Wiley
International Journal of Energy Research
Volume 2025, Article ID 5580399, 19 pages
https://doi.org/10.1155/er/5580399

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Research Article

From Nuclear to PV and Hydro Storage: Exploring the Transition to Renewable Energy Systems

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Received 25 February 2025; Revised 17 July 2025; Accepted 4 October 2025

Academic Editor: Akshay Kumar Saha

The transition from nuclear power to photovoltaic (PV) energy has significant implications for electricity markets and energy storage systems. This study employs a system dynamics (SDs) model to analyze the effects of replacing nuclear energy with PV on market equilibrium and the operation of pumped hydropower storage (PHS). We model two distinct regions, one with stable demand and generation and another with high seasonality, to examine the interplay between generation capacity, market pricing, and storage efficiency. Our findings indicate that while PV reduces reliance on nuclear energy, it leads to increased electricity prices due to higher storage costs and the intermittent nature of solar generation. The introduction of PV also alters intraday and seasonal price dynamics, influencing both market behavior and consumer costs. These results highlight the importance of considering regional conditions and storage capacity when designing energy transition policies. Our study provides insights for policymakers and energy planners on optimizing renewable energy integration while ensuring economic and market stability.

Keywords: energy policy; energy transitions; pumped hydro-storage; renewables; system dynamics

1. Introduction

As evidence of human-induced climate change continues to mount, political leaders are committing to long-term climate-friendly strategies in response to societal and environmental pressures [1]. Given that energy production accounts for a high share of emissions, governments worldwide are implementing policies to encourage more sustainable energy strategies [2]. Switzerland's Energy Strategy 2050, for example, focuses on increasing energy efficiency, phasing out nuclear energy, and expanding renewable energy sources [3]. However, renewables bring new challenges to existing energy infrastructure, particularly due to the intermittent nature of variable renewable energy sources (VRESs) such as wind and photovoltaic (PV) [4]. Unlike conventional energy sources, VRES generation is weather-dependent, leading to supply fluctuations that require strategic interventions to maintain system reliability and flexibility [5].

A range of interventions, including market design, international electricity trade, demand response, and electrical energy storage (EES), have been proposed to address these challenges [6]. EES plays a crucial role in mitigating supply–demand mismatches by storing surplus energy and releasing it when needed [7, 8]. Among EES technologies, pumped hydropower storage (PHS) is the dominant solution, comprising 94% of global EES capacity in 2024 [9]. PHS plants function as large-scale energy reservoirs, using a dual-reservoir system to store and release energy as necessary, with an efficiency range of 70%–80% [10]. Due to their flexibility, longevity (25–100 years), and cost-effectiveness, PHS plants remain the preferred choice for large-scale energy storage [11].

Despite the high initial costs of PHS, these systems have historically reduced energy system operating costs by optimizing the balance between supply and demand [12]. Many PHS plants in Europe and the USA were commissioned between 1960 and 1980 alongside the expansion of nuclear

energy, which requires consistent generation levels for operational efficiency [13]. PHS allows for the shifting of surplus electricity generation to match fluctuating demand patterns, reducing overall peak capacity requirements [14, 15]. In the context of energy transition, PHS has the potential to enhance the integration of VRES, reducing power supply costs and electricity prices [16]. However, the economic viability of PHS remains a crucial factor in determining its role in future energy systems.

Energy models have evolved significantly since the 1970s, influenced by advances in computer science and increasing awareness of energy security and environmental sustainability [17]. Various classification methods exist for energy models, considering their purpose, structure, analytical approach, and sectoral focus [18, 19]. These models play a critical role in energy planning, forecasting, emission reduction, and optimization of energy sources [20].

Several modeling approaches have been employed to analyze energy transitions [21]. Global models [22, 23] and country-specific studies [24] provide insights into energy policy and transition dynamics. Energy transition models often emphasize techno-economic factors [25], but other approaches focus on understanding transitions, informing policy decisions, and facilitating stakeholder engagement [26].

Challenges associated with energy modeling include balancing supply and demand over time and space, managing uncertainty, optimizing complexity, and integrating human decision-making elements [27]. Recent research highlights the importance of incorporating climate change impacts into energy modeling, emphasizing the interaction between regulatory policies and market forces [24]. Simulation-based studies have proven useful in evaluating energy planning, technical feasibility, and economic and environmental impacts [28].

Several studies review existing energy modeling tools. Connolly et al. [29] analyze 37 energy modeling tools, identifying key factors such as sectoral coverage, technology representation, and policy considerations. Schill & Zerrahn [30] examine models addressing high shares of renewables in electricity generation, identifying the need for high-power storage, intraday storage solutions, and cost-effective energy storage deployment beyond 50% renewable penetration.

This study examines the impact of nuclear phase-out and its replacement with PV technology on electricity market equilibrium and the operation of PHS facilities. While our primary focus is on nuclear, PV, and PHS, the findings also provide insights into broader energy transitions involving other renewable and storage technologies. Our objective is to analyze different transition stages to identify optimal end-states for electricity market equilibrium, with particular attention to scenarios in which the regions analyzed seek to maintain a high degree of electricity self-sufficiency. Using a conceptual system dynamics (SDs) model, we simulate energy transitions in two fictional regions, no seasons (NoSs) and seasonal (*S*), calibrated with parameters inspired by Switzerland and Colombia. This theoretical framework allows us to explore the impact of seasonality on electricity markets and the transition toward 100% renewable energy systems.

Our research contributes to the existing literature in two key ways. First, while prior studies examine the feasibility and challenges of 100% renewable electricity systems [31–33], our work takes a macroeconomic perspective to assess the optimality of full renewable integration. By analyzing different transition stages, we highlight how the cost advantages of renewables do not always translate to lower consumer and market prices due to the characteristics of energy storage and conventional generation technologies. Second, we incorporate the role of seasonality, demonstrating that regions with high seasonality and low solar irradiation experience significant increases in market prices as more PV capacity is required. This analysis underscores that energy transition strategies must be tailored to regional conditions, considering factors such as storage resources, climate, and geographic location. Our findings provide valuable insights for policymakers navigating the complexities of energy market transitions.

The remainder of this paper is structured as follows: Section 2 details the methodology, including model parameters, assumptions, and scenarios. Section 3 presents our results, followed by a discussion of key findings in Section 4. Finally, we conclude in Section 5.

2. Materials and Methods

Electricity markets are by nature complex, and even more so when analyzing the effect of phasing out a conventional, rigid technology and replacing it with a novel, intermittent technology: they involve a large number of interacting factors and actors, which creates feedback in the presence of delays. We, therefore, model the system's structure explicitly. This kind of modeling provides an understanding of the dynamics of the industry that would be neglected by optimization methods or simple extrapolation of historical data. SD allows us to include the strategies of the different technologies and their structural interdependencies [34], which is particularly important for policymakers during transition periods. Furthermore, the model-building process strongly contributes to a better understanding of the system and its relevant causalities. Finally, SD allows us to simulate and evaluate alternative future scenarios, giving decision-makers a quantitative tool when choosing a desirable end-state [35].

Energy systems have been studied extensively using SD-based simulation models [36, 37]. Bunn et al. [38] discuss how SD is a valuable tool to learn about systems embedded in a transition. This methodology allows the analysis of the possible effects of changes to the system before their implementation. For instance, SD has been used to analyze energy policies, systems facing transitions toward renewables, and the economic impacts of technological change, among others [39–42]. For example, Castaneda et al. [39] explore the effect of prosumers (entities who produce and consume) when introducing a high share of PV generation. They concluded that, in the long term, consumers can generate death spirals in electricity markets.

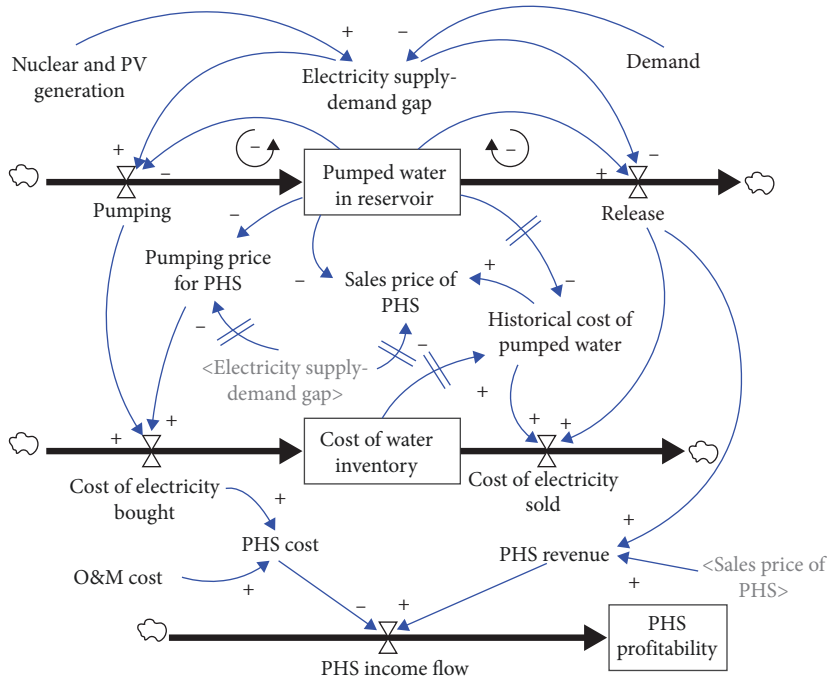


Figure 1: Stock and flow diagram of the model (Appendix A3 for the complete Vensim Map).

Regarding energy policies, Olsina et al. [42] evaluate the dynamics of deregulated electricity markets using an SD Model. Their results show the importance of understanding how the structure of an electricity system (construction delays and imperfect foresight) prevents a mismatch between the demand and supply by considering the demand growth, the investment in capacity, and the retirements. The regulatory mechanisms should be implemented as soon as possible to have the required capacity available and avoid price volatility.

This section may be divided by subheadings. It should provide a concise and precise description of the experimental results, their interpretation, as well as the experimental conclusions that can be drawn. All abbreviations used in this study are listed in Appendix A.

2.1. Model Formulation. This model was developed to analyze the impact of the phase-out of nuclear capacity and its replacement with PV on the role and pricing of PHS facilities. Our objective is not to analyze the transition from a fuel mix of 100% nuclear to 100% PV but to examine the market equilibrium of different stages of the transition to define a preferred end-state.

Figure 1 gives a simplified overview of the processes and underlying causalities of the model. The arrows indicate a causality between two variables, and the sign next to the arrowhead indicates the type of relationship. A "+" ("–") sign indicates that if the cause variable increases, the effect variable increases (decreases). The two parallel lines indicate that the effect will occur with a delay.

The three rectangles (stocks) represent the state variables: the pumped water in the reservoirs, the cost of the water currently in the reservoir, and the PHS profitability. Certain variables appear twice in the structure to avoid crossing arrows, improving legibility. In this case, the duplicated variable is colored gray and surrounded by angle brackets (< >).

The stock and flow structure at the top represents the impact of demand (i.e., consumption) and primary generation on the PHS pumping and generation process. Pumping only occurs when primary generation (i.e., nuclear and PV) exceeds the hourly demand, and PHS generates when there is a residual demand (pumping and generation never co-occur).

The stock and flow structure in the middle represents the costs incurred by PHS as it buys electricity for pumping. On the one hand, the pumping price for PHS depends on the daily supply available for pumping. The pumping price decreases if the average excess generation is high. On the other hand, the pumping price increases if the water level in the reservoir is low. When PHS is generated, the average cost of pumped water in the reservoir has to be covered by the sales price. The sales price is impacted by the daily residual demand and the water supply in the reservoir. The sales price decreases if residual demand is low. The sales price increases if the water level in the reservoir is low due to scarcity pricing. The stock and flow structure at the bottom displays how the sales price of PHS and the amount of water released define the PHS revenue. The PHS running cost depends on the cost of operation and maintenance (O&M) and the cost of electricity bought. The profitability of PHS depends on whether the revenue can cover the running costs and the annual capital cost. As a modeling hypothesis, we assume that for a system to be viable in the long term, PHS must be profitable. Therefore, we model the price setting to cover the total annual costs of PHS. The mathematical

Table 1: Model inputs and main assumptions.

Input	Source	Comment
Electricity demand	[43–45]	We assume an annual demand of 876 GWh for each scenario, reflecting a standardized average hourly demand of 100 MWh.
Solar irradiation	[46]	Average daily irradiation data for each month.
Capacity factor	[47, 48]	Technology and regionally dependent.
PHS efficiency	[10]	We assume an 80% efficiency for PHS.
O&M costs, capital costs,	[47, 49]	Focus on cost ratios, provides a uniform data source.
Life cycle	—	Using the numerical analysis approach proposed in [50], we choose the installed capacity by technology that allows the total demand to be fulfilled, while seeking low spare capacity and curtailment.
Installed capacity by technology	—	We assume an annual demand of 876 GWh for each scenario, reflecting a standardized average hourly demand of 100 MWh.
Reservoir size	—	PV and nuclear capacity are given according to the transition stage. We develop an algorithm to choose the values of the reservoir size to minimize the curtailment.
Nuclear and PV capacity factor	[51]	For nuclear, the capacity factor is 0.9. The capacity factor for PV is 0.2 for the NoS scenario and 0.1 for the *S* scenario.

formulation is provided in Appendix A1, while the graphical representation of nonlinear functional relationships.

2.2. Parameters and Assumptions. The model was created using Vensim DSS 7.3.5. The time horizon is 1 year, and the units are in hours. Our analysis takes a high-level view; we consider a weekly approach. We took a representative day each week to display the demand patterns and the solar irradiation, resulting in 53 different demand and irradiation patterns over the year. As our goal is to analyze the impact of varying transition stages on the pricing and profitability of storage facilities, we assume an isolated system (no border-cross exchange), so pricing and generation are not biased by external factors. We use the solar irradiation and demand patterns of Switzerland and Colombia as an inspiration to calibrate the order of magnitudes of the hourly changes in both patterns. Table 1 summarizes the data sources and assumptions used to calibrate the model.

To be viable across their lifecycle, we assume that each technology sets its sales price to cover its full cost. The lifecycle of nuclear, PV, and PHS plants is 30 years. The model does not include subsidies or out-of-market payments. We assume the same cost structure for the two regions.

The nuclear price bid is set to recover its fixed and running costs. The capital costs are less relevant, as most nuclear plants are amortized. Thanks to its continuous load, nuclear can benefit from high-price periods set by other technologies (i.e., PV and PHS). The bid for nuclear electricity is calculated by multiplying the marginal cost of nuclear by a markup, which changes according to the current water level of the reservoir and excess electricity produced by nuclear and PV.

As new generators, the PV price bid must cover capital and operating costs. As a result, the PV bid is much higher than the nuclear bid, even though PV operating and running costs are comparatively low. Unlike nuclear, PV can rarely benefit from high market prices set by other generators. Most of the time, PVs outperform consumer demand when it is generated due to their periodic nature, which lowers the market price.

The bid price of PHS depends on its capital cost, fixed O&M cost, and marginal costs, which include the variable O&M costs and the average cost of pumped water in the reservoir. To calculate the PHS bid, the marginal cost is multiplied by a contribution margin (CM), which changes according to the water level in the reservoir and the consumer demand that could not be covered by PV or nuclear.

Finally, it should be noted that while the bid of each technology is calibrated to cover its relevant costs, the generators can, at times, benefit from higher prices set by other technologies. As a result, the weighted average price a technology receives for its generation can be higher than its initial bid.

2.3. Scenario Description. The simulation is run for two regions to better understand seasonal impacts. The first is labeled NoSs scenario, a fictional region (inspired by Colombia) used as a base case, where demand and solar input are stable over the year. This allows us to examine the impact of the phase-out on intraday pumping without any seasonal interference. The second region has seasons (*S*), where the daily pattern of consumption and solar irradiation is highly seasonal and solar irradiation is reduced (this region is inspired by Switzerland).

The phase-out of nuclear electricity is represented in five stages, characterized by the share of primary generation that stems from nuclear (100%, 75%, 50%, 25%, 0%). In the first stage (100%), nuclear power is the primary source of electricity. At each subsequent stage, nuclear capacity is reduced by 25% and compensated with PV. At the last stage (0%), PV is the only primary generator. We assume that consumers' electricity demand is the same for all stages. We also assume a central planner dispatching according to the following order: nuclear is first, as it is challenging to curtail; PV follows second, and PHS comes last, as it is not a primary generator. PV is curtailed when necessary to avoid reservoir overflows.

Table 2: Reservoir size in GW and as a percentage (%) of annual consumption by region and phase-out stage.

Scenario	100%		75%		50%		25%		0%	
	GW	%	GW	%	GW	%	GW	%	GW	%
NoS	0.1	0.0	0.3	0.0	0.7	0.1	1.1	0.1	1.6	0.2
S	48.4	5.5	88.1	10.1	128.6	14.7	171.2	19.5	212.0	24.2

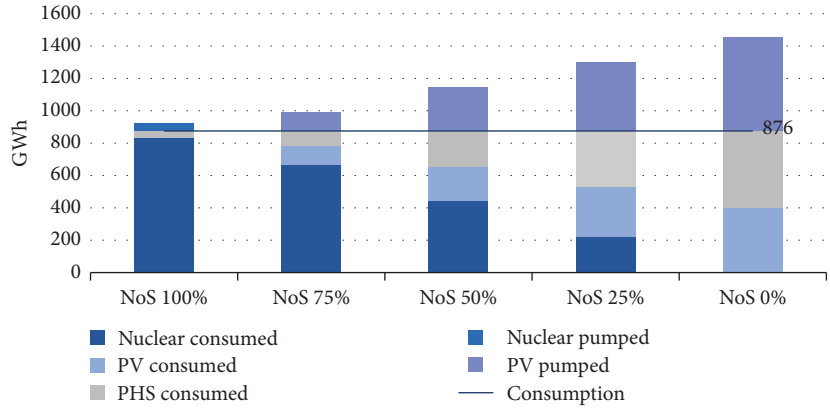


Figure 2: NoS 100%–0%: electricity balance.

Table 2 shows the reservoir size in GW for each scenario and as a percentage of annual consumption. For each scenario, the reservoir size is set at the minimum capacity necessary to fulfill annual total demand. Increasing the PV share in the generation mix for both regions necessitates a larger reservoir size. Due to the absence of seasonal fluctuations, the largest reservoir size required for the NoS scenario (0%) corresponds to 2/3 of the daily consumption. In the case of *S*, the largest reservoir size can supply consumption for nearly 88 days (*S* 0%).

The market price is set by the bid price of the marginal technology that allows the consumption to be met. Consumption includes consumer demand for electricity and electricity used for pumping. The weighted average market price considers the moment and volume of consumption. To assess the financial impact of each scenario for the consumers, we also look into the weighted average consumer price. This measure represents the average price paid for electricity by the end-consumers. It excludes the prices paid by PHS for pumping.

3. Results

We first briefly examine the electricity balance across the five transition stages. Next, we compare the initial (100%) and final (0%) stages of the phase-out concerning their generation pattern, price behavior, and income flow. Third, each technology's market price and sales price will be compared across all phase-out stages. Finally, based on the price analysis, specific transition scenarios will be examined further to investigate the changing behavior resulting from the changing share of generation technologies.

Using the example of NoS, Figure 2 shows that an increasing share of PV generation correlates with a rise in total annual electricity generation. This occurs because intermittent PV production is less likely to match demand in real-time, requiring more electricity to be stored and released, increasing the necessary reservoir capacity (Table 2).

Figure 3 illustrates the effect of seasonal consumption and generation variations for *S*. In scenario *S* 100% (Figure 3a), PHS stores surplus electricity mainly between April and October, which is then released between fall and early spring. In contrast, when PV becomes the primary generator (scenario *S* 0%), PHS operates continuously throughout the year (Figure 3b). The highest energy storage levels occur in July due to peak PV generation and lower demand. During winter, as solar irradiation decreases, PHS generation meets most of the electricity demand from October to March.

Figure 4 shows the generation, consumption, and market price patterns for a representative day. Figure 4a,b allows us to observe the change in the patterns of intraday pumping when switching from 100% nuclear to PV in the NoS scenario. In NoS, 100% pumping occurs between 23:00 and 8:00, when excess nuclear electricity is available. On the contrary, in NoS, 0% pumping occurs between 8:00 and 16:00 when PV generates. These two figures support the conjecture that the continuous nuclear load can profit from high market prices set by PHS. At the same time, PV is mainly generated during low-price hours.

Figure 4 shows the generation, consumption, and market price patterns for a representative day. In the NoS scenario, intraday pumping changes when transitioning from 100% nuclear to PV. In NoS 100%, PHS pumps electricity from 23:00 to 08:00, utilizing excess nuclear power. In NoS 0%, pumping occurs between 08:00 and 16:00, aligning with peak PV generation (Figure 4a,b). This transition highlights how nuclear can benefit from high market prices set by PHS, whereas PV primarily generates during low-price hours.

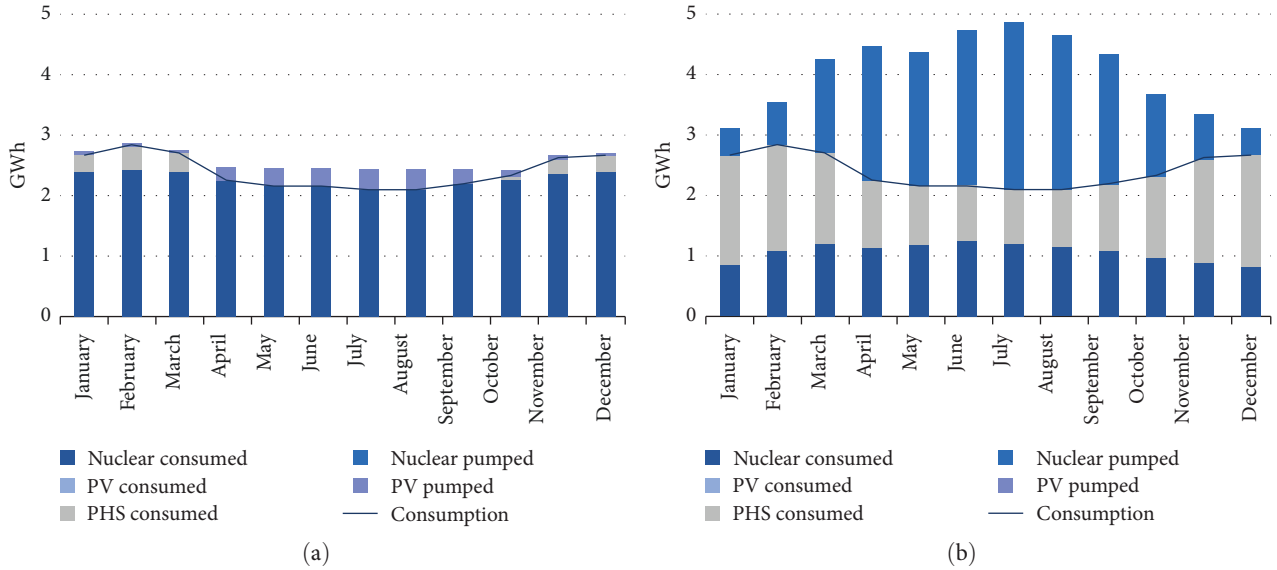


Figure 3: Daily average consumption and pumping by technology by month for *S* scenarios: (a) *S* 100% and (b) *S* 0%.

In seasonal scenarios (Figure 4c–f), S 100% shows PHS generating from 06:00 to 23:00 in winter, with minimal pumping. In contrast, in *S* 0%, PHS pumps throughout the day and generates in the late afternoon and nighttime due to lower PV generation. Contrary to expectations, market prices increase as PHS pumps, as shown in Figure 4d. During summer, PHS pumping patterns shift based on PV availability (Figure 4e,f).

Figure 5 displays the daily pattern of the market price for NoS 100% (Figure 5a) and NoS 0% (Figure 5b). The vertical lines mark when PHS switches from pumping to generating and vice versa. The market price is generally at its lowest point before PHS starts generating, since the reservoir is nearly complete. When water is released from the reservoir, the market price is at its highest when it is almost empty. In NoS, 100% of the market price tends to follow the consumption, meaning it is low during off-peak hours and high during peak hours. However, in NoS 0%, there seems to be no direct correlation between peak price and consumption. Figure 5b shows that the market price is highest at night when consumption is low, since PHS is generating.

Figure 6 displays the annual evolution of the market price for *S*. This curve follows the same pattern in scenarios *S* 100% and 0%, exhibiting an inverse relationship with the reservoir level. Depending on the amount of PHS generation and pumping, the average market price lies somewhere between the PHS sales price and the pumping price curve. Figure 6b shows that the PHS pumping and generation prices diverge more strongly when primary generation is seasonal. This indicates a heightened volatility of the intraday market price, especially between March and May, when the PHS sales price spikes and the pumping price starts to decrease. It is important to note that the weighted average market price encompasses the price paid by the end-consumers and PHS for pumping. The consumer demand in this model is inelastic, meaning the demand does not shift from peak-priced periods to low-price periods. In this case, the higher PHS sales price causes the price paid by the consumers to diverge from the market price. As PV generation increases and consumption decreases during the summer, the reservoir fills up with low-priced electricity by mid-autumn, available to be sold from November onwards, when PV generation decreases while consumption increases (recall Figure 3b). It is important to remember that our pricing algorithm is targeted at covering the full cost of generation, including the historical cost of pumped water. In winter, this pricing algorithm could lead to the economically illogical result that the PHS sales price at night is below the price at which it buys the scarce excess generation for pumping at noon. To avoid this, PHS uses the average daily electricity cost to calculate the maximum price it pays for pumping. This phenomenon can be seen in Figure 4d, where the market price decreases when PHS pumps water at a lower price than the daily average.

Figure 7 displays the regional annual sales revenue in millions by technology and the market price and consumer price by scenario. Looking at the S scenarios, introducing PV leads to a notable increase in market and consumer prices due to the higher capital costs and fixed costs of PHS caused by seasonality. Nuclear is the primary beneficiary of the high market price, as for both regions, its total revenue is higher in scenario 75% than in 100%, despite less generation. The revenues of PV and PHS have grown less, but are still more than proportionally compared to their generation. In every scenario, the PV revenue is below the PHS revenue, even though PV generates more than twice as much as PHS. The market price is higher in the transition stages of the phase-out than in the stages with only one primary source.

Up to this point, the analysis of the results mainly focused on the two extreme stages, where either nuclear or

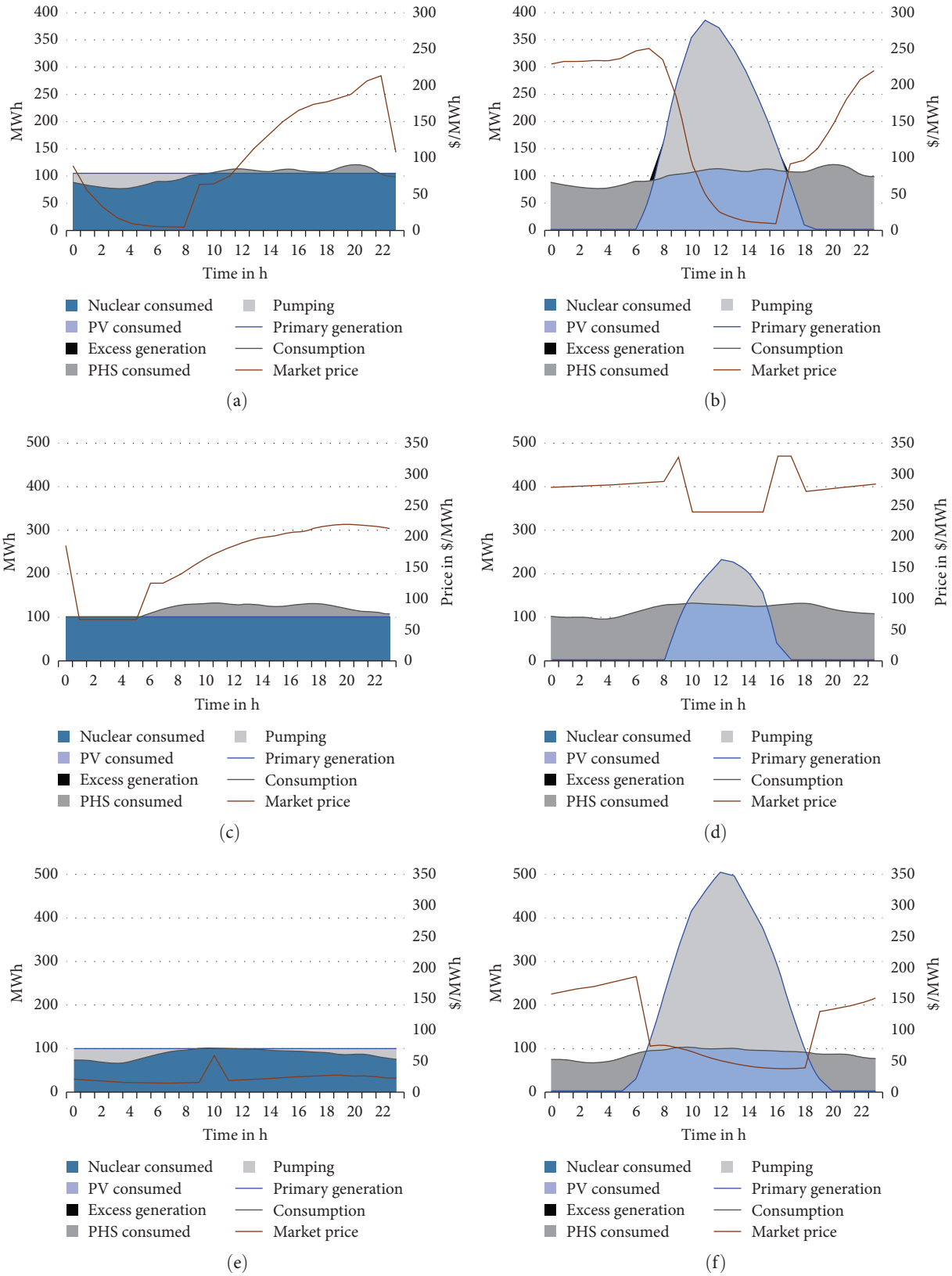


Figure 4: Daily generation, consumption, and market price: (a) NoS 100%, (b) NoS 0%, (c) *S* 100%: January, (d) *S* 0%: January, (e) *S* 100%: July, and (f) *S* 0%: July.

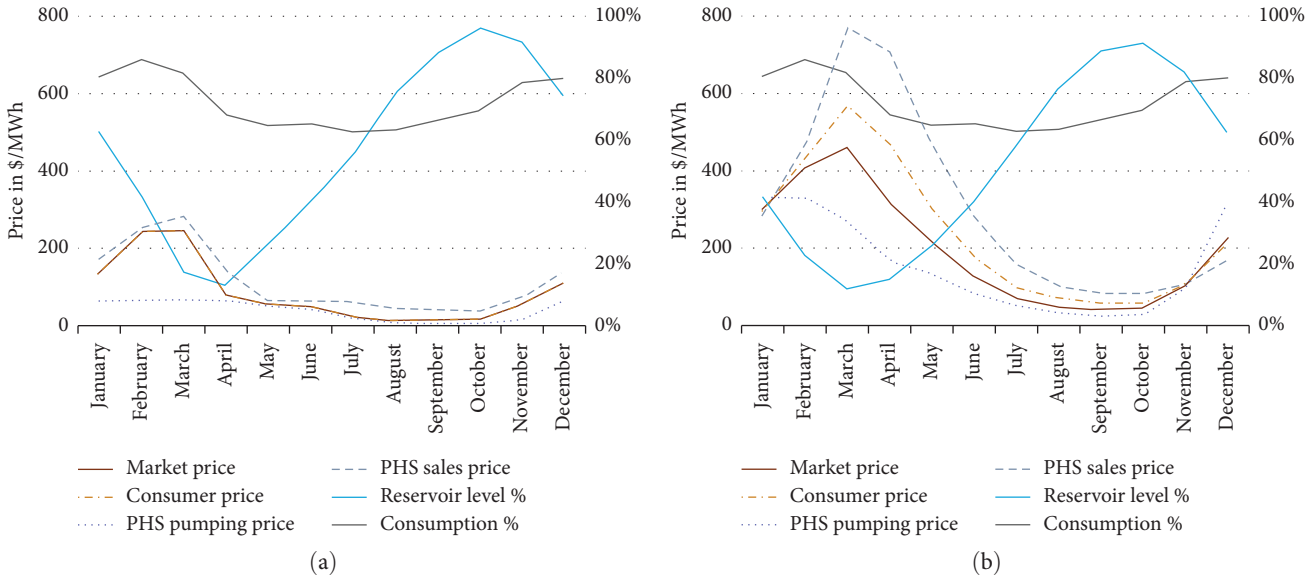


Figure 5: Daily price curve, reservoir level, and consumption of NoS: (a) *S* 100% and (b) *S* 0%.

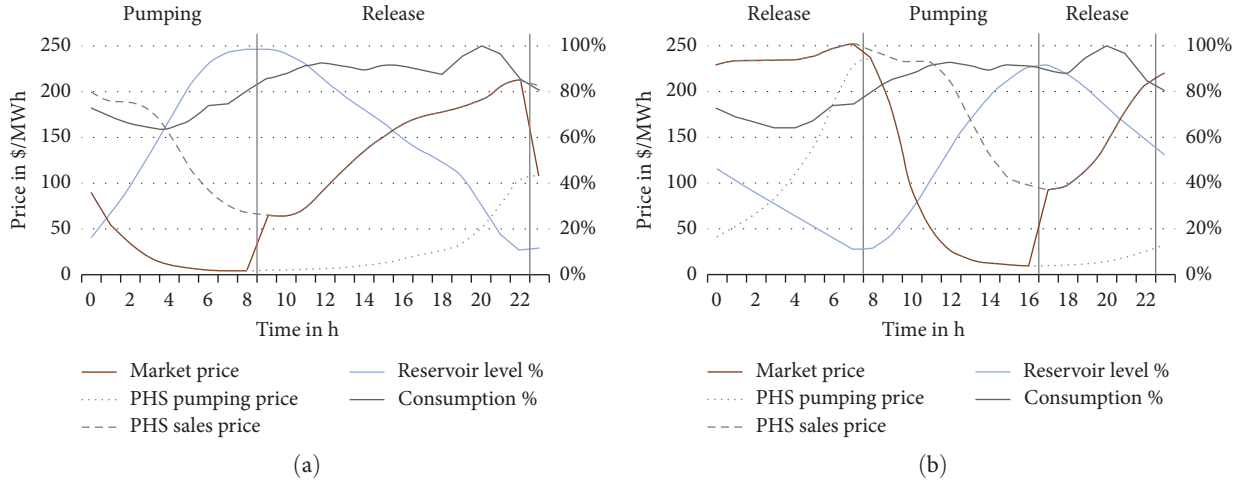


Figure 6: Daily price curve, reservoir level, and consumption of NoS: (a) NoS 100% and (b) NoS 0%.

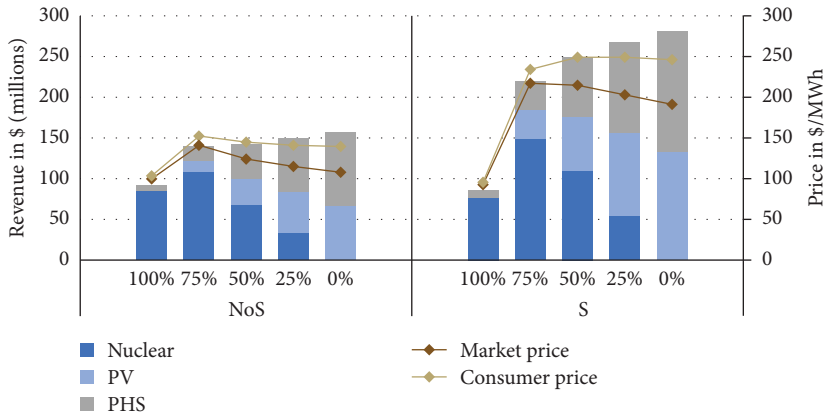


Figure 7: Total sales revenue by technology, market price, and consumer price by region and phase-out stage.

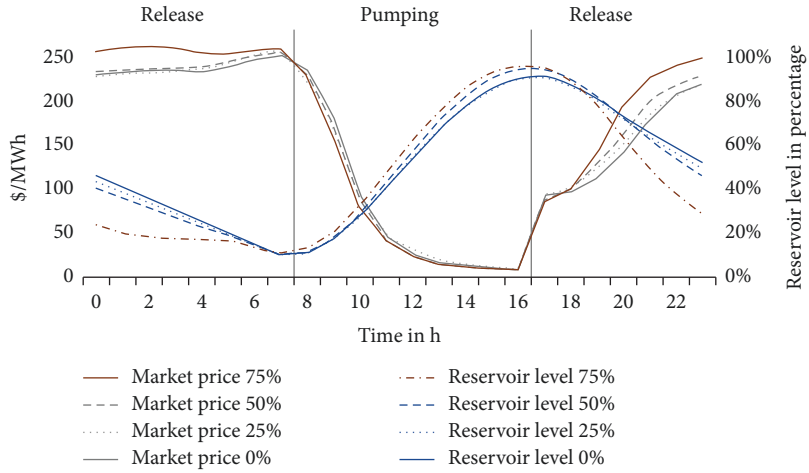


Figure 8: NoS 75%–0%: reservoir water level and market price.

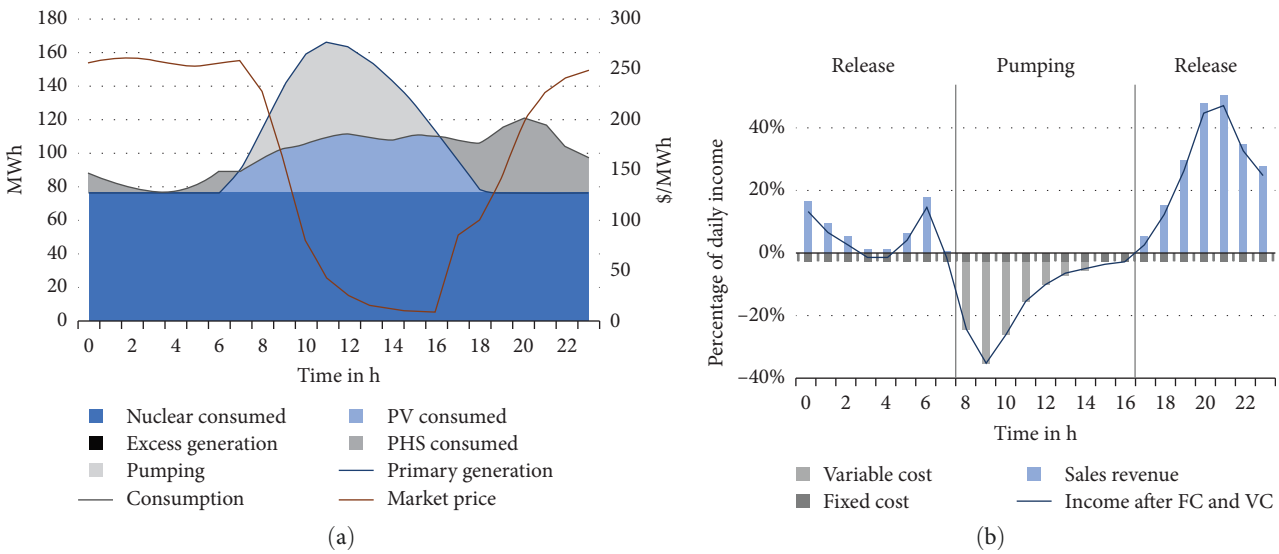


Figure 9: NoS 75%: (a) daily generation and consumption by technology and (b) daily revenue and costs as a percentage of daily income.

PV is the only primary generator (stages 100% and 0%). Out of the two, the price in stage 100% is more favorable for the consumers and, in the case of the seasonal region, for the overall market. Yet, the results in Figure 7 already point to the fact that the transition stages of the phase-out (75%, 50%, and 25%) are even less favorable for the overall market. The explanation for this can be found when looking at the intraday pattern of NoS and the intraseasonal pattern of *S*.

As seen in Figure 7, NoS 75% yields the highest market price, even though the PHS sales price is similar to the other PV scenarios. Figure 8, which depicts the reservoir level and market price of the four scenarios that feature PV (NoS 75%–0%), indicates a negative correlation between the two variables across the four phase-out stages. It shows that the water level of NoS 75% falls most steeply from nearly 100% to 30% between 17:00 and 23:00. This rapid decrease raises the market price more compared to the other PV scenarios. Then, the water level decreases slowly to 10% during the rest of the night until pumping begins at 8:00, keeping the high sales price throughout the night.

This pattern is explained by Figure 9a, which represents the generation and demand pattern of NoS 75%. PHS electricity is mainly used to fulfill the peak demand in the evening (19:00–22:00). Due to the relatively high nuclear baseload and low demand, only a little PHS electricity is necessary during the rest of the night. Nevertheless, this PHS generation still sets the price. Figure 9b shows that in scenario NoS, 75% of the main profits are made between 19:00 and 23:00. When PHS sets the price between 17:00 and 7:00, the weighted average cost of electricity sold (mainly nuclear and PHS) is 10% higher than the weighted average sales price of PHS.

PHS generates less when the market price is at its highest level, as nuclear generation covers most of the consumption. In the end, it is the consumers who have to carry the high costs of the peak price. In the further transition stages (NoS

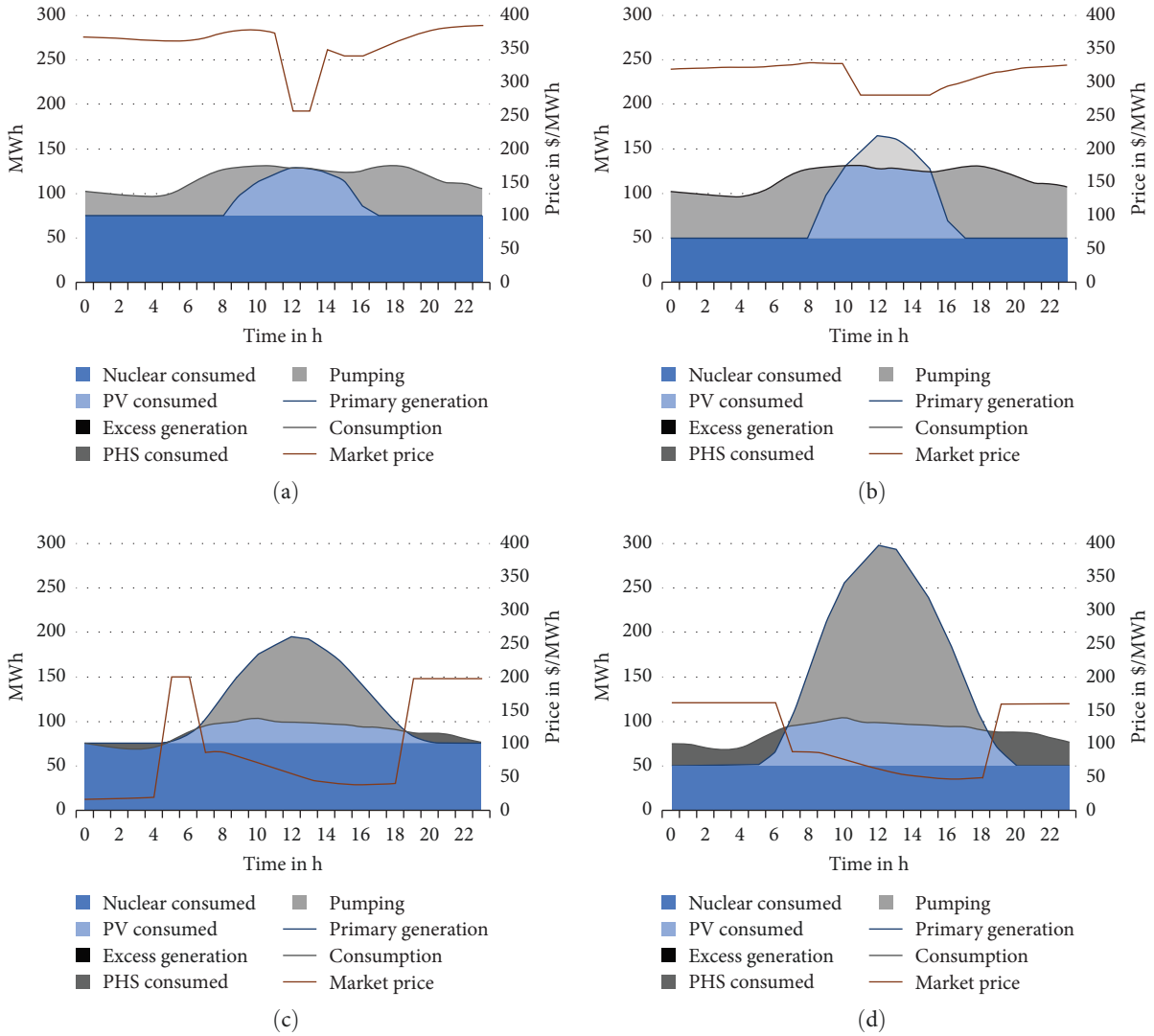


Figure 10: Daily generation, consumption, and market price for the representative day of January and July: (a) *S* 75%: January, (b) *S* 50%: January, (c) *S* 75%: July, and (d) *S* 50%: July.

50% to NoS 0%), PHS gradually increases its share of generation, and the water level of the more considerable reservoir changes more gradually. This decreases the weighted average market price. In conclusion, if PV is introduced into the generation mix, and in the absence of seasonality, the scenario where PV is the only primary source is the most favorable end-state concerning the price level of the market.

Figure 10a shows that PHS only pumps briefly from 12:00 to 13:00 in *S* 75% in winter. This allows PV to benefit from the high prices set by PHS for most of its generation period (9:00–17:00). Comparatively, Figure 10b shows that the market price of *S* 50% is lower, partially due to the increased hours of pumping (11:00–15:00), which is triggered by the higher PV generation. This indicates that the higher the share of PV, the less it can benefit from high prices set by PHS, as their generation is less likely to overlap. As a result, PV has less potential to lower its bid.

The nuclear price increases by 10% between *S* 75% and 50%. By comparing Figure 10c,d, we see that the high share of nuclear generation in *S* 75% can fulfill consumption during off-peak hours at night in summer. As a result, electricity is cheaper in this period compared to *S* 50%, where PHS is

Table 3: Sensitivity analysis parameters and results for scenario *S* 0%.

Variable	PV fixed and capital cost (%)		PV capacity factor (%)		Reservoir size (%)	PHS efficiency (%)	
Change	−25	−50	50	100	−40	−10	−20
PV capacity	–	–	−33	−50	35	+11	+25
Reservoir size	–	–	–	–	−40	–	–
PHS capacity	–	–	–	–	20	–	–
Pumping price	−23	−48	−32	−45	−54	+36	+42
PHS sales price	−10	−20	−15	−20	−10	+120	+270
Market price	−16	−32	−22	−30	−33	+109	+371
Consumer price	−14	−28	−20	−25	−27	+120	+385

generated throughout the night and sets a high price. The low need for PHS generation in summer, in case of a high share of nuclear, also explains why the price paid by consumers is lower in *S* 75% compared to *S* 50%. This indicates that a nuclear generation at the level of off-peak demand positively affects the price consumers pay. However, the low utilization rate of PHS in such a scenario increases the PHS sales price and the market price.

3.1. Sensitivity Analysis. A sensitivity analysis was performed on scenario *S* 0%, where PV is the only primary source. We aim to improve our understanding of the results by exploring the impact of cost changes, capacity factors, reservoir size, and PHS decrease in efficiency due to degradation over time. Table 3 shows the parameter changes and the results after the sensitivity analysis.

For the first test, the PV bid was reduced by 25% and 50%, assuming that both capital cost and fixed O&M cost decreased to the same amount (variable cost is 0). In this case, the capacities remain unchanged while the prices decline drastically. However, even if PV costs decreased by 50%, the market price would still be distinctively higher than in a purely nuclear scenario (*S* 100%).

For the second test, the PV capacity factor is increased to 15% and 20%, the latter being the same as for the NoS scenario. In this case, the PV capacity can be reduced, while the reservoir size and PHS capacity cannot change.

For the third test, the reservoir size is decreased by 40% to a more realistic size, representing 15% of annual demand. In this case, the PV capacity needs to be increased by 35% to avoid a blackout during winter, as PHS generates less electricity. This increased capacity leads to high curtailment in summer, representing 40% of annual consumption, as the excess generation cannot be pumped by PHS. In conclusion, the decrease in costs for PV and an increase in the capacity factor can make the technology more attractive for region *S*. However, there is a strong constraint set by the reservoir size.

We also include degradation in PHS efficiency. Reducing PHS efficiency by 10% and 20% from the baseline of 80% (everything else was constant except for the calculation of the required PV capacity to avoid blackouts) led to sharp increases in electricity prices: market prices rose by 109% and 371%, while consumer prices increased by 120% and 385%, respectively. These effects far exceeded those resulting from changes in PV costs or reservoir constraints. To maintain system adequacy, PV capacity had to be increased by up to 25%, highlighting the additional infrastructure burden. This analysis underscores the critical role of storage technology in maintaining system balance and mitigating price shocks.

Building on [24], we conducted a sensitivity analysis that accounts for the potential impact of extreme weather events on electricity demand. Specifically, we modeled a climate change scenario in which average demand increases by ~5%, with the most pronounced rise occurring during the summer months (reflecting higher cooling needs) while winter demand increases only slightly. This scenario allows us to explore the implications of climate-induced shifts in consumption patterns on system adequacy and storage requirements. Given that all other parameters remain constant, it is not surprising that consumer prices increased by 150%, while unmet demand accounted for 6.5% of total annual consumption.

4. Discussion

The results indicate that transitioning from nuclear to PV significantly impacts market dynamics, particularly in terms of electricity pricing and PHS's role. While PV offers a sustainable alternative to nuclear, its intermittent nature requires greater reliance on energy storage, raising electricity costs. The market price increases across transition stages primarily due to the need for additional storage capacity. While nuclear benefits from high market prices, PV's revenue remains lower due to a mismatch between generation and peak consumption hours. These findings suggest that a complete transition to PV without additional flexibility mechanisms may lead to inefficiencies and economic burdens for consumers.

The price dynamics observed in our study further highlight the differences between nuclear and PV in terms of cost structure. The higher bid price of PV than nuclear significantly contributes to increased electricity prices. Nuclear power plants, already amortized, can operate with lower capital cost considerations. In contrast, PV must account for significant initial investment costs. Additionally, nuclear can capitalize on high prices set by other technologies, while PV is limited. As PV's share in the generation mix increases, its ability to benefit from price fluctuations diminishes, making its bid comparatively more expensive than nuclear.

Another key insight from our study is that consumer prices do not necessarily align with market prices. In both simulated regions, the divergence between consumer and market prices is more pronounced when PV is the primary energy source. This is particularly evident in the seasonal (*S*) region, where the consumer price in a 100% PV scenario is significantly higher than in a 100% nuclear scenario. The high volatility of market prices when PV is introduced suggests that a purely PV-based electricity system could impose financial stress on consumers. In contrast, nuclear energy provides more price stability, as seen in the NoS scenario, where market prices remain relatively stable across transition stages.

Furthermore, storage and seasonality are crucial in determining electricity price behavior. In the seasonal region (*S*), PV's lower efficiency and seasonal fluctuations in solar irradiation significantly reduce the utilization rate of PHS, necessitating a larger reservoir size to maintain supply stability. Our results show that in a 100% PV scenario, the required reservoir size could amount to nearly 25% of annual consumption, which is an unrealistically high amount from an infrastructure and economic standpoint. This highlights a significant challenge in renewable energy transitions: balancing intermittency with feasible storage solutions. One potential mitigation strategy is to maintain a small fraction of nuclear capacity to supply a baseload at off-peak demand levels, particularly in summer, thereby reducing the reliance on costly storage solutions.

The economic feasibility of different transition stages also warrants further attention. While a fully nuclear or PV-based system may offer price stability in the long run, intermediate transition stages (75%, 50%, 25%) present significant cost challenges. Our findings indicate that market prices reach their highest levels during these transition phases due to increased storage demand and inefficient generation patterns. Scenario NoS 75%, for example, exhibits the highest market price among all PV scenarios, driven by rapid reservoir depletion and an increased reliance on PHS generation. These findings emphasize the need for carefully planned transition policies that minimize economic disruptions.

The challenges observed in intermediate stages, such as high price volatility and increasing reliance on storage, highlight the need for supportive policy mechanisms to ensure system stability and investment viability. These mechanisms include capacity remuneration schemes, hybrid support instruments, and renewable portfolio designs aimed at reducing volatility and improving reliability.

Capacity remuneration mechanisms with well-calibrated, quantity-based designs have been shown to reduce both scarcity pricing and unserved energy hours [52]. In contrast, design inefficiencies in capacity auctions have triggered sharp price spikes, with increases of up to 35% in a single auction [53]. Hybrid support schemes also contribute to stabilizing markets. For example, combining certificates with call options can reduce project risk [54], while auction-based support tends to outperform Renewable Energy Target schemes by mitigating integration costs and limiting market power [55]. Moreover, in systems with Renewable Portfolio Standards, volatility in prices and subsidies can raise investment trigger prices by 10.5%, or up to 26.6% when volatility doubles [56]. These findings suggest that blended policy designs with derisking features are most effective in managing hybrid generation phases and supporting smooth transitions.

An important policy consideration is the public's willingness to pay for renewable energy sources. As our results suggest, introducing PV without cost reductions or efficiency improvements leads to significantly higher electricity prices, particularly in regions with seasonal variations and low irradiation. Policymakers should consider consumer willingness to pay for clean energy when designing green electricity programs. In their meta-analysis, Sundt and Rehdanz [12, 57] show that consumer valuation of renewable energy varies, and support is more substantial when renewables replace conventional energy sources. Thus, for a successful transition, measures should be taken to increase PV efficiency and reduce costs, ensuring that renewable adoption remains economically viable and publicly supported.

While our study provides valuable insights into energy transition dynamics, it is subject to certain limitations. The model does not account for international electricity trade, which could alter the generation mix and influence price dynamics. This was a deliberate choice to explore scenarios of national self-sufficiency and to identify the infrastructure and generation capacity required to ensure year-round adequacy without external support. The assumption is particularly relevant for countries like Colombia, used for model calibration, where interconnections with neighboring countries are limited and energy trade remains marginal [58]. By contrast, cross-border exchange plays a key role in Europe, especially for balancing short-term supply and demand. Yet, as solar PV adoption rises across countries, the probability of simultaneous surpluses or deficits increases, reducing the reliability and profitability of exports [59] and contributing to prolonged periods of low or negative prices, as observed in Germany [60].

Historical events such as the COVID-19 pandemic and the energy crisis following the war in Ukraine have also revealed the fragility of international energy cooperation. During periods of stress, national governments prioritized domestic energy security over regional solidarity, at times restricting exports [61, 62]. These cases challenge the assumption that imports can be reliably counted on during emergencies.

Allowing for imports could reduce system costs by providing external supply during periods of low domestic generation, such as winter or reservoir refilling in autumn [63]. If neighboring countries diversify their portfolios (e.g., with wind power), the seasonal region's PHS could provide valuable balancing services. However, such cooperation depends on well-functioning markets and strong institutional alignment, which may not hold during crises.

These trade-offs between cost efficiency and energy security underscore the value of analyzing both self-sufficient and regionally integrated energy pathways. While we focus here on self-sufficiency to examine its structural implications, future work should explicitly assess the role of cross-border trade under different cooperation scenarios.

Another limitation of the model is the assumption of inelastic consumer demand, which omits potential behavioral responses to price signals such as demand shifting or participation in demand response programs. While such mechanisms could reduce storage needs and price volatility, their integration lies beyond the scope of this study. The objective of our model is to assess the structural infrastructure requirements and system behavior under strict national self-sufficiency constraints, isolating supply-side dynamics without the confounding effects of behavioral adaptation. Moreover, it lacks two key elements needed to simulate demand elasticity: population dynamics and macroeconomic feedback. A proper analysis of demand-side flexibility would require medium- and long-term assessments to distinguish between temporary reactions to price shocks and sustained adaptive changes. Rebound effects are also possible, where initial reductions in demand may gradually reverse. Capturing these dynamics would require coupling the electricity model with socioeconomic modules, which we believe would be an important direction for future work.

Additionally, we assume a well-functioning market with regulatory oversight, ensuring companies operate profitably without market power abuse. However, regulatory and market inefficiencies in real-world applications may further exacerbate price fluctuations and consumer costs.

Although our model focuses on PHS, other technologies such as lithium-ion batteries offer advantages that should be explored in future work. Batteries have higher efficiency and faster response, which makes them suitable for managing short-term fluctuations in solar generation and could foster profits due to arbitrage. However, their limited storage duration and higher costs make them less effective for addressing the seasonal imbalances considered in this study. PHS remains more suitable for long-duration storage due to its lower operating costs and large capacity. Future research should examine the role of combined storage solutions to improve system flexibility and reliability.

Ultimately, our findings underscore the importance of strategic energy planning in transitioning toward a sustainable and cost-effective energy mix. While PV offers a long-term pathway to decarbonization, storage solutions, diversified energy portfolios, and flexible regulatory mechanisms are necessary to mitigate adverse price effects. Our model serves as a decision-support tool for policymakers, helping them evaluate different transition scenarios and optimize the integration of renewables into the electricity market. Future work could expand on these insights by incorporating consumer behavior, dynamic market responses, and additional policy interventions, further refining strategies for a smooth and sustainable energy transition.

5. Conclusions

This study analyzes the impact of phasing out nuclear energy and replacing it with PV generation, focusing on the role of PHS and the implications for market equilibrium and electricity pricing. Using an SD model, we examined different transition stages and their effects on price behavior, storage utilization, and energy system stability. Our results indicate that while PV offers a sustainable alternative, its intermittent nature and high initial costs lead to higher electricity prices, particularly in seasonal regions where storage demand increases significantly.

The findings suggest that a fully PV-based system may not be economically optimal without efficiency improvements and cost reductions. Intermediate transition phases (75%, 50%, and 25%) exhibit the highest market price volatility, highlighting the need for carefully managed policy interventions. A hybrid approach, maintaining some level of nuclear baseload alongside PV, may provide a more cost-effective and stable transition.

As policymakers and industry leaders seek to accelerate the transition to renewable energy, balancing sustainability with affordability remains a key challenge. Future research should incorporate consumer behavior, international electricity trade, and evolving regulatory frameworks to refine strategies for achieving an efficient and equitable energy transition.

Nomenclature

AD: Average demand
AEP: Available electricity for pumping
ACPW: Average cost of pumped water
CMPHS: Contribution margin of PHS
CEB: Cost of electricity bought
CES: Cost of electricity sold
CWI: Cost of water inventory
DAAEP: Daily average of available electricity for pumping
DARD: Daily average of residual demand
DA: Daily averaging
DFPV: Demand fulfilled by PV
DPR: Desired pump rate
DRR: Desired release rate
EES: Electrical energy storage
ESE: Electricity supply excess
HD: Hourly demand
HPHSFC: Hourly PHS fixed cost
HPHSR: Hourly PHS revenue
HPHSVC: Hourly PHS variable cost
HS: Hourly solar
HEAP: Hourly excess after pumping
HPHSIAFC: Hourly PHS income after fixed costs
HPHSIAVC: Hourly PHS income after variable cost
HUDAR: Hourly unfulfilled demand after release
MCPHS: Marginal cost of PHS
MCNE: Marginal cost of nuclear electricity
MP: Market price
MB: Markup for bid
MPR: Maximum pump rate
MRR: Maximum release rate
NoS: No seasonal
NB: Nuclear bid
NC: Nuclear capacity
NG: Nuclear generation
NCF: Nuclear capacity factor
OMFCPHSC: O&M fixed cost per PHS capacity
OMVCPHS: O&M variable cost of PHS
POS: Phase-out stage
PHSB: PHS bid
PHSPP: PHS pumping price
PHSSP: PHS sales price
PHSEBITDA: PHS EBITDA
PG: Primary generation
PC: Pump capacity
PE: Pump efficiency
PWR: Pumped water in reservoir
P: Pumping
PHS: Pumped hydropower storage
PV: Photovoltaic
PVG: PV generation
PVBM: PV bid multiplier
PVC: PV capacity
PVCF: PV capacity factor
RNC: Reference nuclear capacity
R: Release
RRC: Remaining reservoir capacity
RWL: Reservoir water level
RC: Reservoir capacity
RD: Residual demand

S:	Seasonal
SDs:	System dynamics
TDR:	Time to discharge reservoir
TFR:	Time to fill reservoir
TC:	Time cap
TP:	Time to pump
TR:	Time to release
TG:	Total generation
TC:	Total curtailment
TPHSCM:	Total PHS contribution margin
TUD:	Total unfulfilled demand
VRESs:	Variable renewable energy sources.

Appendix A

Appendix A1: Model Equations

A1.1: Capacity and Demand. This subsection provides the equations concerning capacity and generation for each technology, as well as for electricity demand.

Name/equation	Parameter value	Unit
AD	100	MWh/h
DA	24	h
NCF	0.9	Dmnl/h
POS	1	Dmnl
PC	20	MWh/h
PE	0.8	Dmnl
PVC	0	MWh
PVCF	0.2	Dmnl/h
RNC	113	MWh
RC	130	MWh
TC	48	h
TP	1	h

State and associated variables

$\frac{d(\text{PWR})}{dt} = P - R$ (PWR(0) = 0)	MWh
$P = \min(\text{DPR}, \text{MPR})$	MWh/h
$R = \min(\text{DRR}, \text{MRR})$	MWh/h
$\frac{d(\text{TC})}{dt} = \text{HEAP}$ (TC(0) = 0)	MWh
$\text{HEAP} = \max(\frac{\text{ESE}-P}{PE}, 0)$	MWh/h
$\frac{d(\text{TUD})}{dt} = \text{HUDAR}$ (TUD(0) = 0)	MWh
HUDAR = $RD - R$	MWh/h
$\frac{d(\text{DAAEP})}{dt} = \frac{\text{AEP}}{\text{DA}}$ (DAAEP(0) = 0)	MWh/h
AEP = PE*ESE	MWh/h
$\frac{d(\text{DARD})}{dt} = \frac{RD}{DA}$ (DARD(0) = 0)	MWh/h

Other variables

DFPV = PVG-HEAP	MWh/h
DPR = AEP*IWLP(RWL) (Figure A1a)	MWh/h
DRR = RD*IWLR(RWL) (Figure A1b)	MWh/h
ESE = Max(PG-HD, 0)	MWh/h
HD = AD*ISHD(t)(Figure A2)	—
HS = ISHSI(t) (Figure A3)	—
$\text{MPR} = \text{Min}(\frac{\text{RRC}}{\text{TP}}, \text{PC})$	MWh/h
$\text{MRR} = \frac{\text{PWR}}{\text{TR}}$	MWh/h
NC = RNC*POS	MW
NC = NCF*NC	MWh/h
PG = PVG + NG	MWh/h
PVG = PVC*min (HS*PVCF,1)	MWh/h
RRC = RC - PWR	MWh
$\text{RWL} = \frac{\text{PWR}}{\text{RC}}$	Dmnl
$\text{TDR} = \begin{cases} \min(\frac{\text{PWR}}{\text{DARD}}, \text{TC}), & \text{DARD} > 0 \\ \text{TC}, & \text{otherwise} \end{cases}$	hH
$\text{TFR} = \begin{cases} \min(\frac{\text{RRC}}{\text{DAAEP}}, \text{TC}), & \text{DAAEP} > 0 \\ \text{TC}, & \text{otherwise} \end{cases}$	hH
TG = R + PG	MWh/h

A1.2: Bid by Technology and Market Price. This subsection provides the parameters and equations used to calculate the bid for each technology, as well as the electricity market price.

Name/equation	Parameter value	Unit
MCNE	3.9	$/MWh
OMFCPHSC	10.8	$/MWh
OMVCPHS	2.3	$/MWh
PVBM	2	Dmnl

Variables

CMPHS = CM(TDR) (Figure A4)	Dmnl
HPHSFC = OMFCPHSC*PC	$/h
HPHSR = PHSSP*R	$/h
HPHSVC = OMVCPHS*R + CEB	$/h
MCPHS = ACPW + OMVCPHS	$/MWh
$\text{MP} = \begin{cases} \text{PHSSP}, & R > 0 \\ \text{PHSPP}, & \text{otherwise} \end{cases}$	$/MWh
MB = MB(TFR) (Figure A5)	Dmnl
NB = MB*MCNE	$/MWh
PHSB = MCPHS*CMPHS	$/MWh
$\text{PHSPP} = \begin{cases} \text{PVBM*NB}, & \text{DFPV} > 0 \\ \text{NB}, & \text{otherwise} \end{cases}$	$/MWh
$\text{PHSSP} = \begin{cases} \max(\text{PHSB}, \text{PHSPP}), & \text{PG} > 0 \\ \text{PHSB}, & \text{otherwise} \end{cases}$	$/MWh

Appendix A2: Graphical Representation of Nonlinear Functional Relationships

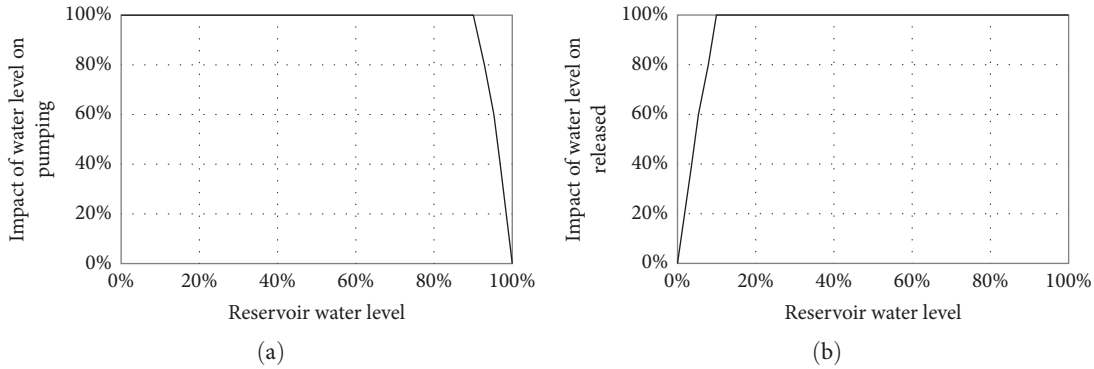


FIGURE A1: (a) Impact of water level on pumping and (b) impact of water level on release.

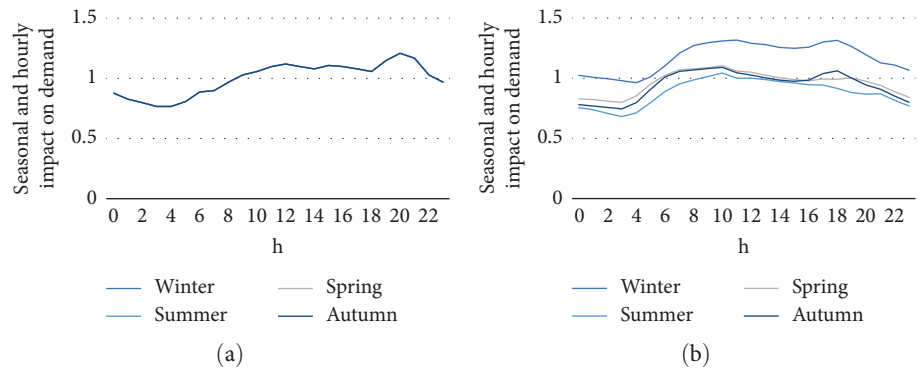


FIGURE A2: Seasonal and hourly impact on demand: (a) ISHD (*t*) NoS scenario and (b) ISHD (*t*) *S* scenario.

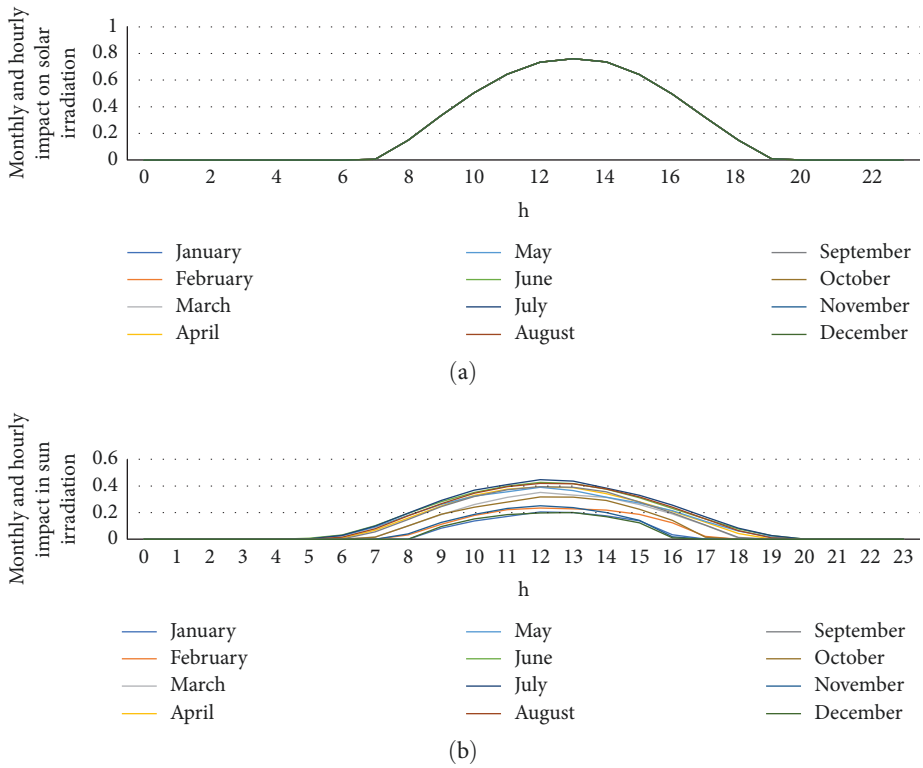
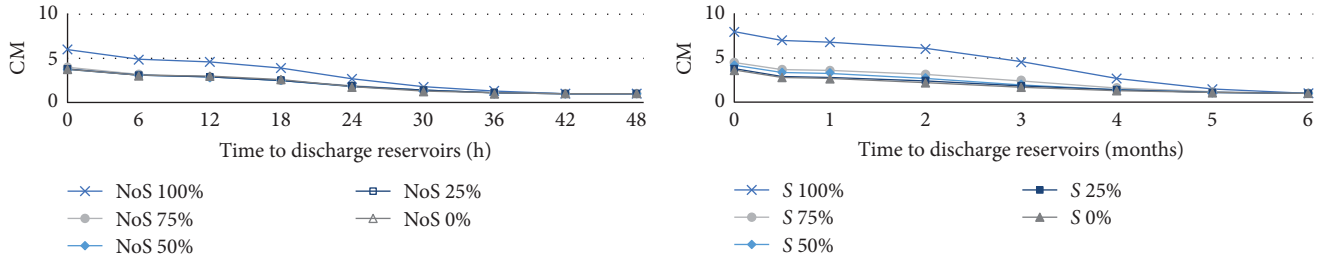
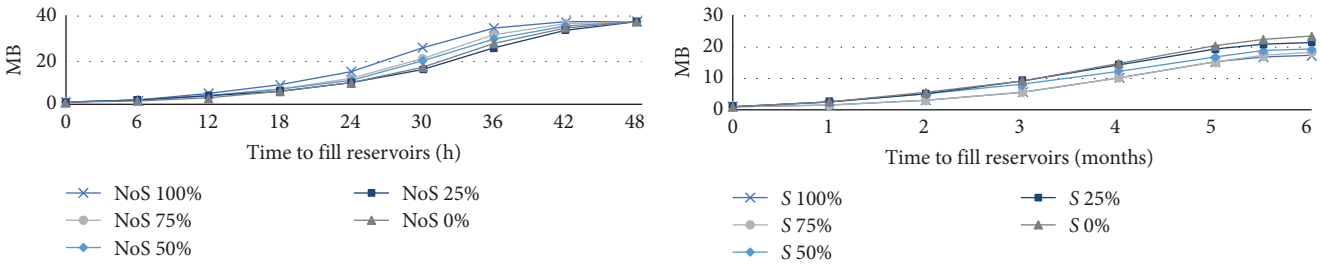


FIGURE A3: Seasonal and hourly impact on sun irradiation: (a) ISHSI (*t*) NoS scenario and (b) ISHSI (*t*) *S* scenario.



(a) (b)

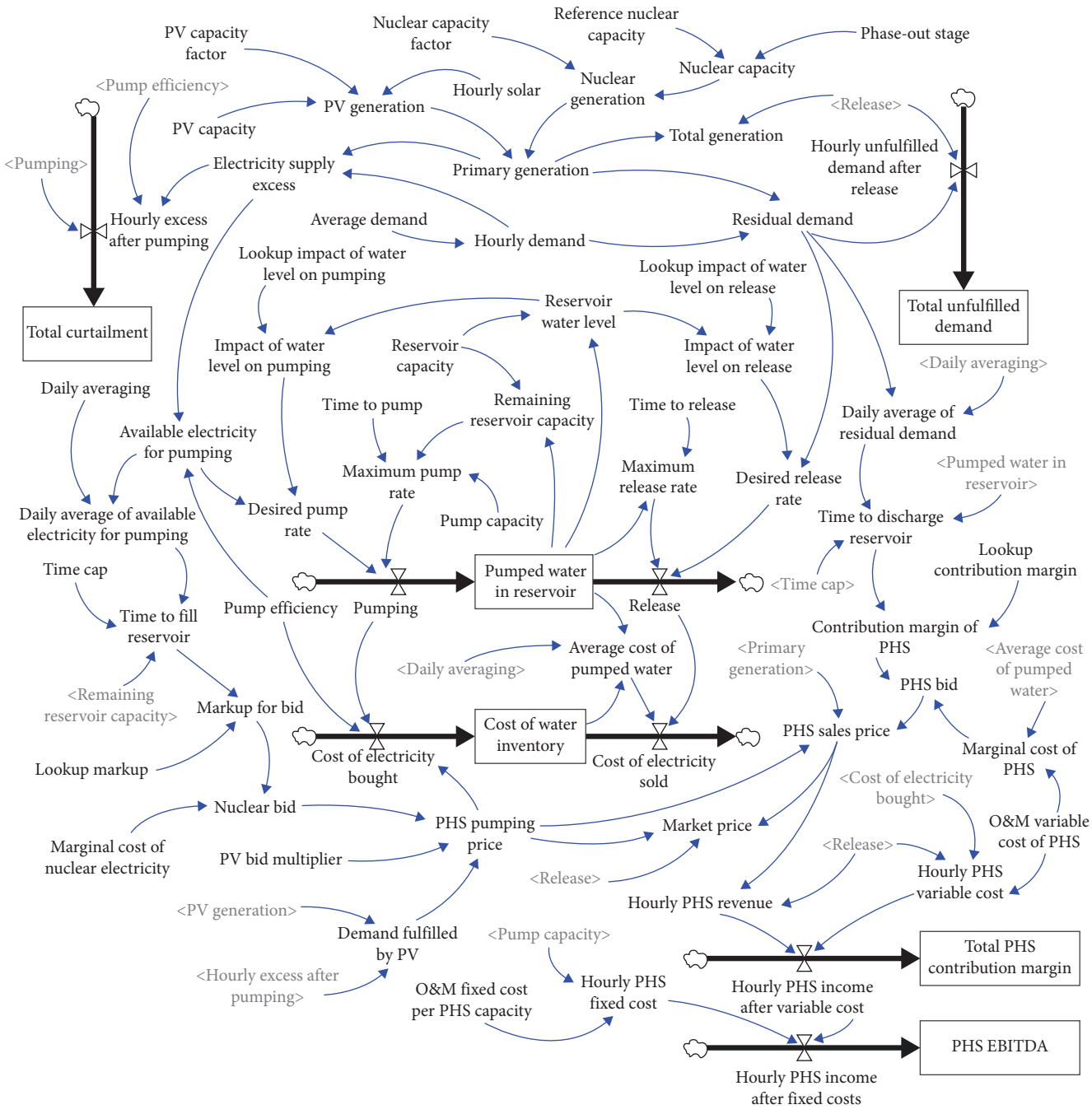
Figure A4: Contribution margin of PHS: (a) CM (TDR) NoS scenario and (b) CM (TDR) *S* scenario.



(a) (b)

Figure A5: Markup bid: (a) MB (TFR) NoS scenario and (b) MB (TFR) *S* scenario.

Appendix A3: Model Map



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Data Availability Statement

The data that support the findings of this study are available from the corresponding author upon reasonable request.

Disclosure

This manuscript builds on prior conceptual work published as a preprint: Walker et al. [64]. From nuclear to PV and hydro-storage. Should we go all the way? USAEE Working Paper Number 21-528. SSRN https://ssrn.com/abstract=3980131.

Conflicts of Interest

The authors declare no conflicts of interest.

Funding

No funding was received for this manuscript.

Acknowledgments

The authors would like to thank Professor Ann van Ackere and Professor Erik Larsen for their valuable feedback and guidance throughout the development of this work.

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