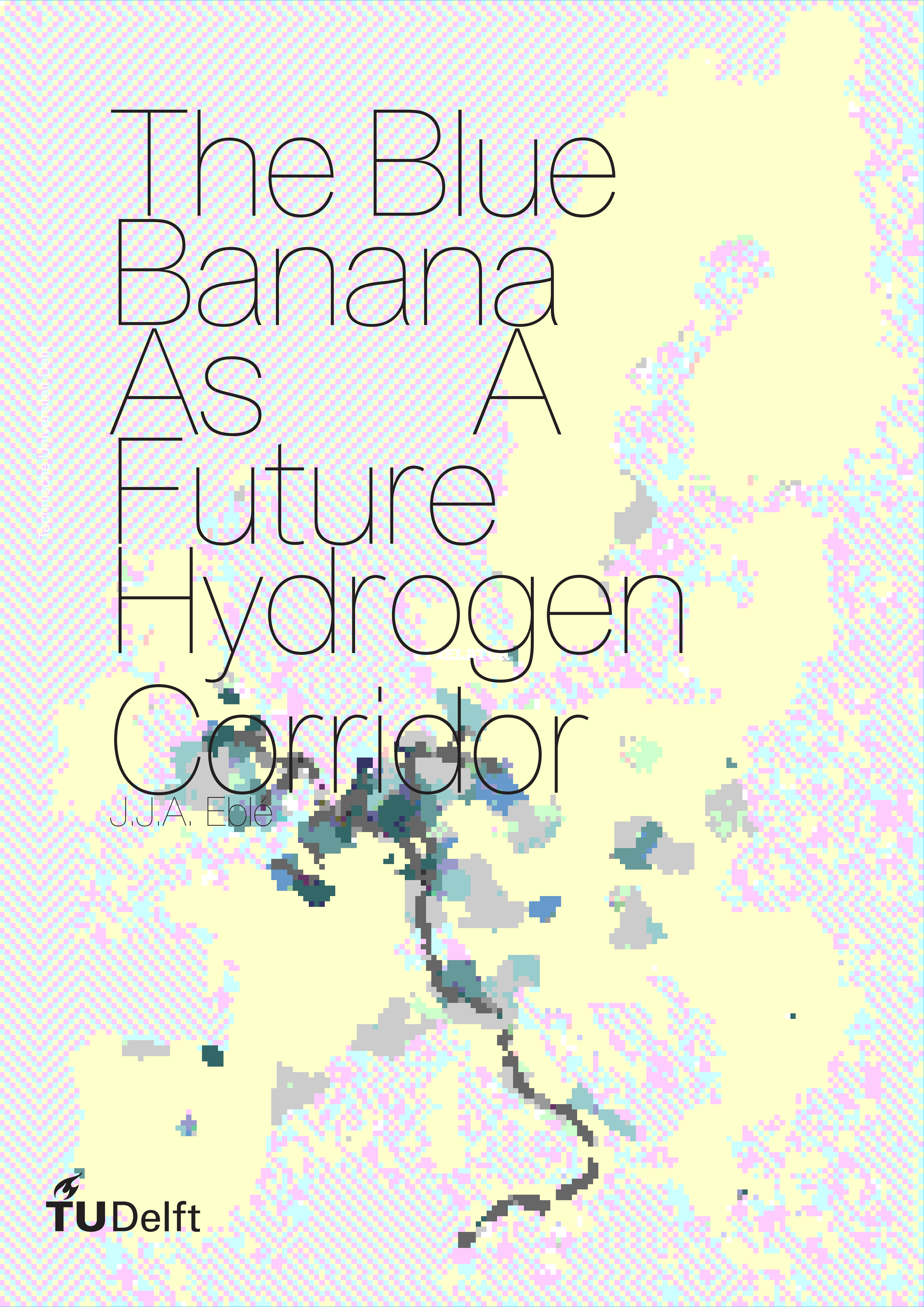

The Blue Banana As A Future Hydrogen Corridor

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by

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Abstract

In order to limit global warming to well below 2°C compared to pre-industrial temperatures, a lot still needs to happen. Carbon free hydrogen as an energy carrier can significantly reduce the CO_2 emissions of the entire energy system. In this report, a concept for a spatially efficient, initial hydrogen corridor in the European Union is proposed. The corridor links up areas with high hydrogen consumption to regions with great hydrogen production potential.

The spatial distribution of hydrogen demand in a bottom-up scenario was determined first. With this information an optimal hydrogen corridor was composed and subsequently the consumption potential for this corridor was estimated. Finally a hydrogen system was designed with plans for production, transmission and storage.

The areas that make up the corridor, going from the Sahara to the North of England, have a combined surface area of only 7% of the EU total. The proposed corridor currently consumes 50% of the total hydrogen consumption in the EU. In 2050 the corridor will consume an estimated 33% of the EU total. In an ambitious scenario, the proposed system is designed to produce and transport almost 31 million tons of hydrogen, or about 1200 TWh, to the corridor. About 35% of the hydrogen is produced in the EU, mainly on the North-Sea, and the rest in the Sahara desert. The hydrogen is distributed among the corridor by identifying 7800 kilometers of existing natural gas infrastructure. The estimated levelised cost of hydrogen transmission amount to $0.12\frac{€}{\mathrm{kg}}$. Next to that more than enough hydrogen storage potential is available in the vicinity of the infrastructure using already existing rock-salt caverns.

Although the project presented in this research may be of large scale and bring severe challenges, the positive environmental consequences are potentially even greater. The EU has the bold ambition to make Europe the first climate neutral continent on the planet and this hydrogen corridor can very significantly contribute to this ambition. Furthermore the EU currently has the political and economic power, as well as the required knowledge, to take a leading role in the development of hydrogen technology. A leading role that may turn out to be very profitable because hydrogen, with its versatility and undeniable strength to decarbonise entire energy systems, will undoubtedly be used by the rest of the world.

Preface

I would like to start by thanking my thesis committee for their assistance during the past months. Especially Prof. Dr. Blok, for daily supervision and helpful comments during a long journey that, in the end, thankfully brought me to a subject that I really enjoyed working on.

I would also like to specifically thank EUROFER, Fertilizers Europe and Dr. Dominic Royé for data and helpful comments.

For always having an answer to whatever question I come up with, my gratitude goes out to the online communities of R and LaTeX.

J.J.A. Eblé, Delft, February 2020

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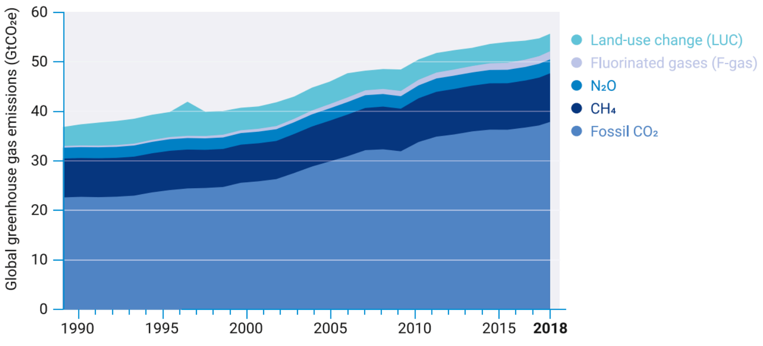
1 Introduction

This section will introduce the main thoughts on which this research was built. The problem that society is facing will first be discussed in section 1.1. This societal problem will be translated into a scientific problem that will mark the beginning of the research, in which there will be an attempt to propose a partial solution to this problem. Section 1.2 will be about determining the current state of the literature regarding the chosen subject and problem. Finally, in section 1.3, the gaps from the literature review will result in several key research questions that, when answered, may help to find a solution for the main issue at hand.

1.1. Identifying the problem

The crisis around fighting climate change and global warming can hardly be described as anything else but one of the biggest challenges that mankind has faced in its history. Five years ago 187 parties have agreed to limit global warming to well below 2°C above pre-industrial levels, and pursue efforts to keep this rise below 1.5°C [UN, 2015]. In order to attempt to illustrate the gravity of this commitment, and the monumental challenge facing humanity, the following pieces of information are provided. First, the annual global greenhouse gas emissions from 1989 to 2018 are presented in figure 1.1.



Source: Olivier and Peters (2019), Houghton and Nassikas (2017) for land-use change emissions, and Friedlingstein *et al.* (2019) for updates from 2016 to 2018

Figure 1.1: Global greenhouse gas emissions, source: [UNEP, 2019].

As a stark contrast to figure 1.1, from 2020 to 2030, scenario planners estimate that emissions need to be cut by a total of 25% for a 66% probability to limit global warming to the previously mentioned 2°C [UNEP, 2019]. This is highly remarkable because yearly growth of these emissions was 1.5% on average in the past decade and, as can be seen in figure 1.1, have gone nowhere but up in the past thirty years, although the rise in emissions has stagnated in 2019.

On a more positive note, there is one region that has achieved a relatively steady decline of emissions over the past three decades: the European Union [UNEP, 2019]. To indicate its pledge, among the 187 parties that signed the Paris Agreement were all 28 member states of the EU as well as the EU itself as an institution. In December of 2019 the EU announced its Green Deal to become the first climate neutral continent on the planet [European Commission, 2019].

Nevertheless, the EU is the third largest emitter of greenhouse gasses, after China and the United States of America [UNEP, 2019]. So reaching this goal of becoming climate neutral is still a tall order and calls for close collaboration of politics, governments, companies, the academic community and other stakeholders. Above all, however, it needs efficient and rapid introduction of new technologies to replace their current carbon intensive equivalents.

Several technologies and concepts have been high on the EU policy agenda for some years now. Increasing the efficiency of how energy is consumed and switching to more efficient fuels for example. In addition there is focus on increasing electrification of certain sectors and subsequently increasing the share of renewables in the electricity mix. These three policy strategies have reduced greenhouse gas emissions from the EU between 1990 and 2016 by 22%, all while GDP has grown by 54% over the same period [European Commission, 2018].

However, new technologies are still crucial because the aforementioned policies will not be enough to reach the objective and hardly affect some energy intensive sectors that are essential to decarbonise. These sectors are the so called *hard to abate sectors*. Many technologies and concepts with more far reaching capabilities for the energy system, including these hard to abate sectors, focus on the use of hydrogen. Hydrogen can become the most important element in the energy transition. *The potential of this disruptor is enormous. With its relatively high energy density, hydrogen can be used as an energy carrier in almost all sectors and a wide variety of applications* [McKinsey, 2018]. This versatility, its multimodality, is well described by figure 1.2, an excerpt from the *Hydrogen roadmap Europe* report [FCH JU, 2019].

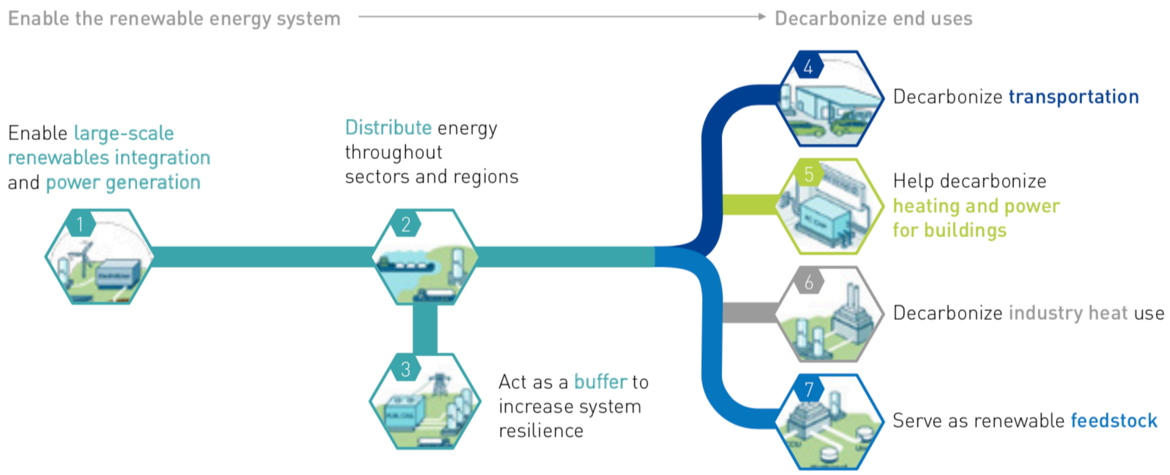


Figure 1.2: Hydrogen as enabler of the energy transition in Europe, source: [FCH JU, 2019].

Another attribute in favor of hydrogen is that it can be produced using electricity. Electrolysis uses an electrical current to split water into oxygen and hydrogen. If the electricity for this process comes from a renewable source, the produced hydrogen is a completely carbon neutral energy carrier.

The vast potential of hydrogen has not gone unnoticed by the European Commission, as it is already mentioned in The European Green Deal [European Commission, 2019]. Even more, further back in 2008 The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) was established, a public private partnership with the European Commission, industries and research organisations. At the start of 2019 this organisation published the [FCH JU, 2019]

[FCH JU, 2019], a detailed pathway for the introduction of hydrogen into the European energy transition.

So, what is the reason that, except for industrial uses, there is no widespread consumption of hydrogen already? Why were there only 120 hydrogen refueling stations in the EU at the end of 2018? [FCH JU, 2019]. The biggest issue is affordability of hydrogen, which is because complex hydrogen technologies have not been scaled up sufficiently.

But the main issue, which also grossly affects research & development, and thus affordability, is that continent wide introduction of hydrogen has suffered under the famous *chicken or the egg* dilemma. Why would one buy a car powered by a fuel cell that runs on hydrogen, if refueling stations that will provide hydrogen are almost nowhere to find? And vice versa; why would a company invest in a hydrogen refueling station if there is no market for this company to profit from?

This vicious circle, combined with the great potential of hydrogen and the bold ambitions of the European Union, calls for the introduction of an infrastructure that is able to supply low carbon hydrogen to end use sectors for a large portion of the EU. An initial hydrogen corridor that has the ability to kick start the bright future of hydrogen and hereby making a serious contribution to the ambition of the EU to become the first climate neutral continent.

1.2. Literature review

This section will give an overview of current literature and state of art regarding hydrogen and hydrogen infrastructure. The production of hydrogen will be discussed in section 1.2.1. Next, section 1.2.2 will explain existing usage of hydrogen. After this, section 1.2.3 will review the possible future use of hydrogen. Additionally scenarios that model the potential future hydrogen demand will be treated in section 1.2.4. Finally the literature of demand analysis and infrastructure modelling will be discussed in section 1.2.5.

1.2.1. Production from grey to green hydrogen

Hydrogen can be produced using several different methods. 95% of hydrogen in the EU is currently produced using fossil fuels [FCH JU, 2019]. An overview of production methods can be found in figure 1.3. The process that is currently used the most, steam methane reforming, and electrolysis, with great future potential, will be discussed is the rest of this chapter.

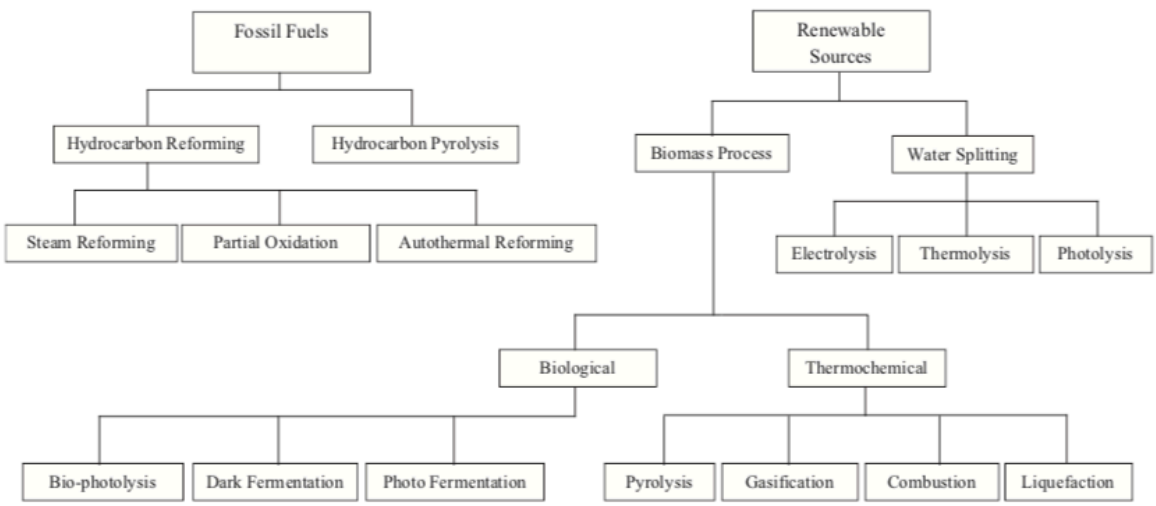


Figure 1.3: Overview of hydrogen production methods, source: [Nikolaidis and Poullikkas, 2017].

Steam methane reforming

The dominant form of production in the EU is called *steam methane reforming* (SMR). Globally 6% of natural gas is converted to hydrogen [IEA, 2019a]. The main steps for production are [Nikolaidis and Poullikkas, 2017]:

1. Methane, of which about 30% is used to fuel the process, together with steam enters the reformer, where the following reaction takes place:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{1.1}$$

2. The water gas shift reaction takes place to produce additional hydrogen with the carbon monoxide:

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{1.2}$$

3. The carbon dioxide and hydrogen are split using pressure swing adsorption.

In short the process converts methane (CH_4) into mainly CO_2 and the desired product, hydrogen. A state of the art steam methane reformer emits 10.9 kilograms of CO_2 equivalent greenhouse gasses to produce 1 kilogram of hydrogen [CertifHy, 2019].

Using this information, the EU hydrogen consumption of 339 TWh in 2018 resulted in the production of almost 100 million tonnes of CO_2, which equals about half the greenhouse gas emissions of The Netherlands in 2017 [Eurostat, 2019b]. This indicates that before hydrogen can even remotely contribute to the decarbonisation of the energy system, production methods will need to become cleaner.

Electrolysis

Luckily, as previously stated, hydrogen can be produced using renewable electricity in combination with electrolysis. Electrolysis splits water into hydrogen and oxygen. Three main electrolyser technologies are currently in use, as presented in table 1.1. The expected technological development, efficiency and capital investment costs, are displayed in figure 1.4.

Electrolyser Type	**Alkaline**	**Solid Oxide Electrolysis Cells (SOEC)**	**Proton Exchange Membrane (PEM)**
Anode reaction	$4OH^- \rightarrow O_2 + 2H_2O + 4e^-$		$2H_2O \rightarrow O_2 + 4H^+ + 4e^-$
Cathode reaction	$2H_2O + 2e^- \rightarrow 2OH^- + H_2$		$4H^+ + 4e^- \rightarrow 2H_2$
Notes	Most mature technology. Relatively low capital costs because use of precious metals is avoided.	Least developed technology. High efficiency but needs high temperature to function. Waste heat recovery from other processes may overcome this problem.	Smaller size and very flexible operating range. Can also produce hydrogen at high pressures which may avoid the extra use of compressors.

Table 1.1: Electrolyser technology overview. Anode & cathode reactions source: [Nikolaidis and Poullikkas, 2017]. Notes source:[IEA, 2019a].

	Alkaline electrolyser			SOEC electrolyser			PEM electrolyser		
	Today	2030	Long term	Today	2030	Long term	Today	2030	Long-term
Electrical efficiency (%, LHV)	63–70	65–71	70–80	74–81	77–84	77–90	56–60	63–68	67–74
CAPEX (USD/kW$_e$)	500 – 1400	400 – 850	200 – 700	2 800 – 5 600	800 – 2 800	500 – 1 000	1 100 – 1 800	650 – 1 500	200 – 900

Figure 1.4: Expected development of electrolyser technologies, source: [IEA, 2019a].

One possibility for electrolysis is to profit from the intermittency of renewable energy sources by creating green hydrogen that would otherwise be curtailed [Troncoso and Newborough, 2011]. Though a fundamental flaw in this concept lies in the fact that curtailment still only occurs for a very limited time, resulting in a low capacity factor, or operating time, for the electrolyser. This in turn greatly impacts the price of the produced hydrogen or the pay-back time of the electrolyser [Nikolaidis and Poullikkas, 2017].

Another option is to choose for dedicated renewable energy for hydrogen production. One area of interest for the EU is the vast wind potential on the North Sea, where as much as 212 GW of wind capacity may be installed in 2050 [WindEurope, 2019]. About 15 GW of wind energy may be available in 2050 in coastal regions of The Netherlands specifically for hydrogen production [Gasunie, 2018]. In addition to the North Sea, at the south of Europe is arguably an even bigger potential source for hydrogen production. The Sahara desert is the world's sunniest area and possesses very favorable wind conditions [van Wijk and Wouters, 2020]. Using the power of the sun alone, only a little over 7% of the surface area of the Sahara could provide the same amount of energy that the entire world consumed in 2016 [van Wijk et al., 2017]. The concept is that hydrogen can be produced in places like these and then transported to the EU, which is a lot more efficient than transporting electricity in these large quantities over these kind of distances [IEA, 2019a].

1.2.2. Existing hydrogen demand

Hydrogen has already been in use for a long period of time, mainly for the feedstock of several industrial processes. Identifying where and how much hydrogen is being consumed obviously requires knowledge about what industries and processes require hydrogen.

Current hydrogen consumption can be split up into two main groups. The first is industry feedstock, which is the largest with a contribution of 96% to the EU total, and the second group is niche applications [FCH JU, 2019]. These niche applications are things like rocket- or automotive -fuel and the semi-conductor industry. For this research the niche applications will not be treated, except for automotive transport, which will be treated as the transport sector in this research. The hydrogen consumption in industry feedstock is dominated by only three industries: refining crude oil, the production of ammonia and the production of methanol. These three industrial sectors consume 91% of the 339 TWh of hydrogen the EU consumed in 2018, which was about 2.4% of total final energy demand [FCH JU, 2019].

Oil refineries

In oil refineries, hydrogen is used to process crude oil into better consumable products like kerosene, gasoline and diesel. With the use of hydrogen, heavy crude oil is 'cracked' into lighter crudes with a higher hydrogen content. In addition, hydrogen is used to remove sulphur from 'sour' crude oil. These processes are called *hydro-cracking* and *hydro-treating desulphurization* [Fraile et al., 2015]. In 2018 these two processes consumed a total of 153 TWh of hydrogen [FCH JU, 2019].

Ammonia

Ammonia is used as a chemical feedstock for numerous products. Of these products, fertilizer for the agricultural sectors is by far the largest consumer of ammonia [IEA, 2019a]. In 2018 the production of ammonia needed 129 TWh of hydrogen [FCH JU, 2019].

Ammonia is produced using the *Haber-Bosch* process. This process converts hydrogen and atmospheric nitrogen into ammonia via chemical equation 1.3 [Vojvodic et al., 2014].

$$\mathrm{N_2 + 3H_2 \longrightarrow 2NH_3} \tag{1.3}$$

Methanol

Methanol is used as a feedstock for synthesis of other chemicals, a fuel or a hydrogen carrier [Cifre and Badr, 2007]. For the production of methanol, 27 TWh of hydrogen was consumed in 2018. Methanol (CH_3OH) can be produced by several processes. The most used process starts by the production of synthesis gas (syngas) from some carbon containing feedstock, often natural gas (equation 1.1). This syngas, a mixture of mainly CO_2, CO and H_2 is subsequently synthesized to methanol by reaction 1.4 and 1.5 [Cheng, 1994].

$$CO + 2H_2 \rightleftharpoons CH_3OH \tag{1.4}$$

$$CO_2 + 3H_2 \rightleftharpoons CH_3OH + H_2O \tag{1.5}$$

One important thing to remark is that production processes may shift towards a slowdown of the use of fossil fuel based syngas for the production of methanol, because of environmental concerns regarding the use of these type of fuels. In that case, using biomass based syngas is one option. The other option is the circular use CO_2, captured and stored from an earlier process or from the atmosphere, and renewable hydrogen to produce methanol using equation 1.5.

1.2.3. Future hydrogen activity in other sectors

Having discussed the current hydrogen consumption, the potential future hydrogen consumption should be looked into as well. Once access and affordability of hydrogen is improved, its use will most likely spread to many other sectors. This section will highlight the main sectors in which hydrogen may be able to play a significant role in decarbonising said sector. The quantities of hydrogen consumption will be discussed in coming chapters.

Iron & steel

The production of steel in the EU emits around 63 million tonnes of CO_2 equivalent annually [Eurostat, 2017]. The current processes rely on the use of fossil fuels and are notoriously hard to make more sustainable. One promising method to produce steel with a lower carbon footprint is called *Direct Reduced Iron*, or DRI. This process uses hydrogen, instead of CO, to reduce iron ore. The product is thus iron and water, instead of iron and CO_2. A schematic representation of the conventional process and the DRI process can be seen in figure 1.5.

HYBRIT, a Swedish joint venture, commenced the pilot phase of a DRI plant in 2018. At later stages in the project, the estimation is that steel may be produced with an emission of only 25 kg of CO_2 per tonne of crude steel, compared to around 1600 kg of CO_2 per tonne of crude steel for the conventional method [HYBRIT, 2017].

Heating

Hydrogen can also be used for heating applications like space heating and supplying heat for industry. Hydrogen is a combustible substance that burns in the presence of a sufficient amount of oxidation agent like oxygen after ignition, just like for instance methane. But burning hydrogen emits no greenhouse gasses. The only product of combustion with oxygen is water vapor.

Burning hydrogen for heat has already been done for numerous years. Before the switch to natural gas, coal gas was a source of energy for industrial- and residential -applications. This gas contained a significant amount of hydrogen and was used for, among other things, heat [Smith et al., 1988]. Next to this, hydrogen is a by-product of several industrial processes. If there is no use for this gas for further applications, it is often burned as a source of heat [IEA, 2019a].

Current hardware is able to burn gasses with a low hydrogen content, which means that blending fractions of hydrogen is a possibility [IEA, 2019a]. But to be able to increase the hydrogen content, or even run on 100% hydrogen, does require changes to existing boilers and gas flow meters [Hellinga et al., 2019]. For industrial heat, similar conditions apply. Severely increasing hydrogen content for heat applications may require changing the burners, although that is obviously dependent on the medium that is currently being combusted [IEA, 2019a].

Transport

In transport hydrogen can be used in a *Fuel-Cell Electric Vehicle*, or FCEV. Hydrogen could also be used in a reciprocating engine, but using a fuel-cell is a lot more efficient, and thus

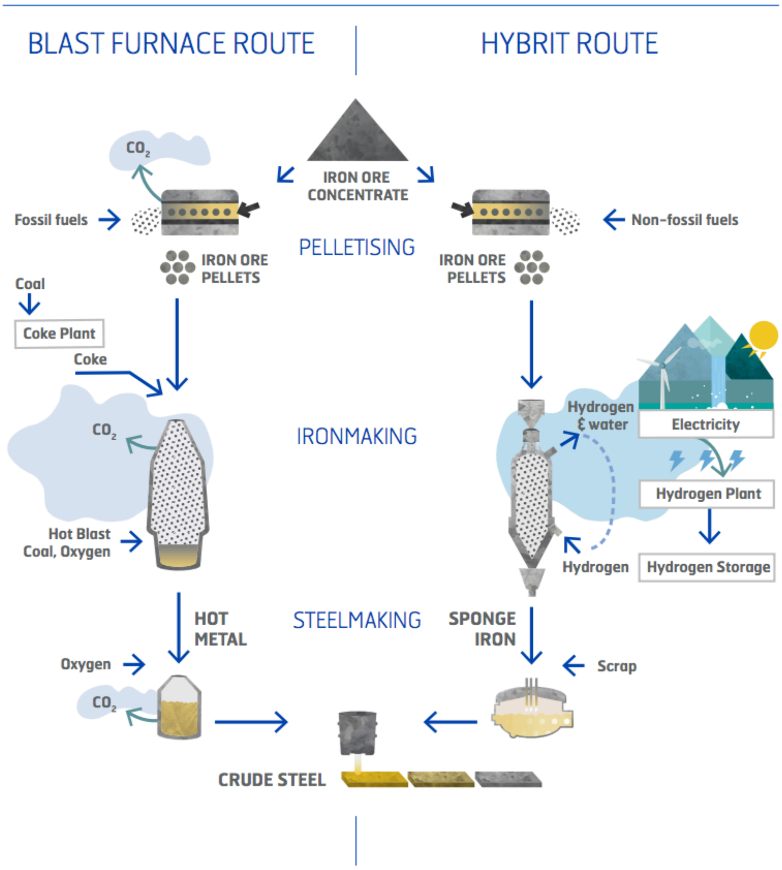


Figure 1.5: Left: conventional method of producing steel, right: direct reduction process, source: [HYBRIT, 2017].

more economical [Gillingham, 2007]. As can be deduced from the E in FCEV, the core of an FCEV is similar to a regular Battery Electric Vehicle, or BEV. It uses electrical energy to power an electric motor. But where a regular BEV uses a battery as a source of its energy, an FCEV utilizes a hydrogen powered fuel-cell. In a hydrogen fuel-cell hydrogen reacts with oxygen. It differs from regular combustion because the fuel-cell utilizes the chemical energy of hydrogen instead of heat energy that arises from combustion [Larminie et al., 2003].

Because of the relatively high energy density of hydrogen, the range of an FCEV is reaching levels of internal combustion engines, about 650 kilometers [Samuelsen, 2017]. Next to that, refueling can be done in about one minute [Samuelsen, 2017]. These properties make an FCEV ideal for carbon neutral long distance travel and other energy intense applications like cargo transportation.

Electricity production

As described in the transport sector, electricity can be produced from hydrogen using a fuel-cell. However, there is also a possibility to produce electricity from hydrogen using already existing hardware. This means that it can be implemented before fuel-cells reach an industrial scale. Reciprocating gas engines can handle gases with a hydrogen content of up to 70% [IEA, 2019a]. Next to this existing gas turbines, dependent on the exact specification of the turbine itself, can run on a fuel mixture containing hydrogen. In Korea a gas turbine has run on a mixture of fuel gas and hydrogen of up to 95%, for 20 years now [IEA, 2019a].

1.2.4. Scenarios that quantify future hydrogen demand

This section discussed the planning and modelling of future energy scenarios, which is a whole scientific area on itself. Companies, governments, scholars and other entities use complex models to evaluate what the energy system may look like in the future. Most of these models arrive in many shapes and forms. Different geographic scales, timelines and types of scenarios exist.

In order to get an idea of how much hydrogen is projected to be used in the future, energy scenarios were collected online on various search engines. For the purpose of this research, the main interest lies in scenarios that specifically mention hydrogen as an energy carrier, and quantify its possible future demand. 29 different scenarios from ten different publications were found that mention hydrogen. All but three specified an estimate for future hydrogen consumption. These scenarios and the corresponding hydrogen demand are presented in table 1.2.

With the scenario that estimates the most hydrogen consumption being over 100 times bigger than the scenario with the smallest consumption, the differences in hydrogen demand between the scenarios from table 1.2 is remarkable. This can be explained by several discrepancies in the approach and method to the scenario planning.

First of all most scenarios are developed with a certain topic or goal in mind. The *business as usual*, also called *baseline* or *BAU*, scenarios illustrate a future energy system with only current and already planned policy, resulting in low demand for hydrogen. These scenarios do not reach intended climate targets.

In addition some scenarios focus on other topics for decarbonisation. The *EE* scenario is based on increasing energy efficiency, while the *ELEC* scenario makes use of higher electrification rates.

Another reason for the differences is the fact that some scenarios make use of different models to compute future consumption, or use the same models but different parameters that determine the outcome.

The last reason is a more trivial one. As can be seen in the column for EU specification in table 1.2, some scenarios have simply defined their Europe area differently than others.

The Ambitious scenario from the *Hydrogen roadmap Europe* is very useful because it is very specific in its estimations of hydrogen consumption quantity [FCH JU, 2019]. Quantities are specified separately for different sectors and processes, which makes it convenient for detailed analysis.

An important thing to mention is the fact that the scenarios presented in table 1.2 use a so called *bottom-up* approach. This essentially means that the transition is modelled from a

Table 1.2: Selected scenarios with an estimated specification of future hydrogen demand. Note: [European Commission, 2018] specifies e-fuels. For each energy unit of e-fuels the assumption is that 1.25 energy units worth of hydrogen is required to produce the e-fuel.

Scenario	**Part of**	**Hydrogen demand** [TWh]	**Time**	**EU specification**
Hydrogen	[Blanco et al., 2018]	4861	2050	EU28+
PtL world	[Blanco et al., 2018]	4222	2050	EU28+
Biomass	[Blanco et al., 2018]	3815	2050	EU28+
95NoCCS	[Blanco et al., 2018]	3210	2050	EU28+
Ambitious	[FCH JU, 2019]	2256	2050	Member states
P2X	[European Commission, 2018]	2195	2050	Member states
1.5 TECH	[European Commission, 2018]	2041	2050	Member states
95	[Blanco et al., 2018]	1919	2050	EU28+
80NoCCS	[Blanco et al., 2018]	1838	2050	EU28+
1.5 LIFE	[European Commission, 2018]	1596	2050	Member states
H2	[European Commission, 2018]	1547	2050	Member states
COMBO	[European Commission, 2018]	1477	2050	Member states
80	[Blanco et al., 2018]	1268	2050	EU28+
Business As Usual	[FCH JU, 2019]	779	2050	Member states
Unfinished Symphony	[World Energy Council, 2019]	558	2050	EER + Oost europa + Rusland
Ecofys Decarbonisation Scenario	[van Exeter et al., 2018]	549	2050	OECD EU (zonder Litouwen en Letland)
Modern Jazz	[World Energy Council, 2019]	279	2050	EER + Oost europa + Rusland
Sky	[Shell, 2019]	234	2050	EER + CEVA + Georgië
BAU	[Blanco et al., 2018]	209	2050	EU28+
ELEC	[European Commission, 2018]	116	2050	Member states
CIRC	[European Commission, 2018]	105	2050	Member states
EE	[European Commission, 2018]	93	2050	Member states
Baseline	[European Commission, 2018]	70	2050	Member states
Hard Rock	[World Energy Council, 2019]	42	2050	EER + Oost europa + Rusland

specific level to a general level, or in other words a gradual integration of technologies across different sectors. The term bottom-up can also be used in a different context, but in this research it will be used as described here.

A so called *top-down* approach is the other way around. *"...the fundamental flaw* [in a bottom-up approach] *lies in the fact that at present there is no market for green hydrogen, and it is therefore very difficult to estimate e.g. adoption rates..."* [van Wijk and Wouters, 2020]. A top-down approach for a hydrogen infrastructure would be to create and push the market with a supply driven approach. With this method and by re-using existing natural gas infrastructure to import cheap green hydrogen from the Sahara desert, Van Wijk and Wouters estimate a potential for hydrogen of around 50% of total final energy demand in the EU [van Wijk and Wouters, 2020].

1.2.5. GIS analysis, infrastructure modelling & corridor concepts

Having described the specifics of current and future hydrogen consumption, the next main subject of research is mapping and visualising this consumption and subsequently analysing the results of this exercise. Because of the aforementioned recent interest in hydrogen, a lot of research has already been done into for example future infrastructure systems. In this section the current state of the on this subject literature will be discussed.

An early research example for infrastructure planning with a Geographic Information System (GIS) based approach was done by Johnson et al. GIS software was used to determine an optimal hydrogen infrastructure in Ohio, United States, between coal plants and populated areas that were used as an indication for hydrogen use in road transportation [Johnson et al., 2008]. Detailed spatial data was combined with a techno-economic model of hydrogen components in ArcGIS, an example of GIS software. The result was that distribution by pipe and centralized production was favourable over other options [Johnson et al., 2008]. In addition, it appeared that regional scale infrastructure aggregation yielded lower hydrogen costs than city level aggregation [Johnson et al., 2008].

Balta-Ozkan and Baldwin conducted research with a case study in the UK. Infrastructure analysis is done using a spatially explicit hydrogen module embedded with the UK MARKAL Energy System model [Balta-Ozkan and Baldwin, 2013]. The network consists of six supply- and twelve demand -centres and is subsequently optimised for production, delivery and use of hydrogen at sub-national level [Balta-Ozkan and Baldwin, 2013]. Notable takeaways are that hydrogen related infrastructures and technologies may initially come with high capital costs, but will become competitive at later stages and that economies of scale are important for hydrogen to succeed [Balta-Ozkan and Baldwin, 2013]. Another model with a case study in the UK is called SHIPMod by Moreno-Benito et al. This model makes use of a mixed-integer linear programming formulation to optimise the hydrogen infrastructure for a sustainable road transport sector [Moreno-Benito et al., 2017]. The result is an economic optimisation for several types and scales of production and distribution in both local and regional scale [Moreno-Benito et al., 2017].

Another example of a model using GIS for an optimised hydrogen distribution network for FCEV demand comes from Baufumé et al. This study investigates the structure of a potential pipeline network along the path of the existing natural gas grid [Baufumé et al., 2013]. Capacities are estimated in Germany for electrolysers using on- and off -shore wind and for hydrogen production from lignite [Baufumé et al., 2013]. A more detailed study for Germany was later undertaken by Reuß et al. Using electrolysis for production, three different transport pathways are investigated [Reuß et al., 2019]. The most beneficial pathway was salt cavern storage, in combination with pipeline transmission and hydrogen gas trailer distribution [Reuß et al., 2019]. Distribution by pipeline would be suitable for areas with a high hydrogen consumption density and would benefit from scaling [Reuß et al., 2019].

Several years ago the first proposition for hydrogen corridors was presented [Stiller et al., 2008]. During a 2006 HyWays infrastructure workshop a list of key indicators was compiled

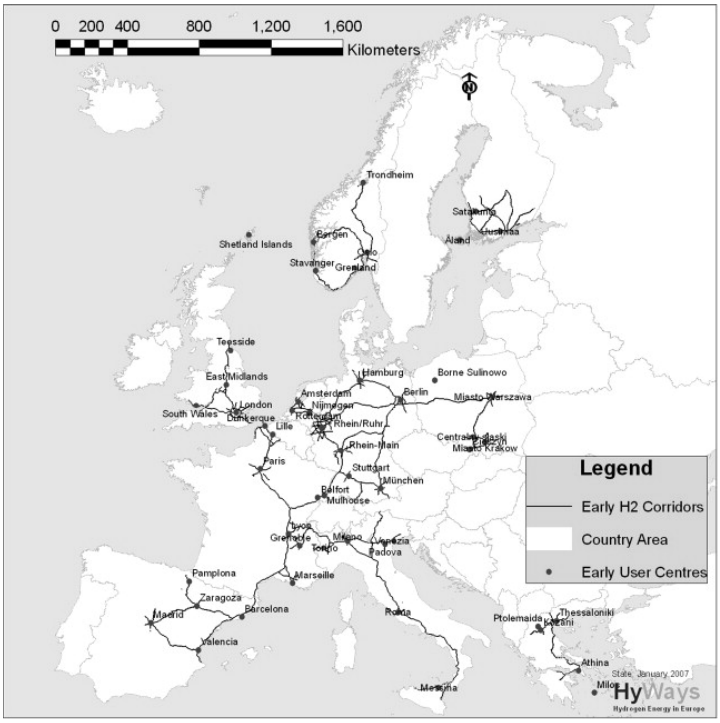


Figure 1.6: Map of selected early hydrogen user centres and corridors, source: [Stiller et al., 2008].

to indicate future early user centers of hydrogen for road transportation [Stiller et al., 2008]. These centers were subsequently connected by existing road infrastructure [Stiller et al., 2008]. This means the early user centers are mostly big cities, and the corridors are the highways that connect these cities. Figure 1.6 presents the corridors that were selected at the time.

In 2012 the European Hydrogen Infrastructure for Transport project was initiated [HyER, 2012]. This project consisted of a first 1000 kilometers long corridor from Gothenburg, Sweden to Rotterdam, The Netherlands [HyER, 2012].

More recently there has been a proposition for a hydrogen network in The Netherlands by the *Hydrogen Coalition*, a group of stakeholders. In this report five industrial clusters in The Netherlands are supplied by green hydrogen using existing natural gas infrastructure [Greenpeace, 2018]. This vision, depicted in figure 1.7, proposed 4 GW of electrolyser capacity in 2030 [Greenpeace, 2018].

In neighbouring country Germany, a similar hydrogen network plan was presented very recently as well. The association of German gas transmission system operators proposed a 5900 kilometer long infrastructure system, of which 90% are already existing pipelines [FNB, 2020]. The network takes the locations of several large industries like steel and chemical facilities into account, as well as possible cheap salt cavern storage possibilities. The proposed network is presented in figure 1.7.

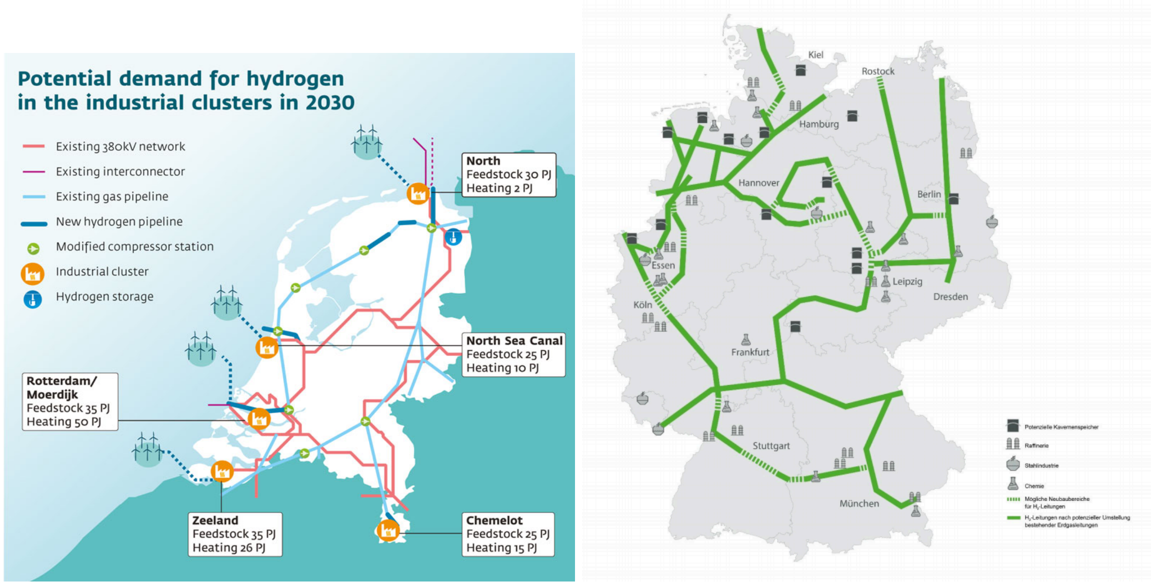


Figure 1.7: Left: Hydrogen infrastructure for The Netherlands, source: [Greenpeace, 2018]. Right: Hydrogen infrastructure for Germany, source: [FNB, 2020]

1.3. Gaps in literature & research questions

One important take-away from section 1.2.5 is that scaling up the production, distribution and consumption of hydrogen will make hydrogen more affordable for the consumer. It also appears several high quality national studies have already been conducted, mostly with a focus only on FCEVs however. Some countries or provinces have planned or already started projects in both trial phases and at further stages of development. National studies are not enough though. If hydrogen is to assume a significant role in the energy transition of the EU there needs to be distribution and production on an international scale, as in fact already is the case with other world scale energy carriers. In addition to scale, not only the transport sector should be evaluated, but other sectors, for example industry, should be evaluated in spatial research as well.

At the moment however there is a lack of knowledge to be able to make strategic decisions on where to begin with an EU hydrogen infrastructure. This research will attempt to contribute to this lack of knowledge by conducting an EU wide research on the current and potential future distribution of hydrogen consumption. The research will also enhance current literature by including more sectors that may see hydrogen use in the future, instead of only focusing on one sector.

With the found insights this research will propose a corridor that is able to serve as a backbone for a potential future hydrogen infrastructure across the EU. In short this research will seek to answer the following main research question:

"For an initial hydrogen corridor crossing the European Union, what would be the most spatially efficient option?"

The term *spatial efficiency* is used differently in many fields. It is used in for instance computer science [Desai and Storbeck, 1990] or to analyse efficiency of businesses [Maté-Sánchez-Val and Madrid-Guijarro, 2011]. However, a definition that is relevant for this specific research is hard to find. The definition of Fisher and Rushton appears to be the most applicable: *"By spatial efficiency is meant the access or distribution costs associated with a given locational arrangement of a service in comparison with those costs associated with the best known alternative arrangement"*[Fisher and Rushton, 1979]. To put it short, for this research the most spatially efficient corridor will be one that has the biggest hydrogen consumption potential in the smallest surface area. Another factor that will be taken into account is the fact that the areas inside the corridor must be able to be easily connected to each other.

The concept that gave rise to the idea that a single corridor can greatly contribute to the future of hydrogen in the EU is the *Blue Banana* [Brunet, 1989]. The Blue Banana is a ribbon of high population and economic activity running from the north of Italy, right across the western part of Germany and covering Belgium and the south of The Netherlands as it ends in the centre of Great-Britain. Because of the activity in this region, the hypothesis is that a lot of current and potential future hydrogen consumption is focused in this area.

In order to be able to accurately answer the main research question. The following specific research questions are proposed:

1. What is the spatial distribution of hydrogen consumption like today and, potentially, tomorrow?
2. Which key areas should be selected as the core for this initial hydrogen corridor?
3. What is, and can potentially be, the hydrogen consumption for these key areas at the time of implementing this corridor?
4. How can sufficient hydrogen be produced for these key areas?
5. How can these key areas be connected to each other to distribute the hydrogen in the best way?
6. What are the economic implications of this infrastructure?

The core of the research will commence by specifying the methodology in chapter 2. After the methodology, the research questions will determine the main structure for the report. The first question will be reviewed in chapter 3. After this, the key areas will be determined in chapter 4. In the next chapter, chapter 5, a scenario will be proposed to determine the consumption of these key areas. Production methods and estimations will be discussed in chapter 6, linked to the fourth research question. Subsequently in chapter 7, there will be a proposition for an EU hydrogen infrastructure that connects the key areas. Finally, in chapter 8, the research will be concluded by discussing the final research question.

After the main research, the results and its implications will be discussed in chapter 9. The final chapter, chapter 10, will conclude the report.

2 Methodology

This chapter describes the methodology along which this research has been conducted. First there will be an explanation for the proposed methods to tackle the research questions. This section will be followed by a scope definition for the research.

2.1. Method

In order to create a structured overview for the used methods, this section will be split up to discuss each research question individually. The questions will be treated in the order presented in the introduction, section 1.3. Figure 2.1 describes the methodical approach in a concise and schematic manner.

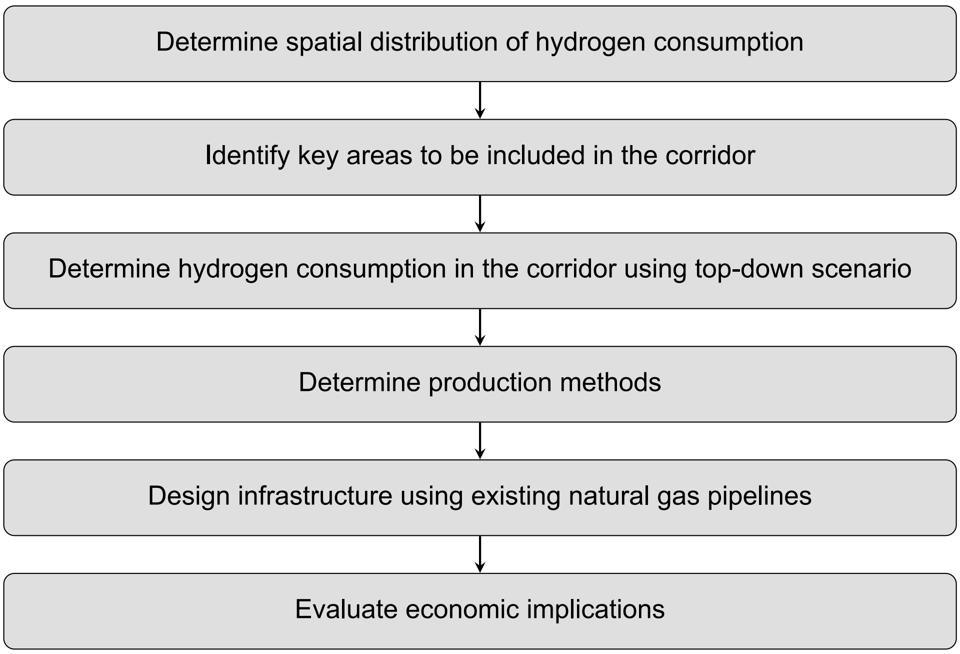


Figure 2.1: Decision process block diagram.

Question 1: What is the spatial distribution of hydrogen consumption like today and, potentially, tomorrow?

Today

To kick off the research, the idea is to map the present hydrogen consumption. In short this can be split up into two parts. First to gather data on consumption, followed by some sort of visualisation or mapping exercise.

Gathering sufficient data means finding information for each specific location. As an indication of size, several hundred locations that consume significant amounts of hydrogen exist today, mainly large scale industrial facilities. A coordinate per location, together with an indication of hydrogen consumption will be sufficient. Hydrogen consumption can also be estimated using a capacity indication of the location specific processes.

After collecting these specifications Geographic Information System, or GIS, software will be used to translate the information to a visual representation. Several types of this kind of software exist, each with pros and cons. For this research ArcGIS from Esri will be used. Mainly because the intuitiveness of this software package and because the TU Delft provides premium ArcGIS accounts to its students.

Finally, the data will be visualised by summarizing consumption in certain regions, or more specifically, NUTS regions. NUTS is an abbreviation for *Nomenclature des unités territoriales statistiques* and will be used throughout this report. The NUTS regions are standardized by the EU and are divided into several NUTS classifications according to region size. In this report the NUTS1 and NUTS2 classification will be used. NUTS1 regions are areas with a population of three to seven million, and NUTS2 areas with a population from eight hundred thousand to one million. Esri provides up to date shapefiles and data for the NUTS1 [Esri Data & Maps, 2019a] and NUTS2 [Esri Data & Maps, 2019b] areas of the EU.

Tomorrow

It should be stated from the beginning that predicting the future is more or less impossible. Modelling and mapping sector activity for the future can shed some light on possible future patterns however. These patterns may provide useful information that can help to answer other research questions.

The first step is to retrieve information about sectors in which hydrogen may be consumed in the future. For a large part of this report, the Hydrogen Roadmap Europe from the FCH JU will be used as a guideline for future sector activity and consumption figures [FCH JU, 2019].

Subsequently, present locations and regional statistics are used to model future sector activity and demand distribution. Although the spatial distribution will undoubtedly change in the near future, this research assumes it will do so more or less insignificantly. Most facilities that consume hydrogen are at their present locations because of several strategic factors like safety, waterway access or in proximity of large cities. These kind of physical location specific attributes hardly change in ten to thirty years, hence in this research, current locations are assumed to be sufficiently accurate to model the future distribution of hydrogen consumption.

Question 2: Which key areas should be selected as the core for this initial hydrogen corridor?

The key areas in the EU can be determined by using the results from research question 1 and the strategic importance of certain areas. The consumption density will be leading criterion for the selection procedure. Next to this, the strategic value of certain areas will also play a role in the selection. Presence of existing gas infrastructure may be relevant for example. Next to this, areas with high expected renewable energy production are also valuable because of the hydrogen production potential.

In the end the final selection will be a result of the numeric and strategic value of the areas. The final selection will consist be done to the scale of NUTS2 areas.

Question 3: What is, and can potentially be, the hydrogen consumption for these key areas at the time of implementing this corridor?

Several arguments arise that could indicate the transition may not be as gradual and uniform as the one portrayed by the 'Hydrogen Roadmap Europe' report [FCH JU, 2019]. That report assumes a gradual *bottom-up* approach for the introduction of hydrogen across the EU. Implementing a large hydrogen infrastructure in the selection of key areas will likely result in an accelerated transition, as was discussed in section 1.2.4.

The key areas are all clusters of high hydrogen consumption. *"Innovation and the commercialization of new technologies take place disproportionately in clusters - Geographic concentrations of interconnected companies and institutions in a particular field."* [Porter and Stern, 2001]. This statement is a leading argument to asses an accelerated case specifically for the selection of key areas.

Because of this, a *kick-start* scenario will be proposed solely for these areas in which the short term potential hydrogen consumption will be estimated.

Question 4: How can sufficient hydrogen be produced for these key areas?

For hydrogen to be a carbon free energy carrier, the production of hydrogen needs to be done using renewable energy. The largest potentials for renewable energy production are not on the European continent but, as was discussed in section 1.2.1, for example on the North Sea or in the Sahara desert. This poses a significant transmission problem to transport the energy to the consumers. This research takes advantage of the issue by proposing large scale hydrogen production at the location of electricity production, which can then be transported to the EU more cost effective than electricity.

The results from research questions 1, 2 and 3 will yield an estimation for the amount of hydrogen that needs to be produced for the areas within the hydrogen corridor. By using existing literature and indications for production methods there will be a suggestion for hydrogen production capacities at the aforementioned regions where hydrogen may be produced.

Question 5: How can these key areas be connected to each other to distribute the hydrogen in the best way?

Now that the areas of hydrogen consumption and the locations of production have been established, these key areas should be connected to create one corridor. As a guideline for the infrastructure, existing natural gas pipelines will form the basis. The energy flow of hydrogen through a pipeline, compared to the energy flow of natural gas through the same pipeline, is between $80 - 97\%$ of the original energy flow of the natural gas, dependent on the calorific value of the natural gas in question [DNV GL, 2017]. This means that, energy wise, substituting natural gas with hydrogen will have little. The existing natural gas pipeline capacity is very similar to the one needed for hydrogen transportation. Next to that, studies have shown that some existing pipelines can be reused for hydrogen transportation without major alterations [DNV GL, 2017].

Other pipelines can be retrofitted for hydrogen transmission or, because the right of way is already in place, additional hydrogen pipelines can be placed. Since regional consumption estimates are known from previous research questions, indications of pipeline capacities between areas can be assessed as well. The infrastructure proposed by this research will be on a level of transmission system operators, which means that regional distribution is considered outside the scope of this research.

Question 6: What are the economic implications of this infrastructure?

Combining all the results from the previous research questions will produce a proposition for the first EU hydrogen corridor. The final task is to evaluate possible total system costs.

Using existing literature for transmission, distribution and production of hydrogen the total system costs can be estimated. Although this will be a rough estimation, it does shed some light on how efficient the corridor can be as a concept to reduce CO_2 emissions.

2.2. Definition of scope

In the following section the system boundaries are declared. First the temporal scope, followed by the geographical scope.

2.2.1. Temporal scope

The research will focus on three main moments in time. These time frames are 2020, 2030 and 2050 for the bottom-up scenario. The decision for these moments comes mainly from the fact that a lot of scenario planning is done using these time frames [FCH JU, 2019], [European Commission, 2018], [International Renewable Energy Agency, 2019]. Next to that, 2020 is chosen to illustrate what the current situation looks like.

The top-down scenario is intended to be as soon as realistically possible. Therefore no exact moment is specified, but the scenario is based on 2030.

2.2.2. Geographical scope

The following section will specify the geographical scope for the different parts of the research. First for the determination of the hydrogen demand, followed by the geographical scope for the production of hydrogen and finally for the hydrogen infrastructure.

Hydrogen demand

The basis for this research is to determine the geographical distribution of hydrogen consumption. Gathering data and presenting results will be limited to the 28 member states of the European Union. Although one of these 28 entities may soon be leaving the EU, in this research the assumption is that the UK and the EU will still be able to collaborate on environmental issues.

The decision to base the research on the EU member states stems mainly from the goal of this research to propose a hydrogen infrastructure spanning multiple borders. The institutional and cross border power of the EU will be very useful in realising a project of this scale. It also builds a strong and structured narrative for action on an EU wide level.

Another reason is because the relevant literature mainly presents important figures for this group of countries. Next to that, this decision was made in order to avoid getting lost in the numerous definitions that describe the area called 'Europe'. The geographical boundaries of the continent Europe are vague and specified differently across the board. Adding to the confusion, countries from the European Free Trade Association (EFTA) or Central European Free Trade Agreement (CEFTA) are sometimes included under 'Europe', as can be seen in table 1.2 in section 1.2.4. The specification of the EU28 is one of the few area definitions that is used the same way in almost all literature.

Production

The main areas of interest will most likely be production on the North Sea using wind energy and North Africa using solar energy and wind energy.

Infrastructure

The infrastructure design will focus on providing a hydrogen infrastructure only for the consumption in the to be identified corridor.

3
Mapping Demand for Hydrogen in the EU

This chapter will aim to shed light on the spatial distribution of hydrogen demand in the EU. Although present figures and locations will be of a high accuracy, the future will always remain uncertain. However, by using the in chapter 2 mentioned methods, the results from this chapter will to some extent indicate future distribution, which will still be of value when planning a possible future corridor.

In section 3.1 the specifications of current and future quantities of hydrogen consumption will be discussed. Subsequently in section 3.2, the locations that were connected to the corresponding consumption figures will be elaborated on. Finally the results of this effort will be presented and discussed in section 3.3.

3.1. Hydrogen consumption quantities

The first task will be to collect figures for hydrogen consumption for current activities, as well as quantity estimates for the future. This research makes use of the data presented by the FCH JU in the Hydrogen Roadmap Europe [FCH JU, 2019]. However, if for some sectors there was no specified amount, other sources will be used to estimate the future consumption. The amounts that will be used in this report are presented in table 3.1 for the currently active processes and table 3.2 for future activity. How these values were sourced or estimated will be discussed in the rest of this section for each sector or process specifically.

For the energy content of hydrogen this research uses the *higher heating value*, which is $39.4\frac{\text{kWh}}{\text{kg}}$. Conventionally the *lower heating value* was used to determine the amount of energy. The difference between these two values is the *latent heat of vaporization*. Because modern technologies are able to use a significant portion the latent heat as well, some devices report efficiencies of well over 100%. As equipment starts to be able to extract this latent heat, it makes sense to assume this energy as a usable type of energy, which is why the higher heating value will be used in this report.

Table 3.1: Hydrogen demand estimates for currently active processes in the European Union in million tonnes of hydrogen per year

Year	Ammonia production	Oil refineries	Methanol production
2020	3.39	3.96	0.35
2030	4.01	3.56	0.53
2050	4.54	1.68	0.64

Table 3.2: Hydrogen demand estimates for future active processes in the European Union in million tonnes of hydrogen per year

Year	Iron & Steel	Industry heat		Road transport	Shipping	Building heat	Electricity generation
		Low	High				
2030	0.32	0	0.20	1.78	0.21	0.63	1.62
2050	3.55	2.00	4.01	17.1	1.98	11.8	2.54

3.1.1. Ammonia

The FCH JU indicates that today 129 TWh, or 3.39 million tonnes of hydrogen is used each year for the production of ammonia [FCH JU, 2019]. Unfortunately no specific values are presented for the future hydrogen demand for ammonia production. So another source was used for the future. Prospects for the ammonia market are positive, the IEA indicates a growth of around 1.7% per year from 2018 to 2030 [IEA, 2019a]. From 2030 to 2050 the growth is estimated to be around 0.63% per year [IEA, 2019a]. Worldwide growth estimates were assumed to resemble the EU figures as well. The resulting values can be found in table 3.1.

3.1.2. Oil refineries

In 2018 the yearly hydrogen consumption for oil refineries was 153 TWh, but the future values are not specified in the Hydrogen Europe Report [FCH JU, 2019]. Calculating the amount of hydrogen consumed by oil refineries is more complex than for other sectors. That is because it depends on several factors. The first important factor is the amount of oil that needs to be refined, which is obviously directly linked to the demand for oil products. Changes in the energy system to reduce the amount of carbon dioxide being emitted into the atmosphere imply that demand for oil products will likely shrink in the near future. However, opinions are very divided about how much and how quick this market will shrink [European Commission, 2018], [Shell, 2019], [British Petroleum, 2019], [World Energy Council, 2019]. In addition to this, hydrogen consumption is dependent on the two things that refineries mainly use it for; desulphurization and hydro-cracking. The density, linked to hydro-cracking, and the sulphur content of crude oil can vary a lot over time and origin of the oil [Eurostat, 2018]. Next to that, fuel quality requirements from governments or organisations can vary over time. The International Maritime Organisation for instance has sharpened regulations for maximum allowed sulphur content in fuel oil for ships starting in 2020 [IMO, 2019]. Policies like these will result in a rising demand for hydrogen to further desulphurise fuel oil.

The interplay of these factors makes it very complex to determine future hydrogen demand for oil refining. The IEA estimates that, in line with current trends, hydrogen demand will slightly rise towards 2030, after which demand will more or less plateau [IEA, 2019a]. However, the aim of this report is to change the energy system in a way that the EU will use substantially less oil in the near future.

To stay in line with the Paris Agreement, the IEA estimates a drop in worldwide hydrogen demand for oil refineries of about 1% per year, on average, from 2018 to 2030 in the *Sustainable Development Scenario* of the World Energy Outlook 2019 [IEA, 2019a]. During this time, oil demand in the EU falls to 69.7% of its 2018 value [IEA, 2019b]. Then, from 2030 to 2040, oil demand shrinks with 45.7% [IEA, 2019b]. Assuming the correlation between oil demand and hydrogen consumption for oil refining is similar from 2030 to 2040 and from 2018 to 2030, the demand for hydrogen in the refining sector declines with about 3.7% per year. Finally, the same yearly drop in demand is assumed between 2040 and 2050. The resulting consumption estimates can be found in table 3.1.

3.1.3. Methanol

In 2018 27 TWh of hydrogen was consumed, but for the future there are no specific estimates [FCH JU, 2019]. The IEA indicates substantial growth for the future of methanol production. From 2018 to 2030 worldwide methanol production is expected to grow with about 4.1% per year [IEA, 2019a]. Prospects for the future, from 2030 to 2050, indicate the growth slows down to about 1% per year [IEA, 2019a]. For this research, it is assumed that the worldwide growth represents growth in the EU as well. The resulting values can be found in table 3.1.

3.1.4. Iron & steel

Steel that uses hydrogen as a new feedstock is expected to make up around 20% of all steel production in the EU in 2050 [FCH JU, 2019]. In terms of amount of energy, the FCH-JU estimates that DRI methods will consume about 7 TWh in 2030. In 2050 this estimate rises to 140 TWh [FCH JU, 2019]. The resulting estimates for consumption can be found in table 3.2.

3.1.5. Industry heat

The FCH-JU estimates that in 2030 8 TWh of high grade heat, which is over 500° Celsius, will be provided by hydrogen. In 2050 this will be approximately 160 TWh, or about 20% of the total demand for high grade heat. Roughly 5% of low- and 8% of medium -grade heat will be provided by about 77 TWh [FCH JU, 2019] of hydrogen. The resulting consumption estimats can be found in table 3.2. The resulting estimations for consumption can be found in table 3.2.

3.1.6. Road transport

Currently, hydrogen transport is only just starting to emerge. In the EU there are currently about 1200 Fuel Cell Electric Vehicles (FCEV), which is about 11% of the global total [IEA, 2019a]. These vehicles can refuel at around 150 hydrogen refueling stations around the EU [HyARC, 2019]. The hydrogen used by these 1200 vehicles is insignificant to the current total. The IEA estimates that worldwide in 2018 less than 0.01 million tonnes of hydrogen was used for transport. This is around 0.009% of total hydrogen consumption.

The FCH JU indicates a goal of 3700 hydrogen refuel stations in 2030 and about 15000 in 2050 [FCH JU, 2019]. Energy use will also grow exponentially. Indications are that in 2050 about 25% of road traffic will be powered by hydrogen. These figures translate to an energy consumption of 70 TWh in 2030 and 675 TWh in 2050 [FCH JU, 2019]. Road transport entails all types of vehicles that travel by road. This sector covers all forms of personal-, public- and freight -transportation. The resulting estimates for consumption in the road transport sector can be found in table 3.2.

3.1.7. Shipping

New regulations by the International Maritime Organisation will require ships to burn cleaner fuel [IMO, 2019]. This will result in a new demand for clean fuels for the shipping industry. Among others, hydrogen or hydrogen derived fuels are strong contenders to become key energy carriers in the shipping sector.

Most scenarios covered in section 1.2.4 do not provide a number for future hydrogen consumption in the shipping sector. *A clean planet for all* by the European Commission does however indicate a fuel mix for the maritime sector in a specific *H2 scenario* [European Commission, 2018]. This scenario estimates a drop in CO2 emissions in the shipping sector of 70% compared to 2008. In this scenario the demand for hydrogen in the international maritime sector is 7.7 Mtoe, which is around 90 TWh or 2.3 million tonnes of hydrogen. There is no specification for 2030. To estimate the value for 2030 the same yearly growth rate as for road transport is assumed, about 12% from 2030 to 2050. The resulting estimates for consumption can be found in table 3.2.

3.1.8. Building heat

The FCH JU estimates a potential hydrogen consumption for the EU in this sector of 33 TWh in 2030. In 2050 this consumption is estimated to reach 579 TWh. This amount is estimated by taking two possible concepts into account. One possibility is to blend hydrogen, to about 10%, with natural gas in existing infrastructure [FCH JU, 2019]. The other option is to completely shift some regions to 100% after upgrading specific hardware [FCH JU, 2019]. The estimated consumption can be found in table 3.2.

3.1.9. Electricity generation

Hydrogen consumption for electricity production is expected to be about 64 TWh in 2030. This figure is projected to rise to around 100 TWh in 2050 [FCH JU, 2019]. The resulting estimations for consumption can be found in table 3.2.

3.2. Consumption locations

To specify the locations where hydrogen is and will potentially be consumed, each process and activity as discussed in section 3.1 will be discussed individually.

3.2.1. Ammonia

Fertilizers Europe, the European association of fertilizer producers, provided a list of plants together with corresponding capacities. In total the list containes 39 plants in the EU with a total combined production capacity of around 20 million tonnes of ammonia. The provided list specifies only city names for locations, while coordinates are needed for the GIS software. The `Geonames` package in `R` was used to link city names to coordinates [Rowlingson, 2019]. This means that plant locations may not be the actual location of the plants, but the nearest town. In general this will not affect the results, as the results are summarised for NUTS2 regions.

The approximate locations can be seen in figure 3.1. The complete list of used plants can not be disclosed and can therefore not be found in the appendices. Finally, the figures for future hydrogen demand from table 3.1 were divided among the plants according to their production capacity.

3.2.2. Refineries

The geographical information used in this research is based on the list from the FracTracker Alliance dating from 2017 [Auch, 2017]. It became apparent that some plants had closed down or increased capacity in the time between compiling the list and conducting this research. There is a yearly updated list by the *Oil & Gas Journal*, but it is only available for purchase. No other lists were found and information was hard to come by. In the end, the list from FracTracker was compared to the openly available Wikipedia list of oil refineries [1]. Where the lists did not match each other, further information was searched online. The final list and refinery capacities can be found in appendix A.

The final list contains 89 refineries with a total production capacity of 13.8 million barrels per day. According to BP the total figure is 14 million barrels for the European Union [BP, 2019]. The difference in capacity was not deemed significant and therefore the list was assumed to be sufficiently accurate and valid for this research. The plant specific hydrogen consumption was distributed among the facilities according to their production capacity. The refinery locations can be seen in figure 3.1.

3.2.3. Methanol

Compiling the list of methanol plants proved harder in comparison to ammonia plants and oil refineries. Production volume is lower and information was hard to obtain. Moreover, there is a high quantity of relatively small plants [Burridge, 2012]. This meant that plants needed to be retrieved manually.

As a starting point, a list of 21 plants was used from 2012 [Burridge, 2012]. After eliminating non-EU plants, only eight were left. These eight plants were manually researched on google to check current activity. One capacity was altered [Thomas, 2019] and one new plant in Rotterdam was added [Nouryon, 2019]. The final list contained nine production facilities with a combined capacity of about 3.7 million tonnes of methanol. These nine locations are displayed in figure 3.1. The final list and capacities can be found in appendix A.

Because the list was incomplete, a different approach was used to assign hydrogen consumption to production plants. A calculation was done on the amount of hydrogen per

[1] `https://en.wikipedia.org/wiki/List_of_oil_refineries#Europe`

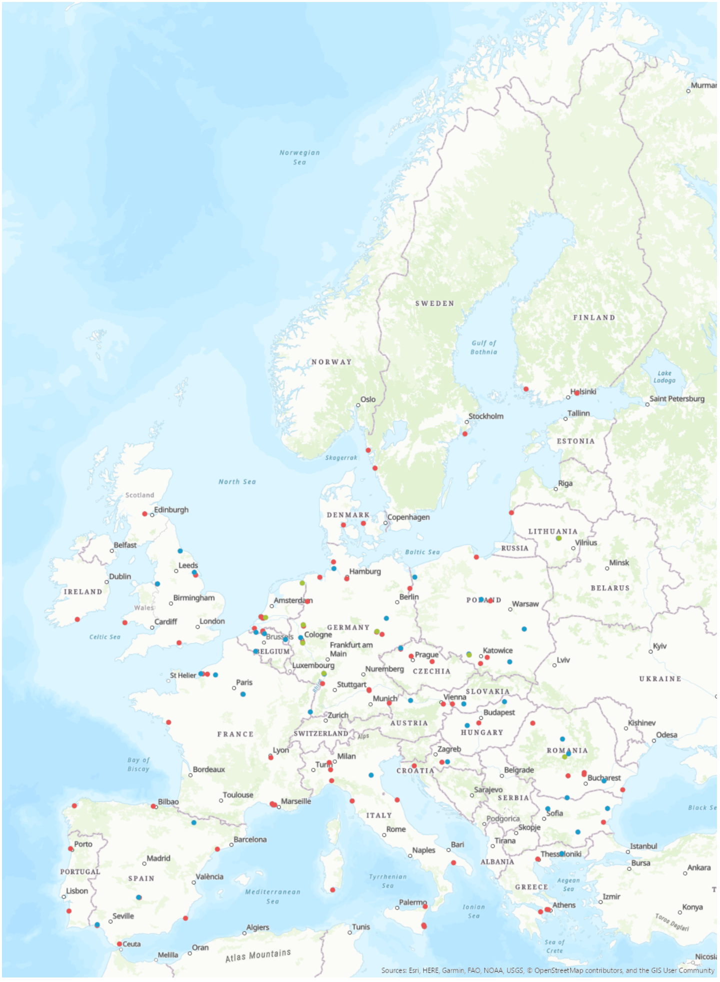


Figure 3.1: Location of ammonia plants (red), oil refineries (blue) and methanol plants (green)

unit of produced methanol.

The IEA estimates that in 2018 12 million tonnes of hydrogen was consumed for the production of methanol [IEA, 2019a]. Next to that, around 91.75 million tonnes of methanol was produced [Methanol Institute, 2019] in 2018. This means that on average about $\frac{12}{91.75}$ = 130.8 grams of hydrogen is needed to produce 1 kilogram of methanol. Stoichiometrically this seems correct. The molar mass of methanol is 32.04, of which 4.03 is hydrogen, which is about 12.6%. The worldwide average of plant capacity was used. This figure for 2018 was 66.7% [Methanol Institute, 2019].

3.2.4. Iron & steel

Locations for current iron and steel production sites and corresponding capacities were provided by the European Steel Association EUROFER. This list contained only town names, so again `Geonames` was used in `R` to provide coordinates for the town names [Rowlingson, 2019].

The list contained a total of 153 major production facilities in the EU of all types. The 153 facilities have a combined total capacity of 193 million tonnes of hot metal. Because of confidentiality the list cannot be found in the appendix. The values presented in table 3.1 are subsequently divided among the facilities in similar fashion to other sectors covered in this research. That is, according to their hot metal capacity compared to the total EU production capacity.

The approximate locations of these plants however can be found in figure 3.2.

Figure 3.2: EU steel plant locations

3.2.5. Industry heat

With a total energy demand of 3200 TWh [FCH JU, 2019] industrial heat is usually broken down in low-, medium- and high -grade heat. As can be seen in table 3.1, because the Hydrogen Roadmap Europe only specifies for two grades, this research will work with two heat grades. High-grade heat is everything over 500° Celsius and low-grade is everything below this level [FCH JU, 2019].

The first important task is to find out which industry sectors use which amount and which grade of heat. As a basis for all computations regarding the breakdown of heat demand in the industrial sector a report from 2015 was used [Kusch, 2016]. This report defines high-grade heat as higher than 400° Celsius, which is a different threshold compared to the Hydrogen Roadmap Europe [FCH JU, 2019]. But because the energy consumption for medium-grade heat is only a small portion of total heat demand [Kusch, 2016], and because large contributors like iron, steel and cement are well above the medium-grade threshold [Panayiotou et al., 2017], the breakdown of Kusch is assumed to still be applicable for the sector breakdown of the estimates of the FCH JU.

Total heat demand in the industry sector is dominated by three main sectors who together account for about 70% of the total. These sectors are metal (iron, steel and aluminium), chemicals and non metallic minerals (i.e. cement, glass and ceramics). So, to simplify this problem, this research will distinguish only four main industry heat sectors: metal, chemical, non metallic minerals and other. The portion of each sector per heat grade is presented in table 3.3.

Table 3.3: Simplified breakdown of industrial heat demand in the European Union [Kusch, 2016]. Note: portions may not add up to 100 % because of rounding.

Sector	Contribution to high-grade heat demand	Contribution to low-grade heat demand
Metal	46.4 %	6 %
Chemical	14.1 %	26.9 %
Non metallic minerals	33.6 %	5.6 %
Other	6 %	61.5 %

With the breakdown complete, the next step is to retrieve geographic data on these four main industry sectors. For the metal industry, the already retrieved locations of iron and steel production facilities is used from section 3.2.4. For the chemical industry sector, the location data from ammonia, methanol and oil refineries, assumed to be part of this sector, from section 3.2.1, 3.2.3 and 3.2.2 are used. Heat for the metal- and chemical -industry was distributed among plants according to their hydrogen consumption, assumed to be a sufficient indication of demand for heat between plants of each sector.

To map the non metallic minerals sector, an online map available on ArcGIS online was used [Arctellion, 2016]. This map contained the location of 258 cement plants. The locations of these plants can be found in figure 3.3. The list of cement plants unfortunately did not contain indications for plant capacities. Next to this, unfortunately no data of other industries in the non metallic mineral sector was found. This means that the complete sector was distributed equally between cement plants.

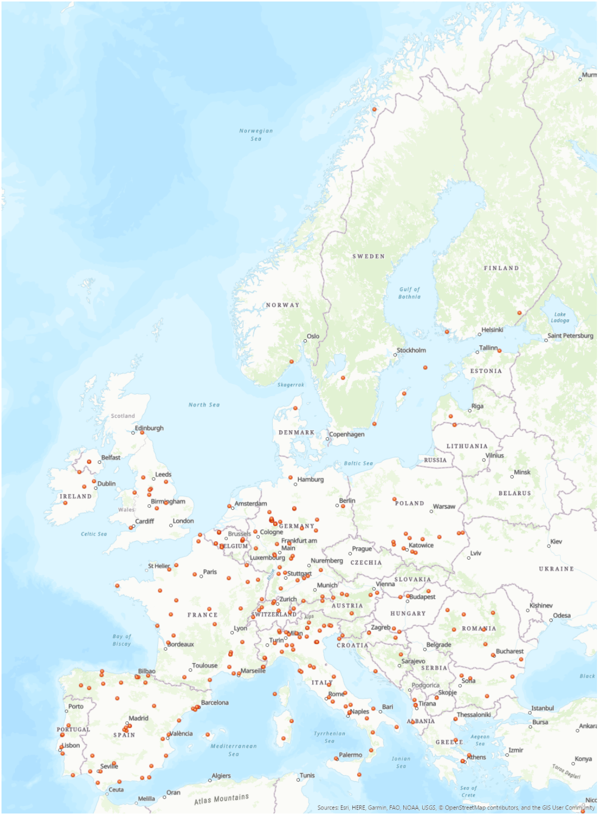


Figure 3.3: EU cement plant locations

The approach to model the 'other' sector was to gather a vast database of locations of overall industrial activity. The final approach was to combine all already retrieved locations from metal, chemical and non metallic minerals together with a list of production plants and suppliers for the automobile industry. The list for the automobile industry contained over 1800 locations and was received from the authors of an article about the European car industry [Klier and Rubenstein, 2012]. Although this is not a very accurate method, it was assumed that this approach would sufficiently indicate industrial locations across the EU that would resemble the 'other' industry heat sector.

The combined list was a list of 2380 coordinates with some form of industrial activity. For this research it was assumed that these locations were a sufficiently accurate representation of industry locations across the EU.

Following the collection of geographical data, the consumption from table 3.1 was combined with the breakdown of table 3.3 to compute specific demand per heat grade per industry sector.

3.2.6. Road transport

Mapping future demand means retrieving information about where road vehicles will potentially be refueled. Assuming roadside refueling will be at similar locations to current gas stations, the decision was made to use these current gas stations as the location for hydrogen demand in the future.

To retrieve information on these locations, OpenStreetMap (OSM) data was used. Especially the `R` package `osmdata` proved very useful [Padgham et al., 2017]. This package makes it possible to download data from the OSM database. Although this data is opensource and therefore not completely reliable, it was assumed that this approach was the most accurate available option.

In OSM all petrol stations are marked with 'amenity' as key and 'fuel' as tag. In addition, a bounding box was needed to assign an area to search in. Adding the bounding box for Europe yielded about 400,000 petrol stations of OSM in all of Europe.

OSM also provides information on location attributes. For petrol stations these attributes can be things like presence of a supermarket, shower or available fuel types. The idea was to use these attributes as an indication for station size, which could then be used as an indication of how much a certain station would be visited. Unfortunately these features are only added to a very small number of stations, so this method can not be used and the decision was made to equally divide demand among petrol stations.

Moving on, 400,000 seemed like an exorbitant amount of petrol stations. Upon further research, this hypothesis proved to be correct. FuelsEurope estimates around 75 thousand active petrol stations in the EU [Fuels Europe, 2019]. After analysing the data more closely, it became apparent that some petrol stations were marked numerous times, but with a slight change in coordinate. For example, there was an area of a little under 5 km^2 in Gerona, Spain, that contained 381 petrol stations. Even closer analysis analysis indicated 63 petrol stations in a little over 1 m^2.

To combat this problem, all duplicates within an area of about 80 by 80 meters, dependent on the latitudinal location, were removed. The size of this area was chosen by manually analysing hotspot behavior, like the one in Gerona, under several area sizes. Increasing the duplicate removal risked removing petrol stations that were simply near other ones. The area in which excess petrol stations were deleted was increased until it was observed that distinctly other petrol stations were incorrectly deleted. Next to that, since the interest lies in the distribution and not the precise numbers, the result was assumed to be sufficient for this research. Unfortunately the final result still was not ideal. The final count indicated 117,000 petrol stations in the EU.

Because ArcGIS charges a virtual currency to perform analysis, and an analysis on 117 thousand points is not free, the data needed to be condensed. In R the petrol station data was plotted in a raster of 296 columns and 376 rows. The center coordinate of these raster squares, together with the count of petrol station in each square were then used for further analysis.

The next step was to use ArcGIS to count the amount of petrol stations in each NUTS1 and NUTS2 region. The idea was to divide the hydrogen consumption between regions according to the amount of petrol stations in said region. However, looking at the amount of petrol stations from the OSM results and comparing them to the actual amount per country [Fuels Europe, 2019], there appeared to be significant discrepancies between them. To increase the accuracy of the results, the country specific distribution of petrol stations from OSM was used in combination with the road transport energy use for each country in particular from 2017 [Eurostat, 2020].

This means that in the end the hydrogen consumption from table 3.1 was first split per country using the 2017 road transport energy use and subsequently divided among the NUTS1 and NUTS2 areas according to the amount of petrol stations in each region.

3.2.7. Shipping

To map the locations of hydrogen demand in the shipping sector, harbors were used. Bunkering, or fueling a ship, is not distributed according to harbor size. Geographic location relative to main shipping routes as well as fuel prices determine the amount of bunker fuel per harbor. For example, of the total 50 million tonnes of bunker fuel for the EU [Fuels Europe, 2019], about 11 is provided by the port of Rotterdam [Port of Rotterdam, 2019].

As a basis for the list, the top 20 ports of the EU by gross weight handled from 2018 was used, which surprisingly contained 32 entries [Eurostat, 2019c]. After removing Turkish ports and manually adding Gibraltar because of bunker volume, there were 27 ports left. These ports were given coordinates from the World Port Index [NGA, 2019].

Because bunker volumes are not public data, specific values for bunker ports were based on a series of news articles and online information. The basis for the large bunker ports was a list found in an old presentation of the International Bunker Industry Association [Nigel Draffin, 2014]. Other specific values were found for Rotterdam [Port of Rotterdam, 2019], Piraeus [Argus Media, 2019] and Algeciras and Barcelona [Rhys Berry, 2018].

Table 3.4: Bunker volumes for main bunker ports in EU

Harbor	Bunkering in million tonnes
Rotterdam	11
Antwerp	7.5
Gibraltar	4
Piraeus	3.6
Amsterdam	3
Marseille	3
Hamburg	2.5
Algeciras	2.2
Barcelona	1.3

Subtracting 3.1 million tonnes of fuel demand for Spanish islands in the Atlantic Ocean [Rhys Berry, 2018] from the 50 million tonnes of demand for the EU [Fuels Europe, 2019], yields a total of 46.9 million tonnes for the EU. The nine ports from table 3.4 yields a total 38.1 million tonnes, or 81.2% of the EU total, while handling 31% of the gross EU weight [Eurostat, 2019c].

The other 18 harbors were given a bunker fuel volume according to their contribution to the 69% of gross weight that is not handled by the 9 harbors presented in table 3.4. The resulting list of 27 harbors supplied a combined bunker volume in 2018 of 40.8 million tonnes, or 87% of the EU total. This means that the mapped future hydrogen consumption will be 87% of the values presented in table 3.1.

3.2.8. Building heat

Retrieving building heat data for each building specific is next to impossible. The approach to map the building heat demand was to use two important factors for this sector: area population and area Heating Degree Days (HDD). HDD indicate how many days and for how many degrees the outside temperature is below a certain threshold. The European Environment Agency uses a threshold of 15.5° Celsius. Eurostat provides HDD data for both NUTS1 and NUTS2 areas [Eurostat, 2019a]. The ESRI shapefiles, usable objects in ArcGIS, for European NUTS1 and NUTS2 areas contained demographic data like population [Esri Data & Maps, 2019b], [Esri Data & Maps, 2019b].

With both population and HDD data retrieved, `R` was used to analyse and handle the data. For each area, the product of its population and HDD was computed. The ratio of this product compared to the sum of products of all areas, was used as the share of total EU heat demand that each area represents.

For example, the NUTS1 region with the highest share of heat demand, 3.66% of EU total to be exact, was Nordrhein-Westfalen in Germany. This is also the area with the largest population of all NUTS1 areas.

3.2.9. Electricity generation

To map the hydrogen demand for electricity generation, the current location of gas fired plants were used. For specific locations and power plant attributes the Global Power Plant Database of the World Resource Institute was used [WRI, 2019]. This list contains exact coordinates and information like capacity. Subsequently, each plant was given a specific hydrogen consumption. The values presented in table 3.1 were divided among the plants according to their installed capacity.

3.3. Results

In the following chapter the results from the previous sections will be presented and analysed. This section will only contain the selection of results that are deemed the most relevant. A concise summary of the result can be found in table 3.5, together with estimates for the ten countries with the highest hydrogen consumption in 2050 in table 3.6. First some results for NUTS1 areas are discussed, followed by more detailed results from the analysis for NUTS2 areas.

Table 3.5: Total EU demand in million tonnes of hydrogen

2020	2030	2050
7.70	12.83	49.55

Table 3.6: The ten countries with highest estimated hydrogen consumption in million tonnes per year in 2050.

Country	Estimated consumption in 2050
Germany	9.0
France	5.6
Great-Britain	5.4
Italy	5.1
Spain	4.0
Poland	3.6
The Netherlands	3.2
Belgium	1.9
Romania	1.7
Austria	1.2

3.3.1. NUTS1

The first look at the spatial distribution will be done at the scale of NUTS1 areas. This scale will yield information on a macro scale that will indicate which broad regions may be of interest. First the results from 2020 will be discussed. In the year this report will be finished, 2020, there is already a significant hydrogen consumption in the EU of over 7.7 million tonnes of hydrogen. Taking these results into account can shed some light on which areas are key for starting a potential hydrogen corridor. Finally the result estimates for 2050 are treated. These results can indicate how the distribution could evolve on a large geographic scale. The results of the NUTS1 results will mostly provide a large scale overview, which indicates where to focus on for the NUTS2 results.

2020

As an illustration for the spatial distribution of current hydrogen consumption, the sum per NUTS1 area is given in figure 3.4. At first glance the consumption appears to be quite spread out across the EU. The region in the West of The Netherlands appears to be the main hot spot.

Figure 3.4 only tells a part of the story though. Obviously the larger the surface area of the NUTS1 region, the more likely it is that this region contains locations that consume hydrogen. But it is also the case that with a larger surface area, the region becomes harder to be converted to an infrastructure system based on hydrogen. It is important not only to look at the sum of the consumption in an area, but also at the density. A high density in consumption indicates a relatively high consumption in a relatively small area. Which implies, in theory, an easier task to switch the areas infrastructure to one that can handle hydrogen.

Table 3.7 specifies the fifteen areas with the highest hydrogen consumption in 2020. From the table, the differences between areas of the consumption in relation to the surface area of the NUTS1 region becomes apparent. Although some areas may contain a large total sum of consumption, it is spread out over a large area.

To combat this problem, the density of consumption should be taken into account as well. Figure 3.5 illustrates the consumption divided by the surface area of the NUTS1 region. Bassin Parisien, the area around Paris, or the South of Spain for example hardly appear in figure 3.5 in comparison to other areas. From this image it is clear that there is one region that contains a lot of hydrogen related activity in a relatively small area. The areas with a dark blue colour are the areas with a high density of hydrogen consumption already today.

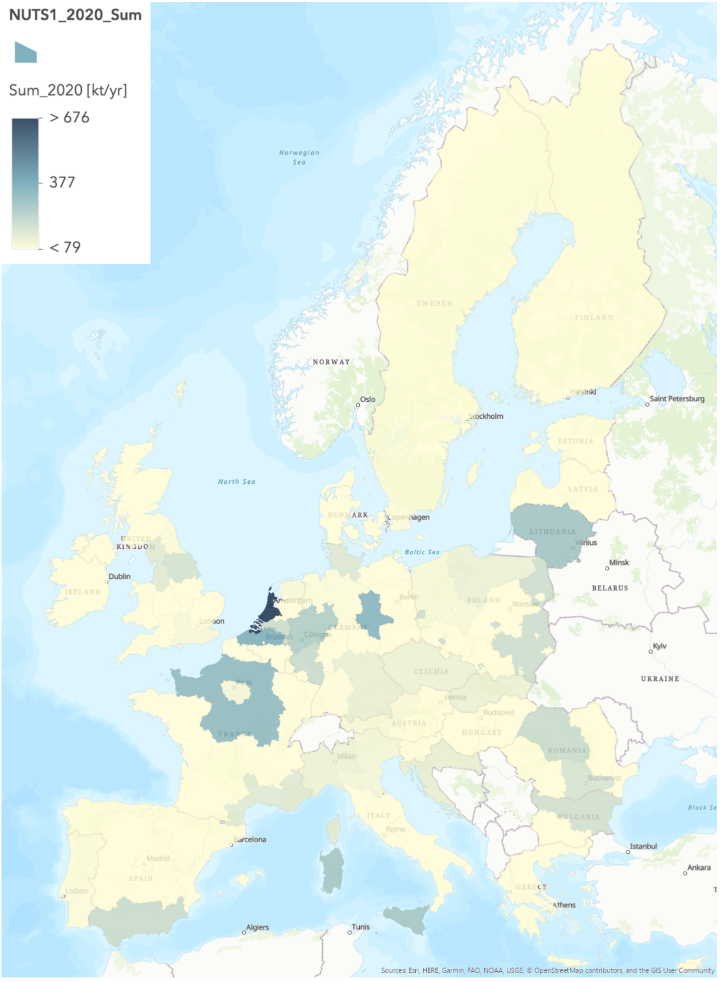


Figure 3.4: Sum of hydrogen consumption in 2020 for NUTS1 regions.

Table 3.7: Fifteen NUTS1 areas with the highest sum of hydrogen consumption in 2020

Country	Area	Sum $\left[\frac{\mathrm{kt}}{\mathrm{year}}\right]$	Density $\left[\frac{t}{\mathrm{km}^2}\right]$
NL	West-Nederland	676.36	74.39
BE	Vlaams Gewest	349.44	26.03
DE	Sachsen-Anhalt	330.23	16.28
FR	Bassin Parisien	310.92	2.14
LT	Lithuania	276.30	4.31
IT	Isole	270.85	5.37
DE	Nordrhein-Westfalen	242.30	7.20
ES	Sur	193.76	1.92
RO	Macroregiunea Unu	193.36	2.85
DE	Rheinland-Pfalz	193.24	9.85
NL	Zuid-Nederland	190.75	26.62
PL	Region Wschodni	186.87	2.55
BG	Severna i Iztochna	177.50	2.60
GB	Yorkshire and The Humber	172.97	11.26
RO	Macroregiunea Trei	165.18	4.57

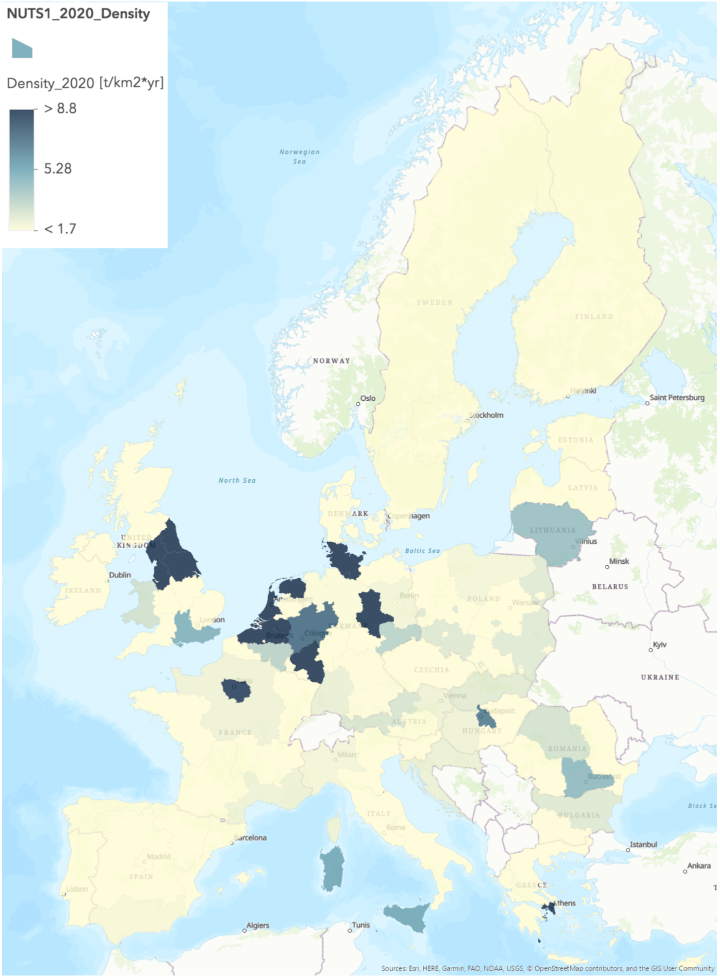


Figure 3.5: Density of hydrogen consumption in 2020 for NUTS1 regions.

2050

Skipping ahead to 2050 to analyse the possible future distribution, the density results of the NUTS1 analysis are presented in figure 3.6. One or two things can be noted from the NUTS1 analyses. Firstly, the main area of interest appear to be within Western Europe. Even more, a prominent cluster appears in the area that was once described as the Blue Banana by Roger Brunet [Brunet, 1989]. A high density in industry and population results in a clear corridor from the north of Italy, right across the western part of Germany and covering Belgium and the south of The Netherlands as it ends in the mid area of Great-Britain.

Supplementary to figure 3.6 the results for the NUTS1 areas are specified in table 3.8. The table is ordered according to hydrogen consumption density.

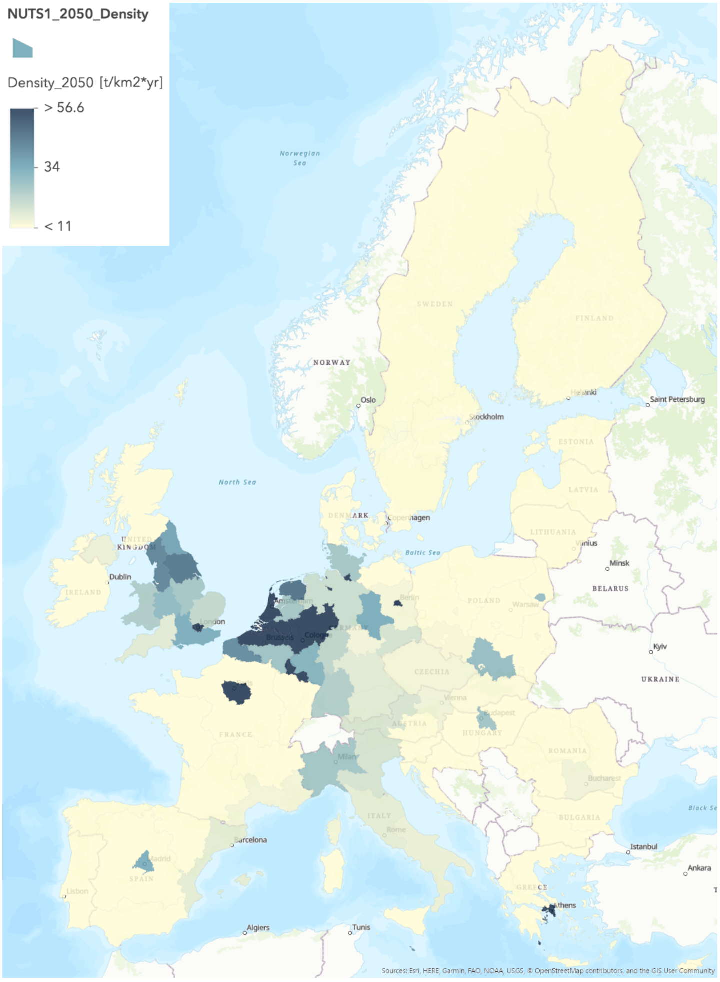


Figure 3.6: Density of hydrogen consumption in 2050 for NUTS1 regions.

Table 3.8: Fifteen NUTS1 areas with the highest density of hydrogen consumption estimates, and a sum of at least the EU average, in 2050

Country	Area	Sum $\left[\frac{\text{kt}}{\text{year}}\right]$	Density $\left[\frac{t}{\text{km}^2}\right]$
NL	West-Nederland	1971.23	216.82
BE	Vlaams Gewest	1346.24	100.30
NL	Zuid-Nederland	523.37	73.03
DE	Nordrhein-Westfalen	1984.36	58.95
FR	Île De France	694.76	58.19
GB	Yorkshire and The Humber	694.29	45.19
GB	North West	607.37	42.42
DE	Sachsen-Anhalt	685.48	33.80
GB	South East	644.00	33.62
DE	Rheinland-Pfalz	628.29	32.03
PL	Region Południowy	817.70	29.11
IT	Nord-Ovest	1551.65	26.91
GB	Wales	518.64	24.86
DE	Baden-Württemberg	873.13	24.53
DE	Niedersachsen	949.69	20.19

3.3.2. NUTS2

After analysing the NUTS1 results, the more detailed NUTS2 results will be presented in this section. Because of the relatively low number of locations that currently consume hydrogen, the results for 2020 are not deemed to be of great importance. This section first provides results for 2030, followed by the results for 2050. As stated in the NUTS1 results, the main area of interest lies around in Western Europe. Because of this, images will focus on this part of the EU instead of the entire region. The results will be given in this section, but will be discussed in the coming chapters. This is done mostly because the tables and figures speak for themselves. Another reason for this is because some of the most relevant comments for this stage of the research were already made in section 3.3.1.

Table 3.9: Fifteen NUTS2 areas with the highest density of hydrogen consumption, and a sum of at least double the EU area average, in 2030

Country	Area	Sum $\left[\frac{\text{kt}}{\text{year}}\right]$	Density $\left[\frac{t}{\text{km}^2}\right]$
NL	Zeeland	382.23	210.75
BE	Provincie Antwerpen	396.01	139.55
NL	Zuid-Holland	408.14	134.62
NL	Limburg	232.41	106.59
NL	Groningen	185.91	78.90
GB	Cheshire	152.71	68.75
GB	East Yorkshire and Northern Lincolnshire	213.17	59.06
DE	Rheinhessen-Pfalz	267.92	39.57
GB	Tees Valley and Durham	110.31	36.67
DE	Köln	208.08	28.62
FR	Haute-Normandie	329.72	27.01
GR	Attiki	102.89	26.37
GB	Hampshire and Isle of Wight	104.78	24.96
DE	Sachsen-Anhalt	422.76	20.85
DE	Münster	125.31	18.36

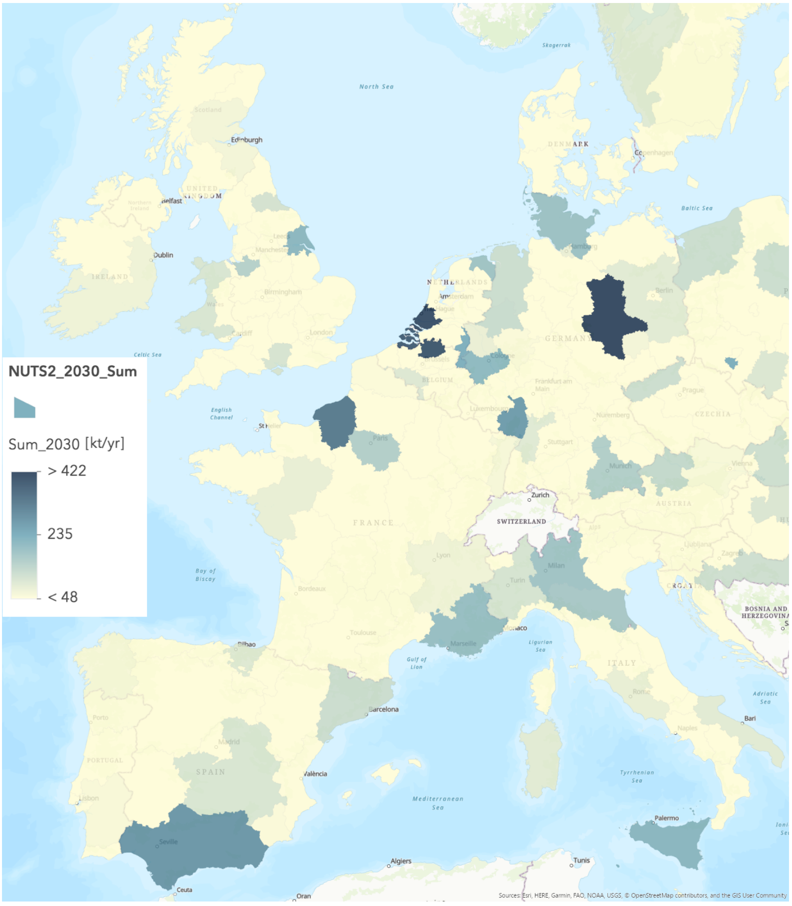


Figure 3.7: Sum of hydrogen consumption in 2030 for NUTS2 regions.

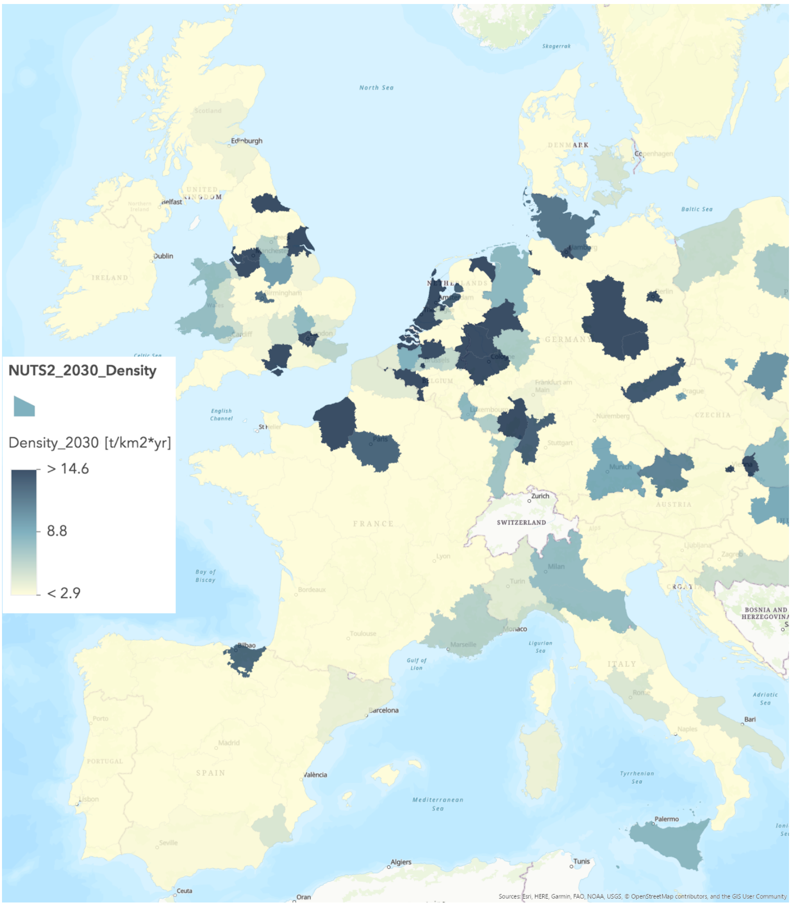


Figure 3.8: Density of hydrogen consumption in 2030 for NUTS2 regions.

Table 3.10: Fifteen NUTS2 areas with the highest sum of hydrogen consumption, and a consumption density of at least double the EU average, in 2050

Country	**Area**	**Sum** $\left[\frac{\mathrm{kt}}{\mathrm{year}}\right]$	**Density** $\left[\frac{t}{\mathrm{km}^2}\right]$
IT	Lombardia	1028.73	43.33
NL	Zuid-Holland	930.23	306.82
BE	Provincie Antwerpen	777.14	273.85
FR	Île de France	698.19	58.48
DE	Sachsen-Anhalt	686.25	33.84
DE	Düsseldorf	672.96	128.86
IT	Puglia	526.76	27.06
FR	Nord - Pas-de-Calais	506.89	41.21
PL	Śląskie	500.60	38.25
NL	Zeeland	498.29	274.75
DE	Köln	481.24	66.20
DE	Rheinhessen-Pfalz	479.13	70.76
NL	Noord-Holland	476.59	168.85
FR	Haute-Normandie	431.94	35.38
IT	Veneto	429.44	23.48

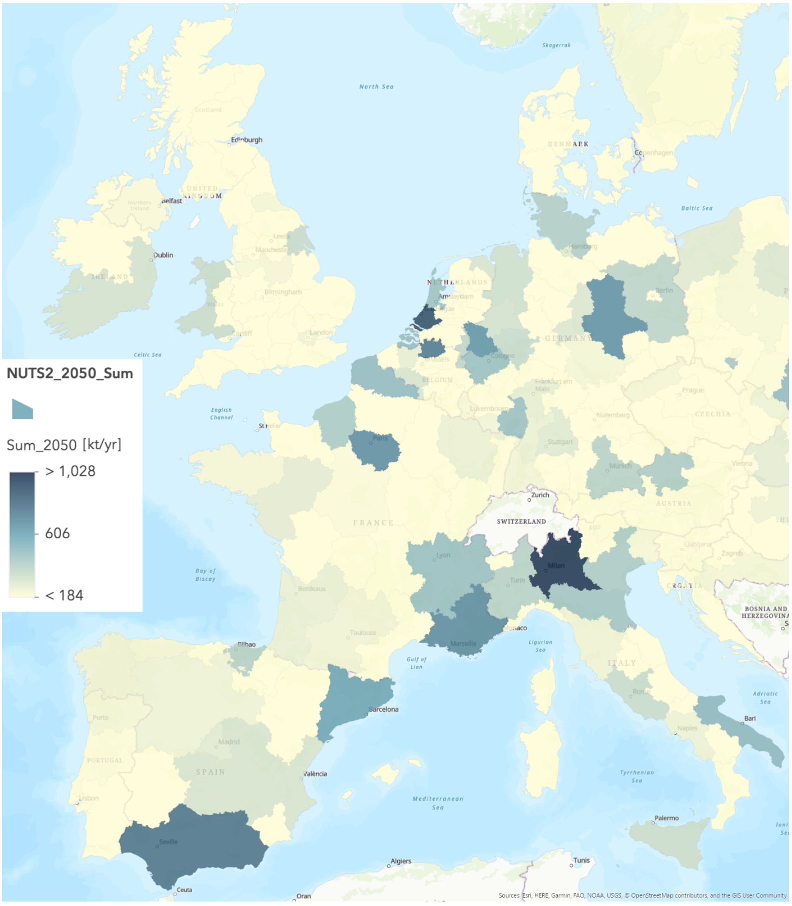


Figure 3.9: Sum of hydrogen consumption in 2050 for NUTS2 regions.

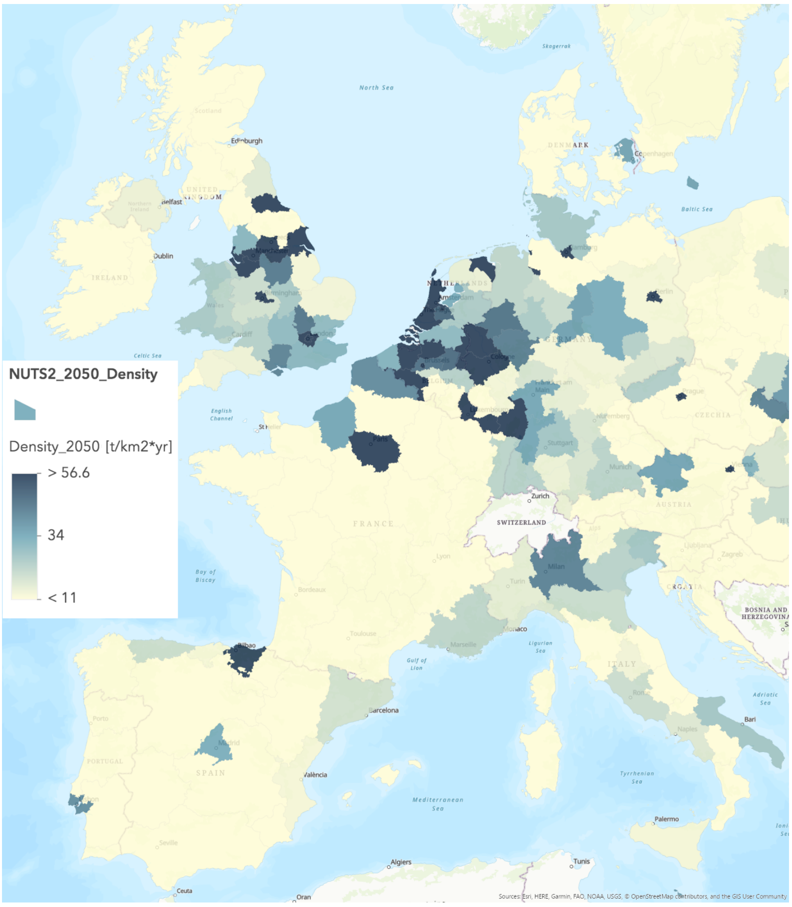


Figure 3.10: Density of hydrogen consumption in 2050 for NUTS2 regions.

4

Selection of Key areas

Having determined the current and the potential future spatial distribution of hydrogen consumption across the EU in chapter 3, this chapter will discuss the selection of the areas that should be part of the hydrogen corridor. Areas will first be chosen according to certain numerical thresholds for hydrogen consumption in an initial selection. These areas will subsequently be narrowed down further by taking their strategic value and geographic location into account.

4.1. Initial selection

Using the results from chapter 3, certain areas with a sufficient hydrogen consumption profile will be selected. The first and directly the most decisive selection was done by looking at the consumption density of a certain area. As was already explained in section 3.3, to convert some areas infrastructure to one that can distribute hydrogen there needs to be a high consumption on a relatively small surface area. Because of this, the consumption density will take the leading role in the selection criterion.

The first selection will be based on the following requirements: an estimated consumption density higher than the EU average in both 2030 and 2050. This means that all areas with a yearly consumption density below 2.97 ton per square kilometer per year in 2030 or below 12.08 ton per square kilometer per year in 2050 will be dropped from the potential corridor.

93 NUTS2 areas, of the EU's 269 total, match these two criteria. These 93 areas take up 17.6% of the EU surface area and consume 53.9% of the estimated total hydrogen in 2050, resulting in a total consumption density of about 37 ton per square kilometer. The areas are presented in figure 4.1.

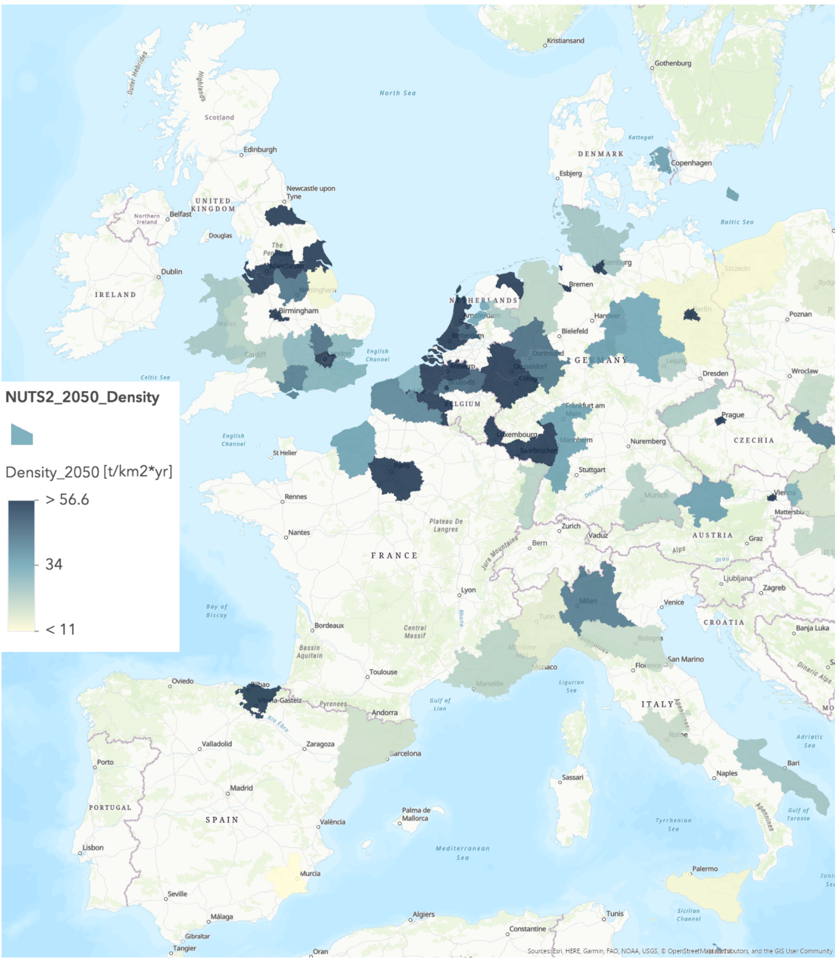


Figure 4.1: Map of preliminary selection of NUTS2 areas. Values for density are illustrated.

4.2. Selection of corridor & strategically relevant areas

In this section a corridor will be selected from the results, followed by adding some areas in proximity of the corridor that are relevant for hydrogen production purposes.

A lot can be learned by comparing the results from chapter 3 to the map of existing natural gas infrastructure [ENTSOG, 2019] [1]. The first thing to note is that the main connection from central Europe to the North of Africa is through Switzerland. It shows that, because of the absence of a pipeline through Austria, a cluster like the one of Oberbayern and Oberösterreich is not well positioned strategically.

Looking at figure 4.1, figure 3.6 and the infrastructure, there is one region that clearly presents itself as the main candidate for a hydrogen corridor. Already briefly discussed in section 3.3 the region that was once described as the Blue Banana stands out over the rest of the EU. Although no clear boundaries for this area exist, it is often described as going from Milan in Italy, crossing the Rhine area and the Benelux towards London [Hospers, 2003]. The description of the Blue Banana will serve as an inspiration for the backbone of the corridor that will be developed in this research. However, in the end the corridor will definitely not be bound by this description.

Having decided what region will serve as the backbone for the corridor, some areas will be added by looking at mainly three regional specific attributes. First of all the distance from the Blue Banana will be weighed in the decision. Next to this, potential hydrogen consumption and production are important.

[1] Unfortunately the image of the ENTSOG map is too large to be included. The source can be found in the bibliography, or the map can be discovered online on `https://transparency.entsog.eu`

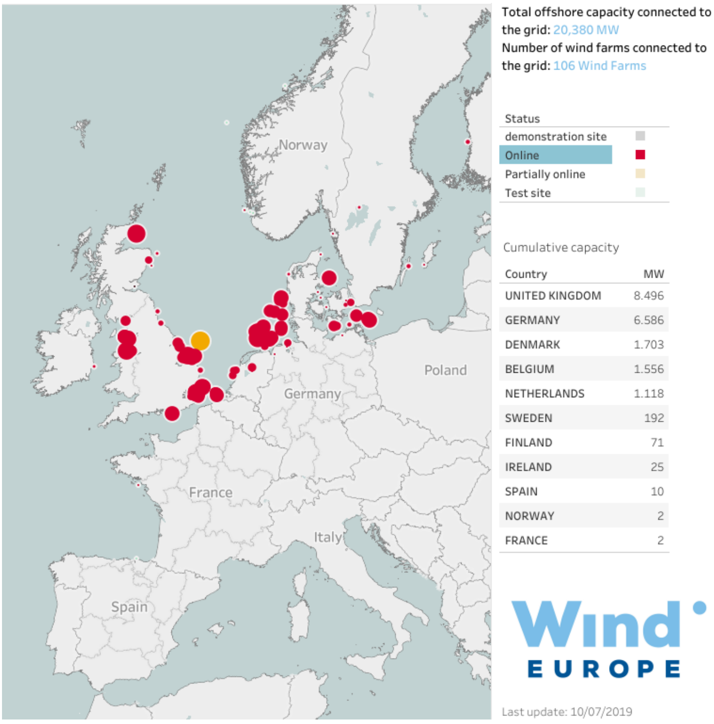


Figure 4.2: Locations of current and planned wind farms in the EU. Source: WindEurope

Access to the wind energy potential of the North Sea will be paramount for the renewable production of hydrogen. An estimated 47% of total EU offshore wind capacity could be installed in the North Sea in 2050 [WindEurope, 2019]. And, as pictured in figure 4.2, the bulk of already existing or planned wind farms are located in the North Sea as well.

Looking at the location of wind farms from figure 4.2, consumption estimates from figure 4.1 and points where existing offshore infrastructure comes on shore [ENTSOG, 2019] [TenneT, 2019], the following regions are included in the corridor: the Northern part of England, the Northern part of The Netherlands, Hamburg, including Schleswig-Holstein, and Bremen, including Weser-Ems.

Additionally, the metropolitan area of Paris and Haute-Normandie are included in the corridor. These areas boast a significant consumption and hydrogen production potential. Especially Haute-Normandie that has access a large potential of wind energy in The English Channel but also a large amount of nuclear energy. The nuclear energy production in fact is so much, that excess capacity, of France entirely, could power 20 GW of electrolyser capacity in 2050 [Scamman and Newborough, 2016].

Finally the region of Sachsen-Anhalt is included because of its large potential of hydrogen consumption and Lazio in Italy is included because of its location along the pipeline through Italy.

4.3. Final specification of corridor

In this section the final specification of the corridor will be reviewed. Table 4.1 presents concise results of consumption figures of the corridor in comparison to the EU total. Almost one third of estimated future hydrogen consumption takes place in the corridor, while the surface area is only around 7% of the EU. This results in a hydrogen consumption density of about 52 ton per square kilometer per year. Additionally, from the start almost half of the current hydrogen consumption is happening in this corridor. This is very useful for the initial phase of the realisation of the infrastructure because already a significant amount of hydrogen consumption takes place in these NUTS2 areas. Figure 4.3 illustrates the corridor on a map. Additionally all NUTS2 areas that make up the corridor are presented in table 4.2.

Table 4.1: Concise final results. Hydrogen demand and surface area.

	2020 [Mt]	**2030** [Mt]	**2050** [Mt]	**Surface area** [million km^2]
EU	7.7	13	50	4.4
Corridor	3.6	5.4	16	0.3
Portion inside the corridor	47%	42%	33%	7%

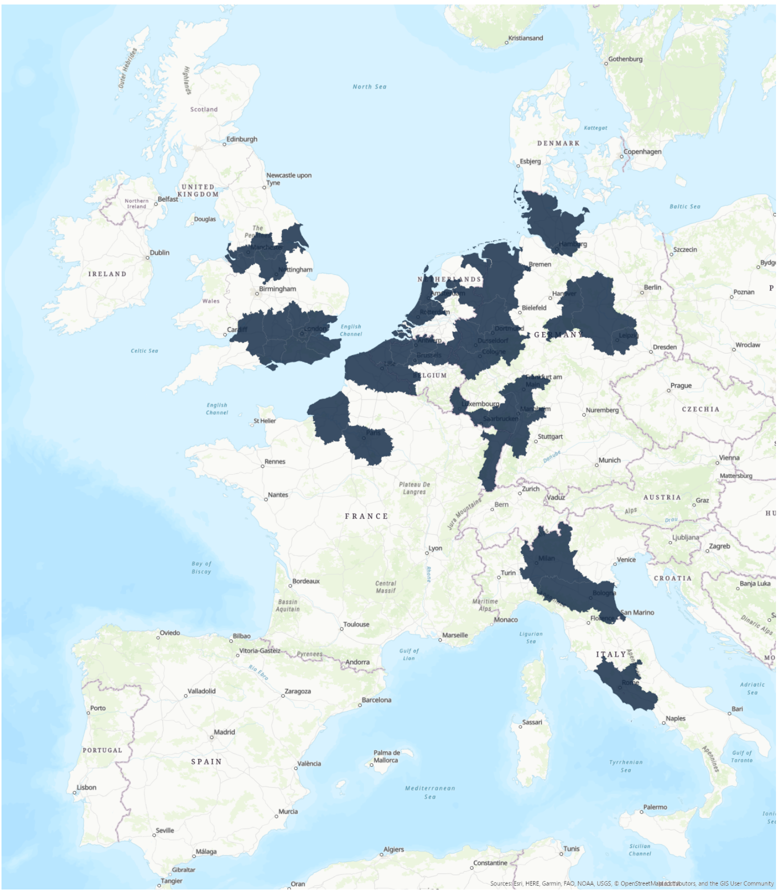


Figure 4.3: Final corridor areas indicated by dark blue colors

Table 4.2: Corridor specification in NUTS2 areas

Country	NUTS code	Area names
BE	BE10, BE21, BE22, BE23, BE24, BE25, BE32	Brussels Hoofdstedelijk Gewest, Provincie Antwerpen, Provincie Limburg, Provincie Oost-Vlaanderen, Provincie Vlaams-Brabant, Provincie West-Vlaanderen, Provincie Henegouwen
DE	DE12, DE50, DE60, DE71, DE91, DE94, DEA1, DEA2, DEA3, DEA5, DEB3, DEC0, DED5, DEE0, DEF0	Karlsruhe, Bremen, Hamburg, Darmstadt, Braunschweig, Weser-Ems, Düsseldorf, Köln, Münster, Arnsberg, Rheinhessen-Pfalz, Saarland, Leipzig, Sachsen-Anhalt, Schleswig-Holstein
FR	FR10, FR23, FR30, FR42	Île de France, Haute-Normandie, Nord - Pas-de-Calais, Alsace
GB	UKD3, UKD6, UKD7, UKE1, UKE3, UKE4, UKF1, UKH2, UKH3, UKI1, UKI2, UKJ1, UKJ2, UKJ3, UKJ4, UKK1	Greater Manchester, Cheshire, Merseyside, East Yorkshire and Northern Lincolnshire, South Yorkshire, West Yorkshire, Derbyshire and Nottinghamshire, Bedfordshire and Hertfordshire, Essex, Inner London, Outer London, Berkshire, Buckinghamshire and Oxfordshire, Surrey, East and West Sussex, Hampshire and Isle of Wight, Kent, Gloucestershire, Wiltshire and Bristol/Bath area
IT	ITC4, ITH5, ITI4	Lombardia, Emilia-Romagna, Lazio
LU	LU00	Luxembourg
NL	NL11, NL21, NL23, NL31, NL32, NL33, NL34, NL42	Groningen, Overijssel, Flevoland, Utrecht, Noord-Holland, Zuid-Holland, Zeeland, Limburg

5

Kick Start Scenario for the Corridor

Chapter 3 maps the hydrogen consumption across EU mostly according to the report from the FCH-JU Hydrogen Roadmap Europe [FCH JU, 2019]. This scenario from that report, and subsequently the mapping exercise from chapter 3 from this research, assumes a bottom-up scenario, as explained in section 1.2.4. This implies a gradual and uniform adoption of hydrogen in the entire EU towards a future with a significant role for hydrogen in the energy system.

The endeavour to estimate the spatial distribution of hydrogen consumption from chapter 3 proved useful to indicate key areas in chapter 4, from where a cross EU hydrogen infrastructure should be implemented.

This chapter will present a *kick-start* scenario in the near future for the hydrogen corridor. First the rationale behind this idea will be presented in section 5.1. Subsequently, section 5.2 explains the changes in the consumption for this scenario. Finally the results of this scenario will be discussed in section 5.3.

5.1. Rationale

Several arguments arise that could indicate this transition may not be as gradual and uniform as the one portrayed by the *Hydrogen Roadmap Europe*. The introduction of a large scale pipeline system in a certain area of the EU would most likely lead to a large acceleration of hydrogen consumption in that region specifically, as also discussed in the methodology in chapter 2.

"Innovation and the commercialization of new technologies take place disproportionately in clusters - Geographic concentrations of interconnected companies and institutions in a particular field." [Porter and Stern, 2001], is a key argument to asses an accelerated case specifically for the corridor.

Given access to cheap and low carbon hydrogen, several sectors will most likely alter feedstock or processes far before 2050. Some sectors, like industry feedstock and industry heat, do not even have to make any large alterations to their day to day processes or activities at all. Hence these sectors, again when given access to cheap and clean hydrogen, can potentially shift the bulk of their consumption in a matter of years, maybe even months.

The hydrogen system this research proposes will largely be based on the existing natural gas infrastructure, which uses pipelines with a capacity of around 50 GW, as an indication of size. All these factors taken into account, the transition to hydrogen in the proposed hydrogen corridor can potentially be a step change instead of a gradual introduction.

Because of this, the hydrogen infrastructure presented in this research will not be based on indications of hydrogen consumption over time. Instead, a new scenario will be presented. A scenario only for the corridor, based on the introduction of a large hydrogen pipeline that will drive the use of hydrogen in the region.

In this scenario there will not be an estimate for hydrogen consumption. Instead there will be an indication of the potential for hydrogen consumption, which should in fact be used to plan a long term cross continent hydrogen system in the near future. More information on hydrogen potential will be presented in section 5.2.

Time wise there will not be an exact time frame for the beginning of this scenario. As a rough indication, and as the values for areas outside the corridor, 2030 is assumed to be a plausible estimate. For this scenario however, the time for action will be indicated by *as soon as possible*. As indicated in chapter 3, the sectors that can consume hydrogen already exist. Therefore action can, and should, be taken today rather than tomorrow.

5.2. Changes in demand

The kick-start scenario will present a potential consumption of hydrogen. This represents the amount of hydrogen that can potentially, but still logically, be consumed when a faster rate of adaptation to hydrogen is assumed. Some sectors may switch to hydrogen a lot faster and easier than others. Existing hydrogen feedstock for some industries can obviously easily be replaced by low carbon hydrogen. But for example in the road transport sector, many more and more complex hardware changes are required. The near future potential for hydrogen consumption in the sectors that are covered in this research are presented in table 5.1.

Table 5.1: Specification of the potential hydrogen consumption in the corridor for the near future

Sector	Specification of potential
Existing pure hydrogen industry feedstock	No change
Iron & steel	40% of production
Industry heat	70 %
Road transport	20% - 25%
Shipping	2050 value
Heating in buildings	60 % of heat currently provided by natural gas
Electricity generation	10% of electricity production in 2030

The potentials were estimated based on several arguments, which will be discussed in the rest of this section. The indications hydrogen consumption potential is given for the corridor only, because these accelerated hydrogen potentials will only be applied to areas within the specified hydrogen corridor.

Iron & Steel

The amount of energy to produce 40% of iron and steel using hydrogen is twice the value that was quoted for 2050 in Hydrogen Roadmap Europe [FCH JU, 2019]. Hydrogen or CCS are the predominant technologies that are able to decarbonise this sector. To commit to emission targets, the region inside the corridor should take a leading role in the decarbonisation. Because of this the decision was made to increase the share of hydrogen in the iron and steel sector to 40%. This correlates to approximately 2.8 million tonnes of potential hydrogen consumption.

Industry Heat

The total demand for industrial heat is estimated at 2264 TWh [Naegler et al., 2015]. Because 40% of steel will be produced with hydrogen, the heat demand for the iron and steel sector will be put 60% of its original value. Industry heat, especially high grade, is extremely tough to decarbonise. Using hydrogen is one of the few options, which is why the potential estimate is estimated at 70%. The ambitious estimate that 70% of industrial heat can be supplied by hydrogen corresponds to around 11.3 million tonnes of potential hydrogen consumption.

Road Transport

For road transport, the quicker acceleration is assumed equal to the amount for transport in 2050 from Hydrogen Roadmap Europe [FCH JU, 2019]. Into energy terms this is about 4.3 million tonnes of potential hydrogen consumption.

Shipping

Just as for road transport, for shipping the rapid change is assumed to be represented by the value from 2050 as presented in chapter 3. This translates to 1.2 million tonnes of potential hydrogen consumption.

Heating in Buildings

To estimate the potential for hydrogen in heat for buildings, the assumption was that within the corridor 60% of heat that is currently supplied by natural gas could be substituted by hydrogen. 44% of current natural gas building heat demand corresponds to 465 TWh [FCH JU, 2019]. This means that 60% of the total is $\frac{465}{0.44} \cdot 0.6 = 634$ TWh. This equals approximately 4.3 million tonnes of potential hydrogen consumption.

Electricity Generation

For both grid-balancing and low-carbon electricity production, about 10% of electricity generation is assumed to be the short term potential for hydrogen. The electricity consumption in 2030 is estimated to be 3233 TWh [FCH JU, 2019]. So the potential for hydrogen is estimated at 323 TWh, or 3.1 million tonnes.

5.3. Results

The scenario results in a hydrogen consumption potential within the corridor of 30.8 million tonnes, as can be seen in table 5.2. This is considerably more than the other scenarios indicate. Especially industrial heat demand attributes to the substantial difference. But when planning something that may be in use for a long period of time, it is important to make decisions based on knowledge about what the future may hold. Figure 5.1 and 5.2 illustrate the how the potential consumption is distributed in the corridor.

Table 5.2: Concise final results. Hydrogen demand and surface area.

	2020 [Mt]	**2030** [Mt]	**2050** [Mt]	**Kick-start** [Mt]	**Surface area** [million km^2]
EU	7.7	13	50	38	4.4
Corridor	3.6	5.4	16	31	0.31
Ratio inside the corridor	47%	42%	33%	81%	7%

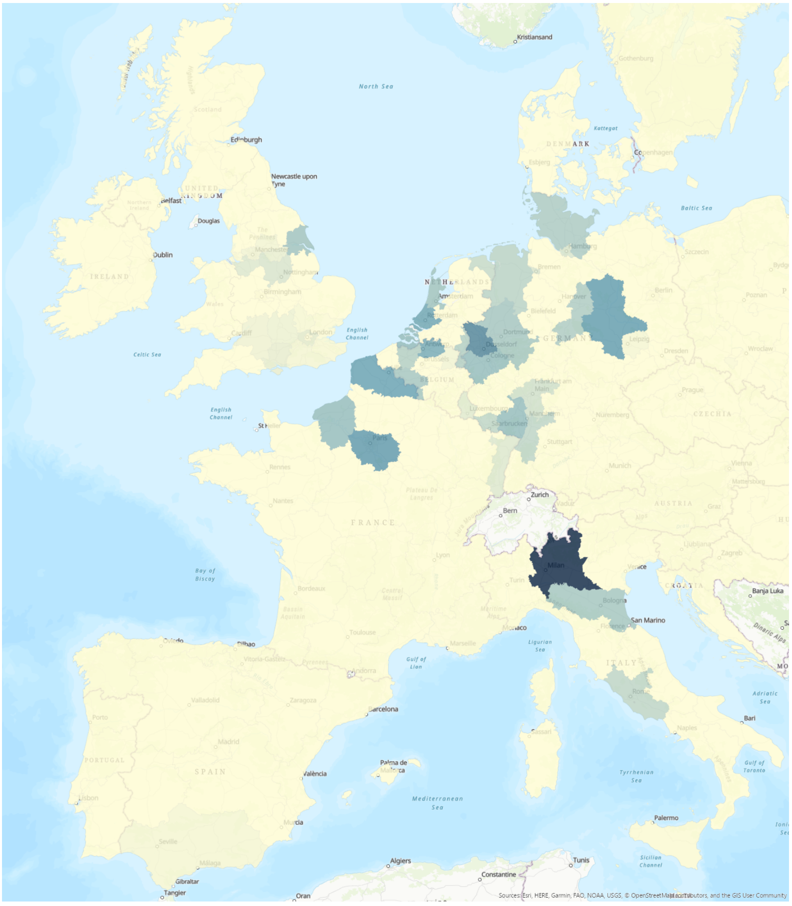


Figure 5.1: Sum of hydrogen consumption in the kick-off scenario for NUTS2 regions.

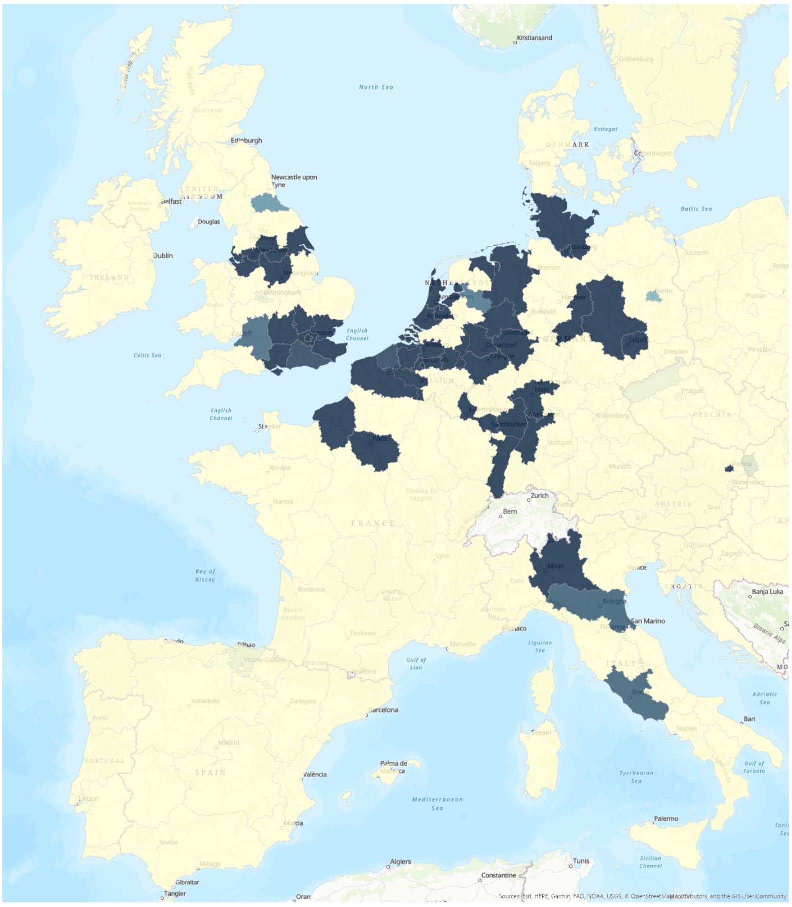


Figure 5.2: Density of hydrogen consumption in the kick-off scenario for NUTS2 regions.

6

Production of Hydrogen for the Corridor

In this following chapter the attention will be on indicating how the hydrogen for the corridor can be produced. As was described in section 1.2.1, current production of hydrogen is mainly done by regular steam methane reforming and emits a lot of greenhouse gasses. Production will need to switch towards electrolysis based hydrogen production, using electricity from a renewable source. In the following section, there is a suggestion for hydrogen production using only carbon free electricity. It must be stated however, that before all this renewable electricity is installed and in function, large scale centralized steam methane reforming with carbon capture and storage may be used to encourage and boost the transition towards the use of hydrogen in the energy system.

Section 6.1 will present the twelve areas in which the corridor will be broken down. Next, in section 6.2, the production methods will be discussed and amounts for production capacity will be quantified.

6.1. Regional breakdown

Since this research approaches the problem from a system-, or TSO -level, the 54 NUTS2 areas in the corridor will be condensed to several separate areas that form clusters inside the corridor itself. The resulting breakdown is shown in figure 6.1. Additional information about which NUTS2 areas are in each broken down region can be found in table 6.1. Table 6.1 also includes the consumption for 2020 to illustrate which areas already consume hydrogen from the start.

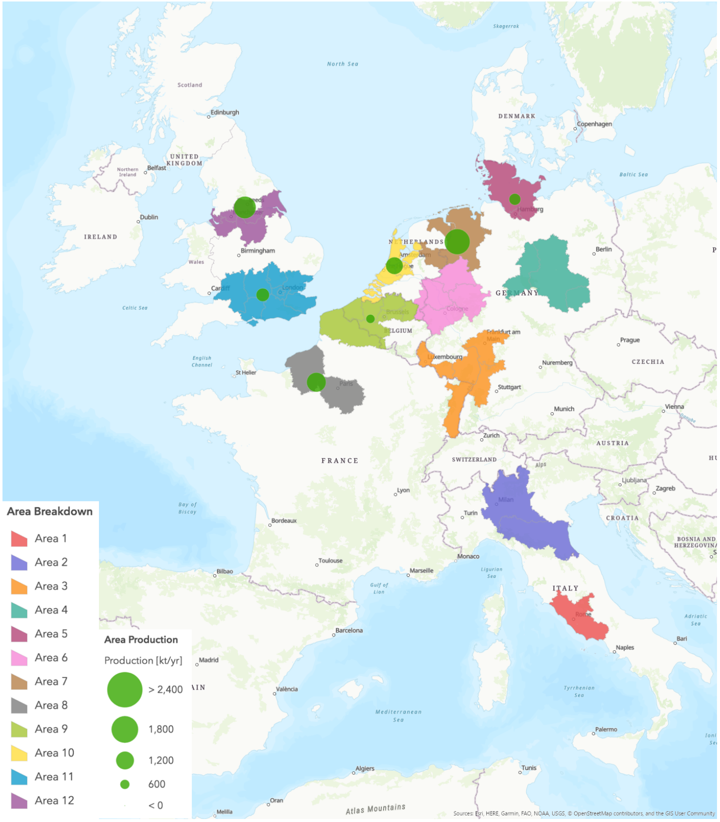


Figure 6.1: Corridor breakdown into 12 areas with hydrogen production per area.

Table 6.1: Area breakdown NUTS2 specification

Area	NUTS2 code	NUTS2 name	Consumption in 2020 $[\mathrm{Mt}]$
Area 1	ITI4	Lazio	0.00
Area 2	ITC4, ITH5	Lombardia, Emilia-Romagna	0.15
Area 3	DE12, DE71, DEB3, DEC0, FR42, LU00	Karlsruhe, Darmstadt, Rheinhessen-Pfalz, Saarland, Alsace, Luxembourg	0.32
Area 4	DE91, DED5, DEE0	Braunschweig, Leipzig, Sachsen-Anhalt	0.39
Area 5	DE60, DEF0	Hamburg, Schleswig-Holstein	0.21
Area 6	DEA1, DEA2, DEA3, DEA5, NL42	Düsseldorf, Köln, Münster, Arnsberg, Limburg (NL)	0.43
Area 7	DE50, DE94, NL11, NL21	Bremen, Weser-Ems, Groningen, Overijssel	0.18
Area 8	FR10, FR23	Île de France, Haute-Normandie	0.41
Area 9	BE10, BE21, BE22, BE23, BE24, BE25, BE32, FR30	Brussels Hoofdstedelijk Gewest, Provincie Antwerpen, Provincie Limburg, Provincie Oost-Vlaanderen, Provincie Vlaams-Brabant, Provincie West-Vlaanderen, Provincie Henegouwen, Nord - Pas-de-Calais	0.41
Area 10	NL23, NL31, NL32, NL33, NL34	Flevoland, Utrecht, Noord-Holland, Zuid-Holland, Zeeland	0.68
Area 11	UKH2, UKH3, UKI1, UKI2, UKJ1, UKJ2, UKJ3, UKJ4, UKK1	Bedfordshire and Hertfordshire, Essex, Inner London, Outer London, Berkshire, Buckinghamshire and Oxfordshire, Surrey, East and West Sussex, Hampshire and Isle of Wight, Kent, Gloucestershire, Wiltshire and Bristol/Bath area	0.09
Area 12	UKD3, UKD6, UKD7, UKE1, UKE3, UKE4, UKF1	Greater Manchester, Cheshire, Merseyside, East Yorkshire and Northern Lincolnshire, South Yorkshire, West Yorkshire, Derbyshire and Nottinghamshire	0.32

6.2. Production

The approach to estimate the production of hydrogen for the corridor will rely on the assumption that hydrogen production will happen at large-scale, centralised and away from densely populated areas. Therefore only three methods of sustainable hydrogen production will be part of this research: production on the North Sea using wind energy, production from nuclear energy in France and production in the Sahara from solar energy.

Electrolyser efficiency is currently over 70% of higher heating value and the efficiency is expected to grow as the technology is scaled up [IEA, 2019a]. The energy required for the transmission of hydrogen, which is dependent on the transmission distance, is about $1-5\%$ [Gupta et al., 2016]. Combining the efficiencies and assuming some efficiency improvements, the assumption is that hydrogen can be produced and transported with 80% efficiency. The production quantity estimates are presented in table 6.2, and for geographic comparison are also included in figure 6.1. In the rest of this section, the different production quantities and methods from table 6.2 will be discussed.

Table 6.2: Hydrogen production per area

Area	**Assumed capacity** [GW]	**Hydrogen production** [Mt]
Area 5	Wind: 10	1.07
Area 7	Wind: 22.75	2.43
Area 8	Wind: 10.45 Nuclear: 3.9	1.81
	Wind: 3 Nuclear: 2.7	0.80
Area 10	Wind: 15	1.60
Area 11	Wind: 11.45	1.22
Area 12	Wind: 19.4	2.07
From Sahara	Wind: 80 Solar: 221	19.8

Wind energy

The estimations for wind energy are based on an off-shore wind energy report by WindEurope [WindEurope, 2019]. This report presents potential capacity indications for specific sea regions, including the North-Sea. Of these indicated offshore wind potential capacities, 50% is assumed to be dedicated for the production of hydrogen. This may seem like a large amount. But looking at the vast potential of wind energy that is located outside of low *Levelised Cost Of Electricity* (LCOE) ranges for electricity transmission to shore, indicates that in the future this vast potential of wind energy far from shore may be used for dedicated hydrogen production. Even more, the developments of for example floating wind turbines may prove these estimates to be low.

The indicated hydrogen production potential for The Netherlands is equally divided among Area 7 and Area 10, while the indicated potential for the North-Sea at the North-Western border of Germany is divided between Area 5 and Area 7.

As a capacity factor for offshore wind energy production, 60% is assumed. This is based on the fact that capacity factors have been steadily rising from about 35% in around 2005, to over 50% in present times [Junginger et al., 2020], which is a capacity factor of 0.5 or 4380 hours per year.

Nuclear energy

Moving on to the nuclear energy potential in France. Three nuclear power plants are located within the corridor. Two in Haute-Normandie: Paluel, with 5.2 GW of nameplate capacity, and Penly, with 2.6 GW. The other nuclear power plant, Gravelines with 5.4 GW of capacity, is in Nord - Pas-de-Calais [EDF, 2017]. The average nuclear power plant in France currently only generates about 73% of its potential energy output on a yearly basis [Scamman and Newborough, 2016]. This number is set do decrease even more as the French government attempts to increase the share of renewables for electricity production [Scamman and Newborough, 2016]. Because of this, about 50% of current installed capacity is assumed to be available for hydrogen production for the corridor.

Energy from the Sahara

The rest, and largest part, of the required hydrogen may be produced in the Sahara desert. All areas inside the corridor consume a total of 31 million tonnes of hydrogen per year, but produce only about 11. This means that about 20 million tonnes of hydrogen will need to be imported every year. To produce this amount of hydrogen in the Sahara from only solar energy, about 390 GW of solar panels would be needed.

An obvious pitfall of this idea is that the electrolyser will only be in service when the solar panels are producing electricity, which in the Sahara is about 2600 hours per year [SOLARGIS, 2017]. To increase operating times for electrolysers, which reduces the overall costs of the produced hydrogen, van Wijk and Wouters propose the use of wind turbines in the Sahara together with the solar panels.

This concept is adopted for this proposition. The assumption is that about 80 GW of wind turbines may be installed in the Sahara. These wind turbines, again assuming a capacity factor of 60%, are able to produce almost 8.5 million tons of hydrogen.

To produce the rest of the required hydrogen, around 221 GW_p needs to be installed on a surface area of about 1.6 thousand km^2. This amount is determined by assuming a solar irradiation of $2500 \frac{KWh}{m^2}$ per year, a 20% solar panel efficiency and an area coverage of 60%.

Steam methane reforming with carbon capture and storage

Especially in the early stages, as the renewable electricity capacity is being developed, there may be a significant role for SMR coupled with CCS. The idea behind this concept is to reform the methane to hydrogen, as explained in section 1.2.1, and then transport the produced CO_2 back to empty gas fields. The natural gas that once was in these now depleted fields was mostly transported to shore using pipelines. So the infrastructure to transport CO_2 back to these fields is often already in place.

New dedicated SMR plants can be equipped with CCS to produce hydrogen for the corridor in the early stages. Already existing SMR plants that are well situated near this existing infrastructure can be retrofitted with technology to capture the CO_2 [CE Delft, 2018].

The estimated CO_2 storage potential in empty gas fields, only for The Netherlands, is estimated at 2.3Gt of CO_2 [CE Delft, 2018]. This is about eleven times the total yearly CO_2 emissions of the Netherlands [Eurostat, 2019b]. For Europe the estimate is about 20Gt of CO_2 [Rütters and the CGS Europe partners, 2013], or about 4.5 times the yearly CO_2 emissions of the EU [Eurostat, 2019b]. Taking into account other geological storage options as well, the estimated potential for the EU is 117Gt of CO_2 [Rütters and the CGS Europe partners, 2013]. This indicates that sufficient CO_2 storage potential is available to use SMR with CCS as a way to start of the consumption of hydrogen in the corridor before sufficient renewable electricity capacity is available.

7 Hydrogen Infrastructure

In this chapter the focus lies on a method to transport the hydrogen from the locations production to the consuming areas. This research focusses only on large distance transmission. For the sake of simplicity, the assumption is that hydrogen is produced and consumed from a single point in the area. Regional distribution is considered outside the scope of this research.

In section 7.1 the imbalance between hydrogen production and consumption will be determined. Section 7.2 will discuss what the existing gas infrastructure looks like and which current pipelines presently connect the areas in the corridor. Subsequently the required updates for the existing gas infrastructure will be pointed out in section 7.3. Finally hydrogen storage possibilities will be discussed in section 7.4.

7.1. Consumption & production mismatch

To indicate how much and to where the infrastructure should transport the hydrogen, first the flow between areas needs to be determined. To do this the mismatch between hydrogen production and consumption for each area is computed. The results are presented in figure 7.1 with specific values for each area given in table 7.1. Note that Area 7 is a net producer of hydrogen.

Table 7.1: Production, consumption and mismatch for each area.

Area	**Consumption** [Mt]	**Production** [Mt]	**Mismatch** [Mt]
Area 1	0.66	0.00	-0.66
Area 2	3.11	0.00	-3.11
Area 3	3.16	0.00	-3.16
Area 4	2.13	0.00	-2.13
Area 5	1.13	1.07	-0.06
Area 6	4.48	0.00	-4.48
Area 7	1.75	2.43	0.68
Area 8	2.07	1.81	-0.26
Area 9	4.33	0.80	-3.53
Area 10	3.31	1.60	-1.71
Area 11	2.10	1.22	-0.88
Area 12	2.53	2.07	-0.46
Sahara	0.00	19.77	19.77

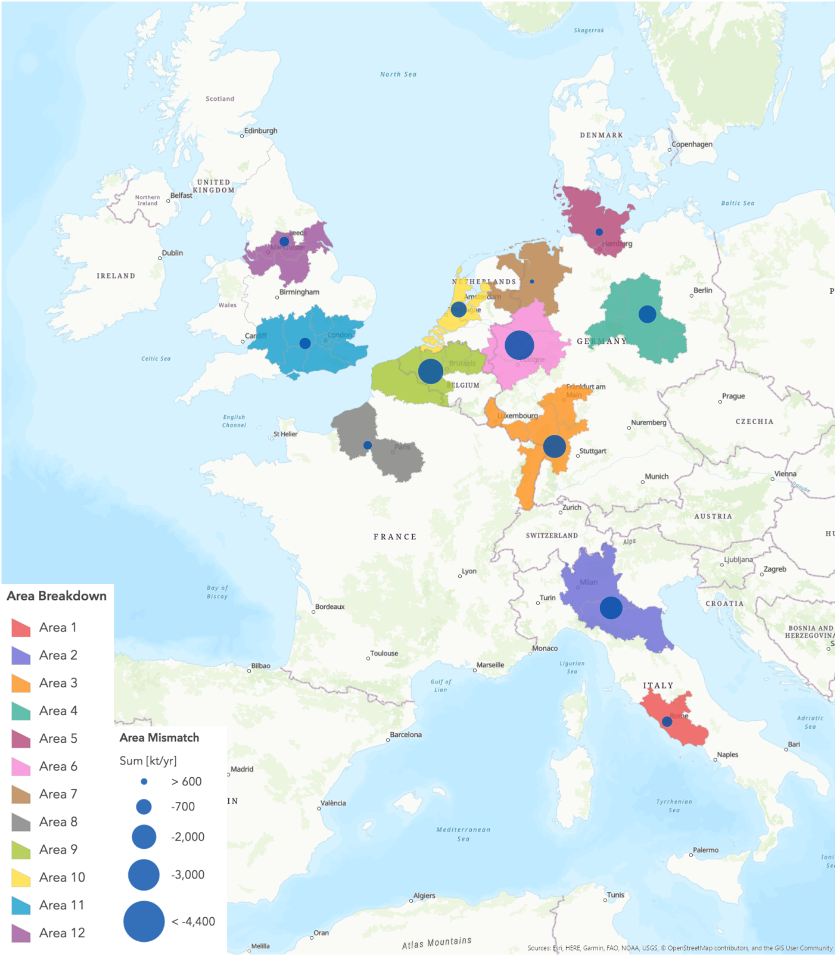


Figure 7.1: Mapped mismatch between production and consumption per area.

7.2. Existing infrastructure

The new, or updated, infrastructure plan for the hydrogen corridor will be based on the existing European natural gas infrastructure. Doing this has several advantages. For example the existing pipelines have already obtained a *right of way* or established path to go from point A to point B. Next to that research has shown that some pipelines appear to be capable of transporting hydrogen. For instance for the existing Dutch gas infrastructure. A stricter surveillance of pressure cycles is proposed to ensure safety, but other than that no real issues were reported for the pipelines [DNV GL, 2017]. Transporting hydrogen instead of natural gas also has little effects for the amount of energy that is transported. The relation between relative energy flow compared to pure natural gas and amount of hydrogen added to blended into the gas can be seen in figure 7.2. The figure illustrates that with pure hydrogen, dependent on the calorific value of the natural gas, between $80-97\%$ of the original energy flow is transported.

Some existing pipelines may need to be altered though, which is called *retrofitting*. Retrofitting can be done in several ways. Of course pipelines can be replaced entirely. But some other smarter, and possibly more economic, methods exist as well. One option is to coat the inside of existing pipelines with a substance that significantly reduces the interaction of hydrogen with the pipe, which can cause hydrogen embrittlement. Another option, especially for sections that require a capacity lower than the current natural gas capacity, is to use an inner tube inside the large natural gas pipeline.

Retrofitting or reusing existing pipelines can be much more favorable over laying new pipelines across new pathways. The existing infrastructure around the proposed hydrogen corridor is presented in figure 7.3.

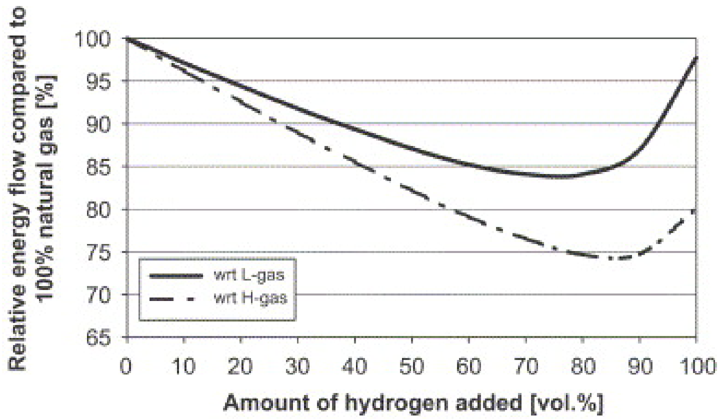


Figure 7.2: Relative energy flow of hydrogen through pipeline compared to natural gas, source: [Haeseldonckx and D'haeseleer, 2007].

From figure 7.3 it becomes clear that there is no shortage of existing pipelines in and around the hydrogen corridor. Even more, all 12 areas of the corridor are already connected to both each other and the Sahara by existing infrastructure. Some sections are even executed two or three times, which opens up the possibility of retrofitting only one or two pipelines so some natural gas can still be transported for some specific purposes.

Figure 7.3: Existing natural gas infrastructure in the proposed hydrogen corridor. Source: [ENTSOG, 2019].

7.3. Infrastructure designated for corridor

From figure 7.3 the relevant sections of existing pipelines will make up the infrastructure for the hydrogen corridor. Pipelines that connect each area inside the corridor are shown in figure 7.4. The infrastructure is split up in fifteen sections that either mark sections between areas or points where the infrastructure splits.

Digital data for spatial analysis of these pipelines is hard to find on the internet, so the sections had to be digitalised manually. Therefore the pathways depicted in figure 7.4 may not represent the exact location.

The values from table 7.1 will then provide the necessary information to estimate the required capacity for each pipeline section. Figure 7.5 illustrates each section's pipeline capacity, illustrated by the thickness of the line.

Finally table 7.2 gives all necessary information like current capacity, estimated future capacity and pipeline length. In addition some relevant notes are included for each section. The current capacity is an indication, based on an assumed hydrogen transportation under a pressure of 100 bar and a hydrogen flow velocity of $25\,\frac{\mathrm{m}}{\mathrm{s}}$. Although this is a viable assumption for velocity, it is higher than the current velocity of natural gas. A monitoring program is recommended to ensure the integrity of the pipeline [DNV GL, 2017].

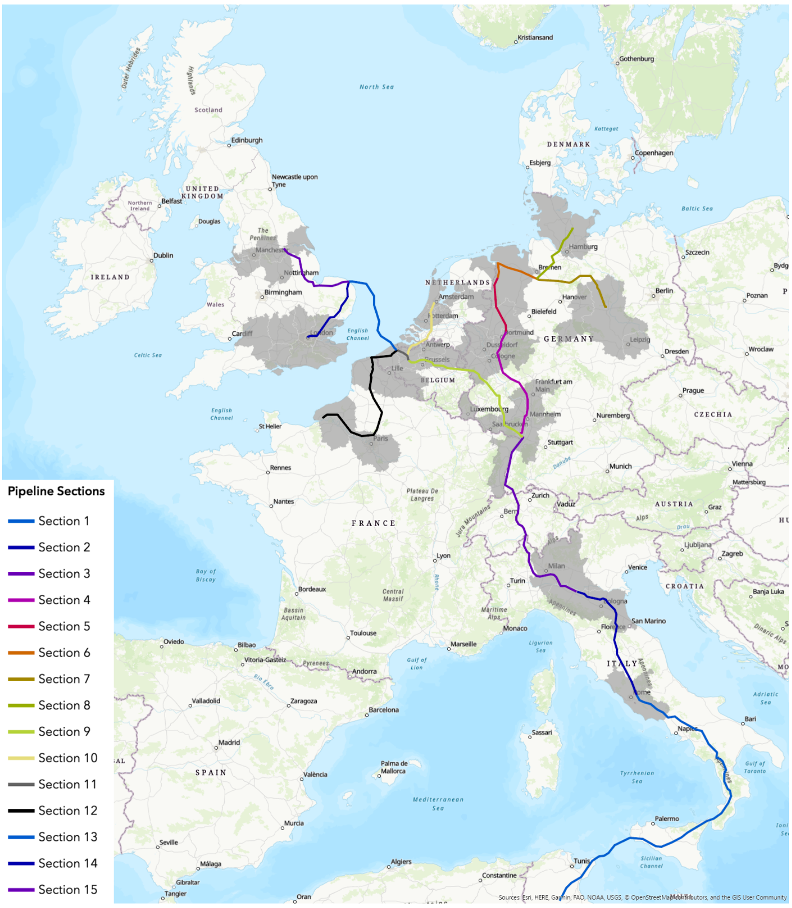


Figure 7.4: Hydrogen infrastructure in the corridor split up into fifteen sections.

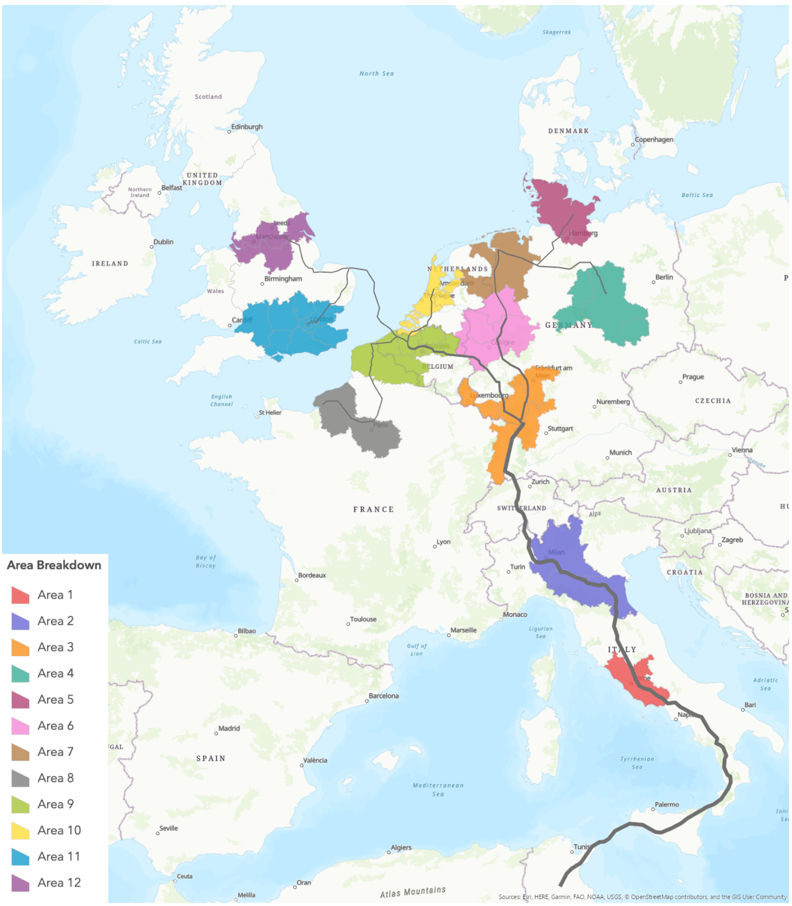


Figure 7.5: Hydrogen infrastructure with pipeline capacity indications.

Table 7.2: Pipeline properties per section

Infrastructure section	**Estimated required capacity** $\left[\frac{\mathrm{Mt}}{\mathrm{year}}\right]$	**Current capacity** $\left[\frac{\mathrm{Mt}}{\mathrm{year}}\right]$	**Length** $[\mathrm{km}]$	**Notes**
Section 1	19.8	7.3	1633	From Sahara to Area 1. Part of TRANSMED. 1200 mm on-shore, 2 x 660 mm & 3 x 500 mm off-shore [Matt Macdonald, 2010].
Section 2	19.1	7.3	593	From Area 1 to Area 2. Part of TRANSMED. 1200 mm [SNAM RETE, 2016].
Section 3	16	4.1	901	From Area 2 to Area 3. Transitgas through Switzerland. From Griespass to Ruswill 1200 mm, from Ruswill to Wallbach 2 x 900 mm [Transitgas AG, 2019]. From French border TENP between 900 - 1000 mm [Fluxys, 2017].
Section 4	6	4.1	542	From Area 3 to Area 6. Part METG, at leas 900 mm [ENTSOG, 2019].
Section 5	1.5	4.1	250	From Area 6 to Area 7. Several large pipelines from Emden to south, at least 900 mm [ENTSOG, 2019].
Section 6	2.2	4.1	245	From Area 7 to Steinrink. Part NETRA. At least 900 mm [ENTSOG, 2019].
Section 7	2.1	4.1	406	From Steinrik to Area 4. Part NETRA. At least 900 mm [ENTSOG, 2019].
Section 8	0.1	4.1	290	From Steinrik to Area 5. At least 900 mm [ENTSOG, 2019].
Section 9	6.8	4.1	695	From Area 3 to Area 9. Part TENP. At least 900 mm [ENTSOG, 2019]
Section 10	1.7	1.8	311	From Area 9 to Area 10. At least 900 mm in Belgium, at least 600 mm in The Netherlands [ENTSOG, 2019]
Section 11	1.6	4.1	73	From Area 9 to Zeebrugge. At least 900 mm [ENTSOG, 2019]
Section 12	0.3	4.1	755	From Zeebrugge to Area 8. At least 900 mm [ENTSOG, 2019]
Section 13	1.3	5	417	From Zeebrugge to Bacton. 1000 mm [Interconnector Ltd., 2015].
Section 14	0.9	4.1	332	From Bacton to Area 11. 900 mm [National Grid, 2017]
Section 15	0.5	4.1	388	From Bacton to Area 12. 900 mm [National Grid, 2017]

After the designated pipeline pathway has been decided it is useful to compare it to the infrastructure propositions that were discussed in section 1.2.5. The illustrations for national infrastructure propositions are repeated in figure 1.7.

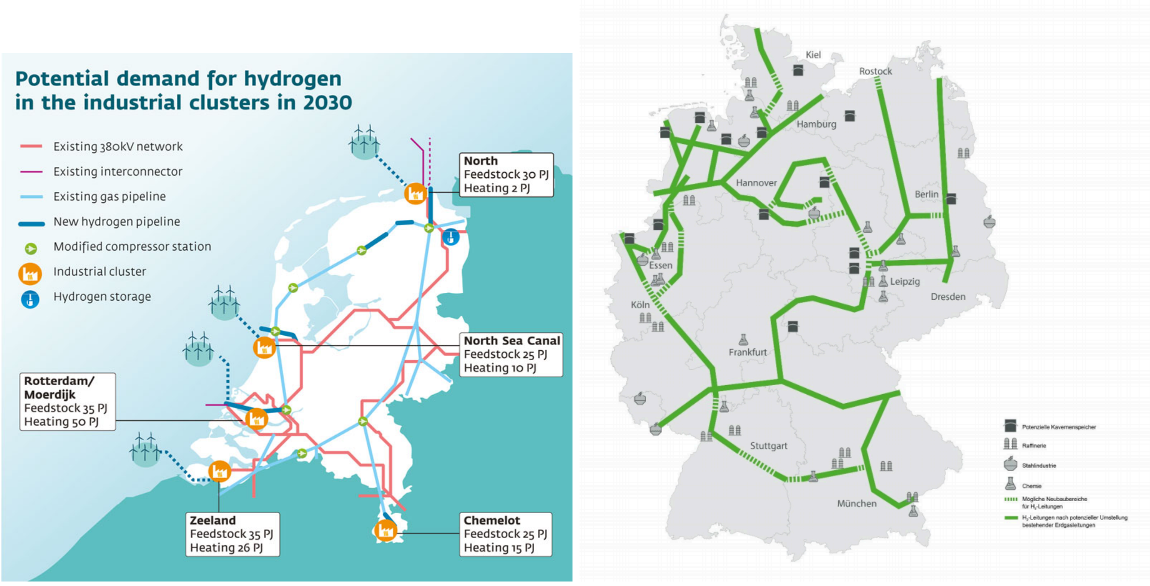


Figure 1.7: Left: Hydrogen infrastructure for The Netherlands, source: [Greenpeace, 2018]. Right: Hydrogen infrastructure for Germany, source: [FNB, 2020] (repeated from page 12)

The studies that gave rise to the infrastructures in figure 1.7 was an approach on a national level, while the corridor presented in this research was based on an international approach at a larger scale. This explains some of the discrepancies.

Similarities between the infrastructure of this research, from figure 7.4, and from figure 1.7 can be seen mostly in the Western part of Germany, where a large portion of the pipelines overlap [FNB, 2020]. For the Dutch infrastructure the similarities appear in the Western part of the country [Greenpeace, 2018].

It shows that the corridor from this research and the two infrastructure concepts from figure 1.7 compliment each other quite well.

7.4. Hydrogen Storage Possibilities

Consumption and production of hydrogen obviously do not happen at the exact same moments in time. This mismatch creates the need for the temporal storage of energy. As the amount of variable renewable energy sources increases, the need for energy storage grows as well, to account for this growing mismatch. This is one of the well known conundrums of the transition to a renewable energy system.

Gaseous substances do offer some form of flexibility. A gas infrastructure system is different to electrical infrastructure in that it allows small consumption and production mismatches for a limited amount of time. But the infrastructure is not able to handle seasonal fluctuations. This is however an important thing to consider. The hydrogen production and the pipeline system assume a relatively regular and steady flow, but consumption is not regular and steady. Take for instance heating. Hydrogen demand for space-heating will be a lot higher in the winter than in the summer.

This creates the need for large-scale energy storage. Underground natural gas storage has already been done cheap and in large quantities for several decades [Caglayan et al., 2020]. This now happens in for instance empty natural gas fields and empty salt caverns. Of these caverns that are already in use, several are located inside the proposed corridor [Michalski et al., 2017]. Even more, several naturally formed salt caverns are currently already in use for the storage of hydrogen [Caglayan et al., 2020].

Salt caverns are long, tube-like, rock salt formations with a size of about 300 meters tall and a diameter of about 60-70 meters [van Wijk and Wouters, 2020]. They are especially suitable for cheap, large-scale hydrogen storage because of several factors, but the main attribute of a salt cavern is the naturally formed rock salt wall. Because of this the cavern is capable of storing hydrogen at pressures of around 200 bar and its inert nature prevents it from reacting with hydrogen [Caglayan et al., 2020].

These caverns are found in different sizes across the EU. Exact storage potential is dependent on parameters like size and depth, but with the indicated size and potential pressure these caverns are able to store about 240 GWh of hydrogen each [van Wijk and Wouters, 2020]. Total salt cavern storage capacity per country is presented in figure 7.7.

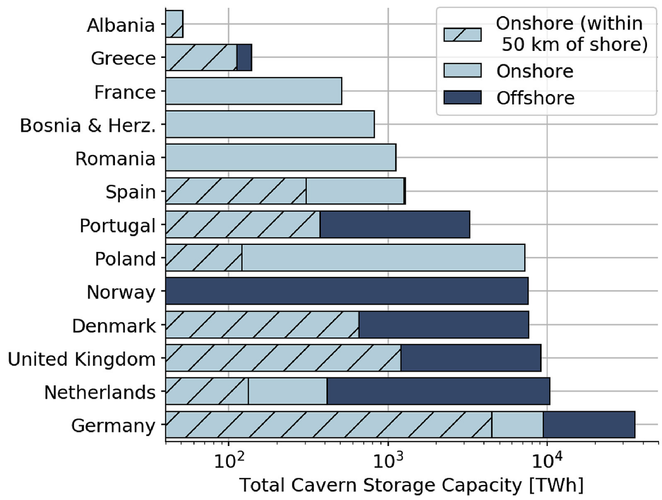


Figure 7.7: Total storage potential per country. Source: [Caglayan et al., 2020]

Current natural gas storage capacity is around 18% of the total natural gas consumption [van Wijk and Wouters, 2020]. This total consumption includes things like heating, feedstock and electricity production. Assuming a similar storage capacity will be needed for the consumption of hydrogen, total seasonal hydrogen storage needs to be about 217 TWh, or 5.5 million tonnes, only for the corridor.

As figure 7.7 indicates, there is enough storage capacity potential in the EU for seasonal fluctuations. Region specific salt cavern storage potential in relation to the location of the corridor pipeline is depicted in figure 7.8.

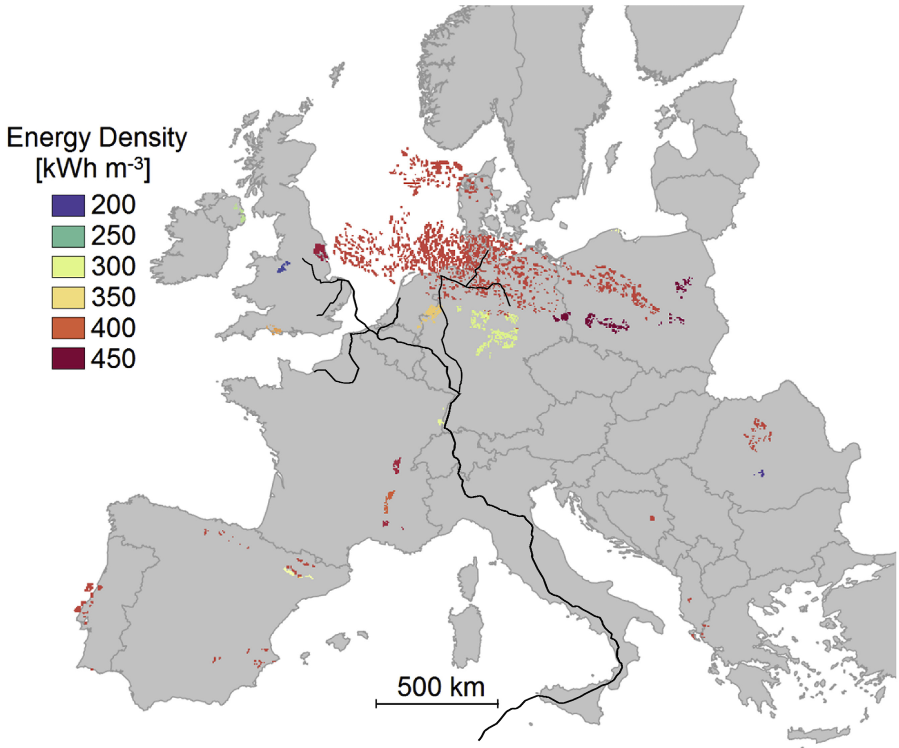


Figure 7.8: Corridor pipeline proposed by this research in relation to locations of salt caverns and storage potential, Source: [Caglayan et al., 2020]

Figure 7.8 indicates that more than enough potential storage is available in close proximity to the proposed pipeline system. The northern part of Germany bears the highest storage potential, but also France, The Netherlands and Great Britain will be able to store more than enough hydrogen for seasonal fluctuations.

Perhaps the most interesting part of this type of storage are the related costs. The total investment that is required to prepare a single salt cavern is about 100 million euros [van Wijk and Wouters, 2020]. With a storage potential of around 240 GWh, this implies that storing hydrogen is a factor 100 times cheaper than storing electricity in batteries, assuming battery storage cost will reduce to about $100\frac{€}{\text{KWh}}$.

8 Economic Implications

In this section the costs for hydrogen for final consumers will be approximated. First the costs of hydrogen production will be discussed. Subsequently the cost of the transport of hydrogen will be estimated. Finally, to conclude the three main aspects of long distance hydrogen transport, the cost of seasonal storage will be indicated. The approach to determine the capital cost and the levelised cost of production, transmission and storage is based on the method used by Van Wijk and Wouters [van Wijk and Wouters, 2020].

8.1. Production

The first part of the cost analysis is the cost of hydrogen production. Figure 8.1 illustrates the cost of hydrogen production per kilogram as a function of the price of electricity, capital cost for electrolysers and electricity price.

The cost of hydrogen production is obviously heavily dependent on the cost of electricity used to produce the hydrogen. In this proposition the main sources of electricity are wind energy, solar energy and nuclear energy. Prices for renewable energy have been plummeting over the past years, with some utility scale PV and wind plants offering bids of 20 $\frac{€}{\mathrm{MWh}}$ [International Renewable Energy Agency, 2019].

With a wind capacity factor of about 60% [Junginger et al., 2020], wind turbines already push load factors to over 5000 hours per year. Including solar energy production will drive load factors up even further.

With an electricity price of about 20$\frac{€}{\mathrm{MWh}}$ and load factors of over 5000 hours, hydrogen can be produced for a little over 1$\frac{€}{\mathrm{kg}}$.

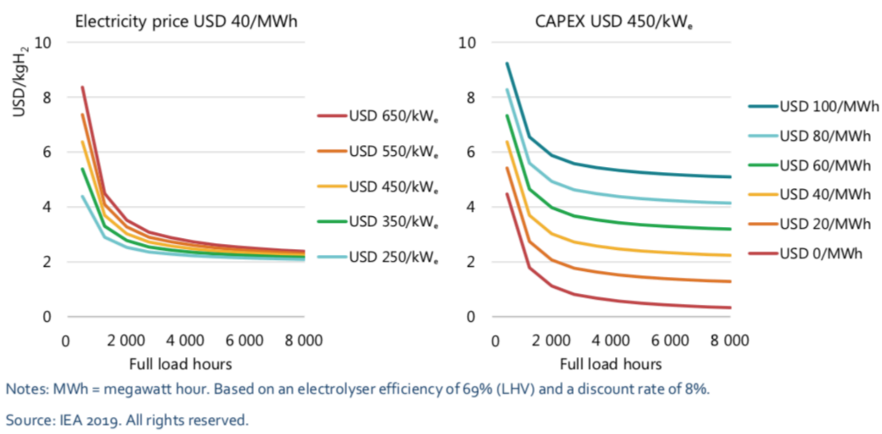


Figure 8.1: Levelised cost of hydrogen, source: [IEA, 2019a].

It must be said though that electricity prices for off-shore wind and nuclear energy are currently higher, which will obviously also result in a higher price of the production of hydrogen.

Prices for hydrogen production using SMR and CCS are also higher. Currently the estimated price in Europe is about $2.3\frac{€}{\mathrm{kg}}$ [IEA, 2019a]. However, in regions like the Middle-East and Russia the prices are around $1.5\frac{€}{\mathrm{kg}}$ [IEA, 2019a]. This means that if the transmission costs are low, it may be favorable to import hydrogen from those regions.

8.2. Transmission

The second aspect of hydrogen cost that will be treated is transmission cost, which is mainly determined by pipeline capital cost, operations and maintenance cost and load factor of the pipeline.

The capital costs for the pipeline is estimated to be 100000 € per GW per kilometer [van Wijk and Wouters, 2020]. The required pipeline capacity is computed using a 70% full load factor for the pipeline. This means that the capacity of the pipeline that will need to be installed is 143% of the estimated required capacity from table 7.2. This is slightly higher than the estimated load factor for the electrolyser. To increase the load factor of the large pipelines running from the Sahara, small scale storage may be used to take care of short term fluctuations. The short term storage during peak hydrogen production will result in a steady flow of hydrogen to the North, which means the pipeline can operate at full capacity for longer. The resulting capital costs per section are given in table 8.1.

The sum of required capital investments for all pipeline sections amounts to about €44.8 billion. Assuming yearly operations and maintenance costs of 1% of the initial capital costs, together with a 40 year lifetime and WACC of 7%, the levelised cost of hydrogen transport will be around $3\frac{€}{\mathrm{MWh}}$, or $0.12\frac{€}{\mathrm{kg}}$.

An important remark is that some sections of these pipelines may be retrofitted or reused, as was discussed in chapter 7. This could significantly reduce the capital costs for some pipeline sections.

Table 8.1: Pipeline properties per section

Infrastructure section	**Pipeline capacity** [GW]	**Length** [km]	**Cost** [Billion €]
Section 1	127	1633	20.7
Section 2	122.8	593	7.3
Section 3	102.8	901	9.3
Section 4	38.5	542	2.1
Section 5	9.7	250	0.2
Section 6	14.1	245	0.3
Section 7	13.7	406	0.6
Section 8	0.4	290	0
Section 9	43.9	695	3.1
Section 10	11	311	0.3
Section 11	10.2	73	0.1
Section 12	1.7	755	0.1
Section 13	8.6	417	0.4
Section 14	5.6	332	0.2
Section 15	3	388	0.1

8.3. Storage

If only salt caverns will be used for storage, and the required storage capacity mirrors the fraction of natural gas storage, a total of about 900 caverns will be needed. Assuming it costs around €100 million to prepare one salt cavern, total capital costs for 900 caverns will be €90 billion. Assuming the caverns will be fully used each season, 1% of capital investments for yearly operation and maintenance, a 40 year lifetime and a WACC of 7%, the levelised cost of hydrogen storage will be around $34\frac{€}{\mathrm{MWh}}$.

9 Discussion

In this chapter the research and its results will be discussed. Section 9.1 includes several remarks for the topics that have been covered regarding key findings, its relevance to gaps in research as stated in section 1.2 and the implications of these key findings. Section 9.2 will describe the limitations of the research and section 9.3 will elaborate on possibilities for future work.

9.1. Discussion of research results

This section will discuss the research results and its implications. First several research topics will be discussed. Subsequently the contributions to the existing literature will be highlighted and finally the research methods will be discussed.

9.1.1. The distribution of hydrogen consumption

The first part of the research, which resulted in findings that formed the basis of the entire research, was determining the spatial distribution of hydrogen consumption. The result indicated the distribution in 2020, or today, and also for the future, 2030 and 2050, albeit with some future uncertainty. The results were provided at a scale of NUTS2 regions.

A remarkable result was that clusters of economic activity together with high population, resulting in a high hydrogen consumption potential, were also quite clustered itself. In the earlier mentioned Blue Banana, the area on which the corridor was inspired, the consumption potential was particularly centered.

The results have provided valuable information on a transmission system operator scale, which may allow transmission system operators and governments to make informed decisions on where and how to implement hydrogen infrastructure. The precise circumstances in the future will most likely not be exactly the same as predicted in this research, but the results do highlight some important patterns that may very well still hold in the future. The use of a geographic component, like spatial distribution, adds a very valuable dimension to scenario planning.

9.1.2. An important area with large consequences

Corridor

The results of the consumption distribution were translated into an optimal initial hydrogen corridor for the EU. The corridor in question is the region from the North of Italy to the North of England. Some other area's in the near vicinity were included as well. These added area's were included because of either a high hydrogen production- or consumption -potential, or both. The resulting corridor covers about 7% of the total surface area of the EU. This corridor concept has not yet been mentioned in existing literature.

While only being a fraction of the surface of the EU, the hydrogen consumption, current and future, inside the corridor appears to be more than significant. Future potential consumption assuming a bottom-up scenario appeared to be around one third of total EU

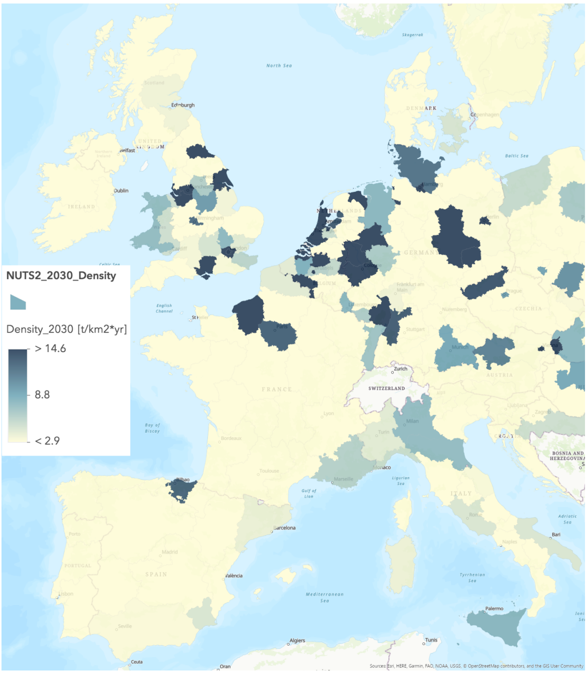


Figure 3.8: Density of hydrogen consumption in 2030 for NUTS2 regions. (repeated from page 34)

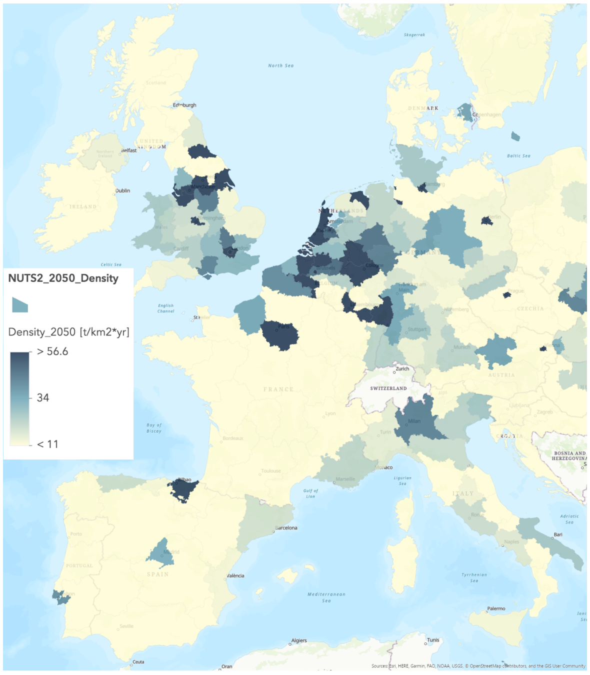


Figure 3.10: Density of hydrogen consumption in 2050 for NUTS2 regions. (repeated from page 36)

consumption. Even more, about half of today's hydrogen consumption takes place inside the corridor.

Two parameters were used as criteria for the selection of key areas; hydrogen consumption density in 2030 and 2050. Key areas are the ones that have an estimated consumption density more than average for both parameters. Only eleven areas meet the average for 2030 but not for 2050, which means the estimated hydrogen consumption in these areas rises slower over time than for other areas. The other way around, so areas that do meet the average consumption density for 2050 but not for 2030, the number is 45 areas. Of these 45 areas, as can be seen by comparing figure 3.8 and 3.10, the large majority is situated in close proximity to the proposed corridor. This presents a clear argument in favor of the proposed corridor as an initial backbone for a hydrogen infrastructure in the EU.

Top down approach

A top-down scenario indicates a viable maximum short term hydrogen consumption potential of about 31 million tonnes per year, solely for the corridor. Many processes are able to convert their use of methane or other fossil fuels to using hydrogen relatively quick. Moreover, the transmission and distribution capacity of existing natural gas pipelines is not far off from the capacity that is needed for hydrogen transportation.

Another take-away in favour is the fact that half of the current hydrogen consumption is in the corridor. This may be very useful for the initiation of the hydrogen system. Because a large part of the current hydrogen market is already centred in the corridor, a large impact can be invoked in a short period of time.

Powerful institutional approach

It must be stated however that the proposed concept is a project of monumental scale and this research will not argue that it is an easy task whatsoever. Rapidly switching several types of processes that have been in use for decades will be tough and should not be underestimated. Arguably the biggest challenges will be regarding the synchronised timing of switching many different processes in different sectors all together, to convert entire regions from using natural gas to hydrogen.

Other big challenges are mainly concerning the production of hydrogen. A lot of renewable electricity capacity will need to be installed. Next to that electrolyser technologies need to be scaled up fast and enough to provide affordable green hydrogen.

The rapid transition will certainly bring great challenges and cannot be done without swift and efficient collaboration of governments, politics, companies and the academic community. But if it is planned carefully and turns out successful, the result will be disruptive and nothing but spectacular.

Luckily the involved stakeholders are well suited for a project like this. The countries are arguably the most developed nations on earth. The coordinating entity, the European Union, possesses great cross-border power. The region is arguably the richest on the planet, both in terms of knowledge and money. This indicates that these stakeholders may be the designated group to undertake a project of this scale.

It is no coincidence that until now, the few national hydrogen infrastructure plans that have been presented, have been developed by countries located inside the proposed corridor.

In the introduction of this research a classic *chicken or egg* problem was given as one of the main reasons that green hydrogen is not yet an affordable fuel. A low consumption of green hydrogen, and thus a low production of green hydrogen, and vice versa. The proposed corridor concept, with investments from the involved countries and the EU, could induce a paradigm shift towards a much more important role for green hydrogen in the energy system.

9.1.3. Difficulties around production

First of all it is important to note that installing several 100 GW of renewable energy sources will take time. Introducing hydrogen as a carbon free energy carrier should be done before all the renewable electricity generation is in place. Currently fossil fuels are consumed decentralised, emitting CO_2 scattered around the EU which makes capturing it near impossible. Starting the transition can be done using large scale centralised steam methane reforming while capturing almost all of the CO_2. This method extracts all the carbon from the energy carrier from the start and allows the large amounts of CO_2 to be transported back into empty gas fields. Now the hydrogen can be used as a completely carbon free energy carrier, to be consumed decentralised without emitting any CO_2. This may not be the ideal solution, as the production of CO_2 is not being prevented. But the main goal is to reduce the CO_2 emitted into the atmosphere. This method achieves exactly that.

The research has indicated that hydrogen production in the EU using off-shore wind energy and some nuclear energy is capable of producing a significant amount of hydrogen. Around eleven million tons. However, with the proposed production methods there is a large dependency of about 64% on hydrogen production from North-Africa.

Developing the off-shore wind potential in the North-Sea should be done to increase the EU hydrogen production. Especially in sea regions far away from shore, making energy transmission by hydrogen instead of electricity a lot more attractive, the potential for hydrogen may be a lot larger than current estimates. With single wind turbines already reaching a capacity of 10 MW and advances in foundation structures, like floating constructions, increasing the flexibility of installation, the assumption that the near future EU off-shore wind hydrogen production may be twice the current estimates is certainly a viable thought. The available area is well illustrated in figure 4.2.

The EU may want to further decrease the dependency on mainly one geographic source of energy. Decreasing dependency on hydrogen from the Sahara can significantly reduce the burden on the pipeline from Tunisia to South-West Germany. The capacity that this research proposes for that section is two to three times larger than the current capacity, which seems a little too extravagant.

Another dependency issue is the overall security of supply of hydrogen. Sourcing the hydrogen from mainly one location makes the system susceptible to problems with political instability or other incidental issues. Little can be said about what will turn out to be the cheapest method of hydrogen production and transportation. It appears to be quite certain however that areas near the equator with copious amounts of sunshine around the year, will be able to produce hydrogen the most economical. This means that imports from places like the middle east make a lot of sense, using for instance ships for transportation. The quickest route to the proposed corridor will then be Italy. Taking this into account implies that increasing the transmission capacity from Italy to the North may make sense after all.

In the end production brings challenges. But the production of hydrogen has one very important quality to it, which makes large scale, centralised production in remote areas very interesting. This quality is the fact that, compared to electricity, there is a lot less need for strict and exact spatial and temporal balance of production and consumption. This allows the production and distribution of vasts amount of carbon free energy to be a lot more carefree than electricity.

9.1.4. Infrastructure

From the research it becomes apparent that all major consumption areas are already connected by large existing natural gas pipelines. The proposed total hydrogen system is composed of about 7800 kilometers of pipeline.

Compared to the existing network, the only large capacity increases will need to be in the section between the Sahara and the South-West of Germany. This capacity increase, and thus also its related costs, can be limited by further developing the off-shore wind in the North-Sea.

In the vicinity of the proposed transmission network, more than enough cheap underground hydrogen storage potential is available in already existing salt caverns.

9.1.5. Economic aspects

One important economic remark is regarding the large scale use of steam methane reforming at the early stages of the corridor concept, before the renewable electricity generation capacity is developed. As stated earlier in this discussion, steam methane reforming coupled with carbon capture and storage can be used to fill the hydrogen infrastructure with carbon free hydrogen. This proposition would result in slightly larger energy costs, as the produced hydrogen will be more expensive than natural gas. It would also result in the steam methane reformers becoming stranded assets as soon as the renewable electricity generation is up and running.

Regarding the transportation costs it should be mentioned that the pipeline installation costs do not behave linearly when pipeline sizes become small. This means that the smaller the pipeline, the larger the levelised cost of hydrogen transportation will become. That implies that some of the smaller sections from the proposed corridor may turn out more expensive than mentioned in table 8.1.

A final remark on the transportation costs also regards the production of hydrogen. The transmission costs may turn out to be as low as $0.12\frac{€}{\mathrm{kg}}$. This means that hydrogen production costs on the North-Sea will need to be very close to the production costs in the Sahara. If the production costs on the North-Sea are only $0.12\frac{€}{\mathrm{kg}}$ more expensive than in the Sahara, it is cheaper to just import it from there.

9.1.6. Contributions to existing literature

The most prominent contribution of this research to existing literature is an indication of the distribution of current, and possible future, consumption of hydrogen. Including this geographic layer as an extra element to scenario planning can be a valuable addition.

Another supplement to existing literature is the introduction of a new corridor concept that can jump start the introduction of the, carbon free, energy carrier hydrogen into the energy system. Identifying clusters, totalling only 7% of the surface area of the EU, and proposing a pipeline system of 7800 kilometers to distribute almost 31 million tonnes of hydrogen.

This research builds on existing literature and improves it by including the combination of several factors. Firstly by increasing the scale at which research was done, now spanning the entire EU. Secondly by taking into account almost all sectors and processes that involve, or may involve, the use of hydrogen. And finally by proposing a pipeline built on routes of existing natural gas infrastructure.

9.1.7. Methodical approach

One of the most important aspects is the fact that adding a geographic component to existing scenario planning. This may be of great value, independent of what the scenario is being planned for. The simplified method can be seen in figure 2.1. In this section each element of the method will be discussed, followed by a discussion on the method as a whole.

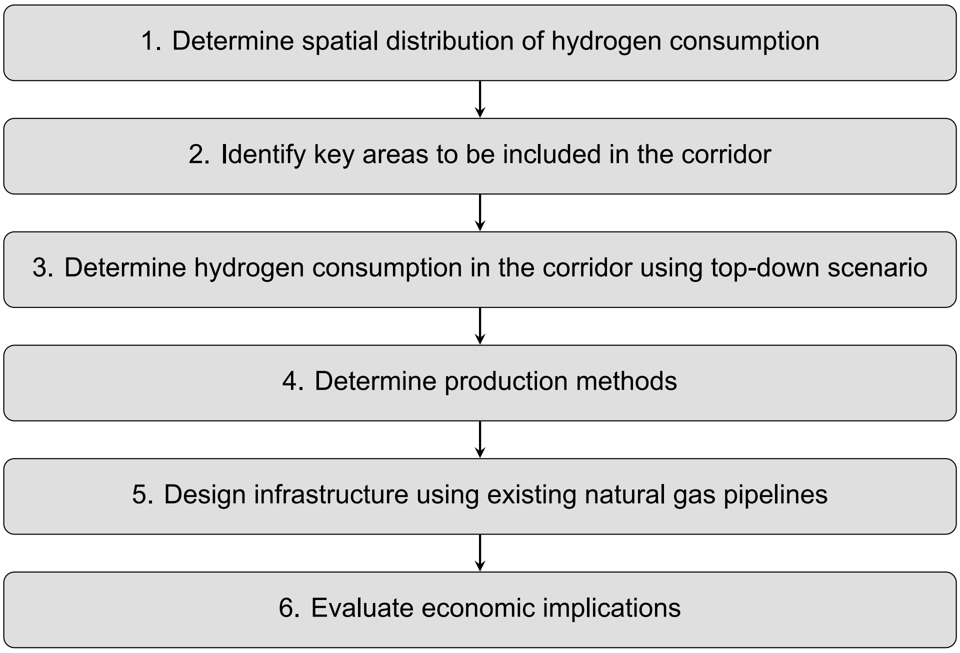


Figure 2.1: Decision process block diagram. (repeated from page 15)

1. Determine spatial distribution of hydrogen consumption

Mostly open source data was used for the research. Several data sources may therefore be impaired and possibly outdated. In addition, for the methanol sector hardly any data at all was found, which affected the research. In addition it is unclear if the HHV or the LHV was used in the *Hydrogen roadmap Europe* report [FCH JU, 2019]. The report does not mention either value. Next to that too easy and straight forward assumptions about locations of industrial heat usage were made, with no data on some relatively large heat consumption sectors like paper. Next to that the research and its result is heavily subjected to future growth estimates and can therefore turn out different than stated in this research.

Although some uncertainties were part of this research, a very significant part of current and future hydrogen consumption was treated in this research. Therefore the results, and especially the clusters and patterns it showed, will likely still hold even if some assumptions turn out wrong. The results proved very useful for this, and possibly other, research. The resulting figures and data are clarifying and helpful.

2. Identify key areas to be included in the corridor

The used selection criteria seem to have functioned well, indicating which clusters should be part of the corridor. An especially remarkable finding is that almost half of current hydrogen consumption is located in the corridor, which is only 7% of the total EU surface area.

3. Determine hydrogen consumption in the corridor using top-down scenario

The proposed scenario is heavily dependent on the amount of hydrogen use in some sectors. Some of these assumptions can be labeled risky and because it is used as a basis for the scenario and the rest of the research, this problem is discussed further in section 9.2.1.

4. Determine production methods

Regarding the capacity factor for electrolysers in the Sahara, it must be stated that there may be difficulties with a large amount of solar power generation, which only produces electricity for a limited amount per day. Electricity from wind, and possibly concentrated solar thermal power, may be able to increase the use of the electrolysers during the night.

For the assumption regarding the production potential on the North-Sea it must be stated that the potential may turn out a lot larger than is currently predicted. This will significantly reduce the burden on the dependency on the production in the Sahara.

5. Design infrastructure using existing natural gas pipelines

In retrospect the method used for this section seemed appropriate. The use of existing pathways for pipeline infrastructure has significant benefits over planning new pathways. The relatively high required capacity for the sections from the Sahara to the South-West of Germany is tricky and may induce scrutiny and discussion.

6. Evaluate economic implications

A high load factor for the pipeline is assumed. This may turn out to be too high. Although it must be said this may be needed for the sections with a high capacity. Possibly including small storage for daily fluctuations to increase the load factor for the pipeline.

The assumption of €10000 per GW per kilometer is for a new pipeline. If some pipeline sections are eligible for reusing or cheaper retrofitting techniques the costs may come down.

Overall methodical approach

In retrospect the overall methodical approach, schematically depicted in figure 2.1, seems solid. Using the distribution of a bottom-up scenario as a first step. Then using this information in conjunction with geographic information system software to identify patterns of high current and future hydrogen consumption. In turn this information was used to develop a corridor combined with a top-down approach to estimate consumption. In general this approach may turn out to be valuable for future scenario or concept planning.

Especially because the bottom-up approaches, even the ambitious ones, prove to be simply insufficient to reach CO_2 emission reduction targets. The ambitious scenario of the *hydrogen roadmap Europe* report [FCH JU, 2019] is just not enough. Only 20% hydrogen for iron and steel production in 2050, coupled with the target of becoming climate neutral, means that the other 80% should be decarbonated using biomass, carbon capture and storage and electrification. It seems hard to imagine how that can be done. In the same report, road transport is assumed to be powered by hydrogen for 25% in 2050. It is also hard to imagine that 75% can be electrified or powered by biofuels. The other ambitious goals in this report spark similar thoughts. This implies that a top-down approach may be needed to tackle climate issues.

9.2. Research limitations

In this section, some of the limitations of the research will be discussed.

9.2.1. Risky assumption as a basis for the kick-start scenario

The main concern is the proposed hydrogen contribution ratios in several sectors for the kick-start scenario in the corridor as stated in table 5.1. In some of these sectors it is difficult to make a valid estimation on the future contribution of hydrogen. Sectors where several technologies are currently mentioned as possible solutions and where the technical development of these technologies will determine which technology will be the most economical option. Or difficulties because the time of implementation is tough to establish, especially since the kick-start scenario does not specify an actual date. The main sectors with large doubt regarding the contribution of hydrogen seemed to be iron & steel, industry heat and residential heat.

To shed some light on some of these doubts, in this section there will be a short sensitivity analysis to check the effects of a change in hydrogen contribution to the total consumption potential. The regular scenario, with a total hydrogen consumption potential inside the corridor of 30.8 million tonnes, assumes the following hydrogen ratios: 40% in iron & steel making, 70% in industry heat and 60% of current consumption of natural gas in residential heat. The results can be found in table 9.1.

Table 9.1: Sensitivity analysis on the hydrogen ratio in doubtful sectors of the kick-start scenario. Results are hydrogen consumption potential inside the corridor in million tonnes.

20% **in iron & steel making**	30.27	50% **in industry heat**	27.54	70% **of natural gas in residential heat**	29.35
60% **in iron & steel making**	31.25	90% **in industry heat**	33.99	20% **of natural gas in residential heat**	32.18

The hydrogen ratio in industrial heat appears to have a significant impact, while the ratios in iron & steel and residential heat do not contribute to very large fluctuations. The distribution of the consumption inside the corridor is also hardly affected by any of the changes in consumption potential. Which means the only significant change is in the total quantity. This will obviously affect the capacity of the pipelines, but other than that there are no consequences worth mentioning.

9.2.2. Regional distribution

Another critical point of the research intent is the fact that only large scale transmission has been taken into account. The issue of regional distribution is a significant problem as well. Regional tests are already being undertaken to find out if regional distribution networks are able to transport hydrogen as safe and reliable as existing natural gas networks. For example the H21 projects in Leeds, The United Kingdom, in which regional distribution of hydrogen is put into practice and studied. While pipeline distribution seems to be possible without major issues, the conversion of equipment like industrial burners, compressors or boilers is especially challenging. Even more when all these types of equipment will need to be converted or replaced around the same time to switch entire regions from natural gas to hydrogen.

9.2.3. Research methods

One of the research methods that turned out to be insufficient was the way in which the ArcGIS software was used. No desktop software for Mac is available, which means the ArcGIS Online software was used. This was sufficient for large parts of the research. But when the amount of data started to grow, the fact that ArcGIS online could not be integrated with R, which was used for data handling, proved cumbersome. Desktop versions of ArcGIS do have the option to integrate the software with R or python. In addition there are several other open-source and powerful GIS software packages available if ArcGIS is not an option. In hindsight extra time should have been spent at the start of the research to find out which software was best for the intended research.

9.3. Proposed future work

Future research should be done in the field of regional distribution. For example by researching how regional distribution networks can transition to hydrogen as quick as possible. A step by step method that indicates which processes in a region can switch at what time and determining what type of system changes should be implemented to help a quick transition. More specific to the proposed corridor of this research it may be helpful to determine which regions should switch to hydrogen first, and how this can be done.

As indicated in the literature review, section 1.2, some existing literature regarding infrastructure planning is done by very detailed optimisation, but lack in encompassing all sectors of the energy system and including larger areas. This research encompasses all sectors of the energy system and includes the entire EU, but lacks in detail and numeric optimisation. Future research should be done using this detailed optimisation, but it should also include larger areas and all sectors of the energy system.

Another possible subject for further research is regarding how the corridor that this research proposes, should develop further into the future. Finding out which regions at what time could be connected to the proposed corridor.

The exact specification of the setup for hydrogen production in the Sahara brings up many questions. How to increase the load factors of the electrolysers and the transmission pipeline for example, which can significantly reduce costs. Also the exact specification of different renewable electricity production methods can be part of the optimisation. A techno-economic analysis can shed light on how this problem can be solved best.

10

Conclusion & Recommendations

In this chapter each research question will be answered separately. The research will be concluded with some recommendations for future research and for policy makers.

10.1. Conclusions to research questions

What is the spatial distribution of hydrogen consumption like today and, potentially, tomorrow?

Current and future hydrogen consumption appears to be highest in the area described as The Blue Banana. Although future consumption is estimated to be more distributed because the consumption itself will spread over more sectors and will be used in more different ways.

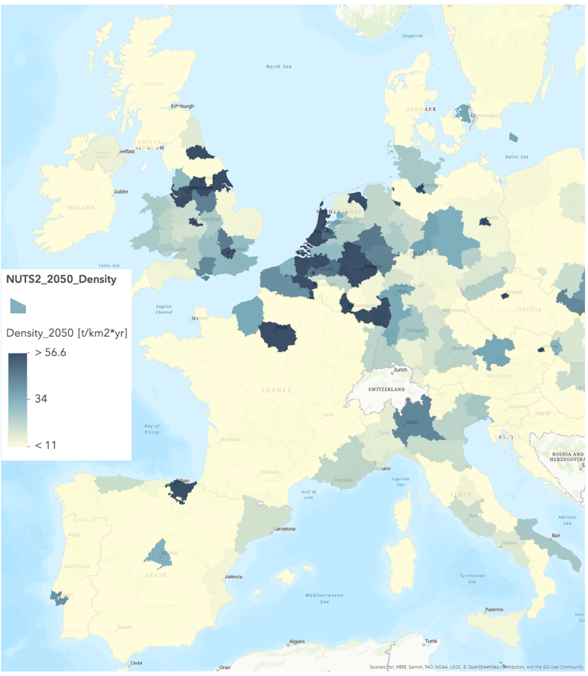


Figure 3.10: Density of hydrogen consumption in 2050 for NUTS2 regions. (repeated from page 36)

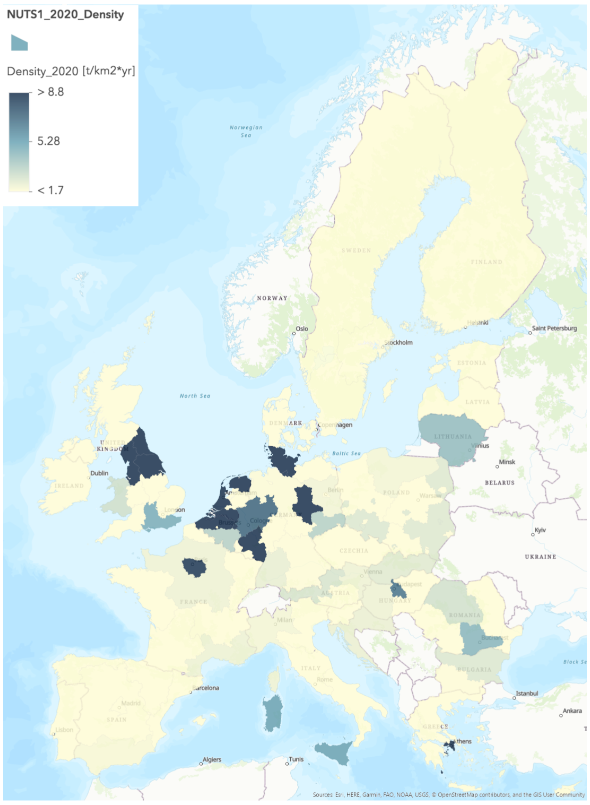


Figure 3.5: Density of hydrogen consumption in 2020 for NUTS1 regions. (repeated from page 31)

Which key areas should be selected as the core for this initial hydrogen corridor?

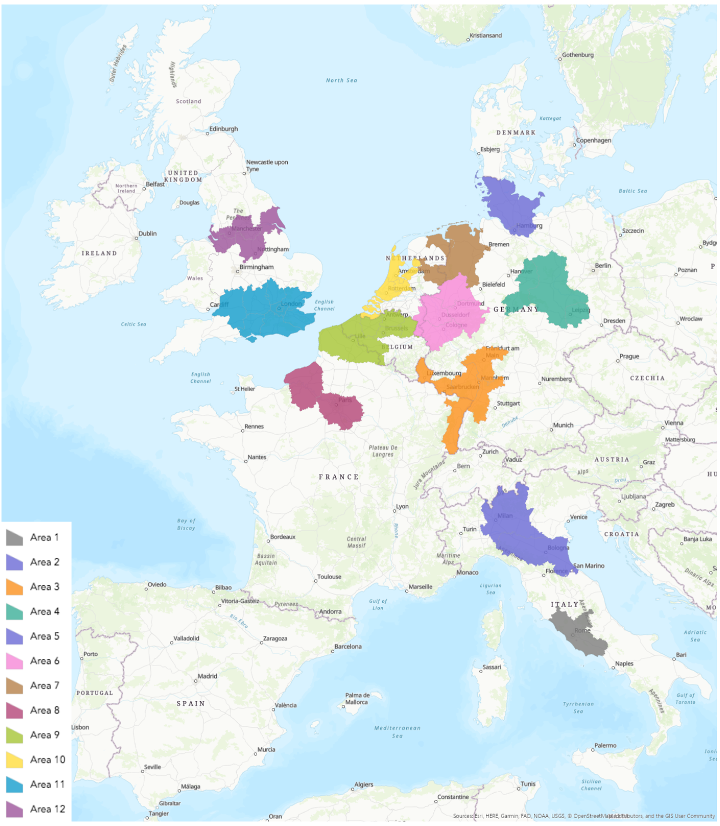


Figure 4.3: NUTS2 regions grouped into twelve (repeated from page 40)

What is, and can potentially be, the hydrogen consumption for these key areas at the time of implementing this corridor?

Assuming a top down approach, where the introduction of a large pipeline system can drive the consumption of hydrogen, the potential viable short term consumption is about 32 million tonnes of hydrogen each year.

How can sufficient hydrogen be produced for these areas?

In Europe, a total of 92 GW of off-shore wind, together with 6.5 GW of nuclear energy should be able to produce about 11 million tons of hydrogen per year. The rest of the required hydrogen for the corridor can be produced with 220 GW of solar energy, together with 80 GW worth of wind turbines.

How can these areas be connected to each other to distribute the hydrogen in the best way?

Based on the existing natural gas infrastructure, the areas can be connected to each other as shown in figure 7.5. No significant capacity increases are necessary except for the section between North-Africa and South-West Germany.

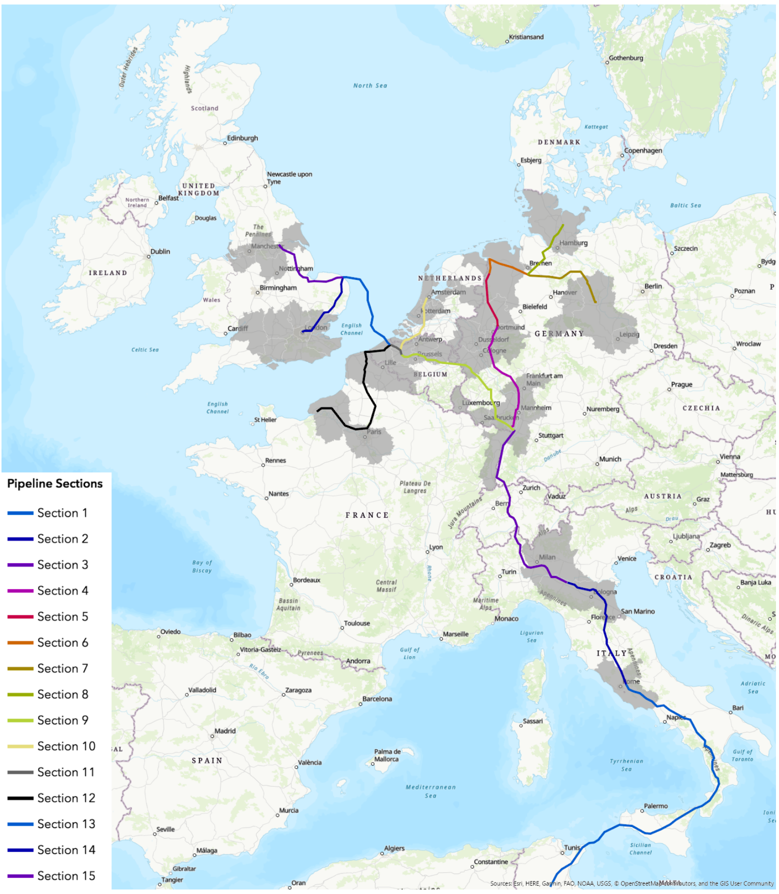


Figure 7.5: Hydrogen corridor with infrastructure split per section. (repeated from page 55)

What are the economic implications of this infrastructure?

Hydrogen can be produced for a little over $1\frac{€}{\text{kg}}$. The proposed corridor reaches levelised cost of hydrogen transmission of around $3\frac{€}{\text{MWh}}$, or $0.12\frac{€}{\text{kg}}$, and requires total investment costs of around €45 billion. The levelised cost of storage will be around $34\frac{€}{\text{MWh}}$.

10.2. Conclusion to main research question

For an initial hydrogen corridor crossing the European Union, what would be the most spatially efficient option?

The corridor that, from this research, seems to be the most spatially efficient is shown in figure 4.3 together with the infrastructure in figure 7.5.

10.3. Recommendations

In this section some recommendations are given. First in section 10.3.1 there are some recommendations for future research. Finally in section 10.3.2 there is some advice for policy makers.

10.3.1. How to improve research

Detailed hydrogen infrastructure optimisation should start by looking at larger areas and include all sectors and processes with hydrogen consumption. In addition there should be research on step by step methods to convert regions from natural gas to hydrogen as quick as possible.

10.3.2. Advice for policymakers

A gas pipeline, dependent on the medium it carries, can transmit about 100 times as much energy as a high voltage electricity transmission cable. The way, and the scale, in which society consumes energy will make it more or less impossible to only rely on renewable electricity to reach international emission targets. Because of this it is tough to imagine a future, carbon neutral energy system without hydrogen as one of the key energy carriers.

Bottom-up, gradual approaches for the introduction of hydrogen appear to be simply insufficient to reach CO_2 emission reduction targets. As stated in the discussion in chapter 9 even ambitious scenario's fall short. Because of this a top-down approach, like the corridor concept presented in this research, may be necessary to reach decarbonisation targets.

1.

The development and manufacturing of renewable electricity generation capacity for hydrogen production should simply start as soon as possible. Developing renewable electricity in a faster pace will be beneficial for the environment, whether it will be used for the hydrogen corridor or not, especially in the coming decade. In general as more renewable electricity capacity will built, more will become available for dedicated hydrogen production.

2.

Make agreements and start broad planning with all stakeholders regarding the hydrogen production, transmission, distribution and storage. All stakeholders include the EU, involved countries (Belgium, France, Germany, Italy, Luxembourg, The Netherlands, The United Kingdom, Switzerland and Tunisia), their transmission- and distribution -system operators for gas infrastructure, industries and energy companies that need to take part in the project.

3.

For each area specifically detailed plans should be developed on how to shift its gas infrastructure from natural gas to hydrogen. These plans should be inclusive. Sectors, processes and equipment should all be part of the plans.

4.

The corridor should be initiated from the areas with the highest current consumption of hydrogen. Specifically this region is area 6, area 9 and area 10 as depicted in figure 4.3, in Belgium, Germany and The Netherlands. These three areas together currently already consume 1.5 million tonnes of hydrogen each year. In the early stages, before enough renewable electricity capacity is available, steam methane reforming coupled with carbon capture and storage should be used to produce hydrogen as a carbon neutral energy carrier.

5.

As soon as sufficient hydrogen production is available, either with electrolysers or steam methane reforming with carbon capture and storage, other areas should be connected to the corridor to make the system function as intended.

A

Additional Consumption Location Information

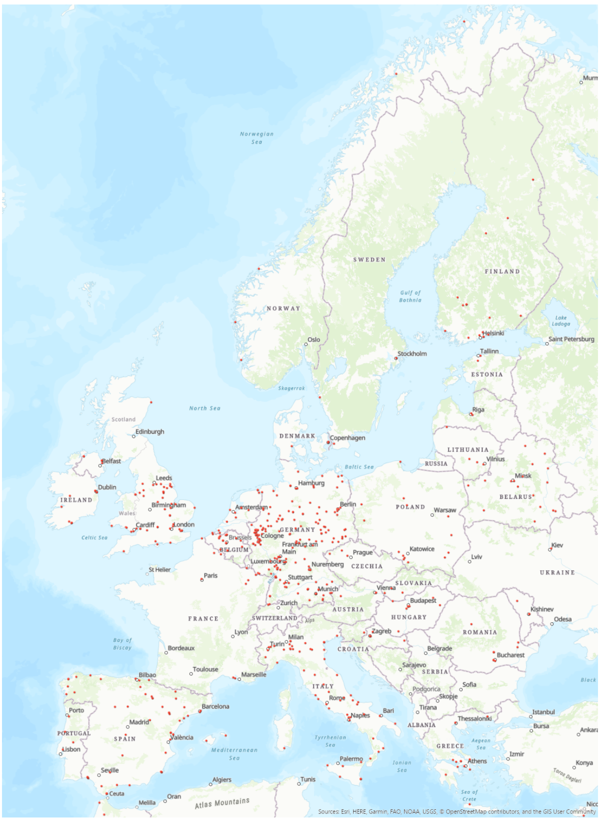


Figure A.1: Electricity gas plant locations

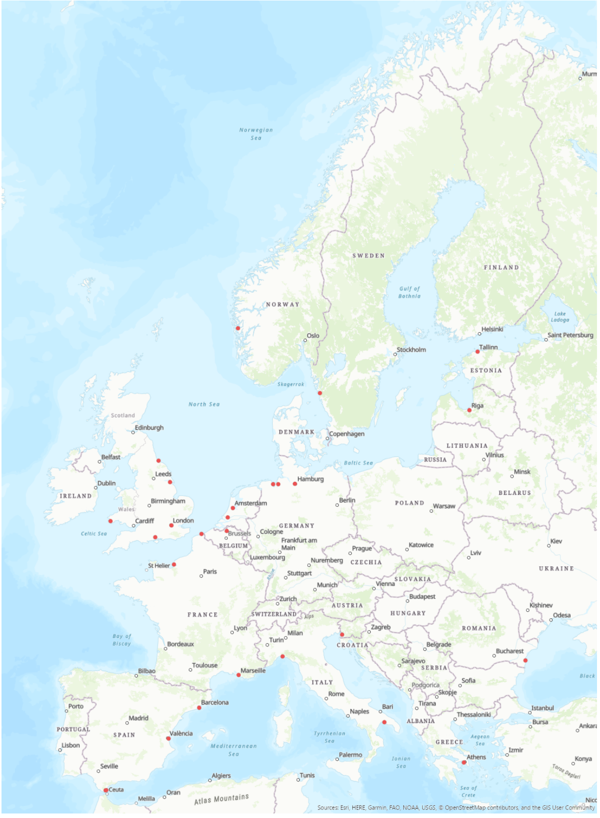


Figure A.2: Locations of the 27 harbors used for this research

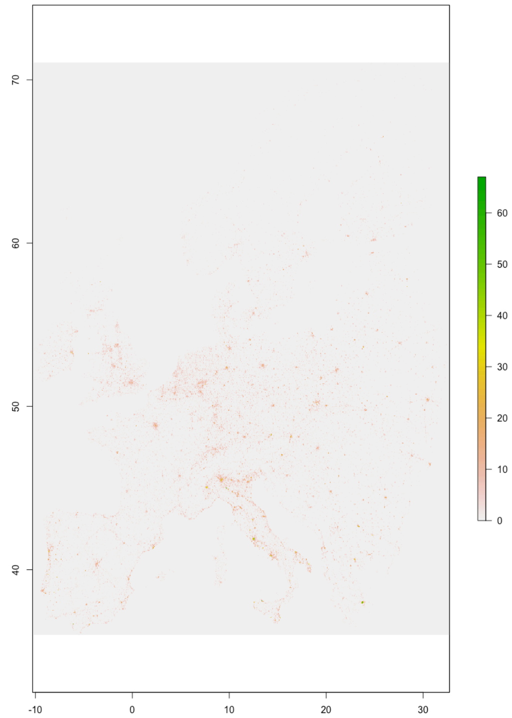


Figure A.3: Raster image of petrol stations in Europe

Figure A.4: European automobile production plants and supplier locations

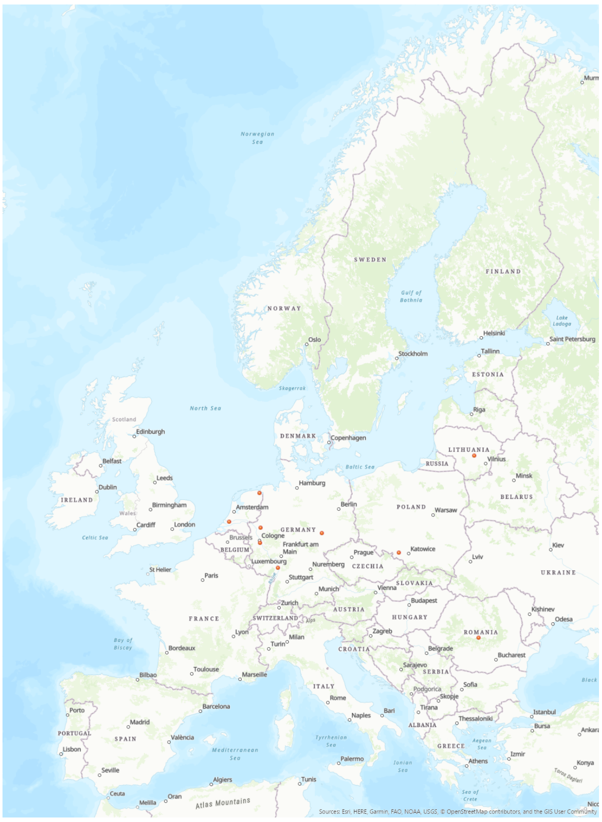


Figure A.5: EU methanol plant locations

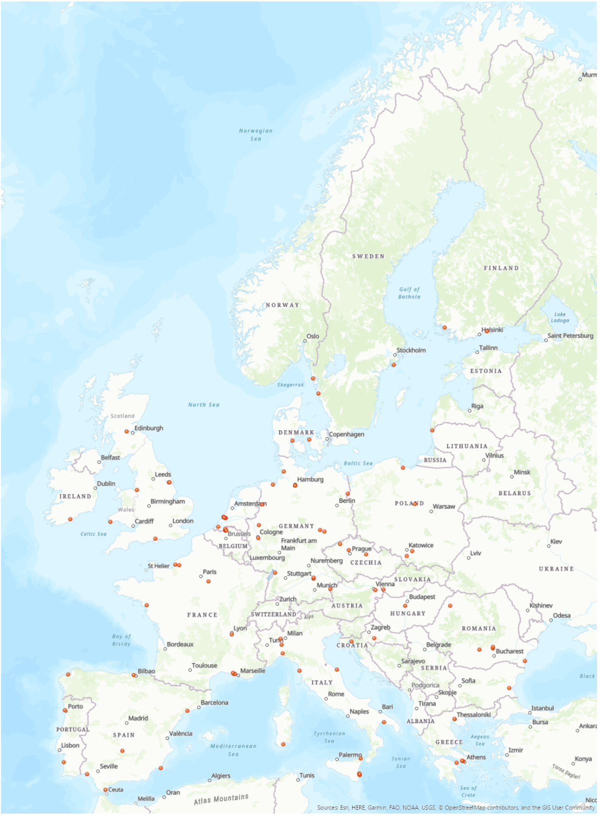


Figure A.6: EU oil refinery plant locations

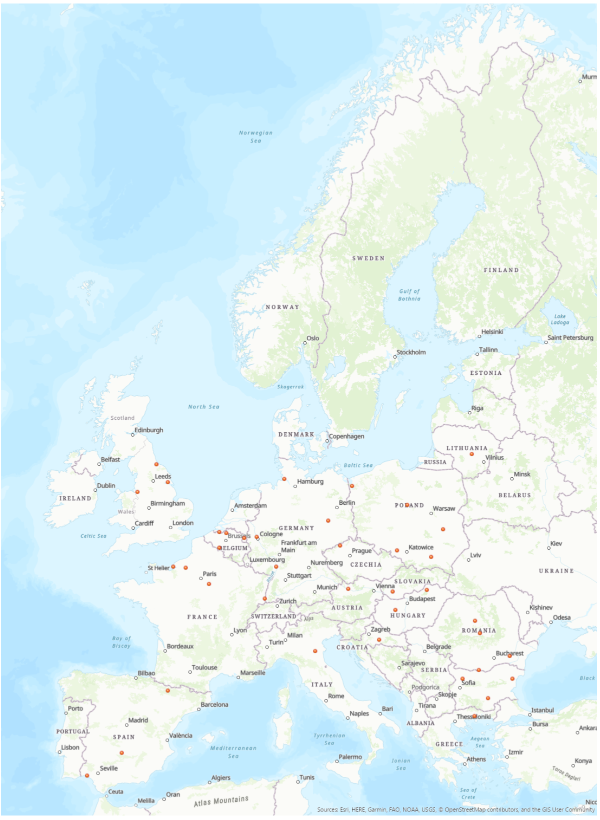


Figure A.7: EU ammonia plant locations

Methanol

Table A.1: List of methanol plants.

Name	Latitude	Longitude	Production capacity $\left[\frac{\mathrm{t}}{\mathrm{yr}}\right]$
Achema Jonava	55.087185	24.326157	130000
BioMCN	53.313166	6.962736	1000000
Chorzow Silekol	50.3102	18.249447	100000
Gelsenkirchen BP	51.597165	7.027678	300000
Ludwigshafen BASF	49.5128	8.418472	480000
Mider-Helm Methanol	51.31783	12.01589	876000
Victoria Viromet	45.707102	24.703164	225000
W2C plant JV Nouryon	51.9	4.483333	220000
Wesseling, Shell & DEA	50.822696	6.994723	400000

Oil refineries

Refinery capacity changed: Pernis Shell.

Refineries closed down: Reichstett, Berre L'Etang, Rome, Mantova, Gela, Porto Marghera, Cremona, Collombey-Muraz, Croyton, Millford, Port Clarence.

Table A.2: List of oil refineries.

Name	Latitude	Longitude	Production capacity $\left[\frac{\text{barrels}}{\text{day}}\right]$
OMV Schwechat Refinery	48.14442	16.49968	175000
Total Antwerp Refinery Belgium	51.26557	4.32158	360000
ExxonMobil Antwerp Refinery Belgium	51.25477	4.34045	333000
Petroplus BRC Antwerp Refinery Belgium	51.3343	4.2907	107500
Vitol Antwerp N.V. Refinery	51.25078	4.37221	35000
LUKEOIL Neftokhim Burgas Refinery Bulgaria	42.5403	27.32689	208000
INA Group Rijeka Refinery Croatia	45.28288	14.5352	102000
INA Group Sisak Refinery Croatia	45.45482	16.407	61000
Ceska Rafinerska Litvinov Refinery	50.56326	13.6123	110000
Ceska Rafinerska Kralupy Refinery	50.25771	14.32684	66000
PARAMO Pardubice Refinery Czech	50.027138	15.743623	15000
StatOil Kalundborg Refinery	55.65622	11.0964	110000
SHELL Fredericia Refinery Denmark	55.593285	9.747105	68000
Fortum Oyj Porvoo Refinery	60.31073	25.53548	160000
Fortum Oyj Naantali Refinery	60.45067	22.09287	40000
Total Gonfreville lOrcher Refinery	49.4868	0.24086	343000
ExxonMobil Port Jerome-Gravenchon Refinery	49.475	0.55077	270000
Total Donges Refinery	47.31425	-2.07209	231000
BP Lavera Marseilles Refinery	43.39076	5.00396	220000
Total Provence Marseilles Refinery	43.39586	5.10314	155000
ExxonMobil Fos-sur-Mer Refinery	43.45032	4.9243	140000
Total Feyzin Refinery	45.67007	4.84185	119000
Total Grandpuits Refinery	48.59059	2.94514	99000
Shell/ExxonMobil/Ruhr Oel/Conoco Karlsruhe Refinery	49.05895	8.32988	285000
Bayernoil Ingolstadt Refinery	48.74925	11.4843	262000
Ruhr Oel (BP/PDVSA) Gelsenkirchen Horst Refinery	51.53767	7.04736	246000
TOTAL Raffinerie Mitteldeutschland Spergau Refinery	51.28805	11.99325	227000
Dow Chemical Buna SOW Leuna Refinery	51.19185	12.35685	222000
Louis Dreyfus Group Wilhelmshaven Refinery	53.54677	8.15151	220000
PCK Raffinerie GmbH Schwedt Refinery	53.09652	14.2352	210000
Shell Rheinland Werk Godorf Cologne Refinery	50.8608	6.98656	162000
Shell Elbe MineralÃ?	53.4866	9.97071	110000
ExxonMobile Ingolstadt Refinery	48.78943	11.47254	106000
Tamoil Holborn Hamburg Refinery	53.48661	9.97078	95000
Shell ErdÃ?	54.15778	9.07351	84000
Ruhr Oel (BP/PDVSA) Emsland Lingen Refinery	52.5612	7.30787	80000
OMV Burghausen Refinery	48.19254	12.84201	70000
Hellenic Petroleum Aspropyrgos Refinery Greece	38.0329	23.604	135000
Hellenic Petroleum Elefsina Refinery	38.04497	23.50778	100000
Motor Oil Hellas Corinth Refinery	37.9185	23.0752	100000
Hellenic Petroleum Thessaloniki Refinery	40.68008	22.88154	66500
Mol Szazhalombatta Refinery	47.28644	18.89803	161000
ConocoPhillips Whitegate Refinery Ireland	51.8198	-8.2441	71000
Saras SPA Sarroch Oil Refinery Italy	39.07734	9.0184	300000
ISAB ERG Impianti Sud Oil Refinery Italy	37.12421	15.2155	214000

Name	**Latitude**	**Longitude**	**Production capacity** $\left[\frac{\text{barrels}}{\text{day}}\right]$
ExxonMobil/Erg Trecate Oil Refinery Italy	45.4398	8.78739	200000
ExxonMobil Augusta Oil Refinery Italy	37.21267	15.17163	190000
ENI Sannazzaro de Burgondi Oil Refinery Italy	45.09985	8.87682	170000
ISAB ERG Impianti Nord Oil Refinery Italy	37.18183	15.1886	160000
ENI Taranto Oil Refinery Italy	40.48947	17.19333	110000
API Falconara Marittima Ancona Oil Refinery Italy	43.6387	13.37947	85000
ENI Livorno Oil Refinery Italy	43.58738	10.3374	84000
ENI/Kuwait Petro Milazzo Oil Refinery Italy	38.20341	15.27267	80000
Iplom Busalla Oil Refinery Italy	44.57471	8.94761	40000
Mazeikiu Nafta Butinge Refinery	56.0602	21.10592	263000
BP ChevronTexaco Nerefco Refinery	51.93009	4.17818	400000
Shell Pernis Refinery	51.87626	4.34651	416000
ExxonMobil Rotterdam Refinery	51.8762	4.29	195000
Total/Lukoil Chemical Vlissingen Refinery	51.44563	3.72905	149000
Gunvor Europoort	51.93256	4.16684	80000
VPR Europoort	51.90931	4.22259	80000
Mazovian Refinery & Petrochemical Works Plock Refinery	52.58807	19.67793	276000
Lotos Gdansk Refinery	54.34837	18.73541	120000
Lotos Czechowice Refinery	49.94005	19.01571	10000
Rafineria Trzebinia Refinery	50.20654	19.46466	4000
Galp Energia Sines Refinery	37.96134	-8.81138	200000
Galp Energia Porto Refinery	41.20912	-8.70418	100000
Rompetrol Petromidia Refinery	44.13401	28.62614	100000
Petrom/OMV Petrobrazi Ploiesti Refinery	44.87176	26.01599	90000
Vega Ploieşti	44.9605	26.02541	20000
Petrotel-LUKOIL Pitesti Refinery	44.80773	24.93421	68000
Suplacu de Barcău	47.27552	22.54604	15000
Mol Slovnaft Bratislava Refinery	48.15	17.11667	110000
CEPSA Gibraltar Refinery	36.18569	-5.39725	240000
Repsol YPF Bilbao Refinery	43.32893	-3.1106	220000
Repsol YPF Tarragona Refinery	41.18305	1.22275	160000
Repsol YPF Puertollano Refinery	38.6731	-4.04945	140000
Repsol YPF a Coruna Refinery	43.35264	-8.4453	120000
CEPSA Palos de la Frontera La RÂ·bida Refinery	37.18408	-6.90394	100000
Repsol YPF Cartagena Refinery	37.57512	-0.92928	100000
Preem Petroleum Lysekil Refinery	58.34458	11.42427	210000
Nyn0 s Petroleum Nynaeshamn Refinery	58.92181	17.96447	90000
Preem Petroleum Gothenburg Refinery	57.70412	11.88376	90000
Esso Fawley Southampton Refinery UK	50.83316	-1.36678	330000
Shell Stanlow Refinery	53.27379	-2.84492	272000
Total Lindsey Oil Refinery	53.64708	-0.25692	223000
ConocoPhillips Humber Refinery	53.63254	-0.24234	221000
ChevronTexaco Pembroke Refinery	51.6857	-5.0271	215000
BP Grangemouth Refinery	56.01678	-3.68497	205000

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