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# Day-Ahead Price Arbitrage for Chebren Pumped Storage Hydropower Using Mixed-Integer Linear Programming

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**Abstract.** Pumped-storage hydropower provides large-scale flexibility by shifting energy from low- to high-price hours. This paper evaluates the day-ahead arbitrage potential of the Chebren pumped-storage concept using a daily mixed-integer linear programming (MILP) scheduling model implemented in MATLAB and driven by hourly HUPX day-ahead prices for 2025. The model captures key operational constraints, including generating and pumping power limits, turbine and pump efficiencies, storage-energy bounds, mutually exclusive operating modes, and daily caps on pumping and generating hours. A representative Chebren parameter set is adopted to illustrate market-driven operation under realistic technical limits. A year-long simulation is carried out by solving the MILP sequentially day by day. The results show that dispatch decisions are driven primarily by intraday price spreads, with negative-price hours forming the most attractive pumping windows. For the adopted configuration, the annual net arbitrage profit reaches €51.95 million, with 599.26 GWh generated and 783.35 GWh consumed for pumping. The proposed workflow provides a transparent benchmark for Chebren's day-ahead arbitrage value and a reproducible basis for sensitivity studies under alternative technical parameters and market conditions.

**Key words.** pumped-storage hydropower, day-ahead electricity market, electricity price volatility, mixed-integer linear programming, price arbitrage

## 1. Introduction

Pumped-storage hydropower (PSH) remains the most established and widely deployed large-scale electricity storage technology, providing essential flexibility services to power systems undergoing rapid decarbonization. With the growing penetration of variable renewable energy (VRE), particularly wind and solar generation, PSH plays a central role in mitigating variability, enabling energy time-shifting, and supporting short-term system adequacy under increasingly volatile operating conditions [1]–[4].

In liberalized electricity markets, the value proposition of PSH has progressively shifted from capacity-driven operation toward market-oriented dispatch, where profitability is increasingly determined by short-term price dynamics. Day-ahead (DA) electricity prices, characterized by pronounced intraday spreads and an increasing frequency of very low or negative price events, have become a key driver of storage operation across European power systems [5], [6]. Recent European market reports confirm that price volatility has increased significantly in systems with high shares of VRE, with more frequent and prolonged negative price events observed across several bidding zones [7]. Similarly, global market analyses indicate that the economic value of storage technologies is increasingly driven by short-term price spreads rather than average price levels, reinforcing the role of arbitrage-based operation [8]. Such price patterns typically emerge during periods of high renewable output combined with limited system flexibility, creating favourable conditions for PSH arbitrage.

Capturing these market opportunities requires an explicit representation of PSH operational characteristics, including mutually exclusive pumping and generating modes, power limits, storage-energy constraints, and efficiency losses. Mixed-integer linear programming (MILP) has therefore emerged as a standard modelling framework for short-term PSH scheduling and DA market participation, as it enables a realistic yet computationally tractable formulation of plant operation under market signals [9]–[12]. Recent review studies further highlight that such formulations remain the dominant approach for short-term scheduling of energy storage systems because they capture operational constraints while preserving computational tractability. Furthermore, related research demonstrates that reduced-complexity formulations remain useful for benchmarking day-ahead scheduling decisions, even when richer hydro-technical detail is omitted [12].

At the same time, contemporary market conditions have renewed the relevance of PSH as a load-increasing flexibility resource. Negative-price episodes enhance the economic attractiveness of pumping and strengthen the case for transparent, reproducible approaches that can benchmark the arbitrage value of both existing and prospective PSH projects under realistic technical and market assumptions [5], [6]. This is particularly important for large, capital-intensive projects in Southeast Europe, where PSH concepts are frequently discussed as strategic enablers of renewable integration but remain insufficiently assessed from a market-based operational perspective. From a system perspective, the value of storage is increasingly recognized not only in terms of energy shifting, but also in its contribution to system flexibility, reliability, and integration of VRE sources [13].

In North Macedonia, the need for flexibility is becoming more pronounced as the generation mix evolves and market-based price signals gain importance. According to the Energy and Water Services Regulatory Commission (ERC), total installed generation capacity was 2632.7 MW in 2023 and increased to 2983.9 MW in 2024, reflecting rapid additions—primarily solar—over a short period [14], [15]. At the same time, the market framework has advanced through the establishment of organized DA trading: the national nominated market operator MEMO launched DA market operations with its first auction on 10 May 2023 [16], and the Energy Community's implementation reporting confirms ongoing operation of the DA segment since that period [17]. This combination of growing VRE capacity and an operational DA market makes market-based valuation of flexibility increasingly relevant for investment and planning in the Macedonian electricity sector. Similar trends are observed across the Western Balkan region, where ongoing market integration and renewable expansion are expected to further increase the need for flexible resources such as energy storage [18].

Within this context, the Chebren concept on the Crna Reka cascade is frequently discussed as a strategic flexibility option for the national system. Publicly available project documentation describes multiple technical variants with different installed capacities and design choices [19]. To keep the analysis transparent and reproducible, this paper adopts one representative parameter set, based on three reversible units, and evaluates day-ahead arbitrage under constraint-consistent operating limits. The paper's contribution is threefold: (i) a clearly stated MILP formulation for DA self-scheduling, (ii) a full-year day-by-day simulation workflow, and (iii) a Chebren-focused benchmark suitable for subsequent sensitivity analyses and future extensions toward reserve co-optimization.

## 2. Case study: Chebren pumped-storage concept

This study considers the Chebren pumped-storage hydropower concept on the Crna Reka cascade in North Macedonia. Fig. 1 shows the cascade layout and the position of Chebren within the system. According to the official project description, the Chebren site is located in the canyon reach of Crna Reka, upstream of the existing hydropower utilization in the area, and is typically discussed within the broader cascade development context [19].

Chebren has been evaluated through multiple planning and study stages over several decades. Publicly available project material indicates that recent pre-feasibility work compares multiple technical alternatives, including reversible and non-reversible configurations, assessed under techno-economic criteria [19]. For the scheduling analysis in this paper, one representative pumped-storage configuration is adopted to define the operational envelope used in the optimization model. The reference case assumes three reversible units, with rated power of 332.84 MW in generating mode and 347.34 MW in pumping mode [20]. This configuration is used as a transparent baseline for day-ahead arbitrage quantification, while acknowledging that alternative official variants may imply different power limits and therefore different economic outcomes.

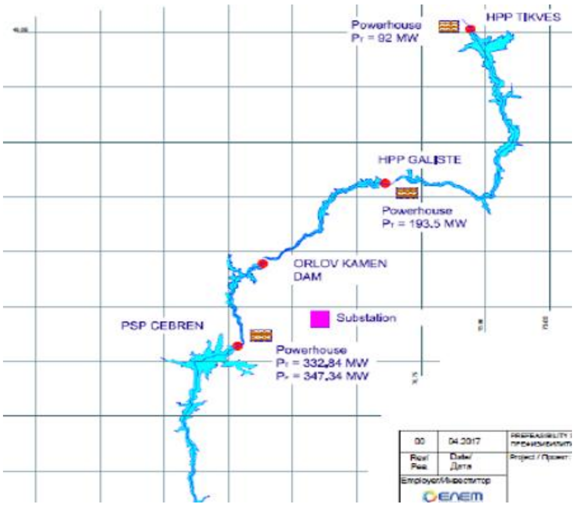


Fig. 1. Crna Reka cascade overview and location of the Chebren pumped-storage concept [19]

## 3. Data set and pre-processing

The optimization is driven by a single exogenous time-series input: hourly day-ahead electricity prices. The study uses HUPX Day-Ahead Market (DAM) prices for the full year 2025, expressed in EUR/MWh and indexed by timestamp (one value per hour) [21],[22]. To keep the workflow reproducible and solver-ready, the raw exports were consolidated into a single input table containing only two fields: Datetime and Price_EUR_MWh. This reduces formatting ambiguity and helps avoid inconsistent preprocessing.

The price series was then aligned with the model's daily 24-hour scheduling horizon. First, timestamps were sorted to enforce chronological order. The series was then screened for missing or invalid entries; where isolated missing hourly prices occurred (NaN), values were completed by linear interpolation using the nearest valid surrounding hours. Next, the time series was mapped into complete 24-hour blocks so that each optimization instance corresponds to one day with hourly prices $\lambda_h$, h=1,…,24. Any remaining incomplete daily blocks (e.g., due to gaps that could not be reliably completed) were excluded to preserve a consistent daily structure. The final dataset is therefore represented as a daily price matrix of size Ndays×24, which is used directly by the sequential day-by-day MILP solver.

To provide a compact view of the 2025 market signal, Fig. 2 summarizes the average DAM price as a function of month and hour of day. Each surface point represents the arithmetic mean of all prices observed for a given month and hour. This representation highlights persistent intraday structure and seasonal shifts in price levels, which are the key drivers of arbitrage schedules under a price-taking assumption.

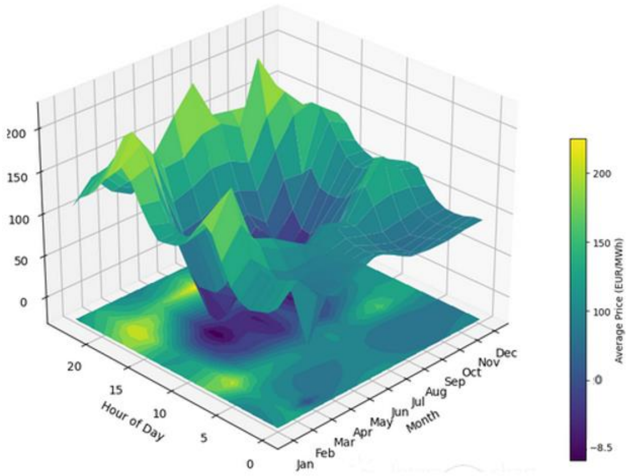


Fig. 2. Average HUPX day-ahead price in 2025 by month and hour of day (EUR/MWh), computed from the hourly dataset

## 4. Methodology: Daily MILP Scheduling Model

The Chebren pumped-storage concept is represented as a price-taking plant that participates in the day-ahead market by shifting energy across hours. In practical terms, the plant pumps when prices are low, including negative-price hours, and generates when prices are high, subject to technical operating limits. To represent this behaviour in a transparent and reproducible way, the scheduling problem is formulated as a daily mixed-integer linear program (MILP) and implemented in MATLAB using intlinprog [23]. Hourly day-ahead prices are treated as exogenous inputs. The optimization is solved sequentially for each day of the year, and the end-of-day storage state is carried over to the next day to maintain intertemporal consistency.

For each hour $h$=1,2,...,24, the model decides the generating power $\boldsymbol{P_h^{\text{gen}}}$ [MW] and the pumping power $\boldsymbol{P_h^{\text{pump}}}$ [MW]. Two binary variables, $\boldsymbol{u_h^{\text{gen}}}$ and $\boldsymbol{u_h^{\text{pump}}}$, indicate whether the unit is in turbine mode or pumping mode during hour h. The storage state is described by $E_h$ [MWh] for $h$=0,…24, interpreted as the stored energy at the beginning of each hour. A one-hour time step is assumed throughout.

### *A. Objective function*

Let $\lambda_h$ [EUR/MWh] denote the day-ahead electricity price in hour $h$. The daily arbitrage profit is expressed as revenue from generation minus the cost of electricity used for pumping. The objective is:

$$\max \sum_{h=1}^{24} \lambda_h\, P_h^{\text{gen}} - \sum_{h=1}^{24} \lambda_h\, P_h^{\text{pump}} \tag{1}$$

### *B. Storage dynamics and operating constraints*

Storage evolution is enforced through an hourly energy balance with turbine and pump efficiencies $\eta_t$ and $\eta_p$:

$$E_h = E_{h-1} + \eta_p P_h^{\text{pump}} - \frac{1}{\eta_t} P_h^{\text{gen}}, h = 1, \dots, 24 \tag{2}$$

The storage state is bounded by the energy capacity $E_{max}$:

$$0 \le E_h \le E_{\max}, h = 0, \dots, 24 \tag{3}$$

Mutual exclusivity between pumping and generating is enforced by:

$$u_h^{\text{gen}} + u_h^{\text{pump}} \le 1, h = 1, \dots, 24 \tag{4}$$

To link the continuous power decisions to the on/off operating modes, the MILP uses standard indicator (big-M) constraints with $\boldsymbol{M = P_{\max}}$ :

$$0 \le P_h^{\text{gen}} \le P_{\max}^{gen}\, u_h^{\text{gen}}, 0 \le P_h^{\text{pump}} \le P_{\max}^{pump}\, u_h^{\text{pump}}, \quad h = 1, \dots, 24 \tag{5}$$

Finally, daily limits are imposed on the number of operating hours in each mode:

$$\sum_{h=1}^{24} u_h^{\text{gen}} \le H_{max}^{\text{gen}}, \sum_{h=1}^{24} u_h^{\text{pump}} \le H_{max}^{\text{pump}} \tag{6}$$

where $\boldsymbol{H_{max}^{\text{gen}} = 6\ \text{h/day}}$ and $\boldsymbol{H_{max}^{\text{pump}} = 7\ \text{h/day}}$ denote the daily maximum operating limits in generating and pumping mode, respectively.

Each day starts from a given storage level, $E_0$. Because the model optimizes over a 24-hour horizon, the solver would naturally tend to empty the reservoir by the end of the day to maximize daily profit. To prevent this, a cyclic boundary condition $E_{24}$=$E_0$ is applied. At the same time, the sequential annual simulation carries the end-of-day storage over to the next day $\boldsymbol{E_0^{(d)} = E_{24}^{(d-1)}}$. Together, these rules maintain a stable daily water volume, keeping the arbitrage calculation realistic and preventing long-term storage drift. Finally, from the optimized hourly schedules, the model calculates the daily profit and energy throughput, which are then aggregated to find the annual net profit, total generated energy, and total pumping energy.

## 5. Results and discussion

The year-long, day-by-day simulation for 2025 indicates that the adopted Chebren reference configuration can extract substantial value from hourly day-ahead price variability. Over the full horizon, the optimized schedules yield an annual net arbitrage profit of €51.95 million, with 599.26 GWh of generated electricity and 783.35 GWh of electricity consumed for pumping. The annual energy balance is consistent with the assumed conversion losses: the ratio Egen/Epump=599.26/783.35≈0.765 matches the implied round-trip efficiency $\eta_t\eta_p$ =0.85×0.90=0.765 . This agreement provides a useful consistency check, confirming that the aggregated annual energy totals are aligned with the assumed conversion losses.

A compact view of how the market signal translates into operation is given in Fig. 3, which shows the net dispatch over a selected multi-day window (days 110–120). Positive values correspond to generation and negative values to pumping. Two features are immediately evident. First, the schedule forms coherent operating blocks rather than rapidly alternating between modes. This is consistent with the imposed constraints—mutual exclusivity, power limits, and daily caps on operating hours. Second, the timing of pumping and generating blocks shifts from day to day. Pumping concentrates in low-price intervals, while generation moves toward higher-price periods, but the exact placement follows the depth and timing of the daily price troughs. In this sense, the dispatch remains clearly price-driven within the model's operating limits.

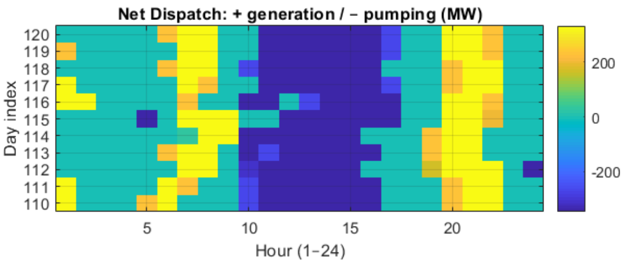


Fig. 3. Multi-day operational overview (days 110–120): net dispatch heatmap showing price-driven pumping and generation blocks (generation positive, pumping negative)

To illustrate the underlying mechanism more directly, Fig. 4 presents a representative day with pronounced negative prices (day 111 / 2025-04-21). The price profile (top panel) exhibits a deep midday trough with strongly negative values. The optimization responds by allocating the available pumping hours to this interval, which appears as negative bars in the dispatch plot (middle panel). As prices recover later in the day, the schedule switches to generation (positive bars), using energy stored during the negative-price block. The storage trajectory $E(t)$ (bottom panel) provides the physical explanation: stored energy rises sharply while pumping and is subsequently depleted during the evening generation hours. This example also clarifies why negative-price events can contribute disproportionately to arbitrage value: they lower, or even reverse, the effective charging cost and typically coincide with larger intraday spreads, while the same daily hour limits still apply.

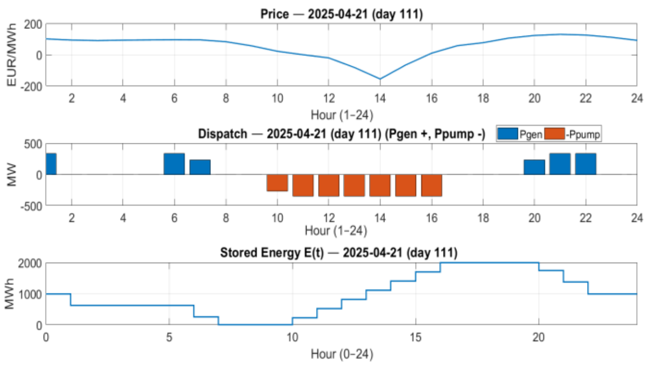


Fig. 4. Representative negative-price day (day 111, 2025-04-21): hourly price profile (top), optimal net dispatch (middle; generation positive, pumping negative), and storage state E(t) (bottom)

Longer-horizon profitability is summarized in Fig. 5, which aggregates the daily results to a weekly and monthly resolution. The weekly moving average (top panel) points to stronger arbitrage conditions during spring and early summer, followed by a gradual weakening toward the end of the year. The cumulative weekly profit (middle panel) increases smoothly, showing that annual performance is built from repeated cycling across many days rather than from a single outlier event. Finally, the monthly totals (bottom panel) provide a compact view of which months contribute most to the annual profit. Months with larger intraday spreads and/or more frequent negative-price hours tend to dominate, which is consistent with the operational logic observed in Fig. 4.

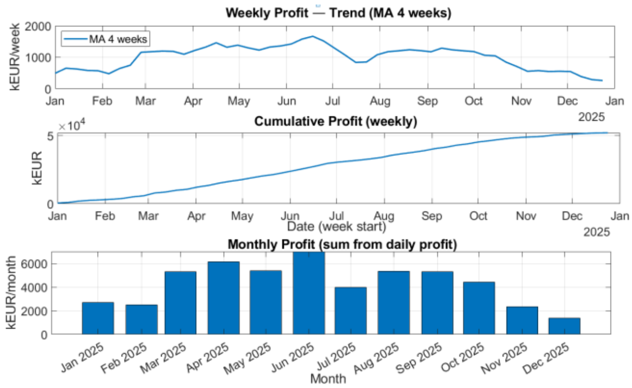


Fig. 5. Annual profitability summary for 2025: weekly profit trend (4-week moving average) (top), cumulative weekly profit (middle), and monthly profit totals (sum of daily profit) (bottom)

For additional context, Fig. 2 summarizes the average 2025 HUPX day-ahead price by month and hour of day. Although descriptive rather than an optimization output, it helps explain the patterns observed in Figs. 3–5 by revealing persistent intraday structure and seasonal changes in the magnitude and frequency of economically attractive spreads. These recurring low-price windows explain why pumping tends to cluster in similar parts of the day, while seasonal shifts help explain the variation in profitability across the year.

Overall, the main drivers of profitability can be attributed to three factors: (i) the magnitude of intraday price spreads, (ii) the frequency and depth of negative price events, and (iii) the ability of the plant to perform multiple charge–discharge cycles within operational constraints. Periods characterized by deep price troughs followed by high peak prices provide the most favourable arbitrage opportunities. Conversely, flatter price profiles significantly reduce achievable margins. This highlights the strong dependence of storage value on market volatility rather than absolute price levels.

In addition to energy-only arbitrage, pumped-storage hydropower plants can derive significant value from participation in ancillary service markets, including frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR), and manual reserves (mFRR). These services typically provide additional revenue streams and may alter optimal operating strategies by reserving capacity for upward or downward regulation instead of pure energy arbitrage. In systems with increasing renewable penetration, such services become increasingly valuable due to higher balancing needs. Consequently, including reserve market participation would likely increase the overall economic value of the Chebren concept, although it may also introduce additional operational constraints and trade-offs between energy and reserve provision.

To examine the robustness of the baseline results, a one-at-a-time sensitivity analysis was carried out around the reference case by varying three key parameter groups: round-trip efficiency, storage energy capacity, and power rating. Table I summarizes the resulting variations in annual arbitrage profit, serving as the primary economic metric for this benchmark.

Table I. - Sensitivity of annual arbitrage profit to changes in efficiency, storage energy capacity, and power rating

| Parameter | Scenario | Annual profit [M€] | Δ Profit [%] | Generated energy [GWh] | Pumping energy [GWh] |
|---|---|---|---|---|---|
| **Baseline** | Reference case | 51.95 | 0.00 | 599.26 | 783.35 |
| **Efficiency** | Low (ηt =0.88, ηp =0.83) | 48.84 | -6.00 | 564.00 | 772.16 |
| **Efficiency** | High(ηt =0.92, ηp =0.87) | 55.17 | +6.20 | 634.63 | 792.91 |
| **Storage capacity** | Low (-20% $E_{\max}$) | 51.18 | -1.48 | 589.26 | 736.31 |
| **Storage capacity** | High (+20% $E_{\max}$) | 56.77 | +9.27 | 662.40 | 827.51 |
| **Power rating** | Low (-20% $P_{gen}, P_{\text{pump}}$) | 45.45 | -12.52 | 530.31 | 662.47 |
| **Power rating** | High (+20% $P_{\text{gen}}, P_{\text{pump}}$) | 62.46 | +20.23 | 718.11 | 897.30 |

Table I shows that annual arbitrage profit is most sensitive to power rating, followed by storage capacity and round-trip efficiency. Under the analysed 2025 price profile, higher power limits substantially improve the ability to capture short-lived price spikes, while larger storage capacity supports the exploitation of longer price spreads. Notably, the sensitivity to storage capacity is highly asymmetric: a 20% reduction barely affects the profit (-1.48%), suggesting that the baseline volume is rarely the active constraint for regular daily cycling, whereas a 20% increase yields a substantial benefit (+9.27%) by allowing the plant to execute deeper intraday charge-discharge cycles during hours with extreme price spreads. Efficiency also has a clear first-order effect, since conversion losses directly determine how much of the pumped energy can be recovered during generation.

Overall, the results should be interpreted as a transparent day-ahead arbitrage benchmark for the selected Chebren reference configuration under the specific 2025 price year. The modelling scope is intentionally limited. The formulation does not co-optimize reserve products, does not represent head-dependent efficiencies, and treats storage constraints through an energy-capacity abstraction without hydrological inflows. More detailed operational features, such as unit-specific constraints, ramping behaviour, or head-dependent performance, could materially affect both dispatch patterns and value estimates. The reported results should therefore be viewed as a transparent first-order benchmark under simplified but explicit assumptions.

## 6. Conclusion

This study developed and applied a daily MILP scheduling model to quantify the day-ahead arbitrage potential of a reference Chebren pumped-storage configuration under hourly HUPX prices for 2025. In the full-year simulation, the optimized schedules yield an annual net arbitrage profit of €51.95 million, with 599.26 GWh generated and 783.35 GWh consumed for pumping. The resulting operating pattern is consistent with the expected economics of storage arbitrage: profitable cycling concentrates in periods with pronounced intraday spreads, while negative-price hours repeatedly emerge as the most attractive pumping windows because they reduce the effective charging cost and increase the discharge margin.

Beyond the plant-level benchmark, the results illustrate the broader relevance of flexibility in a power system with increasing renewable penetration and stronger market-based dispatch signals. In such a setting, a pumped-storage asset such as Chebren can convert volatile price signals into a controllable operating profile by absorbing energy during surplus conditions and returning it during periods of higher system value. The study therefore provides a market-oriented perspective on the role that large-scale storage can play in the evolving Macedonian electricity sector.

Importantly, the reported value should be interpreted as a transparent benchmark rather than a final investment metric. The analysis is intentionally limited to energy-only day-ahead arbitrage under simplified storage representation. It does not include ancillary-service co-optimization, head-dependent efficiencies, detailed hydrology, or more restrictive unit-level operating constraints, all of which can materially affect feasible cycling patterns and estimated value. The complementary sensitivity analysis further shows that annual profitability is particularly influenced by power rating, storage capacity, and round-trip efficiency, confirming that both technical design choices and market conditions are important determinants of economic performance.

Overall, the proposed modelling framework provides a reproducible and interpretable basis for first-order valuation of the Chebren concept under realistic hourly price signals. Future work should extend the model toward joint energy–reserve co-optimization, richer hydro-technical representation, and scenario analysis under alternative price regimes and regional market convergence. Such extensions would move the assessment from a day-ahead arbitrage benchmark toward a more complete system- and investment-oriented evaluation of long-term flexibility options in North Macedonia.

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