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Green Targets, Grey Realities -
Modelling the Regulatory Trade-offs of the EU's Hydrogen Framework through Policy Foresight

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Preface

This Master's thesis was written between January and April 2025 at Sciences Po Paris as part of the two-year Master's in Public Policy (MPP), with a specialisation in energy, environment, and sustainability. The research builds on prior academic work within the programme as well as practical experience gained through internships and student positions focused on hydrogen markets.

I would like to extend my gratitude to my supervisors, Dr. Manfred Hafner and Dr. Chi Kong Chyong, for their invaluable support and guidance throughout the course of this work. In particular, I am deeply thankful for Mr. Chyong's thoughtful guidance, steady encouragement, and intellectual insight, which were instrumental in shaping the quality of this thesis. His genoristy of making available his Energy Futures Optimisation Model provided the foundation for the quantitative analysis.

The paper at hand made use of artificial intelligence for initial research, paraphrasing and rewording, structuring suggestions, and formatting.

I declare that this is an independent work according to the exam regulations of Sciences Po Paris.

Henrik Schmidt
Paris, 22nd April 2025

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Green Targets, Grey Realities - Modelling the Regulatory Trade-offs of the EU’s Hydrogen Framework through Policy Foresight

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Abstract

This study examines the European Union’s policy framework for clean hydrogen. Amid rising concerns over project deliverability and cost competitiveness, we address the core policy challenge of balancing environmental ambition with economic feasibility. This is especially timely research as the European Commission announced a review of its hydrogen policy in February 2025. After a brief overview of the relevant legislative pieces, we calculate the policy-mandated demand for renewable fuels of non-biological origin (RFNBO) in 2030, project increased mandates for 2040, and derive the dedicated renewable power volume needed to meet these targets. We use a European energy system optimisation model and a set of policy scenarios to investigate how varying regulatory approaches — from strict mandates to deregulation — impact hydrogen production, power market dynamics, and greenhouse gas emissions between 2030 and 2050.

The results shows that, without hydrogen imports, the dedicated renewable power needed to meet RED targets is likely to jeopardise power sector decarbonisation in 2030. This follows the assumption that there is a limited pool of renewables markets can draw upon over the next decades. Theoretically, low-carbon hydrogen via reforming with carbon capture could fill in, if carbon storage and transport infrastructure were in place by 2030. In 2040, grid-based electrolysis emerges as a dominant production pathway, to offset renewable intermittencies in Europe’s increasingly decarbonised grids. Low-carbon hydrogen production is phased-out entirely by 2050, as residual emissions become prohibitely expensive. We also find that an increase in nuclear capacity would help decrease commodity and marginal abatement costs.

Key words

Energy Transition, Europe, Hydrogen, Decarbonisation, Renewable Energy, RFNBO

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List of Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ATR	Authermal Reforming
BECC	Bioenergy with Carbon Capture
BZ	Bidding Zones
CAPEX	Capital Expenditures
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Storage and Utilisation
CEF	Connecting Europe Facility
CHP	Combined Heat and Power
DAC	Direct Air Capture
DOE	Department of Energy
EFOM	Energy Futures Optimisation Model
EHB	European Hydrogen Bank
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
ETS	Emissions Trading System
EU	European Union
EWI	Energiewirtschaftliches Institut
FCEV	Fuel Cell Electric Vehicle
G4M	Global Forest Model
GCAM	Global Change Assessment Model
GHG	Greenhouse Gas
GLOBIOM	Global Biosphere Management Model
IIASA	International Institute for Applied System Analysis
IPCC	Intergovernmental Panel on Climate Change
IPCEI	Important Project of Common European Interest
ITC	Investment Tax Credit
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carriers

LTS	Long Term Strategy
MAC	Marginal abatement cost
MS	Member States of the European Union
Mt	Million tonnes
OPEX	Operating Expenditures
PCI	Projects of Common Interest
PEM	Proton Exchange Membrane
PMI	Projects of Mutual Interest
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
RED	Renewable Energy Directive
RFNBO	Renewable Fuels of Non-Biological Origin
RPS	Renewable Portfolio Standard
SAF	Sustainable Aviation Fuel
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyser Cells
TSO	Transmission System Operator
VRE	Variable Renewable Energy

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Why should you read this research?

The following thesis examines the European Union's (EU) policy framework for clean hydrogen, encompassing Renewable Fuels of Non-Biological Origin (RFNBO) and low-carbon hydrogen. Amid rising concerns over project deliverability and cost competitiveness, the EU Commission has announced a review of its hydrogen policy framework within the Clean Industrial Deal, published in February 2025. Against this background, we seek to explore whether the current policy environment in Europe sets the right priorities and can balance out emission reductions with the competitiveness of domestic hydrogen production.

Using an enhanced European energy system optimisation model and a set of policy scenarios, we investigate how varying regulatory approaches — from strict mandates to complete deregulation — impact hydrogen production, power market dynamics, and greenhouse gas (GHG) emissions. Based on hydrogen demand estimates from the European Commission's long-term climate strategies, we calculate the demand-side mandates for RFNBO hydrogen included in the Renewable Energy Directive (RED) for the industrial and transport sectors. For 2030, we can draw upon the legally binding mandates, whereas for 2040, we assume increased mandates in line with the EU's proposed climate target for 2040. From these estimates, we quantify the renewable energy volumes and electrolyser capacities that would need to be dedicated to RFNBO hydrogen production by 2030 and 2040.

Using a strategic foresight approach, we define five scenarios of plausible energy and climate pathways and challenges Europe will likely face over the next few decades. Among these scenarios, one assumes the continuation of the current priority on RFNBOs. In contrast, in another scenario, we assume an extreme deregulation context that relies only on a carbon emission reduction constraint. Using the energy system optimisation model, we can show that attributional emissions from the hydrogen market would be significantly lower when continuing the current RFNBO framework. On the other hand, however, this will come at inevitable trade-offs in power sector decarbonisation, since we assume that both the electricity grid and RFNBO hydrogen have to draw capacities from a limited pool of renewable energies. The uptake of low-carbon hydrogen in 2030 is robust in a deregulation context, contributing up to 64% of total hydrogen production. Its expansion is only limited by the availability of permanent carbon storage capacities. We can also showcase differences in hydrogen and power market dynamics on a regional level, given that 14 European regions are represented in the model.

Coinciding with the announced review of the EU's hydrogen policy, we provide policy recommendations to the Commission and European Member States, informed by quantitative and qualitative results presented here. A recalibration of the EU's Hydrogen Strategy, capacity and demand targets is fundamental. Further proposals touch upon hydrogen imports, RED demand targets, the role of low-carbon hydrogen as a transition fuel, the need to prioritise renewable resources, and the significance of nuclear power in the energy transition.

1. Introduction

In 2023, hydrogen demand in the European Union (EU) stood at 7.3 million tonnes (Mt) (European Hydrogen Observatory, 2024a). About 96% of this hydrogen is produced using unabated fossil fuels as "grey hydrogen" (European Commission, 2024a). Generally, this process uses methane as an input and releases CO_2 as a by-product. If this CO_2 is not captured, it contributes to global warming, making grey hydrogen a significant carbon emitter. Its production generates around 70 - 100 $MtCO_2$ annually in the EU, corresponding to around 3% of the EU's total greenhouse gas (GHG) emissions (European Parliament, 2023; European Environment Agency, 2024a). The emissions intensity of the production of grey hydrogen underlines the need to substitute it with clean[1] hydrogen, which, however, currently makes up less than 1% of hydrogen supply (Hydrogen Europe, 2024b).

As part of the European Green Deal and the "REPowerEU" agenda, the European Commission defined a detailed policy framework for clean hydrogen. The market ramp-up is regulated by provisions included in the Renewable Energy Directive (RED) III, the Hydrogen and Gas Decarbonisation Package, the Delegated Regulation on Renewable Fuels of Non-Biological Origin (RFNBO), and the Delegated Regulation on Low Carbon Hydrogen (to be published in 2025). Many forms of hydrogen are colour-coded; however, the European regulation only includes two classifications of clean hydrogen. First, RFNBO, or "green hydrogen" is produced by electrolysers consuming renewable electricity. Secondly, low-carbon hydrogen can be produced either in an electrolyser sourcing electricity from the grid or by steam methane reforming (SMR) using Carbon Capture and Storage (CCS), i.e. "blue hydrogen".

After an initial hydrogen "hype" (Baker, 2024), the market ramp-up has faced significant headwinds from 2023 onwards due to deliverability problems in the industry. The ramp-up of clean hydrogen is characterised by higher production costs for clean hydrogen, an unwillingness on the demand-side to sign long-term offtake agreements, and the lack of a comprehensive hydrogen infrastructure. Investors have criticised the presence of strict regulations that, while they may achieve high sustainability standards, would lead to remarkably high project costs. Given the focus of the incoming Commission on industrial policy and competitiveness, it is likely that regulatory changes in favour of industry interests will be enacted. A "review" of the European hydrogen regulation, beginning with the launch of a study, has already been announced in the EU's flagship Clean Industrial Deal which was only published in February 2025 (European Commission, 2025a).

Given this timeliness, the thesis seeks to contribute to the scientific debate by answering the following research questions: **Does the current European hydrogen framework strike the right balance between environmental and economic considerations?** We divide this research question into two parts. First, we seek to understand the repercussions of the current RFNBO hydrogen framework on the energy system. Second, we will use strategic foresight to explore the impacts of alternative market conditions, policy and regulatory frameworks on the hydrogen market. In this context, we will seek to find evidence for the hypothesis that the European targets for RFNBO hydrogen demand will increase competition for scarce renewable

[1] For the purpose of this thesis we define clean hydrogen as including both RFNBOs and low-carbon hydrogen.

energies. While at the same time, their benefit in terms of long-run GHG emission savings is likely to be marginal.

The analysis will proceed in five steps. The literature review in Chapter 2 will present the state of the European and American debate on the regulation of hydrogen production. Thereafter, in Chapter 3, the current regulatory framework for RFNBO and low-carbon hydrogen in the EU and their economics will be analysed. In Chapter 4, the methodology of the economic modelling approach is explained in-depth, which employs an extension of the Energy Futures Optimisation Model (EFOM) used in Chyong et al. (2024). Based on this updated model, we can contrast the current policy against several alternative scenario that will also be presented in Chapter 4. The modelling outputs according to each scenario are presented in Chapter 5. With the information provided in the result section, Chapter 6 discusses the implications of each scenario, taking into account recent political developments on the European and Member State level. Finally, Chapter 7 presents policy recommendations aimed at informing the European Commission's upcoming revision of the hydrogen framework.

2. Literature Review

Odenweller & Ueckerdt (2025) quantify the "green hydrogen implementation gap". Using project data, the authors demonstrate that the success rate of hydrogen projects announced for 2023 stood at around 7%, underlining a wide gap between announcements of 4.3 GW and project realisation of only 0.3 GW capacity. This finding is supported by further research (Capgemini, 2024; Wappler et al., 2022) and fits into the broader picture of an ongoing reality check of clean hydrogen ambitions. While Wappler et al. (2022) have deemed the clean hydrogen targets of national strategies "normative" and out of touch with "feasibility", Odenweller & Ueckerdt (2025) examine that the low success rate is caused by surging purchasing costs for electrolysers, low appetite in industries for hydrogen offtake agreements, and regulatory uncertainty.

Regulating hydrogen production in an electrolyser sourcing electricity seems necessary. Zeyen et al. (2024) showed that running an electrolyser in Germany at full capacity with grid electricity would yield attributional emissions[2] of up to 29 $kgCO_2/kgH_2$. This would roughly be three times higher than producing grey hydrogen in an SMR plant at 10 $kgCO_2/kgH_2$ (EU Directive, 2024/1788). For 2030, Brauer et al. (2022) find that unrestricted hydrogen production from grid electricity in Germany, already considering an ambitious renewable share of 80%, would still incur attributional emissions of 3.5 $kgCO_2/kgH_2$. Therefore, in the American and European literature, researchers, just as policymakers, have acknowledged that additional constraints must be established to ensure that hydrogen production does not lead to additional emissions. The details of the regulation are discussed in more detail in Chapter 3.1. However, finding the right balance between regulating the electricity supply to the electrolyser

[2] Attributional emissions are defined as the "share of total grid emissions that would be attributed to hydrogen producers based on their net consumption in a given hour, following a convention similar to the current Greenhouse Gas Protocol Scope 2 location-based emissions accounting guidance" (Ricks et al., 2023).

to ensure low carbon emissions while reducing the levelised cost of hydrogen (LCOH)[3] has proven contentious.

For a single electrolyser project in Germany, Ruhnau & Schiele (2023) demonstrate that the implementation of an annual matching, as opposed to an hourly matching[4], requirement decreases the LCOH by 27 % from 137 €/MWh to 100 €/MWh while only increasing emissions marginally by 0.1 $tCO_2/MWhH_2$. Still, due to excess sales to the grid, both hourly and annual matching yield net-emissions savings to the power grid in the modelled years of 2017-2021. This observation prompts the authors to challenge the general necessity of a strict European hourly matching requirement, as even the annual matching leads to net emission savings, underlining the positive impact of integrating electrolysers into the power system.

The findings of this article aroused firm critique by Ricks et al. (2024), who stress that no general conclusions can be deducted from the marginal emissions of a single electrolyser project. In their previous work, Ricks et al. (2023) found that the hourly matching requirement was the most effective way to minimise additional US power sector emissions. The researchers differentiate between attributional emissions and consequential emissions, which are defined as the *"true long-run electricity system-level emissions impact of hydrogen production, relative to a counterfactual scenario in which the hydrogen production does not occur"*[5]. While hourly matching may have zero attributional emissions, it can still lead to higher consequential emissions in the power system if hydrogen producers occupy limited, high-value renewable resources. Consequently, renewable power demand for electrolysis competes with other renewable power demand, reducing renewables' availability for electrification and decarbonising other uses, which could ultimately contribute to the later retirement of coal or gas power plants.

The research by Ricks et al. (2023) is supplemented by Giovaniello et al. (2024), who dived into the definition of the additionality pillar. They assume that a true "non-compete" additionality is only achieved by integrating electrolysis after optimising the grid. On the contrary, in a "compete" additionality framework, variable renewable energy (VRE) units used for electrolysis must compete with the build-out of VRE units for other applications. According to their model, consequential emissions are lowest under hourly matching and the non-compete framework, while the LCOH tends to be higher. Another key finding of their research is that once implementing a VRE grid target of 60%, both annual and hourly matching requirements meet the most stringent emission threshold from the V45 (Appendix 10.1), even under the compete framework. Giovaniello et al. (2024) find that enforcing a renewable portfolio standard (RPS)[6] under the compete framework yields the same consequential emissions as if no RPS is enforced in the non-compete framework.

[3] Conventionally, the Levelized Cost of Hydrogen (LCOH) is defined as an indication of how much the production of one kg of hydrogen costs over the lifespan of its production assets. The calculation considers both the investment costs (CAPEX), and the costs of operating the assets (OPEX), divided by the total volume of hydrogen production (Vector, 2022).

[4] In an annual matching policy, the electrolysers' electric consumption must be equal to the renewable electricity production at the end of the year. In an hourly policy, the two must match on an hourly basis (Green Hydrogen Organisation, 2024).

[5] Consequential emissions are defined as the "true long-run electricity system-level emissions impact of hydrogen production, relative to a counterfactual scenario in which the hydrogen production does not occur".

[6] Renewable portfolio standards are policies used in the US that require energy suppliers/ generators to meet a minimum threshold of energy demand with renewable energy. They are most used in power markets.

For the European debate, Zeyen et al. (2024) apply the European power system model PyPSA to analyse the impact of different regulatory frameworks and electrolyser operation modes on emissions and the LCOH. The highest emission reductions in the power grid (- 9 $kgCO_2/kgH_2$) are achieved when combining hourly matching with excess power sales to the grid. In contrast, hourly matching in an island model, i.e. without excess sales, always yields zero attributional emissions. With annual or monthly matching, inflexible hydrogen demand yields moderate carbon emissions in the power grid between 2 – 4 $kgCO_2/kgH_2$. Since cheap storage options are available to modulate hydrogen demand, yearly and monthly matching can contribute to net emissions savings. Lastly, the authors underline that the effects of strict temporal regulation decrease with increasing grid decarbonisation. From an 80% VRE share, annual matching would suffice to meet negative consequential emissions, which aligns with previous findings by Giovaniello et al. (2024).

In another article, Ferrús et al. (2024) quantify the effects of technological and geographical diversification on LCOH in Germany. Thanks to smoother generation profiles, portfolio effects average a 39% LCOH reduction, while locational diversification yields another 6–9% LCOH reduction. With these findings, the authors criticise nationally aggregated time series models for underestimating the costs of hourly matching as they ignore these portfolio effects, which are hard to implement for small market players.

This literature strand is remarkable because of the pronounced differences between European and US researchers. While the European literature seems to prioritise the need for lower LCOHs over the most stringent emission thresholds, the US contributors appear to be worried most about the consequential emissions from hydrogen generation. This can be traced back to the different policy environments. In the EU, a clear path to power sector decarbonisation is paved thanks to the cap-and-trade system of the ETS I (Chapter 3.3.1), whose last allowances will be up for auction in 2039. On the other hand, the US power system is far from achieving decarbonisation as fossil fuels make up 50% of power generation since they are much cheaper in the US, given the abundance of fossil resources (Figure 1). California and Washington are the only states with a cap-and-trade system on GHG emissions. The more pressing concern in Europe is thus the cost competitiveness of its hydrogen production, especially when considering the absence of a comprehensive subsidy mechanism (Chapter 3.3.1).

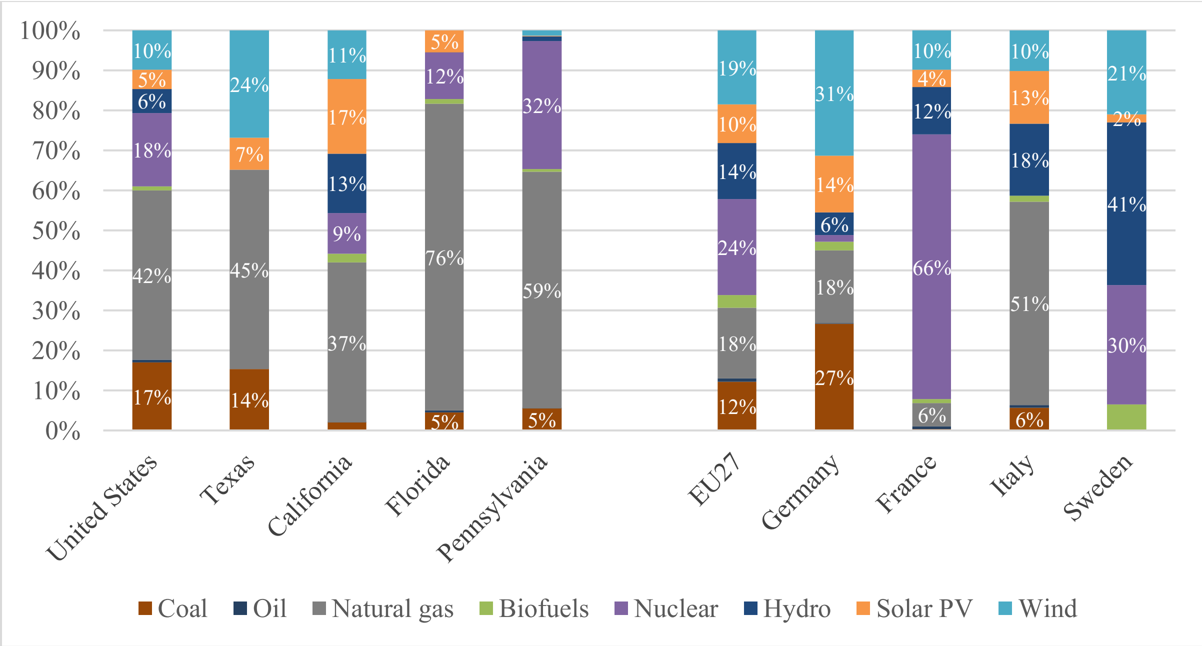

Figure 1: Electricity generation mix in the US, selected federal states, the EU27, and selected European Member States in 2023[7]

Another literature strand deals more in detail with the potential of international hydrogen trade. Based on data from the IEA, Pleshivtseva et al. (2023) find a stable trend towards electrolysis-based hydrogen production in globally announced hydrogen projects. Of the projects planned for 2022 - 2038, electrolysis accounts for 84% of the expected output volume, as opposed to 13% for low-carbon technologies using abated fossil fuels and roughly 3% for other low-carbon technologies, such as methane pyrolysis and biomass-based technologies such as waste gasification. Although the authors find that trade will likely be dominated by renewable hydrogen, the authors point towards a growing interest in low-carbon technologies.

In one recent contribution, Zhang et al. (2024) introduce a range of scenarios for hydrogen trade, which they integrate into a Global Change Assessment Model (GCAM). Their modelling predicts that the EU, Southeast Asia, South Korea, and Japan constantly depend on hydrogen imports. In contrast, the MENA region, Australia, South Africa, and China are the biggest exporters. In these exporting countries, the production costs for green hydrogen can be as low as \$2/kgH_2 by 2050. Although Zhang et al. find that global trade will be dominated by green hydrogen with an approximate share of 78%, they point out that a mere 1\$/kgH_2 increase in green hydrogen production cost can suppress supply between 28 and 70%. Low-carbon hydrogen production based on nuclear electricity in Europe increases most under a scenario without any hydrogen trade.

Alanazi et al. (2025) use a global market equilibrium model with country-specific renewable hydrogen supply curves, demand curves, and specific hydrogen transportation costs to calculate market equilibriums under two policy scenarios and the assumption of a 1.5-degree mitigation scenario. Global hydrogen demand reaches 332Mt in 2050 under a price assumption of 1.5 \$/kg, significantly below the IEA's Net Zero Emissions scenario, which estimates global

[7] Source for EU27 and European countries is Eurostat (2025a; 2025b); US average is dervied from IEA (2025c), the other sources include California Energy Commission (2023), Potomoac Economics (2024), and EIA (2024).

hydrogen demand to be at 530Mt in 2050. Intra-regional trade accounts for 7%, while inter-regional trade makes up 31.2%. This is slightly higher than the 25% finding of Zhang et al. (2024), the IRENA forecast for 2050 of 25 %, and the figure included in the IEA's Global Hydrogen Review 2021 of 20% international hydrogen trade. Morocco and Tunisia emerge as the most important suppliers of hydrogen to Western Europe, covering around 20% of Western Europe's hydrogen demand (24.3Mt). Under the regional independence scenario, Western Europe's demand drops from 24.3Mt to 19.2Mt, as imports can only partly be compensated by new producers such as Ireland, Spain, Denmark, Greece, and Norway.

The future role of biomass in a decarbonised energy market is discussed in depth in Millinger et al. (2025). Their research underlines that equipping biomass sources with carbon capture (BECC) to provide biogenic carbon holds the highest value to the energy system as it contributes to negative emissions and the supply of biofuels necessary for industrial and transport applications. According to the authors, 87% of biomass use is combined with CCS technology in an ideal net-negative energy system. The exclusion of BECC would come at a 13% system cost increase. Importantly, they carve out a trade-off between the provision of electrofuels via electrolysers and biofuels via biomass. If the expansion of VRE or electrolysis is decreased, biomass steps in as a compensator; should electrolysis be excluded from the energy system, the demand for biomass is almost doubled.

Frank et al. (2021) explore how the achievements of Sustainable Development Goals (SDG) interact with emissions from the Agriculture, Forestry and Other Land Use (AFOLU) sector. By linking the Global Forest Model (G4M) with the Global Biosphere Management Model (GLOBIOM), they can quantify various interactions between SDGs, biomass availability for bioenergy usage, carbon prices, and AFOLU emissions. One of their key findings is that protecting biodiverse ecosystems from agricultural use would reduce the global biomass potential by 30% in 2050. Adherence to various SDGs[8] could contribute to a cumulative saving of 45 $GtCO_2e$ by 2050. It could allow the AFOLU sector *"to remain within a 1.5 degree compatible land use emission budget"* (Frank et al., 2021, p.10).

The significant literature discussion has been focused on the trade-offs between affordability and sustainability of hydrogen regulations on the power market. However, with the security of supply, one dimension of the energy trilemma has been blanked out from the discussion around RFNBO hydrogen. As the literature strand on international trade shows, Europe will likely depend on hydrogen imports. This import dependency will likely worsen if the regulation remains strict, as it bars European projects from achieving breakeven points. The linkage of hydrogen regulation with the security of the supply dimension could be explored in more depth.

Furthermore, the literature has focused on the effects on the power market while largely ignoring spill-over effects on other energy sectors, among which, most importantly, the (natural) gas market can be found. If electrolysis-based hydrogen substitutes natural gas-based, unabated hydrogen, small increases in emissions on the power market might be offset with emission savings in the gas market. Thirdly, the role of low-carbon hydrogen and its interaction effects with RFNBO-based hydrogen could be explored more deeply. Low-carbon hydrogen is

[8] SDG 2 Zero Hunger, SDG6 Clean Water and Sanitation, SDG12 Responsible Consumption and Production, SDG15 Life on Land.

set to play a significant role as a transition fuel in the run-up to the 2040s until when electrolyser cost reduces, and its efficiency improves, the existing power demand in the grid has been optimised, and renewable CAPEX decreases. However, little is known about the potential role of low-carbon hydrogen in the European energy market. Lastly, the substitution effects between electric fuels and biofuels, as mentioned in Millinger et al. (2025), could be discussed more in detail.

3. Hydrogen Regulation and Economics in the EU

In the scope of the first von der Leyen Commission's (2019-2024) Green Deal agenda, the EU has developed a comprehensive regulatory framework for the market uptake of clean hydrogen. Although most of the framework has been adopted by the EU, most Member States (MS) still need to transpose the framework into national law. Therefore, a final assessment of the state of the hydrogen policy can only be given in a few years once national law is implemented. Furthermore, as part of the new von der Leyen's Commission (2024-2029) focus on economic competitiveness, the EU has announced within its Clean Industrial Plan that it will *"launch a study to assess the effectiveness of the hydrogen framework"* (European Commission, 2025a). Such a review could pave the way for more significant adaptations towards the end of the 2020s. Nevertheless, regarding these potential changes, this section explores the most critical existing legislations regarding RFNBOs in Chapter 3.1 and low-carbon hydrogen (LCH), as discussed in Chapter 3.2. Thereafter, the economics of clean hydrogen will be assessed in Chapter 3.3 looking at developments pertaining to demand, supply, and infrastructure.

3.1 Renewable Fuels of Non-Biogenic Origin

The Delegated Regulation 2023/1184 on a "Methodology Setting out Detailed Rules for the Production of Renewable Fuels of Non-Biogenic Origin" specifies that RFNBOs must achieve a 70% reduction compared to their fossil fuel comparator. The relevant comparator is heavy fuel oil at a carbon intensity of 94 gCO_2e/MJ, thus mandating that RFNBOs have to be below 28.2 gCO_2e/MJ or 3.38 $kgCO_2e/kgH2$ considering the lower heating value of hydrogen (Delegated Regulation 2023/1184).

Several ways to produce RFNBOs have been laid open in Delegated Regulation 2023/1185, which are shown in Figure 2 below. The first and least complicated option is to connect the electrolyser directly to an on-site renewable power unit, like a photovoltaics (PV) park or a wind energy farm. This option ensures that the electrolyser only sources renewable energy.

The likely standard, however, will be an electrolyser connected to the grid. To guarantee that it consumes only renewable electricity, the operator must sign a Power Purchase Agreement (PPA) with a new renewable energy unit, covering its full electricity needs. The operator and the PPA plant must then ensure compliance with the so-called three-pillar framework, comprising additionality, geographic, and temporal correlation, as depicted in Figure 2; more on this in the following paragraphs. However, there exist several important exceptions to the three pillars.

First, if the bidding zone[9] (BZ) where the electrolyser is located has a renewable share in the power mix of at least 90%, RFNBO hydrogen can be directly produced with grid electricity. The exception applies for five years once the renewable share is reached, even if it should drop below the threshold in one of the following years. The BZ in Northern Sweden and Norway already meet the 90% criteria. As average grid electricity prices in these zones stood around €30-40/MWh before the energy crisis, the production in and export of RFNBOs from these regions becomes very attractive (Holmberg & Tangerås, 2023). Secondly, if the BZ has a very low carbon intensity of 18 gCO_2e/MJ, the additionality criterion does not apply. The last production path encompasses a combination of "fully" renewable energy, as defined as adhering to the three pillars, with "partially" renewable energy sources from the grid. This will be explained more in-depth at the end of this section.

Electrolyser with direct connection	Electrolyser with PPA	BZ RES higher 90%	BZ carbon intensity lower 18 gCO2/MJ	Mix of PPA and grid power
• The electrolyser is only directly connected to a VRE unit without grid access • Only additionality applies	• If connected to the grid, the operator has to sign a PPA to cover its power demand • The sourced PPA power needs to adhere to the three-pillar framework	• If the BZ has a renewable share of 90% or higher, the electrolyser can directly use grid electricity • No further restrains apply	• If the grid has a yearly average intensity of lower 18 gCO2/MJ • Still need for PPA but without the additionality criteria • Older VRE units can be contracted	• Mix of fully renewable (PPA) and partially renewable (grid) electricity • Sum of emissions cannot exceed 28.2 gCO2/MJ • Further accountancy rules apply
• Relevant for on-site renewable energy units • Potentially in offshore context	• Considered to be the standard option in countries with high carbon intensities • E.g. Germany, Poland, Italy	• So far only possible in Northern Sweden and Norway • Potential in further countries by the mid 2030s	• Potential to lower LCOH in Member States with high nuclear share • Especially France and Sweden	• Employed alongside PPA to lower LCOH • Attractive where grid is not too carbon intense (Austria, Spain, Finland)

Figure 2: Different options to produce RFNBO hydrogen in the European Union and their implications

The three pillars are shown in Figure 3. The geographic correlation criterion on the left of Figure 3 requires the electrolyser and its VRE unit to be located in the same BZ. Interconnections between BZs have limited capacity and frequent congestion issues. Thus, if they were not located in the same zone, the flow of power could not always be guaranteed. There are two exceptions to the geographical correlation pillar. First, suppose the VRE unit is located in an offshore bidding zone[10], then the electrolyser can be located in a neighbouring zone (EU 2023/1184, Art. 7). As of today, no offshore BZ exists in Europe, although the idea of establishing one in the North Sea has been floated by some TSOs (TenneT, 2024). A second exception exists for VRE units that are located in a BZ, where the average spot price is higher than the BZ where the electrolyser is located (EU 2023/1184, Art. 7).

The central pillar in Figure 3 shows the additionality criterion, which requires the electrolyser to be connected via a direct physical cable or through a virtual PPA to an

[9] The European Union's Agency for the Cooperation of Energy Regulators (ACER, n.d.) defines a bidding zone as "the largest geographical area in which bids and offers from market participants can be matched without the need to attribute cross-zonal capacity." And further: "Currently, bidding zones in Europe are mostly defined by national borders."

[10] An offshore bidding zone is as of today a theoretical concept that would see the implementation of a separate bidding zone, for example, in the North Sea, so to create a liquid market for offshore wind power which can be better drawn upon from neighboring countries.

"additional" VRE unit for power supply. Article 5 of the Delegated Regulation defined additionality as given once the VRE generation capacity was, at most, commissioned three years before the electrolyser enters into operation, thus making the build-out of new capacities necessary (EU 2023/1184, Art. 5).

Furthermore, RFNBO electrolysers cannot consume electricity generated from hydro, biomass, nuclear, or VRE units that have received public subsidies (Guillotin et al., 2025). Some incentives are created for early movers: electrolyser projects entering into operation before 2028. For these projects, the additionality criterion applies only from 2038 onwards, meaning they can contract with existing renewable units or previously received public subsidies (EU 2023/1184, Art. 11). Two exceptions exist.

First, additionality does not apply when the BZ's average emission intensity is lower than 18 gCO_2e/MJ (EU 2023/1184, Art. 4). In 2023, only the Swedish grid (11.4 gCO_2e/MJ) met this criterion, while France was slightly above the threshold (22 gCO_2e/MJ) (Ember, 2024). In Sweden, new electrolyser projects could contract power from existing, partially or fully depreciated VRE units. The depreciation profile reduces PPA costs, improving the overall economics of electrolyser projects. Another exception exists for repowering, i.e., the modernisation of VRE units, which are most used for wind energy farms. Suppose an existing VRE has undergone significant repowering, which is defined as inferring at least 30% the investment costs of an equivalent new capacity. In that case, the repowering can be considered as fulfilling the additionality criterion (EU 2023/1184, Art. 5).

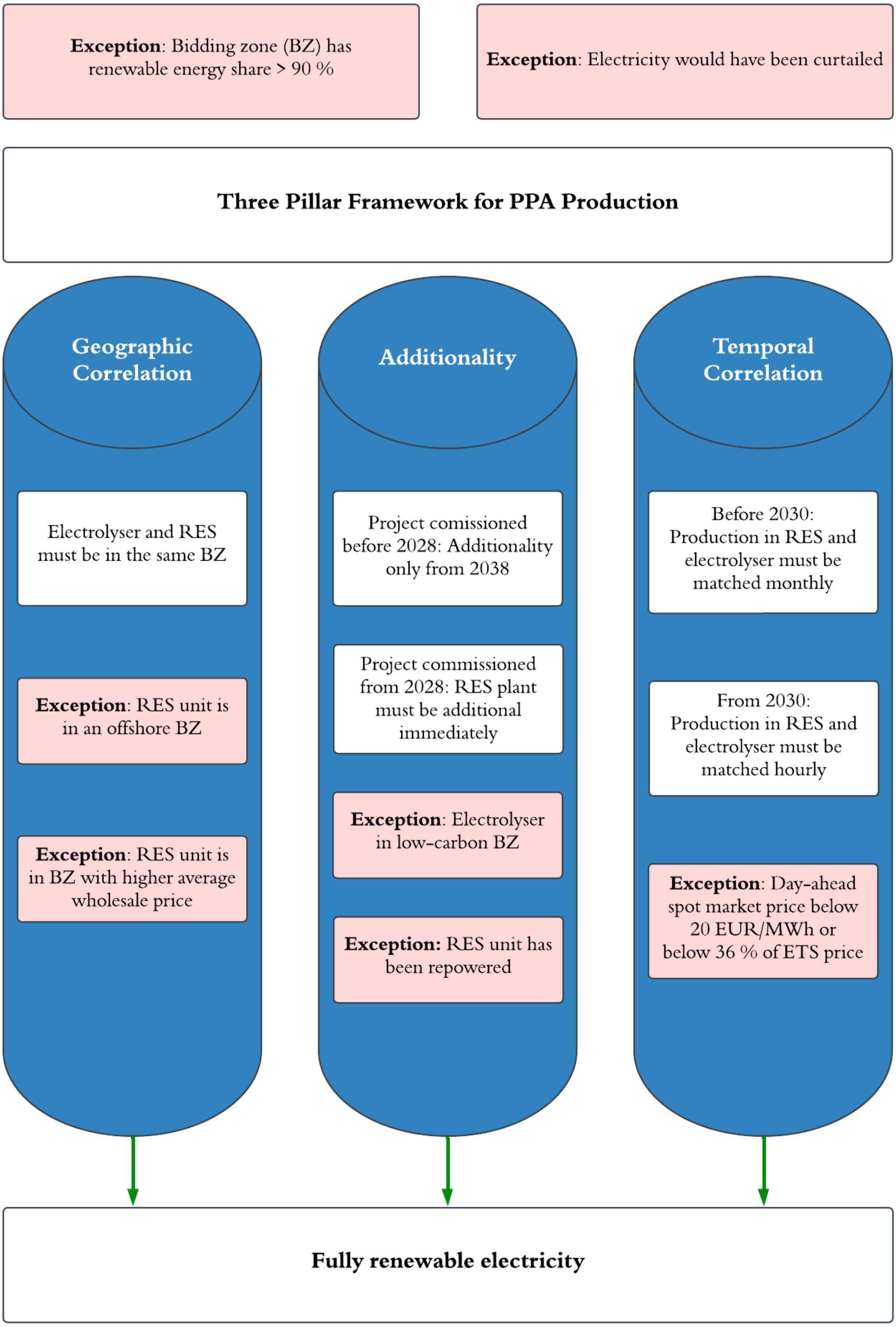

Figure 3: Flow chart towards RFNBO hydrogen production with a dedicated PPA plant

The third and last pillar is temporal correlation, essentially prescribing that the electricity produced in the VRE unit must be temporally matched with hydrogen production in the electrolyser. Two exceptions were put in place. First, suppose the day-ahead spot market price is below 20 €/MWh or below 36% of the ETS price. In that case, hourly matching requirements are suspended, allowing additional power purchases during low power prices/high renewable shares in the grid. The ETS price is set to rise significantly after 2030 (Chapter 3.3.2), which might significantly open up the temporal correlation criterion.

Second, the EU has opted for a loose temporal correlation regulation until 2030, when the temporal correlation must only be met monthly. This means that the VRE unit in each month must produce as much renewable power as the electrolyser has consumed in that month, including for efficiency losses. The operator of the electrolyser can choose to sell the electricity of the VRE unit at times to the grid when power prices are high and procure electricity from the grid when power prices are low, as long as the sum of grid sales and grid procurement is balanced at the end of the month. From 2030 onwards, however, operators will be required to meet the temporal correlation hourly, which may be challenging.

For the PPA path, a general exception exists for the procurement of otherwise curtailed power, which electrolyser operators can always source. The electrolyser's flexible operation reduces curtailment and network costs, as TSOs do not need to reimburse curtailed power production, making the energy market more efficient. Further, "fully" renewable electricity, defined as complying with the three pillars, can be mixed with "partially" renewable as procured from the grid as long as the combined emissions do not surpass the emission's threshold of 3.38 kgCO_2/kgH2 (Türby et al., 2024; Guillotin et al., 2025).

Delegated Regulation 2023/1185 specifies three methodologies to measure the carbon intensity of procured grid electricity, as depicted in Figure 4, taken from Türby et al. (2024). First, the yearly carbon intensity of the BZ can be used to attribute an emission value to the procured grid electricity. Second, the BZ "carbon-free" hours, meaning the hours in which the marginal production unit is renewable, are used and put into relation with the consumed grid electricity. Assuming that the BZ has 500 carbon-free hours in one year, the electrolyser operator can procure as much grid electricity as required in 500 hours for an emission value of 0 gCO2eq/MJ. For every hour beyond that threshold, a default emission value of 183 gCO2eq/MJ is applied (Türby et al., 2024). The third option is to apply emission values based on the emissions of the marginal unit at the hour of production. The option is relatively similar to the second one. However, real-time values instead of yearly averages are used, thus creating incentives for flexible operation, as the operator can procure as much grid electricity as possible if the marginal unit is renewable.

Importantly, these methodologies are not enough themselves. If the weighted average between fully and partially renewable electricity is below 3.38 kgCO_2eq/kgH_2, the hydrogen produced from grid electricity is weighted according to the share of renewables in the BZ two years prior to production time. For example, Austria's BZ in 2023 had a carbon intensity of 30.6 gCO_2e/MJ (Tiseo, 2024). If the operator chose to go with methodology one, this would mean that the operator could source up to 48% of his electricity from the grid; using the formula (share of grid input = emission threshold/ grid carbon intensity). The renewable share in Austria in 2021 was 79% (IEA, 2025a), so that the 48pp of procured grid electricity yield 38pp of RFNBO hydrogen.

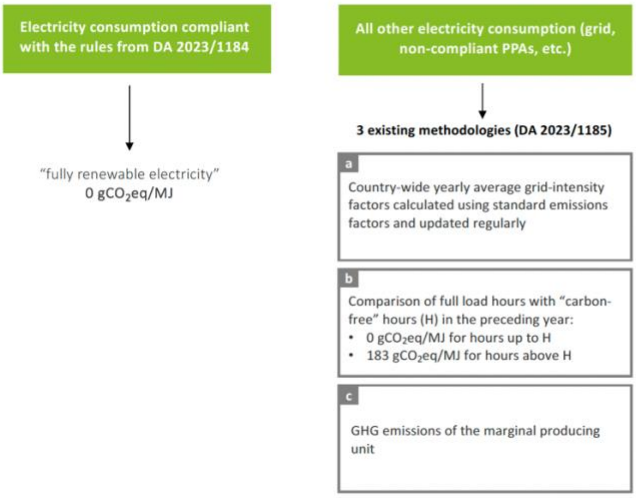

Figure 4: Current accounting methodologies for hydrogen production in the EU (Türby et al., 2024)

3.2 Low-Carbon Hydrogen

Next to RFNBO hydrogen, low-carbon hydrogen has been floated as a transition technology. LCH's benefit is that even though it is not a carbon neutral commodity, its carbon emissions are much lower than grey hydrogen, while production costs tend to be lower than the ones of RFNBO hydrogen (Chapter 3.3). A definition of LCH has been included in the EU's Gas and Hydrogen Decarbonisation Package (Kneebone, 2024) (EU Regulation, 2024/1789; EU Directive, 2024/1788). This stipulates that low-carbon hydrogen, gases, and fuels need to meet a 70% GHG emission reduction compared to their fossil fuel comparator, while covering the *"life cycle of greenhouse gas emissions and consider indirect emissions resulting from diversifying rigid inputs"* (EU Regulation, 2024/1789, Art.9(5)).

In accordance with Article 9 of EU Directive 2024/1788, the European Commission launched in September 2024 a four-week public consultation period on a Delegated Regulation to specificy the methodology for assessing GHG savings from LCH (European Commission, 2024i). The public consultation period ended on October 25; since then the Commission is reviewing the draft. A final draft will be put into effect if neither Council nor Parliament object with a qualified majority (Council of the EU, 2024a). As of April 15 2025, the final version has not been presented, in spite of the Clean Industrial Deal stipulating that the Commission will *"adopt in Q1 2025 the delegated act on low carbon hydrogen"* (European Commission, 2025a).

In line with the fourth package, the draft specifies that the carbon emissions of LCH must be 70 % below its fossil fuel comparator. Just as in the case of RFNBOs, the fossil fuel comparatos is considered to have 94 gCO_2e/MJ (EWI, 2025a). The draft Delegated Regulation outlines two production paths for LCH; either via SMR + CCS or as electrolytic hydrogen via an electrolyser, which sources electricity from the grid. For SMR + CCS, the draft lays out that the total emissions of the fuel should consider its whole life cycle (Figure 5): emissions from inputs (natural gas), processing, carbon capture, transport, storage, distribution of the finished fuel, and its final combustion. From these, net emissions savings from CCS or carbon capture storage and utilisation (CCUS) can be subtracted. The emissions of the input include all emissions linked to the upstream value chain, such as transport, storage, liquefaction, shipping, and regasification. According to EWI (2025a), the production of LCH must at least reach a 88% capture rate to make-up for emissions from natural gas supply chains and processing emissions. The researchers calculate that upstream emissions contribute 1.74 $kgCO_2e/kgH_2$, 0.47 $kgCO_2e/kgH_2$ are residual emissions from processing, 0.53 $kgCO_2e/kgH_2$ are linked to downstream compression, transport, and storage, while carbon leakages account for a minor 0.04 $kgCO_2e/kgH_2$ (EWI, 2025a).

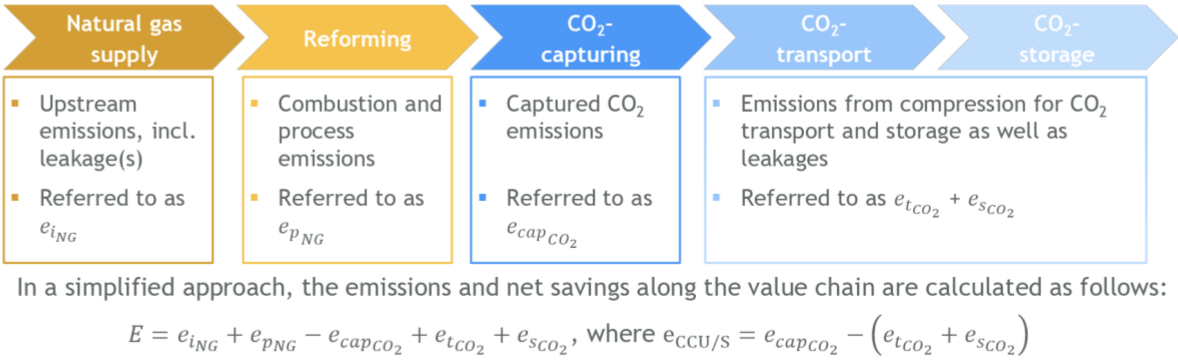

Figure 5: Simplified approach to estimating the emissions from low-carbon hydrogen using SMR + CCS (EWI, 2025a)

Furthermore, the methodology outlines a pathway to produce low-carbon hydrogen in an electrolyser sourcing grid electricity. The exact three methodologies from Delegated Regulation 2023/1185 are proposed to quantify the emissions (Figure 4), each of which can be applied during a full calendar year. In fact, there exist only one distinction between RFNBO and LCH hydrogen production via grid electricity. For the first one, the share of RFNBO output is measured in terms of renewable shares in the grid two years prior to production, while this rule does not apply to LCH. For example, Sweden and France with grid intensities below 28.2 gCO_2e/MJ can produce LCH at baseload activity from their grid electricity. However, if operators were to use some grid electricity in the production of RFNBOs, only 26% of the share of grid input in France, and 64% in Sweden, using the power mix presented in Figure 1, would yield RFNBO hydrogen.

3.3 Economics of Hydrogen in Europe

Approximating the economics of the European hydrogen market is difficult, and as of today, no liquid market for clean hydrogen exists. The European Hydrogen Observatory provides cost estimates for four different hydrogen technologies: unabated SMR (grey hydrogen), electrolysis with grid electricity, SMR with CCS, and RFNBO-compliant hydrogen in an island model. The island model for RFNBO production assumes that the VRE unit is only connected to the electrolyser, rendering procurement from and sells to the grid impossible.

As included in Figure 6, the models predict that RFNBO-compliant hydrogen production is the cheapest in Sweden and Spain, thanks to their abundant renewable resources. On the other hand, countries with better natural gas infrastructure or lower gas taxation, such as France, Germany, or Spain, have more competitive production costs for SMR with CCS. Due to the ETS, the costs of hydrogen production based on grid electrolysis depend primarily on the average wholesale market price, which increases with the share of fossil fuels in the power mix. Therefore, Member States, such as Poland (coal), Italy (gas), or Germany (coal and gas), that still produce a substantial part of their power from fossil fuels have very uncompetitive prices for grid-based electrolysis.

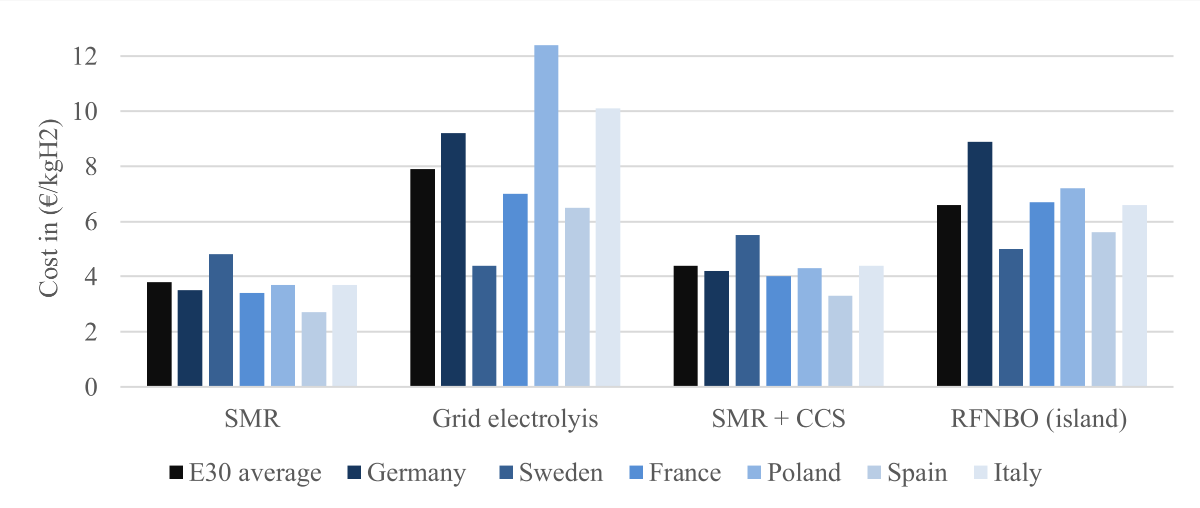

Figure 6: Hydrogen production costs for selected technologies and EU countries (European Hydrogen Observatory, 2024b)

3.3.1 Supply-Side

The European Hydrogen Bank (EHB) is the primary instrument to incentivise the supply of RFNBO hydrogen within the EU's territory. Through its competitive auction design, the EHB allocates production-based subsidies as operating aid (€/kgH_2) to projects with the lowest bidding price. Importantly, only hydrogen compliant with the EU's three-pillar framework is being supported. A critical prequalification criterion is that participants must prove that they have already secured 60% of electricity needs and hydrogen offtake (Guillotin et al., 2025). The EHB set a subsidy ceiling for the first auction round at 4.5 €/kgH_2.

Furthermore, an interdiction of cumulating state aid exists covering the electrolyser, the VRE unit, and the offtaker. However, electrolysers can receive state aid by reducing grid fees or electricity taxation (European Commission, 2024c).[11] The auctions of the EHB are funded through the EU's Innovation Fund, which recycles ETS revenues. Member States can allocate further resources from their national budgets in the Auction-as-a-Service mechanism to direct subsidies to projects in their territories.[12]

The first acution finalised in April 2024, awarded operating aid far below the possible threshold (€4.5/kgH_2) of between €0.37/kgH_2 and €0.48/kgH_2. In total, seven projects were funded to produce 52.6 TWh (1.58 Mt) of RFNBOs; projects have to start production at latest five years after signing the grant agreement, which was done in November 2024 (European Commission, 2024d). Despite the promising low bid results, the seven projects were concentrated on the Iberian Peninsula (Spain, Portugal) and Scandinavia (Norway, Sweden) (European Commission, 2024d). Germany's participation in the Auction-as-a-Service framework was withdrawn, as there was no project in Germany with a bid price below 1.44 €/kgH_2, corresponding to three-times €0.48/kgH_2. The second auction ("IF24") opened in

[11] To find out more on the terms & conditions oft he EHB's second auction, see (European Commission, 2024c).
[12] The maximum bid price awarded for a national project under the auction-as-a-service mechanism cannot exceed three times the last awarded bid price in the central, European auction (BDEW, 2024). If for example, the last subsidised project in the European auction received production aid of €0.5/kgH_2, the national auctions cannot allocate subsidies higher than €1.5/ kgH_2.

December 2024 with a budget of €1.2bn plus national budgets of around €800mn in the Auction-as-a-Service. Some notable changes were made in the terms and conditions, including a lower subsidy ceiling of €4/kgH_2, a dedicated budget of €200mn for projects with offtakers from the maritime transport sector, and the requirement that most of the electrolyser stack is manufactured within Europe (Hydrogen Europe, 2024). The recent publication of the Clean Industrial Deal outlined that the EHB will hold a third auction by Q3 2025 with a budget of €1bn (European Commission, 2025a).

To complement the EHB's efforts to increase the supply of RFNBO hydrogen within Europe, the H2-Global foundation was put in place by the German government to support the imports of RFNBO hydrogen. H2-Global is implemented via a double-sided auction mechanism through Hintco, a subsidiary. Hintco holds competitive auctions on a pay-as-bid basis for producing hydrogen, ammonia, methanol, and sustainable aviation fuels (SAF) to which projects from outside the EU can apply. Once projects are selected, they enter into a supply agreement with Hintco that includes fixed and optional deliveries. Thereafter, the produced products are imported to Germany and auctioned off to the highest-bidding German company in another auction round.

Hintco, and thus the German taxpayer, will cover the cost difference between purchasing and selling prices. Results of the first round of tenders were published on July 11 2024 (H2-Global, 2024). Funding of €397mn was awarded to a single project in Egypt for producing at least 259,000t of green ammonia between 2027 and 2033, covering around 2 % of Germany's annual demand. The awarded price for the project by chemical company Fertiglobe stood at €811/t, almost 37 % below the ceiling of €1280/t. Including transportation costs to the port of Rotterdam, the price per tonne of green ammonia is roughly €1000/t, while conventional ammonia costs around €490/t (S&P Global, 2024). According to analysts, the first tender indicates a hydrogen production price in Egypt of around €4/kgH_2 (Gnievchenko, 2024). The auctions for the production of sustainable aviation fuels was not successful, while the auction for methanol is still ongoing (Renewable Energy Hamburg, 2024). The second auction of H2-Global started on February 19, 2025, as German-Dutch cooperation with a maximum budget of €2.5 billion (Hintco, 2025).

3.3.2 Demand-Side

The 2023 revision of the EU's ETS I implements a steeper linear reduction factor for its allowances of 4.3 - 4.4 % per year from 2024 onwards, compared to the previous 2.2 % (Ibid). In the logic of the ETS' cap and trade system, the carbon price will also rise faster as certificates are phased out faster. Researchers are somewhat divided on the future price path of ETS I certificates, which, as of January 03 2025, stood at 76 €/tCO_2. The conventional price scenarios for 2030 vary between 82 and 160 €/tCO_2 (Ariadne, 2023). From these levels, a significant increase is expected until 2040 and 2050 as the EU's climate ambition increases from a 55% reduction of GHG emissions compared to the 1990 base for 2030, to a 90% reduction in 2040, and then net-zero by 2050. Chyong (2025) modelled that the 90% reduction target for 2040 could imply a carbon price of €17,246/tCO_2e.

The update of the ETS Directive in 2023 states that *"[an] obligation to surrender allowances shall not arise in respect of emissions of greenhouse gases which are considered* *to have been captured and utilised in such a way that they have become permanently chemically bound in a product"* (Directive 2023/959, Art. 12(3)b). Consequently, emission reductions via CCS can be off-set, if evidence is provided that the carbon is stored long-term in underground caverns or products.

The Renewable Energy Directive (RED) III lays out minimum requirements for the consumption of RFNBOs in the industrial and transport sectors. Article 22a of the RED III prescribes that by 2030, 42% of the industry's hydrogen consumption must be covered by RFNBOs, with the mandate rising to 60% by 2035 (Directive 2023/2413, Art. 22a). There are some notable exceptions, including hydrogen produced as a by-product, hydrogen produced by decarbonising industrial residual gas, and hydrogen that is used in the transport sector, e.g. in refineries, as it is counted towards the RED III transport mandate (Ibid).

Article 22b lays out further exceptions. Member States can reduce the share of RFNBO hydrogen to 22% in 2030 if they are on track to meet the EU's final renewable energy consumption target of 42.5%, and if the share of grey hydrogen is not more than 23% in 2030, and no more than 20% in 2035 (Directive 2023/2413, Art. 22b). As of 2023, only four countries - Sweden, Latvia, Denmark, and Finland – achieved a share of renewables in final energy consumption of greater than 42.5%. Larger countries such as France, Germany, and Spain hover around 20% (European Environment Agency, 2025).

Furthermore, two non-binding recitals in the legislation could pave the way for further exceptions. First, Recital 62 of the preamble states that hydrogen produced in retrofitted SMR facilities that have received a grant from the Innovation Fund and achieve at least 70% GHG savings annually should not be included in the calculation of the RED III target (EU Directive, 2023/2413). Additionally, Recital 63 acknowledges that substituting grey hydrogen with RFNBO hydrogen in existing ammonia facilities is challenging, as the share of RFNBO hydrogen cannot exceed 20 – 25% (Corbeau, 2025).

The RED III legislation package does not include any penalties. The design of these is thus delegated to MS (Reglobal, 2025). Regarding the transport sector RED targets in Germany, the government has put in place a €600/tCO_2e penalty for companies which do not comply to the national reduction pathway (BMJ, n.d.). Covered are companies that place in a given year more than 5,000l of fossil fuels on the German market (Ibid.). To avoid penalties, relevant companies can either reduce their own emissions to meet the reduction targets or purchase surplus certificates from other market participants at an average cost of €125/tCO_2e in March 2025 (Schmidt, 2025). The French TIRUERT covering the decarbonisation of the transport sector via clean hydrogen or bio-based fuels implements a penalty based on the (potentially) missing blending volume. For every thousand liters of not adequatley blended fuels, a €1,400 penalty is imposed (Pan American Finance, 2025).

Article 25 of RED III further outlines quotas for the use of RFNBO hydrogen in the transport sector. It puts in place a combined quota of 5.5% for 2030 for the consumption of advanced biofuels and RFNBO fuels in the primary energy supply to the transport sector. The latter must, however, make up at least 1% of the supply in 2030 (EU Directive, 2023/2413, Art. 25). The Directive provides further insights on calculating adherence to the quota.

Article 27(2)c provides that the share of "advanced" biofuels and RFNBOs *"shall be considered to be twice its energy content"* (Ibid). This provision has been described as the "double counting" rule, which permits these fuels to *"help close the cost gap with crop* *biofuels"* (T&E, 2023a). Furthermore, Article 27(2)e provides that advanced biofuels *"supplied in the aviation and maritime transport modes shall be considered to be 1.2 times their energy content and the share of [RFNBOs] shall be considered to be 1.5 times their energy content"* (EU Directive 2023/2413). The thinktank T&E analysed that this rule is meant to incentivise the consumption of RFNBOs and advanced biofuels in the non-road transport sectors *"where direct electrification is not feasible"* (T&E, 2023b). The multiplier comes on top of the double counting rule if fuels are used in aviation or maritime transportation. Also, Member States with ports shall *"ensure that as of 2030 the share of [RFNBOs] in the total amount of energy supplied to the maritime transport sector is at least 1.2 %"* (Directive 2023/2413, Art. 25.1).

Further demand is set to be incentivised by the FuelEU Maritime and ReFuelEU Aviation packages. For maritime shipping, FuelEU outlines GHG reduction targets of -6% in 2030, -31% in 2040, and -80% in 2050 compared to the 2020 baseline. On RFNBOs, it mandates that they must make up 2% of final energy consumption from 2034 onwards, if a voluntary target of 1% up to 2031 is not achieved (T&E, 2023b). Companies that do not meet the GHG intensity targets need to pay penalties of €2,400 for every tonne of surplus GHG emissions (DNV, 2024).

On the other hand, ReFuelEU Aviation is set to incentivise both synthetic fuel and sustainable aviation fuel (SAF)[13] consumption. Importantly, synthetic fuels supplied to the aviation sector can be low-carbon and must not be exclusively supplied by RFNBOs (EU Regulation, 2023/2405). The policy prescribes that 1.2% of Europe's aviation energy demand in 2030 needs to be met by synthetic fuels, which rises to 35% by 2050. On SAF, it mandates that 2% of energy must be supplied by it in 2030 and a further 35% by 2050 (EU Regulation, 2023/2405). As outlined in Article 12 of ReFuelEU aviation, penalties for non-compliance *"have to amount to at least twice the difference in price between SAF and conventional aviation fuel"* (T&E, 2024), which is then multiplied by its missing amount.

3.3.3 Infrastructure

Developing a comprehensive hydrogen infrastructure, including transport pipelines, storages, and import terminals, is one of the key hurdles to achieving market maturity. However, as opposed to the support for hydrogen demand and supply, policymakers and regulators are only slowly turning their attention towards infrastructural needs. The EU is offering support for single hydrogen infrastructure projects via the Connecting Europe Facility (CEF), its underlying Projects of Common Interest (PCI) in the Member States, and its Projects of Mutual Interest (PMI) between Member States and Third Countries.

The sixth list of PCIs and PMIs, published at the end of 2023, included, for the first time, hydrogen infrastructure projects, which make up 65 of the 166 selected projects (Annex VII to EU Regulation 2022/869). Selected projects include, for example, ammonia crackers for hydrogen imports, pipelines, storages, and electrolysers. Furthermore, the European Union

[13] Synthetic fuels are produced from hydrogen "by reacting it with CO2 or nitrogen". They encompass a wide range of potential fuels such as e-methanol, e-kerosene, or e-gasoline (IFP, 2024). In contrast, sustainable aviation fuels "can be produced from a number of sources (feedstock) including waste oil and fats, green and municipal waste and non-food crops (IATA, n.d.).

approved, through the Important Project of Common European Interest's (IPCEI) Hy2Infra wave, €6.9bn in state aid for selected hydrogen infrastructure projects in several Member States to construct electrolysers, storages, and pipelines (European Commission, 2024e).

The German government can be considered the most advanced in developing hydrogen infrastructure in the European context. In July 2024, the operators of the natural gas transmission network presented its plan for a German "hydrogen core network" that is to be developed until 2037 with a total length of 9040km, investment costs of roughly €19bn, and a share of around 60% in repurposed natural gas pipelines (FNB Gas, 2024). The construction of the hydrogen core network is supported through a so-called "temporal cost allocation" account. To limit network charges in the market ramp-up phase, during which hydrogen is supplied only to a few early movers, the investment and operation costs for the core network can be temporally allocated to this amortisation account financed through low-interest loans from the state-owned KfW. The lending facility has a budget of up to €24bn. However, if the account cannot be balanced until 2055, the German government must account for up to 76% of the outstanding payments (Bundesnetzagentur, 2024). The European Commission has estimated that the lower interest loans and risk guarantees equal a state aid of €3bn (European Commission, 2024f). In March 2025, the German network regulator (Bundesnetzagentur) proposed an initial network charge of €25/kWh/h/a, which is now up for consultation (Bundesnetzagentur, 2025). At a capacity usage of 25% this charge would correspond to a transport fee of €11.4/MWh.

4. Methodology

The following sections explain the methodology used to calculate the most important model inputs, presents the five policy scenarios, and explains the model's functionality. In Chapter 4.1, the methodology to estimate Europe's hydrogen and RFNBO demand will be explained. This analysis is divided into separate calculations for the industry and transport sectors. Secondly, once we have estimated Europe's hydrogen demand, we compute how much renewable energy capacity would be necessary to meet RFNBO hydrogen demand. In Chapter 4.2, the choices, narratives, and assumptions of the five policy scenarios will be explained in detail. To close this part, we will explain the modelling framework in Chapter 4.3.

4.1 Hydrogen and RED Demand Estimation

To quantify industrial hydrogen demand for 2030, we draw upon existing data on (grey) hydrogen demand from Hydrogen Europe (2024b). According to the industry association, the average hydrogen demand in the industry between 2019 and 2023 stood at 8.6 Mt (287 TWh), split into 4.4 Mt for refining, 3.6 Mt for chemicals, primarily ammonia and methanol production, and 0.6 Mt for other use-cases, such as industrial heat generation (Hydrogen Europe, 2024b). We use the demand average of the years 2019-2023 as a projection for 2030. While hydrogen demand currently shows a downward trajectory, due to Europe's energy crisis, a slight demand rebound in the chemicals industry can be expected once supply shortages in the natural gas market receide (Alam, 2024). To match the regional configuration of the model, that covers 14 European regions and countries, we compute the demand share of each region based on their historic contribution to the European industrial sector, as included in 1.5 TECH. Germany (22%), France (12%), Iberia (10%), Italy (10%), and the UK (8%) make up the bulk of demand. The industry's existing (grey) hydrogen demand serves as the baseline for 2030, from which we linearly interpolate to match the 2050 projection in 1.5 TECH of 502 TWh (European Commission, 2018). Further hydrogen is applied in industry via e-gases that require hydrogen and carbondioxide as feedstock in their production. We derive electric gas (e-gas) demand for 2040 (62 TWh) and 2050 (124 TWh) from 1.5 TECH, in 2030 we assume that industry does not consume e-gases.

Next to industry, hydrogen and hydrogen-based products are used in the transport sector. Hydrogen can either be directly applied in the road-transport sector in fuel cell electric vehicles (FECVs), for example in public transport or in heavy goods vehicles (HGV), or be used as a feedstock to produce so-called electric liquids (e-liquids), like synthetic fuels. The latter is predominantely required to decarbonise air transport but can in theory also be used to decarbonise road-transport, more commonly know in this context as "e-fuels". Importantly, the energy optimisation model decarbonises road transport endogenously based on passenger and freight transport volumes. The non-road transport sector encompasses inland navigation, rail, and the aviation industry. According to 1.5 TECH, the final energy demand for non-road transport stands at 757 TWh in 2030, of which 663 TWh are attributable to aviation. Final energy demand, according to the baseline LTS of the European Commission, for all transport sectors is around 3705 TWh (European Commission, 2018); thus, non-road transport accounts for roughly 20.4% of transport sector demand in 2030, which rises to 25.2% in 2040 as the demand in road transport falls at a faster pace than non-road transportation. Estimates for road-transport volumes are based on (European Commission, 2016) and have been kept in line with the original model. The basis for non-road transport energy demand is derived from 1.5 TECH. Another sector with e-liquid demand is agriculture. To meet the net-zero requirement in 2050, some of the diesel used in the agricultural sector will need to be substituted by e-liquids, as informed by the LTS. These values remain unchanged in our modelling framework.

To mirror the legal mandates for the consumption of RFNBOs via the RED quota and synthetic fuels as implemented in ReFuelEU Aviation, we calculate the mandate induced RFNBO consumption based on the demand totals computed above. A detailed explanation of the calculation is provided in the Appendix (10.2.1). We expect a continuation of the RED mandates until 2040 and increase the shares proportionately to the 2040 emission reduction of 90%, as proposed by the Commission (2024h). To calculate RED industry demand we assumed that national governments make use of the provided exceptions, such as exempting refineries and a large part of ammonia production. The RED transport quota is implemented by assuming that all of the RFNBO consumption is served by the aviation sector. Even if this was not specifically stipulated in the legislation, it matches the will of the legislatior, as it introduced multiplier and double counting rules to steer demand into the aviation and maritime sectors. Furthermore, we ensure adherence to the ReFuelEU demand quotas for synthetic and bio-based fuels in the aviation industry. Figure 7 breaks down the primary supply needs of hydrogen per year, demand source, and typology (RFNBO or not). Notably, we did not apply any demand quotas to e-gases and e-liquids used in agriculture. By 2050, as we force the model to meet climate neutrality, the demand quotas are omitted.

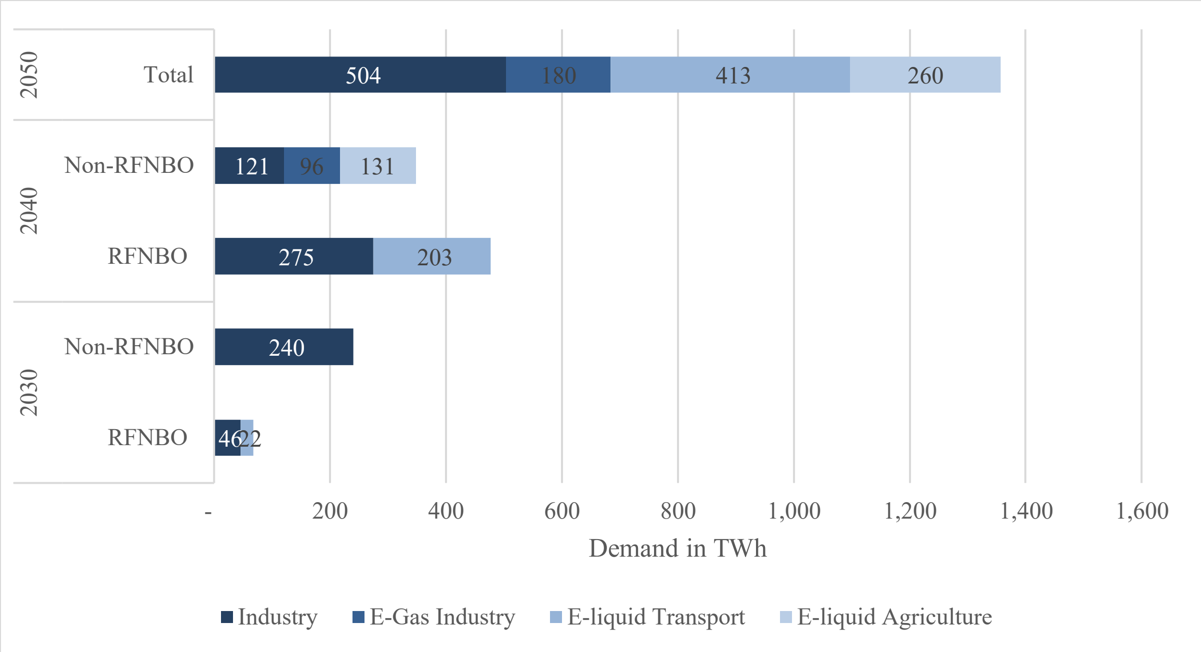

Figure 7: Overview of (RFNBO) hydrogen demand per different sectors and across years

We can compare our findings for 2030 to demand estimates from the IEA and Hydrogen Europe, as included in Corbeau (2025). The hydrogen supply for e-liquid production in 2030 stands at 22 TWh and matches with findings from Hydrogen Europe (20 TWh) and the IEA (27 TWh). The IEA figure might be higher as it also includes maritime hydrogen demand, which is not part of the current model scope. For 2030, our estimate is slightly higher in the industry at 46 TWh, as opposed to 41 TWh (Hydrogen Europe) and 27 TWh (IEA). It should be noted that the IEA and Hydrogen Europe only consider RFNBO demand in the EU27, while our calculations also includes demand from non-EU countries such as Norway, Switzerland, and the UK.

4.2 Scenario Presentation

We create five policy scenarios to explore the repercussions of different regulatory settings on the European energy market. These mirror the current policy landscape, external evolutions related to trade and technological costs, and distinct policy choices Europe could take over the following decades. Essentially, we contrast in different variations a baseline scenario, including the continuation of prioritising RFNBOs, against a deregulation scenario, which sets a more significant focus on low-carbon fuels. Importantly, all scenarios respect emission reductions of 55% in 2030 and net zero by 2050 and use the same assumptions for hydrogen demand.

Baseline (S1)

The baseline scenario can be seen as a business-as-usual case with the continuation of current regulations and technological advancements. Therefore, on the regulatory side, we expect a continuation of the current priority on RFNBOs. The scenario assumes a prolongation of the three-pillar framework for RFNBO hydrogen production, RED quotas until 2040, and ReFuelEU aviation, which aligns with the calculations made in Chaoter 4.1.

Deregulation (S2)
The priority of the European Commission's new mandate for 2025-2029 is to increase the EU's economic competitiveness. This is not only reflected by the publication of Enrico Letta's report on the future of the single European market (Council of the EU, 2024b) and by Mario Draghi's report on EU competitiveness (European Commission, 2024g), but also by the publication of a European Competitiveness Deal at the end of February 2025 (European Commission, 2025a). At the same time, the environmental and climate agenda proposed under the European Green Deal is increasingly viewed critically. Opposition to the priority of renewable technologies originates not only at the extreme right of the Parliament but also within the Parliament's largest faction, the European People's Party (EPP) (Hodgson, 2025; Kolisnichenko, 2025). Under the leadership of Manfred Weber, the EPP has increasingly shifted towards deregulating the European economy and technological neutrality, even if this negatively affects environmental standards (Kurmayer, 2025). Against this background, we abandon the baseline's focus on RFNBO hydrogen by abolishing the three-pillar framework and the RED quotas. We let the model choose whether to produce hydrogen via SMR, SMR + CCS, or electrolysis connected to the grid based on overall economy-wide emissions constraints, technological costs and hydrogen demand.

Geoeconomic fragmentation (S3)
The reelection of Donald Trump as President of the United States of America has reignited fears of a new era of "realism" in which the law of the strongest dominates. Since February 2025, President Trump has announced various tariffs affecting the US' most important trade partners, including the EU. Despite counter-tariffs that have beclouded the macroeconomic outlook for the US, President Trump has not yet backed down. In parallel, EU-China relations are straining as Europe pushes to protect its industries from often subsidised Chinese equipment makers. Consequently, Europe appears to be confronted with three hostile powers, Russia, China, and the US, and its normative approach to free trade and international cooperation might come to its limits. As Weber et al. (2025) pointed out, geoeconomic fragmentation and uncoordinated climate policies will likely determine each other. This might infer increased protectionism, an acceleration of technological decoupling (Cerdeiro et al., 2021), and thus a slowdown in the green transition. In the geoeconomic fragmentation scenario, we assume reduced learning rates for renewable energies, battery technologies, electrolysers, and methanation plants. Furthermore, we do not expect an increase in the efficiency of electrolysers and methanation plants between 2030 and 2050 due to technological decoupling. Given higher costs for renewable energy technologies, we suppose, just as in the deregulation scenario, that the EU shifts away from focusing on RFNBOs as costs become prohibitively high.

Globalisation (S4)
A push for fewer trade barriers intensified technological exchange, and, therefore, a renewed era of globalisation may seem very unlikely today. Despite this, it could be argued that an escalation of trade wars in the second half of the 2020s impairs wealth, economic growth, and global progress. The American two-party system and the growing economic burden of President Trump's trade war make it likely that the next US President takes an opposite approach to trade, promoting liberalisation and a new era of globalisation. If policymakers

come to the conclusion that geoeconomic fragmentation is disastrous for everyone, this might open an avenue to renewed globalisation from 2030 onwards. The globalisation scenario is an extension of the baseline scenario, assuming higher learning rates and efficiencies for various renewable technologies thanks to increased technological cooperation and R&D spending. Due to cheaper renewable investment costs, we expect the EU to uphold its priority on RFNBOs to emerge again as the normative world leader in sustainability, climate neutrality, and green technologies (Manners, 2002; Bradford, 2020; Trevizan, 2024).

Nuclear expansion (S5)

Today, 107 GW of nuclear power plants are installed across the EU27, the UK, and Switzerland (World Nuclear Association, 2025). France accounts for more than half of this capacity (63 GW). The French government has been increasingly successful in building up a pro-nuclear coalition across EU Member States which currently includes 12 Member States[14] (Élysée Palace, 2024). At the same time, traditionally anti-nuclear Member States, such as Germany, Spain, Austria, and, Italy have or are likely to shift their under new governments.[15] This European push towards nuclear energy fits into an international nuclear "renaissance"; as the IEA's Executive Director Fatih Birol recently stated that "nuclear is making a comeback", and that "we have never seen such a big amount of the construction of nuclear power plants in the last three decades" (Hojnacki, 2025)[16]. In the nuclear scenario, we expect that accelerated planning, permitting, and possibly even lower security standards benefit nuclear expansion and that economies of scale effects reduce the investment costs for nuclear capacities. A detailed computation for the nuclear assumptions is provided in the Appendix.

	Baseline	Deregulation	Geoeconomic fragmentation	Globalisation	Nuclear
Scenario Number	S1	S2	S3	S4	S5
Renewable CAPEX	Medium		High	Low	Medium
Renewable efficiency	Medium		High	Low	Medium
RFNBO hydrogen	Island model for 2030, 2040	No		Island model for 2030, 2040	No
RED demand	2030: 67 TWh 2040: 477 TWh	No		2030: 67 TWh 2040: 465 TWh	No
Variation of upper-bound renewables	Yes	No		Yes	No

[14] These countries include next to France: Bulgaria, Croatia, Finland, Hungary, the Netherlands, Poland, Czechia, Rumania, Slovakia, Slovenia, and Sweden.

[15] In Germany, elections in February 2025 gave a majority to the pro-nuclear conservative party (Klöckner & Lunday, 2025), whilst Italy has already announced plans to approve the construction of new nuclear power plants by 2025-2026 (Orlandi, 2024). Also, in Spain, the nuclear phase-out pursued by the left-wing government has been put into question (Kaufman, 2025).

[16] It should be noted that 80% of new nuclear capacity in the last five years was constructed in China (IEA, 2025b).

Nuclear upper-bound in Europe (GW)	2030: 112 2040: 117 2050: 121	2030: 112 2040: 153 2050: 194
Investment costs nuclear	€6000/kW	2030: €6000/kW 2050: €5040/kW

Table 1: Summary of policy scenario assumptions

Table 1 summarises the core assumptions across policy scenarios, while Figure 8 illustrates the scenario combinations that will be analysed in Chapter 5. As outlined in the introduction, the research addresses two core questions: first, assessing the impact of the current RFNBO hydrogen framework on the energy system, and second, using strategic foresight to evaluate alternative regulatory paths.

The result section will begin by constrating the baseline with the deregulation scenario. Through this comparison, we hope to understand trade-offs between the decarbonisation of hydrogen and power markets. Next, we explore how external factors – such as investment costs and electrolyser efficiency – affect hydrogen uptake, using the globalisation (an extension of the baseline) and fragmentation (an extension of deregulation) scenarios. Finally, we quantify the impacts of nuclear expansion by comparing it against both deregulation and baseline contexts to examine whether increased nuclear capacity supports a more resilient hydrogen market.

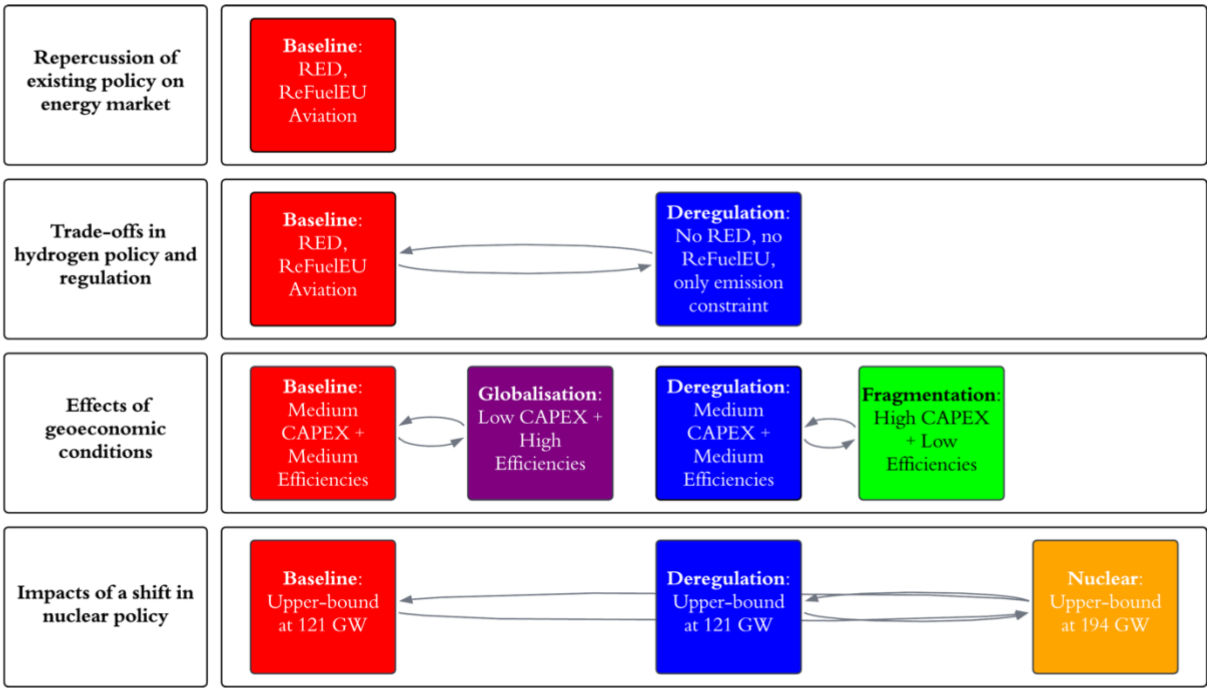

Figure 8: Combinations of policy scenarios according to policy setting

4.3 Modelling Framework

We integrate the policy scenarios into the linear economic optimisation model used in Chyong et al. (2024) based on the modelling system AIMMS[17]. The partial equilibrium model represents the European energy market, covering final energy consumption in buildings,

[17] https://www.aimms.com/

agriculture, industry, and transport. Energy demand for road transport is endogenously modelled based on passenger and inland freight transport activity estimates. In contrast, transport between Europe and other world regions, e.g. international maritime shipping, is not included.

The spatial resolution encompasses 14 European regions, including the EU27, the UK, Switzerland, and Norway.[18] The modelling framework is summarised in Figure 9. As an economic optimisation model, it minimises total energy system costs based on investment, operation, and maintenance costs of technologies, respecting conversion efficiencies and commodity prices. Model constraints include hourly demand and supply, which is exogenously assumed, emission reduction targets, ramping limits for technologies, and physical limitations to the construction of storage and networks.

In line with the European climate targets, we assume a 55% reduction in GHG emissions compared to 1990 levels by 2030 and net-zero emissions by 2050. The reduction target for 2040 is interpolated between these years, so the model is forced to meet a 77.5% emission reduction by 2040. Notably, this is lower than the current proposal for the European climate target 2040. However, based on Chyong (2025), we suppose that a 90% reduction by 2040 would exacerbate system costs. As the model operates under imperfect foresight, it optimises the energy market for every modelled year anew based on the configuration of the last modelled year. We model the European energy market for 2030, 2040, and 2050.

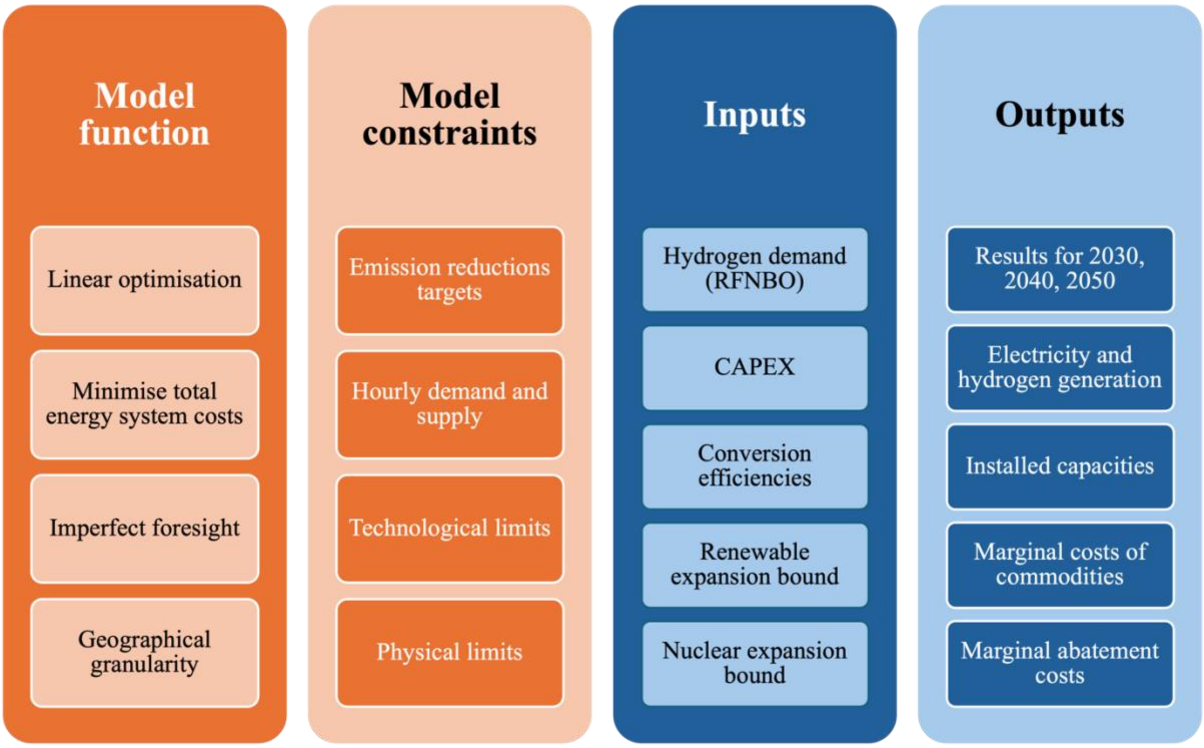

Figure 9: Description of modelling approach

[18] Some countries are explicitly modelled: Belgium, Germany, France, Netherlands, the UK, Poland, Italy, and Ireland. The remaining countries are represented among the following regions: Baltics (Lithuania, Latvia, Estonia), Central Europe (Austria, Switzerland, Slovenia), East Europe (Czech Republic, Slovakia, Hungary), Nordics (Norway, Sweden, Finland, Denmark), Iberia (Spain, Portugal), and Southeastern Europe (Bulgaria, Greece, Croatia, Romania, Malta, Cyprus).

For this thesis, we endogenously model (unabated) hydrogen demand by expanding the industrial demand scope in Chyong et (2024) by explicitly integrating industrial hydrogen as a separate commodity. This is an extension of the previous model version, which assumes that the existing hydrogen demand in the industry is exogenously given as part of the fuel mix projection calibrated to the European Commission's (2018) Long-Term Strategy (LTS) 1.5 TECH scenario. We input the demand data computed in Chapter 4.1 into the model. Thanks to this extension, we can model the hydrogen supply to the industry as a separate fuel.

RFNBO hydrogen production was modelled as follows. We exogenously assume RFNBO production in an "island" model, meaning that electrolysers are directly connected to renewable energy units without grid interaction. Still, this will have wider repercussions on the power market as we use renewable energy units to meet the RFNBO hydrogen demand. We reflect this in lowering the upper bounds for renewable energy expansion based on the calculations in Appendix 10.2.2. The model's upper bound is a constraint which stops it from unrealistically building out the capacity of a given technology. For example, hydropower capacity is limited to 228 GW in 2050, reflecting the geographical limitations to its expansion.

In 2050, based on the 1.5 TECH scenario, the European upper bound for onshore wind is 759 GW, 451 GW for offshore wind, and 1,138 GW for solar PV. Between 2030 and 2050, the upper bounds rise over time to include permitting of new sites, which is considered the primary constraint to renewable uptake alongside manufacturing capacities and grid connection. The European bound is based on the power generation capacity in LTS 1.5 TECH, which has the highest installed capacity of all LTS. Next to European bounds, regional limitations have been implemented based on the JRC's Enspresso database and current expansion rates for renewable energy technologies taken from the 2024 edition of the BP Statistical Review. The model is either restricted by the European or the regional upper bound. To reproduce the competition effects for renewable energy sites, we lower the model bounds for renewable energies according to the RFNBO demand we calculated in Section 4.1. As a consequence, the model will be able to expand less renewable capacity across Europe.

Next to the exogenous computation of RFNBOs, the model can serve hydrogen demand endogenously via six production technologies. First, unabated or grey hydrogen production can be conducted in SMRs. Second, low-carbon hydrogen can be generated in SMRs with CCS at an assumed capture rate of 90% and in autothermal reforming (ATR) plants with a capture rate of 95%. Although ATR produces cleaner hydrogen, thanks to its higher capture rate, investment costs are higher, and its technological readiness level is lower at the time of writing (Türby et al., 2024). The three remaining production pathways include electrolysers, which source grid electricity. These electrolysis technologies are alkaline, proton exchange membrane (PEM), and solid oxide electrolyser cells (SOEC). While generally, the model does not discriminate between the types of grid electricity input, since the model minimises total costs, it can be expected that grid electrolysis is generated at low-cost hours that correlate with the grid share of renewables. In addition to the hydrogen extension, we expand the model by calculating bioenergy supply curves based on Frank et al. (2021), presented in Chapter 2, and a regression for AFOLU emissions based on the carbon and bioenergy price. Details for this extension are presented in Appendix 10.3.

5. Results

The presentation of results will begin with an in-depth description of the baseline scenario that projects the current policy trends until 2050. Afterwards, differences between the baseline and the other four scenarios will be highlighted. To begin with, scenario differences in hydrogen demand and production technologies will be presented before the power market and its emissions are compared. Finally, divergences in commodity costs will be reviewed in 6.4. The analysis will be structured along modelled years, beginning with 2030 and ending with 2050. As we have access to specific data for each region, when it is enriching, specificities between the 14 model regions will be analysed as well, though, in most cases, only the European total will be analysed.

5.1 Baseline Scenario

In 4.1, we estimated the industry's hydrogen demand, and the requirement for e-liquids in the non-road transport sector based on the European Commission's LTS 1.5 TECH. As the model meets this exogenously given demand across all scenarios, the need for hydrogen and its derivatives is relatively static. For the baseline scenario, Figure 10 breaks down the deployment needs of hydrogen in the modelled years. In 2030, industrial hydrogen dominates the total demand mix, as other hydrogen use-cases, especially in the transport sector, are not yet mainstreamed. ReFuelEU Aviation exclusively drives the hydrogen demand to produce e-liquids for the non-road transport sector, although some e-liquid demand exists in the road transport sector (6 TWh). The total e-liquid demand of 18 TWh translates into a need for 32 TWh of hydrogen, given a conversion efficiency for e-liquid production of 57%.

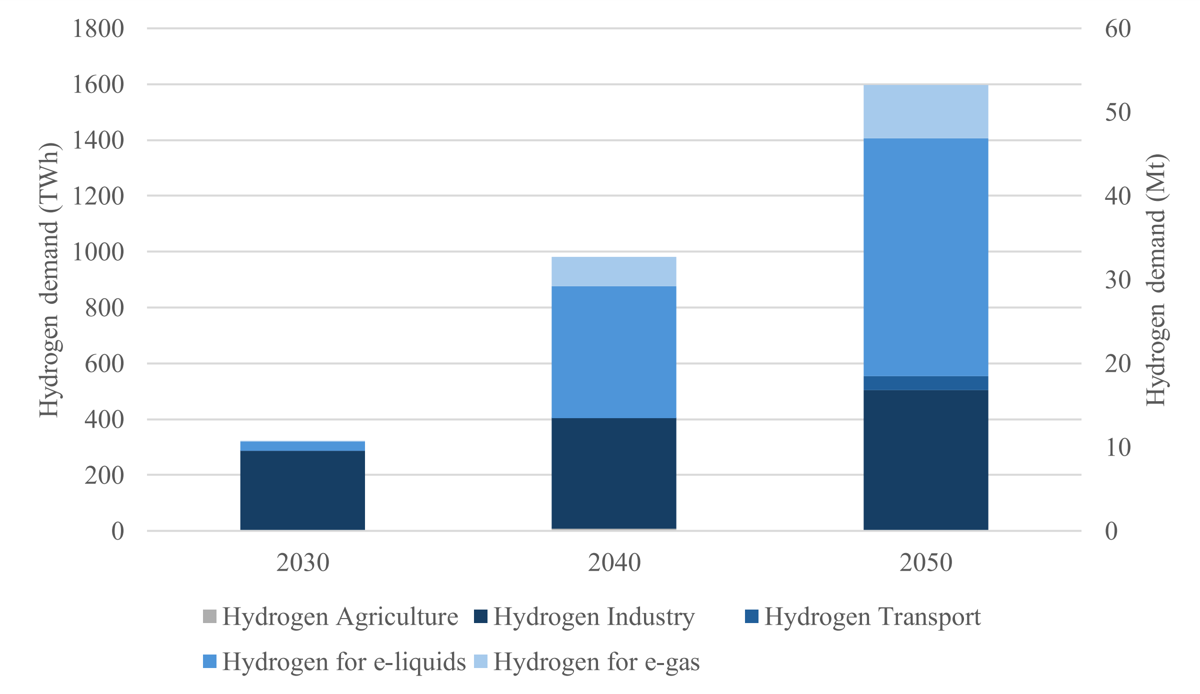

Figure 10: Composition of hydrogen feedstock demand per application in the baseline scenario[19]

By 2040, the industrial sector induces roughly the same demand for hydrogen as the production of its derivative. By that time, e-liquids are needed in non-road transport (203 TWh), road transport (80 TWh), and buildings (85 TWh). In road transport, they are used to supply energy to cars (21 TWh), buses in public transport (17 TWh), and to heavy goods vehicles (HGV), which account for 41 TWh of e-liquid demand. Even as the conversion efficiency for the production of e-liquid rises from 57% to 61%, total hydrogen demand for the production of e-liquids would contribute 473 TWh of hydrogen demand, surpassing industrial hydrogen needs, which stand at 395 TWh in 2040. Furtermore, in 2040 103 TWh of hydrogen is used as a feedstock to produce e-gases used primarily in industries, rising to 191 TWh of feedstock needs by 2050.

By 2050, the use of hydrogen as a feedstock in e-liquid production becomes the dominant demand source. The increase in industrial hydrogen needs from 286 TWh in 2030 to 504 TWh in 2050 is mainly due to the switch from coal or gas to hydrogen in iron and steel making, contributing to 148 TWh of additional demand. Moreover, some hydrogen is directly applied as a fuel in FCEVs in public transport (33 TWh) and HGV (15 TWh).

The hydrogen production mix varies markedly across years in the basline scenario. In 2030, most hydrogen is supplied via SMR and CCS (191 TWh), making up a share of 59% of the hydrogen generation mix. Unabated grey hydrogen production accounts for another 51 TWh of production or 16% of the total supply. Alkaline grid-based electrolysis, producing low-carbon hydrogen, generates another 13 TWh of hydrogen, while the production of RFNBO hydrogen in the island format accounts for the remaining 68 TWh.

[19] The figure displays the supply of hydrogen to various use-cases. For example, “hydrogen for e-liquids” reflects upon the demand for hydrogen as feedstocks in e-liquid production that are then used in non-road and road transport.

The RFNBO demand includes the RED mandates as calculated in Chapter 4.1, roughly contributing around 20% of total hydrogen needs. In the European average, grid-based electrolysis represents less than 4% of production in 2030. Still, it is higher in countries with more favourable renewable energy potential, such as the Nordics (9%) or Iberia (6%).

Between 2030 and 2040, the European grids decarbonise, expanding grid-based electrolysis from 13 TWh to 155 TWh or roughly 15% of the total supply. Although the relative share of LCH production via SMR + CCS falls from 2030, its absolute production still expands from 191 TWh to 301 TWh by 2040. Next to grid-based electrolysis, and abated natural gas reforming, RFNBO electrolysis makes up the bulk of the supply, providing 477 TWh of hydrogen to European countries. Unabated reforming falls from 51 TWh in 2030 to 20 TWh in 2040, pointing towards a lack of competitiveness when emission reductions are increased. Between 2040 and 2050, the conversion in alkaline grid-based electrolysers expands from 155 TWh to 601 TWh, while PEM electrolysis, for the first time, contributes a staggering 818 TWh to the mix in 2050. The divergence in hydrogen production (Figure 11) and hydrogen feedstock demand (Figure 10) is covered via some gaseous hydrogen imports from Northern Africa, which contribute in 2050 178 TWh - 11% of total demand.

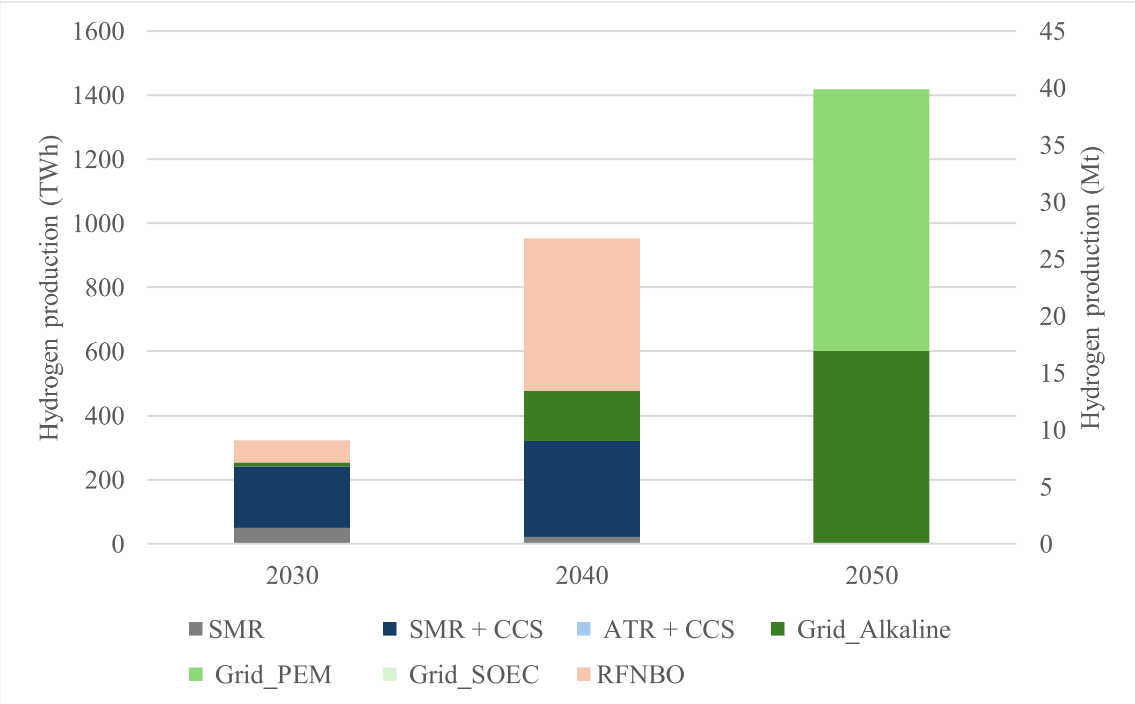

Figure 11: Share of hydrogen production technologies in the baseline scenario

Thirdly, we want to dissect the evolution of the power market in the baseline scenario. Electrical power generation almost doubles in twenty years from 3,744 TWh in 2030 to 7,379 TWh by 2050. Figure 12 depicts the volume of power generation per technology and year and the total carbon emissions from the power sector on the right axis. In 2030, fossil fuels, among them most dominantly natural gas, followed by bituminous coal and lignite, supply 945 TWh of electricity to Europe's power grids, leading to total power sector carbon emissions of 521 $MtCO_2e$. For comparison, in 2023, the power sector of the EU27 emitted 653 $MtCO_2e$, thus not including the emissions of electricity production from the UK, Switzerland, and Norway (Ember, 2025b). By 2040, fossil-powered generation is projected to halve to 409 TWh before it sinks to 89 TWh by 2050, only contributing around 1% of total generation. Abated fossil fuel power generation, most notably in natural gas-based combined cycle gas turbine (CCGT) plants equipped with CCS has not played a major role in the modelled years. CCGT with CCS generates only 6 TWh of electricity in the baseline in 2030, before falling close to 0 in 2040.

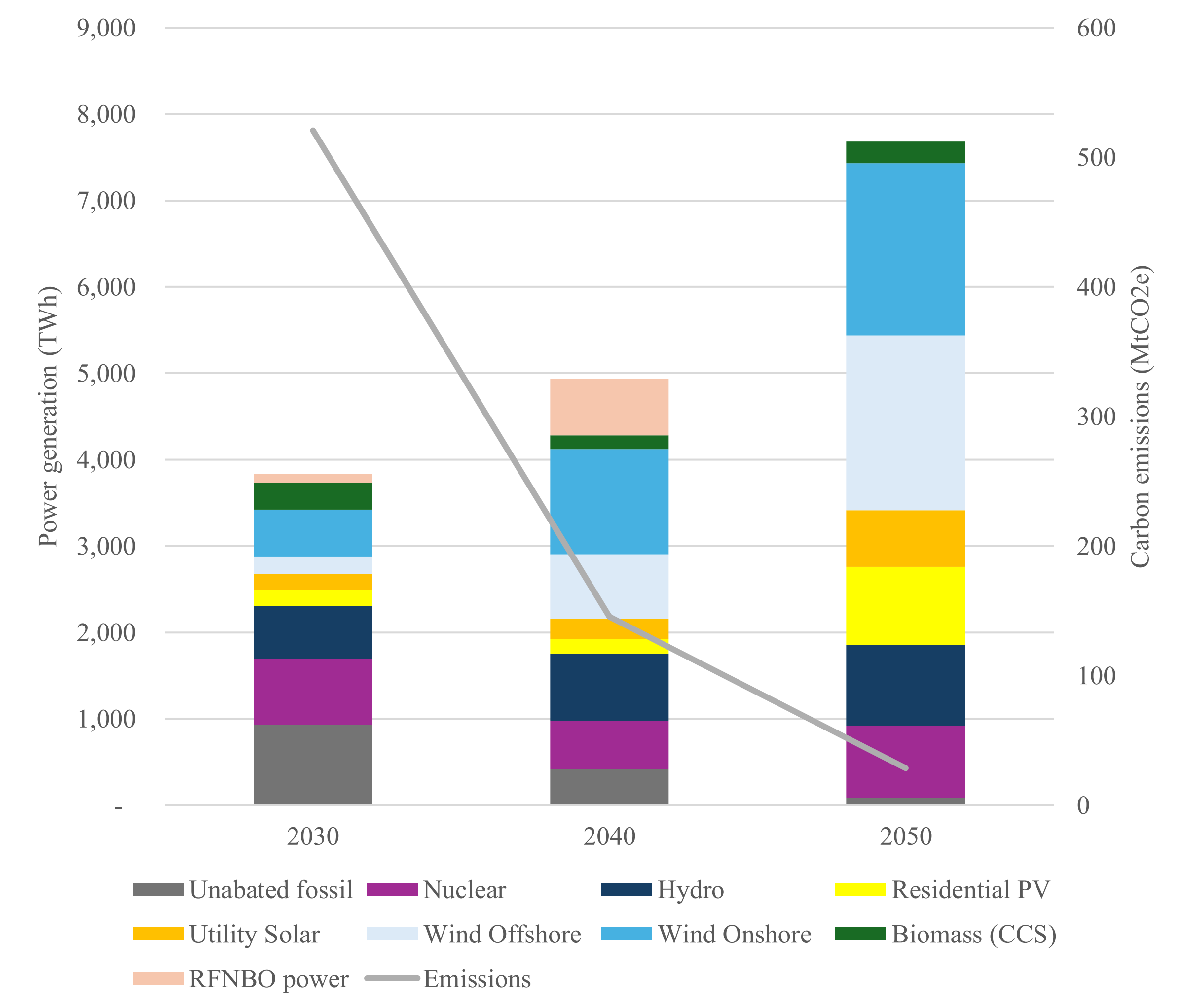

Figure 12: Power generation and power sector carbon emissions in the baseline scenario

In the final configuration of the baseline scenario (2050), wind is by far the dominant source of power supply source. Offshore wind farms generate a staggering 2028 TWh, and onshore wind a further 1990 TWh. Solar power, including both residential and utility-scale photovoltaics (PV), generates an additional 1563 TWh, though residential PV is the most significant source of electricity (910 TWh). Further renewable energy sources include hydro (930 TWh), which is maxed out to its upper bound, biomass (18 TWh), biomass with CCS (236 TWh), tidal wave (32 TWh), and geothermal (16 TWh). The negative emissions from biomass with CCS, also known as bioenergy with carbon capture and storage (BECCS), compensate for some residual emissions in other sectors in combination with direct air capture (DAC).

Together with the AFOLU sector, BECCS and DAC provide emission savings of -423 $MtCO_2e$ in 2050, which are partly stored underground and used as a feedstock to produce e-liquids and e-gases. By 2050, residual carbon emissions are left especially due to natural gas and diesel usage in HGV transport, buildings, and non-road transportation. Interestingly, there seems to be no need for utility battery storages or hydrogen storage in 2050, given the presence of flexible power generation and cross-border power transmission capacities of 602 GW. This is robust increase, as in 2023, only 93 GW of cross-country interconnectors existed in Europe (Cremona, 2023).

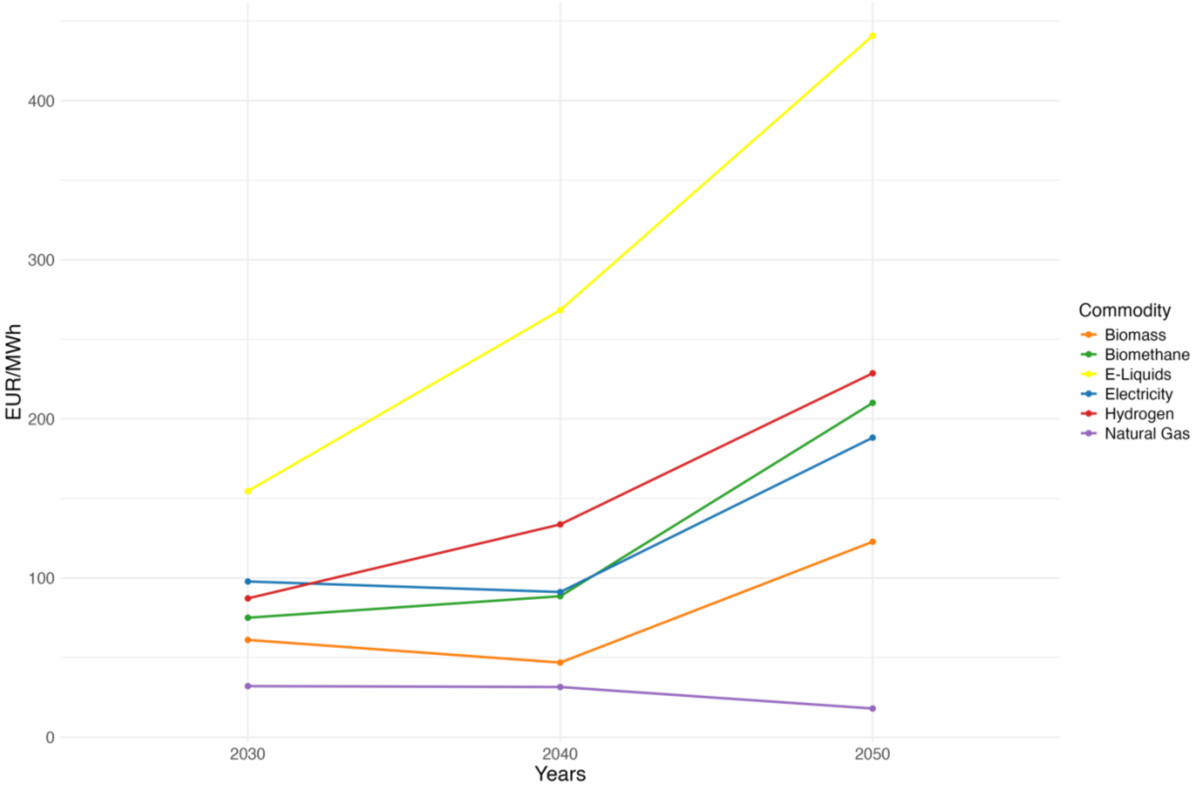

Figure 13: Average production costs of selected commodities in the baseline scenario

Lastly, we want to take a look at cost dynamics. The average marginal production cost of selected commodities in the baseline across years is displayed in Figure 13. These averages are based on hourly and daily short-run marginal production costs and, therefore, come close to an average wholesale market price. In 2030, marginal production costs skyrocket in several hours to over €10,000/MWh. Although, in reality, price spikes occur on the European market, they tend to be much lower at around €500/MWh, given demand-side responses that are not accounted for in the model, as hourly power demand is inflexible. Furthermore, in the real life, price peaks can be diminished through capacity markets or through the activation of market reserve power plants. In order to have a less skewed vision on average marginal production costs, we calculated these for all commodities by excluding the highest and lowest percentile . Among low-carbon commodities, a trend towards higher wholesale market prices is visible in the run-up toEurope's climate neutrality in 2050. This is not the case for natural gas, whose average market price drops from €33/MWh in 2030 to €19/MWh in 2050, since decarbonisation decreases the demand for natural gas.

5.2 Hydrogen Market

In the following three sub-chapters, we highlight key differences between the baseline and the other scenarios, starting with divergences in the evolution of Europe's hydrogen market. In the two scenarios with RED mandates (S1 + S4), the sum of hydrogen demand is slightly higher in 2030 and significantly higher by 2040 (Figure 14). In 2040, this divergence stems from non-road transport e-liquid demand. As ReFuelEU Aviation mandates greater use of hydrogen-based synthetic fuels in aviation, e-liquid demand for non-road transport is forced to be higher in the two baseline scenarios. Yet, since all scenarios are aligned to the LTS 1.5 TECH - which also projects high aviation e-liquid demand in 2050 - the difference in non-road transport sector e-liquid supply narrows by 2050. By that year, the different application patterns of hydrogen and e-liquid use in road transport are more notable.

In the deregulation scenario, hydrogen demand from road transport is higher, as the model favors greater adoption of fuel-cell electric vehicles (FCEV), particularly for heavy goods vehicles (HGV) and public transport. This is especially pronounced in the geoeconomic fragmentation scenario, in which road transport contributes 162 TWh of hydrogen demand. In turn, in this scenario, due to low conversion efficiency, and high investment costs for e-liquid plants, the usage of this commodity in road-transport is absent; pointing towards the possibility of substituting e-liquid with hydrogen usage in road transport or HGV to be more precise.

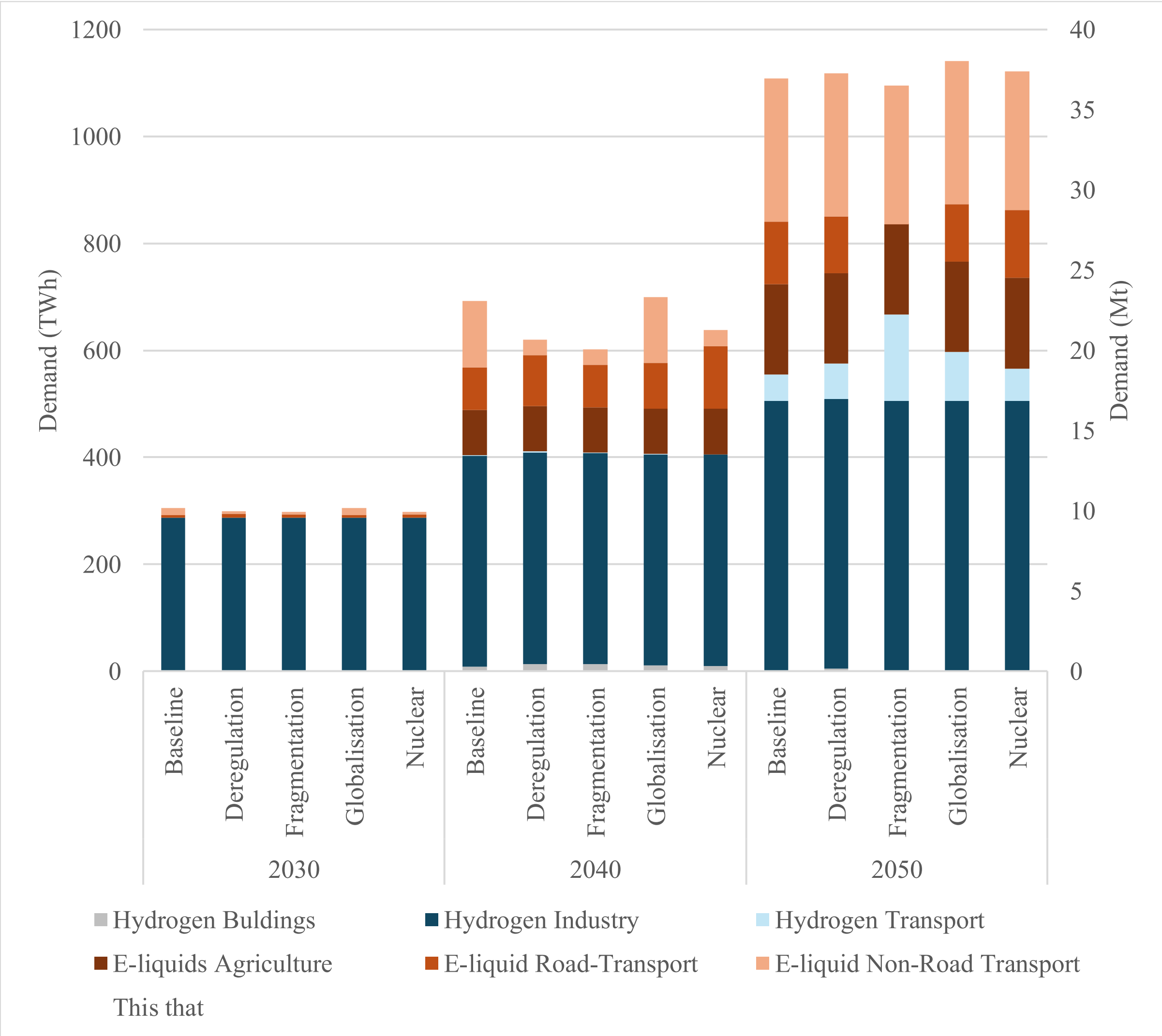

Figure 14: Hydrogen demand per sector, across years and scenarios

As displayed in Figure 15 below, the technological composition of hydrogen production differs significantly. In 2030, the model prefers to produce hydrogen from natural gas in all scenarios, though it is LCH with carbon abatement via CCS. Thanks to the exogenous addition of RFNBO electrolysis, the share of unabated SMR (16%) and abated SMR production (59%)

is much lower in the baseline and the globalisation scenarios. Additionally, around 3-4% of hydrogen across scenarios in 2030 is supplied via alkaline grid electrolysis. The conversion of hydrogen in SMR with CCS plants seems to be physically constrained only by the availability of carbon storages. LCH production in 2030 takes up between 70 and 72 $MtCO_2e$ of European storage capacity, while CCGT-CCS supplies the remaining 3 $MtCO_2e$. Around 3 $MtCO_2e$ are used in e-liquid and e-gas production from this carbon supply.

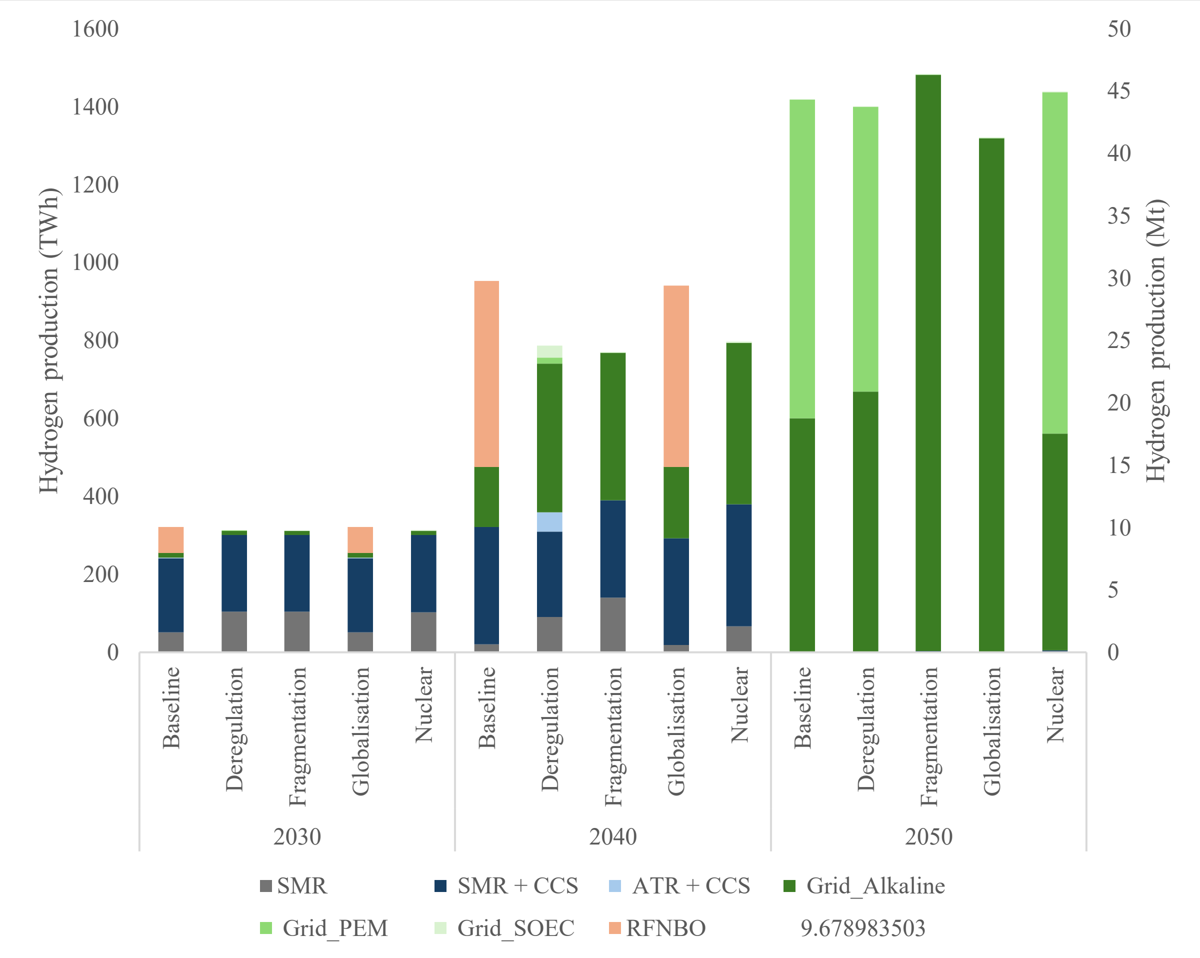

Figure 15: Hydrogen production mix across years and scenarios

The most notable expansion of conversion rates happens for grid-based alkaline electrolysis, which expands from a mere range of 9 - 13 TWh in 2030 to 155 - 415 TWh in 2040. The share of alkaline grid-based electrolysis is lowest in the baseline scnearios (S1 + S4), as the island-based RFNBO electrolysis contributes the lion's share of 465 – 477 TWh in these scenarios. Just as in 2030, the share of fossil-based hydrogen production in SMRs is lowest in the baseline scenarios at 2%, while they still contribute 8-18% of supply in the other scenarios. The share of fossil hydrogen is highest (18%), and the share of grid-based electrolysis is lowest (49%) in the fragmentation scenario since the efficiencies of electrolysers are lower and investment costs higher than in the other scenarios.

In 2040, alkaline electrolysis continues to be the most crucial hydrogen electrolysis technology. Despite having the same electrical efficiency as PEM electrolysis (both at 69%) and lower efficiency than SOEC (79%), the CAPEX of aklaine electrolysis is comfortably lower at €968/kw compared to €1204/kW for PEM and €1388/kW for SOEC. This lower

CAPEX likely accounts for its widespread adoption in 2040. However, some SOEC and PEM electrolysis is used in the deregulation scenario.

By 2050, grid-based electrolysis is the dominant production pathway across all scenarios. When varying investment costs and efficiencies of electrolyser technology, such as in the geoeconomic fragmentation and globalisation scenarios, alkaline emerges as the exclusive electrolyser technology. In the other scenarios, PEM electrolysis plays a significant role as well, given its higher efficiency in 2050 of 79% as opposed to 74% for alkaline, and relatively similar investment costs of €1035/kW for PEM and €852/kW for alkaline.

Figure 16 shows a technological breakdown of hydrogen production technologies for the baseline and deregulation scenarios across selected regions. The selection of regions reflects upon their energy paths. Iberia and the Nordics record very high renewable potentials. Poland and Germany have historically relied on coal-fired power generation, and France generates most of its power from nuclear sources. In 2030, grid electrolysis is absent in Germany and France. Europe's two biggest economies source close to 70% of their domestic hydrogen supply from SMR with CCS in the baseline, as opposed to 79-86% in the deregulation scenario. On the opposite, in 2030, the Noridcs (9%), Iberia (6%), and, surprisingly also, Poland (2%), generate some of their hydrogen in the baseline via alkaline grid electrolysis. The integration of grid-based electrolysis should be largely traceable to these regions' greater renewable energy capacities, making flexible grid-based electrolysis attractive during high solar and wind penetration periods.

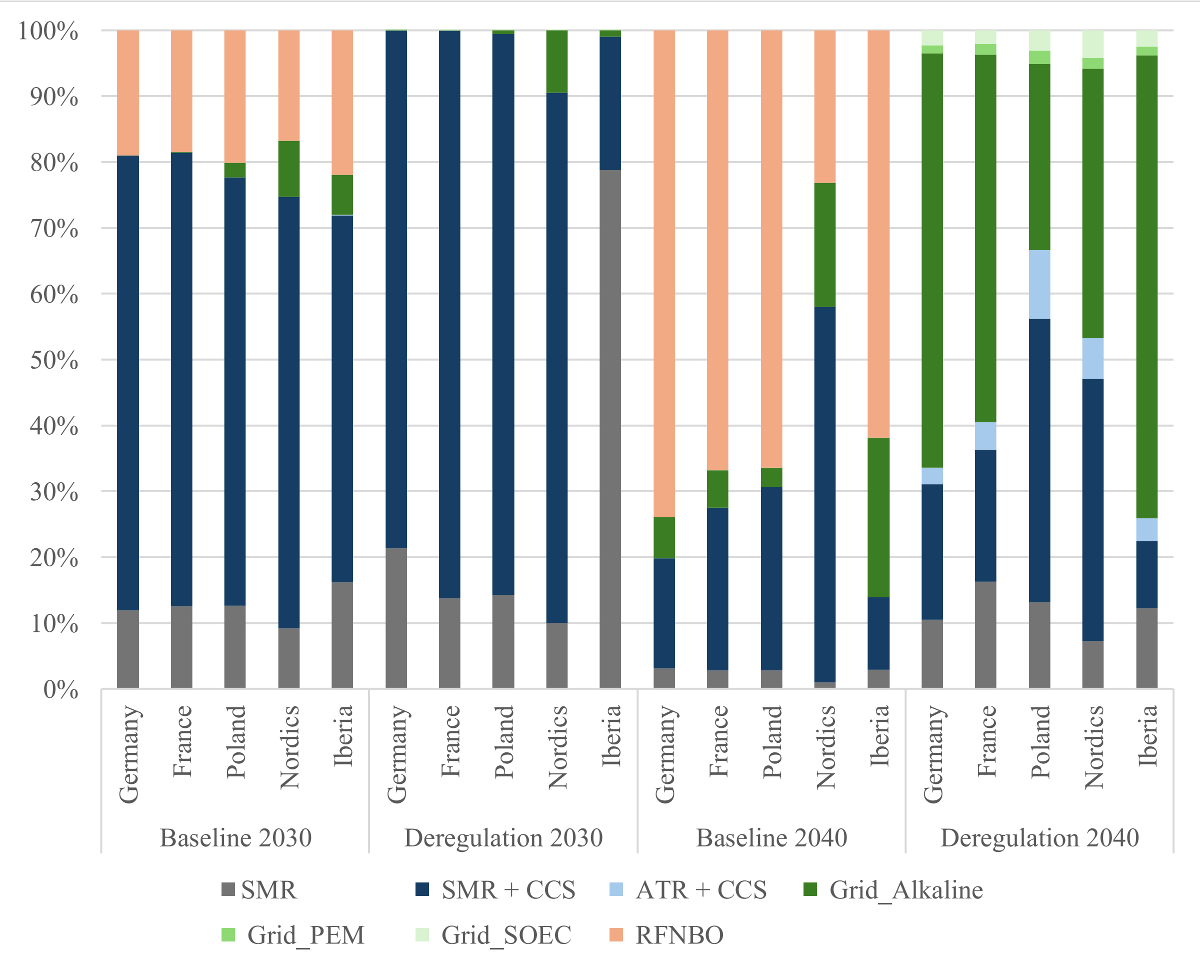

Figure 16: Hydrogen production mix in selected European regions for the baseline and deregulation scenario

Although RFNBO hydrogen demand was proportionally allocated based on each country's domestic hydrogen demand, the final share of RFNBO electrolysis varies significantly across regions. The Nordics have the lowest share of RFNBO production in total hydrogen conversion. It is important to recall that the model allows for cross-border hydrogen transmission. This enables regional or country-level imports and exports that will affect the relative share of RFNBO hydrogen. By 2030, in the deregulation scenario, the total hydrogen transmission capacity between regions is comparatively low at 3 GW, however this capacity rises to 13 GW by 2040, and expands to a staggering 70 GW in 2050. Looking at their respective energy balances, the Nordics and Iberia produce more hydrogen than they consume domestically. Domestic hydrogen demand in the Nordics in the baseline in 2040 is around 38 TWh of hydrogen, while the region converts a total of 95 TWh. Most of this additional hydrogen generation goes into the production of e-liquids and e-gases, which the Nordics then export to other European regions without sufficient self-supply. These include Germany, Eastern Europe, Poland, Italy, and France. Among further net exporters of e-liquids are the UK, Southeastern Europe, and the Netherlands.

The analysis of the hydrogen market indicates that low-carbon hydrogen is the preferred production pathway in 2030, especially in the deregulation context. Its share, however, is sensitive to natural gas prices – regions like the Nordics, with favourable access, lead in low-carbon hydrogen output. RFNBOs contribute significantly to hydrogen decarbonisation by displacing primarily grey hydrogen and, to some extent, low-carbon hydrogen produced via SMRs. In the deregulation context, grid-based electrolysis becomes a key production method from 2040 onwards, closely aligned with increased renewable energy deployment. Overall, the model prioritise low-carbon hydrogen as a transition fuel, only decarbonising hydrogen markets completely in the run up to 2050

5.3 Power Market

Power generation seems to follow the same trends across scenarios. Including RFNBO power demand, electricity generation varies between 3730 - 3837 TWh in 2030, 4784 – 4953 TWh in 2040, and 7439 – 8079 TWh in 2050. In 2030 and 2040, power demand is highest in the baseline scenario, given the additional power demand from RFNBO electrolysis. While the share of RFNBO electricity demand is still relatively low in 2030, RFNBO electrolysis needs a staggering 654 TWh of renewable energy. It thus accounts for 12% of total power demand in 2040 in the baseline. By 2050, power demand is highest in the globalisation scenario at 8079 TWh, as direct electrification is favoured. The respective shares of renewables, nuclear, and fossil fuel power generation compared to the total is plotted as a line and represented on the right axis of Figure 17.

In 2030, renewables contribute roughly 50% of power generation across scenarios, rising to around 80% in 2040 and falling slightly short of 90% in 2050 in the baseline and deregulation scenarios. Due to an increased nuclear power generation, the share of renewables reaches only 82% in the nuclear scenario. These shares consider only grid-based power generation and do not account for RFNBO hydrogen production to avoid double counting.

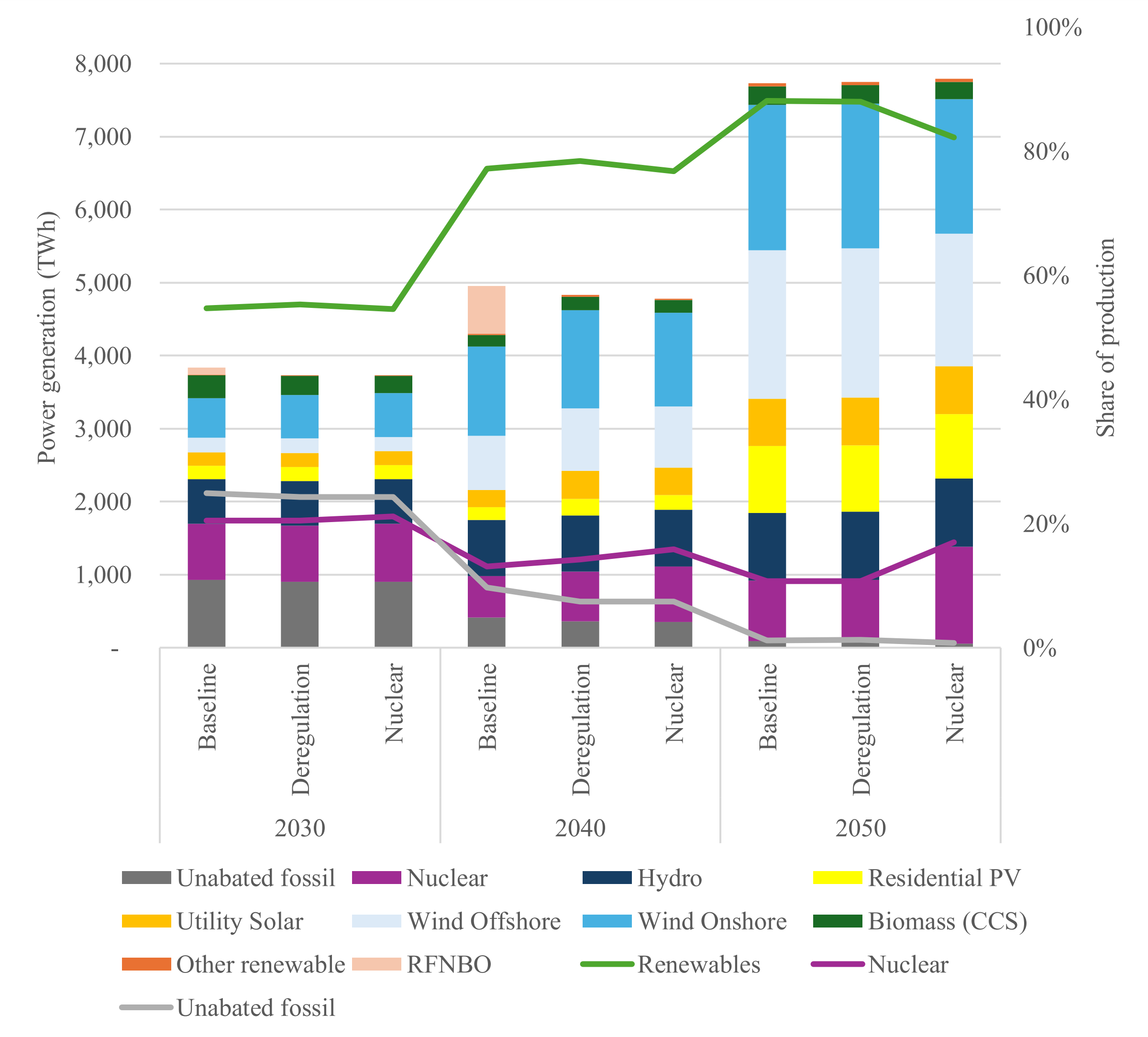

Figure 17: European power generation and respective share of renewables, nuclear and unabated fossil fuels across scenarios

The evolution of nuclear power generation offers interesting findings. In all scenarios, the installed nuclear power generation capacity drops between 2030 and 2040 before it expands to its maximum upper bound in 2050. By that year, in the scenarios without an increase in the nuclear upper bound, the total installed capacity reaches 121 GW and 194 GW in the nuclear scenario. In 2050, compared to the baseline, the nuclear scenario sees an increase in uranium-based power generation from 831 TWh to 1325 TWh. Thanks to this increase, the need for unabated power generation in CCGTs (-29 TWh), residential solar (-21 TWh), offshore (-211 TWh), onshore wind (-155 TWh), and biomass with CCS (-13 TWh) is lower. In 2050, in the nuclear scenario, 17% of power is supplied from nuclear power plants, while the share of renewables decreases to 82%.

A comparison of power sector carbon emissions across scenarios in combination with attributional emissions of hydrogen production is provided in Figure 18. The attributional emissions are calculated based on the conversion of hydrogen per scenario, using standard emission values for natural gas-based hydrogen production and the average annual grid carbon intensity for grid electrolysis while considering RFNBO electrolysis as completely carbon neutral.[20]

In 2030, attributional emissions of hydrogen production are at 22 MtCO2e in the baseline, as opposed to 35-36 MtCO2e in the deregulation scenarios. As RFNBO substitutes natural gas-based hydrogen production, emissions are 13-14 MtCO2e lower in the baseline. Surprisingly, however, carbon emissions from the power sector are 18 MtCO2e higher in the baseline scenario (522 MtCO2e) than in the deregulation context (504 MtCO2e) – this emission increase in the power sector more than balances out the emission savings in the hydrogen sector.

The origin of higher power sector emissions in the baseline lies within the lower potential capacity expansion for renewable energy sources. As renewables are needed for island RFNBO production, the installed capacity in the European grid is lower for utility solar (-6 GW), offshore wind (-1 GW), and onshore wind (-25 GW). The capacity decrease translates into generation losses of 11 TWh for utility solar, 5 TWh in offshore wind, and 46 TWh in onshore wind. To compensate for these losses, the model contracts more fossil fuel power generation (+ 26 TWh) and biomass-based conversion (+44 TWh). Thus, fossil fuel power generation accounts for 24.9% in the baseline in 2030, as opposed to 24.2% in the deregulation scenario. This trend continues in 2040 as the absolute production of RFNBO hydrogen rises. As renewables are removed from the grid to serve power demand for the island RFNBO hydrogen, utility solar (-149 GW) and offshore wind (-21 GW) capacity is much lower.

Things look differently in the 2040 hydrogen market. Given the high cost of electrolysers and low-efficiency rates, the model prefers to keep a higher share of unabated SMR in the hydrogen mix in the fragmentation scenario. Therein, total emissions from hydrogen production double from 2030 levels to 60 MtCO2e. Just as in 2030, the emissions attributable to hydrogen production are lowest in the baseline scenarios at 20 MtCO2e, falling by a mere 2 MtCO2e compared to their 2030 levels. Thanks to a higher share of grid-based electrolysis due to higher nuclear output, hydrogen market emissions are slightly lower in the nuclear scenario (42 MtCO2e) than in the deregulation scenario (47 MtCO2e). While the RED mandates again achieve emission reductions, an adverse combination of high investment costs and low electrolyser efficiency could triple hydrogen market emissions. Although the baseline scenario posts again higher emissions in the power sector (144 MtCO2e), the sum of hydrogen and power emissions (164 MtCO2e) are slightly lower in 2040 than in the deregulation scenario (168 MtCO2e).

[20] The standard values are as follows: 0.27 ktCO2/GWh for grey hydrogen, 0.027 ktCO2/GWh for SMR with CCS (considering 90% capture rate), and 0.0135 ktCO2/GWh for ATR with CCS at a capture rate of 95%.

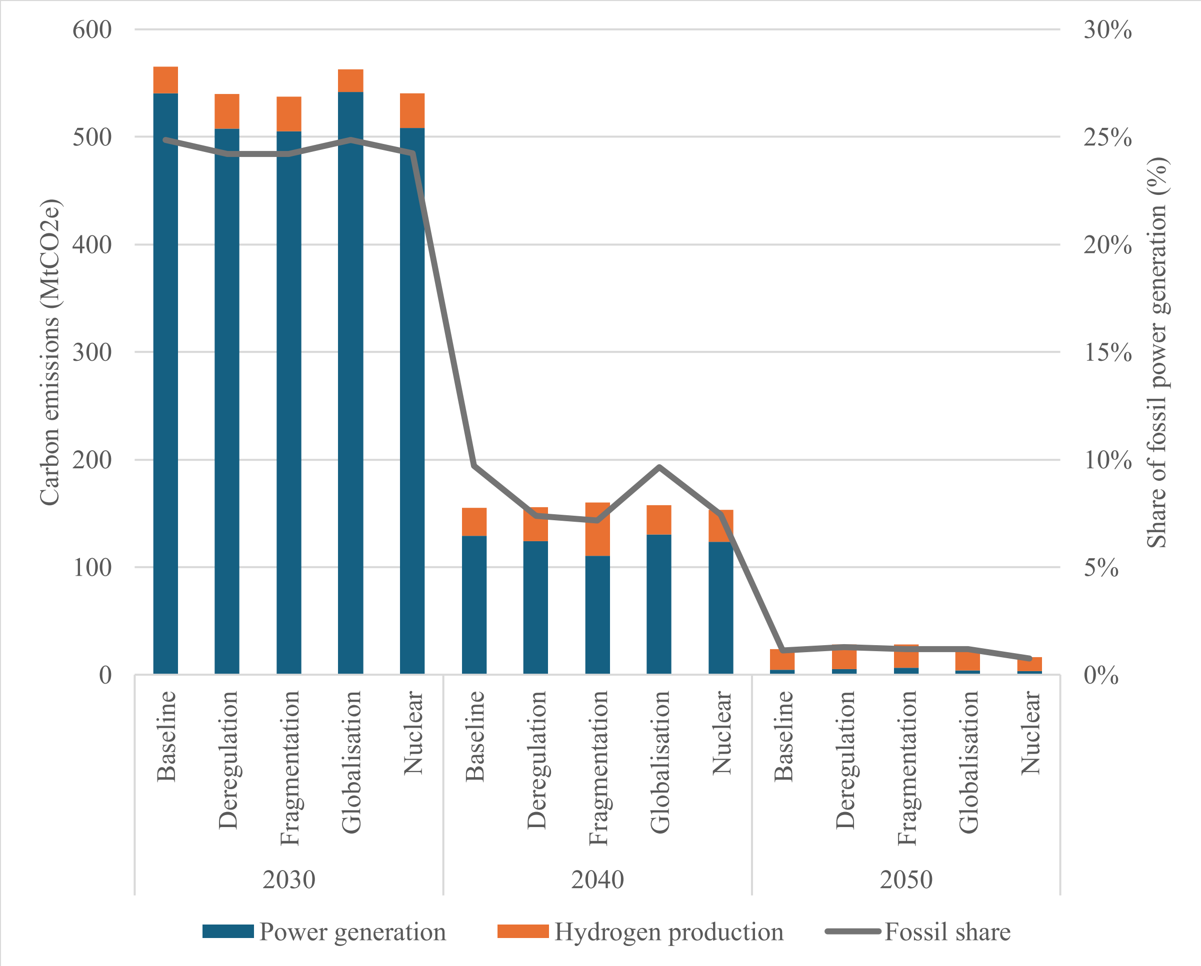

Figure 18: Power sector and hydrogen production emissions with the share of fossil power generation across scenarios

Table 3 provides a regional breakdown of power sector carbon emissions in 2030 and 2040, comparing the baseline against the deregulation scenario. Given its high power demand and historic reliance on bituminous coal in the power sector, Germany accounts for slightly less than one-third of Europe's power sector emissions by 2030. The country also accounts for most of the discrepancy in carbon emissions between the scenarios. This gap stands at 18 MtCO2e, to which Germany contributes 15 MtCO2e.

As we take out utility solar, onshore and offshore wind capacity in the country to accommodate RFNBO production, the German power market struggles to decarbonise, increasing lignite power generation. The input of lignite into the power market rises from 108 TWh in the deregulation scenario to 146 TWh in the baseline. Although lignite coal has a higher carbon intensity than bituminous coal, the model chose to increase the generation of the first fossil commodity. The 20 GW of bituminous coal power plants Germany still maintains in 2030 run at a high load factor[21] of 65%. It therefore seems likely that in the baseline, even Germany's bituminous coal capacity is insufficient to meet peak demand, hence rendering a higher generation of lignite coal necessary.

[21] The load factor or utilisation factor is defined as the ratio between the actual output of a power plant and its installed capacity. In opposition to this, the capacity factor prescribes the ratio between the maximum possible output of a power plant and its installed capacity.

In the baseline, the German power market has 18 GW of lignite coal power plants that produce 61 TWh of electricity at a load factor of 38%. This is because 5 GW of onshore wind and 0.3 GW of offshore wind capacity are unavailable. Simultaneously, the model chose not to expand CCGT power plants, as depreciation of their investment seems impossible given the low utilisation rates. Next to Germany, emissions are slightly higher in Italy (0.6 MtCO2e), Iberia (0.4 Mt CO2e), SEE (0.7 MtCO2e), and France (0.9 MtCO2e).

Region	Baseline in 2030	Deregulation in 2030	Baseline in 2040	Deregulation in 2040
Europe total	520.7	502.3	146	123
Germany	160.7	146.0	32	26
Poland	96.8	97.0	14	9
Italy	47.1	46.5	29	29
Iberia	46.7	47.3	11	9
Eastern Europe	21.1	21.2	7	5
Southeastern Europe	29.1	28.4	5	3
France	9.3	8.4	13	10

Table 2: Regional comparisons of power sector carbon emissions (MtCO2e)

This section highlights that the model consistently optimises Europe's power market with a similar configuration across all scenarios, showing only minor variations in the contributions of biomass, wind, solar, and nuclear energy. Between 2040 and 2050, power demand increases sharply, with an average growth of 300 TWh per year. By 2050, offshore wind emerges as the dominant power generation technology across all scenarios. However, due to constraints on the expansion of renewable energy sources, scenarios involving RFNBO production exhibit higher power sector emissions in 2030 and 2040. This trend is particularly pronounced in the German power market, where coal phase-out progresses more slowly under the baseline scenario compared to a deregulated context.

5.4 Commodity Costs

The model outputs hourly, short-run marginal production costs for the supply of various commodities, including electricity, hydrogen, and e-liquids. Prices for biofuels, such as bioliquids and biomethane, are endogenously modelled based on the biomass supply curve we calculated with the data included in Frank et al. (2021). Furthermore, the model endogenously computes natural gas wholesale prices based on an international trade model. Commodity prices for coal lignite and bituminous, diesel, and uranium are exogenously assumed for each modelled year but are static across scenarios.

We use the short-run marginal costs for electricity, hydrogen, and e-liquids to compute yearly averages across scenarios, as displayed in Figure 19. As the short-run marginal production costs sometimes include extremely severe price spikes, especially in 2030, we exclude the highest and lowest percentile when computing averages. Importantly, we do not consider any government subsidies, which could reduce average production costs.

All low-carbon commodities see an increase in average marginal production costs between 2040 and 2050, driven by higher market demand and the absence of hydrogen or e-liquid import options. Despite higher conversion efficiencies for these two commodities, the cost increases in the electricity market propagate to the hydrogen market. High average production costs for electricity reflect the high investment costs needed to achieve climate neutrality by 2050. Notably, average marginal production costs are lowest in the nuclear scenario, at around 150 €/MWh, compared to well above 180 €/MWh in all other scenarios.

Unsurprisingly, the deglobalisation scenario, with lower efficiency rates and higher investment costs, leads to the highest average costs in the power sector at 217 €/MWh. The second cheapest context is the globalisation scenario, which especially sees relatively cheap production costs for e-liquids at around €370/MWh. Average marginal costs in the scenarios with RFNBO production (S1 and S4) decrease between 2030 and 2040. This is likely explainable by the off-model expansion of the dedicated renewable power for RFNBOs. Given that a lot of hydrogen is produced off-grid, the production of hydrogen does not affect power market costs to the same extent as in the other scenarios. On the power market, by 2050, high prices are likely driven by biomass power plants equipped with CCS. These only have an electrical efficiency of 32%, meaning they need roughly 3 MWh of biomass for every electricity output. As the biomass price stands at around 120 €/MWh in 2050, the power generation in these plants infers average production costs of around 360 €/MWh. Of all commodities, only the wholesale market price of natural gas displays a downward trajectory, dropping from around 35 €/MWh in 2030 to below 20 €/MWh.

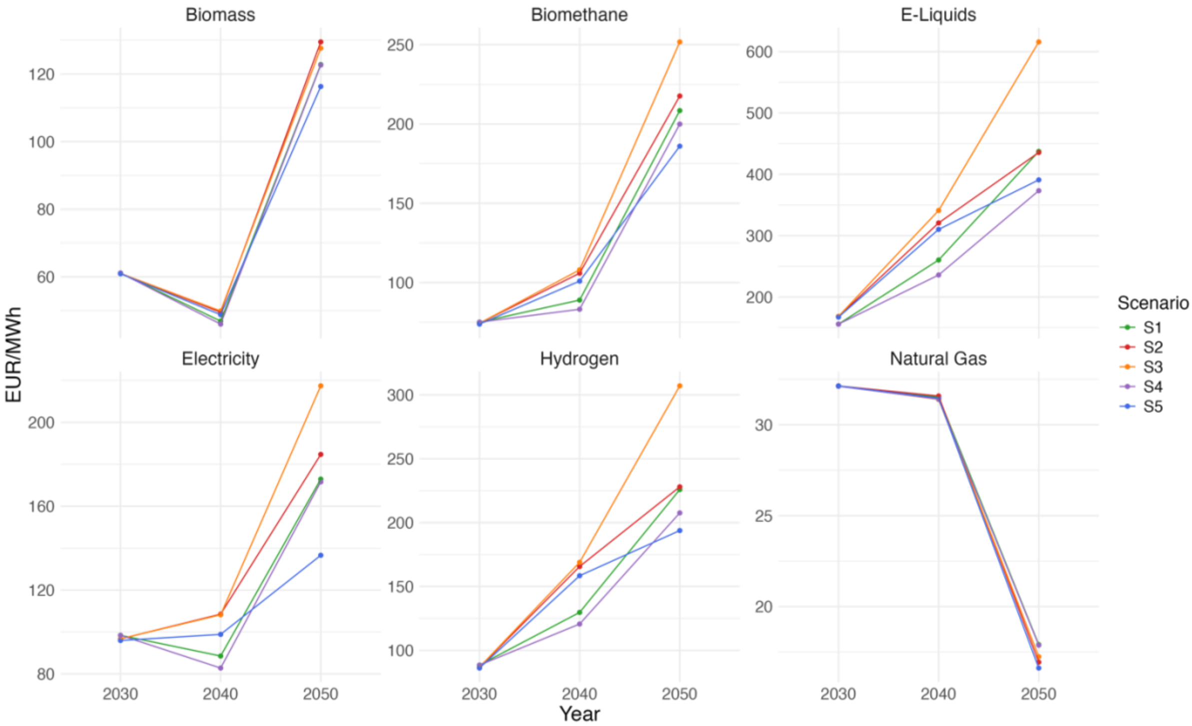

Figure 19: Average marginal production costs for selected commodities across years and scenarios

Figure 20 displays regional variations in the average production costs for electricity compared to the European average. Generally, average costs are higher in Southeastern Europe, Eastern Europe, Central Europe, Italy, Poland, and the Baltics. The Nordics, Iberia, Germany, France, and the Netherlands record lower than average electricity production costs. Especially the Netherlands records average electricity costs well above the average, which can be explained by the country's very large offshore wind resources. In 2050, these make up 97 GW of a 138 GW total capacity. The same can be said for Germany (83 GW), France (80 GW), the Nordics (32 GW), and Iberia (35 GW). Thus, low average electricity prices in 2050 correlate with high offshore wind shares.[22]

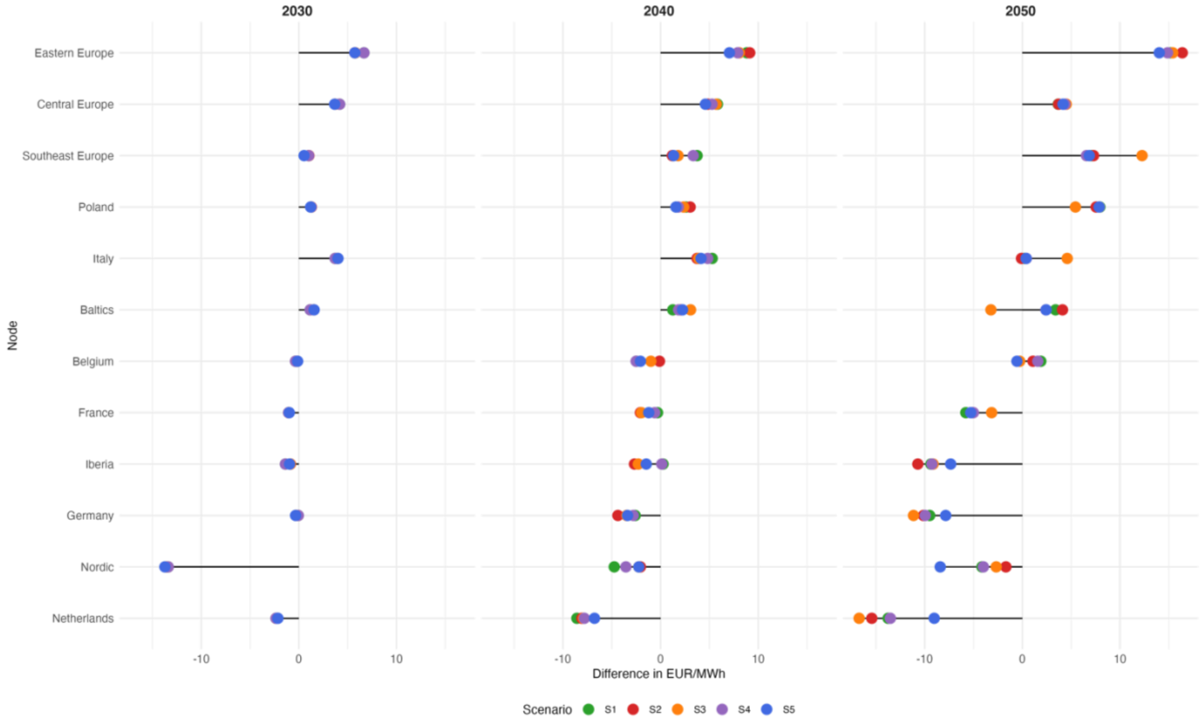

Figure 20: Difference in average marginal production costs of electricity for selected regions compared to the European average

The model is forced to meet both specific sectorial and total emission reductions. The latter includes the European 55% reduction target by 2030 and net-zero emissions by 2050, while the 2040 target is set at the middle of these values at 77.5%. Given this exogenous constraint, we do not apply a carbon price in the model. Nevertheless, the model outputs the marginal abatement cost (MAC) defined as informing "on the costs of an additional unit of emission recution at any given total abatement level" so that the MAC in our modelling indicates how much the reduction of an additional tonne of CO_2 beyond the targets would cost (Table 4). One limitation exists in this regard, as the model entirely relies on supply-side optimisation, whereas demand-side responses, such as lower demand for certain commodities, are not regarded.

As Table 4 below reveals, the MAC is much higher than the current ETS price (€70/tCO_2e). The trends suggest that marginal abatement is cheaper in the baseline and globalisation scenarios in 2040 at around 315-344 €/tCO_2e. This might be explainable with the exogenous modelling of RFNBO hydrogen demand, which subsequently reduces the costs for the model to meet power and hydrogen demand. In this regard, it could be argued that the current policy framework is effective in shifting the costs from the wholesale market to the industrial off-takers. By 2050, the nuclear scenario sees the lowest MAC at 1,327 €/tCO_2e,

[22] For the baseline scenario, in 2050, we assumed a load factor of a maximum of 55% in the Dutch and German North Sea at investment costs of €1,852/kW. It should be pointed out that recent research suggests that load factors might be higher when increasing distances between offshore wind turbines, which would then decrease the maximum installation potential.

whereas the reduction of an additional tonne of carbon emissions in the baseline scenarios would cost around 1,530 €/tCO_2e. The two remaining deregulation scenarios have the highest MAC at 1695-1755 €/tCO_2e. Interestingly, in spite of lower conversion efficiencies and higher investment costs, the geoeconomic fragmentation scenario has a MAC that is slightly lower than the deregulation scenario. Also, in the globalisation scenario, a decrease in technological costs and increase in conversion efficiencies does not seem to significantly reduce the MAC, as it is only 5 €/tCO_2e lower than in the baseline.

	2030	2040	2050
Baseline	190	344	1538
Deregulation	186	424	1755
Fragmentation	186	441	1695
Globalisation	190	315	1533
Nuclear	183	405	1327

Table 3: Implicit marginal abatement cost per scenario and year (€/tCO2e)

This section shows that commodity costs are lowest in the nuclear scenario, followed by the globalisation scenario. In contrast, European production is least cost-competitive under the fragmentation scenario, which reflects higher capital investment and reduced operational efficiencies. As demand for low-carbon commodities rises approaching 2050, average production costs also increase, despite improvements in efficiency and capacity factors. Regions with offshore wind access generally benefit from below-average electricity costs. An analysis of marginal abatement costs indicates they are lowest in the nuclear scenario, while scenarios incorporating RED mandates show lower MAC compared to the deregulation scenario.

6. Discussion

This section will discuss the results and infer implications for European energy regulation and economics. The findings will be placed into current debates around Europe's path to carbon neutrality, energy transition strategy, and financing needs. The discussion will begin with the RFNBO framework and the RED mandates, continue with low-carbon hydrogen, and discuss the role of hydrogen imports before discussing the long-term implications for Europe's energy market.

RFNBO framework

In Chapter 3.1, we have seen the complexity of producing RFNBOs in Europe. Several production pathways exist, one mixing "fully" with "partially" renewable electricity from the grid, diffusing the regulatory boundaries to low-carbon hydrogen. The explicit distinction between RFNBOs and low-carbon fuels appears unclear, as both typologies have to adhere to the same 70% emissions reduction threshold. Also, the literature is not united on the scope and definition of LCH. The German EWI (2025a), for example, seems to consider only abated fossil-based hydrogen as "low-carbon".

In contrast, Türby et al. (2024) define grid-based electrolysis and fossil-based abated hydrogen as "low-carbon". The regulatory framework also seems to confuse leading energy market experts. The current policies are heavily tilted towards incentivising RFNBO production, as LCH cannot be used to fulfil the RED mandates; the exception is ReFuelEU aviation (Burmeister, 2024). This apparent "discrimination" against LCH, although it has to adhere to the same emission standards as RFNBOs, is inconsistent. The regulator should make a choice. Either RFNBOs are "fully" renewable, so no grid electricity should be used in their production – leaving out the 90% renewable exception. Or the regulator should put RFNBOs and low-carbon fuels on the same footing, meaning both can be used to fulfil all demand side mandates.

Some prescriptions of the three-pillar framework also seem to violate other European policy targets, such as achieving a complete European Energy Union. The geographical correlation criterion stands out in this context, which both contradicts the ambition of creating one Pan-European energy market and the efficient allocation of renewable resources. Intuitively, transporting renewable power from Sweden to an electrolyser plant in Poland would be economically efficient since Sweden has higher renewable resources at its disposal, whereas these are more scarce in Poland. One could argue that each European country should develop its own renewable resources first. Secondly, the slow expansion of interconnectors poses a problem in this regard. As the available cross-border capacity should be used to transport renewable power between regions to account for intermittencies, booking interconnector capacity for hydrogen production in a neighbouring country would be contradictory. Therefore, at a second glance, European regulations might be conservative but correct when it comes to the geographical correlation pillar.

Another question is how the 90% renewable threshold was determined in the first place. This figure seems arbitrarily set. In none of our modelled scenarios does the European power mix achieve a 90% renewable energy share. Even with a slightly under 90% renewable share, the model can achieve carbon neutrality by 2050. That the average share does not reach this threshold is primarily owed to another low-carbon power source, namely nuclear, which accounts for 11% of generation in the first four scenarios and 17% in the nuclear scenario. Fossil power generation sinks to 1% in 2050. Consequently, the threshold at its current level discriminates against MS with high nuclear generation capacity, such as France. It disproportionately benefits countries with high hydro shares, like Finland, Norway, or Austria.

RED targets

Quantifying the RED and ReFuelEU Aviation mandates in Chapter 4.1 has proven to be intricate since various exceptions exist. Also, the Commission has not provided sufficient clarifications on calculating the mandates in the non-road transport sector. Still, from these computations, we know that the power demand to meet hydrogen, e-liquid, and e-gas demand with domestic production alone by 2050 is staggering and would account for roughly 26% of Europe's total power generation.

One of the key limitations of the current model and policy framework is that it does not allow for comprehensive hydrogen trade as a mitigation strategy. In the EFOM, only gaseous hydrogen imports from Northern Africa and intra-European trade in hydrogen, e-liuqids, and e-gases are implemented. Therefore, the model's domestic power demand for hydrogen production is artificially high. Nevertheless, hydrogen demand should be reduced wherever possible. In this context, the model's optimised hydrogen demand in road transport should be scrutinisced. Recent technological advancements of batteries have diminshed the future necessity of hydrogen in the road transport sector. Shirizadeh at al. (2024) predict that battery electric vehicles could represent 60-89% of trucks amd 79-96% of buses by 2050. A full forgoing of e-liquids in road-transport would lead to a demand reduction of 120 TWh of e-liquids in the baseline by 2050.

European literature has focused on weighing the advantages and disadvantages of each of the three pillars of the RFNBO policy framework. Despite the publication of numerous articles, little attention has been paid to measuring the three pillar's effects on hydrogen and power markets in conjunction with RED demand estimates. Section 4.1 estimated the renewable energy required for RFNBO hydrogen production. This calculation assumed that the RED mandates would be fully met and that no RFNBO imports would be available in 2030 and 2040. We reduced the maximum potential expansion of renewable energy using a regional breakdown to weigh the effects of meeting the RED mandates on the European energy market. The model's results revealed in Chapter 5.3 that if the RED mandates were met with domestic production only, several countries would struggle to advance their grid decarbonisation compared to the deregulation scenario. This view on competition effects between different renewable use-cases is in line with the research of Ricks et al. (2023) and Giovaniello (2024), presented in Chapter 2.

Germany stands out in this context as the country most at risk of higher power sector emissions when fulfilling the RED mandates with domestic RFNBO alone. Due to lower bounds in the baseline, the model constructed 87 GW of onshore, 19.8 GW of offshore wind, and 16 GW of utility solar by 2030. This compares to 92 GW (+ 5GW) of onshore, 20.1 GW (+ 0.3 GW) of offshore wind, 16 GW of utility solar, and 0 GW of residential solar in the deregulation scenario. In reality, in April 2025, 63 GW of onshore, 9 GW of offshore wind, and slightly more than 100 GW of solar, both utility and residential, capacity was installed in Germany (BWE, 2025) (BWE, 2024). While solar expansion is well above the optimal capacity identified by our energy system model, installed wind capacity in 2025 is below the 2030 target levels. Although acceleration in the build-out of wind energy can be expected in Germany due to faster permitting and recent over-subscribed auctions, the annual onshore wind expansion stood at around 3.5 GW in the last two years (BWE, 2025). It was significantly below 1 GW for offshore wind (BWE, 2024). If these rates hold, Germany's "optimal" capacity of 92 GW onshore and 20 GW offshore wind, as informed by the deregulation scenario, will likely not be met. This problem is independent of RFNBO production in the first place. However, if projects were to be delayed, such as in the areas BP and Total Energies hold,[23] or if significant amounts of RFNBOs were to be produced in the North Sea from offshore wind, grid decarbonisation might even slow down further (Ramakrishnan et al., 2024).

In this context, our RFNBO demand total of 68 TWh (2 Mt) for 2030 is rather conservative. For example, the EU's REPowerEU Plan outlined the ambition to produce 10 Mt of RFNBO hydrogen by 2030 and import 10 Mt (European Commission, 2024a). It is still widely unclear how the Commission created that target (FTM, 2024). If given the chance, the

[23] Total and BP acquired in 2023 leases to develop 7 GW of offshore wind capacity in the German North Sea. Given the high upfront payments they made as "roaylties" to the German government, it is not sure whether projects will be economical and go ahead (Bulja, 2024).

Commission should correct this figure. The industry association "Hydrogen Europe" forecasts that 2.5 Mt of clean hydrogen could be produced in 2030 at current trajectories. However, this includes 0.8 Mt of low-carbon hydrogen, bringing the share of water electrolysis down to 1.7 Mt, slightly below our RED prediction for 2030 (Hydrogen Europe, 2024b).

Assuming that the optimal full-load hours (FLH) of electrolysers in Europe are around 4,500 FLH (Hofrichter et al., 2023), to meet the 68 TWh of RED demand, Europe would need 15 GW of dedicated RFNBO electrolysis capacity. Notably, this excludes the need for hydrogen in the maritime sector. The 15 GW projection from our modelling compares to political electrolyser targets of 40 GW in the EU Hydrogen Strategy, 54.3 GW in the cumulation of national targets, and 125 GW as included in REPowerEU (Figure 21) (Lambert et al., 2024). Although these policy targets may include non-RFNBO electrolysis, the difference between the political ambition and the likely need is staggering.

As of the end of 2024, 385 MW of electrolyser capacity was installed in Europe. The EU's Hy2Infra IPCEI project supports the installation of a further 3.2 GW of large-scale electrolysers. In turn, the first auction round of the EHB (Chapter 3.3.1) allocated subsidies to incentivise the construction of 1.5 GW of electrolysers at €720mn, translation into per GW subsidies of €480mn (European Commission, 2024d). The two upcoming rounds total €2.2bn of EU funding plus at least €700mn of national budgets via the auction-as-a-service mechanism (European Commission, 2025b; European Commission, 2025c). Using the per GW ratio of the first auction would translate into an additional installation of 6 GW, bringing the total existing and subsidised electrolysis capacity up to 11 GW. Using the initial ratio from the first EHB auction round may be problematic, as the funded projects might have been the most competitive across Europe. Still, at least for the second round, one can expect that the fierce competition will move investors to lower subsidy bids. Obviously, on top of the 11 GW of existing and subsidised capacity, we would have to add private investments or further auction rounds of the EHB. While private investment is hard to predict, reaching the 15 GW identified as necessary to meet RED mandates in industry and non-road transport is not as far away as it may seem. However, if final investment decisions are not taken in 2025, it is doubtful that these projects will become operational in 2030. Still, on the supply side, things look more optimistic than initially thought, at least for the mid-2030s.

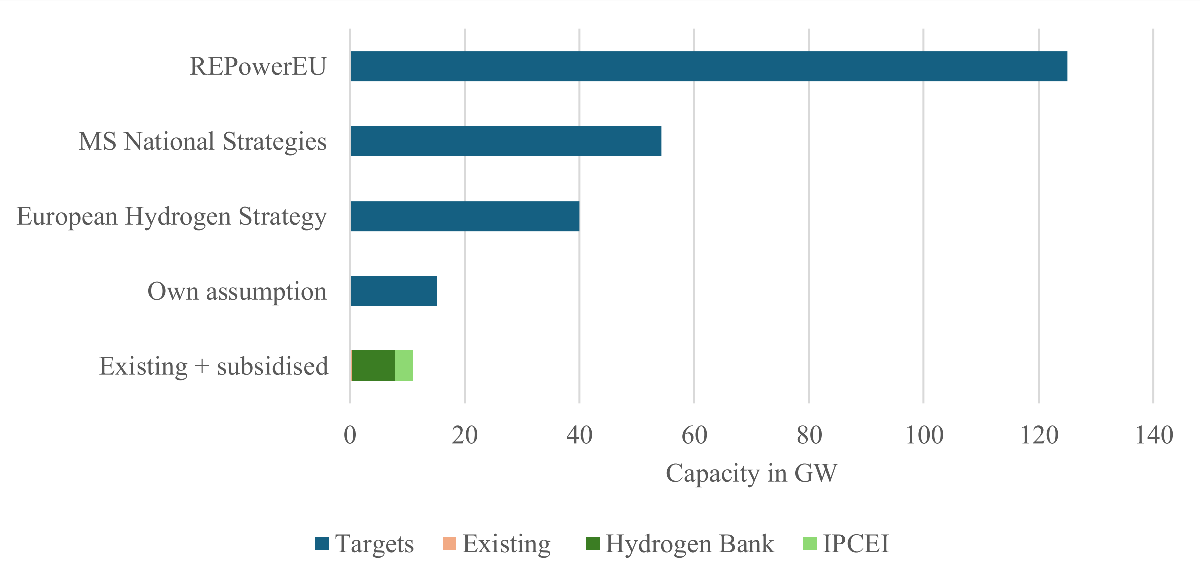

Figure 21: Electrolysis capacity as assumed in political targets, in our model and a current projection for 2030

On the demand side, there appears to be little appetite to sign RFNBO offtake agreements, as there have been only few offtake announcements until April 2025. One notable exception is TotalEnergies Leuna refinery, which in March 2025 signed an offtake agreement with RWE for a yearly supply of 30,000t RFNBO hydrogen (roughly one TWh) starting in 2030 (TotalEnergies, 2025). Further demand may be due to the global carbon pricing system put in place in April 2025 by the International Maritime Organisation (Global Maritime Forum, 2025).

Industrial sectors, such as the European steel or chemical sectors, are in fierce international price competition and have shown reluctance to sign long-term offtake agreements for RFNBO hydrogen, even if governments pledged billions in financial support. In two recent cases, ArcelorMittal and ThyssenKrupp have put plans for hydrogen usage in their steel production on hold, criticising that “green hydrogen is evolving very slowly towards being a viable fuel source” (ArcelorMittal, 2024) (Stratmann, 2024). Such industries can hardly pass on cost increases to customers since cheaper imports of Chinese or Indian steel are available. This is somewhat different in the transport sector, as refineries are better positioned to pass on costs to clients or absorb some surcharges themselves. The regulator uncertainty is further aggravating the situation on the demand side. Member States are very slow to implement the RED legislation into national law, so the demand mandates are ineffective in practice.

Unfortunately, the European legislation delegated defining penalties for non-compliance with RED mandates to Member States. These can apply mandates and, thus, penalties at the national or company level. When choosing the first option, it is somewhat unclear how the national government would hold industries accountable for breaching the mandates. Company-level mandates might, therefore, be more attractive but unpopular with national economic policies. In France, the Netherlands, and Germany, systems with tradeable credits have been established to transpose other parts of the RED legislation, which have substantial penalties for non-compliance (Hydrogen Europe, 2024c).

While the 2025 update of France's national hydrogen strategy outlined that it will soon transpose the RED into national law, no specificieties were provided on non-compliance penalties (Ministère de l'Économie, 2025). Applying a €600/tCO_2e penalty, as currently used to punish RED breaches in Germany, to the hydrogen market would lead to a hefty surcharge on grey hydrogen prices of €4/kgH_2[24], likely rendering most RFNBOs cost competitive. At this point, however, it is entirely unclear whether national governments will apply such penalties.

Falling short of the RED quotas, especially in industry, is not a significant setback. In fact, given the dynamics of the power market, pushing back the RED targets and prioritising the decarbonisation of electricity production is economically more efficient and does not hinder Europe's long-term climate strategy. Several downside risks exist, which could worsen the problems in the power market. Above all, renewed supply chain disruptions due to geoeconomic fragmentation or "deglobalisation" can slow down the expansion of renewables in Europe.

The trade war between the US and China began in April 2025, with both countries raising their import tariffs well above 100%. While the EU is not a direct participant in this trade conflict, spill-over effects are unavoidable and likely strain supply chains. Any trade disruption will likely lead to project delays and soaring investment costs, especially in the crucial onshore and offshore wind industries. This would hit the wind industry when it is still recovering from poor macroeconomic conditions and supply shortages in 2021-2022 (Ember, 2025a) (Weiss et al., 2024). Another downside is data centres. According to the IEA, worldwide power demand from data centres is set to double by 2030 (IEA, 2025d). If this were also the trend in Europe, grid decarbonisation would need to compete with yet another demand source, putting in question whether higher demand for electrolysis, digitalisation, and electrification can be met at current expansion rates.

Low carbon hydrogen

In the model, 59-64% of hydrogen is supplied from SMR + CCS in 2030, falling to 28-39% by 2040. According to the Ten-Year Network Development Plan developed by the European Networks of Transmission System Operators for Electricity (ENTSO-E) and its gas counterpart (ENTSO-G), low-carbon hydrogen could supply 22% of all hydrogen demand in 2030 (EWI, 2025a); the assumed demand stands at 15 Mt, well above our estimate based on historic production levels. In line with our findings, the contribution of LCH by 2050 is only marginal (EWI, 2025a). The IEA's net-zero by 2050 scenario, in turn, predicts that roughly a quarter of the world's global hydrogen production in 2030 could be covered by low-carbon hydrogen (Alanazi et al., 2025). By 2050, although the relative share of LCH decreases to 20%, its absolute production volume will increase from around 20 Mt in 2030 to 75 Mt.

Nevertheless, some downside risks exist around hydrogen production via SMR + CCS. First, we assumed very high carbon capture rates for SMR (90%) and ATR (95%) technologies. The deployment of large-scale CCS technologies in Europe has only been done so far at Norway's Sleipner offshore field, but no information on carbon capture rates has been disclosed. The literature is also divided on whether CCS can achieve these capture rates. In a

[24] The caculation assumes a carbon intensity of RFNBO hydrogen of 3.4 $kgCO_2e/kgH_2$ and of 10 $kgCO_2e/kgH_2$ for grey hydrogen.

report for the Institute for Energy Economics and Financial Analysis, Schlissel et al. (2022) find that utility-scale projects have repeatedly fallen short of the 90% capture rate and deem CCS "a highly risky investment" (Schlissel et al., 2022). This is underlined by further research that also points towards higher emissions when fully accounting for methane leakages (Faber et al., 2025). On the other side, engineers seem to argue that 90% capture rates are achievable from a technical perspective (Torset, 2023). Further insights could be provided once Norway's Northern Lights project goes online, testing the whole carbon value chain from capture, via ship transportation, to offshore storage (Cavcic, 2024). If the oil & gas industry is interested in making low-carbon hydrogen a transition fuel, they should be more transparent about capture rates.

The investment needs constitute the second barrier to LCH's uptake. Across our scenarios, by 2030, the total installed capacity of SMR + CCS would need to reach 28 GW. In the baseline, one GW of SMR + CCS infers investment costs of €900mn by 2030. Thus, total investment costs for 28 GW of SMR + CCS would be over €25bn. When accounting for potential retrofits, the per GW investment costs are decreased to roughly €400mn, which would leading to a total necessary investment of €11bn (Asset, 2018). According to Hydrogen Europe, the announced cumulative production output in Europe for SMR + CCS could reach 6 MtH2 by 2030 (Hydrogen Europe, 2024c). At near baseload activity of SMR plants, around 8,000h per year, this would translate into a capacity of around 25 GW, very close to the identified optimal capacity in 2030. However, most of these projects are "announcements," meaning they are either in concept, feasibility study, or preparatory stages (Hydrogen Europe, 2024c). With the experience from the "green hydrogen implementation gap", it is unlikely that most of this project capacity will indeed come online by 2030 unless a final investment decision is taken in the following months. Further industry limits might be regarded concerning the European manufacturing capacity for CCS technologies.

Thirdly, the availability of CO_2 storage sites in Europe could be another barrier. The modelling results suggest that in 2030, almost all available carbon storage capacity would be used to store sequestered carbon from LCH production. In our model, the European capacities to store carbon reach 75 $MtCO_2e$ in 2030. This figure is based on the EU's Carbon Management Strategy which predicts that by 2030 the volume of CO_2 stored within the EU could reach 50 $MtCO_2e$. To this we added 25 $MtCO_2e$ of storage capacity for the UK, as informed by the UK's North Sea Transition Authority (North Sea Transition Authority, n.d.). Significant upside potential exists when depledted oil and gas fields in the Norwegian part of the North Sea are included, which we have not yet integrated nto the model bounds. However, from now on, only five years remain before the storage capacity target of 75 $MtCO_2e$ is reached. Although the policy debate is shifting to supporting CCS more fiercely than before, as underlined by the publication of the Carbon Management Strategy and the advancement of national CCS projects in countries such as Italy, Norway, and the Netherlands, few countries have created the legal basis to store carbon on their respective territories permanently. A Europe-wide legal basis for carbon transportation across borders has also not yet been implemented, as at the end of 2023, only seven European countries had ratified the amendment of Article 6 of the London Protocol. This Article allows for the export of carbon to other countries (Global CCS Institute, 2024). Furthermore, certification standards, permitting processes, and network planning covering the whole carbon supply chain remain in their infancy.

Grid-based electrolysis is another avenue to produce LCH according to the draft of the Delegated Regulation, as presented in Chapter 3.2. In the baseline scenario, in 2030, under baseload activity, the production of hydrogen from grid electricity would result in attributional emissions of 6.5 $kgCO_2/kgH_2$ in the European average; they are much higher in Germany (11.8 $kgCO_2/kgH_2$) or Poland (21.7 $kgCO_2/kgH_2$), well above the 3.3 $kgCO_2/kgH_2$ threshold. On the contrary, only France, thanks to its high share of nuclear power generation, could produce low-carbon hydrogen at baseload activity via grid electrolysis, resulting in attributional emissions of only 0.6 $kgCO_2/kgH_2$. This holds for the Nordic region as well. On the Iberian peninsula, baseload activity would result in attributional emissions of 5.0 $kgCO_2/kgH_2$.

In the baseline scenario, the total capacity of electrolysis reaches 17.7 GW owing to RFNBO hydrogen (15 GW) and grid-based electrolysis (2.7 GW). Realising this capacity would require investments of €19.5bn in 2030, rising to €141bn in 2040 (145 GW of alkaline) and €377bn by 2050 (233 GW of alkaline and 172 GW of PEM). For alkaline electrolysers, we assumed initial investment costs in 2030 of €1,100/kW and for PEM of €1,400/kW, from where we started applying learning rates based on literature sources and the projected expansion rate of electrolysis presented in the IEA's net-zero scenario. It is very important to note that newer estimates for alkaline electrolysers show investment costs that are 40-60% higher in 2030. The Hydrogen Council estimates investment costs of €1,573/kW in 2030 as opposed to even higher cost estimates by Bloomberg NEF of €1,743/kW. The divergence softens in 2040 as we assumed €968/kw as opposed to newer estimates of around €1,250/kW. By 2050, we assumed €852/kW, contrasted to €1,150/kW. Higher investment costs for electrolysers will lead to higher LCOH, thus decreasing the cost competitiveness of hydrogen in sectors with alternatives, such as HGV or public transport. For hard-to-abate sectors, in which hydrogen may be the only alternative, higher electrolyser costs are likely to drive up abatement costs and delay their decarbonisation.

The role of hydrogen imports

Assuming hydrogen would only be produced within Europe, the energy demand from electrolysis in 2050 would be around 2,000 TWh or 26% of Europe's total electricity generation. Among the different use cases of hydrogen, the production of e-liquids is particularly inefficient and expensive, inferring average production costs of around €400/MWh in 2050.

The need for dedicated renewable energy to produce hydrogen and its derivatives can be diminished by importing them from regions with more favourable renewable resources and higher capacity factors. According to Türby et al. (2024), international hydrogen suppliers have production cost advantages of 28-40% in 2030 and 20-44% in 2050. Costs related to capital borrowing and downstream transport weigh against lower production costs in other world regions. To bring molecules from one region to another, one must account for costs related to their transportation, either via ship or pipeline. In the case of derivatives, one must also include conversion costs in the exporting country and potentially reconversion costs in Europe. Generally, transport via repurposed pipelines is considered the cheapest option (IRENA, 2022). According to the IRENA, constructing new pipelines dedicated to hydrogen imports is only attractive for large projects starting at a transport volume of around one MtH_2 per year (IRENA, 2022).

Longer transport distances, such as for imports from Autralia, Namibia, or Chile, must be done via ships, where the conversion of hydrogen to ammonia is likely to be the cheapest import option (IRENA, 2022). Further options include hydrogen liquefaction or its chemical binding in liquid organic hydrogen carriers (LOHC), but they are more expensive. The conversion of hydrogen into e-liquids and subsequent transport to Europe could also be financially attractive, as current transport costs for oil products are extremely low (Harrington, 2025). According to recent studies, the costs for pipeline transports range between €0.1-0.3/kgH_2, whereas maritime imports infer a surcharge of €1.3-1.6/kgH_2 (Türby et al., 2024). However, it should be noted that the specific costs for pipeline imports also depend on the utilisation factors and that current cost estimates of hydrogen carriers may still vary with technological breakthroughs.

At the moment, hydrogen imports play a critical role in the European Hydrogen Strategy, which predicts that around 50% of clean hydrogen demand in 2030 could be covered by imports (European Commission, 2024a). The German Hydrogen Import Strategy suggests that 50-70% of the country's hydrogen demand in 2030 could be supplied from the outside (BMWK, 2024a). Albeit this includes imports from other European countries, it must be questioned whether in light of Germany's recent dependence on natural gas such high import shares are politically desirable. In any case, it is unclear whether these import levels are attainable by 2030, given the absence of dedicated import infrastructures, such as ammonia crackers, and a comprehensive transmission network. Although the German government prioritises imports via repurposed natural gas pipelines from Norway, Iberia, or Northern Africa, project progress is slow. In September 2024, Norway's Equinor slashed a planned hydrogen export pipeline to Germany, citing a lack of demand for low-carbon hydrogen in Europe (Lea, 2024). This is surprising, as Norwegian gas seems to be optimally suited given that upstream CO_2 and methane emissions from other suppliers, such as Algeria or the US, are much higher, making Norway the "cleanest" supplier (Türby et al., 2024).

Owing to recent project delays, it is likely that hydrogen imports will only start making up a significant share of supplies in the mid-2030s. For the model year 2040, we can expect that hydrogen imports, and especially external e-liquid supply, will repudiate the competition effects between renewable use cases and drive down costs for hydrogen and e-liquids. By 2050, when assuming that half of Europe's hydrogen demand, including derivatives, could be supplied from other world regions, in line with the EU's envisaged import share, the dedicated power demand would be halved from 2,000 to 1,000 TWh, or around 14% of total power generation (7,000 TWh).

Still, relying too much on imports - from potentially autocratic nations - counters Europe's ambition of achieving energy independence. Just as in the case of Russia, the EU could become vulnerable to energy blackmailing if it sources its hydrogen from a few suppliers. From the start of any import strategy, the hydrogen security of supply should, therefore, play a central role. There might also be challenges regarding gas security when repurposing natural gas pipelines too early, for example, from Norway or Northern Africa (EWI, 2025b).

Power market

Moreover, the model sheds light on the role of nuclear power generation. In 2050, nuclear power capacity reaches its maximum upper bound across all scenarios. The installed capacity stands at 121 GW in the first four scenarios and climbs to 193.5 GW in the nuclear scenario. Undeniably, nuclear power plants are thus a central pillar in Europe's climate neutrality. The significantly lower MAC in 2050 under the nuclear scenario further underlines the positive effects of nuclear power. Therein, the MAC of carbon reaches "only" 1,333 €/t instead of much higher values of 1,500€/t and 1,750 €/t in the other scenarios. This implies that a forceful expansion of nuclear power decreases the costs of Europe's energy transition, at least if economies of scale can be achieved. Surprisingly, in 2040, nuclear capacity is far from reaching its maximum upper bound, even in the nuclear scenario with a theoretical maximum of 153 GW. Across scenarios, the installed capacity varies between 81 and 106 GW. Therefore, maximising nuclear production may not be necessary to achieve a 77.5% GHG reduction by 2040, but it is needed for net zero in 2050.

Interestingly, the final European power generation mix for 2050 does not differ significantly across scenarios, factoring out the increased nuclear power in the dedicated scenario. This is somewhat surprising as the variation of technological costs in the fragmentation and globalisation scenarios does not noticeably change the preferred power generation technologies in 2050. Despite higher technological costs, under the geoeconomic fragmentation scenario, the model chooses to increase overall power generation by around 325 TWh compared to the baseline, which is reflected in the usage of biomass + CCS (+60 TWh), offshore wind (+ 100 TWh), onshore wind (+80 TWh), and nuclear (+70 TWh). Contrary, even though investment costs are lower than in the baseline, power generation is decreased by around 120 TWh in the globalisation scenario, accounting for losses in utility solar, offshore, and onshore wind production. Furthermore, hydrogen conversion is also lower in that scenario, reaching only 1321 TWh as opposed to 1421 TWh in the baseline. These results suggest that technological costs, when forcing Europe to reach net zero by 2050, do not significantly change the path towards climate neutrality. This is supported by evidence from the MAC in 2050. This finding, however, is somewhat limited by the exogenous assumption of demand. If demand could adapt to technological costs, we would expect other results.

7. Policy Recommendations

At the writing of this thesis, the European Commission is preparing a review of its hydrogen policy framework - as announced within the Clean Industrial Deal package. This fits into a wider strive of the new von der Leyen Commission to ease regulatory costs, slash red tape, promote technological neutrality, and prioritise market-based solutions. The shift in terminology from "green industrial deal", as presented by the last Commission (2019-2024), to "clean industrial deal" underlines the paradigm change we are likely to see in the next few years. Additionally, in the summer of 2025, the Commission will present the EU's carbon emission reduction target for 2040. This will have extensive ramifications on the continent's strategy towards climate neutrality. Thus, it seems that in 2025 and 2026 a policy window exists in which we strive to place policy recommendations based on our analysis. These proposals are primarily addressed to the European Commission's Directorate Generals for Energy, Internal Markets, and Climate but are also of interest to policymakers in Member States and energy market investors.

Reset European hydrogen strategy and demand targets

First, we recommend lowering the current European demand targets for clean hydrogen. The figures presented for hydrogen volumes and electrolysis capacity are unrealistic and have deteriorated trust in the objectivity of the Commission, which must have given into the "hydrogen" hype. Renewable expansion rates, electrolyser investment costs, and electrolyser efficiencies do at this time not favor the uptake of renewable hydrogen. Correcting demand and supply targets would be a chance to reset and reprioritise Europe's hydrogen strategy. The reduction of hydrogen demand should follow the economic rationale of *"the best energy is the energy not consumed"*; which disproportionately applies to e-liquids and hydrogen, given their conversion inefficiencies. The easiest avenue to reduce future hydrogen and e-liquid demand in Europe is to target the road transport sector, more specifically HGV, which could achieve decarbonisation via other options such as direct electrification or bioliquids. Although the policy framework should not exclude certain technologies outright, direct electrification in road transport could be further incentivised by reducing taxation on electricity, channelling more investments towards the uptake of a comprehensive battery charging network for trucks, and directing more public finances into the battery market to create European battery "champions".

Frontload build-out of low-carbon energy sources

Secondly, we recommend that the Commission, but more urgently that Member States, frontload as much renewable capacity expansion as possible. The faster renewable energies are expanded and the electricity grid is decarbonised, the sooner hydrogen can be produced on the basis of renewable electricity, not least thanks to sector coupling. Currently, the targets for renewable energy expansion are once more questioned in France and Germany (BDI & BCG, 2025). Although pushing back expansion targets, owing to lower-than-expected power demand might save some initial costs for public budgets, these investment needs will inevitably come back in the 2030s. Following through with the current expansion plans for renewable technologies, would give European industries regulatory and investment security and the chance to build-up manufacturing capacities. The need for higher domestic industrial capacities pertains mainly to the fabrication of wind energy, which sees 810 GW of new capacity between 2030 and 2050, CCS technologies (90 GW expansion by 2050), electrolysers (400 GW by 2050), and nuclear (80 GW expansion at best). These figures serve to underline the magnitude of the challenge, which requires enormous manufacturing capacities, swift permitting procedures, and strong power grids. Especially offshore wind has the potential to become the biggest power source in Europe by 2050 pushing down average electricity prices in countries that have expanded their capacities significantly (Chapter 5.4). Since 2021, the German government has been successful in accelerating the permitting of renewables, by classifying their expansion as being in the "overriding public interest and serving public safety". Across Member States, especially the expansion of offshore wind energy should be gaining momentum, which is the preferred renewable energy technology across all our scenarios thanks to high capacity factors.

Demonstrate pragmatism with regard to the RED industry targets

The cost of producing industrial goods in Europe is already in many sectors uncompetitive (European Commission, 2024g). At the same time, European public budgets are strained, due to investment needs in defense and physical infrastructure. It is therefore unlikely and it is also not desirable that the cost gap for RFNBOs is covered via public subsidies. For the RED targets in 2030, European policymaking should show pragmatism and flexibilise the targets by invoking Article 22b. This would allow for the following industry hydrogen mix: RFNBOs (22%), LCH (55%), and grey hydrogen (23%). As only a few low-carbon and RFNBO projects have made final investment decision, even reaching these lower shares could prove to be impossible, especially in case of setbacks of projects funded via the EHB. If that were to be the case, the Commission should push back the industry RED targets completely back to 2035. This would give the renewable industry more time to increase manufacturing capacities to serve both power and hydrogen market needs. Things look somewhat more differentiated in the transport sector, which is generally better positioned to pass on surcharges to end customers. Nevertheless, the substantial demand for e-liquids in aviation and maritime transport may exceed what can be met under current renewable energy expansion rates. In such a case, *ReFuelAviation* should allow for the substitution of synthetic fuels with alternatives—such as advanced bioliquids—particularly around 2040.

Integrate low-carbon hydrogen as a transition fuel

Fourthly, we urgently recommend integrating low-carbon hydrogen as a transition fuel in Europe's climate strategy until the 2040s. The potential of LCH has long been neglected by European policymaking. Our results underline that LCH could cover around half of Europe's hydrogen needs and buy the renewable sector more time to accelerate expansion rates. To allow LCH to play a decisive role on Europe's way to carbon neutrality, several factors need to be delivered. First, the Delegated Regulation on LCH should be adopted to advance regulatory standards and certification. Next up, demand for low-carbon fuels in industry and transport should be stimulated by flexibilising RED mandates. European policymaking should accerlerate the roll-out of CCS manufacturing capacities, for example, by implementing one Important Project of Common European Interest (IPCEI) for this technology. Moreover, the Commission should follow-up on its Carbon Management Strategy, develop regulatory standards for carbon transport and storage, and compel Member States to ratify the amendment to Article 6 of the London Protocol. Also, policy should reflect upon the fear that real-life capture rates might be lower than announced by industries. Therefore, close monitoring and compliance with capture rates needs to be ensured. Lastly, carbon emissions linked to the transport of natural gas, especially from methane leakage, should be reduced over time.

Present a European hydrogen import strategy

Fifthly, we recommend presenting a European hydrogen import strategy outlining import corridors, infrastructure, and implementation timelines. Despite national efforts, large-scale hydrogen imports are realistically not available by 2030. The Commission should, therefore, act as a facilitator by coordinating and aggregating Member States' hydrogen import needs. H2-Global could be updated to a truly European mechanism or integrated within the European Hydrogen Bank as its external branch. Therefore, a European hydrogen import strategy would be ideally suited to accelerate import corridor development and coordinate import infrastructure development while monitoring hydrogen supply security. Hydrogen import dependency could be measured via concentration indicators such as the Herfindahl-Hirschman Index for each derivative. Although the market will likely be concentrated initially, the EU's goal should be to create a liquid market with competing players. Imports from other world regions should be focused on high-value derivatives, such as ammonia or synthetic liquids, which may be prohibitively expensive to produce in Europe. In turn, hydrogen molecules for European industries should be produced domestically or in the EU's close neighbourhood. The import strategy should aim to navigate the complex trade-offs between ensuring energy security and maintaing cost competitiveness. Import shares in the range of 50-70%, as proposed by the German government, may prove politically unsustainable over the long term.

Give nuclear its proper role in the energy transition

We were able to underline that the nuclear scenario has the lowest commodity and marginal abatement costs in 2050, thanks to a capacity installation of 194 GW at investment costs of €5,040/kW. Thus, expanding nuclear power generation on the European level would simplify the continent's path to climate neutrality. Several requirements would be needed to realise such a scenario. To begin with, the nuclear industry would need to demonstrate that it can achieve economies of scale effects. However, the projected increase in installed nuclear capacity from 108 GW in 2040 to 194 GW by 2050 appears overly ambitious, especially in light of recent project delays across Europe. To enable a more linear and realistic expansion – approximately 4 GW annually over two decades – strong and coordinated government support will be essential. This includes long-term investment frameworks, harmonised permitting procedures, and political alignment at the EU level, as advocated by countries like France.

8. Limitation and Conclusion

The following research question was presented in the introduction: "Does the current European hydrogen framework strike the right balance between environmental and economic considerations?" The research topic of this thesis was defined in November 2024; by April 2025, the announced review of the EU's hydrogen policy forestalls the answer to this question. We find an urgent need to reprioristise and restart the EU's hydrogen strategy, not only because of cost concerns, or recent project delays, but also because of the potential negative impact too much RFNBO production could have on the power market. The economic optimisation model prefers to let low-carbon sources supply the bulk of hydrogen until 2040. From then on, Europe will need a decisive expansion of electrolysis capacity and a complete phase-out of hydrogen production based on abated natural gas to achieve carbon neutrality. However, for 2030, the uptake of low-carbon hydrogen is severely limited by the lack of a comprehensive regulatory framework, too short investment periods until 2030, and the availability of carbon storage. Even as the RFNBO policy framework is fully defined and governments have pledged billions in subsidies, market participants have been very slow to make final investment decisions, as they seem not to believe that the regulation will be kept as stringent as that. Thus, for 2030, unlocking sufficient clean hydrogen for Europe seems to be a task as impossible as the squaring of the cycle. Given the past wrong priority setting, grey hydrogen will almost inevitably dominate the hydrogen market in 2030.

In line with previous research (Ricks et al., 2023; Giovaniello et al. 2024), we have been able to show that trade-offs between hydrogen and power market decarbonisation exist at current renewable expansion rates. To address this problem and bring hydrogen decarbonisation back on track in the 2030s, we have presented six policy recommendations in Chapter 7. Only two points shall be echoed here. In the light of the trade policy development since the reelection of President Trump, the EU should be laser-focused on avoiding that the geoeconomic fragmentation scenario, which is detrimental to the European energy market and the costs of the energy transition, materialises. Further, marginal carbon abatement costs rise extremely sharply between 2040 and 2050. Notably, this assumes only a 77.5% emissions reduction of emissions by 2040. To smoothen out the abatement costs, the EU should seek to bring forward some of the later emission savings to the time between 2030 and 2040. While this would ensure a more linear increase in the marginal abatement costs, the high social costs of carbon can only be forestalled if international carbon certificates are explored in-depth to achieve the last few percent of emission savings.

Some important limitations exist in our findings. We have tried to show that renewables are a scarce resource, as Europe's pool is limited by manufacturing capacities, permitting, and grid connections. However, these effects depend highly on real-life renewable expansion trajectories. Historically, solar and wind energy uptake has outperformed analysts' predictions, which might be a spark of hope for Europe's decarbonisation. Further research should explore how a variation of renewable expansion rates affects the hydrogen and power markets. The model and its data will also need updating regarding cross-border electricity transmission capacities, CO_2 storage capacities, and electrolyser investment costs. Despite these minor adjustments, the most significant current limitation of the EFOM is the absence of a comprehensive international hydrogen trade model. Its inclusion will fundamentally change power sector dynamics, hydrogen production costs, and its production mix. This is a point for further research.

9. Resources

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10. Appendix

10.1 Comparative Analysis with the US Regulation

The United States' "hydrogen shot", which was enacted during the Presidency of Joe Biden, pursues the goal of reducing the costs of clean hydrogen to $1/kg by 2031. Currently, the US produces and consumes around 10 Mt of hydrogen annually, 10-15% higher than the European demand (U.S. Department of Energy, n.d.). Both the Infrastructure Investment and Jobs Act, which provided $9.5bn for hydrogen hubs, and the Inflation Reduction Act (IRA), via its 45V production tax credit (PTC), stimulate the ramp-up of the clean hydrogen market.

The 45V PTC scheme has gained international attention. It stands at the heart of the US hydrogen ambition by allocating a production-based subsidy according to the GHG intensity of the hydrogen. The highest PTC of $3/kgH$_2$ is disbursed to the cleanest hydrogen with emissions below 0.44 kgCO2e/kgH$_2$ (Table A.1). All PTCs are paid out over 10 years from operation and are indexed to inflation (Orrick, 2024). Alternatively, project developers can apply for investment tax credits (ITC) under section 48a(15) for renewable energy facilities, such as electrolysers, wind energy, photovoltaics, and battery storage. Unlike the EU's EHB, the subsidies under 45V and 48V are paid out blankly to all applicants without prior participation in an auction. The total state expenditure for these tax credits will thus depend on the scale of clean hydrogen production.

GHG intensity (kgCO$_2$e/kgH$_2$)	0.00 - 0.44	0.45 - 1.49	1.50 - 2.49	2.50 - 3.99
Section 45V rate kg/H$_2$	$3.00	$1.00	$0.75	$0.60
Section 48a(15) rate	30 %	10 %	7.5 %	6 %

Table A. 1: Overview of available 45V PTCs and ITCs under 48V

Similarly to the European Union's approach, the US opted for a three-pillar framework consisting of incrementality (additionality), temporal matching, and deliverability (geographical correlation). However, the US has applied a more lenient regulation in its final guidance for the 45V published by the Department of Treasury on January 09 2025 (U.S. Department of Treasury, 2025). On temporal matching, the DOE has mandated annual matching, as opposed to the EU's monthly, until 2030, when hourly matching will apply. A stark contrast is visible in the final guidance rules on incrementality. Next to RES units, power plants equipped with CCS, which needs to be installed no longer than 36 months before the hydrogen production facility enters into service, are eligible. Older nuclear power plants can supply electrolysers with a maximum output of 200 MWh per operating hour, under the condition that they have signed a 10-year supply contract to extend their lifespan.

Furthermore, incrementality does not apply in states with both an electricity decarbonisation standard, and a carbon cap programme in place, which are only California and Washington. Hydrogen production facilities in these states can consume renewable electricity from units that have existed before, e.g. the states' hydropower facilities, leading to lower costs for PPAs (Lang, 2025). This implies a significant deviation from the European approach because, thanks to the ETS, the EU already has a carbon cap programme but still opted to include additionality. Further differences include deliverability, where units in other regions with transmission rights are eligible, and imports from Canada and Mexico, given the traceability of the power consumption (Cannon et al., 2025) (Bennett et al., 2024).

10.2 Model inputs

If not explicitly marked, conversion efficiencies, investment costs, expansion bounds, energy demand, and carbon emission assumptions were taken over from the EFOM used in Chyong et al. (2024). There is an extensive data explanation available upon request, although the Appendix of Chyong et al. (2024) should provide an overview over the most important assumptions.[25] Apart from the changes presented in Chapter 4, our Appendix lists further modifications to the model and explains how we computed the differnet trajectories for RED demand, dedicated renewables for RFNBO production, investment costs, conversion efficiencies, and the nuclear bound.

10.2.1 RED demand mandates

Based on the assumed industry hydrogen demand for 2030, as depicted in the first column in Figure A.1, we calculate the quota-induced RFNBO demand. This is, however, not a straightforward task as it must be based on assumptions pertaining the exceptions mentioned in Chapter 3.3.2, which among others include potential exclusions of refineries in Art. 22a, (Directive 2023/2413, Art. 22a), the usage of the opt-out option under Article 22b, and a potential exclusion of ammonia production as mentioned in Recital 63 (Directive 2023/2413). We assume that no MS will make use of Article 22b, as the low-carbon hydrogen framework is not yet developed, and all but four MS are far from achieving the necessary final renewable energy consumption. Thus, in all MS the 42% threshold for RFNBO hydrogen will be applied. In line with Art. 22a, we exclude from the RFNBO quota products for energy use, such as kerosene, diesel, or fuel oil, made in refineries. However, we need to assume that a certain share of hydrogen is used in refineries to manufacture products for non-energy. According to Eurostat data for 2020, around 14.5% of the output of oil products in refineries is used for non-energy purposes (Eurostat, 2025).[26] We use this share, including naphtha, bitumen, petroleum coke, and lubricants, to calculate the share of hydrogen used for non-energy purposes. Consequently, we expect that, in reality, the RED quota will apply to 14.5%, or 21 TWh, of hydrogen demand from refineries. This share is added to the second column of Figure A.1.

In the Netherlands, by drawing upon Recital 63, the government transposed the RED III legislation in such a manner that it covers only 40% of current Dutch ammonia production (Krümpelmann, 2025). Although the Netherlands are a frontrunner in the national implementation of the RED quota, it is one of the most important ammonia producers in Europe. That is why we assume that other European countries will take a similar approach in order not to create disadvantages for their ammonia sectors. Thus, a substantial part of ammonia production will be exempted from the the mandate based on competitiveness concerns. We

[25] Data can be accessed here https://www.sciencedirect.com/science/article/pii/S2211467X24000294?via%3Dihub#da0010

[26] This pertains mostly Naphtha, bitumen, petroleum coke, and lubricants, while the production of refinery gas is excluded given its exemption as a by-product.

reflect upon this decision, by putting only 40% of ammonia production, i.e. 34 TWh, into the calculation of the RED mandate, as displayed in the middle column. For the remaining sectors we apply the RED mandate in full. The total hydrogen volume covered by the RED III quota in 2030 then stands at 110 TWh out of an overall hydrogen demand of 286 TWh. Using the 42% mandate, we calculate that the RED-induced RFNBO demand is 46 TWh (1.4 Mt), or 16% of the overall hydrogen demand. This is depicted in the third bar of Figure A.1.

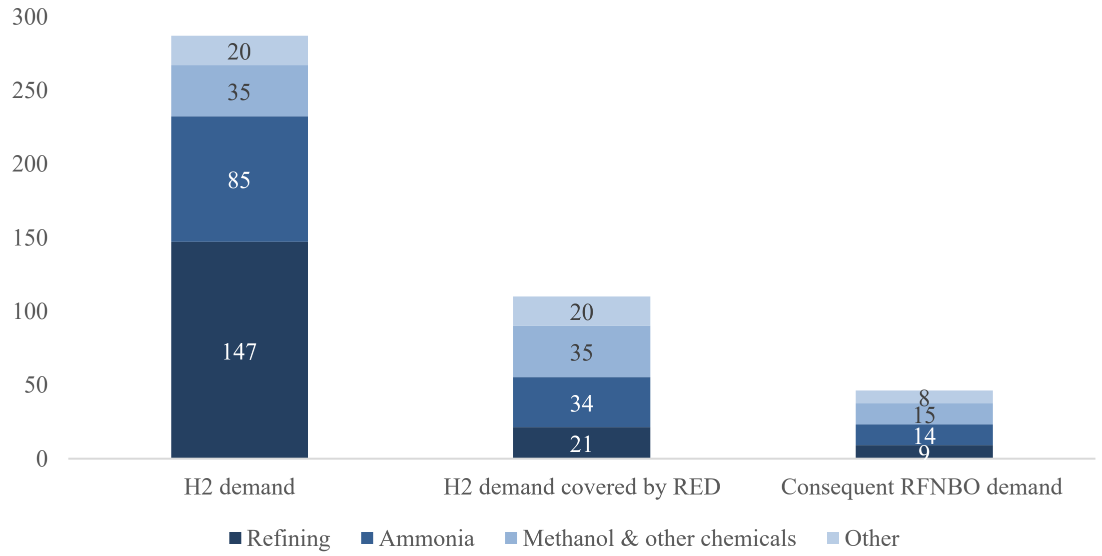

Figure A. 1: Computation of the RED III RFNBO demand in industry by 2030 (TWh)

In 2040, in the results of the EFOM, the renewable share in Europe's grid did not surpass 90%. That is the threshold after which RFNBO production is possible from grid electricity (Chapter 3.1). Although in some countries with high hydropower, the share might indeed be at 90% or even above, the European average stood at 77% in 2040. Consequently, we expect that the RED demand mandates continue in 2040 and we apply them across the board of model regions. As included in RED III, the intermediate target for 2035 is a 60% demand mandate, reflecting a 18pp increase from 2030. For 2040, we assume that, in line with the Commission's recommendation for the 2040 climate target for a 90 % reduction in GHG emissions compared to 1990 levels (European Commission, 2024h), the share of RFNBO hydrogen in industry could be set equally at 90%. By that year, we furthermore expect that the exception for ammonia production runs out. Based on these estimates, which still respects the exemptions for refineries, we compute that the RED induced RFNBO demand could reach 275 TWh in the industry alone. For 2050, we do not implement a continuation of the RED targets, but as the model needs to meet climate neutrality, one can assume that almost all of the hydrogen in 2050 is produced from renewable electricity.

Transport sector RED mandates

As laid out in Chapter 3.3.2, the RED foresees two mandates by 2030. First, it puts in place the combined mandate for RFNBO and advanced biofuels covering 5.5% of the energy supplied to the transport sector. Secondly, as a sub-target to this, RFNBOs need to make up at least 1% of the energy supplied to the transport sector in 2030, so that advanced biofuels can only meet the mandate to the maximum of 4.5%. In addition, we model compliance with the ReFuelEU Aviation policy, which mandates that by 2050 35% of the aviation's energy demand has to be served by e-liquids and at least another 35% by advanced bioliquids.

In recent years, battery electric vehicles (BEVs) have, thanks to significant technological progress on battery efficiency and costs, gained a competitive edge over fuel cell electric vehicles (FCEVs). This is especially true for passenger cars, but there is also an increasing trend in heavy freight transport (Phatale, 2019) (Lee et al., 2024). Therefore, we do not expect hydrogen to be used in passenger vehicles, freight transport, or public transport by 2030. In the non-road transport sector, rail is not seen fit to fulfil the quotas either, as most of its final energy is provided directly by electricity. Given the multipliers that have been put in place to steer e-liquid supply to the maritime and aviation sector, we expect that European policymaking wants the RED quota to be fulfilled by the aviaton sector as well as maritime transport. As we do not include international maritime transportation and energy demand from inland navigation is relatively low, we force the aviation sector to meet demand mandates.

Figure A.2 shows the different steps to calculate the RED-compatible demand for RFNBO e-liquids and advanced bioliquids.[27] In the first step ("initial value"), we calculate the targets against the absolute transport sector demand without respecting the double counting and multiplier rules. Not including these accounting factors, by 2030, RFNBO e-liquids would need to make up 37 TWh of demand, while bioliquids would need to contribute a staggering 167 TWh, given that advanced biofuels are expected to meet 4.5% of demand in our assumptions. Based on this, we apply the double counting rule, as conducted in the second column, effectively halving the above mentioned mandates. In the third and last step, assuming that only the aviation sector fulfils the RED mandate, we apply a 1.2 multiplier for advanced bioliquids and a 1.5 multiplier for e-liquids, as included in the RED legislation.

[27] This is a somewhat skewed assumption, as of course maritime transport can help achieving the RED mandates. However, the energy makret model developped by Chyong et al. (2024) does not include energy demand for international maritime transport.

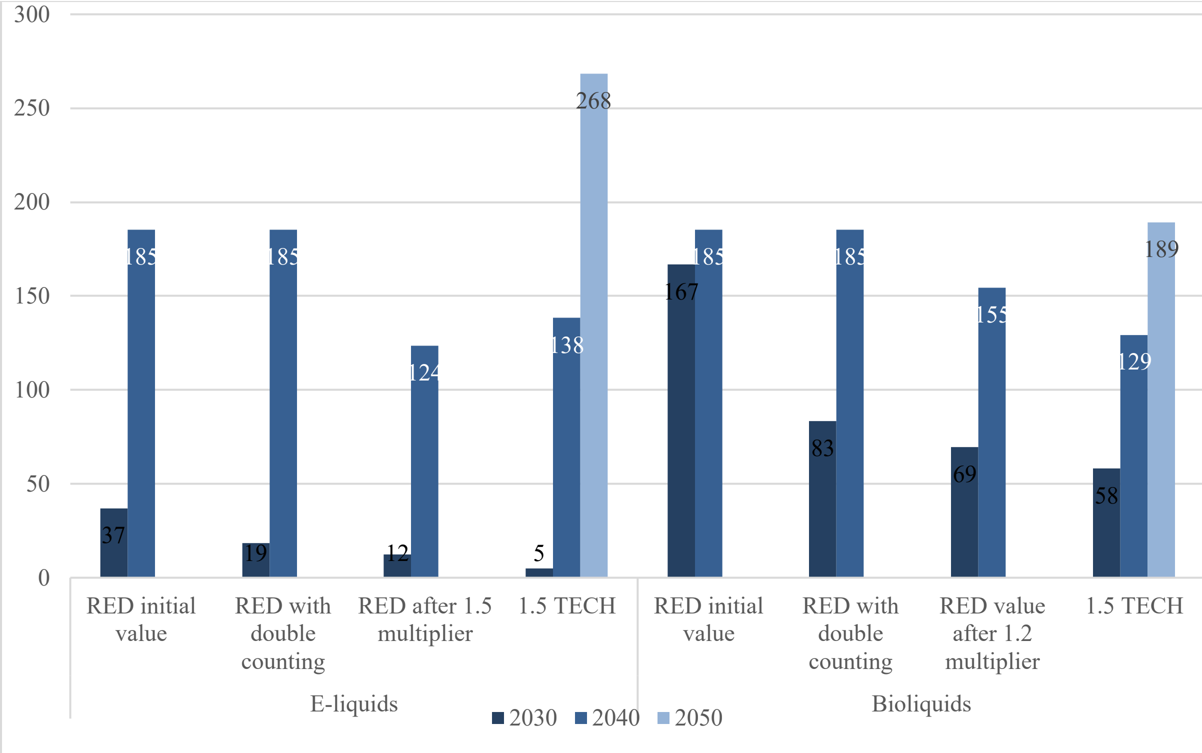

Figure A. 2: Calculation steps for RED transport mandates in 2030 and 2040 (TWh)

For 2040, in industry, we projected a 1.14 fold increase in the RED mandate from 42% to 90% between 2030 and 2040. To better align with the 1.5 TECH estimates, we assume a similar increase in the RFNBO quota for the transport sector. Thus, the combined RED quota rises from 5.5% to 11.8%. Furthermore, we no longer apply the double counting rule in 2040, as we expect that RFNBO hydrogen and advanced bioliquids become more competitive with other energy carriers, not least due to an increase in the carbon price. However, we keep the multipliers in place as they are meant to steer demand into maritime and aviation sectors. By 2040, we expect that e-liquids and bio-liquids fulfil the RED quota equally, as the costs to produce RFNBO fuels sink, leading to a 5.9% mandate for RFNBO and bioliquids respectively. Thus, RED III demand for e-liquids reaches 12 TWh in 2030 while increasing sharply in 2040 to 124 TWh as the mandate increases and the double counting bonus is no longer applied. Bioliquid demand is even higher, ranging between 69 TWh in 2030 and 155 TWh in 2040. For the final configuration in 2050, we respect the targets of the FuelEU Aviation of a 35% share of synthetic fuels, and a further 35% share for bioliquids in final energy consumption of the aviation sector.

10.2.2 Renewable bounds

From the total RFNBO hydrogen demand included in Figure 7, we derive the power needs per region to produce RFNBOs in electrolysers. The regional breakdown of dedicated renewables for RFNBO production ensures adherence to the additionality and geographical correlation criterion. To compute the renewable energy capacity needed to source RFNBOs, we derive from Astriani et al. (2024) that a 65% share of wind energy and 35% of solar photovoltaics is the optimal mix for electrolysis in Europe (Astriani et al., 2024). Furthermore, we assume that offshore wind could supply 5% in 2030 and 15% of total RFNBO power need in 2040.[28] Besides, we account for the fact that some regions might neither have enough potential for utility solar PV or offshore wind.[29] The renewable power capacity needed to produce RFNBO hydrogen is displayed in Figure A.3. As electrolyser efficiencies vary between the baseline and the globalisation scenario, total RFNBO power demand varies slightly as well. The calculated renewable energy capacity for RFNBO hydrogen production is deducted from the regional upper bounds. Through this, we mirror that the pool of renewables available in Europe can either be used for grid or hydrogen purposes. This is in line with the findings of Giovanelli et al. (2024), which highlight competition effects between hydrogen and power markets.

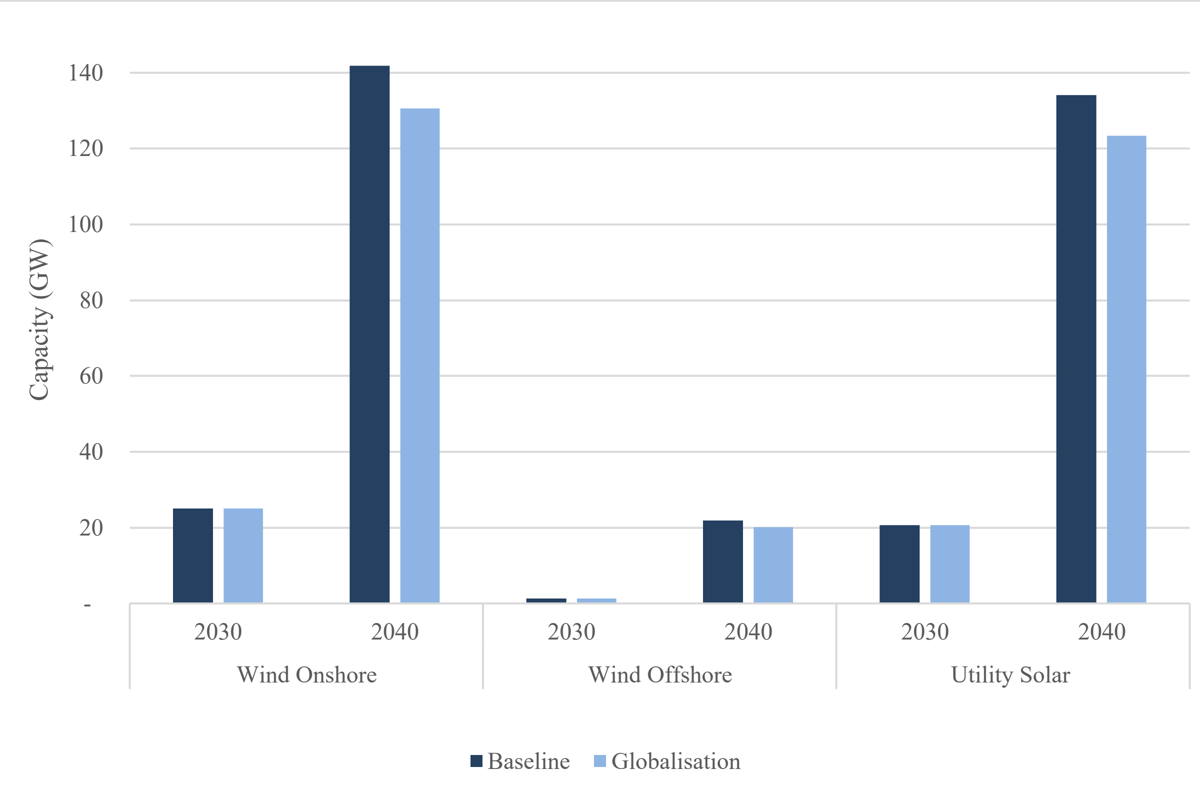

Figure A. 3: Dedicated renewable energy capacity to produce RFNBO hydrogen in the baseline and globalisation scenario

10.2.3 Cost Assumptions

Cost assumptions for renewable energy technologies are based on several data sources to compute different CAPEX trajectories from 2030 to 2050. In the baseline, economic deregulation, and nuclear expansion scenario, we assume medium costs for renewable technologies instead of the geoeconomic fragmentation scenario, in which we assume a conservative trajectory for renewable costs. Again, in the renewed globalisation scenario, progressive costs are incorporated.

We expect that in 2030, in the three cost trajectories, i.e. medium, conservative, and progressive, the CAPEX is still the same. This base CAPEX for 2030 is taken from the data included in Chyong et al. (2024) for electrolysis, batteries, and methanation plants. The

[28] See for example the AquaVentus Project in the North-Sea or the Kintore Hydrogen Project in Scotland.

[29] If a model region does not have offshore wind or solar PV at its disposal, the caluclated power generation capacity is either added to onshore wind or solar PV.

remaining data for 2030 is retrieved from Asset (2018). From the baseline cost in 2030 we compute CAPEX trajectories based on different learning rates (LR)[30], which we derive from the literature. LRs for utility-scale and residential solar PV are expected to be the same, as well as those of SOEC electrolysis and methanation plants, as displayed in the Table A.2 below.[31]

	Conservative	Medium	Progressive
Solar PV	14 %	21 %	27 %
Onshore wind	7.7 %	9.8 %	16.5 %
Offshore wind	1.5 %	4.9 %	12 %
PEM electrolysis	12 %	14 %	20 %
Alkaline electrolysis	8 %	12 %	24 %
SOEC electrolysis	5 %	13 %	21 %
Batteries	14 %	26.5 %	39 %
Methanation	5 %	13 %	21 %

Table A. 2: Assumed learning rates up to 2050

In line with the IEA's Net Zero Roadmap (IEA, 2023), we assume that the global installed capacity of all renewable technologies doubles twice between 2030 and 2050. To simplify the calculation, we expect the first capacity to double by 2040 and the second by 2050. Thanks to the IEA data, we can compute the CAPEX for the most important renewable energy technologies in 2030, 2040, and 2050 along three trajectories. The results are shown in Table A.3 below. CAPEX is given in €2023 value per kW or kWh for battery technologies. Cost reductions are most considerable in the progressive scenarios as the LRs are higher, while the CAPEX trajectories are relatively flat in the conservative scenarios. Thanks to high LRs, solar and batteries witness the highest CAPEX reductions between 2030 and 2050, while offshore wind remains the most expensive renewable power generation technology as it records lower LR than onshore wind or solar.

Technology	Trajectory	2030	2040	2050
Utility solar	Conservative	€663	€573	€496
	Medium	€663	€526	€418
	Progressive	€663	€486	€356
Residential solar	Conservative	€989	€855	€740
	Medium	€989	€785	€623
	Progressive	€989	€725	€531
Wind onshore	Conservative	€1 161	€1 072	€989
	Medium	€1 161	€1 047	€945
	Progressive	€1 161	€969	€809
Wind offshore	Conservative	€2 048	€2 017	€1 987
	Medium	€2 048	€1 948	€1 852

[30] The learning rate is a measurement to quantify the percentual cost reduction for a given technology with each doubling of the global installed cumulative capacity.
[31] For utility solar (Maharjan et al., 2024), for onshore wind (Williams et al., 2017) (Rubin et al., 2015), for offshore wind (Van der Zwaan, 2012), for batteries (Ziegler & Trancik, 2021), for electrolysis (Bello & Reiner, 2024).

	Progressive	€2 048	€1 802	€1 586
Electrolysis PEM	Conservative	€1 400	€1 232	€1 084
	Medium	€1 400	€1 204	€1 035
	Progressive	€1 400	€1 120	€896
Electrolysis alkaline	Conservative	€1 100	€1 012	€931
	Medium	€1 100	€968	€852
	Progressive	€1 100	€836	€635
Electrolysis SOEC	Conservative	€1 595	€1 515	€1 439
	Medium	€1 595	€1 388	€1 207
	Progressive	€1 595	€1 260	€995
Utility batteries	Conservative	€564	€485	€417
	Medium	€564	€414	€304
	Progressive	€564	€344	€210
Residential batteries	Conservative	€768	€660	€568
	Medium	€768	€564	€415
	Progressive	€768	€468	€286
Methanation e-Gas	Conservative	€1 000	€950	€903
	Medium	€1 000	€870	€757
	Progressive	€1 000	€790	€624
Methanation e-Liquid	Conservative	€1 200	€1 140	€1 083
	Medium	€1 200	€1 044	€908
	Progressive	€1 200	€948	€749

Table A. 3: CAPEX assumptions for renewable energy technologies in 2030, 2040, 2050 (€2023/kW) and for batteries (€2023/kWh)

10.2.4 Conversion efficiencies

Efficiency rates of electrolyser and methanation plants for e-gases and e-liquids are displayed in Table A.4. The three efficiency trends (medium, progressive, conservative) are integrated in the policy scenarios. The baseline, deregulation, and nuclear scenarios use the medium efficiency trend, the progressive trend is integrated into the globalisation scenario, while the conservative trend is used for the geoeconomic fragmentation scenario. For electrolysis, all the current efficiency rates and the values for 2050 in the medium scenario are derived from Dias et al. (2020). The 2050 values in the progressive scenario use the efficiency rates assumed in Chyong et al. (2024), which are based on Asset (2018) and Bloomberg New Energy Finance data. The efficiency trends for e-gases and e-liquids were derived from the IEA's Global Hydrogen Review 2021 (IEA, 2021) Assumption Annex as well as Kiani et al. (2021).

Technology	Efficiency trend	2030	2050
Alkaline	Medium	65%	74%
	High	65%	82%
	Low	65%	65%
PEM	Medium	62%	79%
	High	62%	82%
	Low	62%	62%

SOCE	Medium	77%	81%
	High	77%	95%
	Low	77%	77%
E-Gas	Medium	60%	69%
	High	60%	77%
	Low	60%	60%
E-Liquids	Medium	57%	65%
	High	57%	73%
	Low	57%	57%

Table A. 4: Assumed electrolyser efficiency rates between 2030 and 2050 based on the literature

10.2.5 Nuclear Expansion

According to data from the International Atomic Energy Agency, replicated in the World Nuclear Industry Status Report for 2022, the EU27 achieved an expansion of nuclear capacity from 5 GW in 1970 to around 115 GW by 1990. A staggering increase of 110 GW in 20 years (Figure A.4). For the nuclear expansion scenario, we assume that this historic expansion is partly replicable in the EU27, Norway, Switzerland, and the UK between 2030 and 2050.

As of today, the UK is pursuing the ambition to increase its current nuclear reactor fleet from 6 GW to 24 GW by 2050 (UK Government, 2024), whilst French President Emmanuel Macron announced the ambition to construct up to 14 new reactors with a capacity of 1600 MW each for a total maximum of 22.4 GW until 2050 (Le Figaro, 2024). While the construction of six reactors is in concrete planning, the first set to enter into operation in 2035, France holds an option to build another eight. If the UK's and France's ambition would be realised by 2050, this would cause a gross addition of 40.4 GW until 2050, not accounting for the construction of Small Modular Reactors (SMR). However, one would need to deduct the retirement of older reactors from the gross additions, as many reactors currently in operation were built in the 1970s (Figure A.4). On the one hand, the elevation of the upper expansion bound for nuclear capacity in the nuclear scenario must be significant to quantify the effects of higher availability of nuclear power on the hydrogen market. On the other hand, however, the new upper bound must still be based on realistic considerations.

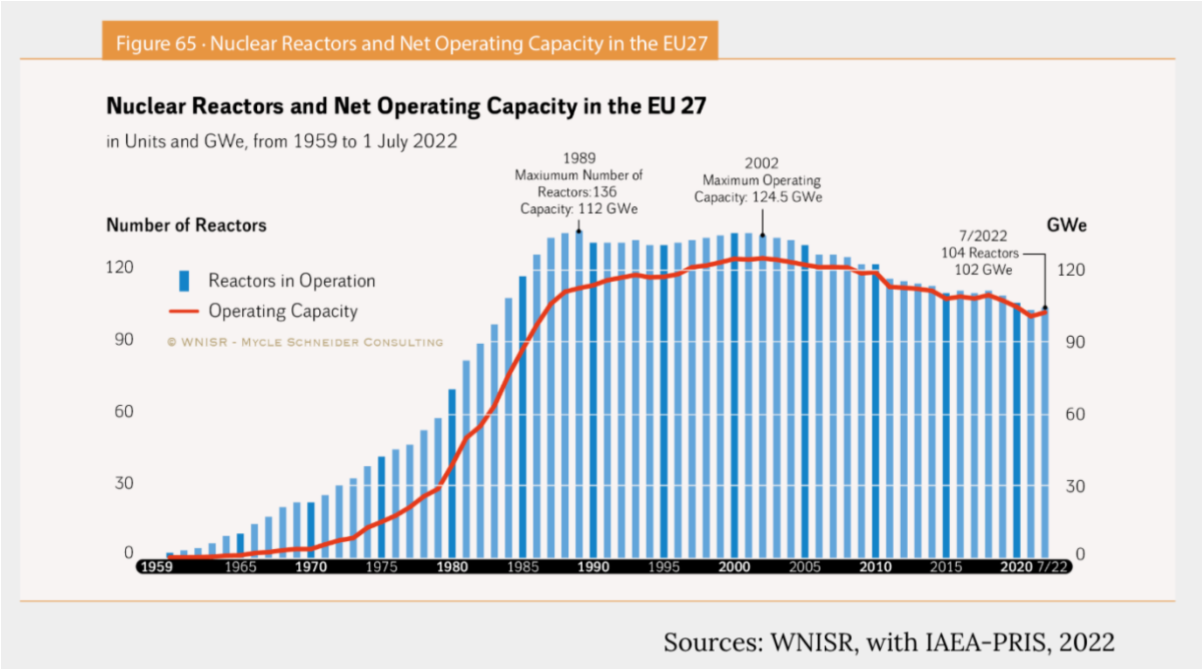

Figure A. 4: Historic expansion of nuclear capacity in the EU27

In Switzerland, citizens passed a referendum in 2017 against constructing new nuclear reactors (World Nuclear Association, 2025). The country still operates four reactors with a total capacity of almost 3 GW, first connected to the grid from 1969 to 1984. Despite the 2017 referendum, there is a growing momentum towards reversing the earlier decision, given higher power demand and decarbonisation efforts (Reuters, 2024). Accordingly, we raise the upper bound for Switzerland to 6 GW, assuming that the country could, at maximum, double the size of its reactor fleet, given that the reactors are rather old (World Nuclear Association, 2025).

Norway, in turn, has currently no active nuclear reactor. As outlined in 4.1, the political debate in Italy, Spain, and Germany is currently discussing whether to continue (Spain) or reintroduce nuclear power generation (Italy, Germany). Consequently, in the nuclear expansion scenario, we expect a consensus among European states to give nuclear power generation a central role in the energy transition. Therefore, we raise the bound for nuclear energy from 121.3 GW by adding additions in the UK (18 GW), half the historic expansion rate in the EU27 (57.5 GW), and three more GW in Switzerland, leading to a new maximum bound of 193.5 GW in 2050, and 152.7 GW in 2040.

Expansion across regions is modelled proportionately to the growth rate between 2030 and 2050 (73%), apart from France and the UK, for which we apply the maximum government targets. Government targets for France and the UK are slightly below the projected growth rate. This is offset by including new nuclear generation in Italy of 2.5 GW in 2040 and 5 GW in 2050, assuming that Italy re-enters nuclear power generation bit-by-bit as announced by its government. A regional breakdown of nuclear energy capacity is provided for in Figure A.5.

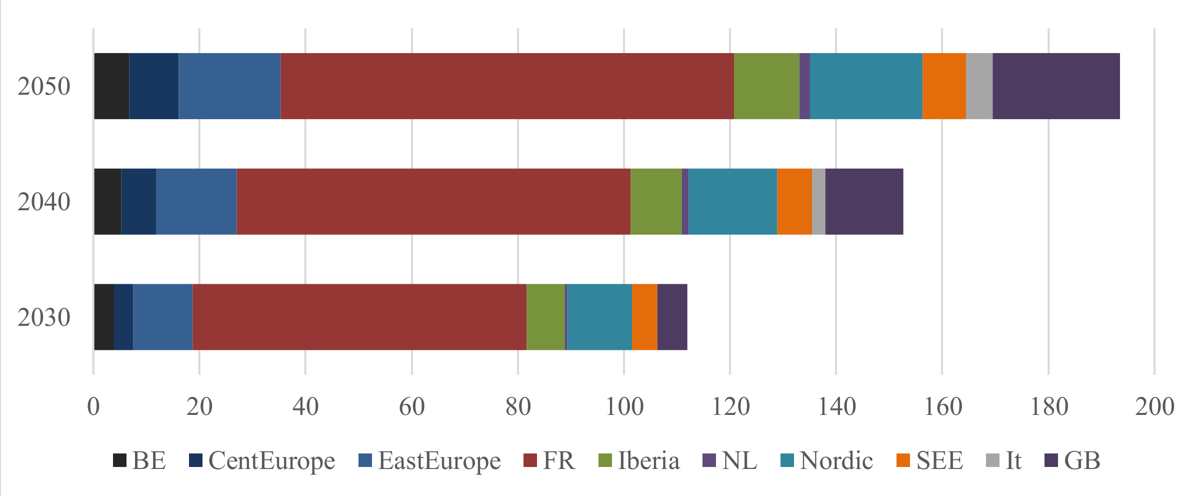

Figure A. 5: Projected growth of nuclear capacity across European regions between 2030 and 2050 in nuclear scenario (GW)

The 193.5 GW projection for 2050 is very close to the optimal power generation profile for Europe, identified by Zappa et al. (2019), of a 200 GW nuclear capacity, given that European nuclear projects achieve cost reductions as opposed to cost increases and project delays at Hinkley Point C, or Olkiluoto-3. In a study for Nuclear Europe (2024) (an industry association), Compass Lexecon assumed 200 GW of nuclear power in 2050 as realistic in the most ambitious scenario owing to a "change in paradigm, giving nuclear a central place in the transition to Net-Zero" (Nuclear Europe and Compass Lexecon, 2024). Still, it must be noted that this number includes large quantities of Small Modular Reactors (90 GW).

Methodologically, the elevation of the upper bound in the nuclear scenario does not mean that the model will necessarily opt to construct all 200 GW by 2050. It only gives it the possibility to do so. Whether the model will choose to build out nuclear capacities to its maximum will largely depend on necessary investment costs. The Asset 2018 dataset highlights an investment of 6000 € per kW to construct nuclear power capacity in 2030, 2040, and 2050. Given programme and productivity effects, large nuclear fleet programmes profit significantly from economies of scale. For example, according to the French Cour des Comptes, the construction costs for nuclear power plants sank in the different French nuclear programmes of the 1960s to 1980s by 6 %, 23 %, and 19 % between the construction of the first and last reactor of the series (OECD, 2020).

To account for these economies of scale, we apply the average of the historic French cost reductions, i.e. a 16 % cost reduction for CAPEX between 2030 and 2050. Thus, investment costs fall from €6000/kW in 2030 to €5520/kW in 2040 and €5040/kW in 2050.[32] This is slightly more conservative than the projections made in ASSET (2018), with economies of scale that include a cost reduction from €5050/kW in 2030 to €4700/kW in 2050. We omit Small Modular Reactors as a power-generating technology because the literature lacks sound data on maximum expansion potentials and investment costs. Small Modular Reactors could be considered in further research on the hydrogen market.

[32] This is a bit more conservative than the assumptions of Nuclear Europe and Compass Lexecon (2024), which estimate a 22 % CAPEX reduction for nuclear between 2025 and 2050.

10.2.6 Emissions

As we model hydrogen production endogenously, we need to back out the corresponding emissions from (grey) hydrogen production in industry. In the MIX scenario included in Chyong et al. (2024), emissions from the industrial sector stand at 659 $MtCO_2e$ in 2030 and sink to 214 $MtCO_2e$ by 2050. We use the GHG emission intensities of fossil fuels as included in Chyong et al. (2024), which for grey hydrogen stand at 0.27 tCO_2/GWh. Given total unabated hydrogen demand in 2030 of 287 TWh, industry emissions of 78 Mt are related to hydrogen production in SMR. In the 1.5 TECH scenario, around 163 TWh of hydrogen are produced by SMR with CCS in 2050. Given an expected carbon capture rate of 90% in CCS, we expect residual emissions from SMR of 16 $MtCO_2e$ by 2050. Thanks to this information, we can scale industrial carbon emissions in 2030 down from 659 Mt to 581 Mt and in 2040 from 214 Mt to 198 Mt, avoiding double counting emissions. Values for 2040 are calibrated to this using the mean of 2030 and 2050 carbon emissions.

Carbon emissions in the non-road transport sector stand at 197, 176, and 155 $MtCO_2e$ between 2030 and 2050, respectively, in the 1.5 TECH scenario. These values need to be adapted to accommodate a reduction in jet fuel demand due to an increase in e-liquids thanks to the RED mandate in 2030 and the subsequent calibration to 1.5 TECH, which further reduces jet fuel demand. Jet fuel has an emission intensity of 0.27 tCO_2e/GWh, as assumed by Chyong et al. (2024). The RED mandate reduces jet fuel demand in 2030 by roughly 6 Mtoe, 12.4 Mtoe in 2040, and 22 Mtoe in 2050. The enhanced consumption of e-liquids and bioliquids in non-road transport thus leads to emission savings of 19, 39, and 68 $MtCO_2e$ between 2030 and 2050. New carbon emissions values for non-road transport thus stand at 178, 137, and $MtCO_2e$ Mt in the RED scenarios (*baseline* and *globalisation*).

Simultaneously, we need to lower the natural gas demand in Chyong et al.'s (2024) data, as industrial hydrogen production via SMR was integrated therein. To do so, we assume that hydrogen production is exclusively supplied by unabated SMR at an efficiency rate of 76% (Collodi, 2017). This is a slight simplification, as in reality, only 90% of hydrogen production capacity in Europe is attributable to reforming. In the remaining 9% of existing capacity hydrogen is produced as a by-product (ethylene, styrene), and 1% accounts for SMR + CCS or water electrolysis (Hydrogen Europe, 2024b).

10.3 Biomass Supply and AFOLU Emission Curves

The energy model used by Chyong et al. (2024) is extended by incorporating two regressions on the level of emissions from the agriculture, forestry, and other land use (AFOLU) sector (eq. 1) and on the level of biomass potential (eq. 2). In the IPCC National Inventory framework on reporting national carbon emissions, AFOLU emissions are split into two sub-sectors, namely sector 3 "agriculture", and sector 4 "land use, land use change, and forestry" (LULUCF). The achievement of carbon neutrality in the EU hinges on LULUCF serving as a significant emissions sink, as all carbon neutrality scenarios include LULUCF emissions savings of -236 and -472 $MtCO_2/pa$ (European Commission, 2018). Combined with emissions from agriculture, they stand in the different scenarios at roughly –40 to –100 $MtCO_2/pa$, as non-CO_2 emissions from agriculture (methane, nitrous dioxide) contribute to high residual emissions. The level of emission savings from the AFOLU sector largely depends on the demand for and supply of bioenergy. An increase in the market price for bioenergy translates into higher demand, higher agricultural intensity, and thus higher emissions from AFOLU. The introduction of a GHG price in AFOLU, in turn, would incentivise more sustainable land use and reduce deforestation, thereby enhancing its function as a sink (Frank et al., 2021).

$\sum$ AFOLU Emissions = $\beta 1$ x Carbon Price + $\beta 2$ x Bioenergy Price + δt_1 + δr_1	(1)

Equation 1: Regression equation for AFOLU sector carbon emissions in Europe

To quantify these trade-offs and integrate them into the energy market model, we use data from a combination of the Global Biosphere Management Model (GLOBIOM) with the Global Forest Model (G4M) conducted by Frank et al. (2021). GLOBIOM is a partial equilibrium model that was developed by the International Institute for Applied System Analysis (IIASA). It is one of the most advanced models for exploring agricultural land use. The IIASA also created G4M, a spatially explicit forestry model to cover CO_2 emissions from deforestation, afforestation, and wood production in managed forests (Frank et al. 2021). Frank et al. (2021) combined the models to analyse competition effects between carbon mitigation targets and key SDG targets such as zero hunger, clean water, sanitation, and life on land. The data used by Frank et al. 2021 is publicly available on Github.[33]

$\sum$ Available Biomass for Bioenergy = $\gamma 1$ x Bioenergy Price + δt_2 + δr_2	(2)

Equation 2: Regression equation for the availability of biomass for bioenergy use in Europe

For our analysis, we use data included in the scenSDG scenario, which implements achieving several SDGs in 2030, as opposed to the scenBASE scenario, which does not assume that SDGs 2, 6, 12, and 15 are achieved by 2030. These SDGs include, among other things, an increase in sustainable food production (SDG 2), a reduction of food waste (SDG 12), a halt of deforestation, and the restoration of degraded land (SDG 15). These environmental and sustainability policies align with the EU's Green Deal framework, as visible in the EU's Nature Restoration Law or Farm to Fork Strategy. It can be expected that the data in the scenSDG scenario will be more in line with the EU's climate neutrality modelling as included in its 1.5 TECH scenario (see below).

Variable	Denotation	Explanation
Emissions|CO_2|Land Use	Mt CO_2/year	Carbon dioxide emissions/ removals from land use, including afforestation, deforestation, forest management, and other LUC
Emissions|N_2O|Land Use	kt N_2O/year	Nitrous dioxide emissions/ removals from land use, including agriculture, manure management, cropland soils, pasture, waste burning, savannah burning

[33] The data is accessible via the following link: https://github.com/iiasa/GLOBIOM-G4M_LookupTable

Emissions|CH_4|Land Use	Mt CH_4/year	Methane emissions from agriculture, rice production, manure management, enteric fermentation, waste burning, savannah burning
Primary Energy| biomass	EJ/year	Total biomass potential for bioenergy (energy crops, roundwood harvest, logging residues, forest industry residues, fuelwood, and other solid energy forms)
Price|Carbon	€2023/tCO_2e	Carbon price on CO_2, N_2O, and CH_4 emissions
Price|Primary Energy|Biomass	€2023/GJ	Biomass price for bioenergy use

Table A. 5: Variables used for the regression analysis

We extract key variables from the lookup table on github, as shown in Table A.5. The data is available for 10 world regions (Table A.6), a world aggregate, and 11 time points ranging from 2000 to 2100 in 10-year steps. The relevant "EUR" region includes several countries that are not part of the energy market model,[34] which we back out from the regression outputs using their historic AFOLU emissions (see methodology under data preparation). Notably, the carbon price ($0 – 3000/t) and the price for primary energy from biomass ($0 – 60/GJ) are assumed exogenously by the authors of GLOBIUM in different combinations. In each of these, the assumed prices are applied from 2020 onwards and are then raised linearly until they reach their final iteration (e.g. 3000) in 2100. The prices in the GLOBIUM dataset are at a 2000 USD price level. To adjust them to current Euro levels, we use the historic 2000 exchange rate between EUR – USD and then apply the Consumer Price Index inflation factor. We include CO_2, N_2O, and CH_4 emissions for our regression analysis. Emissions from methane and nitrous dioxide are mutated to CO_2e using their 100-year global warming potentials from the IPPC's sixth Assessment Report (GHG Protocol, 2024).

Acronym	Region	Definition
CIS	Commonwealth of Independent States	Russia, Ukraine, Former Soviet Union countries
EAS	East Asia	China, South Korea, Japan
EUR	Europe	European Union, Rest of Europe
MAF	Middle East and North Africa	Middle East, Turkey, North Africa
NAM	North America	USA, Mexico, Canada, Rest of Central America
OCE	Oceania	Australia, New Zealand, Pacific Islands
SAM	South America	Argentina, Brazil, Rest of South America
SAS	South Asia	India, Rest of South Asia
SEA	South East Asia	Indonesia, Malaysia, Rest of South East Asia
SSA	Sub-Saharan Africa	South Africa, Eastern Africa, Southern Africa, Western Africa, Congo Basin

Table A. 6: Definition of world regions as used in GLOBIUM

To approximate the trade-offs between bioenergy demand, the GHG price, and the carbon sink potential of AFOLU, we use the regression (eq. 1) above, computed in R-studio using fixed region and time effects. Emissions from AFOLU include the variables 'CO_2 emissions from land use', 'N_2O emissions from land use', and 'CH_4 emissions from land use'. As outlined in the literature review under Chapter 2, there are also important trade-offs between the supply of electrofuels from electrolysis and biofuels from bioenergy sources. To quantify these, we compute another linear regression (eq. 2) with specific fixed time and country effects to

[34] These countries are Albania, Bosnia and Herzegovina, Iceland, Kosovo, Serbia, Montenegro, and Turkey. Andorra, Monaco, and Liechtenstein were omitted as their AFOLU emissions are only marginal.

approximate the bioenergy supply in different world regions as a function of its price (i.e., bioenergy supply cost curves). Thus, eq. 2 quantifies the effects of a higher market demand for biofuels on the bioenergy supply in Europe.

Data preparation

For regression analysis, the dataset was prepared in R-studio. The variables from Table A.5 are filtered into a new data frame that is then transformed from long to panel format. The years are transformed from "X2000", "X2010" to numeric values like "00", "10", etc. To prevent double counting, certain regions are dropped from the data set. These include the less granular AFR (Middle East, Africa), ASIA (South, East, Southeast Asia), LAM (Latin and Central America), OECD (North America, Europe, Pacific OECD), and REF (Russia, Ukraine, Former Soviet Union) partition. Lastly, the world aggregate is excluded from the data frame but kept separately to be able to compare it with the regression results. Prices are transformed to €2023 levels, as explained above. The countries not included in the model are excluded based on their historic AFOLU emissions. For Turkey, Bosnia & Herzegovina, Iceland, Serbia, and Montenegro, data for 2000 was extracted from the UNFCCC Biennial Updates, while newer sources had to be used for Albania (UNFCCC, 2009), and for Kosovo modelling estimates for the year 2021.[35] Emissions from agriculture stood at a total of 64 $MtCO_2e$, while the LULUCF sector contributed emissions savings of -71 $MtCO_2e$, leading to net AFOLU emissions of -7 $MtCO_2e$. Hence, to account for the exclusion of these countries, we add 7 $MtCO_2e$ to our final regression results, reflecting that the countries are relatively small AFOLU emitters and thus unlikely to supply significant numbers of bioenergy to the European market or implement carbon prices on their AFOLU sectors. After the data preparation, the two linear regressions can be performed with fixed time and region effects with the "fixest" Package from R-studio. Fixed effects for time and region are given as an output, while the coefficients for carbon and bioenergy prices are the same across all regions and years.

	AFOLU Total	AFOLU CO_2	AFOLU CH_4	AFOLU N_2O	Biomass potential
CarbonPrice	-0.165***	-0.093***	-0.050***	-0.022***	
	(0.026)	(0.017)	(0.007)	(0.002)	
BioenergyPrice	1.907***	1.798***	-0.049***	0.158***	0.223***
	(0.301)	(0.304)	(0.007)	(0.005)	(0.020)
Num.Obs.	9240	9240	9240	9240	9240
R2	0.550	0.486	0.814	0.822	0.598
R2 Adj.	0.549	0.485	0.814	0.822	0.597
FE: Year	See Table A.9				
FE: Region	See Table A.8				
p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001					

Table A. 7: Overview of regression results with scenSDG

[35] For example, the data for Kosovo shows that its AFOLU sector is a carbon sink at -0.05 $MtCO_2e$. In Albania, AFOLU contributes to carbon emissions of 3 $MtCO_2e$.

Results for AFOLU regression

The regression for AFOLU was performed once for all three greenhouse gases (total) and for each greenhouse gas separately using the CO_2e values. In all performed regressions, the coefficients, i.e. the carbon and bioenergy price, are statistically significant at $p < 0.001$. In the AFOLU (total) regression results, the r-squared is medium strong at 55%. As expected, there is a negative impact of the carbon price on AFOLU emissions, albeit relatively small, as a one-unit increase in the carbon price yields a 0.17 decrease in emissions from AFOLU. On the contrary, a one-unit increase in the biomass price yields a 1.91 increase in emissions from AFOLU, underlying a substantial effect of the biomass price on emissions in the agriculture sector. Region and time-fixed effects are outlined in Tables A.8 and A.9 respectively. Fixed time effects show a significant reduction of emissions from AFOLU over time, from +1499 in 2000 to +404 in 2100. Regional fixed effects underline that AFOLU emissions tend to be lowest at the start in CIS, EUR, MAF, NAM, and OCE regions. In contrast, the baseline AFOLU is higher in tropical regions with intensive agricultural production, such as SSA, SAS, or SEA.

Region	AFOLU Total	AFOLU CO_2	AFOLU CH_4	AFOLU N_2O	Biomass potential
CIS	-797,74	-109,40	-516,73	-171,62	-9,12
EAS	-571,63	-271,45	-296,67	-3,51	-3,43
EUR	-616,67	-154,50	-374,47	-87,70	-6,85
MAF	-644,68	59,81	-532,38	-172,11	-10,22
NAM	-440,80	-43,06	-353,88	-43,86	-0,52
OCE	-689,27	-1,60	-506,80	-180,86	-10,23
SAM	-138,21	139,38	-202,32	-75,27	3,20
SAS	0,00	0,00	0,00	0,00	0,00
SEA	-15,71	448,75	-353,34	-111,12	-5,81
SSA	130,01	454,60	-278,79	-45,81	7,39

Table A. 8: Region fixed effects across the different regressions with scenSDG

Comparing the results for the three greenhouse gases it becomes evident that CO2 is the GHG whose emissions are decreased significantly from 529 $MtCO_2e$ in 2000 to a negative of 504 $MtCO_2e$ in 2100. The same cannot be said about CH_4, whose emissions are only slightly decreased from 709 Mt to 632 $MtCO_2e$, and about N_2O that is emitted more at the end of the century (276 $MtCO_2e$) than at the beginning (261 $MtCO_2e$). This underlines the challenge to reduce non-CO_2 emissions in the AFOLU sector.

Region	AFOLU Total	AFOLU CO_2	AFOLU CH_4	AFOLU N_2O	Biomass potential
2000	1498,53	528,93	708,83	260,77	7,49
2010	1584,02	572,81	729,67	281,55	8,25
2020	1317,69	323,56	704,86	289,26	7,91
2030	1071,86	104,55	682,81	284,51	8,25
2040	923,15	-26,60	666,67	283,08	8,47
2050	799,84	-137,30	655,39	281,75	8,50
2060	700,21	-230,82	649,43	281,60	8,46
2070	606,53	-316,21	642,54	280,21	8,45

2080	525,66	-391,77	638,34	279,10	8,24
2090	447,87	-464,49	634,85	277,50	8,17
2100	403,94	-504,26	632,27	275,93	8,35

Table A. 9: Time fixed effects across the different regressions with scenSDG

Results for biomass potential regression

The regression analysis for the total biomass potential for bioenergy shows that an increase in the bioenergy price induces greater biomass availability. The coefficient for the bioenergy price is statistically significant at $p < 0.001$ and stands at 0.22. Therefore, a one-unit increase in the biomass price for bioenergy causes a 0.22 EJ (or 61 TWh) increase in the total biomass potential for bioenergy, which is a very strong effect on the biomass potential, but is lower than in the scenBASE scenario (0.33), as the production of bioenergy under scenSDG is somewhat more limited given the higher value for biodiversity, and environmental protection. The regression model has a strong r-squared of 60 %. In previous regression runs, the inclusion of the carbon price as an independent variable was not statistically significant. Fixed time effects show that the supply of bioenergy increases gradually over time from a fixed time effect of 7.49 EJ in 2000, 8.5 EJ in 2050, to 8.35 EJ in 2100. Regions with lower biomass potential are the same regions that have lower AFOLU emissions. SSA and SAM regions hold the most considerable biomass potentials at a baseline of 7.39 and 3.2 EJ, respectively, leading all regions at big margins.

Calibration of results to 1.5 TECH

To benchmark our regression results, we compare them to the data of the European Commission's carbon neutrality modelling, namely, the 1.5 TECH scenario, which is an important scenario for the energy market model employed in Chyong et al. (2024). In 2050, the 1.5 TECH scenario assumes a carbon price of €350/tCO_2e, and a gross inland biomass consumption of 252 Mtoe or 10.55 EJ. This combination of inputs causes positive non-CO2 emissions from agriculture of 276.9 MtCO_2e and a carbon sink function of the LULUCF sector of -316.9 MtCO_2e in 2050. Therefore, net savings in AFOLU stand at – 40 MtCO_2e in the 1.5 TECH scenario in 2050 (European Commission, 2018).

1.5 TECH assumes a biomass consumption of 10.55 EJ for bioenergy purposes. We use the second regression (eq. 2) to calculate the necessary bioenergy price to achieve this level of bioenergy supply. Considering the combination of region and time fixed effects, we have a baseline biomass potential of 1.65 EJ in €/2050, on which we need to add a bioenergy price of 39.9 €/GJ to reach 10.55 EJ of biomass supply. Based on this finding and leveraging our first regression (eq. 1) net emissions from AFOLU of 201.5 MtCO_2e would be remaining, split into -253 Mt for CO_2, 262 MtCO_2e for CH_4, and 193 MtCO_2e for N_2O. These results are strikingly different from those included in 1.5 TECH for the AFOLU sector (-40 MtCO_2e). However, the 1.5 TECH scenario modelling includes not just carbon pricing as the only policy instrument to reach net zero but a range of policies and technological improvements that enable the region to reach carbon emissions neutrality by 2050 (European Commission, 2018).

Hence, thanks to technological improvements and additional policies, the carbon price in 1.5 TECH is significantly lower. To account for this difference, we use a carbon price modelled by Chyong et al. (*forthcoming*) that is necessary to reach carbon neutrality by 2050 without any further policy interventions. This economy-wide carbon price stands at roughly

€2000/t in 2050. We calibrate the results again using this extremely high carbon price. The results change significantly. The total CO_2, CH_4, and N_2O emissions decrease to -71 Mt. While CH_4 (180 $MtCO_2e$) and N_2O (156 $MtCO_2e$) are still positive, CO_2 contributes a negative 407 Mt to the sink, pushing the combined emissions down. Under this high carbon price assumption, and with a bioenergy price of 29.4, emissions are significantly higher at around + 100 $MtCO_2e$ using the scenBASE scenario. This points towards a much better sink function of AFOLU when SDG goals are achieved by 2030. To exclude the countries that are not part of the energy market model, we apply a + 7 $MtCO_2e$ increase, pushing the sink function of AFOLU slightly down to -64 $MtCO_2e$, primarily in line with the results achieved in 1.5 TECH (- 40 $MtCO_2e$). However, the latter does not include Switzerland and Norway, while these countries are part of the regression results and the energy market modelling.

Results for scenBASE

	AFOLU Total	AFOLU CO_2	AFOLU CH_4	AFOLU N_2O	Biomass potential
CarbonPrice	-0.206***	-0.101***	-0.071***	-0.034***	
	(0.029)	(0.017)	(0.009)	(0.003)	
BioenergyPrice	4.666***	4.606***	-0.117***	0.177***	0.327***
	(0.706)	(0.712)	(0.013)	(0.006)	(0.033)
Num.Obs.	9240	9240	9240	9240	9240
R2	0.520	0.485	0.750	0.822	0.542
R2 Adj.	0.519	0.484	0.749	0.821	0.541
FE: Year	See Table A.12				
FE: Region	See Table A.11				
p < 0.1, * p < 0.05, ** p < 0.01, *** p < 0.001					

Table A. 10: Overview of regression results with scenBASE

Region	AFOLU Total	AFOLU CO_2	AFOLU CH_4	AFOLU N_2O	Biomass potential
CIS	-753,445	-103,564	-484,026	-165,856	-9,03213
EAS	-364,321	-215,642	-194,087	45,40837	-2,76539
EUR	-457,177	-80,8889	-309,373	-66,9151	-6,58113
MAF	-631,668	67,07679	-527,107	-171,637	-10,3036
NAM	-249,278	42,02513	-276,718	-14,5857	1,037921
OCE	-618,147	58,94764	-492,957	-184,138	-8,85663
SAM	140,4391	336,498	-140,835	-55,2237	10,95963
SAS	0	0	0	0	0
SEA	75,7046	533,8649	-351,746	-106,415	-3,03635
SSA	288,3133	610,17	-271,899	-49,9572	10,39573

Table A. 11: Region fixed effects across the different regressions with scenBASE

Year	AFOLU Total	AFOLU CO_2	AFOLU CH_4	AFOLU N_2O	Biomass potential
2000	1377,02	456,34	672,17	248,51	5,75
2010	1462,51	500,21	693,00	269,29	6,51

2020	1193,95	246,01	670,04	277,90	5,98
2030	995,37	43,49	665,28	286,59	6,55
2040	908,12	-56,08	669,14	295,06	7,16
2050	832,47	-145,59	675,65	302,41	7,43
2060	756,95	-231,18	680,28	307,85	7,59
2070	681,19	-315,32	684,21	312,30	7,70
2080	617,14	-385,86	687,46	315,54	7,63
2090	564,02	-443,93	690,33	317,62	7,67
2100	528,73	-483,65	693,28	319,10	7,88

Table A. 12: Time fixed effects across the different regressions with scenBASE