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Intraday Optimization of Pumped Hydro Power Plants in the German Electricity Market

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Abstract

Historically, the optimal production of hydro power plants was determined once day ahead. Today, many regulatory requirements in the German electricity market make this process much more complex: Power plant operators are committed to report information on planned production and even on provision of balancing energy of each single generator to transmission system operators. As soon as a deviation in the schedule occurs, the information hast to be updated and reported again. These requirements lead to the point where optimization of pumped hydro power plants can no longer be done manually.
In order to fulfil these requirements, EnBW has developed its own optimization model and established a system-based day ahead and intraday asset optimization process. The optimization problem is formulated as a mixed integer problem which determines the minimum operating cost subject to all technical constraints of a hydrothermal portfolio and covering load.
As a post-optimization of this new intraday optimization system we set up an effective multistage looping optimization algorithm for daily pumped hydro power plants considering e. g. reservoir limits, quarter-hourly prices, grid charges and availabilities. A real world case study is presented and discussed.

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Keywords: continuous intraday trading; intraday optimization; mixed integer programming; pumped hydro power plants;

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1. Introduction

With the so called "Energiewende" the conditions on the German energy market have changed fundamentally. A lower price level but most notably the flattened regular price spread between peak and off-peak have influenced the profitability of pumped hydro power plants. A lot of optimization methods for daily hydro power plants struggle to address the new challenges on the energy markets in Germany. Furthermore, new regulatory requirements of the German Federal Network Agency were introduced. Since 2014 energy producers are dedicated to frequently transfer the latest production plan to the transmission system operator.

After giving a short overview on the literature in 1.1, challenges of the energy market and the new regulatory requirements are discussed in 1.2 and 1.3. In 2.1 the implemented intraday optimization model to fulfill the regulatory requirements is introduced. The implementation of hydro plants is explicitly explained in 2.2. Using the model outputs such as accurate reservoir filling levels and price forecasts, we outline in 3.1, 3.2 and 3.3 adopted versions of the algorithm from Lu et al. 2004 and conclude with real world examples in 4.

1.1. Literature review (on pumped hydro storage optimization)

The literature on solving pumped hydro power storage scheduling problems can be separated into two general categories. On the one hand, the literature follows a system economic approach: e.g. Oliviera et al. (1993) solve a mixed integer linear program in a system context and integrate cost-efficient storage capacity. On the other hand, several papers focus on the individual plants and on how to operate a singular or a portfolio of hydro storages. These approaches are mainly based on using whole sale electricity prices and calculating an optimal control strategy.

The latter approach usually separates the optimization between daily pumped hydro power storages with small reservoirs and seasonal hydro power storages with large reservoirs and relatively small machines in comparison to their reservoir size. Literature that deals, among others things, with the daily pumped hydro storage scheduling problem are e. g. Thompson et al. (2004). They present a real option approach for pumped hydro storage operation inspired by financial mathematics. Horsley and Wrobel (2002) use a deterministic continuous price curve and derive valuation methods using duality methods. Lu et al. (2004) suggest an algorithm to determine a bidding strategy for pumped hydro power plants considering reservoir limits. Kanakasabapathy and Swarup (2010) and Zhao and Davidson (2009a and 2009b) expand this idea considering additional aspects such as spinning and non-spinning reserve, storage level-dependent efficiency and random inflows.

1.2. Market environment for pumped hydro power plants

The characteristics of the German electricity market have changed significantly over the past decade. The renewable energy act fostered the exploit of significant amounts of renewable energy resources (RES) that have entered the market in the last years and replaced power generation by fossil fuel power plants. As a consequence, the price at the EPEX Spot Auction decreased since 2012 by 10 % per year on average. This does not only influence the utilization of fossil fueled power plants but also pumped hydro plants.

The renewable generation is not equally distributed in time and space. Further, due to limited storage and a lack of sufficient transmission, generation capacity is not leaving the market. Less price fluctuation can be seen than expected with such amounts of RES in the market. In particular, this effect has reduced the average price spread and thereby the profitability of daily pumped hydro power plants that were constructed to balance production and demand.

This effect is depicted in Fig.1. The exemplary calculation is made for a daily pumped hydro power plant with 500 MW turbine/pump power, an efficiency of 80 % and grid charges of 4 €/MWh for the consumption of energy. In part (a) the historic average spot price and the water values for pumping and water release are plotted. On average a pumped hydro power plant in 2005 could be operated 9 hours a day in pumping and 7 hours in generating mode with an average spread of 32.21 €. In the year 2014 the plant is operated 6 hours in pumping and 5 hours in generating mode taking advantage of an average spread of 21.34 €.

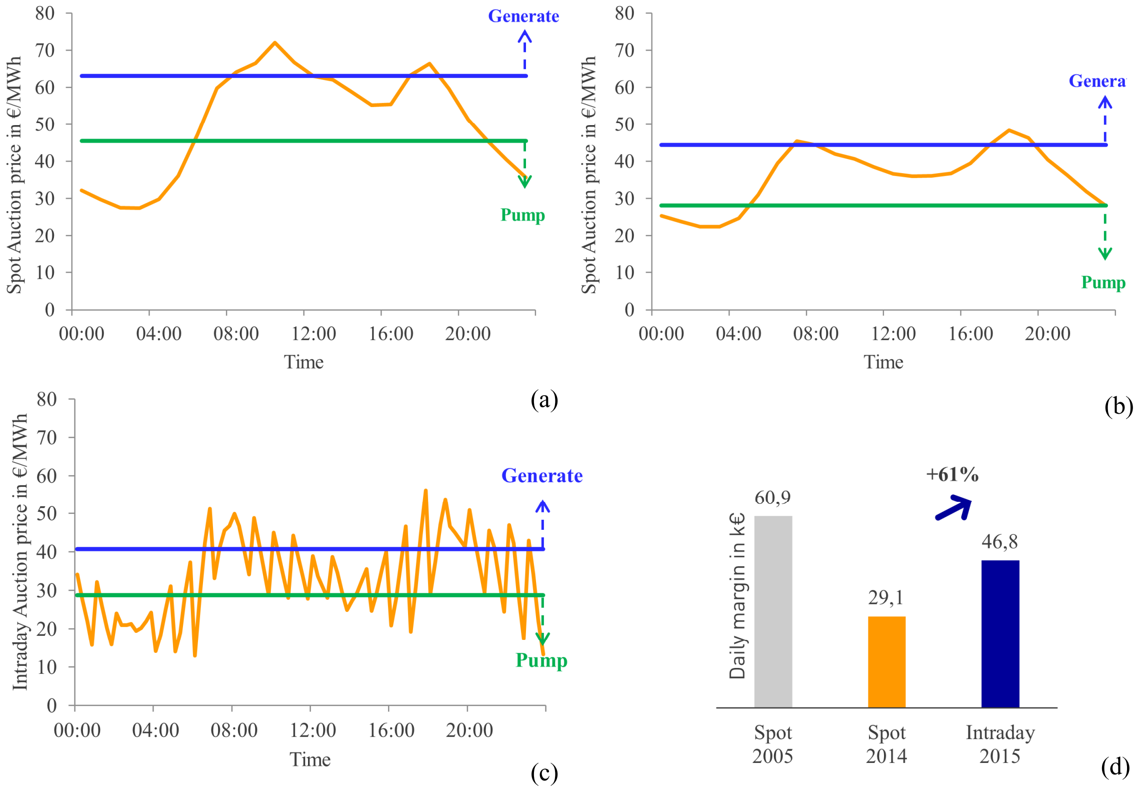


Fig. 1 (a) Average Spot Auction price from Monday to Friday in 2005. (b) Average Spot Auction price from Monday to Friday in (2014). (c) Average Intraday Auction price from Monday to Friday in 2014. (d) Average daily contribution margin.

Expecting a market with full liquidity and no arbitrage between the markets, the operating time in pump and generation mode can be increased to 9 and 7 hours, respectively. It can be seen in Fig.1 (d) that the average daily contribution margin increases again. Nevertheless, in order to trade on revenue opportunities, optimization and dispatch of hydro plants need to be adjusted to the new conditions.

1.3. Regulatory requirements

Beside the changing market conditions, new regulatory requirements have influenced the hydro-thermal dispatch optimization in Germany. The German Federal Network Agency introduced a resolution in 2014 which commits power plant operators to report extensive information on planned production for the current and the following day (Bundesnetzagentur 2014). One major requirement is that the data needs to be updated during the day as soon as planned production changes only slightly. In practice, this means that quarter-hourly production schedules, dispatch potential and reserve provision of every single machine has to be sent to the transmission system operator when the planned production changes. In practice this is basically every 15 minutes the case. In order to meet this requirement, a model-based intraday optimization of all power plants is necessary. This process is not manually achievable; it is highly challenging to optimize a whole power plant portfolio on the required level of detail many times (normally 96 times a day) during the day.

2. Intraday optimization of power plant deployment

In consequence of the new regulatory requirements, EnBW has developed its own optimization model and has set up all necessary processes; thereby it established a decision support for an intraday deployment of power plants. The optimization model replaced the manual experience-based process with an automatic model-based system. The major challenges of an intraday optimization were both the development of a mathematical model and the design of new processes.

2.1. Optimization model

The decision problem is formulated as a mixed integer linear program. The objective function minimizes the costs of the hydro-thermal production. Optionally, the model can use the market to buy or sell energy to meet load requirements. The problem's major constraint is that load has to be covered. It is further constrained by the technical characteristics of the power plants such as maximum capacity, minimum capacity, load change rates, start-up costs, and availabilities. Furthermore, the model takes into account the prices for fuel and CO_2, grid charges, as well as quarter-hourly electricity prices. The sold primary, secondary and minute control reserves are distributed among the power plants in a cost optimal way.

The time horizon spans up to two days (separated into quarters of an hour). The whole problem is solved with a small optimality gap in less than 30 seconds in 95 % of all cases. To improve the runtime and to utilize the system for a short-term intraday optimization the thermal power plants' schedule may be set fixed in periods with prices that do not allow an adjustment of thermal production. As a result the above mentioned information (quarter-hourly production schedules, unused power plant capacity, dispatch potential, and reserve provision of every single machine) is send frequently to the transmission system operator. The intraday optimization also provides decision support for power plant dispatching and real-time trading. The power plant portfolio dispatch is optimized and adjusted constantly by processing and displaying relevant power plant and price data.

2.2. Modeling pumped hydro plants

The hydro storage portfolio deployment is part of the mixed integer optimization. The hydro storages are modelled on a very high level of detail considering reservoir restrictions, hydraulic short circuit of pumped hydro storages, water spillage, inflows etc. Most input parameters have a quarter-hourly resolution. It can be distinguished between hard reservoir restrictions such as maximum/minimum filling levels, flow rates, efficiencies, outflow, inflow and restrictions that can be adjusted by the dispatcher. These include the target energy filling levels (set intraday or at the end of the planning horizon), which can be adjusted depending on the trader's or dispatcher's market assessment and experiences on reserve energy activation. Maximum and minimum filling levels can also be adjusted by complemented security buffers in case of uncertainties in inflow, prices or high probabilities of outages of thermal plants. In the first release state, the optimization was performed just for the current day; the planning horizon has afterwards been extended to at least two days. Optimization across several days has the great advantage that start time and length of the storage cycle are more flexible and the potential of the pumped hydro power plants can be better exploited. Target filling levels can always be set by the dispatch, even within a planning period. Since EnBW's pumped hydro plants can only operate at full power for a couple of hours until reservoir limits are reached, our experience shows that optimizing across more than two days does not offer any advantage.

The intraday optimization generates a significant amount of data which can be used to improve the daily pumped hydro power plants' intraday deployment. The optimization has therefore great potential for traders and dispatchers that obtain significant support for evaluating orders and assessing power plants deployment strategies.

3. Trading pumped hydro storages on the continuous intraday market

The optimization approach is a multistage looping algorithm that runs as a post-optimization after the frequently intraday optimization and delivers accurate time dependent water values as well as the planned production which can guide a bidding strategy for the intraday market. The optimization is based on the algorithm presented in Lu et al. (2004) who first presented a variable length of storage cycles due to limited reservoir capacity. This fits to the new market conditions where e.g. photovoltaics feed-in during the day causes double hump price curves with a second pumping period at midday, or wind feed-in pushing peak hour prices below the average night prices, resulting in long storage cycles over two or three days. We are following the original idea by Lu et al. (2004) and account for some additional challenges, such as grid charges, power plant availability and flat price profiles. Furthermore, we correct some shortcomings hindering the practical application of the algorithm.

The equations and the algorithm are defined using the following symbols:

- ν: grid charges per ¼ MWh
- η: efficiency of (power plant)
- t_g, t_p: number of quarter hours where unit is in generating/pumping mode
- $t_{p,max}$: maximum number of quarter hours where unit can be in pumping mode
- λ_g, λ_p: marginal cost of generating/pumping a ¼ MWh
- E_0, E_T: energy level in upper reservoir at beginning/end of planning horizon
- E_{in}, E_{out}: energy in- and outflow
- $[\tau_0, T]$: planning horizon
- P_g, P_p: maximum power of generator/pump
- $P_{g,\tau}, P_{p,\tau}$: maximum power of generator/pump in period τ (accounting for availabilities)
- F: price forward curve (consists of prices in each period m_τ)
- Ω, Ω': periods sorted in ascending/descending order

The reservoir filling level equation depends on the energy level E_0 at the beginning and E_T at the end of the planning horizon $[\tau_0, T]$. The assumption by Lu et al. (2004), that initial storage level equals terminal storage level does not hold for intraday operations and is thus not needed anymore.

$$E_T = E_0 + E_{in} - E_{out} \tag{1}$$

The set $[\tau_0, T]$ is sorted in ascending order of the corresponding price forward curve F that consists of the prices in each period so that the period with the lowest price is the first and the period with the highest price is the last element of the set. Denote this set as Ω. The set where periods are sorted in descending order of the corresponding price (the period with the highest price is the first and the period with the lowest price is the last element of the set) is denoted as Ω'. The inflow energy can be calculated based on t_p using the following equation:

$$E_{in}(t_p) = \sum_{\substack{\tau\in\Omega \\ \tau\le t_p}} P_{p,\tau}\,\eta \tag{2}$$

The outflow energy is

$$E_{out}(t_g) = \sum_{\substack{\tau\in\Omega' \\ \tau\le t_g}} P_{g,\tau} \tag{3}$$

t_g is defined by:

$$t_g = \frac{P_p \eta t_p - E_T + E_0}{P_g} \tag{4}$$

and $t_{p,max}$ is set as follows:

$$t_{p,max} = \frac{T}{1+\frac{P_p\eta}{P_g}} \tag{5}$$

3.1. Unconstrained optimization algorithm

In comparison to the original algorithm by Lu et al. (2004) grid charges are included here because they have a significant impact on the profitability of operating hydro power plants in Germany. Furthermore, if the price curve is very flat and when the terminal energy level deviates from the initial energy level, a spread-based operation of the power plant is not possible. This situation has been explicitly accounted for in the following algorithm.

Step 1: Obtain a price forward curve F and sort it in an ascending order.

Step 2: Start with $t_p = 1$.

Step 3: Obtain t_g using (4) and find the corresponding λ_p and λ_g from F; if $t_g = 0$, set $\lambda_g = \infty$.

Step 4: Check the optimality condition. Is $\lambda_g \leq (\lambda_p + \nu)/\eta$?

- If the inequality does not hold, set $t_p = t_p + 1$ and go to Step 5.
- If the inequality holds, set $t_p = t_p - 1$, obtain t_g and go to Step 6.

Step 5: If t_p is less than $t_{p,max}$ go back to Step 3. If $t_p > t_{p,max}$, stop.

Step 6: If $t_p = 0$, $t_g = 0$, and $E_T > E_0$, set $t_p = (E_T - E_0)/P_p/\eta$ and determine λ_p. Else find λ_p as well as λ_g from F; if $t_p = 0$, set $\lambda_p = -\infty$; if $t_g = 0$, set $\lambda_g = \infty$. Then stop.

Unlike described in the original algorithm by Lu et al. (2004), the price forward curve is not necessarily monotonous. Thus, slight adaptions of the algorithm were necessary. When the price equals the marginal cost of pumping for the first time, P_p is consumed. If the price meets marginal cost again at a later time, no water will be pumped. When price equals marginal cost for generating power for the first time, $(t_g - \lfloor t_g \rfloor) * P_g$ is generated. This may be less than P_g if the energy comes close to reservoir limits. At any later point when price equals marginal cost for generating, no water will be released. Note that this reasoning works for prices that appear at most twice. If F contains the same price more than two times, water needs to be pumped or released at full power in more than one period where marginal cost equals price.

3.2. Unconstrained optimization algorithm accounting for availabilities

One drawback of the original algorithm is that power plant availability is not considered. An example is the atypical grid usage in Germany. This means that the operator either does not use pumps during predefined hours during the day or has to pay nearly 8 times higher gird charges all the time. The (partial) availability of power plants during the day, grid charges and flat price profiles are addressed in the algorithm here.

Step 1: Obtain a price forward curve F and sort it in an ascending order.

Step 2: Start with $t_p = 1$.

Step 3: Obtain E_{in} by using (2) and determine the necessary E_{out} by means of (1). Set $t_g = 1$.

Step 4: Calculate $E_{out}(t_g)$ using (3).

Step 5: If $E_{out}(t_g) \geq E_{out}$, set $t_g = t_g - \frac{E_{out}(t_g) - E_{out}}{P_{g,(\tau = t_g)}}$, and go to Step 6. If $E_{out}(t_g) < E_{out}$, set $t_g = t_g + 1$ and go back to Step 4.

Step 6: Determine λ_p and λ_g from F; if $t_g = 0$, set $\lambda_g = \infty$.

Step 7: Check the optimality condition. Is $\lambda_g \leq (\lambda_p + \nu)/\eta$?

- If the inequality does not hold, set $t_p = t_p + 1$ and go to Step 8.
- If the inequality holds, set $t_p = t_p - 1$, obtain t_g (Steps 3 – 5, skipping Steps 6 and 7) and go to Step 9.

Step 8: If t_p is less than $t_{p,max}$ go back to Step 3. If $t_p > t_{p,max}$, stop.

Step 9: If $t_p = 0$, $t_g = 0$, and $E_T > E_0$, obtain t_p from $\sum_{\substack{\tau \in \Omega \\ \tau \leq t_p}} P_{p,\tau} = \frac{E_T - E_0}{\eta}$. Then determine λ_p. Else find λ_p as well as λ_g from F; if $t_p = 0$, set $\lambda_p = -\infty$; if $t_g = 0$, set $\lambda_g = \infty$. Then stop.

3.3. Optimization algorithm accounting for reservoir limits

Since the above algorithms may violate reservoir constraints, a second optimization needs to be conducted.

Step 1: Solve the problem with the unconstrained optimization in a time interval $[\tau_0, T]$

Step 2: Check the solution. If the energy level is always within the reservoir limits, stop. If there are violations of the reservoir constraints, go to Step 3.

Step 3: Subdivide the time interval into $[\tau_0, \tau']$, where τ' is the quarter hour where the unconstrained optimization finds the highest or lowest reservoir level (depending on the violated limit). Let E_T in τ' be the value that has been violated (upper or lower limit). Then perform the unconstrained algorithm.

Step 4: Check the solution. If there are more violations, go back to Step 3. If not, set $\tau_0 = \tau'$, let E_0 be the violated limit, and go back to Step 1.

Note that it is reasonable to run the algorithm as soon as a new price forecast is available. The same applies to updated information on plant outages, trades, and reservoir levels.

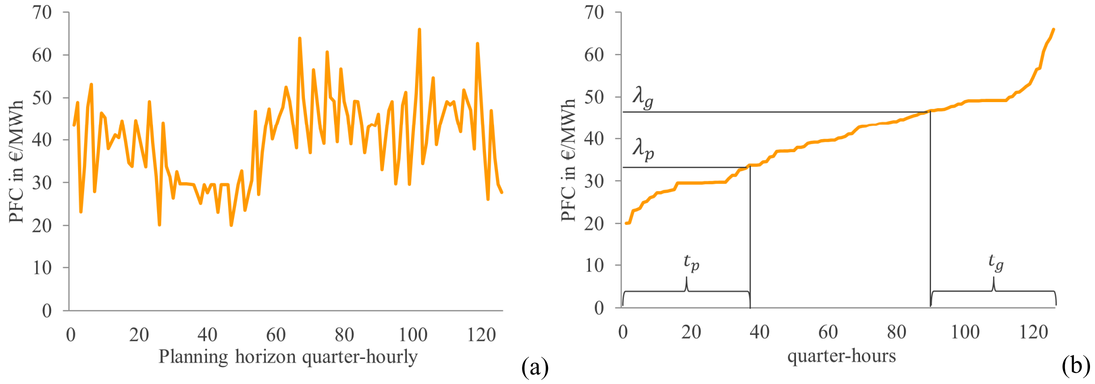
4. Example

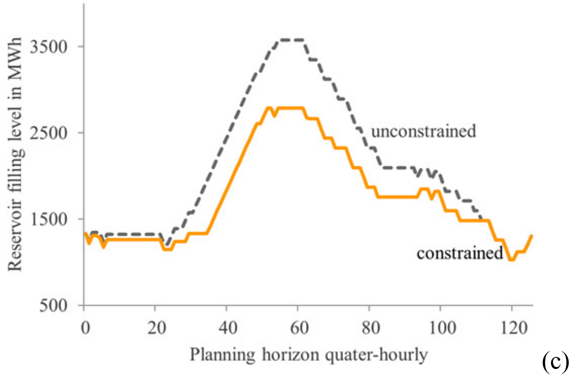
The algorithm has been implemented as an extension to the MIP that determines optimal power plant deployment. This example shows a calculation from August 10th 2015 4:45pm. For the calculation, a price assumption F is needed for the next day(s). This can be a price forward curve or the actually traded market prices, see Fig.2 (a). The efficiency of the plant is set to 0.75 and grid charges are 1.5 €/MWh consumed. The upper limit of the energy storage level is set to 2800 MWh and the lower bound to 300 MWh. In both directions a safety buffer has been set. Start level was 1332 MWh and end level was 1300 MWh. The end level is of minor importance because it just influences the last sub-period with different prices which results in a de-coupling. To ensure this, the end level should be set at least one day ahead. Following the introduced algorithm for the unconstrained case the prices are sorted along the planning horizon Fig.2 (b). From both sides, t_p and t_g are calculated stepwise until the optimality criterion $\lambda_g \leq (\lambda_p + \nu)/\eta$ is reached. The results of this part of the algorithm can be seen in Fig.2 (c). The grey dashed line shows how an optionally large reservoir filled up to nearly 4000 MWh and returned to the end level. In this unconstrained case all hours are used that exceed the spread of efficiency rate plus grid charges. This operation should be equal to the dispatch of seasonal hydro power storages. A constrained daily pumped hydro power plant results in the orange line. In this case the second part of the algorithm applies. The planning period is divided into sub-periods at all points where the reservoir limits have been reached. This is the case in the first iteration in quarter-hour 42, because the maximum storage level has been reached. The sub-periods are again optimized using the first part of the algorithm to optimally exploit the sub-period. In the second sub-period the reservoir limits are reached again in every step until the prices are low enough for water to be released. Therefore, the price for pumping is set to negative infinity in the following periods, see Fig.2 (d). The price for generation can be infinitely large too, but since the calculation is done frequently, it is reasonable to set the generation price equal to the one in the next period with a regular price.

For comparison, we also applied the algorithm to large storages over a period of one year. In this case, the results (water values, filling levels and policies) are equal to the output of a linear deterministic optimization program.

5. Conclusion

In this paper we outline optimal bidding strategies for daily pumped hydro storage power plants in a competitive electricity market considering the perspective of a storage operator and the difficult current market conditions in Germany. Starting form a new regulatory requirement that forces power plant operators to submit precise planning data, an intraday optimization model has been set up. Based on this model output an intraday multistage looping algorithm for an intraday pumped hydro storage optimization has been introduced. Reservoir limits, efficiencies, grid charges and machine availabilities are included in the algorithm. The algorithm has been tested in a real-world application running at a high frequency during the day (in practice at least every 15 minutes). Exemplary results are presented showing the high practicability of the model.





Time in quarter-hours	λ_p in €/MWh	λ_g in €/MWh
[0-52]	29.56	47.82
[53-55]	27.26	46.82
[56-126]	29.68	49.13

(d)

Fig. 2 (a) Exemplary quarter-hourly Intraday Continuous price curve from August 10th 2015 4:45pm until August 11th 2015 11:45pm. (b) Sorted price curve in ascending order. (c) Filling level of the reservoir plotted against the planning horizon. The grey dashed line displays an unconstrained energy reservoir, the solid black line represents a constrained energy reservoir. (d) The table shows the respective water values for each period.

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