Highlights

Prioritizing the Role of Renewable Fuels and Hydrogen Networks in the Transition towards Net Zero Emissions in Western Europe.

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- The use of renewable fuels reduces carbon dioxide emissions by 20%.
- Renewable fuels are only beneficial when used in specific applications.
- A hydrogen network facilitates the energy transition by reducing its costs by 7.5%.
- Gas infrastructures remain valuable assets for renewable gas exchanges.

Prioritizing the Role of Renewable Fuels and Hydrogen Networks in the Transition towards Net Zero Emissions in Western Europe.

Julien Jacquemin[a], Paolo Thiran[b], Sylvain Quoilin[a]

[a] *Université de Liège,, Allée de la Découverte 17, Liège, 4000, , Belgium*
[b] *UC Louvain la Neuve, Place du Levant 2, Louvain-la-Neuve, 3000, , Belgium*

Abstract

Recent developments in the European Union's energy strategy have highlighted the significance of renewable fuels for the sustainability of the continent's energy system. However, their diverse production methods and end-use possibilities, along with untapped cross-sectoral synergies, call for energy modeling to identify optimal pathways for renewable fuel production and utilization. To comprehend the complex mechanisms driving the energy transition, we analyze the potential roles of each renewable fuel and hydrogen interconnections as we increase carbon dioxide emission restrictions. Making use of the model EnergyScope MultiCell, this study encompasses the electricity, buildings, transport, agriculture, and industry sectors across Western Europe, employing an hourly time resolution. The results reveal that renewable fuels prove effective in reducing the final 20% of emissions compared to 1990 levels. Regarding hydrogen use, 80% of the 3300 TWh yearly production is used as an intermediate energy vector for producing other fuels, while the rest is used in road freight transportation and in the steel industry. A hydrogen network facilitates the energy transition by reducing its costs by 7.5%. Despite this, gas infrastructures remain valuable assets, with only 45% of hydrogen interconnections being retrofitted gas pipelines, underscoring their importance for renewable gas exchanges.

Keywords: energy system; renewable fuels; energy planing; multi-sectoral; net zero; hydrogen network

1. Introduction

In its efforts to combat climate change and reduce carbon emissions, the European Commission outlined its strategy in a series of key documents, beginning with the European Green Deal in 2019, which serves as a roadmap toward achieving carbon neutrality target by 2050. Following this, the Fit for 55 [1] legislative package was introduced to accelerate the energy transition and achieve a 55% reduction in CO_2 emissions by 2030. This package notably promotes renewable fuels as a cost-effective solution for advancing the decarbonization of the European Union (EU). More recently, REPowerEU [2] emphasized the importance of these solutions for reducing the EU's reliance on imported fossil fuels, in light of the Russian invasion of Ukraine. These documents also emphasize the necessity of a Pan-European hydrogen network to help achieve these objectives. More specifically, they focus on the use of hydrogen and its derivatives in the transport sector, whether for freight, public, or private transportation, with the goal of producing 330 TWh domestically by 2030, alongside 330 TWh of imports. In 2050, a technical report written by the Joint Research Center (JRC) forecasts hydrogen demand to reach 1300 TWh in their balanced scenario [3].

The expected increase in hydrogen demand in the near future is linked to its potential use in a wide range of applications. In the power sector, hydrogen could be used for energy storage and grid balancing using electrolyzers and fuel cells [4]. In the steel industry, it could be used to transition from basic oxygen furnaces (BOFs) to hydrogen direct reduction (H-DR) for reducing iron ore in the steel production process [5]. Ammonia, methanol, and methane could be produced from green hydrogen feedstock via processes reviewed in [6], which also presents existing and developing production projects. Medium-range flights could be powered by hydrogen by 2050, while long-range flights could be powered by green kerosene [7]. Hydrogen propulsion and its challenges in maritime shipping are also discussed in [8]. In general, the ability of hydrogen to be produced from electricity and converted into other chemicals valuable in the energy sector makes it an ideal energy vector for the decarbonization of the economy. This has led to the development of detailed studies focusing on the advantages and technical feasibility of using hydrogen or its derivatives in specific applications. Examples include the "Position Paper Fuel Option Scenarios" by The Mærsk Mc-Kinney Møller Institute [9], discussing fuel options in the shipping industry; the "Sustainable Fuels for Logistics" report of DHL [10], which explores the possible use of sustainable fuel for road freight transportation; or the "H100 Fife Neighborhood Trial" project launched by the British gas distributor SGN, which aims to demonstrate the advantages of residential hydrogen heating [11]. In a report of the Fraunhofer Institute for Energy Economics and Energy System Technology, many of these solutions are compared based on their efficiency and infrastructure requirements, and a ranking of priority sectors for the use of hydrogen or its derivatives is proposed [12].

While the insights provided by these studies are crucial, they do not consider key aspects of the problem, such as resource availability, operation of the production plants, synergies between sectors, or storage and transport requirements for the fuels. Consequently, they lack a global perspective necessary for comprehensively analyzing the problem. Since one fuel can be used in multiple economic sectors but is often produced from limited resources, it is essential to employ models that represent all these sectors. This approach helps identify which sectors are best suited for which fuels, thereby promoting global efficiency and avoiding fuel shortages in certain sectors.

The European Hydrogen Backbone (EHB) initiative, comprising a group of thirty-three energy infrastructure operators, presents their perspective on hydrogen use through a series of reports, notably forecasting production of 2300 TWh by 2050 for use in the transport, electric power, and heating sectors [13]. However, their methodology is limited to the visions and strategies of national gas and electricity transmission system operators. Recent studies using multi-sector energy models have provided an additional perspective on the role of hydrogen in the economy, complementing the operators' views. Some of these studies are conducted at the national level [14], but they simplify the mechanisms of energy exchange between countries, which limits their ability to fully represent European countries within the energy system and their associated advantages. Other studies focus on self-sufficient, carbon-neutral European energy systems but do not integrate hydrogen networks. Such an example is provided by Pickering et al. [15], who explore the space of cost-effective options to build a carbon-neutral energy system for Europe. Recent studies have analyzed the expansion and benefits of a hydrogen network. Victoria et al. provide the optimal pathway for scaling up specific technologies on our way to 2050 [16], while Neumann et al. give an analysis of the trade-offs between the expansion of the electricity grid and a hydrogen network [17]. Another interesting aspect of recent literature is the integration of Life Cycle Analyses into the standard investments-and-operation energy system modeling. Using such a methodology, Shen H. et al. notably conclude that 45% extra climate impact is caused by the dedicated 50% extra renewable infrastructure for green hydrogen [18]. However, in these analyses, the demand for specific fuels in sectors such as shipping or transportation is exogenously determined. This assumption is based on the belief that certain end-use technologies will dominate specific sectors, while others will not. In reality, determining future final energy conversion technologies depends not only on technological attributes but also on regional resource availability, fuel supply chain costs and efficiency, demand scale, and the potential for alternative uses of fuel across sectors. Such assumptions can lead to suboptimal energy system designs and should therefore be avoided.

To avoid exogenous assumptions about fuel consumption, Karlo Hainsch et al. fully endogenously optimized the capacities of technologies used to meet end-use demands [19]. Other models, such as the PRIMES [20] and TIMES [21] models, focus on determining fuel demand based on market equilibrium principles. Wolfram et al. use a similar model to conclude that the hydrogen economy can reduce the costs of climate change mitigation by 22% [22]. However, these models use time steps based on time slices rather than time steps with high temporal resolution, which creates challenges when analyzing systems with high shares of renewable energy [23].

Scientific literature lacks a high temporal-resolution multi-energy multi-sectoral energy model able to optimize endogenously the demand and use of energy carriers to meet the end-use demands. This work fills this gap by using the EnergyScope MultiCell model [24] and extending its scope by integrating additional demands. The model relies on end-use demands rather than final energy consumption, which allows for endogenously optimizing the installed capacities of the technologies used to supply demand, therefore limiting the assumption made on fuel production and utilization. Moreover, the model uses an hourly time resolution, allowing it to capture effectively the impact of fluctuating energy sources. Finally, the model covers the demands for electricity, high-temperature heat for industrial processes, space heating, hot water, space cooling, process cooling, passenger mobility, freight mobility, and non-energy materials, across the households, services, industrial, and transportation sectors.

The main contribution of this work is the evaluation of the potential role of renewable fuels in the energy transition using an energy model combining critical assets: a whole-energy system with all cross-sectoral interactions, an endogenous optimization of end-use technologies, a representation of gas pipeline retrofitting in the hydrogen network, and a high temporal resolution using an hourly resolution coupled with a typical day approach. In Section 2, the model framework is detailed along with the extensions brought in this work. Sections 3 to 7 present the results obtained and relates them to existing literature. Section 8 discusses the results and present limitations of the model and section 9 presents a conclusion.

2. Model

The program employs linear optimization to determine a solution that minimizes the investment and operating cost of the system. This solution is defined by the amount of resources used, the installed capacity of each technology, their operation at each time step, and the total cost of the system. The inputs of the mathematical model are the parameters defining the resources, the technologies, and the demands.

The energy system that is analyzed can be divided into regions. In this work, western Europe is divided into regions presented in Figure 1. Each region is characterized by its available resources, its energy conversion system, and its demands.

Figure 1: Aggregated regions considered in the model and network topology considered for hydrogen pipelines.

The resources are the primary energy sources (wood, wind, solar, hydro, fossil fuel, etc) that can be available in the region in a certain quantity, or the secondary energy vectors (electricity, hydrogen, ammonia, etc), which can only be produced from primary resources or imported from outside of the global energy system. Each resource is characterized by local and external prices, as well as a CO_2 content. The total CO_2 emissions of the system are computed by aggregating the CO_2 content of all utilized resources. Bio-resources potential of each country is assessed considering only second-generation feedstocks, using the ENSPRESO database [25].

Technologies are either conversion technologies that can transform resources into other types of resources, storage technologies that can store a resource for some time, or end-use technologies that use resources to satisfy a demand. Maximum and minimum installed capacities can be specified for each technology in each region. Renewable technologies relying on intermittent energy sources are accompanied by time series indicating hourly load factors throughout the year. The maximum installed capacity for these technologies is retrieved from the ENSPRESO dataset [1] and is a fixed parameter within the model, as displayed in

[1]https://data.jrc.ec.europa.eu/dataset/6d0774ec-4fe5-4ca3-8564-626f4927744e

Table 1.

	Wind onshore [GW]	Wind offshore [GW]	PV [GW]	Biomass [TWh]
BE-DE-LU-NL	164	81	1233	364
AT-CH-IT	189	3.4	1111	364
FR	193	12	1645	557
DK-SE	188	58	293	219
IE-UK	376	104	919	258
ES-PT	743	0.7	1501	328

Table 1: Maximum installed capacities for wind turbines and solar photovoltaic, and biomass potential for the regions considered in the model.

The model covers the demands for electricity, high-temperature heat, space heating, hot water, space cooling, process cooling, passenger mobility, freight mobility, and non-energy materials, across the households, services, industrial, and transportation sectors. These demands are represented in the model as End Use Demands (EUD), which differs from the Final Energy Consumptions (FEC). The FEC is *"the energy that reaches the final consumer's door"*, as defined by the European Commission [26], while the EUD is the demand that is met using the FEC. For example, in the context of mobility, the EUD might be the number of kilometers traveled by a person, while the FEC would be the energy consumed by the car he is using. This way of representing the demand allows for considering a broad range of possible technologies, with different inputs, efficiencies, prices, etc, to satisfy the EUD and therefore optimize one step further than models based on FEC, as illustrated in Figure 2. In the example, the vehicle could run on diesel, gasoline, hydrogen, electricity, etc. The technologies leading to a system-wide optimal solution can therefore be freely chosen by the optimizer. For each region, each demand is represented by a consumption value per year, as well as an hourly time series giving the ratio of the yearly demand that has to be met at a specific hour, for demands that are time-dependent. Demands that are not time-dependent are freight mobility and non-energy demands. They are equally distributed through the hours of the year.

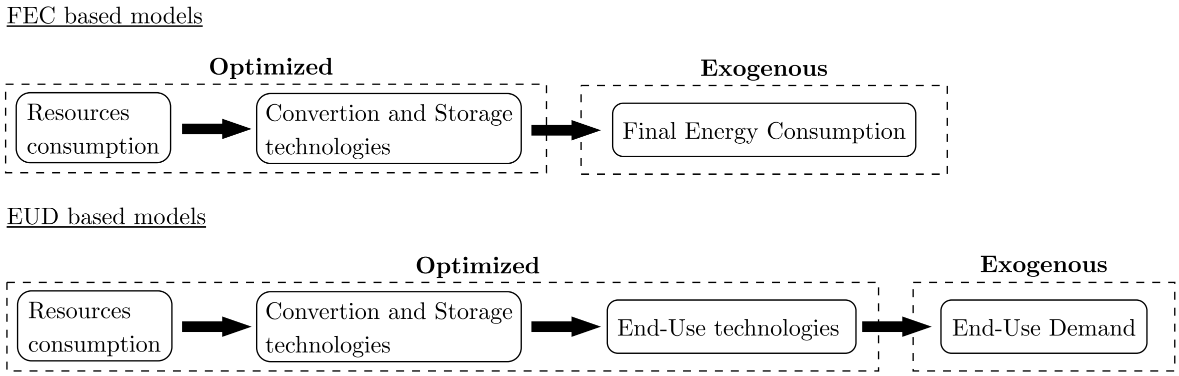


Figure 2: Optimization areas of FEC-based versus EUD-based models.

Each EUD is finally further categorized into End Use Types (EUTs). The proportion of an EUD covered by each of its EUTs is an optimized variable taking values in pre-defined intervals. These intervals allow us to take into consideration societal and technical aspects of the system, for instance, by limiting the use of public transportation to an upper bound. Every EUT is then attributed a set of technologies able to satisfy it, called "the technologies of end-use type". Each technology can also be given a minimum and maximum value for the proportion of their EUT that they must satisfy. The concepts of sectors, EUDs, and EUTs are represented in figure 3.

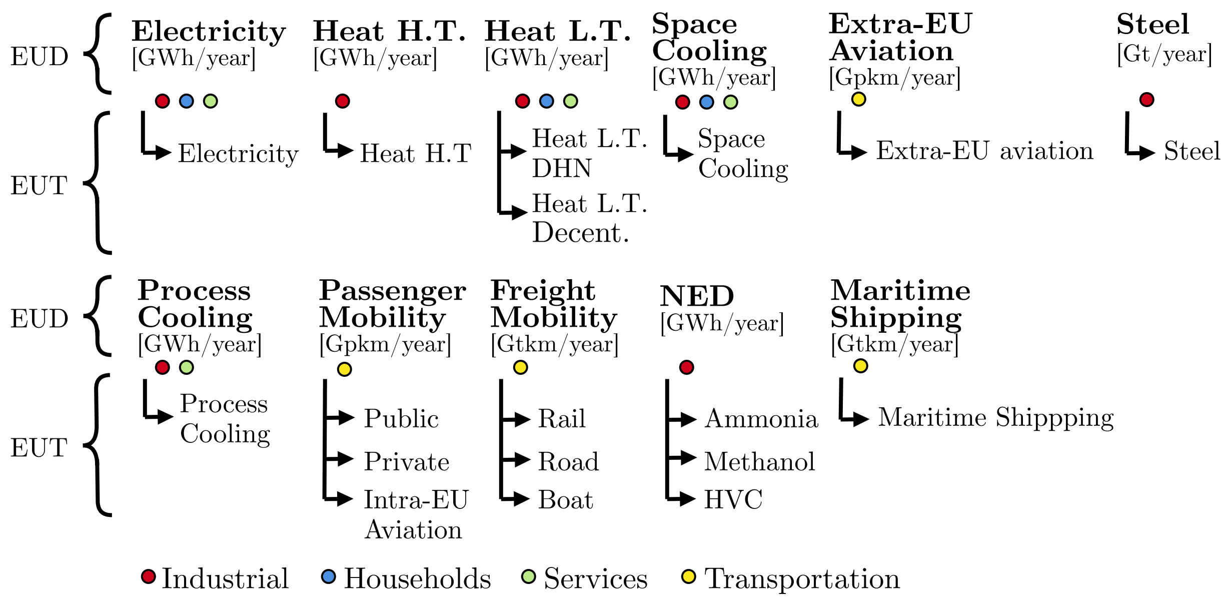


Figure 3: Structure of demand in EnergyScope MC. Abbreviations: "EUD": End-use demand, "EUT": End-use type, "Heat H.T.": High-temperature heat, "Heat L.T. DHN": Low-temperature district heat network, "Heat L.T. Decent.": Decentralized low-temperature heat, "HVC": High-value chemicals, "NED": Non-energy demand.

The working principle of the program is centered around the concept of layers. A layer represents an element that has to be balanced at every time step. The set of layers is the union between all the energy vectors considered in the model and the end-use type EUTs. Each type of energy vector, such as wood, ammonia, gas, solar irradiation, etc., must satisfy an energy balance between its inflow and outflow. Similarly, each EUT works as a layer, as it must meet its part of the demands at each time step using the dedicated technologies. The constraint ensuring the energy balance of each layer is mathematically described in Equation 1, taken from [24].

$$
\begin{aligned}
&\sum_{r \in RES} \left(f(r,l)\left(\mathbf{R}_{\mathbf{t},\text{ local}}(c,r,h,td) + \mathbf{R}_{\mathbf{t},\text{ exterior}}(c,r,h,td)\right.\right. \\
&-(1+\text{ exchanges\_losses }(r))\mathbf{R}_{\mathbf{t},\text{ export}}(c,r,h,td) + \mathbf{R}_{\mathbf{t},\text{ import}}(c,r,h,td))) \\
&+\sum_{j \in TECH \setminus STO} f(j,l)\mathbf{F}_{\mathbf{t}}(c,j,h,td) + \sum_{s \in STO}\left(\mathbf{Sto}_{\text{out}}(c,s,l,h,td) - \mathbf{Sto}_{\mathbf{in}}(c,s,l,h,td)\right) \\
&= \text{end\_uses}(c,l,h,td) \\
&\forall c \in COUNTRIES, l \in L, h \in H, td \in TD
\end{aligned}
\tag{1}
$$

The equation above involves various variables, parameters, and sets. $\mathbf{R}_{\text{t, local}}(c,r,h,td)$ represents the resource r extracted locally in the cell c, used at time step (h,td)[GWh], while $\mathbf{R}_{\text{t, exterior}}(c,r,h,td)$ represents the resource r imported by cell c from outside of the global system. $\mathbf{R}_{\text{t,import}}(c,r,h,td)$ denotes the resource r imported by cell c from the other cells of the system, and $\mathbf{R}_{\text{t, export}}(c,r,h,td)$, the resources r exported from cell c to the other cells of the system. The function $f(j/r,l)$ characterizes the output (positive) or input (negative) of all resources r and technologies j on layer l. The matrix $\mathbf{F_t}(c,j,h,td)$ denotes the working capacity of a technology j at hour h during a typical day td in cell c. The expressions $\mathbf{Sto}_{\text{out}}(c,j,l,h,td)$ and $\mathbf{Sto_{in}}(c,j,l,h,td)$ represent the output and input energy of storage j entering or leaving layer l at hour h during a typical day td, in cell c. The variable $\mathbf{EndUses}(\mathrm{c,l,h,td})$ describes the value of end-use demand required for the layer balance of an end-use demand, while being zero for the layer balance of a resource. Additionally, the sets RES, STO, $TECH$, L, H, and TD encompass all different resources, storage technologies, end-use types technologies, layers, hours of a day, and typical days, respectively.

While enforcing these constraints, the objective of the optimization is to minimize the annualized cost of the system $\mathbf{C_{tot}}$ as defined in Equation 2. The linear variables present in the equation are defined in Equations 3 to 6, both taken from [24].

$$
\begin{aligned}
\min\ \mathbf{C}_{\text{tot}} &= \sum_{c \in COUNTRIES} \sum_{j \in TECH} \left(\tau(j)\mathbf{C_{inv}}(c,j) + \mathbf{C}_{\text{maint}}(c,j)\right) + \sum_{r \in RES} \mathbf{C_{op}}(c,r) && (2)\\
\text{s.t. } \tau(j) &= \frac{\mathrm{i}_{\text{rate}}\left(\mathrm{i}_{\text{rate}}+1\right)^{\text{lifetime }(j)}}{\left(\mathrm{i}_{\text{rate}}+1\right)^{\text{lifetime }(j)}-1} && \forall j \in TECH \quad (3)\\
\mathbf{C}_{\text{inv}}(c,j) &= \mathrm{c}_{\text{inv}}(c,j)\mathbf{F}(c,j) && \forall j \in TECH \quad (4)\\
\mathbf{C}_{\text{maint}}(c,j) &= \mathrm{c}_{\text{maint}}(c,j)\mathbf{F}(c,j) && \forall j \in TECH \quad (5)\\
\mathbf{C_{op}}(c,r) &= \sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} \mathrm{c}_{op}(c,r)\mathbf{F_t}(c,r,h,td)\mathrm{t}_{op}(h,td) && \forall r \in RES \quad (6)
\end{aligned}
$$

In the above equation, $\mathbf{C}_{\text{tot}}$ represents the total annual cost of the energy system in million euros per year (Mio EUR/year). The function τ(j) denotes the investment cost annualization factor of technology j. The variable i_{rate} represents the interest rate, and "lifetime" corresponds to the technology's lifespan in years. The terms $\mathbf{C}_{\text{inv}}(c,j)$, $\mathbf{C}_{\text{maint}}(c,j)$, and $\mathbf{C}_{\text{op}}(c,j)$ represent the technology's total investment cost, yearly maintenance cost, and the total cost of resources for the cell c, respectively, all in Mio EUR/year. The parameters $c_{\text{inv}}(c,j)$, $c_{\text{maint}}(c,j)$, and $c_{op}(c,j)$ specify the technology's specific investment cost, yearly maintenance cost, and the specific cost of resources in each cell c, respectively, all measured in Mio EUR/GW, Mio EUR/GW/year, and Mio EUR/GWh. The function $\mathbf{F}(c,j)$ denotes the installed capacity concerning the primary output in gigawatts (GW). Additionally, the matrix $\mathbf{F_t}(\mathrm{c,i,h,td})$ signifies the quantity of a resource i used or produced at hour h during a typical day td. The set $TECH$ encompasses all different end-use types of technologies in the model, while T represents the set of all periods in the year (8760 hours), and $T\_H\_TD(\mathrm{t})$ corresponds to the set of typical days for periods t.

The results of this paper focus mainly on potential uses that could made of renewable fuels. In the model, those fuels are hydrogen, methanol, ammonia and synthetic fuels (synthetic gas, diesel and oil). The structure of the demand in EnergyScope as described above make it so that no exogenous assumptions are to be made regarding their use. Indeed, the model will optimize the system so as to find the best end-use technologies to satisfy the EUD.

These technologies might be powered by renewable fuel and therefore create the demand for those ones. This is the main difference with the majority of the models used in the literature, as fuel consumption is exogenously fixed in those ones. For the few ones for which this is not the case, they do not model extensively the energy system and/or do not use an hourly resolution but divide the year into a few periods, which decreases the reliability of the model when considering high penetration of renewable energy.

Due to a computational time constraint, the hourly optimization is performed for a specific number of representative days referred to as typical days (TDs). The optimal number of typical days results from a trade-off between accurate energy system representation and computational time. The selection of these days is achieved through a MILP formulation of the k-medoid method, as elaborated in [27] and adapted for EnergyScope MC in [28]. The latter paper analyses the dependence of the design error on the number of typical days and concludes that choosing 10 TDs strikes a good compromise between gain in computational time and error. A slightly higher number of 14 typical days is selected in this work.

It is finally noteworthy that a naive use of the typical days only allows to consider storage on a daily basis. However, as seasonal storage plays a major role in energy systems, levels are optimized through all the hours of the year, following a methodology detailed in [27].

EnergyScope Multi-Cells is an open source model whose code and data are freely available [2]. For the sake of clarity, the particular code and data relative to the present work are made available from a separate repository[3]. Finally, an exhaustive documentation for the latest version of the model is automatically compiled and available online [4].

2.1. Extension of the demand covered by EnergyScope for the purpose of this work

Each region modeled has its specific demand and data for 26 European countries have been gathered by J. Dommisse and J.L. Tychon, with a methodology explained in [29]. The aviation, maritime shipping, and steel production sectors have been further added to

[2] `https://github.com/energyscope/EnergyScope_multi_cells`
[3] `https://github.com/Julien-Jacquemin/EnergyScope_multi_cells`
[4] `https://energyscope-multi-cells.readthedocs.io/en/master/`

the model for this analysis because of their relevance for the hydrogen and e-fuels sectors. Demand data have been adapted from Eurostat[5] [30] and Eurocontrol [31] for aviation, the European reference scenario 2020 [32] for the international maritime shipping, and from the European Steel Association for steel production [33]. An exhaustive list of sources and methodologies for the integration of these demands into the model is available in [34].

2.2. Indroduction of hydrogen network modelling in EnergyScope

In the original model, the regions can exchange wood, ammonia, methanol, diesel, gasoline, waste, and CO_2 via freight transportation, electricity via the electricity grid, and gas via dedicated pipelines. Materials transported via freight transportation add up to the already existing land freight transportation demand [Gt-km]. The additional demand allocated to the exporting country is based on half of the distance between the two furthest cities of the country; the same applies to the importing country. The hydrogen network is not modeled, which is problematic when considering renewable fuel production in Europe.

To model adequately the construction from the ground up of a hydrogen network, the ways the costs of grids and pipeline transmission networks were evaluated in the original model have been modified. In this work, the cost of pipelines and electricity grids related to energy exchange are based on the distance between central nodes of the hydrogen network in each region, as depicted on the European Hydrogen Backbone (EHB) map [35], and adapted in the model as in Figure 1. Investments and operation costs per GW-km are computed via data from IEA [36] for the electrical grid, and from EHB reports for the hydrogen network for new and repurposed pipelines [35] [37]. The cost of gas pipelines is taken as 77% of the cost of new hydrogen pipelines [38]. The exchange capacities of hydrogen and electricity between countries are optimization variables that are constrained by maximum bounds. These bounds correspond to twice the capacities forecast in the Ten Year Development plan (2040) of ENTSO-E [39] and ENTSO-G [40]. The exchange capacities of gas interconnections are taken the same as the ones communicated in the Ten Year Development plan of ENTSO-

[5] Data code: avia_paincc and avia_paexcc

G.

The hydrogen network features the possibility of being obtained from new pipelines or repurposed gas pipelines. While repurposed gas pipelines cost 36% of the price of new hydrogen pipelines, their energy exchange capacity is 40% lower than that of the original gas pipelines. The proportion of repurposed and new pipelines is endogenously optimized by the model. Furthermore, based on reports of various manufacturers, codes and standards, compiled by Marcogas [41], it is considered in this work that gas pipelines can accept until 20% vol. of hydrogen blended in the natural gas without modification of existing infrastructure, for a majority of the utilization cases. A slightly lower value of 17.5% has been used in the study, corresponding to 5% of gas energy flow met by hydrogen.

Below are detailed the constraints added to the AMPL code and the constraints that have been modified to model the energy exchanges. Some variables are created and the syntax is simplified to ease the understanding.

Eq. 7 limits the variable $TransferCapacity$ between maximum and minimum bounds. The parameter tc_{mul} is a multiplication factor used to multiply the reference maximum bound tc_{max}. In our analysis, tc_{max} is the capacity forecast for gas, hydrogen, and electricity transmission network given in the Ten Year Development plan of ENTSO-E and ENTSO-G. tc_{mul} equals 2 for the electricity and hydrogen grid (we consider that more investment could be done), while it is equal to 1 for the gas pipelines. In the Ten Year Development plan, tc_{max} is given for the interconnection between each country. In this work, as we consider regions that are an aggregate of several countries, we summed the interconnection capacities between these regions to obtain tc_{max}, as displayed in Table 2. Eq. 7 is applied for the hydrogen and electricity network, while Eq. 8 is applied to the gas network.

From	To	Capacity [GW]
AT-CH-IT	BE-DE-LU-NL	13.25
AT-CH-IT	FR	4.17
BE-DE-LU-NL	AT-CH-IT	13.25
BE-DE-LU-NL	DK-S	12.08
BE-DE-LU-NL	FR	18.45
BE-DE-LU-NL	IE-UK	8.33
DK-SE	BE-DE-LU-NL	12.08
DK-SE	FR	0
DK-SE	IE-UK	0
ES-PT	FR	9
FR	AT-CH-IT	4.17
FR	BE-DE-LU-NL	18.45
FR	ES-PT	9
IE-UK	BE-DE-LU-NL	8.33

Table 2: Maximum capacities of reference for hydrogen interconnections between countries, in GW[9].

$$\forall\, c_1 \in \text{REGIONS},\ c_2 \in \text{REGIONS},\ i \in \text{EXCH\_NTW - \{"GAS"\}} \tag{7}$$
$$tc_{min}^{c_1,c_2,i} \leq TransferCapacity^{c_1,c_2,i} \leq tc_{mul}^{i} \cdot tc_{max}^{c_1,c_2,i}$$

Eq. 8 relates the fact that the transfer capacity plus the "will be converted" transfer capacity of gas pipeline must be between the maximum and minimum bounds. The lower bound is set almost equal to the upper bound.

$$\forall\, c_1 \in \text{REGIONS},\ c_2 \in \text{REGIONS} \tag{8}$$
$$tc_{min}^{c_1,c_2,\text{"GAS"}} \le TransferCapacity^{c_1,c_2,\text{"GAS"}} + TotalConvCapacity^{c_1,c_2} \le tc_{mul}^{\text{"}GAS\text{"}} \cdot tc_{max}^{c1,c2,\text{"GAS"}}$$

Eq. 9 constrains the total converted capacity of gas pipeline. Hydrogen capacity coming from repurposed gas pipeline should be smaller than the total hydrogen exchange capacity.

$$\forall\, c_1 \in \text{REGIONS},\ c_2 \in \text{REGIONS}$$
$$\begin{aligned}(1 - capacityLoss_{H2\,ntw})\cdot TotalConvCapacity^{c_1,c_2}\\ \le TransferCapacity^{c_1,c_2,\text{"H2"}}\end{aligned} \tag{9}$$
$$\tag{10}$$

Eq. 11, 12 and 13 evaluate the cost of the networks. Eq. 13 states that the whole cost is paid for the hydrogen pipeline capacity that does not come from the repurposed gas pipeline, while a reduced cost is paid for the repurposed capacity. Note that these costs are given per unit of hydrogen capacity.

$$\forall\, c \in \text{REGIONS},\ i \in \text{EXCH\_NTW} - \{\text{"GAS", "H2"}\}$$
$$Cost_{ntw}^{c,i} = \sum_{c_2 \in \text{REGIONS}} cost_{ntw}^{c,c_2,i} \cdot TransferCapacity^{c,c_2,i}. \tag{11}$$

$$\forall\, c \in \text{REGIONS}$$
$$Cost_{ntw}^{c,\text{"GAS"}} = \sum_{c_2 \in \text{REGIONS}} cost_{ntw}^{c,c_2,\text{"GAS"}} \cdot tc_{max}^{c,c_2,\text{"GAS"}} \tag{12}$$

$\forall\, c \in \text{REGIONS}$

$$Cost\_ntw^{c,\text{"H2"}} = \sum_{c_2 \in \text{REGIONS}} cost_{ntw}^{c,c_2,\text{"H2"}} \cdot (TransferCapacity^{c,c_2,i}$$
$$- (1 - capacityLoss_{H2\,ntw}) \cdot TotalConvCapacity^{c,c_2})$$
$$+ cost_{repurpose}^{c,c_2} \cdot (1 - capacityLoss_{H2\,ntw}) \cdot TotalConvCapacity^{c,c_2} \tag{13}$$

Eq. 14 states that the quantity of hydrogen injected in the gas network at a certain time should not be above a fixed ratio of the gas produced at that instant.

$\forall\, c \in \text{REGIONS},\ h \in \text{HOURS},\ td \in \text{TD}$

$$H2_{inj}^{c,h,td} \leq injectionRatio_{max} \cdot Gas_{prod}^{c,h,td} \tag{14}$$

parameters

- $tc_{min}^{c_1,c_2,i}$: minimum transfer capacity in GW for the resources i from the region c_1 to the region c_2.
- tc_{mul}^{i}: multiplication factor for the maximum transfer capacity of resource i. This factor is 1 for gas and 2 for electricity and hydrogen.
- $tc_{min}^{c_1,c_2,i}$: maximum transfer capacity in GW for the resources i from the region c_1 to the region c_2.
- $cost_{ntw}^{c,c_2,i}$: total cost of the network in Mio EUR/GW/year for resource i, from region c to regions c_2.
- $cost_{repurpose}^{c,c_2}$: total cost for repurposing gas pipelines into hydrogen ones in Mio EUR/GW_{H_2} /year, for transfer from region c to region c_2.
- $injectionRatio_{max}$: maximum injection ratio of hydrogen into the gas network.

- $capacityLoss_{H2\,ntw}$: ratio of capacity loss when converting a unit capacity of gas pipeline into hydrogen pipeline.

Variables

- $TransferCapacity^{c_1,c_2,i}$: Transfer capacity for resource i, from region c_1 to region c_2.
- $TotalConvCapacity^{c_1,c_2}$: Total gas capacity converted to the benefit of hydrogen exchange capacity, for transfer from region c_1 to region c_2.
- $Cost^{c,i}_{ntw}$: Total cost of the networks exporting resource i from region c.
- $H2^{c,h,td}_{inj}$: Quantity of hydrogen injected into the gas network, at hour h of the typical day td, in the region c.
- $Gas^{c,h,td}_{prod}$: Quantity of gas produced or imported from the exterior of the global system in the region c, at hour h of the typical day td.

SETS

- REGIONS: The set of all the regions modeled.
- EXCH_NTW: The set of resources that can be exchanged via a network.
- HOURS: The hours of the day.
- TD: The set of all the chosen typical days.

2.3. Scenarios

Throughout the scenarios, we analyze the potential roles of renewable fuels under different emission reduction targets, e.g. by increasing CO_2 emissions reduction from 0 to 100% compared to 1990 levels. Scenarios with and without a hydrogen network are considered so as to capture the impact of this one on the system design. Carbon capture and storage of CO_2 is not included in the model as the aim of this work is to analyze the extent to which renewable fuels could be useful to reach climate objectives. However, negative emissions technologies can be used to provide CO_2 to synthetic fuel production processes such as the production of methanol or diesel. These technologies are direct air capture and point capture, and their electric consumption is taken into account by the model. Note that no point capture technology is used in a net-zero scenario, as the CO_2 would ultimately be released in the atmosphere, and we do not consider CO_2 storage of any kind (underground, plastic, LULUCF). This is also made possible because we do not consider CO_2 emissions related to chemical processes in the industry, such as the cement production process. Imports of fossil resources are permitted, while imports of renewable resources like hydrogen or ammonia are not. This approach is motivated by the will to analyze Europe's potential to meet its demand with renewable sources in a self-sufficient manner, compared to previous and current fossil-based energy supply approaches. The reference scenario for the present analysis is defined as the one with net-zero emissions and equipped with a hydrogen network.

The model is run as an overnight optimization, following a greenfield approach. However, the current capacities of some infrastructures and technologies such as gas pipelines, electricity grid, nuclear, PVs, etc, are imposed as legacy minimum capacities in the model. The problem is made out of 12 358 013 constraints and 8 079 360 variables. We use the CECI cluster NIC5 [42] to run the scenarios. Among others, this cluster features 70 nodes with two 32 cores AMD EPYC Rome 7542 CPUs at 2.9 GHz and 250 GB of RAM. The scenarios are run using 12 of these CPUs, leading to 4 hours of computational time for the reference scenario.

3. System Design

Figure 4 illustrates the Sankey diagram for the reference scenario (net zero emissions with hydrogen network), showcasing the layers, technologies used, end-use demands, and the connecting fluxes.

To reduce CO_2 emissions, massive electrification of the system is required. Electricity production reaches 10300 TWh, compared to a current production of 2300 TWh in those regions. This electricity is produced in the majority by wind technologies (42%), solar PV (41%), and concentrated solar power (9%). The use of electricity is split between the production of hydrogen (35%), specific electrical uses (26%), the heating and cooling sectors (24%), and private electric cars (5%).

Biomass is used to produce methanol and methane. However, a significant share of those fuels is also produced from hydrogen. Methanol (1081 TWh/year) produced from biomass represents 50% of the sector while 48% of it is made from hydrogen. As for methane (544 TWh/year), 60% is made from biomass while the remaining is made from hydrogen as a by-product from the Fischer-Tropsch process.

Heating is split between decentralized (58%) and centralized structures (42%). While decentralized heating is secured by heat pumps, centralized (i.e. district) heating is met at 66.5% by industrial waste heat, which implies efficient integration of those industries inside heat demand clusters such as cities.

The electricity production undergoes a 350% increase compared to the current electricity generation for the regions considered[6]. This increase is of the same order as the tripling of today's generation forecast by F. Neuman and al. [17]. However, it should be noted that a certain amount of CCS is allowed in their model which allows for the use of a certain quantity of fossil fuel while ensuring a net-zeros emission system. However, in EnergyScope, these fossil fuels will need to be produced in a renewable manner via low-efficiency processes, which greatly increases electricity production. Moreover, the regions considered in our analysis, such as Germany and the Netherlands, have the highest proportion of hard-to-abate sectors such as the international shipping and non-energy sectors, which therefore increases the need for electricity production in net-zeros emissions scenarios, compared to regions with lower proportions of hard-to-abate sectors.

Net-zero scenarios from the European Commission [43] forecast a modest 150% increase in electricity production. Different factors can explain this difference. The first reason is that the net zeros scenario from the EU Commission considers a 45% reduction in final energy consumption, while we only reach a 30%[7] reduction which leads to a final energy

[6]Eurostat data code: nrg_cb_e

[7]Compared to the total energy consumption of the region considered, in 2020, obtained from the European reference scenario.

consumption of 8400 TWh. This reduction is mainly related to the use of heat pumps, waste heat from industrial processes, and higher engine efficiency. This difference between the two scenarios is due to the fact we do not consider energy efficiency measures such as increased home insulation or increased efficiency of industrial processes (other than electrification of heat). Also, we based our technological assumptions on the year 2035 and can therefore expect lower efficiency than their 2050 counterparts used for the commission's analysis.

A second reason would be that fossil oil and gas still account for around 12% of the gross inland consumption in the commission's analysis. This is possible thanks to CCS technologies and the accountability of negative emissions from the Land Use, Land Use Change, and Forestry (LULUCF) sector, which is not considered in our analysis. Finally, imports of hydrogen are also considered in their analysis, leading to less electricity production needed to satisfy the demand for hydrogen in Europe.

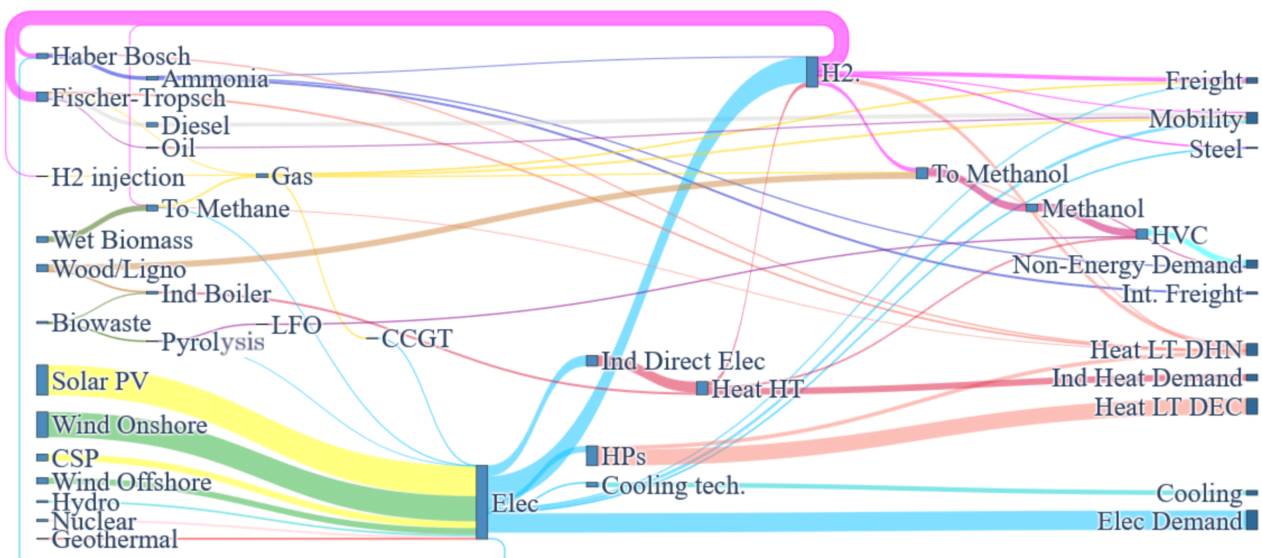


Figure 4: Sankey diagram for the yearly operation of the global optimized system, with net 0 CO_2 emissions [TWh]. Technologies with similar outputs are grouped together. Abbreviations: International maritime Freight (Int. Freight), Low-Temperature Decentralized Heat (Heat LT DEC), District Heating Network (DHN), High-Value Chemical (HVC), Combined Cycle Gas Turbine (CCGT), Industrial Boiler (Ind. Boiler), High Temperature (HT), Concentrated Solar Power (CSP), Light Fuel Oil (LFO), Heat Pumps (HPs).

4. Utilization of electrofuels

With a production of 3315 TWh/year, exclusively via electrolysis, hydrogen is mainly used as an intermediate fuel as it is the input at the origin of 67% of the renewable fuels, corresponding to 79% of its utilization. The rest of the hydrogen is mainly used for land freight transportation (580 TWh), and steel production (83 TWh) as displayed in Figure 7. The installed capacity of electrolyzers reaches 604 GW and is distributed unevenly across regions with, for instance, 31 GW in the BeNeLux & Germany region, and 217 GW in the Iberic peninsula, as presented in Figure 5.

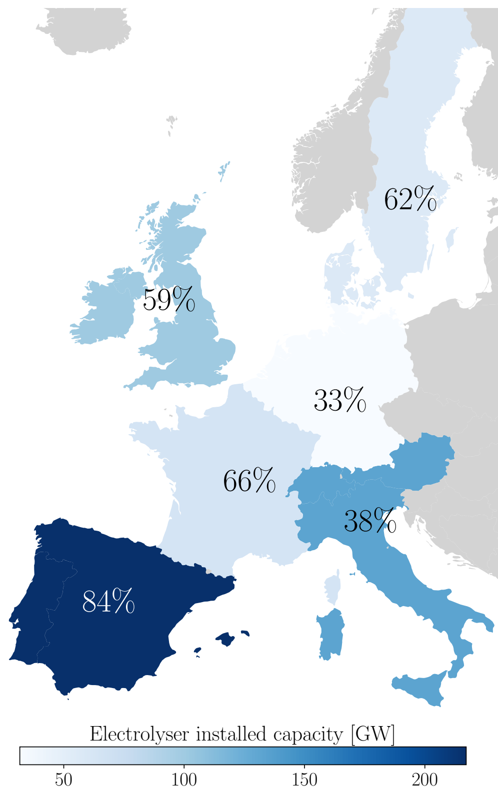


Figure 5: Electrolyzer installed capacity and their yearly load, per region.

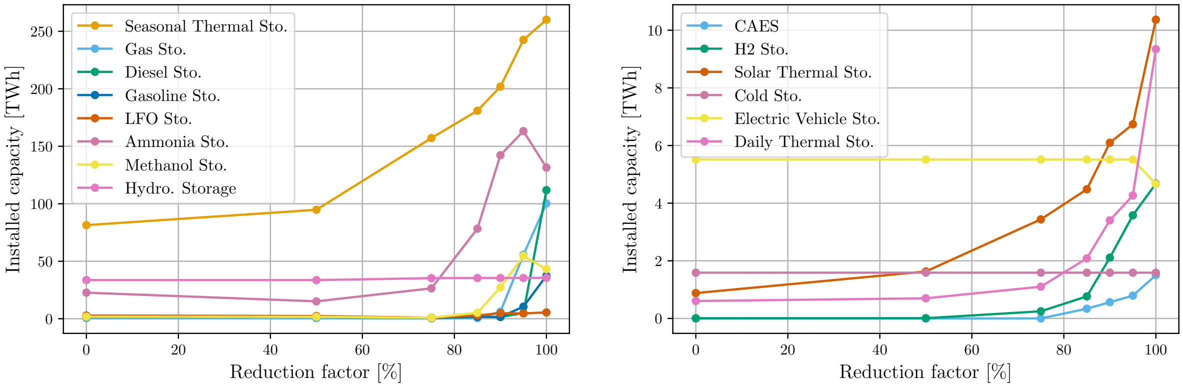
Hydrogen is used at 40% for the production of synthetic fuels via the Fischer-Tropsch process. The process is dedicated here to the production of jet fuel for the aviation sector. However, due to the imperfect selection of the hydrocarbon fraction, lower fractions are also present in the output, leading to a significant production of gasoline and gas as side-products.

The gasoline is used in the mobility sector for private cars and represents 18% of the private car sector. However, these cars are exclusively used in the BeNeLux & Germany region. Due to their lack of renewable resources, these countries are favored for the exportation of this side-product from Spain. On the other hand, gas, which is also produced from biomaterials, is used for freight transport in inland boats, in public buses, and for re-electrification in the BeNeLux & Germany region and in the Italy, Swiss, and Austria region.

18% of the hydrogen is used in the Haber-Bosch process to produce ammonia, which is subsequently used to produce fertilizer and to power ammonia fuel cells in cargo ships. Ammonia is used for shipping due to its efficient production pathways and efficient end-use in fuel cells. Even when considering the same propulsion efficiency for methanol and ammonia, ammonia is the favored energy vector. Finally, 13.5% of the hydrogen is used to produce methanol, which is exclusively used in the non-energy sector.

Regarding hydrogen production, the EU Commission forecasts 511 GW of electrolyzer capacity, which represents 0.04 GW per TWh of final energy consumption, compared to 0.071 in this work and 0.087 in [17]. The commission considers CSS technologies and negative LULUCF emissions and therefore allows for a significant fossil energy use. The need for renewable fuels is thereby reduced and the installed electrolyzer capacity is lower. Load factors obtained in the results are displayed in Figure 5.

Differences exist between the view of the EHB and the output of the model regarding hydrogen use. While hydrogen is not used at all for heating or power generation in this analysis, the EHB sees 350 TWh of hydrogen used for industrial and domestic heating and 650 TWh for power generation. The results obtained in the present work are more in line with the mainstream concept of "Clean Hydrogen Ladder" [44], with mild differences when it comes to land freight transportation and long-term storage of hydrogen. The former sector uses large quantities of hydrogen in the present results, while the latter is not selected by the optimizer, in favor of long-term storage under the form of synthetic fuels (Figure 6).



(a) Seasonal storage. *(b) Daily storage.*

Figure 6: Evolution of daily and seasonal storage capacities with increasing CO_2 emission constraints.

Direct use of hydrogen for freight transportation is prioritized when considering increased constraints on CO_2 emissions. It is followed by the use of ammonia for international shipping, the use of methanol for non-energy demand, and finally the use of synthetic fuels for aviation. Renewable fuels derived from hydrogen make their appearance after 85% CO_2 emissions restriction. This aligns with other works, in which the last 10% of decarbonization will be the most challenging due to the adoption of emerging, costlier technologies to address the remaining small fraction of hard-to-abate sectors [45]. In scenarios considering CO_2 storage or LULUCF negative emissions, aviation should be the first sector to benefit from fossil fuel utilization.

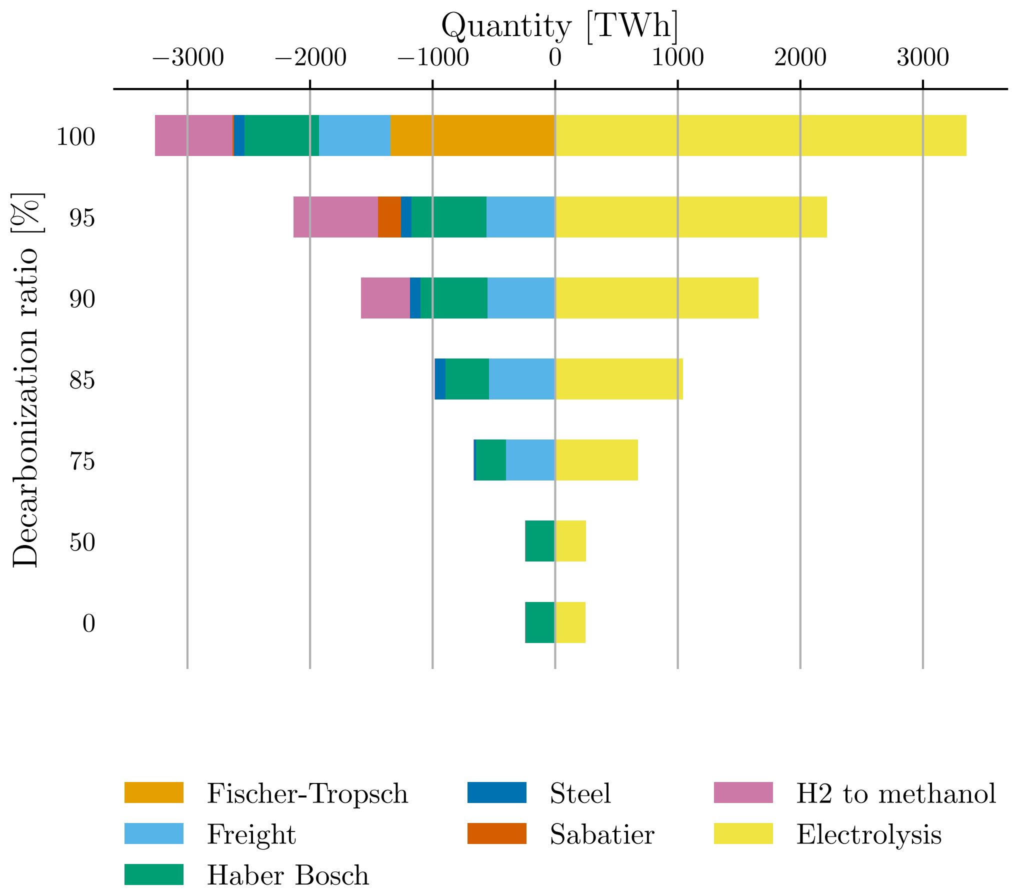


Figure 7: Production and consumption of hydrogen.

5. Impact of renewable fuels in the energy transition

Figure 9 illustrates the increase of the system costs in Mrd EUR/year, relative to the cost of the 0% CO_2 system, encompassing discounted investment costs and annual operation and maintenance costs, as CO_2 emissions decrease.

The cost trajectory can be divided into three segments: from 0 to 50%, 50% to 85%, and 85% to 100% reduction. The cost increase in the first segment is relatively small, while it is much more substantial in the second and the third.

- In the first segment, the reduction in CO_2 emissions is achieved by substituting coal-based electricity production with renewables and gas-based electricity. This design change allows for abating 50% of the CO_2 emissions with almost no cost implications. It does not constitute true electrification, as total electricity production remains relatively unchanged. However, it should be noted that heat pumps are used from the start of decarbonization and the evolution of home heating electrification is therefore not captured.

- The system electrification and the take-off of the direct use of hydrogen take place in the second segment, during which electricity production increases by 1880 TWh.
- The third phase marks the extensive use of hydrogen-derived fuels. These fuels could contribute to abate the last 20% of EU emissions but their use would contribute largely to the price of the energy transition.

In case only renewable fuels are used to reach net zero, the abatement cost of the last ton of CO_2 would be as high as 870 euros/ton_{CO_2} (Figure 8). It would drop down to 300 euros/ton when using CO_2 sequestration according to findings by M. Victoria et al. in her study over the speed of technical transformations required to reach our climate objectives[16], compared to about 90 €/ton in the current ETS market. This result further reinforces the "10% concept", according to which the last 10% of emission reductions are the most challenging, at least with the technologies available today.

Figure 9 shows that a hydrogen network is only useful when used alongside renewable fuels, which is in agreement with findings from [16], in which a hydrogen network only appears in 2035 after strong electrification of the demand and installation of electrolysis plants.

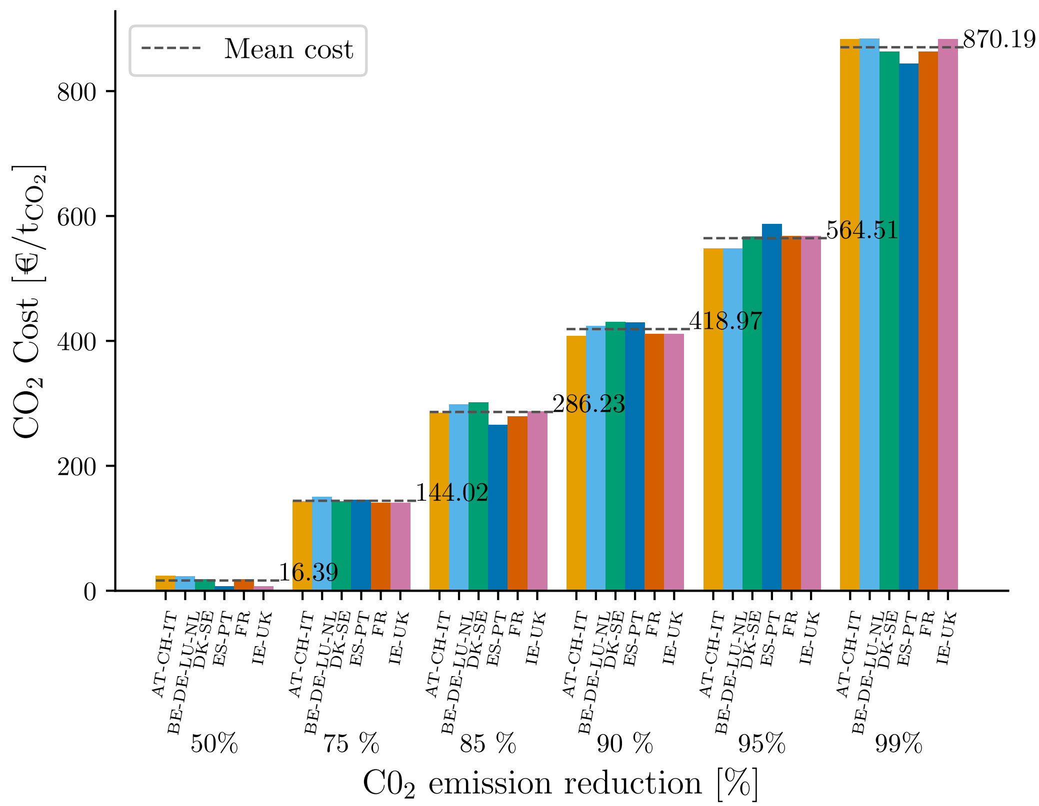


Figure 8: Evolution of the abatement cost for the last ton of CO_2 with increasing CO_2 emission constraints.

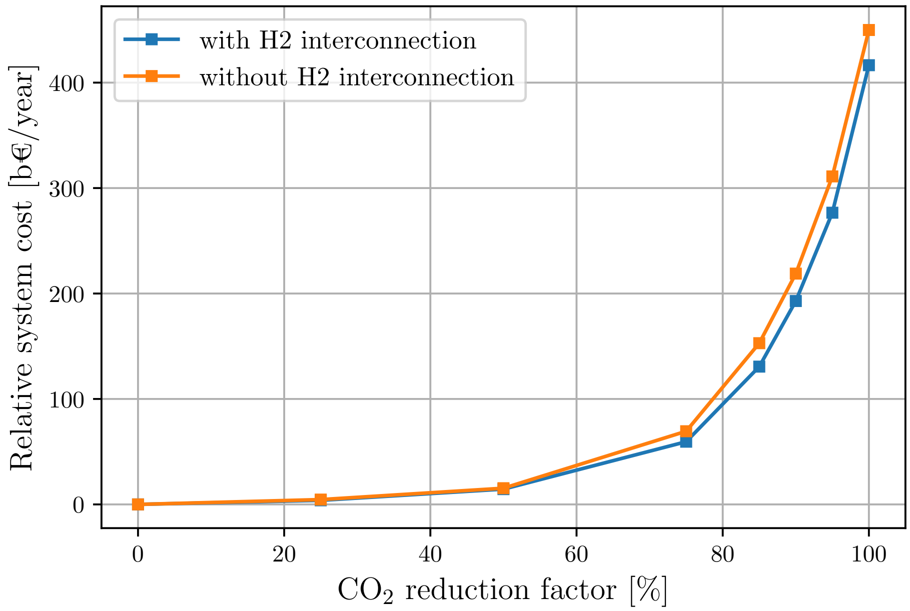


Figure 9: System total price when considering hydrogen interconnections or not, with increasing percentage of CO_2 emissions reduction, compared to 1990. The cost is given relatively to the cost of a system without CO_2 emissions constraints

Figure 10 provides insights into the sectors most impacted by the decarbonization process. Transitioning from 0 to 100% emission reduction results in a system cost increase of 417 Mrd EUR/year in the reference scenario. The distribution of costs across sectors and infrastructure is illustrated in the same figure. Prices used for fossil fuels are 0.04, 0.06, 0.08 and 0.1 EUR/kWh for gas, LFO, gasoline and diesel respectively.

The shift of electricity production towards renewable technologies necessitates 341 Mrd EUR/year. These technologies rely on variable energy sources, thus requiring grid reinforcement and storage facilities, contributing to an indirect cost of 191 Mrd EUR/year. Conversion technologies play a role in transforming electricity into energy vectors suitable for challenging-to-electrify sectors, such as aviation, maritime, and non-energy sectors. Electrolyzers, Haber-Bosch, Sabatier plants, and other conversion technologies contribute to a 154 Mrd EUR/year increase in the system cost. After electrification, the mobility and heating/cooling sectors transitioned to more expensive but efficient technologies, including hydrogen fuel cells and electric vehicles. Additionally, reducing fossil fuel imports enables regions to save 322 Mrd EUR per year when comparing the two scenarios.

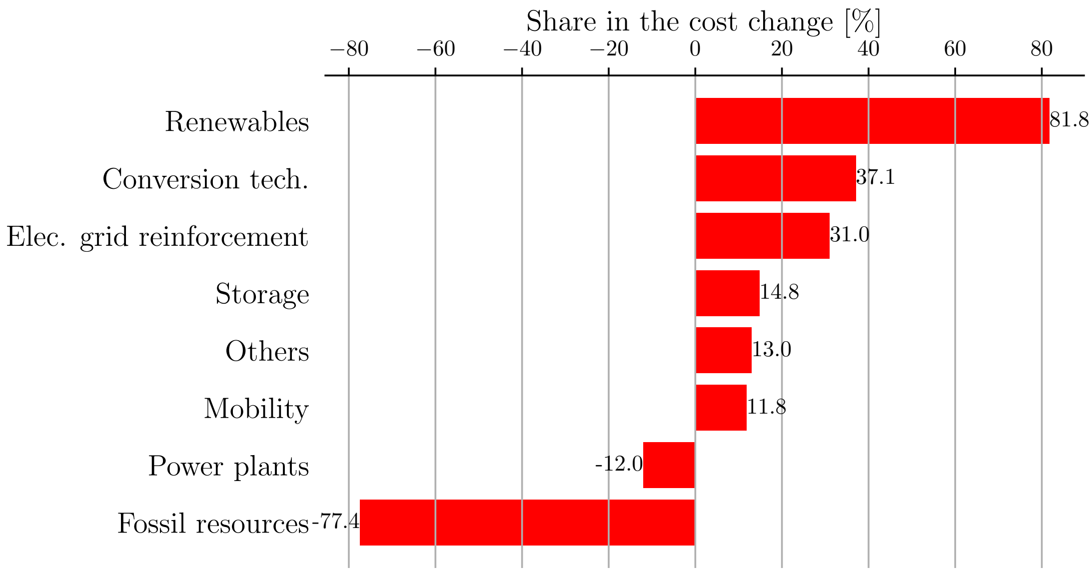
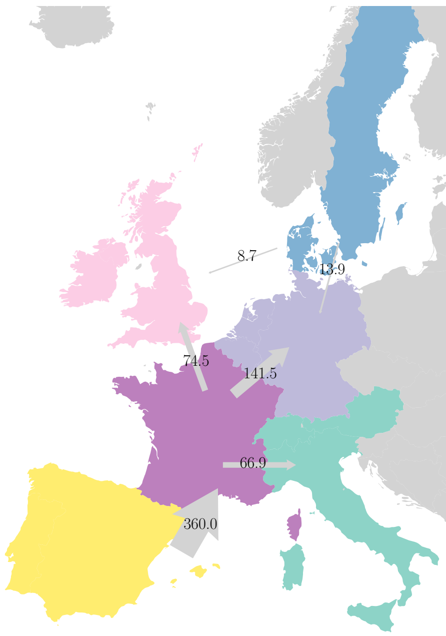


Figure 10: Allocation of system cost difference between 0% and 100% CO_2 emissions, categorized by groups. "Renewables" comprises all the renewable electricity production technologies, "Conversion tech." are all the conversation technologies, "Elec. grid reinforcement" refers to the cost necessary to reinforce the grid due to renewable penetration, "Storage" are storage technologies, "Others" are all the end-use technologies not represented elsewhere in the graph, "Mobility" are the end-use technologies for mobility, "Power plants" are the electricity production plants that are not renewable and "Fossil resources" refers to the importation or exploitation of fossil resources.

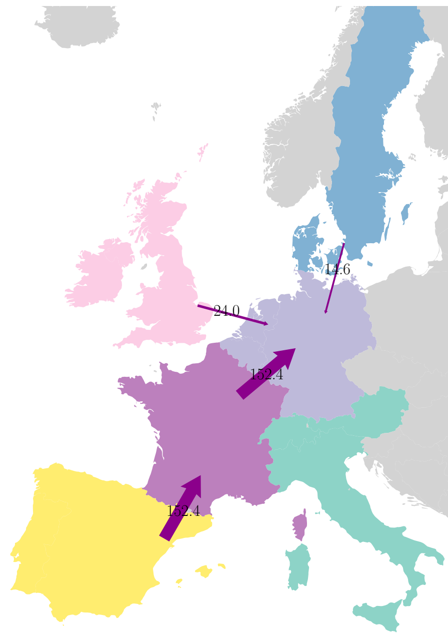
6. Impact of a hydrogen network on system cost and design

Figure 9 shows that a hydrogen network could decrease the cost of energy transition by 7.5%. In contrast to the findings presented in [17], the advantageous outcome attributed to the hydrogen network does not primarily manifest as a mitigation of electricity network bottlenecks. Instead, it resides in the use of more efficient technologies within central Europe, thereby contributing to a reduction in the required installed capacities of renewable sources, as detailed in Figure 14. Indeed, when no hydrogen network is considered and electricity lines are saturated, energy is exported to the center of Europe (energy intensive) via the already existing gas pipelines. This renewable gas, obtained from biomass or electricity via low-efficiency processes, is then used inefficiently in further conversion processes or in combustion engines. Building a hydrogen network allows to transport efficiently a chemical that is the ideal intermediate to produce ammonia or methanol, leading to a more straightforward and efficient production chain for these fuels. Moreover, ammonia can be used in fuel cells to power container ships, leading to an efficiency gain compared to propulsion using natural gas.

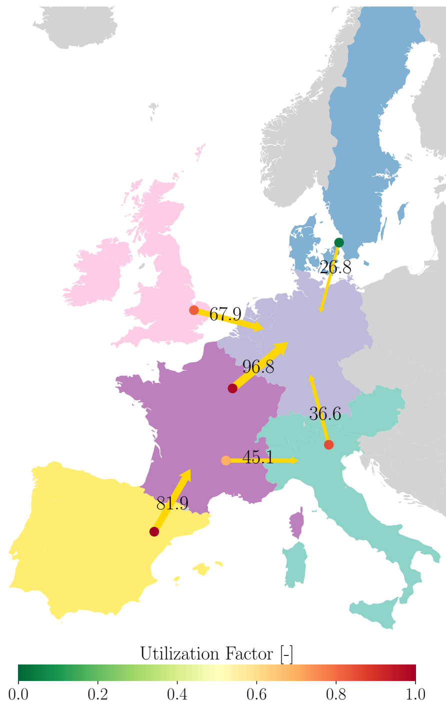
The cost difference between a system with and without a hydrogen network is building up thanks to the direct use of hydrogen in freight transportation, steel, and ammonia production, but is not influenced by the increase in production of methanol or synthetic fuels as shown in Figure 9. This is because methanol and synthetic fuels can be transported between countries via road freight transportation in a cheap way. This makes the local production of these fuel and their transport by freight cheaper than exchanging hydrogen and producing the fuels abroad. The exchange of hydrogen to produce synthetic fuels or methanol would indeed lead to an exchange of hydrogen that will subsequently be lost during energy conversion processes, meaning that a significant part of the hydrogen network serves no purpose other than transporting energy that will be lost. It is therefore more cost-efficient to reduce the size of the hydrogen network and exchange the other fuels via road freight transportation.



(a) Diesel exchange.



(b) Gasoline exchange.



(c) Gas exchange.

Figure 11: Exchange of synthetic fossil fuels between Western European countries in the reference scenario.

Diesel exchange between Spain and France amounts to 360 TWh/year, followed by the exchange of gasoline and methanol with 150 and 120 TWh/year, respectively (Figure 11).

Due to the ability to transport large quantities of energy via electricity, hydrogen, and other renewable fuels, Spain stands out as Europe's renewable fuel factory, with 217 GW of electrolyzer installed capacity and supplying 13% of the total FEC of the other countries. In addition to technical, logistical, and societal complications that could arise with building such a capacity in a single region, this could create energy autonomy problems for the rest of Europe, especially for the BeNeLux and Germany regions.

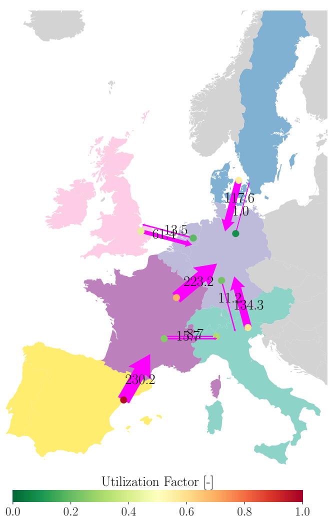


Figure 12: Yearly hydrogen exchange in Twh.

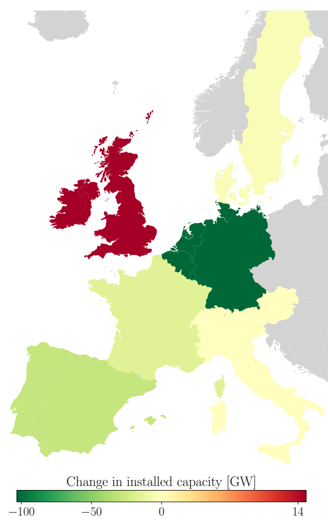


Figure 13: Change in renewable installed capacities between the scenarios with and without hydrogen network.

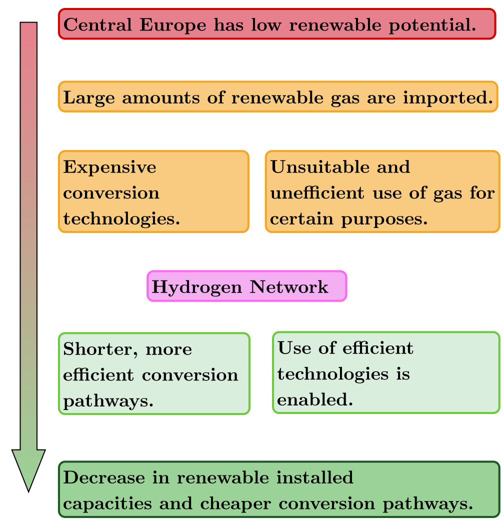


Figure 14: Process by which the hydrogen network decreases the system cost.

7. Design of the hydrogen network

Table 3 shows that the network is oriented towards providing energy to the BeNeLux and Germany region. It taps into solar resources in the south and wind resources in the north. As discussed in the previous section, the hydrogen network helps develop simpler production and conversion pathways and allows using more efficient technologies in central Europe. The hydrogen network can be composed of newly built pipelines or pipelines repurposed from natural gas. The proportion of pipeline repurposed is endogenously optimized by the model. The capacity of hydrogen interconnection is optimized but is limited to a maximum equal to twice the forecast for 2040 from the TYNDP of the ENTSO-G.

Gas is used for freight transport in boats, in bus transport, and to be turned back to electricity in central Europe. It is obtained from biomass and is also a by-product of the Fischer-Tropsch process. Table 3 provides insights into the design of newly constructed and repurposed hydrogen interconnections, differentiating between three design types. The first design type involves surplus gas transfer capacity, which can be readily converted to hydrogen capacity. Here, all hydrogen transfer capacity is derived from repurposed gas pipelines. The second design type pertains to critical inter-regional energy transfer routes, exemplified by the Spain/BeNeLux route. For such routes, the optimizer maximizes the available transfer capacity for every energy vector, resulting in the exclusive construction of new hydrogen pipelines, with no repurposed gas pipelines. The third design type is a mix of both approaches. Overall, 45% of the hydrogen exchange network is repurposed from existing gas pipelines, which corresponds to 24% of the gas network being repurposed. These findings assign a larger share of synthetic natural gas exchanges compared to other studies. For instance, the EHB proposes that 60% of hydrogen exchange capacity could originate from gas pipelines [35], rising to 69% in [17]. The same study estimates a range of 29% to 49% of the gas network converted into hydrogen pipelines.

From	To	H_2 Capa. [GW]	$\frac{H_{2,\text{ repurposed}}}{H_{2\text{ tot}}}$	$\frac{\text{Gas}_{\text{ repurposed}}}{\text{Gas}_{\text{ tot}}}$
BE-DE-LU-NL	IE-UK	8.7	1	0.23
BE-DE-LU-NL	AT-CH-IT	5.8	1	0.33
DK-SE	BE-DE-LU-NL	24	1	0.3
ES-PT	FR	27	0	0
FR	BE-DE-LU-NL	36.92	0	0
FR	AT-CH-IT	7.1	0.29	0.32
AT-CH-IT	BE-DE-LU-NL	26.5	0.57	0.84
IE-UK	BE-DE-LU-NL	16.67	0.64	0.65

Table 3: Gas and hydrogen exchange networks design.

8. Discussion and limitations of the work

The present work focuses on the design of a self-sufficient Western Europe energy system and shows that such a system is technically feasible. It is however important to note that energy imports from non-considered European countries could impact the optimal energy exchange routes obtained in the present simulation. Increasing the geographical scope of the model could for example results in more energy imported from the East and less from the South. Also, considering the import of renewable fuels from international energy hubs is not allowed in the present simulation, but could significantly impact the design of the European system and might even result in a more cost-effective design.

Interestingly, the results obtained in this work exhibit an uneven spatial distribution between production and consumption in Europe, with Spain and Portugal massively producing energy and the BeNeLux & Germany importing large quantities of energy. This can only be allowed by a sustained deployment of the interconnection infrastructure, which might be hindered e.g. by social acceptance issues and might prevent reaching the design detailed in this report. Energy security concerns by individual EU countries might also lead to a more even distribution of the generation capacity than the one computed here, which is sub-optimal from a modeling perspective but justifiable from a political point of view. Future work might usefully include an energy sufficiency constraint for each individual country.

It is important to note that the optimization performed in this work is an overnight (also sometimes referred to as "snapshot") optimization under increasing emissions constraints. A legacy capacity is assumed, but all the new capacity additions are assumed to happen simultaneously. This is opposed to pathway scenarios in which the system is re-optimized at regular times steps (e.g. 5 years) under evolving boundary conditions. Our approach allows reducing the uncertainty relative e.g. to long-term cost evolution, but the results clearly lack a time perspective. This approach however allows to simplify the analysis and directly relate the required technological changes to the CO2 reduction ambition.

The capacity factors of the renewable technologies are considered constant in each area. However, they might decrease because the most profitable locations are selected first, or they might increase due to technical improvements. These effects are not contemplated in the present work and are left for future works.

It has been demonstrated that energy system designs obtained via linear optimization can vary significantly with a limited impact on the cost objective function [15]. This involves that near-optimal solutions exist and might more easily be put into application when considering factors not taken into account in the model, such as resource availability or social barriers. Even though these aspects are mentioned while discussing the results, a formal near-optimal space analysis such as the one proposed in [15] could usefully be included in the definition of the scenario.

Regarding road freight transportation, improvements to the model to better represent the cost of hydrogen use related to charging network infrastructure are planned for future versions. Similarly, for inland waterways freight transportation, the addition of hydrogen and electricity technologies to the existing set (diesel, methanol, and natural gas) is considered relevant.

From the results on energy storage capacities presented in Figure 6, we deduce that hydrogen storage is primarily used in the later stages of decarbonization to temporarily store hydrogen before its conversion into other chemicals, in order to maximize the utilization rate of those industries. However, we would like to emphasize that storage in salt caverns is not currently represented in the model, but it could significantly improve the profitability of long-term hydrogen storage, as its cost could approach that of storing methanol, ammonia, and other renewable fuels [46]. The implementation of hydrogen storage in salt caverns is therefore considered for future model improvements.

Finally, it is worthwhile to note that all the proposed models, methods, and data are released with an open license to ensure transparency and reproducibility of the work [47]; they can be freely downloaded, adapted and re-used from a dedicated Github repository[8].

[8] https://github.com/Julien-Jacquemin/EnergyScope_multi_cells

9. Conclusions

In this work, the multi-sectoral multi-energy model EnergyScope MultiCell has been extended and used to analyze the potential role of renewable fuels in the decarbonization process of Western Europe. The model endogenously optimizes the end-use technologies, which is highly relevant for this analysis since it allows us to get rid of the exogenous assumptions on fuels utilization across sectors.

The study demonstrates that Western Europe has the potential to achieve self-sufficiency in meeting its energy demands with net-zero CO_2 emissions, driven by strong synergies across various energy sectors. This achievement remains attainable even without relying on CO_2 storage. However, reaching such ambitious decarbonization goals comes at a cost, with an increase of 417 billion euros per year (+25%) compared to the optimal system design with 1990 emission levels.

Renewable fuels play a pivotal role, particularly in the latter stages of decarbonization (above 85%), effectively addressing emissions in challenging sectors. Their utilization results in a substantial increase in system costs due to the adoption of expensive conversion technologies and the massive increase in electricity needs, which entails significantly higher costs to decarbonize the last 10%. Biomass and hydrogen contribute significantly to renewable fuel production processes, accounting for 33% and 67% of the processes' inputs, respectively. Hydrogen's utilization is predominantly focused on its conversion into other energy vectors, accounting for 79% of its application. Some hydrogen applications are more suitable than others and should be prioritized. This can be seen when considering increasing levels of decarbonization, with the direct use of hydrogen in road freight transportation and steel production showing up first, followed by the use of ammonia in ship propulsion, methanol for plastic and chemicals, and at last synthetic fuels for aviation.

The usefulness of a hydrogen network becomes evident after surpassing the 50% emission reduction threshold, coinciding with the initiation of direct hydrogen use within the system. In a fully decarbonized scenario, a hydrogen network leads to a system cost reduction of 1.7% (equivalent to 34 billion euros per year), representing approximately 7.5% of the overall energy transition cost. This reduction is primarily attributed to a decrease in the installed capacity of renewable electricity production technologies across Europe. The benefits of the hydrogen network are mainly related to the direct use of hydrogen and ammonia to satisfy the demand, as other fuels such as synthetic fossil fuels or methanol can be exchanged by freight. The exchange of hydrogen to produce synthetic fuels would indeed lead to an exchange of hydrogen that will subsequently be lost during energy conversion and therefore unnecessarily large hydrogen interconnection. Spain provides 950 TWh/year or 13% of the final energy demand of the other regions, which is a key challenge in terms of interconnection infrastructure. This uneven distribution also raises questions regarding the energy autonomy of the different countries in Western Europe.

Renewable gas and repurposed gas pipelines remain relevant even in a fully decarbonized energy system. Notably, only 24% of gas pipelines are repurposed, contributing to 45% of the future hydrogen exchange network. These findings underscore the importance of renewable gas, more than other literature forecasts where gas pipelines constitute 60% to 70% of the hydrogen network through repurposing.

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