HyUSPRe

Hydrogen **U**nderground **S**torage in **P**orous **Re**servoirs

Report on H2 supply from Renewable Energy Sources, H2 demand centers and H2 transport infrastructure

Prepared by: Theresa Groß[1], Philipp Dunkel[1] (eds.),
David Franzmann[1],
Heidi Heinrichs[1],
Jochen Linßen[1],
Detlef Stolten[1,2]

[1]Institute of Energy and Climate Research - Techno-economic Systems Analysis (IEK-3), Forschungszentrum Jülich GmbH, 52428 Jülich, Germany

[2]Chair for Fuel Cells, RWTH Aachen University, c/o Institute of Energy and Climate Research (IEK-3), Forschungszentrum Jülich GmbH, 52428 Jülich, Germany

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Executive summary

The HyUSPRe project includes the mapping of potential sites of hydrogen generation, transport, and usage. In a later stage of the project, these determined spatially resolved potentials of hydrogen supply and demand in European countries will be used as input parameters for the techno-economic assessment of a future European hydrogen system.

Within this report, an assessment of wind and photovoltaic potentials in Europe is performed to determine the amount of hydrogen that can be produced in Europe. This analysis shows that about 67 PWh_{H2} can be produced annually by renewable energy sources in Europe. In addition, the potential for hydrogen import from other non-European countries and the corresponding import cost curves for different import ports in Europe are determined. Here, values for import costs between 8.5 $€_{ct}/kWh_{H2}$ to 9.8 $€_{ct}/kWh_{H2}$ are obtained.

The second part of the report describes future hydrogen demand scenarios for Europe to reduce greenhouse gas emissions in industry and transport sector. Three different demand scenarios are developed for the short- and long-term future. For the long-term future, hydrogen demand between 3,000 and 5,000 TWh_{H2}/a are observed, depending on the market shares of the different industrial process routes and transport modes considered.

In the last part, options for the setup of a hydrogen transport infrastructure are evaluated. Hydrogen pipelines are considered as the main technology for the transmission infrastructure. Both the installation of new pipelines and the reassignment of existing gas infrastructure shall be considered in future energy systems assessment. According to the literature, new pipelines can be built next to existing natural gas pipelines, roads, or railways. This results in a candidate grid used to determine the shortest routes between hydrogen demand, supply and storage which will be used in the energy system modelling conducted in HyUSPRe.

About HyUSPRe

Hydrogen **U**nderground **S**torage in **P**orous **Re**servoirs

The HyUSPRe project researches the feasibility and potential of implementing large-scale storage of renewable hydrogen in porous reservoirs in Europe. This includes the identification of suitable geological reservoirs for hydrogen storage in Europe and an assessment of the feasibility of implementing large-scale storage in these reservoirs technologically and economically towards 2050. The project will address specific technical issues and risks regarding storage in porous reservoirs and conduct an economic analysis to facilitate the decision-making process regarding the development of a portfolio of potential field pilots. A techno-economic assessment, accompanied by environmental, social and regulatory perspectives on implementation will allow for the development of a roadmap for widespread hydrogen storage towards 2050, indicating the role of large-scale hydrogen storage in achieving a zero-emissions energy system in EU by 2050.

This project has two specific objectives. Objective 1 concerns the assessment of the technical feasibility, risks, and potential of large-scale underground hydrogen storage in porous reservoirs in Europe. HyUSPRe will establish the important geochemical, microbiological, flow and transport processes in porous reservoirs in the presence of hydrogen via a combination of laboratory-scale experiments and integrated modelling, establish more accurate cost estimates and identify the potential business case for hydrogen storage in porous reservoirs. Suitable stores will be identified, and their hydrogen storage potential will be assessed. Objective 2 concerns the development of a roadmap for the deployment of geological hydrogen storage up to 2050. The proximity of hydrogen stores to large renewable energy infrastructure and the amount of renewable energy that can be buffered versus time varying demands will be evaluated. This will form the basis to develop future scenario roadmaps and prepare for demonstrations.

Abbreviations

API ..... *Application programming interface*
BEV ..... *Battery Electric Vehicle*
BF ..... *Blast furnace*
BOF ..... *Basic oxygen furnace*
BTX ..... *Benzene, Toluene, Xylene*
CCS ..... *Carbon dioxide capture and storage*
CH3OH ..... *Methanol*
CO ..... *Carbon monooxide*
CO2 ..... *Carbon dioxide*
EAF ..... *Electric arc furnace*
EHB ..... *Initiative European Hydrogen Backbone*
EPRTR ..... *European Pollutant Release and Transfer Register*
ETS ..... *European Union Emission Trading System*
EU ..... *European Union*
EUTL ..... *European Transaction Log*
FCEV ..... *Fuel cell electric vehicle*
FCHO ..... *Fuel Cell Hydrogen Observatory*
FLH ..... *Full load hour*
FT ..... *Fisher-Tropsch*
GHG ..... *Greenhouse gas*
GLAES ..... *Geospatial Land Availability for Energy Systems*
H2 ..... *Hydrogen*
H2-DRI ..... *Hydrogen Direct Reduced Iron*
HVC ..... *High value chemicals*
IEA ..... *International Energy Agency*
JRC ..... *Joint Research Centre*
LCOE ..... *Levelized cost of electricity*
LCOH ..... *Levelized cost of hydrogen*
LH2 ..... *Liquid hydrogen*
LNG ..... *Liquefied natural gas*
LOHC ..... *Liquid Organic Hydrogen Carrier*
LPG ..... *Liquefied petroleum gas*
MTA ..... *Methanol-to-Aromatics*
MTBE ..... Methyl tert-butyl ether
MTG ..... *Methanol-to-Gasoline*
MTO ..... *Methanol-to-Olefins*
NH3 ..... *Ammonia*
NUTS ..... *Nomenclature des unités territoriales statistiques*
PtX ..... *Power-to-X*
PV ..... *Photovoltaics*
RES ..... *Renewable energy source*
SAF ..... Sustainable aviation fuels
SMR ..... *Steam-Methane-Reforming*
TRL ..... *Technology readiness level*

Table of Content

1 Introduction

To highlight the role of large-scale hydrogen storage in achieving a zero-emissions energy system in the EU by 2050, this report maps potential sites of hydrogen generation from renewable energy sources and also hydrogen demand centers in Europe. The results will be integrated into a European energy system model for the assessment of zero-emission energy systems in the future (WP7).

First, an assessment of wind and photovoltaic potentials in Europe is performed to determine the amount of hydrogen that can be produced in Europe. Furthermore, the potential for hydrogen import from other non-European countries and the corresponding import cost curves for different import ports in Europe are determined.
In addition to the hydrogen supply, the future hydrogen demand for Europe is also analyzed, especially regarding the decarbonization of the industry and transport sectors in the European energy system.

In the last step, options for the setup of a hydrogen transport infrastructure are evaluated. Hydrogen pipelines are considered as the main technology for the transmission infrastructure. Both the laying of new pipelines and the reassignment of existing gas infrastructure will be considered in future energy systems assessment. Thus, a candidate grid for the routing of new hydrogen pipelines is presented.

1.1 Temporal and geographical scope

The presented investigation of potential hydrogen supply and demand centers in Europe covers the 27 countries of the European Union EU as well as the United Kingdom, Norway, Switzerland, Albania, Liechtenstein, North Macedonia, Montenegro and Serbia. This limitation is done due to limited data availability and data quality for other European countries. To determine the hydrogen demand potential in Europe, the analysis is performed for the short- and long-term future. The years 2030 and 2050 are chosen to be representative.

The analyses are done for the regions defined in the so-called NUTS-2021 (Nomenclature des Unités Territoriales Statistiques) classification (for more information about NUTS, see [1]). In total, 298 regions are considered in the analyses. In addition, 63 offshore regions are considered to assess the potential for electricity generation by offshore wind turbines.

2 Hydrogen supply in Europe

There are two options for hydrogen supply in European hydrogen systems to match possible future hydrogen demand: First, hydrogen can be produced within European countries. Second, hydrogen can be imported from non-European countries. To reach the greenhouse gas emission reduction targets, the hydrogen generation should be based on renewable energy sources that are described as zero emission electricity generation technologies. Hydrogen generation pathways producing carbon or carbon dioxide as a by-product that must be utilized or stored are not considered in this study – either for the domestic hydrogen generation, or for the hydrogen import potential.

2.1 Hydrogen supply from renewable energy sources

Within this report, only the potential of domestic hydrogen supply from renewable energy sources (RES) in the considered regions in Europe is investigated. That means that the electricity required for hydrogen generation via water electrolysis must be supplied by renewable energy sources, e. g. wind turbines and photovoltaics (PV). Firstly, the relevant technologies and the methodology to obtain the potential for renewable electricity generation are described. Based on these estimated spatially resolved renewable energy supplies, the hydrogen generation potential and resulting costs for the generated hydrogen are determined.

2.1.1 Methodology

This report focuses on three main renewable energy sources that offer large future expansion capacity in Europe. Considered renewable energy sources are onshore wind turbines, offshore wind turbines and open-field photovoltaics.

To obtain the potential of renewable energy generation from the three sources above, two main steps are undertaken:
In a first steps possible locations of future RES are determined using the open-source toolkit Geospatial Land Availability for Energy Systems (GLAES) [2]. GLAES enables the identification of eligible locations by excluding land areas from the usage by RES. These exclusion criteria may include sociopolitical, physical, conservational, and economic constraints. Water bodies, natural habitats, urban settlements, or airports, for example, are areas that are not available for RES installation. These areas are excluded from the available land area for RES. In this way, all areas eligible for RES can be identified.
In a next step, wind turbines or PV modules can be placed inside the eligible area considering an exogenously defined distance between each wind turbine or PV module.
A list of possible exclusion criteria for land eligibility analyses can be found in Ryberg et al. [2].

In the next step, the energy generation for each of these placements is individually calculated employing the open-source Renewable Energy Simulation toolkit (RESKit) [3]. Based on the RES placement, the technical details of the RES and weather data, the hourly generation of electricity at the specific location is calculated. Based on that, the production costs of electricity for each placement are determined, identifying preferential locations for RES. Production costs of electricity are calculated as the levelized cost of electricity (LCOE).
A more detailed description of the used methodology for estimating RES potentials can be found in the studies of Ryberg et al. [2], Ryberg [4] and Caglayan et al. [5]. The described results in this report are also based on those previous studies, using the same exclusion criteria for land eligibility analyses, turbine and PV module designs, as well as weather data to calculate generation curves for the considered regions in Europe.

To calculate hydrogen generation potentials, we assume hydrogen generation at the location of electricity generation. Hydrogen generation is performed via electrolysis. The electrolyzer is assumed to have the same full load hours (FLH) as the RES, i.e., all generated electricity is used to generate hydrogen. This assumption allows the estimation of an upper bound for hydrogen generation. Based on the additional costs and conversion losses for the electrolysis, the levelized cost of hydrogen (LCOH) and the hydrogen generation potential at each location are calculated.

2.1.2 Hydrogen generation potential and costs

Hydrogen is generated from renewable energy sources via electrolysis. Techno-economic assumptions for each technology are listed in Table 1, based on assumptions from [3], [5]–[7], and are used to calculate LCOH. All cost assumptions are based on projections for long-term future. The capital cost for wind turbines is given for reference turbines. Based on the methods described by Ryberg et al. [3] and Caglayan et al. [5], optimal turbine designs are determined for each turbine placement, resulting in different capital costs for each location.

Table 1. Techno-economic parameters for the considered technologies to calculate LCOH (based on techno-economic assumptions for reference turbines and PV modules from [3,5-7]).

Name	Capital Cost [€/kW]	Annual Operating Cost [% Capital Cost]	Economic Lifetime [years]	Interest Rate [%]	Efficiency [%]
Onshore Turbine	1100	2	20	8	-
Offshore Turbine	2300	2	20	8	-
Open-field PV	520	1.7	25	8	-
Electrolyzer	500	3	10	8	70

Figure 1 shows the results of hydrogen generation potential by country:
United Kingdom, Norway and Ireland have the highest hydrogen generation potential based on offshore wind electricity generation.
Spain, France, Italy, and Portugal have the highest hydrogen generation potential for open-field PV electricity generation due to the higher solar insolation in the southern European countries.
Sweden, Finland, and France show the highest hydrogen generation potential based on onshore wind electricity generation. The total hydrogen generation potential is about 67 PWh_{H2}/a based on electricity generation by RES. Compared to the estimated future hydrogen demand of about maximum 5 PWh/a (cf. section 3.4.2), Europe is able to supply future demand without the urgent need for hydrogen import.

In the following sections, the hydrogen generation potential is described for the three different RES.

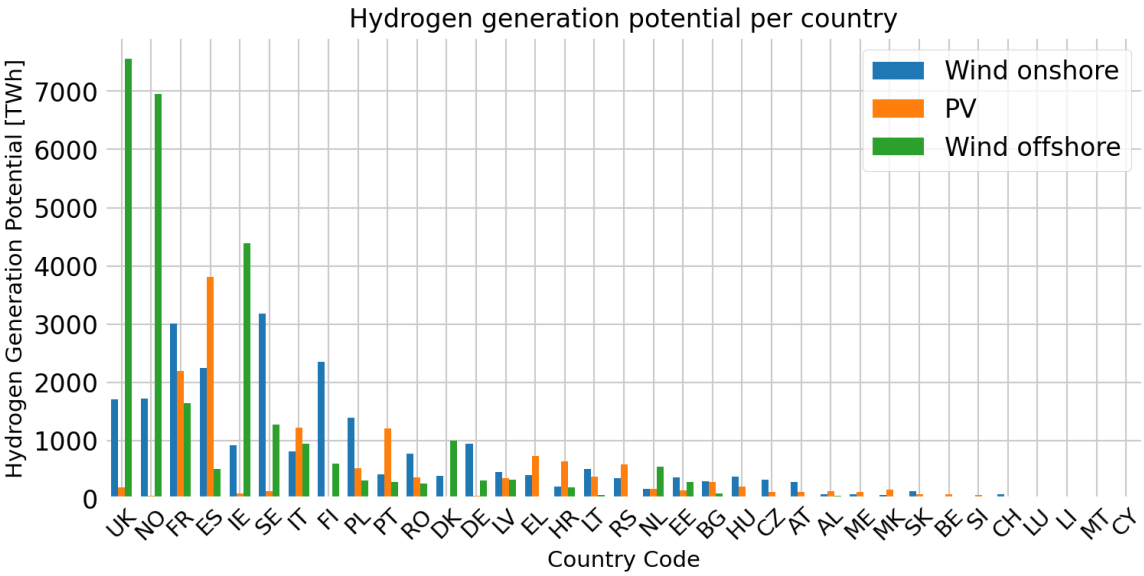

Figure 1. Hydrogen generation potential per country per technology.

Onshore wind turbines

Figure 2 shows the hydrogen generation potential based on electricity generated by onshore wind turbines for each considered NUTS-2 region in Europe. In total, about 24 PWh/a of hydrogen can be produced if all eligible locations for onshore wind turbines are exhausted (cf. [3]). Regions with a large land surface area, e.g., NUTS-2 regions in Sweden and Finland, show the highest hydrogen generation potential. Highest values for wind onshore potentials are in France, Sweden, Finland, and Spain (cf. Figure 1).

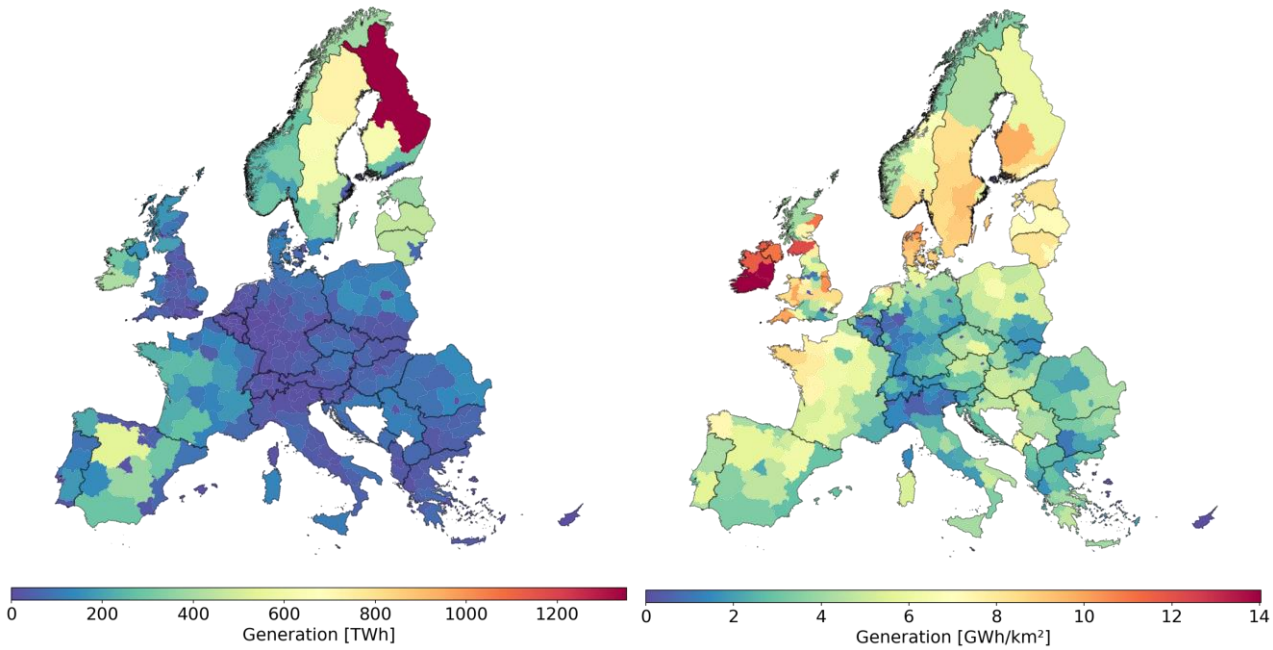

Figure 2. Maximum Onshore Hydrogen Generation Potential shown for NUTS-2 regions (in total: 24.2 PWh_{H2}/a). Left, total generation of each region is shown. Right, generation per area of each region is shown.

The hydrogen generation potential based on electricity provided by onshore wind turbines is highly correlated to weather conditions, especially wind velocities. Therefore, the northern countries and countries with a high share of coastal areas on the North Sea have a higher potential for onshore wind electricity generation.
Those areas also have low LCOH in a range of about 5 to 8 $€_{ct}/kWh_{H2}$ as it is shown in Figure 3. Regions with less hydrogen generation potential, e.g. Austria and Switzerland, also have higher LCOH with more than 10 $€_{ct}/kWh_{H2}$. On the right side of Figure 3, most of hydrogen generation potential is allocated to LCOH between 6.5 and 8.5 $€_{ct}/kWh_{H2}$. These estimated LCOH are just only in the case that electrolyzers are placed on-site and all generated electricity is used for hydrogen generation so that no electricity transmission infrastructure is necessary.

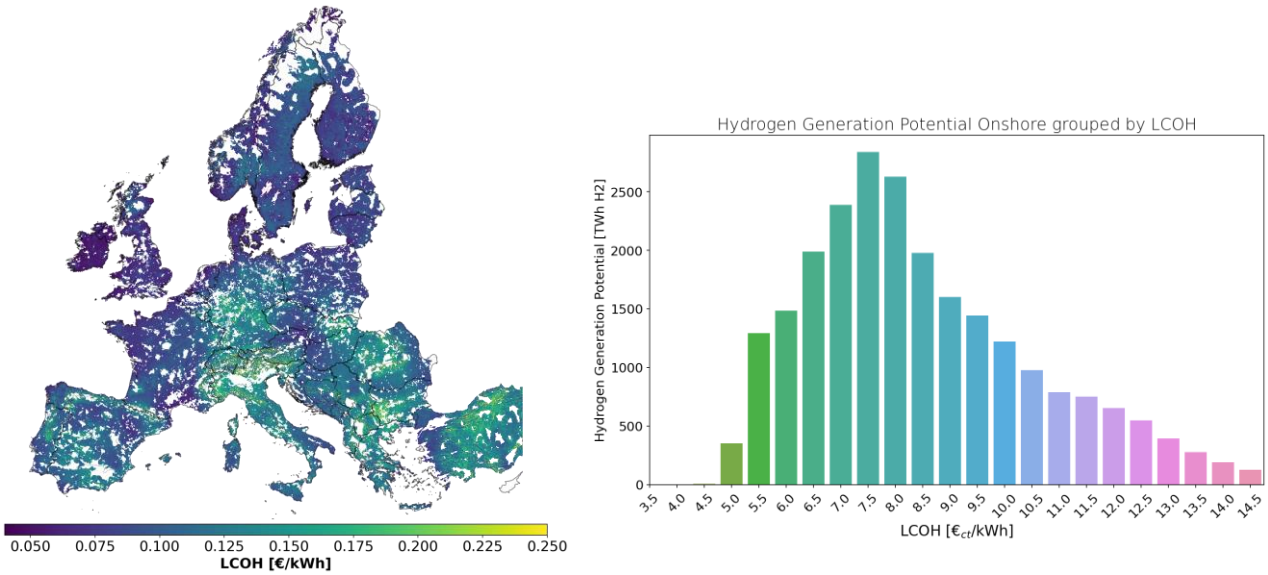

Figure 3. Estimated LCOH for onshore wind turbines. Left, spatially resolved distribution of LCOH (areas without turbine placements are shown in white). Right, hydrogen generation potential grouped by estimated LCOH.

Offshore wind turbines

Offshore turbines are located near coasts of the studied European regions. The assessment of hydrogen generation potential has been done for 63 additional offshore regions. The offshore regions are assigned to the land regions with connected shores. The highest hydrogen generation potential is in the North Sea area as shown in Figure 4. In total, 28 PWh_{H2} can be generated by offshore wind power.

Due to the higher investment costs for installation of offshore wind turbines, LCOH ranges from 7 to more than 10 $€_{ct}/kWh_{H2}$. So, the costs for offshore hydrogen generation are slightly higher than onshore. The North Sea regions show the lowest LCOH as can be seen in Figure 5. Hereby, LCOE increases with the distance to coast due to the fact that cost-optimal turbine design and foundations change with higher water depths (cf. [5]). The offshore regions in the Mediterranean Sea show higher LCOH up to values of 20 $€_{ct}/kWh_{H2}$.

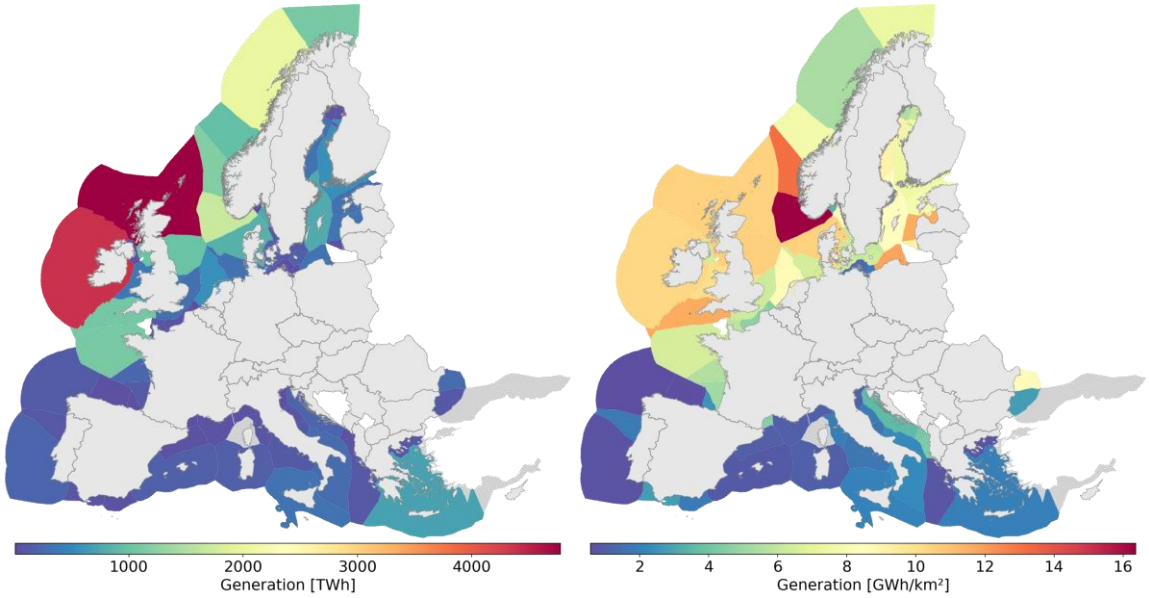

Figure 4. Maximum Offshore Hydrogen Generation Potential for 63 offshore regions (in total: 28.5 PWh_{H2}/a). Left, total generation of each offshore region is shown. Right, generation per area of each region is shown.

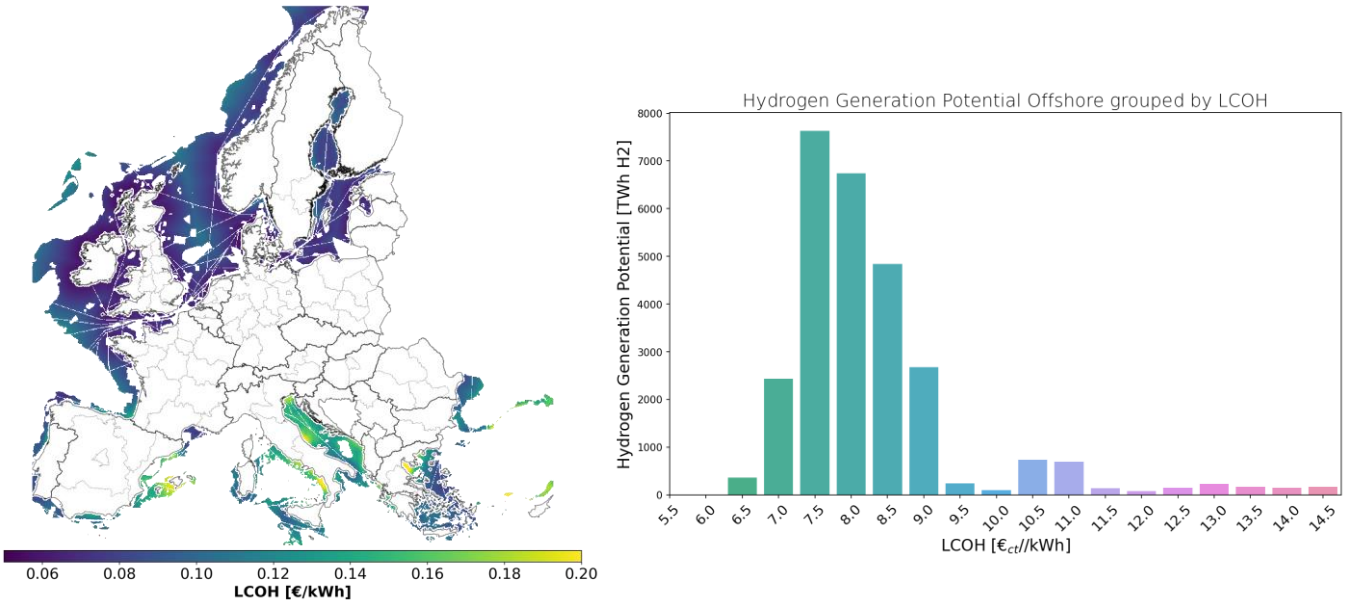

Figure 5. Estimated LCOH for offshore wind turbines. Left, spatially resolved distribution of LCOH (areas without turbine placements are shown in white). Right, hydrogen generation potential grouped by estimated LCOH.

Open-field Photovoltaics

As third RES, open-field PV modules are considered for European hydrogen generation potential. The methodology for determining the PV potential is described in Ryberg [4]. For validation purposes, the global solar atlas [8] is used which provides solar potentials up to a latitude of 60°. Due to a lack of validation data for latitudes above 60°, PV potential is not determined for regions in Northern Europe, in agreement with Caglayan [9].
Figure 6 shows the hydrogen generation potential based on solar power for the NUTS-2 regions in Europe. In total, about 14 PWh_{H2} can be anually generated by the determined open-field PV potential. This potential is lower than the wind-based hydrogen generation potential due to the diurnal fluctuation of solar power generation. Spain has the highest potential for hydrogen generation based on open-field PV followed by France. In general, Southern regions have higher solar potential than Northern regions resulting also in lower LCOH for hydrogen generation. LCOH ranges from 7 to 15 $€_{ct}/kWh_{H2}$ as can be seen in Figure 7.

Based on the results by Ryberg [4], the total open-field PV capacity in Germany is c. 54 GW. That´s because road- and rail-side areas are not considered for the placement of open-field PV parks. If those areas are also considered for the placement, the maximum capacity of open-field PV in Germany would increase to about 250 GW, so that hydrogen generation potential in Germany also increases. For the hydrogen generation potential analyses in this report, the chosen constraints for land eligibility determination are the same for all studied countries. Therefore, the calculated hydrogen generation potential based on solar power can be seen as a lower bound.

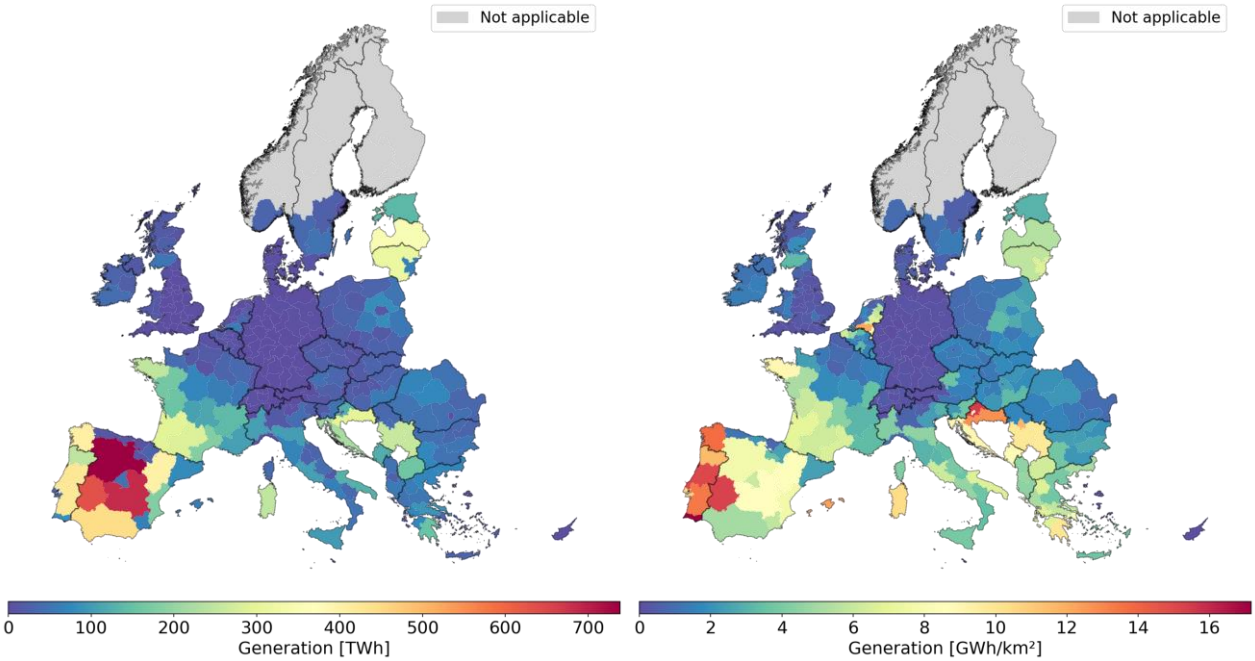

Figure 6. Maximum PV Hydrogen Generation Potential (in total: 14.3 PWh_{H2}/a). Left, total generation of each region is shown. Right, generation per area of each region is shown. Due to a lack data, regions with a latitude above 60° are not considered.

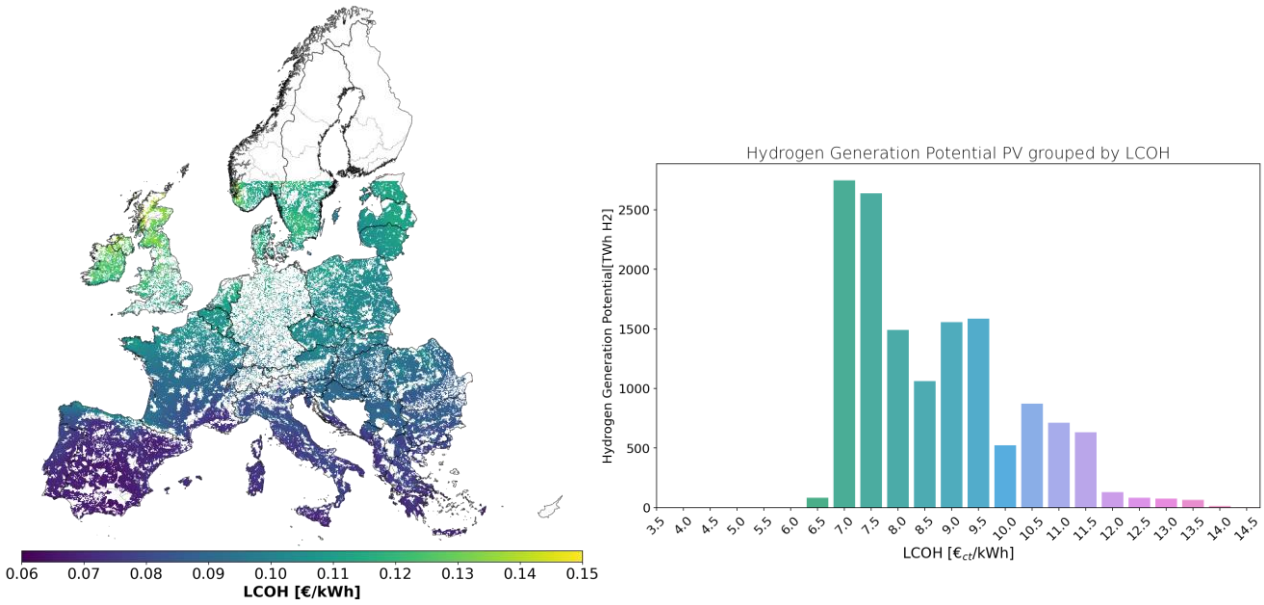

Figure 7. Estimated LCOH for open-field PV. Left, spatially resolved distribution of LCOH (areas without PV placements are shown in white). Right, hydrogen generation potential grouped by estimated LCOH. Due to a lack data, regions with a latitude above 60° are not considered.

2.2 Hydrogen import potential

The possibility of producing hydrogen from renewable energy sources in industrialized nations such as the European ones are limited. Although the determined hydrogen generation potentials are higher than the estimated demand, it might be necessary to import hydrogen from other parts of the world to cover the future hydrogen demand in Europe. In regions with high solar radiation, e.g., Libya, and high amounts of wind, e.g., Patagonia, hydrogen can be cheaply produced and transported to Europe.

2.2.1 Methodology

To assess the hydrogen import potentials and the resulting costs of hydrogen, a model developed at the Institute of Energy and Climate Research - Techno-economic Systems Analysis (IEK-3, Forschungszentrum Jülich) is used [2,3]. This model analyzes the generation potential of hydrogen based on renewable energy in preferential regions and develops a worldwide hydrogen supply infrastructure via shipping under economic considerations. Potential pipeline transport from African countries is not considered.

The model considers the whole supply chain of hydrogen, starting from energy generation and ending with supply at the destination port in the demand region (cf. Figure 8). The supply chain starts with the electricity generation from renewable energy sources in the preferential regions. This is followed by the domestic supply chain, considering the transmission of electricity, production of hydrogen, pipeline transport in the region to refining and storage facilities, and refining and storage needs. Afterwards the shipping to demand regions is modeled. The final price of imported hydrogen is calculated by considering all the costs of the entire supply chain infrastructure.

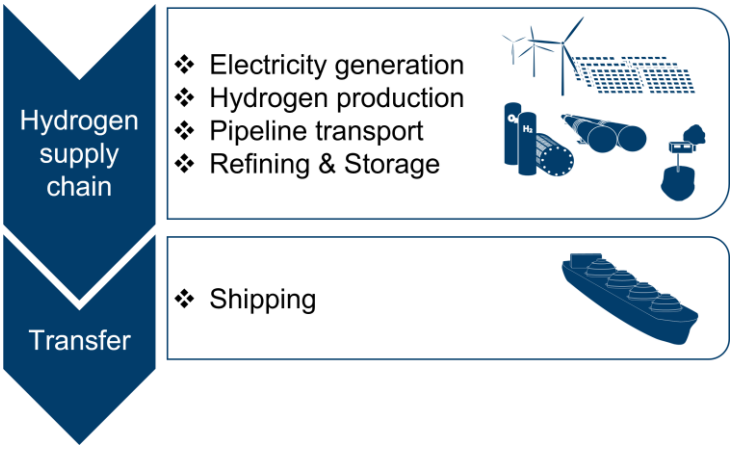

Figure 8. Considered supply chain for costs of hydrogen import.

Hydrogen supply chain at preferential regions

Heuser [3] selected preferential regions based on regions with high wind potential using mean wind speeds and based on regions with high solar radiation. Tropical and subtropical zones and arid to semi-arid regions were found to be preferential for generating renewable energy using PV, e. g. Namibia, Libya, and Egypt. Areas with high wind potentials are regions in the south of South America and the west coast of Canada as well as Iceland. Preferential regions that are considered in the model are listed in the appendix (cf. Table A1). For these preferential regions, the generation potentials for renewable energy sources are calculated. The generation potentials of renewable energy are assessed using the same workflow as described in section 2.1. A first step involves the determination of land availability for the placement of renewable energy sources with the tool Glaes [2]. In the next step, the energy generation from the renewable energy sources is calculated with the tool RESKit considering weather data [3]. The model assumes the exclusive usage of renewable energy generation for hydrogen production.

The first step of the inland supply chain involves hydrogen production at wind and PV parks via electrolysis. Electrolysis sites are located within park centers. Electrolyzer capacity is determined by a cost optimum. Inland transport of hydrogen is modeled via pipeline transport. Pipeline routes and capacities are determined with the goal of minimizing the total cost of the system. For each preferential region, one port is defined where all the hydrogen is transported to. Before pipeline transport, hydrogen is compressed. Recompressing stations for pipeline transport are considered as well. At the port, Hydrogen conditioning is necessary to change the aggregate state of the hydrogen for storage and ship transport. Hydrogen is stored at the port either in a liquid state as liquid hydrogen (LH2) or chemically bound within a liquid organic hydrogen carries (LOHC).

Transfer of hydrogen

Since the transport of LOHC was found to be more expensive, the shipping is solely conducted via LH2 tankers powered with hydrogen. The price of overseas transport is calculated based on the shipping distance.

The total price of imported hydrogen at the demand region is then the cumulated investment and operational costs of the whole hydrogen supply chain. The underlying model depicts a worldwide hydrogen supply infrastructure. Hydrogen generated in the preferential regions is distributed to meet worldwide demand. The distribution is carried out based on a cost-optimized coverage of the estimated demand.

For this report, the global hydrogen demand for 2050 is estimated using two methodologies. For Europe, the methodology presented in section 0 of this report is used. The hydrogen demand of the rest of the world is estimated only approximately. Following the scope of section 0, the hydrogen demand in the rest of the world in the sectors industry and transport is considered. For the industry sector, the current natural gas demand in each country is collected from data from the United Nations [12]. The current natural gas demand is then scaled to 2050 based on the energy demand from IEA´s World Energy Outlook 2021(International Energy Agency, 2021). To obtain a hydrogen demand for the industry sector per country, it is then assumed that all the natural gas demand is replaced by hydrogen. Transport demand projections for each country in the world are taken from the study by Khalili et al. [13]. Hydrogen demand in the transport sector in 2050 is then estimated by assuming a 100% market penetration of fuel cell electric vehicles (FCEV). Due to a lack of data, other transportation modes are not considered.

The hydrogen demand per country is afterward aggregated to six world regions (Africa, Asia Pacific, Central and South America, Eurasia, Middle East, and North America) following the definition of the IEA. For each of these world regions, one or multiple ports were defined where hydrogen can be imported. In case of multiple ports, the port selection for each region is based on the minimum shipping distance from the preferential region. For Europe, hydrogen imported is enabled at four different ports. These ports were selected based on the availability of liquefied natural gas (LNG) terminals. The selected ports are Barcelona (Spain), Huelva (Spain), Revithoussa (Greece), and Rotterdam (Netherlands). The European hydrogen demand is distributed to these ports based on the current and planned LNG terminal capacities.

In the last step, the model distributes the hydrogen generated in the preferential regions based on the defined demand in a cost-optimized fashion. Model outputs are the hydrogen import costs at the import port and the respective origins of the imported hydrogen.

2.2.2 Import potential and costs

The estimated global hydrogen demand for 2050, excluding Europe, is calculated to 15,993 TWh (533 Mt H2). This demand is assumed to be fixed. Based on this, model runs with different European hydrogen demands are conducted, resulting in hydrogen import cost curves at the four considered import ports. Most of the hydrogen demand is covered by regions where PV could be built, namely regions in Northern Africa (Libya, Morocco, Namibia, Egypt) and the Middle East (Saudi Arabia). Iceland is the only region that exports hydrogen generated by wind turbines. The import routes and corresponding preferential regions are shown in Figure 9.

The hydrogen import costs at the four considered European ports for different total European hydrogen demands are given in Figure 10. Depending on the import port and total European hydrogen demand that has to be covered by imports, hydrogen import costs range from 8.5 $€_{ct}$/kWh to 9.8 $€_{ct}$/kWh.
The origins and shares of hydrogen arriving at the import ports are illustrated in Figure 11. Here, for 9 different total hydrogen demands, shown at the bottom of each bar, the origins of hydrogen at each port are shown. For Rotterdam, for example, hydrogen is imported from multiple preferential regions. For an increasing total hydrogen demand, the number of regions increases even more.

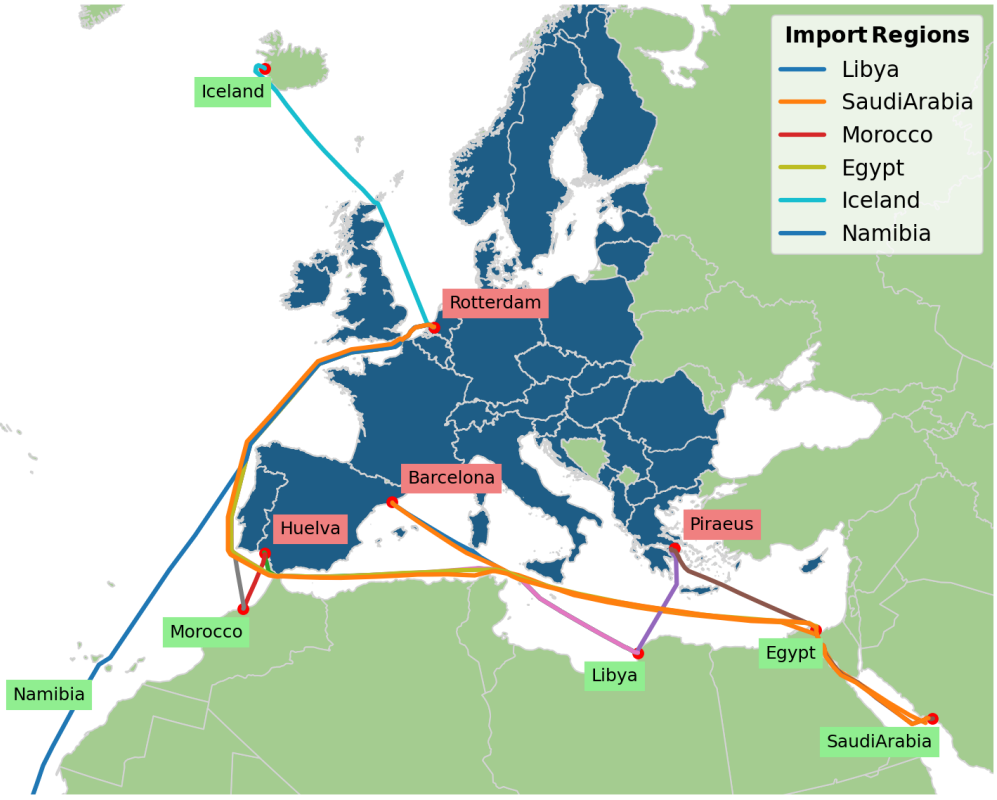

Figure 9. Import routes of hydrogen from preferential regions.

Two factors are responsible for the increase or decrease in the hydrogen import costs shown in Figure 10:
Firstly, a change in the hydrogen import costs depending on the demand results from the fact that for higher demands, hydrogen must be imported from multiple preferential regions. As the hydrogen originating from different preferential regions has different costs, increases and decreases in the hydrogen import costs can be observed.

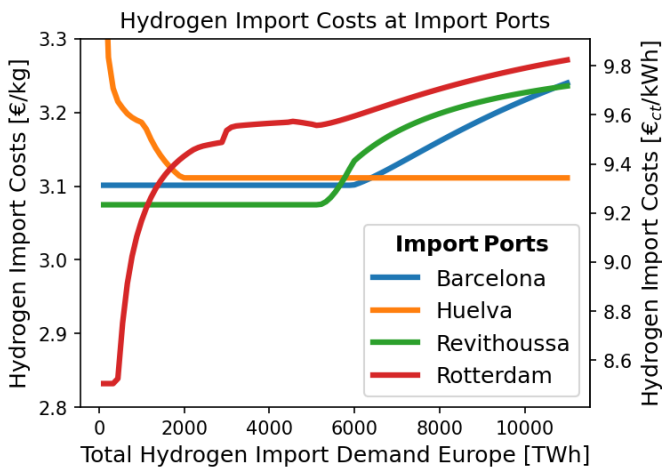

Figure 10. Hydrogen import cost curves at different European ports.

Secondly, higher demand leads to higher infrastructure-related costs in the preferential regions and, therefore, an increase in hydrogen import costs. The increase in infrastructure-related costs is mainly because at some point the most preferential PV placements that result in the lowest electricity price are depleted. Additional demand has then to be covered by less preferential PV placements leading to higher electricity costs and thus also to higher hydrogen import costs.

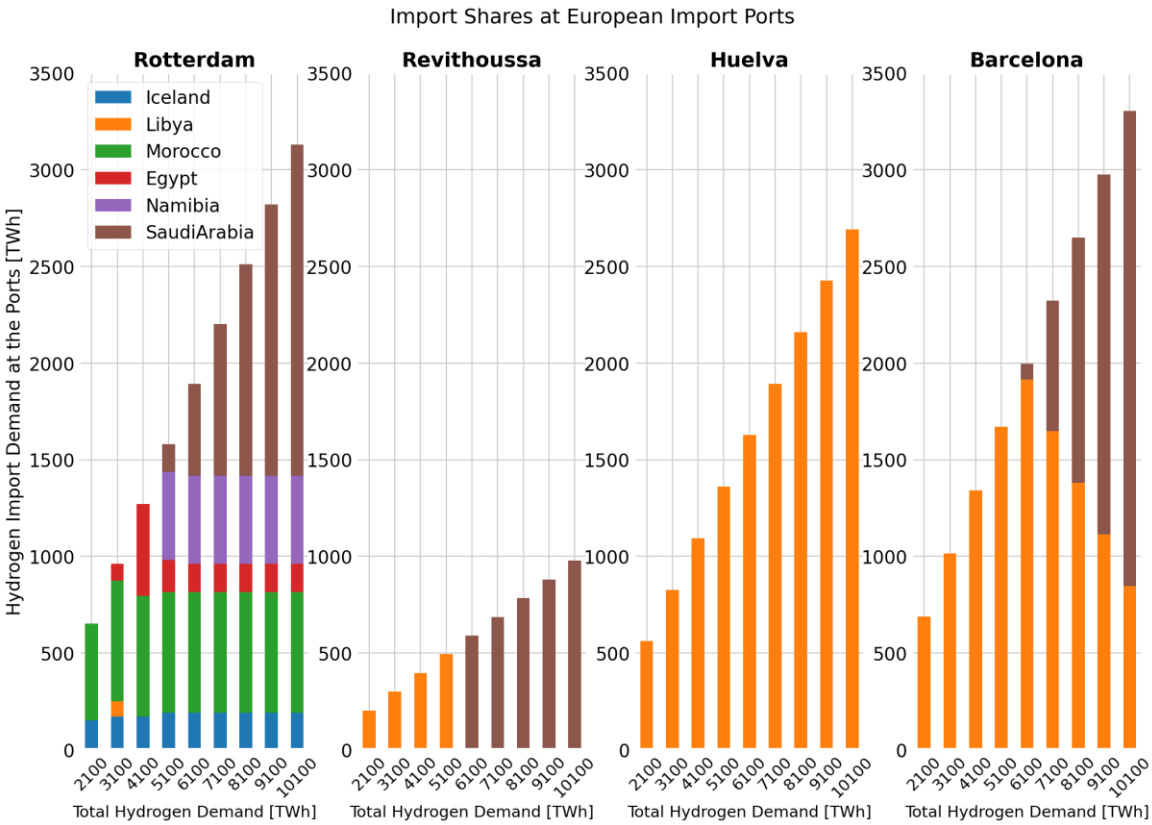

Figure 11. Import Shares at different total hydrogen import demands at the four European ports.

3 Hydrogen demand centers in Europe

Hydrogen is seen as key technology to achieve the EU´s Green Deal goals of greenhouse gas (GHG) neutrality until 2050 by the European Commission. Two main lead markets for hydrogen application are the industrial and the transport sectors. Industry and transport combined are responsible for almost half of all the EU-28 GHG emissions (see Figure 12), which totaled 4,134 Mt of $CO_{2\,\mathrm{eq}}$ in 2018 [14]. In the industry, hydrogen brings the opportunity to decarbonize carbon intensive industrial processes. Hydrogen also offers solutions for various hard to abate parts of the transport sector. These include applications for heavy-duty road transport, or to decarbonize aviation and the maritime sector. Furthermore, hydrogen can be used as an energy storage medium to balance the renewable energy-based electricity system of the future.

The hydrogen strategy of the European Commission envisions that in the phase from 2025 to 2030 local hydrogen demand centers will emerge in which the hydrogen demand will be based on decentralized production. The uptake of hydrogen demand will furthermore result in the need for an EU-wide infrastructure to transport hydrogen from areas with large renewable energy potential to demand centers across the EU. For the years from 2030 to 2050 the European Commission sees the utilization of hydrogen at large scale, especially for sectors which are hard to decarbonize [15].

This part of the report aims to identify the hydrogen demand centers that could arise across Europe up to 2050, resulting from the utilization of hydrogen in the industry and transport sector. Section 3.1 gives an overview of the current hydrogen demand in Europe, followed by the sections 3.2 and 0 which cover the potential use of hydrogen in the industry and transport sector, respectively. Hydrogen demand centers are assessed in three different scenarios and presented in section 3.4.

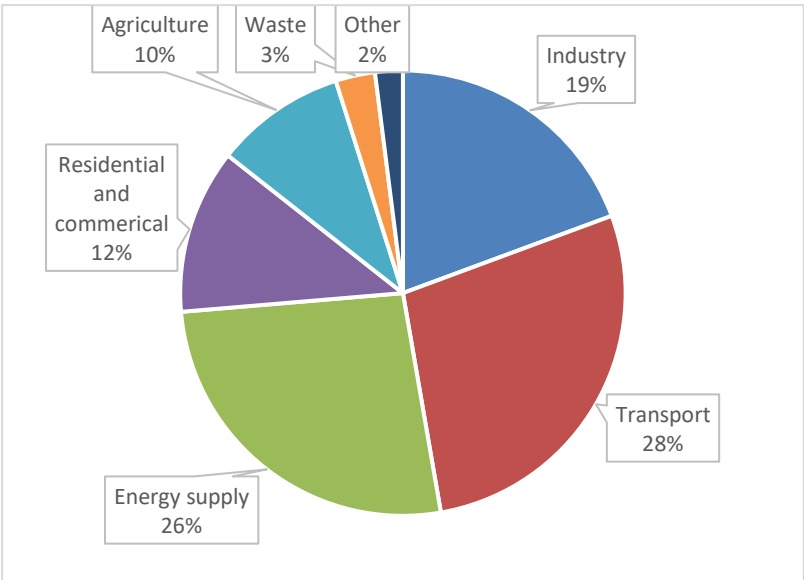

Figure 12. GHG emissions in EU-28 in 2018 (based on [14]).

3.1 Overview of current hydrogen usage

The total annual hydrogen production in Europe was estimated at 9.75 Mt (325 TWh) in 2007 [16]. Applications are mainly in refinery (47 %), ammonia (40%), and methanol (8%), where hydrogen is used as feedstock [17].
In Europe, 95% of EU hydrogen is produced by steam methane reforming (SMR) from natural gas. 64% of hydrogen is produced on-site, while 21% arises as a by-product and 15% is supplied by traders. [18]

The production of hydrogen via SMR is a carbon intensive method due to the use of (fossil) natural gas as feedstock. The CO_2 emissions from SMR hydrogen production are about 9 kg CO_2 /kg H2 [19]. Therefore, the hydrogen produced in Europe today can primarily be described as 'grey' hydrogen. Consequently, the current hydrogen production in Europe results in 88 Mt of CO_2 each year. Ammonia production results in 44 Mt of CO_2 emissions [20]. Other sources estimate 23.9 Mt of CO_2 emissions [21]. In the future, this grey hydrogen can be replaced by green hydrogen from renewable energy sources to reduce the emissions of the processes.

3.2 Potential for hydrogen usage in industry sector

The industry sector accounted for 19% (878 Mt CO_2 eq) of the EU's GHG emissions in 2018. Of that, 22% arises from the production of iron and steel, 19% from refineries, 8% for the production of petrochemicals, and 5% for fertilizer production [22]. Figure 13 shows the shares of industry GHG emissions in 2018.

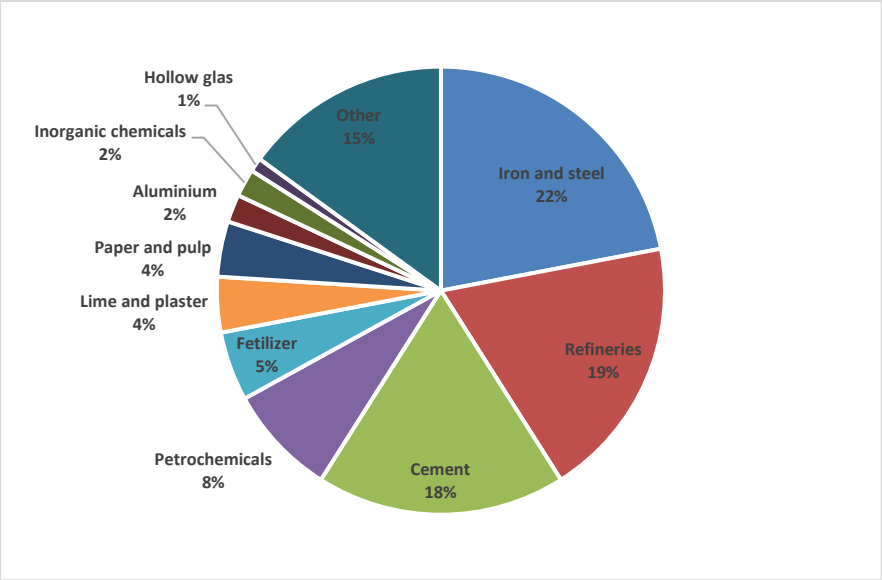

Figure 13. Industry GHG emissions in 2018 (based on [22]).

Material economics estimate that 46% of industry emissions (in steel, cement, plastics, and ammonia production) are process-related, while 54% are energy-related. Other sources estimate process emissions to be 21% [22]. Process-related emissions are due to the, e.g., use of coal in the reduction of iron ore, while energy-related emissions arise from electricity usage for heat and steam production.

Green hydrogen could play a significant role in decarbonizing the main carbon-intensive processes. Here, there are multiple ways to use green hydrogen: As a feedstock, green hydrogen can be used to replace grey hydrogen, or it can be used in novel processes replacing carbon intensive processes. Hydrogen can also be used to replace fossil fuels for heat production. The generation of high temperature process heat with natural gas can be substituted by hydrogen burners.

Green hydrogen can be used in the iron and steel sector, where conventional primary steel production can be substituted with steel produced via hydrogen-based direct reduction of iron (section 3.2.1). It can also be utilized in ammonia and methanol production and in refineries, where grey hydrogen can be replaced with green hydrogen. Novel processes with hydrogen application have been developed for the production of high value chemicals (HVC). HVC commonly refer to two groups of primary petrochemicals, olefins and aromatics. Olefins include ethylene, propylene and butadiene which are mainly used for plastics production such as polyethylene [23]. Aromatics are used as intermediates for a variety of chemical products. Hydrogen can also be used to produce synthetic fuels. This application is not covered here but can be found in the chapter for the transport sector (0). Hydrogen usage for high temperature heat applications is treated separately (section 3.2.3) due to different methodology. The industrial processes considered in this report are listed in Table 2.

This chapter is structured as follows: The introduction is followed by the description of processes where hydrogen is used as feedstock. They are treated in the individual subchapters, Iron and steel (3.2.1), ammonia (3.2.2), Methanol (3.2.2), High Value Chemicals (HVC) (3.2.2) and refineries (3.2.2). Future potential of hydrogen in high temperature heat applications for different processes is assessed in section 3.2.3. Section 3.2.4 gives an overview of the data sources used and the underlying methodology used for estimating the future hydrogen demand in the industry sector.

Table 2. Process specific hydrogen consumption and TRL of process.

Sector	Process	Technology	H2 Feedstock Demand [MWh/t]	TRL	Source
Iron & Steel	**Primary steel**	H2-DRI	1.8	8	[24]–[26]
Chemical industry	**Ammonia**	Green hydrogen	5.9	7	[25], [27],
Chemical industry	**Methanol**	Green hydrogen	6.294	7-9	[25], [27],
Chemical industry	**Olefin**	MTO	17.829	8-9	[25]
Chemical industry	**Aromatics**	MTA	27.09	6-7	[25]
Chemical industry	**Refineries**	Green hydrogen	0.2664 (per ton of oil)	7-9	[28], [30]
Industry	**Heat**	H2-burner	process dependent	process dependent	[31], [32]

3.2.1 Iron and steel

Steel is produced in Europe by two pathways. The primary route and the secondary route. In the primary route, crude steel is produced from iron ore in a two-stage process in a blast furnace (BF) and a basic oxygen furnace (BOF), collectively known as Basic Oxygen Steelmaking (BOS). In the secondary route, recycled steel scarp is melted in an electric arc furnace (EAF).

In 2019, the total crude steel production in the EU was 157 Mt. 58.6% of the steel was produced via the primary route by basic oxygen steelmaking (BOS), while 41.4% was produced via the secondary route in electric arc furnaces (EAF). The major steel production capacities lie in the countries Germany, Italy, France and Spain which produce over 54% of all European steel. In 2019, a quarter of all steel output was produced in Germany (24.8%, 39 Mt), followed by Italy (14,7%, 23 Mt) and France and Spain (9.1%, 14.4 Mt and 8.6%, 13 Mt) [33].

Primary steel production
The primary steel production process is depicted in Figure 14. Feedstocks for the process are iron ore limestone or other flux and coal. In the blast furnace, iron ore is reduced with CO to pig iron using coke. In a second step oxygen is used to remove carbon from the pig iron in the basic oxygen furnace (BOF). As a result, steel is formed with a carbon content of less than 0.05 % [27]. The steel is then further processed in continuous casting and rolling mills. This process is highly energy and carbon intensive. Per ton of final steel around 1.8 tons of CO_2 are produced and 14.8 GJ of energy in form of coal is needed [34].

Secondary steel production
The production of secondary steel with an electric arc furnace is shown in Figure 14. Here, recycled steel scrap is melted in an electric arc furnace (EAF) using electricity. Since the processing step of iron ore reduction is not required, this route is less energy and carbon intensive than the primary production route. CO_2 emissions for the secondary route arise mainly from the CO_2 emissions from electricity and further processing steps. Secondary steel production releases 0.53 tons of CO_2 per ton of final steel, mainly due to non-decarbonized electricity generation and further processing in consecutive casting and rolling steps [34].

The most promising decarbonization option for the primary steel production process uses hydrogen in hydrogen-based direct reduction of iron (H2-DRI). The process is depicted in Figure 14. In direct reduction plants, hydrogen is used instead of coke for the reduction of iron ore. The resulting sponge iron is afterwards melted to steel in an electric arc furnace (EAF).

The process of direct reduction of iron (DRI) is already established. 5% of global steel production is produced by DRI. DRI process today use mainly natural gas or coal as the source of the reducing agent [20]. Hydrogen based direct reduction of iron ore has been investigated since the mid-1900's, with the first commercial scale H2-DRI plant built in 1999 [26].

If hydrogen and electricity from renewable energy sources are used, the CO_2 emissions of the H2-DRI process are around 0.025-0.094 tons of CO_2 per ton of steel [26], [29].
The H2-DRI process requires investments in new plants due to the different process. Many European steel companies have started projects for pilot plants including Salzgitter, ThyssenKrupp and Arcelor Mittal. An overview can be found in [35]. In 2021, the steel company SSAB announced that it had produced the world’s first fossil-free steel from renewable hydrogen [36].
The technology readiness level (TRL) given in the literature is around 6-8 [24].

A transition option for the time when large quantities of hydrogen are not yet available would be direct natural gas-based reduction (NG-DRI) and gradual conversion from natural gas to hydrogen.

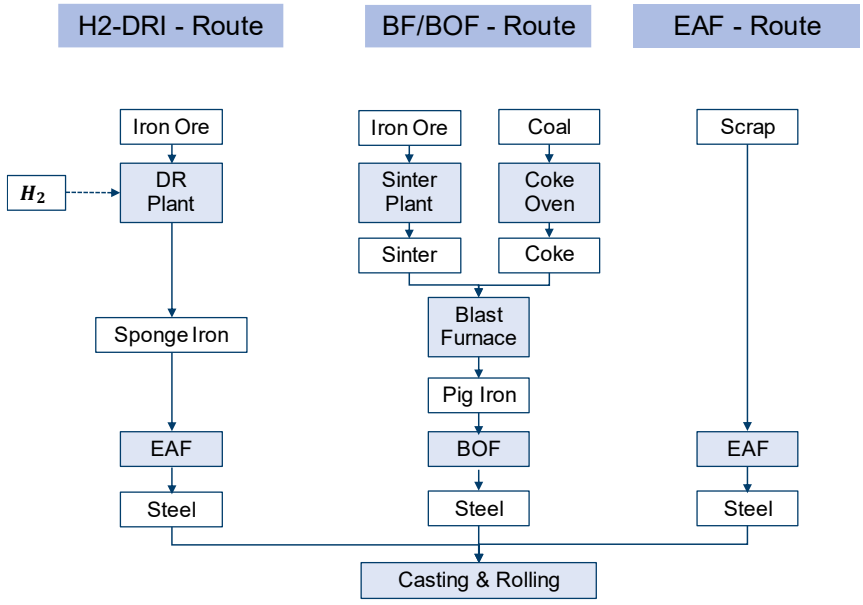

Figure 14. Iron & Steel production pathways and alternative hydrogen pathway.

For the modeling of the H2-DRI process, it is assumed that 1.88 MWh of hydrogen are needed per ton of produced steel [26]. Hydrogen demand per ton of product is also listed in Table 2.

3.2.2 Chemical and petrochemical industry

Europe is the second largest chemicals producer in the world with 499 bn€ (EU27) in sales after China (1547 bn€). The chemical industry in Europe produces important basic and specialty chemicals, characterized by a high value chain and a large number of processing steps. Products of the chemical industry include polymers, petrochemicals, basic and specialty chemicals, and pharmaceuticals [25].

The chemical and petrochemical industry is very energy and carbon intensive. In 2019 the chemical and petrochemical industry had a final energy consumption of 54000 ktoe, accounting for 21% of total energy consumption in the industry sector. Of that, 36% is covered by natural gas and 29% is provided by electricity [37]. According to a study by Agora Energiewende, the chemical industry was responsible for 17.5% of all industrial process emissions in Europe in 2018, making it the third largest industrial emitter of GHG in Europe [38]. Yang et al. [39] found that just 18 base chemicals are responsible for the major share of energy demand (80%) and GHG emissions (75%). However, due to the highly integrated production processes the decarbonization of the chemical industry will pose a challenging task.

Green hydrogen could support this effort in multiple ways. In the following the focus is on industries which have a future potential for green hydrogen usage as feedstocks (i.e. non-energy related use). These include the production of ammonia, methanol, high value chemical production including olefins and aromatics, and refinery products.

Ammonia

Currently, about 200 Mt/p.a. of ammonia (NH_3) is produced worldwide, making it the second most produced chemical in the world after sulfuric acid (H_2SO_4). Ammonia is mainly used as fertilizer (80%), the remaining 20% is used for food production, industrial materials, refrigerants and additives [40].

Ammonia is commonly produced in a two-step process: synthesis gas production and ammonia synthesis via the Haber-Bosch process. 90% of synthesis gas production in Europe is done by steam-methane reforming (SMR) [41].Here, natural gas is used to produce synthesis gas (primarily consisting of hydrogen and carbon monoxide). The hydrogen from this process step is then used together with nitrogen, typically obtained from air, in the Haber-Bosch process. Here, ammonia is produced at 150-350 bar and temperatures of 450-550 °C [25].

Due to the usage of natural gas and the heat demand of the process, ammonia production generates around 1.83 tonnes of CO_2 per ton of ammonia and is responsible of 1.3% of all CO_2 emissions in the EU [25], [42]. However, part of the CO_2 is used to produce urea. The total production volume of ammonia is currently at 17 million tons per year [25]. Additional demand for ammonia in the future might arise in the transport sector and is covered in section 0.

Decarbonizing the production of ammonia is possible by simply replacing the grey hydrogen produced by SMR with green hydrogen. The TRL of low-carbon ammonia production is at 7 [25], Neuwirth et al. [28] list it at 9. Additional compression for hydrogen will be necessary to compress hydrogen to the 150-350 bars required for the Haber-Bosch process [25]. A process scheme is depicted in Figure 15. Hydrogen demand per ton of product can be found in Table 2

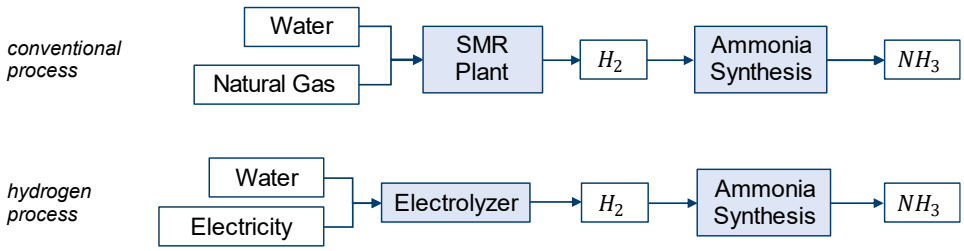

Figure 15. Conventional and hydrogen-based ammonia production.

Methanol

Methanol is produced in large quantities worldwide. Global production was at 60.6 million tons in 2012. In Europe the production volume is 1.5 million tons [25]. Methanol has a wide variety of derivatives. Formaldehyde is the most important, accounting for 30% of the global methanol demand [41]. Further uses of methanol include the production of methyl tert-butyl ether (MTBE) and acetic acid [25].

In Europe methanol is produced, similar to ammonia, in a two-step process. First, synthesis gas is produced by SMR, followed by methanol synthesis at low pressure levels (50-100 bar) and temperatures between 220-230 °C. The produced methanol is afterwards purified by distillation. The synthesis gas differs in composition from the one used for ammonia synthesis [43]. Conventional methanol production using natural gas as feedstock results in CO_2 emissions of 0.52 to 0.67 tons of CO_2 per ton of methanol. Methanol production from other feedstocks has even higher CO_2 emissions. Oil based methanol has even higher

emissions of 1.376 $t_{CO_2}/t_{methanol}$, and coal and lignite based methanol 5.285 and 5.020 $t_{CO_2}/t_{methanol}$ respectively [25], [41].

In the future methanol demand could increase significantly. Due to its potential future application to produce plastics and fuels (see section 3.2.2 and 0), methanol is seen as a promising platform and intermediate chemical.

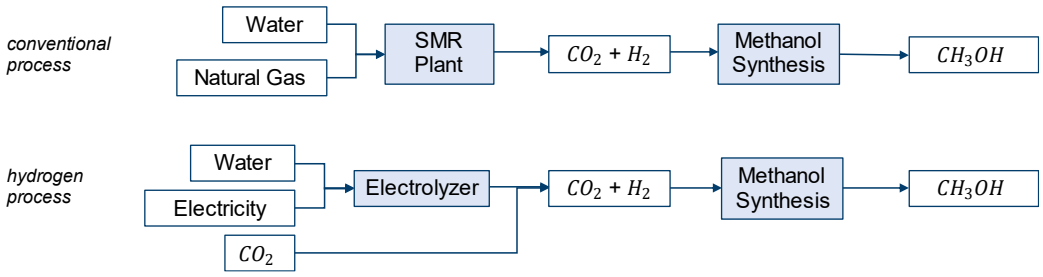

Figure 16. Conventional and hydrogen-based methanol production.

Low-carbon methanol production based on green hydrogen involves producing hydrogen from water and renewable energy as well as providing a CO_2 stream. Sources for CO_2 could be other industrial processes or biomass. The process is then similar to conventional methanol production and shown in Figure 16. Preliminary hydrogen purification and compression might be necessary. After the methanol synthesis, water formed during the synthesis is removed by distillation [25].

Renewable methanol pilot plants are already in operation, such as the George Olah Renewable Methanol Plant in Iceland which started in 2011. Low-carbon methanol production is at TRL 7 [25]. Other sources cite a TRL of 8-9 [28]. Hydrogen demand per ton of product can be found in Table 2.

High Value Chemicals (HVC)

In this report both olefins and aromatics are covered by the term high value chemicals (HVC). The largest share of olefin production is accounted for by ethylene, propylene and butadiene. They are important building blocks for a variety of products including plastics (e.g. polyethylene or polypropylene). Aromatics, commonly referred to as BTX (Benzene, Toluene, Xylene) are produced in smaller quantities and are also used for the production of polymers as well as fibers, resins and detergents [25].

In Europe, HVCs are produced in steam crackers with mostly Naphtha as feedstock and to a lower extent also liquefied petroleum gas (LPG). Here, Naphtha is cracked at temperatures of around 800°C into smaller hydrocarbons with shorter chain length [25], [43]. The resulting gas is cooled and dried and afterwards fractionated into the products at different temperatures. The main product from steam cracking in Europe by volume is Ethylene (21.7 Mt p.a.), followed by propylene (17 Mt p.a.). BTX production volume is at 15.7 million tons in Europe [25]. The majority of steam crackers are integrated into chemical sites or refinery sites [41]. Current emissions from Naphtha based steam cracking are estimated at 1.6-1.8 ton of CO_2 per ton of HVC [44].

In the future, olefins and aromatics can be produced via methanol via the Methanol-to-Olefins (MTO) and Methanol-to-Aromatics (MTA) route [45]. If the methanol is produced from renewable energy and hydrogen sources, respectively, these routes are an option to decarbonize the HVC production.

In a first step, hydrogen and carbon dioxide have to be first converted to methanol which can then be processed to olefins or aromatics. A process scheme can be found in Figure 17. The MTO process is at TRL 8-9, while the MTA process is at TRL level 6-7 [25], [38]. Ongoing projects with planned pilot plants include the Carbon2Chem Project, Carbon4PUR and the Rheticus-Project. It is estimated that application maturity will be reached between 2025-2030 [38]. Hydrogen demand per ton of product can be found in Table 2.

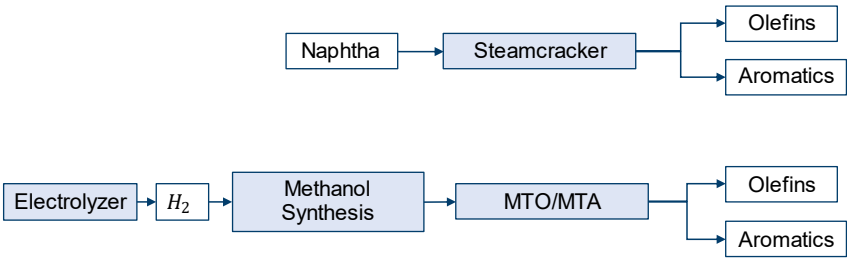

Figure 17. Conventional and hydrogen-based production of HVC.

Petroleum Refining

Refinery products are the basis for many products in the chemical industry and fuel production. In refineries, crude oil is separated into hydrocarbon fractions by atmospheric distillation followed by cracking, reforming and treating steps to obtain a variety of petroleum products. These products include LPG, Kerosene, Naphtha and a variety of fuels such as diesel and gasoline [39].

According to the Eurostat energy balance, crude oil demand in refineries was at 577 Mtoe in 2019 in the EU28 [37]. 66% percent of the oil input is turned into fuels for transport, while 14% is used as feedstock for industrial use. The CO_2 intensity varies from refinery to refinery ranging from 0.09-0.22 ton of CO_2 per ton of crude oil [39]. As shown in Figure 13, refineries account for 19% of the industrial CO_2 process emissions making it the second largest industrial emitter of CO_2 in the EU.

In refineries, hydrogen is needed for the hydrocracking and hydrotreating processes. Here, hydrogen is mostly produced via SMR or as a byproduct of catalytic reformulation [46]. In hydrocracking, hydrogen is used to break down the products into molecules with smaller chain lengths. Hydrotreating uses hydrogen to desulfurize crude oil [47]. The current hydrogen demand of refineries in Europe is estimated at 153 TWh [17].

The refining process can only be partly decarbonized with hydrogen. To do so, the hydrogen currently generated by SMR can be directly replaced by green hydrogen generated from renewable energy.
According to the IEA, the production of hydrogen for refinery purposes is responsible for 20% of total refinery emissions [48]. Neuwirth et al. estimate the TRL of green hydrogen for hydrotreating to be between 7 and 9 [28]. A simplified process scheme can be found in Figure 18. Hydrogen demand per ton of crude oil can be found in Table 2.

In the long term, the oil demand in refineries is assumed to decrease. Refinery products can be produced via alternative green routes, such as the Methanol-to-Olefins (MTO) and Methanol-to-Aromatics (MTA) routes. Furthermore, fossil fuel demand is assumed to decrease due to efficiency improvements and increased penetration of EV into the passenger car fleet [49]. Additionally, fossil fuels can be substituted by synthetic fuels in the future.

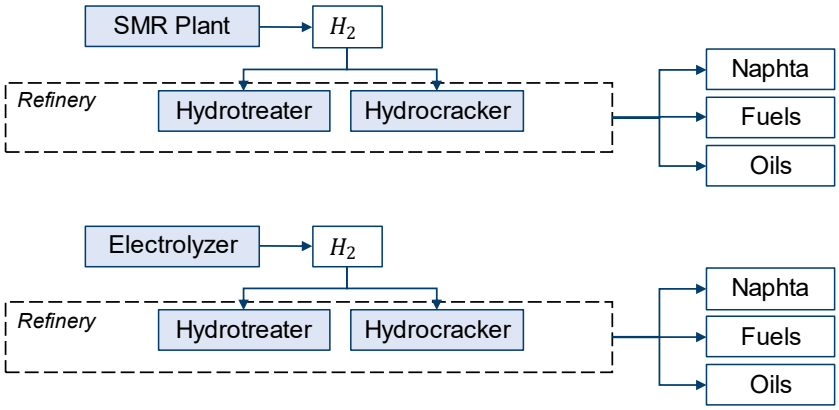

Figure 18. Conventional and future hydrogen production for refinery applications.

3.2.3 Heat applications

According to estimates from the European Commission, 50% of all direct emissions of industry in Europe can be attributed to furnaces and 20% to steam and hot water generation [22]. An analysis by Madeddu et al. for 2015 showed that primary steel production, followed by chemicals, paper and food production, are the sectors with the highest energy demand [50].

Process heat is needed at different levels in different industrial processes ranging from low temperature (< 100 -200°C) to mid temperature (200-500°C) to high temperature (500 - >1000°C) heat. Low and temperature process heat is assumed to be supplied by electricity in the future by using compression heat pumps, electric boilers or infrared heaters [50]. Due to the high electrification potential for low and mid temperature process heat, application of hydrogen is not considered in this report. Therefore, this report only focuses on hydrogen for high temperature process heat applications.

Today, high temperature process heat is mainly provided by natural gas and other fossil fuels. Here, hydrogen could be a decarbonization option, especially in cases where electricity cannot be used to provide the necessary heat levels. These would mostly be processes that require heat above 500°C [21], [22], [51], [52].

Industry sectors which require process heat above 500°C include steel production, chemicals, ceramics and glass, cement and non-ferrous metals (e.g. aluminum). An overview can be found in [31], [50], [53]. In this report, we consider chemicals, cement, non-ferrous metals, glass and steel production as industries where hydrogen could be used to decarbonize the provision of high temperature process heat.

After decarbonizing the steelmaking process, the further processing (continuous casting and hot rolling) requires high temperature heat as well. These processing steps show potential for

a substitution with hydrogen in burners. The melting process in glass production takes up 85% of the total energy demand [28].The necessary heat is provided by natural gas at temperatures above 1000°C and could be replaced by hydrogen fired burners. Neuwirth et al. list an TRL of 4-5 for a hydrogen-fired glass furnace.

Thermal energy in the cement industry is mainly needed to produce clinker in rotary kilns and the drying step in the raw mill (where raw materials are ground). The thermal energy demand makes up 88% of the total energy demand [54]. Traditionally, coal is used to provide thermal energy, but recently alternative fuels such as used tires, waste oil or plastic waste have also been used to reduce CO_2 emissions. 40% of emissions in the cement industry result from the combustion of fuels for thermal energy generation [55]. According to a study by the European Commission, there are no European projects focusing on hydrogen in furnaces, but it is assumed that it is possible to decarbonize the high temperature heat demand with hydrogen [30].

3.2.4 Data sources and methodology

Future hydrogen demand in this report is estimated through several different steps and follows a bottom-up approach. In a first step the location and production capacities for each considered process were researched, resulting in a plant level database. An overview of the sources is given in Table A3 in appendix. In a second step, based on the process specific hydrogen consumption, the future market share of the hydrogen-based production route and the future product demand, the future hydrogen demand is estimated for multiple scenarios. The methodology is visualized in Figure 19. The industrial database is then used to distribute the hydrogen demand to the respective plants.

Plant level database

Several different sources were used for the location and capacities of the industrial sites.
In the literature, there were already approaches to assess production capacity of industrial plants. The Hotmaps project used emission data from the European Union Emission Trading System (EU ETS) and EPRTR (European Pollutant Release and Transfer Register) among other things to estimate the production capacity of industrial plants. For the estimation of hydrogen demand in high temperature heat processes, a similar approach will be used. Apart from that, several commercial sectoral databases exist. However, they have not been utilized as openly available data could be found for all the processes.

Steel
As the ETS and EPRTR do not distinguish between primary steel and secondary steel production, the Hotmaps database could not be utilized. Instead, a database of steel production plants was created with publicly available data from Eurofer and the Global Energy Monitor´s steel plant tracker consisting of the location, capacity and production type for each plant [56], [57].

The Global Energy Monitor steel plant tracker was used as a basis as it contains the exact location as well as the capacity and type of the plant. However, the steel plant tracker only contains steel plants with capacities larger than 5000 kt/pa. Therefore, the data was compared to the data from Eurofer. Any missing plants were added to the database. As the data from Eurofer did not contain any location data but only city data, the Google Maps API was used to get the exact coordinates of these plants.

Chemical and Petrochemical Industry
In 2017, the Joint Research Centre (JRC) compiled a report on energy efficiency and GHG emissions in the chemical and petrochemical industry [41]. As a result of this report, a chemical industry database for Europe was built. This database was shared by JRC with the authors of this report. The database contains detailed information on facilities producing 26 chemical products, with production capacities, processes, and energy consumption. Detailed information can be found in [41]. From this database, plant details and capacities of the considered processes were extracted. Since the database contained partially incorrect or missing location data, the Google Maps API was used to georeference the individual plants. The processes considered were the production of ammonia, methanol, olefins and aromatics.

To obtain refinery locations and capacities, public data from Concawe were used [58]. The location data from Concawe was only accurate on a city level. Therefore, the Google Maps API was again used to georeference the individual plants using a query that included the refinery facility owner and city.

The resulting data was then merged into a single database containing the plant name, the owner, capacities, product type and plant location. This database is then used to distribute the potential hydrogen demand based on several demand scenarios (see 0) for each process to plant level. Afterwards the hydrogen demand is aggregated to NUTS-2 level and can be found in section 3.4.

Heating applications
Due to the larger number of industries with high temperature heat needs and the lack of sector specific databases, a simplified approach was chosen, where the different industries are not covered individually. The approach follows in parts the approach chosen by the Hotmaps project. For estimating plant capacities, data from the European Transaction Log (EUTL) was used. The EUTL, run by the European Commission makes the data from the EU ETS (European Union Emissions Trading System) publicly available. The purpose of the EU ETS is to limit and reduce emissions for energy-intensive industries. Each facility is assigned an emissions budget based on process type and reported production volumes. The budget is based on benchmarks for each process, expressed in tons of GHG emitted per ton of product produced. If needed, emission allowances can be traded with other companies. Abrell processed the EUTL data and added exact locations for each plant [32]. The resulting EUTL database contains the plant names, identifiers, respective activity code, the location of the plant, and the verified emissions from 2008 to 2020. The activity code is used to categorize each plant in the ETS into a process (e.g., glass manufacturing).

Using the underlying benchmark value for each process type (activity code respectively) and the verified emission for the target year, it is possible to estimate the capacity of individual plants.
As the ETS does not distinguish between primary and secondary steel production, steel production sites were replaced with the data from our own database.

In order to select the relevant processes with high temperature heat demand, estimates from Rehfeldt et al. were used [31]. They investigated several different processes and published the specific energy consumption as well as the process heating temperature distribution. From these, processes were chosen that showed process heating temperature needs above 500°C. These processes were then matched to their activity ID in the ETS. This way, each activity ID and therefore each plant in the ETS can be assigned a specific energy demand per temperature level.

The final database accordingly includes the installation ID, the installation location, the verified emissions for the target year, the activity ID, the estimated installation production volume based on the activity ID´s benchmark and verified emission, as well as the estimated process heat demand for two temperature levels [500-1000°C, > 1000°C] of the installation. Figure 19 depicts the different steps.
Following the descriptions in section 3.2.3, it is assumed that part of this high temperature heat can be provided by hydrogen in the future.

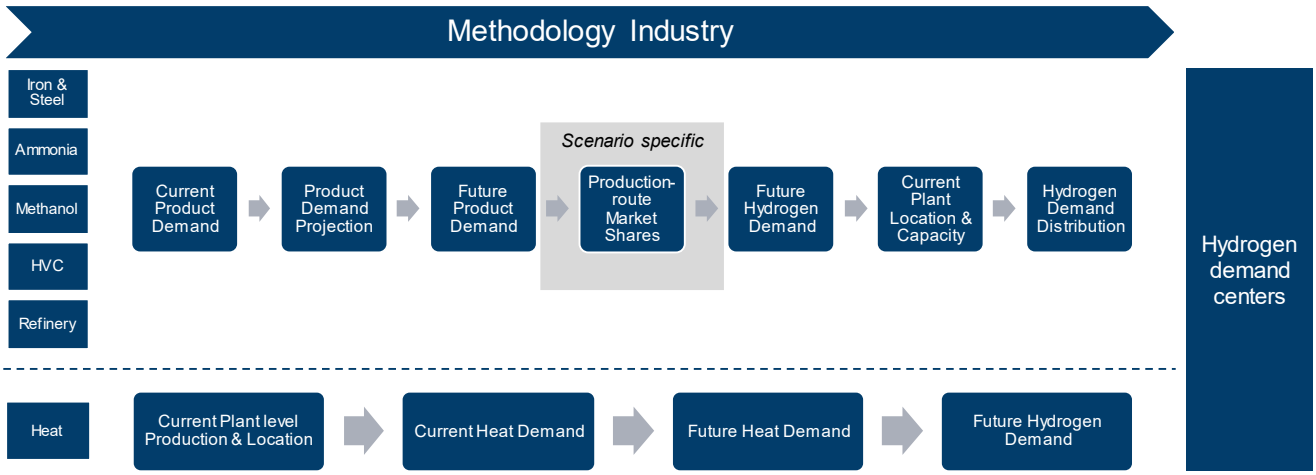

Figure 19. Methodology process of future hydrogen demand estimation in industry.

Methodology of future hydrogen demand estimation

The methodology estimating the future hydrogen demand in the industry sector follows a bottom-up approach. For all considered processes, the general approach is the following: The current European demand for the product is scaled to 2050 using an activity index (e.g. population projection). For each process the market share of the production route in 2030 and 2050 is defined. Based on the product demand produced via the hydrogen-based production route and the process specific hydrogen demand (Table 2), an overall hydrogen demand can be derived for each process. This demand is then distributed to plant level respectively at NUTS-2 level according to the current plant capacities assessed in the previous section.

For many processes there are also other decarbonization options such as the utilization of CCS or production routes via biomass. However, as this report focuses on hydrogen utilization, these options are not explicitly considered. Instead, they are collectively summarized under the conventional production routes. Therefore, all scenarios are created assuming the development of a hydrogen economy, allowing large shares of hydrogen in all sectors. Assumptions on both hydrogen consumption and market shares are the same for all of Europe. No country specific values are assumed. Three different scenarios are created considering different degrees of hydrogen penetration and can be found in section 3.4. Table 3 lists the considered assumptions and sources used for the hydrogen demand estimation for each process.

Ammonia production
Ammonia demand in Europe is currently 17 Mt p.a. [25]. Since ammonia is mainly used for fertilizer, population growth has been chosen as a proxy to project the ammonia demand to the target year. Population growth projections for the EU were obtained from Eurostat [59]. Two production routes are considered. The first one is the conventional route via SMR, and the second route is via green hydrogen from renewable energy sources. To model the evolution of the share of the two production routes, a sigmoid function is used. For the production of ammonia, a hydrogen demand of 5.9 MWh per ton of ammonia is considered [42].

Methanol production
Methanol demand is 1.5 Mt p.a. [25]. Following the approach in [25], an 1% p.a. increase in demand until 2050 is assumed. Thereby, two production routes are considered, with the first one being the conventional route using hydrogen produced from SMR. The second route is the substitution of that hydrogen with green hydrogen. The evolution of the share of the two production routes is modelled with a sigmoid function. The green hydrogen demand for one ton of methanol is assumed to be the stochiometric value of 6.3 MWh/$t_{Methanol}$.

Iron & steel production
Primary steel demand is currently 90.5 Mt p.a. [33].The current steel demand is projected to 2050 using assumptions from material economics which assumes a 0.6% increase in steel demand p.a. until 2040 [20]. After 2040 the steel demand is assumed to stabilize and stay constant until 2050.
Two production routes are considered for the primary steel production: the current BF-BOF and the H2-DRI route. The development of the share is modelled with a sigmoid function and can be found in section 3.4. The feedstock demand for one ton of crude steel produced via the H2-DRI route is 1.88 MWh of hydrogen [26].

Olefin production
Demand for olefins is currently 33 $Mt_{ethylene_{eq}}$ p.a. [60]. Olefin demand is projected to future years using the physical output (in kt of ethylene eq) of basic chemicals from the POTEnCIA scenario [61]. Production routes considered are conventional production in steam crackers with naphtha and production via hydrogen to methanol followed MTO (methanol-to-olefins). The development of the share is modelled with a sigmoid function. The feedstock demand for one ton of olefins from hydrogen is 17.829 MWh.

Aromatics production
Demand for aromatics is currently at 15.7 Mt p.a. [60]. Product demand is projected using the physical output (in kt of ethylene eq) of basic chemicals from the POTEnCIA scenario of the European Commission [61]. Production routes considered are conventional production in steam crackers with naphtha and production via the route hydrogen to methanol followed MTA (methanol-to-aromatics). The development of the share is modelled with a sigmoid function. The feedstock demand for one ton of olefins from hydrogen is 27.09 MWh.

Refinery
Current oil demand for refineries in Europe is 577 Mt according to the Eurostat energy balance [37]. This demand is projected to the target year using the development of crude oil and petroleum products according to the EU Reference Scenario 2020 [62]. Two pathways are considered: the use of hydrogen produced via SMR and the use of green hydrogen produced by electrolysis from renewable energy. Due to lack of data, we assume for the green hydrogen pathway that all of the refinery hydrogen demand needs to be provided externally. None of the hydrogen demand is met from internal sources such as catalytic reforming. Hydrogen consumption in refineries usually differ strongly depending on the

processes used in the refinery. Since no data is available on the consumption of hydrogen in individual refineries, we assume the same value for all refineries. The hydrogen feedstock demand is set to 7.2 kg of hydrogen per ton of oil [30]. The resulting current hydrogen demand (138 TWh) is in range with estimations from FCHO (136.52 TWh Hydrogen) [46].

Heating demand

This report assumes a constant high temperature heat demand for future years. Increased production is assumed to be canceled out by improvements in energy efficiency and heat integration. Two options are considered: the current technology or replacement with H2-burners and furnaces. Technology penetration is modelled again with a sigmoid function. The share of heat demand at the two temperature levels replaced by hydrogen burners is defined in the different scenarios. Energy demand in case of using hydrogen is assumed to be the same as the energy demand for the respective process and can be found in [31].

Table 3. Data and Assumptions for methodology.

Process	Current Dermand [Mt]	Activity index proxy	Market shares	Considered Pathways
Primary steel	90.5 [33]	Material Economics projection [20]	Sigmoid function	BF-BOF, H2-DRI
Ammonia	17 [25]	Population growth projection [59]	Sigmoid function	SMR, H2-based
Methanol	1.5 [25]	1 % p.a. increase [25]	Sigmoid function	SMR, H2-based
Olefins	38.7 [25]	POTEnCIA projection chemical industry [61]	Sigmoid function	Naphtha, MTO
Aromatics	15.7 [25]	POTEnCIA projection chemical industry [61]	Sigmoid function	Naphtha, MTO
Refinery	577 (crude oil) [37]	Crude oil and petroleum products [62]	Sigmoid function	SMR, H2-based
Heat	Based on ETS, Process specific	Constant	Sigmoid function	Fossil fuels, H2-burner

3.3 Potential for hydrogen usage in transport sector

In 2019, the transport sector accounted for 29% of the EUs greenhouse gas emissions. As it can be seen in Figure 20, largest emitters are road transport with 71.7% of the total GHG emissions in the transport sector, followed by aviation and maritime [63].

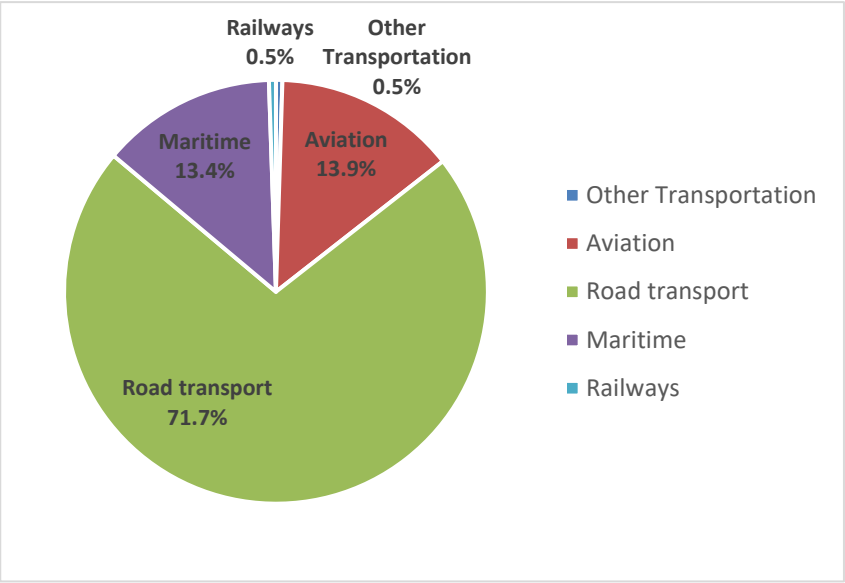

Figure 20. GHG emissions transport sector 2019 (based on [63]).

On the energy side, the transport sector accounted for 31% of the final energy consumption in 2019 [37]. Passenger transport accounted for 69% and freight transport for 31% of final energy consumption in transport sector in 2015. The largest share in both, passenger and freight transport, is transportation via road accounting for 83% of the total energy demand.

Transport demand in passenger transport is projected to increase by a factor of 1.4 from 2015 to 2050. Freight transport by factor 1.55 in the same time period according to the EU Reference Scenario 2020 [62].

In order to reach the European Union's goal of climate neutrality in 2050, GHG emissions from transport need to be reduced significantly in the coming years. In the short run reductions may be achieved by transport avoidance measures and efficiency improvements. In the long run, climate neutrality is only possible by switching to alternative (green) fuels or alternative climate neutral drive trains such as battery electric vehicles (BEV) or fuel cell electric vehicles (FCEV) with energy from renewable sources.

This report covers all four major transport modes (road, aviation, maritime, rail) and considers passenger and freight transport for each transport mode. For aviation, both domestic and international traffic are considered. This report focuses on scenarios with a high integration of hydrogen into the transport sector.

The potential role of hydrogen in the future transportation system is diverse. Hydrogen can be directly used as fuel in FCEV. It can also play an indirect role being a feedstock for various synthetic fuels in Power-to-X (PtX) applications.

One advantage of synthetic fuels (synthetic kerosene, diesel and gasoline) is that they can directly substitute their fossil-based counterparts. They can therefore be used as drop-in fuels making use of existing infrastructure and drivetrains. A variety of EU-funded research projects exist regarding alternative transport fuels. Ortega et al. identified 12 projects in the area of aviation fuels, two projects in the maritime sector and 31 projects dealing with biofuels for road transport [64]. In the US several types of synthetic jet fuels have been approved and can already be used by blending with 50% conventional jet fuel [65]. In 2021, the European Commission proposed a regulation in which fuel suppliers will have to blend a minimum level of sustainable aviation fuels (SAF) into jet fuel from 2025 [66]. For 2030 this value is 5% and 63% for 2050 with a minimum of 28% based on electricity. An analysis from Clean Skies for Tomorrow identified planned and existing projects for the production of sustainable aviation fuels (biofuels, synthetic fuels) and found 28 plants with a theoretical total production capacity of 3 Mt of fuels per year until 2027, most of them being bio-based. Power-to-liquid projects also exist but only at pilot and demonstration level [67].

This report considers both the application of hydrogen in FCEV as well as the application of hydrogen for PtX. Options considered for PtX fuels include the production via the Fischer-Tropsch synthesis (FT), the production via the Methanol-to-Gasoline (MTG) route and in a broader sense also the production of ammonia and methanol with hydrogen as maritime fuels [68].

The hydrogen demand in the transport sector will be modelled using transport activity projections, market shares of different technologies (e.g., FCEV, BEV), and fuel consumption. All values are exogenously defined. For a more complete picture, the considered fuels and drivetrains are listed in Table 4. These will be considered in the market share projection for each transport sectors. The hydrogen demand will then be calculated from the amount hydrogen necessary to produce the respective fuel.

Table 4. Considered Fuels and Drivetrains for each sector.

Fuel/Drivetrain	Road	Aviation	Maritime	Rail
ICE fossil	x	x	x	x
ICE MTG	x			
ICE FT	x	x	x	x
ICE Biofuel	x	x	x	x
BEV	x	x		x
FCEV	x	x		x
Ammonia			x	
Methanol			x	
LNG			x	

3.3.1 Methodology

This report distinguishes between 4 transport modes (road, aviation, maritime, rail), each split up into passenger and freight transport. A general overview of the different steps for assessing the hydrogen demand in the transport sector is given in Figure 21.

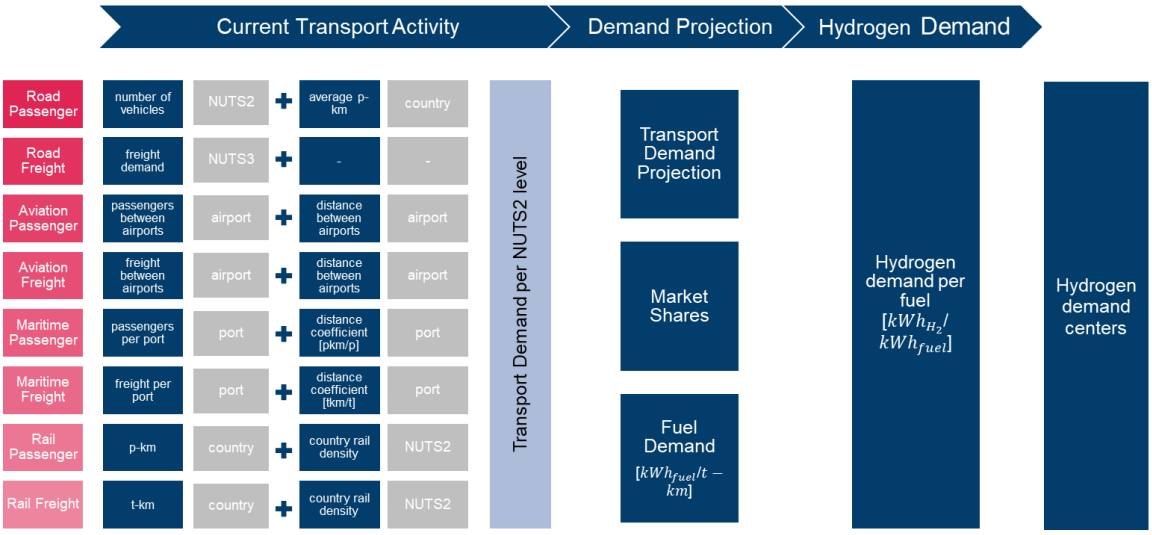

Figure 21. Methodology of future hydrogen demand estimation in the transport sector.

Mobility demand

The modeling of transport demand is carried out in two steps. The starting point is the calculation of current transport activity, expressed in passenger-kilometers (p-km) or tonne-kilometers (t-km). The Eurostat transport database serves as the basis for most sectors [69].For all sectors, Eurostat data from 2019 was used if available. For the calculation of road passenger demand, the number of vehicles per NUTS-2 region from Eurostat was used and multiplied with the average p-km per vehicle for the respective country in 2015 obtained from the JRC-IDEES database. For road freight, the annual road freight transport demand in t-km was available per NUTS3 region.

Data on passenger and transport rail activity (in p-km and t-km) were only available at country level. They were disaggregated to NUTS-2 level using the density of the rail network. For the aviation sector, Eurostat gives the number of passengers or freight (expressed in tonnes) between airports per year. Using the direct distance between the airports, the transport activity was calculated. The transport activity was split half between source and target airport.

The calculation of the maritime transport activity follows the approach described by Ortiz-Imedio et al [70]. They used the number of passengers per port per year (p/a) obtained from Eurostat and calculated distance coefficient, passenger-kilometer per passenger (p-km/p) or tonne-kilometer per ton (t-km/t) to obtain the transport activity in p-km and t-km, respectively. The target granularity for the hydrogen demand is NUTS-2 level. Therefore, all data was aggregated to this level.

In the next step, the transport activity for each region is projected to the target year by using transport activity projections for the EU from the EU Reference Scenario 2020 [62].

Market shares

The next step involved distributing the transport demand for the target year to the different drive trains. This was done by using projections on the market shares. These projections are taken from literature or are the authors' own assumptions when no data was available. Market shares are assumed to be the same for each region in Europe, due to the lack of data.

Efficiency improvements / Fuel demand
After distributing the transport demand to the different drivetrains, the projected energy efficiency per drivetrain, expressed in kWh/t-km or kWh/p-km, was used to calculate the energy demand. Projected energy efficiencies are obtained from a study conducted by Khalili et al. [13] or - if not available - from inhouse model calculations and are assumed to be the same for all of Europe. From this, the hydrogen demand to produce the respective fuel of the drivetrain is calculated. The hydrogen demand per fuel can be found in Table 5. To produce one kWh of fuel via the Fischer-Tropsch route, 1.306 kWh of hydrogen are needed. To produce one kWh of gasoline via the Methanol-to-Gasoline, 1.24 kWh of hydrogen are needed. Both values were taken from the analysis of Schemme et al. and were converted using the LHV of hydrogen [68]. For the production of one kWh of methanol and ammonia as shipping fuel, 1.139 and 1.142 kWh of hydrogen are necessary, respectively [25], [42].

Table 5. Hydrogen demand per fuel type or drivetrain.

Fuel/Drivetrain	Hydrogen Demand per kWh of fuel [kWh_{H2}/kWh_{Fuel}]
ICE fossil	-
ICE MTG	1.240 [68]
ICE FT	1.306 [68]
ICE Biofuel	-
BEV	-
FCEV	1
Ammonia	1.142 [25]
Methanol	1.139 [25]
LNG	1.198 [25]

Hydrogen demand
In this report, it is assumed that the hydrogen demand from the transport sector will be met by dedicated, new fuel production facilities. Due to the high uncertainty about the size and location of such plants, the hydrogen demand is not allocated to, for example, current refinery locations. For all transport modes the hydrogen demand is therefore located in the respective transport demand region. In three different scenarios the market shares in each sector are varied to obtain different hydrogen demands in the transport sector. They are discussed in section 3.4.

3.4 Future demand scenarios

3.4.1 Comparison with literature

Various studies already assessed potential hydrogen demand for future years based on both bottom-up or top-down approaches. In Figure 22, a comparison of estimated future hydrogen demand for 2030 and 2050 in literature is given (cf. Table A2 in appendix for further information about the studies). Only recent studies published within the last five years were considered. Hydrogen demand for 2050 ranges from 991 TWh up to 4,631 TWh. For 2030 only a few studies show significant hydrogen demand ranging from 327 TWh up to 1,070 TWh. While most studies see the largest share of hydrogen demand in the industry and transport sector, the results illustrate the high uncertainty associated with predicting the future hydrogen demand. According to a document from Joint Research Centre (JRC), hydrogen accounts for 10-23% of EU final energy consumption in 2050 in most studies [71].

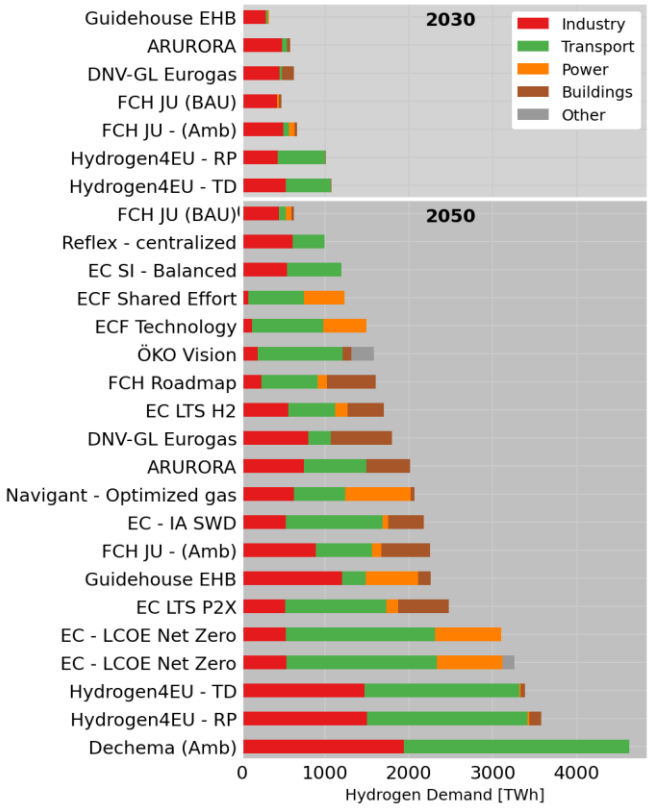

Figure 22. Future hydrogen demand for 2030 and 2050 in literature. Corresponding sources are linked in the appendix (cf. Table A2).

3.4.2 Scenario description and results

To assess the impact of different degrees of hydrogen integration, three future European demand scenarios are developed. All scenarios assume that hydrogen will play a large role in industry and in the transport sector in future. Alternative options for industry such as CCS or increased biomass are not explicitly modelled and are collectively summarized under the traditional production route. The degree of hydrogen integration is mainly set by different market shares of hydrogen usage in each considered subsector in industry and transport. Product demand or transport activity is the same for each scenario. The scenarios for 2050 in the transport sector aim for complete decarbonization and therefore assume a complete phase-out of fossil fuels or fossil-based processes.

Baseline Scenario

The baseline scenario assumes a high integration of hydrogen as feedstock in industry in 2050. 100% of the product demand of the considered processes in 2050 will be met by a hydrogen-based process. For 2030, 7% of the demand is covered with green hydrogen. For process heat provision a moderate usage of hydrogen of 30% for temperatures between 500-1000°C and 50% for temperatures above 1000°C for 2050 are assumed, following the assumptions from the European Hydrogen Backbone (EHB) initiative [42]. For 2030, 3% of heat demand between 500-1000°C and 4% of heat demand above 1000°C is assumed to be supplied by hydrogen burners. In the transport sector, different market shares of hydrogen-based fuels are assumed depending on the transportation mode. Assumed market shares in the different transportation modes are shown in the appendix (cf. Section 0.1).

The baseline scenario envisages a 18% share of hydrogen demand in road passenger transport in 2050, while most of the transport demand is met by BEV (79.6%). Assumptions for the share of ICE, BEV and FCEV are taken from EU Reference Scenario 2020 1.5 Tech [62]. ICE fuel demand was split between MTG-based, FT-based and bio-based fuels. For 2030, the European Commission's RED II directive is considered, assuming that 10.5% of the ICE fuel demand is met by first generation and advanced generation biofuels [72].
For freight transport, market shares were taken from the EU Reference Scenario 2020 1.5Tech [62]. Fossil fuel market shares for 2050 were redistributed evenly between MTG-based, FT-based and bio-based fuels. In 2030, MTG-based and FT-based fuels account for 2% of the ICE fuel demand. Hydrogen in 2050 is used in 55% of the fuels for freight transport, mainly by FCEV trucks.
Current market shares based on transport activity (tkm/pkm) for rail passenger and freight transport are taken from Eurostat. Based on the current electrification rate of 65%, an increasing electrification of rail transport was assumed. For 2030, the electrification rate is 70% and for 2050 80%. The remaining 20 percent in 2050 are met by synthetic fuels (10%) and trains run with fuel cell technology (10%).
For maritime transport, scenario data from the DNV Maritime report [73] are used for the baseline scenario. Scenario 23 from that report is used for both passenger and freight transport. For 2030, only 20% of maritime transport is assumed to be decarbonized, with 10% FT-based diesel and 10% ammonia-fueled ships.
The aviation sector is modeled in the baseline scenario according to the assumptions of the EHB [42]. However, the baseline scenario assumes a higher hydrogen share. 50% of the demand in 2050 is covered by synthetic kerosene from the FT-route and 10% from hydrogen usage in fuel cells for short-range flights.
Based on the scenario assumptions, the hydrogen demand for industry and transport is calculated according to the methodology described in the sections 3.2 and 0.

Figure 23 shows the hydrogen feedstock demand in industry for 2030 and 2050, reaching over 1800 TWh in 2050. Most of the hydrogen demand originates from the production of HVC reaching over 1400 TWh. Hydrogen demand for the H2-DRI process is 165 TWh. Hydrogen demand to produce ammonia and methanol and in refineries are 99 TWh, 14 TWh and 79 TWh, respectively. The high amount of hydrogen demand to produce HVC is due to the assumption of full substitution of conventional production routes with the very hydrogen intensive Methanol-to-Olefins (MTO) and Methanol-to-Aromatics (MTA) processes.

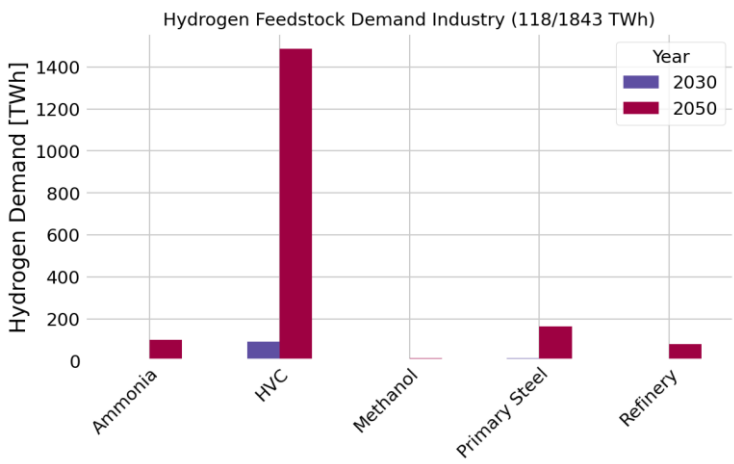

Figure 23. Hydrogen Demand Feedstock Industry (Baseline Scenario).

Hydrogen demand for process heat applications reaches moderate 197 TWh of hydrogen demand and shown in Figure 24. Hydrogen Demand Process Heat (Baseline Scenario)). The largest shares are in the chemical industry, cement production and for casting and rolling in primary and secondary steel production.

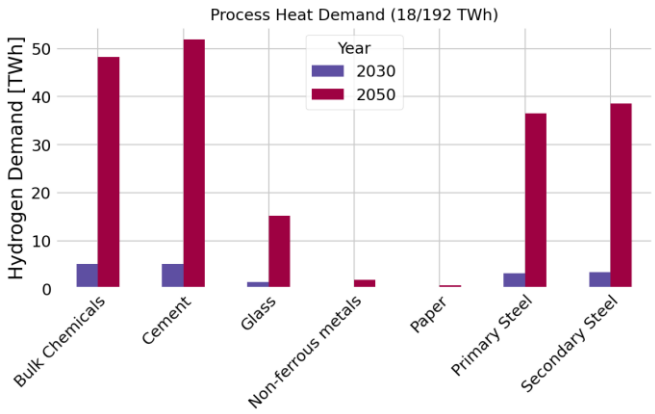

Figure 24. Hydrogen Demand Process Heat (Baseline Scenario).

In the transport sector hydrogen demand sums to 1950 TWh. The largest share arises due to passenger flights and road freight transport (924 TWh and 450 TWh) and is shown in Figure 25.

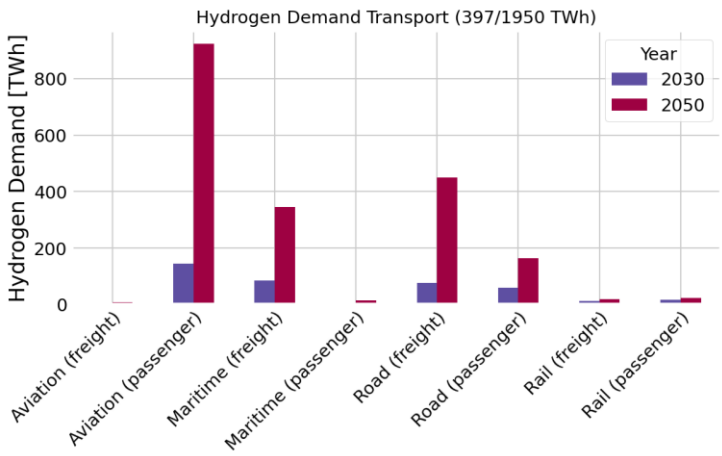

Figure 25. Hydrogen Demand in Transport (Baseline Scenario).

For 2050, the distribution of the overall hydrogen demand is shown in Figure 26.The hydrogen demand is almost 4000 TWh and significantly larger than in 2030. Figure 26 clearly shows the development of hydrogen demand centers in a few distinct regions in Europe. These regions are mainly located at the industrial clusters in Netherlands, Belgium and Germany. Further clusters arise at the London region in the UK, the Paris region in France, as well as in locations in southwest of Europe.
Of all countries, Germany has by far the highest hydrogen demand with almost 1000 TWh, followed by the UK with almost 500 TWh.

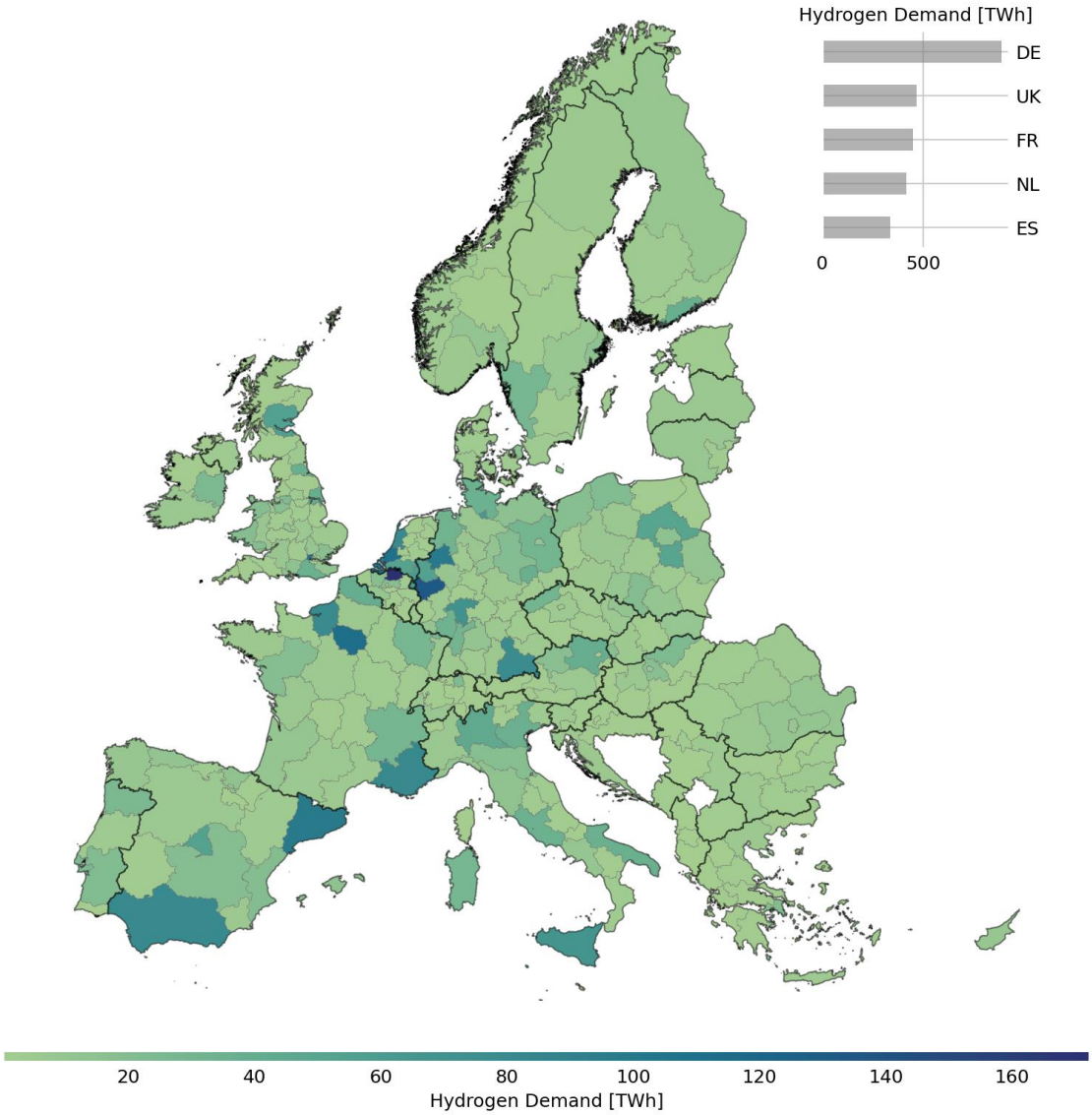

Figure 26. Total Hydrogen Demand 2050 (Baseline Scenario).

In Figure 27, Figure 28 and Figure 29, the allocated hydrogen demand in Europe is shown for industry sector, process heat and transport sector in 2050, respectively. Figure 27 shows the hydrogen demand for feedstock in industry along with the current locations of industrial sites with hydrogen application. Hydrogen demand is located at specific demand centers in various parts of Europe. The highest share of demand is located at the industrial centers in Germany, Netherlands and Belgium. Further demand centers are located in the south of Spain, Italy and France. The country with the largest hydrogen demand is Germany, followed by the Netherlands and France.

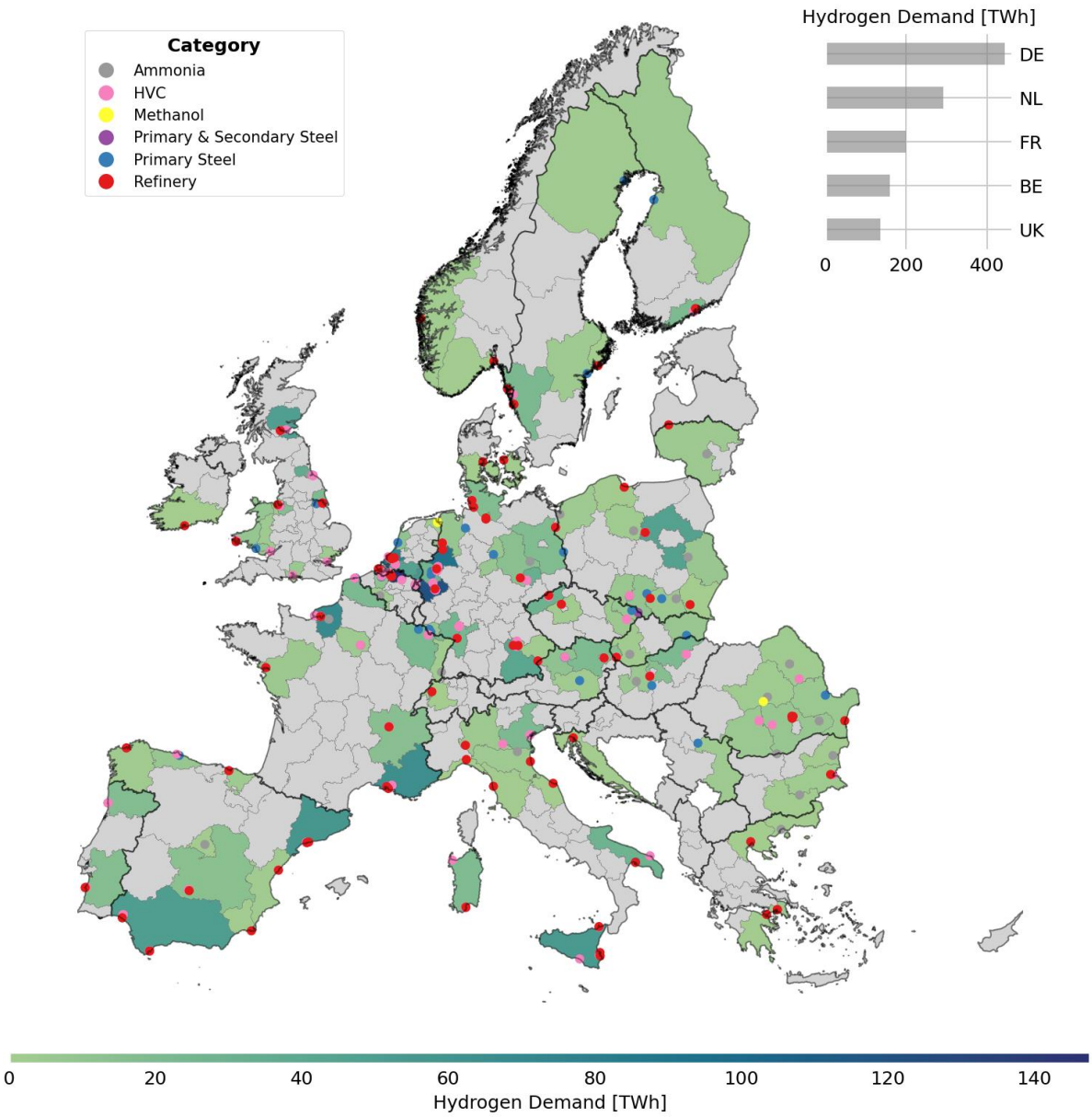

Figure 27. Hydrogen Demand Industry 2050 (Baseline Scenario).

Hydrogen demand for process heat in 2050 is shown in Figure 28. Similarly, demand centers arise. Again, the industrial region in Germany, Netherlands and Belgium show high demand. Furthermore, a demand center arises in Northern part of Italy due to the location of a high number of industrial plants, such as secondary steel production plants.

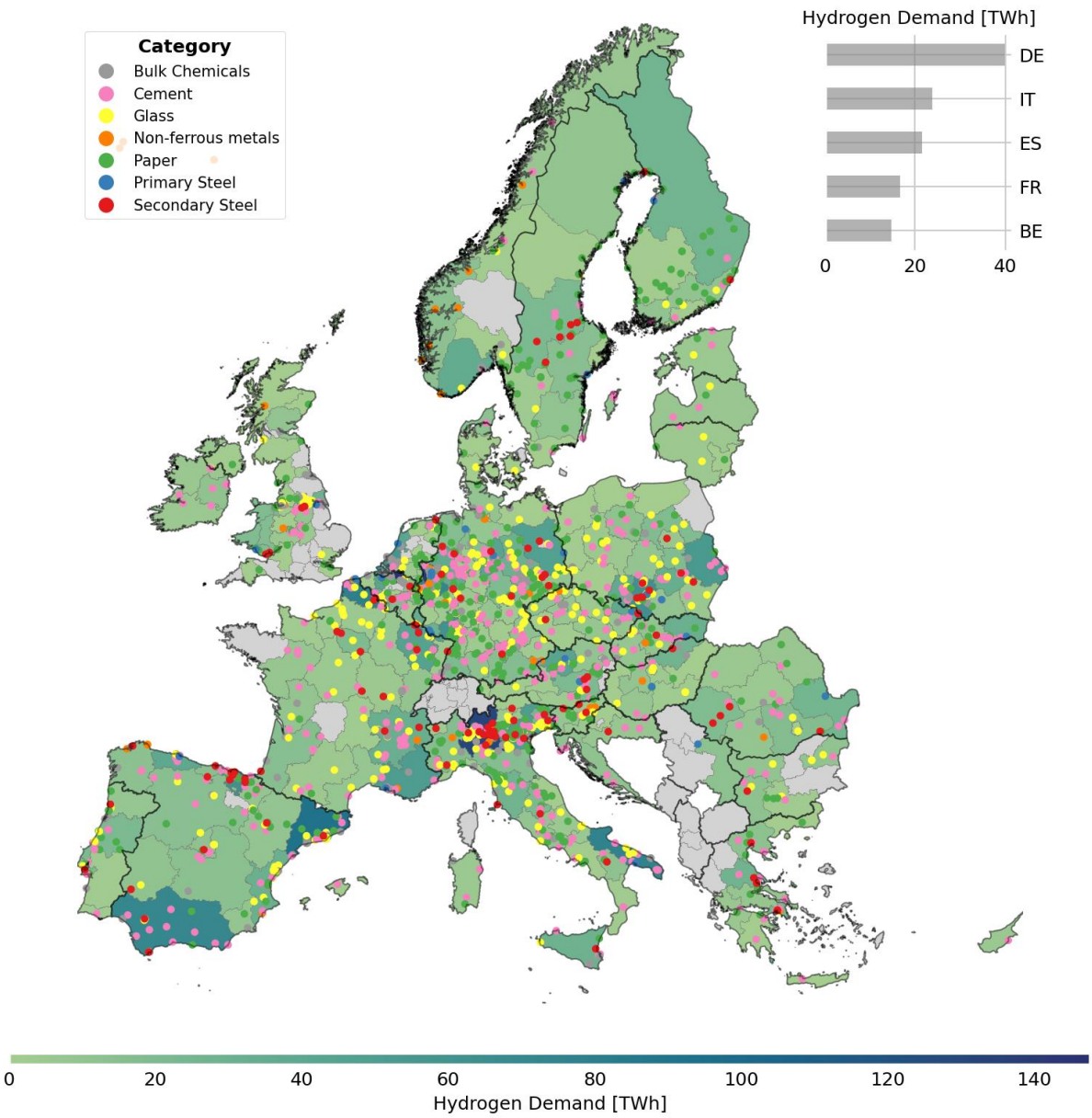

Figure 28. Hydrogen Demand Process Heat 2050 (Baseline Scenario).

Hydrogen demand centers for transport are shown in Figure 29 along with locations of airports and ports. As already evaluated, the largest share of hydrogen demand arises from aviation, followed by road freight and maritime freight demand. Therefore, hydrogen demand centers are located mainly in regions containing ports and airports. Regions with high hydrogen demand are the region containing the Frankfurt airport in Germany, the London airport in the UK and airports near Paris in France.

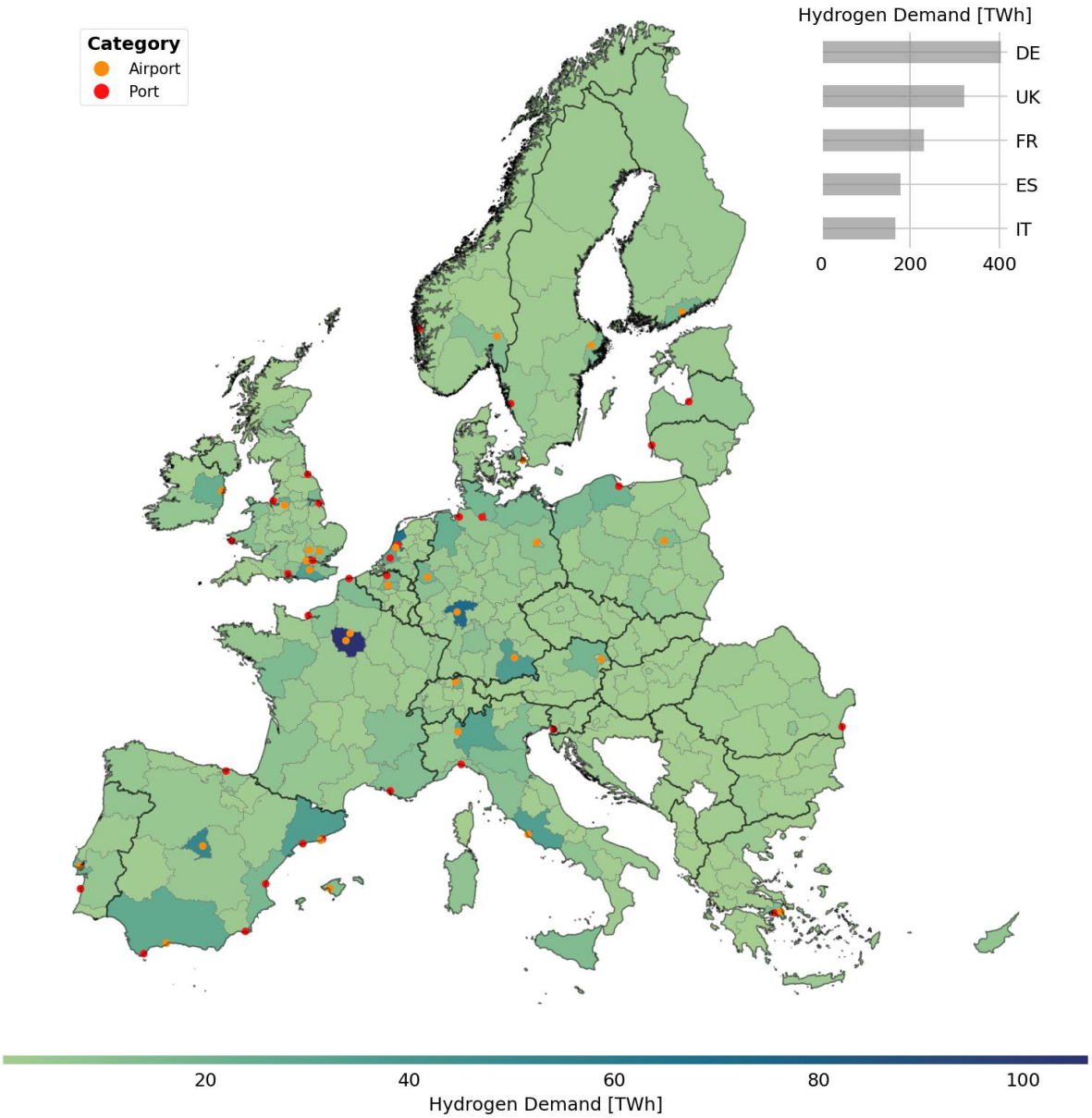

Figure 29. Hydrogen Demand Transport 2050 (Baseline Scenario).

Scenario "Low"

The scenario *low* envisions a slightly lower hydrogen integration in industry and transport than the baseline scenario.
In the transport sector, a higher share of biomass-based fuels is assumed, lowering the need for synthetic fuels and hydrogen-based drivetrains.
The hydrogen penetration in the industry feedstock sector is lowered from 100% to 80% in 2050.
This results in a hydrogen demand of 95 TWh for 2030 and 1,475 TWh for 2050.
Hydrogen's share of the demand for process heat is assumed to be 1.6% and 15% (2030 and 2050) for heat between 500-1000°C and 2.5% and 30% of heat demand above 1000°C. High temperature heat demand from hydrogen in 2050 is 107 TWh.
The shares of road passenger demand are again taken from the EU Reference Scenario 2020 [62]. In the *low* scenario the share of biofuels is higher, however. The shares of road freight demand are also taken from the EU Reference Scenario 2020, assuming a high share of biofuels. Hydrogen is only used to cover 14% of the transportation demand in the road freight sector. The hydrogen penetration in the maritime sector is modelled using scenario 13 from the DNV study [73]. In 2050, 30% of the demand is met by biofuels and 70% by hydrogen fueled drivetrains. The aviation sector uses the assumptions from EHB with both 40% market penetration of FT-based fuels and biofuels and 10% share of BEV and FCEV for short distance flights. This results in an overall hydrogen demand for the transport sector of 1,568 TWh. The total hydrogen demand for this scenario is 404 TWh for 2030 and 3,150 TWh for 2050.

Since the location of the industrial sites and location of airports and ports is the same in all scenarios, the hydrogen demand centers are the same as in the baseline scenario and are not presented here.
Assumed market shares are given in the appendix (cf. Section 0.1).

Scenario "Max"

The scenario *max* envisions a very high hydrogen integration in industry and transport sectors that also develops more quickly compared to the baseline scenario. In the transport sector, all the demand is met by either hydrogen fueled drivetrains or BEV. The hydrogen penetration in the road passenger transport is the same as in the baseline scenario. The only difference is the stronger uptake of synthetic fuels in 2030, which cover almost 6% of the total transport demand in passenger transport.
The same assumption is used for road freight transport. Assumptions are the same as in the baseline scenario with a higher share of hydrogen based synthetic fuels already in 2030. For the maritime sector the assumptions are the same as in the baseline scenario. For the aviation sector, the production of aviation fuel from biomass sources compared to the baseline scenario is omitted and substituted by FT-based fuels. The hydrogen demand for the industry sector is the same as in the baseline scenario. For the process heat demand a 100% coverage for both heat levels by hydrogen burners is assumed. In total, this results in a hydrogen demand of 748 and 4,998 TWh in 2030 and 2050.

Since the location of the industrial sites and location of airports and ports is the same in all scenarios, the hydrogen demand centers are the same as in the baseline scenario and are not presented here.
Assumed market shares are given in the appendix (cf. Section 0.1).

Comparison of the scenarios

As can be seen from the previous description, the three scenarios differ significantly in the level of hydrogen integration in industry and transport sector. A comparison of the total hydrogen demand values for all three scenarios in 2050 can be seen in Figure 30.

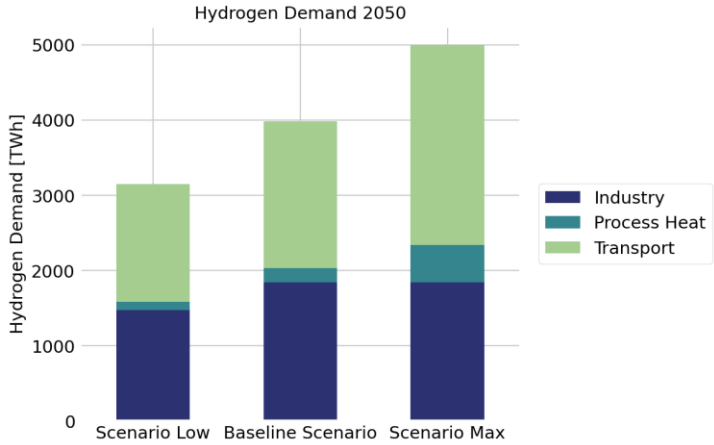

Figure 30. Overall hydrogen demand in the three scenarios in 2050.

Figure 31 depicts the hydrogen demands for the different considered processes and transportation modes in 2050. The highest deviations in hydrogen demand between the scenarios can be seen for the transportation modes of aviation, and road freight transport, as well as in the production of HVC and the generation of process heat.
Compared to the literature, the described demand scenarios are quite ambitious and have high total hydrogen demand (cf. section 3.4.1).

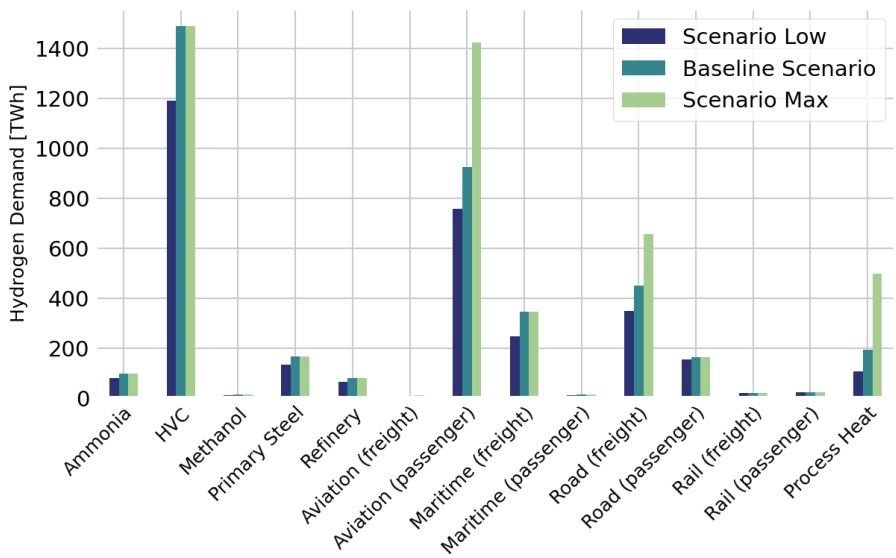

Figure 31. Hydrogen demand in 2050 in the three scenarios for different processes and transportation modes.

4 Hydrogen transport infrastructure

4.1 Options for future hydrogen grid

With the uptake of hydrogen demand until 2050, there will be a need for EU-wide hydrogen transport infrastructure to transport hydrogen from locations with high-RES potential to demand and storage locations. Since the location of these hydrogen supply centers will potentially not be located near demand and storage locations, hydrogen may need to be transported over considerable distances.
Potential hydrogen demand centers were identified in Chapter 0. A comparison between cheap hydrogen production and import locations reveals the large distance between supply and demand. The need for seasonal hydrogen storage, an evaluation of which is part of the HyUSPRe project, will additionally increase the need for hydrogen transport.

Hydrogen can be transported by trucks carrying hydrogen in either liquefied or gaseous state or by using a liquid organic hydrogen carrier. Other options are the use of pipeline or transportation via ships. To transport large amounts of hydrogen over large distances, transport by pipeline was found to be the most economic option. Wulf et al. [74] evaluated hydrogen transport options in a life cycle assessment and found that hydrogen pipeline transport has the least environmental impact for longer distances (>100km) in the analyzed categories compared to liquid organic hydrogen carriers and pressurized gas truck transport.

While Europe has the largest hydrogen pipeline distribution network in the world (status as of 2009) with 1,600 km of pipelines, these are multiple regional networks operated by merchant industrial gas companies (e.g. Air Liquide) [16]. Compared to the total length of the natural gas grid in Europe (over 2.2 million kilometers of pipelines in Europe that connect large geographical areas), this current hydrogen pipeline network is negligible [75].
Such a hydrogen distribution and transmission network does not exist currently. However, both the hydrogen strategy of the European Commission and other studies see the need for the development of a hydrogen transmission backbone by 2030 [15], [42]. Two main options exist for the creation of such a hydrogen pipeline network: building new dedicated hydrogen pipelines or reassigning existing natural gas pipelines [76]. Advantages of reassigning existing natural gas pipelines include the lower costs due to the already available infrastructure. Potential issues that are subject of research are the potential embrittlement of steel due to hydrogen. Furthermore, when reassigning natural gas pipelines to hydrogen pipelines, security of supply for natural gas needs to be ensured especially during the transitional phase [76]. Building new dedicated hydrogen pipelines requires significantly higher costs.

Levelized costs of transportation for reassigned natural gas pipelines have been estimated by Guidehouse to be around 0.07-0.15 €/kg/1000Km, compared to 0.16-0.24 €/kg/1000Km for new hydrogen pipelines [77]. Investment costs range from 0.3-0.6 M€/km for reassigned pipelines, while the cost for new pipelines is estimated to range from 0.93 to 3.28 M€/km for different pipeline diameters [18].
A study by EHB envisaged the development of a 11,600km (2030) and 39,700km (2040) hydrogen pipeline network connecting main hydrogen centers in Europe consisting of both repurposed pipelines (69%) and new hydrogen pipelines (31%) [42].
A future hydrogen transmission grid will probably be a combination of reassigned natural gas pipelines and newly built hydrogen pipelines [15]. For the construction of future candidate grids, we therefore consider both options.

4.2 Methodology

The goal of this part of the report is the assessment of possible hydrogen pipeline connections and the creation of pipeline candidate grids. These candidate grids should connect hydrogen supply, demand, and storage centers. Since hydrogen storage centers are going to be evaluated as part of this report, they are currently not available. We therefore only present the methodology for the candidate grid creation, which will be conducted in WP7 once all input data are available.
Besides repurposing existing natural gas pipelines, new dedicated hydrogen pipelines can be built to connect hydrogen supply and demand centers. In accordance with the literature, it is assumed that new pipelines can be built next to existing natural gas pipelines, roads, or railways [9], [78].

4.2.1 Possible pipeline connections

Data on the natural gas grid as well as the rail and road grid in Europe was used to create a database of all possible pipeline connections. The SciGRID Gas dataset was used as the data base for the current European gas transportation network [79]. SciGrid Gas provides processed geo-referenced data on compressor stations, LNG terminals, LNG storages and gas pipelines collected from various official sources. The data base for the current rail and road network was the EuroGlobalMap dataset [80]. The three datasets were further processed and merged resulting in a single pipeline candidate grid.
Two candidate grids have been created: One is based on new pipelines (all above-mentioned datasets), and one based on repurposed natural gas pipelines (only SciGrid Gas dataset). The reason for this is the different underlying cost assumptions as well as the capacity restriction for repurposed natural gas pipelines that do not exist for new pipelines. The candidate grid for new pipelines is shown in Figure 32.

Figure 33 shows the candidate grid for reassignment of natural gas pipelines based on the ScriGrid gas data set [79]. Color and thickness of the lines reflect the potential transfer capacities for hydrogen transport of each pipeline that are simplified estimated by the mass flow equation based on an average fluid velocity of 15 m/s and a density of 5.7 kg/m^3 (adapted from the assumptions of Baufumé et al. [78]).

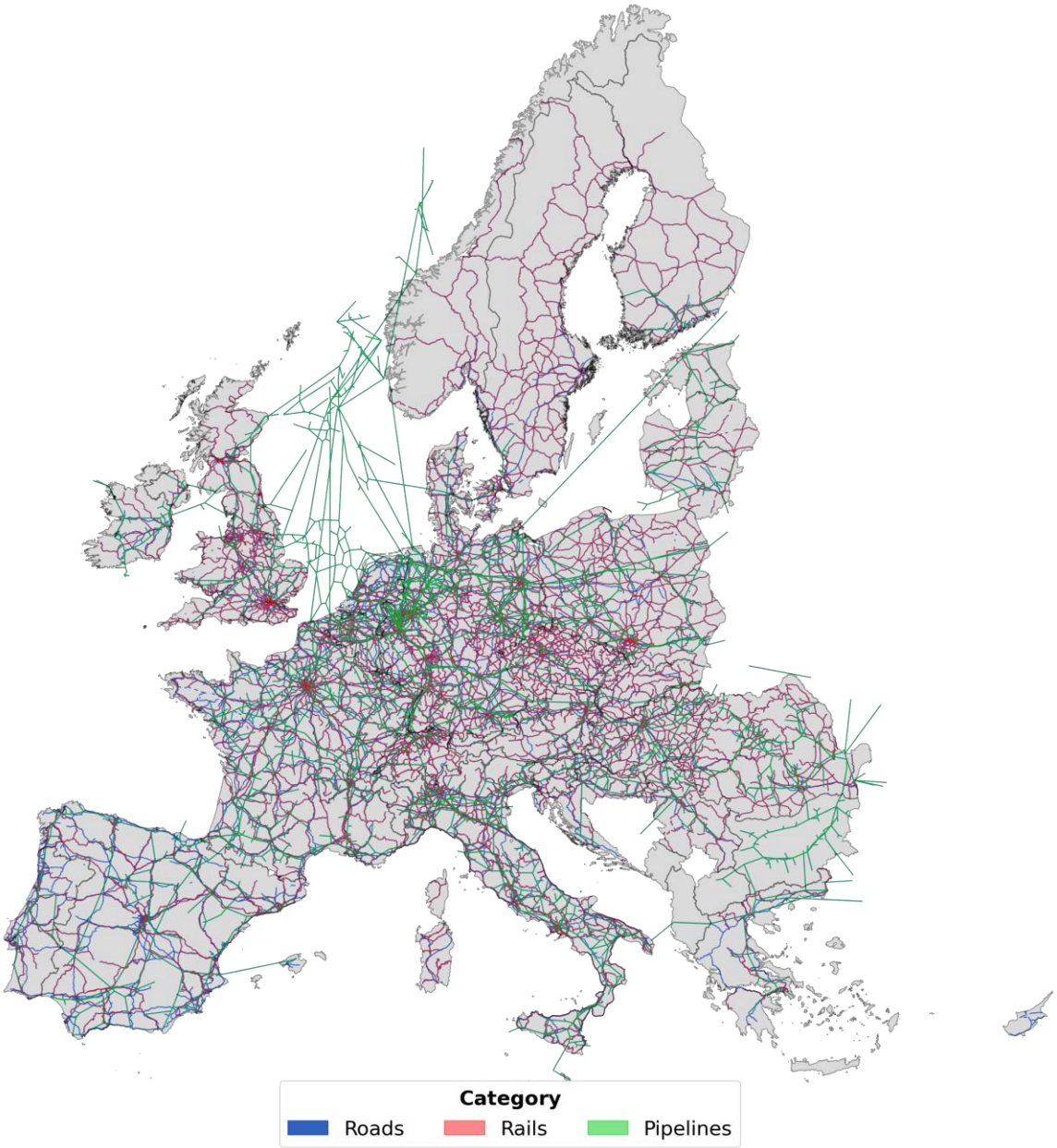

Figure 32. Candidate grid for new pipeline connections (for illustration purposes only roads classified as highways in the EuroGlobalMap dataset are shown) based on [79,80].

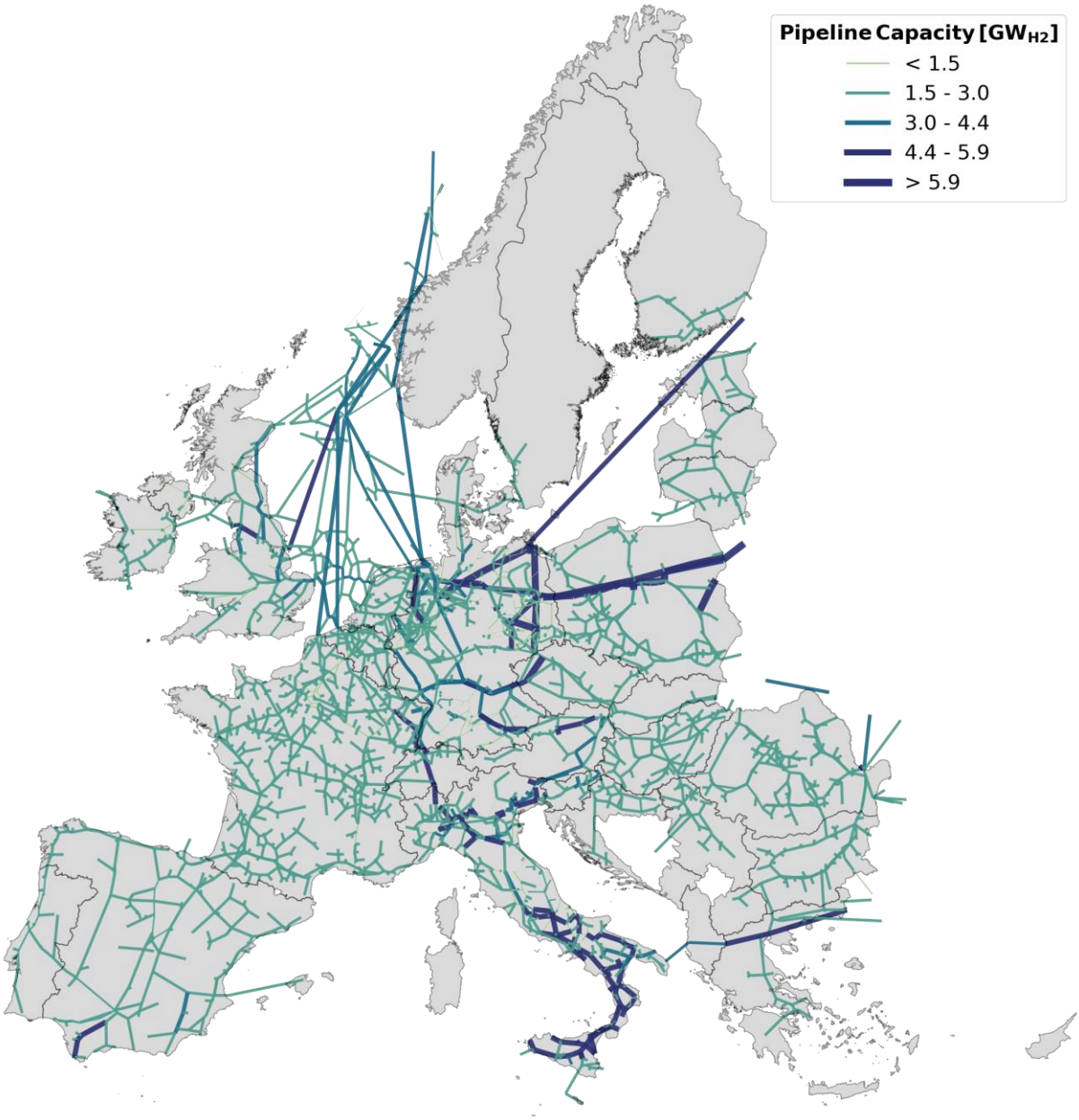

Figure 33. Candidate grid for reassignment of natural gas pipelines to hydrogen transport (based on SciGrid Gas data set [79]). Color and thickness of the lines reflect estimated potential of hydrogen transfer capacities if the pipelines are reassigned to hydrogen transport.

4.2.2 Connecting supply, demand and storage centers

The candidate grids can then be used to identify possible pipeline connections between supply, demand and storage centers. Hydrogen supply, demand and storage centers are given on a NUTS-2 level granularity (see sections 2 and 0). Therefore, supply, demand and storage centers are areas rather than point locations.

To connect two centers (supply, demand or storage) or NUTS-2 regions, respectively, with new hydrogen pipelines, the shortest paths between the centers on the candidate grid are calculated. Since the center is an area (NUTS-2 region), the point on the candidate grid

nearest to the centroid point of the regions is used as starting point for the calculation of the shortest path. The shortest path is then a possible pipeline connection between the two centers.

Demand centers can be defined by setting a user defined threshold on the minimum demand per region and excluding regions below that threshold. The remaining regions represent the demand centers. The same approach is used to identify supply and storage centers. Here the threshold variable is the maximum generation and the storage capacity in that region, respectively. As an example, pipeline routes are shown for 3 arbitrary supply, demand and storage centers in Figure 34.

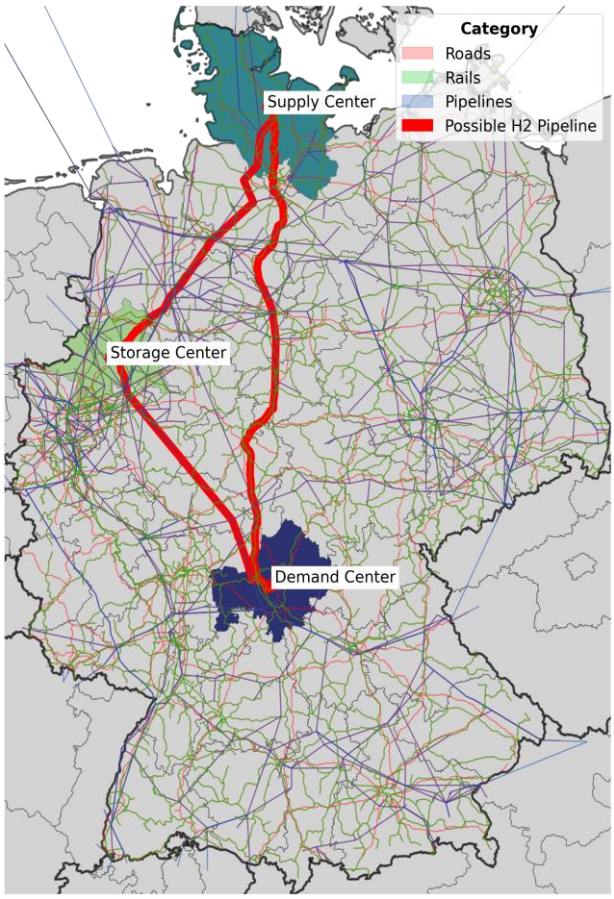

Figure 34. Example pipeline grid for three supply, demand and storage regions in Germany.

When no thresholds are set, a network that connects all regions is created. An example is shown in Figure 35. In this case, all NUTS-2 regions of Germany are connected to each other by the shortest path between two neighbored regions based on the candidate grid shown in Figure 32. Further analysis of future hydrogen candidate grids will be carried out as part of the energy system analysis in WP7.

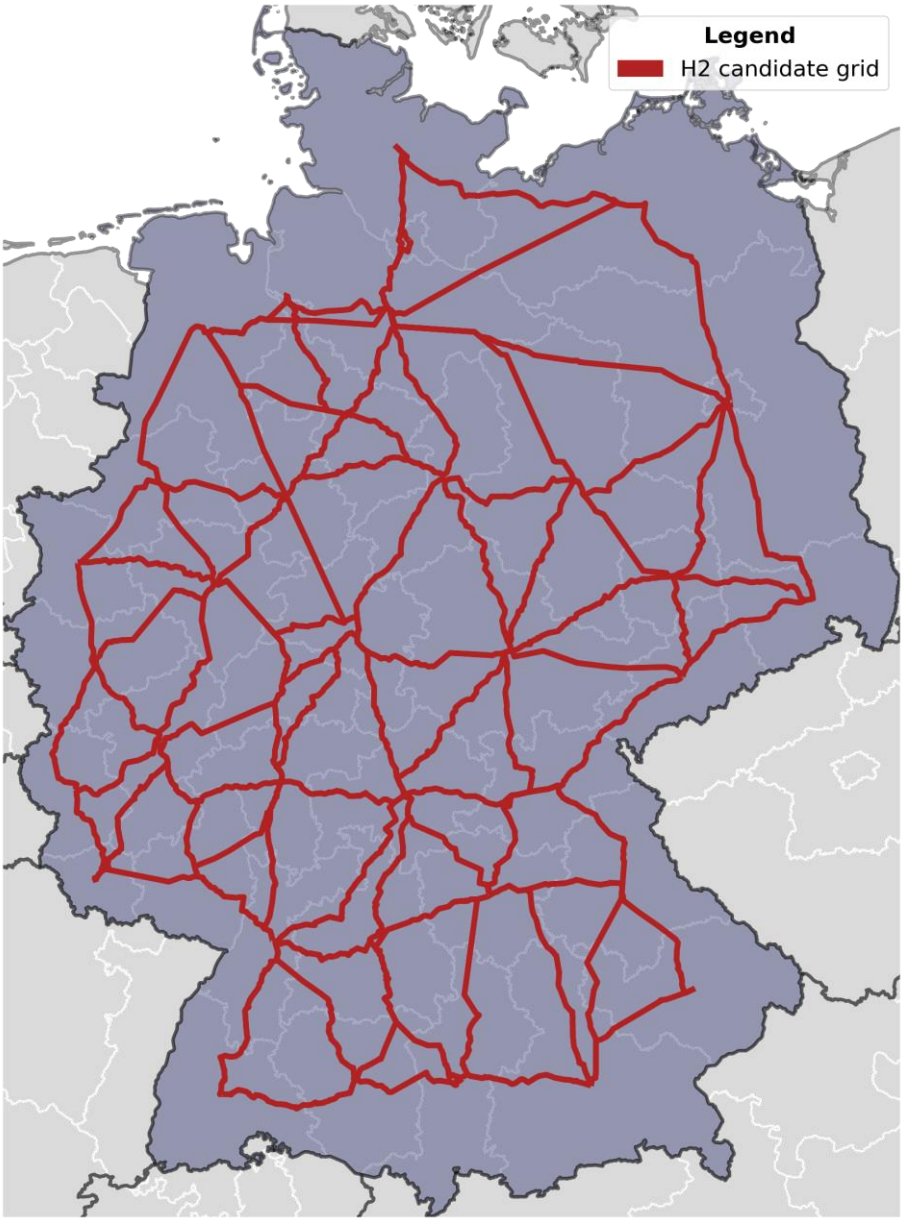

Figure 35. Candidate grid for new pipelines if all considered regions should be able to be connected to the grid shown for the example of Germany. For simplification, just neighbored regions can be directly connected to each other.

5 Concluding remarks

The report maps potential sites for hydrogen production from renewable energy sources and hydrogen demand centers in Europe. It also describes the methodology for identifying candidate grids for future hydrogen transport infrastructure. All results are integrated into a European energy system model for the assessment of future zero-emission energy systems (WP7).

In this report, the potentials of wind power and photovoltaics in Europe were evaluated to determine the amount of hydrogen that can be produced in Europe. The analysis shows that about 67 PWh_{H2} hydrogen can be produced annually from renewable energy sources in Europe, with costs ranging from 5 to 15 $€_{ct}$ per kWh_{H2}, depending on the type of renewable energy source.
Regions where hydrogen can be produced at low cost are in northern Europe for wind power, especially around the UK and the North Sea. Low-cost hydrogen from open-field PV systems can be produced in southern Europe, particularly in Spain, Portugal, and Italy. In addition, the potential of hydrogen imports from other, non-European countries was investigated. The cost of hydrogen imports ranged from 8.5 $€_{ct}/kWh_{H2}$ to 9.8 $€_{ct}/kWh_{H2}$, which is more expensive than much of the hydrogen production in Europe would be.

Hydrogen is considered by the European Commission to be one of the key technologies for achieving the EU's Green Deal targets of greenhouse gas neutrality by 2050.
In this report, we investigated two key lead markets for hydrogen applications, the industrial and transport sectors, and assessed their future hydrogen demand potential in 2030 and 2050. We identified key hydrogen applications for use as a feedstock in the industry sector, namely in the steel industry, the chemical industry and in petroleum refining, taking into account both existing and future applications of hydrogen. Future hydrogen demand was estimated for the years 2030 and 2050 on NUTS-2 level. Highest hydrogen demand arises in the transport sector (1,950 TWh in 2050, Baseline scenario), followed by the industry sector (1,842 TWh) and high-temperature process heat application (192 TWh). The demand can be summarized as following:

- The total hydrogen demand as feedstock in the industry in the baseline scenario was found to be 118 TWh in 2030 and 1,842 TWh in 2050.
- Here, the production of high value chemicals was identified as application with the highest hydrogen demand potential, reaching over 1,400 TWh in 2050. Hydrogen demand for the production of steel reaches 165 TWh in 2050. For the production of ammonia, methanol and in refineries hydrogen demands of 99 TWh, 14 TWh and 79 TWh arise, respectively.
- Hydrogen demand for high-temperature heat applications reaches 18 TWh and 192 TWh in 2030 and 2050 in the baseline scenario, with the highest demand arising in the cement industry.
- In the transport sectors, all transportation modes were considered, namely aviation, maritime, road and rail transport. Both, freight and passenger transport were considered in the analysis. Hydrogen demand in the transport sector totaled 397 TWh for 2030 and 1,950 TWh for 2050. The highest demand arises in the categories of passenger flights and road transport, followed by freight shipping and passenger cars. Other categories showed comparably low demands.

Similar to the vision of the European Commission's hydrogen strategy [15], we have identified that local hydrogen demand centers will emerge. These hydrogen demand centers are located in today's distinct industrial centers in Europe, as well as in places with high transportation needs, such as airports and ports.

In order to evaluate the hydrogen demand potentials, we introduced two additional demand scenarios with a lower and a higher hydrogen demand, which are used for the techno-economic analyses in WP7. For the short-term future, hydrogen demands between 400 and 750 TWh_{H2}/a are observed. For the long-term future, hydrogen demand between 3,000 and 5,000 TWh_{H2}/a are observed. Comparing these to the hydrogen production potentials, it is noticeable that the entire demand can be met by production within the EU.

The long distances between hydrogen demand centers and hydrogen supply centers necessitate an EU-wide hydrogen transport infrastructure. For longer distances, pipeline transport has proven to be the most economical option. In this report, potential hydrogen candidate grids were identified from newly constructed hydrogen pipelines and reassigned natural gas pipelines. Further analysis of future hydrogen candidate grids will be conducted as part of the energy system analysis in WP7.

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Appendix

Table A1. List of preferential regions considered in the import model (cf. Section 2.2).

Renewable Energy Source	Preferential Region
Wind	Argentina (Patagonia)
	Chile
	Iceland
	Norway
	UK
	Ireland
	Canada (British Columbia)
	Canada (Newfoundland)
	China (Inner Mongolia)
Solar	USA
	Mexico
	Peru
	Chile

Table A2. Sources for abbreviations in Figure 22 (cf. Section 3.4.1).

Study Abbreviation	Source
EC - Impact assesment SWD	[81]
EC JRC - LCEO Net Zero	[82]
Guidehouse EHB 2021	[42]
FCH Roadmap	[17]
EC LTS	[83]
Öko Vision	[84]
ECF Shared Effort	[85]
Navigant Optimized gas	[21]
Hydrogen4EU	[86]
AURORA	[87]
EC SI	[30]
Dechema	[25]
Reflex	[88]

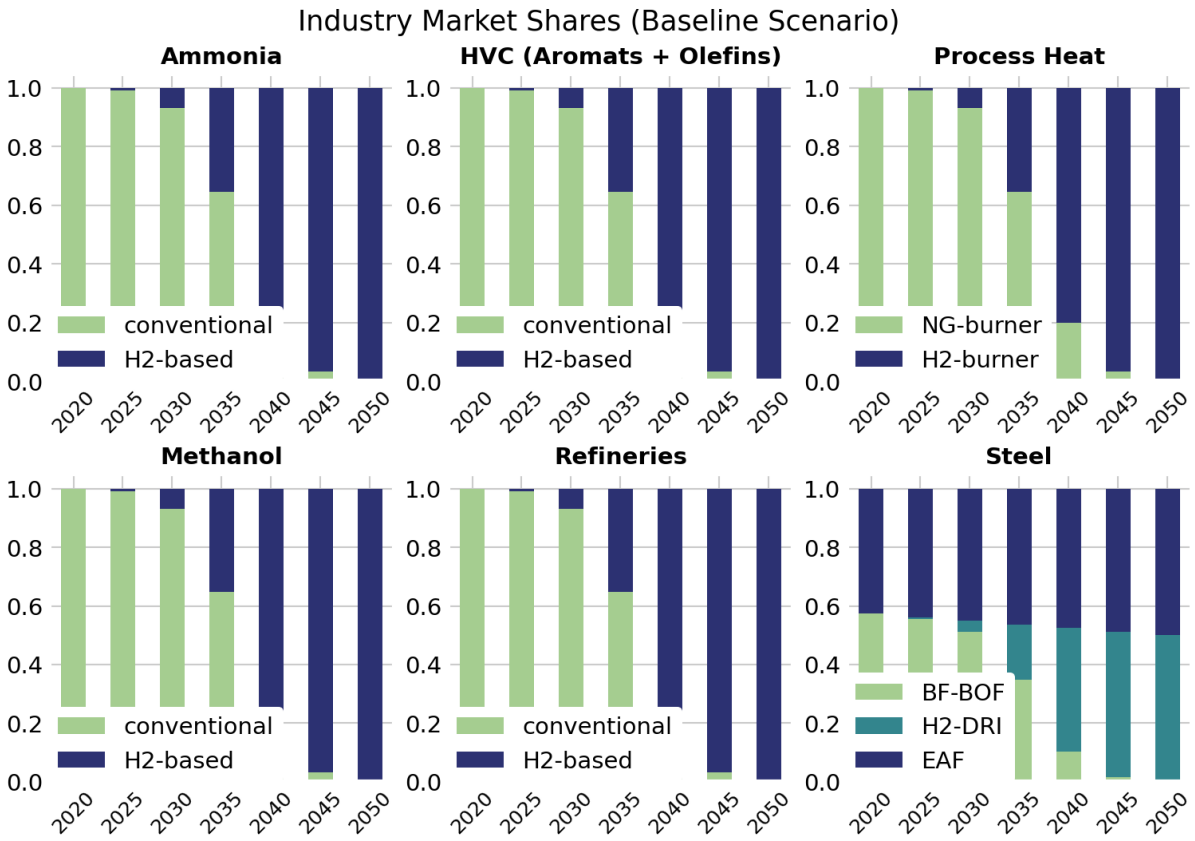
Table A3. Sources for industry database (cf. Section 3.2.4).

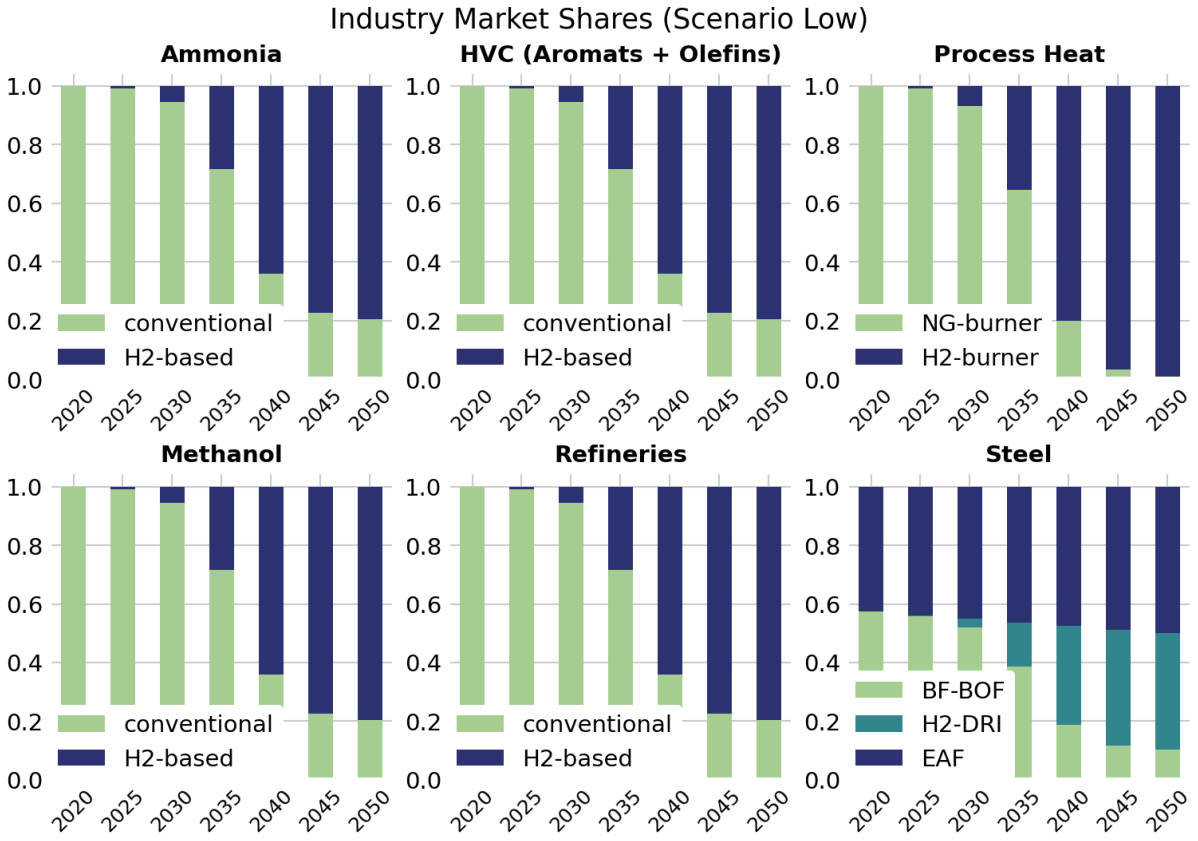
Process	Source	Source
Iron & Steel	Eurofer and Global Energy Monitor	[56], [57]
Chemial Industry (Ammonia, Methanol, HVC)	JRC plant database	[41]
Refineries	Concawe	[58]
Heat	European Transaction Log	[32]

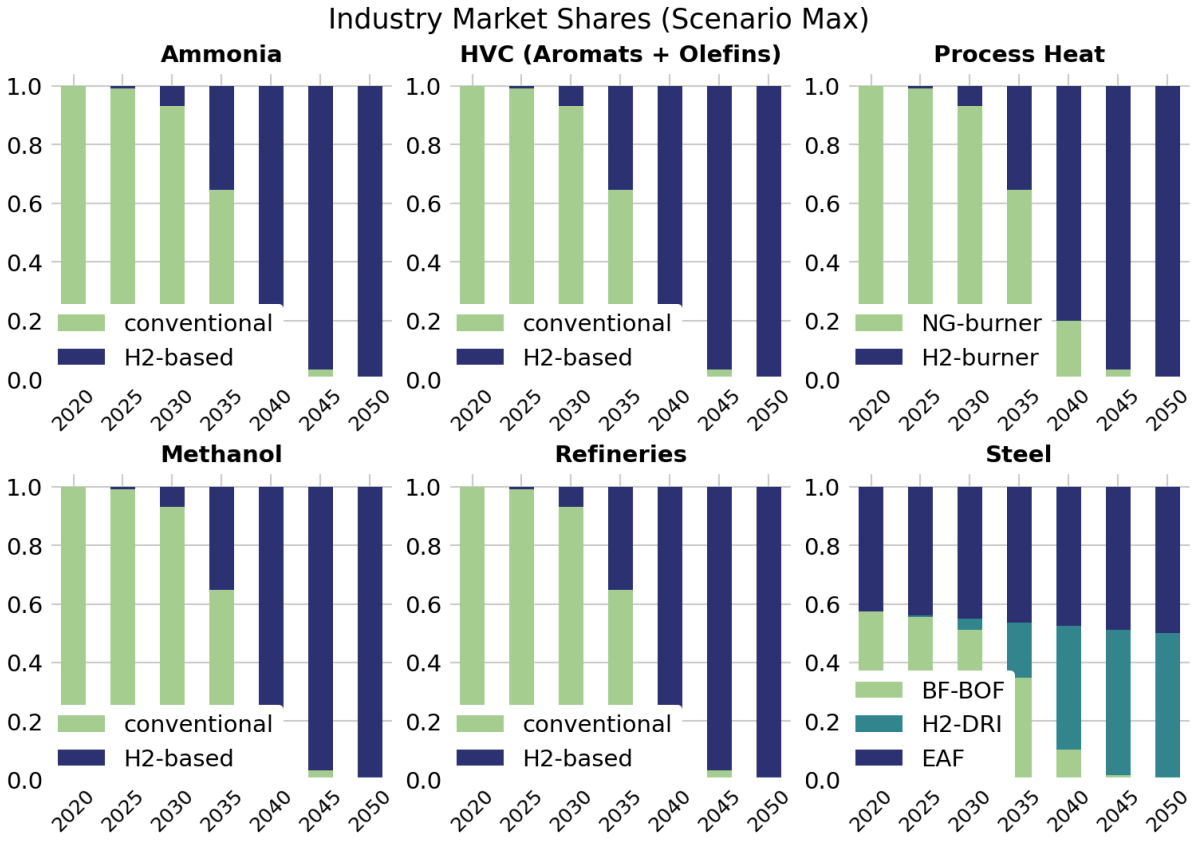
Assumed Market Shares in the three Scenarios

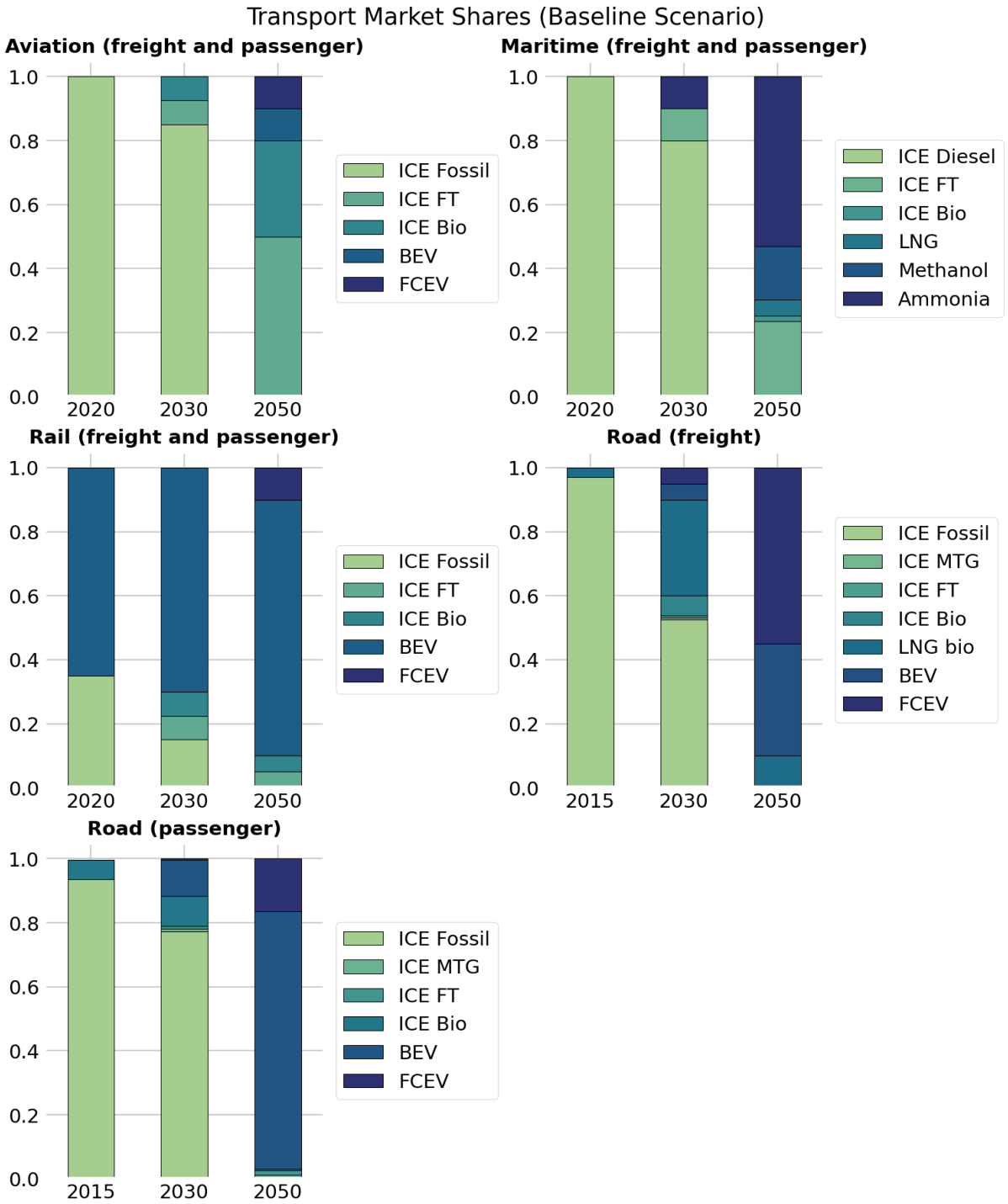
In the following, the market shares for each of the three created scenarios (*Baseline Scenario, Scenario Low, Scenario Max)* for the industry and transport sector are given. The underlying data and assumptions are described in Chapter 3.4.

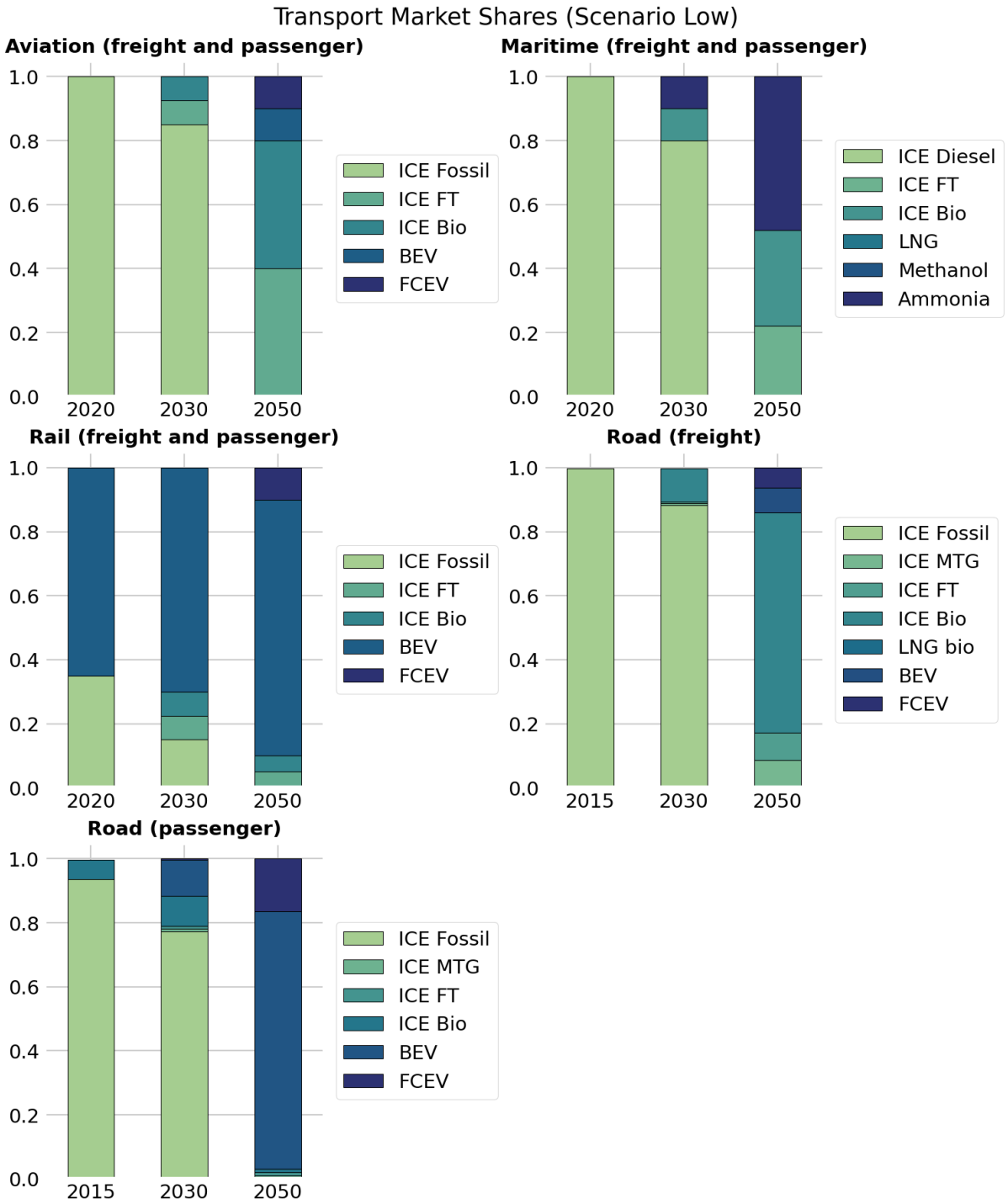
Here, the market shares for the different industry sectors are shown for the years from 2020 to 2050 in 5-year steps for each scenario.
For the transport sector the market shares are given for a current year and for 2030 and 2050. Market shares for aviation, maritime and rail are assumed to be the same for passenger and freight. Different assumptions about market shares were made for road freight and road passenger transport, respectively.

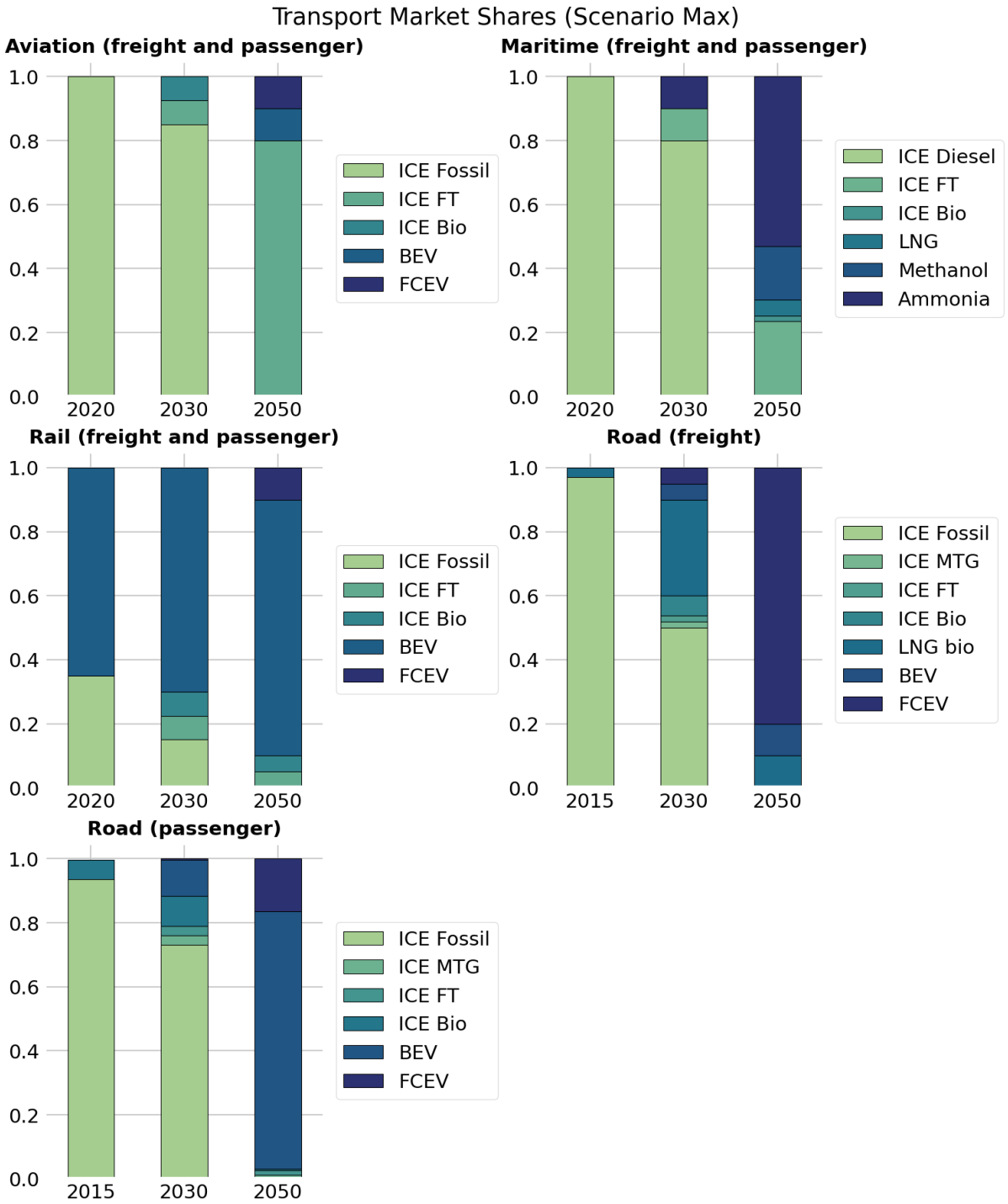



Industry Market Shares (Scenario Low)
Ammonia
HVC (Aromats + Olefins)
Process Heat
Methanol
Refineries
Steel
conventional
H2-based
NG-burner
H2-burner
BF-BOF
H2-DRI
EAF
1.0
0.8
0.6
0.4
0.2
0.0
2020
2025
2030
2035
2040
2045
2050


Industry Market Shares (Scenario Max)
Ammonia
HVC (Aromats + Olefins)
Process Heat
Methanol
Refineries
Steel
conventional
H2-based
NG-burner
H2-burner
BF-BOF
H2-DRI
EAF
1.0
0.8
0.6
0.4
0.2
0.0
2020
2025
2030
2035
2040
2045
2050


Transport Market Shares (Baseline Scenario)
Aviation (freight and passenger)
1.0
0.8
0.6
0.4
0.2
0.0
2020
2030
2050
ICE Fossil
ICE FT
ICE Bio
BEV
FCEV
Maritime (freight and passenger)
ICE Diesel
ICE FT
ICE Bio
LNG
Methanol
Ammonia
Rail (freight and passenger)
ICE Fossil
ICE FT
ICE Bio
BEV
FCEV
Road (freight)
2015
2030
2050
ICE Fossil
ICE MTG
ICE FT
ICE Bio
LNG bio
BEV
FCEV
Road (passenger)
ICE Fossil
ICE MTG
ICE FT
ICE Bio
BEV
FCEV


Transport Market Shares (Scenario Low)
Aviation (freight and passenger)
1.0
0.8
0.6
0.4
0.2
0.0
2020
2030
2050
ICE Fossil
ICE FT
ICE Bio
BEV
FCEV
Maritime (freight and passenger)
ICE Diesel
ICE FT
ICE Bio
LNG
Methanol
Ammonia
Rail (freight and passenger)
ICE Fossil
ICE FT
ICE Bio
BEV
FCEV
Road (freight)
2015
2030
2050
ICE Fossil
ICE MTG
ICE FT
ICE Bio
LNG bio
BEV
FCEV
Road (passenger)
ICE Fossil
ICE MTG
ICE FT
ICE Bio
BEV
FCEV


Transport Market Shares (Scenario Max)
Aviation (freight and passenger)
1.0
0.8
0.6
0.4
0.2
0.0
2020
2030
2050
ICE Fossil
ICE FT
ICE Bio
BEV
FCEV
Maritime (freight and passenger)
ICE Diesel
ICE FT
ICE Bio
LNG
Methanol
Ammonia
Rail (freight and passenger)
ICE Fossil
ICE FT
ICE Bio
BEV
FCEV
Road (freight)
2015
2030
2050
ICE Fossil
ICE MTG
ICE FT
ICE Bio
LNG bio
BEV
FCEV
Road (passenger)
ICE Fossil
ICE MTG
ICE FT
ICE Bio
BEV
FCEV