the LCOE to storage technologies instead of energy produced with pure generators. The difference between a long-term and a short-term storage makes the building of a new indicator, including the storage duration, necessary. This will further influence the technology design of the storage plant and of the contract terms to better integrate the characteristics of flows, in both value and volume.

5. Conclusions

The absence of a clear role of the energy storage, as a weekly or daily storage, as a stand-alone market player or a service provider, indicates that the decision to invest into new PHS facilities keeps being integrated into a broad central energy planning strategy. In a context where the French power system evolves towards longer and faster system services, the regulator needs rethinking the role of both energy storage and generators in providing ancillary services (Tang et al, 2018). In particular, nuclear power plants need clear signals on the adjustment speed necessary to follow the load which becomes more variable with the massive entry of wind and solar power, while energy storage needs clarification on the complementary or substituting role it will play in future scenarios.

However, the complexity of market segments makes the operation with multiple contracts difficult and sometimes conflicting since the capacity reserved for one service is unavailable for the provision of another market segment. Transactions costs could add to computational issues to determine in real-time the optimal share to supply wholesale market and the share reserved for balancing; these shares are evolving at every inbalancing time step. In France, the current time step of imbalances is currently of 30 minutes, but by 2025, it must align to the European regulation providing the obligation for all control areas to introduce the imbalance settlement period of 15 minutes, and to bring the generators' bids closer to the real time (EC, 2017).

Probably two simple contractual options could be foreseen, one concerning a fixed share of ancillary services the storage should provide such as to optimaly use the remaining capacity on the spot market, determined as adjusting variable. Another option is to identify the beneficiary of the service support such as to regularly legitimate some forms of vertical integration, e.g. with the TSO (Transmission System Operator) or with generators such as renewable plants and the nuclear power fleet. As the mangement of the PHS plants seems to be decentralized with some plants pumping and other discharging at the same time, contracts need clarification on a case by case basis. Ultimately, the general public needs understanding the strategic value of the asset such as to locally accept building new PHS projects and to financially support the high investment costs.

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