Exploring the outcomes of low-carbon hydrogen regulation in the EU

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***Abstract*—Achieving the Paris Agreement's 1.5°C target relies on effective decarbonization strategies, with hydrogen emerging as a pivotal solution. The hydrogen economy is struggling to take off, with the absence of clear regulatory standards defining what qualifies hydrogen as clean. This paper explores the regulatory design frameworks essential for advancing the clean hydrogen economy in the European Union, focusing on carbon accounting methods and emission reduction thresholds. By coupling an electricity market model with a hydrogen trade model, the study examines cost-optimal production strategies under various CO_2 accounting and threshold policies. The results show that using hourly marginal emissions factors to account for grid emission reduce system-level CO_2 emissions by 16 $MtCO_2eq$ between 2030 and 2050 with minimal cost increases compared to using a yearly average emission factor. Additionally, a decreasing threshold allows to achieve cumulative savings of 157 $MtCO_2eq$ between 2030 and 2050.**

***Index Terms*--Low-carbon hydrogen, modelling, energy policy, renewable energy sources, optimization models**

I. INTRODUCTION

Achieving the Paris Agreement's objective of limiting global temperature rise to 1.5°C and attaining net-zero emissions necessitates effective decarbonization options, among which hydrogen emerges as a pivotal solution [1-2]. Recognizing this imperative, the European Union (EU) has set ambitious hydrogen targets through regulatory measures, underscoring hydrogen's role in the energy transition [3-4]. Clean hydrogen can effectively reduce industrial emissions as a feedstock in the sustainable production of chemicals or steel or as an energy carrier providing carbon-free high-temperature heat [5-7]. Hydrogen could also fuel the transport segments that cannot easily be electrified either by directly feeding a fuel cell engine (especially in heavy road transport) or as a feedstock in the production of sustainable alternative fuels [8]. In addition, it can store energy and serve as fuel for backup power production to cope with the variability of renewables in future power grids [9]. Nevertheless, while hydrogen's potential role in decarbonizing the economy is recognized, the hydrogen economy is struggling to take off. More than 600 projects have been announced in the EU, but only 10% advanced to the final investment decision stage [10].

Clean hydrogen production costs must be kept sufficiently low and competitive to foster adoption, stimulate demand, and signal the deployment of the necessary supply infrastructure. However, this expansion must not come at the cost of increased emissions. This is where regulation plays a crucial role, it can help manage the trade-offs between affordability and climate integrity among the different supply routes. The regulation shapes the market structure and costs, and can lead to critical effects upstream in the power and gas supply sectors, significantly impacting GHG emissions.

The first step in setting the regulation is to identify what "clean hydrogen" means and how to certify its production induces effective GHG emissions reductions. The European Commission (EC) have introduced the "renewable hydrogen" and "low-carbon hydrogen (LCH)" definitions [11]. The European Commission has put clarity on the renewable hydrogen definition by releasing two delegated acts (DA). The first one sets out the methodology to define renewable hydrogen (also called Renewable Fuels of Non Biological Origin, RFNBO) through the introduction of the concept of "fully renewable electricity" [12]. It lays out multiple situations in which consumed electricity can be considered "fully renewable". This act encompasses the criteria such as temporal correlation, geographical correlation and additionality which are already addressed in the literature [13-15]. If the electricity respects these criteria, the carbon footprint is set at zero. The second act on GHG emissions accounting methodology [16] establishes rules for calculating hydrogens' GHG emission and defines the minimum required emissions reduction threshold. Emissions are assessed using a lifecycle assessment, and at least 70% of savings compared to a "fossil fuel comparator" are required to be defined as "clean", corresponding to a maximum of 3.38 $kgCO_2eq/kgH_2$. However, these acts do not give clarity on how grid electricity can be used when the 70% threshold is respected but cannot be defined as "fully renewable". No clear definition and regulation have been adopted on "low-carbon hydrogen".

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The existing literature highlights the significance of costs in shaping the future hydrogen market [17-18] but overlooks how regulation influences competition among different supply routes and the associated GHG emissions from hydrogen production [19]. Several studies focus on the impact of hydrogen regulation on induced emissions and costs, they mainly focus on the regulation of renewable hydrogen and the criteria of geographical correlation, temporal correlation and additionality [13-15], neglecting low-carbon grid-based or gas-based hydrogen. Additionally, they often treat supply pathways, regulatory impacts, and market dynamics separately.

This paper contributes to the literature by addressing regulatory uncertainties essential for achieving climate targets and kick-starting the hydrogen economy. It provides insights into the EU hydrogen market, including grid-based and gas-based production pathways. We examine how regulatory frameworks impact overall system-level emissions, production costs, supply chain competition and hydrogen production volumes. Specifically, we analyze the impact of CO_2 accounting for grid-based electrolytic hydrogen and the CO_2 thresholds defining low-carbon hydrogen on cost-optimal production strategies, leading to policy recommendations.

II. METHODOLOGY

A. *Modelling architecture.*

Two models are coupled to evaluate the interactions and synergies among grid-based electrolysis, renewable production, and fossil gas-based production. An electricity market model represents the future European electricity system, including hydrogen production and exchange (hereafter, the hydrogen-integrated electricity market model) and an international hydrogen trade model that incorporates hydrogen imports and gas production (hereafter, the import model). The modelling allows to comprehensively assess the economics and competition between the different production routes of clean hydrogen (Figure 4.) and accounts for variations in technology costs, energy economics, hydrogen infrastructure, and demand across different years.

Our analysis models the period from 2030 to 2050 in five-year intervals, employing an iterative approach without assuming perfect foresight, with an hourly resolution. We assume an exogenous hydrogen demand (TABLE III.) for each country of the EU that must be met at each timestep. Our modelling framework represents the demand and supply balance of electricity and hydrogen at the country level in the EU and includes trade flows from potential exporting countries outside the EU.

B. *Model description*

1) *Import model*

The import model investigates the prospective global hydrogen market trade flows by evaluating the renewable and low-carbon hydrogen production potential of countries outside Europe and identifying supply and trade patterns to Europe. The model is adapted from [18], it captures the hydrogen value chain from production to consumption, covering upstream (production) and midstream (conversion, transport, reconversion). Costs and volumes are calculated for off-grid renewables and methane with CO_2 abatement. Renewable costs depend on land availability, deployment rates of wind/solar, and power density, while gas-based hydrogen considers consumption trajectories, trade balance, and resources. Transport options include hydrogen trucks and pipelines domestically, with cargoes and pipelines for international transport.

2) *Hydrogen-integrated electricity market model*

This model is a linear programming model for electricity and hydrogen capacity expansion and economic dispatch under a total system cost minimization. It is composed of two linked modules. The first one, the power module incorporates investment and operations decisions by modelling the equilibrium between the electrical demand and the production, it represents the day-ahead commitment of each power plant unit based on their marginal costs and technical constraints. The market price is deduced from the marginal value of the supply and demand constraint. The second one, the hydrogen module, models the equilibrium between hydrogen demand and hydrogen production. As one production route considered for hydrogen production is grid-based electrolysis, the hydrogen module is linked to the power module through the electrical load of the grid-connected electrolyzers. This module allows the system to install and operate electrolyzers, produce hydrogen from electrolysis, exchange hydrogen through pipelines, import hydrogen from outside Europe, and produce hydrogen from natural gas thanks to the coupling with the import model. The objective of this optimization problem is to minimize the total system costs, encompassing all costs related to the power and hydrogen investment and production.

C. *Scenario definition*

For assessing the impact of key regulations on the costs, traded volumes and GHG emissions, different policy scenarios (TABLE I.) are considered based on key influencing parameters analyzed in the literature review. Their design focuses on the low-carbon certification scheme and definition, focusing on the grid-based GHG emissions accounting methodologies and setting the emission threshold to be aligned with reaching climate neutrality. Using the IEA's net-zero scenario [20], a threshold compatible with the climate target would lead to 1 $kgCO_2eq/kgH_2$ in 2050**.**

The scenarios are compared to understand the impact of regulatory designs on the four pillars: environmental integrity, industrial competitiveness, the take-off of the European hydrogen economy, and the EU's energy independence.

TABLE I. SCENARIO DEFINITION

Scenario	GHG accounting methodology – Grid emission factor	Required reduction threshold
Scenario 1	Yearly average emission factor	70% reduction threshold ($3.38kgCO_2/kgH_2$)
Scenario 2	Hourly marginal emission factor	70% reduction threshold ($3.38kgCO_2/kgH_2$)
Scenario 3	Hourly average emission factor	70% reduction threshold ($3.38kgCO_2/kgH_2$)
Scenario 4	Yearly average emission factor	Linearly decreasing threshold converging towards 1 $kgCO_2eq/kgH_2$ in 2050

III. RESULTS AND DISCUSSION

A. Market outlook

The availability of resources, historical investments, and policy decisions have resulted in substantial national disparities across European electricity mixes. These disparities directly impact the carbon intensities of existing national grids and, consequently, the feasibility of "low-carbon" grid-based hydrogen production in the short term (Figure 1.). In 2023, using a yearly average EF, only four countries in Europe – Sweden, Norway, France and Switzerland – would be able to produce grid-based hydrogen below $3.38kgCO_2/kgH_2$. Ten countries, including Austria, Spain, Portugal, Belgium, and Denmark, would generate hydrogen with lower GHG intensities than the average hydrogen carbon content obtained via SMR ($9kgCO_2eq/kgH_2$) and in eighteen European countries, the use of grid electricity for hydrogen production would result in GHG emissions surpassing $9kgCO_2eq/kgH_2$.

In the future, electricity mixes will evolve by integrating higher shares of renewables, lowering carbon content (Figure 1.). In 2030, the carbon intensity of baseload hydrogen production from the power grid is still higher than the threshold in Germany, Italy, Belgium, the Netherlands and Poland, with 5, 5.2, 8.2 and 5.3 $kgCO_2eq/kgH2$ respectively. In 2040 and 2050, the yearly average carbon content is set to fall below 3.38 $kgCO2eq/kgH_2$ all over Europe, thus enabling grid-based hydrogen production.

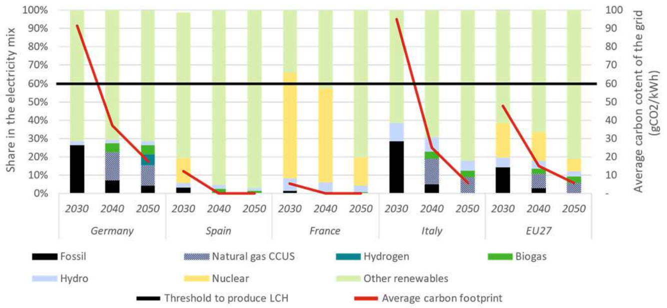


Figure 1. Evolution of the electricity mix and carbon content for selected countries and EU27

As a result, countries above the threshold cannot produce grid-based hydrogen with a yearly average EF and must rely only on renewable production, gas-based production or hydrogen imports (from inside Europe or international supply). In 2030, 54% of the demand is to be met through domestic electrolytic hydrogen, 9% of the demand is supplied by gas-based production and 37% by import from international trades. In the long term, as CO_2 infrastructure becomes fully available and global production costs decrease, the hydrogen demand is met by 62% domestic electrolytic hydrogen, 21% gas-based hydrogen, and 17% imports.

B. CO_2 accounting for grid based electrolyzers

Using hourly EF enables countries to produce grid-based hydrogen below the threshold sooner than when relying on yearly average GHG emissions but is more stringent for countries that were already below the threshold, as the ability to produce is more limited.

Overall, the hourly marginal EF allows for 57% of hydrogen demand to be met through electrolytic hydrogen in 2030, compared to 54% with yearly average accounting. This increased domestic supply reduces import shares by 3 percentage points by 2030. Similar results are obtained by using hourly average EF. One of the main differences is that grid-based production increases by 13% when using an hourly average EF compared to the hourly marginal EF, since the EF are less constraining on an hourly basis.

In contrast to the rigid yearly average EF, the hourly marginal EF provides signals for flexible electrolyzer operations, aligning their dispatch with the power system needs. Grid-connected electrolyzers flexibly absorb surplus power, aligning their operation with system needs (Figure 2.). This ensures hydrogen production is clean, cost-effective, and optimized for periods of high renewable output and low electricity prices.

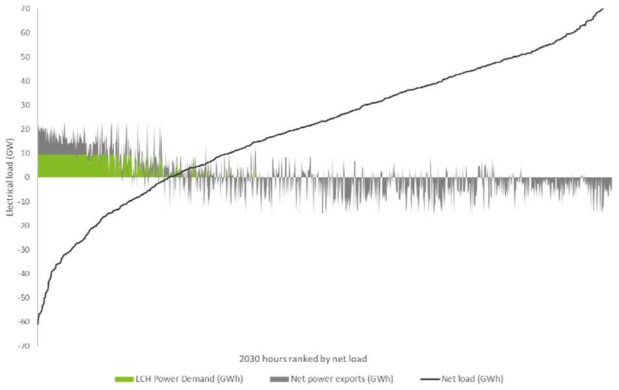


Figure 2. Germany's 2030 grid-based hydrogen production pattern and net load with hourly marginal EF

Furthermore, using an hourly EF allow to decrease the system-level emissions and the development of supply chain capacity for electrolyzers. Using an hourly marginal EF enables the development of 8 GW of additional electrolyzers by 2030 (TABLE II.), contributing to a 4 $MtCO_2eq$ reduction in 2030 and a cumulative 16 $MtCO_2eq$ reduction by 2050.

Alternatively, adopting an hourly average EF allows for even greater electrolyzer integration, 11 GW by 2030, but achieves a smaller environmental benefit, with only 5 $MtCO_2$ avoided between 2030 and 2050 compared to the yearly average EF.

TABLE II. PERFORMANCE COMPARISON BETWEEN SCENARIOS

		Yearly average EF and static threshold (Scenario 1)	**Hourly marginal EF and static threshold (Scenario 2)**	**Hourly average EF and static threshold (Scenario 3)**	**Yearly average EF and decreasing threshold (Scenario 4)**
Average LCOH	**2030** (€/kgH_2)	3.62	3.66	3.65	3.62
	2050 (€/kgH_2)	2.82	2.87	2.85	2.96
Installed electrolyzer capacity	**2030** (GW)	40	48	51	40
	2050 (GW)	361	360	357	386
Share of hydrogen imports	**2030** (%)	37%	34%	38%	37%
	2050 (%)	17%	17%	18%	19%
Gas demand	**2030** (bcm)	3.6	3.6	3.6	3.6
	2050 (bcm)	56	56	56	24
Avoided emissions*	**2030** ($MtCO_2eq$)	/	-4	-2	0
	2050 ($MtCO_2eq$)	/	-1.5	0	-20
	Cumulative ($MtCO_2eq$)	/	-16	-5	-157

Marginal EF are generally higher than average EF. In case of high renewable penetration, average EF can be very low leading to less stringent values. In 2030, the difference between the two EF methods is $155gCO_2/kWh$ in average in the EU, equating to 8.4 $kgCO_2/kgH_2$ for grid-based hydrogen. By 2050, this gap narrows to a difference of $1.25kgCO_2/kgH_2$. Thus, marginal EF impose stricter constraints, driving higher system-level emissions reduction ($-11MtCO_2$ between 2030 and 2050). However, the stringency of marginal EF comes at little extra cost, with the LCOH for grid-based hydrogen rising by 7% in 2030 and 13% in 2050. The average LCOH across all supply routes only increase by 1%, mainly due to a shift in the quantity supplied by each production route.

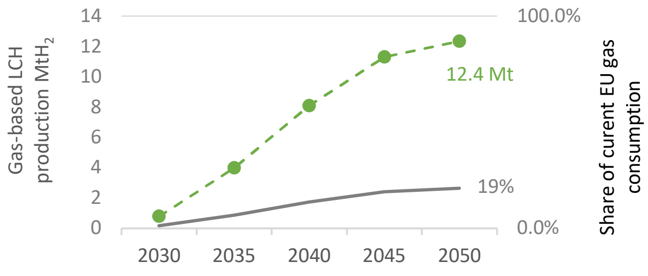
C. CO_2 decreasing thresholds

The emission threshold of 70% requires the CO_2 intensity of grid electricity to be around 60 CO_2eq/kWh (depending on the efficiency of the electrolyzer). The fast development of renewables and low-carbon technologies in the electricity makes the EU27 cross this threshold by 2030 on average and from 2040 for all countries (Figure 1.). This means the current static threshold would become irrelevant within the next decade for grid-based hydrogen production if the yearly average EF is used.

In 2030, the difference compared to a static threshold is minimal. In 2040, 21% of the demand is met through gas-based production, which is a 13% decrease compared to a static threshold. The difference is even greater in the long term. In 2050, electrolytic production represents 72% of the supply, compared to 62% with a static threshold, and gas-based hydrogen only 9% against 21% using a stating threshold. This means that adopting a decreasing threshold leads to lower dependency on gas, and lower emissions.

The shares of natural gas required to produce LCH could go from about 3.5 bcm in 2030 to between 24-56 bcm in 2050 (Figure 3.). This is about 1.2%, and 8-19% of the total EU27 gas demand of 2023. Even if it remains limited in 2030, this natural gas consumption would come off the top of current natural gas uses in Europe and would counter the expected descending trend of the REPowerEU plan. While the share of hydrogen imports is projected to be 9% by 2050, compared to 21% under a static threshold, this does not necessarily indicate an increase Europe's energy autonomy. Rather, it signifies a strategic shift in the type of commodity Europe depends on. By embracing a decreasing threshold for hydrogen, Europe effectively reduces its reliance on natural gas while increasing its dependency on hydrogen.

a) Static threshold



b) Decreasing threshold

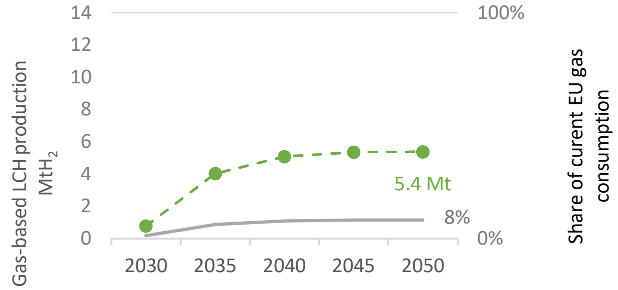


Figure 3. Gas-based LCH supply and associated natural gas demand comparison between static threshold (Figure a) and a decreasing threshold (Figure b)

Emissions are lowered in a decreasing threshold compared to the static threshold scenario because the highest emitting sources are no longer accepted. A larger share of the demand is supply with electrolytic hydrogen which entails lower emissions, even when considering consequential emissions (TABLE II.). By integrating less gas-based hydrogen, over the period studied, adopting a linear decreasing threshold leads to 157 $MtCO_2eq$ avoided compared to the static threshold. We find that LCOH values increase by 3.8% in 2040 and 4.8% in 2050. This is due to more production from electrolysis which are associated with more costs. However, the increase is small compared to the emissions avoided.

IV. DISCUSSION AND CONCLUSION

We focus on key regulatory items critical for the deployment of the clean hydrogen economy. We evaluate scenarios with varying carbon accounting methods and thresholds for classifying hydrogen as "low carbon", analyzing their impact on emissions, production costs, and the share of different hydrogen pathways in the production mix. Using an integrated approach, we combine an electricity market model, encompassing hydrogen production, with an international hydrogen trade model. The hydrogen-integrated electricity market model projects the future European electricity system, while the trade model accounts for non-European hydrogen imports and gas-based production.

The competitiveness of four supply routes is analyzed in this study – hydrogen production from dedicated renewables, grid-based production, fossil gas-based production, and imports. The competitiveness of these routes in each country is influenced by the potential for renewable energy, the electricity mix, and access to natural gas supplies and CO_2 infrastructure.

Considering a yearly average EF and a maximum carbon intensity of 3.38 $kgCO_2eq/kgH_2$, 54% of the demand is be met through domestic electrolytic hydrogen, 9% of the demand is supplied by gas-based production and 37% by import from international trades in 2030. In the long term, as CO_2 infrastructure becomes fully available and global production costs decrease, the hydrogen demand is met by 62% domestic electrolytic hydrogen, 21% gas-based hydrogen, and 17% imports. Gas-based production, which are cost-competitive in some member states, could supply almost 25% of EU hydrogen demand in average between 2030 and 2050.

Compared to the rigid yearly annual EF, using an hourly EF encourages electrolyzer operations at times when renewables or nuclear power generation dominate the electricity mix, boosting electrolytic low-carbon hydrogen production. Overall, the hourly marginal EF allows for 57% of hydrogen demand to be met through electrolytic hydrogen in 2030. This increased domestic supply reduces import shares by 3 percentage points in 2030. Additionally, using hourly marginal EF allows for CO_2eq emission reduction at the system level, entailing 16 $MtCO_2eq$ reduction over the period 2030-2050. This reduction comes at a small cost for production hydrogen, with a slight increase of the average LCOH to 3.66€/kgH_2 in 2030 and 2.87€/kgH_2 in 2050. Using an hourly average EF leads to lower system-level emission reduction compared to the hourly marginal EF, with additional 11 $MtCO_2$ emitted over the period.

Compatibility with the EU's net-zero target would require the carbon intensity threshold of "low-carbon" hydrogen to decrease from 3.38 to 1$kgCO_2eq/kgH_2$ in 2050. Adopting a decreasing threshold would yield cumulative GHG emission savings of up to 157 $MtCO_2eq$ from 2030 to 2050, as compared to a static threshold. Gas-based low-carbon hydrogen supply would then peak by the mid-2040s and accounts for only around 9% of EU hydrogen supply by 2050. In this case, domestic renewable hydrogen production covers about 72% of the supply. As upstream emissions entail different emissions in each region, only natural gas from Norway would be compliant with such decreasing threshold for low-carbon hydrogen production.

Developing the low-carbon fuels regulation and certification scheme will require delicate trade-offs between multiple objectives. The regulation will have implications on (i) EU hydrogen and power GHG emissions, (ii) EU industrial competitiveness – through access to low-cost hydrogen supply, (iii) EU dependency on hydrogen and natural gas imports and (iv) on the take-off of the EU hydrogen industry. In these considerations, environmental integrity must remain at the forefront, ensuring that the hydrogen produced is genuinely low-carbon. Towards 2050, progressively lowering emissions thresholds will be essential to phase out production that relies on fossil gas with significant upstream emissions and electricity from grids with residual emissions.

Similarly, enforcing an hourly marginal EF leads to environmental benefits at little extra cost. It would enforce the operation of electrolyzers according to the carbon intensity of the grid, improving system flexibility and creating market opportunities that would otherwise have been blocked with an accounting method based on annual averages.

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APPENDIX

Figure 4. Modelling architecture with the coupling of two models and key metrics as outputs

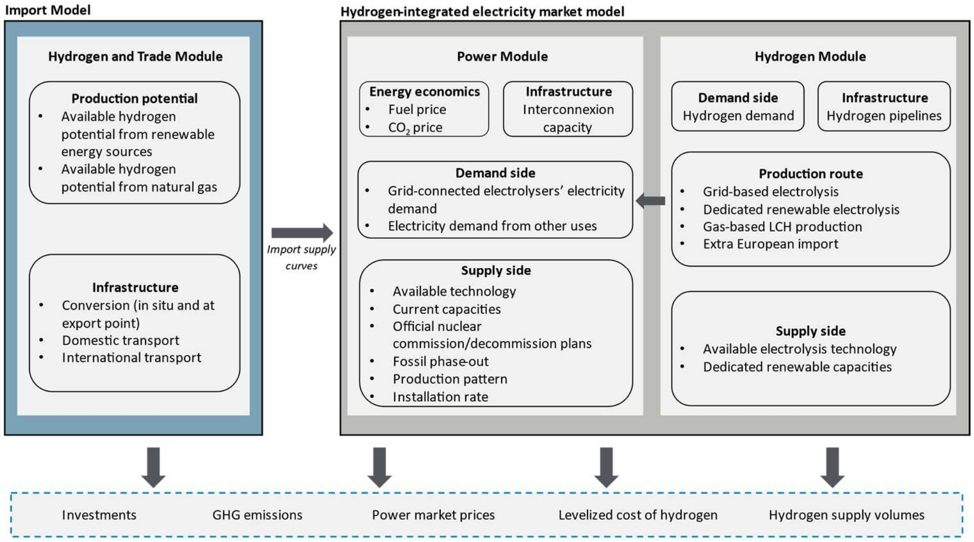

TABLE III. COUNTRY-LEVEL HYDROGEN DEMAND

	Hydrogen demand (MtH2)				
	2030	**2035**	**2040**	**2045**	**2050**
Austria	0.2	0.4	0.6	0.9	1.3
Belgium	0.6	1.0	1.4	2.6	4.0
Czechia	0.2	0.3	0.4	0.6	0.9
Finland	0.2	0.3	0.4	0.7	1.0
France	1.1	1.9	2.8	4.7	6.6
Germany	2.3	4.6	7.2	11.9	16.1
Greece	0.1	0.2	0.2	0.4	0.5
Hungary	0.1	0.2	0.2	0.4	0.5
Ireland	0.1	0.1	0.2	0.4	0.5
Italy	0.7	1.3	1.8	3.3	5.0
Netherlands	1.0	1.7	2.4	4.5	7.0
Poland	0.3	0.6	0.8	1.4	1.8
Portugal	0.2	0.3	0.4	0.8	1.1
Romania	0.2	0.3	0.4	0.7	1.0
Slovakia	0.1	0.1	0.2	0.3	0.4
Slovenia	0.0	0.1	0.1	0.2	0.2
Spain	1.2	2.0	2.9	5.1	7.5
Sweden	0.2	0.4	0.6	1.1	1.7
Bulgaria	0.1	0.1	0.2	0.3	0.5
Estonia	0.0	0.0	0.0	0.1	0.1
Croatia	0.0	0.1	0.1	0.1	0.2
Lithuania	0.0	0.1	0.1	0.2	0.3
Denmark	0.1	0.2	0.3	0.6	0.9

Source: The demand is extracted from European Commission (2024). Since the EC does not provide any official 2030 figure, a literature review and an assessment of different national and European targets was conducted leading to likely baseline demand of 300 TWh in 2030. Repartition across each countries is made for each sector (Iron & Steel, chemistry, other industry, aviation, maritime, heavy-duty road transport), proportionally to their historical energy demand for that sector, derived from analysis based on (European Commission et al., 2021; European Commission, Joint Research Centre, 2020; Eurostat, 2023a, 2023b, 2023c)