Hydrogen and the Decarbonization of the Energy System in Europe in 2050 : A Detailed Model-Based Analysis

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Abstract

The paper aims to address the potential of low-carbon and renewable hydrogen in decarbonizing the European energy system; specifically, reducing emissions by 55% in 2030 compared to 1990, and targeting net-zero emissions by 2050. The methodology relies on a cost-optimization modelling approach using three models complementarily: a detailed European TIMES-type model (MIRET-EU); an aggregated model for the European energy system, allowing endogenous cost reductions based on technology deployment in a dynamic programming formulation for investment strategies (Integrate Europe); and a dedicated model for assessing hydrogen import options for Europe (HyPE). Two policy-relevant scenarios have been developed: Technology Diversification (TD) and Renewable Push (RP). Both lead to climate neutrality in Europe in 2050 but the RP scenario differs by setting new reinforced targets for renewable technologies in Europe. Results show that hydrogen production would increase sharply in the coming decades, exceeding 30 million tons (Mt) by 2030 and more than 100 Mt by 2050 in both scenarios. Polyvalence of hydrogen in decarbonizing the European energy system for certain hard-to-abate energy uses in transport and industry is also observed. European hydrogen production relies on a diverse mix including both renewable and low-carbon technologies. It is complemented by hydrogen imports from neighboring regions, that represent between 10 and 15% of total demand in 2050. Access to existing cross-border pipelines is a critical advantage compared to maritime transport. Notably, there are considerable cost reductions due to technology deployment for solar power and hydrogen production by electrolyzers.

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Highlights

- European hydrogen demand could exceed 100 million tons per year by 2050.
- 15% of H_2 needed to reach carbon neutrality could be imported from outside Europe.
- More than half of H_2 is used for transport, the rest is dominated by industry.
- 1800 GW of solar and wind power is needed for the roll-out of renewable hydrogen.
- Resilience of natural gas in European energy transition by 2050 with uptake of CCS.

Keywords: European Green Deal; Carbon neutrality; Hydrogen; Bottom up model; Learning-by-doing model; Hydrogen import model

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List of abbreviations and acronyms

BECCS Bioenergy with carbon capture and storage
CAPEX Capital expenditures
CCS Carbon capture and storage
CCUS Carbon capture, utilization, and storage
DACCS Direct air CO_2 capture with storage
EU European Union
GFEC Gross final energy consumption
GHG Greenhouse gas
HyPE Hydrogen import model
JRC Joint Research Centre
LULUCF Land use, land-use change, and forestry
MIRET Model for Integrating Renewables in Energy and Transport
Mt Million tons
NECP National Energy and Climate Plans
OPEX Operational expenditures
RP Renewable Push scenario
TD Technology Diversification scenario
TPEC Total primary energy consumption
TWh Terawatt-hour
VRE Variable renewable energy

1. Introduction

The past few years have seen a global and significant acceleration of industrial and government ambitions for reducing greenhouse gas (GHG) emissions following the Paris agreement[4].Governments have started developing strategies to decarbonize their economies. The European Green Deal[5], published in 2019, enacts the EUEU policy shift towards net-zero emissions. The European Climate Law[6] sets the goal of becoming a climate neutral society by 2050. In addition, the EU defines intermediate targets for 2030 including a 55% cut in greenhouse gas emissions (compared to 1990), a share of 32% of renewable energy in gross final energy consumption, and an energy efficiency of 32.5% relative to a business-as-usual scenario.

Decarbonizing the European member states over the next thirty years represents a formidable challenge for policymakers and industries. It requires a deep transformation of the energy sector, which accounts for nearly three quarters of the European GHG emissions. Model-based deep decarbonization scenarios are useful instruments to shed light on the way forward to achieve carbon neutrality. In Europe, many

[4] https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement
[5] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en
[6] https://ec.europa.eu/clima/eu-action/european-green-deal/european-climate-law_fr

analyses from academics, institutional stakeholders and consulting firms have been published. Country analyses have been conducted for Germany [1][2], for France [3][4], for the UK [5][6], and for Ireland [7], among many others. The entire EU is covered in EU [8], [9] and [10], while scenarios at the global scale are investigated in [11], [12] and [13]. These recent studies univocally conclude that transforming the energy systems to net-zero emission is technically possible with existing technologies, that renewable energies and clean electricity will have a major role for replacing fossil fuels, that energy efficiency and behavioral changes are important levers to reduce final energy consumption and abate emissions, and that major challenges exists in the so called hard-to-abate sectors which might lead to the need of including carbon capture and utilization and storage and even carbon removal options. However, most of the scenarios differ in the type of models deployed in the assessment, their intrinsic boundary conditions, their scope, and the level of detail how the different countries, sectors, technologies, and assumptions are represented.

In Europe, the decarbonization targets are defined at the EU level and then implemented in each member state, which can lead leading to heterogeneities on the pathways towards net-zero for individual countries. Studies at the country level allow to grasp high level of detail of country specificities. Since electricity and other commodities are traded at the regional level, also the regional context should be included in national studies. Global scenarios employ aggregated models such as integrated assessment models (IAM) which are useful tools to represent cross-regional interactions as well as the nexus between energy, land, economy, and the climate [14]. They, but are, however, less detailed than local energy system models, and use to have regional aggregation which tends to disregard important differences between countries regarding the availability of existing infrastructure, availability of resources, costs, and energy/climate governance, among others. Scenarios produced with EU-wide energy system models have numerous advantages since they cover the policy-relevant scope where climate and energy policies are defined. Moreover, they can handle the different sectors and sub-sectors with good level of detail and can grasp cross-country synergies. The key energy models used in the official decarbonization scenarios of the European Commission are the JRC-EU-TIMES model [15], featuring very detailed sectoral representation of sectors and commodities; POTEnCIA [16] capturing behavioral changes and financing heterogeneities between member states;; the PRIMES model [17][18], which represents the price formation of the different energy commodity markets and captures country-specific incentives; and METIS [19] which handles a high level of temporal representation relevant for modeling the off take of renewables, among other. They are all European-wide partial equilibrium models with country level disaggregation.

As the marginal abatement costs of reducing the last 10-20% CO_2 emissions becomes very steep and entails significant uncertainties [20], models aiming to assess net-zero emission scenarios require integrating additional mitigation and carbon offsetting options. Furthermore, detailed sectoral interactions must be modelled to fully explore the implication of the objective which introduces higher complexity in the models [21][22] and uncertainties in the results. The crowding out effect of CO_2 emission reductions is driven by the hard-to-abate sectors (i.e. iron steel, cement industry, chemicals, and heavy transport) for which only few and costly decarbonization options exist [23]. Those challenges were assessed in [24] which found that significant synergies from sector coupling enabled by the development of hydrogen and e-fuels allow emission reductions in hard-to-abate sectors, and ranked hydrogen-related technologies among those for which cost decrease through R&D could lead to

significantly reducing the cost of the EU clean energy transition[7]. Similar conclusions are discussed in [25] from a wider framework.

Hydrogen has been identified as a key building block in the European energy transition, which may address those limitations and uncertainties[8]. It is a versatile and multifaceted alternative fuel that can be used as an energy carrier, for end-use energy consumption, and as a feedstock to produce other fuels and industry products. However, many questions remain open: to what extent will hydrogen contribute to the decarbonization of each sector; ?, how complementary are the different supply options; what infrastructure investments are required to enable the future hydrogen economy; and the extent to which technology costs can be driven down during the pathway?

The objective of this paper is to assess the extent to which renewable and low-carbon hydrogen[9] can foster sector integration and be a key enabler of the transition towards a net-zero in Europe.-It builds upon the literature on modeling the European energy system under deep decarbonization scenarios [26][27][28], and the importance of gas under EU carbon neutrality [29]. The models used align on the scope and data of those used in the official scenarios of the European Commission and extends the representation of hydrogen-related technologies and applications. This paper is an outcome of a joint industry research project charting potential pathways for hydrogen to contribute to the EU's goal of net zero GHG emissions, based on actual European targets and open modelling frameworks [30]. In addition, it is a cross-sectoral and multi-disciplinary research project aiming to support the understanding of the potential contribution of low-carbon and renewable hydrogen in reaching the European energy transition goals. The originality of this study relies on soft-linking three task specific models from three research institutes located in two European countries (IFP Energies Nouvelles (France), SINTEF (Norway) and DELOITTE Economic team (France)). Additional novelties are:

- Soft-linking of three different models with three paradigms: A detailed EU optimization model, an integrate model with an endogenous technological learning, and a hydrogen import model.
- Comparing with a previous detailed EU model [15], an extensive representation of hydrogen production technologies and end-uses for unfolding them in particular in hard-to-abate sectors has been carried out.
- Optimizing the potential cost reduction of maturing technologies such as renewables and hydrogen-related technologies through the explicit formulation of technology learning,
- Optimizing hydrogen imports from non-EU countries toto support domestic EU production to further reduce the cost of transition.
- Including enacted official EU objectives as for the EU Climate Law[10], at country-level disaggregation (i.e., individual targets as for the National Energy and Climate Plans (NECPs)) [11].

[7] The authors identify identifies hydrogen-related technologies, wind, solar, batteries, heat pumps and direct air capture.

[8] https://ec.europa.eu/energy/topics/energy-system-integration/hydrogen_en

[9] There is still debate between policy-makers, industrial stakeholders, and researchers on the categorisation and terminology for the different hydrogen sources. This paper builds upon the definitions given by the EU hydrogen strategy. Low-carbon hydrogen corresponds to hydrogen produced from low-carbon energy sources such as nuclear or fossil fuels with carbon capture (*e.g.*, reformers with CCS). Renewable hydrogen corresponds to hydrogen produced from renewable energy sources (biomass or electrolysis, with electricity produced by renewable energy sources).

[10] https://ec.europa.eu/clima/eu-action/european-green-deal/european-climate-law_en

[11] National Energy and Climate Plans. Further information available at: https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en#final-necps

This paper is structured as follows: the modelling framework and a brief description of the overall structure of the three models, and their specific features and assumptions are described in detail in Section 2. Section 3 presents the main results while Section 4 discusses the results and their limitations. Section 5 provides the main conclusions.

2. Method

2.1. Modelling framework

The modelling framework used in this study combines three models where each performs a dedicated task. These models are soft-linked, and their interactions are illustrated in **Fig. 1**:

- **MIRET-EU:** A TIMES-type detailed European energy system optimization model, which produces the final outputs from the study. Future technology costs are exogenous inputs since it is a linear model.
- **Integrate Europe:** An aggregated optimization model for the European energy system, allowing endogenous cost reductions based on technology deployment in a dynamic programming formulation for investment strategies.
- **HyPE:** A dedicated model for calculating hydrogen import options for Europe.

Fig. 1: Modelling framework that soft-links a detailed energy system model, a learning optimization model, and a hydrogen import model.

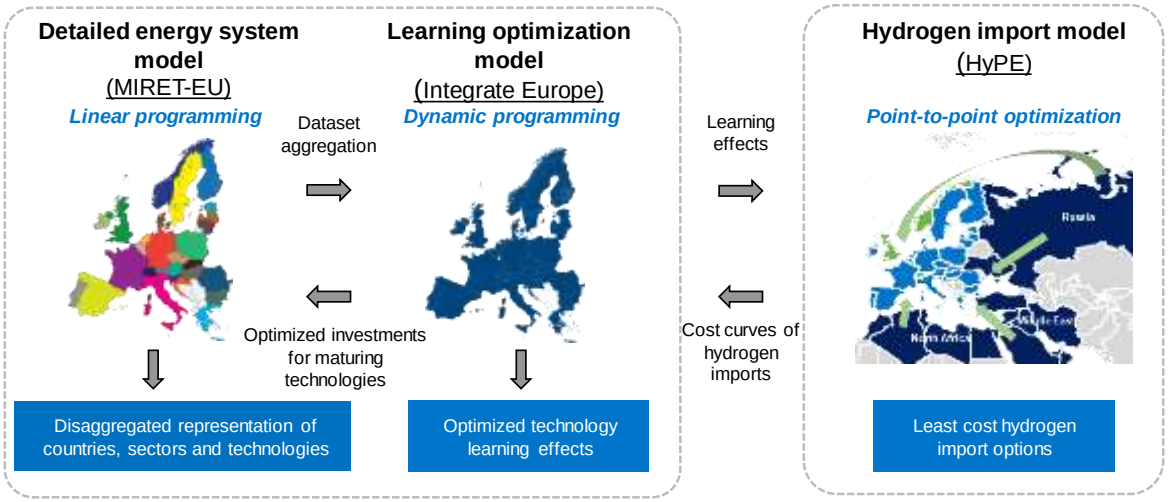


Fig. 1. illustrates the relationship between the three models employed in this study, which are *soft-linked* to harness the complementary strengths of each model. This approach accounts for endogenous cost reductions through investments and the avoidance of lock-in effects in terms of technology selection.

The first link between the MIRET-EU and Integrate Europe models is that they rely on a shared technology database. However, a more aggregated version of the dataset is utilized for Integrate Europe, cf. the "Dataset aggregation" arrow. In addition, Integrate Europe is initialized based on the first-round simulation results from MIRET-EU, which are used to set some variables exogenously and to calibrate e the more aggregated investment options in the former model.

The first-round results from Integrate Europe include optimized investments on a pan-European level and corresponding reduction in investment costs (€/MW) due to endogenous technology learning for the following technologies:

- wind power,
- wind power ,
- solar PV,
- natural gas reforming with CCS,
- electrolysers, and
- biomass-based investments: power generation with CCS, hydrogen production from gasification with CCS, and bio-refinery.

The resulting technology costs, for instance for electrolyzers, are then forwarded to the HyPE model, cf. the ""Learning effects"" arrow. The HyPE model then calculates the corresponding cost curves for hydrogen imports. Those cost curves are then used in the final round of simulations for the two other models, cf. the "Cost curve of hydrogen imports" arrow.

The invested capacities in the second/final simulation by the Integrate Europe model are used to build minimum constraints for invested amounts per technology, in sum for all areas, in the second/final MIRET-EU simulation, cf. the "Optimized investments for maturing technology" arrow. In addition, the corresponding investment costs per technology are forwarded to MIRET-EU. The minimum constraints for invested amounts are needed to ensure that MIRET-EU invests sufficiently relative to the future reduction in technology costs. The final simulation is then carried out by MIRET-EU.

Each of the three models are described in the following subsections. The description of the Integrate Europe model also explains how future technology costs are estimated as a function of technology deployment trajectories using the concept of learning-by-doing. More information on the models, including a detailed description of their input, can be found in Ref. [30].

2.2. MIRET-EU model

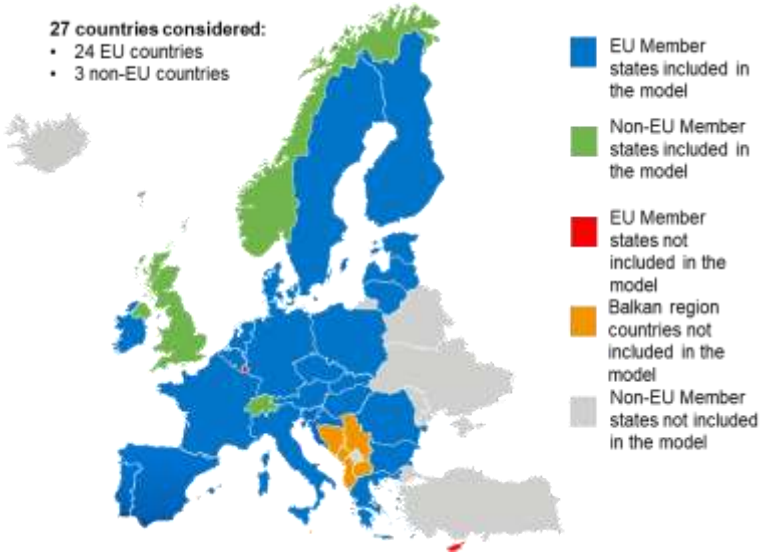
MIRET-EU is a bottom-up techno-economic, multiregional, and inter-temporal partial equilibrium model of the European energy system developed by IFPEN for more than ten years. It is based on the TIMES[12] model generator. The TIMES model is developed within the Energy Technology Systems Analysis Program (ETSAP)[13] over a period of almost twenty years by the International Energy Agency (IEA). The energy dynamics are estimated by minimizing the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimizers [31][31]. A few models have already been developed at European scale using the TIMES model over the last fifteen years. The Pan-European TIMES (PET) model has been developed by the Kanlo team following a series of European Commission (EC) funded projects (NEEDS[14], RES2020[15], REACCESS[16], REALISEGRID[17], COMET[18], Irish-TIMES[19]) between 2004 and 2010 [32]. The JRC-EU-TIMES

[12] TIMES is the successor of the former generators MARKAL and EFOM with new features for understanding and greater flexibility. The manuals and a complete description of the TIMES model appear in ETSAP documentation (https://iea-etsap.org/index.php/documentation)
[13] Created in 1976, it is one of the longest running Technology collaboration Programme of the IEA
[14] http://www.needs-project.org/
[15] http://www.cres.gr/res2020
[16] http://reaccess.epu.ntua.gr/
[17] http://realisegrid.rse-web.it/
[18] http://rdgroups.ciemat.es/documents/10907/86733/Comet_12Dec.pdf/b29424d6-1287-4644-9192-c2994daef02e
[19] https://www.epa.ie/pubs/reports/research/climate/Irish%20TIMES%20Energy%20Systems%20Model.PDF

model is developed in the Joint Research Centre (JRC) of the European Commission as an evolution of the PET model of the RES2020 project [15]**Erreur ! Source du renvoi introuvable.**. Databases related to residential, services, and hydrogen from the JRC-EU-TIMES have been used with additional modifications on techno-economic characteristics into MIRET-EU. Therefore, the modelling framework of MIRET-EU follows the same framework developed successively in the PET, the JRC-EU-TIMES, MIRET-FR[20] and TIAM-IFPEN[21] [33][34][35] models. In addition, expertise from IFP Energies Nouvelles was used for specific sectors such as transport, refineries and bioenergy conversion technologies, hydrogen infrastructure, power sector, and industry.

The detailed energy system model (MIRET-EU) represents the European energy system divided into 27 European countries, including 24 EU member states and 3 non-EU countries (**Fig. 2**).

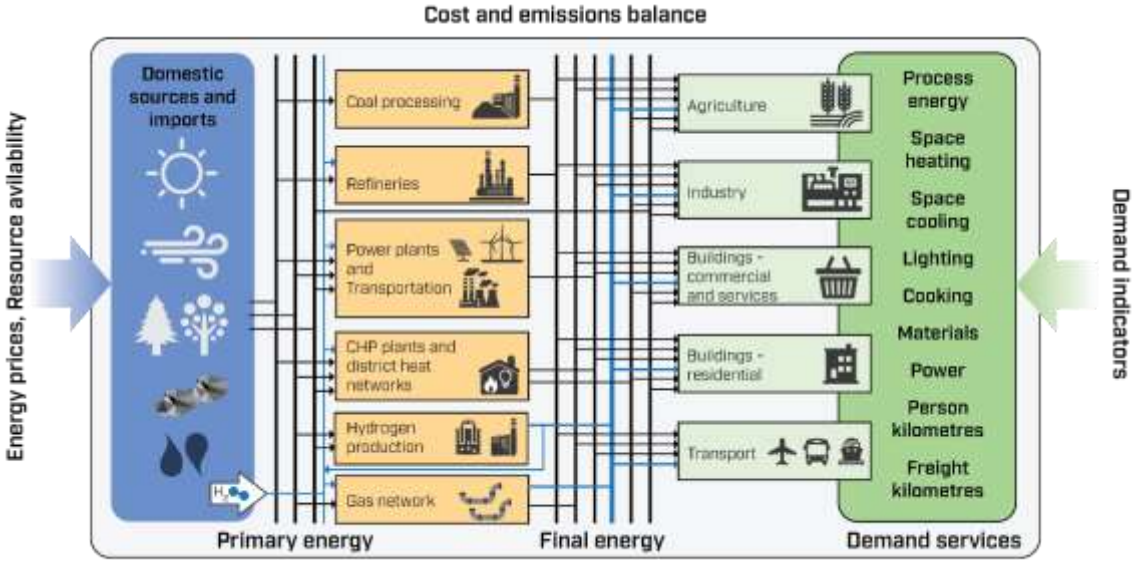
Fig. 2: Geographic coverage.



Each country has its own energy system with its main demand sectors and the possibility of trade (oil, electricity, natural gas, hydrogen, and captured CO_2). The model fully describes for each country existing and future technologies, logically interrelated from primary resources to energy services demanded by end-uses (**Fig. 3**). Every year is divided into four seasons (spring, summer, autumn, winter) which are in turn disaggregated into day, night, and peak. Each time slice has its own demand and generation profiles.

[20] The version developed for France.

Fig. 3: Partial view of the Reference Energy System with its interdependencies in the MIRET-EU model [36]



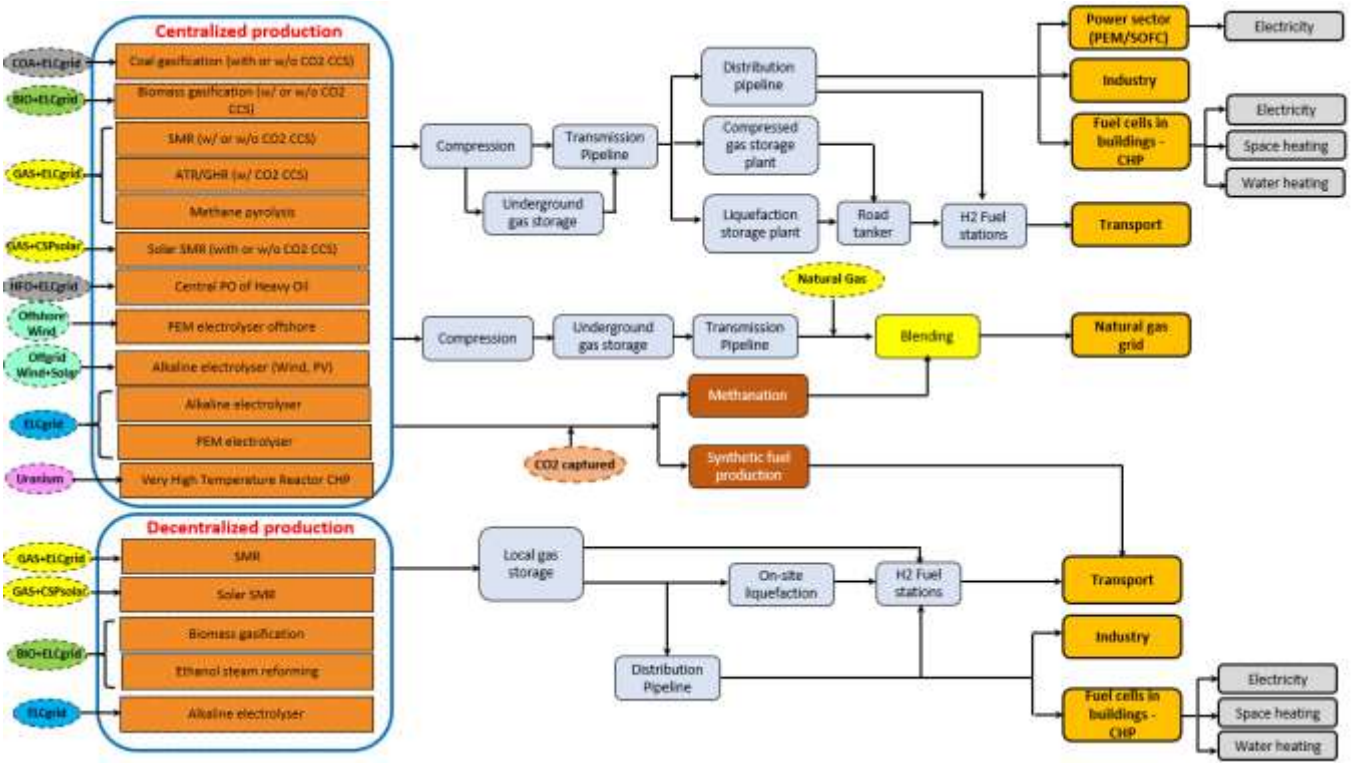
The reference energy system (RES, **Fig. *3***) is helpful to picture the relationships among these various entities using a network diagram. Processes are represented as boxes and commodities as vertical lines. Commodity flows are represented as links between process boxes and commodity lines. The RES is composed of:

- **<u>A primary energy supply block</u>** including:
    - imported and domestic primary energy sources (uranium, bioenergy[22], crude oil, coal, natural gas) and
    - renewable potential (hydro, wind, solar, geothermal, biomass).
- **<u>An energy technology block</u>** with technologies to transform primary energy into energy vectors and energy services, including:
    - Power generation.
    - Oil refining and biorefinery (first and second generation) units are modelled based on IFPEN's approach and recognized expertise in the field. The production chain is divided into feedstock pre-processing, production processes, and blending (Blending of diesel B7, B10), gasoline SP95 grades E5, E10 and E85, and jet fuels.
    - The end-use technologies related to agriculture, industry, transport, residential, and services.
    - Hydrogen supply chain (**Fig. 4**): This figure displays the diagram of hydrogen supply chain. It includes hydrogen production, delivery, and end-use technologies. The production options are disaggregated under centralized vs. decentralized and by size (large, medium and/or small). In the decentralized option, hydrogen is produced close to where it is consumed, whereas in the centralized option, large scale hydrogen facilities are considered producing hydrogen that needs to be delivered to end-users *via* an extensive transport and distribution infrastructure. Most of the hydrogen techno-economic assumptions considered in the model have been provided by the JRC to IFP Energies Nouvelles in June 2019. They are based on the JRC hydrogen structure in

[22] Derived from ENSPRESO database related to bioenergy potentials for EU and neighbouring countries [37]

TIMES input data available for the development of the hydrogen sector in MIRET. The main references for the data are Ref. [38][39][40][41][42]. In total, more than 30 hydrogen production options are considered by process type (with and w/o CCS), by size, and/or by system design (centralized vs decentralized).

Fig. 4: Hydrogen supply chain in the MIRET-EU model



- **<u>A final energy/energy services demand block</u>** such as industrial demands, space and water heating demands, mobility demands in the transport sector, trades (oil products, electricity, hydrogen, CO_2 captured), etc.
- **<u>A policy block</u>** which includes measures and constraints of several types affecting all sectors. Some are of a microscopic nature, such as quality norms for refinery products, the number of functioning hours of fuel turbines, power plants, etc. Some are macroscopic in nature, *e.g.*, global emission constraints or sectoral restrictions.

2.3. Integrate Europe model

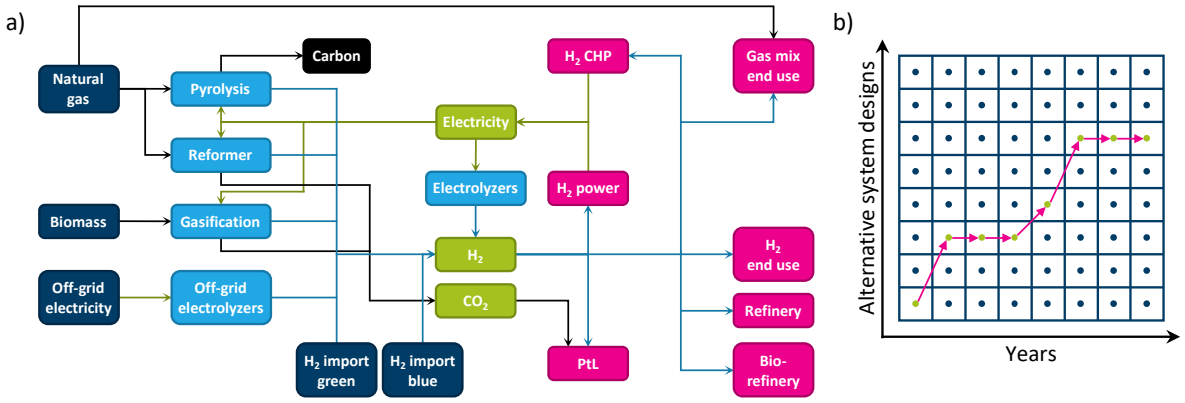
Integrate Europe is an aggregated energy system model for Europe that includes endogenous technological learning. The main task of the model is to determine optimal investment strategies over a planning horizon of several decades while simultaneously satisfying the energy service demand and conforming with policy constraints such as CO_2 emissions reduction targets. Hence, there is competition between the different energy carriers and technologies over their value chain from generation to end-use.

2.3.1. <u>Solution method</u>

The model performs a system optimization, minimizing the total present value of all costs. The energy system costs are minimized by considering both investment costs (CAPEX) and operational costs (OPEX). Integrate Europe has a two-step approach to calculate optimal investment strategies. First, for

the calculation of the OPEX, a diurnal optimization based upon linear programming (LP) is carried out for each combination of season, analyzed year, and energy system design. Second, the optimized OPEX of all possible system configurations for every year is forwarded to the investment algorithm, to provide information about how investments will affect operational costs. The optimization of investments is then performed *via* dynamic programming (DP), considering all costs and learning effects between investment packages. **Fig. 5** a) illustrates the hydrogen operational modelling focusing on hydrogen production. Each dot in **Fig. 5** b) represents the annual operating costs for a given energy system design and year as calculated by the operational part of the model, where the red arrows and green dots represent the optimal investment pathway. See Ref. [43] for further elaboration of the methodology.

Fig. 5: Solution concept for Integrate Europe with a) simplified graphical representation of the LP part of the model, focusing only on the hydrogen components and their connection and b) representing the solution method of the of the investment analysis. The blocks *Electricity*, CO_2, and H_2 include the respective storage.



2.3.2. Learning-by-doing

Learning-by-doing refers to the cost reduction that occurs due to increased technology deployment. The learning model included in this study assumes a fixed percent reduction in unit investment costs every time the aggregated investment doubles for that technology. This model is known as a *one-factor learning curve* and the percent reduction is the technology-dependent *learning rate*. The learning rate is calculated from historical data for mature technologies or using surrogates for immature technologies. Future technology costs are then affected by both endogenous European investment and exogenous forecasts for investments in the rest of the world. The implementation is explained in detail in Ref. [44].

The learning-by-doing mechanism leads to a nonlinear optimization problem since investment costs per unit of capacity become a variable instead of being a parameter. The optimization problem can also become non-convex if learning effects are high. However, the discrete DP solution methodology handles both nonlinear effects and possible non-convexities. Using backwards DP allows the transition cost to a new investment state to be dependent on the previous investment state. To the authors' best knowledge, this is a novel feature in this type of energy system models.

2.3.3. Reducing the problem size

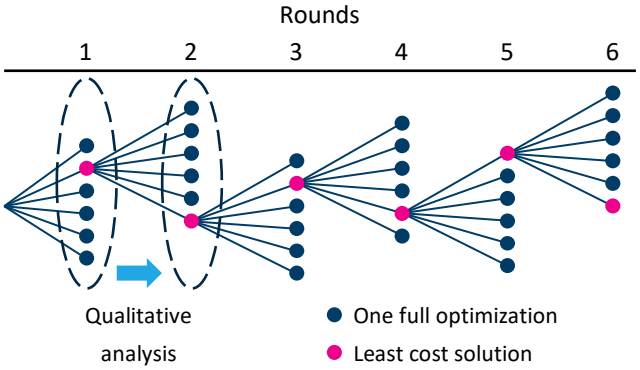
If x is the number of elements in the discrete set of investment options, those elements can be combined to 2^x different system designs. However, considering all investments in the whole European energy system towards 2050, the number x is very high. Therefore, to make the problem size tractable, the following simplifications are implemented:

a) Technology representation is less detailed than in MIRET-EU.
b) Investments are calculated for an aggregated Europe and not per country. Costs for energy transport and storage are added through a mark-up.
c) As we consider pathways for decarbonizing the energy system, investments in coal- and oil-based technologies are not available.
d) End-use technology investments are optimized for each decade in the linear part of the model, subject to the non-retired capacity from 2020.
e) For some technologies where technology learning is considered less important, operational costs include the capital costs through levelized cost calculations.
f) Investment options are bundled into six types of investment packages[23] per computation: 1) renewable power, 2) hydrogen production from natural gas, 3) electrolyzers, 4) conversion of hydrogen, 5) bio-based investments, and 6) conversion of natural gas to power or heat. Each of those packages has several ambition levels. The total number of packages is 20.
g) For each type of investment package, ambition level 1 must be selected before ambition level 2, and so on. This heuristic is needed to handle learning effects consistently, and it also reduces computational time.
h) Initial results from MIRET-EU are utilized for a) within-package designs, notably for the renewable electricity package, and b) setting some investments exogenously (hydropower, nuclear power, an amount of gas-power capacity needed for future grid stability, and methane pyrolysis).

2.3.4. Improved optimization by tuning of packages

The sizes and content of packages are tuned iteratively by solving the model several times, as illustrated in **Erreur ! Source du renvoi introuvable.**.

Fig. 6: Iterative search for least cost using Integrate Europe.



Each blue dot represents one optimization, *i.e.*, a complete model run that calculates the optimal investment pathway. However, for round 1, several competing sets of investment packages are specified, and the model is then solved for each of them. The competing sets of investment packages vary in terms of capacity (GW) for each technology in each package. The best solution discovered in round 1, *i.e.*, the optimization result with the lowest total cost, is then taken as a reference case for round 2. The specification of new packages applied for round 2 is developed partly based on results from round 1 and partly based on a qualitative assessment of the system's operation. This process continues until there is

[23] Each package can include investments in several technologies, *e.g.*, different types of renewable power generation in the investment package for renewable power. For each included technology in an investment package, there is also a specified capacity (GW) specified.

no further progress in the search in terms of an improved objective function – typically after seven rounds. This procedure converges towards a local cost minimum; however, there is no guarantee of global optimality.

2.4. Hydrogen import model (HyPE)

In recent years, research on the international trade of energy commodities have been very active. The common line of model-based approaches capturing the fundamentals of such markets is the adoption of a supply chain models where each step of the delivery chain is considered. Following the recent literature on international hydrogen trade [45][46][47][48], a supply chain optimization model of hydrogen with high spatial and temporal resolution was developed. Resolution is particularly important for capturing the competitivity of international trade. As highlighted by Heuser et al. [48], transport costs might be as important as production costs when transport distances are significant and multiple conditioning and reconditioning steps need to be added. In this paper we focused on the possible exporting countries in the vicinity of Europe (see **Fig. 7**) and not on a global hydrogen market.

The overarching principles of the methodology are:

I. CO_2 neutrality of European energy imports: "decarbonization of energy imports can be achieved *via* decarbonizing imported natural gas (either pre-combustion or post-combustion), or by importing any other renewable or decarbonized gases (*e.g.*, H_2/LH_2, P2G, Biomethane, etc.)" [49].

II. Technology neutrality of hydrogen production: "Natural gas converted to hydrogen at import point/city gate (main study) or direct hydrogen imports" [49].

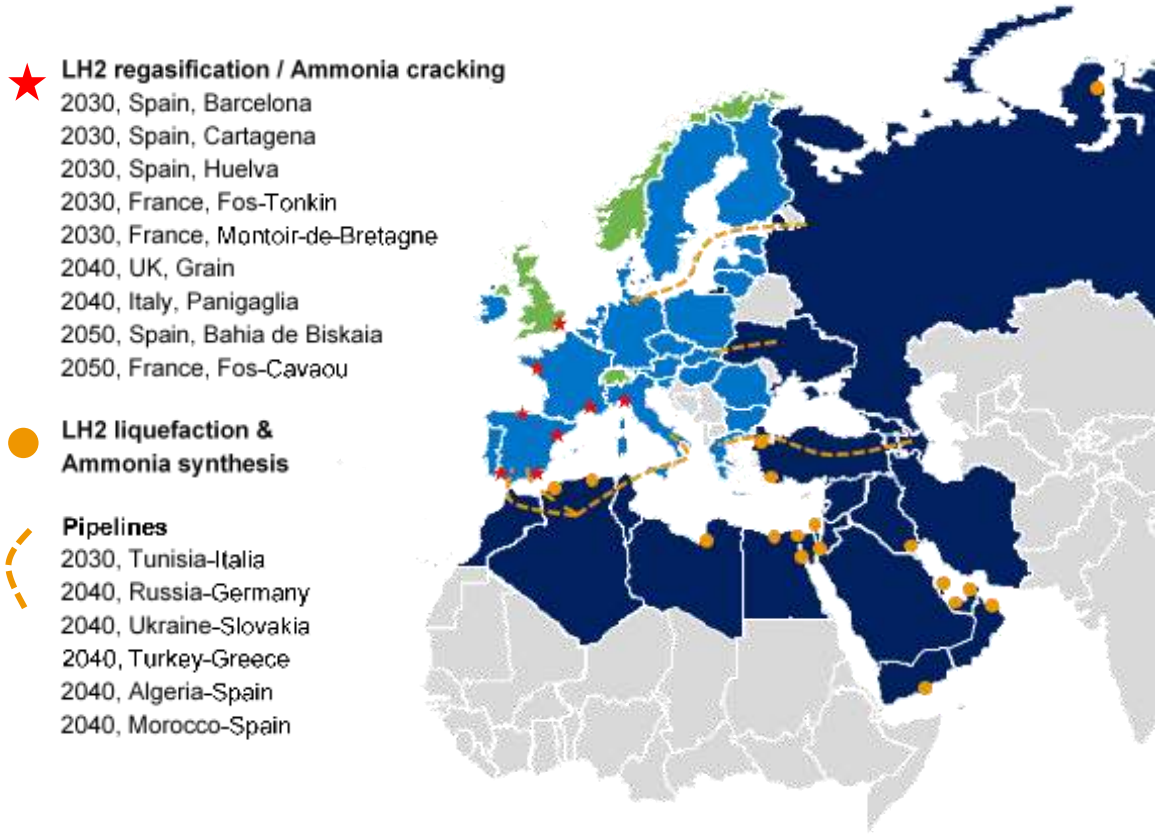
Therefore, hydrogen can be produced upstream by a large portfolio of technologies such as methane reforming with CCS, methane pyrolysis, dedicated off-grid[24] wind, PV or wind+PV hybrid systems with electrolyzers (location dependent), and biomass gasification, each leading to different production costs[25]. The national renewable energy installation trajectories towards 2050 are assumed to follow a similar installation pace as it was observed for solar and wind power in Europe from 2000 to 2018 [50][51]. This deployment pace is said to be conservative in absolute terms as the economics of wind and solar have improved since early 2000s, and faster renewable deployment can in theory be expected in the coming decades. Furthermore, to also consider domestic decarbonization efforts of the potential exporting countries, only 50% of the maximum installed capacity is assumed to be dedicated to hydrogen exports to Europe.

In the midstream, depending on the nature and location where hydrogen is produced, inland transport and logistics might be required for moving it to an exporting point such as a harbor or the inlet of an interconnector. For ensuring road accessibility to an exporting point, only renewable energy locations within a 1000 km distance around exporting points have been considered as possible candidates. Thus, the domestic transport segment is assumed to be assured by trucks (either in compressed or liquid form)[26]. For the international transport segment, dedicated hydrogen interconnectors, ammonia

[24] On-grid electrolyzers were not included to avoid any indirect emissions associated to the use the local electricity mixes with uncertain CO_2 intensities.
[25] Since the CO_2 capture rates of reformers with CCS are around 90-95%, for the hydrogen to be considered carbon neutral it is assumed that the environmental externalities due to the remaining emissions (5-10%) are compensated by paying a CO_2 tax of 30 €/tCO_2.
[26] Conditioning and reconditioning steps and its costs are considered in each case.

shipping, and liquified hydrogen (LH_2)[27] have been considered, whose costs associated to conditioning and reconditioning are included. Whereas for ammonia only new terminals are considered, vintage LNG terminal capacity with decreasing utilization rates are candidates to be refurbished to LH_2 terminals. Natural gas interconnectors are likewise assumed to be converted to hydrogen following the figures of the European Hydrogen Backbone study [52].

Fig. 7: Geographical scope considered for hydrogen imports to Europe and alternative routes.



Note: Existing gas basins are also entry points for hydrogen shipping.
Source: Hydrogen for Europe study, partially based on data from the European Hydrogen Backbone

2.5. Policy scenarios towards 2050

Two policy-relevant scenarios that lead to carbon neutrality have been developed and served as the basis for the quantitative work (**Table 1**). The Technology Diversification (TD) pathway represents a scenario where a wide range of technologies are considered to minimize the cost of the transition to net-zero emissions. It assumes a perfect market, underpinned by the European Climate Law and already legally binding targets and objectives for renewable energy supply, energy efficiency, and CO_2 emissions. This scenario corresponds to a technology-agnostic approach: the selection, deployment, and use of each technology is based on their techno-economic characteristics and endogenous cost reduction potential. The resulting optimized investments show the cost-efficient path for the transformation of the energy system, as calculated by the models. Existing support schemes are not considered in the scenario design. The policy block in the TD scenario, which comprises all policy assumptions at country and EU-level

[27] Ships are assumed to transport the hydrogen carrier (*i.e.*, LH_2 or ammonia) and be fueled by it (*e.g.*, the boil off gases). Bunkers fueled by ammonia are assumed to be commercially available only by 2035.

that have been explicitly implemented through constraints in the model, is in line with the agenda of the European Green Deal and EU pillars and targets. It includes:

- EU CO_2 emission targets: A minimum of 24% cut in emissions by 2020 (*cf.* 1990 level, in line with the latest figures), a 55% reduction by 2030 (in line with the foreseen European Green Deal target),), and a 100% net CO_2 emission reduction at the European level to comply with the EU's commitment to be climate neutral by 2050.
- Enacted CO_2 reduction objectives are accounted for in the model by adding sector-specific reduction targets: 21% and 43% emissions reduction by 2020 and 2030 (*cf.* 2005 level,, including aviation) from the EU emissions trading system (EU ETS) sectors[28] according to Directive 2009/29/EC and the Directive (EU) 2018/410 of the European Parliament and of the Council[29]. For the target beyond 2030, *i.e.*, in 2050, our model relies on the assessment of the JRC which expected a reduction of around 70% (aviation excluded).
- Energy efficiency targets: At least 20% improvement in energy efficiency by 2020 (Energy Efficiency Directive [2012/27/EU]) and at least 32.5% by 2030 (Directive on Energy Efficiency [2018/2002]) for the European Union. The latter objective corresponds to a primary energy consumption not exceeding 1 128 Mtoe (million tons of oil equivalent), or no more than 846 Mtoe of final energy consumption for the European Union in 2030 (UK excluded)[30].
- CO_2 emission performance standards in road transport: A target of 95 g CO_2/km is applied to the EU fleet-wide average emission of new passenger cars for the period 2020-2024, with 15% reduction from 2025 (which is equivalent to 80.75 g CO_2/km) between 2025 and 2029, and 37.5% reduction from 2030 onwards (around 60 g CO_2/km) as set by regulation (EU) 2019/631.
- Renewable Energy Directives (RED) and the National Energy and Climate Plans (NECPs): At least a share of renewables of 20% in their gross final energy consumption by 2020 (RED I 2009/28/EC), and at least 32% by 2030 (RED II 2018/2001/EU) with a clause for a possible upwards revision by 2023. The REDs include a transport sub-target, which also ensures that a minimum of 10% of energy consumed in transport (road and rail) by 2020 (RED I) is renewable energy, and a minimum of 14% by 2030 (RED II). The NECPs provided the national objectives for share of energy from renewable sources in gross final energy consumption and for phasing out of coal and nuclear plants for power generation.

The Renewable Push (RP) scenario differs from the first scenario by setting new reinforced targets for renewable technologies in Europe. In that latter scenario, the share of renewable energy supply in gross final energy consumption is set as a modelling constraint at respectively 40%, 60% and 80% in 2030, 2040 and 2050. This is to be compared to the current legally binding target of 32.5% for 2030, that is considered as constraint in the TD scenario. The comparison between the two scenarios thus allows for an all-other-things-equal comparison of a deliberate focus on renewable technologies, a prominent feature in the current policy debate (national strategies, fit-for-55 package, etc.).

Table 1: Scenario specifications.

Target	Year	Technology Diversification pathway	Renewable Push pathway
	2030	–55%	–55%

[28] The system covers power and heat generation, energy-intensive industrial sectors, and commercial aviation within the European Economic Area.

[29] The JRC has also assessed the EU ETS emission reduction trajectory beyond 2030, *i.e.*, until 2050,

[30] Equivalent to 1 273 Mtoe of primary energy and/or no more than 956 Mtoe of final energy when UK included.

CO_2 reduction with respect to 1990 levels	2050	–100%	–100%
Energy efficiency target with respect to business as usual	2030	32.5%	32.5%
Share of renewable energy supply in gross final energy consumption	2030	32%	40%
	2040		60%
	2050		80%

2.6. Other assumptions and data sources

The macroeconomic drivers, population, and GDP have been derived from the EU Reference 2016 scenario. The fossil fuel prices on the world market are based on the EU Reference scenario 2016 as considered by the JRC, however it was updated to account for the COVID-19 effect (**Table 2**).

Table 2 : Macroeconomic data and energy commodity prices evolution.

	Scenario	Period					
		2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
Population average annual growth rate	EU Reference 2016	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
GDP average annual growth rate	JRC POTEnCIA 2019	1.43%	1.28%	1.26%	1.34%	1.48%	1.54%
Fuel prices average annual growth rate	Crude Oil	6.64%	1.95%	0.85%	1.15%	0.46%	0.45%
	Coal	1.42%	3.72%	1.15%	0.83%	0.00%	1.27%
	Natural Gas	6.66%	1.69%	1.32%	0.67%	0.02%	0.69%

Source: JRC-EU-TIMES, JRC POTEnCIA 2019, Authors.

The energy demand projections have been extracted from the JRC-EU-TIMES model in order to consider a common and public database (**Table 3**). It is worth mentioning that these data still do not consider the global situation currently experienced with Covid-19 pandemic, which will possibly result in the reduction of the European industrial production and a drop in its energy demand. The Covid-19 crisis may also bring changes to the energy demand of the residential and service sectors, and in the transport activity.

Table 3 : Energy demand projections by sector.

Sectors	Year						
	2020	2025	2030	2035	2040	2045	2050

Industry								
Energy intensive sectors production (Mt)	**Iron and Steel**	180.0	181.1	180.4	179.3	178.7	178.1	177.5
	Cement	186.5	190.4	194.1	197.4	200.7	204.1	201.0
	Pulp and paper	112.5	119.5	123.7	125.6	126.6	128.3	130.8
	Ammonia	16.0	16.3	16.5	16.7	16.8	16.9	17.1
	Chlorine	10.3	10.5	10.6	10.6	10.7	10.8	10.9
	Pulp & paper	112.5	119.5	123.7	125.6	126.6	128.3	130.8
	Lime	28.2	29.7	31.1	32.3	33.5	34.5	35.4
	Glass	37.2	37.7	37.7	37.7	37.6	36.8	35.2
	Copper	0.25	0.24	0.26	0.26	0.26	0.26	0.27
	Aluminium	7.5	7.6	7.8	7.9	7.9	7.9	7.9
Non-energy-intensive sectors energy demand (PJ)	**Other Non-Ferrous Metals**	354.3	357.9	367.6	370.8	375.0	378.7	382.0
	Other Non-metallic mineral products	622.6	658.6	693.7	723.0	753.6	779.6	803.1
	Other Chemicals	2 110.6	2 236.8	2 363.9	2 496.4	2 639.8	2 777.1	2 915.3
	Other industrial sectors	3 900.0	4 102.2	4 314.6	4 545.4	4 793.3	5 044.1	5 308.1
Agriculture								
Energy service demand (PJ)	**Energy demand**	1 164.5	1 170.8	1 174.8	1 179.1	1 183.4	1 185.8	1 188.1
Residential and Services								
Number of households (000units)	**Number of households**	184 554	188 401	192 329	196 338	200 431	204 609	208 875
Services surface evolution (Mm^2)	**Services surface**	6 638.6	6 788.4	6 941.5	7 098.2	7 258.3	7 422.1	7 589.6
Electric appliances (Million Appliances)	**Residential electric appliances**	4 995.1	5 102.9	5 212.8	5 312.9	5 419.1	5 524.3	5 633.9
	Services electric appliances	150 321	158 730	167 553	174 018	180 839	187 598	194 540
Transport								
Passenger transport activity (Billion passenger-km)	**Road transport**	7 012.9	7 280.9	7 565.7	7 800.5	8 013.0	8 212.6	8 383.0
	Rail, metro and tram	626.2	682.9	733.5	782.5	834.2	882.0	929.7
	Aviation	1 786.0	1 982.7	2 184.5	2 380.8	2 598.4	2 781.4	2 961.0
Freight transport activity (Billion ton-km)	**Road transport**	3 285.2	3 502.9	3 710.5	3 865.8	4 009.1	4 125.5	4 219.6
	Rail transport	515.6	566.8	614.6	653.2	696.2	727.6	755.8
	Aviation	45.5	50.2	54.9	59.5	64.9	69.7	74.3

Source: JRC-EU-TIMES 2019.

The data for learning rates for the learning-by-doing implementation can be found in Ref. [53]. As the identified learning effects vary significantly, statistical analyses were performed on the most recent reported values and the median value was utilized. Global capacity expansions were based on the Energy Technology Perspective 2017 and 2020 (Beyond 2 °C Scenario).

Moreover, other special constraints have been considered for the power sector, the deployment of CO_2 storage and the deployment rate of heat pumps in the residential sector:

- To ensure the reliability of the power grid in each country considered in the study, a restriction of minimum 20% back-up capacity from controllable electricity production within each country is applied.
- On basis of Ringrose and Meckel's analysis [54], the available injection rates for CO_2 to permanent storage, is restricted to 1.0 Gt per year from 2020 to 2040, 1.2 Gt per year in 2045 and 1.4 Gt per year in 2050.
- The potential of heat pumps has been implemented following the latest assumptions from the JRC heat pump analysis, allowing for an almost 10-fold increase by 2050.

The models are calibrated and built using data from renowned databases and data sources such as the JRC European Commission, the International Energy Agency (IEA), IRENA, BP, the World Energy Council and scientific literature (**Table 4**).

Table 4: Data sources.

Data	Sources
Inventories of existing and future technologies	JRC data catalogue (IDEES 2018, POTEnCIA 2019, JRC-EU-TIMES (2012, 2019), ENSPRESO 2019, BREFs reports, …), IEA data catalogue (IEA 2019b, IEA MoMo model, ETP 2017, ...), IRENA (2018), de Vita et al. (2018), ENTRANZE database, KanoRs database (Pan-European TIMES PET36), IFPEN data catalogue (CEDIGAZ and RafGen model), ETSAP community database and specialized literature.
Fossil fuel reserves and trade capacities	World Energy Council, BP Statistics, US Geological Survey, TYNDP (ENTSOG 2020, ENTSOE 2016) and specialized literature.
Power generation	National Renewable Energy Laboratory (NREL), PLATTS database, IRENA, IEA's World Energy Outlook and specialized literature, POTEnCIA 2019, de Vita et al. (2018), ENSPRESO 2019, IRENA.
Hydrogen production technologies	H21 North of England report (2018), Blanco et al. (2018a), Blanco et al. (2018b), Sgobbi et al. (2016), Bolat et al. (2014a), Bolat et al. (2014b), Schmidt et al. (2017), NREL Technical report (2009), Parkinson et al. (2018), Keini et al. (2018).

3. Results and discussion

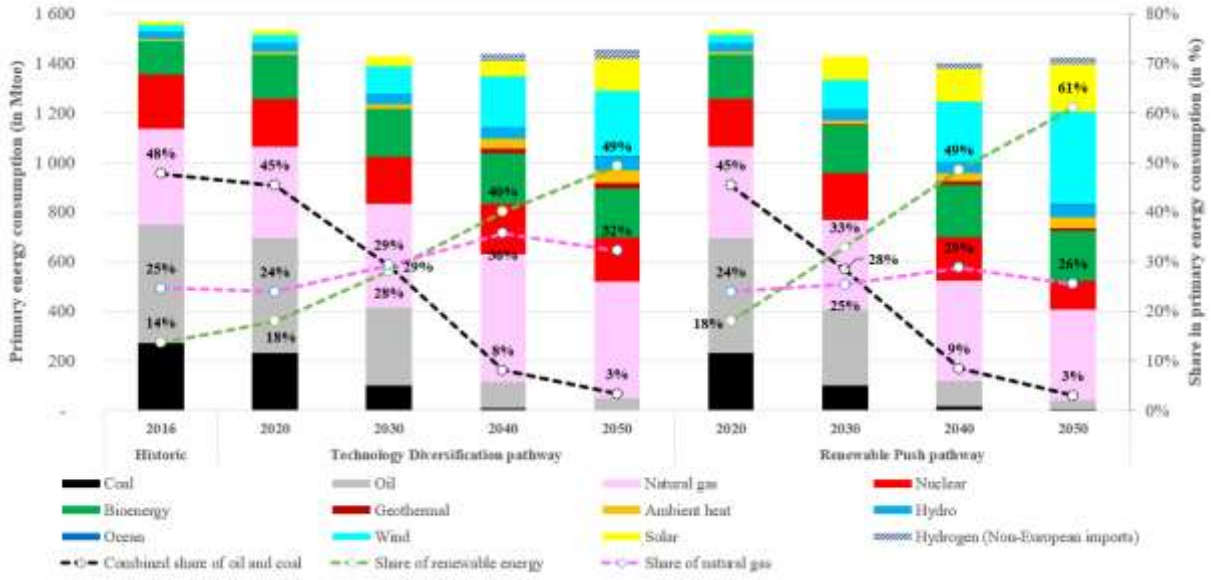
3.1. Pathways to achieve carbon neutrality by 2050

3.1.1. Outlook for primary and gross final energy consumption mix

Decarbonizing the European energy system by 2050 has an important impact on total primary energy consumption (TPEC) mix. **Fig. 8** presents the evolution of the TPEC in both scenarios (RP and TD). The mix sees a shift towards renewables because of considered targets, including CO_2 emission

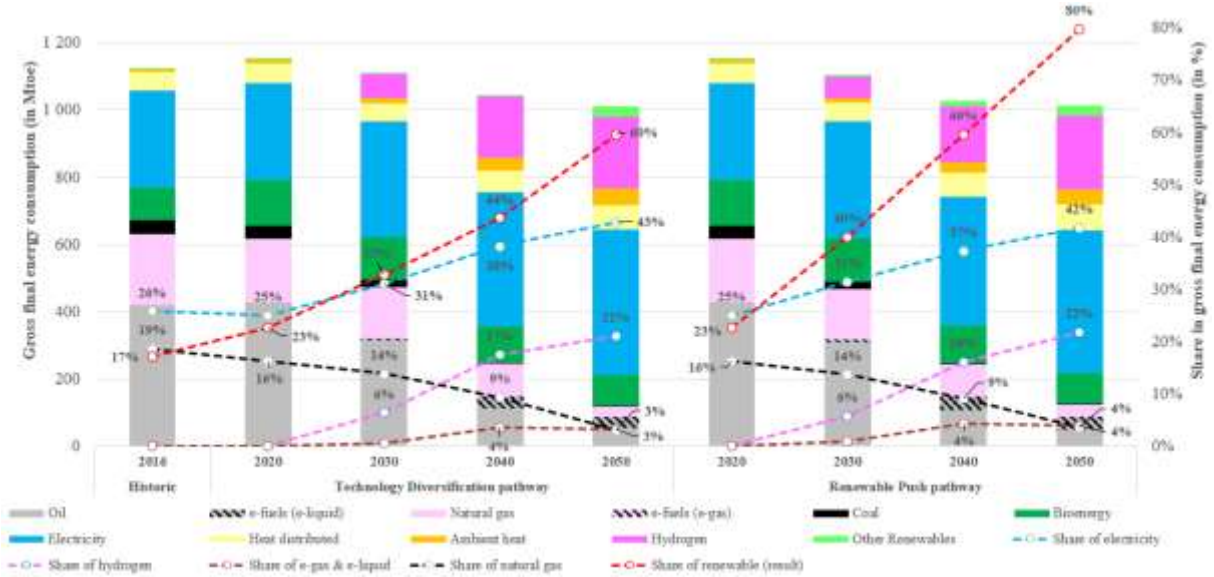
reduction, renewable energy share, or phaseouts in the coal and nuclear sector. There is a strong decrease in oil and coal in TPEC by 2050 in both scenarios, dropping to only 3% in 2050 from 45-48% in 2016. It is worth mentioning that natural gas still represents around 25-33% of the TPEC by 2050 due to the uptake of low carbon technologies, *i.e.*, CCS. In the TD scenario, the share of renewable is around half of the TPEC in 2050 (which is almost three-fold higher than in 2020), while it achieves almost two thirds in the RP scenario. The energy efficiency target's impact can be observed in both scenarios, with a downward trend (between -0.2 and -0.3%/year according to the scenario) of the TPEC between 2016 and 2050. In both scenarios, bioenergy is the second source of renewable energy after wind with around 200 Mtoe, achieving the maximum potential assessed by ENSPRESO BaU scenario by 2050.

Fig. 8: Evolution of total primary energy consumption.



The same downward trend (-0.3%/year between 2016-2050) is observed in gross final energy consumption (GFEC), which levels at 1 010 Mtoe by 2050 (**Fig. 9**). Renewable energy represents 33% of the GFEC in 2030 in TD scenario against 40% in the RP scenario. This share doubles in both scenarios to achieve 60% and 80% by 2050 in TD and RP, respectively. It should be noted that while the increasing share of renewable energy in RP is due to the specified targets, the increase in TD beyond 2030 is a consequence of other targets such as net-zero CO_2 emissions by 2050. The renewable energy uptake is sustained by very ambitious investments in wind and solar, with a tenfold and fifteenfold increase of supply between 2016 and 2050 in TD and RP respectively, achieving 390 and 560 Mtoe by 2050 (**Fig. 8**). This is also reflected in the increased electricity in the GFEC. Hydrogen sees a significant penetration, achieving more than 20% of GFEC by 2050, *i.e.*, more than 210 Mtoe. Meanwhile, e-fuels increase to a 3-4% share of GFEC by 2050, mainly due to their increasing use in aviation. Hydrogen and hydrogen-derived fuels thus represent almost 25% of GFEC by 2050 in both scenarios.

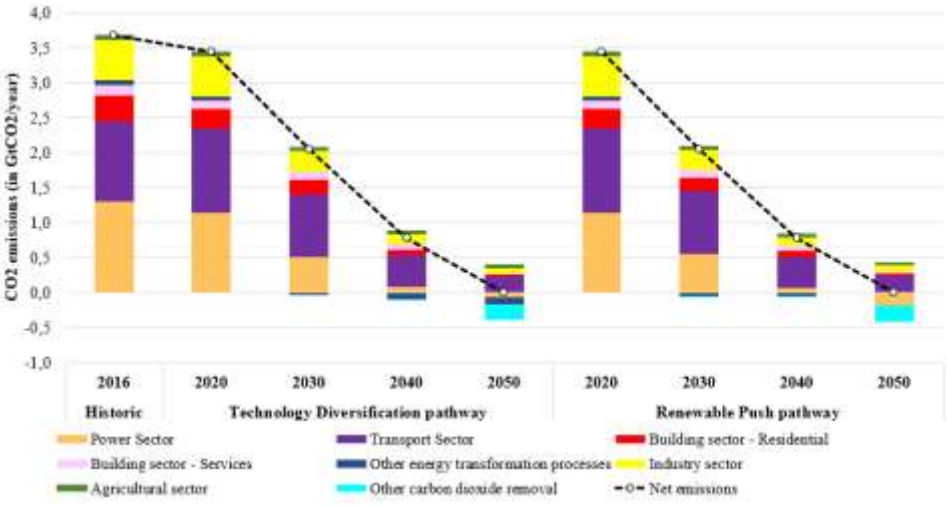
Fig. 9: Evolution of Gross final energy consumption.



3.1.2. Outlook for CO_2 emissions and future CCUS deployment

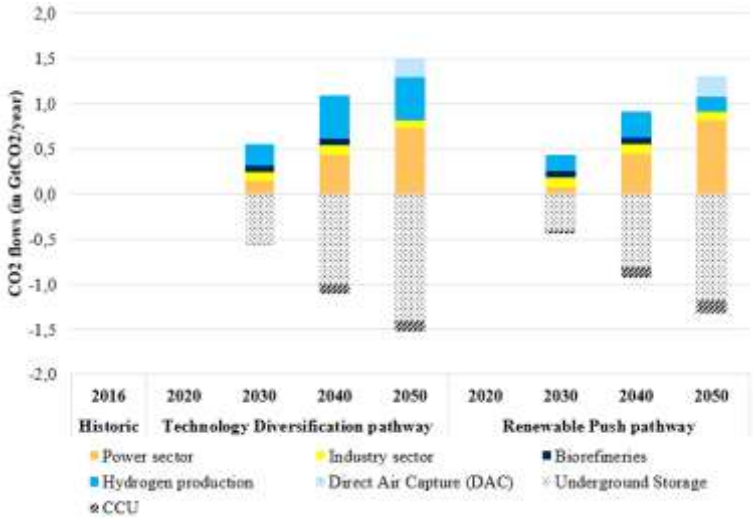
Fig. 10 shows that bioenergy with carbon capture and storage (BECCS) sees an increasing role in the power sector, biorefineries, and the production of renewable hydrogen. Negative emissions associated with BECCS and direct air CO_2 capture with storage (DACCS) offset the remaining emissions from the use of fossil fuels in the hard-to-abate sectors (transport and industry). The power sector's net CO_2 emissions reach in 2050 around -75 Mt CO_2 in TD and -195 Mt CO_2 in RP due to the increasing uptake of BECCS. The potential of carbon dioxide removal through DACCS also increases significantly in the same period, reaching 225-235 Mt CO_2 of negative emissions by 2050. A higher constraint on the share of renewables in GFEC displaces the negative emissions from "other energy transformation processes" (production of hydrogen from BECCS and reformer with CCS) to the power sector, mainly due to a higher production of renewable hydrogen from electrolyzers in RP (see Section 3.2 below)

Fig. 10: Evolution of the CO_2 emissions between 2016-2050.



The CCUS value chain in the model recovers CO_2 captured in industry, power sector, hydrogen production, second generation of biofuels (lignocellulosic), or from the atmosphere *via* DAC. The captured CO_2 emissions can be from fossil or biogenic sources.

Fig. 11: Evolution of the CO_2 flows.



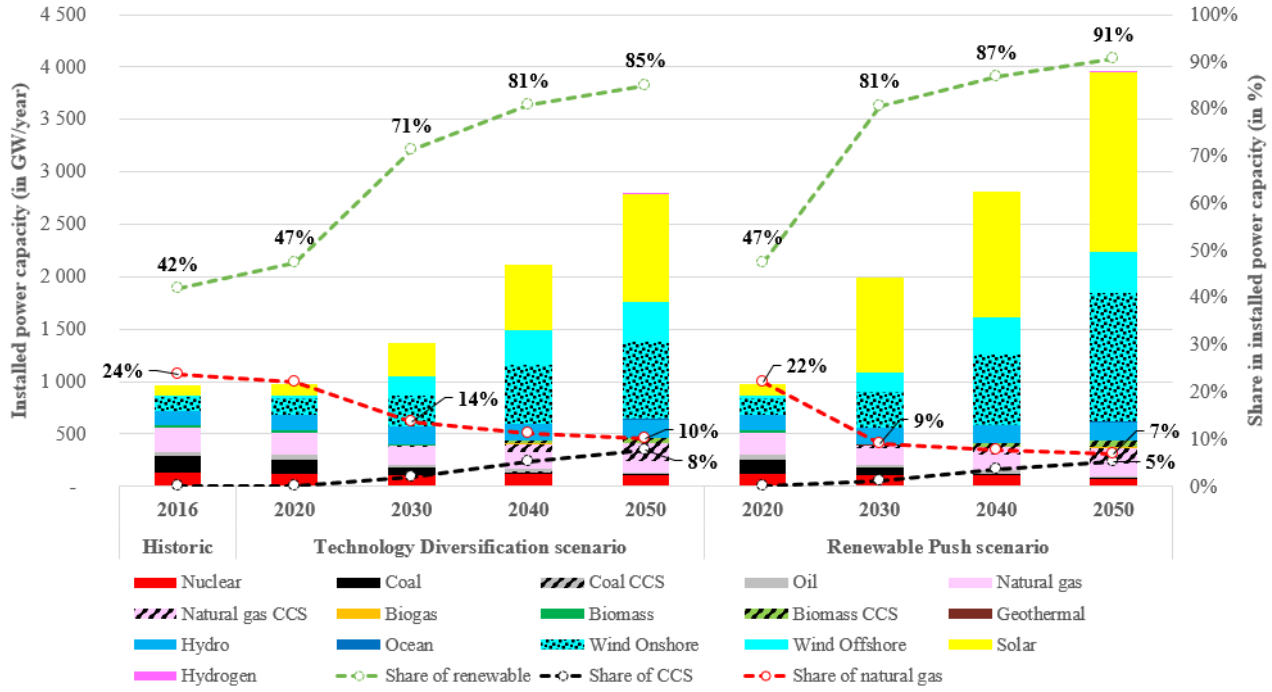
Those captured emissions are either stored permanently in sinks (depleted oil/gas fields, enhanced coal beds, deep saline aquifers), traded, or reused to produce e-fuels or e-gas. **Fig. 11** highlights that the CCUS value chain, almost non-existent today, accounts for about 1.5 Gt by 2050, or 40% of the emissions of 2016. It should be noted that the 1.4 Gt restriction for permanent storage in 2050 is only binding in the TD scenario. The power sector remains the main source of captured CO_2, followed by hydrogen production and DAC in both scenarios. CCS is further applied to decarbonize the industry sector. In both power and hydrogen production, CO_2 is captured from BECCS and natural gas-based technologies with CCS, pinpointing co-dependencies between the development of natural gas, bioenergy potential, and BECCS in the decarbonization pathways. The more widely CCS is available, the more fossil-based technologies with CCS can be used to produce electricity and hydrogen. In addition, the higher the bioenergy potential, the more BECCS can play an important role. Almost 97% and 94% of the captured CO_2 is stored permanently in 2030, while the rest is reused to produce e-fuels in TD and RP, respectively. The development of CO_2 storage in the TD scenario is in line with the increasing annual injection capacities considered in Section 2.6, reaching the maximum limit of 1 Gt CO_2/year in 2040 and 1.4 Gt CO_2/year in 2050. The earlier development of renewables in the RP scenario, due to the policy constraint on the share of renewables in GFEC in in that scenario, decreases the injection rate by about 20% (805 Mt CO_2) in 2040 and by more than 15% (1 170 Mt CO_2) in 2050. This confirms that a pathway focused on renewables still needs CCUS to reach the neutral emission target. The use of captured CO_2 increases to 8% (127 MtCO_2) and 11% (151 Mt CO_2) by 2050 in TD and RP, respectively. More limitation on the development of CO_2 underground storage capacity induces stronger competition between BECCS, DACCS, fossil-based technologies with CCS, and renewable energy in the future. A sensitivity analysis relaxing the constraint on CO_2 injection capacities illustrates this dependency (see Section 3.3).

3.1.3. Outlook for the power sector

As seen in Section 3.1.1, the share of electricity in GFEC doubles between 2016 and 2050, from 26% (290 Mtoe) in 2016 to 43% (432 Mtoe) and 42% (423 Mtoe) in 2050 in the TD and RP scenarios, respectively. This increasing use of electricity to achieve carbon neutrality has a clear and direct impact on power generation. The total installed power capacity is expected to reach between 2 800 GW and around 4 000 GW by 2050, equivalent to a threefold and fourfold increase compared to 2016 value in the TD and RP respectively (**Fig. 12**). The acceleration of renewables deployment, mainly wind and solar, is the main driver of this push, followed by natural gas-based power plants with CCS and BECCS.

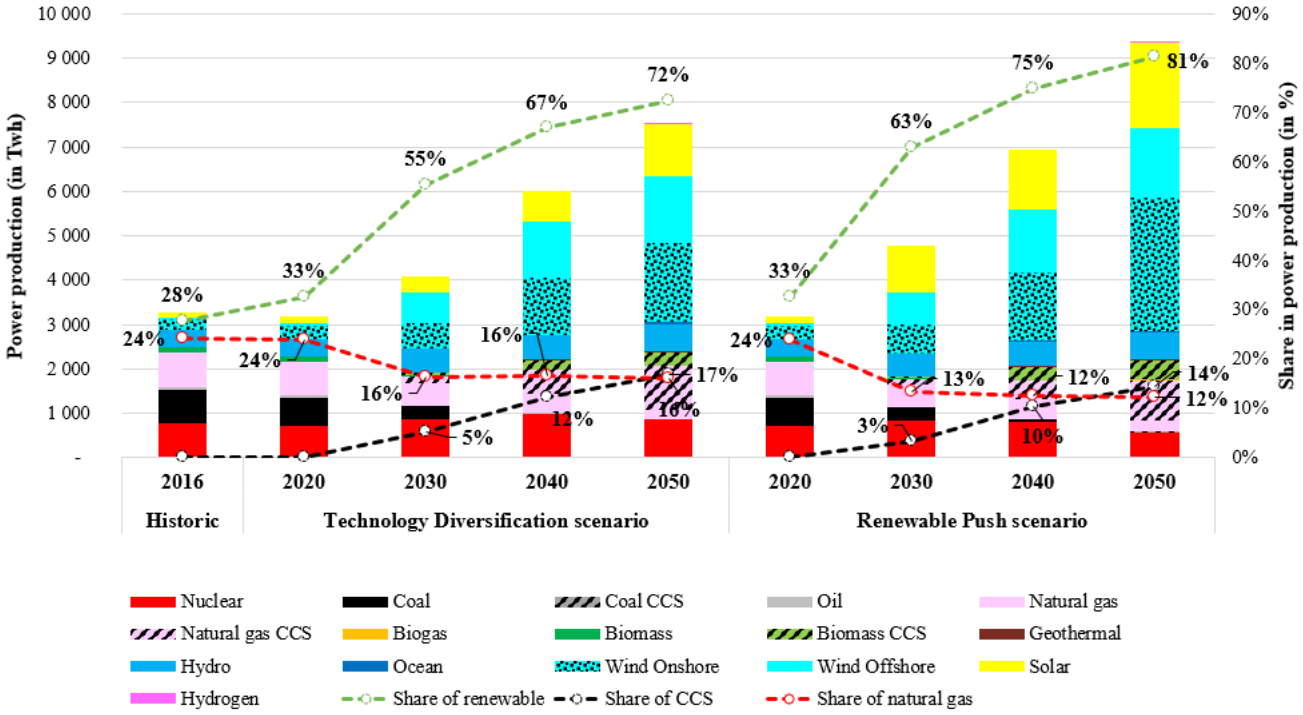
All those technologies serve to decarbonize the European power sector by 2050 and even allow net negative emissions in the sector. This increasing share of VRE, wind and solar, shed light on the increasing role of off-grid renewables to produce hydrogen (power-to-hydrogen, PtH2) *via* electrolyzers. Direct connection of VRE to off-grid electrolyzers is increasingly contributing to the flexibility of power supply, mitigating curtailment, and safeguarding the reliability of the power grid.

Fig. 12: Evolution of the total installed capacity between 2016-2050.



Electricity generation increases from 3 300 TWh in 2016 to 7 500 TWh in 2050 in the TD scenario and 9 400 TWh in the RP scenario (**Fig. 13**). The share of VRE (solar and wind) increases significantly over the same period, from 12% of total electricity generation in 2016 to 60% in 2050 in TD and 70% in RP. By 2050, electricity consumption for hydrogen production *via* electrolysis (on-grid and off-grid) exceeds 1 800 TWh in the TD scenario and 3 700 TWh in the RP scenario, corresponding to 40% and 60% of the VRE production respectively. The growing role of hydrogen in the European energy transition (see Section 3.2) contributes to the accelerated integration of VRE into the energy system. The results show that most PtH2 is operated in an "off-grid" set up, with electrolyzers primarily powered by a direct connection to solar and wind onshore and offshore (**Fig. 16**). Such off-grid PtH2 from wind and solar represents more than 85% of hydrogen production *via* electrolysis in 2050 in the TD scenario, while it is around 95% in an accelerated deployment of renewables in the RP scenario. This renewable hydrogen is mostly dedicated to hard-to-abate energy end-uses in industry, transport, and buildings. Simultaneously, a smaller amount of hydrogen is fed back into the electricity sector as a flexibility option, complementing other solutions such as gas-fired power plants with CCS or BECCS.

Fig. 13: Evolution of the power production between 2016-2050.

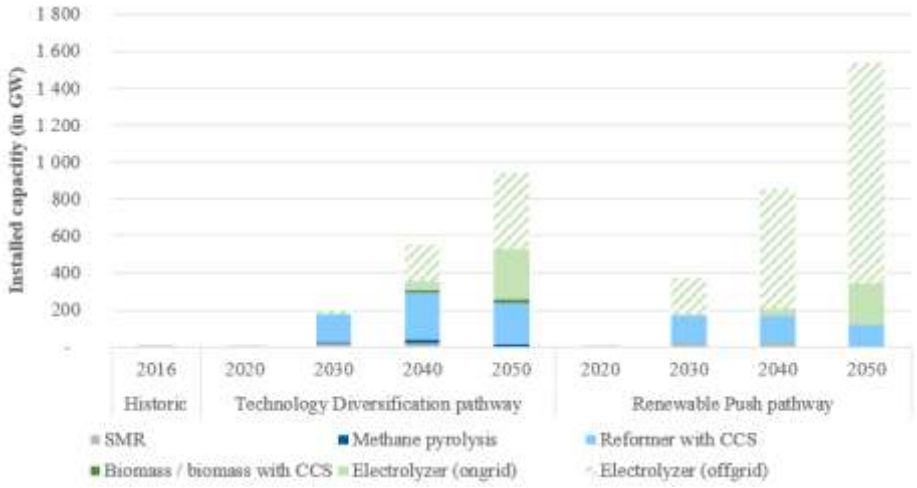


Natural gas still plays a certain role in the power sector, decreasing from 24% of total installed capacity in 2016 to 10%, equivalent to 285 GW in 2050 in the TD scenario and to 7% (around 270 GW) in the RP scenario (of which about 60% is plants with CCS, in both scenarios). By 2050, it represents 17% and 14% of total electricity generation (compared to 24% in 2016) in the TD and RP scenario, respectively. Natural gas with CCS demonstrates its highest value in the mid-load segment with an average load factor of around 65%. The remaining turbines (combined-cycle and open cycle turbines without CCS) serve as peaking units with a load factor of around 23% in 2050. Electrification and decarbonization of electricity generation are confirmed as two of the key buildings blocks to achieve low-carbon energy transition.

3.2. What is the potential of hydrogen in the decarbonized European energy system?

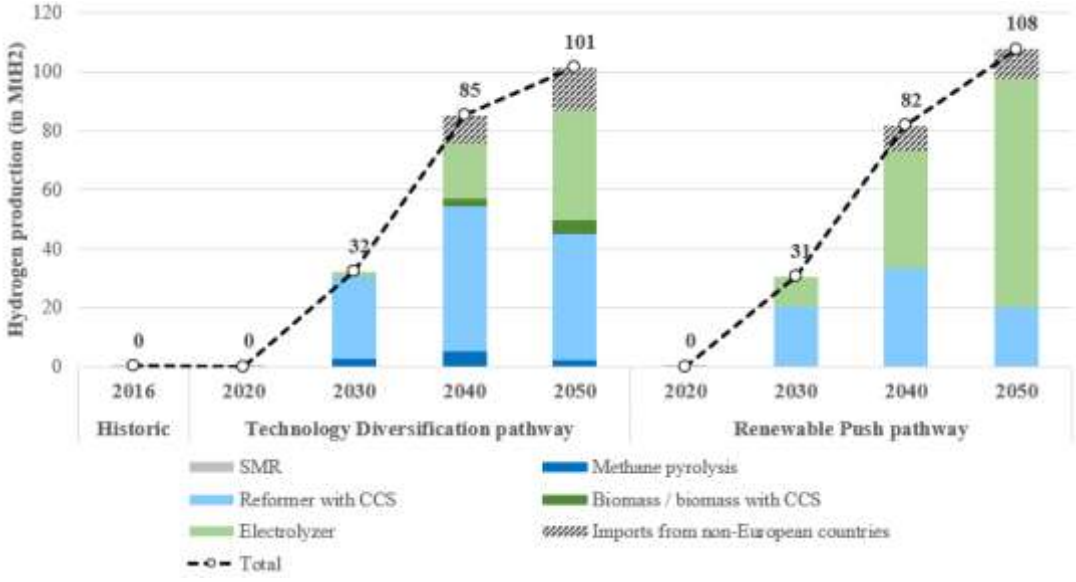
In terms of installed capacity, electrolyzer capacity increases significantly from about 20 GW in 2030 to 690 GW of installed capacity in 2050 in the TD scenario, while it increases tenfold in 2030 and doubles in 2050 in the RP scenario compared to the TD scenario (**Fig. 14**). Off-grid solar, onshore wind, and offshore wind capacity connected directly to electrolyzers is about 132 GW, 353 GW, and 122 GW respectively in 2050 in the TD scenario. In the RP scenario, these capacities increase more than sixfold in the case of solar, while onshore wind more than doubles and offshore wind increases by more than a third compared to the TD scenario.

Fig. 14: Evolution of the installed capacity in hydrogen production by technology type.



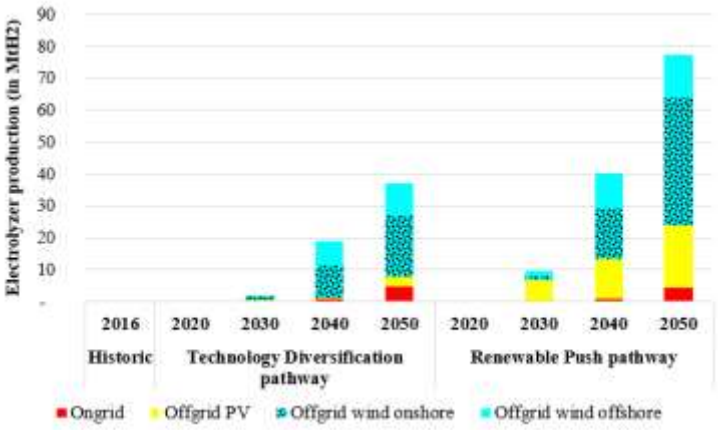
Hydrogen production increases significantly, exceeding 30 million tons (Mt) by 2030 (triple the current policy objective described in the EU hydrogen strategy), and more than 100 Mt by 2050 in both scenarios as shown in **Fig. 15**. By 2050, this is equivalent to between 3 400 TWh and 3 600 TWh in lower heating value (LHV) (more than total current electricity production in **Fig. 13**) or around 300 Mtoe (27% of 2016 gross final energy consumption) in the TD and RP scenarios respectively. Hydrogen thus soon becomes one of the main energy carriers of the future European energy system and replaces natural gas as the main gaseous carrier. Early investments are needed to initiate technology learning effects and increase hydrogen production over the next decade and achieve the required volume. A significant share of this hydrogen is produced with low-carbon technologies that rely on natural gas (reformers with CCS or pyrolysis) as shown in **Fig. 15**. Reformers with CCS dominate the low-carbon hydrogen production mix from 2030 to 2050. In the TD scenario, low-carbon hydrogen production reaches around 55 Mt in 2040 before decreasing to around 45 Mt in 2050 (equivalent to 52% of the total hydrogen production). The higher penetration of renewable energy which is observed in the RP scenario has a downward impact on the role of low carbon hydrogen, but it still has a role to play in this scenario: low-carbon hydrogen production in 2050 still amounts to around 20 Mt by 2050 (*i.e.*, 20% of the total hydrogen production) in that scenario.

Fig. 15: Evolution of hydrogen production by technology type.



More detailed results on power sources of electrolyzers show the increasing importance of renewable hydrogen (off-grid electrolyzers and BECCS) in the coming decades in both scenarios, being another opportunity of VRE integration (**Fig. 15** and **Fig. 16**). This renewable hydrogen is mainly produced from electrolyzers that can either be connected to the electricity grid (on-grid electrolyzers) or coupled with off-grid renewable plants (**Fig. 16**).

Fig. 16: Electrolyzer production by power source.



About 1.5 Mt of hydrogen is produced from off-grid electrolyzers (mainly with off-grid wind onshore) in 2030 in the TD pathway, against 10 Mt in the RP scenario. The massive investments in electrolyzers (**Fig. 14**) and VRE capacities (**Fig. 12**) contribute to the rapid increase in renewable hydrogen production until 2050, reaching 18 Mt and 40 Mt in 2040 in the TD and RP scenarios respectively, and then more than 30 Mt and about 75 Mt respectively in 2050. Electrolysis accounts for 90% of total renewable hydrogen production in 2050 in the TD scenario, while it is the sole supplier in the RP scenario. In the TD pathway, renewable hydrogen production from off-grid electrolyzers is supplemented by BECCS production, around 2.5 Mt in 2040 and 5 Mt in 2050, which also has the advantage of delivering negative emissions in the long term.

Fig. 15 shows furthermore the importance of hydrogen imports from neighboring regions from 2030 onwards. Thanks to the repurposing of cross-border gas infrastructure the imports increase and play a role in the European carbon neutrality target. About 9 and 10 Mt of hydrogen is imported from North Africa, Russia, Ukraine, and the Middle East by 2040, increasing to 10 and 15 Mt by 2050 in the TD and RP scenarios respectively. This imported volume represents 11% of total hydrogen supply in 2040 before increasing to 15% in 2050 in the TD scenario, while the share is unchanged in the RP scenario at 10% over the same period due to the accelerated continental deployment of renewable energies. Most imports from the neighboring regions rely mainly on cross-border pipeline infrastructure and low-carbon hydrogen produced from natural gas.

Fig. 17: Evolution of investment costs through learning-by-doing for renewable hydrogen production with electrolysis and renewables in the TD scenario between 2020 and 2050.

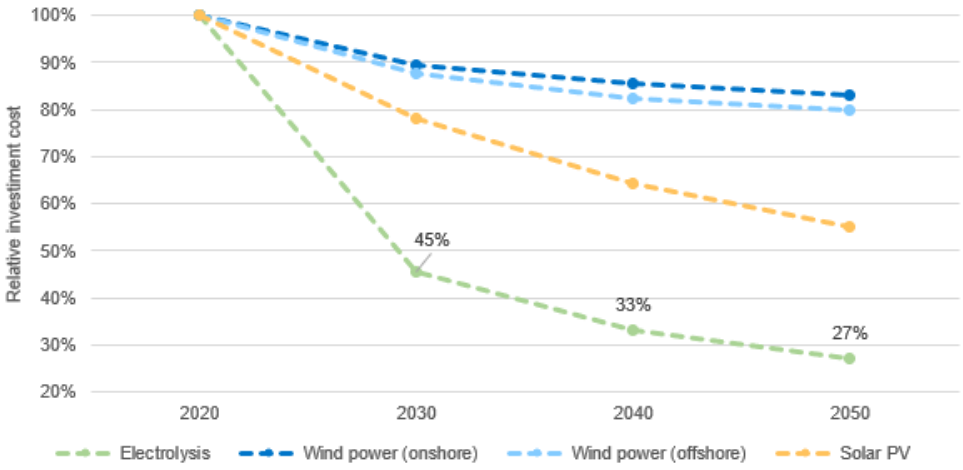
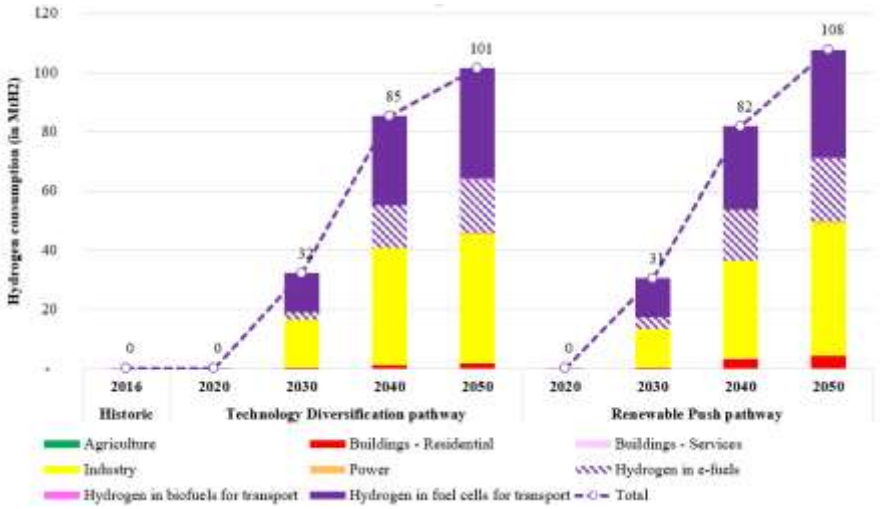


Fig. 17 shows the observed cost reduction for renewable power generation and electrolyzers through learning-by-doing. It highlights that the increasing number of installations increases their competitiveness over the period to 2050 as comparable fossil technologies excluding natural gas reforming with CCS do not experience a similar cost reduction. Furthermore, it highlights that especially solar PV and electrolyzers have a significant cost reduction potential owing to the high learning rates, relatively low installed capacity (for electrolyzers), and the increasing number of installations.

Fig. 18 : Evolution of hydrogen consumption by sector.



The sectoral breakdown of hydrogen demand in **Fig. 18** shows the polyvalence of hydrogen in decarbonizing the European energy system. Hydrogen is particularly relevant in hard-to-abate sectors such as transport and industry. Around 55 Mt of hydrogen is consumed by the transport sector in 2050 equivalent to about 55% of the total hydrogen demand, either in fuel cells, to produce e-fuels, or in biorefineries for second generation biofuels. Demand for hydrogen for e-fuels, mainly used in aviation, is around 20 Mt. Hydrogen, e-fuels, and other hydrogen-based solutions provide alternative decarbonized fuels to heavy road transport, aviation, and shipping, thus addressing some of the limitations faced by electric mobility in terms of energy density, weight, range, and fueling. Meanwhile, hydrogen demand in industry reaches around 45 Mt in both scenarios by 2050. About 60% of this industrial hydrogen demand is consumed in heat and steam processes (15% in chemicals and 45% in

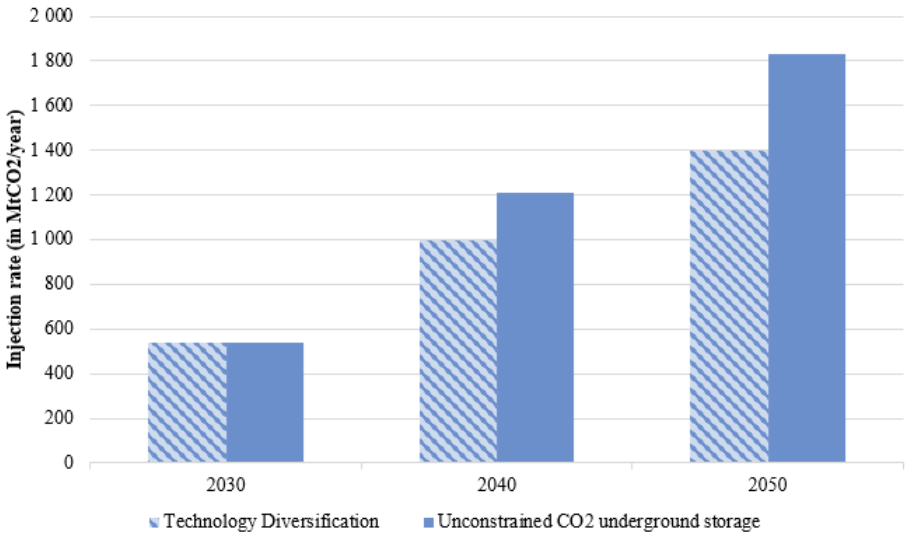
non-energy intensive industries), the remaining 40%, or about 18 Mt, is consumed as alternative route for direct reduced iron (DRI) in the iron and steel industry. Hydrogen also contributes, to a lesser extent, to the decarbonization of buildings and electricity production with about 2.2 Mt and 5.1 Mt in the TD and RP scenarios respectively. This limited penetration in these sectors is due to the competition with other available options, such as renewables (VREs, biogas, BECCS), heat pumps, and continued use of natural gas.

Finally, supporting the deployment of the hydrogen value chain would require between € 3.1 and € 5.5 trillion in investments between 2021 and 2050. As shown in **Fig. 17**, there is significant potential for cost reduction through learning-by-doing. This will require, among other things, a rapid and synchronized start of investments in the hydrogen value chain to ensure the development of hydrogen supply and demand, thus avoiding the risks of stranded assets in the 2040s.

3.3. Sensitivity analysis on future development of the underground CO_2 storage

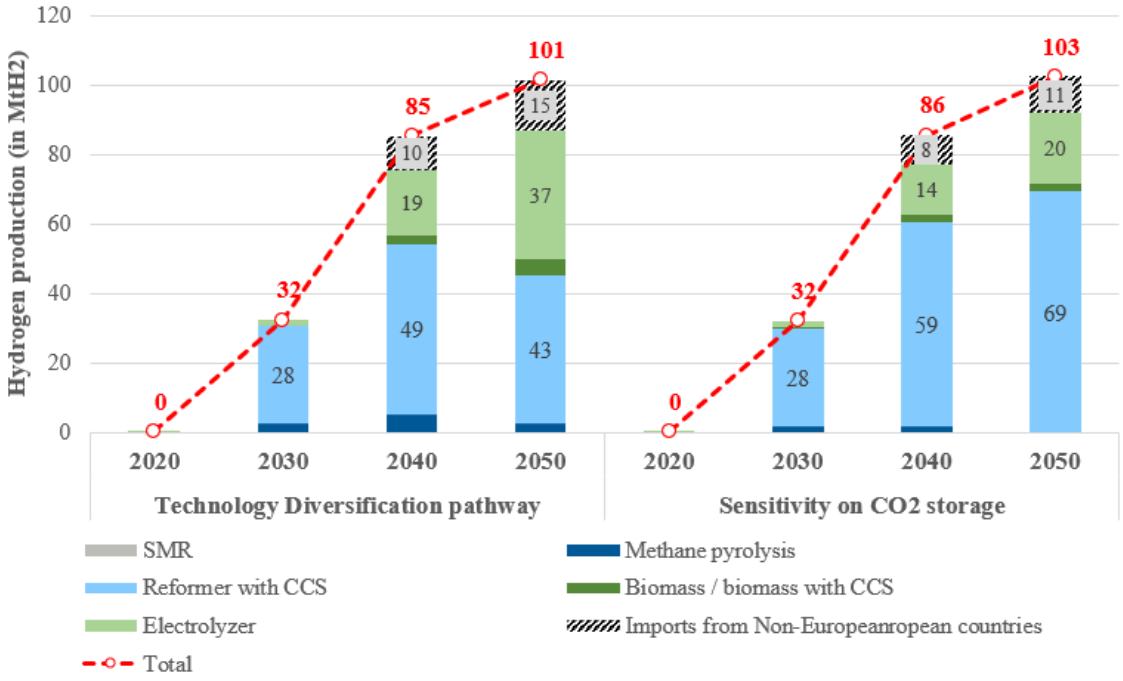
The central scenarios assume maximum CO_2 annual injection rates of 1.0 Gt from 2020 to 2040, and 1.2 Gt and 1.4 Gt in 2045 and 2050 respectively (see Section 2.6). A relaxation of this cap, *i.e.*, no restriction on the annual CO_2 injection rate, has been assessed. This sensitivity analysis on the TD scenario allows pinpointing the role of CO_2 underground storage potential in the decarbonized European energy system (**Fig. 19**).

Fig. 19: Evolution of CO_2 injection rate.



An unconstrained CO_2 underground storage scenario leads to higher injection rates as seen in **Fig. 19**. The CO_2 injection rate reaches more than 1 800 Mt which is some 400 Mt higher than the limitation implemented in the TD scenario. The results highlight the upper limit of the potential for carbon capture and removal technologies in Europe to achieve carbon neutrality by 2050.

Fig. 20: Impact on the hydrogen production mix.



Decreases by around 45% of hydrogen from electrolyzers and by around 30% of the hydrogen imported from non-European countries are observed in 2050 with an unconstrained development of CO_2 underground storage, while low-carbon hydrogen increases by more than 60% to 69 Mt. Limiting the injection rate, as is the case in the TD scenario (**Fig. 20**), thus hinders the adoption of technologies with CCS such as, primarily low-carbon hydrogen, but also technologies such as BECCS and DACCS.

The higher development of reformers with CCS in the sensitivity scenario induce lower cumulative investments in the hydrogen value chain of around €700 billion by 2050 due to the decrease in off-grid renewable electricity investments (–€477 billion) and in electrolyzers (–€245 billion).

4. Discussion

The first half of this section focuses on two important questions: 1) Why is there a need for hydrogen? 2) Can we explain why the different hydrogen production technologies take different shares in total hydrogen production within the planning period? The second half compares the results to previously published studies and identifies limitations and uncertainties in the study, both methodological and general.

4.1. Why is there a need for hydrogen?

In a decarbonized energy system, hydrogen is essential both on the supply- and demand-sides. Furthermore, it avoids stranded assets from the natural gas infrastructure networks. On the demand side, hydrogen provides an answer to the challenges of deep electrification and the limits of energy efficiency. Moreover, it proves to be a particularly cost-efficient solution for certain hard-to-abate energy uses, notably in transport and industry.

In transport, hydrogen, e-fuels, and other hydrogen-based solutions provide energy-dense fuels and gases to heavy and long-distance road transport, aviation, and shipping. These energy carriers address some of the limitations electric mobility faces regarding energy density, weight, range, and refueling. Biofuel is also an important technology for decarbonizing the transport sector. However, biomass, the

feedstock for biofuels, is also needed for decarbonization in other sectors, and the total potential is limited.

In industry, decarbonization relies on the combined use of electricity, hydrogen, distributed heat, increased efficiency in production processes, and CCUS, with specific solutions and constraints for each subsector. Simply speaking, there is no "one size fits all" solution for the entire industry sector. Whereas the share of electricity in industry's energy consumption remains stable throughout the outlook period, hydrogen helps compensating for the considerable decrease in the use of fossil fuels. The biggest part of industrial hydrogen consumption is for steelmaking. In this sector, hydrogen is particularly well suited as reduction agent replacing coke. Also, hydrogen is used extensively for process heat and steam generation in all sectors as its properties allow it to replace natural gas.

On the supply-side, costs can be avoided in the power system by operating electrolyzers when renewable energy is available either on-grid or off-grid. Here, hydrogen can be produced on-grid when there is a surplus of power while off-grid hydrogen production allows continuous demand through cheaper storage of hydrogen compared to electricity.

Furthermore, including low-carbon hydrogen from natural gas together with renewable hydrogen, would allow to build upon the existing European natural gas infrastructure, and have a more diversified portfolio of assets and risk. This would allow reducing the costs for achieving the climate ambitions.

4.2. What explains the shares of different hydrogen production technologies?

Each of the hydrogen production technologies has advantages and disadvantages, which helps to explain their relative production in the outlook period, see **Table 5**.

Table 5: Advantages and disadvantage for hydrogen production technologies

Type of production	Advantage	Disadvantage
Natural gas reforming w/CCS	Low costs, high efficiency	Need for CO_2 infrastructure and storage, requires CO_2 compensation (<100% capture)
Electrolyzers	Interact well with renewables	Expensive (notably in early decades), and need for electricity without associated GHG emissions
Bio gasification w/CCS	Provides negative emissions	Limited resource availability, high costs, and need for CO_2 storage
Pyrolysis	Does not need CO_2 storage	Higher natural gas consumption compared to reforming, uncertain black-carbon market

Natural gas reforming dominates hydrogen production in the first decades of the outlook period because of the relatively low costs for this technology and its independence of renewable electricity. However, as the emission ceiling is lowered step by step, several factors are limiting further technology upscaling:

1. Negative emissions must compensate for the remaining CO_2 emissions in natural gas reforming, through BECCS or DAC. However, the available bio resources are limited, and DAC is expensive.

2. The constraint for maximum yearly injection rate to CO_2 underground storages becomes active. This constraint limits the possible growth for all CCS-based technologies, including natural gas reforming and the needed BECCS emission compensation resulting in a trade-off between different technologies with CCS.
3. Increasing shares of renewables in primary energy supply leads to an improved competitiveness of electrolyzers through the avoided costs for electrical storage and transmission achieved when electrolyzers offer flexibility by producing whenever the renewable energy is available. In addition, considerable learning effects further drive the uptake of the green electricity and electrolyzer technologies.

Consequently, hydrogen production from natural gas reforming stays at a high level due to its relatively low costs. In contrast, the electrolyzers share in total hydrogen increases gradually over time. One disadvantage for all hydrogen production technologies excluding off-grid electrolysis is their dependence on the respective energy markets. This can in turn impact the profitability of the different technologies.

4.3. Comparison to other studies

This study focuses on pathways towards full decarbonization of the European energy system by 2050, where CCS deployment is permitted in all scenarios considered herein.. Hydrogen import was accounted for *via* a linked model with improved geographical resolution. The closest studies are the studies of Blanco et al. [27][38] which use the comparable JRC-TIMES model. Both studies differ in all three aspects. Hence, the results also differ. This is especially visible in two sectors: 1. Hydrogen production from natural gas reforming with CCS plays a more important role, and 2. Power-to-liquid is used less. The former is explained by the improved process parameters of natural gas reforming with CCS, highlighting recent developments to achieve capture rates above 90%. The latter can be explained by the possibility to compensate remaining CO_2 emissions with DACCS. Hence, e-fuels are mostly used in the aviation sector due to the lack of alternatives. The total hydrogen demand is however the same order of magnitude as in the 95% emission reduction scenarios in [27].

The strategic vision "A Clean Planet for All" [28] of the EU uses a holistic model that also accounts for non-CO_2 greenhouse gas emissions and sinks through land use, land-use change, and forestry (LULUCF). Hence, it is difficult to compare the results. However, it can be seen that the total hydrogen consumption is increased in this study compared to the net-zero scenarios (70-80 Mtoe corresponding to around 24.5-28.0 Mt of hydrogen compared to around 100 Mt of hydrogen in this study). This difference may be due to the inclusion of different end-use technologies or more expensive production technologies (Best Available Technologies); the exact reason cannot be pinpointed without a complete knowledge of their data set.

It is harder to compare the results to studies with different geographical coverage. van der Zwaan et al. [55] focus in their recent study on Western Europe with North Africa included endogenously in the model. A key difference here is that North Africa is included while East Europe is excluded. Hence, the potential for renewable power generation as well as energy demand differs. However, it can be noted that in their study, hydrogen import is significantly larger than in this study, although this study also includes hydrogen import from other regions than North Africa. A key difference may be the representation of each North African country as a single node while this study uses both a high geographical and temporal resolution when calculating the costs of hydrogen imported to Europe in the HyPE model.

4.4. Uncertainties and limitations

Uncertainties and limitations for assessment of the future development of energy systems can be grouped into four categories: 1. future costs and efficiencies of existing technologies;; 2. disruptive, new technologies or energy carriers;; 3. demand;; 4. other assumptions (policy, foreign trade, market functioning and integration, wider societal issues, *etc.*). In addition, methodological limitations may impact the results of this study.

Future technology costs are, in general, hard to predict. This paper considered both endogenous and exogenous cost reductions to estimate the expected technology cost development. Since learning effects are internalized in the model, uncertainties in the learning rates may affect the cost prediction. As an example, recent cost increases in solar PV will not be captured by the single-factor learning rate approach. Furthermore, novel technologies like industrial scale electrolyzers, methane pyrolysis, and carbon capture technologies have a negligible installed capacity today, making the calculation of learning rates *via* historical data very difficult. Therefore, component learning rates or surrogates must be used. Since cost reductions due to endogenous learning depend on the relative increase in cumulative capacity, which is higher for low initial capacities, assuming a too low initial capacity can result in an overestimation of the cost reduction potential.

Similarly, technology development may significantly affect the development of the energy system. Specifically, disruptive technologies that are unknown today may significantly alter the picture of the future energy system. One example of such disruptive technologies is the recent development in battery electric vehicles, which significantly exceeded previous predictions. As unknown technologies cannot be represented in a model, they may alter the future energy system from the scenario results. Ammonia is expected to play a significant role in a future decarbonized energy system as a new energy carrier, both as storage medium for hydrogen due to simpler storage potential[54] and as potential fuel for shipping [57]. To date, ammonia is mostly used as commodity for nitrogen fixation from air to produce fertilizer. Hence, ammonia is in this study only included as demand. Including ammonia as an energy carrier would require reliable techno-economic data for both ammonia bunkering networks and propulsion systems.

The total energy and commodity demand is a third important factor driving the results. The demand is based on other models. Since these models also have limitations and uncertainties, there is an error propagation that may affect the optimization of the future energy system. One example is the cement demand, whose production is responsible for 7% of the global emissions today. This demand can, *e.g.*, be reduced through 1. increased recycling and 2. substitution by wood. These developments may be included in the external model, but possible feedback effects between the external model and the energy system models in this study are not represented. Another example could be behavioral changes in transportation, *i.e.*, a switch from motorized individual transport to either public transport or unmotorized individual transport like bicycles.

Other essential factors are the assumptions. used As discussed in the previous paragraphs, these can be grouped as cost and efficiency assumptions and system assumptions. The latter corresponds to, *e.g.*, limitations on CO_2 injection capacities and biomass availability. Through sensitivities, we identified that both the assumptions mentioned significantly impact the future energy system. Hence, using different baseline assumptions may result in entirely different future energy systems.

The methodology also has additional limitations. First, as outlined previously, using endogenous cost reductions in energy system models can result in problems [58]. In addition, three models are soft linked in this study. Soft linking of models is problematic when convergence is not achieved in a two-way linking as used in this study. For example, if the aggregated energy system in Integrate Europe was to

underestimate the requirements for energy transport infrastructure, the model would likely *overestimate* the total investment in technologies that require significant energy transport infrastructure.. This would in turn cause suboptimal minimum constraints to be used by MIRET-EU, compared to if the proper grid investments had been accounted for in a more direct manner.. To reduce the risk of such inconsistencies and ensure convergence between the models, multiple calibration runs were performed in this study..

5. Conclusions

This paper assesses the contribution of renewable and low-carbon hydrogen to the transition of the European energy system towards net zero emissions by using a novel modeling framework (see section 2). In the two scenarios assessed, European hydrogen demand reaches 30 Mt by 2030 and exceeds 100 Mt by 2050. At this date, actual hydrogen and hydrogen embedded in e-fuels, ammonia, or methanol cover about 25% of gross final energy consumption. Hydrogen is a versatile answer to the limitations of deep electrification and energy efficiency improvements. It is a cost-efficient solution especially in hard-to-abate sectors such as industry or in the transport sector, where it is consumed in fuel cells, in biorefineries, and as feedstock to produce e-fuels. These results are in line with recent findings in the EU [27] and in the U.S. Northeast [59]. Moreover, it was found that around 10% of the hydrogen demand is supplied by imports from non-EU countries. and in the U.S. Northeast [59]. Moreover, it was found that around 10% of the hydrogen demand is supplied by imports from non-EU countries.

Both scenarios demonstrate the value of a diversified hydrogen production mix based on renewable and low-carbon technologies confirming the vision stated in the EU hydrogen strategy considering both as key building blocks[31].. Low-carbon hydrogen produced from natural gas serves most of the projected demand in the 2030s and is critical to the uptake of the hydrogen economy. Renewable hydrogen from electrolysis or biomass with CCS develops more strongly from the mid-2030s, helping to meet the bulk of the additional demand growth. It takes a lead role in the Renewable Push scenario, where higher binding targets are assumed for renewable energy supply. In that scenario, renewable hydrogen is used to absorb, store, and transport most of the additional energy from renewable sources. European inland production is complemented by renewable and low-carbon hydrogen imports from neighboring regions, which represent between 10 and 15% of the total demand in 2050. Access to existing cross-border pipelines is a critical advantage compared to maritime transport.

The required significant investments for achieving a hydrogen economy need to start quickly and be synchronized to ensure the timely development of both supply and demand of hydrogen, and to avoid risk of stranded assets in the 2040s. These results also confirm the importance of deploying the CCUS supply chain in parallel to achieve CO_2 neutrality. At a general level, an approach that considers a wide range of technologies, as depicted in the Technology Diversification scenario, is less capital intensive and helps European society save more than a trillion euros over the next thirty years.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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[31] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0301&from=EN

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7. Supplementary materials

Appendix A : Model documentation

A.1 MIRET-EU model

A complete description of the TIMES model equations appears in the ETSAP[32] documentation. The model estimates the energy dynamics by minimizing the total discounted cost of the system over the selected multi-period time horizon through powerful linear programming optimizers. The components of the system cost are expressed on an annual basis while the constraints and investment variables are linked to a period. The total cost is an aggregation of the total net present value of the stream of annual costs for each of the countries modelled. It constitutes the objective function (Eq. 1) to be minimized by the model in its equilibrium computation. A detailed description of the objective function equation is provided in Part II of the TIMES documentation (Loulou et al., 2016). We limit our description to giving general indications on the annual cost elements contained in the objective function:

- investment costs incurred for processes,
- fixed and variable annual costs,
- costs incurred for exogenous imports and revenues from exogenous exports,
- delivery costs for required commodities consumed by processes, and
- taxes and subsidies associated with commodity flows and process activities or investments.

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} (1 + d_{r,y})^{REFYR-y} * ANNCOST(r,y) \qquad \text{(A. 1)}$$

NPV is the net present value of the total cost for all regions (the objective function);

ANNCOST(r,y) is the total annual cost in region *r* and year *y* (more details in section 6.2 of PART II (Loulou et al., 2016)

$d_{r,y}$ is the general discount rate;

REFYR is the reference year for discounting

YEARS is the set of years for which there are costs, including all years in the horizon, plus past years (before the initial period) if costs have been defined for past investments, plus a number of years after end of horizon (EOH) where some investment and dismantling costs are still being incurred, as well as Salvage Value; and

R is the set of regions/countries in the area of study.

The MIRET-EU model is data driven[33], its parameterization refers to technology characteristics, resource data, projections of demand for energy services, policy measures, among other. This means that the model varies according to the data inputs while providing results such as technology pathways or changes in trade flows for policy recommendations. For each country, the model includes detailed descriptions of numerous technologies, logically interrelated in a Reference Energy System – the chain of processes that transform, transport, distribute and convert energy into services from primary resources and raw materials to the energy services needed by end-use sectors.

[32] https://iea-etsap.org/index.php/documentation

[33] Data in this context refers to parameter assumptions, technology characteristics, projections of energy service demands, etc. It does not refer to historical data series

A.2 Integrate Europe

Integrate is a software for planning of complex and geographically confined energy systems.[34] The model can optimize investments in infrastructure for the most relevant energy carriers, including electricity, heating, cooling, natural gas, hydrogen, waste, and biomass, including conversions between these. Each technology is represented by a separate module in the model. The main energy component types are sources, conversion, storage, transport/distribution, end-use and markets.

The model combines linear programming (LP) for the calculation of operating costs with dynamic programming (DP) for the calculation of optimal investments. As shown in **Fig. 5** b), the model first calculates operating costs for all states and years, and then the optimal investment path is calculated.

The objective of the investment optimization is to find the investment pathway that minimize the net present value of all costs in the planning period, cf. Eq. (A.2).

$$\min_{I_{t\in T, d\in D}} \left\{ \sum_{t\in T} \delta^{t-T_{start}} \left(c_t^{inv} + c_t^{ope} \sum_{\tau\in\{1,\dots,T_{step}\}} \delta^{\tau-1} \right) - \delta^{T_{end}+T_{step}-T_{start}} \Phi \right\} \quad \text{(A.2)}$$

The Boolean investment variable I_{td} is one if investment d is carried out in year t and zero otherwise. See [43] for a further elaboration of the Integrate model.

Symbols

c_t^{inv}	Investment costs in investment period t
c_t^{ope}	Annual operating costs for years in investment period t
D	Set of investment options
I_{td}	Binary investment variable, for investment period t and investment option d
T_{end}	First year of final investment period
T_{start}	First year of first investment period
T_{step}	Number of years for each investment period
δ	Discount rate for one year
Φ	Residual value of investments at the planning horizon

Integrate Europe is based upon the Integrate model methodology. For the representation of the European energy supply system as an aggregated single geographical node, a new set of components were developed to represent 12 European energy resource types, 6 markets trade to/from the European energy system, 24 conversion technologies, 3 storage types, 10 end-use energy carrier types, and 7 energy need types. For each component type, a subset of technologies can be specified to represents the variation in characteristics for existing capacity or new investment options. Feasible energy flows between components are specified by connecting them, as shown for hydrogen components in **Fig. 5** a).

For each coupling between an end-use energy carrier and energy need there is a subset of corresponding end-use technologies. Among other things, those technologies are represented by existing capacities at the start of the planning period, levelized investment costs, and a maximum relevant utilization. The

[34] https://www.sintef.no/en/software/integrate/

latter is included because the energy needs are aggregated categories. Existing capacities are depreciated linearly, whereas new capacity is optimized as a part of the operational optimization, typically once per decade.

A.3 HyPE model

HyPE is a delivery chain optimization model aiming at minimizing the total cost of hydrogen supply for a given set of production locations, exporting points, importing points and demand clusters. Choosing the most cost-efficient way to supply hydrogen to Europe requires considering different production technology options in the upstream (e.g. renewable energy, natural gas), transport modalities (e.g. trucks, pipeline and cargoes) and transport molecule (i.e. ammonia, liquified hydrogen, gasified hydrogen) in the midstram. The importing points and demand clusters are defined in the downstream. The resulting cost structure for supplying hydrogen from point-to-point is therefore driven by each of the steps of the delivery chai, ie. production costs, conversion and reconversion costs, terminal loading and unloading for the case of maritime routes and transport cost, which depends on the transport technologies and routes considered.

$$
\begin{aligned}
min_{(tech,xp,t,xe,xi,\ tmol,tm,trans)}\{ & \sum_{(\boldsymbol{tech,xp,t}) \in (\boldsymbol{TECH,XP,T})} \boldsymbol{PC_{tech,xp,t}} + && \textit{(Production costs)} \quad \text{(A.3)} \\
& \sum_{(\boldsymbol{xe,xi,tmol,t}) \in (\boldsymbol{XE,XI,TMOL,T})} (\boldsymbol{CC_{xe,tmol,t}} + \boldsymbol{RC_{xi,tmol,t}}) + && \textit{(Conversion and reconversion costs)} \\
& \sum_{(\boldsymbol{xe,xi,t}) \in (\boldsymbol{XE,XI,T})} (\boldsymbol{LC_{xe,t}} + \boldsymbol{UC_{xi,t}}) + && \textit{(Terminal loading and unloading costs)} \\
& \sum_{(\boldsymbol{trans,ts,tm,t}) \in (\boldsymbol{TRANS,TS,T})} \boldsymbol{TC_{trans,ts,tm,t}} + && \textit{(Transport costs)} \\
& \sum_{\boldsymbol{xi,t} \in (\boldsymbol{XI,T})} \boldsymbol{NSDP_{xi,t}} \} && \textit{(Non-served demand penalty)}
\end{aligned}
$$

Symbols

$tech$	Set of production technologies
$trans$	Set of transport alternatives
xp	Set of production locations
t	Set of time steps
xe	Set of export points
xi	Set of import points
$tmod$	Set of transport modalities
$tmol$	Set of transport molecule
ts	Set of transport segments

The cost-minimization is performed in a country-neutral and technology neutral way. hydrogen production costs are calculated based on the time and location specific considerations (i.e. renewable potential, natural gas prices, land availability, WACC, etc) to compute the LCOH for the different production technologies considered. The countries under the scope are covered with a grid of 2.5 degrees from which centroids are defined to calculate the location specific LCOH of renewable hydrogen. Low-

carbon hydrogen from natural gas and biomass are assumed to be produced nearby consumption and/or export sites within the exporting countries. The time availability of infrastructure for handling hydrogen (i.e., new hydrogen pipelines, natural gas pipelines reconverted to hydrogen and hydrogen terminals) are assumptions to the model which costs are integrated in the optimization. Further details are available in ref. [30].

A.4 Technical assumptions

Technological data regarding hydrogen production technologies used in the model are described and detailed in the table below.

Table 6 : Hydrogen production technologies – Technological Data

Technology	Size [MW]	Fuel Efficiency [PJ/PJ$_{H2}$] (LHV)				Life			Source
		Fuel	2020	2030	2050	2020	2030	2050	
Coal gasification, large size, centralized	1667	Coal	1.67	1.67	1.67	25	25	25	6, 9, 10
Coal gasification, medium size, centralized	434	Coal	1.67	1.67	1.67	25	25	25	6, 9, 10
Coal gasification + CO_2 capture, large size, centralized	1667	Coal	1.72	1.72	1.72	25	25	25	6, 9, 10
Coal gasification + CO_2 capture, medium size, centralized	442	Coal	1.72	1.72	1.72	25	25	25	6, 9, 10
Biomass gasification, small size, decentralized	0.7	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9, 10
		Grid electricity	0.03	0.03	0.03				
Biomass gasification, medium size, centralized	33	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9, 10
		Grid electricity	0.03	0.03	0.03				
Biomass gasification + CO_2 capture, medium size, centralized	33	Biomass	2.10	2.10	2.10	25	25	25	6, 8, 9
		Grid electricity	0.03	0.03	0.03				
SMR, large size, centralized	1530	Natural gas	1.32	1.32	1.32	25	25	25	1, 9
		Grid electricity	-0.02	-0.02	-0.02				
SMR, medium size, decentralized	2	Natural gas	1.36	1.27	1.27	25	25	25	6, 8, 10
		Grid electricity	0.25	0.07	0.07				
SMR + CO_2 capture, large size, centralized	1502	Natural gas	1.385	1.385	1.385	25	25	25	1, 8, 9
		Grid electricity	0.015	0.015	0.015				
ATR + CO_2 capture, large size, centralized	1260	Natural gas	1.36	1.36	1.36	25	25	25	8, 9
		Grid electricity	0.04	0.04	0.04				
GHR + ATR + CO_2 capture, large size, centralized	1260	Natural gas	1.28	1.20	1.20	25	25	25	8, 9
		Grid electricity	0.06	0.05	0.05				
Ethanol steam reforming, decentralized	0.01	Ethanol	1.47	1.47	1.47	10	10	10	6
		Grid electricity	0.08	0.08	0.08				

PEM electrolyzer	NA[35]	Grid electricity	1.60	1.55		6[36]	7	9	2, 3, 7, 9, 10
Alkaline electrolyzer, large size, centralized	72	Grid electricity	1.55	1.45		20	20	20	2, 3, 7, 9, 10
Alkaline electrolyzer, wind off grid, centralized	NA[35]	Wind off grid	1.55	1.45		30	30	30	2, 3, 7, 9, 10
Alkaline electrolyzer, PV off grid, centralized	NA[35]	PV off grid	1.55	1.45		30	30	30	2, 3, 7, 9, 10
PEM electrolyzer, offshore, centralized	NA[35]	Wind offshore	1.5			20	20	20	2, 3, 7, 9, 10
Alkaline electrolyzer, small size, decentralized	0,6	Grid electricity	1.55	1.45		20	20	20	2, 3, 7, 9, 10
Very High Temperature Reactor CHP, centralized	600	Uranium		1.5			60	60	6, 10
Kvaerner process, centralized	19	Natural gas	1.75	1.75	1.75	25	25	25	6
		Grid electricity	0.35	0.35	0.35				
Molten media methane pyrolysis, large size	420	Natural gas	2.05	2.05	2.05	20	20	20	11
Non-catalytic methane pyrolysis, small size	2.8	Natural gas	2.50	2.50	2.50	20	20	20	12

Source :

1. IEA 2019: The Future of Hydrogen
2. Blanco H., Nijs W., Ruf J., Faaij A., 2018a, Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization, Applied Energy 232, pp. 617-639
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[35] No reference size for costs provided. However, it is expected that the sizes are in the range between *Alkaline electrolyzer large size* and *Alkaline electrolyzer small size*, that is between 0.6 MW and 72 MW.

[36] The lifetime in *PEM electrolyser* are increasing due to R&D. Direct application in offshore parks has a higher lifetime due to the lower capacity factor and may be limited by the lifetime of the offshore wind turbines.