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Decarbonizing the Greek Electricity System Under the Energy Storage Context: Between Ambition and Reality

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Abstract

Decarbonization has been set as the ultimate target of the European energy policy, and, under this frame, Greece has substantially reformed its electricity mix over the last two decades. Yet, the rapid transition of the country's electricity production system towards a model that strongly relies on non-controllable renewables, without improving its energy storage means, has caused several adverse impacts that reasonably raise serious concerns about its sustainability. Further questions arise when accounting for the projections and underlying assumptions reported in the National Energy and Climate Plan. In this vein, key policy, societal, technical, sustainability and science issues are discussed, involving the challenges, perspectives and potential drawbacks of Greece's long-term energy planning. To reveal the critical role of storage, a toy simulation-optimization model is applied at the national scale to evaluate several scenarios of wind and solar P/V development under the premise of a theoretically fully decarbonized mix. This allows the exploration of trade-offs between energy storage and power capacity needs against key performance metrics (frequency and quantity of deficits and percentage of rejected renewable energy). Preliminary feasibility issues are also highlighted by considering alternative configurations of pumped hydropower storage units and associating their approximative investment costs with scale and geometry.

Keywords: electricity mix; energy policy; electrical energy storage; simulation; reliability; pumped hydropower storage; decarbonization; National Energy and Climate Plan

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1. Introduction

Decarbonization has fundamentally reshaped global economic and environmental policies, a shift decisively anchored by the 2015 Paris Agreement, which catalyzed a worldwide mandate for the reduction in greenhouse gas emissions [1]. Evidently, the European Union (EU) has been at the forefront of this transition, having already presented the "*Roadmap for moving to a low-carbon economy*" [2] prior to the Paris Agreement, while also playing an integral role in shaping the latter [3]. Through comprehensive legislative roadmaps such as the Green Deal and the "Fit for 55" package, the EU has formalized a legally binding commitment to achieve climate neutrality by 2050, alongside an interim goal of reducing net emissions by at least 55% by 2030 compared to 1990 levels [4,5].

At the core of the EU's decarbonization strategy lies the rapid expansion and integration of renewable energy (RE) sources, with emphasis on wind and solar, since hydroelectricity is well-developed in most Member States. The revised Renewable Energy Directive (RED III) underscores this commitment by setting a minimum target of a 42.5% renewable energy share in the EU's final energy consumption by 2030 [6]. This policy push has yielded transformative results across the continent's energy systems, with solar and wind now collectively generating more electricity than fossil fuels. The widespread proliferation of homegrown renewables, which is also one of the goals of the recently announced renewable energy framework for the next decade [7], has also enhanced energy security and system resilience—a concept of paramount importance for all critical infrastructure [8]—particularly in light of recent geopolitical disruptions affecting fossil fuel supply chains [9].

The integration, however, of such high shares of variable renewable energy into the EU's liberalized and market-oriented electricity structure introduces complex systemic challenges [10]. In contrast to traditional dispatchable fossil fuel plants, wind and solar generation are inherently intermittent and stochastic, depending on randomly varying weather conditions. In a competitive electricity market where prices are dictated by real-time supply and demand dynamics, typically through marginal pricing, this intermittency translates to severe market volatility [11]. As such, periods of high renewable output frequently lead to grid congestion, excessive curtailments and instances of zero or negative wholesale prices [12]. Conversely, prolonged periods of low renewable generation, also referred to as energy droughts [13–15], can trigger steep price spikes, as more expensive resources (e.g., natural gas) are called upon to meet the resulting deficits. To reconcile the physical realities of renewable generation with the economic mechanisms of the electricity market, system flexibility is critical. This can be achieved through large-scale electrical energy storage (EES) systems, which have emerged as an indispensable requirement for addressing transmission constraints and overgeneration risks. ESS allows for the temporal decoupling of electricity generation from immediate consumption, thus mitigating price volatility and preventing excessive curtailments through the balancing services required to maintain system stability in modern decarbonized grids [16,17].

The Greek electricity system exemplifies the aforementioned dynamics. As the country accelerates its phase-out of lignite and rapidly expands its solar and wind capacities, the Greek wholesale electricity market, operating under the European Target Model since 2020, has increasingly encountered periods of high price volatility, structural grid congestion and localized oversupply [18]. Given that Greece's National Energy and Climate Plan (NECP) [19] envisions an exceptionally high penetration of renewables by 2050, achieving flexibility is now the primary bottleneck for the nation's decarbonization goals, making large-scale energy storage planning all the more relevant. On the mainland's interconnected grid, numerous studies demonstrate that the large-scale integration of non-controllable renewables (mainly wind and solar) requires the parallel development of bulk energy storage. In this vein, the two most established EES options have been analyzed at the national scale, namely batteries [20] and pumped hydropower storage (PHS) [21–23]. A common assumption of all associated studies is the maintenance of a significant share of thermal units, specifically natural gas, within the examined energy mixes.

The rapid penetration of renewable energy in the Greek energy mix under limited EES availability, combined with the strong reliance on imported natural gas, causes several distortions in the electricity system, including systematically growing power curtailments due to grid constraints [24], and in the energy market, eventually resulting in unreasonably high electricity prices [25]. On the other hand, the long-term evolution of the national energy policy targets, as outlined by the NECP, raises several questions about their overall realism and feasibility.

Triggered by this, the objective of this article is twofold. First, acknowledging that energy storage is the catalyst for the transition towards decarbonization goals, a theoretical exercise, facilitated via a toy simulation-optimization model, is employed to contrast storage and power capacity quantities with key performance metrics with respect to power deficits and surpluses, considering different levels of renewable penetration. Following relevant attempts employed for other EU countries [26], the whole analysis lies upon the prerequisite of *full decarbonization* of the Greek electricity system, in terms of eliminating dependence on fossil fuels, keeping hydroelectricity as the sole controllable source, and expanding the installed capacity of wind and solar sources. The derived outcomes serve as supporting arguments for the second objective, which is to provide a brief critical view of Greece's energy future from different perspectives.

The paper is organized as follows. Section 2 provides an overview of the recent evolution of the electricity mix of Greece to reveal the urgent need for EES solutions. Sections 3 and 4 involve the first research objective, namely the estimation of energy storage and power capacity requirements for several RE development scenarios and their potential implementation via alternative PHS configurations. The second objective is operationalized in Section 5 by discussing the energy future of Greece with respect to NECP's planning assumptions from five different viewpoints, involving policy, societal, technical, sustainability and scientific issues. A closure of the overall research is given in Section 6.

2. Overview of Energy Mix Evolution in Greece

2.1. The Greek Electricity System at a Glance

For a long period, namely from the late-50s to the mid-90s, the electricity generation system of continental Greece primarily relied on domestic sources, i.e., lignite and hydroelectricity. Since then, following the major EU goal of the green energy transition under a liberalized market model, the country has drastically reduced its reliance on lignite in favor of natural gas imports and rapidly expanding renewables. The RE portfolio is dominated by wind plants and solar P/V units of all scales. Hydropower is mainly provided by 16 large storage plants (>15 MW), generally operating for peak power generation while also fulfilling irrigation, water supply and flood control uses. From 2014, their installed capacity stabilized at 3.17 GW, while the share of small (<15 MW) hydroelectric plants in the mix is only 0.25 GW. The country also hosts a pumped storage capacity of 0.70 GW across two large hydroelectric complexes (i.e., located on the rivers Aliakmon and Nestos).

A noteworthy fact is that while electricity needs has remained practically stable over the last two decades (around 50 TWh on an annual basis, with an hourly maximum load of up to 10.8 GW), the installed power capacity of the interconnected system has increased (more than doubled), and so have net electricity imports. Furthermore, from 2024 to 2025, renewable energy curtailments also more than doubled, increasing from 0.9 to 1.9 TWh (i.e., about 5% of total production from RE sources).

Figure 1 presents the evolution of key energy quantities of interest (annual electricity production, hourly peaks, and installed capacity of controllable sources and energy storage units) for 1958–2050. The values up to 2024 are derived from historical data, while the rest are based on projections retrieved from the recently submitted (January 2025) National Energy and Climate Plan [19]. This document outlines the strategic roadmap of Greece to achieve the so-called "climate neutrality" goal by 2050, a key pillar of which is the structural reformulation of its overall energy production and consumption model. The associated projections of installed capacity and produced electricity by source, as well as of EES capacity, are presented in Figure 2. The main electricity generation sources are illustrated separately, while the other sources, whose contribution to the energy mix is

minimal, comprise small hydropower (<15 MW), biomass, oil, and combined heat and power units.

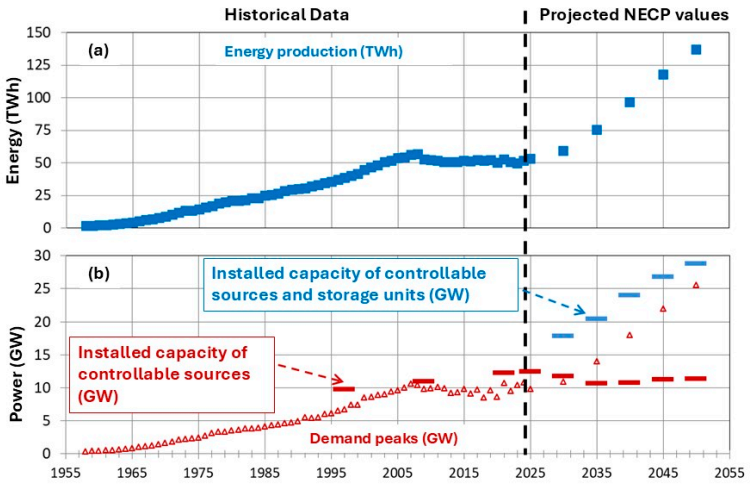

Figure 1. Historical evolution (1958–2025) of annual electricity production (**a**) and peak hourly demand (**b**) vs. installed capacity of controllable sources and storage units in the interconnected system of Greece, and projected values up to 2050, according to the NECP assumptions.

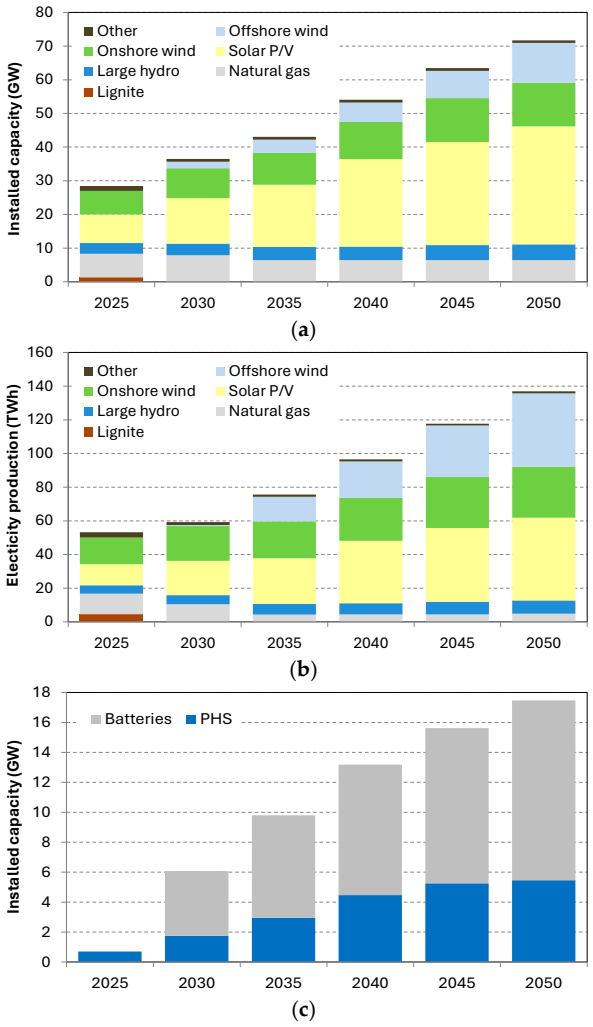

Figure 2. NECP projections for the period 2025–2050 with respect to the Greek energy mix: (**a**) installed power capacity by source; (**b**) annual energy production by source; (**c**) installed power capacity of EES components, i.e., batteries and PHS units.

A critical outlook on the recent development of the Greek electricity system, as well as the targets set by the NECP up to year 2050, following the conclusions obtained by the subsequent analyses, is provided in Section 5.1.

2.2. Insights into the Last Decade's Generation vs. Demand Data

Focusing on the last decade (2015–2025), for which full time series of hourly electricity production by source and associated demand data are available at the national level, a brief analysis of them is attempted to reveal the ultimate shortcoming of the Greek electricity system, which is the lack of energy storage means. The raw data were retrieved from the European Network of Transmission System Operators for Electricity (ENTSO-E). This analysis involves electricity demand contrasted with the associated production from the three major renewable sources, namely large hydropower (referring to hydroelectric reservoirs with a capacity of >15 MW), wind and solar P/V.

The evolution of RE supply vs. demand data on an annual basis is presented in Table 1. The four variables exhibit quite different statistical behavior. In particular, the variability of electricity demand is minimal (average 50.28 TWh, standard deviation 1.27 TWh), while generation from the three renewable sources is characterized by significant fluctuations. However, in the case of hydropower, since the installed capacity of large hydroelectric plants is stable, this variability is explained by the stochastic nature of the underlying hydrological processes, while the systematically growing production from wind and solar P/V sources is mainly due to the increase in their share of the energy mix, as shown in Figure 3. It is observed that during the first half of the examined period, the installed capacity of solar P/V sources remained practically stable, followed by a sharp increase, while the power penetration indicated quite a different pattern, with a milder development that seems to have stabilized. Nevertheless, the overall footprint of RE development resulted in an exceptional change in the percentage of demand covered by the three renewables, from 22.8% in 2015 to close to 50% in 2024 and 2025.

Table 1. Evolution of the share of the three major renewable sources (hydropower, wind, and solar) with respect to electricity demand during 2015–2025.

Year	Hydropower (TWh)	Wind (TWh)	Solar (TWh)	Demand (TWh)	Ratio of Demand Covered by RE
2015	4.47	3.59	3.54	50.92	0.228
2016	4.22	3.62	3.75	50.56	0.229
2017	3.04	3.65	4.23	51.57	0.212
2018	4.39	3.42	4.88	51.24	0.248
2019	2.93	3.61	5.79	51.68	0.239
2020	2.44	3.98	7.44	48.84	0.284
2021	4.57	4.74	9.03	51.17	0.358
2022	3.36	6.28	9.39	48.74	0.390
2023	3.40	8.63	9.44	47.88	0.449
2024	2.65	11.40	10.93	50.47	0.495
2025	2.49	11.43	10.49	49.98	0.488
Average	3.45	5.85	7.17	50.28	0.329
St. deviation	0.83	3.17	2.82	1.27	0.111

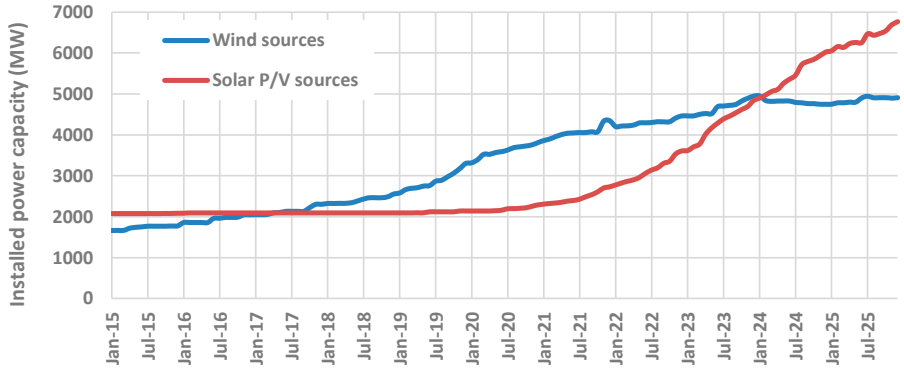

Figure 3. Monthly evolution of the installed capacity of wind and solar P/V sources during 2015–2025.

As the increasing energy production from two out of the three RE sources is the outcome of increased installed capacity, their comparison should preferably be done using a dimensional measure, namely the capacity factor CF. The latter is a typical metric in power systems, defined as the ratio of actual electricity production, E, during a time interval, T, to the theoretically maximum output obtained by operating the system at its nominal capacity, P_{max}, thus $CF = E/(P_{max}\ T)$. The evolution of the 2015–2025 values for the three RE sources is depicted in Figures 4–6, considering two temporal scales of interest, namely the daily and the 20-day moving average. Different statistical conclusions are detected from each source, particularly:

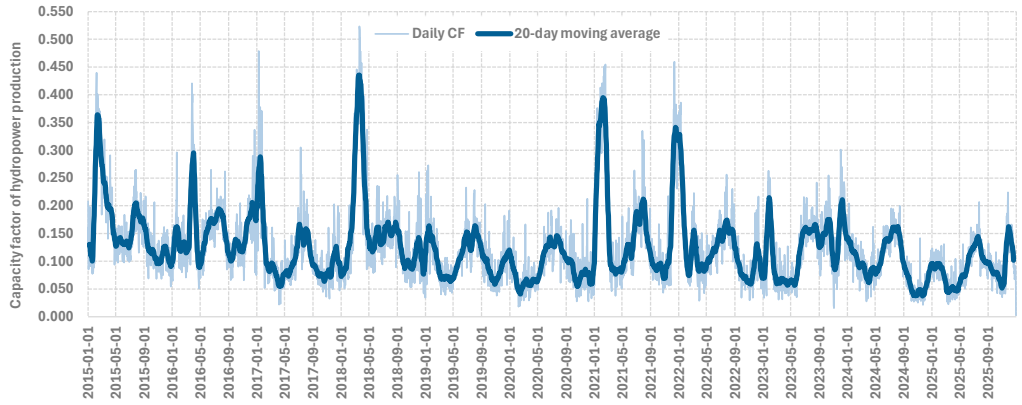

Figure 4. Capacity factor of hydropower production by large (>15 MW) plants from 2015 to 2025 across two scales (daily and 20-day moving average).

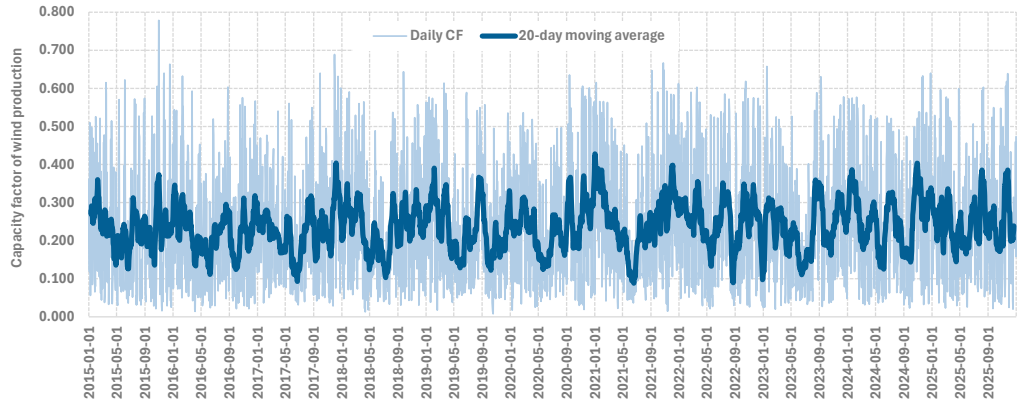

Figure 5. Capacity factor of wind power production from 2015 to 2025 across two scales (daily, 20-day moving average).

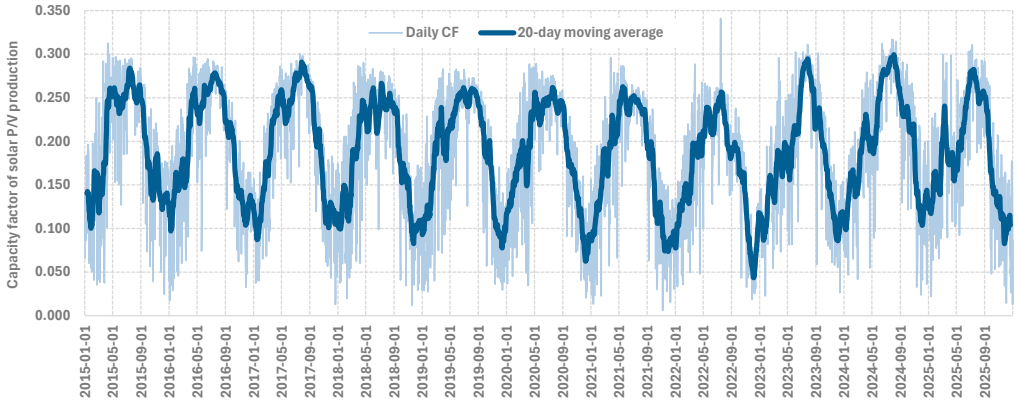

Figure 6. Capacity factor of solar P/V energy production from 2015 to 2025 across two scales (daily and 20-day moving average).

- Hydropower production exhibits substantial variability because of the role of large hydroelectric reservoirs in peak energy production, yielding relatively low *CF* values except during flooding periods, during which the hydroturbines operate continuously to prevent unessential spills. Finally, the stochastic nature of the driving hydroclimate at the over-annual scale, namely the clustering of wet and dry years, which is referred to as long-term persistence and is attributed to the so-called Hurst–Kolmogorov dynamics [27], is reflected in the transformation of inflows to hydropower.
- Wind production exhibits significant variability across all scales, even at the seasonal one, thus being by far the least predictable among the three renewables.
- P/V production is driven by solar dynamics, thus relying on intraday and seasonal cycles, while its long-term variability is limited. The daily *CF* values range from less than 5% in December to 30% in June.

The mean *CF* values of hydropower, wind and solar P/V sources are 12.4%, 23.8% and 18.7%, respectively.

Regarding electricity demand, its evolution at the daily and 20-day scales over the decade 2015–2025 is shown in Figure 7. While the annual demand values are practically constant, as already commented on in Section 2.1 (Table 1), the intra-annual pattern of the more recent years differs from that of the past. In particular, the spread between low- and high-demand periods is amplified, indicating that the electricity needs during fall and spring are clearly reduced, while demand during the summer month is growing. In fact, this reflects the overall socioeconomic status of Greece, which can be characterized by tourism expansion contrasted with adverse demographic evolution and deindustrialization.

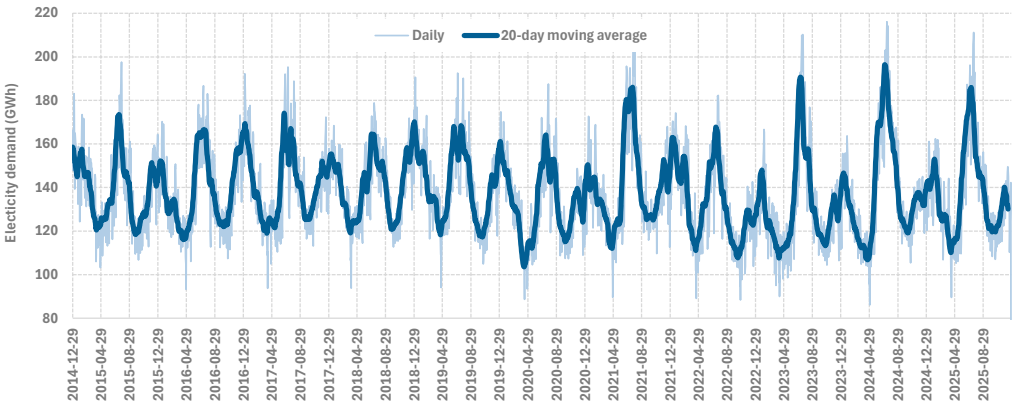

Figure 7. Electricity demand from 2015 to 2025 across two scales (daily and 20-day moving average).

3. Toy Simulation-Optimization Model for Exploring a Full Decarbonization Perspective

3.1. Rationale, Assumptions and Limitations

The analysis of the recent evolution of the electrical energy balance of Greece across scales revealed the urgent necessity for power regulation through storage to overcome energy surpluses and deficits derived from non-dispatchable energy sources, i.e., wind and solar P/V. Given that the long-term strategy is to move towards mostly decarbonized systems, thus progressively replacing conventional thermal units with renewables, it would be useful to investigate—at least to preliminary degree—whether this goal is feasible under the current technological means.

To answer the hypothetical question whether Greece can rely on an energy mix without fossil fuels through enhancing the share of renewables and supporting them with large-scale EES, a toy simulation-optimization model is established. The model runs for a single year on hourly basis (8760 time steps), using as inputs the electricity demand contrasted with the wind, solar P/V and hydropower production data of 2025. Except for hydropower, these data can be considered as representative of the current state in Greece. For convenience, the sum of wind and solar PV production is treated as a common renewable energy source. In 2025, its share of the total energy mix was 44% of annual demand (22.0 vs. 50.2 TWh), while the contribution of hydropower was only 5% (2.5 GWh), since that year was very dry (in general, during hydrological years 2022–2023 to 2024–2025, Greece was hit by a prolonged drought, the most severe of this century so far). Nevertheless, the use of a dry year in the context of an EES simulation exercise is a conservative assumption with minimal impacts on the derived quantities, also accounting for the limited contribution of hydropower to total electricity production.

Under this premise, several mixings are investigated, starting from the 2025 benchmark and then proceeding to future scenarios of renewable development, which are approximatively configured by applying a multiplier $\lambda_{RE} \geq 1$ to the hourly wind and solar data values. Although this assumption is simplistic, it is sufficient for such a macroscopic level of analysis. Specifically, eight scenarios are determined in terms of λ_{RE}, namely $\lambda_{RE} = 1.0$ (current state), $\lambda_{RE} = 1.5$, $\lambda_{RE} = 2.0$, $\lambda_{RE} = 2.17$ (specific scenario for which the total power supply equals the total demand), $\lambda_{RE} = 2.5$, $\lambda_{RE} = 3.0$, $\lambda_{RE} = 3.5$, and $\lambda_{RE} = 4.0$.

The above assumption is also in line with the NECP projections up to 2050 with respect to energy production by source (Figure 2b). Figure 8 illustrates the anticipated evolution of wind (both onshore and offshore) and solar P/V generation in dimensionless terms, i.e., by dividing to the annual values for year 2025 (for convenience, the 2025 data were obtained from the NECP). Until 2040, the derived curves exhibit similar linear slopes, thus indicating an almost uniform development of the two renewables. During 2040–2050, the two curves deviate, which is attributed to the wide expansion of offshore wind power in such a short time (cf. the critical discussion of the NECP's projections in Section 5.1). Nevertheless, when accounting for the total production from the two VRE sources, it is shown that their expected increase compared with the current conditions will be a little more than fourfold, which is also consistent with the upper value of the multiplier λ_{RE}.

Regarding the share of hydropower, it is considered to remain unchanged, since the national strategic energy plan does not seek the development of new large hydroelectric projects in the foreseeable future (for a long time, the hydropower capacity has remained stable at 3.17 GW). In this vein, in all energy mixing scenarios, the hourly production values of 2025 are considered, referring to non-favorable hydrological conditions, which is a rather conservative hypothesis. It is also highlighted that the correspondence of the observed hydropower outputs of 2025 to a hypothetical energy balance induced by a mix of renewables with EES elements introduces quite significant bias, since hydroelectric

reservoirs are already used as major regulators of the Greek electricity system; thus, their production scheduling is significantly dictated by the current scheme of energy sources (they are mostly used for generating peak energy).

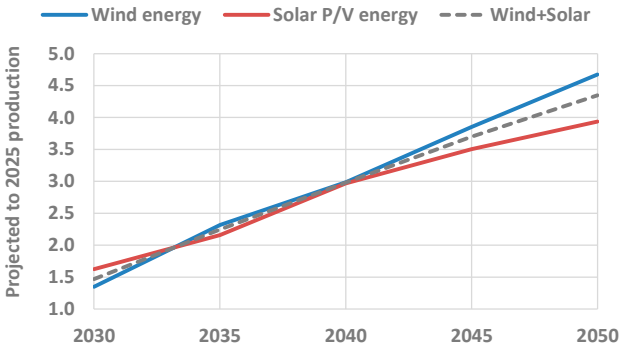

Figure 8. NECP's projections of wind and solar P/V production, divided by the 2025 values.

Within the simulations, a conceptual national-scale storage system is represented as an overall unit, the key properties of which are its energy and power capacities, S_{max} and P_{max}, respectively, which are set as the two design variables to optimize for each scenario. The first refers to the total amount of energy that can be stored in or discharged from the EES unit, while the second indicates the maximum instantaneous amount of electric power that can be absorbed or generated on a continuous basis. Under the toy model approach, P_{max} during the charge and discharge phases may be considered identical.

Another technical characteristic of the energy storage unit, which is handled as constant, is the round-trip efficiency, η_r, defined as the ratio of usable energy discharged to the total energy required to charge it over a full cycle. In real-world ESS systems, η_r depends on the underlying technology and site-specific characteristics. In fact, this term is the product of several efficiency components across the charge–storage–discharge chain, which are applicable to all kinds of energy transformations, and may also account for self-discharge losses (e.g., in the case of batteries). For simplicity, within the toy model context, the latter can be omitted, while η_r is split into two equal multipliers η_c and η_d, referring to the charge and discharge phases, respectively. Finally, by assigning a typical round-trip value of $\eta_r = 0.70$ and setting $\eta_c = \eta_d = \sqrt{\eta_r}$, we get $\eta_c = \eta_d = 0.837$.

3.2. Governing Equations of the Simulation Model

Let S_{t-1} be the known energy storage at the beginning of each time step $t = 1, \ldots n$, and let D_t and E_t denote the demand and the total generation by wind, solar and hydropower sources, respectively. For convenience, all quantities are expressed in terms of energy units. The simulation model relies upon the energy balance equation:

$$S_t = S_{t-1} + E_{c,t} - E_{d,t} \quad (1)$$

where S_t is the stored energy at the end of time step t, while $E_{c,t}$ and $E_{d,t}$ are the charged and discharged energy, respectively. When the energy produced exceeds the associated demand; thus, $E_t - D_t > 0$, the charge phase is activated, which is subject to two constraints, namely the power capacity, expressed in terms of maximum energy that can be absorbed, and the available storage excess, i.e.:

$$E_{c,t} = min[\eta_c(E_t - D_t),\ \ \eta_c\, P_{max}\, \Delta t,\ \ S_{max} - S_{t-1}] \quad (2)$$

where Δt is the time resolution of simulation (hourly in this analysis). The charged quantity $E_{c,t}$ plays the role of the inflow to the ESS unit; thus, $S_t = S_{t-1} + E_{c,t}$, while the final energy surplus is $E_s = E_t - D_t - E_{c,t}/\eta_c$, where $E_{c,t}/\eta_c$ is the absorbed electrical energy.

On the contrary, when $\Delta E_t = E_t - D_t < 0$, the discharge phase is activated to fulfill the associated deficit. The discharged energy is also subject to power and storage availability constraints; thus:

$$E_{d,t} = min[(D_t - E_t)/\eta_d,\ \ P_{max}\,\Delta t/\eta_d,\ S_{t-1}] \tag{3}$$

At the end of time step, the quantity $E_{d,t}$ is subtracted from the EES unit; thus, $S_t = S_{t-1} - E_{d,t}$, while the output energy $\eta_d\, E_{d,t}$ is injected into the grid. Hence, the final deficit (expressed in negative terms) is $E_{def,t} = E_t + \eta_d\, E_{d,t} - D_t$.

To implement the simulation, the initial energy storage value, S_0, is required and should be carefully determined to ensure stationarity, i.e., $S_0 = S_n$. When the simulation time horizon is short (e.g., up to a few years), this condition becomes important, since the derived power deficits and surpluses are strongly dependent on the deviation between the initial and final states of the system.

3.3. Setup of the Optimization Problem

For each development scenario of the Greek electricity system, expressed in terms of the renewable energy increase factor λ_{RE} with respect to 2025 production, an optimization problem is formulated with respect to the design variables S_{max} and P_{max}, whose major objective is the maximization of the system's reliability. The latter is a common performance metric for all kinds of production schemes driven by uncertainties and is identified as the frequency of the successful delivery of their services. In the case of electricity systems, this translates into the adequacy and availability of power delivery to match the load demand [28]. The theoretical definition of reliability is expressed in probabilistic terms, i.e.:

$$a := 1 - \mathcal{P}[Y_t < D_t; t \in \mathcal{T}] \tag{4}$$

where Y_t and D_t refer to the system's yield (in our case, electrical energy production) and demand, respectively, at time t, within a specific period $\mathcal{T}$. Since Equation (4) does not have an analytical solution, Monte Carlo approaches are preferred, representing Y_t and D_t through a simulation model and accounting for the generated deficits and their associated frequencies of occurrence. In the context of the toy simulation model of the Greek electricity mix, reliability is empirically evaluated as the percentage of time where the derived energy production equals or exceeds the associated demand.

It is underlined that the reliability of a storage-based electrical energy system, under given power production and demand data, is maximized when the storage and power capacity values, S_{max} and P_{max}, become large enough that they do not act as binding constraints within Equations (2) and (3). However, this would result in extremely large storage dimensions, which are far from desirable from both technical and financial perspectives. Another point of attention concerns the preservation of the stationarity condition, i.e., $S_0 = S_n$, which is crucial because of the very short duration of simulation, i.e., one year (2025). It is argued that the toy model serves as a demonstration exercise, which is nevertheless essential for revealing the key shortcomings of Greece's energy strategy and discussing potential remediations at an abstract level.

To ensure techno-economically feasible and consistent solutions, two external constraints are introduced into the optimization problem by means of penalty terms, while

the initial storage, S_0, is also handled as an unknown control variable. In this respect, the objective function to be maximized is formulated as follows:

$$maximize\ f(S_{max}, P_{max}, S_0) = a - w_1\ S_{max} - w_2|S_0 - S_n| \quad (5)$$

where a is the reliability (dimensionless), and w_1 and w_2 are weighting coefficients set to be equal to 10^{-7} and 10^{-6}, respectively, with all storage quantities expressed in MWh. The above values were tuned through preliminary investigations, allowing the detection of reasonable trade-offs between the overall performance criterion, i.e., reliability, and the major dimension of the conceptual EES system, namely its storage capacity. To define the decision space, the upper 1% quantile of deficits was used as the upper feasible value of the power capacity P_{max}, while the storage capacity was restricted such that the charging time did not exceed 48 h; thus, $S_{max}/P_{max} \leq 48$. This is also a reasonable assumption, considering the abilities of current EES technologies. It is remarked that during the optimization procedure, this constraint was allowed to be slightly violated to prohibit being trapped in solutions that were far from optimal.

It should be noted that for sufficiently long simulations, such as those driven by synthetic power production and demand data, both the use of S_0 as a control variable and the penalty term $w_2|S_0 - S_n|$ would be redundant.

Since the objective function (5) is nonlinear and its feasible space is only determined by the allowable bounds of the three variables, S_{max}, P_{max} and S_0, the underlying problem belongs to the global optimization family, for which numerous solvers are available. Due to the small number of control variables, it was easily handled via common evolutionary algorithms.

3.4. Results

As mentioned above, eight development scenarios are investigated in terms of the multiplier λ_{RE}, expressing the ratio of the simulated to the current (year 2025) electrical energy production from renewables (wind and solar P/V), whose value is increased from one (current scenario) to four. It is recalled that the actual 2025 data are used for both the hourly electricity demand and the associated production from large hydroelectric projects. For each scenario, the underlying simulation-optimization problem is solved, providing the following results:

- Optimized storage and power capacity (also including the initial storage ensuring stationarity conditions);
- Hourly simulated data of the energy absorbed from the grid to charge the EES system, energy discharged from the storage system and injected into the grid, remaining surpluses to be rejected, and remaining deficits that must be fulfilled by alternative sources (i.e., imports from external grids or activation of conventional thermal units);
- Key performance metrics, including reliability, as defined in Section 3.3 (also expressed in terms of failure probability, $1 - a$), the ratio of annual deficits to demand, and the ratio of rejected-to-produced energy from wind, solar and hydropower sources.

An example of the simulated storage data, as well as the surpluses (rejected energy) contrasted with the deficits on an hourly basis, for $\lambda_{RE} = 3.0$ (scenario 6), is shown in Figures 9 and 10, respectively. Surpluses occur either due to overproduction by the hypothesized energy mix, consisting of the three renewables (i.e., wind, solar P/V and hydropower), or exhaustion of the storage system's capacity (256 GWh in this specific case). On the other hand, deficits occur whenever the available energy storage tends to zero, so that the difference between demand and production cannot be fulfilled by the storage system.

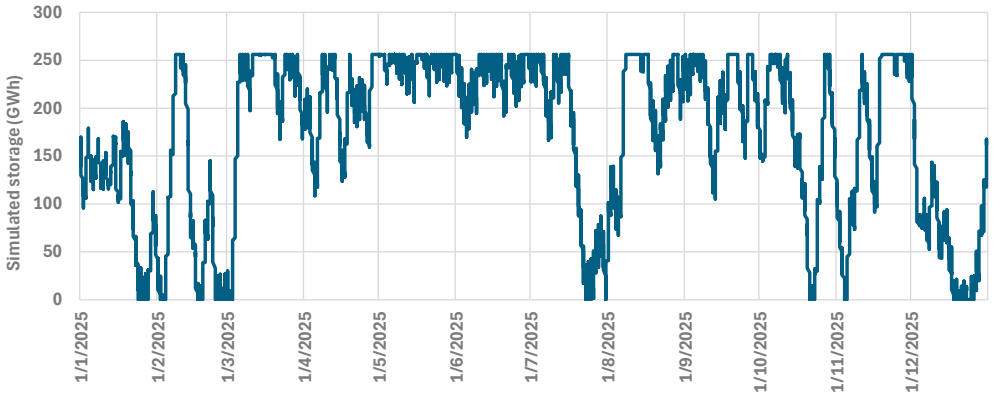

Figure 9. Simulated energy storage for scenario 6 ($\lambda_{RE} = 3.0$, $S_{max} = 256$ GWh, and $P_{max} = 5.33$ GW).

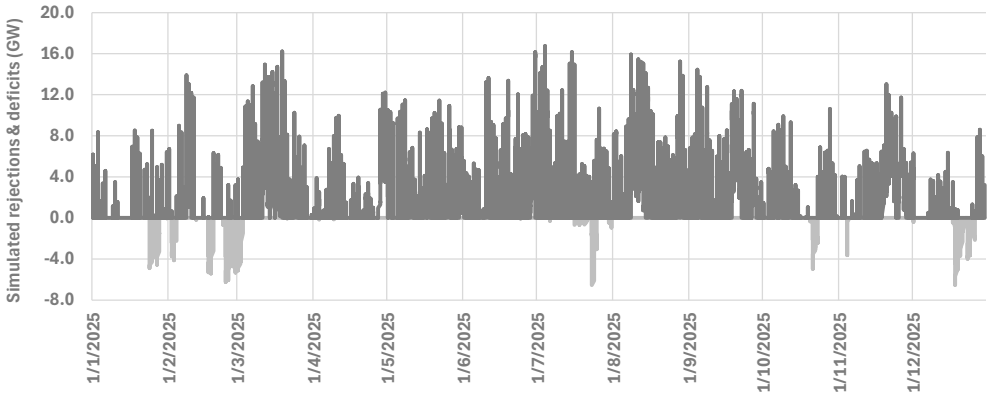

Figure 10. Simulated power rejections (dark grey, positive values) and deficits (light grey, negative values) for scenario 6 ($\lambda_{RE} = 3.0$, $S_{max} = 256$ GWh, and $P_{max} = 5.33$ GW).

Table 2 summarizes all key output data, while the scatter plots of Figure 11 illustrate the evolution of four quantities of interest (optimized energy storage and power capacity, with blue and orange colors, respectively, rejected-to-produced power by renewables, reliability, and mean annual supply-to-demand ratio) with respect to the multiplier λ_{RE}. It also reports the maximum continuous charging or discharging time per scenario, which is computed as the ratio of the storage to the power capacity. In most scenarios, this is far below the upper limit of 48 h, thus indicating that the associated constraint is not binding.

Table 2. Key results of the examined simulation-optimization scenarios.

Scenario	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Ratio to 2025 wind and solar production, λ_{RE}	1.00	1.50	2.00	2.17	2.50	3.00	3.50	4.00
Annual supply (GWh)	24,483	35,476	46,469	50,185	57,463	68,456	79,449	90,442
Annual demand, year 2025 (GWh)	50,178	50,178	50,178	50,178	50,178	50,178	50,178	50,178
Optimized storage capacity, S_{max} (GWh)	6	60	255	268	263	256	171	163
Optimized power capacity, P_{max} (GW)	3.96	5.46	5.64	5.61	5.48	5.33	5.18	5.04
Maximum charging/discharging time (h)	1.6	10.9	45.2	47.7	48.1	48.0	33.0	32.3

Table 2. *Cont.*

Scenario	1	2	3	4	5	6	7	8
Rejected energy (GWh)	1	10	950	2052	6379	15,753	26,780	37,778
Annual energy deficits (GWh)	25,727	15,783	7490	5346	2768	1049	647	323
Reliability (perc. of time without deficits)	0.042	0.401	0.707	0.786	0.880	0.952	0.966	0.978
Electrical energy deficits to demand	0.513	0.315	0.149	0.107	0.055	0.021	0.013	0.006

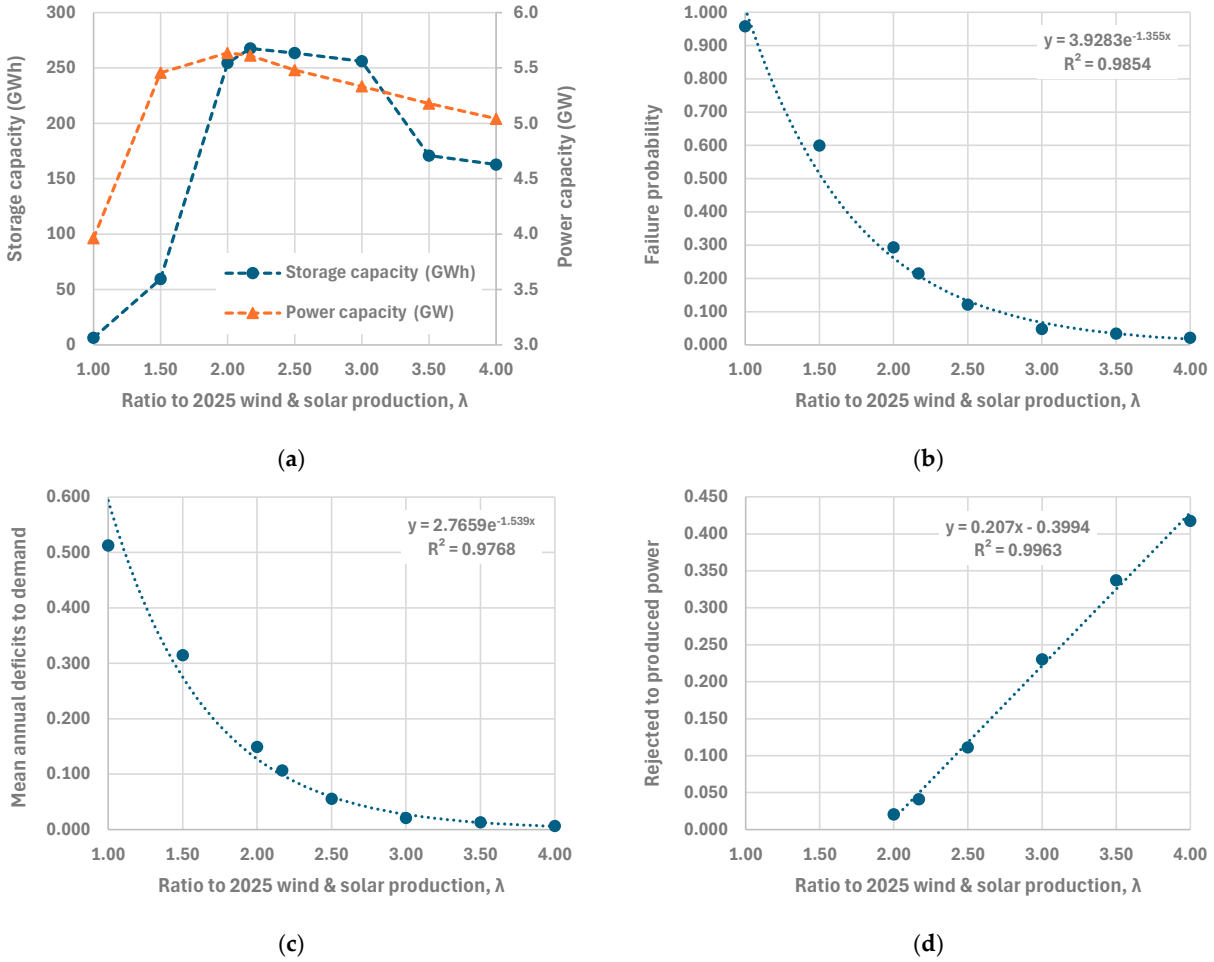

Figure 11. Scatted plots of the key quantities of interest with respect to the 2025 production from wind and solar P/V sources: (**a**) optimized energy storage and power capacity; (**b**) failure probability; (**c**) mean annual deficits-to-demand ratio; (**d**) rejected-to-produced energy by all renewables (wind, solar, and hydro).

An interesting outcome is that the functions $S_{max} = f(\lambda_{RE})$ and $P_{max} = f(\lambda_{RE})$ are not monotonic, since the energy storage and power capacity needs increase up to scenario 4, following the assumption that the total supply equals the total demand ($\lambda_{RE} = 2.17$), after which they decrease (Figure 11a). This behavior is reasonable, considering that under an infinite availability of renewable energy, the associated demand would be fulfilled with 100% reliability; thus, the ESS needs would tend to zero, while also creating tremendous surpluses. It should be emphasized that this is just a theoretical condition, which appears because the major objective of the optimization exercise is the maximization of reliability. Regarding the optimal power capacity of the conceptual EES system, it follows a similar pattern, although exhibiting much smaller fluctuations, around a value of 5.0 to

5.6 GW. It is remarkable that under the current RE production level, the required storage capacity is relatively small (6 GWh), offering minimal regulation and thus resulting in a far-from-acceptable reliability of 4.2%. This outcome is expected, since the available power sources in the country (wind, solar P/V, and large hydro) cover a little less than half of the corresponding electricity needs.

On the contrary, all performance metrics in Table 2 display a systematic (i.e., monotonic) pattern as the share of wind and solar P/V energy increases. Specifically, reliability increases asymptotically up to a threshold of about 98%. Equivalently, as shown in Figure 11b, the failure probability asymptotically decreases to a lower limit of about 2%, while this behavior is well-approximated by an exponential decay function. A similar mathematical expression is fitted to the ratio of annual power deficits to demand (Figure 11c), which may be regarded as a quantitative definition of failure. Finally, the percentage of rejections with respect to supply is practically zero up to $\lambda_{RE} = 1.5$, after which it increases almost linearly, reaching over 40% for the most extreme scenario, i.e., $\lambda_{RE} = 4.0$ (Figure 11d). This indicates that the advantages offered by a hypothetical expansion of current wind and solar P/V production, regulated by large-scale EES systems, will be counterbalanced without a carefully designed surplus management policy.

To investigate the impacts of utilizing the hydropower generation data from a remarkably dry year, which is not representative of the average hydrological regime of Greece, a comparative simulation is employed for scenario 6 by setting the associated values from the wettest year, 2021, as model input. As shown in Table 1, in 2021 the large hydropower units produced 4.57 TWh, which is almost double the 2025 generation (2.49 TWh). As expected, by running the simulation model with the storage and power capacity values reported in Table 2, i.e., 256 GWh and 5.33 GW, respectively, the system's reliability increases slightly from 95.2% to 96.4%, while the annual deficits decrease from 1049 TWh to 520 TWh.

4. The Potential of Pumped Hydropower Storage

4.1. Overview of Pumped Hydropower Storage Technology

PHS is the process of storing energy by pumping water from a lower reservoir to a higher one during periods of surplus electricity generation (charge phase), thereby converting electrical energy into gravitational potential energy. In the opposite case, i.e., when the demand exceeds supply, the water is released to the lower reservoir, thus reconverting the stored potential energy into electrical energy (discharge phase). These conversions are employed through reversible hydrodynamic machines, which operate as pumps to lift water from the lower to the upper reservoir and as hydroturbines, in the opposite direction, to produce hydroelectricity. PHS is by far the most mature and extended large-scale storage technology worldwide, representing over 94% of the world's energy storage (total storage capacity: ~9000 GWh; total power capacity: ~200 GW). Due to its favorable relief, PHS is a promising solution for the sustainable energy future of Greece [29], both from the perspective of wide-scale projects in the mainland (see Section 5.3) and as an essential component of the local electricity mix of non-interconnected islands [30,31]. In fact, for large island grids, such as Crete or Samos, the optimal sizing and integration of PHS and dedicated energy storage have proven economically crucial for capturing rejected wind energy, reducing reliance on local thermal stations and ensuring autonomous system stability [32,33].

From a design perspective, the major challenge within PHS planning is to detect a suitable configuration that minimizes the horizontal distance and maximizes the elevation difference between the two reservoirs. The horizontal distance should be as short as possible to minimize the length of water conveyance works, which affects both the hydraulic losses

and the cost of the water conveyance system, while the vertical distance should be as large as possible to maximize the hydropower potential.

The electrical power consumed to lift water at a flow rate q_p is given by:

$$P_p = \gamma \, q_p \, h_m / \eta_p \tag{6}$$

where γ is the specific weight of water (9.81 kN/m^3), h_m is the so-called manometric head, namely the sum of the gross head (water level difference between the two reservoirs, Δz) and the hydraulic losses along the piping system, and η_p is the pumping efficiency. Both variables are nonlinear functions of flow, while the hydraulic losses also depend on the geometrical and hydraulic properties of the piping system.

On the other hand, the generated power via discharging at a flow rate q_g is given by:

$$P_g = \gamma \, q_g \, h_n \, \eta_g \tag{7}$$

where h_n is the so-called net head, namely the gross head after subtracting the hydraulic losses, and η_g is the efficiency. The ratio of the net to the gross head is called the hydraulic efficiency and is symbolized by η_h. Provided that $q_p = q_g$, the manometric head is $(1 + \eta_h)$ times the gross one, while $h_n = (1 - \eta_h)$.

In the context of large-scale PHS systems, employing 24- to 48-h regulation, η_h is of the order of 0.95 to 0.97, η_g is slightly greater than η_p, P_p is slightly greater than P_g, and the round-trip efficiency is defined as:

$$\eta_r = \eta_p \eta_g \eta_h / (2 - \eta_h) \tag{8}$$

which may reach 70%. This parameter accounts for all means of electro-mechanical (E/M) and hydraulic losses, while self-discharge losses are expressed in terms of water losses due to evaporation and leakage processes, which are rather negligible and are therefore typically omitted. Considering that the energy produced is about 0.70 times the energy consumed, the pumping time, t_p, should be set 1.40 times the generation period, t_g. Nevertheless, within a full cycle, the products $t_p q_p$ and $t_g q_g$ must equal the same water volume recycled from the lower to the upper reservoir and vice versa, which in turn determines the useful storage capacity of the smaller reservoir (typically the upper one).

4.2. Investigation of Alternative PHS Design Configurations

To assess the feasibility of establishing an (almost) fully decarbonized electricity generation system in Greece, the outcomes of RE development scenario 6 are considered (Table 2), assuming a treble in wind and solar P/V production with respect to the 2025 data. Following the NECP projections, this is expected to be done by 2040 (Figure 8). The optimization analyses for this scenario resulted in a conceptual national-scale EES system with a storage capacity of about 255 GWh and a power capacity of 5.3 GW. This combination allows continuous charging for 255/5.3 ≈ 48 h (Table 2).

To implement this in practice, while also accounting for economies of scale, these two quantities are split into $m = 10$, 50 and 100 PHS projects of equal size. For convenience, closed-loop PHS systems (i.e., without external inflows) comprising two equal reservoirs are considered. The reservoirs are located at four different elevation differences, i.e., $\Delta z = 100$, 200, 300 and 400 m, thus resulting in 3 × 4 = 12 alternative configurations.

The total efficiency of 0.70 is shared between the hydraulic and E/M components by setting $\eta_h = 0.95$ and $\eta_p = \eta_g = 0.88$, respectively, which yields $\eta_r = 0.70$ (Equation (8)), as already assumed in the previous simulations. Therefore, the hydraulic losses are estimated to be 5% of the total head, thus $h_m = 1.05 \, \Delta z$. For the given energy storage capacity of each

PHS unit, E_{max}/m, the corresponding volume of water to be lifted is (a multiplier equal to 3600 s/h should be applied to convert GWh to hm^3):

$$V_{max} = \frac{1}{m}\frac{\eta_p\, E_{max}}{\gamma\, h_m} \quad (9)$$

The maximum pumped volume V_{max} also equals the useful capacity of each of the two reservoirs, since this is the maximum quantity to be recycled during a full charge–discharge phase. In the absence of site-specific information, a 10% increment is applied to estimate the total (gross) storage capacity of each reservoir, i.e., $S_{tot} = 1.10\, V_{max}$. Apart from the useful storage, this also includes the so-called dead storage, employing sediment management up to the intake elevation, and the freeboard storage above the maximum operational pool level up to the dam crest, employing flood retention.

4.3. Preliminary Economic Assessment

PHS systems are subject to significant capital expenditures due to civil works, tunneling, dam construction, and electro-mechanical equipment, yet relatively low and stable operation and maintenance costs. In this vein, to assess the financial viability of the alternative schemes at a preliminary level, an estimation of the two major cost components is attempted, referring to the reservoir and the E/M equipment. The first is associated with energy capacity, while the second is associated with power capacity requirements.

Following the abstract approach of [34], which investigated the electricity storage requirements of the Greek electricity system, the investment costs of the energy and power capacity components are initially set to 20 €/kWh and 580 €/kW, respectively. By substituting the values with respect to the running scenario of 255 GWh (storage) and 5.3 GW (power), respectively, the estimated costs reach 5.10 and 3.07 billion € (8.17 B€ in total), respectively. Although this value is quite good guidance, the application of "flat" unit cost values fails to account for the key issue of economies of scale, which is essential in a strategic planning approach, where the question arises of whether to develop a few large-scale ESS projects or distribute the storage and power needs among numerous small ones. This dilemma is common across all aspects of water–energy systems [35]. To address this question, it is essential to establish scale-dependent relationships for estimating the cost of storage- and power-related infrastructure.

In contrast to solar- and wind-energy-related components (e.g., solar panels and wind turbines), which are industrial products and whose design and, eventually, costing are more or less standardized, a similar attempt for water storage components (reservoirs) presumes the analysis of quite complex civil infrastructure (dams and ancillary works), whose design and associated cost are strongly affected by local characteristics (topography, hydrology, geology, geotechnical properties, foundation conditions, seismic loads, permeability, etc.). In the absence of such data, and to ensure realistic outcomes, a comprehensive analysis of macroscopic techno-economic information was employed, involving up to 170 small- to medium-scale reservoirs across Greece, most of which constructed in the 90s and 00s. The cost of each project was adjusted to 2025 prices and then divided by the associated total storage capacity, thus yielding the following power-type unit cost regression formula:

$$c_R = 1014 {V_{tot}}^{-0.34} \quad (10)$$

where c_R denotes the cost per cubic meter of storage (€/m^3), and V_{tot} is the total storage capacity (m^3). As shown in Figure 12, although the spread of real-world unit costs is significant, which is attributed to site-specific effects, the derived values clearly follow a scaling pattern. By expressing Equation (10) in terms of absolute cost, we get $C_R = 1014 {V_{tot}}^{0.66}$. The exponent of 0.66 is fully consistent with the so-called "six-tenths rule", which is com-

monly used as a heuristic in engineering and economics for comparing the costs of similar products in terms of their capacity [36].

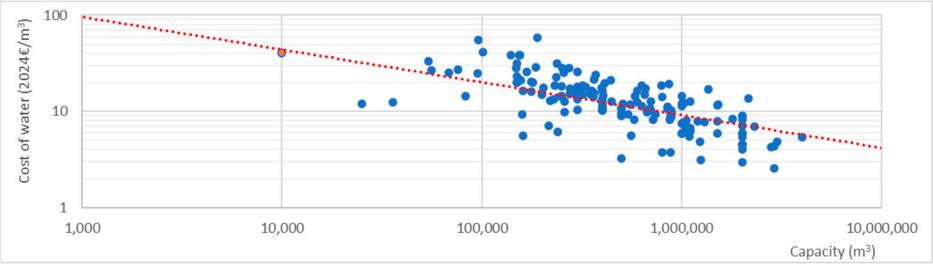

Figure 12. Unit investment cost (adjusted to 2025 values) of small- to medium-size reservoirs in Greece with respect to their storage capacity (m^3).

The cost analysis for the E/M components followed a similar approach based on the analysis of actual cost data from about 60 hydropower development studies in Greece [37], leading to the derivation of the following empirical relationship, which expresses the turbine cost as an increasing function of the power capacity, P_{max} (kW), and a decreasing function of the elevation difference (gross head), h (m):

$$C_T = 0.00322\ {P_{max}}^{0.88}\ h^{-0.19} \quad (11)$$

This cost function (expressed in M€) has a similar parameterization to other empirical expressions found in the literature [38], which are, however, based on rather outdated data, whilst Equation (11) relies on recent information exclusively retrieved from native projects, thus being more representative of Greece's technical and financial environment.

4.4. Investment Costs Across Scales

Following the rationale explained in two previous sections, the key technical and economic characteristics were estimated for the 12 configurations of the Greece EES system based on PHS, which are summarized in Table 3. All quantities of interest exhibit significant variability across the different configurations, thus revealing the major role of scale on the one hand and the elevation difference on the other. For instance, the required gross storage of each reservoir component ranges from 78.4 hm^3 (configuration 1a: 10 PHS units with an elevation difference of 100 m) to only 2.0 hm^3 (configuration 4c: 100 PHS units with an elevation difference of 400 m). On the other hand, the power capacity depends only on the breakdown parameter m. For the large-scale configuration, i.e., $m = 10$, its value is 530 MW.

Table 3. Key design and cost data for the 12 alternative configurations of the PHS units. Reservoir and cost values refer to individual projects, while the total investment cost refers to the entire system.

Configuration	**1a**	**1b**	**1c**	**2a**	**2b**	**2c**	**3a**	**3b**	**3c**	**4a**	**4b**	**4c**
Number of PHS units (scale, m)	10	50	100	10	50	100	10	50	100	10	50	100
Elevation difference, h (m)	100	100	100	200	200	200	300	300	300	400	400	400
Manometric head, h_m (m)	105	105	105	210	210	210	315	315	315	420	420	420
Storage capacity, E_{max} (GWh)	25.5	5.1	2.6	25.5	5.1	2.6	25.5	5.1	2.6	25.5	5.1	2.6
Power capacity, P_{max} (GW)	0.53	0.11	0.05	0.53	0.11	0.05	0.53	0.11	0.05	0.53	0.11	0.05

Table 3. *Cont.*

Configuration	1a	1b	1c	2a	2b	2c	3a	3b	3c	4a	4b	4c
Recycled water, V_{max} (hm^3)	78.4	15.7	7.8	39.2	7.8	3.9	26.1	5.2	2.6	19.6	3.9	2.0
Reservoir capacity, S_{tot} (hm^3)	86.3	17.3	8.6	43.1	8.6	4.3	28.8	5.8	2.9	21.6	4.3	2.2
Reservoir cost, C_R (M€)	172.1	59.6	37.7	109.0	37.7	23.9	83.5	28.9	18.3	69.0	23.9	15.1
Turbine cost, C_T (M€)	143.6	34.8	18.9	125.7	30.5	16.6	116.3	28.2	15.3	110.0	26.7	14.5
Total investment cost (G€)	4.88	7.70	9.44	3.44	5.30	6.44	2.83	4.30	5.19	2.48	3.73	4.48
Unit storage cost (€/kWh)	6.8	11.7	14.8	4.3	7.4	9.4	3.3	5.7	7.2	2.7	4.7	5.9
Unit power cost (€/kW)	271	329	357	237	288	313	219	266	289	208	252	274

Regarding the total investment cost, in terms of reservoir and E/M expenditures, this ranges from 2.48 to 9.44 billion € (average 5.02 B€). Despite the highly approximative character of this study, also due to the fact that several important elements of the overall water–energy system have not been accounted for (e.g., water conveyance, connections, and transmissions), the whole exercise seems convincing in the long run and potentially viable under the strategic goal of eliminating Greece's dependence on fossil fuels.

5. A Critical Look at the Energy Future of Greece

5.1. Future Energy Policy Fallacies and Myths

As mentioned in Section 2.1, in January 2025 the Greek government released the updated version of the NECP, which is a strategic plan that sets out a detailed roadmap regarding the accomplishment of specific energy and climate objectives through 2050. Key features of the future energy mix in terms of installed power capacity and annual energy production (Figure 2) that call for scrutiny are: (a) regarding controllable sources, the decommissioning of lignite power plants by the end of 2026 and reliance on imported natural gas and large hydroelectric plants, for which a mild expansion is foreseen until 2050 (from 3.2 GW to 4.7 GW); (b) the extensive deployment of non-dispatchable wind and solar sources (from 15.5 to up to 60 GW), including 11.8 GW of offshore wind parks; and (c) a significant increase in current EES levels (0.7 GW), mainly via batteries (12.0 GW) and secondarily through PHS units (5.5 GW). Surprisingly, biomass is practically disappearing from the mix (current capacity 161 MW, to be reduced to just 42 MW in 2050), although this renewable source, which is an excellent paradigm of the circular economy [39], could also serve as a vital pillar for the sustainable development of Greece's rural societies [40,41] and wildfire protection.

According to the NECP, the vast expansion of the overall power capacity of the Greek electricity system is justified by the substantial increase in current annual demand from around 50 TWh to 130 TWh by 2050. This is mainly attributed to electromobility and hydrogen production, absorbing 24.1 and 28.7 TWh, respectively. In the authors' perception, a massive electrification of the transportation domain in Greece is an ambitious yet highly uncertain assumption. Assuming an annual consumption of 3.0 MWh (200 Wh/km) for an average electric vehicle covering 15,000 km, the cited electrical energy corresponds to approximately 8 million electric vehicles. Indicatively, in 2024, fewer than 7 million four-wheeled vehicles of all types were in circulation in Greece, of which only 45,000 were electric (14,000 battery electric vehicles and 30,000 hybrids).

Furthermore, the NECP projections regarding annual electricity needs do not align with the observed consumption trends of the last two decades. It is highlighted that the national record so far (56.9 TWh) goes back to 2008, while since 2010 the demand has remained practically stable at around 50 TWh (Table 1). It is also important to remark

that the historical maximum in year 2008 took place with an installed capacity of just 13.0 GW, thus yielding a capacity factor of 50%. In 2025, the annual demand of 50.0 TWh (Table 1) was achieved with more than double the capacity, i.e., 27.6 GW, which yields a $CF = 21\%$, while the anticipated demand of 130 TWh under a total power capacity of 72 GW also results in a similarly low CF value. Since this quantity is globally used as a macroscopic dimensionless metric of power system performance, the resulting CF raises concerns regarding the efficiency of the future energy mix. A major question is whether electricity prices should be adapted to compensate for the imbalance between the relatively low energy production and the tremendous investments in terms of power capacity.

Another questionable assumption involves the asymmetrical development of non-controllable energy sources compared with controllable ones. According to the NECP projections, the installed capacity of natural gas and large-scale hydropower will decrease over the next ten years and stabilize at 10.9 GW after 2035. On the other hand, wind turbines and photovoltaics will continue to increase, reaching 59.8 GW by 2050. The lack of control will introduce significant complexity into grid management, increase blackout risks, and make the electrical power system highly vulnerable to prolonged energy droughts and periods of peak demand. As shown in Figure 1, controllable sources will be unable to cover future peak demand as early as 2030. At the same time, extensive electricity curtailment (already commenced in 2025) is expected to occur during periods of abundant solar and wind production but low demand (e.g., during spring and autumn). Accounting for the outcomes of our simulations (Section 3.4), the planned energy storage projects (Figure 2c) seem to be insufficient. By 2050, a storage capacity of 17.5 GW is planned, constituting only 29% of the installed capacity of VRE sources.

Nevertheless, apart from the numerous technical issues arising with respect to the NECP targets and assumptions, the extent of the investments to be implemented (in terms of power, EES and grid infrastructure) to achieve them within such a short time horizon (less than 25 years) render the whole endeavor far from realistic.

5.2. The Social Prosperity Dimension

The technological pathway selected to satisfy electrical energy needs is not a purely technical matter but also a political and socioeconomic choice. This is because the mode in which electricity demand is covered directly affects quality of life, the cost of living, industrial competitiveness, and essential services. In this respect, long-term energy planning should not be assessed in terms of technical and financial performance but also through its contribution to social prosperity and energy security.

This dimension becomes particularly important when considering per capita energy consumption. Previous analyses by Sargentis & Koutsoyiannis [42] have shown that energy use is strongly associated with key indicators of human development, including life expectancy and economic welfare. Such relationships do not imply that energy consumption alone determines prosperity; rather, they highlight that sufficient, affordable, and reliable energy availability is a necessary condition for modern societies. The recent European energy crisis further demonstrated this vulnerability, as the deterioration of energy affordability was associated with broader social and health-related consequences, including a reduction in life expectancy, as reported in a relevant analysis by *The Economist* [43].

Historically, the prosperity of post-war Europe was largely founded on the expansion of abundant and affordable energy, infrastructure development, and economies of scale. This development model, broadly consistent with Keynesian economic principles, supported industrialization, employment, public services, and rising living standards. In Greece, and more generally across Europe, large-scale energy infrastructure played a

central role in this process by providing dispatchable power, system stability, and relatively low prices.

The contemporary energy transition has attempted to reproduce a similar investment-driven development logic. The concept of a "New Green Deal" was, in principle, based on the idea that large capital mobilization toward new energy infrastructure could stimulate economic activity while reducing dependence on fossil fuels. As a general policy direction, this rationale is not necessarily problematic. However, its practical implementation depends critically on whether the promoted technologies are technically mature, economically scalable, and capable of delivering reliable energy services.

The difficulty is that several technologies presented as investment-ready have not yet demonstrated the same systemic characteristics as conventional large-scale energy infrastructure. Wind and solar P/V sources can indeed increase domestic energy production and reduce fuel import dependence. However, their stochastic nature introduces additional requirements for balancing, storage, curtailment management, grid reinforcement, and backup capacity. As shown in the previous sections, the integration of high shares of VRE does not automatically generate economies of scale at the system level because additional infrastructure is required to compensate for intermittency effects and energy droughts.

This creates a structural tension. On the one hand, renewable energy expansion may enhance national self-sufficiency by exploiting domestic resources. On the other hand, if this expansion is not accompanied by adequate storage and controllable capacity, it may increase the complexity, cost, and fragility of the electricity system. Therefore, the relevant question is not whether renewable energy should be developed, but whether its development is planned in a way that preserves affordability, reliability, and social welfare.

From a social prosperity perspective, it is also necessary to question the premature decommissioning of existing infrastructure that enhances energy security. Dispatchable power plants and other controllable assets may remain valuable during the transition, not because they represent an ideal long-term solution, but because they reduce exposure to extreme system states, energy droughts, and market volatility. Removing such assets before equivalent reliability is ensured through storage or other balancing mechanisms may transfer technological risk directly to households and productive sectors.

Consequently, energy transition strategies should be evaluated not only by their nominal decarbonization targets but also by their capacity to maintain the material foundations of prosperity. A socially sustainable transition requires sufficient energy availability, low exposure to price shocks, protection against energy poverty, and a realistic appreciation of system complexity. Otherwise, the pursuit of green growth may lead to an increasingly difficult management problem, where the main challenge becomes not the production of renewable electricity itself but the control of instability introduced by its large-scale stochastic integration.

5.3. On the Feasibility of Energy Storage Development Through PHS

Greece is particularly well positioned to leverage PHS, owing to its favorable morphology and portfolio in water infrastructure. The most efficient configuration of new PHS schemes is the addition of storage facilities to existing reservoir systems, given that a large enough elevation difference is ensured over a short distance. In this vein, three layout options are offered: (a) the connection of existing hydroelectric reservoirs in series via reversible turbines; (b) the use of existing hydroelectric reservoirs as lower storage components (provided that their water levels exhibit small fluctuations) and the construction of upper reservoirs of much smaller capacity in their vicinity; and (c) a similar layout that takes advantage of natural lakes or water supply reservoirs as lower storage components, which essentially requires additional interventions compared with existing hydroelectric systems.

In this context, Stefanakos [44] employed a thorough screening across Greece and detected 7, 15 and 6 potential schemes with respect to options (a), (b), and (c), respectively, ensuring a power capacity of 400, 1500 and 275 MW, respectively. This yields a sum of 2175 MW that could be added to the existing PHS capacity of 700 MW, thus reaching a future potential of ~3.0 GW in total. The unit investment costs, including the civil works and the purchase and construction of the pumping station and piping, were estimated to be 520, 725 and 855 €/kW, respectively (2012 prices).

The theoretical exercise conducted in Section 3 concluded that exclusive reliance on renewables would require an energy storage of 255 GW and a power capacity of 5.3 GW. As also indicated in Section 4, this could be implemented by means of closed-loop PHS systems with an average storage capacity of 19.5 hm^3, a mean elevation difference of 250 m and a mean power capacity of 230 MW. These quantities are well aligned with previous studies, as well as with PHS projects that are already under development or at the design stage. In particular, the Hydro Pumped Storage Complex in Amfilochia [45], which is the country's largest investment in energy storage and is at a mature construction phase, involves the development of two independent upper reservoirs of 5.0 and 2.0 hm^3 (useful storage), at elevation differences of 238 and 284 m, respectively. The total installed capacity is 680 MW (production) and 730 MW (pumping). Another iconic investment is the Sfikia-Mprava project, which is planned to comprise an upper reservoir with a useful storage capacity of 18 hm^3, at a mean elevation difference of 420 m above the lower one (i.e., the existing hydroelectric reservoir of Sfikia). The generation and pumping capacities of this scheme are 441 and 467 MW, respectively.

Nevertheless, it is essential to remember that the projected power capacity requirements according to the NECP are far beyond the 5.3 GW estimated by considering the current demand levels. Under the NECP assumptions (Figure 2), the EES needs in the long run will be much greater, i.e., 17.5 GW, thus necessitating the parallel development of electrochemical means, i.e., batteries. In the authors' opinion, PHS should be deemed as a priority, accounting for its maturity, scale advantages and extended life cycle, in contrast to batteries, which are also subject to several environmental concerns and reliance on crucial rare earth elements, thus being sensitive to geopolitical disruptions [46].

5.4. Water as the Pilar of a Sustainable Energy Mix

While the shift towards renewable energy and EES is essential for the overall decarbonization goal, evaluating these systems strictly through this lens risks overlooking critical interdependencies, most notably those related to water. Water is intrinsically linked to the energy transition, as it is simultaneously a vital enabler and a resource increasingly strained by it. In a deeply decarbonized mix, water will not only be the means of hydroelectric energy generation but also a key regulating medium for all non-controllable renewables through PHS. As mentioned in Section 5.3, Greece should benefit from its favorable geomorphology to deploy quite a significant number of large-scale PHS systems. On the other hand, under the extensive development of EES systems in the long run, the classical role of hydroelectric reservoirs as peak energy generators may require to be adapted so that they operate as base load units while also providing power balancing services to the national electricity grid [29].

The multidimensional role of water in a future era without fossil fuels, and its association with the inherently uncertain and perpetually changing climate, was manifested early on by Koutsoyiannis et al. [47]. The physical footprint of this new paradigm links energy policy to the broader Water–Energy–Food–Land (WEFL) nexus. Acknowledging that each element of the nexus competes for resources (e.g., land and water) with the rest, the quest for synergistic solutions is a pivotal step towards achieving sustainability.

Certainly, one of the most promising solutions along this path is offered by the so-called agrivoltaics technology, i.e., the installation of P/V panels at suitable elevations and distances to allow the coexistence of agricultural activities and renewable energy production. This dual configuration not only maximizes land-use efficiency but also ensures reduced water requirements, increased yields for specific crops, and reduced soil erosion [48]. Crucially, it answers the dilemma of developing solar energy on arable areas [49], proving that a "symbiosis" of food and energy on the same land is not only realistic but also mutually beneficial. In the authors' opinion, this win–win option, which is totally missing from the official long-term energy planning of Greece as specified in the NECP, should be set as a prime development goal for the country.

In a similar context, the development of floating PVs over distributed open water components (with emphasis on hydroelectric reservoirs) may also offer multiple benefits, resulting in minimal occupation of productive land, reduced evaporation losses and increased panel efficiency due to cooling [50]. In Greece, such projects are still in the early design stages, while their environmental impacts are not yet well understood [51].

5.5. Outlining a Holistic Modeling Framework for Strategic Energy Planning

A national-scale energy planning strategy should rely on a holistic approach, under well-justified assumptions, procedures and decisions.

To ensure an optimal energy mix, a twofold objective must be fulfilled across different levels of detail. At the upper level, the optimization problem should be set as the maximization of the *complementarity* between all desirable power sources and EES means [52,53]. This would entail the best plausible synchronization of electricity generation with demand across scales, thus improving reliability, eliminating surpluses, and eventually resulting in limited regulation needs.

On the other hand, the lower level of such analysis should emphasize the *spatial reliability* dimension per source, namely the probability of achieving a guaranteed level of power production over a given region through an optimal dispersion of the associated additional projects. Regarding the two key RES, i.e., wind and solar P/V, previous analyses within the spatial reliability context showed that these could achieve a theoretical maximum capacity factor of 47% and 19%, respectively [54]. Interestingly, the *CF*s projected by the NECP for year 2050 are 27% for onshore wind plants and 16% for solar P/V, which are practically identical to the present values. This signifies that despite the development of extensive EES units, the anticipated performance of wind energy will still be poor.

Since the electrical energy domain is dominated by renewables that depend on hydroclimatic processes and market-oriented drivers that rely on socioeconomic and geopolitical dynamics, it is subject to multiple and interrelated uncertainties. In any attempt to delineate a country's energy strategy in the long run, uncertainty is the elephant in the room. However, this structural issue is totally missing from the NECP, which is based on fully deterministic and rather optimistic projections. In contrast to this, the authors' explicit position is that any exercise aimed at deploying an optimal energy mix should follow the stochastic simulation paradigm [55]. This requires expressing the key inputs and conversions in stochastic means and interpreting the techno-economic outcomes derived within a risk-aware context.

It is recognized that the implementation of the abovementioned theoretical framework in practice introduces numerous methodological and computational challenges [56]. Even an abstract modeling attempt at the national scale would comprise a tremendous number of inputs, decision variables and constraints. In this vein, research should focus on effective and efficient planning tools [57], taking advantage of state-of-the-art algorithms and advances in computational power to support rational decision-making.

6. Conclusions

The realization of the decarbonization objective in Greece is at a turning point, as the penetration of renewables is rapidly evolving, while the other pillar of this ambitious endeavor, namely the development of EES, remains at an infant stage.

Key objective of this research was to reveal the crucial role of storage in a decarbonized energy scene and to provide practical implications based on a macroscopic simulation-optimization framework. The scenario-based investigations allowed the capture of the complex trade-offs between the level of penetration of additional VRE sources into the Greek electricity mix, i.e., wind and solar P/V, the frequency and quantity of the derived energy deficits, the two key characteristics of EES (i.e., total storage and associated power capacity), and the power rejections due to overproduction by renewables.

Considering the (practically stable) electricity demand conditions of the last 15 years, it has been indicated that, to achieve a reasonable reliability level of the order of 95%, a tripling of current wind and solar P/V production is required, assisted by EES systems with a total storage capacity of 255 GWh and a total power capacity of 5.3 GW. It was also shown that the implementation of the EES requirements and their potential financial viability strongly depend on scale and geometric issues.

Beyond this theoretical exercise, this article also aimed to open a dialog with respect to national-scale energy planning over the next two decades, starting from the official projections of the NECP. The major concerns are: (a) the sudden and intense increase in projected electricity needs, in full contrast to running trends, which in turn translates more than doubling the current installed capacity of renewables and EES components in a too short time horizon; (b) the lack of a clear funding plan for such giant infrastructure (in terms of new power and EES projects, grid transmission upgrades, new connections, etc.), and the plausibly negative implications for electricity prices and the emerging issue of energy poverty; and (c) the omission of biomass and agrivoltaics, which are two promising solutions for fostering the circularity paradigm, establishing effective synergies across the WEFL nexus, and supporting the country's rural economy.

Eventually, the question of whether the decarbonization of the Greek electricity system is a utopia or can be realized to a sufficient extent is far from being adequately addressed. In fact, a clearly justified answer requires several additional levels of analyses within a multidisciplinary, uncertainty-aware context that seeks the optimization of the national energy mix across all its dimensions, i.e., technical, economic, social, and environmental. This context should also explicitly account for all the different roles and uses of water, which is expected to play a pivotal role towards a sustainable future.

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Abbreviations

The following abbreviations are used in this manuscript:

CF	Capacity Factor
EES	Electricity Energy Storage
E/M	Electro-Mechanical
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
NECP	National Energy and Climate Plan
P/V	Photovoltaic
PHS	Pumped Hydropower Storage
RE	Renewable Energy
VRE	Variable Renewable Energy
WEFL	Water–Energy–Food–Land

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