Challenges for hydropower and new nuclear

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Abstract

This report investigates how new nuclear capacity, when introduced into a liberalised electricity market with high renewable penetration, alters wholesale price formation and the profitability of Swiss hydropower. Spain's 2024 day-ahead market is used as a proxy for the conditions that Switzerland and Europe are likely to face as renewable penetration increases, since Spain already operates with over 60% annual wind and solar generation and has limited interconnection capacity, making it a clear illustration of supply-driven price dynamics. An assessment of Spain's price distribution shows that market revenues fall short of the levels required for new nuclear investment, with prices exceeding typical cost benchmarks of 100–145 EUR/MWh in only 3–26% of hours; consequently, any new plant would function operationally as low-marginal-cost baseload under long-term revenue guarantees. Reconstructing the merit order under this assumption reveals systematic price suppression and a contraction of scarcity hours as 1.6–3.2 GW of nuclear displaces higher-cost marginal generation. These altered price dynamics translate into substantial hydropower revenue impacts: run-of-river facilities lose 29–42% of profits (€304–441 million for the Swiss fleet), reservoir plants experience 15–19% reductions (€452–603 million fleetwide), and pumped-storage revenues decline by 4–13% under zero-cost nuclear and 9–13% when nuclear bids at its short-run marginal cost. At the scale of the Swiss hydropower fleet, these effects correspond to total annual profit losses approaching one billion euros, depending on the nuclear capacity and cost assumptions considered. Overall, the analysis shows that the primary economic effect of new nuclear in a high-renewable system arises from structural changes in market price formation rather than direct cost competition, with important implications for hydropower revenues, investment capacity, and long-term system planning in Switzerland.

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1. Introduction

The economics of power markets are undergoing a fundamental transformation as power systems shift towards renewable generation (JRC, 2024). In markets with rapidly growing shares of renewable energy, price formation increasingly reflects the availability of supply rather than fluctuations in demand (Hirth, 2013). In other words, markets that were historically demand-driven, where price changes were primarily linked to consumer load, are becoming supply-driven, with prices instead responding to variable renewable output such as solar and wind. Appendix A treats this in more detail illustrating this transition for Spain over the period 2015-2024, showing how supply-side variables have gained increasing explanatory power for electricity prices.

This report examines one aspect of this transition: how the addition of new nuclear capacity affects the profitability and use of existing hydropower resources, with a particular focus on implications for Switzerland.

Hydropower has long played a central role in balancing electricity systems, providing both seasonal storage and short-term flexibility (IEA, 2021). However, as more zero-marginal-cost generation enters the market, first from variable renewables, and potentially from subsidized nuclear baseload, the price spreads that historically rewarded hydro flexibility may shrink (IEA, 2024). Understanding these dynamics is particularly important for regions like Switzerland, where hydropower remains a dominant component of the power mix (contributing ~60% of domestic generation), yet discussions around new nuclear investments are resurfacing as part of the long-term decarbonization strategy (Panos 2024).

Spain as an Empirical Test Case

Spain is used here as an empirical proxy for Europe's likely market structure within the next five to ten years. The implicit assumption of adding nuclear capacity over a short time horizon should not be interpreted as a realistic construction scenario. Rather, it is a necessary analytical assumption to isolate and examine the structural effects on market price formation in a power system with high renewable penetration. In practice, the construction of a new nuclear power plant in Switzerland, as in most European countries, would involve significantly longer lead times, likely on the order of twenty years or more, given technical, regulatory, and political constraints. The analysis should therefore be understood as a counterfactual exploration of market mechanisms, rather than as a realistic investment timeline. Spain has already completed much of the energy transition that other European markets are now entering: in 2024, solar and wind together supplied over 60 % of annual electricity demand (REE, 2024). Second, Spain's relative isolation from the wider European grid makes it a nearly self-contained market, allowing a clearer observation of internal supply-demand dynamics. The

interconnection capacity with France (2,800 MW) represents only 6.2 % of Spain's peak demand (45,000 MW), compared with values above 40 % for Switzerland.

This relative isolation is precisely what makes Spain analytically useful. Switzerland's electricity market is strongly coupled with those of its neighbours, functioning both as an importer and exporter and as a key transit hub within continental Europe; as a result, domestic price formation is largely driven by regional, cross-border dynamics. Studying Spain therefore provides a forward-looking view of what the integrated European system may resemble once renewable penetration reaches similar levels. Spain's present situation can thus be interpreted as a laboratory for Europe's future and, by extension, for Switzerland's market exposure within that system. Irrespective of where new generation capacity is physically located, a high penetration of renewable energy in neighbouring countries is likely to have direct effects on wholesale electricity prices in Switzerland. Given the high degree of coupling in European electricity markets, price formation in Switzerland is largely driven by regional, cross-border dynamics rather than by domestic supply–demand conditions alone. Consequently, even in the absence of a comparable transformation of the Swiss generation mix, renewable penetration levels similar to those currently observed in Spain in neighbouring markets would be sufficient to significantly alter the price structure faced by Swiss producers. This strong market integration therefore justifies the use of the Spanish case as an empirical laboratory for analysing price-formation mechanisms and their potential implications for Swiss hydropower in a high-renewable European context.

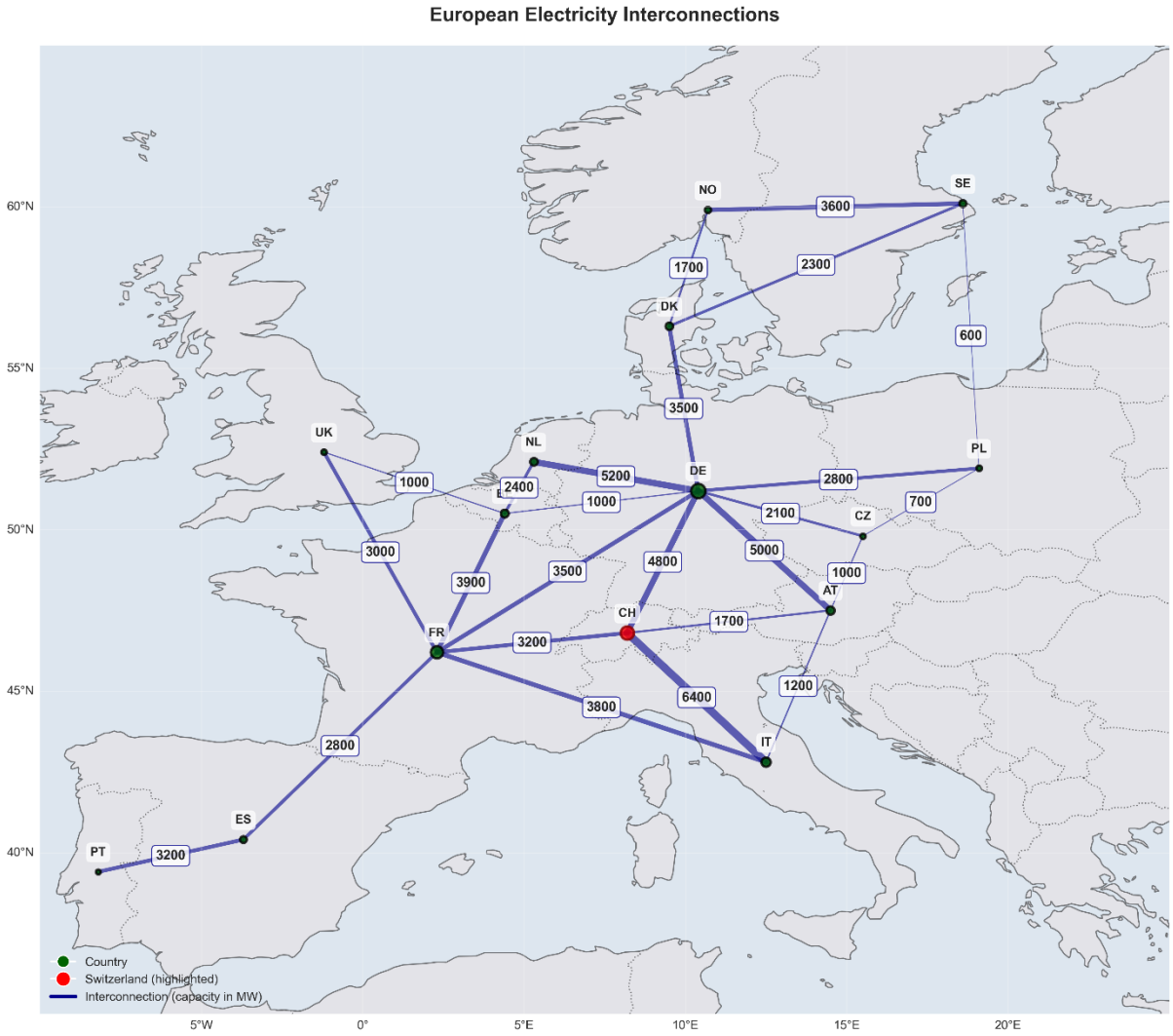
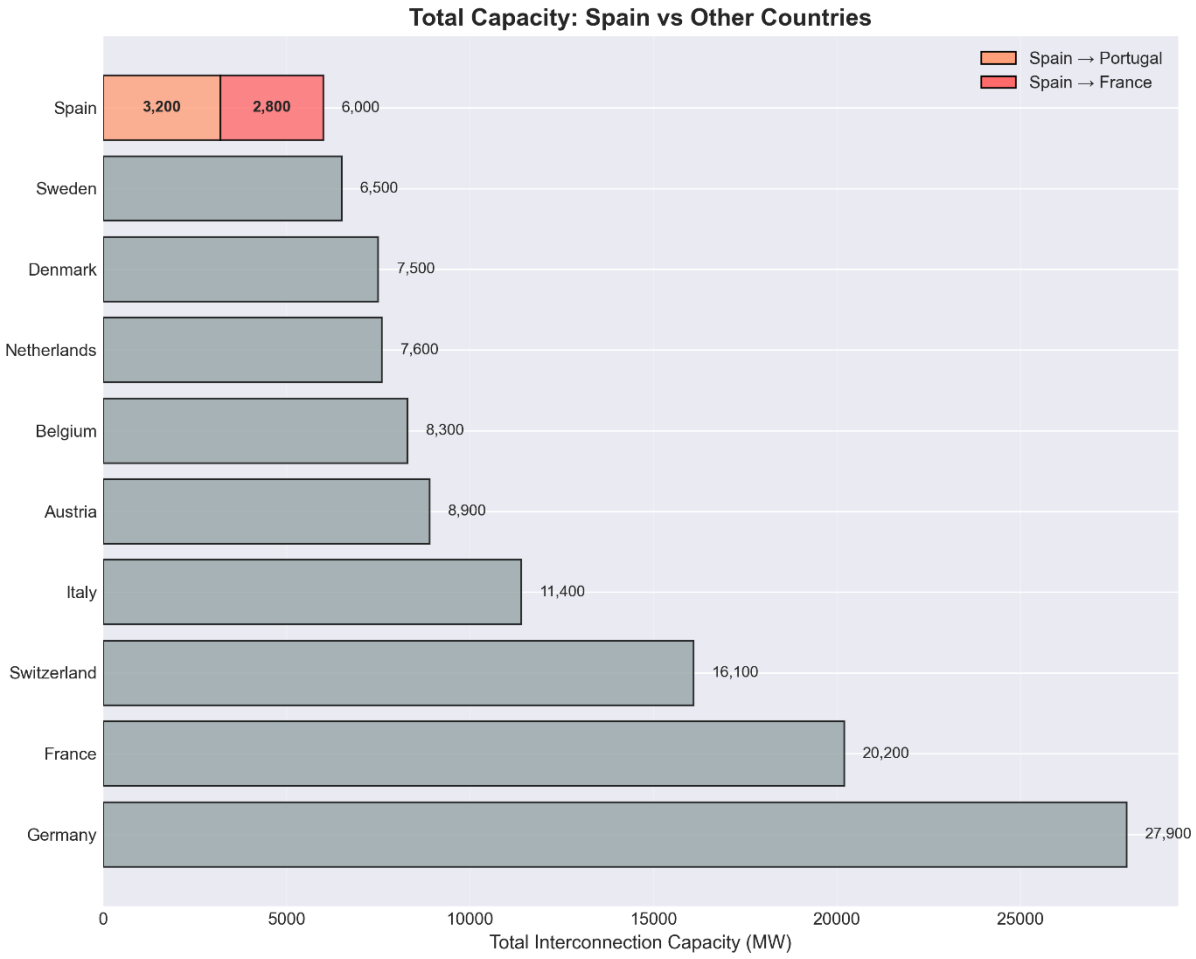


Figure 1.1: Interconnections in Europe.


Total Capacity: Spain vs Other Countries
Spain → Portugal
Spain → France
Spain
3,200
2,800
6,000
Sweden
6,500
Denmark
7,500
Netherlands
7,600
Belgium
8,300
Austria
8,900
Italy
11,400
Switzerland
16,100
France
20,200
Germany
27,900
0
5000
10000
15000
20000
25000
Total Interconnection Capacity (MW)

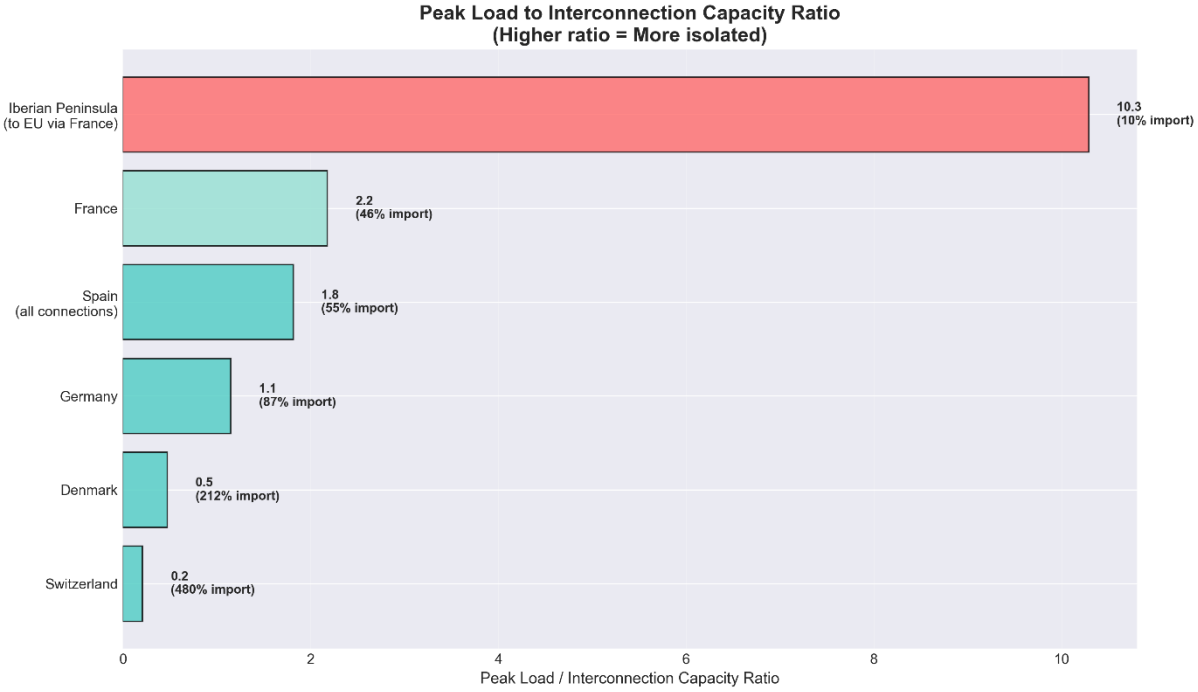
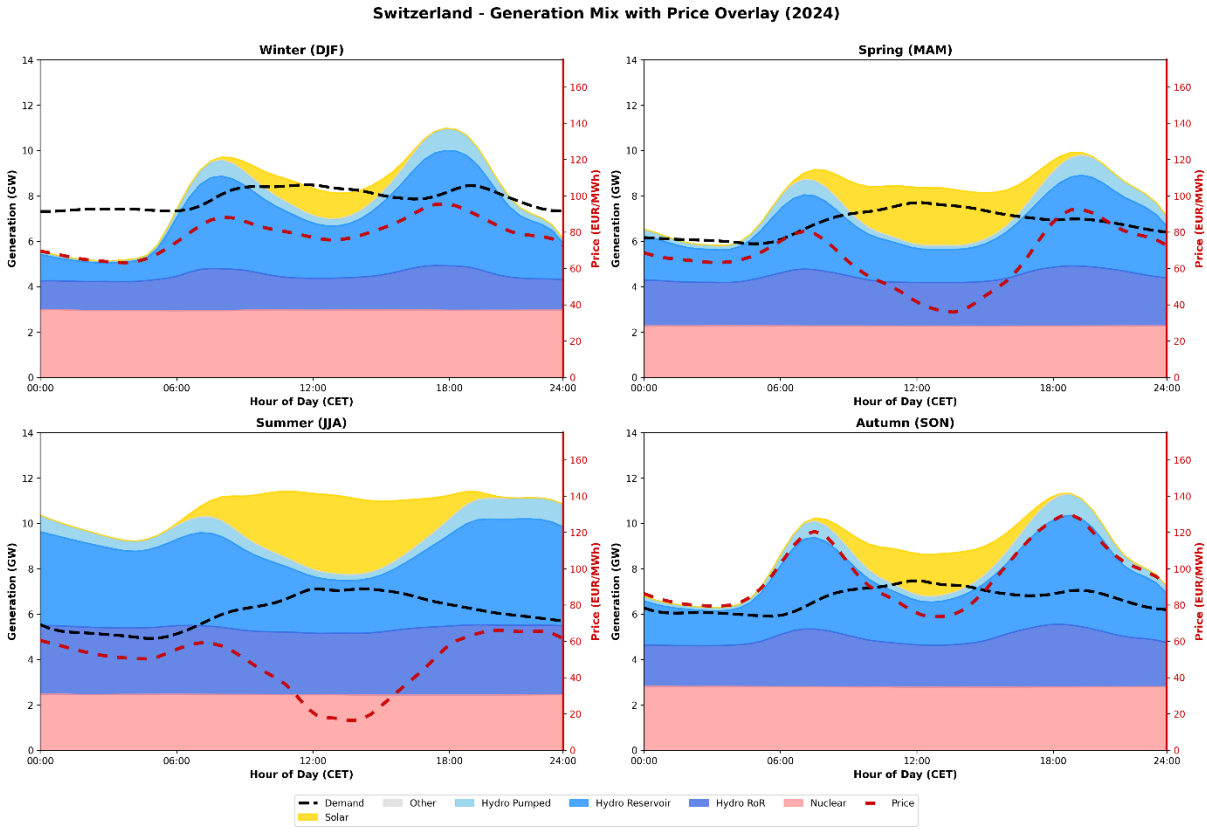

Peak Load to Interconnection Capacity Ratio
(Higher ratio = More isolated)
Iberian Peninsula
(to EU via France)
10.3
(10% import)
France
2.2
(46% import)
Spain
(all connections)
1.8
(55% import)
Germany
1.1
(87% import)
Denmark
0.5
(212% import)
Switzerland
0.2
(480% import)
0
2
4
6
8
10
Peak Load / Interconnection Capacity Ratio

Figure 1.2: total interconnection capacity (above) and ratio to peak load (below) for various countries and regions within Europe.



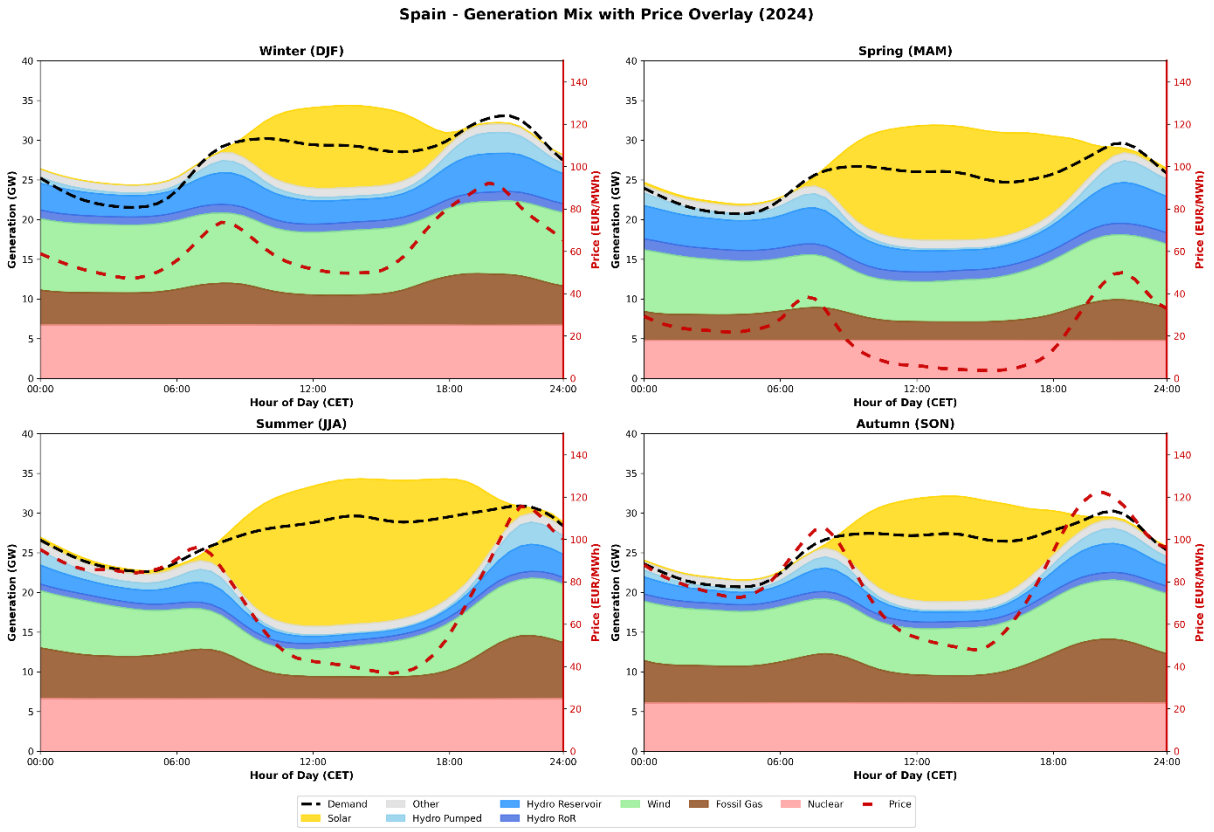


Figure 1.3: Seasonal daily generation profiles for Switzerland (top) and Spain (bottom).

Spain's detailed and transparent day-ahead market (OMIE, 2024) provides hourly aggregate supply and demand curves, enabling a precise reconstruction of market clearing mechanisms and controlled scenario simulations. Our analysis proceeds in three stages:

1. Nuclear viability assessment: evaluate whether new nuclear power plants could operate profitably in a competitive market without subsidies, using Spain's 2024 price distribution as a benchmark.
2. Merit-order impact analysis: assess the effect of introducing subsidized nuclear (zero marginal cost) on market clearing prices and on the profitability of three hydropower technologies: run-of-river, reservoir, and pumped storage.

The potential impacts of large-scale deployment of battery energy storage systems (BESS), as observed in California, on European electricity markets will be examined in a subsequent phase of this project, scheduled for Q1 2026.

The concluding section reflects on what these insights imply for Switzerland. While Switzerland's generation mix differs substantially from Spain's (Figure 3b), with existing nuclear providing ~29% baseload and hydropower ~60% of generation, the mechanisms identified in Spain, price suppression through zero marginal cost nuclear baseload addition, apply universally to liberalized electricity markets.

2. Nuclear Assumptions: Can new nuclear be viable?

The Nuclear Renaissance, Its Challenges, and Value in Liberalized Markets

After decades of stagnation, nuclear development is again being promoted as part of decarbonization strategies, with nearly 70 GW of new capacity under construction and over 40 countries considering extending or adding to their fleets (IEA, 2024). However, the sector faces persistent challenges: repeated cost overruns and construction delays (often by factors of two to three), financing constraints, and a concentrated, fragile supply chain (Muellner 2012). While international agencies such as the IEA outline scenarios in which new nuclear capacity could play an expanded role in low-carbon power systems (IEA, 2024b; IEA, 2025), other assessments emphasise the historical gap between announced projects and those actually delivered, with frequent delays and cancellations, as documented in the World Nuclear Industry Status Report (2024). The expected innovations, particularly Small Modular Reactors (SMRs), remain at the prototype stage.

The IEA recognizes that while renewables such as solar and wind exhibit very low (essentially zero) marginal costs once installed, nuclear power carries high upfront capital intensity and continuous fixed operating costs (IEA, 2024). Nevertheless, nuclear provides system-level value beyond short-term market prices:

- Stable and predictable generation costs over decades
- Continuous, non-intermittent electricity production, contributing to system reliability under normal operating conditions
- Enhanced energy security through diversification away from imported fossil fuels, albeit with continued dependence on imported nuclear fuel and services.

In liberalized markets, nuclear struggles to monetize these attributes. Its large fixed costs require stable long-term revenues, whereas prices in liberalized markets increasingly reflect the near-zero marginal cost of renewables. To remain viable, nuclear depends on out-of-market remuneration mechanisms that recognize its non-intermittent, low-carbon value. This empirical evidence supports the IEA's assessment that mechanisms ensuring predictable revenues are needed for new nuclear projects (IEA, 2025).

This chapter tests that assertion quantitatively. Using Spain's day-ahead electricity market as a proxy for a mature, high-renewable European system, we examine whether a new nuclear plant, at realistic cost levels, could recover its costs through market prices alone.

Reference Cost

Benchmark Selection

A widely cited benchmark for European new-build nuclear is the Hinkley Point C project in the UK. Under its 35-year Contract-for-Difference (CfD), the plant is guaranteed a strike price of £92.50/MWh (2012 prices**)** (BEIS 2020). That value reflects the full cost of financing, construction, operation, and decommissioning.

To express it in 2024 euros, two adjustments are applied:

1. Inflation from 2012 to 2024 ≈ +30% (UK CPI)
2. Average 2024 exchange rate ≈ 1 GBP = 1.17 EUR

Combined, this gives a value of roughly 145 EUR/MWh (2024 EUR).

This aligns with international cost assessments:

- IEA (2020), Projected Costs of Generating Electricity, reports LCOEs for new nuclear between 100–150 EUR/MWh for OECD Europe.
- IRENA (2025), Renewable Power Generation Costs in 2024, places advanced nuclear in a similar range, well above new solar or onshore wind.
- Coffey (2023) finds that coupling nuclear with integrated thermal or electrical storage could raise total generation costs by 10–25% relative to standalone reactors (Coffey, 2023), underscoring how additional flexibility, while valuable to the grid, further increases capital intensity.
- Lazard (2025) finds a new nuclear (unsubsidized LCOE): approximately 141–251 USD/MWh

For this study, LCOE benchmarks of 100 EUR/MWh and 145 EUR/MWh (2024 EUR) are adopted as representative mid-range and high-end estimates for new nuclear in Europe. Additionally, a short-run marginal cost (SRMC) of 45 EUR/MWh is used to represent existing nuclear plants with amortized capital costs.

Empirical Test: Spanish Market Price Distribution (2024)

Methodology

To assess whether new nuclear can recover its costs through market revenues alone, we analyze the distribution of hourly day-ahead electricity prices in Spain during 2024.

The analysis compares three cost thresholds against the 2024 price distribution:

- 45 EUR/MWh: Short-run marginal cost (SRMC) for existing reactors (with amortized capital)
- 100 EUR/MWh: Typical mid-range estimate for new nuclear projects (LCOE)
- 145 EUR/MWh: Hinkley Point C benchmark (full-cost recovery including financing)

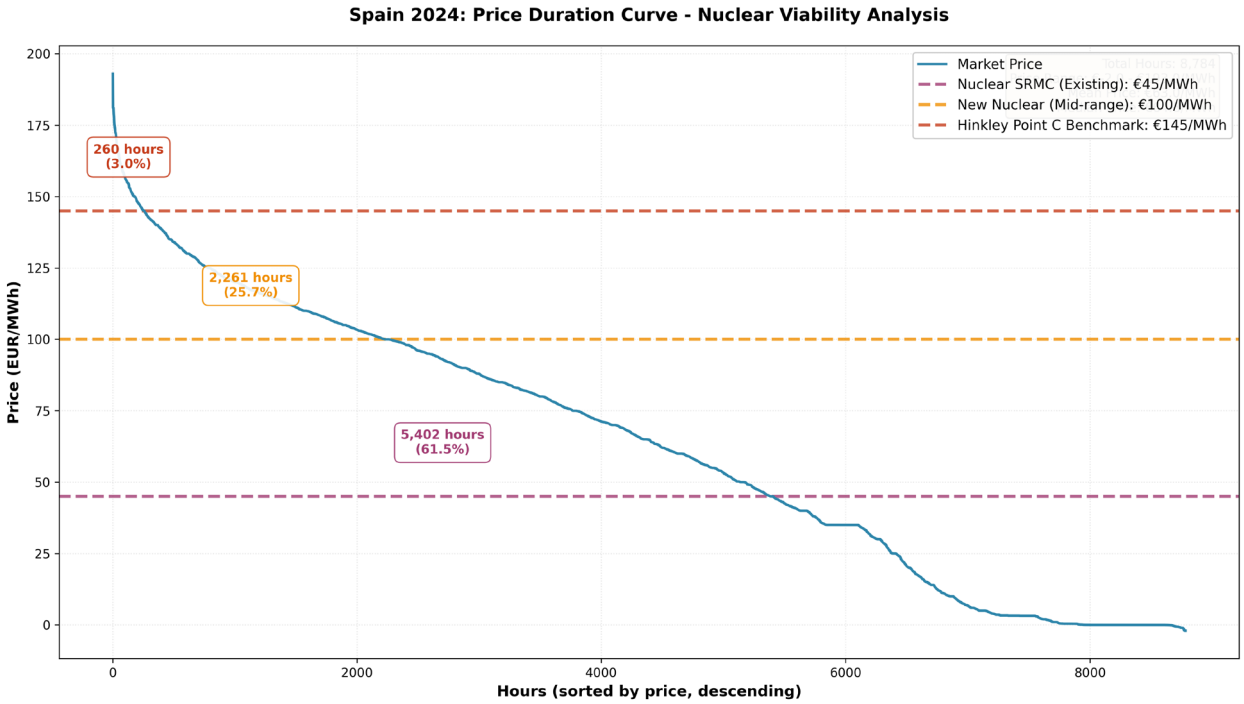


Figure 2.1: Price Duration Curve and Nuclear Viability Benchmarks (Spain 2024): Price duration curve showing hourly day-ahead market prices for Spain in 2024, ranked from highest to lowest. Horizontal lines indicate three nuclear cost benchmarks: existing nuclear SRMC (45 EUR/MWh, purple), new nuclear mid-range LCOE (100 EUR/MWh, orange), and Hinkley Point C benchmark (145 EUR/MWh, red). Shaded boxes indicate the share of hours where market prices exceed each threshold, with corresponding percentages and average prices during profitable hours.

Key Findings

The results presented in Figure 2.1 and detailed in Appendix Figures A2.1–A2.3 show how the distribution of hourly electricity prices in Spain during 2024 relates to representative cost benchmarks for nuclear generation. The price duration curve illustrates that market prices vary between roughly 0 and 200 EUR/MWh, with most hours concentrated below 100 EUR/MWh.

The number of potentially profitable hours are compared for the three cost thresholds:

- 45 EUR/MWh (SRMC): Approximately 5,402 hours (≈61% of the year) with market prices exceeding this threshold. Mean market price during these hours: ~94 EUR/MWh.
- 100 EUR/MWh (New nuclear mid-range): 2,261 hours (≈26% of the year) above this threshold. Mean market price during these hours: ~122 EUR/MWh.
- 145 EUR/MWh (Hinkley Point C): Roughly 260 hours (≈3% of the year) above this threshold. Mean market price during these hours: ~156 EUR/MWh.

This progression highlights how most hours lie well below full-cost benchmarks for new generation, reflecting the increasing dominance of low-marginal-cost renewable supply in setting market prices.

Implications for Market Design

Because the fixed-cost component of nuclear investment is substantial, most recent projects are developed under out-of-market remuneration mechanisms designed to ensure predictable revenues, such as:

- Contracts-for-Difference (CfDs): Guaranteeing a fixed strike price regardless of market fluctuations (e.g., Hinkley Point C)
- Regulated Asset Base (RAB) models: Allowing regulated rate-of-return on capital invested
- Long-term offtake agreements: Securing revenue streams through bilateral contracts with governments or utilities

From a market-clearing perspective, these arrangements make nuclear output appear as zero-marginal-cost generation, continuously available at ~0 EUR/MWh and thereby displacing higher-cost resources from the supply curve. As summarized by the IEA (2024):

"The strong comeback of nuclear energy must be underpinned by mechanisms ensuring predictability of future cash flows."

Operationally, this corresponds to treating new nuclear capacity as a must-run resource bidding at zero cost in the day-ahead market.

Under an energy-only market framework, the price conditions observed in 2024 indicate that a new nuclear investment would not be able to recover its full costs within time horizons compatible with the economic lifetime of the asset. Market prices exceed levels required for full cost recovery (on the order of 100–145 EUR/MWh) during only a limited share of annual hours, implying payback periods extending well beyond several decades. In practice, this means that new nuclear projects cannot be amortised through wholesale market revenues alone and require revenue-stabilisation

mechanisms to become financially viable. These mechanisms do not shorten the payback period but rather make cost recovery possible in the first place, reinforcing the conclusion that new nuclear cannot be assessed solely on the basis of spot market price signals.

Conclusion

The observed 2024 price distribution in Spain provides clear empirical evidence for the IEA's assertion that new nuclear requires out-of-market support mechanisms in liberalized electricity markets. Key conclusions:

1. Market prices exceed 45 EUR/MWh during roughly three-fifths of the year (61%), enabling existing nuclear plants with amortized capital to remain profitable.
2. Market prices exceed 100 EUR/MWh during only one-quarter of hours (26%), creating severe revenue shortfalls for new nuclear at mid-range cost assumptions.
3. Market prices exceed 145 EUR/MWh (Hinkley Point C benchmark) during 3% of hours (~260 hours annually), rendering full-cost recovery through energy-only markets economically unfeasible.
4. These reference levels provide a quantitative basis for understanding why nuclear investment requires predictable, non-market revenue streams such as Contracts-for-Difference or Regulated Asset Base models.
5. In liberalized markets with high renewable penetration, the increasing dominance of zero-marginal-cost generation in price formation creates a systematic revenue gap for capital-intensive baseload technologies like nuclear.

Implications for Subsequent Analysis

In the next chapter, new nuclear capacity is represented as a 0 EUR/MWh tranche within the Spanish supply curve. This approach follows the practical treatment of contract-protected nuclear output as zero-marginal-cost generation and enables assessment of how such additions modify overall price formation and affect the revenues of other technologies, particularly hydropower, whose generation remains directly exposed to spot-price variations.

This modeling choice reflects economic reality: subsidized or contract-protected nuclear operates as price-taker baseload, bidding at zero in day-ahead markets and displacing higher-cost generation from the merit order. The subsequent analysis quantifies how this supply-side intervention affects:

- Market clearing prices across all hours
- Run-of-river hydropower capture prices (non-dispatchable)

- Reservoir hydropower dispatch optimization and revenues (dispatchable)
- Pumped storage arbitrage opportunities (price spreads)

3. Impact of zero marginal cost nuclear on the Spanish Day Ahead Market

Chapter 4 established that new nuclear power plants cannot recover full investment costs in a liberalized electricity market dominated by low-marginal-cost renewables. To represent the situation in which such plants are nonetheless deployed under public-support mechanisms, we now model nuclear generation as zero-marginal-cost supply added to the market. The objective here is to assess how this additional baseload alters the aggregate supply–demand equilibrium and to quantify its effect on the market exposure of run-of-river hydropower, which operates continuously and cannot easily adjust output.

The analysis uses Spain's 2024 market data from OMIE as a proxy for a high-renewable European system representative of what Switzerland may experience within the next decade as discussed in the first section.

Nuclear Marginal Cost Scenarios

This analysis examines two distinct scenarios for nuclear deployment, reflecting different policy and financing contexts:

Zero Marginal Cost Nuclear (0 EUR/MWh)

This scenario represents new nuclear capacity operating under comprehensive out-of-market support mechanisms (Contract-for-Difference, Regulated Asset Base models) that guarantee full-cost recovery independent of wholesale market prices. From a market-clearing perspective, such plants behave as price-takers bidding at zero marginal cost. This represents the most aggressive form of subsidized baseload deployment.

Short-Run Marginal Cost Nuclear (45 EUR/MWh)

This scenario represents nuclear plants with fully or largely amortized capital costs, operating at their short-run marginal cost (SRMC). At 45 EUR/MWh, this reflects fuel cycle costs, variable operations and maintenance, and incremental wear-and-tear expenses. This scenario is relevant for:

- Life extension decisions for existing nuclear fleets
- Nuclear plants with partial capital recovery through past subsidies
- Assessment of existing nuclear competitiveness in spot markets

As shown in Chapter 2 (Figure 2.1), approximately 61% of Spanish market hours in 2024 (5,403 hours) exceeded 45 EUR/MWh, with a mean price during these hours of ~94 EUR/MWh. This indicates that SRMC nuclear operates during most hours but not continuously, creating different market impacts than zero-cost nuclear.

Methodology

OMIE Aggregate Supply-Demand Curves

Hourly aggregate supply and demand curves for the Spanish day-ahead electricity market were obtained from OMIE (Operador del Mercado Ibérico de Energía - Polo Español). For each hour of 2024, OMIE provides:

- Supply curve: Cumulative offered quantity (MWh) and corresponding bid prices (EUR/MWh)
- Demand curve: Cumulative requested quantity (MWh) and corresponding willingness-to-pay prices (EUR/MWh)
- Actual clearing price and traded volume from the market auction

These curves represent the aggregated bids from all market participants and are published post-auction as part of OMIE's market transparency requirements. The curves follow a step-function format where each step represents a bid block at a specific price level.

Merit Order Price Reconstruction Model

Market Clearing Mechanism

The electricity market clearing price is determined by the intersection of aggregate supply and demand curves. At the clearing point, the quantity supplied equals the quantity demanded, and the *marginal supply bid* (last unit needed to meet demand) sets the market price.

The clearing point (Q*,P*) satisfies:

$S(P^*) = D(P^*) = Q^*$

where S(P) is the supply function (quantity offered at price P) and D(P) is the demand function (quantity requested at price P).

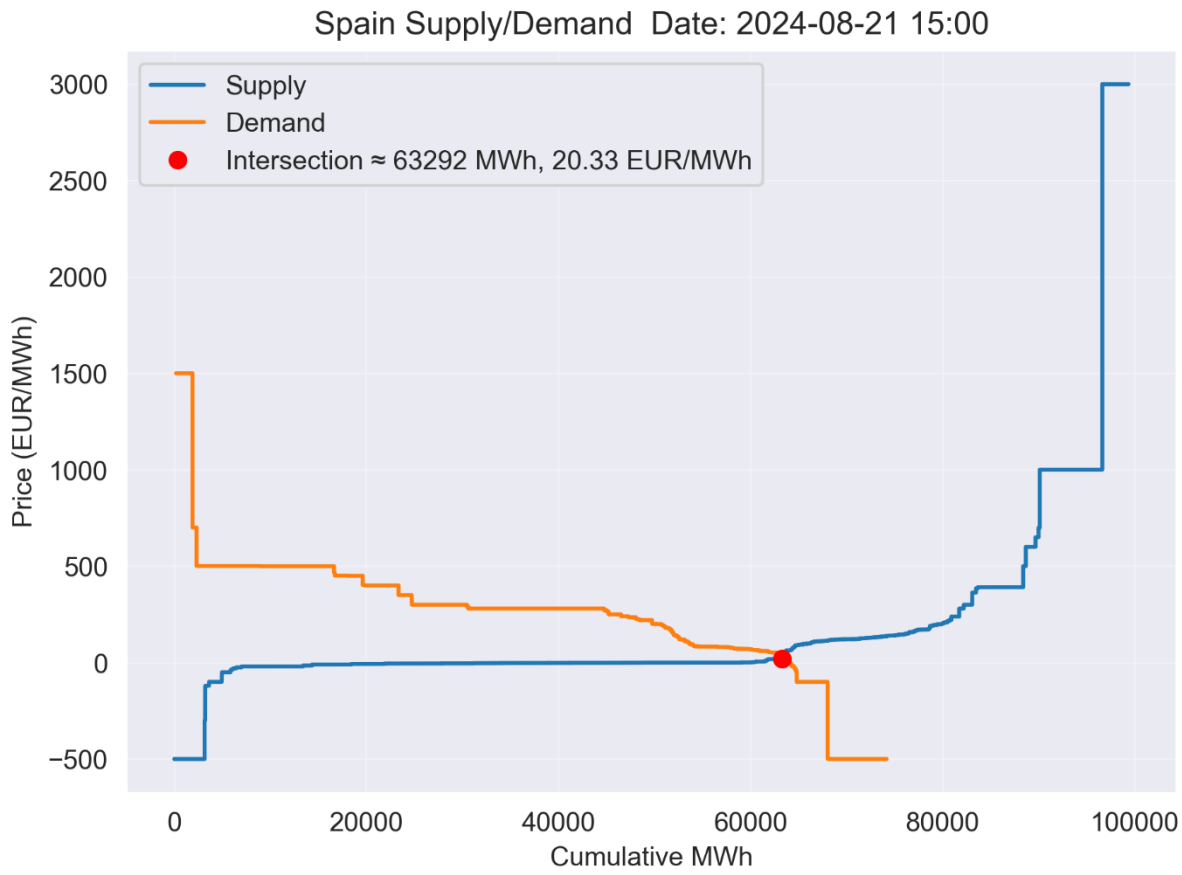


Figure 3.1: Example Merit Order with supply and demand (bids). Clearing price is found as the intersection of these two curves. These are generated for every hour for the day ahead market in spain for the year 2024.

Nuclear Addition Simulation

Supply Curve Modification

Nuclear baseload generation is simulated by adding a supply block at either zero marginal cost (0 EUR/MWh) or SRMC of 45 EUR/MWh to the merit order stack. This reflects the operational characteristic of nuclear plants where marginal generation costs (primarily fuel) are near zero, and the plants operate as baseload due to technical and economic constraints.

The modified supply curve S'(P) is constructed as:

$S'(P) = S(P) + Q_{nuclear} \quad \text{for } P \geq 0$

where $Q_{nuclear}$ is the additional nuclear capacity (1.6 GW and 3.2 GW). For hourly resolution, MW equals MWh.

Implementation procedure:

1. Extract incremental supply blocks (price, quantity pairs) from original curve
2. Add nuclear block: (price = 0 EUR/MWh, quantity = Q_nuclear MWh)
3. Aggregate blocks by price level (sum quantities at same price)
4. Sort blocks by ascending price
5. Recompute cumulative quantities to create modified supply curve

Merit Order Effect

Adding nuclear supply shifts the supply curve rightward, resulting in a merit order effect where:

- Lower-cost generation displaces higher-cost generation
- The marginal generator shifts to a lower-cost technology
- Market clearing price decreases

The price reduction is most pronounced during hours when the original marginal generator has high costs (e.g., gas peaking plants during high-demand periods). During hours when renewable generation already provides low-cost supply, the incremental price impact of nuclear addition is smaller.

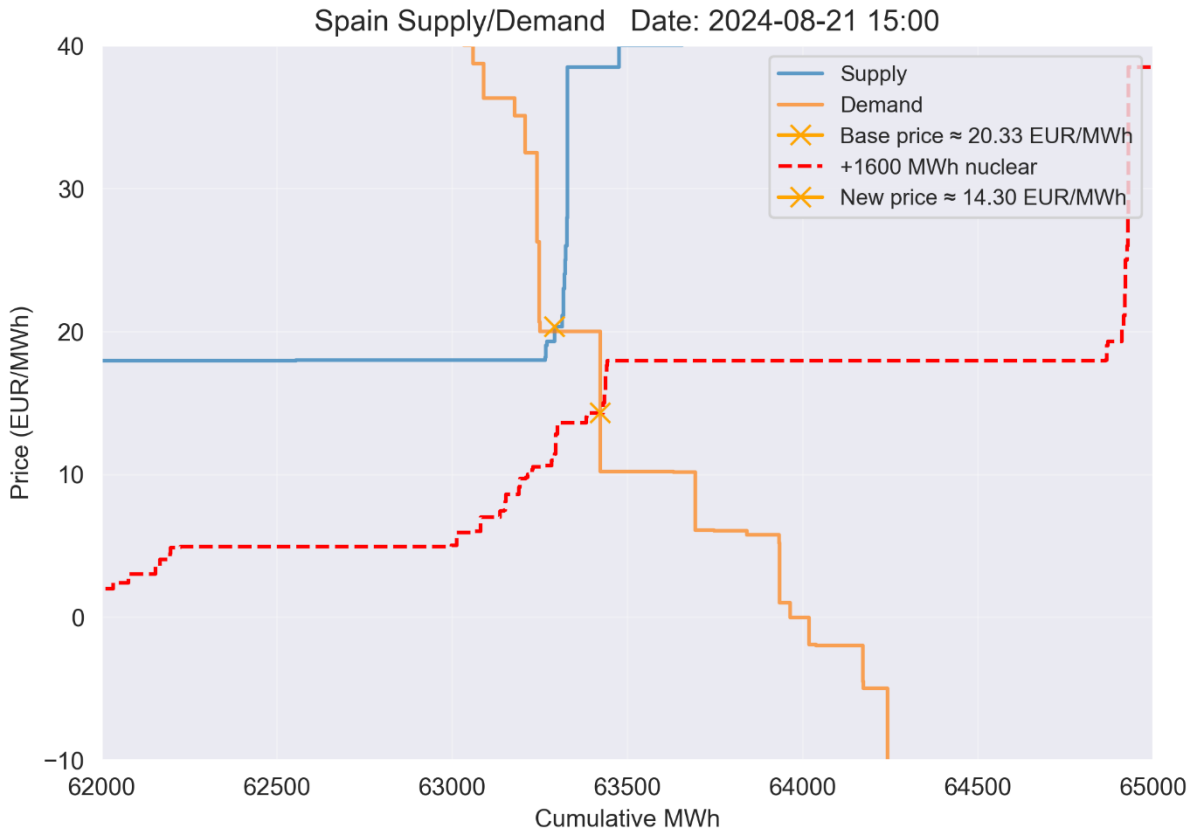


Figure 3.2: Zoom on the Merit order to show the impact of adding a nuclear tranche

Nuclear Capacity Scenarios

Three scenarios were evaluated for comparison:

1. Baseline: No nuclear addition (reconstruction of actual 2024 market)
2. Nuclear 1600 MW: Single EPR-type reactor (1,600 MW capacity)
3. Nuclear 3200 MW: Two EPR-type reactors (3,200 MW capacity)

For each scenario, hourly clearing prices were recomputed for all 8,784 hours of 2024 (366 days in leap year)

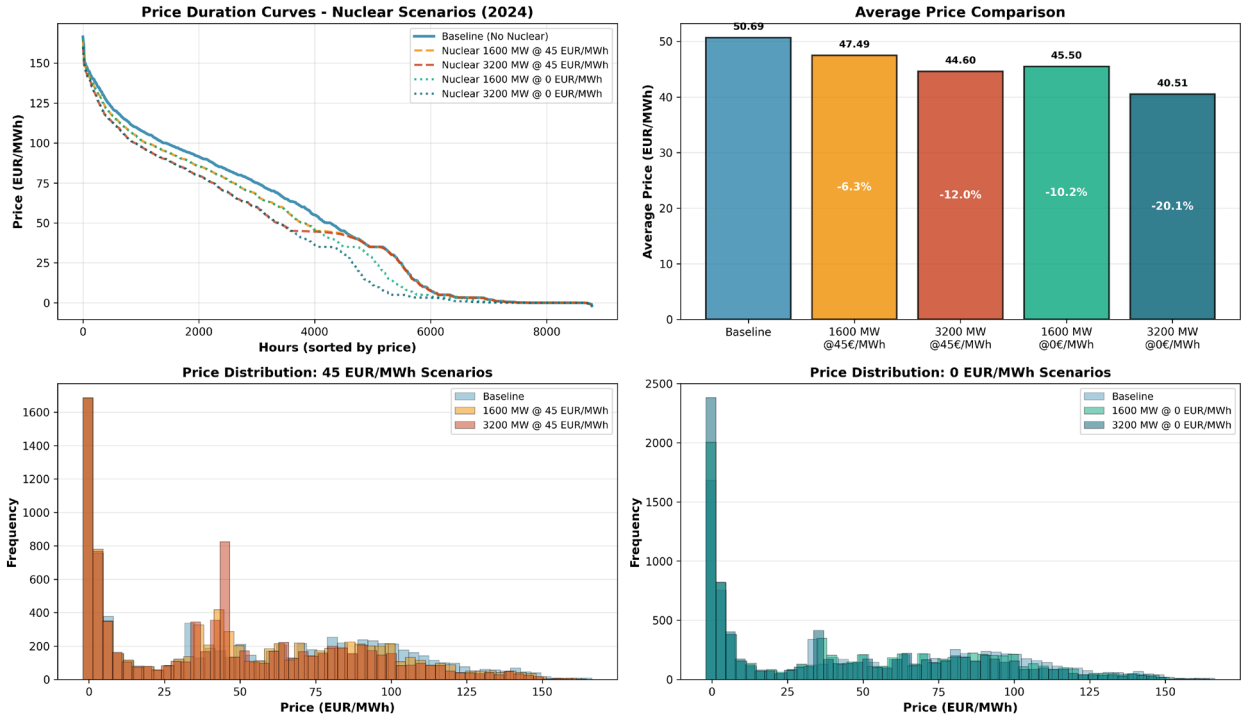


Figure 3.3: Price Duration Curves: Nuclear Scenario Comparison with zero marginal cost nuclear (0 EUR/MWh) and SRMC nuclear (45 EUR/MWh) added to the 2024 Spanish merit order.

Model Assumptions and Limitations

The merit order simulation incorporates several simplifying assumptions:

- Static demand: Demand curves remain unchanged when nuclear is added (no demand response to price changes)
- Perfect competition: All generators bid at marginal cost with no strategic behavior
- No capacity constraints: Existing generators can adjust output instantaneously (no ramping constraints)
- No transmission constraints: Power flows freely within the bidding zone (no congestion)

These assumptions provide a tractable first-order approximation of price impacts. In reality, demand may exhibit some price elasticity, generators may adapt bidding strategies, and transmission congestion could create locational price differences. However, for long-term profitability analysis of hydropower resources, the simplified merit order approach captures the primary price suppression mechanism and allows for a comparison of various scenarios.

4. Impact of New Nuclear on Hydropower Profitability

Overview and Approach

Having established that new nuclear requires out-of-market revenue support to be viable (Section 2), this chapter examines the consequence of nuclear addition on existing hydropower resources. This supply-side intervention systematically suppresses market clearing prices, creating negative externalities for other generators, whose revenues remain directly exposed to spot price fluctuations.

The analysis quantifies profitability impacts for three distinct hydropower technologies using Spain's 2024 market as a test case:

- Run-of-River: Non-dispatchable continuous generation with minimal storage capability. Profitability is calculated using the "capture price" methodology (Hirth, 2013), which measures the generation-weighted average electricity price. Representative plant: 100 MW capacity, 7.1 EUR/MWh marginal cost. Swiss fleet: 4,200 MW total capacity.
- Reservoir: Dispatchable generation with seasonal energy storage, optimizing dispatch based on price signals. The optimization follows energy-constrained dispatch methods (Geth et al., 2015), where plants maximize revenue by generating at full capacity during the highest-price hours within their annual energy budget. Representative plant: 57 MW capacity, 100 GWh/year energy budget, 12.8 EUR/MWh marginal cost. Swiss fleet: 7,500 MW capacity, 25 TWh/year energy budget.
- Pumped Storage: Energy arbitrage through price spread exploitation, with pumping during low-price periods and generation during high-price periods (Connolly et al., 2011). Representative plant: 900 MW power rating, 3.6 GWh storage, 75% round-trip efficiency, 15.8 EUR/MWh marginal cost. Swiss fleet: 1,600 MW power rating, 8 GWh storage.

Capacity values represent maximum observed generation from ENTSO-E Transparency Platform for the year 2024 (ENTSO-E 2024), rounded to nearest hundred MW. Marginal costs of production are taken for example hydropowerplants of each category as reported in (Barry et al. 2015).

Two nuclear capacity scenarios are examined: 1,600 MW, corresponding to a single large EPR-type reactor, and 3,200 MW, corresponding to two such units. These values are consistent with the net electrical capacities of recent EPR projects, such as Flamanville 3 in France, Olkiluoto 3 in Finland, and the Taishan units in China, which each have capacities on the order of 1.6 GW. The resulting additions represent

approximately 3.5% and 7% of Spain's 2024 peak demand, respectively, and are chosen to reflect realistic reactor sizes while remaining small relative to total system demand. Detailed methodology is provided in Appendix D.

Summary of Profitability Impacts

Table 4.1 presents the comprehensive impact assessment for Switzerland's entire hydropower fleet.

The baseline scenario represents the 2024 Spanish electricity market without additional nuclear capacity. This scenario uses actual observed market conditions: hourly day-ahead clearing prices from OMIE (Spanish market operator), historical generation patterns, and existing supply-demand dynamics. The baseline establishes reference profitability levels for each hydropower technology under current high-renewable market conditions (>60% solar and wind penetration), against which nuclear addition scenarios are compared.

Spain's 2024 market serves as a proxy for Europe's likely structure within 5-10 years, as discussed in Section 1. The baseline thus represents not only Spain's current state, but a forward-looking view of Swiss market exposure once continental European renewable penetration reaches similar levels.

(a) Addition of 1600 MW Nuclear

Technology	*Capacity (MW)*	*Baseline Profit (M€)*	*1600MW @ 0 €/MWh (M€)*	*Δ (M€/yr) / Δ (%)*	*1600MW @ 45 €/MWh (M€)*	*Δ (M€/yr) / Δ (%)*
Run-of-River	4,200	1,049	705	-344 (-32.8%)	744	-304(-29.0%)
Reservoir	7,500	2,477	2,025	-452 (-18.3%)	2,025	-452(-18.3%)
Pumped Storage	1,600	101	97	-4 (-3.8%)	92	-9(-8.9%)
TOTAL	13,300	3,627	2,827	-800(-22.1%)	2,861	-766(-21.1%)

(b) Addition of 3200 MW Nuclear

Technology	*Capacity (MW)*	*Baseline Profit (M€)*	*3200MW @ 0 €/MWh (€)*	*Δ (M€/yr) / Δ (%)*	*3200MW @ 45 €/MWh (M€)*	*Δ (M€/yr) / Δ (%)*
Run-of-River	4,200	1,049	608	-441 (-42.1%)	690	-358 (-34.2%)
Reservoir	7,500	2,477	1,874	-603 (-24.3%)	1,874	-603 (-24.3%)
Pumped Storage	1,600	101	99	-2 (-2.1%)	89	-11 (-11.1%)
TOTAL	13,300	3,627	2,581	-1,046 (-28.8%)	2,653	-972 (-26.8%)

Representative Plant Analysis: Zero-Cost Nuclear (0 EUR/MWh)

This section presents profitability impacts on representative hydropower plants under zero-cost nuclear scenarios, where nuclear generation bids into the market at 0 EUR/MWh regardless of actual operational costs.

Run-of-River Hydropower

Figure 4.1 presents the profitability analysis for a representative 100 MW run-of-river plant under zero-cost nuclear scenarios. The baseline net profit is €24.90 million annually, with a capture price of €57.15/MWh. Under the 1600 MW nuclear scenario, net profit decreases to €16.74 million, representing a -32.8% reduction. The 3200 MW scenario results in €14.44 million net profit, a -42.0% decrease from baseline.

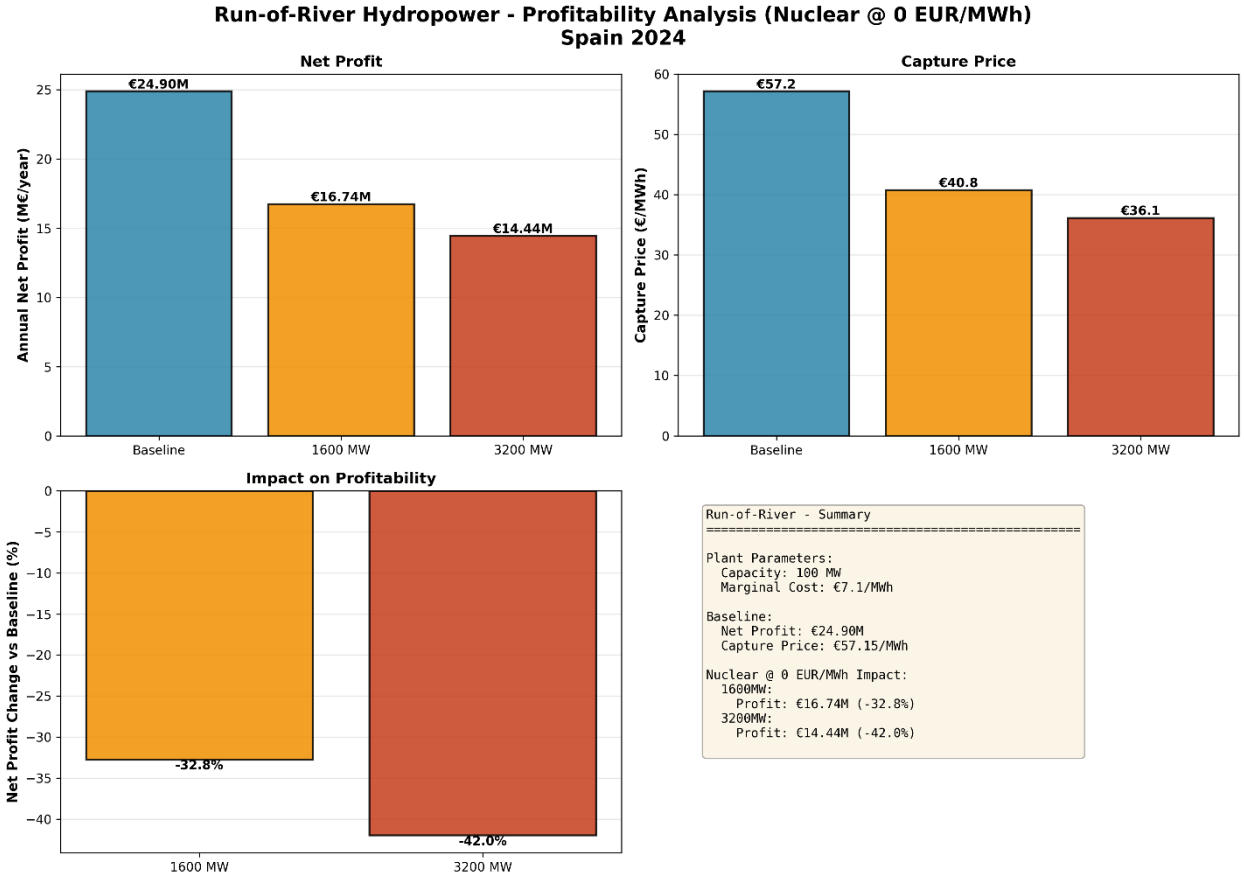


Figure 4.1: Run-of-river hydropower profitability under zero-cost nuclear scenarios (0 EUR/MWh). Left panels show absolute profit and capture price values; lower left panel displays percentage change from baseline; right panel summarizes plant parameters and results.

The profitability reduction in run-of-river facilities under zero-cost nuclear reflects the non-dispatchable nature of this technology. Unlike reservoir or pumped storage facilities, run-of-river plants cannot adjust output timing to avoid low-price periods

created by baseload nuclear generation. The capture price decreases from €57.15/MWh at baseline to €40.80/MWh (1600 MW) and €36.10/MWh (3200 MW), indicating systematic price suppression during generation hours.

The capture price is the revenue-weighted average market price received by a generator for its actual production. Mathematically:

Capture Price = Total Revenue / Total Generation (MWh)

For run-of-river hydropower, the capture price typically differs from the average market price because generation is determined by water availability rather than price signals. Unlike dispatchable technologies that can concentrate generation during high-price hours, run-of-river plants operate continuously when water flows, regardless of market conditions.

Reservoir Hydropower

Figure 4.2 presents results for a representative 57 MW reservoir facility with a 100 GWh annual energy budget. Baseline net profit is €11.41 million with an average dispatch price of €126.97/MWh. The 1600 MW zero-cost nuclear scenario reduces net profit to €9.73 million (-14.8% change), while the 3200 MW scenario yields €9.27 million (-18.8% change).

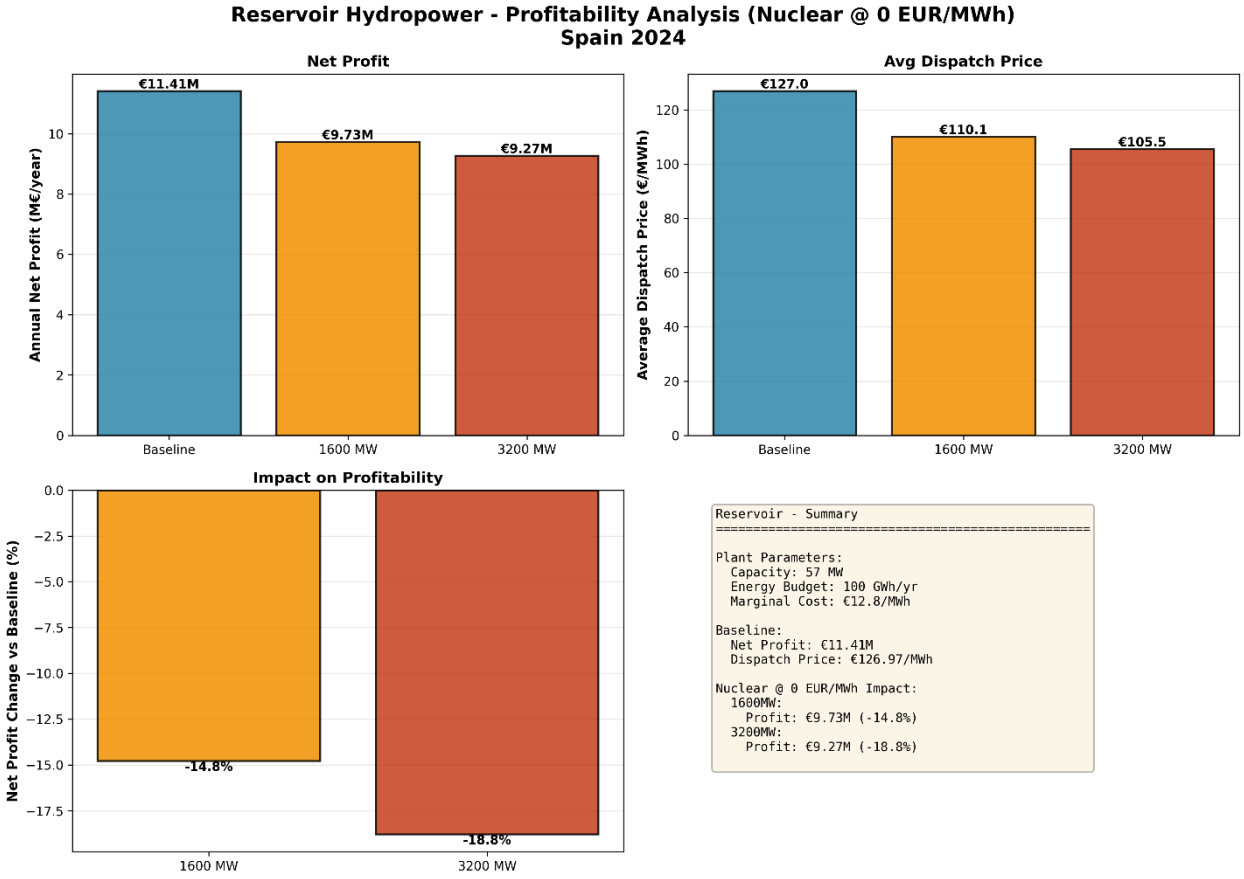


Figure 4.2: Reservoir hydropower profitability under zero-cost nuclear scenarios (0 EUR/MWh). Displays net profit, average dispatch price, percentage changes, and operational parameters.

Reservoir facilities demonstrate moderate resilience through dispatch optimization. The average dispatch price decreases from €126.97/MWh to €110.08/MWh (1600 MW) and €105.50/MWh (3200 MW). While absolute price levels decline, reservoir operators partially mitigate losses by concentrating dispatch during remaining high-price periods. The proportionally smaller profit reduction compared to run-of-river (-15% to -19% versus -33% to -42%) demonstrates the value of dispatch flexibility in managing baseload nuclear impacts.

Pumped Storage

Figure 4.3 shows profitability for a representative 900 MW / 3.6 GWh pumped storage facility with 75% round-trip efficiency. Baseline annual revenue is €50.89 million, with an average daily spread of €62.9/MWh across 361 profitable days. Under 1600 MW zero-cost nuclear, revenue changes to €47.94 million (-5.8%), with 356 profitable days. The 3200 MW scenario yields €48.90million (-3.9%), with 361 profitable days.

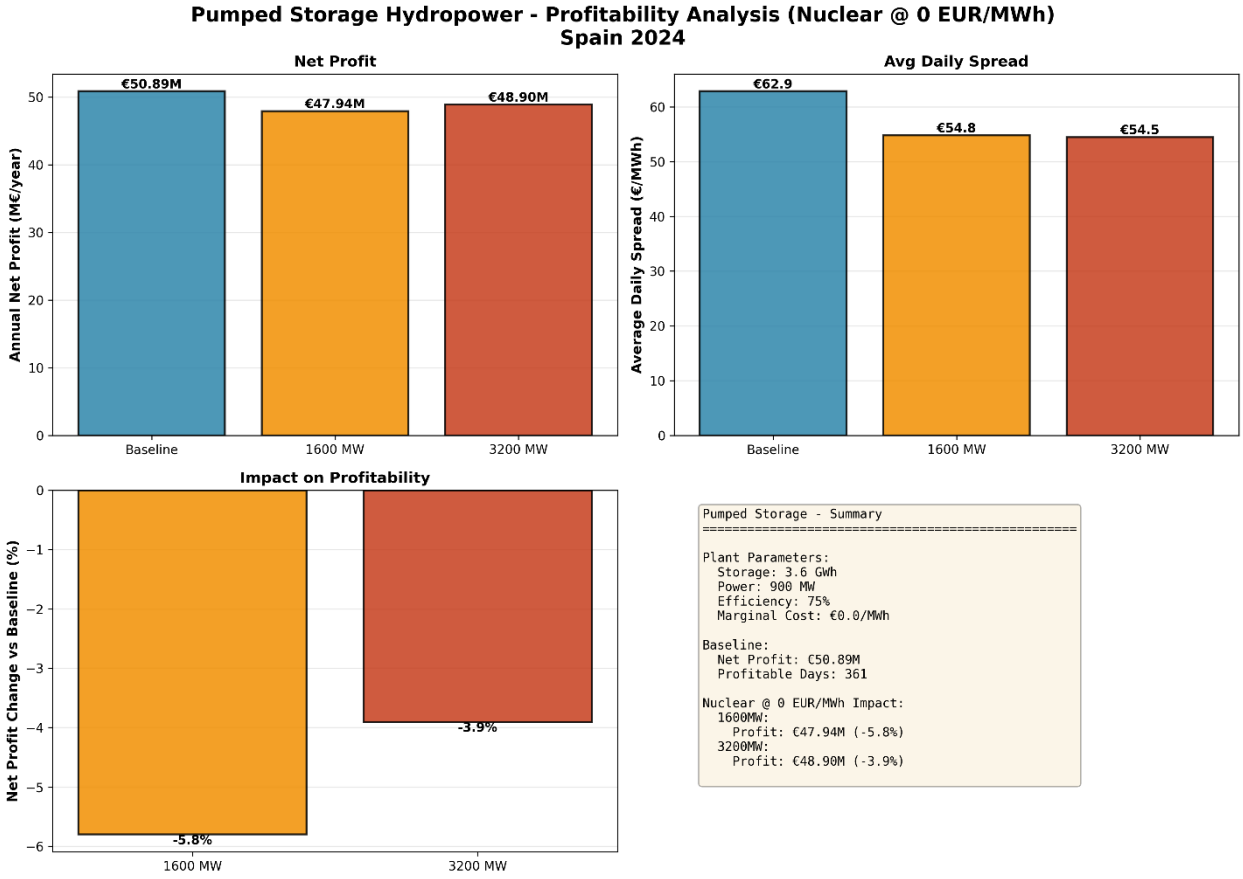


Figure 4.3: Pumped storage profitability under zero-cost nuclear scenarios (0 EUR/MWh). Shows total revenue, average daily price spreads, and impact on profitability.

Pumped storage demonstrates relative resilience under zero-cost nuclear scenarios, with revenue reductions of 5.8% to 3.9%. This limited impact reflects the arbitrage nature of pumped storage operations. Zero-cost baseload nuclear primarily acts as a downward shift of the overall price level rather than a fundamental alteration of the price structure. As a result, daily price spreads (on which pumped storage profitability depends) are comparatively preserved evenas average prices decline. The maintenance of profitable days near baseline levels (356-361 versus 361 baseline) indicates that daily cycling opportunities persist despite baseload nuclear presence.

Representative Plant Analysis: Short-Run Marginal Cost Nuclear (45 EUR/MWh)

This section examines profitability impacts under nuclear scenarios with 45 EUR/MWh marginal cost, representing conventional SRMC-based market participation by existing nuclear facilities.

Run-of-River Hydropower

Figure 4.4 presents run-of-river profitability under SRMC nuclear scenarios. Baseline conditions yield €24.90 million annual profit with a €57.15/MWh capture price. The 1600 MW SRMC nuclear scenario reduces profit to €17.70 million (-28.9% change), while 3200 MW yields €16.41 million (-34.1% change).

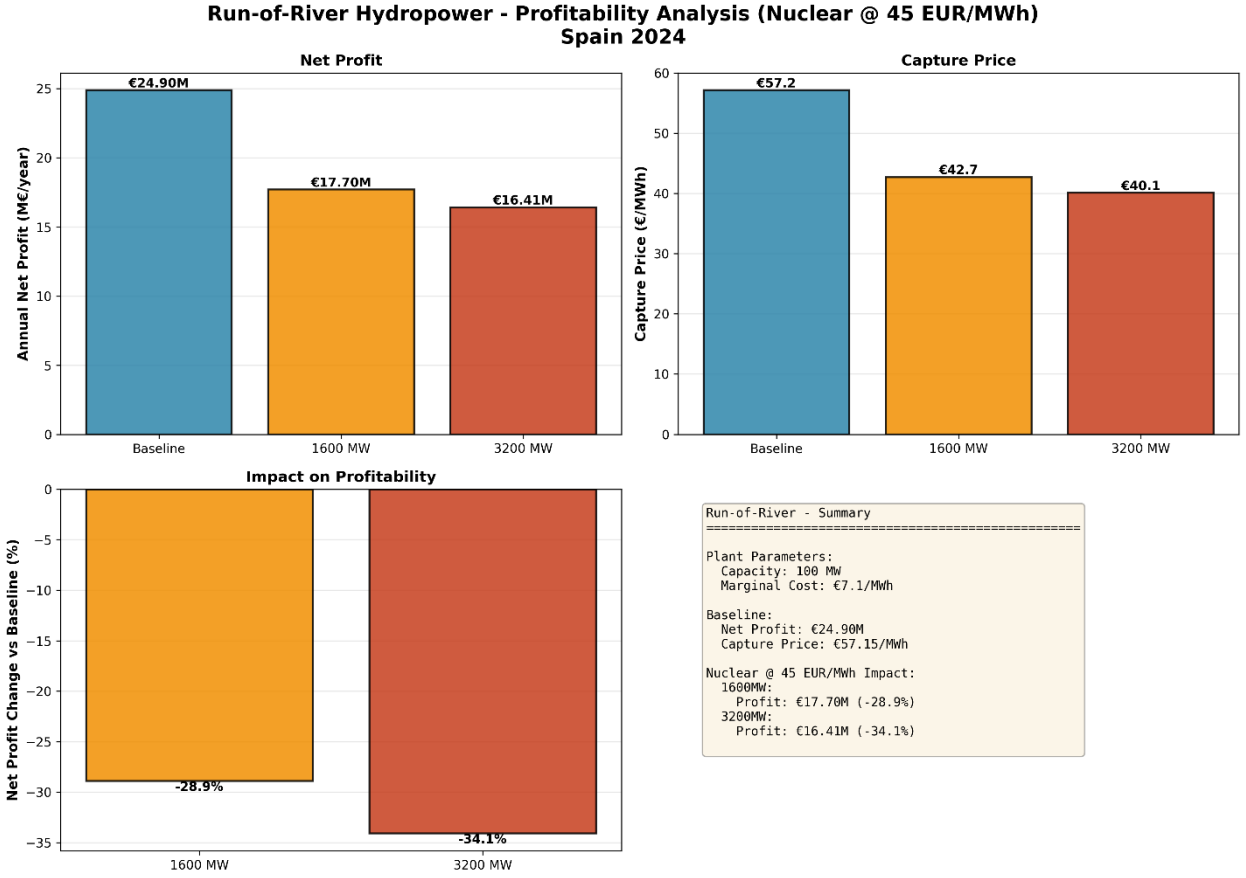


Figure 4.4: Run-of-river hydropower profitability under SRMC nuclear scenarios (45 EUR/MWh). Layout identical to Figure 4.1 for direct comparison of nuclear cost assumptions.

Comparing Figures 4.1 and 4.4 reveals differential impacts based on nuclear marginal cost. Under SRMC nuclear (45 EUR/MWh), the 3200 MW scenario reduces run-of-river profit by 34.1%, compared to 42.0% under zero-cost nuclear. The capture price decreases to €42.70/MWh (1600 MW) and €40.11/MWh (3200 MW), representing

smaller reductions than under zero-cost nuclear (€40.73/MWh and €36.20/MWh respectively). This difference reflects the price floor effect: SRMC nuclear at 45 EUR/MWh prevents market clearing prices from falling below this level during many hours, whereas zero-cost nuclear permits prices approaching zero.

Reservoir Hydropower

Figure 4.5 presents reservoir profitability under SRMC nuclear. Baseline net profit is €11.41 million with average dispatch price €126.97/MWh. The 1600 MW scenario yields €9.73 million (-14.8% change), while 3200 MW results in €9.27 million (-18.8% change).

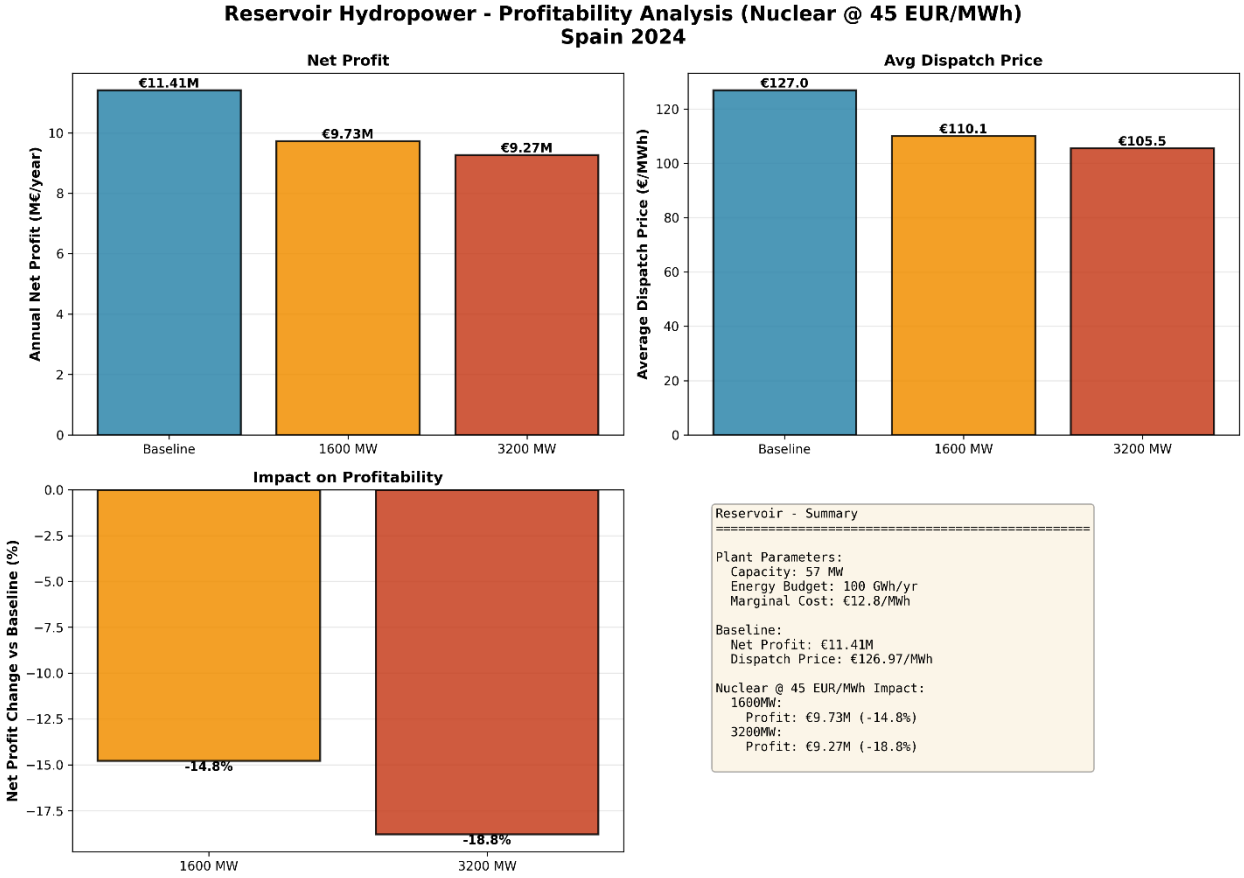


Figure 4.5: Reservoir hydropower profitability under SRMC nuclear scenarios (45 EUR/MWh).

A notable observation emerges when comparing reservoir impacts across nuclear cost assumptions (Figures 4.2 and 4.5): profit reductions are identical at 14.8% (1600 MW) and 18.8% (3200 MW) for both zero-cost and SRMC nuclear scenarios. Average dispatch prices are likewise identical: €110.08/MWh (1600 MW) and €105.50/MWh (3200 MW) under SRMC nuclear versus €110.08/MWh and €105.50/MWh under zero-cost nuclear. This suggests that reservoir dispatch optimization selects the same hours for generation regardless of nuclear marginal cost, targeting the highest-price periods where nuclear does not set the market clearing price in either scenario.

Pumped Storage

Figure 4.6 presents pumped storage profitability under SRMC nuclear. Baseline revenue is €50.89 million annually with average spread €62.9/MWh across 361 profitable days. Under 1600 MW SRMC nuclear, revenue decreases to €45.54 million (-10.5% change) with 356 profitable days. The 3200 MW scenario yields €44.44 million (-12.7% change) with 361 profitable days.

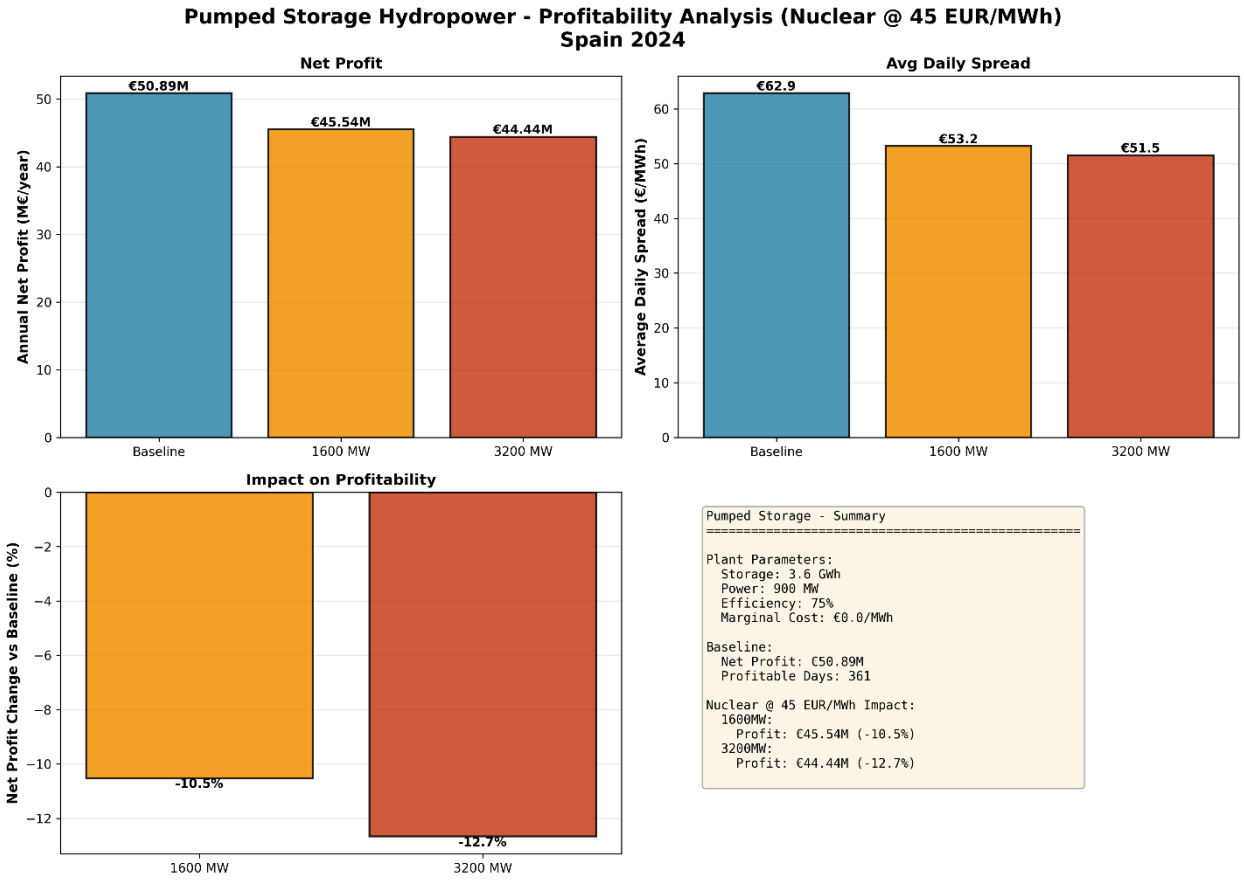


Figure 4.6: Pumped storage profitability under SRMC nuclear scenarios (45 EUR/MWh).

Pumped storage exhibits contrasting behaviour across nuclear cost assumptions. Under SRMC nuclear (45 EUR/MWh), revenue losses reach 10.5% to 12.7%, exceeding the 5.8% to 3.9% losses under zero-cost nuclear (Figure 4.3). This difference stems from how each assumption affects arbitrage spreads. Zero-cost nuclear can depress prices across many hours, including peak periods; however, it tends to push off-peak prices closer to zero more frequently, which can preserve (and in some cases widen) diurnal spreads relevant for arbitrage. By contrast, SRMC nuclear (45 EUR/MWh) introduces an effective price floor during baseload hours, lifting off-peak prices toward 45 EUR/MWh while still exerting downward pressure on peak prices through additional baseload availability. This combination compresses price

spreads (e.g., €49.45/MWh at 3200 MW SRMC versus €52.22/MWh at 3200 MW zero-cost), directly constraining arbitrage profitability.

Swiss National Hydro Fleet Analysis: Zero-Cost Nuclear (0 EUR/MWh)

This section scales the analysis to the Swiss national hydropower fleet, comprising 4,200 MW run-of-river, 7,500 MW reservoir, and 1,600 MW pumped storage capacity. Capacity and energy budget estimates are derived from 2024 observed generation patterns in the ENTSO-E transparency platform (maximum generation). All profitability calculations use Spanish market prices to assess cross-border market impacts.

Run-of-River Fleet

Figure 4.7 presents the Swiss run-of-river fleet profitability under zero-cost nuclear. Baseline annual profit is €1.05 billion with capture price €57.15/MWh and 20.9 TWh annual generation. The 1600 MW scenario reduces profit to €0.70 billion (-32.8% change, €-344 million absolute loss). The 3200 MW scenario yields €0.61 billion (-42.0% change, €-441 million absolute loss).

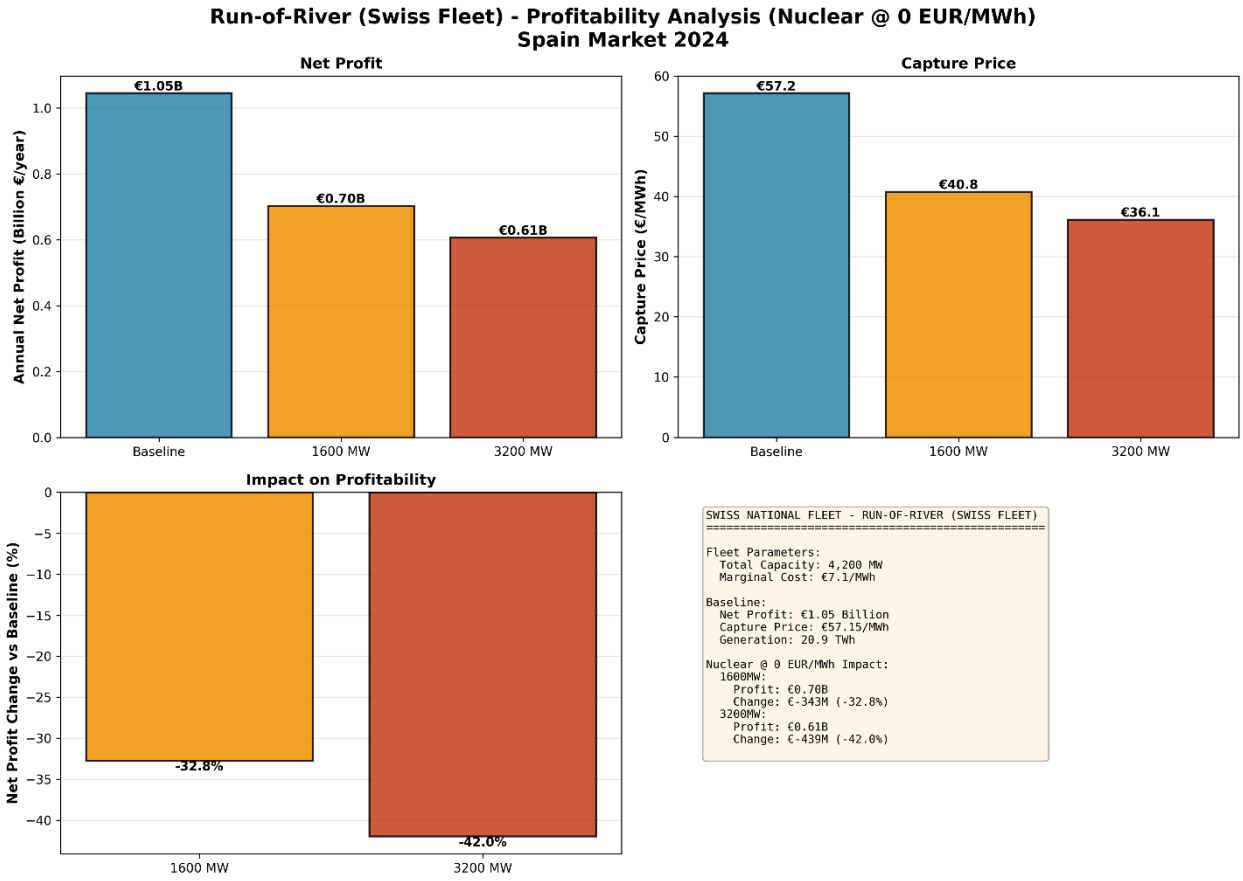


Figure 4.7: Swiss run-of-river fleet profitability under zero-cost nuclear (0 EUR/MWh). Values in billions EUR reflect national-scale operations.

The Swiss run-of-river fleet exhibits the most severe profitability erosion among all technologies examined, with the 3,200 MW nuclear scenario generating annual losses

of €441 million relative to the baseline case without additional nuclear capacity. This substantial impact reflects the non-dispatchable nature of run-of-river generation combined with the significant installed capacity (4,200 MW producing 20.9 TWh annually). The capture price decline from €57.30/MWh to €36.22/MWh under the 3,200 MW zero-cost nuclear scenario indicates systematic suppression of revenues across all generation hours.

Reservoir Fleet

Figure 4.8 shows Swiss reservoir fleet profitability under zero-cost nuclear. The baseline annual profit is €2.48 billion with average dispatch price €111.90/MWh across 3,333 dispatched hours. The 1600 MW scenario reduces profit to €2.02 billion (-18.3% change, €452 million loss). The 3200 MW scenario yields €1.87 billion (-24.3% change, €603 million loss).

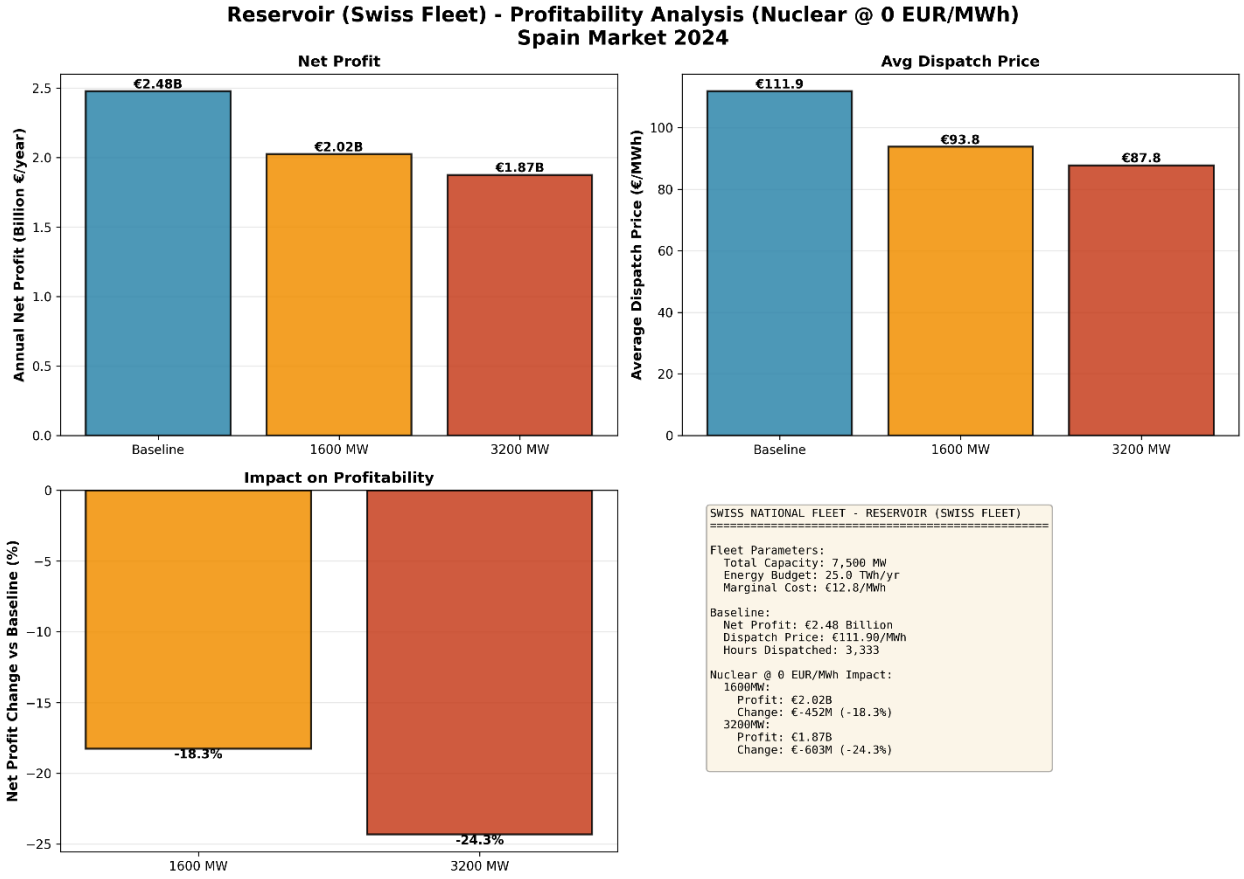


Figure 4.8: Swiss reservoir fleet profitability under zero-cost nuclear (0 EUR/MWh). Represents 7,500 MW capacity with 25 TWh/year energy budget.

The Swiss reservoir fleet represents the largest component of Swiss hydro profitability (€2.48 billion baseline) and experiences substantial absolute losses under zero-cost nuclear scenarios (€452 million at 1600 MW, €603 million at 3200 MW). However, proportional impacts (18.3% to 24.3%) remain more moderate than run-of-river losses, demonstrating the value of dispatch optimization in mitigating baseload nuclear impacts. The dispatch price reduction from €111.90/MWh to €87.79/MWh (3200 MW) reflects concentrated generation during peak periods where prices remain elevated.

Pumped Storage Fleet

Figure 4.9 presents Swiss pumped storage fleet profitability under zero-cost nuclear. Baseline revenue is €0.11 billion annually across 360days. The 1600 MW scenario yields €0.10 billion (-3.9% change)The 3200 MW scenario produces €0.10 billion (-2.1% change)

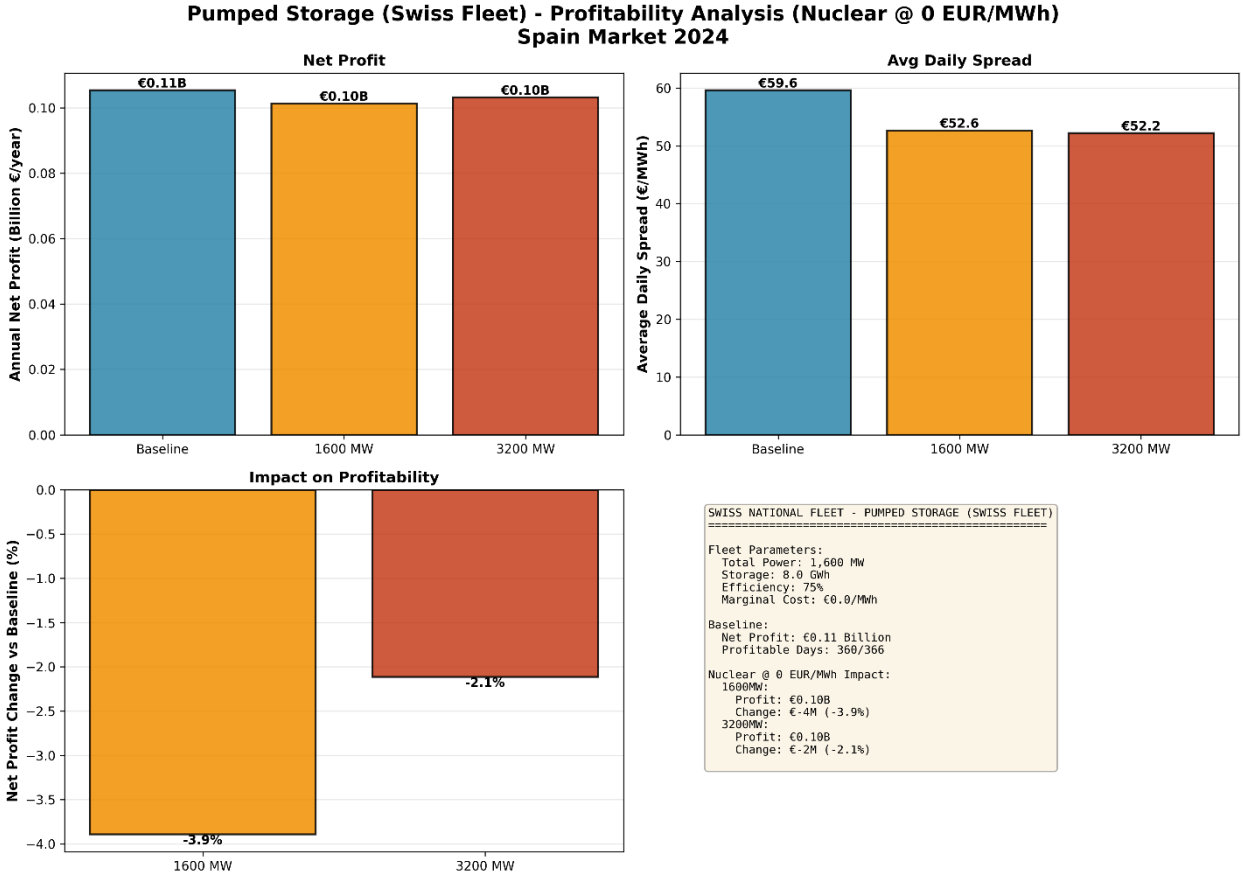


Figure 4.9: Swiss pumped storage fleet profitability under zero-cost nuclear (0 EUR/MWh). Fleet comprises 1,600 MW power rating with 8 GWh storage capacity.

The Swiss pumped storage fleet demonstrates notable resilience under zero-cost nuclear, with revenue reductions of only 3.9% to 2.1%. Absolute losses (€4-2 million) are minimal compared to run-of-river and reservoir impacts. This resilience reflects the preservation of arbitrage opportunities under zero-cost baseload generation, where amplified diurnal spreads maintain cycling profitability. The maintenance of profitable days near baseline confirms that daily arbitrage opportunities persist despite baseload nuclear presence.

Swiss National Hydro Fleet Analysis: SRMC Nuclear (45 EUR/MWh)

This section examines Swiss fleet profitability under SRMC nuclear scenarios, enabling assessment of how conventional nuclear market participation affects national-scale hydropower economics.

Run-of-River Fleet

Figure 4.10 presents Swiss run-of-river fleet profitability under SRMC nuclear. Baseline profit is €1.05 billion with capture price €57.28/MWh. The 1600 MW scenario reduces profit to €0.74 billion (-29% change, €304 million loss). The 3200 MW scenario yields €0.69 billion (-34.1% change, €358 million loss).

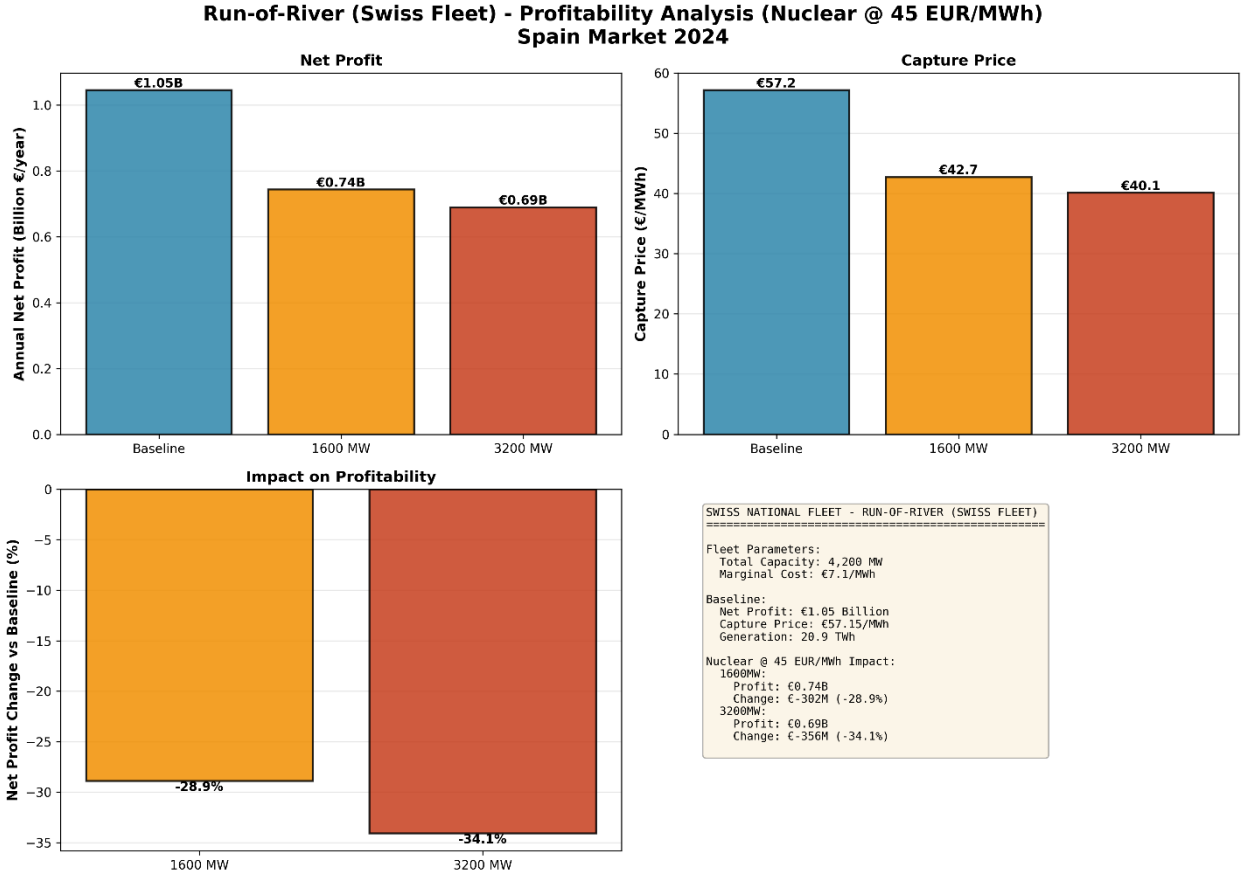


Figure 4.10: Swiss run-of-river fleet profitability under SRMC nuclear (45 EUR/MWh).

Comparing Figures 4.7 and 4.10 reveals moderating effects of SRMC nuclear relative to zero-cost scenarios. Under 3200 MW SRMC nuclear, run-of-river losses reach €358 million (34.2%), compared to €441 million (42.1%) under zero-cost nuclear. The capture price decreases to €40.11/MWh (SRMC) versus €36.22/MWh (zero-cost), demonstrating the price floor effect of 45 EUR/MWh nuclear bidding. Nevertheless,

absolute losses remain substantial (€358 million annually), representing significant value erosion for Swiss run-of-river operators.

Reservoir Fleet

Figure 4.11 shows Swiss reservoir fleet profitability under SRMC nuclear. Baseline profit is €2.48 billion with dispatch price €111.90/MWh. The 1600 MW scenario yields €2.02 billion (-18.3% change, €452 million loss). The 3200 MW scenario produces €1.87 billion (-24.3% change, €603 million loss).

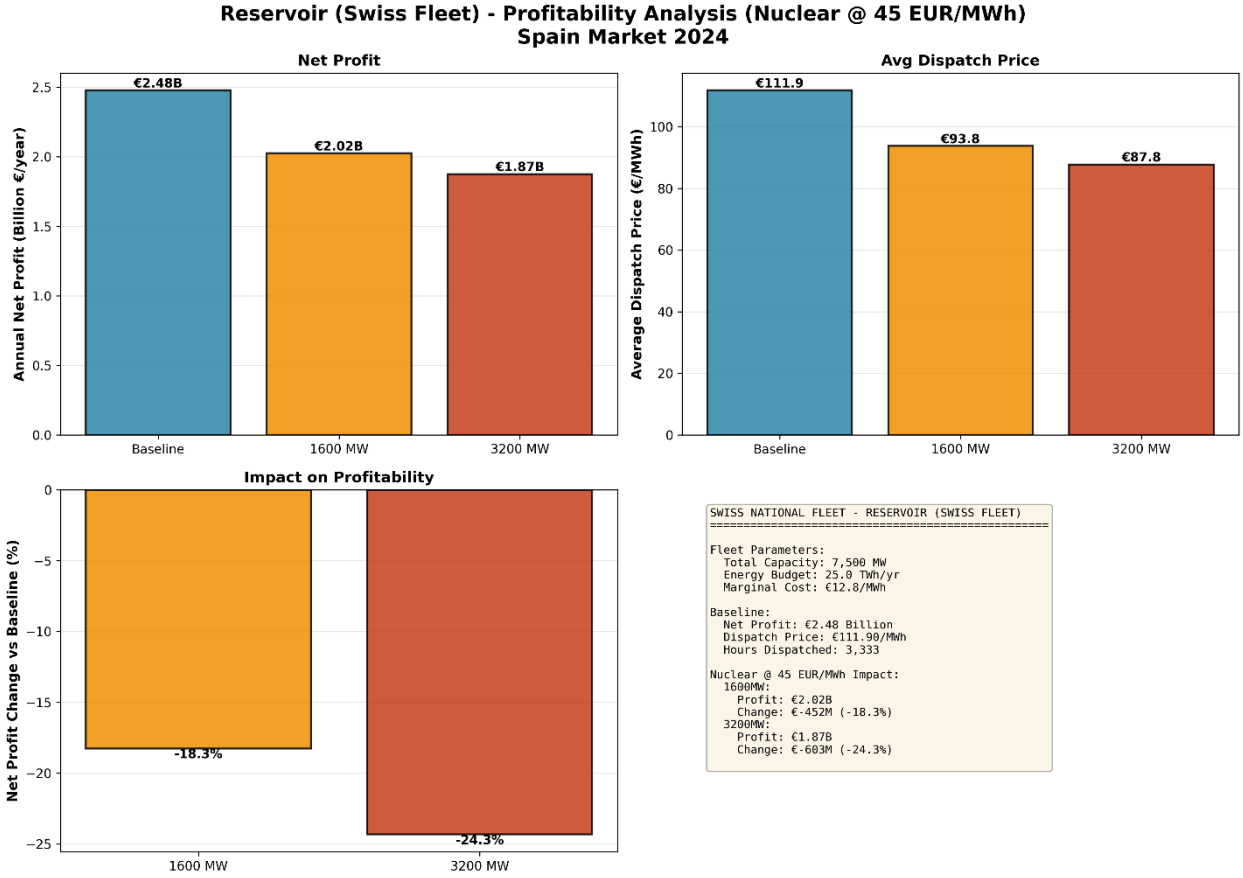


Figure 4.11: Swiss reservoir fleet profitability under SRMC nuclear (45 EUR/MWh).

Consistent with individual plant results (Section 3.2), Swiss reservoir fleet impacts are identical across nuclear cost assumptions: 18.3% loss at 1600 MW and 24.3% at 3200 MW under both zero-cost and SRMC nuclear. Absolute losses (€452 million at 1600 MW, €603 million at 3200 MW) likewise match across scenarios. This insensitivity to nuclear marginal cost confirms that reservoir optimization targets scarcity pricing periods where neither zero-cost nor SRMC nuclear sets marginal prices. The identical dispatch prices (€93.80/MWh at 1600 MW, €87.78/MWh at 3200 MW) across both nuclear cost scenarios support this interpretation.

Pumped Storage Fleet

Figure 4.12 presents Swiss pumped storage fleet profitability under SRMC nuclear. Baseline revenue is €0.105 billion. The 1600 MW scenario yields €0.096 billion (-8.9% change The 3200 MW scenario produces €0.093 billion (-11.2% change

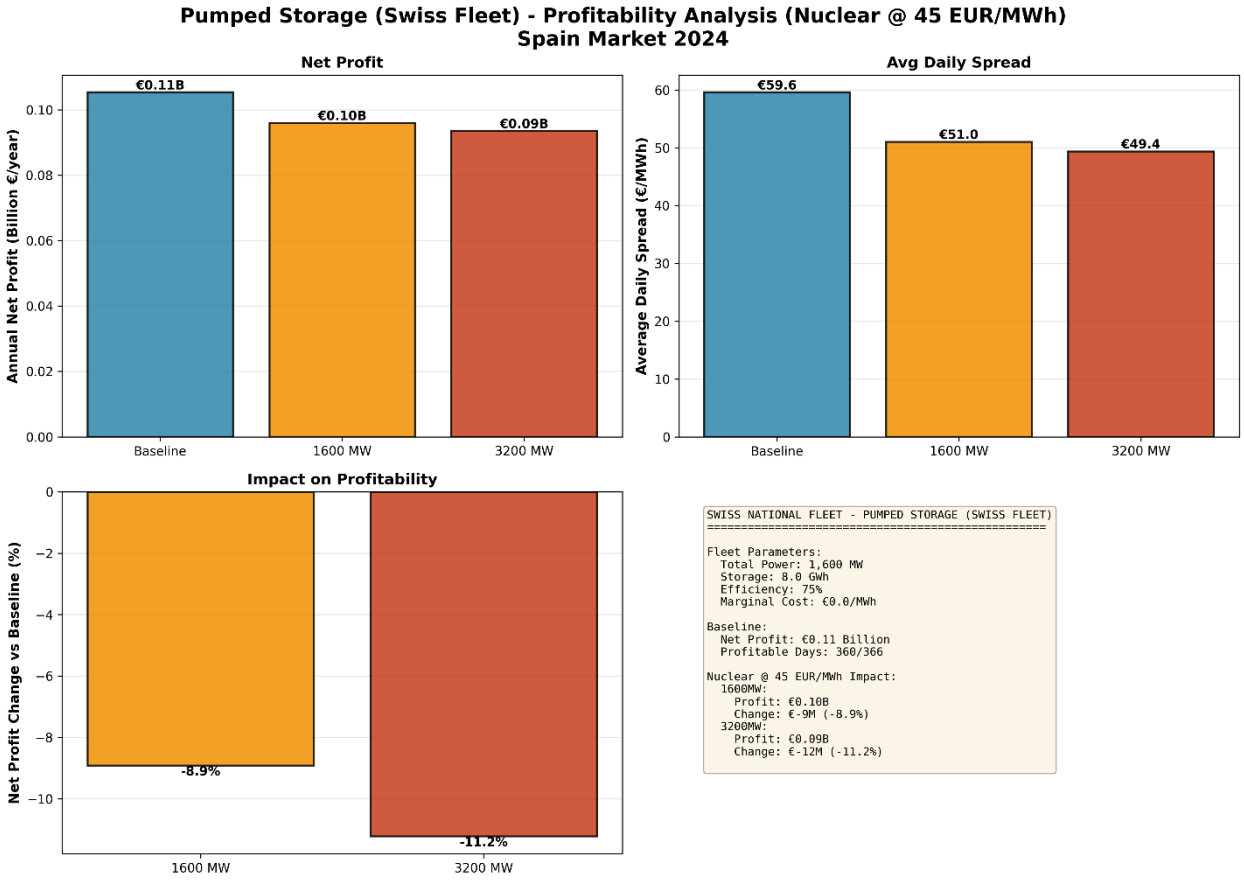


Figure 4.12: Swiss pumped storage fleet profitability under SRMC nuclear (45 EUR/MWh).

Swiss pumped storage exhibits sharply contrasting behavior across nuclear cost assumptions. Under SRMC nuclear, losses reach 8.9% to 11.2%, substantially exceeding the 3.8% to 2.1% (€4-2 million) losses under zero-cost nuclear (Figure 4.9). This reversal reflects the compressed arbitrage spreads under SRMC nuclear: the 45 EUR/MWh price floor elevates off-peak prices while baseload availability suppresses peak prices, reducing cycling profitability. Conversely, zero-cost nuclear maintains larger spreads by driving off-peak prices toward zero while preserving elevated peak prices, partially sustaining arbitrage opportunities despite lower absolute price levels.

The analyses show that each type of hydropower faces a different profitability trajectory, shaped mainly by how flexibly it can operate and by the market revenues it relies on.

Run-of-river plants are affected the most. They face revenue losses of 29–42% per plant and €304–441 million per year for the Swiss fleet under nuclear scenarios. Because run-of-river generation cannot be shifted in time, these plants cannot avoid selling into periods where nuclear baseload pushes prices down. Losses are greater under a zero-cost nuclear assumption than under an SRMC-based one, since zero-cost nuclear removes the marginal-cost price floor and allows prices to fall close to zero whenever nuclear dominates the supply.

Reservoir hydropower shows moderate resilience by adjusting its production to higher-priced periods. Losses reach 15–19% for individual plants and €452–603 million for the fleet. Importantly, results are the same under both zero-cost and SRMC nuclear scenarios. This indicates that reservoir operators concentrate their output during scarcity periods, where nuclear does not set marginal prices regardless of its cost structure. In other words, reservoir profitability depends mainly on the tightness of peak supply–demand conditions, not on the cost of baseload nuclear.

Pumped-storage plants respond differently depending on the nuclear cost assumption. Under zero-cost nuclear, they lose 4–13% of revenue per plant and €2–4 million for the fleet. Under SRMC nuclear, losses increase to 9–13% per plant and €9–11 million fleetwide. This seemingly paradoxical effect follows from arbitrage dynamics: zero-cost nuclear still preserves usable price spreads for buying and selling energy, whereas SRMC nuclear imposes a 45 EUR/MWh price floor in off-peak hours while simultaneously lowering peak prices through abundant baseload availability. The result is a compression of arbitrage margins under the SRMC assumption.

5. Conclusions

This study assessed two linked questions: whether new nuclear capacity can operate profitably in liberalized electricity markets, and how such new capacity affects the profitability of existing hydropower resources when deployed under out-of-market schemes. Using Spain's 2024 market as a forward-looking analogue for European and Swiss conditions, the empirical evidence reveals a consistent set of effects.

Market prices rarely reach the levels required for full-cost recovery of new nuclear projects. Across all hours of 2024, prices exceeded 100 EUR/MWh in only 26% of hours and exceeded a full-cost benchmark of 145 EUR/MWh in just 3% of hours, while surpassing the short-run marginal cost of existing nuclear (45 EUR/MWh) in roughly 61% of hours. These distributions show that new nuclear cannot viably recover its investment costs through energy-only revenues and would, in practice, enter the merit order as contract-protected baseload bidding at or near zero marginal cost.

Once such baseload is introduced, wholesale price formation changes systematically. Adding 1.6–3.2 GW of nuclear capacity shifts the supply curve, suppressing clearing prices across most hours, reducing the depth of mid-merit price segments, and narrowing the number of scarcity periods that historically sustain flexible generation. These effects follow directly from the merit-order effect: when a guaranteed baseload resource bids at zero or at its fuel cost, higher-cost marginal units are displaced, compressing both the level and structure of market prices.

Hydropower revenues adjust accordingly. Run-of-river plants, unable to shift production, face the steepest declines, with profit reductions of 29–42% for representative facilities and an estimated €304–441 million annually for the Swiss fleet. Reservoir hydropower retains partial resilience through dispatch optimisation but nevertheless experiences substantial losses: 15–19% per plant and €452–603 million at fleet scale. Pumped-storage outcomes depend on nuclear's bid structure. Under zero-cost nuclear, daily spreads remain partially intact, limiting revenue reductions to 4–13% per plant and €2–4 million fleetwide. Under SRMC-based nuclear, the 45 EUR/MWh price floor compresses spreads more sharply, increasing losses to 9–13% per plant and €9–11 million fleetwide.

Taken together, these results show that the economic consequences of new nuclear in a high-renewable system are transmitted primarily through changes in wholesale price formation. For Switzerland, where hydropower provides both a dominant share of domestic generation and the flexibility that stabilises the wider continental system, these altered price dynamics have direct implications for revenue stability, reinvestment capacity, and long-term system planning. Further work should evaluate interactions with large-scale storage deployment, ancillary-service and capacity-

market revenues, and the implications for Europe-wide adequacy under high-renewable conditions.

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