VALUATION OF LARGE SCALE ENERGY STORAGE: OPTIMISATION VS SIMULATION METHODS

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Abstract

Electricity storage is likely to be key in the transition to low carbon economy such as to handle the variability of renewable energy sources. Yet, its economics remains confusing in terms of regulation and business, hence investors and policy makers need clarification on storage evaluation. This paper investigates modelling techniques such as to build an open-source calculator that best reproduces the storage operation based on average charging and discharging profiles.[3] We then compare results of costs and revenues with actual economic indicators and with optimized operation. We find that despite accurate simulation, large differences exist among models and that there is no correlation between the lowest cost and the highest profits, which further fuels controversies about the storage value. The volatility of the market shows that supplying more with storage does not imply earning more, and that intensive use of storage can be loss making. Storage operation is then not a matter of using more, but using it at the right moment, as the energy storage is moment specific. Storage evaluation can clearly not be generalized, even if the seasonality slice is the week period; it is instead the *hourly* price profile which best estimates the value, as a proxy of the power system behaviour, since storage primarily supports the system, as a complement more than a substitute to power generators. In front of the variety of evaluation techniques, we conclude that methods should be understood from the perspective of the user's scope, to evaluate: the market benefits (Optimisation), the grid requirements (backcasting Observation), the storage plant behaviour (Simulation).

Key words:

Energy storage, modelling methods, system benefits, private rents, levelised costs, pumped hydro storage.

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1. Introduction

The levelised cost of energy (LCOE) is the common indicator used in the investment decision-process to calculate the cost of operation of an energy project such as to predict the profitability or to compare similar projects. More specifically, it is defined in Short, Packey and Holt manual for economic evaluation as an indicator that allows alternative technologies to be compared regardless of their characteristics (scale of operation, sources of energy…) thus, it is mainly recommended for ranking technologies given a limited budget of investment [1]. The French Agency for Ecological Transition defines the LCOE as the cost that breaks-even the investment and the operation cost of a generating plant over its expected lifetime [2]. The International Energy Agency's report on electricity generation costs [3] is using the LCOE indicator as a comparison tool to rank technologies that operate on different scales.

This paper investigates the evaluation techniques applied to storage technologies, by means of observation of past behaviour, which is further compared to ideal, optimized operation and tries to generalize the behaviour by means of a simulator. The aim is to determine the impact of modelling techniques of the energy storage operation, to highlight key parameters and hypothesis beyond those commonly used in the LCOE formula.

The academic research employs the LCOE to evaluate and compare energy storage technologies [4], where in practice controversies arise about the use of the LCOE concerning its legitimacy to compare technologies that are not pure energy generators, such as energy storage. The LCOE is calculated by the ratio of the total discounted cost over total generated energy. Physically, the energy storage unit extracts energy from the grid, or directly from a power plant, in order to supply it back at another time. The calculus of LCOE does not account for the cost of the energy being stored, and it is only the amount of energy discharged which is considered. The literature then highlights that the cost of charging electricity cannot be computed in the LCOE formula as a fuel cost because of the specific nature of the electricity cost and its sources [5].

Studies on storage comparison suggest an alternative metric for energy storage called levelised cost of storage (LCOS) which differs from the LCOE on the way the cost of charging is included. Jülch and Smallbone introduce the LCOS by including the charging cost of electricity directly in the annual cost of the storage system [6], [7], like a fuel cost in a traditional LCOE, which reveals also the behaviour of power system. This is similar to the LCOE approach of the International Energy Agency that adds a carbon tax [3]. On an opposite train of thought, authors like Kapila [8], Zakeri and Syri [9] define a *net* levelised cost of storage which removes the cost of charging electricity must be removed from the formula. This parameter being inherently market specific, they do not consider it in the evaluation of storage cost but in the evaluation of the energy cost, resuming the definition of LCOS as the original LCOE net of the system charging cost.

Giap et al, in their research on fuel cell [10], underline that current LCOS neglects the design characteristics of energy storage technologies such as the use of external heat source for energy storage with an adiabatic process or hybrid storage system. Based on the LCOE definition of Short et al [1], they provided a new definition of LCOS which considers the difference between the levelised annual costs of charging and the price of discharging, and in this way the lost amount of electricity after each cycle as a consumed cost. In other terms, the cost of using electricity from the grid is defined here as the loss between charged energy and discharged energy, which is a profit if the cost of charging energy is lower than the cost of discharging.

As stated by Kapila et al [8], and Xie et al [11], economic analysis of large scale energy storage are still blurry and primarily focusing on the unit capacity capital cost of energy storage plant without taking into consideration the system needs and the market value that drives the operation of storage.

To fill the gap on the economic indicators used in the energy storage related studies, this paper provides a techno-economic analysis of a large scale energy storage plant with focus on modelling methods and their impacts on economic indicators.

The study case is the French storage plant Grand'Maison, as power systems around the world will massively need bulk storage in the future to meet decarbonisation targets with renewables. Two models are built, based on observation and on optimisation, such as to generalize an operation profile and to build a simulation tool adapted to Grand'Maison characteristics. Optimization of price arbitrage allows computing costs and profits with perfect price forecasts, and then compare actual results and simulated indicators with ideal case of price arbitrage. We conclude that cost calculation should integrate the seasonality of prices on the one hand, and the system needs issued from observation on the other hand. In terms of indicators, the levelised cost of energy does not seem appropriate to evaluate energy storage, and levelised cost of storage, while improved, could reveal the cost of technologies. Yet, using these indicators alone do not predict the future profitability of the plant as profits remain correlated with the operation, while costs do not.

In the following, Section 2 details the case study with respect to energy storage plant characteristics. Section 3 describes the methodology based on three models, Section 4 presents the main results in support to the analysis of key recommendations on the use of methods on cost evaluation, and the Final section concludes.

2. Case Study

The French energy consumption is made of fossil fuels (60%) and electricity (20%) [12]. In the future, these ratios will change such for the electricity to replace fossil energy, following the targets of the environmental and ecological transition of the French Multiannual Energy Program (MEP) [13]. Needs of flexibility to set the supply–demand equilibrium at any time is primordial to fulfil the gap between conventional-based and intermittent renewable electricity. The need for more energy storage technology to bridge this gap is not yet significant until 2028-2030 according to the system operator as it mainly relies on the existing infrastructure of power plants, national grid and interconnections with neighbouring countries. However, long term scenarios mapping nuclear phase-out mirror large requirements in terms of storage and flexibility [4].

Within the Paris agreement goal to reach net-zero emissions by 2050, an electrical power mix with a high penetration of variable renewable energy will necessarily need energy storage. Whether batteries, hydrogen or hydraulic based, new storage facilities have to be profitable quick enough to compete with existing installations, essentially interconnections, which will be challenging especially for recent storage technologies, which didn't reach maturity. Hence, it is key in the planning phase the knowledge of their cost and the simulation of their operation in order to best anticipate the installation of new facilities in support to new investments.

Pumped hydro energy storage (PHS) is currently the most important installed technology and the most advanced large-scale energy storage and, in some contexts, the only economically competitive technology. In France, the energy storage fleet cumulates 5,108 MW installed plants and discharges some 7,000 GWh /year, while new projects are planned since the PHS fleet is supposed to increase to 8 GW by 2050, according to the French system operator, RTE [12]. However, adding new PHS plants needs reconsidering the economic model as the current market structure does not trigger new investments without huge short-term financial contribution. To anticipate investments, it is useful to look into existing PHS plants to understand their operation, if they can be further optimised, and what analytical method can best fit its constraints. The case study covers next the largest PHS plant in France, Grand'Maison (Table 1), located in the French Alps mountain (south-east of the country), with a nominal power of 1,800 MW (or 35% of the installed storage capacity in France).

Table 1. Grand'Maison technical parameters [14]

Nameplate Capacity	1,800 MW
Turbine Rated Output	1,789 MW
Pump Rated Output	1,160 MW
Reservoir Volume	140,000,000 m^3
Dam Volume	14,300,00 m^3
Hydraulic Head	955 m
Discharge Duration	30 h
Turbine Flow Rate	217 m^3/s
Pump Flow Rate	135 m^3/s
Estimated Reservoir Capacity	518,519 MWh
Estimated Dam Capacity	52,963 MWh

From 2014 to 2019, Grand'Maison storage plant has pumped on average 2,000 GWh/year and discharged 2,500 GWh of electricity. With a dam volume of 14.3 Mm^3 and a reservoir of 140 Mm^3, Grand'Maison can offer a discharge duration of 30 hours. The power plant is mainly used to smooth electricity prices during demand peaks of electricity [15] as seen at Figure 1, where storage occurs over low price periods.

Fig 1. Daily average storage operation and market price over 2014 – 2019

The period of study is from 2014 to 2019, such as to include large price variability situations while still remaining representative of the current power mix. The power price is hourly defined based on data documented from Epexspot website.[4]

[4] https://www.epexspot.com/en/market-data

3. Methodology

Three models have been built, one based on backcasting and actual data of the plant operation, called next Observation; one based on the Optimisation of flows in front of spot power prices; and a third based on the Simulation of the operation based on average profiles of charging and discharging.

3.1. Three models general overview

Figure 2 depicts the steps of the method building by inputs, algorithms and outputs.

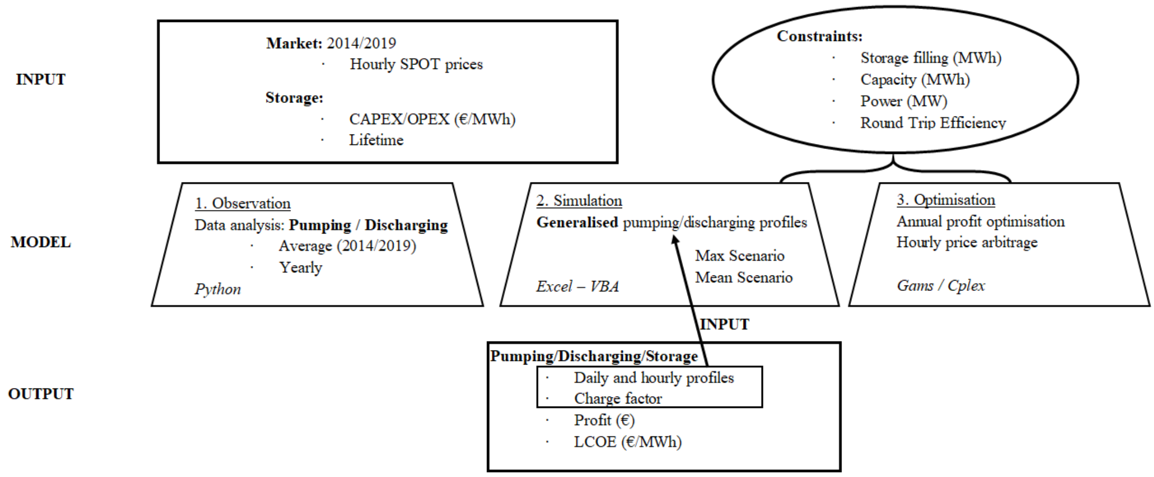

Fig. 2. Flow chart of three models based on Observation, Optimisation and Simulation

The Observation allows building an average profile of operation which is further injected into the Simulation. Optimisation and Simulation return indicators such as the hourly volume of pumping, discharging and storage, along with the hourly capacity factors. Others indicators are the aggregated volumes of each energy type (pumped, discharged and stored) over the year, and financial indicators such as the levelised cost of energy and profits. The LCOE of the system is computed as follows:

$$LCOE = \frac{(CAPEX * CRF) + \sum_{n=1}^{n} OPEX_n + \sum_{h=1}^{8760}(P_h * Stor\_in_h)}{\sum_{h=1}^{8760} Stor\_out_h} \quad (1)$$

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (2)$$

With i representing the discount rate, n the life cycle of the technology, CRF the capital recovery factor, CAPEX the capital expenditure and OPEX the yearly fixed operation and maintenance costs. CAPEX and OPEX are fixed respectively of 1,406,000 €/MW and 4.6 €/MW following the average cost documented by Zakeri and Syri [9].

3.2. Optimisation

An optimisation model is built to maximise the profit of Grand'Maison storage plant from arbitrage. The model is implemented in the Gams software using linear programming with the

Cplex software. The model is dynamic over 8,760 time slices in order to mimic the behaviour of a storage plant over one year.

In order to maximise profits (π_i), the dynamic operation of the pumped hydro storage system, i.e the energy fed into the grid every hour ($Discharge_h$) and the energy absorbed from the grid ($Charge_h$), is driven by perfect foresights of the hourly spot market price (P_h) of the selected year (i) as follow:

$$\pi_i = \sum_{h=1}^{8760} (Discharge_h - Charge_h) * P_h \tag{3}$$

As feasibility conditions, the energy stored and discharged are constrained by the capacity of the reservoir (*Capacity*), its current energy stock level ($Stock_h$), the efficiency (*eff*) of the technology and its nominal power (*Power*) such as:

$$Stock_h = Stock_{h-1} + (Stor\_in_h * eff) - (Stor\_out_h / eff) \tag{4}$$

$$Stock_h \leq Capacity \tag{5}$$

$$Stor\_in_h \leq Power \tag{6}$$

$$Stor\_out_h \leq Power \tag{7}$$

3.3. Simulation

Grand'Maison storage plant is simulated using Excel and implemented in Visual Basic for Application. The tool is available on line. [5] The objective is to simulate the storage plant without market prices anticipation. To that, an average profile of the plant behaviour is built based on historical data published by the French electricity transmission system operator, RTE [16]. In line with Ursat and al. [15], we show at Figure 1, that Grand'Maison storage plant mostly charges when prices are low and generates electricity when prices are high. Based on that observation, we build a binary profile for pumping and generating (Table 2).

The model simulate Grand'Maison operation as a standalone storage plant with no interaction with the French electricity system, meaning that the operation is only driven by the state of charge of the reservoir and the capacity factor profiles. The model first calculates the amount of energy pumped and generated ($Charge_h$, $Discharge_h$) following the selected profile (CF_h). For simplicity, pumped energy appeared as negative value where generated energy appears positive:

$$Charge_h = -(Power * CF_h) \tag{8}$$

$$Discharge_h = Power * CF_h \tag{9}$$

Dynamics of storage is defined hourly as follows:

[5] https://uncloud.univ-nantes.fr/index.php/s/iiWnogjComfHb5j

$$Stock_h = Stock_{h-1} + (Stor\_in_h * eff) - (Stor\_out_h / eff) \quad (10)$$

The input and output of electricity are subsequently adjusted following the storage constraints:

$$For\ Stock_h = 0 : Discharge_h = Stock_{h-1} * eff \quad (11)$$

$$For\ Stock_h > Capacity : Charge_h = (Stock_{h-1} - Capacity)/eff \quad (12)$$

By default, every simulation starts with the storage capacity filled-in by one third.

4. Results

This part presents the three models' results for the storage plant in terms of volumes, costs and profits. They vary by model, but basically the three methods are justified by the user scope: *Observation* is used to understand the operation of the technology as part of the overall system; *Optimisation* is used to accurately predict the storage operation in front of given power prices, and *Simulation* is used to predict costs and profits based on average profiles of charging and discharging.

4.1. Main results from Observation

The Observation case results in the average profile of storage plant for charging and discharging (Table 2). Three profiles are built, such as the binary profile (pumping or discharging), and two profiles with capacity factors assigned as follows: the "Mean" profile based on the average capacity factor of the plant over the period 2014-2019, and the "Max" profile based on maximum capacity factor recorded over the period. Note that, based on the actual data, charging and discharging rarely attain their maximum capacity.

Table 2. Capacity factor profiles obtained from Observation (further used in Simulation)

Hours in a day	Binary profile	Mean	Max
00:00-01:00		-7 %	-82 %
01:00-02:00		-33 %	-84 %
02:00-03:00		-45 %	-84 %
03:00-04:00		-58 %	-84 %
04:00-05:00		-62 %	-84 %
05:00-06:00		-56 %	-84 %
06:00-07:00		-29 %	-84 %
07:00-08:00		-1 %	-84 %
08:00-09:00		12 %	93 %
09:00-10:00		19 %	96 %
10:00-11:00		18 %	99 %
11:00-12:00		16 %	98 %
12:00-13:00		15 %	96 %
13:00-14:00		8 %	90 %
14:00-15:00		1 %	94 %
15:00-16:00		-6 %	-84 %
16:00-17:00		-7 %	-84 %
17:00-18:00		4 %	96 %
18:00-19:00		20 %	100 %
19:00-20:00		34 %	100 %
20:00-21:00		24 %	92 %
21:00-22:00		9 %	83 %
22:00-23:00		14 %	77 %
23:00-24:00		15 %	92 %

	Discharging
	Pumping

As already noted in the literature (Ursat et al. [15]), Grand'Maison storage plant is mainly used for **price arbitrage** to maximize profits. We find similar outcomes (Fig. 3), i.e. a positive correlation between the plant operation and spot prices, although the Pearson correlation coefficient (r) is only 0.40, which can either be interpreted as a weak correlation, or explained with the few outliers data points. A non-parametric correlation coefficient, Kendall's tau, is further calculated in order to test a correlation coefficient less sensitive to outliers. We obtain the score of 0.30 that could be considered as a moderate to strong correlation. This further reveals that beyond price arbitrage motivation, the storage operation is probably triggered by other contractual obligations, such as system services, balance adjustments or nuclear plant support, as part of the EDF operator diversified portfolio.

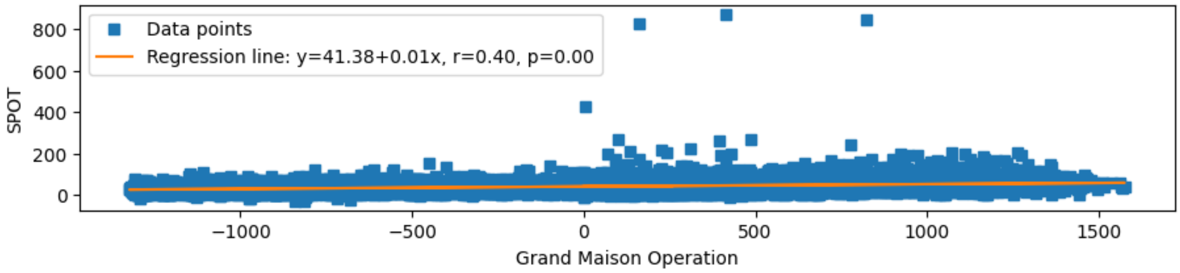

Fig 3. Correlation between Grand'Maison actual operation and spot market prices (2014 – 2019)

4.2. Comparison of the three method results

Results are next depicted in physical flows, by means of capacity factor indicators, by comparing scenarios Observation, Optimisation and two Simulations. Over the period 2014-2019, **capacity factors** are constant by assumption in both Simulations, and are respectively the highest (22%) and the lowest (8%) among scenarios (Fig. 4). Note that the capacity factor varies the most over the period in Optimisation (from 12% to 18%) according to business opportunities identified each year; and that the Observation exhibits rather stable capacity factors, as if storage would follow contract provisions different from pure price-arbitrage, as mentioned above.

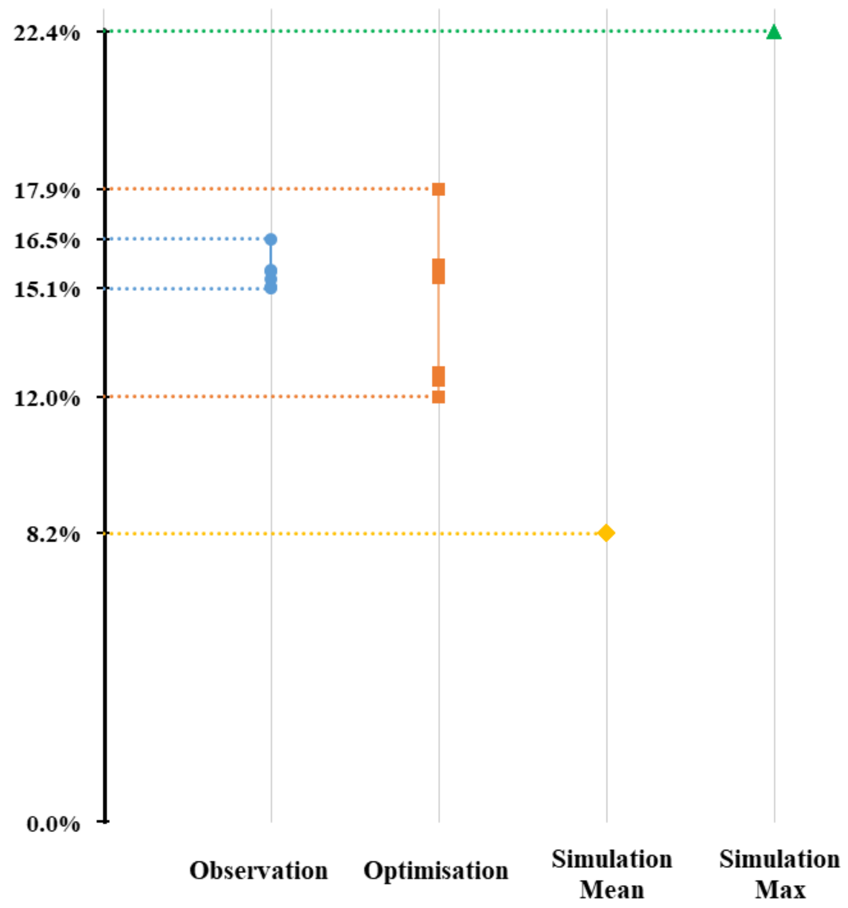

Fig 4. Grand'Maison capacity factor range for discharging, over 6 years, by method

Results over the period 2014-2019 show that volumes or **capacity factor and profits** are not related, meaning that the volume can be low and the profit high (as in 2014) and also, that at similar volumes or capacity factor, the profit can be low (in 2018). Figure 5 illustrates contrasting results by scenario by means of variations in 2018 related to 2014: at rather stable capacity factors (the blue bars are low), profit records noticeable high (Simulations – Max) and Low (Simulation – Min) variations.

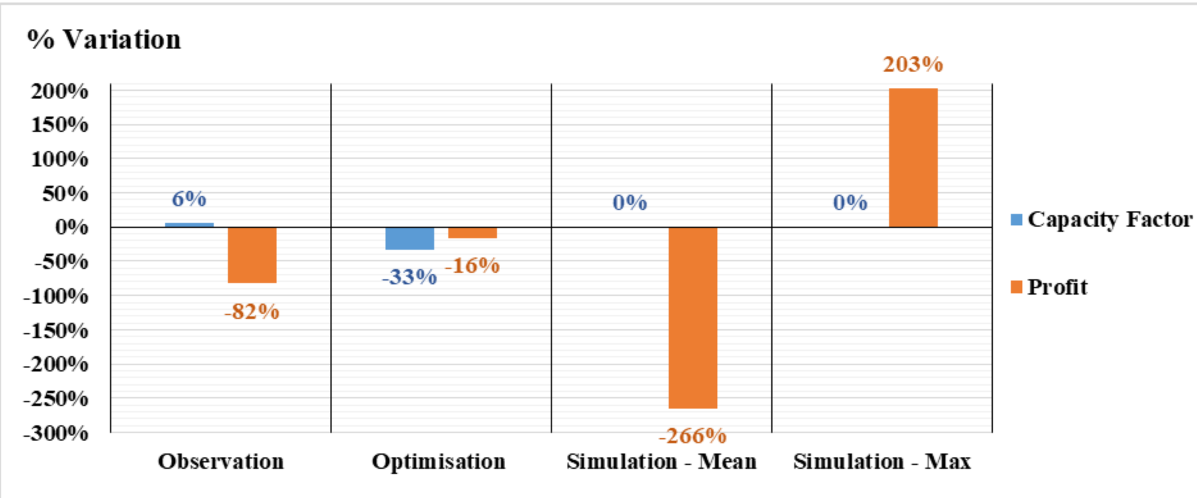

Fig 5. Variation of Capacity Factor and Profit between 2014 and 2018

This further means that evaluating storage based on only the volume or the capacity factor is incomplete in front of price **volatility** and that discharging a certain amount of energy is moment specific. Comparing results among scenarios (Fig. 5 and 6) shows that a small increase in volumes or capacity factor, of 2 points from Observation to Optimisation (respectively 16% and 18% in 2014), worth 20 M€ of profit variation; and more surprisingly, we note that the highest capacity factor can penalise the business plan, as Simulated – Max shows, with a large loss (of -14 M€, up to -44 M€). This proves the volatility of storage market value, and allows stating that supplying more does not imply earning more.

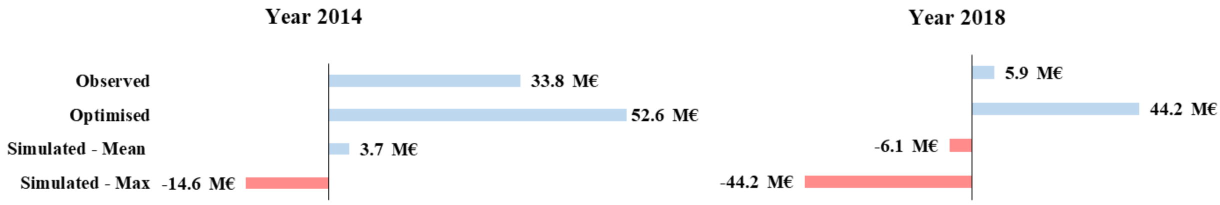

Fig 6. Storage Profit by year, 2014 and 2018

Beyond hourly and yearly operation, the **cost calculation** step is critical to investment decision and the choice of technology [4]. While the LCOE indicator is commonly used to that, the concept of variable costs included in the formula (Eq. 6) faces controversies on two aspects: the cost of charging electricity should be ignored because this reflects the system behaviour and that charging cost should remain exogenous to other actors' decisions, which the literature calls the Levelised Cost of Storage (LCOS, [8], [9]); and alternatively, while still considering this cost, the value is limited to the average baseload electricity price over a period. We next compute the levelised cost without the charging cost (LCOS) and on the top we add the levelised *hourly* charging cost, in average from 2014 to 2019 (Fig. 7). This shows how significant charging costs could be (up to 150% of the LCOS in Simulation – Max), and shows also the volatility of the cost indicator, by method used.

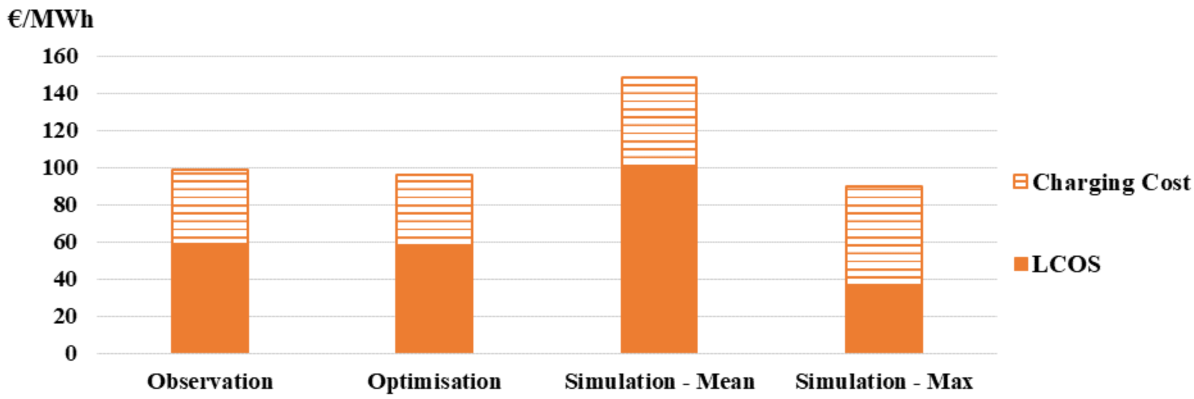

Fig 7. Decomposition of LCOE, with and without charging cost, by method, in average 2014-2019

By scenario, we note that there is a correlation between the capacity factor (Fig. 4) and the LCOE (Fig. 7, the sum of LCOS and charging cost), such as the higher the energy volume is, the lower the LCOE becomes. This is an interesting outcome, since the more the storage operates the cheaper the case is, as the scenario Simulation – Max shows, but as a reminder this is also the less profitable case leading to large losses. Observation and Optimisation follow the same trend of high energy flows supplied resulting in low costs; they respectively display capacity factors of 23% (LCOE of 59 €/MWh) and 22% (LCOE of 58 €/MWh).

By year, the lowest LCOE is found in Simulation – Max (Table 3). Intuitively, the Optimisation should generate the lowest LCOE as we expect to minimize the charge cost and maximize profits; instead, the LCOE fluctuates between 77 and 113 €/MWh and is the higher than in Simulation – Max (in the range 80 - 103 €/MWh). Note that the LCOS is fixed for both Simulations Mean / Max (100.2 €/MWh and 36.6 €/MWh respectively), as they operate each year with a fixed capacity factor. This reveals that without optimisation, when charging is not driven by market prices, the charge cost is not optimised, hence the cost is higher if based on the average profile as in Simulations.

Table 3. Levelised cost of energy by year and by scenario

€/MWh	Observation	Optimisation	Simulation - Mean	Simulation - Max
2014	85.8	77.2	138.0	80.8
2015	99.3	89.3	146.2	87.3
2016	94.4	87.6	142.8	83.5
2017	100.8	111.2	153.7	96.5
2018	109.5	112.9	161.5	103.2
2019	101.7	99.0	148.4	88.8

Comparing profits and costs by method (Fig. 8) allows understanding that the two indicators are not related, and a high LCOE can exhibit low profits so that the business case cannot relate on cost only. For instance, maximum capacity factor (Simulation – Max) can lead to low profits because charging and discharging are not market price driven, which means that the intensive use of storage can be loss making. Storage operation is not a matter of using more but using it at the right moment (Optimisation). An intensive use of storage makes discharging factors increasing which results in a low LCOE, yet profit remains negative (Simulation – Max). In between, actual operation combines price arbitrage and system needs, and profits are here positive (Observation).

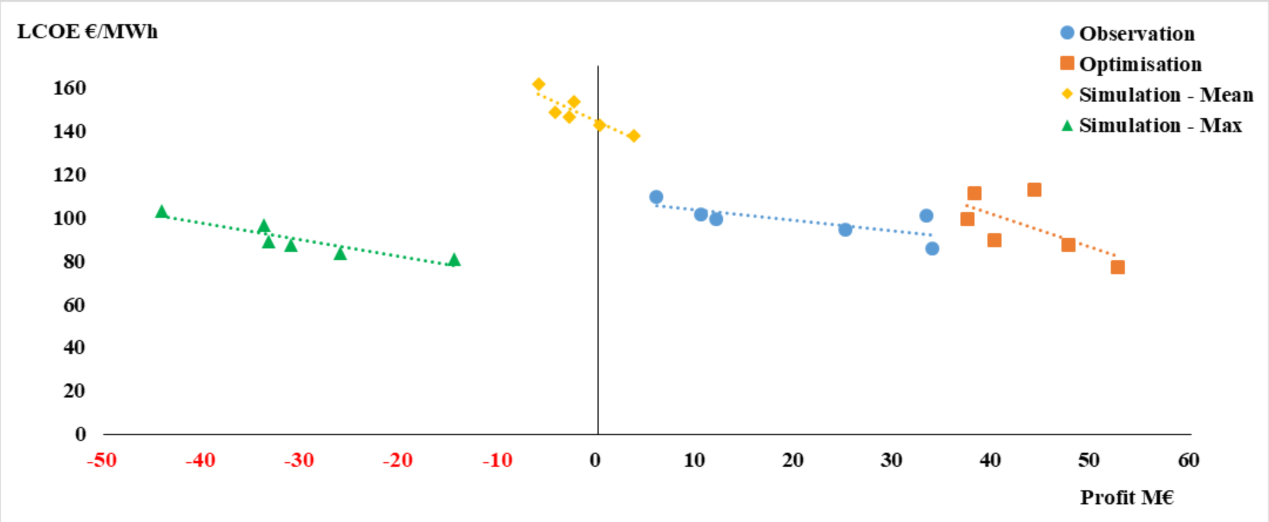

Fig 8. LCOE and profits by scenarios

Graph reading. Results for each model are represented as trends relating LCOE to profits. For instance, Simulation – Max records an LCOE of 103 €/MWh for a profit of - 44 M€ (2018), down to a LCOE of 81 €/MWh for a profit of - 14 M€ (2014).

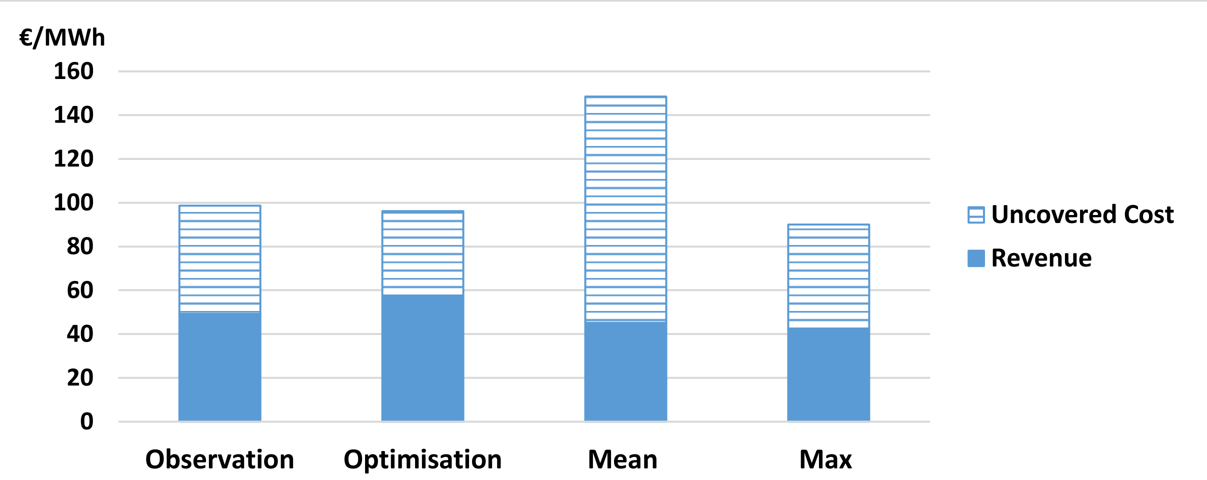

Fig 9. Revenue by scenarios in average 2014 - 2019

We now consider the **revenue** obtained by Grand'Maison plant on the market. All scenarios revenues range between 42 and 57 €/MWh, with Simulation – Mean and Optimisation recording the lowest and highest revenues. When compared to the total cost (Fig 9. Sum of uncovered cost and revenue), we note that the actual performance of PHS cannot entirely be covered with price arbitrage operations. On average, the revenue by scenario can recover 50% of the total cost, or even lower shares (30% in Simulation – Mean).

4.3 Synthesis of results

To summarize main differences, Optimisation returns best results in terms of profits (highest) and LCOE (lowest), with surprisingly low energy volumes. Observation shows that the actual profit would be positive with however less profitable price-arbitrage outcome, while Simulation based on given operation profiles records negative profits and moderate average costs, showing firstly the limits of calculators while based on average figures, and secondly that high capacity factors lead to low LCOEs and most of the time to negative profits.

Regardless of modelling methods and hypothesis, the indicators of cost and profits remain the key investment indicators in the decision making of energy projects. Profit from arbitrage is generally perceived as the direct value of storage operation on an hourly basis, while the LCOE connects the whole investment to the operation over the lifetime.

Then the modelling method becomes a function of the actor willingness to study either potential benefits (by using price arbitrage optimisation), grid requirements (through observation) or technical requirements (through simulation). Each method will serve a different purpose of the decision making as surprisingly each of them leads to different results, despite of a similar basis of sound economic and technological constraints.

Minimising storage LCOE based on Observation is mostly used by the transmission operator in order to select technologies in line with their specific service needs. Maximising profit method, such as Optimisation and Simulation, are the appropriate tool for investors looking for quick returns on investment. Mixing several actor objectives and combining different modelling techniques allow building an overall perspective of the plant operation, the system needs, the revenues and uncovered costs, which gives a better understanding of agents' surpluses. The French system in particular faces large ramping constraints and storage supplies valuable support to grid as energy-block, which is different from a price arbitrage operation; therefore, as any storage application is system dependent, we recommend storage evaluation to be based on both past observation of the system needs and market pricing as mirror of the supply-demand balance.

Results interpretation and their use are challenging. LCOE values are not correlated to profits, and only refer to break-even costs, i.e. discharging profitability threshold, hence cannot be relevant of the support to investment decision as it does not guarantee cost recovery. An annual evaluation of the LCOE instead could be a good information on the way the storage plant operation could be adjusted and in time, optimized. The way levelised cost of storage is defined through the paper ignores the cost of charging electricity. From a technical point of view, the cost of charging electricity should not be a part of this indicator as it is not an endogenous parameter to the system. Yet, storage operation relying on the system needs, the decision to charge and discharge electricity is not entirely triggered by price-arbitrage. Electricity charge is therefore a parameter not to set aside as, as in some cases it is a benefit instead of cost when storage avoids electricity curtailment for example, and needs to be rewarded accordingly.

Costs recovering examination reveals that the actual performance of PHS is partly rewarded by price arbitrage on the market, the energy-only segment, letting still some costs uncovered. Other market segments could be included, namely ancillary services in support to the system as a whole, made of generators, consumers and the grid. We identify the capacity market, as storage can save grid investments for peaking generators and grid extension, and reserve markets for balancing services. However, storage cannot cumulate multiple contracts due to conflicting provisions of gate-closure timelines, capacity made unavailable for some services and the lack of specific regulation [17]. The French regulators admits these caveats and seems to foreseen beforehand some State support for investments in new storage plants [13].

In light of the plans put forward under the French Energy Act to install more PHS plants, the storage investment decisions seem to be system-level determined, related much more to political targets: fewer dispatchable generators in the future power mix (partial phase-out of nuclear, closure of coal-fired units), more renewables (+55 GW wind and solar by 2030), and increasing the need for security of supply and grid reliability. For new actors to entry the market, the current regime needs to move towards a competitive frame, to identify the interests and requirements of new actors. We conclude that the uncovered costs are considered by planners positive system externalities as a guarantee of grid stability, renewable integration, price shedding and secure delivery. These "social benefits", obtained here by the difference between cost and market revenues, need further investigation in support to appropriate regulation.

5. Conclusion

The French guidelines in terms of renewable adoption do not send clear market signals in terms of energy storage investments, and the only large-scale energy projects remain to date the centralized plans of pumped-hydro storage [12]. The current infrastructure with over-capacity of nuclear power plants and large interconnections are for the moment the main competitors of new storage facilities. In the future, the need of storage will increase with the penetration of intermittent renewables and nuclear phase-out. Hence, storage evaluation is essential to industry such as to focus the R&D efforts on the right technologies early enough such as to be mature by the time of massive needs of system balancing.

Most of dedicated studies in the literature to energy storage evaluation show how complex the anticipation of market design is. This paper builds on existing indicators to evaluate the energy storage and employs three modelling techniques such as to underline advantages of each method and to understand circumstances of their use. We complement the literature with a calculator that depicts hourly the operation of storage and conclude that the storage operation cannot be generalized based on average profiles only, even when the seasonality slice is the week period, as results still underestimate profits or overestimate costs. In line with other studies, we conclude that storage evaluation is system-specific and depends on many exogenous criteria such as the weather, geography and politics. A high rate of operation might lower LCOE but negatively act on profits value. Ultimately, it is the hourly price profile which best evaluates the storage, as a proxy of the system behaviour and needs, since storage is primarily used in support to the power system, as a complement more than substitute to power generators. Storage operation being the resultant of the power system, the LCOE computation should reflect the system behaviour as well, hence integrate at best price profile for each charging / discharging mode, and for each arbitrage and reserve provision service.

Evaluating energy storage through levelised cost indicator remains an issue as it does not take into account the energy stored neither its seasonality. Indicators such as LCOE or LCOS tend to be calculated only based on the electricity discharged, which is appropriated to pure power generator. Energy storage main function is to delay electricity injection into the grid to a better moment, and is either charging, discharging or retaining energy. The value of using an energy storage technology should then depend not only on the volume of discharged electricity, but also the volume of storage and its duration; so far, these two parameters are still ignored by the market and from evaluation techniques, and need further investigation.

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Annex 1. Summary of profit from every scenarios modelled

M€	Observed	Optimised	Simulated (Mean)	Simulated (Max)
2014	33.8	52.6	3.7	-14.6
2015	12.0	40.2	-2.9	-31.1
2016	25.0	47.6	0.1	-26.1
2017	33.2	38.1	-2.4	-33.8
2018	5.9	44.2	-6.1	-44.2
2019	10.5	37.3	-4.3	-33.4