Master's Thesis - Energy Science

# Powering Europe with sun and wind

## A pan-European analysis of overbuilding intermittent renewables with proactive curtailment


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**Abstract**

The European Commission has set a goal of becoming the first net-zero emission continent. To achieve this, their REPowerEU proposal aims to increase the share of renewable electricity generation to 45% by 2030. The proposal includes tripling the current solar photovoltaic capacity and more than doubling the current wind power capacity. As the share of intermittent renewable energy sources on the grid increases, it becomes even more important to find ways to transform this intermittent power into firm power: power that can meet demand at all times.

In this study, we develop a model to determine the optimal mix of solar photovoltaic power, wind power, lithium-ion battery storage, and hydrogen storage that can guarantee firm power for 37 European and neighboring countries. We accomplish this by developing a model that optimizes the deployment of production and storage capacities and the hourly dispatch of storage and interconnections. Our Pan-European Intermittent Renewable Overbuilding and Curtailment Optimization Model (PEIROCOM) uses the demand and interconnection capacity projections of the European Resource Adequacy Assessment (ERAA) as input. Bidding zones have a copper plate assumption and are modeled as nodes only connected through HVAC and HVDC interconnections. The potential for onshore and offshore wind energy, as well as underground hydrogen storage, is considered. The model finds the optimal deployment and dispatch values using linear programming in combination with the time-hierarchical solution method.

We demonstrate that it is technically and economically feasible to meet the electricity demand of the entire European grid using only solar PV and wind power. We showed for the first time that overbuilding and proactive curtailment is feasible on a continental level and that hydrogen storage can play a significant role in reducing system costs when overbuilding generation capacity. Our results indicate that the ideal firm kWh premium in a lithium-ion-only scenario would be 3.95, with 51% of all generated electricity curtailed. When hydrogen storage is added, the firm kWh premium falls to 2.95 while reducing the curtailment to 32%. Additionally, we showed that with proactive curtailment, most of the projected 2030 interconnections could handle a fully intermittent renewable grid; an increase in interconnection capacity does not significantly reduce system costs.

# Contents

# Glossary

**ATB** Annual Technology Baseline. 5

**CAPEX** capital expenditures. 8, 14

**CorRES** time series simulation tool for variable renewable energy. 4

**CRF** capital recovery factor. 8

**ENTSO-E** European Network of Transmission System Operators for Electricity. 4, 5

**ERAA** European Resource Adequacy Assessment. 1, 4, 5, 19

**EU** European Union. 8

**HVAC** high voltage alternating current. 4, 5, 17

**HVDC** high voltage direct current. 4, 5, 17

**IRES** intermittent renewable energy sources. 3–5, 10, 14, 16, 17, 19

**LCOE** levelized cost of energy. 3, 5–8, 10, 18

**LP** linear programming. 1, 7, 10, 19

**NREL** National Renewable Energy Laboratory. 5, 18

**OPEX** operating expenditures. 8

**PEIROCOM** Pan-European Intermittent Renewable Overbuilding and Curtailment Optimization Model. 1, 4, 6, 7, 19, 20

**SoC** state of charge. 8

**solar PV** solar photovoltaic. 1, 3–6, 11, 14, 16–19

**THS** time-hierarchical solution method. 1, 7, 8, 21

**WACC** weighted cost of capital. 8

# Chapter 1

# Introduction

The European Commission aims to make Europe the first net-zero emission continent [1, 2]. The REPowerEU plan targets a renewable electricity generation share of 45% by 2030, which includes tripling the current solar photovoltaic (solar PV) capacity to 592 GW and more than doubling the current wind power capacity to 510GW [3]. In some European countries, intermittent renewable generation already supersedes the demand during peak hours [4, 5]. However, decarbonization scenarios show the share of renewable energy sources (RES) for electricity could increase from 38% to over 90% [6, 7, 8]. The demand-generation imbalance will only rise with the continued expansion of solar PV and wind power due to the inherent disparities between electricity consumption and intermittent renewable generation.

Dispatchable energy sources have always supplemented intermittent renewable energy sources (IRES) to ensure resource adequacy. Capacity credit, a key indicator for resource adequacy, is the capacity a generation technology can supply during peak residual load hours. Research into capacity credit shows that the combination of IRES with storage can drastically improve the capacity credit of solar PV [9, 10]. This indicates that future power systems could rely less on dispatchable capacity for resource adequacy when IRES and storage are combined.

To ensure resource adequacy, a power system needs the ability to supply power whenever there is demand, also called firm power. To illustrate the relative costs of transforming intermittent power into firm power, Perez introduced the concept of the firm kWh premium, which, as shown in Formula 1, is the ratio of the levelized cost of energy (LCOE) of a firm kWh and the LCOE of an unconstrained kWh [11].

$$\text{Firm kWh premium} = \frac{\text{Firm LCOE}}{\text{Unconstrained LCOE}} \quad (1)$$

Recent studies analyzed whether it would be possible to create firm power with only IRES, requiring no or almost no dispatchable capacity. Specifically, these studies analyzed if overbuilding generation capacity could reduce system costs by requiring less storage capacity. Budischak et al. optimized curtailment of oversized wind and solar capacity with battery storage to supply up to 99.97% of the electricity demand throughout the year using different storage technologies [12]. However, they did not provide firm power throughout the year. Perez et al. were the first to analyze the costs of guaranteeing 100% firm power throughout the year employing overbuilding and curtailment [11]. However, this study only included lithium-ion storage, requiring significant overbuilding in the IRES only scenarios. Gupta et al. analyzed the best storage methods depending on the supply mode and scale of the deployment. While they analyzed 100% firm power scenarios, the study was mainly focused on finding the best technologies for different deployment scales [13]. Most recently, Remund et al. published a paper analyzing firm power in ultra-high renewable energy scenarios for Switzerland; this paper showed it would be economically feasible to power Switzerland with only IRES, hydropower, and some biogas [14].

This project analyzes firm power for the first time on a continental scale while incorporating multiple storage technologies to solve both short and long-term discrepancies in generation and demand. We analyze the cost premium of converting intermittent renewable power into firm power for the European electricity system using only IRES. It includes the EU-27 member states, Albania, Bosnia and Herzegovina, Switzerland, Montenegro, North Macedonia, Norway, Serbia, Turkey, Ukraine, and the United Kingdom. These countries had in 2019 a combined annual electricity consumption of 3.5PWh or 14.7% of the global consumption [15].

# Chapter 2

# Methodology

Historically, researchers have used different modeling methodologies to find the optimal combination of IRES, storage, and curtailment. For example, Budischak et al. created their own Regional Renewable Electricity Economic Optimization Model (RREEOM), and Perez et al. created a model using the nested Brent optimization method [12, 11, 16]. However, these methods are inadequate for modeling the European electricity grid with an hourly resolution; the greater geographical scope and multiple storage technologies require a model that can optimize deployment and dispatch simultaneously.

We create an optimization model specifically designed for the European power system. Our dedicated Pan-European Intermittent Renewable Overbuilding and Curtailment Optimization Model (PEIROCOM) can model the deployment and dispatch of a fully IRES European grid on an hourly timescale. The model is written in Python, and Streamlit is used to provide an accessible user interface [17]. A demo of the model is publicly available on `https://demo.peirocom.eu/`. Figure 1 shows a screenshot of the user interface during optimization. The source code is published on GitHub and licensed under the terms of the MIT License [18].

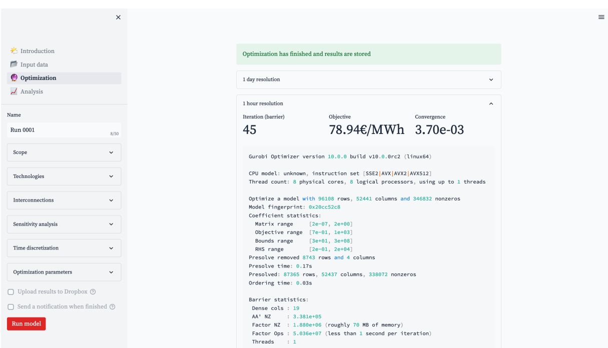


**Figure 1:** Screenshot of the PEIROCOM interface

This chapter explains how the model works and why we made particular decisions. First, we describe the various data inputs, then present the framework of the model, and lastly, we explain the mathematical core of the model.

## 2.1 Data

The model requires three types of data: time series with demand and capacity factors, technology parameters, and country-specific data, such as potential capacity.

### 2.1.1 Time series

The European Network of Transmission System Operators for Electricity (ENTSO-E) creates the annual European Resource Adequacy Assessment (ERAA). This assessment analyzes the European power system's resource adequacy for the next decade [19]. Aside from the assessment's results and conclusions, the input data for the ERAA is also made public. The published data of the 2021 ERAA includes hourly time series for demand, capacity factors for solar PV and onshore and offshore wind, and net transfer capacities [20]. ERAA generates the time series for the capacity factors and electricity demand using climate data from 1982 to 2016 [21]. The CorRES model, developed by DTU, generates the capacity factors for solar PV and wind power [22]. The demand data are two time series ranging from 1982 to 2016, with the expected demand in 2025 and 2030. ERAA projects the demand for both years while using historical climate data. Lastly, the net transfer capacities are two time series with the expected net transfer capacity per hour in 2025 and 2030 for both high voltage alternating current (HVAC) and high voltage direct current (HVDC) interconnections.

Although ENTSO-E provides the projections for both 2025 and 2030, this study only uses the 2030 data since we are simulating a fully IRES electricity grid, which will take beyond 2030 to materialize.

### 2.1.2 Technology parameters

Our study includes solar PV, onshore wind, and offshore wind for electricity generation. Other intermittent renewable energy sources, such as wave and tidal power, are not included since these have almost no currently installed capacity. The lack of capacity makes it harder to project future costs and attain hourly capacity factors for each European country. Furthermore, solar PV and wind power accounted for 75% of the global generation capacity added in 2021 [23], indicating they will be the driving force behind the decarbonization of the electricity sector in the coming decades. Some studies analyzing firm power also include scenarios with dispatchable energy sources, such as hydropower or gas-peaking power plants [11, 14], but we focused exclusively on IRES due to limited time.[1]

Lithium-ion and hydrogen storage are used to store electricity. Lithium-ion storage has a high round-trip efficiency, making it suitable for smoothing the hourly generation fluctuations. Hydrogen storage has a lower efficiency and very low storage costs, making it better suited for seasonal storage. There are various methods to produce and store hydrogen, but this study only uses electrolysis for production and subterranean salt caverns for storage. Lastly, hydrogen is only considered as a storage method for the electricity grid; we do not account for future hydrogen use in industry.

Table 1 shows the technology assumptions. We use the 2050 projections in the Annual Technology Baseline (ATB) published by the National Renewable Energy Laboratory (NREL) for solar PV, onshore wind, offshore wind, and lithium-ion storage [24]. The assumptions for hydrogen storage are taken from Guerra et al. [25]. Both ATB and Guerra et al. also provide costs for a conservative and advanced scenario; these values are aggregated in Appendix G.

The efficiency of high-voltage interconnections depends on many variables and is impossible to model without specific data on each interconnection. Therefore, we assume an efficiency of 95% for both HVAC and HVDC interconnections.

### 2.1.3 Country data

The currently installed solar PV, onshore wind, and offshore wind capacity are retrieved from ENTSO-E's transparency platform [26]. If the 2022 data is unavailable for a country, the most recent available data is used; when no data is available, no currently installed capacity is assumed. Appendix E includes an overview of the currently installed capacities used in this study.

The techno-economical potential per country for onshore and offshore wind is taken from Ryberg et al. and Caglayan et al., respectively [27, 28]. Both research projects provided the potential per LCOE. For onshore wind, the potential up to €50/MWh is considered; for offshore wind, the potential up to €60/MWh is used, as this is the lowest bracket Caglayan et al. provided.

Solar PV potential is not considered in this study. Although solar PV has a limited technical potential on rooftops and other structures in the built environment [29], even in densely populated European countries, only a fraction of the land would be required to meet the demand with solar PV.

Caglayan et al. analyzed the onshore and offshore technical potential for hydrogen storage in salt cav-

[1] The 2021 ERAA does include daily data on run-of-river and weekly data on reservoir and pumped hydropower [20].

**Table 1:** Generation and storage technology assumptions [24, 25]

| | **Solar PV** | **Onshore wind** | **Offshore wind** | **Lithium-ion** | **Hydrogen** |
|---|---|---|---|---|---|
| **Economic life** | 30 years | 30 years | 30 years | 15 years | 18 years |
| **WACC** | 4.4% | 4.4% | 4.4% | 5% | 5% |
| **CAPEX** | €700/kW | €760/kW | €1945/kW | €243/kW<br>€81/kWh | €1300/kW<br>€1/kWh |
| **O&M** | €10/kW/year | €33/kW/year | €71/kW/year | $2.5\%_{\text{CAPEX}}$/year | $2.5\%_{\text{CAPEX}}$/year |
| **$\text{SoC}_{\text{min}}$** | | | | 20% | 0% |
| **$\text{SoC}_{\text{max}}$** | | | | 100% | 100% |
| **Round-trip efficiency** | | | | 85% | 40% |

erns [30]. We only include onshore salt caverns as this is the main focus of Caglayan et al., and the onshore potential alone provides significant cumulative storage potential. Figure 2 shows how most of Europe's underground hydrogen potential is concentrated in a few countries.

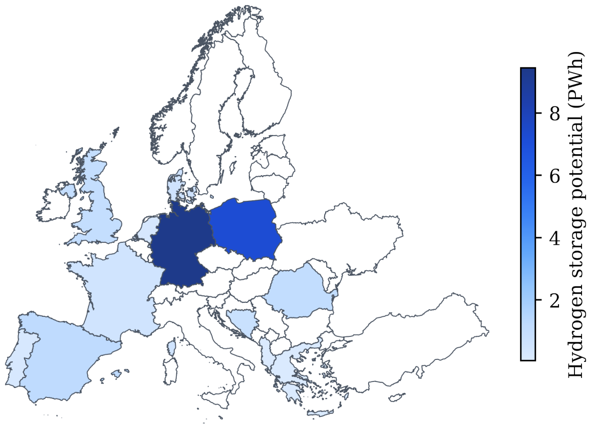


**Figure 2:** Hydrogen storage potential in onshore underground salt caverns

A table with assumptions for all generation and storage capacity potentials is available in Appendix F. No maximum potential is considered when the potential of a specific technology in a country is not available.

Population and land area statistics are retrieved from the World Bank [31, 32]. Maps are generated using the 10-meter subunits dataset from Natural Earth [33] and projected with the Lambert azimuthal equal-area projection [34]. Distances between the geographical centers of countries are calculated with the same map data from Natural Earth and the pyproj library [35] projecting the WGS 84 reference system [36]. Appendix A includes a table with the population and land area per country.

## 2.2 Framework

The model's objective is to determine the lowest LCOE that can be achieved in a European electricity grid that runs entirely on solar, wind, and storage. In addition, it considers interconnection capacities between bidding zones, country-level generation potential, and hydrogen storage potential. While the model optimizes only the LCOE, it creates and stores all relevant installed capacities as well as the time series for generation, storage flows, and interconnection flows. These capacities and time series can be used to determine secondary objectives, such as the firm kWh premium, charging patterns, and country-specific indicators.

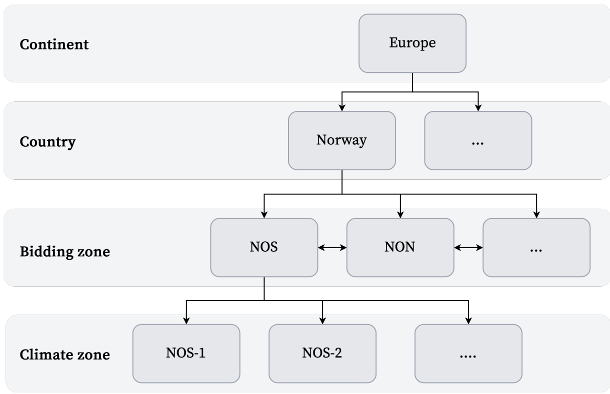


**Figure 3:** Geographical levels

Figure 3 shows the four different geographical levels that must be considered when modeling all relationships. Everything in the model happens within a continental context, the highest geographical level. Many statistics, such as generation potential and population, are only available on a national level. Subsequently, each country has one or more bidding zones, forming the third geographical level. This level is the backbone of the model since interconnections are modeled between different bidding zones, and a copper plate assumption is made for everything that happens within a bidding zone. Climate zones make up the fourth level. Each climate zone is a geographical subset of a bidding zone; therefore, each is part of a single bidding zone. The hourly capacity factors for solar PV and wind power are available on this level, and thus generation capacities are optimized per climate zone. A table with all bidding zones is included in Appendix B, and tables with all onshore and offshore climate zones are included in Appendix C and D, respectively.

To facilitate the data flowing through PEIRO-COM, the processing is divided into three stages: preprocessing, optimization, and post-processing. Figure 4 depicts the primary data flow and storage formats. The preprocessing step is only performed once; it cleans up the time series data and stores them per bidding zone as a CSV file. The technology and country-specific parameters do not have to be preprocessed, as this data is already in a usable format. The optimization step is at the model's core and is more thoroughly explained in Section 2.3. The optimization stores the complete state of the model as CSV files and the optimization log as a text file. Finally, the post-processing step can generate various tables and charts from the output data, such as correlation plots, duration curves, choropleth maps, and sensitivity analyses. All tables are exported as LaTeX files, and the charts are exported as high-resolution PNG files. This last step is intentionally separated from the optimization step so multiple analyses can be performed without rerunning the optimization, which can take several days.

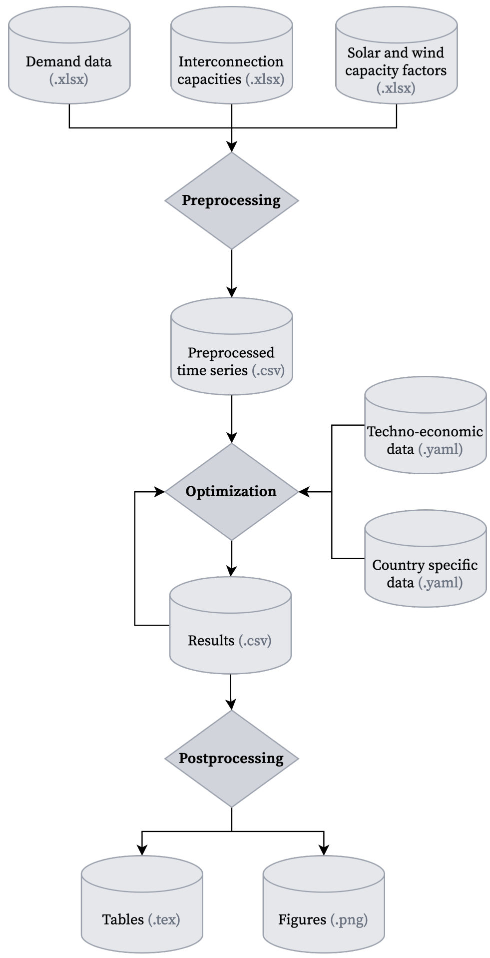


**Figure 4:** Data flow in PEIROCOM

PEIROCOM optimizes both the required capacity of generation and storage technologies and the hourly dispatch of the storage technologies. It creates a linear programming (LP) model with Python and uses the Gurobi Optimizer to optimize all variables [37]. For each time step, multiple variables are required to optimize both the storage dispatch and interconnection flows. Modeling all countries will therefore require 3-4 million variables per modeled year. Due to the high number of variables, even LP solvers with advanced heuristics, such as Gurobi, require substantial computational power to solve such a LP problem. PEIROCOM employs two techniques to reduce this computational complexity. Firstly, it uses the time-hierarchical solution method (THS) developed by Weimann and Gazzani [38]. This method is specifically designed to model energy systems with a high penetration of intermittent renewable energy. THS improves the modeling speed without reducing the data resolution; it does this by first optimizing the model with a large interval length (e.g., 1 day) and using the results of this optimization as the lower bound for the variables in the optimization with a higher resolution (e.g., 1 hour). Our tests show that two steps with 24 and 1-hour resolution increase speed the most while introducing the least amount of error for this model. Next, the interior-point algorithm, also called the barrier method, is selected to solve the model since our tests show that it is the fastest in finding a solution when modeling more than a few weeks of data. The second leap in performance is made by disabling the crossover from the interior point solution, generated by the barrier method, to a basic solution. The barrier solver stops when the relative difference between the primal and dual objective is less than a specified value ($10^{-3}$ for all our simulations). After this step, the Gurobi optimizer converts the interior point solution of the barrier method to a basic solution with the simplex algorithm. However, tests for our model show that this has almost no impact on the final LCOE. Disabling this step improves the simulation time significantly. However, disabling crossover means that some constraint violations and bound violations remain. This compromise is deemed acceptable since tests with a smaller geographical and temporal scope were done during the design phase, which indicated that the error in LCOE and firm kWh premium caused by not converting the results to a basic solution is well below one percent. Using THS and removing crossover from the final optimization step makes it feasible to optimize installation capacity and hourly storage dispatch simultaneously on a multi-year and continental scale.

## 2.3 LP problem definition

As mentioned before, PEIROCOM is at its core an LP. The THS runs the optimization multiple times, where only the resolution of the time steps and lower bounds change each time.

A specific time instance is given the index $t$, and its duration is assigned $\Delta t$. The range of all time instances in the modeled climate years is specified as $T$.[2] The length of the time instance depends on the THS resolution.

The letters $C$, $BZ$, and $CZ$, respectively, stand for countries, bidding zones, and climate zones. $BZ_c$ specifies the collection of all bidding zones in a country; the climate zones in a specific country or bidding zone are denoted by $CZ_c$ and $CZ_{bz}$, respectively. A climate zone's country and bidding zone are denoted, respectively, by $c_{cz}$ and $bz_{cz}$.

Generation and storage technologies are indicated by G and S, respectively. P indicates the power flows: $P_{demand}$, $P_{production}$, $P_{export}$, and $P_{storage}$ indicate the power flow of demand, generation, net export, and net storage, respectively. The charge and discharge storage flows are modeled separately and are indicated by $P_{charge}$ and $P_{discharge}$. The round-trip efficiency of a storage system is indicated by $\eta_s$. The interconnections for a given bidding zone are labeled $I_{bz}$. Lastly, self-sufficiency is indicated by $\Phi$.

The objective of the optimization problem is to minimize the firm LCOE for the entire European region, as shown in Formula 3. The costs are split into capital expenditures (CAPEX) and operating expenditures (OPEX). The capital recovery factor (CRF) is indicated by $\alpha$ and is dependent on the weighted cost of capital (WACC) and economic lifetime (L) as seen in Formula 2.

$$\alpha = \frac{\mathrm{WACC}}{1 - (1 + \mathrm{WACC})^{-\mathrm{L}}} \tag{2}$$

The objective function is subject to the following ten constraints.

*Constraint 4a*: Production plus net storage and net export flow must match or exceed demand in each time instance. The production, storage, and export power flow in this constraint are, for clarity, defined separately in Equation 5.

*Constraint 4b*: Each storage system's energy level must always equal the previous energy level plus the net energy flow to that system. This constraint also incorporates the charging efficiencies, which, as seen in Table 1, can vary significantly per technology. Only the round-trip efficiency is known; therefore, we assume the same efficiency for charging and discharging.

*Constraint 4c*: The energy at the last time step must equal the energy in the first time step of that storage system. This guarantees that the storage systems are not excessively depleted at the end of the modeled period.

*Constraint 4d*: The state of charge (SoC) of each storage system in any given time step must be between the minimum and maximum SoC of that storage technology.

*Constraints 4e and 4f*: The charging and discharging capacity for each storage system must be greater than that system's highest charging and discharging power.

*Constraint 4g*: The installed generation capacity per climate zone must be between the currently installed capacity and the potential capacity. Although the installed and potential capacity is only available per country, the generation capacity is determined per climate zone. Therefore, the capacity potential per climate zone is defined as the potential per country over the number of climate zones in that country.

*Constraint 4h*: As shown before in Figure 2, each nation has a different potential to store hydrogen in salt caverns. The hydrogen storage capacity must not exceed this; the hydrogen potential per bidding zone is calculated similarly to the wind potential.

*Constraint 4i*: Interconnections are modeled as unidirectional flows; energy that flows through an interconnection must, therefore, always be between zero and the interconnection limit. Two variables, one for each direction, are used to model bidirectional connections.

*Constraint 4j*: The self-sufficiency of each country must be above the defined minimum self-sufficiency. One of the main goals of the REPowerEU plan is to increase the independence of the European Union (EU) and its member states [39]. Taking this shift in policy focus into account, each country in our model must generate 80% of its electricity domestically. The curtailment and net storage flows are included; curtailed energy and charging losses do not count toward the minimum self-sufficiency ratio.

[2] All italic uppercase variables specify a set. The corresponding lowercase variant specifies an item in this set. Borrowing the cardinality notation from set theory, vertical bars around a set indicate the number of items in the set.

$$\text{minimize} \qquad \frac{\sum_g^G \sum_{cz}^{CZ} \Big( \alpha_g \cdot \text{CAPEX}_{g,cz} + \text{O\&M}_{g,cz} + \sum_s^S \sum_{bz}^{BZ} \alpha_s \cdot \text{CAPEX}_{s,bz} + \text{O\&M}_{s,bz} \Big)}{\sum_{bz}^{BZ} \sum_t^T \text{P}_{\text{demand},bz,t} \cdot \Delta\text{t}} \tag{3}$$

$$\text{s.t.} \quad \text{P}_{\text{demand},bz,t} \leq \text{P}_{\text{production},bz,t} - \text{P}_{\text{storage},bz,t} - \text{P}_{\text{export},bz,t} \qquad \forall bz, t \tag{4a}$$

$$\text{E}_{s,bz,t} = \text{E}_{s,bz,t\text{-}1} + \Delta\text{t} \left[ \sqrt{\eta_s} \cdot \text{P}_{\text{charge},s,bz,t} - \frac{\text{P}_{\text{discharge},s,bz,t}}{\sqrt{\eta_s}} \right] \qquad \forall s, bz, t \in \{2, ..., T\} \tag{4b}$$

$$\text{E}_{s,bz,t=1} = \text{E}_{s,bz,t=|T|} \qquad \forall s, bz \tag{4c}$$

$$\text{SoC}_{\text{min},s} \leq \frac{\text{E}_{s,bz,t}}{\text{C}_{s,bz}} \leq \text{SoC}_{\text{max},s} \qquad \forall s, bz, t \tag{4d}$$

$$0 \leq \text{P}_{\text{charge},s,bz,t} \leq \text{P}_{\text{charge,max},bz,s} \qquad \forall s, bz, t \tag{4e}$$

$$0 \leq \text{P}_{\text{discharge},s,bz,t} \leq \text{P}_{\text{discharge,max},bz,s} \qquad \forall s, bz, t \tag{4f}$$

$$\frac{\text{C}_{\text{current},g,c_{cz}}}{|CZ_{c_{cz}}|} \leq \text{C}_{g,cz} \leq \frac{\text{C}_{\text{potential},g,c_{cz}}}{|CZ_{c_{cz}}|} \qquad \forall g, cz \tag{4g}$$

$$0 \leq \text{C}_{s,bz} \leq \frac{\text{E}_{\text{potential},s,c_{bz}}}{|\text{BZ}_{c_{bz}}|} \qquad \forall s, bz \tag{4h}$$

$$0 \leq \text{P}_{\text{export},i,t} \leq \text{P}_{\text{interconnection limit},i,t} \qquad \forall i, t \tag{4i}$$

$$\Phi_{\text{min}} \leq \frac{\sum_{bz}^{BZ_c} \sum_t^T \big( \text{P}_{\text{production},bz,t} - \text{P}_{\text{curtailed},bz,t} + \text{P}_{\text{storage},bz,t} \big)}{\sum_{bz}^{BZ_c} \sum_t^T \text{P}_{\text{demand},bz,t}} \qquad \forall c \tag{4j}$$

$$\text{P}_{\text{production},bz,t} = \sum_g^G \sum_{cz}^{CZ_{bz}} \big( \text{C}_{g,cz} \cdot \text{CF}_{g,cz,t} \big) \tag{5a}$$

$$\text{P}_{\text{storage},bz,t} = \sum_s^S \big( \text{P}_{\text{charge},s,bz,t} - \text{P}_{\text{discharge},s,bz,t} \big) \tag{5b}$$

$$\text{P}_{\text{export},bz,t} = \sum_i^{I_{\text{hvac},bz}} \big( \text{P}_{\text{export},i,t} - \text{P}_{\text{import},i,t} \big) + \sum_i^{I_{\text{hvdc},bz}} \big( \text{P}_{\text{export},i,t} - \text{P}_{\text{import},i,t} \big) \tag{5c}$$

# Chapter 3

# Results

This chapter describes the results of our research. First, the ideal curtailment and a detailed analysis of the optimal scenario are covered. Then, a sensitivity analysis of the number of modeled climate years, interconnection, self-sufficiency, and technology costs is performed.

## 3.1 Curtailment

There is a tradeoff between the required generation and storage capacity when designing a firm power grid with IRES. When there is just enough generation capacity to meet demand, almost no energy can be curtailed, resulting in substantial storage capacity requirements. Less storage capacity is required when there is plenty of generation capacity since more power can be curtailed, but this would increase the costs for generation capacity. Therefore, curtailment is the ideal indicator to illustrate this tradeoff between generation and storage capacity. The curtailment could not be used directly as the step size due to how the storage systems are modeled and the nature of LP. Therefore, the cumulative storage costs were used as a proxy variable for curtailment. An exponential step size was used because the effect of adding more storage diminishes with more storage. In each step, 10% more storage costs were added.

Figure 5 displays the relationship between curtailment and the firm kWh premium when only lithium-ion storage is included. The lowest premium of 3.95 is achieved when 51% of the generated energy is curtailed. Figure 6 shows the same relationship when hydrogen is added as a storage method. With hydrogen, the minimum premium reduces to 2.95 while also requiring a curtailment of only 32%. The average LCOE across Europe is €130/MWh with only lithium-ion storage and €93/MWh with lithium-ion and hydrogen storage.

Both figures stop at roughly 80% curtailment. This is caused by the country-level potential of onshore and offshore wind; the extra generation capacity required for further curtailment would violate these constraints.

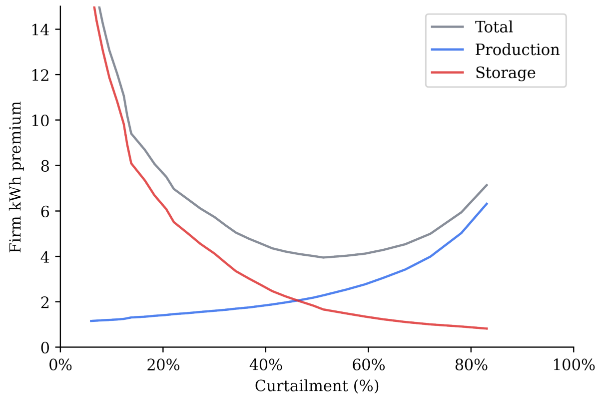


**Figure 5:** Firm kWh premium as a function of IRES curtailment with lithium-ion storage

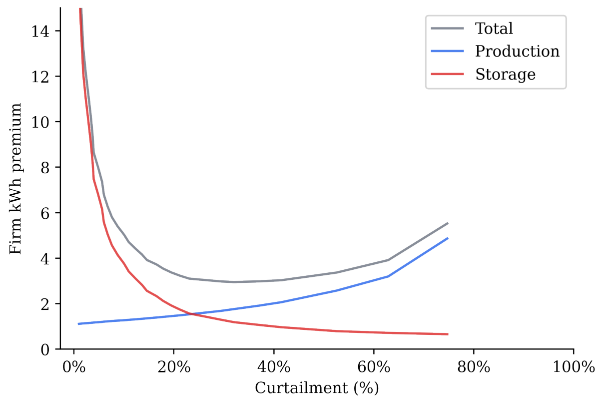


**Figure 6:** Firm kWh premium as a function of IRES curtailment with lithium-ion and hydrogen storage

## 3.2 Energy flows

Analyzing the energy flows provides a unique insight into how the various technologies work together. Figure 7 shows a Sankey diagram of the average energy flows aggregated for all countries and all time steps. This analysis, and subsequent analyses without explicit mention, analyze the optimal lithium-ion + hydrogen scenario. On average, 86% of the electricity demand is generated domestically; the remaining 14% is imported. Of all electricity consumed or exported, 83% is directly generated or imported and did not need to be stored. Of the stored electricity, only a quarter comes from hydrogen storage, with the other three-quarters from lithium-ion storage.

There are also energy flows between lithium-ion and hydrogen storage. 8% of the electricity used to generate hydrogen and 12% of the electricity generated from hydrogen flows via lithium-ion storage. This illustrates the synergy of multiple storage technologies. Lithium-ion works as a partial intermediary for hydrogen storage, reducing the required capacity of hydrogen electrolyzers and thereby increasing the capacity factor of the costly electrolyzers.

Figure 8 shows where the energy generated by each generation technology goes first. Only 29.4% of the generated solar PV is immediately consumed when generated, whereas 49.7% and 62.7% of the onshore and offshore wind energy is immediately consumed. The electricity generated by solar PV is 62% more curtailed than that generated by the onshore wind; this makes sense as solar PV is cheaper than wind energy, allowing for more curtailment with a similar firm kWh cost. Offshore wind has even less curtailment, but this technology is deployed in only seven countries, which creates a skewed view compared to the averages for solar PV and onshore wind deployed in all European countries.

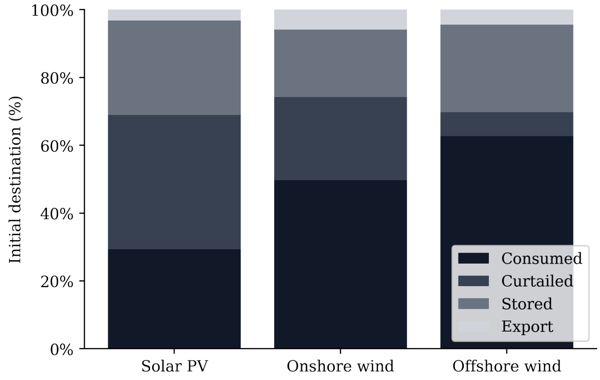


**Figure 8:** Initial destination of generated electricity per generation technology

## 3.3 Countries

The relative and absolute capacity of solar PV, onshore wind, and offshore wind are shown in Figures 9 and 10. Unsurprisingly, solar PV is predominantly used in Southern Europe, whereas onshore wind has a higher penetration in Northern Europe. Offshore wind is less deployed and has only a meaningful share in the North and Baltic Seas. Figure 11 displays the relative electricity production per country; this figure illustrates how offshore wind, despite its relatively small capacity, still generates substantial electricity in some countries due to its higher capacity factor.

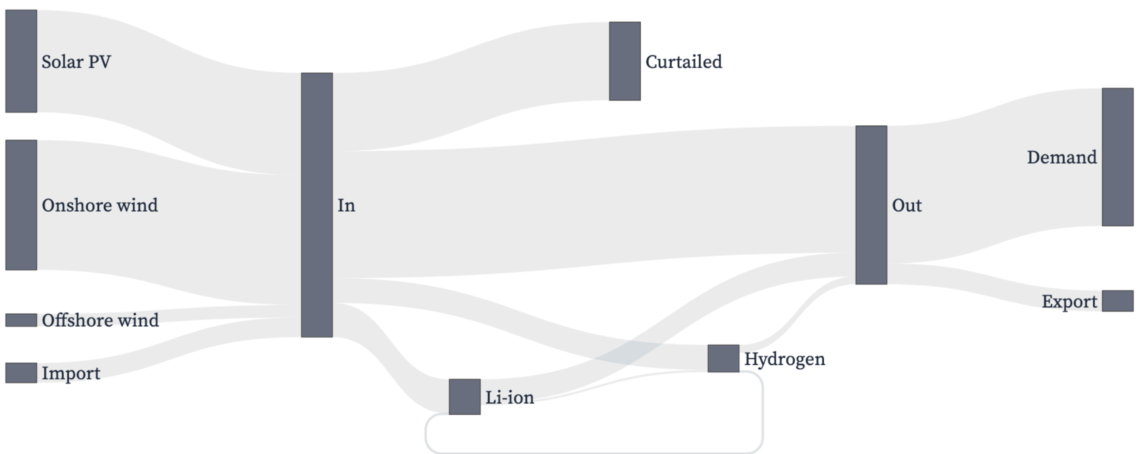


**Figure 7:** Sankey diagram of the average energy flows

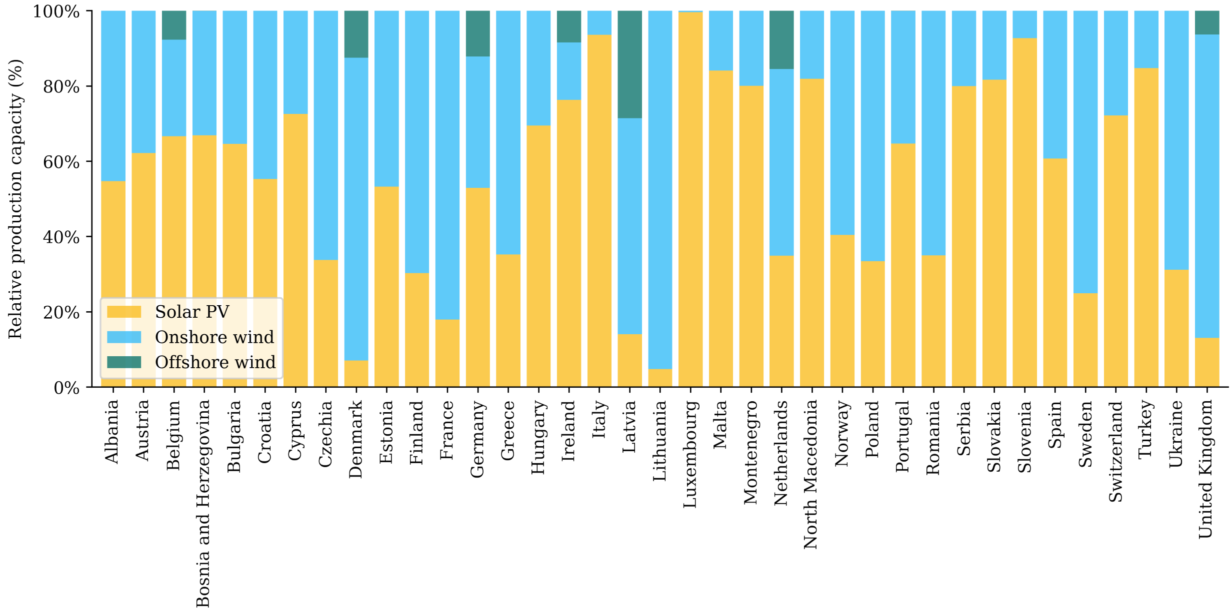


**Figure 9:** Relative production capacity per country

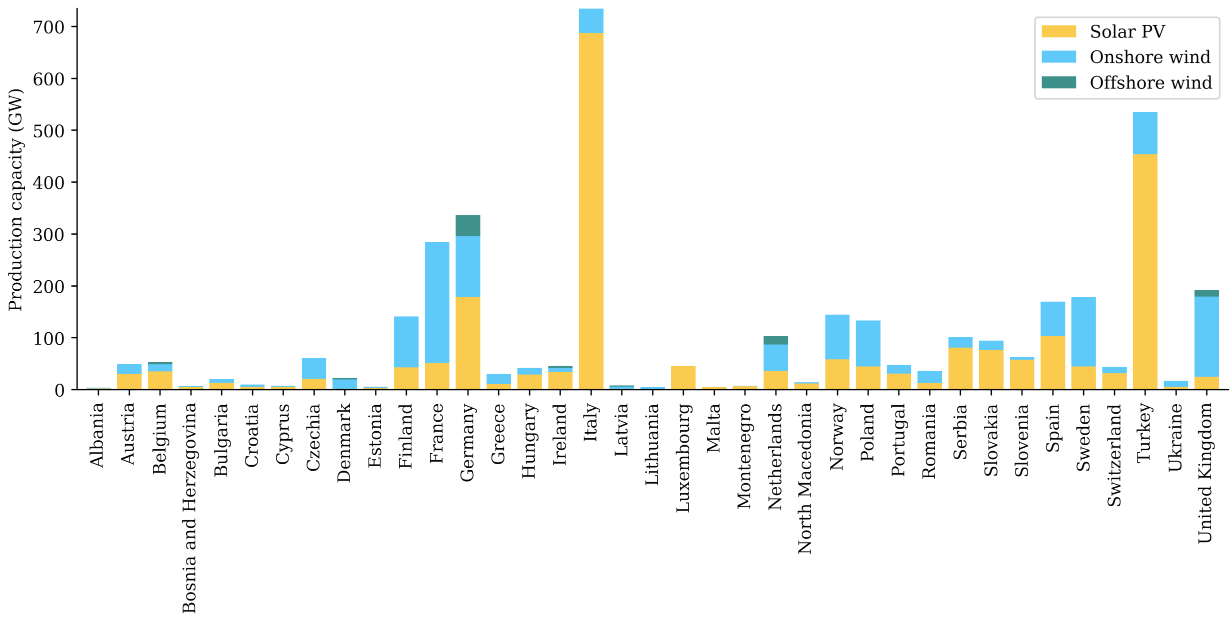


**Figure 10:** Production capacity per country

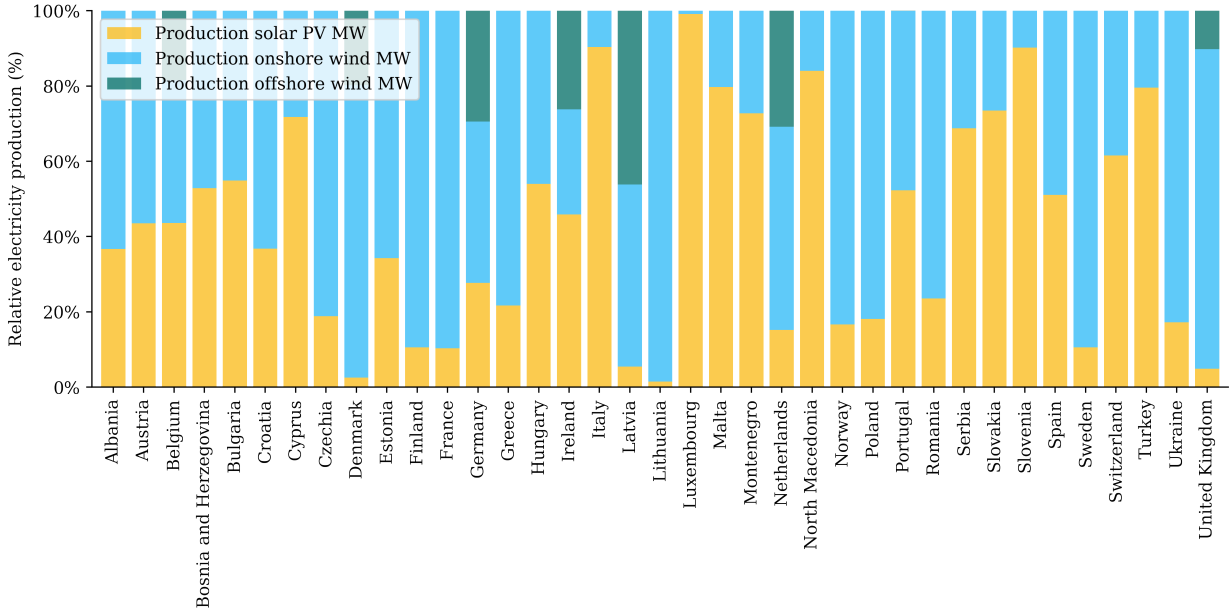


**Figure 11:** Relative electricity production per country

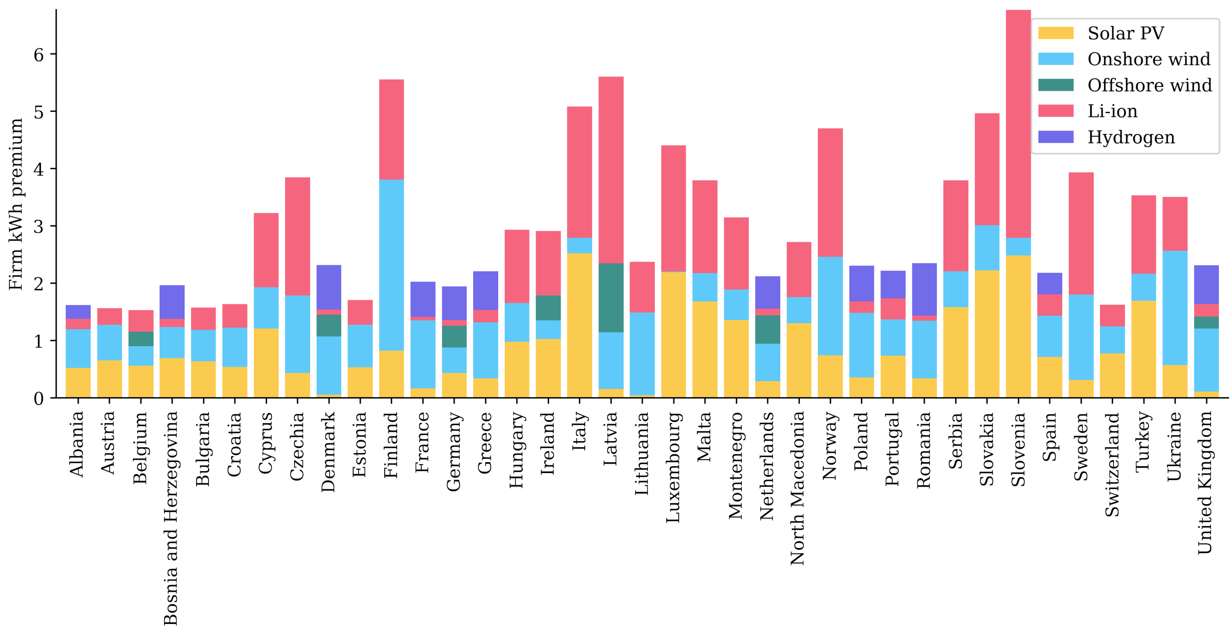


**Figure 12:** Composition of firm kWh premium per country

Across the European region, the capacity factors for solar PV, onshore wind, and offshore wind are, respectively, 14.9%, 30.2%, and 50.3%.

Figure 12 depicts how the different generation and storage technologies contribute to the firm kWh premium for each country. All countries with hydrogen storage have a premium below 2.36, whereas countries without hydrogen storage have premiums up to 6.77.

The optimal curtailment in a lithium-ion + hydrogen scenario is, on average, 32%, but this ratio differs significantly per country. Figure 13 shows the curtailment per country, where some countries have to curtail two-thirds of the generated electricity. The countries with the lowest curtailment ratios are those that have the potential to store hydrogen in underground salt caverns or have sufficient interconnection capacity to a neighboring country with such potential. Figure 14 displays the cumulative results of Figure 12 geographically. Figure 13 and 14 together illustrate again how countries with a high curtailment ratio also have above-average premiums, indicating that the firm kWh premium is adversely affected by the necessary overbuilding of generation capacity due to the lack of seasonal storage.

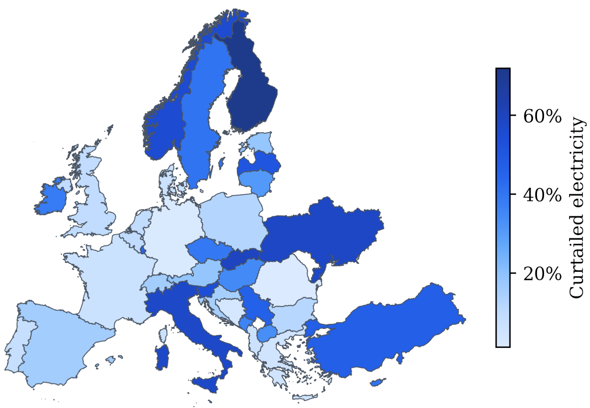


**Figure 13:** Curtailed electricity per country

## 3.4 Investments

In the scenario with lithium-ion and hydrogen storage and optimal curtailment, a total generation capacity of 2.3TW, 1.4TW, and 0.08TW are required for solar PV, onshore wind, and offshore wind, respectively. This is an increase of fifteen times for the currently installed solar PV capacity, eight times for onshore wind, and three times for offshore wind. The scenario requires 11TWh of lithium-ion storage and 113TWh of hydrogen storage; this is enough storage capacity to power the entire European region for 24 hours and 244 hours, respectively. The CAPEX investment would be 2.9 trillion euros for generation capacity and 1.5 trillion euros for storage capacity.

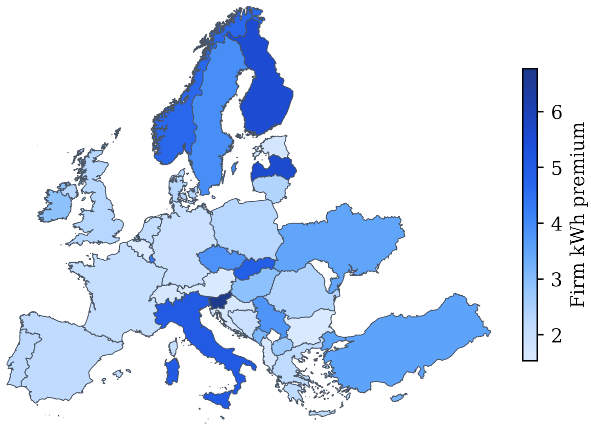


**Figure 14:** Firm kWh premium per country

## 3.5 Climate years

The reliability and robustness of a fully IRES energy model will increase when more climate years are included since more periods with reduced renewable generation need to be accounted for, making the system better equipped to deal with climatological edge cases. However, modeling multiple years at an hourly level requires significant processing power. Figures 15 and 16 show the relationship between the number of years modeled and the firm kWh premium for a lithium-ion only and lithium-ion + hydrogen scenario. Due to the limited computational power available and extremely long simulation durations for simulations with more than ten years, only up to 15 of the available 35 years were modeled for Figures 15 and 16. The latest available years were used for all analyses (e.g., 2002 to 2016 for the 15-year analysis).

Formula 6 displays an algebraic approximation of the relationship between the number of included climate years and the firm kWh premium. The values for a, b, and c in this formula are shown in Figures 15 and 16 for their respective scenario. Due to the logarithmic nature of the function, the change in the firm kWh premium diminishes when more years are included.

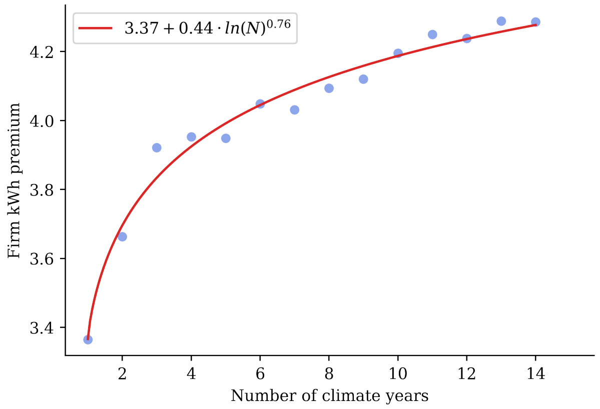


**Figure 15:** Firm kWh premium as a function of modeled climate years (lithium-ion storage)

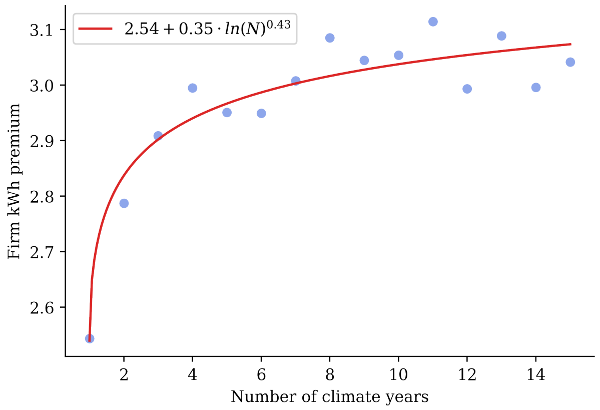


**Figure 16:** Firm kWh premium as a function of modeled climate years (lithium-ion + hydrogen storage)

Formula 7 shows the derivative of the firm kWh premium. Only b and c affect the derivative, and since these values are smaller for the lithium-ion + hydrogen scenario, this scenario stabilizes earlier. Figure 17 is a graphical representation of Formula 7. It illustrates how the relative derivative of the firm kWh premium decreases significantly in the first few years and then tapers off; the relative derivative of the firm kWh premium goes below 2% when including more than four years.

$$\text{Firm kWh premium}_N = a + b \cdot \ln(N)^c \tag{6}$$

$$\begin{aligned}&\text{Change in Firm kWh premium}\\&= \text{Firm kWh premium}\frac{d}{dN}\\&= \frac{b \cdot c \cdot \ln(N)^{c-1}}{N}\end{aligned} \tag{7}$$

The required computational power increases roughly linear to the number of climate years, but the firm kWh premium changes logarithmically. Formula 7 shows that doubling the number of climate years from five to ten years will impact the final firm kWh premium by only 11% for the lithium-ion + hydrogen scenario. This illustrates the diminishing returns of including more than a few climate years. Therefore, all other simulations use five years (2012-2016) of climate data.

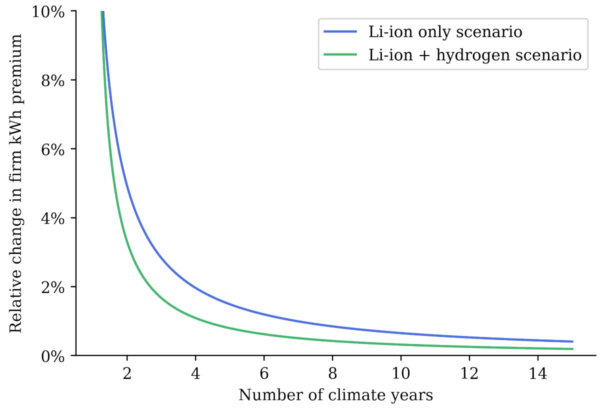


**Figure 17:** Relative derivative of the firm kWh premium as a function of modeled climate years

## 3.6 Duration curve

The power of geographical smoothing is well illustrated with duration curves. Figures 18, 19, and 20 show the duration curve for the demand, generation, and curtailed energy, respectively. Each thin line represents the duration curve for a particular country, the blue area depicts the range of the duration curves of all countries, and the main line resembles the duration curve for the whole continent.

The demand is, on a national level, already relatively stable. Still, the demand duration curve is even more gradual for Europe. Figure 18 depicts how the European electricity demand is 80% of the time between ±23% of the mean demand.

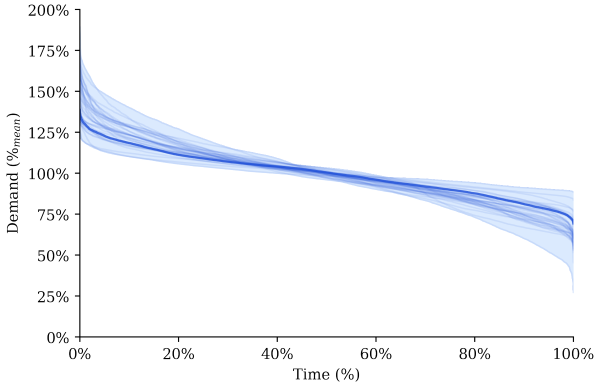


**Figure 18:** Duration curve of demand relative to the mean demand

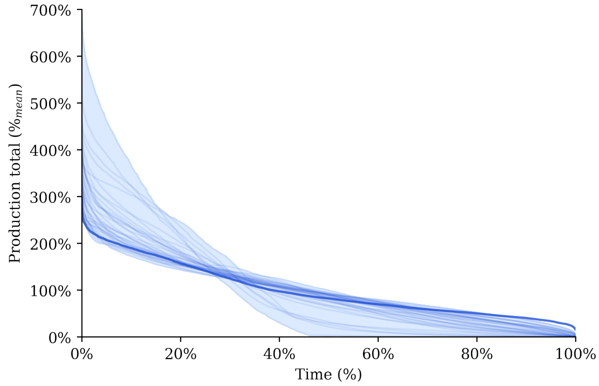


**Figure 19:** Duration curve of generation relative to the mean generation

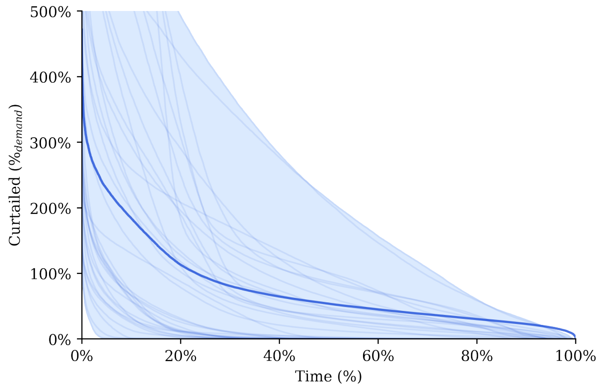


**Figure 20:** Duration curve of curtailed energy relative to demand

Figure 19 shows the production duration curve relative to the mean production for all production technologies aggregated. This figure illustrates that most countries generate more than double their mean production 15-25% of the time. However, this peak is significantly less pronounced for the European average, indicating that geographical smoothing could help lower the production peak when the appropriate interconnection capacity is available.

The same peak can be seen in Figure 20, which displays the curtailment duration curve relative to the demand. Due to varying deployment of generation and storage capacity, the curtailed electricity curve varies significantly between countries. Still, across Europe, half of all curtailed energy is curtailed in just 20.3% of the overall time. This also illustrates the difficulties of not curtailing electricity, as many storage options are not financially viable when used only sparingly. Figure 20 also shows that at almost any moment, some energy is curtailed somewhere in Europe; 98.8% of the time, 10% or more of the European electricity demand gets curtailed, compared to 81.1% of the time for the average country.

## 3.7 Interconnections and self-sufficiency

This is the first study looking on a continental level at the ideal combination of overbuilding and curtailment in a fully IRES scenario. One of the main benefits of analyzing intermittent renewables on a supranational level is the geographic smoothing of both the demand and generation profiles. Figures 21, 22, and 23 show the correlation between the distance of the geographical centers of the two countries and the coefficient of determination of demand, solar PV generation, and onshore wind generation, respectively. These figures show each combination of countries, resulting in $\frac{37 \cdot 36}{2} = 666$ data points. Figure 21 shows that the correlation in demand gradually decreases when the distance between two countries increases. Figure 22 shows that the coefficient of determination of solar PV generation is significant even between countries that are thousands of kilometers apart. This strong correlation between solar PV generation is mainly due to the nocturnal cadence. However, Figure 23 shows that the coefficient of determination for onshore wind generation quickly drops when the geographical centers of countries are more than a few hundred kilometers apart. These three correlations indicate that sufficient interconnection capacity could help smooth generation and demand profiles to some extent.

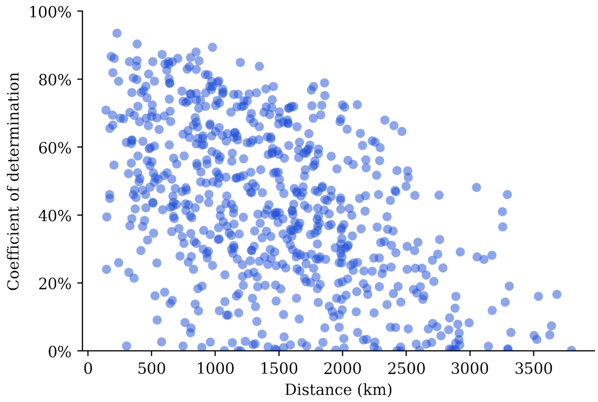


**Figure 21:** Correlation of electricity demand as a function of distance

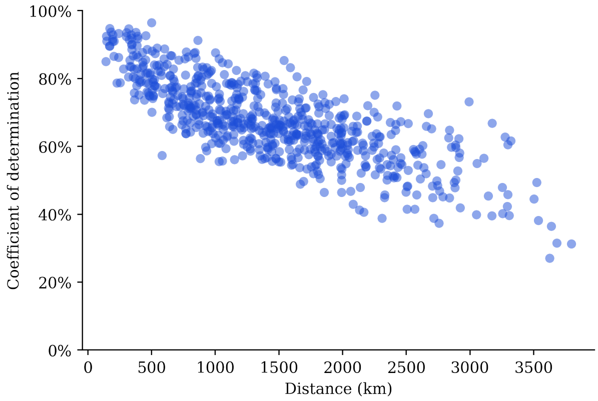


**Figure 22:** Correlation of solar PV generation as a function of distance

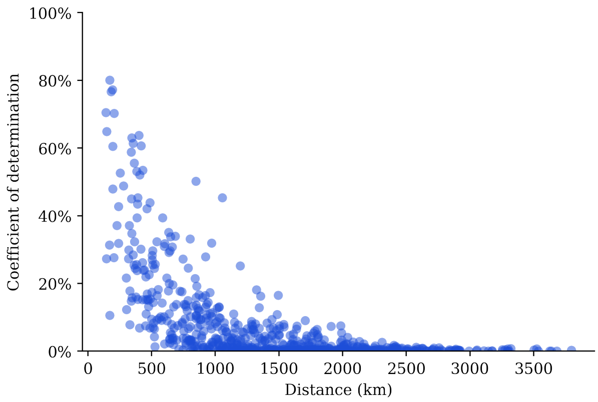


**Figure 23:** Correlation of onshore wind generation as a function of distance

Figure 24 shows the relationship between interconnection capacity and firm kWh premium. With a limited interconnection capacity, the firm kWh premium is relatively sensitive, but this sensitivity reduces as interconnectivity increases; the firm kWh premium would drop by merely 1.7% to 2.91 when the currently anticipated interconnection capacity increases by 20%. Figure 20 showed that almost always some energy is curtailed in Europe, but Figure 24 shows that increasing all interconnection capacities has no significant impact. This indicates that only some interconnections might be significantly limited by their capacity; with overbuilding, storage, and curtailment, most of the projected 2030 interconnections could be powerful enough to handle a fully IRES electricity grid.

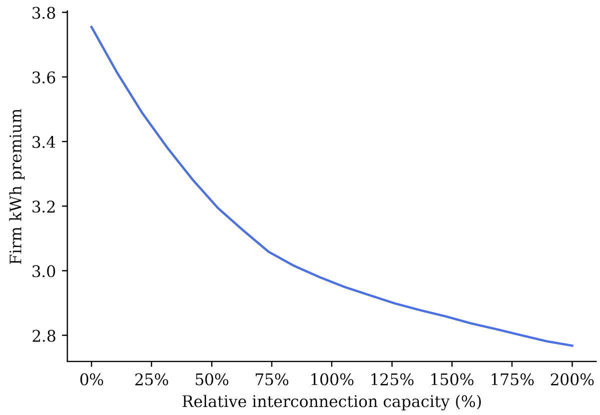


**Figure 24:** Sensitivity analysis of the interconnection capacity on the firm kWh premium

Figure 25 illustrates that the HVAC and HVDC interconnection efficiency has almost no impact on the firm kWh premium. There is only a 0.13% difference in firm kWh premium between 80% and 100% interconnection efficiency. The raggedness of the line is due to the very narrow y-axis, which only comprises 0.27% of the firm kWh premium.

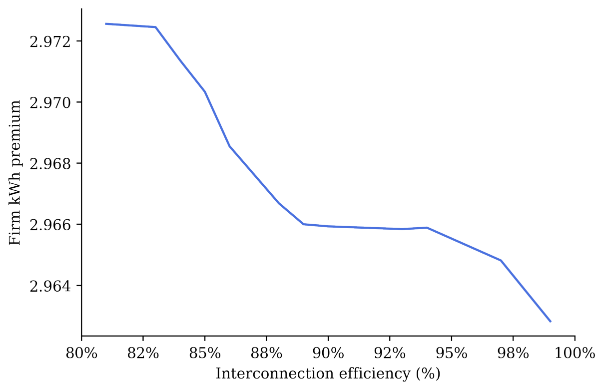


**Figure 25:** Sensitivity analysis of the efficiency of interconnections on the firm kWh premium

Figure 26 depicts the firm kWh premium as a function of the minimum self-sufficiency. Self-sufficiency has up to 80% no meaningful impact on the premium, but requiring all countries to be fully self-sufficient would increase the firm kWh premium by 6%.

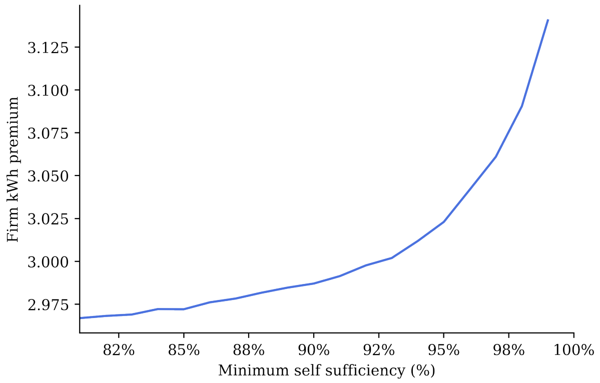


**Figure 26:** Sensitivity analysis of the self-sufficiency on the firm kWh premium

## 3.8 Technology costs

One of the most significant assumptions in the model is regarding costs. A different assumption in the costs of one of the included technologies could shift the balance of used technologies, thereby affecting the LCOE and firm kWh premium. The firm kWh premium will decrease when the generation technology costs rise since the generation technology costs are both in the numerator and denominator. Therefore, the firm LCOE is shown instead of the firm kWh premium.

Creating a sensitivity plot by applying a fixed factor over all technologies might create a skewed view of the actual sensitivity of the technology costs, as the uncertainty distribution might differ between different technologies. This uncertainty is exacerbated by the different technology readiness levels of the technologies used. NREL and Gupta et al. do, however, provide the costs for a conservative, moderate, and advanced scenario. The costs in these scenarios can be found in Appendix G.

Figure 27 displays how the firm LCOE changes as the costs of each technology shift from the conservative to the advanced scenario. Solar PV and onshore wind have a moderate impact on the firm kWh LCOE. However, onshore wind could provide more upside when the advanced scenario becomes a reality. The offshore wind scenarios have almost no impact on the firm kWh LCOE. Lithium-ion storage offers the most significant risk; in the conservative scenario, the firm kWh LCOE would increase by 15% to €110/MWh.

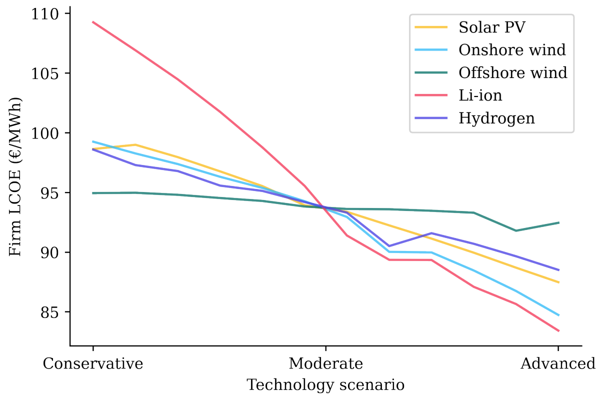


**Figure 27:** Sensitivity analysis of the technology scenarios on the firm LCOE

# Chapter 4

# Discussion

We demonstrate that overbuilding and dynamic curtailment is the most cost-effective way to deploy IRES in a fully decarbonized system on a continental scale, confirming earlier research by Budischak, Perez, and Remund [11, 12, 14]. For example, Perez et al. found that with only lithium-ion storage and an optimal curtailment ratio of roughly 50%, the firm kWh premium in Minnesota would be around 5. Our results indicate that the European region has a similar curtailment ratio of 51%; however, the European region does have a moderately lower firm kWh premium of 3.95. Furthermore, we show for the first time that the number of modeled climate years has a diminishing effect on the firm kWh premium.

PEIROCOM is an LP that optimizes only for the total system costs; however, many other factors, such as subsidies and public perception, influence real-world decisions about the deployment of generation capacity. For instance, non-landlocked countries with dense populations might favor offshore wind power over onshore wind power, despite the higher costs of offshore wind. This study used a top-down approach to installing capacity and curtailing energy; we did not examine how legislation could require particular generation facilities to curtail at specific times and how this would affect future investment in IRES. Furthermore, due to our historical dependence on fossil fuels, curtailment is still publicly regarded as a negative externality that should be avoided. Some public debate might be required before substantial proactive curtailment becomes publicly acceptable.

The demand data used in this study came from the ERAA 2030 projection. However, a fully renewable European electricity system will only become a reality by 2035, and a fully IRES electricity grid will be realized even later. By this time, the daily and annual demand profiles might have changed significantly due to the continued electrification of heating, transport, and industry. Additionally, it is unclear how climate change would affect the generation profiles of intermittent renewables. Furthermore, demand response could play a significant role in aligning demand and intermittent renewable electricity generation, but was not considered in this study.

To simplify the model, only solar PV, onshore wind, and offshore wind are included in this study. However, earlier research indicates that gas-peaking power could significantly reduce system costs [11], but they did not include seasonal storage; further research is required to analyze if peak power is still beneficial when seasonal storage is included.

This study only includes hydrogen storage in underground salt caverns, but hydrogen storage is also possible in depleted gas fields and above-ground storage. Diversifying hydrogen storage methods would allow for more dispersed hydrogen storage, thus reducing the system costs in regions with no suitable salt caverns. Moreover, hydrogen is being considered for many industrial processes. This presents both challenges and opportunities, as increased hydrogen demand necessitates more generation capacity, but it may also result in additional demand response capability from the industry.

Although interconnection capacity between different bidding zones is included in the model, a copper plate assumption is made for energy flows within a bidding zone. However, grid congestion is already a significant issue for European transmission system operators. Therefore, a more thorough examination of the exact location of generation and demand is required to improve our high-level analysis. In addition, we did not analyze the sensitivity of specific interconnections to identify which interconnections are most worthwhile to upgrade, nor did we analyze intercontinental interconnections.

# Chapter 5

# Conclusion & outlook

This study demonstrates that it is technically and economically feasible to meet the electricity demand of the entire European grid using only solar PV and wind power. We showed for the first time that overbuilding and proactive curtailment is feasible on a continental level and that hydrogen storage can play a significant role in reducing system costs.

We found that providing firm power with only lithium-ion storage will have a firm kWh premium of 3.95, but this premium can be reduced to 2.95 by including hydrogen. The optimal curtailment ratio is 51% when only lithium-ion storage is used and 32% when hydrogen is also included. Additionally, our study found that the average LCOE across Europe is €130/MWh with only lithium-ion storage and €93/MWh with lithium-ion and hydrogen storage. We also analyzed the energy flows in the system and found that, on average, 86% of the electricity demand is generated domestically, with the remaining 14% imported. Furthermore, we illustrated how the synergy between lithium-ion and hydrogen storage would reduce the required capacity of electrolyzers.

The PEIROCOM model is designed to be fully dynamic and can be applied to different regions or geographic levels. However, future research could improve upon this model in various ways. Firstly, adding the option for run-of-river, reservoir, and pumped hydropower would allow for more versatile scenarios and lower costs in mountainous countries. Additionally, adding the option for different solar PV orientations could increase the accuracy of the model while reducing the firm kWh premium.

Additional research is also necessary to determine the optimal placement of generation and storage capacities within bidding zones and to analyze whether grid congestion within these zones would require additional generation or storage capacity. Expanding this research to include multiple hydrogen storage options, such as depleted gas fields and tank storage, would provide further insights into potential cost reductions and enable more European countries to store energy seasonally. Lastly, we encourage further research into the opportunities and challenges of the interaction between lithium-ion and hydrogen storage.

In summary, our research provides compelling evidence that with overbuilding and proactive curtailment, intermittent renewable energy sources can be a reliable and cost-effective source of firm power on the European continent.

# Acknowledgements

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# Appendix A

# Country statistics

| | NUTS 2 | Population (million) | Land area ($km^2$) |
|---|---|---|---|
| **Albania** | AL | 2.81 | 27400 |
| **Austria** | AT | 8.96 | 82520 |
| **Belgium** | BE | 11.59 | 30280 |
| **Bosnia and Herzegovina** | BA | 3.26 | 51200 |
| **Bulgaria** | BG | 6.90 | 108560 |
| **Croatia** | HR | 3.90 | 55960 |
| **Cyprus** | CY | 1.22 | 9240 |
| **Czechia** | CZ | 10.70 | 77198 |
| **Denmark** | DK | 5.86 | 40000 |
| **Estonia** | EE | 1.33 | 42750 |
| **Finland** | FI | 5.54 | 303940 |
| **France** | FR | 67.50 | 547557 |
| **Germany** | DE | 83.13 | 349390 |
| **Greece** | GR | 10.66 | 128900 |
| **Hungary** | HU | 9.71 | 91260 |
| **Ireland** | IE | 5.03 | 68890 |
| **Italy** | IT | 59.07 | 295717 |
| **Latvia** | LV | 1.88 | 62230 |
| **Lithuania** | LT | 2.80 | 62620 |
| **Luxembourg** | LU | 0.64 | 2574 |
| **Malta** | MT | 0.52 | 320 |
| **Montenegro** | ME | 0.62 | 13450 |
| **Netherlands** | NL | 17.53 | 33670 |
| **North Macedonia** | MK | 2.07 | 25220 |
| **Norway** | NO | 5.41 | 364285 |
| **Poland** | PL | 37.78 | 306130 |
| **Portugal** | PT | 10.30 | 91605 |
| **Romania** | RO | 19.12 | 230080 |
| **Serbia** | RS | 6.84 | 87460 |
| **Slovakia** | SK | 5.45 | 48080 |
| **Slovenia** | SI | 2.11 | 20136 |
| **Spain** | ES | 47.33 | 499556 |
| **Sweden** | SE | 10.42 | 407283 |
| **Switzerland** | CH | 8.70 | 39516 |
| **Turkey** | TR | 85.04 | 769630 |
| **Ukraine** | UA | 43.81 | 579400 |
| **United Kingdom** | UK | 67.33 | 241930 |

# Appendix B

# Bidding zones

| | **Zones** |
|---|---|
| **Albania** | AL00 |
| **Austria** | AT00 |
| **Belgium** | BE00 |
| **Bosnia and Herzegovina** | BA00 |
| **Bulgaria** | BG00 |
| **Croatia** | HR00 |
| **Cyprus** | CY00 |
| **Czechia** | CZ00 |
| **Denmark** | DKE1, DKW1 |
| **Estonia** | EE00 |
| **Finland** | FI00 |
| **France** | FR00, FR15 |
| **Germany** | DE00 |
| **Greece** | GR00, GR03 |
| **Hungary** | HU00 |
| **Ireland** | IE00 |
| **Italy** | ITCA, ITCN, ITCS, ITN1, ITS1, ITSA, ITSI |
| **Latvia** | LV00 |
| **Lithuania** | LT00 |
| **Luxembourg** | LUB1, LUF1, LUG1 |
| **Malta** | MT00 |
| **Montenegro** | ME00 |
| **Netherlands** | NL00 |
| **North Macedonia** | MK00 |
| **Norway** | NOM1, NON1, NOS0 |
| **Poland** | PL00 |
| **Portugal** | PT00 |
| **Romania** | RO00 |
| **Serbia** | RS00 |
| **Slovakia** | SK00 |
| **Slovenia** | SI00 |
| **Spain** | ES00 |
| **Sweden** | SE01, SE02, SE03, SE04 |
| **Switzerland** | CH00 |
| **Turkey** | TR00 |
| **Ukraine** | UA01 |
| **United Kingdom** | UK00, UKNI |

# Appendix C

# Onshore climate zones

| | Zones |
|---|---|
| **Albania** | AL00 |
| **Austria** | AT00, AT01, AT02, AT03 |
| **Belgium** | BE00, BE01, BE02, BE03 |
| **Bosnia and Herzegovina** | BA00 |
| **Bulgaria** | BG00, BG01, BG02 |
| **Croatia** | HR00, HR02 |
| **Cyprus** | CY00 |
| **Czechia** | CZ00, CZ01, CZ02 |
| **Denmark** | DKE1, DKW1 |
| **Estonia** | EE00 |
| **Finland** | FI00, FI01, FI02 |
| **France** | FR00, FR01, FR02, FR03, FR04, FR05, FR06, FR07... |
| **Germany** | DE00, DE01, DE02, DE03, DE04, DE05, DE06, DE07 |
| **Greece** | GR00, GR01, GR02, GR03 |
| **Hungary** | HU00, HU01, HU02, HU03 |
| **Ireland** | IE00 |
| **Italy** | ITCA, ITCN, ITCS, ITN1, ITS1, ITSA, ITSI |
| **Latvia** | LV00 |
| **Lithuania** | LT00 |
| **Luxembourg** | LUB1, LUF1, LUG1 |
| **Malta** | MT00 |
| **Montenegro** | ME00 |
| **Netherlands** | NL00, NL01, NL02, NL03, NL04 |
| **North Macedonia** | MK00 |
| **Norway** | NOM1, NON1, NOS0, NOS1, NOS2, NOS3 |
| **Poland** | PL00, PL01, PL02, PL03, PL04, PL05 |
| **Portugal** | PT00, PT01, PT02 |
| **Romania** | RO00, RO01, RO02, RO03 |
| **Serbia** | RS00, RS01 |
| **Slovakia** | SK00 |
| **Slovenia** | SI00 |
| **Spain** | ES00, ES01, ES02, ES03, ES04, ES05, ES06, ES07... |
| **Sweden** | SE01, SE02, SE03, SE04 |
| **Switzerland** | CH00 |
| **Turkey** | TR00 |
| **Ukraine** | UA01, UA02 |
| **United Kingdom** | UK00, UK01, UK02, UK03, UK04, UK05, UKNI |

# Appendix D

# Offshore climate zones

| | Zones |
|---|---|
| **Albania** | AL00 |
| **Austria** | - |
| **Belgium** | BE00 |
| **Bosnia and Herzegovina** | BA00 |
| **Bulgaria** | BG00 |
| **Croatia** | HR00 |
| **Cyprus** | CY00 |
| **Czechia** | - |
| **Denmark** | DKE1, DKW1 |
| **Estonia** | EE00 |
| **Finland** | FI00, FI01, FI02 |
| **France** | FR00, FR01, FR02, FR03, FR04, FR08, FR09, FR13 |
| **Germany** | DE00, DE11, DE12, DE13, DE02, DEKF |
| **Greece** | GR00, GR01, GR03 |
| **Hungary** | - |
| **Ireland** | IE00 |
| **Italy** | ITCA, ITCN, ITCS, ITN1, ITS1, ITSA, ITSI |
| **Latvia** | LV00 |
| **Lithuania** | LT00 |
| **Luxembourg** | - |
| **Malta** | MT00 |
| **Montenegro** | ME00 |
| **Netherlands** | NL00, NL11, NL12, NL31, NL32, NL33 |
| **North Macedonia** | - |
| **Norway** | NOM1, NON1, NOS0, NOS3 |
| **Poland** | PL00, PL04 |
| **Portugal** | PT00, PT02 |
| **Romania** | RO00 |
| **Serbia** | - |
| **Slovakia** | - |
| **Slovenia** | SI00 |
| **Spain** | ES00, ES02, ES04, ES06, ES09, ES10, ES11 |
| **Sweden** | SE01, SE02, SE03, SE04 |
| **Switzerland** | - |
| **Turkey** | TR00 |
| **Ukraine** | UA02 |
| **United Kingdom** | UK00, UK02, UKNI |

# Appendix E

# Currently installed capacity

| | Solar PV (GW) | Onshore wind (GW) | Offshore wind (GW) |
|---|---|---|---|
| **Albania** | - | - | - |
| **Austria** | 2.50 | 3.50 | - |
| **Belgium** | 4.79 | 2.79 | 2.25 |
| **Bosnia and Herzegovina** | - | 0.14 | - |
| **Bulgaria** | 1.31 | 0.70 | - |
| **Croatia** | 0.10 | 0.92 | - |
| **Cyprus** | - | - | - |
| **Czechia** | 2.05 | 0.34 | - |
| **Denmark** | 1.54 | 4.64 | 2.31 |
| **Estonia** | 0.37 | 0.33 | - |
| **Finland** | 0.01 | 3.18 | - |
| **France** | 14.30 | - | 0.01 |
| **Germany** | 56.35 | 55.56 | 7.79 |
| **Greece** | 3.82 | 4.15 | - |
| **Hungary** | 2.21 | 0.32 | - |
| **Ireland** | - | 1.92 | - |
| **Italy** | 5.14 | 10.66 | - |
| **Latvia** | 0.01 | 0.09 | - |
| **Lithuania** | 0.26 | 0.67 | - |
| **Luxembourg** | 0.26 | 0.17 | - |
| **Malta** | - | - | - |
| **Montenegro** | - | 0.12 | - |
| **Netherlands** | 16.07 | 7.30 | 3.76 |
| **North Macedonia** | 0.02 | 0.04 | - |
| **Norway** | - | 5.11 | - |
| **Poland** | 6.04 | 7.89 | - |
| **Portugal** | 1.03 | 5.33 | 0.02 |
| **Romania** | 1.16 | 2.96 | - |
| **Serbia** | - | 0.53 | - |
| **Slovakia** | - | - | - |
| **Slovenia** | 0.29 | - | - |
| **Spain** | 14.64 | 27.74 | - |
| **Sweden** | - | 12.10 | - |
| **Switzerland** | - | - | - |
| **Turkey** | - | - | - |
| **Ukraine** | 5.36 | 1.11 | - |
| **United Kingdom** | 13.47 | 13.93 | 12.16 |

# Appendix F

# Generation and storage potential

| | Onshore wind (GW) | Offshore wind (GW) | Hydrogen storage (TWh) |
|---|---|---|---|
| **Albania** | 16.37 | 0.00 | 50 |
| **Austria** | 111.70 | 0.0 | 0 |
| **Belgium** | 13.55 | 4.72 | 0 |
| **Bosnia and Herzegovina** | 92.45 | - | 800 |
| **Bulgaria** | 8.49 | 0.00 | 0 |
| **Croatia** | 34.18 | 0.00 | 0 |
| **Cyprus** | - | - | 0 |
| **Czechia** | 40.89 | 0.0 | 0 |
| **Denmark** | 150.55 | 172.35 | 600 |
| **Estonia** | 144.67 | 81.81 | 0 |
| **Finland** | 777.50 | 46.92 | 0 |
| **France** | 1079.71 | 177.11 | 510 |
| **Germany** | 117.39 | 40.98 | 9450 |
| **Greece** | 72.09 | 9.50 | 110 |
| **Hungary** | 17.03 | 0.0 | 0 |
| **Ireland** | 317.53 | 648.74 | 0 |
| **Italy** | 109.49 | 0.00 | 0 |
| **Latvia** | 155.11 | 85.16 | 0 |
| **Lithuania** | 221.93 | 14.09 | 0 |
| **Luxembourg** | 0.17 | 0.0 | 0 |
| **Malta** | - | - | 0 |
| **Montenegro** | 28.01 | 0.00 | 0 |
| **Netherlands** | 78.85 | 77.07 | 300 |
| **North Macedonia** | 5.76 | 0.0 | 0 |
| **Norway** | 747.17 | 641.03 | 0 |
| **Poland** | 419.54 | 79.68 | 7240 |
| **Portugal** | 59.67 | 2.83 | 250 |
| **Romania** | 38.14 | 0.00 | 1100 |
| **Serbia** | 23.65 | 0.0 | 0 |
| **Slovakia** | 17.38 | 0.0 | 0 |
| **Slovenia** | 4.58 | 0.00 | 0 |
| **Spain** | 391.32 | 25.71 | 1260 |
| **Sweden** | 841.93 | 166.65 | 0 |
| **Switzerland** | 13.68 | 0.0 | 0 |
| **Turkey** | 468.07 | 0.46 | 0 |
| **Ukraine** | - | - | 0 |
| **United Kingdom** | 690.00 | 1028.93 | 1040 |

# Appendix G

# Technology scenarios

| | | Conservative | Moderate | Advanced |
|---|---|---|---|---|
| **Solar PV** | **CAPEX** | €912/kW | €700/kW | €520/kW |
| | **O&M** | €12/kW/year | €10/kW/year | €8/kW/year |
| **Onshore wind** | **CAPEX** | €900/kW | €760/kW | €525/kW |
| | **O&M** | €41/kW/year | €33/kW/year | €24/kW/ |
| **Offshore wind** | **CAPEX** | €912/kW | €700/kW | €520/kW |
| | **O&M** | €12/kW/year | €10/kW/year | €8/kW/ |
| **Lithium-ion** | **Power CAPEX** | €260/kW | €243/kW | €104/kW |
| | **Energy CAPEX** | €143/kWh | €81/kWh | €57/kWh |
| | **O&M** | $2.5\%_{\text{CAPEX}}$/year | $2.5\%_{\text{CAPEX}}$/year | $2.5\%_{\text{CAPEX}}$/year |
| **Hydrogen** | **Power CAPEX** | €1950/kW | €1300/kW | €650/kW |
| | **Energy CAPEX** | €1.5/kWh | €1/kWh | €0.5/kWh |
| | **O&M** | $2.5\%_{\text{CAPEX}}$/year | $2.5\%_{\text{CAPEX}}$/year | $2.5\%_{\text{CAPEX}}$/year |