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Working Paper

Hydrogen in the European power sector: A case study on the impacts of regulatory frameworks for green hydrogen

HEMF Working Paper, No. 02-24

Provided in Cooperation with:

University of Duisburg-Essen, Chair for Management Science and Energy Economics

Suggested Citation: Radek, Julian; Breder, Marco Sebastian; Weber, Christoph (2024) : Hydrogen in the European power sector: A case study on the impacts of regulatory frameworks for green hydrogen, HEMF Working Paper, No. 02-24, University of Duisburg-Essen, House of Energy Markets & Finance (HEMF), Essen

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Hydrogen in the European power sector – A case study on the impacts of regulatory frameworks for green hydrogen

HEMF Working Paper 02/24

by

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July 2024

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Open-Minded

Abstract

To ensure sustainable green hydrogen (H₂) production, the European Union (EU) has introduced regulatory frameworks, such as the Delegated Act on Renewable Hydrogen. These regulations aim to ensure positive environmental effects through green hydrogen by establishing criteria of additionality, as well as spatial and temporal correlation. However, concerns have arisen among stakeholders regarding the potential barriers these criteria may pose to the growth of the EU hydrogen economy. Our analysis examines the implications of these regulations, analyzing the effects of the criteria on green hydrogen production from a system perspective. By doing that, we can assess the interplay with hydrogen production in European non-EU countries, as well as the role of third country import prices and quantities, while accounting for the EU objective of achieving net zero emissions by 2050. Our findings indicate that the EU hydrogen economy may be substantially affected by restrictive criteria for green hydrogen. Policy makers are therefore advised to carefully assess whether a level playing field can be established and to avoid overly restrictive unilateral measures.

Keywords: Hydrogen economy, Green Hydrogen, Energy market modeling, Regulation

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1 Introduction

Its commitment to achieving complete decarbonization by 2050 forces the European Union (EU) to implement an appropriate regulatory framework for the energy sector. This mandate arose from the dual necessity of implementing agreed-upon climate targets while maintaining the resilience of the EU's economy. In light of its crucial role in the extensive decarbonization of the industry and the transportation sector, hydrogen (H₂) is given special attention. In the long term, green H₂ is expected to be obtained from renewable electricity through electrolysis, both domestically and abroad. However, during the transition phase, H₂ production through electrolysis is not necessarily "climate-friendly", as the prevailing electricity mix still contains large amounts of fossil-based electricity. This dependency is a consequence of the limited availability of renewable energy sources, such as wind and solar energy, in the European power sector.

With the REPowerEU initiative, the EU Commission pursues ambitious goals for security of supply, diversified supply routes, and climate protection (EU Commission 2022b, 2022c). Crucial elements of the REPowerEU initiative are the acceleration of the ramp-up of the hydrogen market and the expansion of renewable energies. Additionally, comprehensive regulations should prevent the support mechanisms for green hydrogen production from leading to side effects. However, some still oppose the Delegated Act supplementing Directive (EU) 2018/2001, also known as RED II, which sets the framework for future rules on European hydrogen production (EU Parliament 2018; Frontier Economics 2021; Becker and Berks 2022; dena 2022; EU Commission 2022a; RWE 2022). Critics claim that instead of accelerating the development of the hydrogen economy, the delegated act imposes unnecessary constraints on it. On the 20th of November 2023, the EU passed the Directive (EU) 2023/2413, also known as RED III, which raises the EU's renewable energy targets. However, in the build-up to RED III, the delegated act was not altered.

This paper analyzes the validity of the criticisms regarding the constraints imposed on green hydrogen production through the delegated act in conjunction with the RePowerEU initiative.

We investigate what impacts these limiting factors have on EU hydrogen development in light of the crucial role attributed to hydrogen by both the EU Commission and its member states. We particularly focus on how the relationship between domestic production and imports is affected. Since there will also be feedback effects from neighboring countries, we consider continent-wide effects in Europe instead of an isolated view on domestic effects in a single country.

For our analysis, we use an extended version of the European energy market model *E2M2s* (Swider and Weber 2007; Spiecker et al. 2013; Spiecker and Weber 2014; Bucksteeg et al. 2019; Blumberg et al. 2022), which enables analysis of the long-term development of the European electricity and heat markets. Notably, it allows for the determination of the expansion of conventional and renewable plant capacities. A particular strength of the model is the stochastic representation of the renewable feed-in by means of recombining trees, as well as the reduction of the computation time by means of the typical day method. Policy regulations may be incorporated into the model with the help of additional constraints.

The remainder of this paper is structured as follows: Section 2 reviews relevant literature on regulations regarding the hydrogen ramp-up while considering European energy systems. In Section 3, we introduce our methodological approach. Based on this, the investigated case is presented in Section 4. In Section 5, we show the numerical results of our analysis and present a discussion. Section 6 provides concluding remarks and policy implications.

2 Context and Literature Review

[The Regulatory Challenge] The Delegated Act was created to prevent side effects arising from support mechanisms for green hydrogen production, such as increases in CO₂ emissions through the electrolyzer's electricity consumption. Thus, additional requirements are defined to ensure sustainable green electricity and hydrogen production (cf. Appendix A). The delegated act stipulates that after a short transition period until the end of 2026, only hydrogen produced with electricity from newly built and unsubsidized wind and solar power plants will be labelled as green hydrogen (**additionality criterion**). For electricity obtained via the public grid, electrolyzers

are required to produce hydrogen, while electricity is generated (almost) simultaneously from these new wind turbines and solar panels (**temporal correlation criterion**). Furthermore, both the RES plant and the electrolyzer must be located in the same bidding zone (**geographical correlation criterion**). An exception is given for neighboring bidding zones. In this case, however, the day-ahead electricity price in the bidding zone of the renewable plant must be at least equal to that in the bidding zone of the electrolyzer. To our knowledge, such strong criteria regarding the use of renewable electricity do not exist for other areas. Criticisms mostly address these three main criteria: temporal correlation, geographical correlation, and additionality. These criteria are particularly relevant for the early stage of the energy system transformation phase, as fossil fuels will still be used for electricity generation. According to the regulation, H₂ is classified as “green” once the mean share of renewable electricity within a bidding zone exceeds 90% of that of the preceding calendar year. However, shares of 90% and above are expected to be reached only toward the end of the energy system transformation.

Several issues arise from these criteria, including (a) a heightened administrative burden, particularly burdensome for smaller industry players, potentially escalating compliance costs and time; (b) a potential distortion of competition, especially in favor of larger corporations capable of meeting intricate criteria, potentially impeding market entry for smaller entities; (c) uncertainties introduced by criteria for accrediting grid electricity, which are linked to time-varying regional conditions like the proportion of renewable energy in a bidding zone; (d) the necessity for extensive documentation and location-specific requirements, imposing additional financial burdens, particularly if significant infrastructure investments are essential. These criticisms underscore the importance of judiciously balancing environmental objectives with economic realities to ensure a hydrogen deployment that is both effective and economically viable. Regarding the intended decarbonization of the energy system, the criticisms imply that the regulatory criteria exert a dampening effect on investments in green hydrogen and hence slow down the energy transition (cf. Section 1). At its core, the regulatory challenge poses a fundamental economic question: How should a regulation be designed to not only incentivize

investment in green hydrogen but also foster energy security and decarbonization in the emerging hydrogen market?

[Scientific Discussion] In recent years, research on energy systems has given significant attention to the growth of hydrogen production due to its potential to reduce GHG emissions in hard-to-abate sectors as well as the corresponding technological challenges and dynamics. For example, Barbir (2009) states that, due to its characteristics (i.e. CO₂-neutrality, storability and substitute for many processes), green hydrogen is considered a key driver for the energy transition. To date, there are several system studies with different levels of detail on H₂ for both Germany and Europe: Some studies focus on overall transition pathways (Bartholdsen et al. 2019; Lux and Pfluger 2020) and decarbonization (Bucksteeg et al. 2023), while other papers point to the spatial component of H₂ ramp-up (Michalski et al. 2017; Vom Scheidt et al. 2022; Jarosch et al. 2022; Lux et al. 2022; Breder et al. 2022). Two other research streams consider investment decisions or incentives from an investor perspective, as well as market valuation (Michalski 2017; Glenk and Reichelstein 2019, 2020; Ruhnau 2022) and research on infrastructure requirements and sector coupling (Guandalini et al. 2015; Robinius et al. 2018; Gils et al. 2021; Wietschel et al. 2021; Gils et al. 2022; Peterssen et al. 2022).

Several publications have already addressed the criteria defined in the delegated act more specifically. Villavicencio et al. (2022) assess the impact of the additionality principle, temporal, and geographical correlation for the operation of electrolyzer systems on social welfare and CO₂ emissions by using a capacity expansion model. The authors claim that, with the progressing energy transition, the necessity for this regulation diminishes, since with increasing shares of renewable energy, the observed trade-off between the economic necessity of capacity build-up and the negative environmental impacts becomes obsolete. The authors focus on 2030 and follow a two-step approach to optimal capacity development. Ruhnau and Schiele (2022) use a dispatch and investment model to analyze whether a flexible definition of green hydrogen reduces costs without increasing emissions. The authors provide numerical evidence that confirms their hypothesis and find that simultaneity leads to oversized components of combined

wind–electrolysis facilities and, therefore, increased costs. The focus is on the temporal correlation criteria in a case study for Germany based on data from 2017-2021. Schlund and Theile (2021) present a model framework including a mixed-integer linear program and a Markov chain Monte Carlo simulation for stochastic electricity market prices to assess the effect of simultaneity on the grid-connected electrolyzer's dispatch. One of the authors' key results is that simultaneity reduces the CO₂ emission intensity of hydrogen while constraining the profits from cost-optimal dispatch. The short-term analysis was done for Germany using historical data. Based on a discussion of the temporal correlation criterion, Pototschnig (2021) promotes a balancing requirement on a yearly basis instead of an hourly one, as electrolyzers will then operate at their optimal utilization rate, thereby limiting the need for a larger renewable electricity generation capacity.

Various PtG business cases were also considered independently (or semi-independently) of the discussed regulatory settings. For Germany and for Texas, Glenk and Reichelstein (2019) investigate the case of a PtG connected physically to a RES plant, which also has the option to sell electricity to the electricity market. H₂ is produced when the revenues of H₂ are higher than those from the optional sale of energy from RES. For a case without grid connection of the RES plant, Brändle et al. (2021) show that the total cost of electricity generation must be covered by H₂ sales. An optimization against electricity prices is possible for PtG plants connected to the electricity grid and co-located with a RE generator (Glenk and Reichelstein 2020; Hurtubia and Sauma 2021). Other cases were discussed by Nguyen and Crow (2016), Huber et al. (2021), and Ruhnau (2022).

None of the previously mentioned studies address the regulatory issues from a long-term pan-European perspective considering a European H₂ grid and third country imports. Therefore, in the following pages, we contribute an analysis at the European scale, spanning multiple simulation years and considering international location effects in detail.

3 Methodology

In the subsequent sections, the methodology of the present paper is described. First, the energy system model E2M2s is introduced (Section 3.1), followed by a description of the hydrogen sector model extensions that were implemented for this publication (Section 3.2). Finally, the model constraints derived from the RED II criteria¹ (cf. Section 2) are presented (Section 3.3).

3.1 The Energy System Model E2M2s

To investigate the influences of the criteria formulated in the Delegated Act on Article 27 of the second Renewable Energy Directive (RED II), the energy system model E2M2s is used. The E2M2s is a linear optimization model for the long-term development of European electricity and heat markets that has been applied in several publications – most recently in Blumberg et al. (2022)². Further applications can be found in the works of Swider and Weber (2007), Spiecker et al. (2013), Spiecker and Weber (2014) and Bucksteeg et al. (2019).

Compared to dispatch-only models, the E2M2s is also capable of determining optimal capacity expansion for renewable and conventional generation technologies, storage technologies, and other flexibility options. It is capable of optimizing multiple simulation years dynamically. Starting from the generation and flexibility stack of the base year, simulations for multiple study years are carried out. Investments for the intermediate years are added to the given capacity. After a simulation, the sum of the base capacity and endogenously added capacity serve as the base capacity input for the following simulation year. That is, the results of previous years influence the upcoming simulation and, thus, myopic foresight is applied. The objective is to minimize the total system costs, which consist of investment costs, fixed costs, and operational costs. Existing capacities cover at least their fixed and operational costs, whereas additional capacities cover their full cost, including annualized investment costs. Several technologies are available for

¹ Although RED III is already passed (cf. Section 1), the delegated act was implemented to complement RED II. Therefore, we refer to the criteria as RED II criteria.

² For a comprehensive overview of other modeling aspects of the E2M2s (e.g. e-mobility and reserve provision), we refer to the open access publication by Blumberg et al. (2022).

endogenous capacity expansion. Although the focus lies on the endogenous expansion planning of electrolyzers and the expansion of biomass, nuclear³ and hydrogen-fueled power plants, renewable energy plants, battery storage, and heat pumps, it is possible to capture the effects on other technologies and the interactions between them. The main constraints are serving the electricity and heat demands of every time segment and all market areas. A more detailed description of these and other model constraints can be found in the study by Spiecker et al. (2013).

To reduce the computational burden, a typical day approach with aggregated time segments is applied. Eight different typical days are used to represent a complete year: a weekday and a weekend day from each of four representative months. Also, for a typical day, the temporal granularity is aggregated. A day is separated into seven time segments of different lengths, which are derived from the structure of electricity demand during a day. This results in 56 time segments in total.⁴ A main feature of the model is the consideration of uncertainties of renewable infeed via the stochasticity of recombining trees. A typical day is separated into four equal parts between which the transition to another node is possible. That is, different renewable nodes that have different infeed values (high, mid, low) and probabilities derived from a complete time series of selected weather years exist for every part of the day. This leads to 96 possible nodes in total.⁵ Via assignment sets, the parts (and nodes) of a day can be assigned to the time segments. Further model features include startup and shutdown costs, power plant availabilities, reserve provision, time-coupling storage optimization, and cross-border energy trading via net transfer capacities (NTCs).

Political constraints for capacity expansion can be implemented if necessary (e.g., coal or nuclear phase-out in Germany). CO₂ emissions are regulated either via a fixed price or via an emission cap. In the first case, it is uncertain whether decarbonization goals are met. In the second case,

³ Only for selected countries without nuclear phase-out.

⁴ Two typical days · four months · seven segments per day = 56

⁵ Two typical days · four months · four parts per day · three possible nodes = 96

decarbonization goals are met, and a CO₂ price is determined endogenously via the margin of the CO₂ constraint. In this paper, we assume that the decarbonization targets of the energy sector will be fulfilled and therefore apply the emission cap.

To ensure security of supply, alongside accounting for the variability of renewable energy input, a capacity constraint is enforced. This constraint guarantees specific levels of dispatchable generation capacity (e.g., gas or hydrogen turbines). Renewables are assessed based on their installed capacity multiplied by their minimum capacity factor (or minimum inflow for run-of-river and hydro reservoirs). The dispatchable capacity must be sufficient to meet the internally calculated maximum demand.

3.2 Hydrogen Sector Modeling in the E2M2s

For this paper, the hydrogen sector has been incorporated into the model to represent its potentially pivotal role in decarbonizing the European economy. For this reason, a hydrogen demand constraint is added to the model (see equation (1)). Thus, the electricity and hydrogen sectors are modeled in an integrated manner, where the demand for electricity and hydrogen directly influences the operation of sector-coupling technologies, such as electrolyzers and hydrogen-fueled power plants.

The supply side consists of domestic electrolysis ($y_{y,n,t,z,iPtH2}^{H2}$), hydrogen imports ($x_{y,n,t,zz,z}^{H2}$) from neighboring European market zones (zz), and imports from third countries ($v_{y,z}^{H2}$) that are not part of the modelled geo scope. The demand side consists of the exogenous hydrogen demand $D_{y,z}^{H2}$ (e.g. from the industry sector), endogenous demand from the consumption of hydrogen fueled gas turbines ($y_{y,n,t,z,iH2}^{H2,cons}$) and heat boilers ($y_{y,n,t,z,iH2HB}^{H2,cons}$) as well as exports to neighboring zones ($x_{y,n,t,z,zz}^{H2}$). Unlike electricity and heat demands, hydrogen demand is balanced yearly for every simulation year y under the assumption of non-restrictive storage capacities of the grid and seasonal storages. To obtain yearly values, the variables must be multiplied with the probability ρ_n of the respective node n and the hourly resolution γ_t and frequency δ_t of the time segment t .

$$\begin{aligned}
& \sum_{n,t,iPtH2 \in I} y_{y,n,t,z,iPtH2}^{H2} \cdot \rho_n \cdot \gamma_t \cdot \delta_t + \sum_{n,t} x_{y,n,t,zz,z}^{H2} \cdot \rho_n \cdot \gamma_t \cdot \delta_t + v_{y,z}^{H2} \\
& = D_{y,z}^{H2} + \sum_{n,t,iH2 \in I} y_{y,n,t,z,iH2}^{H2,cons} \cdot \rho_n \cdot \gamma_t \cdot \delta_t + \sum_{n,t,iH2HB \in I} y_{y,n,t,z,iH2HB}^{H2,cons} \cdot \rho_n \cdot \gamma_t \quad (1) \\
& \cdot \delta_t + \sum_{n,t} x_{y,n,t,z,zz}^{H2} \cdot \rho_n \cdot \gamma_t \cdot \delta_t \quad \forall y, z
\end{aligned}$$

Intra-European exchanges are regulated through hydrogen transfer capacities (HTCs), while third country imports are governed by an import price and depend on the scenario (cf. Section 4.2, a maximum import quantity ($v_y^{H2,max}$) for the entire modelled geographical scope (cf. Equation (2)). To realistically model third country imports, such imports are only possible for market areas ($zH2Imp$) which have pipeline connections to third countries (e.g., Spain and Poland) or terminals (e.g., Netherlands and Germany).

$$\sum_{zH2Imp \in z} v_{y,zH2Imp}^{H2} \leq v_y^{H2,max} \quad \forall y \quad (2)$$

The main model's outputs are (among others) capacity expansions; dispatch of generators and flexibility options; production quantities of electricity, heat, and hydrogen; cross-border flows; endogenous market prices; and CO₂ emissions.

3.3 RED II Constraints in the E2M2s

The RED II criteria *additionality*, *temporal correlation*, and *geographical correlation* (explained in Section 2) are implemented in the E2M2s as follows:

Separate wind onshore, wind offshore, and photovoltaic technologies that are primarily used for electrolysis are implemented in the E2M2s. That is, electrolyzers cannot use electricity produced by other technologies. Excess production of these technologies can also be used to serve the exogenous electricity demand. Electrolyzers ($iPtH2$) and RES technologies ($iRES$) are coupled via the assignment set $I_Coupled(iPtH2)$. By design, coupled technologies are located in the same bidding zone (or market area) z , which fulfills the criterion of geographical correlation. To ensure temporal correlation, the electricity consumption of electrolyzers ($y_{y,n,t,z,iPtH2}^{cons}$) must be lower

than or equal to the electricity production of the coupled RES plant ($y_{y,n,t,z,iRES}$) in every year y , node n and time segment t as depicted in equation (3).

$$y_{y,n,t,z,iPtH2}^{cons} \leq \sum_{iRES \in I_{Coupled}(iPtH2)} y_{y,n,t,z,iRES} \quad \forall y, n, t, z, iPtH2 \quad (3)$$

The required additionality for renewable energy capacity is considered by investment for the same simulation year. That is, only electrolyzers and separate RES plants, built for the same simulation years, are coupled. These constraints are only applied to EU market areas.

4 Case Study

In the following sections, key input parameters and the investigated scenarios are presented. The scenario analysis is executed as follows. As explained in Section 3.1, the model is capable of simulating several study years. Here, we simulate the years 2025, 2030, 2035, and 2045 on the path to climate neutrality. Since RED II criteria are mostly important for the transition phase, we focus on the years 2030 and 2035 when presenting and discussing the results in Section 5.

4.1 Input Data

The E2M2s needs a variety of input data, since it covers the electricity, district heating, and the hydrogen sector. In the following section, the most important input parameters with respect to the present case study are presented.

Demand

Exogenous demand values are based on the Global Ambition scenario of the TYNDP 2022 (ENTSO-E and ENTSOG 2022). These values exclude demand from storage technologies, electrolyzers, and hydrogen power plants since their demand is endogenously optimized. Table 1 shows the electricity and hydrogen demand aggregated for the EU countries.

Table 1: Exogenous European electricity, hydrogen and heat demand [TWh]

Demand [TWh]	2030	2035
Electricity	3910	4204
of which EU	3225	3455
Hydrogen	352	875
of which EU	322	791
District heat	381	396
of which EU	376	390

CO₂ Limit

As described in Section 3.1, a Europe-wide CO₂ cap is applied and enforced via a constraint in the model. Rather strict CO₂ emission limits are applied under the assumption that the energy sector needs to be decarbonized earlier to achieve the overall emission reduction goals (i.e.,

climate neutrality). Therefore, the emission cap is set to zero in 2045. The reduction paths are depicted in Figure 1.

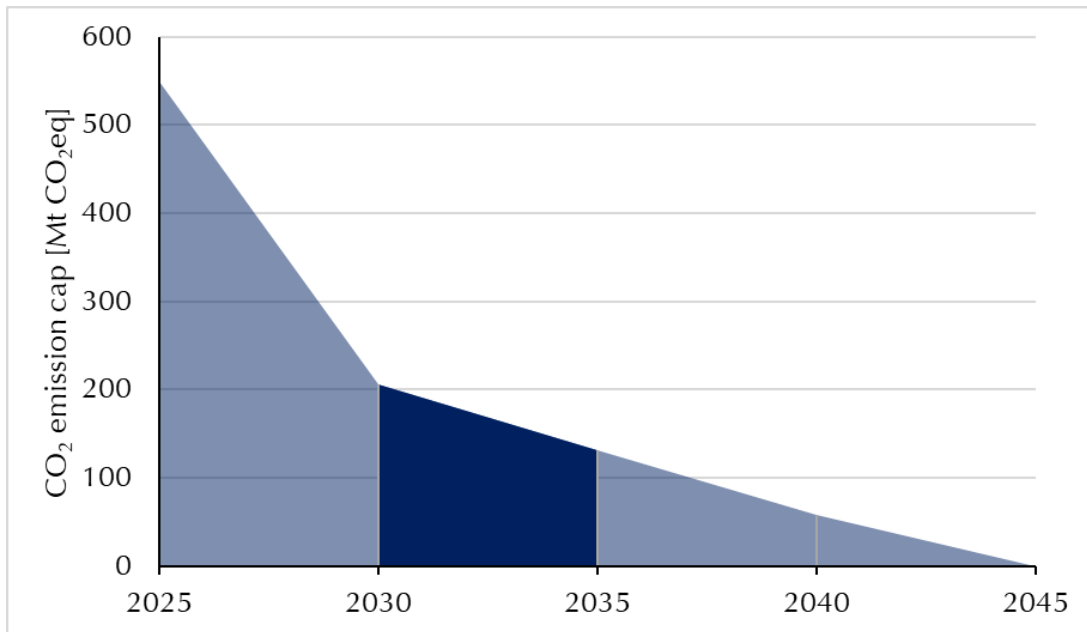


Figure 1: CO₂ emission reduction path for the considered sectors in Europe [Mt CO₂eq]

Investment Costs

Endogenous investments are influenced by the need to meet demand and comply with the imposed CO₂ cap. However, these decisions are also influenced by the specific costs of investing in different technologies. While the primary focus is on expanding electrolyzers, other investment options, such as renewables, battery storage, and hydrogen-fueled power plants, are also considered to account for possible interactions. Table 2 provides an overview of the investment costs associated with hydrogen and renewable technologies (for a complete overview of investment costs cf. Table 9 in Appendix B). For renewable energy systems (RES) used in conjunction with electrolyzers (PtH₂), costs are increased by one euro per kilowatt to ensure that the solver is not indifferent and that they are only added if necessary for electrolysis.

Table 2: Investment costs of selected technologies [€/kW]⁶

Technology	2030	2035
H2 combined-cycle power plant (H2_CC)	1019	992
H2 CC with extraction condensing steam turbine (H2_CC_EXC)	1106	1068
H2 gas turbine (H2_GT)	545	525
H2 GT with flexible waste heat utilization (H2_CC_CH2)	850	820
Power-to-hydrogen (PtH2)	733	658
Solar (SUN)	714	680
Wind offshore (WIND_OFF)	2250	2149
Wind onshore (WIND_ON)	1083	1071

Renewable Energy Sources (RES)

The expansion of renewable energies is determined not only by endogenous optimization based on investment costs but is also driven by political decisions. As a result, an exogenous path for the development of RES capacities is pre-specified as a lower bound for the RES expansion. Additionally, there is an upper bound for RES capacities in each simulation year, which limits the sum of the exogenous capacity and the endogenously added capacity (cf. Figure 2). This prevents unrealistically high RES investment in early simulation years. The exogenous paths are interpolated and extrapolated from the values of the TYNDP 2022 Distributed Energy scenario for 2025, 2030, and 2040. The maximum capacities are retrieved by scaling up the exogenous values by a factor of 2. In addition, spatial availability is a limiting factor in RES deployment; therefore, maximum capacities are imposed on a country-by-country basis.

⁶ References are detailed in the Appendix.

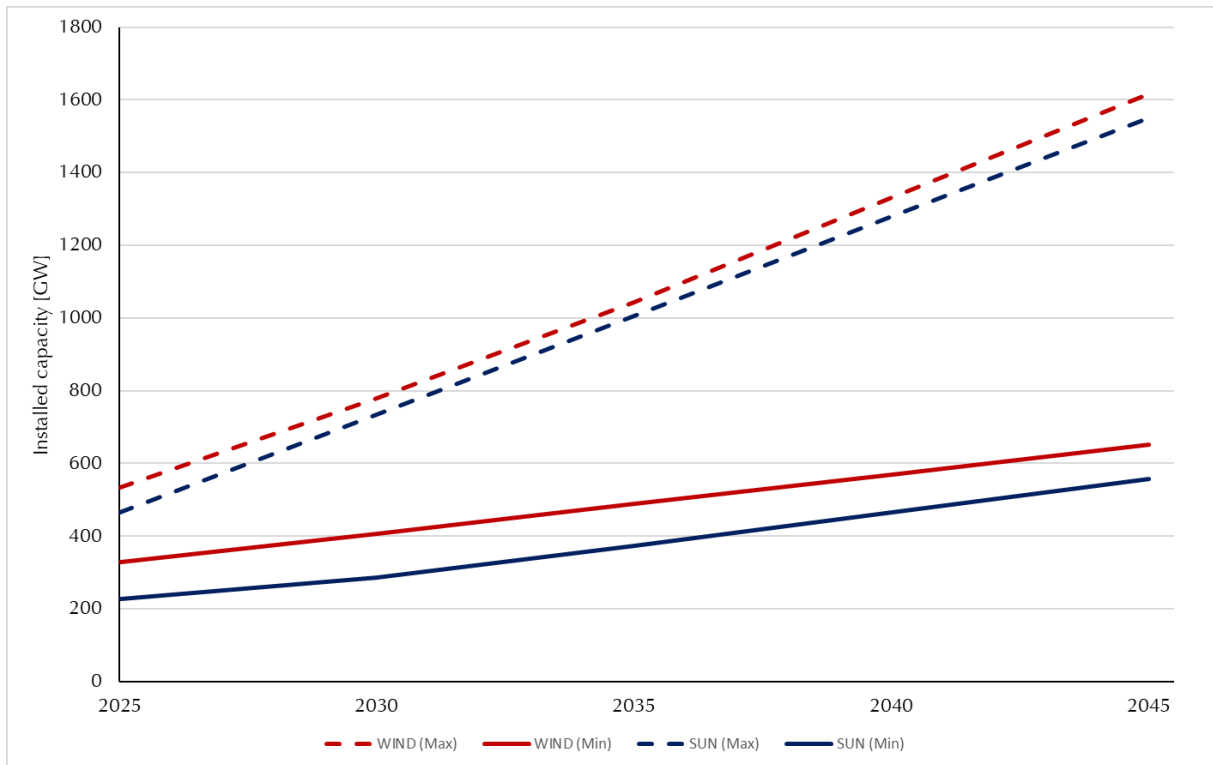


Figure 2: Range of possible RES capacities in Europe [GW]

H₂ Transfer Capacities (HTCs)

As described in Section 3.2, intra-European H₂ exchange is implemented in the model to account for European plans to develop a H₂ grid. The HTC values for H₂ exchange between European countries, as well as the Net Transfer Capacities (NTCs) for electricity exchange, are based on the TYNDP 2022 Distributed Energy Scenario. A selection is shown in the following table, displaying the HTCs in 2035 for five selected European countries.

Table 3: HTCs for selected EU countries in 2030 and 2035 [MW]

2030							2035						
From \ To	AT	DE	ES	FR	NL	UK	From \ To	AT	DE	ES	FR	NL	UK
AT	0	1000	0	0	0	0	AT	0	1250	0	0	0	0
DE	1000	0	0	1485	2411	0	DE	1250	0	0	7201	6447	0
ES	0	0	0	3258	0	0	ES	0	0	0	6316	0	0
FR	0	1485	3258	0	0	0	FR	0	7201	6316	0	0	0
NL	0	2411	0	0	0	5558	NL	0	6447	0	0	0	5558
UK	0	0	0	0	5558	0	UK	0	0	0	0	5558	0

The input data that vary between cases are presented in the following section.

4.2 Scenarios

To quantify the effects of the RED II criteria on the ramp-up of hydrogen technologies in Europe, the respective results are compared to the results of cases in which the RED II constraints presented in Section 3.3 are deactivated (*Base*). That is, electrolyzers can utilize electricity from all available technologies. The first setting, with *high import price levels (HP)*, is the main scenario, whereas the following two scenarios serve as sensitivities to investigate further effects. The influence of third country hydrogen imports is investigated via an additional setting with *lower hydrogen import prices (LP)*. Furthermore, an upper limit on imports from third countries (cf. Section 3.3) is introduced in another scenario based on an assessment of export potential. Since the effects of the import price level are negligible in the case with *limited imports*, the latter setting is only considered with the *high price level (HP_LI)*. This leads to six simulation runs in total (see Table 4).

Table 4: Scenario and case overview

Run	Scenario	Case	RED II restrictions	High import price level	Low import price level	Limited 3 rd country imports
Base_HP	HP	Base		X		
RED_II_HP	HP	RED II	X	X		
Base_LP	LP	Base			X	
RED_II_LP	LP	RED II	X		X	
Base_HP_LI	HP_LI	Base		X		X
RED_II_HP_LI	HP_LI	RED II	X	X		X

The different price levels for imports from third countries are shown in Table 5. Import prices start at the same level in 2025 but differ by 25 €/MWh_{H2} in the following simulation years. While the differences are rather small, the results show that they already significantly influence the model's results.

Table 5: Costs for imports from third countries [$\text{€}/\text{MWh}_{\text{H}_2}$]

Simulation year	High import price level	Low import price level
2025	150	150
2030	125	100
2035	100	75
2045	75	50

The import quantity constraints are taken from the Global Ambition scenario of the TYNDP, which lists the export potentials of several countries. Excluding European countries that are modeled endogenously, the following import limits are obtained.

Table 6: Hydrogen import limits for Europe [TWh]

Year	2025	2030	2035	2045
Import limit	43.18	86.35	324.25	794.89

5 Results and Discussion

This section presents the results of the case studies focusing on the capacity expansion of electrolyzers and fluctuating renewables. Also, production quantities, curtailment, and full load hours (FLH), as well as energy exchanges among European countries and imports from third countries, are reported as key indicators for decarbonization pathways. Since RED II is a directive of the European Union, most of the results are aggregated on the EU level. Furthermore, the presentation of results focuses on the intermediate years 2030 and 2035, which are critical milestones on the path to climate neutrality. First, the results of the *main case HP* are discussed in detail before the sensitivities *LP* and *HP_LI* are analyzed and compared to the main case.

5.1 Main Case

Figure 3 and Figure 4 depict the aggregated electrolysis capacity and the H₂ balance for aggregated zones in 2035 in the scenario with *high import prices (HP)*, both for the case without regulation (*Base*) and for the case with regulation (*RED II*). These outcomes for a pivotal year of the energy transition serve as the first indicator of market dynamics caused by the regulation (cf. Appendix C and Appendix D for detailed country level results).

When RED II criteria are applied, Central Europe invests less in domestic electrolysis (29.85 instead of 44.52 GW; -33%), while capacities on the British Isles increase (78.03 vs. 72.39 GW; +8%). A decrease is also observable on the Iberian Peninsula (-28%), in Southeastern Europe (-100%), and in Eastern Europe (-27%). The states in these regions (with a few exceptions) are also subject to the *RED II* regulation, which indicates a decreased attractiveness of hydrogen investments under *RED II*.

Focusing on the H₂ balances in Figure 4, the domestic production decreases by more than half in Central Europe (33.72 vs. 70.55 TWh). The Iberian Peninsula shows a similar strong tendency (35.16 vs. 54.99 TWh). Minor positive effects on domestic production can be observed in Northern Europe (81.44 vs. 79.53 TWh), the Baltic states (1.77 vs. 1.64 TWh), and the British Isles (159.83 vs. 156.40 TWh). Expressed in absolute figures, the negative effects in Southeastern

Europe and Eastern Europe are comparatively small. As EU regulations do not apply to the United Kingdom or to Norway, *RED II* leads to limited shifts of hydrogen production towards European non-EU countries.⁷ The energy balances depicted in Figure 4 moreover indicate that *RED II* induces a substantial switch in all EU countries from domestic production to imports.

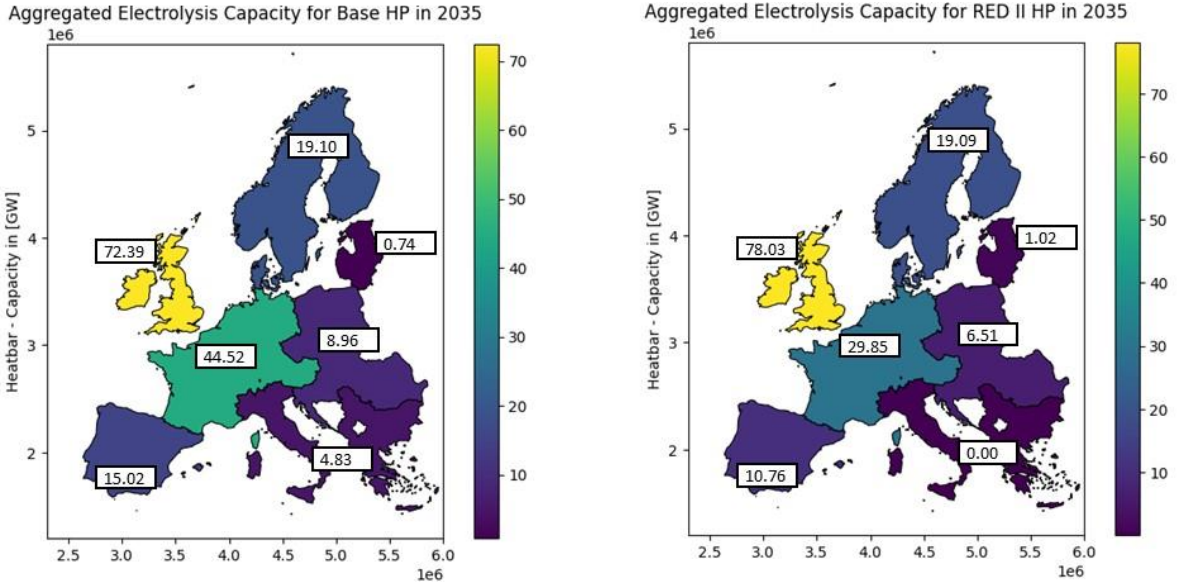


Figure 3: Key results for the cases *Base HP* (left) and *RED II HP* (right) in 2035 - installed electrolyzer capacities.

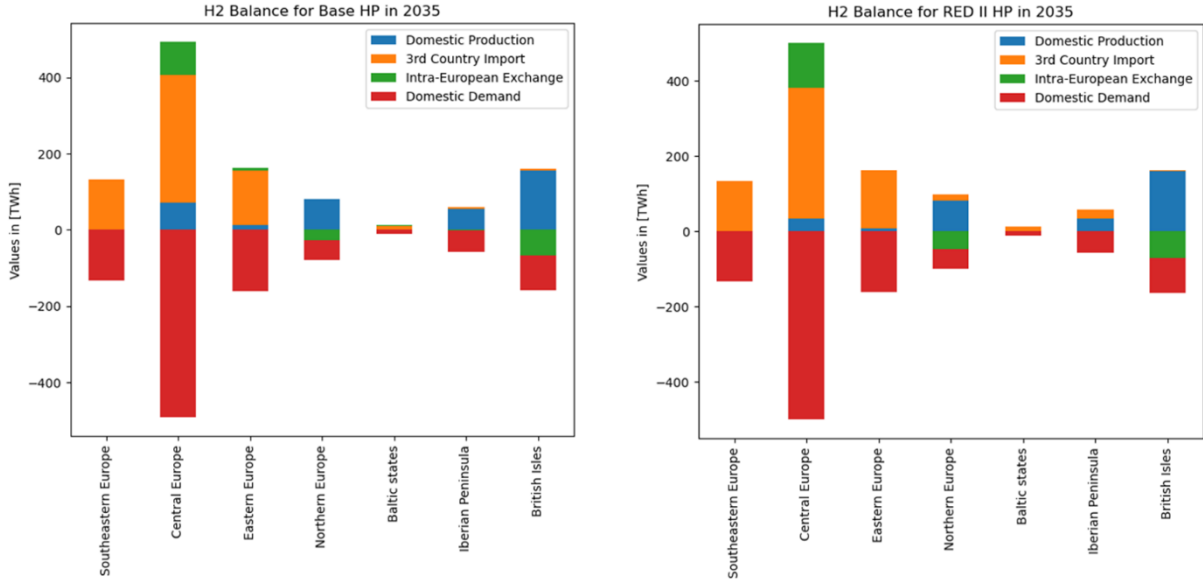


Figure 4: Key results for the cases *Base HP* (left) and *RED II HP* (right) in 2035 - H₂ energy balance.

⁷ Results on country level are listed in the Appendix.

When *RED II* regulations are enforced, third country imports increase in all regions except for the British Isles. The intra-European exchanges show a clear trend of increasing imports for Central Europe. Intra-European imports decrease in other EU countries, and the Iberian Peninsula ceases to export. Meanwhile, non-EU countries increase their exports to other parts of Europe.

The results of the *HP* case have two facets. On the one hand, RED II has a dampening effect on domestic production in the EU, especially in Central Europe and on the Iberian Peninsula. For the British Isles and Northern Europe, this effect is less observable due to the presence of non-EU states within each zone. On the other hand, due to the combined effects of geography and renewable potential, Central Europe and the Iberian Peninsula are relying more heavily on imports. This is also true for Eastern Europe. Moreover, the non-EU states are taking on a role as exporters or as transit countries for third country imports. To better understand the interdependencies, a variation in key scenario assumptions is needed. Hence, in the next subsections, we consider alternative scenarios regarding third country import prices, as well as import limits, and discuss the transition path between 2030 and 2035.

5.2 Scenario Variations

The following subsections contain a comparison of results for all simulated scenarios and cases aggregated at the EU level. Both the effects of the RED II criteria within a scenario and the effects of price levels and import limitations are analyzed and discussed.

System costs

Table 7 shows the total system costs for each case across the entire geographical scope. This includes investment costs, fixed costs, and operational costs, encompassing fuel costs, start-up costs, transmission costs for electricity and H₂, as well as import costs for H₂ imports from third countries. For all settings and study years, the simulations with RED II constraints lead to higher total system costs. However, in relation to the scale of the system costs, the differences are rather small, ranging from €1.08 billion in the *low price setting (LP)* in 2030 to €4.34 billion in the *high price setting* with restricted third country imports (*HP_IR*) in 2035. Comparing the settings reveals

that the lowest system costs occur in the *LP* setting due to lower H₂ import costs, whereas the highest system costs arise in the *HP_IR* setting. This is expected since additional binding constraints necessarily lead to higher objective function values in optimization models.

Table 7: Total system costs and differences in 2030 and 2035 [bn. €]

Scenario \ Case	2030			2035		
	Base	RED II	Diff.	Base	RED II	Diff.
HP	438.07	439.54	1.48	524.40	525.73	1.33
LP	431.60	432.69	1.08	499.84	501.56	1.72
HP_LI	438.52	440.39	1.87	529.33	533.66	4.34

Electrolyzer capacity

Figure 5 shows the capacities of electrolyzers, including those of the different electrolyzer-RES combinations (for details at country level cf. Appendix C). In the *Base* case, where no RED II constraints are applied, electrolyzers (PtH₂) can make use of different energy sources. In 2030, the differences between the *Base* and *RED II* cases are rather small. As cheap imports may substitute for domestic production, the low import price scenario leads to lower electrolysis capacities compared to the high price scenarios. On the contrary, the scenario with *limited import quantities* yields the highest capacities, as domestic production is pushed upward by limits on imports from third countries. In 2030, there is also little difference between the *Base* and *RED II* cases when imports are limited. In all other scenarios, especially in 2035, the impact of *RED II* leads to lower electrolyzer capacities compared to the corresponding *Base* case. Again, a substantial increase of capacity can be observed for the cases with limited imports, rising from around 80 GW in 2030 to 187 GW and 172 GW, respectively. This is caused by rising exogeneous hydrogen demand (cf. Table 1). The increase for the other cases is rather low, and for the *RED_II_LP* case, it is almost zero.

Given the rising domestic demand for H₂⁸ and increasingly stringent CO₂ emission regulations, the limitations imposed by *RED II* have higher impacts on the deployment of electrolyzers from 2030 to 2035.

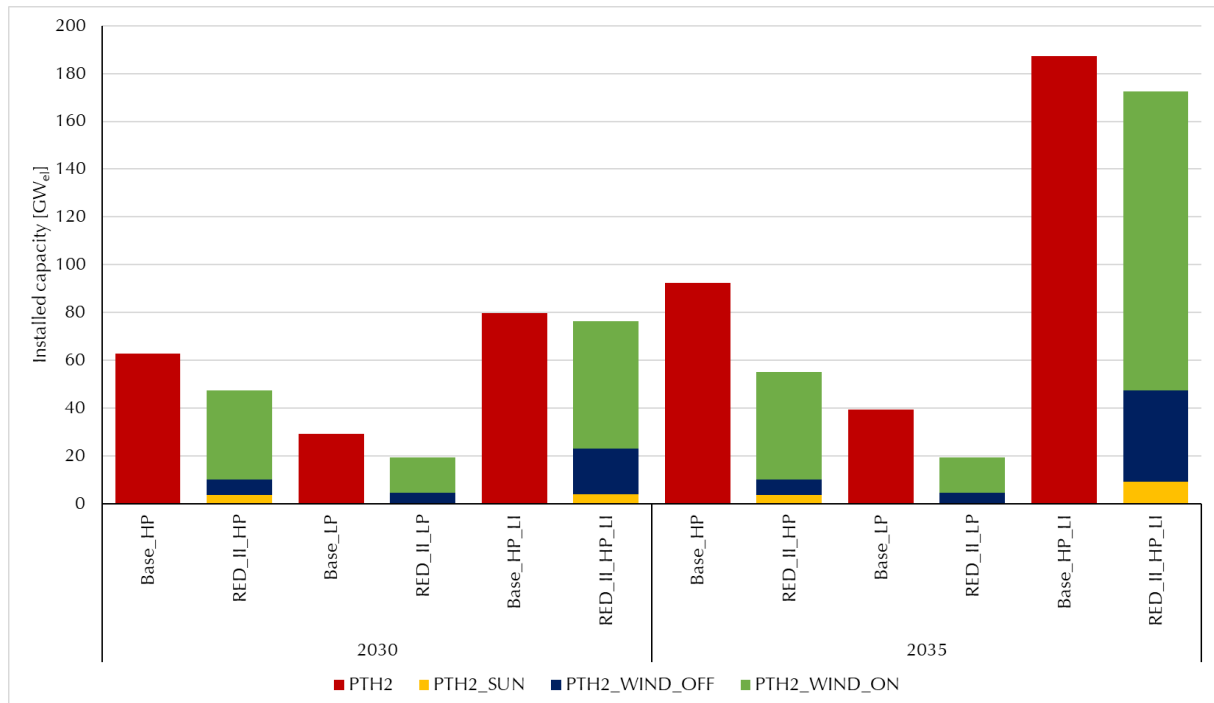


Figure 5: Electrolyzer capacity in the EU in 2030 and 2035 by technology combinations [GW_{el}]

Renewable Energy Sources (RES) capacity

The distribution of the RES technologies that are coupled with electrolyzers in the *RED II* cases is quite similar across scenarios (Figure 5). In general, onshore wind is the dominant source, while offshore wind becomes more important only when import limitations are applied. The coupling of solar energy (PV) with electrolyzers does not increase substantially between 2030 and 2035. Due to its lower FLHs, PV is generally used for general electricity production and is not that attractive for coupling with a capital-intensive technology like electrolyzers (cf. Figure 6).

The overall conclusion based on Figure 5 and Figure 6 is that enforcing RED II constraints not only hampers electrolyzer implementation, but also leads to somewhat lower overall RES capacities. The impact remains limited for two reasons. On the one hand, overall electricity

⁸ Domestic H₂ demand is driven by industry and H₂-power plants (use of H₂ as long-term storage for renewable electricity).

demand is much larger than hydrogen demand. On the other hand, changes in intra-European trade balances for electricity may somewhat compensate for the lower use of RES for hydrogen production.

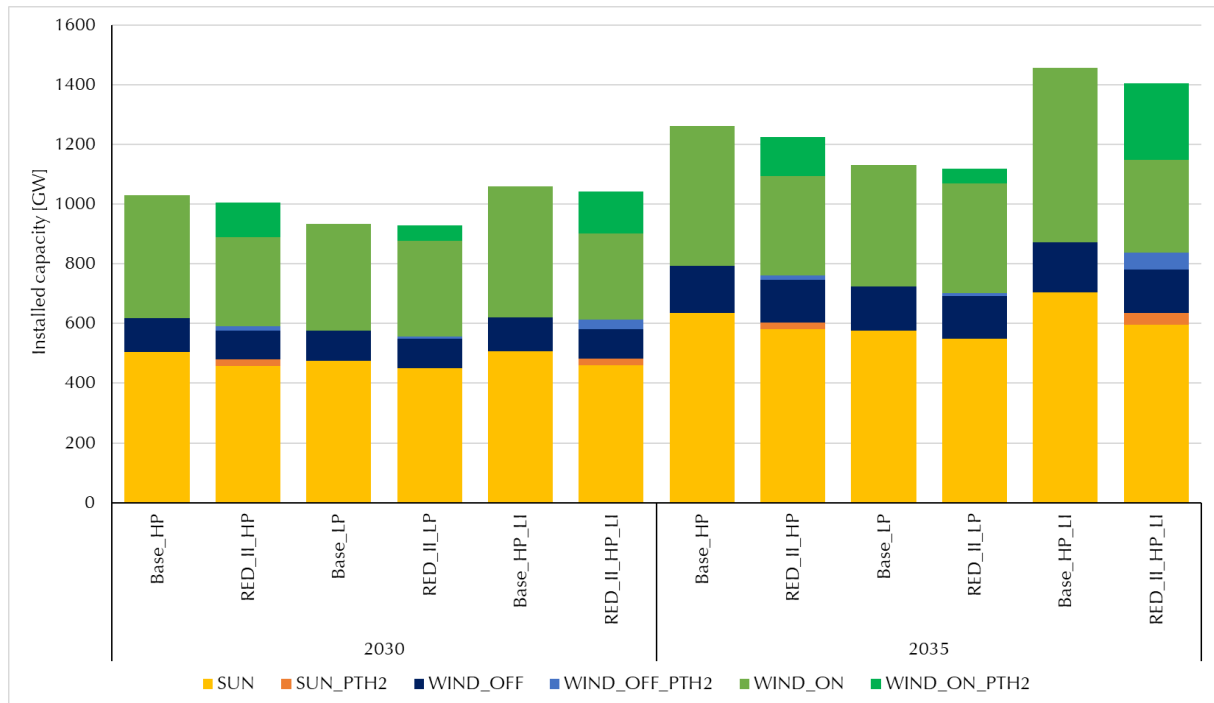


Figure 6: RES capacities by technology in the EU in 2030 and 2035 [GW]

Hydrogen balances

Three key findings may be derived from the H₂ balances depicted in Figure 7 (for details at country level cf. Appendix D). First, the distribution of supply sources differs substantially between the three scenarios: *high import price*, *low import price*, and *high import price with limited import quantities*. Second, the differences in demand between *Base* cases and *RED II* cases within the same scenario are small, but demand is generally slightly smaller in the *RED II* cases. Thus, substitution of H₂ is difficult, even for those applications where demand is determined endogenously (mainly power and heat generation). Third, domestic electrolysis contributes less to overall supply when the RED II constraints are active. The difference is mainly offset by imports from other European countries, notably Norway and the UK (cf. Figure 4, as well as Table 10 in Appendix E). Low import prices lead to an overall increase in H₂ utilization compared to the other cases, as H₂-fired power plants and heat boilers are used to a higher

degree. Here, domestic electrolysis and intra-European imports⁹ play only a minor role, as they are less competitive against low import prices from third countries. With restricted third country imports, domestic electrolysis becomes more competitive. This effect increases significantly until 2035 in the case with high import prices and limitations on third country imports (*HP_LI*). In general, the contribution of third country imports rises from 2030 to 2035, when the exogenous hydrogen demand increases and import prices decrease by 25 €/MWh.

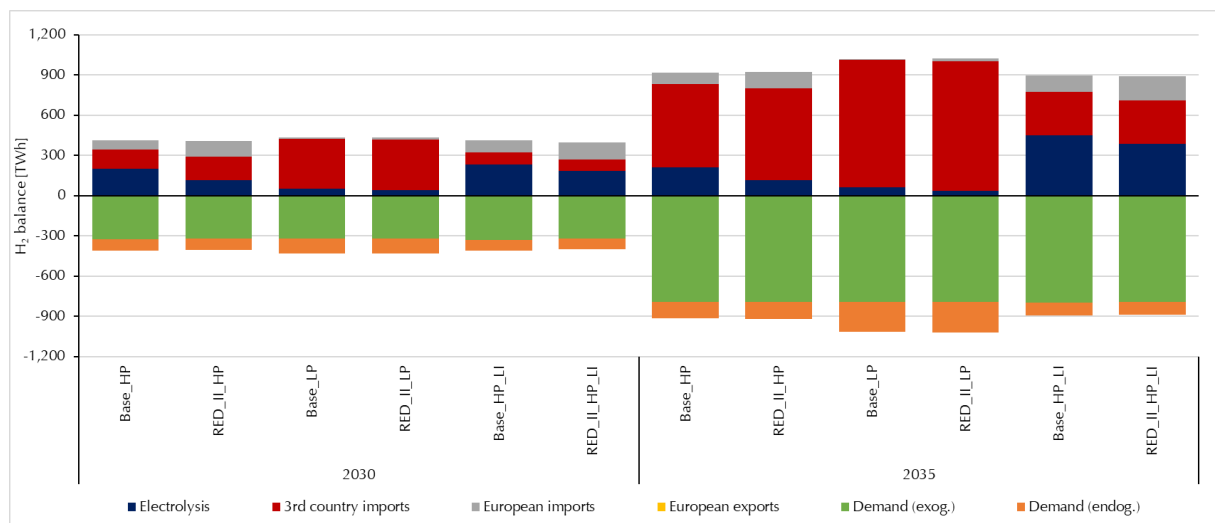


Figure 7: Hydrogen balances (supply & demand) of the EU in 2030 and 2035 [TWh]

Full Load Hours (FLH) of electrolyzers

The FLHs of electrolyzers (Figure 8) indicate the impact of RED II on the operation of electrolyzers in the EU under different scenarios. Since reduced competition occurs with third country imports due to higher prices, electrolyzers are employed more extensively than they are when H₂ is imported from the highly competitive global hydrogen market. As the RED II directive leads to a very substantial decrease in electrolyzer capacities in the *low price* scenario (cf. Figure 5), the utilization of the remaining electrolyzers increases somewhat compared to the corresponding *Base case*. This contrasts with the other scenarios, in which the relative capacity decrease is less pronounced, yet the implementation of the RED II directive also results in reduced FLH. By 2035, the FLH decreases, but the drop in FLH between *Base cases* and *RED II* cases also diminishes.

⁹ Intra-European imports and exports refer here to imports from and exports to European non-EU countries that are part of the modeled geoscope.

The decline in FLH from 2030 to 2035 is more pronounced in the *Base* cases due to a substantial rise in electrolysis capacities but relatively modest increases in domestic production. Even in scenarios with high import prices, third country imports prove advantageous to a significant extent.

Overall, the results clearly indicate a more important role for electrolyzers in the electricity market without the RED II directive.

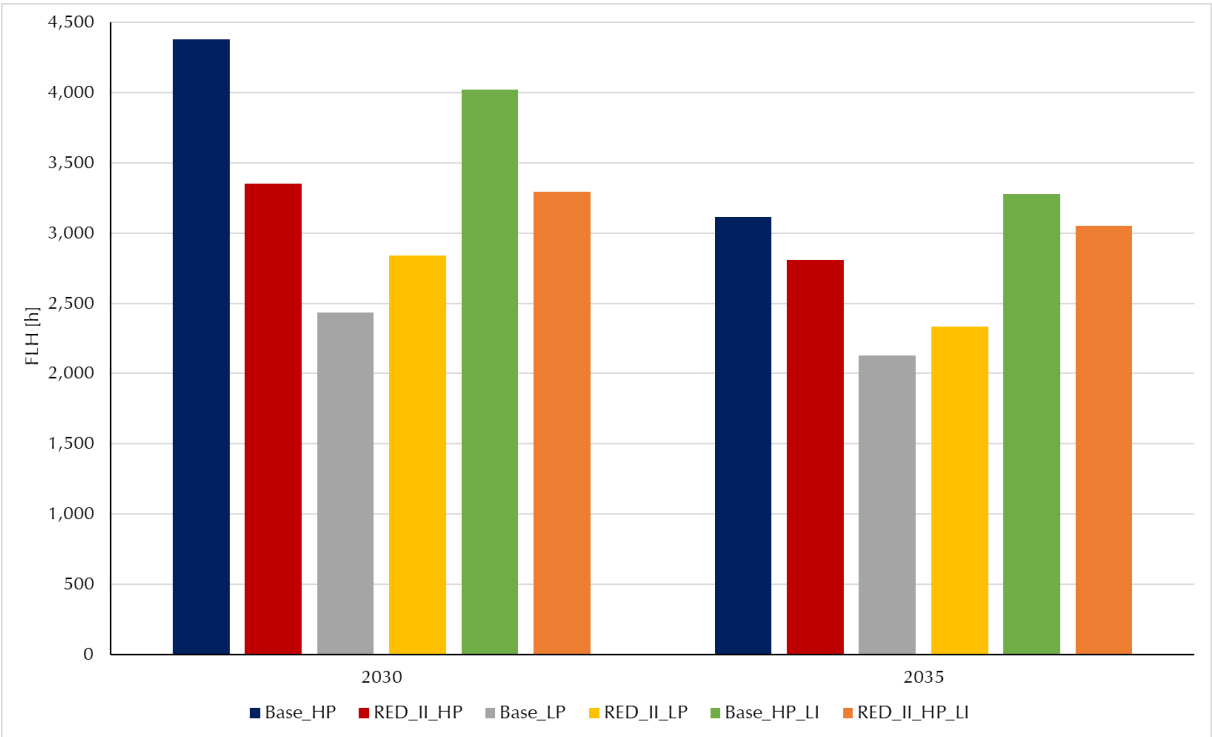


Figure 8: Full load hours (FLH) of electrolysis in the EU in 2030 and 2035

Electricity balances

Table 8 shows key elements of the electricity balance for EU and non-EU countries. RES production in the EU is only moderately reduced in the *RED II* case of the *HP* scenario, with almost no changes in the *LP* and *HP_LI* scenarios. A more pronounced effect can be observed for the electricity demand of electrolyzers, with a substantial decrease between the *Base* and *RED II* case for EU countries and an increase for non-EU countries. The use of hydrogen for electricity production is hardly affected, and the same is true for electricity production from other sources.

Most noticeable are the shifts in electricity imports.¹⁰ In the non-EU countries, net electricity exports decline due to their greater importance as H₂ exporters in the *RED II* cases. Here, non-EU countries use electricity for domestic H₂ production to a higher degree, while EU countries have less electricity demand for electrolyzers due to outsourced H₂ production. This effect is particularly relevant in the *HP_LI* scenario, where net imports of EU countries decrease by 70 TWh, eventually becoming negative.

Table 8: Electricity balances for EU and non-EU countries in 2035¹¹

Scenario	TWh Region	RES production		H ₂ -based production		Other production		Net imports		Electrolyzer demand		Other domestic demand	
		Base	RED II	Base	RED II	Base	RED II	Base	RED II	Base	RED II	Base	RED II
HP	EU	2121	2061	71	76	1840	1831	83	28	288	155	3828	3841
	Non-EU	589	591	1	1	509	509	-83	-28	227	285	789	788
LP	EU	1886	1888	130	134	1798	1783	65	31	84	45	3795	3791
	Non-EU	398	385	1	1	523	521	-65	-31	65	89	792	788
HP_LI	EU	2478	2478	56	54	1832	1857	50	-20	614	526	3803	3842
	Non-EU	594	599	1	1	518	525	-50	20	276	358	786	787

RES Integration

The integration of RES is a key aspect of the energy transition. Given that the raised criticisms (see Section 1) predominantly address the H₂ ramp-up, we will focus on RES integration, especially regarding curtailment, as shown in Figure 9 for all cases in 2030 and 2035.

In 2030, curtailment is higher in all *Base* case scenarios, but this trend reverses in 2035. In that period, curtailment more than doubles in all *RED II* cases. This suggests that *RED II* engenders suboptimal incentives for the operation of RES, particularly concerning coupled technologies. Moreover, individual RES sources, such as solar (SUN), offshore wind (WIND_OFF), and onshore wind (WIND_ON), experience less integration compared to the corresponding *Base* cases. The increase in curtailment under *RED II* in 2035 is noteworthy, as it indicates inefficiencies in incentivizing RES integration within the specified timeframe.

¹⁰ The sum of differences of EU and non-EU net imports is zero since no third country electricity imports and exports are considered.

¹¹ RES production includes production from the fluctuating RES wind onshore, wind offshore and solar.

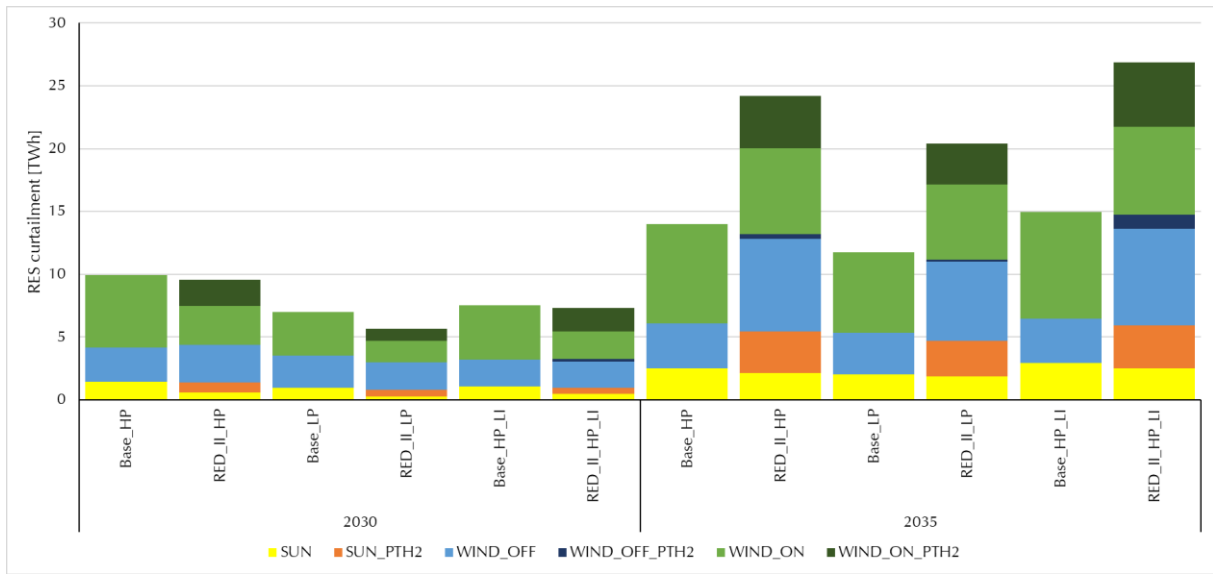


Figure 9: Curtailment of RES in the EU in 2030 and 2035 [TWh]

6 Conclusion and Policy Implications

Based on the results presented in Sections 5.1 and 5.2, RED II constraints lead to higher system costs and dampen the expansion of electrolysis capacity in the EU. However, the scale of the effect is highly dependent on the scenario settings. In particular, the price for H₂ imports from third countries strongly influences the results unless import quantities are limited (scenarios *HP* and *LP*). If a limit on third country imports is introduced (scenario *HP_LI*), it becomes a binding constraint, and European electrolyzer expansion is driven mainly by the residual H₂ demand unmet by imports. Yet under the *RED II* constraints, the role of non-EU countries as H₂ exporters increases, which results in a decrease of their net electricity exports. The spatial allocation of electrolyzers within the EU (cf. Figures and Table in the Appendix) is influenced by both RED II constraints and intra-European transmission capacities. The RED II criteria do not substantially affect renewable deployment in the EU, although they lead to somewhat higher curtailment.

From these results we derive the following policy implications: Even with unlimited imports at low prices, investment in electrolysis inside the EU is viable. Therefore, the regulatory framework must support domestic ramp-up without undermining decarbonization goals. One difficulty is finding a balance between reasonable criteria for the sustainability of H₂ and potential disincentives for investors. A basic requirement for consistent regulation is that imports are evaluated based on criteria similar to domestic production to avoid distortionary effects. In principle, this could be done via the EU's Carbon Border Adjustment Mechanism (CBAM) (EU Commission 2023) or via regulations similar to RED II that address imports. However, no such regulations are currently in place effectively.

One might also argue that with a comprehensive CO₂ emission trading regime inside the EU and in the absence of distorting sectoral policies (such as quotas for green hydrogen in steel production), additional regulation of green hydrogen is superfluous. However, since distorting incentives are likely to prevail for various reasons, RED II regulations serve as a safety net to avoid the backfiring of H₂ support mechanisms. Our results, however, suggest that under the

assumption of compliance with the ambitious decarbonization targets in all simulations, RED II criteria substantially reduce incentives for a domestic European H₂ economy. Consequently, hydrogen production in European non-EU countries and imports from third countries serve as substitutes for domestic hydrogen. The strengths of these effects largely depend on the price elasticity of alternative supplies, as illustrated by the scenario with import limitations.

Our model analyzes electrolyzers on an aggregated level for market zones, allowing us to focus on the regulatory implications for investment incentives. Further research may consider a detailed grid representation and individual units in order to compare market-oriented and grid-friendly operations (i.e., the effect on FLH and the profitability of electrolyzers). We focused on European interactions and dependencies, neglecting inner-country constraints regarding grid transport and storage capacities for H₂. The integration of seasonal H₂ storage may provide additional insights into the temporal aspects of imports and the level and operation of domestic electrolyzer capacities.

Acknowledgements

We acknowledge support from the Open Access Publication Fund of the University of Duisburg-Essen.

Data Availability

Data will be made available on request.

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Appendix

Appendix A: Summary of EU Commission delegated act: C/2023/1087

Article 3: Regulations for the Accreditation of Renewable Electricity:

- Fuel producers can accredit electricity as fully renewable when the electricity is obtained through a direct connection to a facility generating renewable electricity.
- Criteria for accreditation include the interconnection of facilities, the timing of the commissioning of the electricity generation facility, and integration into the grid or proof of exclusive use for fuel production.
- Specific regulations apply when using grid electricity, as outlined in Article 4.

Article 4: General Provisions for Accrediting Grid Electricity:

- Fuel producers can accredit grid electricity as fully renewable under certain conditions, including the share of renewable energy in the bidding zone and the emission intensity of the electricity.
- Various accreditation options for grid electricity exist, depending on regional conditions and emission intensity.

Article 5: Additionality:

- The condition of additionality is met when fuel producers either generate renewable electricity themselves or have contracts for the purchase of renewable electricity that is produced in an external plant.
- Specific conditions regarding the commissioning time and subsidies are outlined.

Article 6: Temporal Correlation:

- Conditions for temporal correlation between the generation of renewable electricity and the production of renewable fuel are established.
- Temporal correlation is applicable until the end of 2029 and is subsequently adjusted to ensure that renewable fuel is produced shortly after renewable electricity.

Article 7: Geographic Correlation:

- Geographic correlation concerns the location of electrolyzers and renewable electricity generation facilities.
- Criteria relate to the bidding zone where the facilities are located, and additional criteria may be introduced by member states to consider national planning of hydrogen and power grids.

Appendix B: Investment Costs

Table 9: Investment costs [€/kW] in 2030 and 2035

Technology	2030	2035
BATT_STO	444	392
BIOM_ST	2,845	2,843
BIOM_ST_EXC	2,880	2,880
H2_CC	1,019	992
H2_CC_EXC	1,106	1,068
H2_GT	545	525
H2_GT_CH2	850	820
H2HB22	280	277
NUCL_ST	3,323	3,323
PTH2	733	658
SUN	714	680
WIND_OFF	2,250	2,149
WIND_ON	1,083	1,071

Since sources provide values for different years, missing values were interpolated linearly.

Sources: (Fraunhofer-Institut für System- und Innovationsforschung ISI et al. 2017; Frontier Economics 2017; The Boston Consulting Group and Prognos 2018; Deutsche Energie-Agentur GmbH and ewi Energy Research & Scenarios gGmbH 2018; dena 2018; Erlach et al. 2018; Gils et al. 2019; Lux and Pfluger 2020; ENTSO-E and ENTSOG 2020; Prognos et al. 2020; Fraunhofer ISI and Consentec 2021; Merten et al. 2021)

Appendix C: H₂ Import-Export Balances in Europe

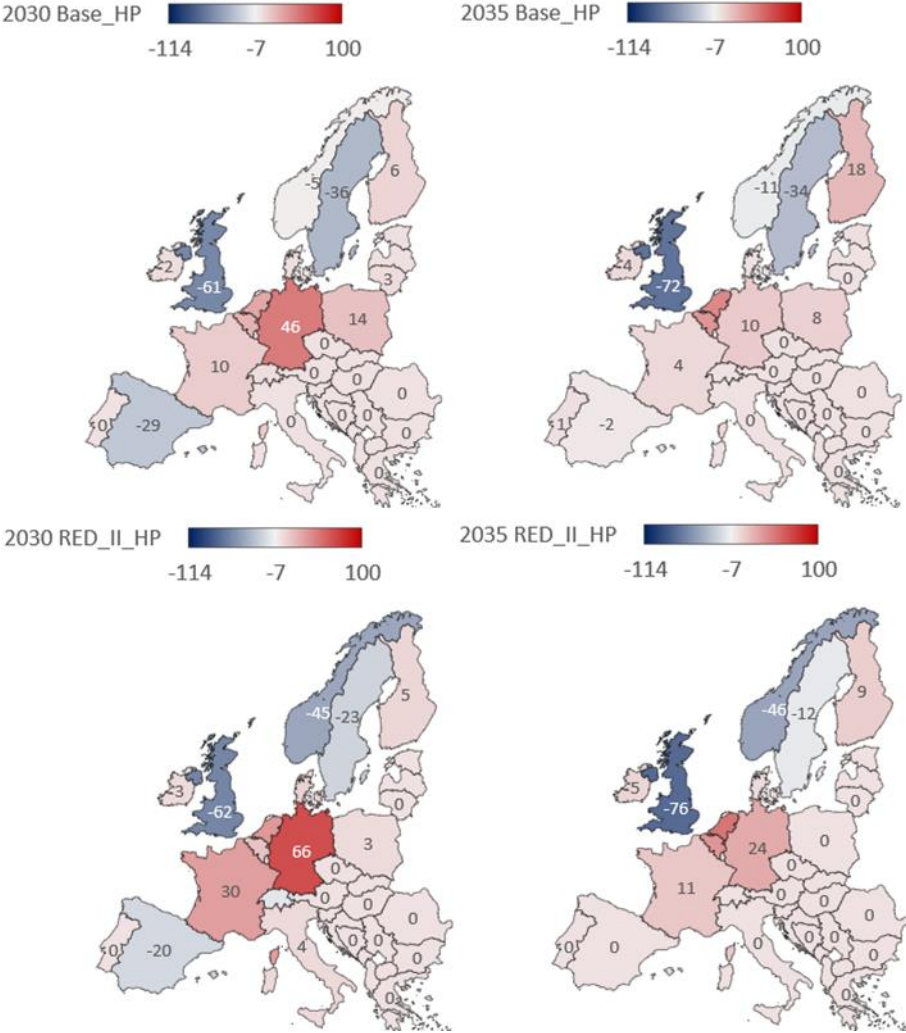


Figure 10: Intra-European imports (+) and exports (-) of H₂ by country [TWh] (HP Case)

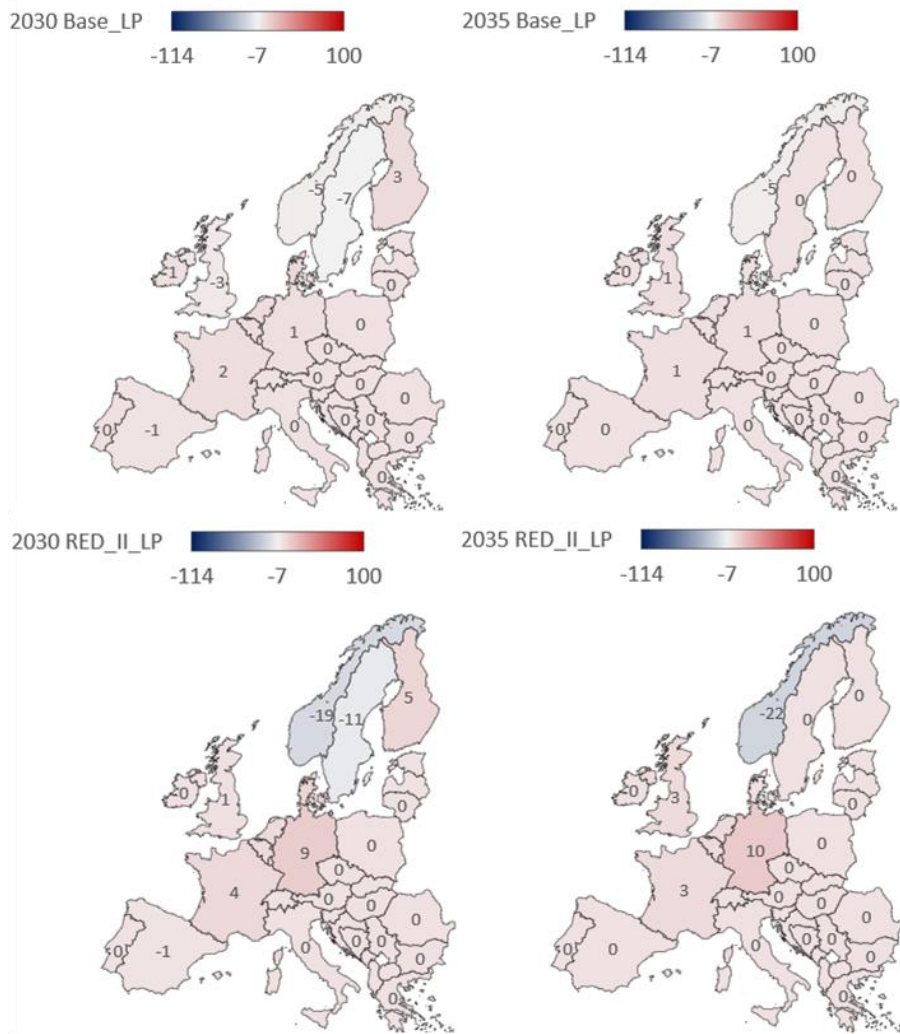


Figure 11: Intra-European imports (+) and exports (-) of H₂ by country [TWh] (LP Case)

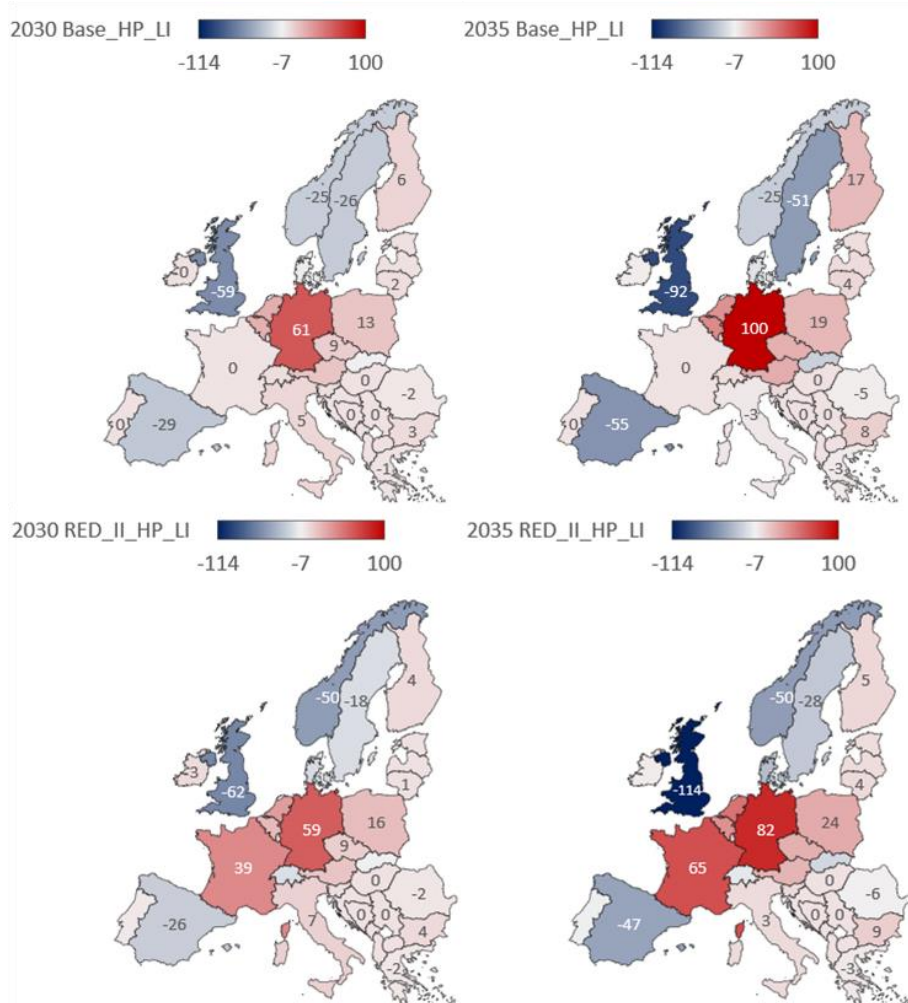


Figure 12: Intra-European imports (+) and exports (-) of H₂ by country [TWh] (HP LI Case)

Appendix D: Electrolyzer Capacity in Europe

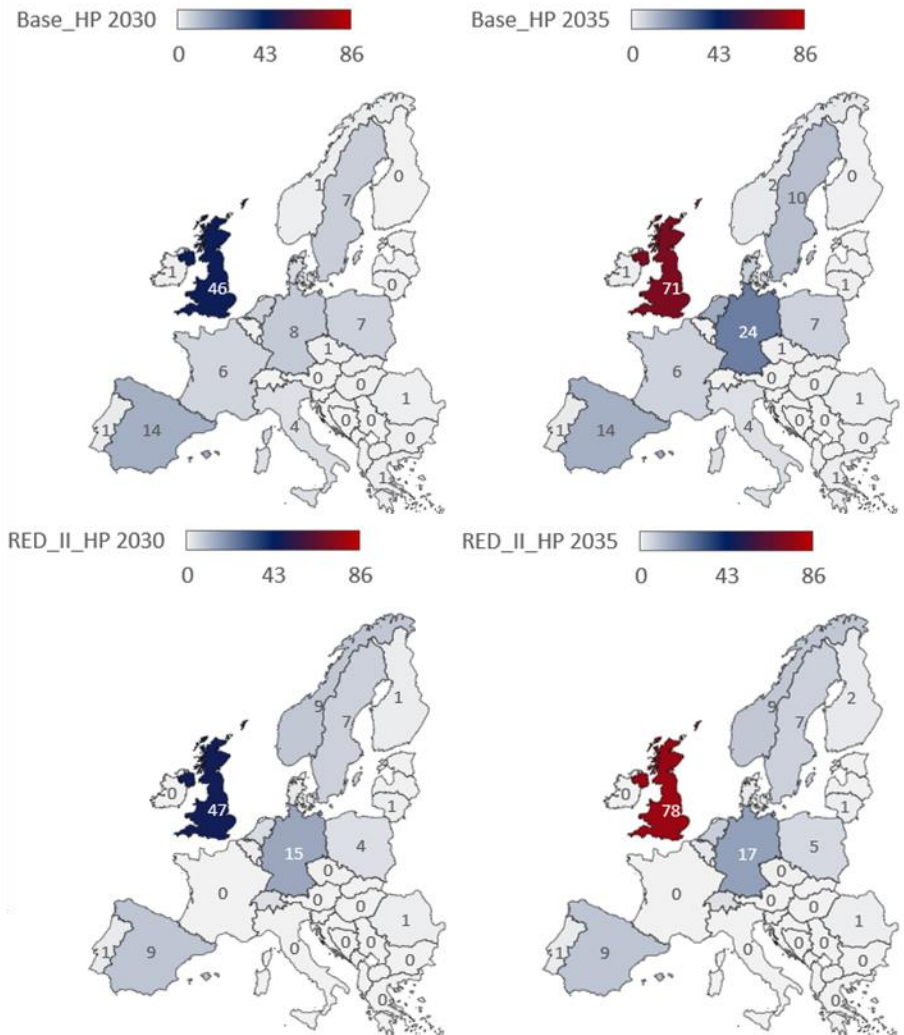


Figure 13: Electrolyzer capacity in Europe [GW] (HP Case)

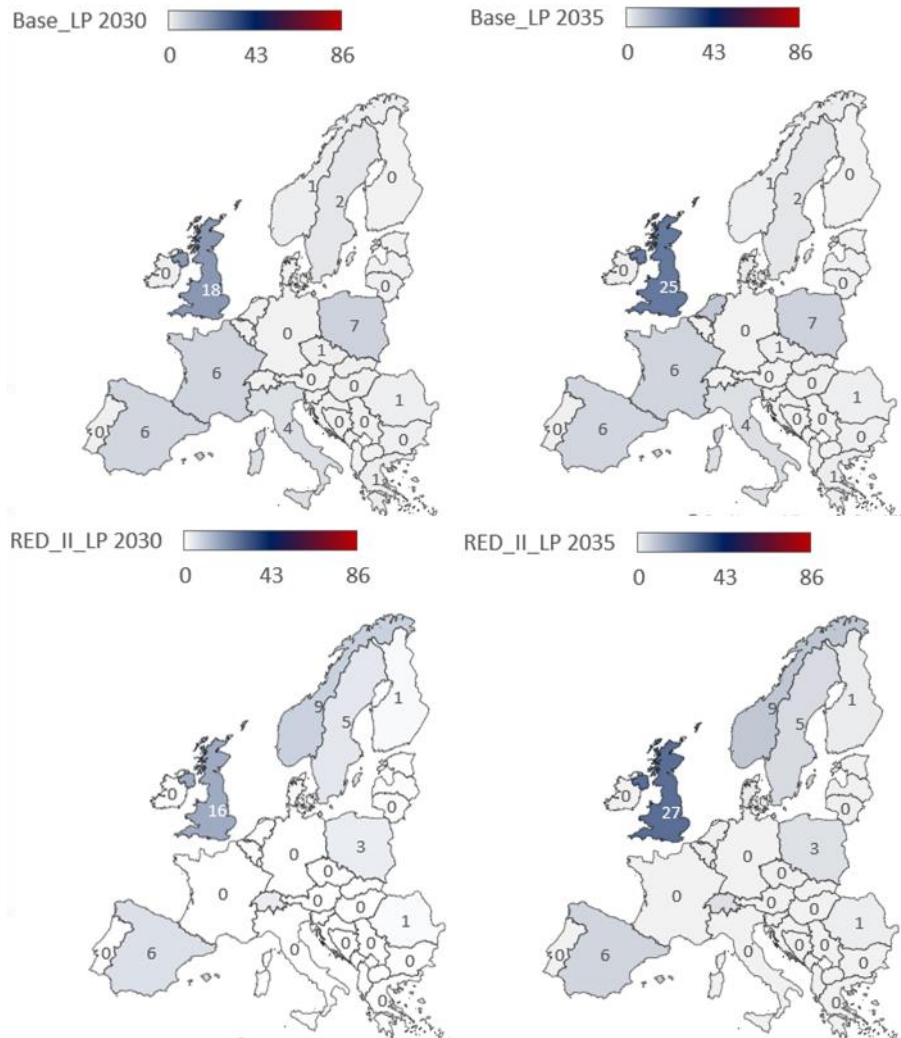


Figure 14: Electrolyzer capacity in Europe [GW] (LP Case)

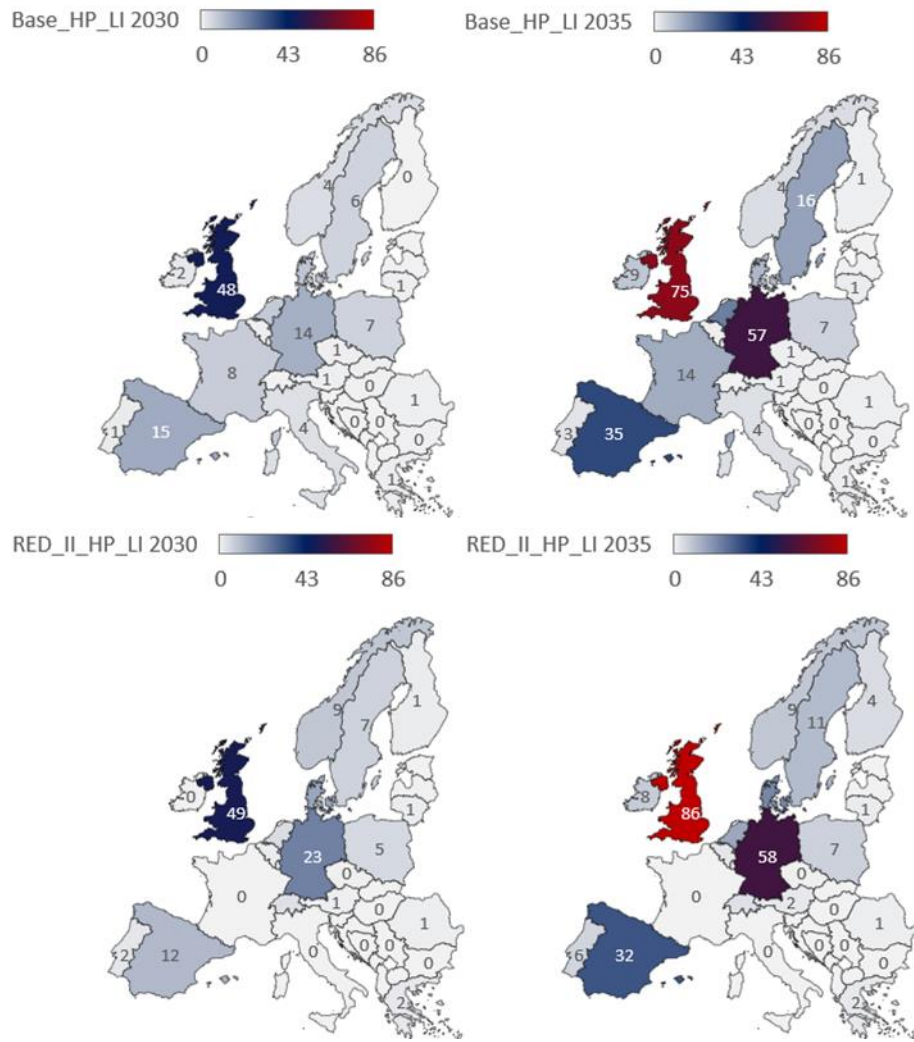


Figure 15: Electrolyzer capacity in Europe [GW] (HP LI Case)

Appendix E: H₂ Data on Country level for HP Case in 2035

Table 10: Country-level H₂ data for the Base and RED II cases of the HP scenario in 2035

TWh	Domestic production		3rd country import		Intra-European net import		Total domestic demand		Electrolyzer capacity	
	TWh	TWh	TWh	TWh	TWh	TWh	TWh	TWh	GW	GW
EU										
Country	Base	RED II	Base	RED II	Base	RED II	Base	RED II	Base	RED II
AT	0.00	0.00	26.02	26.20	0.00	0.00	26.02	26.20	0.00	0.00
BE	0.00	2.51	7.82	5.83	32.96	33.73	40.78	42.07	0.00	2.14
BG	0.07	0.00	8.47	8.54	0.00	0.00	8.54	8.54	0.30	0.00
CZ	0.31	0.28	22.94	22.98	0.00	0.00	23.25	23.25	0.55	0.47
DE	29.61	19.75	239.19	240.89	10.43	24.16	279.22	284.80	23.89	16.70
DK	17.05	4.15	0.00	10.31	0.31	3.01	17.35	17.46	6.57	1.73
EE	0.10	0.00	0.55	1.82	1.17	0.00	1.82	1.82	0.07	0.00
ES	50.17	31.31	0.00	16.50	-2.36	0.00	47.81	47.81	13.58	9.27
FI	0.67	2.84	0.00	7.37	18.00	8.51	18.66	18.71	0.34	1.85
FR	21.74	0.00	42.19	56.77	4.21	11.49	68.14	68.27	6.50	0.00
GR	0.34	0.00	12.61	12.95	0.00	0.00	12.95	12.95	0.79	0.00
HR	0.03	0.00	3.95	3.98	0.00	0.00	3.98	3.98	0.11	0.00
HU	0.18	0.02	19.63	19.79	0.00	0.00	19.81	19.81	0.50	0.08
IE	1.10	0.00	2.68	2.60	3.84	5.02	7.61	7.61	0.92	0.00
IT	0.82	0.00	110.71	111.53	0.00	0.00	111.53	111.53	3.74	0.00
LT	1.39	1.58	6.02	5.84	0.00	0.00	7.41	7.41	0.58	0.86
LU	0.00	0.09	2.84	2.97	0.00	0.00	2.84	3.06	0.00	0.08
LV	0.15	0.20	2.40	2.35	0.00	0.00	2.55	2.55	0.09	0.16
NL	19.21	9.39	14.65	16.18	39.41	47.82	73.27	73.39	14.13	7.53
PL	10.35	8.31	60.48	70.54	7.64	0.00	78.48	78.85	6.51	5.15
PT	4.82	3.85	3.77	5.73	0.99	0.00	9.58	9.58	1.43	1.49
RO	0.21	0.25	23.97	23.93	0.00	0.00	24.18	24.18	0.67	0.81
SE	51.28	28.45	0.00	0.00	-34.34	-11.52	16.94	16.94	10.41	6.77
SI	0.00	0.00	3.16	3.16	0.00	0.00	3.16	3.16	0.00	0.00
Non-EU										
AL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CH	0.00	1.98	1.99	0.01	0.00	0.00	1.99	1.99	0.00	3.40
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	10.54	46.00	0.00	0.00	-10.54	-46.00	0.00	0.00	1.79	8.73
RS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UK	155.30	159.83	0.00	0.00	-71.69	-76.22	83.61	83.61	71.47	78.03
Totals										
Total EU	209.91	112.96	622.85	687.86	82.23	122.22	914.99	923.04	92.30	55.10
Total Non-EU	165.84	207.81	1.99	0.01	-82.23	-122.22	85.60	85.60	73.26	90.16
Total	375.75	320.77	624.84	687.86	0.00	0.00	1000.59	1008.64	165.56	145.26

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