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Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization

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HIGHLIGHTS

- Power-to-Liquid (PtL) can reduce import costs and improve EU energy independence.
- Biomass-to-Liquid (BtL) combined with PtL boosts production of carbon neutral fuels.
- Electrolysis potential is the largest when there is limited carbon storage.
- Transport demand is met by electricity and hydrogen complemented by PtL/BtL.

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ABSTRACT

Hydrogen represents a versatile energy carrier with net zero end use emissions. Power-to-Liquid (PtL) includes the combination of hydrogen with CO_2 to produce liquid fuels and satisfy mostly transport demand. This study assesses the role of these pathways across scenarios that achieve 80–95% CO_2 reduction by 2050 (vs. 1990) using the JRC-EU-TIMES model. The gaps in the literature covered in this study include a broader spatial coverage (EU28 +) and hydrogen use in all sectors (beyond transport). The large uncertainty in the possible evolution of the energy system has been tackled with an extensive sensitivity analysis. 15 parameters were varied to produce more than 50 scenarios. Results indicate that parameters with the largest influence are the CO_2 target, the availability of CO_2 underground storage and the biomass potential. Hydrogen demand increases from 7 mtpa today to 20–120 mtpa (2.4–14.4 EJ/yr), mainly used for PtL (up to 70 mtpa), transport (up to 40 mtpa) and industry (25 mtpa). Only when CO_2 storage was not possible due to a political ban or social acceptance issues, was electrolysis the main hydrogen production route (90% share) and CO_2 use for PtL became attractive. Otherwise, hydrogen was produced through gas reforming with CO_2 capture and the preferred CO_2 sink was underground. Hydrogen and PtL contribute to energy security and independence allowing to reduce energy related import cost from 420 bln€/yr today to 350 or 50 bln€/yr for 95% CO_2 reduction with and without CO_2 storage. Development of electrolyzers, fuel cells and fuel synthesis should continue to ensure these technologies are ready when needed. Results from this study should be complemented with studies with higher spatial and temporal resolution. Scenarios with global trading of hydrogen and potential import to the EU were not included.

1. Introduction

Global surface temperature has already increased by 0.9 °C and global mean sea level has already risen by 0.2 m compared to pre-industrial times. To limit the temperature increase to 2 °C by 2100, cumulative emissions over the 2012–2100 period have to stay within 1000 $GtCO_{2e}$. Delayed action will only lead to more drastic changes required later on to stay within the carbon budget [1]. To achieve this target, key alternatives are carbon capture and storage (CCS), sustainable biomass use, energy efficiency and renewable energy sources (RES). Hitherto, a lot of attention has been given to the power sector, which is the one with the highest RES penetration mainly through the

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contribution of hydropower, wind and solar. Nevertheless, for a fully decarbonized system, the emissions from all sectors of the energy system (power, heat, transport), but also non-energy related sectors (e.g. agriculture and land use) have to be eliminated.

A promising option to decarbonize all sectors is to use a versatile energy carrier that can be easily transported and converted in mechanical power, heat and other forms of energy. This has been the motivation to propose an electricity based economy and hydrogen economy [2–5]. In spite of fulfilling the requirement of versatility, electricity has two main disadvantages. First, there are no existing technologies to directly store large amounts of it for long (> 1 month) periods of time. The best (fully developed) technology is pumped hydro storage, which constitutes more than 99% of existing electricity storage capacity [6]. However, in its conventional configuration, it is limited by geographical constraints (e.g. existence of reservoirs, height difference and water source) and its potential might still not be enough to satisfy the needs of a fully renewable system [7]. The other disadvantage of electricity is that sectors like aviation and maritime transport present challenges for electrification due to weight, drag and space requirements.

Hydrogen can provide a solution for transport, while still being a versatile energy carrier to be used across sectors. Tail pipe emissions for hydrogen are zero since it does not contain carbon. Instead, its emissions are defined by the production technology and upstream value chain [8–12]. A proposed route for a low CO_2 footprint is to use RES electricity for hydrogen production with electrolysis. This would allow moving away from fossil fuels in transport, which can contribute to energy security (electrolyzers can be installed locally and produce hydrogen from local RES sources), lower market volatility (oil is a global market continuously affected by upheavals and political interests) leading to more stable prices and smaller effect on consumers. With hydrogen, the end use technology can change to a fuel cell rather than an internal combustion engine leading to a higher efficiency[2] and less energy required per traveled distance. It can complement the usually shorter range of electricity vehicles. Fast response electrolyzers can provide flexibility and balancing to the power system while reducing curtailment. Lastly, it can have distributed applications where hydrogen is produced and consumed locally. Among its disadvantages are the infrastructure development needed, the current high costs for electrolyzers and fuel cells where the potential development is linked to learning curves and technology deployment, their efficiency loss (typical efficiencies for electrolyzers are 65–75% (HHV) on energy basis [13]) and the volumetric energy density in spite of being higher than batteries, it is still about 4 times lower than liquid fuels.[3] Even with the importance of volume (due to drag) in aviation, hydrogen has been continuously evaluated for such application [14–18]. A key limitation for this use is cost, where the fuel can represent up to 40% of the operating cost and a small increase due to drag or weight can represent a large increase in total cost.

Current global hydrogen production is in the order of 50 mtpa,[4] out of which the EU28 share is close to 7 mtpa (equivalent to 0.84 EJ). Industry sector dominates with more than 90% of the use. 63% of this is used by the chemicals sector (ammonia and methanol), 30% by refineries and 6% by metal processing [19]. Only 9% of the hydrogen market is merchant (meaning traded between parties as most of it is actually produced on-site and resulting from process integration). The size of the transport sector is 12.3 EJ for road transport (cars, trucks, buses) and close to 2 EJ for both aviation and navigation sectors (where the largest contribution is from international transport by a ratio of 9:1 vs. domestic).[5] Even if hydrogen covers only a small part of the sector, it would imply a significant increase in H_2 production capacity compared to current values.

This study uses a bottom-up cost optimization modeling approach that includes capacity expansion, covers the entire energy system for EU28+ (EU28 plus Switzerland, Norway and Iceland). The reason for this choice is to be able to evaluate the Power-to-X (PtX) options and integration between sectors and at the same time, consider the optimal capacities needed to achieve a low carbon system. Scenarios evaluated cover 80–95% CO_2 reduction by 2050 (vs. 1990) in agreement with the EU strategy [20]. The main targeted questions for hydrogen are to identify the production technologies as well as its main process chains, end use allocation to the different sectors and infrastructure cost. On PtL, the main questions are sources for CO_2, competition with biofuels, electricity and hydrogen itself and range of conditions (system constraints) that make the technology attractive. Given the long term nature and high uncertainty associated to the evolution of the system, an objective is to do a systematic analysis of system drivers that favor or constrain these technologies and determine their robustness (e.g. if deployment is present across multiple scenarios). This complements a previous exploration of Power-to-Methane [21], which is another technology satisfying similar boundary conditions in addition to the competition for the CO_2 molecule with PtL.

2. Literature review and gaps

The literature review is divided mainly into two sections: one tackling the activities at EU level from research to policy with the objective to put in perspective the levels of deployment foreseen in this study in comparison with current policies and initiatives. The second section summarizes trends and gaps observed in previous energy system models that have focused on hydrogen and based on this, identifies the additions of this work to that literature.

2.1. Hydrogen landscape in the EU

Activity at the EU level on hydrogen can be analyzed from three different perspectives: research activities, roadmaps and potential role in future low-carbon systems and consideration in current policy frameworks.

In terms of research, 90% of all the EU funds for hydrogen are covered by the FCH JU (Fuel Cell and Hydrogen Joint Undertaking), which is a public private partnership. The first phase ran from 2008 to 2013 with a budget of 940 M€ and a second phase from 2014 to 2020 with an increased budget of 1330 M€. In terms of roadmaps, one of the best known is HyWays [22]. It was published in 2008 and considered start of commercialization by 2015, 2.5 million FCEV (Fuel Cell Electric Vehicles) by 2020 (EU) and a penetration rate of up to 70% for FCEV by 2050 (~190 million FCEV). A more recent roadmap has been done by the IEA in 2015 [23], which proposes 30,000 FCEV worldwide by 2020, 8 million by 2030 and 30% penetration by 2050. In terms of future scenarios for EU as a whole, the EU Reference Scenario [24] only considers hydrogen for transport, where it barely plays a role with 0.1% by 2030 and 0.7% by 2050. This only considered a (greenhouse gas) GHG emission reduction target of 48%. On the other hand, the Energy Roadmap 2050 [25] does have a more ambitious target (80% reduction), but make no mention of hydrogen and transport relies on higher efficiency standards, modal choices, biofuels and electricity. The 2 °C scenario with high hydrogen from IEA [23] uses hydrogen for transport and foresees a demand of 2 mtpa for 35 million FCEV in EU4[6] by 2050.

In terms of policy, hydrogen and synthetic fuels are not explicitly mentioned in most of the directives. The Renewable Energy Directive

[2] 42–53% for fuel cells, while an ICE is around 20%.

[3] The mass energy density is around 2.5 times higher for hydrogen, which would lead to less weight. The trade-off for fuel consumption is drag (volume) vs. weight.

[4] mtpa = million tons per annum.

[5] Eurostat. [nrg_100a] – Simplified energy balances – annual data.

[6] Germany, France, Italy and United Kingdom.

[26] establishes a target for a share of advanced renewable fuels (6.8% for 2030) and has specific targets for biofuels (3.6%), but none for hydrogen. A recent revision (June 2018) [27], includes a mandatory minimum of 14% of renewables in Transport by 2030, to be achieved via obligations on fuel suppliers. The mutual consent to cap conventional biofuels EU-wide at a maximum of 7% opens perspectives for electricity, hydrogen and PtL/BtL in transport. It also suggests the extension of guarantees of origin for renewable gases like hydrogen or biomethane. The Fuel Quality Directive (FQD) is based on a mandatory 6% GHG reduction by 2020 compared to a 2010 fossil reference of 94.1 gCO_2/MJ [28] and only mentions hydrogen in the reporting guidelines 2015/652 [29]. Hydrogen falls in the category of electricity storage providing flexibility (supply driven) rather than an alternative for sustainable transport (demand driven). For example in the Clean Energy Package, it is presented as an alternative to integrate Variable Renewable Energy (VRE) and clustered under the FCH JU. Storage is not focused anymore only on power, but also extended to promote sectorial integration options (PtX) [30].

In most of these documents [26,28–32] hydrogen will contribute to achieve the targets. However, they do not have specific actions to promote hydrogen uptake. EU policy framework does not hinder hydrogen development, but it does not provide a strong support either. This conclusion was reached back in 2010 through a more detailed analysis [33], but it seems it has not changed since. Different support schemes are needed for hydrogen. As an energy carrier, policies should not only target production, but also its distribution (different from VRE). It is not fully compatible with existing infrastructure (different than biofuels) and it requires incentives for its development.

2.2. Hydrogen in future low carbon systems

Studies on hydrogen can broadly be classified in the following categories:

- Technology [13,34–37]. Tackle breakthrough in material, operating conditions, testing, efficiency, operational performance and outlook for the future for electrolysis and fuel cells.
- Supply chain [38–46]. Discuss the different alternatives for production, storage and distribution to end user considering cost, scale (H_2 use) and efficiency, but focused only on hydrogen.
- Geo-spatial studies (GIS – Geographic Information System) [47,48]. Establish the link between potential sources for hydrogen (e.g. wind farms) and demand (e.g. cities) considering their spatial distribution.
- Economic [18,49–53]. Compare levelized cost of potential future technologies with steam methane reforming and make sensitivities around raw materials, gas prices and learning curve effect.
- Energy [54–81]. Hydrogen use in different sectors (transport, power, heating, industry, storage) capturing the effect of policies through commodity and technology substitution considering cost and emissions.
- Storage [82–86]. Role of hydrogen as long-term or seasonal storage in a RES system.
- Power [87–102]. Use of electrolyzers to provide grid services (i.e. balancing) and aid VRE integration. Wind integration and even nuclear integration studies fall in this category.
- Roadmaps [22,103–105]. Describe the various roles hydrogen can have in a future energy system, potential benefits and establish actions to promote its use at various dimensions (research, funding, regulation, among others).
- Policy [33]. Understand level of subsidy (or tax cut) for hydrogen to be used across sectors along with its impact on GHG emissions and contribution to reduction targets.

Many previous studies have assessed the role of hydrogen with an energy system model [54–81] (the same category as this study). There is also a recent review on hydrogen in low-carbon systems [106]. Some trends across studies are:

- There seems to be a trade-off between spatial resolution and portion of the energy system covered. Four scales are identified: (1) global studies with focus on hydrogen for cars [63–65,107–114]; (2) national studies covering the entire energy system [54,57–60,62,66,67,79–81]; (3) local studies looking at optimal locations and routes for the infrastructure (focused on hydrogen) [55] and (4) more specific cases to optimize fueling stations and specific routes for a community [56].
- There is also a trade-off in spatial scope, resolution and the extent to which parameters are endogenous. Some studies [79–81] have high spatial and temporal resolution (hourly and 12–402 regions for Germany), but take demand for commodities (electricity and hydrogen) as exogenous parameters and do not consider the competition between energy carriers and the dynamics of supply-demand. In the other extreme, there are studies (e.g. [63–65]) that have a wider geographical scope (EU/global) with endogenous demand and prices for the commodities at the expense of temporal and spatial resolution (representative time slices and regions that include various countries).

Some of the gaps that remain from this literature are:

- Competition between all sectors (residential, commercial, industry, power and transport) for hydrogen use.
- Incorporate competition between alternative sources of fuel (e.g. hydrogen, methane, XtL,[7] electrofuels and biofuels).
- A systematic analysis of the relation between hydrogen potential and different system configurations (e.g. biomass potential, CO_2 target, fuel prices).
- Hydrogen role considering a differentiation between technology specific drivers (e.g. capital expenditure -CAPEX learning curve) and system drivers (e.g. CO_2 reduction target) to establish performance targets for the technology.
- Cover both the entire energy system (alternative uses), spatial distribution of infrastructure and consumer choices for technology adoption in private transport.

Some gaps in literature that are closed with the current study are: (1) the geographical scope is the entire European region; (2) considering trading and dynamics between countries; (3) additional sectors other than transport are considered and (4) in transport itself, even though additional features such as inconvenience cost, risk aversion, anxiety cost, among others are not included, there is a finer cost and efficiency resolution for cars for the model to progressively change towards new technologies and have enough options to do so [115]. The study includes up to 95% CO_2 reduction scenarios, competition between hydrogen, PtL, synthetic fuels and biomass for transport and robustness of the technologies for a range of potential future scenarios. It also allows analyzing the transition to renewable hydrogen for sectors already using it (e.g. refineries). Gaps that will remain after this study are spatial consideration of sources, infrastructure and sinks, validation of results with a higher temporal resolution and behavioral component in modal shifts for private transport.

This model has also been used in the past for evaluating the potential role of hydrogen in EU [116]. Differences with respect to such work are further model development (additional technology portfolio and focus on PtX representation) and the systematic parametric analysis to identify the drivers and barriers for hydrogen in multiple potential scenarios.

[7] XtL refers to synthetic fuels produced by biomass, coal and gas to liquids (Fischer Tropsch), where BtL is the more relevant for low-carbon scenarios.

3. Modeling approach and structure

The modeling approach is based on cost optimization covering the entire energy system and it includes investment, fixed, annual, decommissioning and operational cost, as well as taxes, subsidies and salvage value as part of the objective function. The software used is TIMES (The Integrated MARKAL-EFOM System) [117–119], which is a bottom-up (technologically rich), multi-period tool suitable to determine the system evolution in a long-term horizon. The model uses price elasticities of demand to approximate the macroeconomic feedback (change in demand as response to price signals), which allows transforming the cost minimization to maximization of society welfare.

Technology representation is achieved through a reference energy system, which provides the links between processes. Each process is represented by its efficiency (input-output), cost (CAPEX and OPEX) and lifetime. Prices for all commodities are endogenously calculated through supply and demand curves. Several policies can be added including CO_2 tax [120], technology subsidy [121,122], regulations, targets, energy efficiency [123], feed-in tariffs, emission trading systems [124] and energy security [125], among others. A common application involves the exploration of decarbonization pathways [58,126–128]. Key output of the model is the capacity needed for every technology, energy balance for each country in each time period, trading, total emissions and cost breakdown.

Some of the aspects that are not covered with JRC-EU-TIMES are: macro-economy (except for the interaction through price elasticity), power plant operation (e.g. minimum stable generation, start-up time and cost), land use, climate (e.g. reduced form geophysical model), behavioral choices for private transport, supply of resources (e.g. biomass), agriculture and non-CO_2 emissions and pollutants. Natural cycles (hydrological, carbon) in the biosphere, political and social aspects are also omitted in the approach. Due to the focus on energy systems (leaving changes in agricultural practices, biomass burning, decay, petrochemical, solvents out of the scope) and only CO_2 (no CH_4, N_2O, NO_x and pollutants), the model effectively covers around close to 80% of GHG emissions, noting that for 2014, the energy sector represented 68% of the GHG emissions, industry 7% and agriculture 11%, while CO_2 was 90% of the GHG emissions [129].

The model has been thoroughly described before [61,130–132]. Below are sections that have either been modified or that are essential to understand for this study with extra information (data) in Appendix A and a list of the changes done as part of this study in Appendix B.

3.1. Overview of major inputs

The main exogenous parameters for JRC-EU-TIMES are:

- Macroeconomic. Demand for services and materials and fuel prices are aligned with the EU reference scenario that has PRIMES as centerpiece of the modeling exercise [24].
- Technology parameters. This covers cost, efficiency and lifetime for the technologies and their evolution in time. Sources are mainly [133,134], while technology specific discount rates are from [24].
- Technology potentials. Each country has maximum flows for all energy resources and associated mining production cost for fossil fuels. The constraints for each country are taken from GREEN-X and POLES models, as well as from the RES2020 EU funded project, as updated in the REALISEGRID project [116].
- Interconnection between countries. This is relevant for electricity (ENTSO-E and Annex 16.9 of [116] for specific values), CO_2 transport cost (taken from [135]) and gas.
- Base year calibration. Mainly done with Eurostat and IDEES (Integrated Database on the European Energy Sector) database [136]. For more detail on the categories used for each sector, refer to [116].

3.2. Hydrogen network

The hydrogen system is divided in 4 main steps: production, storage, delivery and end use.

- For production, there is a total of 23 processes, where variations arise from fuel (methane, biomass, coal, electricity), technology (reforming, gasification, electrolysis and variations therewith and carbon capture) and size (centralized, decentralized). Techno-economic parameters can be found in [131]. The model did not include PEM (Proton Exchange Membrane – Technology Readiness Level 7-8 [137]) or SOEC (Solid Oxide) electrolysis (TRL 6-7 [137]) and these were added since they have potential for high efficiency and low cost [49,138]. Three sets of data were used for PEM to cover the uncertainty in future performance. For data used, refer to Appendix A.
- For storage, there are 3 alternatives: underground storage,[8] centralized tank and distributed tank (20 MPa). The production technologies connected to underground storage are the ones applied at large scale or corresponding to a medium size of a conventional technology. Centralized tank is used for relatively unconventional technologies (e.g. Kvaerner, oxidation of heavy oil) and smaller scale production.
- For delivery, there are different pathways that can be followed, including: compression, transmission, natural gas blend, liquefaction, road transport, ship transport, intermediate storage, distribution pipelines and refueling stations (L/L, L/G, G/G). Not all combinations among these are possible (e.g. liquefaction and injection to the grid) and this results in 20 delivery chains considered. For the reasoning in selection, refer to [139]. Delivery cost for transport is between 1 and 6 €/kg depending on the delivery route chosen. The most expensive steps are refueling (up to 3.8 €/kg) and distribution pipeline (3 €/kg). The simplest pathway is blending which covers compression, storage and transmission (~1 €/kg). See Appendix A for more details and cost breakdown for individual steps.
- In terms of end use, the hydrogen can be blend with the natural gas (up to 15% in volume) and end up in any of the applications of this commodity, used in the residential sector to satisfy part of the space heating demand (μCHP), industry (steel), transport (cars, buses, trucks) or be used for fuel synthesis (combined with CO_2). For blending, 10% is already possible in some parts of the system [140] and the impact of using higher concentrations has also been assessed [141]. The main limitations are on tolerance of the end-use devices (e.g. CNG stations, gas turbines and engines) rather than on infrastructure. Looking at a 2050 time horizon, it is expected that this is de-risked, but 15% is chosen to avoid overreliance on the alternative.

A representation of these different steps is shown in Fig. 1. A diagram with more detail on the delivery paths is presented in Appendix C.

3.3. Sectorial use of hydrogen

Hydrogen in the residential sector can be supplied by 4 pathways: centralized hydrogen with underground storage or tank, decentralized production and by blending with natural gas. It can be used directly to satisfy space heating demand through a PEM or solid oxide fuel cell (μCHP) to satisfy both power and heat or blend with natural gas and satisfy the same need with existing technologies. This is an improvement introduced in this study, where the previous version only counted with a burner to satisfy space heating demand. For the specific data, refer to Appendix A.

[8] Typical values are 500,000 m^3 with a hydrogen net storage capacity of 4 kt [198].

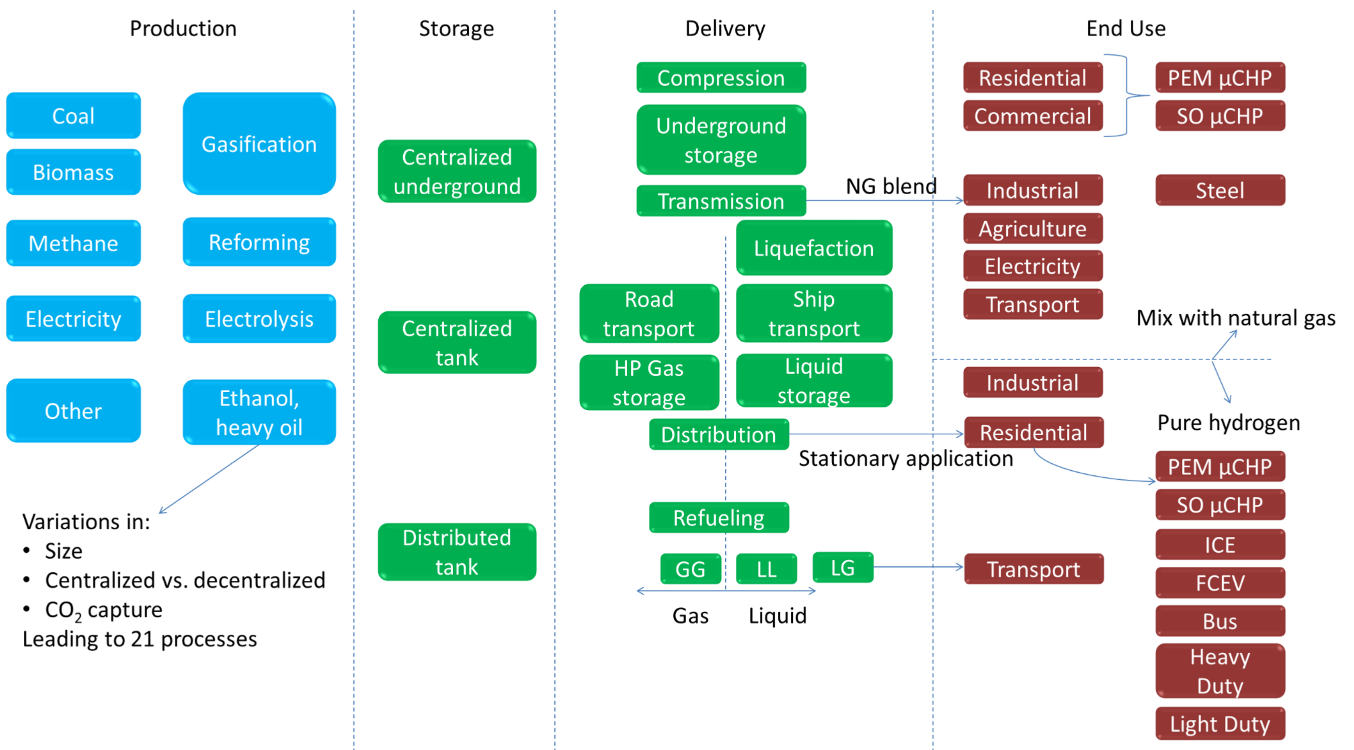

Fig. 1. Structure of the hydrogen supply and delivery chain in JRC-EU-TIMES.

In the EU, steel represents 4.7% of the CO_2 emissions [142]. Improvements for the industry are divided in two categories: enhanced operation and upgrading of current assets (e.g. process control, heat integration, gas recovery, insulation, monitoring) and technology changes (Corex/Finex iron making, MIDREX, EnergIron/HYL, Direct Sheet Plant (DSP) and CCS) [143]. The two most relevant improvements for this study are the possible use of carbon capture (which could provide CO_2 for possible use downstream) [144] and hydrogen as reduction agent (e.g. MIDREX process) [142,145]. It has been shown [146] that H_2 is the technology with the largest CO_2 reduction potential in steel, in spite of resulting in a net increase of energy demand. For more details on the steel sector, refer to Appendix A.

Hydrogen can also be used for refineries and ammonia production, which currently are 2.1 and 3.6 mtpa of the 7 mtpa EU total demand [19]. Part of the hydrogen in refineries comes from internal processes (catalytic reforming), that needs to be supplemented by additional production with methane reforming [147], while for ammonia, reforming is the step where nitrogen is introduced in the process. For refineries, hydrogen production was disaggregated from the rest of the processes subtracting the equivalent natural gas that would be used. Data from [148] was used for refineries, which contains the hydrogen demand per country. For ammonia, using pure hydrogen requires changing the process configuration by eliminating the reforming step and adding an ASU (Air Separation Unit) to obtain the nitrogen and electrolysis to produce the hydrogen. Techno-economic data was taken from [149,150], electricity consumption for the combined process (NH_3 conversion, compression and cooling plus ASU) is 0.39 kWh/kg NH_3 (still optimistic compared to [150] that estimates a 10 MW consumption for processes other than electrolysis for a 300 t/d plant) and a hydrogen requirement is close to 190 kgH_2/ton NH_3. The cost included for this step includes the synthesis loop, ASU, compression and ammonia storage since electrolysis is a separate process in the model. This leads to a specific CAPEX of 145 €/ton for a size of 2200 t/d. To put these numbers in perspective, cost is almost half of the conventional process (270 €/ton for a similar scale [151]). The main reason for this perceived advantage of the electrolytic route is that 145 €/ton does not include electrolysis (which is the most expensive component at around 350–500 €/ton on NH_3), while the cost for the conventional process does include hydrogen production (reforming).

3.4. CO_2 use

The CO_2 molecule has two possible destinations, either underground storage or re-conversion to an energy carrier. The alternatives for CO_2 use are shown in Fig. 2.

Potential CO_2 sources are industrial (steel, ammonia, glass and paper), power and supply (BtL, biogas, H_2 production) sector. Direct air capture (DAC) is introduced as a separate process. This is done as a sensitivity analysis to avoid overreliance on the technology and assess alternatives in case it does not develop as expected. Syngas is not explicitly modeled as a commodity, but instead is inside the (clustered) processes and techno-economic parameters. Processes in Fig. 2 include the electrolyzer, reverse water gas shift, Fischer Tropsch (or methanol) and upgrading section. For data used for Power-to-Methane (PtM) refer to [21], while data for PtL (including co-electrolysis) can be found in Appendix A. There is a range of chemical intermediates that can be produced from CO_2 (e.g. urea, carboxyls, carbamates, inorganic complexes, polymers) [152,153] through different processes (e.g. photocatalysis, mineral carbonation, photosynthesis, electrochemical reduction, algae) [154]. However, the entire petrochemical value chain is not explicitly included in JRC-EU-TIMES, but instead clustered in fewer processes. Therefore, there is no technological detail to consider routes that use pure CO_2 as feed in order to be able to make trade-offs between the alternatives. The other possible sink for CO_2 is underground that has a cost between 3.3 and 10 €/ton [155,156].

3.5. Transport fuels

The transport sector is divided in road transport, aviation and navigation. Road transport in turn is divided in sub-sectors (freight and passenger) and can be satisfied with different fuels. The combination of fuels that can be used in each transport sector is shown in Table 1, while

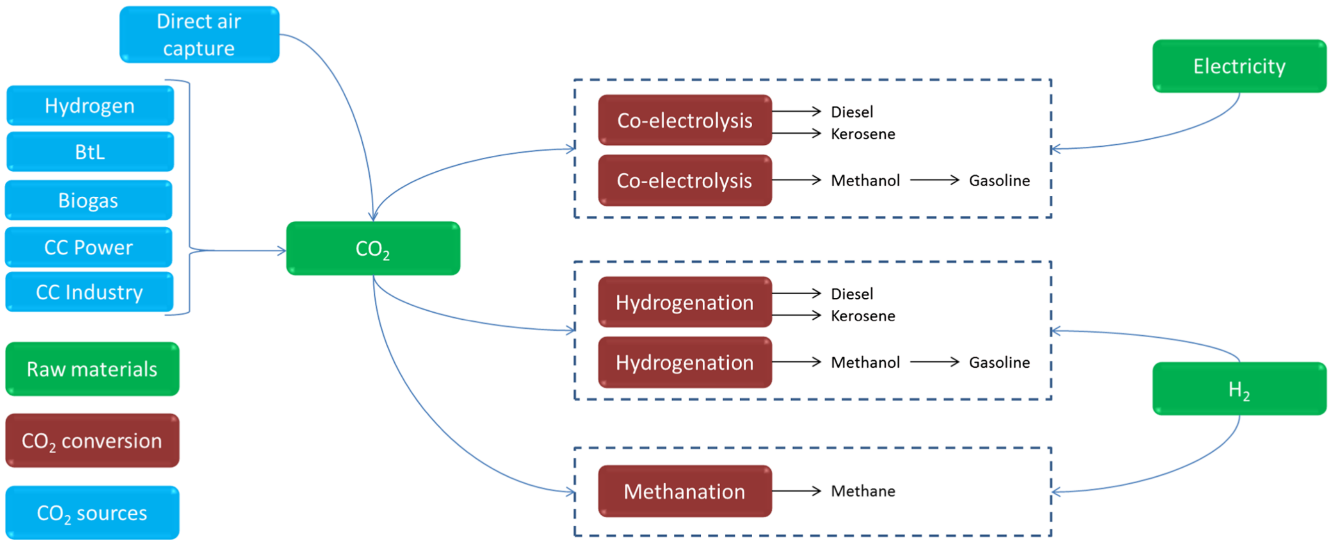

Fig. 2. Alternatives for CO_2 use in JRC-EU-TIMES.

Table 1
Combination of fuels use by transport sector.

	Gasoline	Diesel	Fuel oil	Jet fuel	CNG	LMG[b]	LPG	Ethanol	2nd gen biofuels	Electricity	H_2
Bus	x	x			x	x	x	x	x	x[a]	x
Light Duty	x	x			x		x	x	x	x	x
Heavy Duty	x	x			x	x		x	x	x[a]	x
Car	x	x			x		x	x	x	x	x
Aviation				x					x		
Navigation		x	x			x			x		

[a] It means option and data are available, but only done as a sensitivity analysis to avoid an overly optimistic scenario.
[b] LMG = Liquified Methane Gas, which is used instead of LNG (Liquified Natural Gas) since methane can come from PtM, biogas or natural gas. Once they are mixed in the grid, they cannot be differentiated. Henceforth, LNG will be used to refer only to natural gas (i.e. import).

the alternative intermediate carriers and conversion routes to produce the fuels are shown in Fig. 3. For specific considerations for this section, as well as fuel shares refer to Appendix A.

The terminology used here follows [157]. Electrofuels is the parent term for fuels obtained from power (i.e. PtX). Synthetic fuel is used for XtL (since results do not have coal or gas to liquids, this term implies BtL). Biofuels encompass both 1st and 2nd generation. A potential energy carrier for aviation is hydrogen, but this is not included in this work. In spite of the vast research on this topic [14–18], its maturity was deemed too low to rely on it as possible low-carbon solution. Furthermore, at this point, there is high uncertainty in the cost and efficiency figures and even though assumptions could be taken for these values, risks associated to technology deployment, performance and learning curve effect are more difficult to capture.[9] Ammonia as fuel or storage [158,159] is not included in this study.

Similarly, for navigation, several options have been studied, including hydrogen, batteries, anhydrous ammonia, compressed air and liquid nitrogen, wind, solar and nuclear powered [160], but it was decided not to include these. LMG is also an alternative quickly arising for navigation in EU and where efforts are being done to close the gaps in regulatory framework to enable the use of LMG and develop the required infrastructure [161]. This is driven by a benefit in sulfur emissions and a stricter regulation [162] rather than having CO_2 emissions in mind. LMG is included in the model and its potential for heavy duty and marine transport has already been evaluated [21].

For both sectors, there is a large contribution (50–75%) to GHG reduction from changes in operations, mechanical design, materials and aerodynamics to CO_2 emissions reduction that are not captured as part of the current model, so there is an overreliance in fuel switch [163], which in reality might be lower than what the model predicts. The model has also been expanded with electric options for heavy duty (battery-based) and buses with data from [164] and has been included in Appendix A. Currently, it is foreseen that electric heavy-duty trucks will already be competitive in Europe by 2030 for regional distances [165], so it seems feasible that by 2050 it will be possible that all categories are electric. Estimates by IEA [166] consider a third of the stock electric by 2050, with another third hybrid and only the remaining fraction running on diesel. For buses, already in 2017, 13% of the global municipal bus fleet was electric (99% of the electric buses in China), while 1.6% of the EU fleet was electric. Already today, a 250-kWh bus has a lower total cost of ownership than a diesel or CNG bus. Barriers are the scalability and business models to promote the cost decline, standardization of charging infrastructure and potential effect on the electricity grid [167].

3.6. Biomass

Biomass competes not only among fuels for the transport sector (biodiesel, ethanol, jet fuel), but also among sectors. If combined with CCS for power generation it can lead to negative emissions that can compensate for positive emissions elsewhere in the system. Fig. 4 shows the variety of sources considered as “biomass”, as well as the potential pathways to satisfy the end demand.

[9] This could be done by changing the interest rate, but it would still require a sensitivity of the technology deployment with different rates, which is still not directly risk.

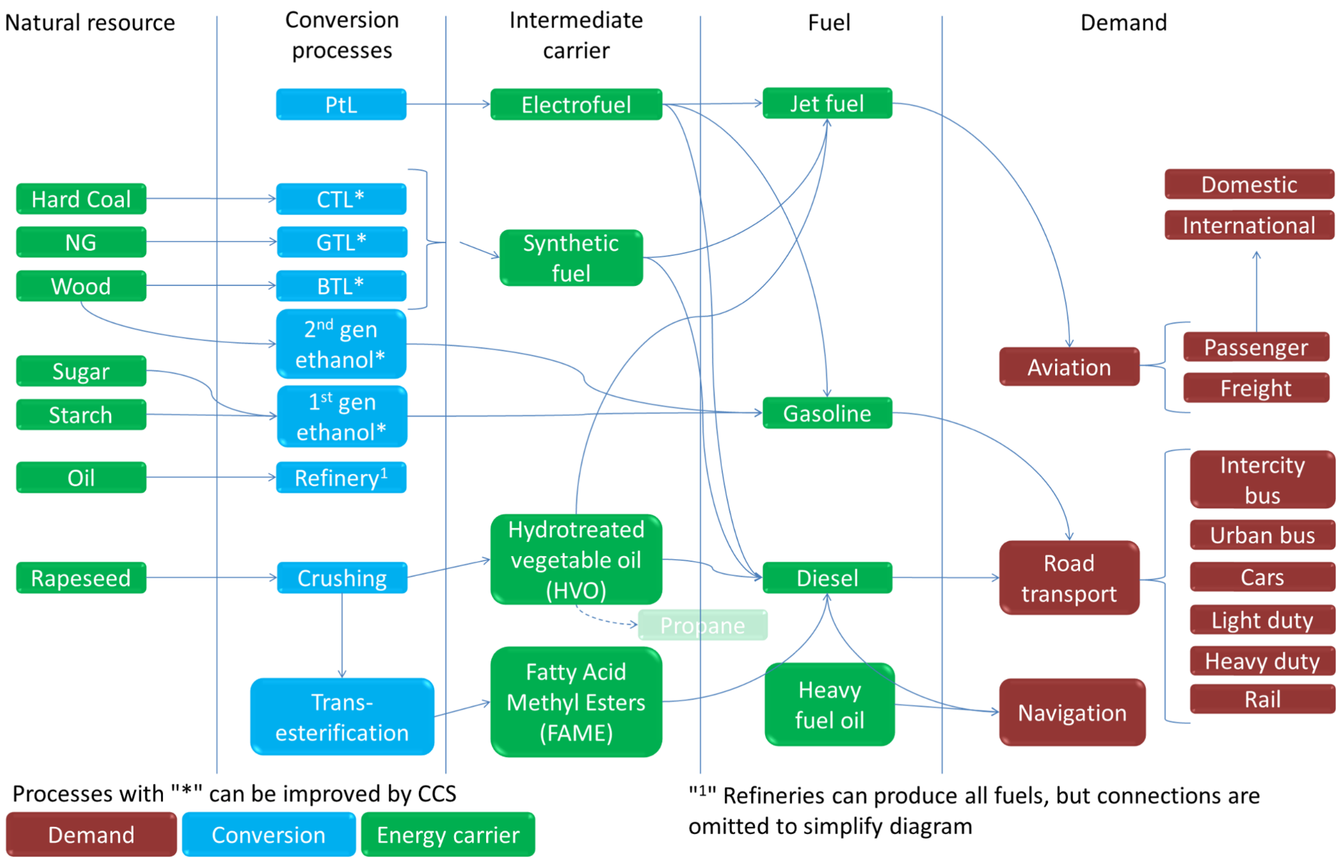

Fig. 3. Technology pathways for fuel production and use for final demand.

Some notes to bear in mind are:

- Starch and sugar can only be used for ethanol production, while rapeseed is the one that can be used for hydrotreated vegetable oil (HVO). Therefore, for starch and sugar there is no competition with either other fuels or sectors. The choice is only if the pathway should be used and to what extent.
- Wood products can also be used for biogas production (not shown in the diagram) and satisfy demand on the cement sector (which otherwise could not be satisfied).
- "Common uses" in Fig. 4 refer to applications that biogas, biosludge, municipal waste and wood products have in common, but not for agricultural crops.
- Biomass conversion to satisfy chemical demand is limited to producing the feedstock (e.g. synthetic oil and gas) needed. Explicit alternative processes for olefins, BTX and aromatics were not included.

The potential is between 10 and 25.5 EJ/yr for EU28+ by 2050. This is based on [168] and in agreement with previous studies (6.2–22 [169], 14 EJ/yr [170], 18.4–24 [171] EJ/yr). Most (> 85%) of the biomass has a cost below 5 €/GJ. Two of the ones above this cost are rapeseed and starch (17 and 21.9 €/GJ respectively), which can only be used for 1st generation biofuels and ultimately imply gasoline production for blending. Around half of the biomass potential falls in the forestry source and could be used for 2nd generation biofuels. Although, it has the largest absolute potential, it is in direct competition with uses for electricity, heating, industry and hydrogen. Pathways not included are the ones for chemicals production since this is an energy model (sector is partially aggregated). A previous study [137] has shown that biomass gasification with downstream conversion to methanol and ethylene already have a competitive cost compared to the fossil route in spite of the much larger energy consumption, while propylene and BTX actually lead to a CO_2 increase if biomass were used. For the specific values refer to Appendix A and for assumptions with respect to land use, logistics, heating value, scope of each category, potential by country, refer to [168].

4. Scenario definition

Methodology falls in the category of technical scenarios, which consider ranges and different values for the input. This excludes the synthesis of complete storylines that describe a plausible evolution of the system towards alternative futures. These constitute the quantitative part of a scenario analysis, where the purpose has been mainly to analyze how changes in the future system can affect hydrogen and PtL capacity and energy. This should be followed up by complementary approaches and technology push/pull policies to promote deployment. Scenarios analyzed should not be seen as forecasts since it is unlikely they are achieved within the specified time frame. To put the scenarios in perspective, CO_2 reduction targets analyzed are between 80 and 95% compared to 1990. From 1990 to 2015, EU achieved close to 22% GHG reduction.[10] In a similar period of time (32 years until 2050), achieving the target would not only mean nearly tripling the pace, but also that the more difficult (i.e. expensive) reduction will be achieved faster. Instead the scenarios analyzed are meant to provide insights into the critical technology parameters as input to the decision making process, assessing the uncertainties in future scenarios and their possible consequences (impact analysis).

The parameters that were varied across scenarios are listed in

[10] Greenhouse gas emissions by sector (source: EEA) (tsdcc210), indicator Profile (ESMS).

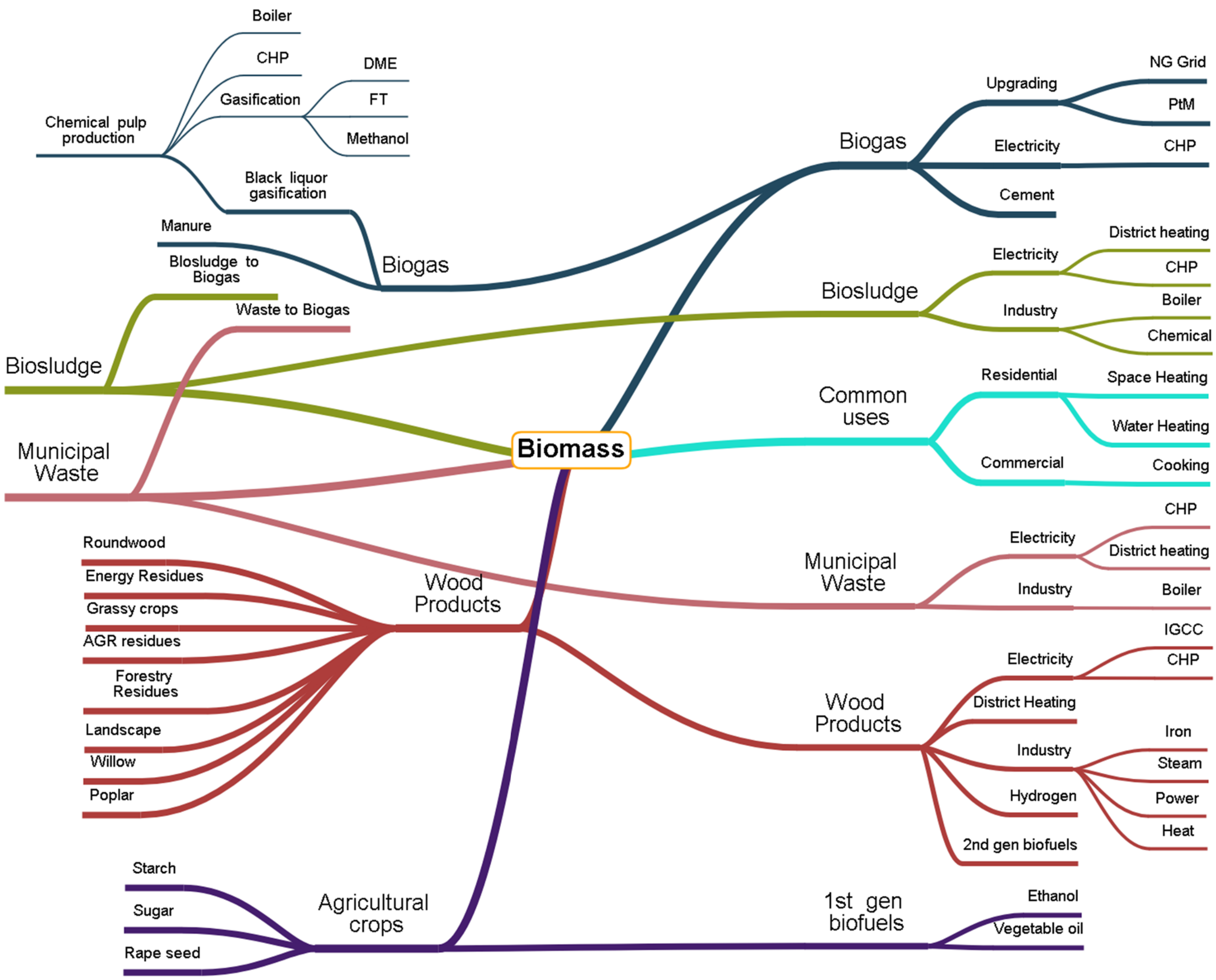

Fig. 4. Biomass sources and sinks covered in JRC-EU-TIMES.

Table 2
Key parameters varied across scenarios to identify trends and shifts in the system.

Parameter	Explanation	Rationale	Scenarios
CO_2 reduction target	Total emissions target for 2050 compared to 1990	It is expected that hydrogen and PtL will play a larger role as target becomes stricter	• 80% CO_2 reduction[a] • 95% CO_2 reduction
CCS	Absence of CO_2 underground storage	This has been identified as key option to decarbonize the energy system, specially sectors other than power	• CO_2 storage available[a] • No CO_2 storage
Biomass	Refers to potential for crops, forestry, biogas and waste (refer to Table 14 in Appendix A)	Biofuels are an alternative for transport, but biomass can also be used for other sectors. This assesses the current uncertainty with respect to potential	• Reference (~10 EJ/yr)[a] • Low (~7 EJ/yr) • High (~25.5 EJ/yr)
PtL performance	CAPEX, OPEX and efficiency (Table 8, Table 10)	Developments in co-electrolysis, catalyst for FT and methanol, possible heat integration can lead to a range of PtL performance (see Table 10)	• Reference (400 €/kW)[a] • Optimistic (300 €/kW) • Conservative (500 €/kW)
PEM performance	CAPEX, OPEX, lifetime and efficiency of the technology (Table 4)	Technology is its early stages. Learning curve is dependent on deployment which is in turn uncertain, as well as breakthroughs in research	• Reference (750 €/kW)[a] • Optimistic (400 €/kW) • Conservative (1000 €/kW)
VRE Potential	Higher PV and wind potential	Initial estimates are conservative. More VRE will lead to more electricity surplus to deal with where H_2 and PtL can play a role	• Ref (320/1650 GW[b])[a] • High (1140/3700 GW) [172,173]

[a] Assumption for the reference scenario.
[b] First number refers to onshore wind, while the second number refers to solar.

Table 2. These include parameters impacting the entire system and were identified as having a large effect on it (e.g. CO_2 reduction target) and specific ones for the technology that deal with the uncertainty in data. They were combined in over 50 scenarios (see Appendix D for a full list of scenarios and parameters varied). The combinations were done based on previous studies [54–81] and results observed in initial runs. They are further reduced to the 8 main scenarios described below, which are used to facilitate understanding of results. Insights from the rest are included in the discussion were relevant, but not shown in graphs.

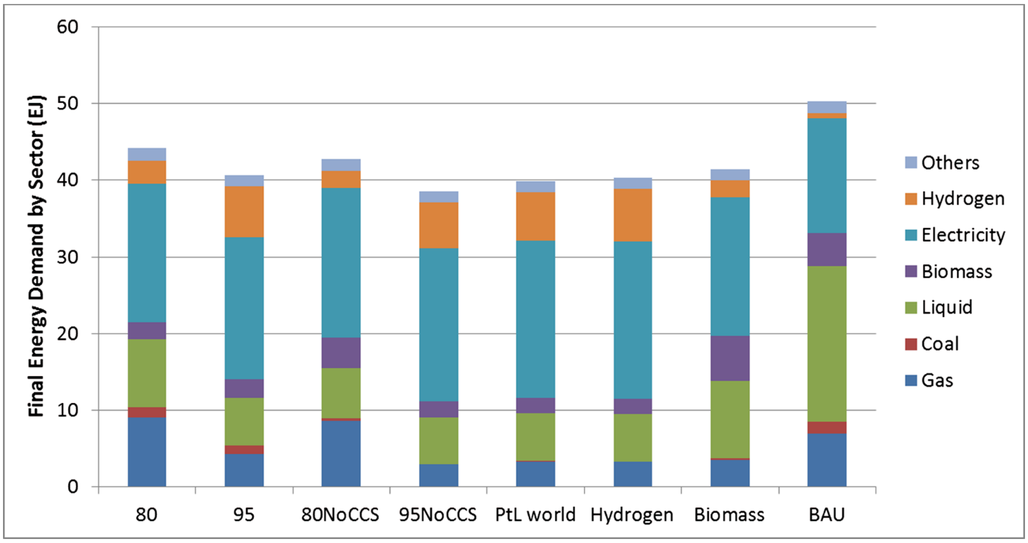

Fig. 5. Final energy demand by delivery carrier for main scenarios.

- Low-carbon (2 scenarios). It considers 80 and 95% CO_2 reduction with no other constraints.
- No CCS (2 scenarios). 80 and 95% CO_2 reduction with no CO_2 underground storage since it has one of the largest impact over the technology choices and cost (CO_2 price), as well it can present challenges of social acceptance in the future.
- PtL world (1 scenario). It assumes 95% CO_2 reduction and the best foreseen PtL performance ("Optimistic" in Table 10) to establish the upper bound in technology activity in a world with no CCS and high VRE (with higher need for flexibility).
- Hydrogen economy (1 scenario). This uses 95% CO_2 reduction, optimistic PEM performance (Table 4) and has SOEC as possible production technology. No CCS and high VRE are considered to promote electrolysis.
- Biomass economy (1 scenario). It uses the highest biomass potential (~25.5 EJ/yr including import), CO_2 storage is not possible (conservative assumption), 95% CO_2 reduction and high VRE potential.
- Business as Usual – BAU (1 scenario). This implies limited CO_2 reduction potential assuming there is limited efforts after currently established regulations are achieved. This assumes a 48% CO_2 reduction by 2050, aligned with the EU reference scenario [24].

Another set of scenarios is done to establish the price and demand curve for hydrogen by sector. For this, different scenarios are done with a fixed supply hydrogen price to determine the uptake in each of the demand sectors. This allows understanding (1) the maximum hydrogen price that makes it attractive for a specific application and (2) the additional demand for a lower price. In reality, when there is additional demand for example for electrolysis, this would affect electricity prices, which in turn affect the competition between hydrogen and electricity in downstream use. This supply-demand dynamic is inherently considered in the model, but it is further disaggregated in these scenarios. By setting a fixed hydrogen price, it simplifies the analysis by focusing only on the demand side. The scenario chosen for the analysis was one with 95% CO_2 reduction, no CO_2 storage (to have PtX as possible demand sectors), high VRE potential (requiring more flexibility) and no other deviations from the reference scenario. When changing any of these conditions, the optimal solution (e.g. CO_2 price, electricity mix, biomass use) is different, leading to a different demand curve. However, results obtained with this scenario were seen to be in line with trends observed in other scenarios.

5. Results and discussion

Results are divided in two main sections. (1) Introduction of the overall system, its energy balance and composition (5.1) as well as the cost breakdown and main contributors (5.2); (2) parts of the system that are important for hydrogen and PtL since they are the subject of this work, including hydrogen use and sources, PtL contribution to fuel demand and CO_2 sources and biomass balance. Hydrogen and PtL are expected to play a role in low-carbon systems, which will only be achieved in the long term. Mid-term (2030) results had little variance across scenarios since they are determined by the existing policy framework. Therefore, results focus on the 2050 time horizon comparing alternative scenarios. Only main scenarios are shown in the various sections, but insights from the sensitivities have also been included in the discussion. Given the plethora of results, only a few have been selected for this section, while some complementary ones can be found as Supplementary Information. To facilitate understanding, each section starts with the two most important ideas followed by the more in-depth explanation and each paragraph starts with a header with the main topic discussed.

5.1. Energy demand and electricity mix

Hydrogen complements electricity as main energy carrier and enables the downstream liquid production through PtL. Without applying further regulatory instruments, CO_2 storage would prolong the use of fossil fuels in the system, while still achieving the same CO_2 emission target.

To reduce emissions either energy consumption or the CO_2 emitted per unit of energy has to be lower. Fig. 5 explores the former by illustrating the total final energy demand for EU28+ with a split by energy carrier.

Energy efficiency. Final energy demand decreases by 2050 (vs. 46.4 EJ/yr for EU28+ in 2016[11]). This is in spite large increases in services demand. Demand (traveled distance) increases by 27% (2015–2050) in private transport, 20% for buses and almost 40% for heavy-duty and even larger (+80–100%) in aviation. Industrial output increases by an average of 20%. Therefore, the reduction in final energy demand is achieved by widespread use of more efficient options to achieve 5–17% reduction by 2050. Across scenarios, demand for space heating in the residential sector decreases by 30–40% due to stricter

[11] Indicator [tsdpc320] from Eurostat.

regulations implementing energy efficiency measures (insulation). A 40% reduction in demand of the residential sector is also accomplished through a shift to electricity, which has almost 75% share across the main scenarios, halving biomass contribution and nearly eliminating gas use (reduction of 90–95% vs. 2015). Similarly, private transport reduces its energy demand by almost 60% (7.9–3.4 EJ) in large part due to electric vehicles, which have 60–70% share of the market, while the rest is due to the use of more efficient cars. These are cost-optimal results, where political will and policy instruments are required to produce feasible business cases and drive the system in this direction. *BAU* is still different from today due to higher use of carbon neutral biomass, lower cost for VRE (and higher deployment) and further allowance reduction for the emission trading scheme.

Energy carrier composition. 40–50% of the total mix of the final energy demand is met by electricity followed by liquid fuels that are still used for aviation and marine transport (15–25% of the mix, lower when the system is more restricted and higher with the highest biomass potential) and hydrogen (demand for steel constitutes around 5% of the total demand, while heavy-duty road transport can shift to hydrogen in some scenarios). Biomass contribution is relatively small since its direct use to satisfy end use services is limited and instead it is transformed to one of the other energy carriers. Gas is largely displaced by RES in the power sector and by electricity in space heating. More detail of the drivers behind gas demand is part of a separate publication [21].

Primary Energy Supply. The use of CO_2 storage prolongs fossil contribution in the system. For 80% CO_2 reduction, fossil fuels still provide 60% of the primary energy (see Appendix I), while their contribution decreases to 53% for 95% CO_2 reduction. This quickly drops to 36 and 16% for those two respective scenarios once CO_2 storage is no longer possible (since that CO_2 will ultimately end up in the atmosphere regardless of the fuel substituted) and remain at that level once a higher VRE potential is used. With the high biomass potential (~25.5 EJ/yr), biomass is almost entirely used and can provide almost 40% of the primary energy supply. With a more modest potential (~10 EJ/yr), the primary suppliers are wind and solar with 50% of the mix when their potential is the highest. There are two opposite effects for low carbon scenarios: (1) Higher electricity share leads to lower PES; (2) More, biomass, hydrogen and PtX lead to higher PES (and lower efficiency).

Electricity balance. Close to 50% of the electricity demand is for electrolyzers (in scenarios without CO_2 storage). This already creates an additional flexibility during winter peak, when these units are turned down and demand is almost halved. Additionally, there is around 350–420 GW installed capacity of gas turbines, around 130 GW of nuclear, 180 GW of hydro, geothermal, CHP and storage complement the rest of capacity to be able to meet demand during winter peak. This is in line with previous studies [170] analyzing a 100% RES scenario for EU that had a total electricity generation of almost 12,000 TWh with consumption from the electrolyzers at almost 6200 TWh.

5.2. Annual system costs and H_2 and PtL contribution

Annual cost is 8–11 M€/PJ (of demand) for hydrogen, while these are almost 100 € for every ton of CO2 used for PtL. The two items that cause the largest decrease in marginal CO_2 price are the possibility of CO_2 underground storage and a high (25.5 EJ/yr) biomass potential.

Understanding of cost is necessary to understand how its structure changes across scenarios and the effects that hydrogen and PtL have on the system. To aid this, Fig. 6 shows the cost breakdown for the main scenarios.

System cost breakdown. Total cost includes all costs ranging from facilities and infrastructure on large scale including equipment for industry to costs on the consumer side such as heat pumps, district heating, insulation measures and vehicles. A large part of this (~1700 bln€) is actually the purchase of transport vehicles (cars, trucks and buses), composed around two thirds by private cars and out of which around 75 bln€/yr are from battery specific additional costs (compared to diesel/gasoline vehicles). The next largest sector is power (between 500 and 1000 bln€) followed by the residential sector. CAPEX represents the largest contributor to cost with around 77–81%[12] (4100–4700 bln€) for all main scenarios. The single parameter with the largest effect is a high biomass potential, which can decrease annual costs by 440–510 bln€/yr compared to a scenario using the reference potential (and with 95% CO_2 reduction). The cost increase due to the tighter CO_2 target is larger (220–440 bln€/yr[13]) than the respective increase due to the absence of CO_2 storage (100–230 bln€/yr). This is in line with IPCC reports [174] that indicate CCS as a key technology, whose absence can lead to almost 140% higher total discounted cost (2015–2100). The combination of a high biomass potential with carbon capture (BECCS) allows achieving the lowest annual cost in a scenario that still reaches 95% CO_2 reduction,[14] but still 4% higher than the *BAU* scenario. The two sectors with the largest changes across scenarios are transport and power. Specific cost for power is around 75 M€/yr per TWh of electricity demand. Deviations from this value are due to: (1) lower VRE potential (increasing to 85–90) and (2) higher transmission cost (increasing to 90). In the transport sector, cost is 96–98% comprised by the vehicles purchase cost, which is in turn driven by the average efficiency target of the fleet. Most efficient cars can be up to 20% more expensive, while heavy-duty trucks using hydrogen can be 35% more expensive than their diesel counterparts (see Appendix A for data and sources). Costs in the industry sector fluctuate between 115 and 140 bln€/yr depending mainly on the CO_2 price. Major cost components are steel and paper with 17 and 50 bln€/yr respectively.[15] Costs associated to the residential sector are relatively constant at 400 bln€/yr, out of which 120 bln€/yr correspond to the insulation measures, 4–20 bln€/yr for batteries and almost 180 bln€/yr are other appliances (for cooking, lighting and similar). The combination of lower gas demand and internal production of hydrogen and liquids (BtL/PtL) allows reducing the import bill from 420 bln€/yr in an 80% CO_2 reduction scenario to 350 bln€/yr for 95% CO_2 reduction to only 50 bln€/yr with no CO_2 storage and only decreasing further as more constraints are added since it limits the use of fossil fuels. Higher degree of electrification leads to grid expansion whose associated cost is proportional to demand increase. Grid costs range between 60 and 130 bln €/yr and add 10–15 €/MWh to the electricity price only for the new grid.

Discussion of system cost. To put these numbers in perspective, there are different references that can be used. One is the total (expected) size of the economy. With an expected growth of 1.7% per year [175], EU economy would reach almost 28,000 bln€ by 2050. IEA estimates [176] that cumulative investment for EU in energy supply will be almost 2900 bln€[16] (2012€) from 2014 until 2035 for a 450 ppm scenario. However, this scenario considers 20% increase in primary energy demand in OECD (assuming a similar trend for Europe) and it only focuses on the supply side (power, oil, coal, gas and biofuels). This leads to an annual investment of around 150 billion€/yr, which is the same as the historical trend for 2013 considering that in the last 15 years, annual investment in global energy supply has more than

[12] These are overnight costs. The rest is fixed and variable OPEX, but without fuel prices since that is money transfer between processes to pay for their respective costs.

[13] Largest cost increase corresponds to scenario without CO_2 underground storage.

[14] This corresponds to Scenario 11 in Table 17 and not to the *Biomass* scenario that does not allow CO_2 storage.

[15] This does not include fuel cost (which is a major component of steel cost [199] when considered as stand-alone process) since that is endogenous in the model and reflected as costs in other sector (e.g. hydrogen production).

[16] Value in reference is in US dollars and a conversion rate of 1.2 $ to € was assumed, which is assumed throughout this article.

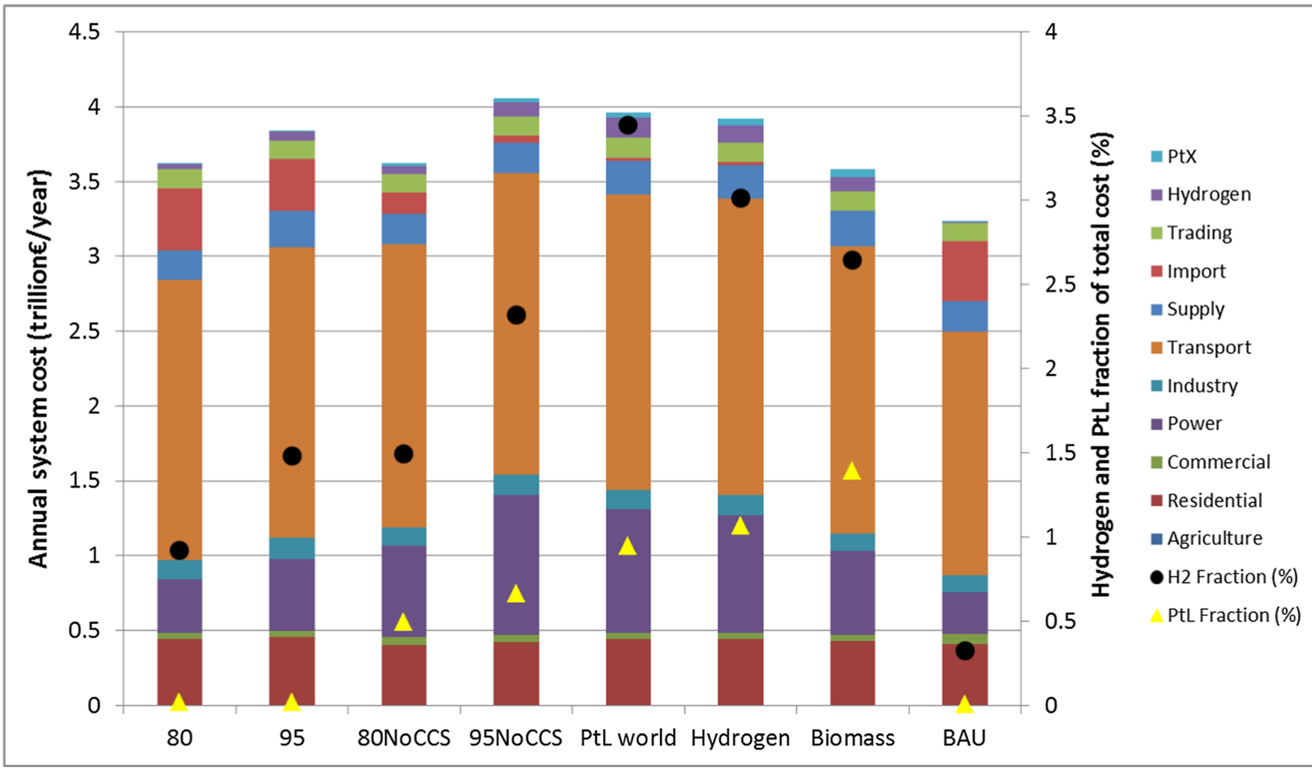

Fig. 6. Sectorial split for annualized system cost for 2050 including H_2 and PtL fraction.

doubled at a global level from 700 to 1600 bln€ (Europe represents on average 10% of the global investment) [176]. By adding stricter constraints, including the downstream costs (which are actually larger than supply) and including the OPEX component, the costs will greatly increase. A final reference is the total expected costs in a scenario where the CO_2 reduction is not as drastic (*BAU* scenario, which has 48% CO_2 reduction). With a *BAU* pathway, the system would have annual cost of 3250 bln€. Therefore, the more ambitious scenario of 80% reduction implies a 12% increase of the annual cost or around 1.4% of the GDP for 2050 with respect to the *BAU* scenario.

Hydrogen cost. It is between 20 and 140 bln€/yr, where naturally this is proportionally related to the flows presented in Fig. 7. The specific cost is between 8 and 11 M€/PJ of hydrogen demand. For 95% CO_2 reduction with no other restrictions, infrastructure represents almost half of these costs. This includes pipelines, compression, refueling stations, among others. This excludes the downstream use, where vehicles can represent 225 bln€/yr and buses up to 30 bln€/yr. As additional constraints are added, production contribution becomes larger reaching fractions close to 85% of the total cost (see Appendix J for breakdown for each main scenario) for the scenarios where heavy-duty transport shifts away from hydrogen (e.g. high biomass potential or electric option possible). The reason for this is that with more restrictions, the importance of PtL is higher and the fraction of hydrogen being used for PtL increases (see Section 5.3). When it is used for PtL, it is assumed they will be co-located and the infrastructure requirement is much lower. To put this number in perspective, HyWays [22] estimated in 2007 a cumulative investment for infrastructure build-up of 60 bln€ up to 2030. It has been estimated [177] that the total infrastructure (production, transport and refueling) for hydrogen is around 600 M €/TWh (1.3 bln€/yr per mtpa of hydrogen demand). Taking the hydrogen flow range of 20–120 mtpa (~670–4000 TWh), the total cost would be ~800–2400 bln€ with the annual cost depending on the lifetime and interest rate assumed. Assuming 5% and 30 years lifetime, the annual cost would be 25–210 bln€/yr. The same study [177] estimates the cumulative investment for the 2025–2030 period as 60 bln€ (for the 10 European countries[17] included in HyWays) increasing from almost 7 bln€ in the previous 5 years and which was enough to reach a 12% penetration of FCEV. Production step was also found to be 60–80% of the hydrogen cost. Currently, global investment in hydrogen production only by the petrochemical industry is around 90 bln€/yr with the hydrogen market having a valuation of 350–420 bln€/yr [178].

PtL cost. This is between 0 and 50 bln€/yr. The annualized cost is almost 100 € for every ton of CO_2 used for PtL. CAPEX constitutes around 75% of the total cost, but this can be related directly to the input data used since the OPEX does not include the raw material prices and the other components of the value chain (i.e. CO_2 capture, downstream use). To put this in perspective, fossil liquids that are displaced by PtL can be used as reference. Global investment in exploration and production of oil (and gas) is ~540 bln€/yr, while looking ahead, the cumulative new investment in oil facilities for EU28 estimated by the IEA [176] is 330 bln€ (2012€) for the period 2014–2035.

CO_2 prices. A *BAU* scenario leads to 125 €/ton of CO_2. By only making stricter the CO_2 target, the price increases to 350 €/ton for 80% CO_2 reduction and nearly 740 €/ton for 95% CO_2 reduction. This can drastically decrease with higher VRE potential achieving a reduction of 120 €/ton, but this is only the scenario when CO_2 storage is not possible meaning that the system is more restricted, electricity is more needed and a higher VRE potential makes a larger difference. The other large positive change is that with a higher biomass potential, the marginal CO_2 price decreases by 360–540 €/ton, mainly due to the high versatility of biomass to be used across sectors and because combined with PtL allows reducing the emissions from the transport sector, which is the one with the highest abatement cost. Among the negative drivers, absence of CO_2 storage increases CO_2 price to 580 and 1300 €/ton respectively, representing the largest (negative) change in CO_2 price caused by a single variable. This is in agreement with previous findings

[17] France, Germany, Greece, Italy, the Netherlands, Norway, Finland, Poland, Spain and the United Kingdom.

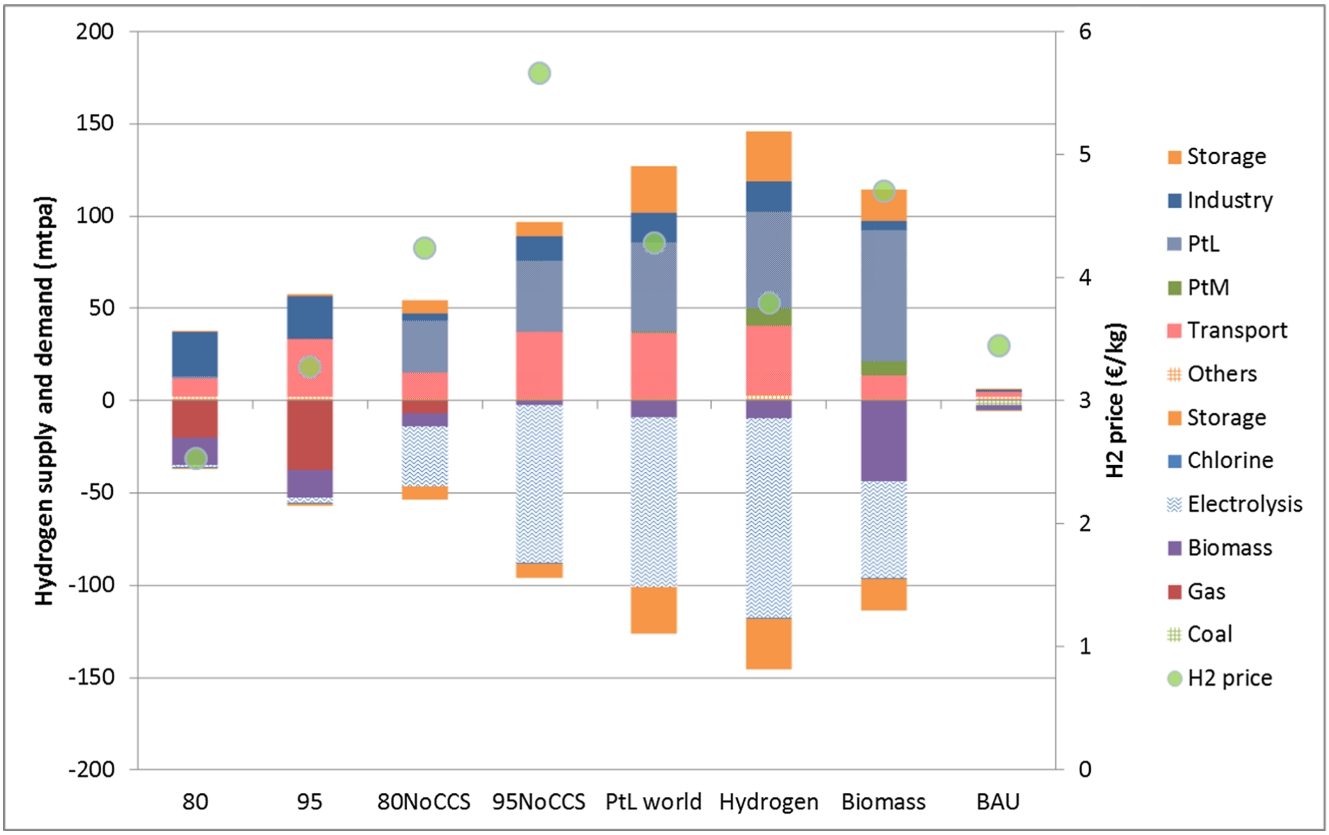

Fig. 7. Technology mix for hydrogen production and sectorial use across main scenarios.

[174] that show the importance of having CCS in the technology portfolio.

To achieve a zero-emissions scenario by 2050, one of the key constraints (CO_2 storage, biomass or VRE potential) needs to be relaxed. Otherwise, it might be too costly to pursue (95% CO_2 reduction scenarios already reach 1300 €/ton with electricity system three times as large). Another option is direct CO_2 capture from air coupled with low-cost VRE. However, the rates of change and investment needed exclude the possibility of delaying action.

5.3. Hydrogen balance

Limiting the number of flexibility options the energy system has to achieve the CO_2 target increases the reliance on hydrogen. This means installing around 1000 GW of electrolyzers (plus the VRE capacity upstream) and shifting steel production to hydrogen in a time span of 30 years, which will make the transition to low-carbon more challenging.

The key questions to be answered in this section are what the main sources of hydrogen are, where it is being used and how the demand changes across scenarios. The hydrogen production and demand are shown in Fig. 7.

Hydrogen demand. The smallest hydrogen flows are observed for scenarios with CO_2 storage, given that with storage as possibility, CO_2 is not used and there is limited hydrogen consumed by PtL. Even then, flows are in the order of 40–60 mtpa (4.8–7.2 EJ), which are still much higher than current total consumption in the EU (7 mtpa [36]). In these scenarios, the uses are for two sectors, namely industry (steel) and transport. Within transport, the sector providing the largest difference (discussed further in Section 5.5) is heavy-duty. Demand in this sector can be up to 4 EJ (~33 mtpa) and it is driven by either more constraints in the system (making low carbon options more necessary for heavy-duty) or lower H_2 price (e.g. through better PEM performance). Demand for buses is relatively low and constant at 0.4–0.45 EJ, while FCEV consume around 0.5 EJ. Note that the hydrogen demand for buses changes to electricity as soon as the electric option is allowed. Given that buses can already be competitive today, it is realistic to assume this demand will shift to electricity. The car fleet is dominated (~60%) by Battery Electric Vehicles (BEV) and FCEVs represent around 10–15% of the fleet. A sensitivity done with 30% lower cost for FCEV increased the FCEV share to 30%. The focus of this article is on the hydrogen/PtL nexus, while analysis of cost and efficiency evolution for powertrains and effect on future demand is part of an upcoming publication by the authors.

Electrolyzer capacity. It is noteworthy that the difference in cost between the 95% CO_2 reduction scenario and the *Hydrogen* scenario is relatively small (2.4%). However, when looking at hydrogen flows (and PtL contribution), the systems are fundamentally different. This introduces a dimension (other than cost) that can prove fundamental to realize the transition, which is rate of change. Whereas the 95% scenario has almost 80 GW of electrolyzer capacity, the absence of CO_2 storage increases this capacity to almost 1000 GW, due to the combined effect of electrolysis having to replace steam reforming in the counterfactual case and doubling of the hydrogen flow for the additional PtL demand. This is also in line with previous studies looking at a possible 100% RES scenario for the EU [170] which estimated 960 GW. To put this in perspective, current global capacity of electrolyzers is around 8 GW [23], assuming this is distributed by regions proportional to hydrogen demand (EU is 7 out of 50 mtpa globally), EU should have close to 1 GW of installed capacity. To reach 80 GW of an unrestricted scenario (95% CO_2 reduction) implies an annual growth of almost 15% a year, which implies a similar growth to what wind has experienced in the 2007–2017 period (18% a year [179,180]). On the other hand, a capacity of 1000 GW requires a 24% growth per year, which is still less than the 32% observed for PV in the 2012–2017 period [179,180], but it seems optimistic to assume this sustained growth for the entire period until 2050. Therefore, limiting technological choices of the system could lead to a longer timeline for implementation due to the large changes required in the composition of the system linking the results from this study to the CO_2 reduction target (and associated constraints) rather than a specific 2050 timeline.

Hydrogen in other studies. To be able to compare these numbers with previous studies, two factors should be considered (1) most of the previous studies focus on the transport sector (e.g. [109–111]) and (2) the more restricted the technology portfolio is, the larger the hydrogen role will be since there are fewer choices to reach the same target. Since this study explores those more constrained scenarios, it is expected that hydrogen flows are larger. Ref. [113] assesses a global scenario with 400 ppmv of CO_2, where hydrogen reaches a 20.6% share of final energy consumption, but only for 2100, while for 2050 it is between 3 and 4%. One of the studies by international organizations with a prominent role for hydrogen is the Advanced Energy Revolution from Greenpeace. This achieves 100% CO_2 reduction for the energy system by 2050 and uses hydrogen in transport, industry, buildings and power [181]. Hydrogen flow is around 27 mtpa (~3.2 EJ) for Europe (excluding steel and PtL) and constitutes almost 11% of the final energy demand, which is close to the 33 mtpa in the *95%* scenario for this study (excluding steel). Shell Sky Scenario reaches 300 MtonCO_2 emissions (equivalent to 95% CO_2 reduction vs. 1990) by 2060 with a hydrogen flow of 1.9 EJ/yr. Most of the hydrogen growth in their case is after 2060, reaching a hydrogen flow of 4.8 EJ/yr [182].

Hydrogen for steel. Steel demand is expected to be around 177 mtpa (practically the same as the base year) for 2050. With a specific hydrogen demand of 17 GJ/ton of steel [142], the sector could use up to 25 mtpa of hydrogen if satisfied entirely by direct reduction. There are 3 parameters that define the use for this sector: CO_2 price, biomass potential and coal availability. The main driver is the possible coal use. If coal is not allowed (e.g. due to general ban of fossil fuels), then almost 95% of the demand is satisfied with hydrogen, reaching a demand of 24 mtpa for the sector. This happens even for 80% CO_2 with CCS and the reference biomass potential. In case coal is allowed, hydrogen satisfies around 25% of the demand for the same 80% CO_2 reduction scenario. In scenarios with higher biomass potential (~25.5 EJ/yr), biomass use enables positive emissions elsewhere in the system (usually industry and transport). This happens even for high CO_2 prices. For example, for 95% CO_2 reduction and no CO_2 storage (and still coal allowed), the (marginal) price is around 930 €/ton for CO_2. With this price, around 75% of the steel demand is satisfied with an electric option for the furnace (from only about 33% with the reference biomass potential). Note that in EU27, there are already almost three times as many electric arc furnaces as there are blast furnaces (232 vs. 88 for 2013 [107]). Therefore, decarbonization of electricity could lead to a potential reduction of the steel CO_2 footprint limited by the availability of scrap metal (used for electric arc). However, electrowinning (solution or suspension in acid or alkaline solution) [145] is another option to electrify the primary steel production. The complementary technology (to direct reduction) is carbon capture, which is also affected by the potential use downstream. In ambitious scenarios where hydrogen constitutes 18% of the final energy demand and allows reducing 6 GtCO_2/yr on a global basis, steel only shifts around 10% (global basis) to this production method [183]. Similarly, [175] estimates that less than 5% of the steel demand is satisfied with this route.

Hydrogen for PtL. For the scenarios without CO_2 storage, PtL becomes attractive and it is the dominant component of hydrogen demand. These options (storage/use) are not mutually exclusive, but PtL is only enabled when the most attractive (i.e. lower cost) option (storage) is not possible. Hydrogen demand can reach up to 70 mtpa for a scenario with a large biomass potential since it promotes the use of BtL and the downstream use of the CO_2 for PtL (requiring hydrogen). Hydrogen storage becomes larger for higher VRE potential since it allows bridging the daily pattern gap by solar, enabling to operate the electrolyzer with large daily load swings, while still satisfying the demand. This is a consequence of the large hydrogen flows (electrolyzers can consume up to 50% of the electricity demand) that cannot act as "base load" (i.e. constant demand) since there are periods when there is not enough generation. Besides, storage that is more suitable for daily patterns (e.g. batteries) would only displace electricity use in time, while that energy is not needed as electricity, but as hydrogen instead. The highest demand is from the *Hydrogen* scenario with almost 120 mtpa (14.4 EJ). This is enabled by cheaper hydrogen due to an optimistic PEM performance and SOEC use, which leads to the cheapest hydrogen in scenarios without CO_2 storage (3.8 €/kg). This relatively cheaper hydrogen also enables the use in PtM, which is absent in most of the other scenarios.

Hydrogen for other applications. Applications that are missing are the conventional ones in the present (refineries and chemicals, specifically ammonia). Given the strict CO_2 target, satisfying transport with conventional oil and refineries will lead to not achieving the target. Therefore, alternative routes are chosen and in these future scenarios, refineries activity is drastically reduced (to 20% or less than their current output) and its associated hydrogen demand as well for most of the scenarios. For ammonia, a new process was introduced using pure hydrogen and oxygen (ASU), but the process carries the disadvantage of the use of a more expensive commodity (hydrogen vs. natural gas) and the extra investment for the air separation. This is in agreement with previous studies [175] that show a limited shift to this route in a below 2 °C scenario. The preferred option to decarbonize ammonia is carbon capture, even when no CO_2 storage is available as the CO_2 can be used.[18]

Hydrogen production. In scenarios without CO_2 storage, electrolysis is the main technology used for hydrogen production while steam reforming with carbon capture is used when CO_2 storage is possible. This is in agreement with previous studies [184]. This leads to some inefficiency since the hydrogen is used downstream in a sector where electricity could be used (private transport). Nevertheless, a key element is VRE contribution for electricity, the larger its share the higher the need for options to manage surplus. Electrolyzers represent one of these alternatives to balance their variability when equipped with hydrogen storage. Using BEV in combination with control and communication infrastructure to use the batteries as storage could be an alternative. Another option is electricity storage which continues to get cheaper and could reach prices of 125 €/kWh by 2030 and down to 83 €/kWh in the longer term [185,186]. A limitation they have is their low energy density, which is important for this study considering electrolyzers produce up to 120 mtpa, equivalent to almost 5500 TWh of electricity input in a year. This (large) electricity consumption for the electrolyzer is in line with [170] that estimates 6200 TWh for electrofuels. However, this considers no hydrogen for transport and 100% for electrofuels production.

Hydrogen distribution. In terms of delivery pathways, the fraction for transport is delivered through compression, centralized storage, distribution and refueling in gas-gas stations at a cost between 4.6 and 6 €/kg. There is no use of liquefaction and delivery of liquid hydrogen in any of the scenarios. Use in steel follows a similar pathway with compression, transmission and distribution pipelines (~3.6 €/kg). Use in PtL, which represents the largest demand when there is no CO_2 storage, is assumed to be produced directly where it is needed, similar to the current case in refineries. This PtL fraction can be up to 50% of the demand. Refer to Appendix F for the delivery pathways for the main scenarios.

5.4. Price and demand relation by sector

Higher relative cost to decarbonize transport and industry (in the

[18] CO_2 flows from ammonia are small compared to the emissions in the entire system, where emissions from NH_3 production are in the order of 11 mtpa, while total emissions are 228 mtpa for 95% CO_2 reduction.

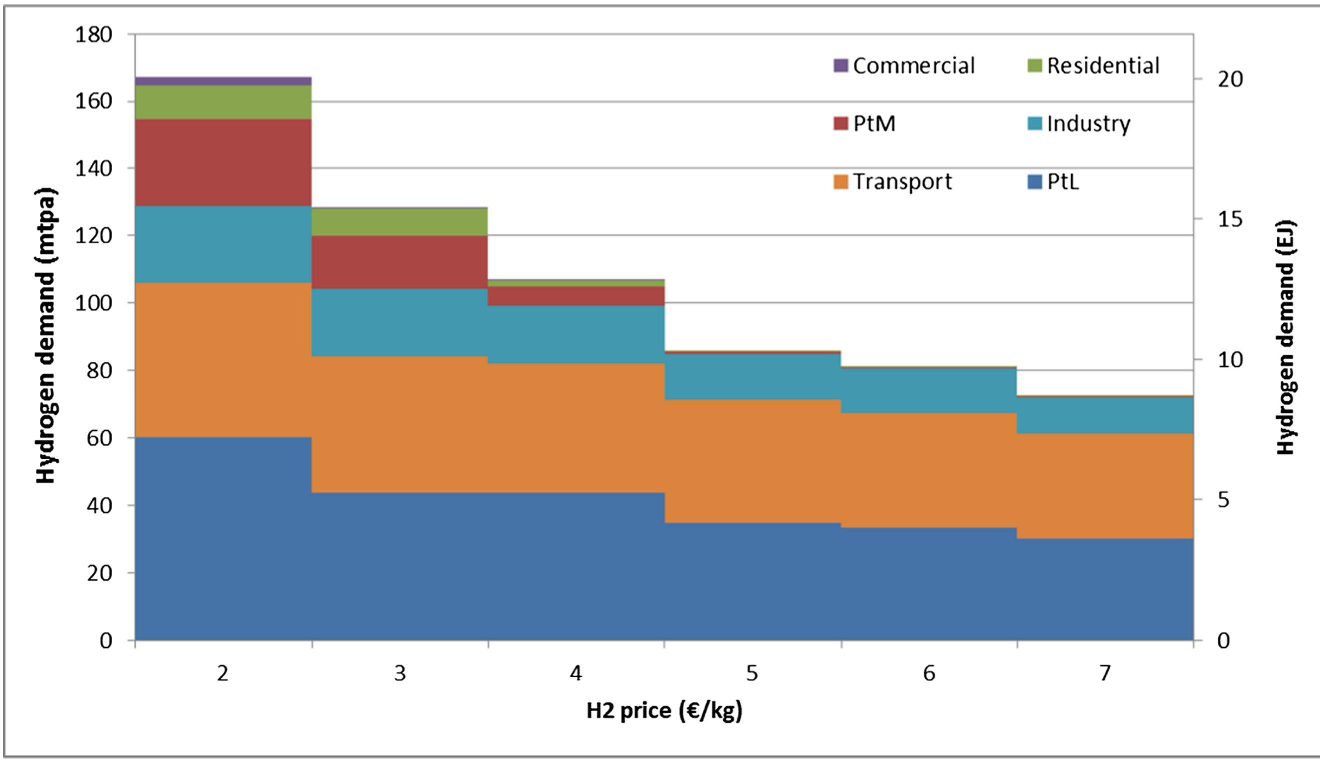

Fig. 8. Price – demand curve for hydrogen in a scenario with 95% CO_2 reduction, no CO_2 storage and high VRE potential.

absence of CO_2 storage) makes these sectors more resilient to higher hydrogen prices.

This section presents changes across the system due to a variable hydrogen price. For this, the hydrogen demand was detached from the supply side by providing an external constant price. This was done for a scenario with 95% CO_2 reduction, no CO_2 storage (to have PtX as part of the hydrogen demand) and high VRE potential (with a larger need for flexibility in power). The price – demand curve is depicted in Fig. 8, where the hydrogen price represents only the production cost with the distribution cost varying depending on the sector and pathway chosen. Additional results are presented in Appendix F.

Demand at high prices. Two sectors that are prominent even at high hydrogen prices are PtL and transport. Even with 7 €/kg (plus distribution cost for transport), demand for these sectors already amounts to almost 60 mtpa. Demand in transport is mainly (80%) in heavy-duty trucks, driven by the fact that hydrogen is a zero tailpipe emissions fuel that displaces fossil fuels in spite of the higher (+30%) cost for the truck itself. PtL demand is driven by aviation (around 45 mtpa of hydrogen if satisfied fully with PtL) and by the fact that diesel trucks (even more efficient ones) are cheaper than hydrogen ones (see Table 12 in Appendix A). This leads to a compensation of the lower pathway efficiency by a lower CAPEX. The last sector to have a demand with the highest hydrogen price considered is industry. With a hydrogen price of 7 €/kg around 50% of the steel demand is satisfied with direct reduction.

Demand at low prices. Up to 5 €/kg, these three sectors have marginal increases in demand, with the largest change in steel where hydrogen increases its share to satisfy two thirds of the demand. At prices below 4 €/kg, PtM starts being attractive. The additional gas covers 35% of the gas demand for a 2 €/kg hydrogen price, with most (80–90%) of the extra gas used for heat production, either through boilers for industry or CHP for district heating. Use in the residential sector (through μ-CHP with fuel cells), becomes significant at 3 €/kg, while use in the commercial sector does not start until it reaches 2 €/kg. In terms of market share, a price of 2 €/kg, translates into a 2.5 and 14% share of the heating demand satisfied with hydrogen for the commercial and residential sector respectively.

Interaction with CO_2 price. The increase in CO_2 price per every unit of increase of hydrogen price is lower as the hydrogen becomes more expensive (see Appendix F). This means the largest CO_2 price increase is almost 150 €/ton for the change from 2 to 3 €/kg of H_2, while the increase from 6 to 7 €/kg of H_2 causes an increase of 50 €/ton in the CO_2 price. This occurs since hydrogen demand decreases and the part of the system that becomes more expensive also becomes a small fraction of the total (with increasing hydrogen price). Higher CO_2 price also leads to the use of more expensive resources for electricity. Particularly, the use of wind and solar in places with a lower capacity factor, that translates into a higher cost. This, in combination with the use of more efficient (expensive) options for road transport, causes an increase in total annual investments in the system by up to 1%.

Drivers for hydrogen price. The hydrogen price is a result of the combination between CO_2 and fuel prices. In scenarios with CO_2 storage, the CO_2 prices are (on average) lower (350 €/ton for 80% CO_2 reduction) resulting in lower hydrogen prices in the range of 2.5–3.4 €/kg with the lower bound corresponding to cheaper methane (~15 €/GJ), which is the main source for hydrogen. When there is no CO_2 storage, CO_2 prices are higher (1000–1400 €/ton) and this is reflected in the hydrogen price that reaches 3.8–5.7 €/kg. For these scenarios, electrolysis is the main technology used and changes that produce cheaper electricity also result in cheaper hydrogen. The use of higher VRE potential can decrease H_2 price by 1.4 €/kg, while the use of optimistic PEM performance (see Table 4 in Appendix A) can decrease the cost by 0.3–1.4 €/kg with the larger change associated to more restricted scenarios.

Impact on other commodities. Hydrogen price also has an indirect effect on biomass use. With lower hydrogen prices, the cost for electrofuels is lower and reduces the share of BtL. This enables biomass use for other sectors, especially power (through gasification). A similar effect takes places in the power sector, where PtM becomes more attractive at lower H_2 prices and displaces the more expensive VRE resources with the lower cost gas (see Appendix F).

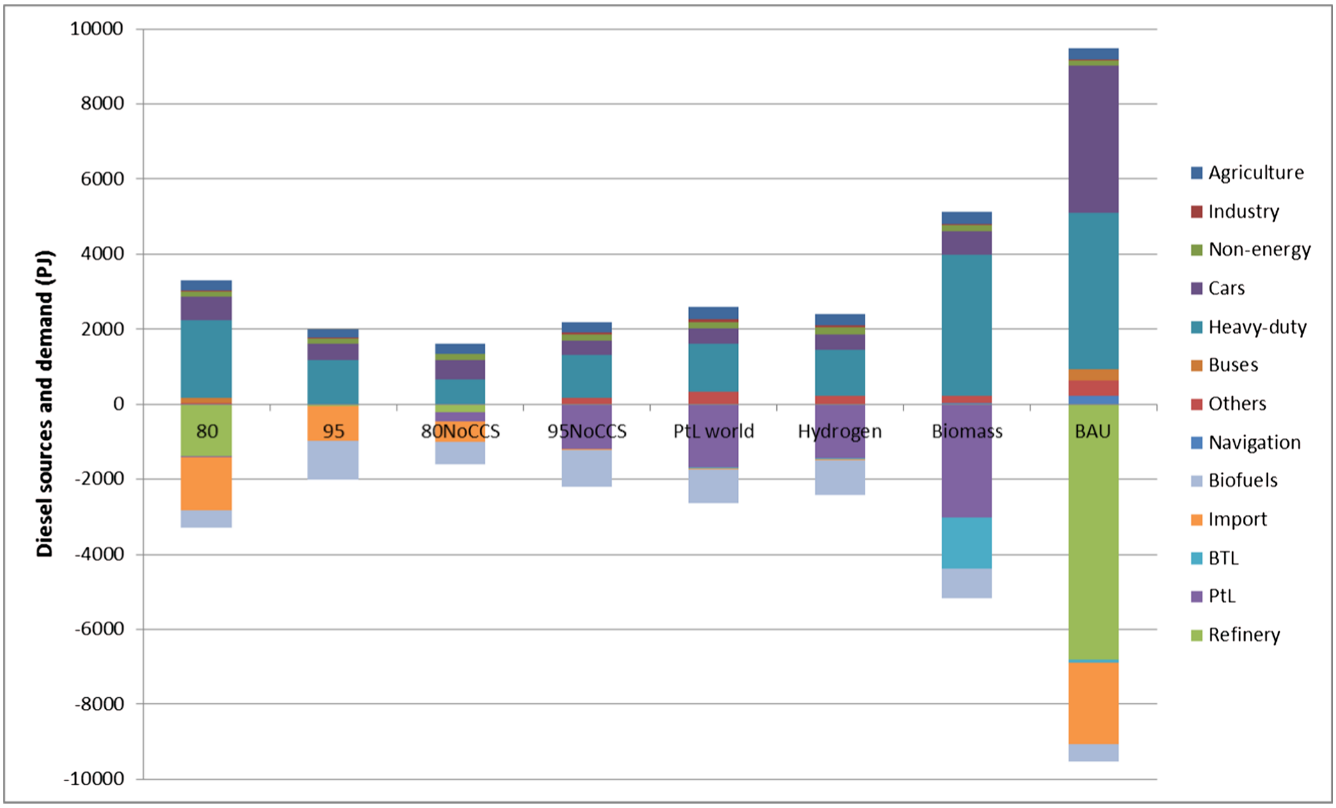

Fig. 9. Technology mix for diesel production and consumption sectors across main scenarios.

5.5. Diesel and jet fuel balances

These two represent the largest liquid fuels demand for its use in transport and the main fuels produced by PtL when it is present in the system. Therefore, it is important to understand what the dynamics with competing alternatives are and when PtL prevails over other options. This is linked to where these are being used (specifically for diesel since jet fuel only has aviation as end use sector) and highly linked to the use of biomass (next sub-section). The balance for diesel is shown in Fig. 9, while the jet fuel balance can be found in Appendix E, but it is also discussed below.

The preferred energy carrier in transport is electricity, complemented by hydrogen in applications that are more difficult to electrify (i.e. heavy-duty trucks) and synthetic fuels in aviation. PtL acts as a complement of BtL increasing its carbon efficiency to produce more liquid fuels.

Diesel demand (80%). The *80%* scenario with no restrictions is the one resembling the most the current state. Direct import of refined fuels represents almost 50% of the supply, while the other major source is through internal refining activities (with imported oil). The share of biofuels is more modest at only 14% of the supply. Heavy-duty is the largest demand, which is in turn satisfied 90% with diesel. This scenario uses more efficient trucks, but no fuel change yet. As basis for comparison, the diesel demand for 2015 is in the order of 7.5 EJ. The largest drop in demand (initial demand close to 3.5 EJ) is associated to private cars, which shift mostly (60–70%) to electricity. This is followed by light commercial vehicles (1.6 EJ), which completely change to electricity as well and buses (0.5 EJ) that shift to hydrogen. For jet fuel, it is mostly (> 95%) satisfied with import and refinery output since the CO_2 target is not so strict as to promote non-fossil options for this sector. In cars, the benefit of lower CO_2 footprint and higher pathway efficiency prevails over the cost increase for higher electricity network cost. To avoid an overly optimistic scenario where almost 100% of the cars are electricity-based, a maximum share of 80% was used. This leads to the remaining 20% being covered by a mix of hydrogen, BtL and diesel, where the latter comes mainly from PtL.

Diesel demand (95%). For the 95% CO_2 reduction scenario, biomass combined with CCS, enables negative emissions and the possibility for positive emissions in both diesel and jet fuel. This has also been seen in previous studies [184]. The largest difference (with respect to 80% CO_2 reduction) is that the higher CO_2 prices drive heavy-duty transport to use hydrogen, which becomes 50% of the demand, decreasing diesel demand by more than 1 EJ.

BtL/PtL synergy. With no CCS, PtL becomes attractive. Furthermore, for the high biomass potential or 95% CO_2 reduction, BtL also arises as supply option. A disadvantage of BtL is that the energy efficiency is relatively low (~40%). The fraction of the biomass that can be used for BtL is between 4.4 and 17.4 EJ (reference and high potential), which translate into 1.8 and 7 EJ of liquid product. Therefore, when the reference potential is used, wood and forestry residues are mostly used for jet fuel rather than diesel. Most of the benefit is actually for the CO_2 produced (70% of the carbon in the biomass), used downstream for PtL, which in turn constitutes 50–65% of diesel supply. This is in agreement with previous studies [187]. With a high biomass potential then there is enough biomass to enable BtL for diesel production directly. This makes available more CO_2 used for PtL and the overall diesel demand doubles exploiting this effect and the fact that diesel trucks are cheaper. In this case, PtL is needed since there are no negative emissions from biomass plus CCS (no CO_2 storage). The combination of these factors leads to an installed capacity of almost 600 GW across EU28+ producing almost 6.7 EJ and satisfying 50–60% of diesel and 60–90% of jet fuel demand. Another option that arises with a broader scope (than energy only) is a positive effect of agriculture, forestry and other land use (AFOLU) that could compensate higher emissions in the energy system. This is the effect seen in IPCC reports (AR5 – WGIII [174]) where the scenarios with no CO_2 storage has positive emissions from energy compensated by negative emissions in AFOLU.

Jet fuel supply. For aviation demand (see Fig. 20 in Appendix E), there are 3 combinations. For scenarios with CO_2 storage, it turns out to be better to use biomass in combination with CCS and achieve negative emissions elsewhere in the system to be able to have positive emissions in aviation. Therefore, in scenarios with CO_2 storage, jet fuel demand is satisfied mostly with import (fossil oil outside EU). Once CO_2 storage is limited, PtL becomes attractive, CO_2 from biomass can be used to produce jet fuel. In a scenario with 80% CO_2 reduction and no CO_2 storage, part of the supply (60%) has shifted to PtL, with the remaining 40% still being satisfied by import. The last scenario is one where there is no CO_2 storage (enabling PtL) with a stricter (95%) CO_2 target. This makes necessary BtL (as source for jet fuel).

Fuel choice for heavy-duty transport. With regards to diesel (see Fig. 21 in Appendix E), the largest swing sector is heavy-duty transport. BAU still has trucks running on diesel, when the CO_2 reduction target is increased from 48 to 80%, LMG arises as potential option composing 40% of the fleet, while decreasing further the CO_2 emissions to 95% of their original level, makes hydrogen more attractive (50% of the fleet with only 20% LMG, 10% biodiesel and 10% import). When there is no CO_2 storage available, the sector is mostly (70%) dominated by hydrogen complemented by diesel (from PtL and BtL). LMG is not attractive anymore since it results in tailpipe CO_2 emissions and PtM is not attractive enough to produce LMG from PtM product as value chain (see [21] for a more detailed discussion on PtM). Diesel contribution is more dependent on biomass potential than on PtL performance. When the potential is the highest, diesel can increase its share to satisfy up to 90% of the demand, while changes in PtL performance only change diesel contribution by 10%. All these options are rendered not attractive if an electric alternative for the trucks is introduced, in which case the share of electricity is between 70 and 100% for this sub-sector. This is in agreement with previous estimates by IEA [175] that show the same order of preference for diesel, hydrogen and electricity as energy carriers as the scenario becomes more restrictive, with diesel at around 5–10% of the fleet for a below 2 °C scenario.

Effect of different PtL performance. A sensitivity analysis was done (see Appendix G for results), assessing the impact for ± 150 €/kW change in CAPEX and +5/−10% points in efficiency (due to differences in heat integration). The largest effect was due to the efficiency. PtL installed capacity changed around 10 GW (from a reference value of almost 430 GW[19]) with every percentage change (both directions). A 150 €/kW increase in CAPEX led to 50 GW lower installed capacity, while a decrease by the same magnitude only increased capacity by 25 GW. The combination of both lower CAPEX and higher efficiency led to 530 GW of installed PtL capacity. Even though the changes in CO_2 use were relatively small, these made a large difference for the other CO_2 use option (i.e. PtM). When PtL efficiency was 8–10% points lower, PtM capacity increased by 2.5 times from 27 to 67 GW, but it still represented less than 14% of the CO_2 use. The best PtL performance can lead to lower annual cost by 25 bln€/yr with relatively modest decrease in marginal CO_2 price of 15 €/ton. When PtL performance was conservative (see Table 10), combined with a low biomass potential (~7 EJ/yr), then it is the point where atmospheric capture starts to be necessary for the system. At this point, < 1% of jet fuel demand is satisfied through this route, but any negative changes (e.g. increase in demand, lower CO_2 emissions) will make this need larger.

Failure to develop PtL. When PtL is not available (e.g. for social acceptance issues or resource scarcity), it is substituted by mostly LMG in heavy-duty transport. This halves diesel demand to around 1 EJ (for 95% CO_2 reduction). At the same time, around 30% of the aviation demand needs to be satisfied with import (outside EU), while maximizing the use of biofuels. This leads to 30–80 bln€/yr higher annual cost. The relative flexibility diesel has is that it can be substituted by electricity, hydrogen or LMG in its uses, while aviation demand has limited choices and the use of BtL without a downstream use for the CO_2 limits the carbon-neutral fuel in the system.

5.6. Biomass balance

The energy system will use most (~95%) of the biomass potential below 12.5 €/GJ since it is considered carbon-neutral. There is a need to define the potential that still ensures the carbon neutrality of that biomass.

As highlighted before, biomass has high importance due to its possibility to satisfy demand with (close to) zero net emissions. Therefore, this section aims to understand the dynamics defining its distribution among the different sectors. For this, Fig. 10 shows the supply and demand across the main scenarios, whereas insights from all the scenarios are included in the discussion below. This includes 13 scenarios that deviate from the reference potential.

Biomass allocation. At a first glance, the use of biomass seems balanced across sectors. On a closer look, each type of biomass is associated to specific sectors with only the wood and forestry having a more complex set of variables to define its end use. Industrial and municipal wastes are mainly used for the commercial sector and residential sector (60/40 split). Rapeseed and biodiesel displace its oil-derived counterpart. Bioethanol and sugar crops are blend with gasoline for private transport. Biogas is used for industrial heat generation and in case no coal is allowed this is more than 95% of its use. The complementary use is for electricity production, which becomes more relevant for stricter scenarios. Biogas upgrading with either PtM or carbon capture is hardly used, except for the scenarios that combine a high biomass potential with cheap hydrogen (better PEM performance). This is in line with current use comprising close to 60% for electricity and 30% for heat production, with only around 10% of the biogas injected to the grid and most of it having specific users [188]. For wood and forestry, the primary use is for hydrogen production followed by electricity (close to 70/30 split) in scenarios with CCS. However, when there is no CCS (and CCU possibility) and high (95%) CO_2 reduction, then BtL becomes the main alternative. Its share is around 60% for 95% CO_2 reduction and no CO_2 storage and increases to 80% as PtL becomes more limited (e.g. lower efficiency) or only 20% as PtL becomes more attractive (e.g. cheaper hydrogen). BtL is also enabled by a higher biomass potential. BtL has a low (~30%) carbon efficiency, which means there is more carbon available for PtL than carbon directly in the BtL product. Direct use for industry only occurs for relatively low CO_2 targets (*BAU* and *80%*) or when the potential is the highest. For scenarios with a low biomass potential, the amount of biomass used for hydrogen production has the highest reduction in comparison to the reference potential (~80%), followed by industry (~65%) and power (~12–25%).

Potential used. Almost the full potential is used across scenarios for the various levels of biomass explored (7–25.5 EJ/yr). Even in the less strict scenario (80% CO_2 reduction), over 95% of the potential below 12.5 €/GJ is used. Only for stricter scenarios (95% CO_2 reduction with no CO_2 storage) part of the more expensive sources (e.g. rape seed) are used for ethanol, leading to almost 95% use of the full potential. This implies the use of even the most expensive sources, which are up to almost 30 €/GJ (compared to an average price of 6 €/GJ for the full potential). For scenarios with high biomass potential, almost all of it is used. Starch, sugar and crops (leading to 1st generation biofuels) and more expensive than 8–10 €/GJ are not used. Accordingly, biomass use is between 22.5 and 23 EJ/yr and it is 1 EJ/yr lower for the scenarios with higher VRE potential. The higher potential is mainly driven by higher availability of wood products, which is a versatile category given that it can be used in all sectors (see Fig. 4). Therefore, an increase in its quantity still keeps the flexibility to change its allocation depending on the constraints.

[19] Scenario *P2GF95CCSVRE*, which is Nº 27 from Table 17.

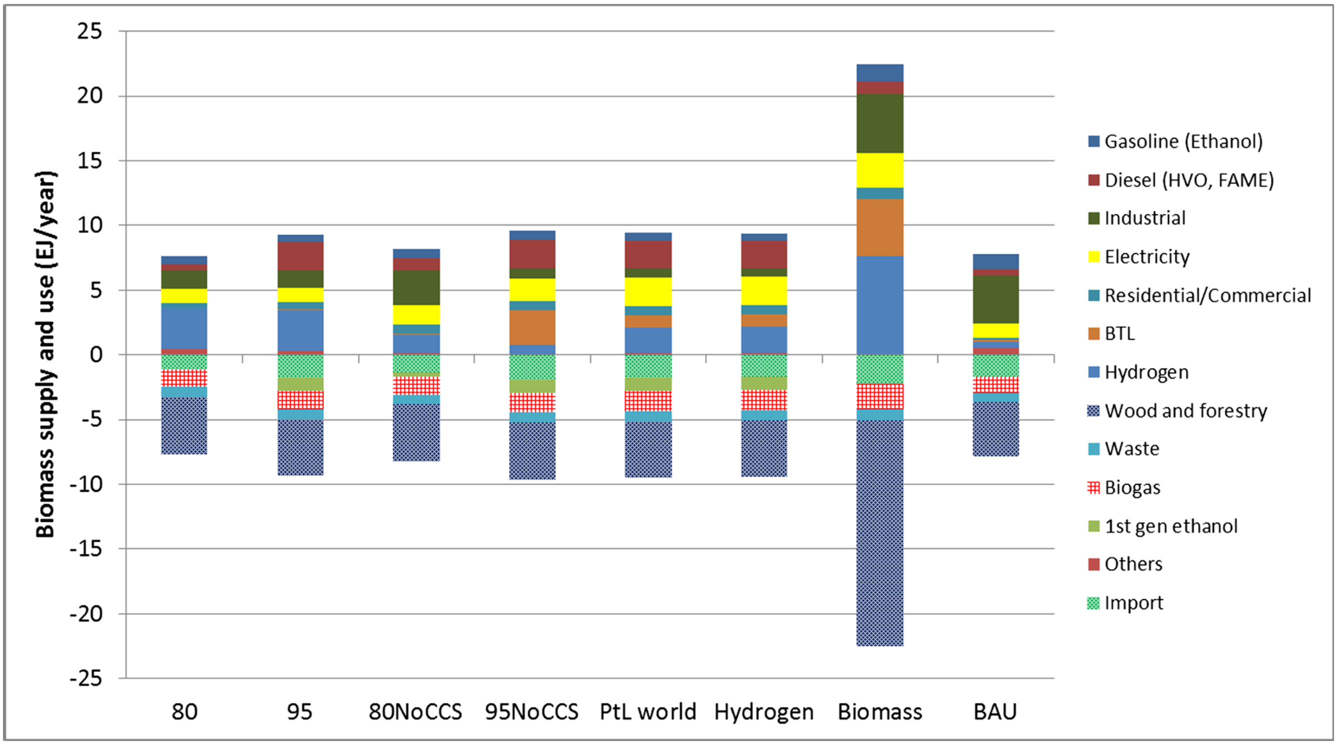

Fig. 10. Biomass potential use by category and sectorial use across main scenarios.

CO_2-neutral emissions. Biomass (together with PtL using DAC) is one of the critical alternatives for net zero emissions for aviation and navigation (which do not count with an electric or hydrogen alternative). In the balance of CO_2 emissions (see Appendix H), these two sectors reach up to 60% of the (tail pipe) emissions (for 80% CO_2 reduction) and can only be compensated if the CO_2 was originally sourced in the air or if they are compensated by negative emissions elsewhere in the system. CO_2 originally from air can be obtained through biomass, namely BtL and hydrogen production (with gasification) when CO_2 storage is not possible. BtL emissions would become significant if there were no CO_2 sinks since the process needs to remove CO_2 to adjust the H_2/CO ratio needed for Fischer Tropsch. These emissions could be as high as 350 mtpa (more than the total emissions allowed for 95% CO_2 reduction) in case there is no sink (although these emissions would be carbon neutral). BtL with carbon capture can use the carbon twice to satisfy transport demand, directly in the BtL process and by providing the CO_2 for PtL. At the same time, BtL is favored by PtL by further using the CO_2. Ultimately the CO_2 is released through the PtL route, but at least fossil fuel is displaced. To provide bio-derived fuels, one of the two (storage or use) needs to be possible. PtM does not provide the same flexibility since the relative size of marine transport is smaller (in terms of energy demand). The critical factors about aviation and navigation are that their demand will greatly increase in the coming decades, more than tripling on a global level by 2050[20] [175] and the other is the absence of electricity and hydrogen. Hydrogen has been identified as a main carrier in deep decarbonization scenarios, although it cannot be claimed to be the best alternative [189].

Competition with hydrogen. Biomass can be a competitor or enabler depending on the scenario. If CO_2 storage is possible, a larger biomass potential will lead to a greater use for hydrogen production becoming the dominant source, but the net hydrogen flow in the system will be lower due to the negative emissions achieved by biomass, which make possible higher emissions in transport, decreasing the need for PtL and therefore hydrogen. However, when no CO_2 storage is possible, a higher biomass potential hardly affects the total hydrogen flow, but instead increases the share for PtL use since there is more CO_2 available from BtL (+50%).

[20] Aviation demand is expected to grow by at least 4–5%/yr and navigation has experienced over 10%/yr growth since 2000.

5.7. CO_2 sources and sinks

Biomass-based processes combined with carbon capture are needed in low-carbon scenarios, either for negative emissions or to provide CO_2 for downstream use. The role of direct air capture can be significant if it reaches a level of 300 €/ton and 7 GJ/tonCO_2 of energy consumption.

PtL is an alternative for CO_2 use and for maximum abatement the CO_2 would come from air (direct capture or biomass). This section aims to explore what the sources of CO_2 for PtL are, how these flows change for different scenarios and the competition with other possible sinks for CO_2. Fig. 11 shows the sources and sinks for CO_2 across the main scenarios.

CO_2 storage. The low-carbon scenarios with CCS have the largest CO_2 flows with nearly 1.4 GtCO_2 captured and stored underground. To put this in perspective, currently there are 21 projects in operation or under construction that capture 37 mtpa with most of the experience being in EOR (Enhanced Oil Recovery) rather than a dedicated underground storage [190]. Another standard to add some perspective is the expected CCS contribution in future scenarios. IEA estimates CCS contribution will be 6.8 GtCO_2/yr to stay within 2 °C increase and 11.2 GtCO_2 for 1.5 °C [175]. Although these numbers are for 2060 and on a global level, they show the importance of the technology contribution. Consequently, 1.4 GtCO_2 is a challenging target given the current progress, infrastructure development [191] and investment needed to achieve such order of magnitude. The more ambitious CO_2 target leads to more than 30% increase in the CO_2 stored since there is a larger need for neutral and negative emissions mainly to compensate for the emissions in transport. CCS leads to lower system cost at the expense of prolonging the use of fossil fuels in the system, which are the main source for hydrogen and most of their use in power is with CCS.

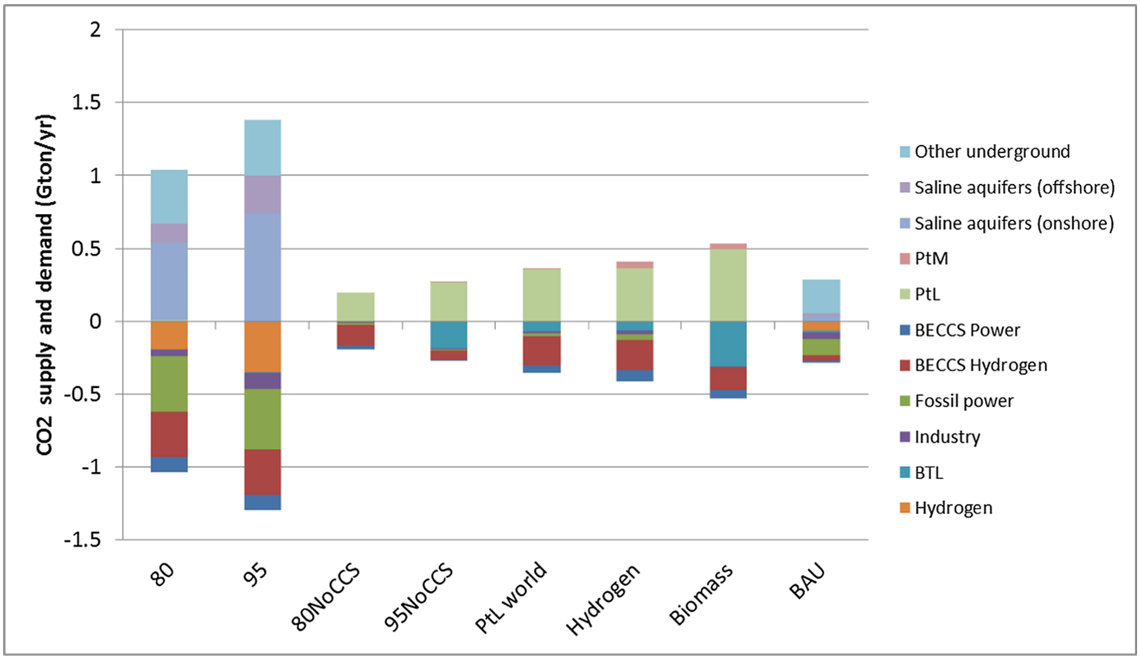

Fig. 11. CO_2 sources and sinks across main scenarios.

CO_2 sources are balanced across sectors with similar shares for power and hydrogen and a smaller role for industry. BECCS supplies between 30 and 40% of the CO_2 with the reference potential, while it can provide almost 75% of the CO_2 with the highest biomass potential. In spite of the relatively low BECCS contribution from power, it makes a big difference in the electricity footprint. The zero operational emissions from renewables combined with these negative emissions lead to a footprint between −10 and 5 gCO_2/kWh for most of the scenarios and it can reach −100 gCO_2/kWh for scenarios with high biomass potential. This effect is not necessarily due to a high BECCS contribution (although it reaches 10–11% of electricity production in scenarios with high biomass potential), but because there are hardly any positive emissions besides the occasional use of gas turbines.

Sources of CO_2 used. This is drastically changed when CO_2 storage is not allowed and the flows are reduced to between 200 and 500 Mton/yr. One reason for this is that CO_2 that goes in either PtL or PtM will ultimately end up in the atmosphere and the biomass potential is not high enough to sustain a level above 1 $GtonCO_2$/yr in a carbon-neutral way. CO_2 is used preferentially for PtL and only marginally for PtM, since the gas demand itself is largely reduced and hydrogen used as feed is too expensive to use for methane in most scenarios. Wood, forestry and grassy crops are the most versatile sources that can be used across sectors and that have the possibility of CO_2 capture in downstream uses. For the reference biomass potential, these sources would amount to 350–450 $MtonCO_2$/yr if all would be processed with carbon capture (depending on the route followed). When the potential is the highest (*Biomass economy)*, this increases to almost 1700 Mton/yr. Therefore, only when the potential is the highest a similar CO_2 flow as the ones seen in low carbon scenarios could be sustained. Over 85% of the CO_2 comes from biomass and ensures that the liquid produced downstream is carbon neutral. However, there is a small (~7%) contribution from fossil fuels in power generation. The model does not include the match between sources and sinks, but instead assumes the production and use of a common commodity. This would be the equivalent of a grid where all the producers and users are connected. To allocate specific sources, a model with higher spatial resolution is needed.

One of the sectors providing CO_2, both when there is the possibility for CO_2 storage and when it is absent, is cement. Its flow is relatively small compared to the downstream use in PtL. It is more relevant for the industry itself, since it reduces its specific emissions, but the contribution to the overall CO_2 reduction is limited. The use of carbon capture in cement can have a high energy penalty (5 MJ of additional energy per $kgCO_2$ captured and a CO_2 penalty of nearly 0.5 kg CO_2 per every unit of CO_2 captured [192]).

Drivers for CO_2 use. The main driver is transport since other sectors can be satisfied with hydrogen or electricity. Demand in the transport sector is around 5, 4, 2 and 0.5 EJ for heavy-duty trucks, aviation, marine transport and buses respectively. Assuming marine transport is satisfied with LMG, while the rest of the sectors are satisfied with PtL products, this establishes the upper bound of 800 $MtonCO_2$/yr that could be used. However, in the scenarios analyzed, two major deviations from this maximum use is the use of hydrogen for heavy-duty trucks (which is the preferred (70%) energy carrier when there is no CO_2 storage and 95% CO_2 reduction) and the supply of jet fuel by BtL or import, which can be dominant for scenarios with higher biomass potential (BtL) or with CO_2 storage (import). Another reference for CO_2 use is the substitution of fossil-based feedstock for the chemical industry, which is estimated to have an upper bound of 290 $MtonCO_2$/yr [137]. The same study [137] also estimates that 380 $MtonCO_2$/yr are needed to satisfy the fuels demand foreseen in the 2 °C scenario by IEA ETP [175] for the transport sector. Currently, the global market for CO_2 use is ~200 $MtonCO_2$/yr, mainly for urea and inorganic carbonates (120 and 50 Mton/yr respectively) [193].

DAC. Direct CO_2 capture from air is not shown in Fig. 11 since the base assumption is that there is limited improvement in technology performance until 2050. However, if DAC is promoted and reaches a performance of 300 €/ton and 7 $GJ/tonCO_2$ of energy consumption, it can be an important component of future low-carbon systems. Its deployment is seen in scenarios with high CO_2 target (95%), possible CO_2 storage and reference or low biomass potential (10 EJ/yr). The pathway of air capture for downstream use for electrofuels is very limited (< 10 Mton/yr). This occurs since these pathways include the CAPEX for air capture (300 €/ton), the CAPEX for upstream heat and electricity consumption of this unit (indirectly reflected as commodity price), CAPEX for hydrogen production (electrolyzer) and for the liquid synthesis step. Therefore, this makes this option (of DAC plus CO_2 use) too expensive and DAC mostly arises in combination with CO_2 underground storage. Capacities of over 400 Mton/yr of CO_2 were observed for the *95%* scenario (with CO_2 storage and a biomass potential of 10 EJ/yr). With a high biomass potential, there is enough carbon-neutral CO_2 and there is no need for DAC.

CO_2 use impact on system efficiency. It has been argued [194] that PtL actually leads to a net CO_2 increase compared to fossil alternatives and to higher energy consumption [191] with conventional oil having around 20 EROI (Energy Return On energy Invested) [195], while PtL will have an EROI lower than 1 leading to an increase in primary energy consumption. This is still relevant as long as there are targets for primary energy consumption [196], but it could be less relevant in the future when there is abundant supply of electricity from RES. For all the scenarios explored, the CO_2 constraint was binding and dominant over the primary energy consumption.

6. Conclusions

This study addressed *uncertainties about future configurations of the energy system* by running an extensive parametric analysis for scenarios that achieve 80–95% CO_2 reduction by 2050 (vs. 1990). Among the insights developed from the results is that hydrogen acts as complement to electricity and grows as more constraints are added to the system. Action is needed to close the gap between the current focus on renewable hydrogen for refineries and fuel cell vehicles to cover applications like steel and heavy-duty transport, as well as to close the gap in deployment to kick-start and accelerate the cost decline of the technologies. The extent to which PtL is built will be mainly defined by policy adoption on CO_2 storage (CO_2 use is favored by absence of storage) and biomass availability (more neutral CO_2 to be used).

The three largest drivers for hydrogen are limitations on CO_2 storage (e.g. social acceptance), low biomass potential (depending on sustainability criteria) and low technology cost. With limited CO_2 storage, hydrogen can only be supplied by electrolyzers, which could represent almost 50% of the electricity demand. Operational limits for the flexibility of electrolyzers including their response time should be validated since they play a large role in dampening VRE fluctuations. Attention to demonstration projects should be focused not only in transport, but also in industry. Steel proved to be one of the key sectors that shifts to hydrogen for restricted scenarios with up to 25 mtpa (3 EJ/yr) of hydrogen demand. Heavy-duty transport seems to be a promising application for hydrogen, especially as the CO_2 target becomes stricter. This application combined with fuel cell vehicles and electric drive-train can contribute to the reduction of oil demand, energy security and lower CO_2 emissions. For this reason, research in fuel cells should continue to ensure that cost and efficiency trends make the business case possible for these applications. Industry and transport are resilient to high hydrogen prices (> 5 €/kg), but achieving lower costs through research on electrolyzer components and their manufacturing processes can be beneficial as hydrogen proved to be a versatile energy carrier for lower costs. A low-carbon energy system can be achieved at 10% higher costs than a business-as-usual scenario.

Noting that today, hydrogen is used mostly in refineries and chemicals, there are large gaps to close in terms of regulatory framework to set targets that promote hydrogen use in the various sectors ("market pull"), a subsidy scheme to technology specific to improve the business case in these early stages where technologies are still not economically competitive, initiatives with stakeholders from all the elements in the value chain (from production to distribution and end use) could help overcome the infrastructure barrier (large investment needed). Failure in any of these could compromise hydrogen growth reflected in either higher system costs or failure to achieve the CO_2 emissions target.

The preferred sink for CO_2 is underground storage and only when it is limited, the use for liquid fuels arises. Research and demonstration of CCS is necessary if levels of up to 1.4 Gton of stored CO_2 per year are to be reached by 2050 (vs. almost 4 GtonCO_2/yr of emissions today). Biomass is one of the main CO_2 sources and in combination with CO_2 storage, it can lead to negative emissions that allow positive emissions in sectors which are more expensive to decarbonize. Biomass gasification for hydrogen production and liquid production (Fischer Tropsch) are the dominant CO_2 sources for scenarios with limited underground storage. Demonstration projects that include carbon capture in these processes are necessary, especially to further develop concepts where carbon use is maximized by additional hydrogen. Specifically aviation drives the need for Power-to-Liquid, where a major advantage in the end use sector is minimal changes to existing infrastructure. PtL acts as a complement to biofuels rather than a competing alternative. When PtL is used, it satisfies between 60 and 90% of the aviation demand and 50–60% of diesel which contributes to EU energy security and reduction of the energy-related import bill.

This study should be complemented with a higher temporal (to study electricity grid stability and generation ramping) and spatial (potential spots with electricity grid congestion) resolution to better assess the potential of multi-carrier energy systems. The potential fuel shift in aviation and navigation should also be complemented by trade-offs with energy efficiency and mechanical design. More options for the petrochemical industry like bio-based feedstock should also be explored. Better wind and solar resources outside EU could also be exploited to produce electrofuels at lower cost. This involves the trade-off between lower production cost vs. additional cost for transport and decreased energy security, GDP (through investment) and job creation [151,197]. Ammonia as potential energy carrier for sectorial integration should also be evaluated in future studies.

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Appendix A. Supplementary material

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