Impact of a price-maker pumped storage hydro unit on the integration of wind energy in power systems

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ABSTRACT

The increasing integration of larger amounts of wind energy into power systems raises important operational issues, such as the balance between power generation and demand. The pumped storage hydro (PSH) units are one possible solution to mitigate this problem, once they can store the excess of energy in the periods of higher generation and lower demand. However, the behavior of a PSH unit may differ considerably from the expected in terms of wind power integration when it operates in a liberalized electricity market under a price-maker context. In this regard, this paper models and computes the optimal PSH weekly scheduling in a price-taker and price-maker scenarios, either when the PSH unit operates in standalone and integrated in a portfolio of other generation assets. Results show that the price-maker standalone PSH will integrate less wind power in comparison with the price-taker situation. Moreover, when the PSH unit is integrated in a portfolio with a base load power plant, the role of the price elasticity of demand may completely change the operational profile of the PSH unit.

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1. Introduction

Wind power has grown considerably worldwide in the last two decades, with a global installed capacity rising from 6 GW, in 1996, to 318 GW, in 2013 [1]. As wind power varies its availability over different timescales, the integration of larger amounts of wind into the power systems raises important technical challenges [2]. Among these is the imbalance between generation and demand, which is increasingly important in periods of low demand and high wind availability, resulting in the potential occurrence of over-generation [3].

Considering the high efficiency of the pumping cycle and its storage capacity, the pumped storage hydro (PSH) units are increasingly seen as a solution to integrate the over-generation, avoiding the need for wind power curtailments [4–6]. This interaction between wind power and PSH units is relevant in countries with a high share of wind power, such as Portugal [3,7], Ireland [8,9] and Denmark [10], as well as in many other countries around the world [11–16].

This solution assumes that the PSH units have the incentive to store the over-generation in the most beneficial way to the power system, condition that is met in a centralized dispatch context. However, when trading in a liberalized electricity market, the PSH unit will pursue a profit maximization strategy, purchasing electricity for pumping and selling its generation in the day-ahead electricity market when profitable [17–19].

Considering the PSH unit as a price-taker [20], in periods with low demand and high wind generation, which drive market prices down, there is an incentive for the PSH unit to pump water, leading to an adequate integration of wind power.

However, when a PSH unit is a price-maker [21–23] and operates in standalone mode, its profit maximization strategy leads to a decrease of storage levels and, therefore, the capacity to integrate wind power would be considerably reduced, as shown in Ref. [24].

Moreover, the PSH unit may be integrated in a generation company (GenCo) that has a generation portfolio with different power technologies. In this perspective, the PSH unit can behave strategically [25,26] to influence the market clearing price (MCP) in order to increase the revenue obtained by the power plants in the portfolio. In this context, the behavior of the PSH is not straightforward because the drivers of the PSH scheduling are more complex.

Regarding the study of the optimal PSH unit operation strategy in liberalized markets there is some relevant research performed by
several authors. This is the case of [17] that developed an algorithm to determine the optimal bidding strategy for the day-ahead and ancillary services markets.

In addition to the day-ahead and ancillary services markets, Ref [27] also takes into account bilateral contracts in order to reach the bidding strategies that maximize the profit.

Considering the impact of market power in the behavior of a generation unit, several authors have developed methodologies to compute a strategy that optimizes its operation, such as [21], in a deterministic context, and [22,28,29], using a stochastic approach. Also, with the objective of maximizing the yearly profit, Ref [23] considers the impact of the market power, through a residual inverse demand function for yearly profit maximization, considering a deterministic first stage of one month and a stochastic approach for the other months.

In order to evaluate how the behavior of a PSH unit may differ from the power system objective of integrating wind power, this paper models a PSH unit and computes the optimal weekly scheduling in a price-taker and price-maker scenarios, when the PSH unit operates standalone and integrated in a GenCo with a portfolio of generation assets.

For this purpose, simulations were carried out using real data from the Iberian Electricity Market (MIBEL) for the price-maker situation, in order to compare with the price-taker outcomes. The effect of the PSH unit operation on the MCP was modeled by a residual inverse demand function with a variable elasticity that depends on the slopes of the demand and supply curves.

In the price-maker assumption, the inclusion of the PSH unit in a portfolio was pursued for 4 scenarios with different capacities of the base load thermal power plant: 500, 1000, 1500 and 2000 MW. The non-linear PSH profit optimization problem, subject to technical constraints, was solved using the MINOS solver of the GAMS programming language.

The paper is organized as follows. Section 2 presents the analysis of the day-ahead electricity market MCP, the mathematical formulation of the PSH profit maximization and the solution methodology to solve the PSH scheduling problem. Section 3 presents and discusses the results related to the scenarios simulated. Conclusions are drawn in Section 4.

2. Methodology

2.1. Market clearing price

In most of the day-ahead electricity markets, such as the MIBEL, market participants submit hourly electricity supply offers and demand bids for the entire following day.

For each hour of the day, the supply curve is built upon the supply offers, sorted by increasing offered prices, and the demand curve is built upon the demand bids, sorted by decreasing bided prices.

As an example, Fig. 1 illustrates the supply and demand curves of 1 h of the MIBEL day-ahead electricity market.

The last dispatched offer block sets the MCP for that hour, which takes into account the intersection of the supply curve (S line) with the demand curve (D line). It should be noted that there are complex offers that imposes constraints, which leads to some merit offers being disregarded when these conditions are not met. As a consequence of that, the supply curve shifts left, as represented by S' line of Fig. 1. In this case, the market clearing quantity (MCQ) and MCP are set at E0 and π0, respectively, as shown in Fig. 1.

2.1.1. Effect of the PSH unit operation on the MCP

Under a double-sided auction mechanism, as is the case of MIBEL, buyers and sellers submit their competitive bids and offers to the day-ahead market. In this context, unlike other power plants, such as thermal, that just generate electricity, the PSH units also consume electricity to perform pumping.

Thus, the effect of the PSH unit can influence the MCP in two different ways. On one hand, when the PSH unit pumps, it submits purchase bids that shift the demand curve to the right, pushing the MCP up. On the other hand, when the PSH unit generates, it submits sale offers that shift the supply curve to the right, pushing the MCP down.

To illustrate this effect, consider Fig. 2a where the PSH unit makes a purchase bid of $\Delta E_1$ that shifts the demand curve (represented by D line) to the right, to the position represented by D’ line. With this action, the intersection of the demand curve with the supply curve (S line) takes place at a higher price point of $\Delta \pi$.

This change in price depends on the slope of the supply and the demand curves, given by $\gamma$ and $\beta$ respectively, as represented in Fig. 2b, which can be expressed in terms of the changes in quantities and prices, given by:

$$\tan \gamma = \frac{\Delta \pi}{\Delta E_1} \quad (1)$$

$$\tan \beta = \frac{\Delta \pi}{\Delta E_2} \quad (2)$$

$$\Delta E = \Delta E_1 + \Delta E_2 \quad (3)$$

Considering a generator convention, when the PSH unit pumps, the respective purchase bid energy will be considered negative, that is $\Delta E < 0$. Moreover, when the PSH unit generates, the

![Fig. 1. Supply offers (S and S’) and demand bids (D) of 1 h of the day-ahead electricity market of MIBEL.](image)

![Fig. 2. Influence of the PSH unit operation on the MCP.](image)
respective sale offer energy will be considered positive, that is, \( \Delta E > 0 \).

Taking into account (1)–(3), the relationship between the changes in price and the changes in quantity is given by:

\[
\delta = \frac{\Delta \pi}{\Delta E} = \frac{\tan(\gamma) \cdot \tan(\beta)}{\tan(\gamma) + \tan(\beta)}
\]

(4)

To represent the effect of the PSH unit operation on the MCP, it was considered a residual inverse demand function with a slope given by (4).

Through the slope of the residual inverse demand function, given by (4), it is possible to evaluate the residual demand elasticity, which, by convention, is represented by positive values:

\[
\epsilon = \frac{\Delta \pi}{\Delta E} = \frac{\pi_0}{E_0}
\]

(5)

The residual demand elasticity can be grouped into three categories: unity, when \( \epsilon = 1 \); inelastic, when \( \epsilon < 1 \); and elastic, when \( \epsilon > 1 \).

Fig. 3 shows three cases in which, for each one, a power plant generates \( E_A \), which is paid at \( \pi_a \). When the power plant increases the generation to \( E_B \), the MCP will decrease. However, this decrease will depend on the residual demand elasticity.

When the residual demand elasticity is unity (Fig. 3a), the percentage increase of generation causes an equal percentage change on the MCP. Thus, the revenue lost represented by area 2 is equal to the revenue added, represented by area 1, being equally attractively operating in point A or point B.

When the residual demand elasticity is inelastic (Fig. 3b), the percentage increase of generation causes a greater percentage change on the MCP. Thus, the revenue lost represented by area 2 is greater than the revenue added, represented by area 1. Therefore, it is not attractive to increase generation.

On the other hand, when the residual demand is elastic (Fig. 3c), the percentage increase of generation causes a smaller percentage change on the MCP. Thus, the revenue lost represented by area 2 is smaller than the revenue added, represented by area 1. Therefore, it is attractive to increase generation.

### 2.1.2. Residual demand

A residual inverse demand curve expresses the MCP of the day-ahead electricity market on the quantity of electricity bid/offered by the GenCo.

The operational modes of the PSH unit are: pumping, generation and off-line. In the periods of pumping, the PSH unit will consume electricity and, therefore, the MCP will rise. On the other hand, when the PSH unit generates, the MCP decreases. When the PSH unit is off-line, the MCP remains unchanged.

Following the approach of [30], the inverse demand function is modeled by an approximated sigmoid function, given by:

\[
\pi(E) = \frac{k_0}{1 + e^{-\epsilon E}}
\]

(6)

where \( \pi(E) \) is the ex-post MCP, that is, after the influence of the PSH unit operation; \( E \) is the electricity consumed or generated by the PSH unit; \( k_0, k_1, k_2 \) are parameters of the sigmoid function; \( E_0 \) is the ex-ante MCP, that is, without the PSH unit intervention.

The parameters \( k_0, k_1, k_2 \) are calculated in order to fit the sigmoid function to the real data of demand and supply. To meet this goal, the following conditions are to be met:

\[
\pi'(0) = \alpha \cdot \delta
\]

(7)

\[
\pi(0) = \pi_0
\]

(8)

\[
\lim_{\epsilon \rightarrow \infty} \pi(E) = \pi_{\text{max}}
\]

(9)

From (7), if the PSH unit is off-line, the slope of the residual inverse demand function must be equal to the slope of the day-ahead electricity market, given by (4). A multiplier factor \( \alpha \) was implemented in order to modify the slope of the day-ahead electricity market, thus modifying the influence of the PSH unit on the MCP.

From (8), if PSH unit is off-line, the MCP of the residual inverse demand function remains equal to the MCP of the day-ahead electricity market without the PSH unit operation \( (\pi_0) \).

Condition (9) assures that the sigmoid function has a maximum value of \( \pi_{\text{max}} \).

Thus, the sigmoid function parameters are computed according to the following equations:

\[
k_0 = \pi_{\text{max}}
\]

(10)

\[
k_1 = E_0 + \frac{\pi_0^2 \cdot \ln \left( \frac{k_0}{\pi_0} - 1 \right) \cdot \left( \frac{k_0}{\pi_0} - 1 \right)}{-\alpha \cdot \delta \cdot k_0}
\]

(11)

\[
k_2 = -\frac{\pi_0^2 \left( \frac{k_0}{\pi_0} - 1 \right)}{-\alpha \cdot \delta \cdot k_0}
\]

(12)

The real MIBEL residual inverse demand slope corresponds to \( \alpha = 1 \). This is taken as the price-maker scenario for the present study. When \( \alpha < 1 \), the MCP is less affected by the PSH unit operation. In the limit case of \( \alpha = 0 \), the bids and offers of the PSH unit will not affect the hourly MCP, which represents the price-taker assumption. On the other hand, if \( \alpha > 1 \) the operation of the PSH unit will affect more the hourly MCP, which corresponds to increasing degrees of influence on market price.

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Fig. 3. Residual demand elasticity cases.
2.2. GenCo profit maximization problem

The following assumptions are made:

1. The GenCo may have a PSH unit and also a thermal power plant;
2. The hourly thermal power plant generation is known a priori;
3. The electricity generated and consumed by the GenCo power plants are sold and bought in the day-ahead electricity market. The electricity offered by the thermal power plant already belongs to the supply curve, so its generation does not affect the MCP;
4. The operation and maintenance costs of both power plants, as well the fuel costs of the thermal power plant are null;
5. The PSH unit may either generate electricity using stored water in the upper reservoir or consume electricity to pump water back to the upper reservoir;
6. The volume of water stored in the upper reservoir is represented by an equivalent energy level;
7. The initial and final energy levels of the upper reservoir are known a priori.

The aim of a GenCo, trading power in a liberalized electricity market, is to maximize its profit in a given period of time, subjected to operational constraints. This problem can be formulated as follows:

\[
\max \sum_{i=1}^{H} \pi \left( E_g^i, E_p^i \right) \cdot \left( E_g^i + E_p^i + E_f^i \right)
\]

s.t.

\[-E_p^{max} \leq E_p^i \leq 0 \quad i = 1 \text{ to } H \tag{14}\]
\[0 \leq E_g^i \leq E_g^{max} \quad i = 1 \text{ to } H \tag{15}\]
\[W^i = W^{i-1} - \eta_p \cdot E_p^i - \frac{E_g^i}{\eta_g} \quad i = 1 \text{ to } H \tag{16}\]
\[W^i = W^0 \quad i = 0 \tag{17}\]
\[W^i \geq W_H \quad i = H \tag{18}\]
\[W^{min} \leq W^i \leq W^{max} \quad i = 1 \text{ to } H \tag{19}\]

where \(E_p^i\) is the hourly electricity pumped by the PSH unit; \(E_g^i\) is the hourly electricity generated by the PSH unit; \(E_f^i\) is the hourly electricity generated by the thermal power plant; \(W\) denotes the hourly energy storage level in the upper reservoir; \(\pi (E_g, E_p)\) is the hourly residual inverse demand function, given by (6). Superscript \(i\) is the time index.

Parameters \(\eta_p\) and \(\eta_g\) are the pumping and generation efficiencies of the PSH unit, respectively; \(W^0\) is the initial energy level in the upper reservoir and \(W^H\) is the minimum energy required in the upper reservoir at the final optimization period; Minimum and maximum energy levels of the upper reservoir are \(W^{min}\) and \(W^{max}\), respectively; \(E_g^{max}\) and \(E_p^{max}\) are the maximum hourly pumping and generation that the PSH unit can perform, respectively.

The objective function given in (13) is the operational profit of the GenCo, which accounts for the hourly revenues of the purchase and sale electricity in the day-ahead electricity market.

The operation limits of the PSH unit are represented in (14) and (15). Since thermal power plant generation is known a priori, it is considered that it respects the operational limits.

The energy stored in the upper reservoir, for a specific hour, depends on the operation of the PSH unit in that hour, and the energy stored in the previous hour. Thus, if the PSH unit pumps water, the stored energy will increase. However, due to the pumping efficiency \((\eta_p)\), the stored energy is lower than the pumped energy. On the other hand, if the PSH unit generates electricity, the stored energy will decrease and, due to generation efficiency \((\eta_g)\), the energy stored used is higher than the energy generated [31]. Thus, the energy stored in the upper reservoir is given by (16).

Since initial and final energy levels of the upper reservoir are known a priori, conditions (17) and (18) must be met.

The operation limit of the upper reservoir is represented by (19). As the optimization problem is nonlinear, it is important to analyze its convexity. In this regard, the objective function is pseudo concave and the constraints, being linear, define a convex set of feasible solutions. Therefore, the optimality conditions are, not only necessary, but also sufficient.

2.3. Solution algorithm

The optimization problem (13)–(19), presented in the previous section, is a non-linear problem and was solved using the MINOS solver of the GAMS programming language [32].

To determine the slope of the demand and supply curves, a linear approach was carried out in the neighborhood of the MCP for each hour.

The algorithm used to determine the optimal operation profile of the PSH unit, which belongs to a GenCo included in the day-ahead electricity market, is as follows:

1. Read the following data:
   a. Pumping and generating efficiencies of the PSH unit;
   b. Maximum, minimum, initial and final storage levels of the upper reservoir;
   c. Maximum hourly pumping and generation that PSH unit can perform;
   d. Hourly ex-ante MCP and MCQ;
   e. Hourly demand and supply curves;
   f. Hourly thermal power plant generation;
2. Compute the linear regression of the hourly slope of the demand and supply curves;
3. Compute the hourly slope of the residual inverse demand function, given by (4);
4. Compute the hourly sigmoid function parameters, given by (10)–(12);
5. Solve the optimization problem, given by (13)–(19), using the MINOS optimization package of GAMS, and save the obtained results.

3. Results and discussion

The described methodology is applied to study the behavior of a PSH unit that trades power in the liberalized electricity market of MIBEL, comparing a price-taker with a price-maker situation.

Moreover, the behavior of the PSH is also investigated when this unit is integrated in a portfolio of generation assets owned by a GenCo that also includes a base load thermal power plant.

The maximum output power of the PSH unit, when generating, and maximum power consumed, when pumping, is 1000 MWh per hour; the storage level ranges from a minimum of 500 MWh and a maximum of 70,000 MWh; the pumping efficiency is 80% and the
generation efficiency is 90%, leading to an efficiency of the global pumping cycle of 72% ($80\% \times 90\%$).

The PSH unit submits purchase bids (to buy power for pumping) and sale offers (to sell generated power) for each hour of the day-ahead electricity market of the MIBEL in a time frame of one week (168 h).

In the beginning of the operation period (midnight of Monday) the storage level of the PSH unit is 5000 MWh, which should be at least the storage level at the end of the operation period (next Monday) in order to guarantee that the analysis is focused only on the pumping-generation cycle, i.e. the PSH profit comes only from the price arbitrage during the week of operation.

The data considered for the day-ahead electricity market are obtained from the market operator of the MIBEL website [33], for the week from 7 to 13 of November of 2011.

Fig. 4 presents the hourly MCP and MCQ traded in the MIBEL for the entire week under analysis, which clearly shows the short-term relationship between the traded quantity and market price.

Notice, however, the sharp decrease in prices at the end of the week, which come close to zero. This is related to other price drivers other than demand, such as renewable generation. In fact, the wind power generation increased at the end of this week, as it is shown in Fig. 5 that presents the hourly market clearing price and wind generation of the Portuguese system for the week under analysis.

The elasticity of the inverse demand function was computed for each hour of the week and is presented in Fig. 6 along with the MCP. These are the two major drivers of the PSH scheduling, as it will be shown afterward.

The first simulation carried out was the price-taker standalone PSH situation (PSH not included in a broader portfolio of generation assets). The PSH scheduling under these circumstances is presented in Fig. 7, which shows the hourly MCP and the PSH operation.

The schedule shown in Fig. 7 is typical for a price-taker PSH, which pumps when prices are low and generates when prices are high, taking into account the storage capacity and the pumping cycle efficiency (which is 72% in this case study, as previously indicated).

From Fig. 7, it can be observed that the PSH operates in pumping mode when the market price is below 40.10 €/MWh, in generation mode when the market price is above 56.05 €/MWh, and is off-line for prices between these two values. The relationship between these two threshold values is 72% (40.10/56.05), which is equal to the pumping cycle efficiency.

Practically speaking, a price-taker PSH unit will maximize its profits by making price arbitrage between the low market prices of some periods (typically in off-peak hours with high wind generation) and the high market prices of other periods (typically in peak hours with low wind generation), provided that the relationship
between low prices and high prices exceeds the pumping cycle efficiency.

In this regard, as the high wind generation will drive prices down, this would create the economic incentive for the PSH unit to pump, and therefore to store the potential excess of wind power of these periods. The stored energy will be delivered to the system by the PSH unit when it operated in generation mode in the peak hours, with lower wind availability, where prices will be high.

The main question addressed in this work is exactly to know how different from the well established price-taker setting would be the behavior of the PSH in a price-maker situation, namely if it would still integrate adequately the excesses of wind power generation.

Moreover, the consequences of the integration of the PSH unit in a generation portfolio of a GenCo with a base load thermal power plant are also investigated.

For this purpose, simulations were carried out for the price-maker situation in order to compare with the price-taker outcomes. In the price-maker assumption, the inclusion of the PSH in a portfolio was pursued for 4 scenarios with increasing capacities of the base load thermal power plant: 500, 1000, 1500 and 2000 MW. It is assumed that the thermal capacity included in the portfolio is already in the market and, therefore, its influence is already presented in ex-ante prices.

The results obtained are presented in Table 1 for the aggregate week under analysis in what concerns the energy pumped/generated by the PSH unit and the base load thermal power plant, in the different scenarios.

It can be observed that, for the standalone scenarios of the PSH unit, the price-maker situation leads to a reduction of the pumped energy (from 40,278 MWh, of the price-taker, to 31,135 MWh, of the price-maker). However, when the PSH unit is integrated in a portfolio with a base load thermal power plant, the pumped energy increases as the capacity of the thermal plant also increases. For the higher capacities studied of 1500 and 2000 MW, the pumped energy is even higher in the price-maker situation (41,566 and 45,061 MWh, respectively) when compared to the price-taker case.

For the same set of scenarios, the realized price of the PSH in different modes, the thermal power plant and the portfolio, is presented in Table 2. The realized price is obtained by dividing the weekly total revenue by the total energy and gives the average price received (for generation) or paid (for pumping) for each case. For the “PSH Global” case, the realized price was computed as the net hydro revenues (generation — pumping revenues) over the PSH generation. For the “PSH and Thermal Plant” case, the realized price was computed as the total portfolio revenues over the total generation (PSH generation plus thermal generation). The total profit of each scenario is also presented.

Comparing the standalone price-taker with the price-maker situation, it is observed that the PSH unit increases the realized price in the later case and operates less, as seen in Table 1. This happens, notwithstanding the fact that the profit decreases in the price-maker scenario because, on average, the PSH generates at a higher price ($64.04 vs $63.59/MWh) and pumps at a lower price ($18.40 vs $19.85/MWh).

The most interesting result concerns the behavior of the PSH when integrated with a base load thermal power plant. It can be seen from Table 2 that the realized price of the portfolio “PSH and Thermal Plant” increases as the thermal power plant capacity increases. Taking into account that the “PSH Global” realized price decreases and the “Thermal Plant” realized price increases, it is

### Table 1

<table>
<thead>
<tr>
<th>Thermal plant capacity (MW)</th>
<th>Price-taker</th>
<th>Price-maker</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy (MWh)</td>
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<td></td>
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<tr>
<td>PSH pumping</td>
<td>–40,278</td>
<td>–31,135</td>
</tr>
<tr>
<td>PSH generation</td>
<td>29,000</td>
<td>22,417</td>
</tr>
<tr>
<td>PSH global</td>
<td>–11,278</td>
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<tr>
<td>Thermal plant</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PSH and thermal plant</td>
<td>–11,278</td>
<td>–8718</td>
</tr>
</tbody>
</table>

### Table 2

<table>
<thead>
<tr>
<th>Thermal plant capacity (MW)</th>
<th>Price-taker</th>
<th>Price-maker</th>
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</thead>
<tbody>
<tr>
<td>Realized price (€/MWh)</td>
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<tr>
<td>PSH pumping</td>
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<td>18.40</td>
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<td>PSH generation</td>
<td>63.59</td>
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<td>PSH global</td>
<td>36.01</td>
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<td>Thermal plant</td>
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<td>0.00</td>
</tr>
<tr>
<td>PSH and thermal plant</td>
<td>36.01</td>
<td>38.48</td>
</tr>
</tbody>
</table>

![Fig. 8](image)
clear that the PSH unit is driving its behavior toward an increase in prices, when it pumps, and a moderate decrease in prices, when it generates, so that the thermal power plant substantially increases its revenues, although the PSH is penalized with this situation. This is a typical portfolio behavior, where an asset — the PSH unit — is scheduled on its own loss for a greater benefit of another asset — the thermal power plant —, resulting in a major gain for the whole portfolio (PSH and thermal power plant).

The main explanations of these findings will be investigated in the following analysis. For that purpose, we will focus the analysis on the most relevant scenarios: PSH in standalone situation under price-taker and price-maker assumptions, and PSH integrated with a thermal power plant of 2000 MW. These scenarios are named standalone price-taker scenario, standalone price-maker scenario and portfolio price-maker scenario, respectively.

Fig. 8 presents the PSH schedule for the 3 scenarios, both in chronological sequence (upper graph) and in ascending sequence (lower graph). Fig. 9 presents the corresponding ex-post price (i.e. price after the PSH operation in the market) and the demand elasticity.

From the results presented in Fig. 8 it is observed that, compared to the price-taker scenario, the PSH pumps and generates at the same periods and at a lower level in the standalone price-maker scenario. This leads to the first conclusion that, under the standalone price-maker assumption, the PSH unit will integrate less wind power than in the price-taker paradigm. The reason for this relies on the influence of the PSH operation on the MCP, which reduces the incentive to pump, because it increases the price, and to generate, because it decreases the price, as can be seen in Fig. 9.

The same criteria of the price-taker applies to the price-maker profit maximization, that is the price relationship between pumping and generating should exceed the pumping cycle efficiency. In fact, the maximum pumping price and minimum generation price for the price-maker scenario is 40.19 €/MWh and 56.00 €/MWh, respectively, which results in a relationship of 72% (40.19/56.00). Nonetheless, there is a reduction of pumping, especially in the hours with low demand elasticity (upper graph of Fig. 9), because in those hours the price increases due to the higher PSH operation. This is particularly clear in hours 2 to 6 (elasticity below 0.33) and 98 to 103 (elasticity below 0.41). Notice that, due to a higher demand elasticity, in hours 127 to 129 (elasticity between 0.55 and 0.99) and hours 136 to 138 (elasticity between 0.79 and 0.99), the pumped energy substantially decreases in the standalone price-maker situation (upper graph of Fig. 8) but the prices do not increase that much (upper graph of Fig. 9).

The analysis of the portfolio price-maker scenario (PSH and base load 2000 MW thermal power plant) leads to very different conclusions about the PSH behavior. The first observation is that the PSH unit pumps and generates in different hours and the global level of pumping (and consequently of generation) is higher than in the price-taker situation.

In fact, for this level of thermal capacity (2000 MW), the PSH operation is more driven to the realized price of the portfolio than for its own profit maximization. As a consequence, the pumping is performed preferably in hours that not only have low prices, but also have low demand elasticity, so that the impact on price is increased. With this action, the PSH unit increases significantly the MCP, valuing the electricity sold by the thermal power plant. Notice that an increase of 1 €/MWh in the MCP will lead to a decrease of the PSH profit of 1000 € (if pumping at maximum power of 1000 MW) and an increase of 2000 € of the thermal unit profit.

Fig. 10 illustrates the PSH scheduling as a function of the ex-post MCP for the standalone price-taker scenario (line), the standalone price-maker scenario (squares), and the portfolio price-maker scenario (triangles).

In the standalone price-taker scenario (line in Fig. 10), the PSH pumps when the MCP is below 40.10 €/MWh and generates when the MCP is above 56.06 €/MWh, as explained previously (Fig. 7).

In the standalone price-maker scenario (squares in Fig. 10), the PSH operates in the same mode as in the price-taker scenario but pumps and generates at a lower level due to its influence on the MCP. That is, the mode of operation of the PSH is still driven by the
MCP but the level of pumping and generation in each hour is influenced by the demand elasticity.

For the portfolio price-maker scenario, the demand elasticity has an increased role in the PSH scheduling, either in the mode and level of operation. To illustrate this fact it is worth focusing the analysis on points A, B, C and D of Fig. 10. Although the MCP is very close for the points A, B and C, as shown in Table 3, the PSH is pumping in point A, is off-line in point B and is generating in point C. The reason for this relies on the demand elasticity. In fact, although the price is quite high, the demand in point A is very inelastic so the PSH has an incentive to pump in order to increase the price received by the thermal power plant of the same portfolio. Point B, although inelastic, has a higher elasticity and the PSH is off-line, whereas in point C, due to the higher elasticity and also to the high price, the PSH is generating at 567 MWh. Moreover, in point D, which has a lower price than point C, the PSH is generating at a higher level (1000 MWh) because of the high elasticity of demand. Under these circumstances, the PSH can generate without significantly lowering the MCP for the thermal power plant (and for itself).

It is therefore concluded that the effect of the demand elasticity might be dominant over the MCP in the PSH operation, as can be seen from Fig. 11, which presents the PSH unit scheduling as a function of the demand elasticity and MCP for the portfolio price-maker scenario.

### 4. Conclusions

This paper evaluates how the behavior of a PSH unit may differ from the power system objective of integrating wind power in a price-maker context, when the PSH unit operates standalone and integrated in a GenCo with a portfolio of generation assets.

The effect of the PSH unit operation on the MCP was modeled by a residual inverse demand function with a variable elasticity that depends on the slopes of the demand and supply curves.

For the price-taker standalone scenario, as high wind generation will drive prices down, this would create the economic incentive for the PSH unit to pump, and therefore to store the potential excess of wind power of these periods. The stored energy will be delivered to the system by the PSH unit, when it operates in generation mode, in the peak hours with low wind availability, where prices are high. Therefore, under the price-taker assumption, the PSH unit will contribute for the integration of wind power as expected from system modeling approaches based on a centralized dispatch paradigm.

However, in a price-maker standalone scenario, the PSH will integrate less wind power than in the price-taker situation. The reason for this relies on the influence of the PSH operation on the MCP, which reduces the incentive to pump, because its operation in pumping mode increases the price, and to generate, because its operation in generation mode decreases the price.

When the PSH unit is integrated in a portfolio with a base load thermal power plant, the pumped energy increases as the capacity of the thermal plant also increases. For the higher capacities studied, of 1500 and 2000 MW, the pumped energy is even higher than in the price-taker situation.

The results obtained show that, with the increase of the nominal power of the thermal power plant, the PSH operation is less driven by the MCP and responds more significantly to the demand elasticity, which may completely change the operational profile of the PSH unit.

As a consequence, the relationship between the high wind penetration and pumping is no longer guaranteed, as in the case of the price-taker assumption, and the ability to integrate the excess of wind power does not necessarily apply.

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