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The case of North Rhine-Westphalia, Germany

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Master's Thesis

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Abstract

In response to the growing urge towards decarbonisation, more and more initiatives have been set to reduce and/or compensate the level of CO_2 (carbon dioxide) emitted by human activities, which is one of the main responsible of the incumbent threats of "global warming" and "climate change". "Climate neutrality by 2050" has become a decisive topic for political agendas worldwide and, against that background, the hydrogen economy can play a significant role. More and more countries have launched roadmaps and strategies for the creation of hydrogen value chains at national and international level. Also on regional scale, local integrated hydrogen ecosystems are growing, the so-called "Hydrogen Valleys". These include German region North Rhine-Westphalia (NRW), which officially presented a hydrogen roadmap in November 2020, establishing targets for both the short (2025) and medium terms (2030) for the adoption of hydrogen in the sectors of Mobility, Industry, Energy & Infrastructure.

The purpose of the present thesis is to investigate techno-economic strategies for the introduction of a hydrogen infrastructure in NRW over the next 15 years (2035), enabling the achievement of the abovementioned targets. Moreover, being buses explicitly mentioned within NRW hydrogen roadmap, the present thesis focuses on strategies to ensure the optimal deployment of hydrogen buses within the region.

The work is conducted with support from the research institute of Forschungszentrum Jülich (FZJ), North-Rhine Westphalia, Germany. A simulation model (H2MIND) developed by FZJ is taken as main research tool. The output from two other models by FZJ (FINE-NESTOR and FINE-Infrastructure, respectively), which defined the scenario behind the NRW H_2 Roadmap, are reviewed and served as starting point for the adaptation of the H2MIND model. An integrative mapping activity regarding i) existing bus depots for NRW population mobility and ii) existing steel production sites in Germany serves the purpose of increasing the resolution of H2MIND model in the geospatial description of the potential hydrogen refuelling stations for bus companies in NRW.

Both the hydrogen demand and production derived from FINE-NESTOR are distributed geospatially over Germany for the years 2025-2030-2035, according to the hydrogen-related technologies modelled within H2MIND. The demand is broken down into Buses, Trains, Cars, Heavy-Duty Vehicles (HDVs) and Light Commercial Vehicles (LCVs), Material Handling Vehicles (MHVs), Industrial uses for Steel, Ammonia, Methanol and other Chemicals. The production is modelled around onshore wind power plants, steam methane reforming industrial locations and import. Four hydrogen supply chain pathways were compared by H2MIND simulations: i) transport and distribution by gaseous hydrogen trailers ('GH_2 trucks'), ii) transport and distribution by liquefied hydrogen trailers ('LH_2 trucks'), iii) transport via newly built hydrogen pipelines plus distribution via gaseous hydrogen trailers ('new pipelines'), iv) transport via reassigned natural gas pipelines plus distribution via gaseous hydrogen trailers ('reassigned NG pipelines').

The analysis and assessment of the H2MIND simulation results are conducted mainly on economic merit. The key variable used for the assessment is the weighted average Total Expense (TOTEX) [€/kg H_2]. This comparison is carried out from global-cost perspective, then the cost breakdown is considered in order to identify specific features in the cost determination. The weighted average TOTEX is calculated also for the case of onsite renewable energy-based electrolysis at bus hydrogen refuelling stations, in order to understand how such a strategic choice could impact the overall hydrogen supply chain cost – various shares of self-sufficiency at bus depots are considered, ranging from 0% (fully centralized configuration, no self-sufficiency) to 100% (total self-sufficiency, complete independent).

An overall three-fold increase in hydrogen demand is expected between the years 2025 and 2035 (from 450.72 kt/yr to 1,862.33 kt/yr in Germany, and from 177.87 kt/yr to 519.16 kt/yr in NRW). Both on national and regional level, the main demand driver is expected to shift from the Industrial sector (in 2025) to Mobility (in 2035). As for the geospatial distribution, NRW concentrates the highest hydrogen demand in the country, covering alone approximatively one third of the total German hydrogen demand. Within NRW, the relevance of a district depends on what hydrogen-consuming sector is considered. For Mobility and public transportation, based on the allocation factors used within H2MIND model, Köln ranks as the district with highest demand in many mobility sectors. For buses, Aachen, Wuppertal, Düsseldorf are the three top cities in the ranking in addition to Köln. Recommendation is that investments focus on high hydrogen-demand districts during the start-up phase of infrastructure development (period 2025-2035), where higher utilization factors of the infrastructural assets are expected and financial risks are therefore minimized. Looking into the weighted average TOTEX for the four analysed pathways, gaseous hydrogen trailers (‘GH_2 trucks’) are the most convenient option for connecting production and consumption during the start-up phase of infrastructure development (period 2025-2035). Growing cost competitiveness is expected for ‘reassigned NG pipelines’ after 2035, thanks to the increased hydrogen demand and the higher utilization factor for pipelines. For the period 2025-2035, a fully centralized hydrogen supply pathway is the best option for covering bus-related hydrogen demand in the introductory phase of hydrogen infrastructure creation, with cost parity for onsite electrolysis being expected for the future after 2035.

Keywords

Hydrogen; Infrastructure rollout; Supply chain pathways; Mobility; Hydrogen buses.

Sammanfattning

Som svar på kraven på minskade koldioxidutsläpp har fler och fler initiativ tagits för att minska och/eller kompensera nivån av CO2 (koldioxid) som släpps ut på grund av mänskliga aktiviteter, vilket är en av de främsta orsakerna till de nuvarande hoten om "global uppvärmning". ” och ”klimatförändringar”. "Klimatneutralitet till 2050" har blivit ett avgörande inslag på politiska agendor världen över och mot den bakgrunden kan vätgasekonomin spela en betydande roll. Fler och fler länder har lanserat färdplaner och strategier för att skapa värdekedjor för vätgas på nationell och internationell nivå. Även i regional skala växer lokala integrerade vätgas-ekosystem, de så kallade "vätgasdalarna". Dessa inkluderar den tyska regionen Nordrhein-Westfalen (NRW), som officiellt presenterade en färdplan för vätgas i november 2020, som fastställde mål för både kort (2025) och medellång sikt (2030) för införandet av vätgas inom sektorerna rörlighet, industri, Energi & Infrastruktur.

Syftet med denna avhandling är att undersöka tekniska och ekonomiska strategier för införandet av en vätgasinfrastruktur i NRW under de kommande 15 åren (2035), vilket gör det möjligt att uppnå ovan nämnda mål. Dessutom, eftersom bussar uttryckligen nämns i NRW:s vätgasfärdplan, fokuserar detta examensarbete på strategier för att säkerställa en optimal utplacering av vätgasbussar inom regionen.

Arbetet bedrivs med stöd från forskningsinstitutet Forschungszentrum Jülich (FZJ), Nordrhein-Westfalen, Tyskland. En simuleringsmodell (H2MIND) utvecklad av FZJ används som huvudverktyg för forskning. Resultatet från två andra modeller av FZJ (FINE-NESTOR respektive FINE-Infrastructure), som definierade scenariot bakom NRW H2 Roadmap, granskas och tjänade som utgångspunkt för anpassningen av H2MIND-modellen. En integrerad kartläggning av i) befintliga bussdepåer för NRW-befolkningsrörlighet och ii) befintliga stålproduktionsanläggningar i Tyskland tjänar syftet att öka upplösningen av H2MIND-modellen i den geospatiala beskrivningen av potentiella vätgastankstationer för bussföretag i NRW.

Både vätgasefterfrågan och produktionen från FINE-NESTOR distribueras geospatialt över Tyskland för åren 2025-2030-2035, enligt de vätgasrelaterade teknologierna som modelleras inom H2MIND. Efterfrågan är uppdelad i bussar, tåg, bilar, tunga fordon (HDV) och lätta kommersiella fordon (LCV), materialhanteringsfordon (MHV), industriell användning för stål, ammoniak, metanol och andra kemikalier. Produktionen är modellerad kring vindkraftverk på land, ångmetanreformerande industrilokaler och import. Fyra varianter av vätgasförsörjningskedjan jämfördes med H2MIND-simuleringar:

i) transport och distribution med gasformiga vätgassläp ('GH2-lastbilar'), ii) transport och distribution med släp för flytande väte ('LH2-lastbilar'), iii) transport via nybyggda vätgas rörledningar plus distribution via släp för gasformigt vätgas (”nya pipelines”), iv) transport via tidigare naturgasledningar plus distribution via släp för gasformigt väte (”om-utnyttjade naturgasrörledningar”).

Analysen och bedömningen av H2MIND-simuleringsresultaten utförs huvudsakligen på ekonomiska meriter. Den nyckelvariabel som används för bedömningen är den vägda genomsnittliga totala kostnaden (TOTEX) [€/kg H2]. Denna jämförelse görs ur ett globalt kostnadsperspektiv, sedan analyseras kostnadsfördelningen för att identifiera specifika egenskaper i kostnadsbestämningen. Det viktade genomsnittet av TOTEX beräknas även för fallet med elektrolys baserad på förnybar energi på plats vid vätgastankstationer för bussar, för att förstå hur ett sådant strategiskt val skulle kunna påverka den totala kostnaden för vätgasförsörjningskedjan – olika andelar av självförsörjning vid bussdepåer övervägs, allt från 0 % (helt centraliserad konfiguration, ingen självförsörjning) till 100 % (total självförsörjning, fullständigt oberoende).

En övergripande trefaldig ökning av efterfrågan på vätgas förväntas mellan åren 2025 och 2035 (från 450,72 kt/år till 1 862,33 kt/år i Tyskland och från 177,87 kt/år till 519,16 kt/år i NRW). Både på nationell och regional nivå förväntas den främsta efterfrågedrivkraften flyttas från industrisektorn (2025) till mobilitet (2035). När det gäller den geospatiala fördelningen, koncentrerar NRW den högsta efterfrågan på vätgas i landet, och täcker ensam ungefär en tredjedel av det totala tyska vätgasbehovet. Inom NRW beror ett

distrikts relevans på vilken vätgasförbrukande sektor som betraktas. För Mobilitet och kollektivtrafik, baserat på allokeringsfaktorer som används inom H2MIND-modellen, rankas Köln som det distrikt med högst efterfrågan inom många mobilitetssektorer. För bussar är Aachen, Wuppertal, Düsseldorf de tre bästa städerna i rankingen förutom Köln. Rekommendation är att investeringar fokuserar på distrikt med hög efterfrågan på vätgas under uppstartsfasen av infrastrukturutveckling (perioden 2025–2035), där högre utnyttjandefaktorer av infrastrukturtillgångarna förväntas och finansiella risker därför minimeras. Om man tittar på det vägda genomsnittliga TOTEX för de fyra analyserade varianterna, är släp med väte i gasform ('GH2-lastbilar') det lämpligaste alternativet för att koppla samman produktion och konsumtion under uppstartsfasen av infrastrukturutvecklingen (perioden 2025–2035). Ökande kostnadsfördelar förväntas för "om-utnyttjade naturgasrörledningar" efter 2035, tack vare den ökade efterfrågan på vätgas och den högre utnyttjandefaktorn för rörledningar. För perioden 2025–2035 är en helt centraliserad vätgasförsörjningsväg det bästa alternativet för att täcka bussrelaterad efterfrågan på vätgas i den inledande fasen av etablerandet av en vätgasinfrastruktur, med kostnadsparitet för elektrolys på plats vilket förväntas vara lösningen efter 2035.

Table of Contents

List of Figures

List of Tables

List of Acronyms and Abbreviations

AEM	Anion Exchange Membrane
ATR	Autothermal Reforming
BEV	Battery Electric Vehicle
CAPEX	Capital Expense
CC(U)S	Carbon Capture (Utilization) and Storage/Sequestration
CHP	Combined Heat and Power
DRI	Direct Reduction of Iron
FCEB	Fuel Cell Electric Bus
FCEV	Fuel Cell Electric Vehicle
FZJ	Forschungszentrum Jülich
GH_2	Gaseous Hydrogen
GIS	Geographic Information System
H_2	Hydrogen (molecular)
HDV	Heavy-duty vehicle
HHV	Higher Heating Value
HRS	Hydrogen Refuelling Station
HSC	Hydrogen Supply Chain
LCA	Life Cycle Assessment
LDV	Light-duty vehicle
LCV	Light commercial vehicle
LH_2	Liquid Hydrogen
LOHC	Liquid Organic Hydrogen Carrier
MCFC	Molten Carbonate Fuel Cell
MHV	Material-handling vehicle
MILP	Mixed Integer Linear Programming
MRR	Metropolregion Rhein-Ruhr
NG	Natural Gas
NRW	North Rhine-Westphalia
OPEX	Operating Expense
P2C	Power to Chemicals
P2G	Power to Gas
P2L	Power to Liquid
PAFC	Phosphoric Acid Fuel Cell
PEMFC	Proton Exchange Membrane Fuel Cell
PSA	Pressure Swing Adsorption
RES	Renewable Energy Sources
SDG	Sustainable Development Goal
SMR	Steam Methane Reforming
SOFC	Solid Oxide Fuel Cell
TOTEX	Total Expense
TRL	Technology Readiness Level
TSA	Temperature Swing Adsorption

1 Chapter 1 – Introduction

This Chapter provides the framework of the present study, namely the background and rationale of the push towards the H_2 economy, as well as the Objectives of the investigation, the Methodology and its limitations. The structure of the study is also presented here.

1.1 Background

Nowadays, there is a compelling need for "decarbonization". This term refers to the process of reducing and/or compensating the level of CO_2 (carbon dioxide) emitted by human activities. These are responsible, together with the emission of other greenhouse gases, for the gradual increase of the average temperature of the atmosphere. Thus, they are directly related to the global threats of "global warming" and "climate change". These phenomena have been extensively documented by international organisations (IEA and IPCC, for example), who also have elaborated scenarios and recommendations for policy makers in order to contain their negative effects [1][2].

The target of "climate neutrality by 2050" – meaning the achievement of net zero balance for greenhouse gas emissions [3] – has recently become a decisive topic for political agendas on a global scale. As a result, massive investment initiatives have been launched with the purpose of making economies less carbon-intensive – to mention an example, the European Green Deal was launched by the EU in 2019 [4]. The energy sector, in particular, is at the heart of this transition, accounting on average for more than 70% of global greenhouse gas emissions [5]. This set of investment actions resonates also with the series of recovery packages (the European Next Generation EU, 2020, as an example) earmarked to stimulate the economic recovery from the coronavirus crisis which stroke the world in 2019. As IEA stated [1], "as the world continues to grapple with the impacts of the Covid-19 pandemic, it is essential that the resulting wave of investment and spending to support economic recovery is aligned with the net zero pathway".

In such a context, hydrogen may play a significant role for the decarbonization of the energy and industrial systems. Hydrogen is the first element of the periodic table, with a very simple, bi-atomic molecule (H_2). This simple element has a wide versatility of applications, which can be summarized as follows (Chapter 2 can be referred to for a more thorough overview of the State of the Art of hydrogen technologies). From the point of view of energy systems, it can serve as energy carrier, as much as electricity or heat. Being extremely reactive with other elements, it cannot be found in nature in its molecular form; its generation can happen through different kinds of processes and from different material sources – mainly fossil fuels for "grey" and "blue" H_2, water for "green" H_2. When produced through electrolysis – that is, the split of the water molecule H_2O in its basic elements, H_2 and O_2, using electricity – hydrogen can serve as storage for renewable energies, representing an interesting opportunity for increasing the penetration of variable sources (Wind, Solar) into the power system and, at the same time, stabilizing the power grid. Not only as storage, hydrogen can also serve as fuel – for combustion or for electrochemical conversion in fuel cells – , extending its applicability from pure energy purposes to the transport sector (hydrogen-based electric vehicles). In addition, hydrogen is also used as feedstock within some industrial sectors (refineries, petrochemical, iron and steel, cement, etc.). It is worth mentioning that, when generated in the so-called "clean" way – that is, in combination with renewable energy sources –, hydrogen use will result in zero direct CO_2 emissions: this may be particularly interesting for the so-called "hard-to-abate" sectors, in which electrification through clean electricity is not a viable alternative to fossil fuel-based incumbents.

All above considered, it can be easily understood why more and more countries worldwide are launching roadmaps and strategies for the creation of hydrogen ecosystems at national and international level, as a way towards a carbon-free and more resilient economy. Germany [6], France [7], The Netherlands [8], Australia [9], Japan [10], Chile [11] can be reported as significant examples of this trend – country's strategies differ in terms of hydrogen production pathways and key hydrogen end uses according to each country particularity.

Also on regional scale, it can be observed the gradual configuration of numerous clusters around the concept of hydrogen economy, the so-called "Hydrogen Valleys", for which it is possible to identify certain specificities (refer to Chapter 3 for a more detailed overview on the topic). The Northern Netherlands [12] and the BIG HIT initiative on the Orkney Islands, Scotland [13] [14] can be mentioned as typical (and historically most famous) examples of such clusters. These cities and regions are pursuing ambitious plans to deploy hydrogen-based technologies in the coming years. Several initiatives and projects are in place, aiming at demonstrating the market readiness of those technologies. The transport sector is the main area of application for these initiatives, with specific segments which could take advantage of hydrogen-based solutions – buses, long-haul trucks, trains for non-electrified railroads; also, steel production and the (petro)chemical industry may benefit from the introduction of clean hydrogen into their processes. The range of possibilities increases even more if the so-called 'e-fuels' (synthetic fuels produced from clean hydrogen) are taken into consideration: ammonia and methanol, for example, can serve as fuels within the shipping sector, as well as feedstock for further industrial processes. Such regional clusters are not disconnected from what is happening on country level: while national governments are shaping the hydrogen value chain with a global perspective and a top-down approach, these valleys play a central role in the development of countrywide H_2 value chains in a perspective of integration through a bottom-up approach.

The development of hydrogen valleys can indeed contribute to the rapid achievement of the maturity of such hydrogen-based technologies. The German region North Rhine-Westphalia (NRW) has moved as well in this direction. In November 2020, the region has officially presented the roadmap for the creation of its regional hydrogen economy [15]. Ambitious targets have been established for both the short and medium terms – with milestone in years 2025 and 2030, respectively – in order to contribute to the achievement of carbon neutrality by 2050, and they cover the key areas for hydrogen valleys: Mobility, Industry, Energy & Infrastructure. A dozen projects are already in the pipeline, with a corresponding volume of 4 billion euros, clearly representing the intention of North Rhine-Westphalia to rely on hydrogen in the future [16].

1.2 Problem statement and Objectives

Considering the background described in the previous section, it seems particularly relevant for NRW to push forward the discussion about hydrogen value chain implementation in the region by elaborating more detailed plans for the achievement of its targets. Therefore, the present thesis will investigate techno-economic strategies for the introduction of a hydrogen infrastructure in NRW over the next 15 years (2035).

According to the typical pattern of hydrogen valleys (as it will be bettered illustrated in Chapter 3), mobility, in particular public transportation, represents the key sector for the introduction of hydrogen technologies within a regional community. Moreover, being buses explicitly mentioned within NRW hydrogen roadmap targets, the present thesis will focus on strategies to ensure the optimal deployment of hydrogen buses within the region.

The work is conducted with support from the research institute of Forschungszentrum Jülich (FZJ), North-Rhine Westphalia, Germany. A special focus will be put on the so-called 'Metropolregion Rhein-Ruhr' (MRR), a metropolitan area entirely within the federal state of North Rhine-Westphalia which includes several major urban concentrations in Germany. FZJ represents a key stakeholder for MRR, being one of the main competence centres for hydrogen in the area.

The merit of the results of the analysis will be defined mainly on economic basis. The key variable used for the assessment will be the *weighted average TOTEX*, expressed in €/kg H_2. This cost will be determined by the investment cost of the technologies deployed for the transport and storage of hydrogen from the points of sourcing to the points of hydrogen consumption (see Chapter 4 for a detailed description of the Methodology for the investigation).

1.3 Method of Attack

For the selection of the method of attack, the literature has been consulted. The typical approach for infrastructure development planning consists of doing a preliminary background study and setting up a simulation model. Dagdougui [17] provides a review of used models for investigating the hydrogen supply chain, identifying three categories for modelling approaches:

i) *Mathematical optimization methods*. They look for optimal configurations that respond to some specific criteria (economic, safety, environmental). The typical approach is to present the general mathematical formalization of the hydrogen supply chain problem, followed by an application of the model for a national or regional case study.

ii) *Decision support system based on Geographic Information System (GIS)*. They construct the infrastructure based on spatial dimension, therefore they depend strongly on the local territorial condition, such as transportation network, population, available resources, local policies and others.

iii) *Transition models to future hydrogen supply chain scenarios*. The objective here is not to model the hydrogen infrastructure from the mathematical viewpoint, but to understand the behaviour of the HSC in certain areas assuming specific scenarios. Usually, these kinds of studies are accompanied with the cost estimation of the hydrogen pathways (e.g., Life Cycle Assessment cost, LCA)

Based on these three categories, the following examples can be provided: Yang et al [18] formulate an *optimization* problem for the hydrogen supply chain network based on the off-grid wind-hydrogen coupling system in the Chinese province of Fujian; Stiller et al [19] have developed a *GIS-based regional model* for hydrogen demand and fuelling station networks for the design of the pathways of hydrogen fuel in Norway; Lee et al. [20] have evaluated the environmental aspects of hydrogen pathways in Korea according to hydrogen production methods, production capacities and distribution options, applying the *LCA methodology*.

In addition to simulation models, other possible methods to investigate hydrogen infrastructure development could be taken into consideration, but they show significant limitations. More specifically:

1) creating an *experimental setup* or a *pilot-based study*. This step is necessary for validating the result of a study by means of a check in real conditions; however, it is typically a time consuming and very costly step, with high risk of failure or too generic results if not properly designed. It is therefore good practice to keep this method for later stages of a study, often in combination with preliminary simulation rounds. In this way, thanks to the simulation results, precision would be enhanced in the setup of a demo site.
2) limiting the work to *literature study*, without making a model, might jeopardise the investigation because the results would not achieve the level of detail requested.
3) making an *interview study* with relevant stakeholders for the case under analysis (technology manufactures, potential end users, etc.), without making a model, might end up with the same outcome as of a pure literature study.

The low suitability of an immediate experimental approach or of pure literature / interview studies for the definition of strategies for the implementation of a hydrogen infrastructure and supply chain reflects, to the author best knowledge, in the very little availability of applicative examples within publications – only an article could be found, in which Jreige et al. [21] surveyed consumer preferences for hybrid and electric vehicles in Lebanon in order to obtain recommendations and insights for the deployment of the charging infrastructure.

All above considered, a supply chain model will be pursued as the best method of attack for the purpose of the present study. The work will be conducted in continuation to the research of the Institute of Energy and Climate Research, Techno-economic Systems Analysis (IEK-3) at Forschungszentrum Jülich, North Rhine-Westphalia, Germany [22].

It is expected that the present thesis will be beneficial for the successful accomplishment of further stages of FZJ research (e.g., definition of an initial portfolio of projects for the implementation of hydrogen infrastructure in North Rhine-Westphalia), increasing the precision of the underlying assumptions and input data.

1.4 Boundaries and Limitations

As it will be extensively explained in Chapter 4, the scope of the present analysis is limited to a particular set of categories for hydrogen demand technologies; other contributors to hydrogen demand are not taken into consideration because they are not expected to have a relevant impact on hydrogen demand by 2035, in the light of the state of the art of hydrogen-based technologies and of the targets set by the NRW region (explanation is provided in Chapter 2 and Chapter 3). The mobility sector is represented by buses, trains, trucks and material-handling vehicles; scenarios also assume relevant hydrogen demand from the industrial sector; however, no demand is taken into account for other mobility sectors like shipping and aviation, nor for energy uses within the power system (e.g., large-scale energy storage or power / heat generation plants).

Most importantly, it is to be remarked that the purpose of the present thesis is limited to the investigation of possible pathways for the achievement of NRW hydrogen-related targets. The evaluation of which hydrogen technologies are to be recommended for a political roadmap – aiming at investing and stimulating market adoption – is out of the scope of the present study. A fair comparison of hydrogen-based solutions with other similar technologies (e.g., fuel-cell and battery-based electric vehicles) should be the basis for the discussion and it should aim at understanding the cost-benefit stake for the community in the framework of the overarching goal of decarbonization and carbon neutrality. Such a comparison is obviously complex and should take into account different factors – namely economic, social and environmental. Nevertheless, as a starting point for a personal investigation, it might be of interest for the reader to know that extensive literature can be found related to the so-called 'hard-to-abate' sectors, in which electrification through clean electricity is not a viable alternative to fossil fuel-based incumbents. As examples, it is worth mentioning here the report by Agora Energiewende and AFRY Management Consulting [23], who recommend initiating the diffusion of hydrogen-related technologies from certain industrial processes (namely iron ore reduction, ammonia and methanol production, production of petrochemicals for plastics and fuels and plastics recycling) over mobility; also, Madeddu et al. [24] point out that hydrogen may not be as interesting for heat generation as other options, namely direct electrification using renewable energies (from heat pumps to arc furnaces), especially when it comes to industrial demand for process heat, which spans over different grades of temperature (from below 100°C to 3500°C).

1.5 Structure of the Thesis

The present report will be organized according to the following structure:

1. An overview of the State of the Art of the different segments of the hydrogen value chain highlights opportunities and limitations of available technologies as a way to decarbonize the economic system for the timeframe under analysis (Chapter 2).
2. The dynamics of the hydrogen value chain creation are then described – through the concept of "Hydrogen Valleys" – highlighting the role of regional-scale initiative and identifying the key drivers for success. The discussion moves on to the features and targets of the region under analysis (North Rhine-Westphalia) underlying the reasons why it is a potential candidate for the development of a Hydrogen Valley itself (Chapter 3).
3. Chapter 4 will provide a deeper insight into the research methodology, the investigation tools used for the thesis (*H2MIND*, Python-based simulation model) and its adaptation to the simulation scenario.
4. Chapters 5, 6 and 7 will finally present the results of the analysis and their discussion, together with the conclusions and the key issues for future work.

2 Chapter 2 – State of the Art of Hydrogen technologies

The present Chapter provides an overview of the State of the Art of the different segments of the hydrogen value chain, with focus on market readiness of the available options, in order to highlight their potential opportunities and limitations for the creation of a hydrogen economy in NRW, within the timeframe under analysis (2025-2035). The overview starts from the end of the value chain (final uses), since the demand for hydrogen is the basic driver for the infrastructure creation and its pace of completion. The 'Technology Readiness Level' (TRL) scale is used to express the market readiness of a technology – its explanation opens the Chapter.

The *Technology Readiness Level* (TRL) scale is a measurement system used to assess the maturity level and the usability of a particular evolving technology, introduced by the standard ISO 16290:2013 [25]. Its application is used for benchmarking, risk management and funding decision making. Each technology project is evaluated against a defined set of criteria and then a TRL rating is assigned based on the project progress status. There are 10 TRL levels, corresponding to the different stages in the market development process -from the simple 'Idea', through the 'Technology Formulation' and the construction of a 'Prototype' to the 'Demonstration' and the full 'Commercial deployment'. TRL 0 is the lowest rank, TRL 9 the highest: the description of the TRLs adopted by the EU Commission is reported in Table 1.

Table 1 TRL rating description adopted by the EU Commission [26][27]

Rating	Description
TRL 0	*Idea*. Unproven concept, no testing has been performed.
TRL 1	*Basic research*. Principles postulated and observed but no experimental proof available.
TRL 2	*Technology formulation*. Concept and application have been formulated.
TRL 3	*Applied research*. First laboratory test completed; proof of concept.
TRL 4	*Small scale prototype* built in a laboratory environment ("ugly" prototype).
TRL 5	*Large scale prototype* tested in intended environment.
TRL 6	*Prototype system* tested in intended environment close to expected performance.
TRL 7	*Demonstration system* operating in operational environment at pre-commercial scale.
TRL 8	*First of a kind commercial system*. Manufacturing issues solved.
TRL 9	*Full commercial application*, technology available for consumers.

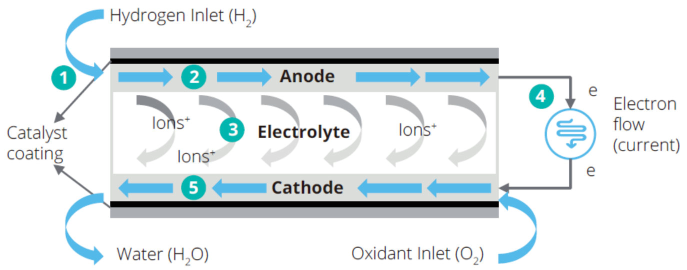
Following is the overview of the State of the Art of hydrogen applications for the different segments. Focus will be on key parameters like efficiencies, costs and Technology Readiness Levels (TRL).

2.1 Hydrogen final uses

Hydrogen is a particular versatile commodity. It is not an energy source itself; it is an energy carrier (the same as electricity): from this perspective, it can find application in different areas of power systems, as a fuel and/or as energy storage; however, hydrogen can also be used as feedstock within some industrial sectors.

When it comes to power generation, the application most commonly associated to hydrogen is '*fuel cell*'. Broadly speaking, a fuel cell is an electrochemical reactor in which a fuel and an oxidant convert their chemical energy directly into electricity; various materials can serve as fuel (e.g. methanol, methane, sodium borohydride, organic matters); however, 'fuel cell' has been used recently almost exclusively to describe reactors using hydrogen as fuel [28][29].

Main components of a hydrogen fuel cell are the electrodes, where reactions take place – the release of electrons from molecular hydrogen (anode) and the formation of water (cathode) – and the electrolyte, the selective matrix which allows the movement of ions while electrons flow through an external circuit. Figure 1 shows the general operating principle of a fuel cell stack.



1 – H_2 molecules enter the H_2 electrode (anode); 2 – The H_2 molecules interact with the catalyst on the anode, releasing electrons and forming a positively charged ion H^+; 3 – Ions cross the electrolyte and reach the second electrode (cathode); 4 – The electrons flow through an electrical circuit, generating power; 5 – Ions H^+, oxygen molecules and electrons interact with the catalyst on the cathode to form water vapor.

Figure 1 Operating principle of the fuel cell stack [29]

In general, all fuel cells have the same basic configuration — consisting of an electrolyte and two electrodes. But there are different categories of fuel cells, classified primarily by the kind of electrolyte used. The electrolyte determines the kind of chemical reactions that take place in the fuel cell, the temperature range of operation, and other factors that determine its most suitable applications. Table 2 reports the high-level comparison of five typical fuel cell technologies. More details about fuel cells can be found in [28]–[31].

Table 2 High-level comparison of five typical fuel cell types [31]

Fuel Cell Type	Common Electrolyte	Operating Temperature	Typical Stack Size	Electrical Efficiency (LHV)	Applications	Advantages	Challenges
Polymer Electrolyte Membrane (PEM)	Perfluoro sulfonic acid	<120°C	<1 kW - 100 kW	60% direct H_2;[i] 40% reformed fuel[ii]	• Backup power • Portable power • Distributed generation • Transportation • Specialty vehicles	• Solid electrolyte reduces corrosion & electrolyte management problems • Low temperature • Quick start-up and load following	• Expensive catalysts • Sensitive to fuel impurities
Alkaline (AFC)	Aqueous potassium hydroxide soaked in a porous matrix, or alkaline polymer membrane	<100°C	1 - 100 kW	60%[iii]	• Military • Space • Backup power • Transportation	• Wider range of stable materials allows lower cost components • Low temperature • Quick start-up	• Sensitive to CO_2 in fuel and air • Electrolyte management (aqueous) • Electrolyte conductivity (polymer)
Phosphoric Acid (PAFC)	Phosphoric acid soaked in a porous matrix or imbibed in a polymer membrane	150 - 200°C	5 - 400 kW, 100 kW module (liquid PAFC); <10 kW (polymer membrane)	40%[iv]	• Distributed generation	• Suitable for CHP • Increased tolerance to fuel impurities	• Expensive catalysts • Long start-up time • Sulfur sensitivity
Molten Carbonate (MCFC)	Molten lithium, sodium, and/or potassium carbonates, soaked in a porous matrix	600 - 700°C	300 kW - 3 MW, 300 kW module	50%[v]	• Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Low power density
Solid Oxide (SOFC)	Yttria stabilized zirconia	500 - 1000°C	1 kW - 2 MW	60%[vi]	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Solid electrolyte • Suitable for CHP • Hybrid/gas turbine cycle	• High temperature corrosion and breakdown of cell components • Long start-up time • Limited number of shutdowns

2.1.1 Transport

IRENA reports that "the transport sector, as a whole, accounted for about 25% of global energy-related CO_2 emissions in 2017" [32], thus representing one of the main challenges to the decarbonization of the global energy system. Hydrogen has been largely investigated as a means to tackle the decarbonization of the transport sector, raising the interest in particular for those hard-to-abate segments where electrification may not be an option. *Conventional internal combustion engines* could be easily adapted to burn pure hydrogen (HICEs), however they are not expected to play a significant role in the long term due to lower efficiencies and to the emission of NO_x during combustion [33]. *Hybrid solutions* (for example, bi-fuel powertrain configurations) do not seem to be optimal solutions either: they may allow for the use of existing infrastructure, but they are not zero-emission and could eventually be displaced by lower-carbon options [33], [34]. Research interest has therefore focused on *Fuel Cell Electric Vehicles* (FCEVs). These devices generate electricity from the fuel to power an electric motor and they do not have harmful tailpipe emissions (only water and heat), as long as they use green hydrogen; therefore, they may represent an option to achieve zero emissions in the transport sector. From a system perspective, key components of a hydrogen-based FCEV are: the fuel cell stack and its auxiliary systems (H_2 supply system, air supply system, water management system, heat management system), the hydrogen tank, the battery (with functions of backup/buffer) and the electric motor (Figure 2). These vehicles are equipped with a fuel tank onboard which has to be refilled in a hydrogen refuelling station. Proton Exchange Membrane (PEM) fuel cells are the dominant technology for transport applications, due to their high-power density, low operating temperature (50-100°C), short start time, electrical output responsiveness to the drive cycle needs (rapid and deep) and ease of use of its oxidant (atmospheric air) [29], [34].

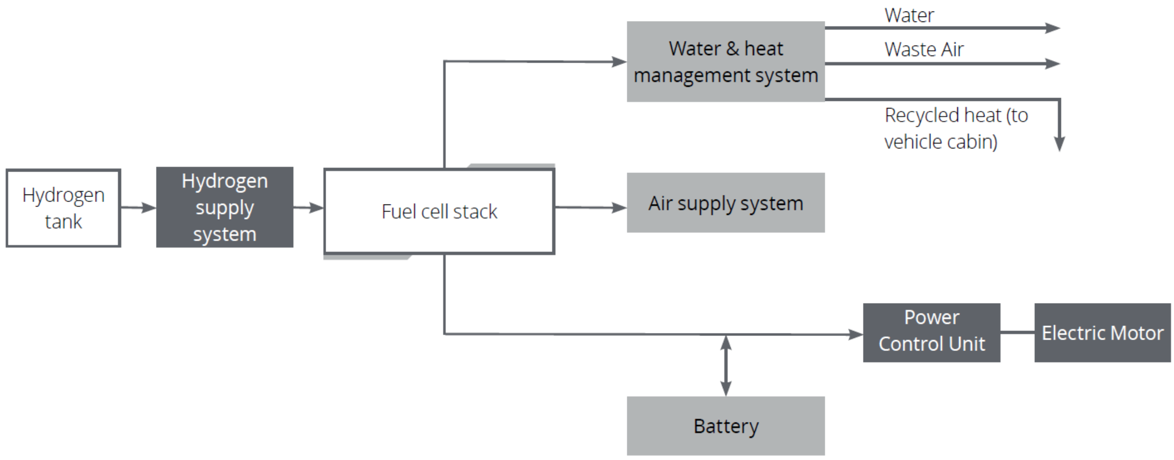


Figure 2 Fuel cell vehicle operation principle [29]

2.1.1.1 Road transport

In general, FCEVs are still at an early stage of deployment, limited to niche markets, and suffer from the comparison with Battery Electric Vehicle (BEVs), which are at a more mature market stage especially in the road transport sector. Nevertheless, in [35] the 'Fuel Cells and Hydrogen 2 Joint Undertaking' (FCH-JU) reports a series of arguments in favour of hydrogen FCEVs over BEVs in a large-scale transport decarbonization scenario. Being the comparison of the two technologies out of the scope of the present thesis, an overview of those arguments is here provided for the sake of completeness. It is left to the reader any detailed considerations about validity. Depending on the road transport segment under analysis, FCEVs may prove to be more advantageous for users than BEVs with respect to:

1. *Energy density vs. vehicle range*. "Hydrogen has a significantly higher energy density than batteries, both in terms of volume and weight. This implies that given limitations in the weight and size of the energy storage in the vehicle, a FCEV can drive further and transport more payload than a BEV." [35] By this criterion, trucks and buses are expected to lean towards FCEV models; for cars and light-commercial vehicles, the "use case" will determine the preferred technology (e.g., short daily ranges will orient towards BEVs).
2. *Refuelling times*. "Modern FCEVs achieve ranges of up to 800 km and hydrogen refuelling is 10 to 15 times faster than fast charging, fully refilling a car in five minutes instead of one hour." [35]
3. *Impact on user behaviour*. "For passenger cars, FCEVs offer similar ranges and refuelling times as ICE vehicles. With a hydrogen refuelling station infrastructure in place, consumers would not need to adjust their behaviour." [35] This is in contrast with BEV current trend of recharging the vehicle during periods of low use, which is reported to pose a question for the future, when the diffusion of vehicle sharing, platooning and autonomous driving will lead user behaviour to expect uninterrupted availability of the vehicles.

From a system perspective, reported advantages are:

1. *Impact on the refuelling/recharging infrastructure*. Taking hydrogen refuelling one tenth to one fifteenth of the time fast charging requires, it that means that "the HRS infrastructure requires about 10 to 15 times

less space to fuel the same number of vehicles." Also, "one HRS can serve 10 to 15 times more vehicles as one fast charger, which makes the expansion of the hydrogen infrastructure become less costly with an increasing FCEV fleet compared to a fast-charging infrastructure." [35]

2. *Cost of HRS deployment*. The higher refuelling speed is beneficial for stations cost. "When fully utilized, HRS are estimated to cost only half of the CAPEX per refuelling compared to fast chargers. Therefore, it is also an attractive business case for operators." [35]
3. *Grid balancing for power network*. The hydrogen infrastructure "can balance the grid by producing hydrogen from surplus electricity and it provides a technical solution for seasonal storage of variable renewable energy." [35] This in opposite trend to fast chargers, which "add peak demand".

Despite any potential advantages, FCEVs are currently more expensive for end users and the lack of a widespread infrastructure is an entry barrier. However, costs are expected to improve significantly in the near future. According to a cost analysis by Deloitte China and Ballard [29], in 2019 FCEVs were "approximately 40% and 90% more expensive than BEVs and ICE vehicles on a per 100 km basis considering acquisition and operational costs together". Deloitte China and Ballard report that, from the acquisition perspective, the fuel cell system and the mark-up on other components results in high costs due to lower economies of scale. From the operation perspective, hydrogen fuel is the primary cost driver. However, "the Total Cost of Ownership of FCEVs is forecasted to become lower than that of BEVs by 2026, and lower than that of ICE vehicles around 2027".

For the purpose of the present thesis, when it comes to road transport, the distinction can be made between the following two categories of vehicles: heavy-duty vehicles (HDVs) and light-duty vehicles (LDVs). According to EU Commission, "HDVs are defined as freight vehicles of more than 3.5 tonnes (trucks) or passenger transport vehicles of more than 8 seats (buses and coaches)" [36]. For LDVs no clear definition is to be found in EU; the reader can refer to cars and light commercial vehicles as part of this category, as opposed to HDVs. Within EU, light commercial vehicles (LCVs) are commercial carrier vehicles for goods or passenger, with a gross vehicle weight of no more than 3.5 tonnes – examples are: commercially-used pickup trucks, vans and three-wheelers [37]. The next sub-sections will focus first on LDVs (cars, LCVs, forklifts) and then on HDVs (buses, heavy trucks).

Passenger cars

These vehicles are usually composed of a hybrid electric powertrain combining a hydrogen fuel cell with a battery. This layout applies when the fuel cell is used as main propulsion system (60-100 kW for European cars) and a small battery is used to smooth fuel cell power fluctuations. It is also possible to observe smaller stacks (< 20 kW) attached to a BEV in a 'range-extender' mode (FC RE-EVs): this means that most journeys are completed using a battery, with switch to the fuel cell for less-frequent longer journeys. Due to the need for high energy density, refuelling pressure is quite high (700 bar), impacting material resistance and costs of components [34].

Globally, passenger cars are expected to play a significant role for the development of hydrogen infrastructures in the medium- and long-term scenario. As an example: the California Fuel Cell Partnership has outlined targets for 1,000,000 FCEVs by 2030 [38]; a target of 800,000 FCEVs by 2030 is included in Japan's "Hydrogen Strategy 2017" [39]; the European Fuel Cells and Hydrogen 2 Joint Undertaking Hydrogen Roadmap has recommended a target for EU by 3.7 million fuel cell passenger vehicles on road by 2030 [35].

Today, pure fuel cell cars are already commercially available, being therefore at the highest technology Technological Readiness Level (TRL 9), but have low adoption due to limited refuelling infrastructure as well as high acquisition cost. Four models are currently offered in serial production, by Toyota, Hyundai and Honda (Table 3).

Table 3 Hydrogen fuel cell cars available

Name	Manufacturer	Country	On the Market Since	Approx. Cost	Additional information	
Mirai	Toyota	Japan	2014	EUR 79,000	Availability in EU limited to BE, DK, DE, F, N, NL, S, UK	[40]
Clarity Fuel Cell	Honda	Japan	2017	EUR 51,000	Only available in California and Japan	[40]
ix35 Fuel Cell	Hyundai	South Korea	2013	EUR 65,000	In commercial service by car sharing service BeeZero (Munich, Germany) or world's largest FCEV taxi fleet "HYPE" (Paris, France)	[40]
NEXO	Hyundai	South Korea	2018	EUR 69,000	n.a.	[40]

Table 4 Technical performance of commercially available fuel cell cars

Name	Manufacturer	Range	Fuel consumption	
Mirai	Toyota	500 km	0.76 kg / 100 km	[41]
Clarity Fuel Cell	Honda	589 km	0.77 kg / 100 km	[42]
ix35 Fuel Cell	Hyundai	594 km	1.00 kg / 100 km	[43]
NEXO	Hyundai	756 km	0.84 kg/100 km	[44] [45]

Light commercial vehicles (LCVs)

Fuel cell-based electric vehicles have an interesting potential for inner and inter-city application – for example, within the sector of delivery vans, postal services, logistics, taxis, garbage trucks, street sweepers. The accessible range is enough to cover most of the typical inner- and inter-city tasks, which require approx. 150 km [29]. This kind of vehicles is compatible with environmental requirement and noise regulations in urban areas, which would encourage the government and fleet operators to accelerate its adoption.

Also, short refuelling times compared to BEVs will allow for higher operational efficiency of fleets. Commercial fleets are actually an interesting segment for this kind of FCEVs, which could accelerate the diffusion of refuelling stations: return-to-base fleets such as delivery vans and taxis, or passenger cars in a future car-sharing economy are usually associated with dedicated refuelling depots, which will see high utilisation and consequent reduction in overall costs of the provided service. Back-to-base operation means fewer refuelling stations are needed and are more highly utilised, reducing initial refuelling costs.

The structure of the vehicle is similar to cars – mainly a hybrid electric powertrain (fuel cell and battery) and storage tank (capacity and pressure range depending on the specific model, 3-6 kg at 350 or 700 bar) [46], [47]. Fuel cell-based commercial vehicles are beginning to move from prototype stage to first commercialization (TRL 7-8). It is an example, 'H2-tech' vehicle model series by HYVIA, joint venture between Renault Group and Plug Power: they have announced that they will bring to market their first three fuel cell models in Europe by end of 2021 / 2022 – two for transport of goods (Master Van, Master Chassis Cab), one for transport of people (Master City Bus) [46]–[48]. For some specific end-uses (mostly, delivery vans); fuel cells appear to be investigated also as range extender for existing battery-powered vans and as power suppliers for components of the vehicle (for example, loader and compactor garbage trucks, as prototype demonstration) [40].

Table 5 Hydrogen fuel cell light commercial vehicles (selection)

Name	Manufacturer	Country	On the market Since	Approx. Cost	Additional information	
H2-tech	HYVIA (Renault)	France	2022	n.a.	Series of 3 LCVs for transport of goods and people. To market from 2022.	[46]–[48]

Forklifts

Even if a niche, forklifts represent a consolidated market for hydrogen vehicles already since 2008 (TRL 9). Used for material handling at warehouses, recycling plants, construction sites and municipal utilities, the advantage resides in the short refuelling time, compared to battery-based equivalent vehicles, reducing operating costs in a typical high throughput warehouse [33].

Buses

Buses are one of the most adopted hydrogen fuel-cell applications. Fuel cell electric buses (FCEBs) typically use 350 bar compressed hydrogen for on-board storage (the cylinders are accommodated on the bus roof, thus loosening the constraint on space occupancy and gas compression), so refuelling station requirements for buses are also for 350 bar delivery, reducing costs for compression and refuelling [34]. Similarly to light-duty commercial vehicles, the application in return-to-base fleets is an interesting option also for FCEBs. Buses typically feature regular, predictable routes, which requires few refuelling stations.

Various demonstration initiatives have included the creation/extension of a fleet of fuel cell electric buses, and more initiatives are still in the pipeline for implementation. According to the magazine 'Sustainable Bus' [49], around 150 fuel cell buses were put in operation in Europe in the period 2012 – 2020 under projects co-funded by Europe, and over 200 additional fuel cell buses will hit the road by end of 2021 in the framework of EU-funded projects JIVE 1 and JIVE 2 (Joint Initiative for Hydrogen Vehicles across Europe [50]). Plans are there to reach over 1,200 FCEBs in operation by 2025. Being most of them publicly operated, FCEBs represent a proper choice for early application of fuel cell technology. Moreover, FCEB acts as a highly-visible, green-society initiative of public transportation, showcasing the potential for urban mobility in regions and cities. Such a favourable condition can count on a technology gradually moving from a pre-commercial stage to series production (TRL 8-9) [40], [51].

To mention some manufacturers currently researching on FCEBs: Van Hool, Solaris, CaetanoBus, VDL, Wrightbus [49].

Table 6 Hydrogen fuel cell buses available (selection) [40], [50]

<table>
<tr><th>Name</th><th>Manufacturer</th><th>Country</th><th>Since</th><th>Approx. Cost</th><th>Additional information</th></tr>
<tr><td>A330 FC</td><td>Van Hool</td><td>Belgium</td><td>2019</td><td rowspan="5">< 650,000 €</td><td>Deployment in Aberdeen (Scotland, UK), as part of strategy to create a hydrogen economy in the region</td></tr>
<tr><td>Exqui.City 18 FC</td><td>Van Hool</td><td>Belgium</td><td>2019</td><td>Applied in the world's first hydrogen-powered Bus Rapid Transit (BRT) system (Pau, France)</td></tr>
<tr><td>Urbino 12 hydrogen</td><td>Solaris</td><td>Poland</td><td>2019</td><td>n.a.</td></tr>
<tr><td>H2.City Gold</td><td>CaetanoBus</td><td>Portugal</td><td>2019</td><td>n.a.</td></tr>
<tr><td>VDL SLF-E H2</td><td>VDL</td><td>Netherlands</td><td>2020</td><td>Battery-electric bus with fuel cell range extender, realized adding a trailer (housing the fuel cell technology) to the bus. [52]</td></tr>
<tr><td>H2Bus Consortium (project)</td><td>Wrightbus</td><td>United Kingdom</td><td>2020</td><td>< 375,000 € (after funding)</td><td>The first phase of the EU-funded project aims at the deployment of 200 H_2 FCEBs (out of 600 in total) and supporting infrastructure in Denmark, Latvia and the UK by 2023. In parallel, the consortium will remain active in other clusters across Europe to reach the targeted 1,000 bus deployment.</td></tr>
</table>

Table 7 Technical performance of commercially available FC electric buses [53], [54]

Name	Manufacturer	Range	Fuel consumption
A330 FC	Van Hool	300 km	9 – 11 kg / 100 km
Exqui.City 18 FC	Van Hool	300 km	
Urbino 12	Solaris	350 km	
H2.City Gold	CaetanoBus	400 km	
VDL SLF-E H2	VDL	350 km	

Heavy trucks

Fuel cells show a considerable potential for long-haul HDVs. These are used by operators in the fields of logistics/shipping or logistics-intensive industries (food and beverage retail, for example), construction and O&M services (especially for infrastructure assets): these applications require high utilization, long travel distances (>500 km for inter-regional routes), thus high energy requirements.

Most major manufacturer are in the R&D stage, generally at an advanced prototype or pre-commercial demonstration-stage, designed/adapted to service specific use cases (TRL 7-8). To mention some examples: Toyota and Kenworth are testing 10 fuel cell electric trucks with a 480-kilometre range in the US [55][56]. Anheuser-Busch InBev (an international drinks company) ordered 800 hydrogen trucks from Nikola Motors to be in operation in 2020 [57]. Hyundai is expected to deliver 1 000 fuel cell electric trucks in the Swiss market between 2019 and 2023 [58]. Also, the Volvo Group has announced its plans to engage with its natural competitor Daimler Truck AG in a 50/50 joint venture ‘cellcentric’, in order to develop and produce fuel cells for heavy-duty vehicle applications starting from 2024 [59].

The positive aspects of fuel cells applied to trucks reside in fast refuelling times, which is particularly advantageous for fleet operators in order to reduce the downtime in their operations. Fuel cell technology is becoming increasingly mature and optimized for heavy duty applications, approaching ranges and refuelling times close to conventional vehicles. This provides fuel cell heavy duty vehicle a great potential to displace diesel and battery electric heavy-duty trucks in the long term. Interest could grow as diesel trucks begin to be banned from major city centres. However, fuel cell heavy-duty trucks adoption is proceeding at a relatively slow pace (if compared for example, to buses), due to a combination of factors, related in particular to costs (vehicle cost expected to be significantly higher as for standard trucks; high hydrogen cost, breakeven point highly dependent on fuel prices) and limited availability of refuelling infrastructure.

For such applications, the size of onboard hydrogen tanks ranges higher than 30 kg, at 350 bar pressure [58], [60].

Table 8 Hydrogen Fuel Cell trucks projects (selection)

Name	Manufacturer	Country	On the market Since	Additional information	
T680	Kenworth, Toyota	United States	2019	Kenworth vehicle powered by Toyota hydrogen fuel cell electric powertrains unveiled in 2018, the current step is real-world testing of 10 vehicles with Total Transportation Services Inc. at the ports of Los Angeles and Long Beach in Southern California (operation from 2020)	[61], [56]
Nikola One	Nikola Motors	United States	2020-21	Hydrogen-fuelled Class 8 truck, aimed to be in production in 2020-2021. In May 2018, Anheuser-Busch placed a provisional purchase order for up to 800 leases of the hydrogen-powered truck versions.	[57], [62]
H2-Share (prototype)	VDL	Netherlands	n.a.	The project aims to demonstrate (TRL 7) a 27-ton rigid truck fuelled by hydrogen with a flexible low energy mobile H_2 refueler. The goal is to test the truck at six locations in Germany, The Netherlands, Belgium and France. Demonstration started in April 2020.	[63]
Xcient Fuel Cell	Hyundai	South Korea	2020	Hyundai Hydrogen Mobility (HHM), joint venture with Swiss company H_2 Energy, will lease the trucks to commercial truck operators (e.g. supermarkets) on a pay-per-use basis, in order to avoid initial investments for the fleet customers. Hyundai plans to put 1,600 trucks on Swiss roads by 2025, using green H_2 generated from hydropower.	[60]

Table 9 Technical performance of commercially available FC electric HDVs [53], [54]

Name	Manufacturer	Range	Fuel consumption
T680	Kenworth, Toyota	480 km	
Nikola One	Nikola Motors	1900 km	4.6 kg / 100 km
H2-Share (prototype)	VDL	400 km	
Xcient Fuel Cell	Hyundai	400 km	

2.1.1.2 Rail transport

Hydrogen-based fuel cell trains are an interesting option for the replacement of diesel trains and for the decarbonization of routes where electrification is hard to put in place, because technically difficult or uneconomic, due to route length, harsh geographic conditions or lack of space in urban areas [33]. The technology is in an early commercial stage gradually shifting to commercial maturity (TRL 8-9), with trains tested and prototyped in several countries and several markets over the last 20 years, including Japan, USA, Denmark, Spain, South Africa and the UK [34], [64]. In Germany, manufacturer Alstom successfully completed trial operation of two hydrogen trains Coradia iLint over the period 2018-2020, and 41 series trains could be in regular service by 2022 [65]. Successful test was completed in the Netherlands in 2020 [66]. Series vehicles have been sold also in Austria and Italy, with start of operation in 2022-2023 [67], [68]. Parallelly, Alstom has also announced plans to convert a fleet of trains in the UK, together with Eversholt Rail operator, through the design of a new hydrogen train for the UK market. The train, codenamed 'Breeze', could run across the UK as early as 2022, in line with the government target of eliminating diesel trains by 2040 [69].

Coradia iLint is a 2-cart, low-floor passenger train. The fuel cell composition (PEM modules, supplied by Canadian-based Hydrogenics) and hydrogen fuel tank (350 bar, 15°C) are placed on the roof of the train while the lower portion of the train is fitted with the traction system (motor, AC/DC and DC/DC power converters, auxiliaries) and a lithium-ion battery composition. Energy storage and intelligent management systems onboard the vehicle ensure low energy consumption. Kinetic energy recovered during braking and surplus energy generated by the fuel cell is stored in lithium-ion batteries. The train can carry 150 seated passengers and 150 standing passengers. It is capable of attaining a range of up to 1,000 km at a maximum speed of 140 km/h [70].

Table 10 Hydrogen fuel cell trains (selection) [70]

Name	Manufacturer	Country	Since	Approx. Cost	Additional information
Coradia iLint	Alstom	Germany	2017	n.a.	First passenger train in the world to run on a hydrogen fuel cell, designed specifically for use on non-electrified lines.

2.1.1.3 Water transport

Water transport is a relevant source of CO_2 emissions, accounting for approx. 10% of transport emissions. Potential for decarbonization is high, considering that 20% of the global fleet is responsible for 85% of the net greenhouse gas emissions from the sector, according to IRENA [32].

Different low-carbon options are emerging for decarbonizing the maritime sector, some of which are based on hydrogen. Ammonia and methanol (two of the so-called 'e-fuels'), produced from renewable power or biomass, look promising for ocean-going vessels, while electrification via batteries or fuel cells may be more suitable for short-distance vessels (i.e., ferries, and coastal and river shipping) [71]. However, competitive fuel prices are key, and these solutions all come at a considerable cost premium. Currently, the maritime sector is heavily dependent on low-cost, low-grade refining residues: therefore, a combination of cost reduction and regulatory change will be needed to shift the sector its current fuel.

As a fuel for water transport, hydrogen can be burned in internal combustion engines either with air (requiring post-combustion treatment to limit nitrogen oxides emissions) or pure oxygen; it can also be used in fuel cells. However, the use of hydrogen poses some major challenges [71], first of all how to store it. Also, hydrogen storage may require more space on cargos compared to bunkering fuels in the current system (up to 8 times more, to give the same amount of energy). That makes it more feasible, for now, for use in vessels on short voyages. That is also one of the main reasons why other hydrogen-based synthetic fuels, such as methanol and ammonia, are being considered.

Ammonia, another fuel which can be either combusted or used in a fuel cell. is easier and more economical to store than hydrogen (needing refrigeration but not cryogenic temperatures) and requires around half the space since it is denser. It can also be converted back to hydrogen onboard a ship, meaning it could be loaded and stored on the ship as ammonia but ultimately used in a hydrogen fuel cell. The production of hydrogen-based ammonia, however, implies additional cost (on top of hydrogen cost, which is already high) and efficiency losses. Another hurdle is that ammonia is more toxic than conventional bunker fuels; still, in theory, the toxicity of ammonia and related safety concerns could be managed via regulation and technical measures, which could benefit from the decade-old ammonia production industry [71].

At the moment, ammonia is seen by many in the industry as the most viable option, but research is still in early stages – as an example, a consortium of companies was recently granted EU funding to install the world's first ammonia-powered fuel cell on a vessel in 2023 [72]. As for hydrogen, solutions based on internal combustion are already in a prototype stage (TRL 5-6): Belgium's Compagnie Maritime Belge (CMB) built its first hydrogen-powered passenger shuttle boat, operating since 2017 in Belgium. It will provide a hydrogen ferry for Japan by April 2021 and is involved in a tug boat project with the port of Antwerp [73], [74]. As for fuel cells, research is in early stage, test and operation are targeted for end of the decade. Two projects are relevant from this point of view: i) a EU-funded Danish-Norwegian project aiming at building a 1,800-passengers ferry with a 23-MW hydrogen fuel cell ('Europa Seaways') to operate between Copenhagen and Oslo by 2027 [75]; ii) the prototype good ship Topeka under the EU-funded HySHIP project, ferrying cargo and delivering hydrogen supplies to strategic areas using 1-MWh battery and a specialised hydrogen fuel cell [76].

2.1.1.4 Aviation

Aviation accounts for 11% of all transport emissions. Aviation is dependent on high-energy-density fuels due to mass and volume limitations of aircrafts. With current aircraft designs, this limits the options of alternative fuels suitable for replacing jet fuel to some advanced biofuels and synthetic drop-in fuels [32].

Hydrogen is involved in the production of e-fuels, together with CO_2. The most interesting e-fuel is the 'synthetic kerosene' (synthetic paraffinic kerosene, SPK), which could replace fossil jet fuels and biofuels, since it can be chemically identical to fossil kerosene, and it could in theory meet all aviation performance and safety specifications.

Hydrogen-powered planes are also technically feasible. Still, the stage of development is not so advanced: until now, only small-scale fuel cell aircrafts or auxiliary power units (APU) on large conventional aircrafts are in prototype stage (TRL 5); hydrogen as propeller for large conventional aircrafts, is in concept stage (TRL 2), they would require a radical redesign of airframes [40]. An example of such kind is Airbus ZEROe initiative, presenting in 2020 three different concept of hydrogen aircraft, based on three different powertrain technologies, which concepts target 2035 for commercialization [77]:

- A turbofan or turbofan project (120-200 passengers) with a range of over 2,000 nautical miles, capable of operating intercontinental and powered by a *gas turbine engine* modified to run on hydrogen, rather than jet fuel. Liquid hydrogen will be stored and distributed through tanks located behind a pressurized rear bulkhead.
- A turboprop project (up to 100 passengers) that uses an *internal combustion engine* powered by hydrogen. It would be able to travel more than 1,000 nautical miles, making it a perfect option for short-haul travel.
- A "blended-wing body" project, literally a mixed wing body (up to 200 passengers) in which the aircraft's wings merge with the main body. The exceptionally wide fuselage opens up multiple options for hydrogen storage and distribution.

2.1.2 Industry

The industrial sector is another area of interest for hydrogen applications. Here, the use of hydrogen can be two-fold: not only can it be used as clean energy source for heat and electricity; it can serve itself as alternative feedstock for the transformational processes, replacing currently used fossil materials. This is an extremely relevant potential in terms of decarbonization of the industrial sector, which accounts for around 28% of total global CO_2 emissions [32]. Four industrial sectors in particular account for around three-quarters of total industrial emissions: iron and steel, chemicals and petrochemicals, cement and lime, and aluminium. At the moment, hydrogen is already widely used in the industrial sector, but its production is based on conventional fossil primary sources (natural gas, coal). Leveraging demand for low-carbon hydrogen in these sectors can therefore play an important role in the creation of a hydrogen value chain. While in some cases the use of green hydrogen can intervene on the main production processes (e.g. steel), in others it can be used in side processes, in combination with CCS, for the conversion of the CO_2 into synthetic fuels, plastics or other chemicals (e.g. cement).

2.1.2.1 Iron and steel

Two main production pathways are currently in use for steel making, depending on the kind of furnace used for iron extraction and conversion into steel. Both use mainly iron ore as raw material (steel scrap can also be recycled as input for steel making). In the first pathway, a Blast Furnace is used for iron production, then the Basic Oxygen Furnace is used for steel production (BF-BOF). This pathway involves limestone and coke as reducing agents of iron ore. The second pathway involves the Direct Reduction of Iron followed by steelmaking in an Electric Arc Furnace (DRI-EAF), using coal and natural gas as reducing agents. Around 71% of global steel is produced via BF-BOF; most of the remaining 29% of steel is produced via DRI-EAF [32], [78]–[80].

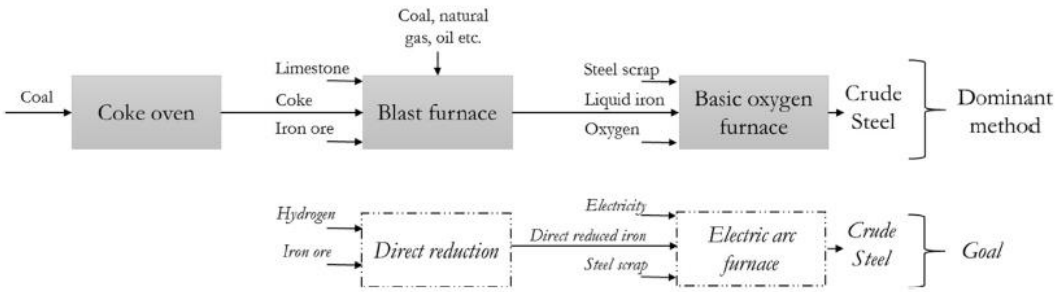


Figure 3 The dominant method BF-BOF (in 2017) and the long-term goal DRI-EAF (for 2045), in the case of Swedish iron and steel industry [79]

Hydrogen can be used for steel production in two ways. First, it can be used as injection material to blend reducing agents in conventional blast furnaces (coke, natural gas, etc.), to increase the use of fuel and to improve the furnace performance. The first pilot plants using hydrogen injection have recently been set up (ArcelorMittal in Bremen, for example [81]), however this option will never offer carbon-neutral steel production because regular coking coal is still a necessary reductant agent in the blast furnace [82].

A second approach to steelmaking is using hydrogen as reducing agent in DRI-EAF. If green hydrogen is used as feedstock and renewables are used as energy source for the process, the potential for decarbonization is very high – 80-95% fewer CO_2 emissions than conventional processes. The DRI-EAF route with green hydrogen has benefited greatly from research and development (R&D) efforts over the past decade. At least six plants are being piloted, mainly in Europe. One relevant example is the Swedish project HYBRIT (Hydrogen Breakthrough Ironmaking Technology). In 2017, SSAB (the main Swedish steel producer) LKAB (state-owned mining company, iron ore extractor) and Vattenfall (the state-owned energy company) have launched a joint venture company (HYBRIT Development AB) to fully develop a hydrogen-based direct reduction process to replace coal or natural gas [79], [83]. However, hydrogen-based technology is still in its experimental stage. Although the pre-feasibility studies have been successful, the technology needs to be tested at a pilot plant from 2018 to 2024, followed by demonstration plants from 2025 to 2035 in Sweden before it becomes commercially mature [84]. Another example in Sweden is the venture 'H2 Green Steel', founded in 2020: it targets the construction of a plant in Boden, integrated with a giga-scale electrolyser, in order to start operations by 2024 and to achieve five million tonnes of fossil-free steel annual production by 2030 [85]. Challenges are multiple: the investment needed for a transition to hydrogen-based reduction is extremely high; the process requires a lot of electricity and poses the question of the impact on the national power supply system; also, infrastructure is a relevant issue, in terms of how to store and supply hydrogen [79]. Still, push towards technological shift is also present in Sweden: SSAB needs to import coal to reduce the iron in its blast furnaces, while at the same time Sweden has availability of fossil-free electricity, which may even result in a continued surplus in the future and may potentially be used for hydrogen-based DRI. Secondly, the vision of Sweden in general is to phase out coal consumption and to completely phase out greenhouse gas emissions by 2045 [79].

Germany is also considering hydrogen-based DRI technology. Thyssenkrupp, the largest steelmaker in the country, will build a DRI plant in Duisburg by 2025, targeting 3 million tonnes of green steel by 2030 [86]. Salzgitter will complete a feasibility study for a DRI plant in Wilhelmshaven, Lower Saxony by 2021 [86]. ArcelorMittal, the world's largest steelmaker, has commissioned to DRI technology provider Midrex a demonstration project on an industrial scale in Hamburg, aiming to produce 100 000 tonnes of steel annually using green hydrogen. [87].

Table 11 Examples of small- and large-scale research and pilot projects exploring renewable hydrogen-based direct reduced iron

Name	**Key stakeholders**	**Country**	**Additional information**	
HYBRIT	SSAB, LKAB, Vattenfall	Sweden	Began pilot plant operations in September 2020	[79], [83]
H2 Green Steel	Vargas	Sweden	Construction of a greenfield steel plant in northern Sweden (Boden and Luleå, Norbotten), to start operations by 2024 and to achieve five million tonnes of fossil-free steel annual production by 2030.	[85]
Duisburg DRI	thyssenkrupp Steel, Air Liquide DE, VDEh-Betriebs-forschungsinstitut	Germany	The construction of a DRI plant is planned in Duisburg by 2025 at earliest. The plant will be operated using natural gas as long as sufficient quantities of hydrogen are not available. In the short term (end 2021), an existing conventional blast furnace is to be converted to the partial use of hydrogen (H2Stahl project).	[86], [88]
	thyssenkrupp Steel, thyssenkrupp Uhde Chlorine Engineers, STEAG		Joint feasibility study of a water electrolysis plant (500 MW), to be the basis for project development of a hydrogen hub (HydrOxy Hub Walsum).	[89], [90]
H_2 Hamburg	ArcelorMittal, Midrex	Germany	Demonstration project of an industrial-scale plant at ArcelorMittal Hamburg site, where DRI is already in place. DRI will be run initially with grey hydrogen sourced from natural gas, switching to green hydrogen from RES once available in sufficient quantities and at an economical cost.	[81], [87]
Salzgitter Low CO_2 Steelmaking (SALCOS)	Salzgitter, Fraunhofer Institute, Avacon, Linde, Tenova	Germany	Gradual replacement of blast furnaces with direct reduction plants at Salzgitter plant, going into operation as early as 2026 and achieving full range by 2050.	[91]

These pilot projects are important demonstrations of what can be achieved, but the scale is currently very small. According to the technology assessment by the initiative 'Green Steel for Europe' [92], the current TRL of H_2-based DRI ranges from TRL 6 to TRL 8 (pilot and pre-commercial demo stage), depending on the share of hydrogen in the direct reduction process, with lower TRLs for (almost) 100% hydrogen operation.

2.1.2.2 Refineries

Refineries are large industrial consumers of hydrogen, which is used in many stages of the refining chain [93]. For example, hydrogen is injected for the removal of sulphur from distillation products (*hydro-desulfurisation*, HDS) [94], which is very corrosive and contributes to environmental pollution (the so-called 'acid rains') in the form of the combustion product SO_2 (sulfuric anhydride). Hydrogen is also used to upgrade heavy distillation products by thermally cracking them into lighter, more valuable molecules (*hydro-cracking*) in the presence of a catalyst [95].

Currently, most of the hydrogen used in the oil refining sector is supplied by fossil fuels – for example, through Steam Methane Reforming (SMR) of natural gas. Still, projects are in place to investigate the possibility of using green hydrogen to reduce refinery CO_2 emissions. One relevant example is the EU-funded REFHYNE project in Germany, which aims at integrating a 10-MW PEM electrolyser into Shell's Rhineland Refinery in Wesseling, North Rhine-Westphalia. The electrolyser has entered operation in July 2021 [96], [97]. Other initiatives are in a very early stage, with the signature of venture agreements – Lingen (Germany) [98] and Sarroch (Italy) [99], for example. Considering that green hydrogen can already be used in the existing refining installations, with no need for modification on existing plants, the only drivers for the economic viability of these initiative lie in the costs of electrolysers and related infrastructure; also, Technology Readiness Level is the same as for electrolysis technology currently commercially available (TRL 9) [100].

Table 12 Examples of projects exploring renewable hydrogen-based refineries

Name	Key stakeholders	Country	Description	
REFHYNE	Shell, Sintef, ITM Power, Thinkstep, Elementenergy	Germany	Launched in 2018, integrating a 10-MW PEM electrolyser into Shell's Rhineland Refinery in Wesseling, North Rhine-Westphalia. The electrolyser has entered operation in July 2021	[96], [101]
Green H_2 for Lingen refinery	bp, Ørsted	Germany	Construction of a 50-MW electrolyser for the production of green hydrogen at bp's refinery in Lingen (Lower Saxony), to replace 20% of the refinery's current fossil-based hydrogen consumption. The final investment decision on the project is expected to be reached in early 2022, with the start of operations expected by 2024.	[98], [102]
Green H_2 for Sarroch refinery	Enel Green Power, Saras	Italy	Construction of a 20-MW electrolyser powered by local renewable energy, to supply green hydrogen to the Saras refinery at the Sarroch industrial site in the province of Cagliari (Sardinia). a memorandum of intent was signed on February 2021.	[99]

2.1.2.3 Petrochemicals, synthetic fuels, ammonia and methanol

In the petrochemical sector, fossil fuel feedstocks are used to produce a range of "primary petrochemicals" which are the "building blocks" for a wide range of chemicals and products (Figure 4) – for example, plastics, fibres, solvents, inorganic chemicals and hundreds of other types of products. Two groups of primary petrochemicals are particularly important: *olefins* (principally ethylene, propylene and butadiene) and *aromatics* (benzene, toluene and xylenes). Petrochemicals are conventionally obtained from steam cracking of crude oil-derived feedstocks (naphtha) or from cracking of natural gas hydrocarbons, however it can also be produced by direct cracking of crude oil. The conventional process is a pyrolysis of hydrocarbons in a water vapour-based environment [32].

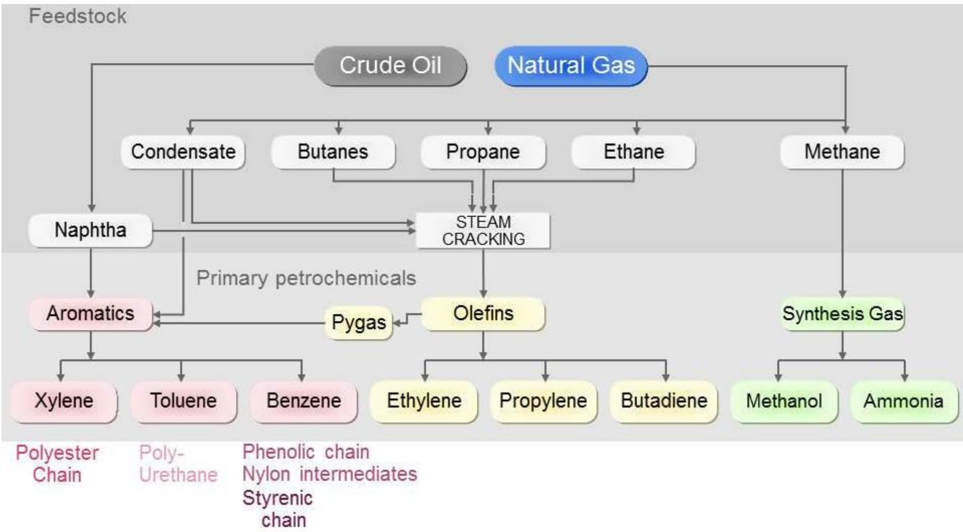


Figure 4 Conventional feedstock and primary petrochemicals [32], [103]

Ammonia and *methanol* are also particular important. Both are conventionally produced from syngas (a mixture of carbon monoxide and hydrogen) derived from natural gas or from coal gasification. Ammonia is primarily used in making fertilisers, methanol has a role as building block for other chemicals, including olefins as part of an alternative production route; both ammonia and methanol, however, could have a much wider role.

Clean hydrogen can contribute to the decarbonization of the production of these chemicals. In general, it can be referred to the term 'synthetic fuels' to define a range of hydrogen-based fuels obtained from syngas, which have conventionally been produced through chemical processes from a carbon-based source such as coal or natural gas (or nitrogen-based, in the case of ammonia). When synthetic fuels are produced using renewable electricity, they are sometimes called ‘synfuels’, ‘power fuels’ or ‘e-fuels’. This term usually includes the green version of hydrogen, synthetic gas (e.g., methane, propane) and synthetic liquid fuels and chemicals (e.g., methanol, diesel, gasoline, kerosene, ammonia, Fischer-Tropsch products). These hydrocarbons can then be further refined into different chemicals – including “primary petrochemicals”. The ability to turn electrical energy into chemical bonds creates new opportunities for liquid chemicals such as methanol and ammonia. These can be used as storage for electrical energy and help overcome the intermittency of renewable sources. They can raise interest also as liquid fuels: compared to hydrogen, their compression or cooling is much more affordable (liquid ammonia, at atmospheric pressure cooled to -33 °C, or pressurised at 9 bar at room temperature); they show a high volumetric energy density; they can be distributed in a more cost-effective way using the existing infrastructure (in carbon steel pipelines, rail cars, trucks and ships). In such a way, output commodity chemicals can serve both as means for energy storage as a fuel and of desired chemical products.

Hydrogen can be used in two main ways for the production of synthetic fuels. It can be produced through green electrolysis and used as feedstock for *thermochemical processes*. From this perspective, production of green synthetic fuels is based on three main processes: Fischer-Tropsch and methanol synthesis (for carbon-based products), and Haber-Bosch (for ammonia). Green production of synthetic fuels is less mature than conventional fossil syngas-based techniques: thermochemical processes in combination with renewable-electrolysis hydrogen in input are entering the early stages of commercialisation (TRL 8-9), with demonstration projects proving the techno-economic viability of the technology integration [104]–[106]. Projects have started to assess the use of green methanol and ammonia as fuels for the shipping sector – Maersk, for example, has signed on to such initiatives in Denmark.

An alternative pathway is represented by the so-called ‘Power-to-Liquid’ (P2L) or ‘Power-to-Chemicals’ (P2C) processes. These processes are called ‘*electrochemical*’ because they take in water and nitrogen/carbon dioxide and transform them directly into desirable commodity chemicals through the use of electricity from a renewable source, without the intermediate step of water electrolysis to generate hydrogen. Examples are to be found for ammonia production ($2N_2(g) + 6H_2O(g,l) \leftrightarrow 4NH_3(g) + 3O_2(g)$) [107] and co-electrolysis of CO_2 and H_2O for syngas production. Thermochemical processes usually require high temperatures and pressures in the reacting environment (e.g. 450°C and 200 bar for Haber-Bosch ammonia synthesis: $N_2(g) + 3H_2(g) \leftrightarrow 2NH_3(g)$); replacing pressure with voltage in an electrochemical route to drive conversion, the thermodynamics of the system become favourable without the use of elevated pressures; voltage may also help to accelerate the kinetics with a suitably designed catalyst [107]. Although still in a very early stage of market readiness (e.g., TRL 2-5 for syngas production by co-electrolysis of CO_2 and H_2O to ethylene [108]), electrochemical processes may come with a relevant economic potential.

Table 13 Examples of small- and large-scale research and pilot projects exploring renewable hydrogen-based chemicals

Name	Key stakeholders	Country	Description	
Leuna hydrogen site	Linde	Germany	Pilot plant for RES-based electrolysis in the city of Leuna, to demonstrate the techno-economic feasibility of green H_2 value chain, including production of low-emission chemicals and fuels.	[104], [109]
Liquid Wind	Axpo, COWI, Carbon Clean Solutions, Haldor Topsoe, Nel Hydrogen, Siemens Energy	Sweden	Wind power-fed H_2 electrolyser and CO_2 capture (CCU) to produce green methanol (eMethanol). First facility is expected to start operation in 2024, up to 500 standardised facilities are planned to be developed internationally by 2050.	[110], [111]
Carbon2Chem	Thyssenkrupp	Germany	Target is to demonstrate long-term stability of the conversion of steel mill process gases into chemical products. A pilot plant started operation at steel production site in Duisburg in March 2018, to produce ammonia, methanol and higher alcohols from steel-mill process gases (containing CO_2), together with H_2 produced by a 2-MW alkaline water electrolyser. The project is now in its second phase, aiming to investigate market upscale and transferability to other industries (e.g. cement and lime producers, waste incineration plants). The second phase of the project will also serve to bring the project to market readiness. Funds have been earmarked until 2024.	[112]
Circlenergy (green methanol)	Carbon Recycling International (CRI)	Iceland	EU funded project, for the conversion of CO_2, extracted from the nearby geothermal power plant together with H_2 from by-product/waste gas or produced from RES-based water electrolysis (alkaline), to produce renewable *methanol*. With production started in 2012, the project is currently in Phase 2, with expected conclusion by mid-2021, focusing on scaling up the technology and attracting investment to build and operate new plants.	[113], [114]
Green ammonia Esbjerg	Maersk, DFDS, et al.	Denmark	A Memorandum of Understanding (2021) has been signed in support to the construction of a facility for the production of power-to-X green *ammonia* from surplus power from offshore wind turbines. Ammonia will be used as green fuel in the shipping industry and as green fertilizer in the agriculture sector. Excess process heat will be used to provide heating to one-third of the local households in Esbjerg. The facility is planned to start producing green ammonia in 2026.	[115], [116]
Green ammonia Yara	Yara, Statkraft, Aker Horizons	Norway, Australia, Netherlands	Agreement aiming to establish Europe's first large-scale green *ammonia* project in Yara's existing ammonia facility in Porsgrunn (Norway), switching the source of hydrogen from hydrocarbons to renewable-powered water electrolysis. RES electricity for the plant would come from the Norwegian power grid (being 98% hydroelectric). Shipping, agriculture and industrial applications will be target sectors for ammonia. The project could be realized within 5-7 years (2026). Pilot programs are already underway in other countries: in Australia (Pilbara) for ammonia synthesis based on solar power; in the Netherlands (Sluiskil), for green ammonia from wind power.	[117], [118]

2.1.3 Heat

Heat is a fundamental energy form, which is used for a multitude of purposes. Being produced mainly by combustion of fossil fuels, heat generation represents one of the main areas for decarbonisation. Still, the challenge of its decarbonisation is particularly complex, due to a series of reasons. The wide range of applications – residential, commercial, industrial – make heat requirements very diverse, ranging from dispersed low temperature space heating to large high-temperature industrial loads, with no one solution capable of meeting all heat demands. Heat demand requires highly flexibility of supply, due to its daily and seasonal variation. Fossil heating fuels provide this flexibility at a lower cost than low-carbon alternatives less competitive and risk increasing energy poverty.

In terms of hydrogen applications, technologies have been investigated also for the heat sector. Two applications are mainly relevant for heat production: *hydrogen boilers* and *Combined Heat and Power* (CHP) systems. Existing *hydrogen boilers* (with particular reference to the domestic ones) can run on mixtures with hydrogen at low levels (up to approx. 20%), without substantial re-design necessities [119]. Boilers fully running on hydrogen require more relevant adjustments – mainly on the burner – and some prototypes have already been tested and demonstrated. Even if technologically ready (TRL 7), hydrogen boilers aren't yet being manufactured for installation; this is because gas networks don't currently contain hydrogen. An interesting idea of product for domestic applications is the "hydrogen-ready" boiler by Worcester Bosch [120], which represents a good trade-off between the commercial readiness of the technology and the current lack of required hydrogen infrastructure. Such a boiler is designed to run effectively on natural gas, but it can simply be converted to hydrogen in the future, without the need for an entirely new heating system ("taking around an hour and involving the change of a couple of components" [120]), if hydrogen gas becomes reality. The prototype has been presented in the UK in 2019, with the country considering a gradual shift of the national natural gas grid to 100% hydrogen over the next years. In such a context, Worcester Bosch has called on the UK government to mandate hydrogen-ready boilers for new installations by 2025 [121]. Another manufacturer in the field of hydrogen boilers is Baxi: they are developing and testing boilers running on 100% hydrogen, with their parent company, BDR Thermea Group, having a hydrogen boiler on a field trial in Rozenburg, Netherlands [122]. Both Baxi and Worcester Bosch have installed hydrogen-burning boilers, in specially built demonstration houses as part of the UK Government-funded 'Hy4Heat' programme, which is also supporting the development of hydrogen-ready gas cookers, fires and gas meters [123].

While hydrogen boilers aren't available yet to buy, combined heat and power (CHP) systems already make use of hydrogen, by means of combustion devices (internal combustion engines or Stirling engines) or fuel cells. Fuel cell CHP are a reality on the market (TRL 9), although they are currently expensive. PEMFCs and SOFCs are typically used for domestic and small commercial sector, where they hold the largest market share for micro-CHP systems; SOFCs, PAFCs and MCFCs are typically used for larger commercial systems [33]. Fuel cell micro-CHP could be cost competitive with other heating technologies as long as costs of traditional fuel become dominant; such a scenario is however likely to happen no earlier than 2050 – according to Baldino et al. hydrogen heating technologies will still be more expensive by that time [124]. A selection of hydrogen fuel cell micro-CHP products is provided in Table 14.

Table 14 Hydrogen fuel cell micro-CHP (selection)

Name	Manufacturer	Country	Since	Cost	Additional information	
BlueGEN	SOLIDpower	Italy, Germany	2012	10,000€ – 25,000€	SOFC, 85% combined efficiency	[40], [125]
Vitovalor	Viessmann	Germany	2014		PEMFC, 90% combined efficiency	[40], [126]
Elcore 2400	Elcore	Germany	2014		PEMFC, 99% combined efficiency	[40]

In industry, hydrogen can also be an option to provide heat, driven by the need to decarbonize the sector; however, long equipment lifetime and investment cycles in conservative sectors, as well as competition with electric alternative heating technologies, may make the diffusion slow. Hydrogen could replace natural gas as a fuel for burners and furnaces; it could also be introduced into several high-temperature industries including cement and aluminium, although commercialisation is not expected before 2030 [33].

2.1.4 Power system

To complete the overview on hydrogen technology applications, it is important to mention the potential for the power sector. Hydrogen being an energy carrier, can be used to store and produce electrical energy during critical moments for power systems, helping strengthen their resilience and flexibility, which today are more and more required due to the increasing share of intermittent renewable energy sources installed (solar and wind, in particular).

From this perspective, the so-called 'Power-to-Gas' (P2G) processes are particularly relevant. They show interesting potential for 're-electrification' and 'sector coupling': by combining production, storage and consumption within the same system, excess electrical energy is converted into storable chemical energy in the form of hydrogen. Surplus electricity is used to power hydrogen production via water electrolysis. The resulting gas may then be stored and used when required (for instance by a fuel cell or hydrogen turbines) or undergo further processing to produce grid-compatible methane, also known as synthetic natural gas (SNG). Equally, it can then be converted back to electricity or used to displace demand for natural gas in the heating (and power) sector, or for transport.

Benefit from hydrogen to power systems can be multiple. Hydrogen is able to provide large-scale long-term energy storage, thanks to the fact that its chemical properties do not degrade over time (differently from batteries); with changes to turbine design, hydrogen can also be burnt in existing gas turbines, run currently on natural gas; fuel cells are flexible, controllable, typically co-located with demand (minimising losses in transmission and distribution). All the above leads to think of hydrogen as a possible option to increase the matching between electricity demand and renewable energy production. It can be used for shifting demand peaks and for providing ancillary services (e.g., reserve capacity for frequency regulation).

2.2 Production

Hydrogen can be produced in different ways. Typically, a colour is associated to it according to the production process. Table 15 summarize the existing hydrogen categories based on colour.

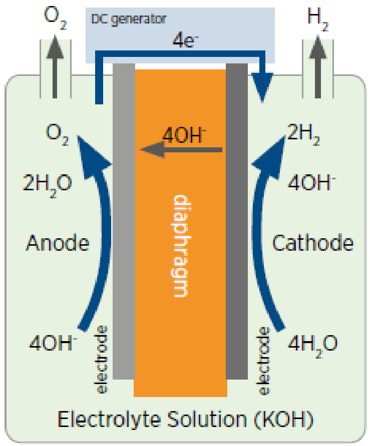
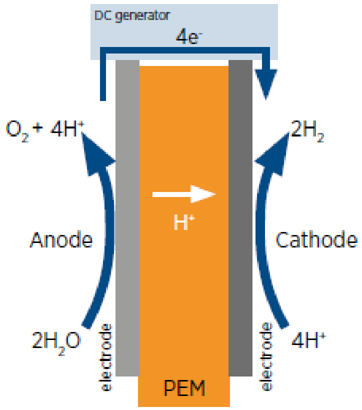
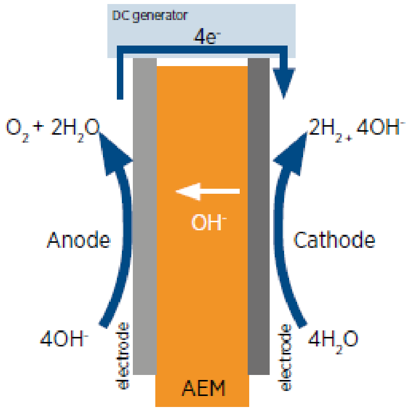
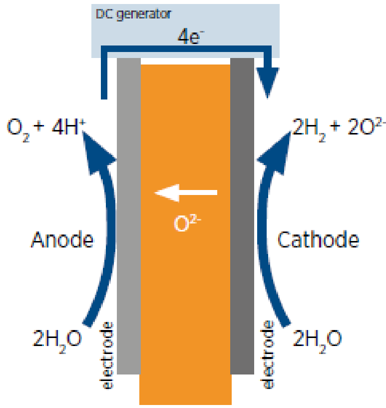
Table 15 Categories of hydrogen production methods (hydrogen 'colours') [127]–[129]

Name	Definition
Grey	Produced through steam methane reforming (SMR) of natural gas, with no control of CO_2 emissions – thus released in the environment.
Black, Brown	Produced through gasification of coal - bituminous (black) and lignite (brown). No control of CO_2 emissions – thus released in the environment.
Blue	Produced from fossil fuel, with sequestration of CO_2 emissions, in order to result carbon neutral.
Turquoise	Produced through thermal splitting of methane via methane pyrolysis. Carbon is removed in a solid form instead of CO_2 gas.
Green	Produced through water electrolysis using renewable electricity, to produce hydrogen gas and oxygen. The process is not associated with CO_2 emissions during the production process.
Pink, Red, Purple	Produced through water splitting using nuclear energy – power for electrolysis (pink); heat for high-temperature catalytic splitting (red); power and heat for combined chemo-thermal electrolysis (purple)
Yellow	Produced through water electrolysis using mixed electricity from renewable energies and fossil fuels (grid electricity)
White	Naturally occurring geological hydrogen found in underground deposits or hydrogen as merely a waste product of other chemical processes (by-product)

Almost the totality of hydrogen produced today (99%) is fossil-based. Out of 90 Mt of H_2 produced in 2020, 59% was sourced from reforming of natural gas ('grey' H_2) and 21% from coal gasification ('black' or 'brown' H_2). Almost all the remainder (21%) was by-product H_2 produced in facilities designed for other products (e.g., refineries, production of chlorine) [130]. Grey and black/brown processes are associated with high levels of CO_2 emissions; however, the need for decarbonization is pushing the research towards new production methods. Several emerging hydrogen production routes are at earlier stages of development today: they range from high-temperature steam electrolysis, solar water splitting (artificial photosynthesis), thermochemical processes in association with nuclear or concentrating solar power plants to biological hydrogen production [131]–[135].

When hydrogen production does not generate CO_2 emissions, it is called renewable or '*green hydrogen*'. Recently, the option at the centre of the international debate as source of green hydrogen is water electrolysis based on electricity from renewable energy power plants (e.g., solar PV, on- or offshore wind). Electrolysers, the systems where water is split into hydrogen and oxygen by means of electricity, consist of two electrodes separated by an electrolyte, the media responsible for transporting the generated chemical charges (anions (-) or cations (+)) from one electrode to the other. Four different categories can be distinguished based on the electrolyte and temperature of operation, which in turn will guide the selection of different materials and components: Alkaline Water Electrolysers, Proton Exchange Membrane (PEM) and Anion Exchange Membrane (AEM) and Solid Oxide Electrolytic Cells (SOEC). Table 16 shows the main features of the four types of water electrolysers [136].

Table 16 Characterisation of the four types of water electrolysers [136]

	Alkaline	**PEM**	**AEM**	**Solid Oxide**
Structure and Reactions	 Anode: $4OH^- \leftrightarrow 2H_2O+O_2+4e^-$ Cathode: $4H_2O+4e^- \leftrightarrow 2H_2+4OH^-$	 Anode: $2H_2O \leftrightarrow O_2+4H^++4e^-$ Cathode: $4H^++4e^- \leftrightarrow 2H_2^-$	 Anode: $4OH^- \leftrightarrow 2H_2O+O_2+4e^-$ Cathode: $4H_2O+4e^- \leftrightarrow 2H_2+4OH^-$	 Anode: $2O^{2-} \leftrightarrow O_2+4e^-$ Cathode: $2H_2O+4e^- \leftrightarrow 2H_2+2O^{2-}$
Operating temperature [°C]	70-90	50-80	40-60	700-850
Operating pressure [bar]	1-30	< 70	< 35	1
Electrolyte	Potassium hydroxide (KOH) solution + ZrO2 stabilized separator with sulphide (PPS) mesh	Perfluorosulfonic acid (PFSA) membranes	Divinylbenzene (DVB) polymer support with KOH or NaHCO3	Yttria-stabilized Zirconia (YSZ)
Electrode / catalyst (oxygen side)	Nickel coated perforated stainless steel	Iridium oxide	High surface area Nickel or NiFeCo alloys	Perovskite-type (e.g. LSCF, LSM)
Electrode / catalyst (hydrogen side)	Nickel coated perforated stainless steel	Platinum nanoparticles on carbon black	High surface area nickel	Ni/YSZ

Information about market readiness of the single electrolyser types are provided by IRENA and Staffel et al. and IEA [33], [136], [137]. Alkaline electrolysers are the incumbent technology (commercially available, TRL 9), with a 100-year history. They are the most mature, durable and cheapest technology. A direct voltage current is applied between an anode and a cathode submerged in a liquid alkaline electrolyte, typically a highly concentrated potassium hydroxide solution (KOH). The electrodes and produced gases are physically separated by a porous inorganic diaphragm (also called a separator) that is permeable to the KOH solution. Units can be several MW in size but have a limited operating range (from a minimum of 20–40% to 150% of design capacity) and slow start-times. With growing interest in integration with renewable energy, development aims to improve its dynamic operation. As alkaline electrolysers are the most mature electrolysis technology, they dominate the market, especially for large-scale projects (both already operational and announced). However, many new projects are now opting for PEM designs.

PEM electrolysers are rapidly reaching maturity They were introduced in the 1960s and became commercialised in the last decade (TRL 9). They have faster response and start-up and a wider dynamic range (0–200%), more suitable for intermittent power supply, and therefore are of particular interest for power-to-gas applications in association with renewable energy. They have higher power density (and thus are smaller) due to their solid plastic electrolyte, and have a high-pressure output (e.g. 70-80 bar) reducing the energy required for downstream compression. However, capital costs are currently approximately twice those of alkaline, and cell lifetimes need to improve. AEM electrolysers have similar system design concepts to that of PEM electrolysers. Due to the low maturity of this technology, however, AEM electrolysers are still limited to a much narrower range of power input in comparison to PEM electrolysers.

SOEC use a solid ceramic electrolyte and operate at very high temperatures (700-900°C). They are the best in terms of efficiency (more than $80\%_{LHV}$), but they are still transitioning from the laboratory to the demonstration phase (TRL 6-7). Projects involving high-efficiency SOECs are beginning to be announced, nearly all of them in Europe; however, electrolyser users remain divided over whether the operational benefits of PEMs (flexibility) and SOECs (efficiency) are worth the additional costs compared with alkaline electrolysers.

Examples of projects currently under development in the world are reported in Table 17, showing how target sizes are increasing year after year. In March 2020, a 10 MW project started operation in Japan, and a 20-MW project in Canada is under construction. Plus, there have been several announcements for developments in the order of hundreds of MWs that should begin operating in the early 2020s. This trend is confirmed by the targets set by EU in their research and innovation funds: the call "Horizon 2020 Green Deal", launched in 2020, has included the development and demonstration of a 100 MW electrolyser within the areas of investigation, for upscaling the link between renewables and commercial/industrial applications [138].

Although there is little dedicated hydrogen production via water electrolysis today, electrolysers are not a new technology. As reported by van Wijk and Chatzimarkakis, "today's worldwide electrolyser installed capacity is operated mostly for chlorine production. By electrolysis of salt dissolved in water, chlorine is produced from the salt, but at the same time hydrogen is produced from water as a by-product, partly used to produce heat or steam. Globally, a large part of these chlorine electrolysers has been produced by European companies and, therefore, the electrolyser industry and supply chain in Europe have a strong world market position today. Especially the European industry delivers advanced high-quality electrolysers which meet high safety standards. This is a good starting position to build a leading water electrolyser industry in Europe" [139]. Availability of data, given the confidentiality and the retention of competitive advantage, makes it difficult to provide cost estimates for electrolysers. In contrast to manufacturer-based cost data, which are available to a limited extent, more data from previous studies and research are available. From this perspective, two references are helpful. The focus is on Alkaline and PEM electrolysers, being AEM and SOEC still lab- / demo-scale, with a longer way to go, making cost projections highly unpredictable. A technical report within the Hydrohub GigaWatt Scale Electrolyser project [140] determined Total Installed Costs (TIC) for a greenfield GW green hydrogen plant in a port area in the Netherlands for Alkaline and PEM electrolyser as for 2020, to 1400 €/kW and 1800 €/kW respectively.

This includes indirect costs and owner's costs (expenses for engineering, project management, construction supervision, and commissioning) as well as contingency (+30%) for investment decision. Saba et al. [141] performed a comparison of cost studies over the previous 30 years, and projections of these costs for electrolyser systems. As for Alkaline technology, the spread of the estimations for the future investment costs (year 2030) are narrowed towards the values of 787-906 $€_{2017}/kW_{HHV\text{-}Output}$; for PEM technology, the spread is 397-955 $€_{2017}/kW_{HHV\text{-}Output}$.

Table 17 Hydrogen electrolysers (selection)

Name	Manufacturer	Country	From	Additional information	
Fukushima Hydrogen Energy Research Field (FH2R)	Toshiba	Japan	2020	Connection of largest-class alkaline electrolyser project (10 MW). Hydrogen is intended to power stationary hydrogen fuel cell systems and fuel cell vehicles.	[142]
Bécancour PEM electrolyser	Air Liquide	Canada	2021	Largest PEM electrolyser in the world (20 MW) inaugurated end Jan-21 in Bécancour, Quebec, for North American industrial use and mobility markets.	[143]
Arrowsmith Hydrogen Project	Infinite Blue Energy	Australia	2022	Australian company Infinite Blue Energy secured funding for a 52.2-MW project near Perth, to begin operations in 2022.	[142], [144]
GrInHy	Sunfire	Germany	2022	EU H2020 project, implementing High-Temperature Electrolysis of the MW-class, based on Solid Oxide Electrolysis Cells (SOEC), using iron-and-steel industry heat at Salzgitter Flachstahl factory. A prototype will produce 200 Nm^3/h of hydrogen at nominal power input of 720 kW.	[145]
MULTIPLHY	Sunfire	Netherlands	2024	EU H2020 project, targeting the first commercial-scale use of high-temperature solid-oxide electrolysers at Neste's biofuel refinery in Rotterdam. The 2.6-MW plant will enter operations by end of 2024.	[146]

Although green hydrogen is a necessity for decarbonization, the reality is that no substantial volumes of green hydrogen are expected to be available any time soon [147]. The need of a transition phase is recognized by the EU Commission in 2020 in the 'EU Hydrogen Strategy' [148]: during such a phase, electrolysis will gradually increase over time, running in parallel to other sources of hydrogen. At the moment, hydrogen already makes sense for storing excess electricity from renewable sources at a medium- or long-term scale, which otherwise would be curtailed and thus wasted; however, such hydrogen amount won't be enough to cover the huge demand that is needed to decarbonise the energy and productive systems. Replacing fossil fuel-based energy sources with renewables for electricity generation is expected to take at least until 2030. In the meantime, other forms of low-carbon hydrogen are therefore needed to rapidly reduce emissions and to support the development of a viable market. Such alternatives include the so-called 'blue hydrogen', sourced from conventional natural gas or coal technologies in combination with carbon capture and storage (CCS). 'Turquoise hydrogen', obtained from gas pyrolysis and the generation of carbon in solid form instead of CO_2, is also included here.

According to IEA [137], "*blue hydrogen* is still the main route for low-carbon hydrogen production because production costs are lower than for other low-carbon technologies like water electrolysis". Table 18 describes the conventional methods for the production of hydrogen from fossil sources and the required contribution from CCS to make it blue hydrogen. Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) for natural gas, and gasification for coal. By SMR, providers can easily capture about 60% of the total carbon by separating the CO_2 from the hydrogen; the additional must be extracted from the exhaust gas, which is relatively expensive today, allowing for up to 90% total capture rate. By ATR, all the CO_2 is contained in the reactor at elevated pressure enabling high-capture percentages (up to 95% of CO_2 emissions). Coal gasification allows for a relatively easy capture of CO_2, like the ATR plant. However, the coal gasification plant emits about four times more CO_2 per kg of hydrogen produced than the ATR plant, increasing the amount of carbon that must be transported and stored.

Table 18 Conventional H_2 production processes and role of CCS for blue H_2 [149]–[151]

Technology	Description	Role of CCS
Steam Methane Reforming (SMR)	SMR combines *natural gas* and pressurised steam to produce syngas, which is a blend of carbon monoxide and hydrogen. SMR reaction is endothermic, it operates in a range of 500-900°C for which heat is generated via the burning of natural gas.	Up to 60% of the total CO_2 can be separated from H_2 by the SMR plant itself; the additional part must be extracted from the exhaust gas, allowing for up to 90% total capture rate.
Autothermal Reforming (ATR)	ATR combines oxygen and *natural gas* to produce syngas, using an endothermic and exothermic reaction and creating a heat balance. The process temperature is between 900-1,150°C. ATR requires oxygen as input, however it does not require the burning of natural gas for heat input. ATR technology is typically used for larger plants compared with SMR technology.	All the CO_2 is contained in the reactor at elevated pressure enabling high-capture percentages (up to 95% of CO_2 emissions).
Coal gasification	Gasification produces hydrogen by reacting *coal* with oxygen and steam.	Relatively easy capture of CO_2, however emissions per kg of H_2 produced are about four times higher, increasing the extra effort.

According to Dickel, "many world-scale SMR/ATR plants are successfully in operation, and the technology is in its mature status. The resulting relatively pure CO_2 needs to be collected and transported to be safely sequestered in geological structures. While carbon *capture* technology is available at large capacities and there are no principal obstacles to building them, the core issue for decarbonising natural gas via SMR/ATR is *sequestering* large volumes of CO_2 produced as a by-product. Some time will be needed to develop the CO_2 sequestration infrastructure, the necessary rules and regulations, and economic schemes" and business models [151]. In other words, each stage of the CCS has been technically available and used in different commercial sectors for years, and there exist solutions which are individually mature already (TRL 8-9); however, the joint application of these technologies to CO_2 emission sources is still too penalizing in energy and economic terms, thus limiting their application on a large scale [152], [153]. According to IEA, six projects, with a total annual production of 350 kt of low-carbon hydrogen, were in operation at the end of 2019, and more than 20 new projects have been announced for commissioning in the 2020s, mostly in countries surrounding the North Sea [154].

Table 19 Blue hydrogen projects (selection)

Name	Stakeholder	Country	From	Additional information	
Adriatic Blue	Eni	Italy	2022	By taking advantage of the combination of depleted offshore gas deposits and existing infrastructures, Ravenna area will provide a secure CO_2 storage site for the production of blue hydrogen. Demonstration start-up is expected in 2022 and full start-up in 2026.	[155], [156]
CS licence	Eni	United Kingdom	2025	Licence awarded to Eni for the repurpose of depleted hydrocarbon reservoirs in the East Irish Sea, close to Liverpool, to permanently store CO_2 captured in northwest England and northern Wales. After feasibility studies, Eni will make the final investment decision by 2023, and start-up by 2025.	[157]
H-vision	Port of Rotterdam	Netherlands	2026	In the port of Rotterdam, blue H_2 will be produced from residual gases from refineries, supplemented with natural gas off the grid. CO_2 released during the process is captured and transported to depleted gas fields under the North Sea or used as feedstock (e.g., for methanol). The first installation will start supplying industrial parties in Rotterdam with hydrogen in early 2026.	[158], [159], [160]
HyNet North West	Progressive Energy, Cadent	United Kingdom	2026	H_2 production from natural gas including the creation of UK's first CCS infrastructure for Northwest England and North Wales. H_2 and CCS infrastructure are planned to enter operations by 2026, with plans on extension to other UK areas by 2050.	[161]
H2Teesside	BP	United Kingdom	2027	Located in Teesside (North-East England), the project would combine CCUS with H_2 production, with initial 500 MW of blue H_2 capacity in production by 2027 and up to 1 GW additional installed capacity to be deployed by 2030.	[162]
Northern Lights CCS	Equinor, Shell, TotalEnergies	Norway	2024	Development of CCS infrastructure in Western Norway, to transport CO_2 from capture sites by ship to a terminal for intermediate storage, before being transported by pipeline for permanent storage in a reservoir 2.6 km under the seabed. Phase 1 of the project will be completed in 2024 with a capacity up to 1.5 Mt/year of CO_2.	[163], [164]

The other option for low-carbon hydrogen generation is *turquoise hydrogen*. Pyrolysis splits methane CH_4 into H_2 and C molecules with the addition of energy. Dickel reports: "Unlike electrolysis or SMR, pyrolysis is a dry process, it does not require water. Carbon is produced as a solid by-product, which may be used, for instance, for tyre or ink production and in any case can be transported by truck or rail and commercially used or easily deposited onshore without hazard or much cost." [151] Several pyrolysis technologies are being explored. Plasma-based decomposition is the closest process to commercialization (TRL 7-8). The first commercial scale methane pyrolysis plant is the Olive Creek Plant in Nebraska, operative at full production capacity by 2021, with plans to expand to South Korea [152], [165], [166]. Processes targeting the hydrogen production through thermal or catalytic decomposition are at early pilot stage or even at laboratory stage (TRL 3-4). As an example, a small-scale pilot plant using a catalytic-assisted fluidised bed is supposed to become operational by Hazer in Perth (Australia) in 2021 [152], [165]. As reported by Dickel, "the drawback" of turquoise hydrogen "is that the technology is in its early days and needs substantial scaling up". This may imply only a marginal role for methane pyrolysis in the achievement of early decarbonization by 2030 [151].

2.3 Transport & Distribution

As for other commodities, if the point of use is not located in the same place as the point of production, the problem of delivery rises. A series of options are available for hydrogen transport and distribution, in terms of hydrogen ways and forms of delivery. Three ways of delivery can be identified: pipelines, trucks and ships. Moreover, hydrogen can be transported as a compressed gas (GH_2); as a liquid (LH_2) or bonded to various 'carriers', such as ammonia, methanol or Liquid Organic Hydrogen Carriers (LOHC). The choice of the suitable combination is affected by different factors, such as the hydrogen volumes to be displaced, the expected fluctuation (rather, stability) in the demand flow, the delivery distance, the geography/terrain to cover and the end-use quality requirements on delivered hydrogen.

Transporting compressed gaseous hydrogen via *pipelines* has the highest long-term economic potential when large volumes of hydrogen are demanded [22]. It also seems an interesting solution for the conversion of electricity from large-scale solar and wind power plants, usually located far from the hydrogen consumption point. A cost comparison between the natural gas interconnector Balgzand Bacton Line BBL (2006) and the high-voltage direct-current submarine power cable BritNed (2011) suggests that transport and storage costs for hydrogen are 10-20 times cheaper than for electricity. Both projects required roughly the same investment for their construction (approx. 500-600 million euros) and both connect the Netherlands and the United Kingdom; however, BritNed only has a capacity of 1 GW, whereas the BBL pipeline has a total capacity of more than 20 GW [167], [168]. In general, a fundamental difference between electricity transport by cables and hydrogen transport by pipelines is the capacity of the infrastructure. An electricity transport cable has a capacity between 1-2 GW, while a hydrogen pipeline can have a capacity between 15 and 30 GW. Besides, transporting electricity via cables is subject to losses, while hydrogen transport by pipelines is not expected to have losses [169].

Different options have been proposed when it comes to pipeline-based hydrogen infrastructure. *New hydrogen pipelines* can be built as part of a dedicated grid, and the technology is commercially proven (TRL 9). To confirm this, American manufacturer Air Products builds, owns and operates systems since 1970 (the reader can refer to [170] for more details about typical materials, geometries and encountered challenges), and dedicated hydrogen pipelines were built in Europe much longer time before – for example, the grid in Rhine-Ruhr, long 240 km and still in operation, dates back to 1938 [171]. Table 20 provides an overview of the existing hydrogen pipeline grids in Europe, which represent a total length of at least 1400 km. Research and lessons learned from first hydrogen projects show that dedicated hydrogen pipelines do not differ significantly from natural gas pipelines; capital costs for newly built hydrogen pipelines are estimated to be 10-50% more expensive than its natural gas counterpart, though region-specific factors such as typical dimensioning of pipes affect this range [169].

Table 20 Existing hydrogen pipeline grids in Europe [171]

System	Country	Length	Manufacturer	Since	Pressure
North-West Europe pipelines connecting sea ports (Rotterdam, Antwerp, Zeebrugge, Ghent) and industrial sites (Charleroi, Waziers)	Belgium, France, Netherlands	966 km	Air Liquide	mid-1980s	100 bar
Rhein-Ruhr Pipeline from Castrop-Rauxel to Leverkusen, through Chemiepark Marl	Germany	240 km	Air Liquide (operator)	1938	11/23/300 bar
Leuna-Merseburg	Germany	100 km	Linde	n.a.	20/25 bar
Europoort	Netherlands	50 km	Air Products	n.a.	
Chemical Industry	Sweden	18 km	n.a.	n.a.	5/28 bar
ICI Teesside, Yorkshire	United Kingdom	16 km	n.a.	mid-1970s	50 bar

The use of existing natural gas pipelines for the delivery of gaseous hydrogen is another interesting case. A first step in this direction is *blending hydrogen into natural gas* stream. This could be an option in the very early stages, especially at distribution level, as demonstrative actions to gain acceptance from the customer base. This is what may justify ongoing initiatives such as SNAM's experiment of introducing a share of hydrogen – 5% in volume first, then 10% – into the Italian gas transmission network. The goal was to supply two industrial companies in Italy (Contursi Terme, Salerno), a pasta factory and a mineral water bottling company [172], [173]. However, blending will not significantly contribute in the long run to the creation of a solid hydrogen infrastructure, mainly for two reasons: first, at the moment it is difficult and extremely expensive to separate hydrogen from the gas stream at the grid exit on an industrial scale; second, blending H_2 with CH_4 has narrow technical limitations. It is generally accepted that natural gas-consuming devices and pipeline operation are safe with up to 5-15% of H_2 content (in volume), after which the risk of failure in pipeline materials increases, and replacing the existing natural gas compressors and their drives with hydrogen-specific ones becomes necessary [151], [174]. At the moment, the market readiness of blending can be assessed on TRL 7 (pre-commercial demonstration, with solution working in expected conditions).

Full *reassignment of existing natural gas pipelines* seems therefore a more interesting case for investigation. Specific adjustments and protective measures are required in this case, in order to minimize material failure due to hydrogen-induced damage. Hydrogen-induced material fracturing (a process called 'hydrogen embrittlement') is caused by hydrogen permeation into the crystalline steel structure and leads to the degradation of the material's mechanical properties, which are required for correct pipeline utilization. Therefore, as reported by Cerniauskas et al. [22], four different options can be identified in literature. The first consists of the application of an inner coating to chemically protect the steel layer. The second consists of implementing an additional pipeline within the already existing one. The third is the admixture of inhibitors to the hydrogen stream. The fourth option is represented by the use of existing NG pipelines with no structural modifications, in combination with adjusted operational strategies and maintenance activities (examples of adjustments are: minimization of pressures fluctuations in order to prevent initial crack formation; regular monitoring of crack width using PIGs). To the author's best knowledge, only two demonstration projects are to be reported to date, which leads to associating a market readiness level of TRL 7. The first one consists of the conversion of the 12-kilometre-long pipeline between Dow Benelux and Yara, in Norther Netherlands, the other one regards the conversion of an 11-km-long pipeline near Lingen, in Lower Saxony, Germany – the reader refer to Table 21 for further details.

Table 21 Natural Gas reassignment projects

Name	Stakeholder	Country	Since	Additional information	
Dow Benelux - Yara	Gasunie	Netherlands	2018	12-kilometre-long pipeline entered operations in 2018. The project is in line with the goal of creating a Northern Netherlands' hydrogen infrastructure by 2025 (169 km overall: 29 km newly built, 140 km converted from existing parallel gas infrastructure) and a Dutch hydrogen backbone by 2030 (1,150 km). Triggered by the earthquakes in 2018, the Netherlands decided to close the Groningen Field (Europe's largest onshore natural gas field) by 2022 and to transition away from their role as leading European natural gas economy.	[175], [176], [12]
GET H2 Nukleus - Lingen	BP, Evonik, Nowega, OGE, RWE	Germany	2023	The conversion of the 11-kilometre-long pipeline is part of a model test to demonstrate the pipeline's suitability for hydrogen at the maximum operating pressure and the expected change in operating load. Subsequently, three further lines in the project are to be tested using the same procedure. All this lies within the framework of the 'GET H2' initiative, targeting the operation of 130 km converted gas pipelines by 2023 ('Nukleus' stage of the project) and the extension of this hydrogen infrastructure by 2030.	[177], [178]
H2 Startnetz	FNB Gas	Germany	2030	Plan of the national association of gas pipeline operators to create a 1,200-kilometre grid by 2030, connecting consumption centres in North Rhine Westphalia, Lower Saxony and Southern Germany to production sites in Northern Germany. About 1,100 km would come from reassigned NG pipelines, while 100 km would be built anew.	[179]

As said, pipelines for gaseous hydrogen are the most economically viable transport method when a very high energy transportation capacity is demanded; however, when pipelines do not apply or when it is required to bridge the development to a full pipeline network, the other ways of delivery come into play.

Trucking is an attractive option for short and medium range distances. Tube trailers and liquid tankers are the most mature solutions (TRL 9) – examples of manufacturers currently on the markets are: Calvera [180], Linde [181]. *High-pressure containers*, or 'tube trailers', consist of pressure vessels designed to store gaseous hydrogen (GH_2) at a rated pressure(200 or 500 bar) , packaged in a container, and mounted on a trailer to transport the compressed hydrogen gas [182]. They are available in different pressure vessel types, with different configuration for vessel package. In general, they are typically associated to the last leg of hydrogen delivery, the distribution part, especially in connection with the hydrogen supply for hydrogen refuelling stations (HRSs) for the mobility sector [182]. Figure 5 shows the schematic representation of tube trailer delivery pathway. The hydrogen produced at a central production plant may be transported via transmission pipeline to a distribution terminal, where hydrogen is compressed and loaded into pressure vessels mounted on a trailer (tube trailer) for trucking to HRSs. The tube trailer with the hydrogen payload is then transported from the terminal to an HRS, where it is swapped with the onsite (empty) tube trailer. The tube trailer configuration and loading pressure influence the hydrogen payload, thus the number of deliveries to HRSs.

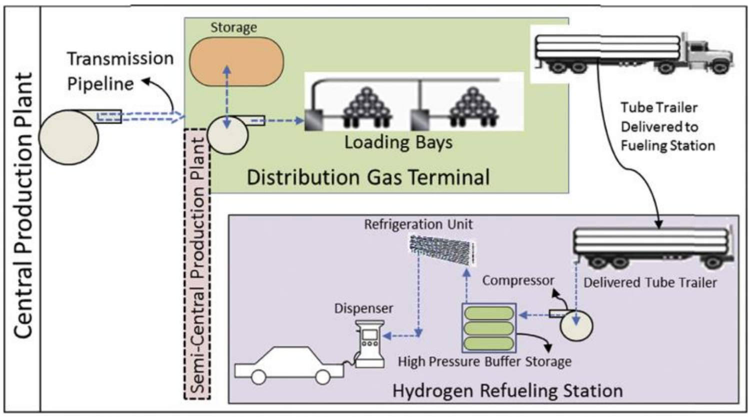


Figure 5 Schematic representation of the hydrogen tube trailer delivery pathway [182]

Solutions for *liquefied hydrogen* (LH_2) consist of super-insulated, cryogenic tanker trucks or 'liquid tankers'. Over longer distances, trucking liquid hydrogen is more economical than trucking gaseous hydrogen because a liquid tanker can hold a much larger mass of hydrogen than a gaseous tube trailer [183]. To have an idea, the reader can consider that a reference value of mass density for liquid H_2 is 44.4 kg/m^3 (at 3 bar and -253°C), while the same for gaseous H_2 spans between 23.7 kg/m^3 (at 350 bar and 20°C) and 38.7 kg/m^3 (at 700 bar and 20°C) [184]. However, the liquefaction process is very energy-intensive, it consumes in the range of 17 % of hydrogen HHV [185], and hydrogen boil-off during transport (0.3%-3%) may even increase energy losses [186]. As an alternative for road transport, *liquid organic hydrogen carriers* (LOHC) are indicated – methanol can fall within this category. Such a transport integrates a two-step cycle, whose ground principle is the reversible hydrogenation/dehydrogenation of carbon double bounds (as reported in Figure 6): (1) loading/storage of hydrogen (hydrogenation) into the LOHC molecule and (2) unloading/release of hydrogen (de-hydrogenation). During the storage period, hydrogen is covalently bound to the respective LOHC. Since the (optimal) LOHC is liquid at ambient conditions and shows similar properties as crude oil-based liquids (e.g. diesel, gasoline), it can easily be handled, transported and stored, therefore a stepwise implementation would be possible using the existing crude oil based infrastructure [186], [187]. For economic feasibility, the most critical parameters identified are the heat supply method for releasing hydrogen at the end-user site and the investment costs for LOHC reactors [188]. In terms of commercial maturity, LOHCs are also being investigated for trucking but are still in project demonstration stage (TRL 6-7) – as an example, the project HySTOC in Finland is demonstrating LOHC-based H_2 distribution to a commercially operated HRS [189].

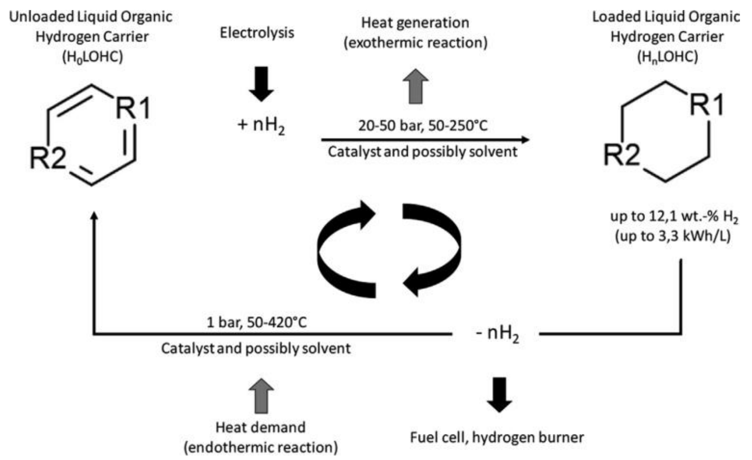


Figure 6 Concept of the LOHC storage [186]

Shipping is an attractive option for long range distances. Three shipping options are the most discussed as alternatives to pipelines: ammonia (NH_3), liquefied hydrogen (LH_2) and liquid organic hydrogen carriers (LOHC). *Ammonia* ships are commercially available (TRL 9). Compared to hydrogen, storage tanks of liquefied NH_3 pose less technical difficulties since ammonia is in a liquid state below -33.6°C at atmospheric pressure and below 25°C at 10 bar. For more information, the reader can refer to [190], by the Norwegian company ECONNECT Energy. Shipping of *liquefied hydrogen* and *LOHC* is still in a prototype stage of market readiness: TRL 5-7. Japan will demonstrate a liquefied hydrogen supply chain by the first quoter of 2022 for commercialization after 2025, with a pilot ship with a capacity of 1250 m^3 of LH_2 operating between Australia and Japan [152], [191]. As for LOHC, Japan successfully completed the commercial demonstration project in 2021 for an organic hydride supply chain operating between Brunei and Japan using company Chiyoda's SPERA Hydrogen Technology based on hydrogenation/dehydrogenation cycles of toluene and methylcyclohexane, MCH. This way. hydrogen could be transported by ship in liquid form at ambient temperature and pressure [152], [192]–[194].

2.4 Storage infrastructure

Hydrogen can be stored in different ways and different forms. As reviewed by Andersson and Grönkvist [195], three main categories can be identified: (1) physical storage of pure hydrogen as compressed gas (GH_2) or refrigerated liquid (LH_2); (2) storage via adsorption onto or into a material, held by relatively weak physical van der Waals bonds; (3) chemical storage atomic in which atomic hydrogen is bonded (absorbed) to other elements – it can results in Metal hydrides (MHx) or Chemical hydrides (Ammonia, Methanol, LOHC).

For large scale long-term (seasonal) storage, underground cavities are an attractive option for hydrogen, since it is in line with the opportunity of reassigning the existing natural gas infrastructure. The knowledge gained by the natural gas sector can be easily transferred to the case of hydrogen storage due to the similarities in cavern design, construction and operation [196]. Three main types of underground storage in geological formations are in use today for natural gas: depleted oil and gas fields, aquifers and salt caverns. Parameters to be taken into consideration for the choice are: cushion gas requirement (amount of gas required to maintain the integrity of the cavern); potential level of contamination of the stored hydrogen, flexibility in operation, injection rates and withdrawal cycles. Depleted oil and gas reservoirs and deep-seated aquifers pose challenges in terms of cushion gas and purification requirements; moreover, in porous rock structures, hydrogen might react with mineral constituents and/or be used by microorganism, with possible consequent depletion of the hydrogen stored and/or plugging of pores. Also, gas leakage risk is greater for hydrogen than leakage from natural gas storage. Salt caverns are most likely better suited for hydrogen storage, because salt is chemically inert to hydrogen and because rock salt is one of the geological materials with the lowest permeability [196], [197]. Storage technology and operating conditions of compressed hydrogen gas in *salt caverns* are similar to natural gas. The necessary equipment to inject and withdraw hydrogen to and from the salt cavern comprises a compression station (reciprocating compressor), cooling systems (to keep the effect of compression below maximum operating temperature and enable higher volumes of stored hydrogen), control valve (for expansion of extracted hydrogen) – see Figure 7.

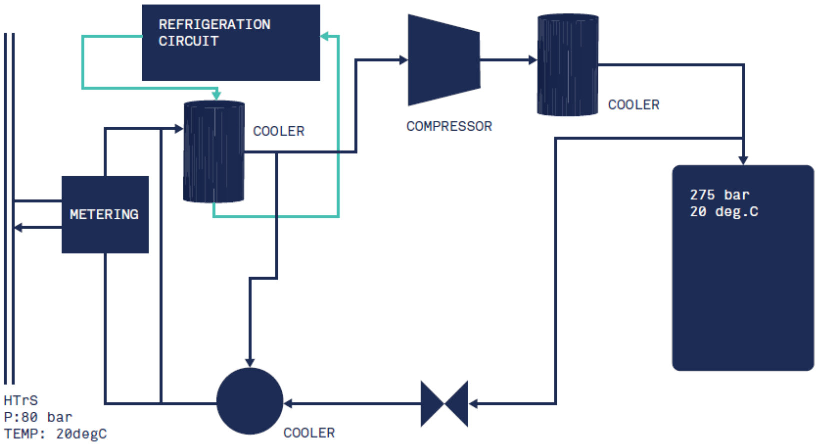


Figure 7 Hydrogen salt cavern storage units [198]

However, hydrogen energy density by volume is nearly one third of that of natural gas. For efficient storage, hydrogen gas is compressed in underground salt caverns up to a pressure of 200 bar and above. Thus, gaseous hydrogen energy storage is more costly than natural gas storage: the total installation costs, including piping, compressors and gas treatment, are about € 100 million [139], [196].

Salt caverns have been used for many decades for storing hydrogen, according to IEA they are a commercially available and competitive technology (TRL 9) but need further integration efforts. Examples can be found in the UK and the United States – details in Table 22.

Table 22 Existing salt-cavern hydrogen storage sites [198], [199]

Name	**Operator**	**Country**	**Since**	**Volume [m³]**	**Depth [m]**	**Pressure range [bar]**	**Capacity [MWh]**
Teesside	Sabic	United Kingdom	1972	3 x 70,000	365	45	27,000
Clemens Dome	ConocoPhilips	USA	1983	580,000	1,000	70-140	81,000
Moss Bluff	Praxair	USA	2007	566,000	1,200	55-150	123,000
Spindletop	Air Liquide	USA	2017	906,000	1,340	70-200	274,000

2.5 Final considerations on Hydrogen technologies

The overview provided in the present Chapter has shown the reader that various options are available for each segment of the hydrogen value chain, from production to end use, and that they offer different levels of technological maturity and market readiness. Figure 8 reports a summary of TRL levels previously indicated, for the described hydrogen technologies.

As already stated, the purpose of the present thesis is to investigate techno-economic strategies for the introduction of a hydrogen infrastructure in NRW over the next 15 years. This is performed by the application of the simulation model H2MIND, developed by FZJ and further described in the rest of the present report. The focus of the analysis is on the short- and medium-term perspective, therefore the period 2025-2035 is considered as the reference timeframe. In line with this consideration, only mature technologies with high market readiness levels – TRL 8 and TRL 9 – are to be considered for the model. They have been highlighted by a red box in Figure 8. By comparing the model assumptions described in Chapter 4 with Figure 8, the reader will be confirmed that the technology selection by FZJ in H2MIND is still a good approximation of the State of the Art of hydrogen technologies along the entire value chain.

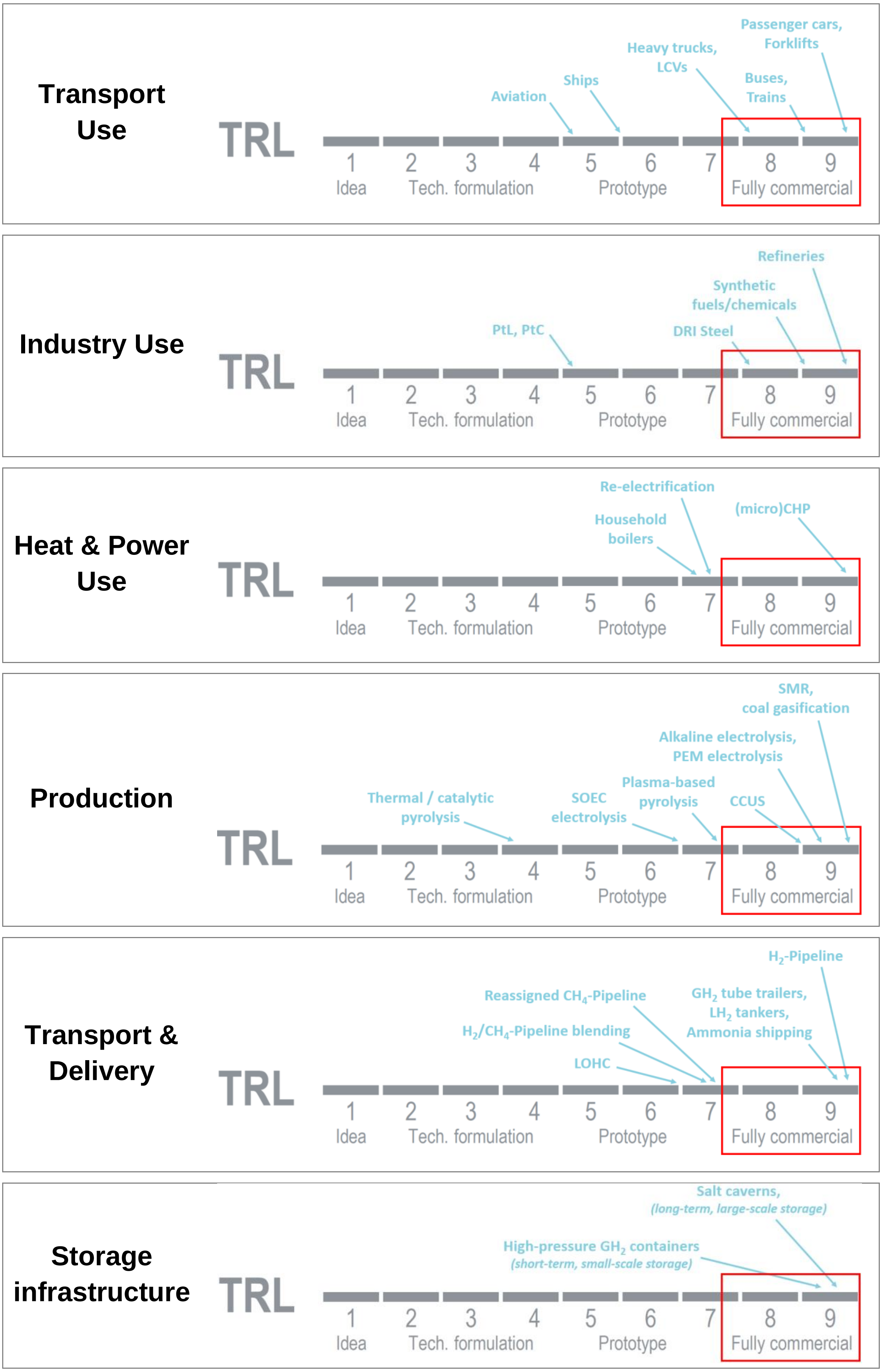


Figure 8 Market readiness of hydrogen technologies, for all segments of supply chain

3 Chapter 3 – Hydrogen Valleys

The present Chapter focuses on the dynamics of the hydrogen value chain creation highlighting the role of regional-scale initiative and identifying the key drivers for success. The discussion moves on to the features of the region under analysis (North Rhein Westphalia) underlying the reasons why it is a potential candidate for the development of a Hydrogen Valley itself.

On international level it can be observed the gradual configuration of "ecosystems" around the concept of H_2, the so-called "Hydrogen Valleys", for which it is possible to identify certain specificities.

Particularly relevant in identifying the features of Hydrogen Valleys is the work of the "*Fuel Cells and Hydrogen Joint Undertaking*" (FCH JU), public private partnership supporting research, technological development and demonstration activities in fuel cell and hydrogen energy technologies in Europe. Its aim is to accelerate the market introduction of these technologies, realizing their potential as an instrument in achieving a carbon-clean energy system.

In 2017, FCH JU launched the "Regions and Cities Initiative" to support European regions and cities towards their green energy transition with fuel cells and hydrogen. They published the first study on the development of business cases for a wide range of fuel cells and H_2 applications in regions and cities. Building on the conclusions of this study, they launched the call for the first "Hydrogen Valley" projects in 2019. This is the birth of the term "Hydrogen Valleys": cities, regions, islands or industrial clusters where a number of H_2 applications come together in an integrated H_2 ecosystem.

The study by FCH JU and Roland Berger [14] is a particularly thorough resource for understanding the concept of "Hydrogen Valleys", their evolutionary dynamics, key features, etc. It is based on the analysis of 89 regions and cities participating in the initiative.

3.1 Key features

Specifically, 'Hydrogen Valleys' can be defined as regions aiming to cover more and more of the entire hydrogen value chain, in one coordinated initiative or a portfolio of projects linked to each other, ultimately creating a local ecosystem. The conceptual overview of a Hydrogen Valley can be seen in Figure 9. Key features of a Hydrogen Valley have been enucleated as follows:

1. *Coverage of the entire value chain*. The establishment of a complete local ecosystem covering H_2 production, storage, distribution, refuelling and a variety of use cases and applications is the primary ambition.
2. *Demonstration of sector coupling*. Hydrogen Valleys can showcase how the use of green hydrogen from RES-based electrolysis can enable sector coupling and increase the use of renewable energy not only for electricity generation, but also for thermal, industrial and mobility purposes.
3. *Variety of use cases*. Hydrogen Valleys combine different use cases and applications, potentially from different energy sectors, in a single coherent project.
4. *Integrated approach*. Hydrogen Valleys go beyond the scope of individual sub-projects, they are linked to each other to demonstrate their systemic interaction in a clearly defined local setup. This can also lead to the generation of additional revenue streams, e.g., by offering grid balancing services.
5. *Scaling*. Allowing for large-scale hydrogen use and application deployments improves the business case: larger volumes for applications allow for reduced purchase prices (OPEX costs, e.g., prices for green electricity on the spot market) and for lower relative investment costs for infrastructure (capex costs, e.g., cost for electrolysers); they also ensure higher levels of infrastructure asset utilisation, e.g., increasing the base-load offtake of refuelling stations. All this could cut costs for hydrogen production, as lower prices for green electricity can be achieved.

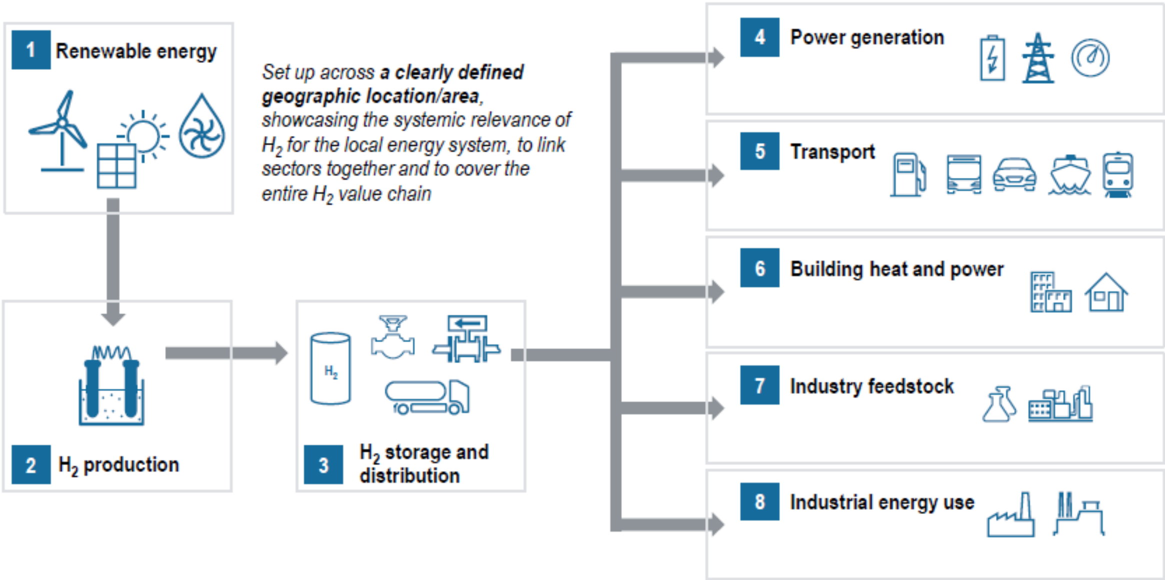


Figure 9 Conceptual overview of a Hydrogen Valley [14]

After the above-mentioned study, FCH JU launched in 2021 a "Hydrogen Valley Platform" [200], mapping existing initiatives in EU and the world, in order to collect data and observe the dynamics of their development. Today, more than 30 regions, from 15 countries, have been tracked within the platform with the status of existing 'Hydrogen Valley' concepts. Table 23 shows a selection of initiatives worldwide and their status of implementation.

Table 23 Examples of initiatives in the world (selection) [200]

Country	Initiative	Status of implementation
Netherlands	HEAVENN	Start of implementation
	Hydrogen Delta	Concrete project plan agreed by main stakeholders
United Kingdom	HyNet North West England	Concrete project plan agreed by main stakeholders
	BIG HIT Orkneys Island	Fully implemented
Germany	H2Rivers/H2Rhein-Neckar	Start of implementation
	HyBayern	Concrete project plan agreed by main stakeholders
	Norddeutsches Reallabor	Concrete project plan agreed by main stakeholders
	eFarm	Start of implementation
	Hyways4future	High level plan on government level exists
Denmark	HyBalance	Fully implemented
Spain	Green Hysland Mallorca	Concrete project plan agreed by main stakeholders
France	Zero emission valley Auvergne-Rhône-Alpes	Start of implementation
	Normandy Hydrogen Deployment Plan	Start of implementation
	Hydrogen Territory Bourgogne Franche Comté	Start of implementation
	CEOG, French Guiana	Concrete project plan agreed by main stakeholders
Italy	South Tyrole an hydrogen valley	Start of implementation
Austria	WIVA P&G	Start of implementation
EU IPCEI	Blue Danube > Green Crane	High level plan on government level exists
	Black Horse > New Green Flamingo	High level plan on government level exists
	Green Octopus	High level plan on government level exists
USA	ACES, Utah	Initial funding received
	Port of Los Angeles, California	Start of implementation
Chile	Hy-Fi (Hydrogen Facility Initiative)	High level plan on government level exists
Thailand	Phi Suea House	Fully implemented
China	Pearl River Delta (Foshan)	Start of implementation
	Beijing-Zhangjiakou	Start of implementation
	Rugao	Fully implemented
Japan	Fukushima Plan for New Energy Society	Start of implementation
Australia	Neoen Crystal Brook Energy Park	High level plan on government level exists
	Eyre Peninsula Gateway	Start of implementation

Hydrogen Valleys are the result of an evolutionary process of hydrogen-oriented regions over time. Figure 10 shows the three-stage development process identified by FCH JU and Roland Berger [14] for cities and regions towards Hydrogen Valleys. The most advanced regions have started with individual demonstration projects in the past, going from some mobility applications or single electrolysers to produce green hydrogen; now they are going beyond the scope of individual deployment projects, with an integrated value chain. Many regions and cities in Europe have already deployed individual applications and started to build up local hydrogen infrastructure. While substantial efforts have been made in this regard, activities in most cases have only been realised on a project-based approach with a limited project lifetime. They have also only included individual applications or have only established parts of the hydrogen value chain locally. The next development stage for regions and cities with the long-term goal of building up a local hydrogen economy is to link individual projects to each other and start creating a dedicated local hydrogen ecosystem. Establishing such initial local ecosystems can then serve as a basis for further rollout and uptake of local H_2 use, with the establishment of a local H_2 economy as the ultimate goal.

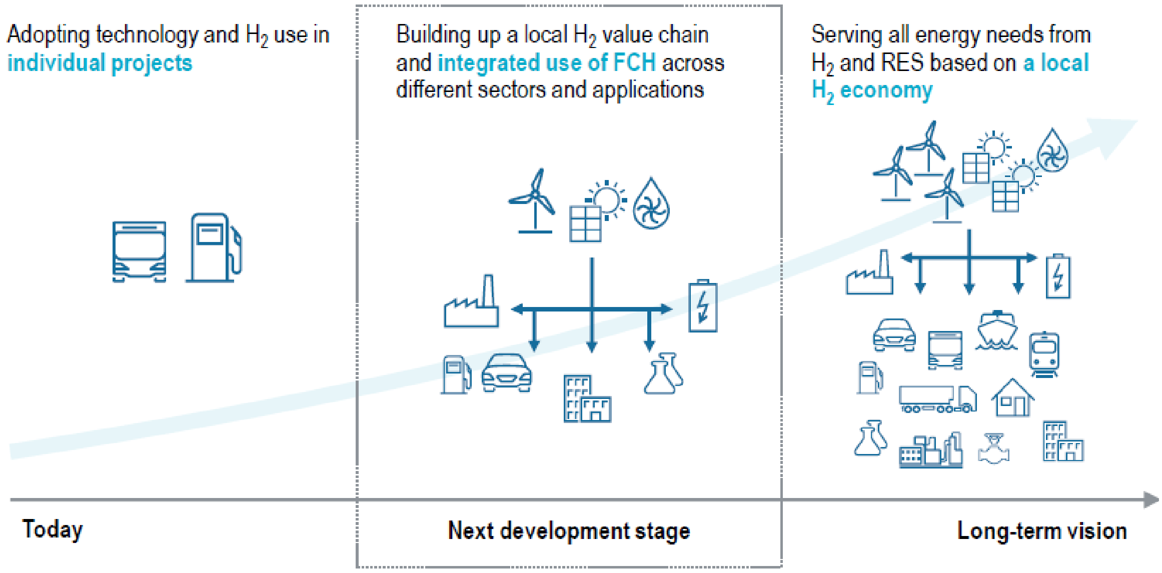


Figure 10 Hydrogen Valleys development process [14]

Based on the cities and regions analysed within their study, FCH JU and Roland Berger have defined the following groups of cities/regions, according to their development stage and level of experience [14]:

1. *Orientation seekers*. Regions and cities in this group consider hydrogen as one technology option to realize their green energy and emission reduction ambitions, but have only just started to investigate its local feasibility. Typically, these regions and cities have not yet developed any hydrogen-related projects, but are exploring whether this could be an option for the future. They intend to develop a basic understanding of the technology as a basis to assess its local feasibility, no decisions have yet been made to go forward with the technology in general and with any potential deployment projects in particular.

2. *Early-stage newcomers*. Regions and cities in this group typically also have no experience with hydrogen deployments so far, but are in the early stages of developing their first deployment projects. To gather experience with the technology, they typically plan to realise small-scale projects (e.g. 5-10 buses), and to potentially scale up later. Typical choices are mature and established transport applications (e.g. cars, vans, buses etc.), which present the opportunity to start with smaller deployment volumes (e.g. up to 10 vehicles at most). In contrast to orientation seekers, early-stage newcomers have relevant basic knowledge of the technology and have already made the decision to realise their first hydrogen deployment projects. Even though project development may already have started, they are in an early development stage and still need to solve major challenges. Strong presence of this category is to be found within the EU-13 new member states and southern European countries, where experience with hydrogen deployments is generally scarce.

3. *Ambitious newcomers* or *experienced FCH users*. These regions and cities aim to implement more ambitious, large-scale hydrogen deployments. Regions in this group mainly stem from countries in Europe which already have substantial experience, in particular from Scandinavia, the UK, Belgium, the Netherlands, Germany and France. Regions and cities in this group have either already realised projects in the past or have not yet gathered any experience but have thoroughly investigated the feasibility. On this basis, they have fleshed out well-scoped deployment plans. Their projects are typically more advanced, some including less-developed transport applications (e.g., trucks or ships/ferries), as well as stationary or industrial use applications. Deployment volumes are typically higher (several dozen applications in total). They typically show a high degree of local commitment, usually having the political backing and stakeholder support needed for implementation. They have a local hydrogen strategy or a clear ambition to continue using the technology in place in the long term.

4. *Hydrogen Valley developers*. These regions and cities are pursuing very ambitious plans to realise very large-scale hydrogen deployments as a local 'Hydrogen Valley', typically associated with plans to migrate to

a local hydrogen economy in the long run. Again, this category mainly consists of countries which already have substantial experience in hydrogen deployments, in particular the UK, Belgium, the Netherlands, Germany and France. In many cases, these ambitions are documented in existing local hydrogen strategies or roadmaps that also highlight existing stakeholder support to develop and realise relevant projects. Most of these regions are building on prior FCH deployment experience and have already reached advanced stages of project development. They have typically secured broad stakeholder support and face specific challenges in terms of developing their projects.

FCH JU and Roland Berger [14] have identified *three basic archetypes* for Hydrogen Valleys, considering the main focus in their portfolio of initiatives and associated investments involved – still, although a certain focus might prevail, smaller-scale deployments in other sectors could complement the set of projects. Figure 11 clearly shows these archetypes focuses: 1) energy/heat, 2) industrial use or 3) transport.

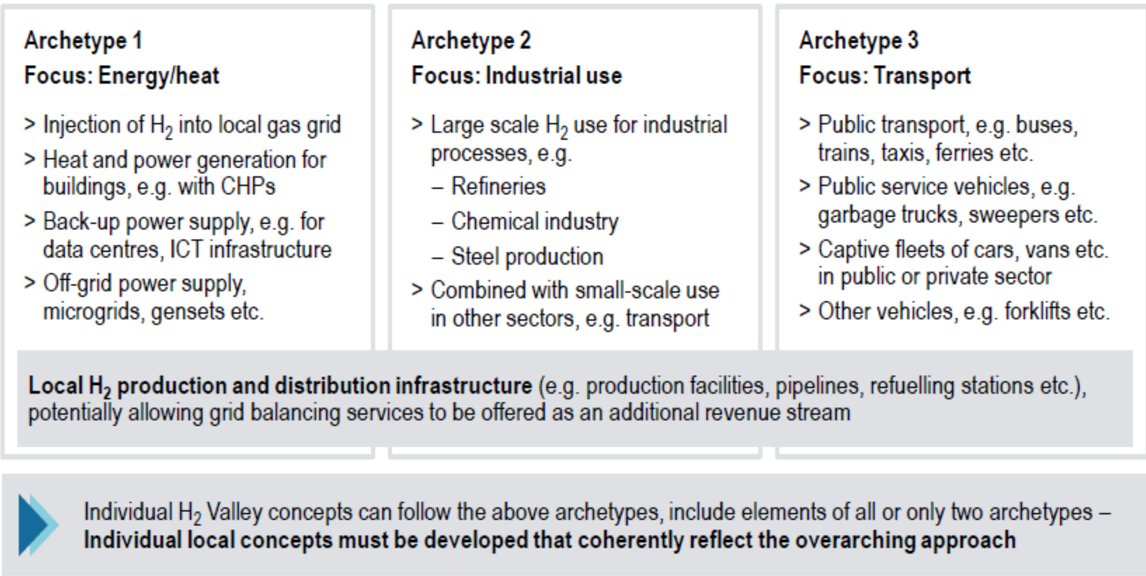


Figure 11 Potential Hydrogen Valley archetypes [14]

The study reports that the majority of the analysed Hydrogen Valley concepts have a clear focus on the *transport* sector (Archetype 3). Typical transport applications are those with the most advanced technological maturity and commercially already available – mainly public transport buses, trains, garbage trucks, cars and delivery vans – although some regions look at projects with mobility applications that are in their early development stages (e.g. maritime applications, heavy-duty trucks and special-purpose vehicles for construction work, fire services, port operations etc.).

Besides transport, a number of Hydrogen Valley plans also include large-scale projects in the steel production and (petro)chemical sector, where hydrogen is already used as feedstock for *industrial use* (Archetype 2). Making such activities part of Hydrogen Valley projects has the advantage that they are technically not complex, they can realise very large volumes of hydrogen offtake and can get close to or create a viable business case. Applications in other sectors with smaller hydrogen offtake volumes could then potentially benefit from lower-priced hydrogen. To a lesser extent, domestic energy and heat provision with CHPs are also part of some Hydrogen Valley concepts (Archetype 1).

In general, apart from the focus of hydrogen end uses described by the above-mentioned study by FCH JU and Roland Berger, other criteria for characterize Hydrogen Valleys can be read in Table 24.

Table 24 Other criteria for describing Hydrogen Valleys

Criteria	Description	Examples	
Geography / Location	• Remote locations (islands, etc.) focus more on Energy (heat and power) • Urban / industrial clusters combine the three end-use focuses	• Northern Netherlands cluster • REMOTE project	[12], [201]
Local resources	• Renewable Energy for "Green H_2" • Use of Natural Gas for "Blue H_2"	Off-shore wind in North EU, Tidal energy: • BIG HIT, UK Solar PV / onshore wind in South EU: • Italian clusters • Sines, Green Flamingo, PT Blue hydrogen: • North of England, UK	[13], [198], [202], [203]
Proximity to existing infrastructure	• natural gas grid • port for maritime connection • electricity grid (sector coupling).	• Northern Netherlands converting existing low-pressure natural gas grid • Sines, PT port for maritime connection to the Port of Rotterdam	[12], [203]

To better illustrate the concepts described so far, three examples of Hydrogen Valleys currently under implementation are provided in the following, highlighting how they can be categorized according to the criteria explained before.

BIG HIT, Orkney Islands, Scotland

The "BIG HIT" project ("Building innovative green hydrogen systems in an isolated territory: A pilot for Europe") is located on the Orkney Islands, Scotland (Figure 12). It entails the implementation of a fully integrated concept for hydrogen production from renewables, hydrogen storage, transportation and distribution, as well as utilisation for heat, power and mobility applications [13], [14]. Thanks to its position in the North Sea, Scotland's island and rural locations have access to vast renewable resources. Despite this, they suffer from high fuel costs resulting in high levels of fuel poverty. This is the result of a combination of factors including constrained electricity grids, limited penetration and/or interconnection of gas grids and the high costs of transporting fuel. High fuel prices and carbon intensive fuels have a negative impact on energy intensive industries and commercial activities, such as the whisky and distilling sectors (Scottish Minister for Energy, Connectivity and the Islands. 2020). The strategy pursued by Orkney Islands and the BIG HIT project is therefore to make use of locally abundant wind and tidal energy, to inject the power in the grid for local uses and to use the excess power (curtailed) for hydrogen production.
From a *production* perspective, local tidal turbines and community wind turbines on the islands of Eday and Shapinsay are the driver: the excess power, which could not be exported otherwise, is converted into hydrogen as a way to get around the grid restrictions Orkney is facing at the moment. Two proton exchange membrane (PEM) electrolysers are installed (1 MW on Shapinsay island and 0.5 MW on Eday island), producing about 50 ton/year of green hydrogen from constrained renewables. The electrolysers are both located close to the renewable generation assets.

From the *storage* and *transport/distribution* perspective, five high-pressure tube trailers for compressed gaseous hydrogen are used to transport hydrogen between the islands and use sites (Kirkwall harbour and mainland Orkney).

As for the *applications*, hydrogen utilisation focuses on heat and power generation and mobility purposes (mainly Archetype 1, with some of Archetype 3). Hydrogen is used as:

- backup energy source when tidal energy not directly available. It is converted back into heat and power by a 75-kW fuel cell stationary CHP system, serving several buildings, a marina and 3 ferries (when docked) in Kirkwall harbour.
- heat source for school buildings, with two catalytic hydrogen boiler systems.

- fuel for the operation of zero-emission hydrogen vehicles in and around Kirkwall. One hydrogen refuelling station in Kirkwall fuels the 5 Symbio hydrogen fuel cell road vehicles for Orkney Islands Council – vans equipped with fuel cell range extenders.

Annual hydrogen demand is estimated at about 10-15 tons for the applications currently deployed, while total annual H_2 production capacity already goes as high as 100-150 tons but has the potential to be ramped up to 200 tons. Plans exist to further expand currently installed infrastructure and use cases/applications, which would significantly increase H_2 consumption and make greater use of existing production capacity. Furthermore, it is planned to exploit the replication potential of the concept in other locations.

The concept reflects all the basic principles of Hydrogen Valleys as stated above: establishing a complete local H_2 value chain, demonstration of sector coupling by featuring local hydrogen production from renewables, establishing different hydrogen use cases and pursuing an integrated approach to link individual sub-projects. Even though future Hydrogen Valleys will likely aim for larger scales, the Orkney Island concept can serve as a role model.

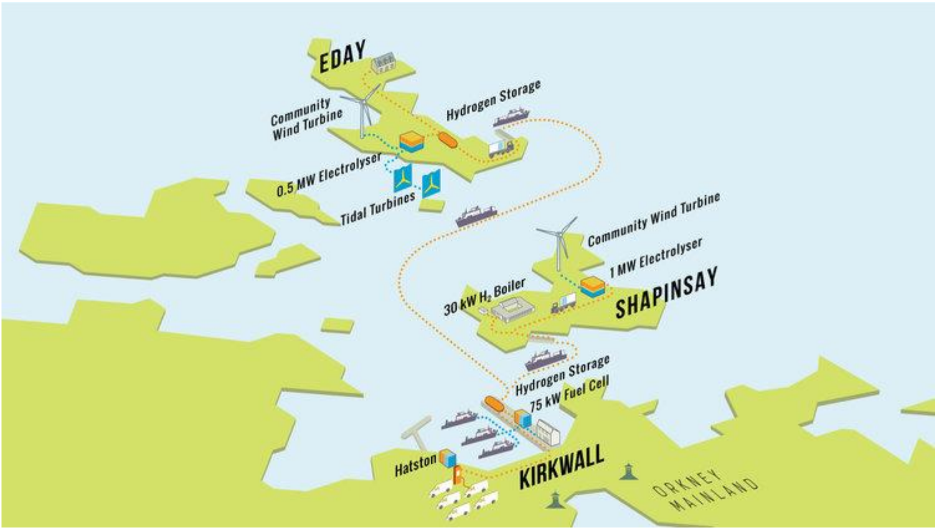


Figure 12 BIG HIT project [13]

The Northern Netherlands

Another relevant example is the case of Northern Netherlands. This region has released their Hydrogen Investment Plan 2020 [12], stating their objectives over the next 10 years, configuring their portfolio of projects into an integrated Hydrogen Valley initiative.

The decision to close out the Groningen gas field (Europe's largest onshore natural gas field) by 2022, after the earthquakes in 2018, triggered the Netherlands' need to transition away from its role as the leading European natural gas economy and to pivot the purpose of the existing knowledge and infrastructure. Given the comparable characteristics of hydrogen and natural gas, the Netherlands saw hydrogen as a natural industry extension, allowing them to build on existing gas knowledge, infrastructure and trading experience, while targeting the economic benefits of the projected growth in hydrogen demand.

The existing project pipeline consists of more than 50 projects in the value chain (production, transport, storage) and end uses (industry, transport, power, buildings) for a roadmap up to 2030, with a systemic approach in place to gradually shift from a set of pilots and demo projects to a mature, scaled-up Northern Netherlands hydrogen ecosystem.

The Northern Netherlands road map has been implemented following two phases. Phase 1 (2020 to 2025) focuses on scaling up and maturity of the regional value chain, Phase 2 (2025 to 2030) is more for the expansion of the hydrogen ecosystem coverage to all of North-western Europe.

As for the *applications*, the focus of end uses here is quite transversal among the archetypes. The hydrogen demand use cases will shift from industry feedstock (Ammonia, Refining, Chemicals) today, to more industrial energy (Iron and Steel), transportation (Trucks and others) and other use cases (Buildings, heating and power) towards 2030 and beyond. This can count on the fact that Northern Netherlands is surrounded by developing hydrogen demand hubs (e.g., Chemelot, North Rhine-Westphalia) and has access to main European hydrogen offtake markets, covering 25% of the hydrogen demand of north-western Europe, by 2030 – from Benelux, Western Germany, and Northern France).

The geographical location and the corresponding local resources are particularly favourable for hydrogen *production*. The long-term ambition is to put in place a capacity 75% green hydrogen (6 GW equivalent) and 25% blue hydrogen: by 2030. In order to achieve this, an important role will be played by the expansion of wind power capacity, for which North Sea shows a large offshore potential (north of Northern Netherlands has available space for over 20 GW). There is also the possibility of producing hydrogen at industrial hubs (Delfzijl, Eemshaven, Emmen).

As for the *transportation* infrastructure, the country's natural gas heritage provides the Netherlands with a dense, at-scale pipeline infrastructure, with high-quality parallel gas pipelines, salt caverns for hydrogen storage, and strategically located ports. Given the proximity of the to the projected hydrogen offtake markets in North-western Europe, green hydrogen can already be supplied via hydrogen trucks while the pipeline infrastructure is being developed. As for the pipeline infrastructure, the goal will be first to complete the Northern Netherlands hydrogen infrastructure by 2025, with 29 km of newly built pipelines plus around 140 km of existing pipelines from the parallel gas infrastructure. Next, by 2030, the objective will shift towards the creation of a dedicated Dutch hydrogen backbone (around 1,150 km) and a European hydrogen backbone (approximately 6,800 km), connecting the Netherlands, Germany, Belgium and parts of France.

North of England, UK

Launched in 2016, the *H21 programme* is a collaborative gas industry initiative, aiming at converting the UK gas network to carry 100% hydrogen by 2050. Within the portfolio of projects, *H21 North of England* [198] aims specifically at the conversion to hydrogen of the gas network across North of England between 2028 and 2035 (Figure 13 shows the areas involved).

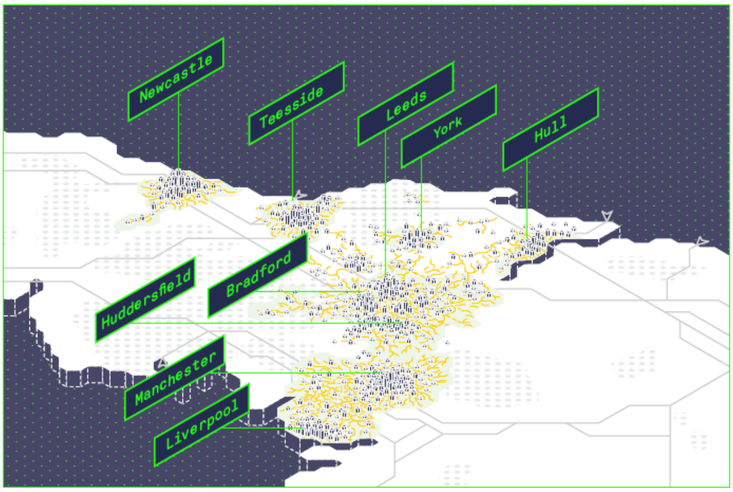


Figure 13 Cities and areas involved in H21 NoE project [198]

Focus here is typical for end-use Archetype 1. The main long-term goal of the project is to achieve full decarbonisation of heat by 2050 – in all sectors: residential consumption, as well as industrial clusters and commercial users.) The expected impact is relevant, considering that almost half of the energy consumed in the UK is to provide heat. In addition to the decarbonization of UK heat sector – which is H21 programme primary strategy – two other scenarios are also investigated:

1) the combined supply of heat and power to support the electric power system and complement the offshore wind capacity
2) The supply of energy for the full set of end usage: heat, power and transportation.

As for the hydrogen *production*, main feature of the H21 project is the important role played by blue hydrogen. The design incorporates a 12.15 GW hydrogen production facility, for the reforming of natural gas via Auto Thermal Reforming in combination with carbon capture and storage scheme (CCSS) – this latter scaling to 20 million tonnes per annum by 2035.

As for the *infrastructure*, key feature is the expected full conversion of existing gas network for hydrogen transport, including the creation of required 8 TWh of inter-seasonal storage and all associated onshore infrastructure.

3.2 North Rhein-Westphalia: potential and targets towards a hydrogen valley

All above considered, some considerations can be formulated also about North Rhine-Westphalia (NRW) (Figure 14), which is the case under analysis for the present study. NRW is a state (*Bundesland*) in Western Germany. It is both the most important industrial location in Germany as well as one of the largest metropolitan regions in Europe. Around 20% of the German gross domestic product is generated in the region [15].

Figure 14 Germany and North Rhine-Westphalia

Potential is there for NRW to be considered already as a local Hydrogen Valley in Germany. Several specific factors contribute to the status [15], [204]:

1) The local industry already has a significant demand for hydrogen (42 TWh or 1,265 kt per year, according to FZJ calculations [15]), with request from refineries, chemical and steel plants. Such a demand is expected to grow over the next years, in connection with two main leverages. First, the region can be considered the main industrial cluster in Germany, with high industrial density and many of the potential future large-scale hydrogen consumers. Second, NRW is one of the largest metropolitan areas in Europe, so mobility and residential hydrogen applications could further stimulate demand.

2) NRW can count on an already existing infrastructure for transport and storage of hydrogen, located in the Rhine-Ruhr area (MRR) and operated by Air Liquide: this is the largest hydrogen network in Germany, running from Castrop-Rauxel to Leverkusen in Chemiepark Marl, with a total length of 240 km (Figure 15).

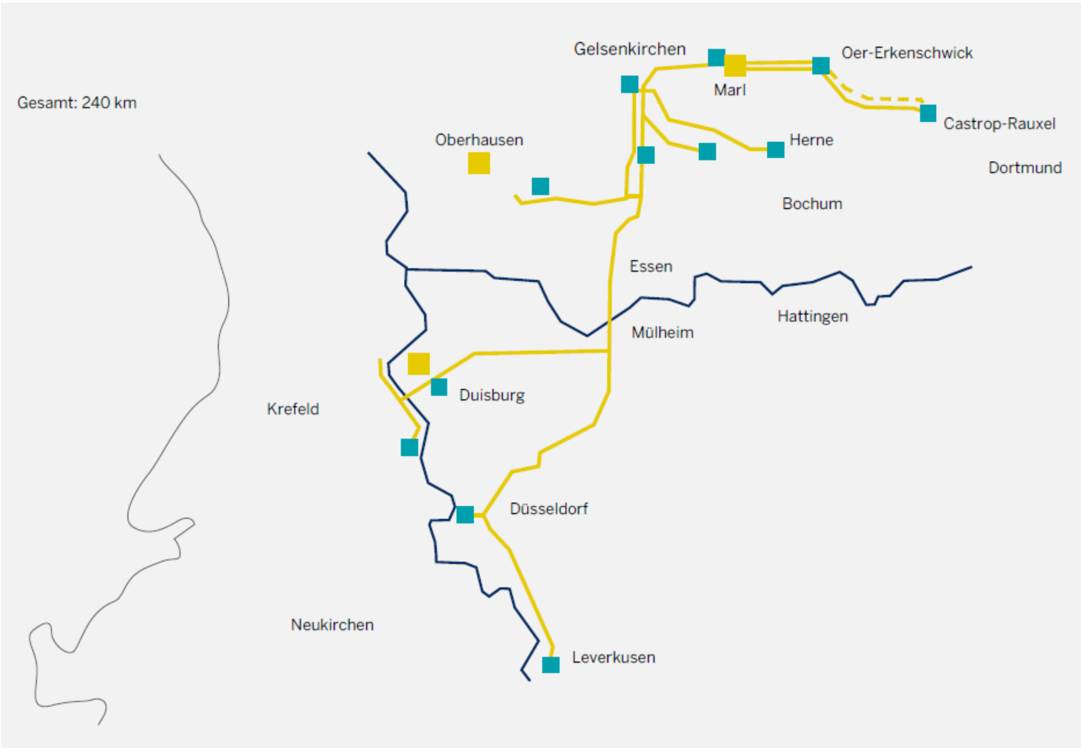


Figure 15 Existing hydrogen network (Air Liquide) in Rhine-Ruhr area, North Rhine-Westphalia [15]: current production (yellow) and consumption (green) sites can be observed.

Infrastructure in NRW becomes even more a relevant leverage topic when considering the existing, fine-meshed, Natural Gas grid in the region. Broadly speaking, North-West Europe is characterized by a very well-developed and internationally connected energy infrastructure network with numerous feed points for energy carrier imports (for example via ports). Favourably, a process is currently taking place to convert L-gas pipelines (Low Calorific Value) to H-gas (High Calorific Value)[1],which mainly affects the Netherlands, Lower Saxony and North Rhine-Westphalia (Figure 16): in such a context, natural gas pipelines will be released, opening up opportunities for reassignment for hydrogen transport. These lines can connect the future hydrogen consumption centres (industrial), for example in the Rhein-Ruhr

[1] The composition of natural gas varies according to its origin and influences its energy content. The higher the nitrogen level, the lower the natural gas' calorific value (the amount of heat generated by combustion). There are two types: 'L-gas' (Low calorific value) coming mainly from Groningen, which has high levels of nitrogen; 'H-gas' (High calorific value) coming from the North Sea, Russia and Algeria. The decision to shut down the Groningen gas field by 2022, coming to the end of its operational lifespan, requires that the entire L-gas transmission and distribution network in North-West Europe is converted to transport H-gas [230].

region, in Lingen (or also Chemelot, NL) with the production centres in the North, where offshore wind energy sites reside (European North Sea).

Figure 16 L-Gas area, subject to conversion. The northern and western federal states are particularly affected: Lower Saxony, Bremen, North Rhine-Westphalia, Rhineland-Palatinate, Saxony-Anhalt and Hesse [205].

3) To increase the strategic value of infrastructure in NRW, it is worth mentioning the presence of the Rhine and other rivers, which represent potentially interesting water ways for hydrogen transport, and also the existence of energy storage capacity in the form of salt caverns – in line with the rest of North-West Europe – which can be filled with hydrogen in the future, contributing to further integration of renewable energies and to the security of supply.

4) NRW enjoys a strategic position also from the point of view of hydrogen generation facilities. Hydrogen is already generated within the region as industrial by-product (chlorine production). Being part of North-West Europe, the region is also geographically close to the North Sea, which is an excellent location for offshore wind energy; northern Germany and the Netherlands are also good locations for onshore wind energy generation: all this potential renewable energy can be fed into future electrolysis plants. In addition to new locations, an interesting renewable energy potential is offered by wind and PV energy systems in the region which are currently benefitting from the subsidies of the so-called EEG ('Erneuerbare-Energien-Gesetz', Renewable Energy Act[2]) and which will gradually be withdrawn from subsidies in the coming years. As an example; for the municipalities of Duisburg and Rhein-Kreis Neuss only, for the year 2030, around 130 MW of post-EEG wind and PV capacity are expected to become potentially available for hydrogen generation [204].

[2] The '*Erneuerbare-Energien-Gesetz*' (EEG) or 'Renewable Energy Sources Act' is a series of German laws that originally provided a feed-in tariff (FIT) scheme to encourage the generation of renewable electricity. The EEG first came into force on 1 April 2000 and has been modified several times since. The original legislation guaranteed a grid connection, preferential dispatch, and a government-set feed-in tariff for 20 years, dependent on the technology and size of project [231].

5) NRW has established close ties with neighbouring European regions. From this perspective, it is worth mentioning the potential for import and export from the Netherlands, currently investigated by ongoing initiatives (Hy3 project [206], RH_2INE project [207], to make an example).

6) In NRW, more than 130 projects are in the pipeline – as examples, H2Stahl [208], HyGlass [209], the electromobility tender "Modellkommune /-region Wasserstoff-Mobilität NRW" [204], [210] – giving evidence of already existing local hydrogen initiatives.

All above considered, the condition of NRW recalls the profile of a '*Hydrogen Valley developer*'. The roadmap issued in November 2020 [15], together with the long list of past and ongoing local initiatives, is evidence of NRW's awareness of its key role in a future hydrogen market and therefore of its strong ambition to realise a local hydrogen ecosystem in the long run. The roadmap consists of official targets for short- (2025) and medium-term (2030) horizon. These targets, reported in Table 25, can be regrouped into three main sectors: Industry, Mobility, Energy & Infrastructure – evoking in its spirit the essence of the three basic Hydrogen Valleys archetypes outlined by FCH JU and Roland Berger in their report [14].

Table 25 Targets to 2025 and 2030 set within NRW hydrogen roadmap [15]

NRW Targets	**to 2025**	**to 2030**
Industry	• First large-scale DRI plant for hydrogen-based *steel production* in Duisburg • First *power-to-liquid* demonstration plant for the production of synthetic fuels and raw materials with a capacity of several 100 tons per day in the area Cologne/Wesseling • First large-scale industrial plants for climate-neutral *ammonia* and *methanol* synthesis • Test and pilot plant for hydrogen production via *pyrolysis*	• Expansion of hydrogen-based *steel production* • Integrated use of synthetic fuels and CCUs in the *tile and brick* industry in an industrial scale plant • Demonstration project for a hydrogen-fired rotary kiln in the *foundry* technology • Development and testing of processes for the use of hydrogen in the *cement* industry • Pilot plant for the complete substitution of natural gas by hydrogen for heat production in *glass* production
Mobility	• More than 400 fuel cell *trucks* in the region • Min. 20 *hydrogen refuelling stations* for trucks and 60 for cars • 500 hydrogen *buses* for public transport • The first hydrogen inland *ships*	• 11,000 fuel cell *trucks* over 20 tons • 200 *hydrogen refuelling stations* for trucks and cars • 3,800 fuel cell *buses* for public transport • 1,000 fuel cell *waste collectors*
Energy & Infrastructure	• 120 km of *hydrogen pipelines* in NRW, in the framework of the overall German target of nearly 500 km. Connection of NRW to the first interregional hydrogen pipelines • Installation of more than 100 MW of *electrolysis* plants for industrial use • Increasing development of Natural gas-based *electricity and heat generation* towards hydrogen compatibility	• 240 km of *hydrogen pipelines* in NRW, in the framework of the overall German target of 1,300 km • 1 to 3 GW of *electrolysis* capacity installed in NRW • First investments in *electricity and heat generation* systems based on hydrogen

4 Chapter 4 – Methodology and Investigation setup

The purpose of the present Chapter is to provide an overview of the research method used in this thesis. Section 4.1 describes the research process. Section 4.2 details the simulation model used for the investigation (H2MIND). Section 4.3 focuses on the data collection and model inputs used for this research. Section 4.4 justifies the reliability and validity of the data collected. Section 4.5 describes the model setup for the data analysis. Finally, Section 4.6 describes the framework selected to evaluate the simulation results.

4.1 Research process

Since the purpose of the present thesis is to investigate infrastructure deployment strategies within the framework set by NRW roadmap to 2030, the research process described below is followed – a schematic representation can be seen in Figure 17.

Starting point of the process is the study of previous work carried out by Forschungszentrum Jülich (FZJ) on the topic. In [211], the authors investigate and formulate the reference scenario for the definition of the targets included in NRW roadmap; therefore, this publication is taken as main source for the quantitative input values to the present thesis research. The work by Cerniauskas et al. [22], [212] investigates techno-economic strategies for countrywide hydrogen infrastructure development in Germany by 2050, by setting his own multiple technology diffusion scenarios. In order to pursue his research Cerniauskas and FZJ team have developed a simulation model – called *H2MIND* – which is here taken as main research tool.

Building on such existing material by FZJ, the attempt by the present thesis is to combine the results of the optimization models behind NRW roadmap and described in [211] – called *FINE-NESTOR* and *FINE-Infrastructure* – into the simulation model from Cerniauskas et al. [22], [212]. The second stage in the research process, therefore, consists of the adaptation of the simulation tool in order to recreate the NRW roadmap scenario.

In parallel to this, a data collection phase is also carried out. It has a double purpose: on the one hand, it is intended to complement H2MIND model where not ready to accommodate FINE-NESTOR results; on the other hand, it aims at an increased resolution in the geospatial description of the potential hydrogen refuelling stations for bus companies in NRW.

Final step is represented by the simulation of the FINE-NESTOR scenario and its evaluation according to the framework described in Section 4.6.

Figure 17 Research process applied for the present thesis

4.2 H2MIND model

The H2MIND model [212] was developed in the programming language *Python*, using the coding paradigm of Object-Oriented Programming (OOP) [213]. One of the main purposes of the model is to determine the weighted average TOTEX [€/kg H_2] for a certain amount of hydrogen demand in a certain year t, within a pre-defined hydrogen supply chain pathway and configuration of hydrogen infrastructure. In order to do so, the model implements the following operational sequence – a schematic representation can be seen in Figure 18.

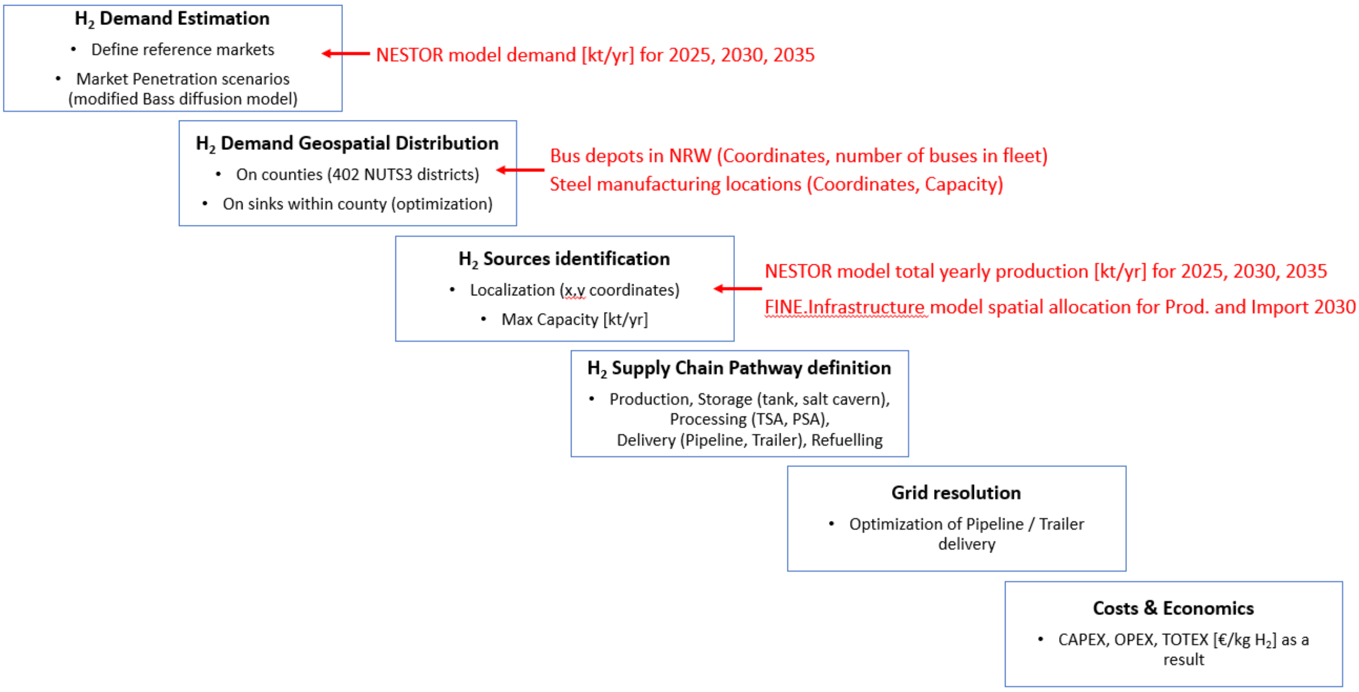


Figure 18 H2MIND model operational sequence and model adaptation (red) to FINE-NESTOR optimal scenario

The first main phase of H2MIND consists of the *estimation of the expected hydrogen demand for a certain year t* under analysis: this is taken as input value for subsequent calculations. The model takes into consideration a set of categories of hydrogen consuming technologies / sectors (Table 26) which serve as reference markets for the hydrogen demand estimation. A market penetration coefficient [%] and a hydrogen specific consumption [kg H_2 / 100km, for vehicles] are associated to each category by H2MIND. For this purpose, an enhanced version of the 'Bass-model' is developed in [212]. The 'Bass model' consists of a differential equation that describes the diffusion process of technology and innovation within a population. Graphically, it is represented by an S-shaped curve. It models the interaction among the adopters of a product, classified as innovators and imitators. For further details on the original Bass model (out of the scope of the present thesis) the reader can refer to [214].

Table 26 H2MIND Reference Markets [212]

ID	Reference market	Definition
1	Buses	Local bus fleets for public transportation
2	Trains	Train fleets on non-electrified lines
3	Private cars	Individual cars which are refuelled at public HRSs (private passenger cars, individual commercial cars)
4	Commercial cars	Car fleets which are refuelled at dedicated HRSs (commercial cars, public service cars)
5	Public HDVs and LCVs	Individual trucks and light commercial vehicles which are refuelled at public HRSs
6	Commercial HDVs and LCVs	Truck or light commercial vehicle fleets which are refuelled at dedicated HRSs
7	MHVs	Forklifts
8	Industry	Ammonia, methanol, petrochemical industry, refinery (for non-transportation purposes), steel

Once the expected hydrogen demand for each reference market is determined, the next H2MIND step consists of its *geospatial distribution* over the territory under analysis – Germany, in this specific case. The geospatial distribution of hydrogen demand is based on the official list of German districts 'Amtlicher Gemeindeschlüssel' or AGS (Official Community Keys) [215], matching with the more general

EUROSTAT 'Nomenclature of Territorial Units for Statistics' or NUTS (French: Nomenclature des Unités Territoriales Statistiques) [216]. A hydrogen demand allocation factor is calculated for each reference market and each of the 402 German districts, based on to the geospatial distribution of a specific set of criteria, as reported in Table 27.

Table 27 Criteria for geospatial hydrogen demand distribution on district level [212]

ID	Reference market	Allocation criteria
1	Buses	Population, Income
2	Trains	Diesel train lines, Diesel train mileage, Federal financial support for regional development
3	Private cars	Population, Population density, Income, current car density
4	Commercial cars	Commercial area extension, number of cars
5	Public HDVs and LCVs	Loaded freight mass, Unloaded freight mass
6	Commercial HDVs and LCVs	Commercial area extension, number of vehicles
7	MHVs	Area of logistical buildings
8	Industry	Plant capacity

Within a district, the hydrogen demand is allocated depending on the spatial distribution of demand locations (hydrogen 'sinks') – that is, technology-specific HRSs and industrial plants. These locations are entered as fixed input to the model for all considered technologies except for public refuelling infrastructure (private cars and public HDVs/LCVs), for which a MILP problem is solved to identify the optimal number and size of HRSs to cover the demand for every district. Table 28 reports additional criteria and constraints used by H2MIND to carry out the geospatial allocation of HRS capacity within each German district.

Table 28 Criteria for the geospatial allocation of HRS capacity within an AGS district [212]

Type	Public HRSs		Non-public HRSs					
Application	Private cars	Public HDVs	Buses	Trains	Comm. cars	Comm. HDVs	MHVs	Industry
Max. number of sinks	9800	8000	402	170	90	10000	7150	2340
Capacity distribution within district	MILP		Equally among the sinks		Commercial area		Logistic area	Max capacity
Constraints	'Small' if < 10%	'Small' if < 5%	Fleet > 50	Fleet > 10	Fleet > 500	Fleet > 500	Fleet > 120	-

After the hydrogen demand modelling, H2MIND addresses the production side of the hydrogen supply chain: a methodology is applied to incorporate *technologies and locations for hydrogen production* in Germany into the model. A fixed set of eligible locations is entered as input: for each location, geospatial coordinates, minimum and maximum hydrogen production capacity [kt/yr] are specified, together with the kind of production technology. H2MIND considers two ways of producing hydrogen, either by SMR (grey H_2) or by electrolysis (green H_2); this latter is sustained by renewable electricity produced by large-scale onshore wind power plants. The original H2MIND input for hydrogen sources consists of a set of 87 locations in total – 15 for 'wind-type' and 72 for 'industrial-type' sites. As shown in Figure 19, 'wind-type' sources are mainly located in North Germany, closer to the windy regions of Northern Sea, whereas the 'industrial-type' ones are more concentrated in Central and Southern Germany. The model also is designed to include locations for hydrogen import from abroad, via shipping of liquefied H_2 ('port-type' locations) and gaseous import via pipeline. The choice of these locations is the result of the application of a set of selection criteria, which are considered to drive the development of hydrogen generation over time. As stated by Cerniauskas, 'due to the transitive nature of infrastructure introduction, the importance of various hydrogen sources will vary in different phases of infrastructure development': for this reason, the focus of the present thesis is placed on short- and medium-term hydrogen production locations. From this perspective, H2MIND takes into consideration capacity which is either currently existing or planned to be implemented by 2025 or which will not require any extension of the existing energy infrastructure. Table 29 summarizes the kind of short-term hydrogen sources considered for H2MIND. The reader will appreciate a brief clarification about 'post-EEG onshore wind parks': these are intended as part of the RES plants which are expected to fall out of the EEG[3] feed-in tariff scheme starting by 2020, and for which the only available options are decommissioning or a repurposing of generated energy to keep operation (e.g., by direct connection to an electrolyser).

Table 29 Short-term hydrogen sources considered in this work [212]

Existing production	**Planned production by 2025**	**Production linked to current energy infrastructure**
Underutilized SMR	Electrolyser commercialization projects	Electrolysers at post-EEG onshore wind parks (off-grid)
By-product hydrogen	-	-
Existing electrolysers	-	-

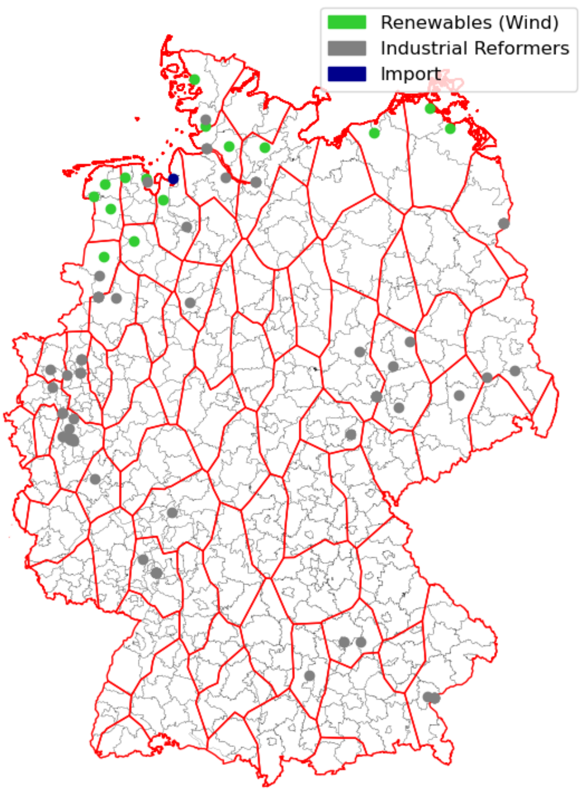


Figure 19 H2MIND source locations: Wind plants, Industrial reformers, import harbours

Last step of the H2MIND case definition is the *characterization of the hydrogen supply chain (HSC) pathway* to be simulated. Hydrogen undergoes a series of stages, from production to end use, which represent a specific sequence of interactions among the components of the hydrogen infrastructure. Figure 20 shows a schematical representation of such possible interactions. The processes and their possible alternatives are listed in Table 30. The input parameters of the components included in the pathways are reported in Appendix A.

[3] See the note in Chapter 3 for explanations about EEG.

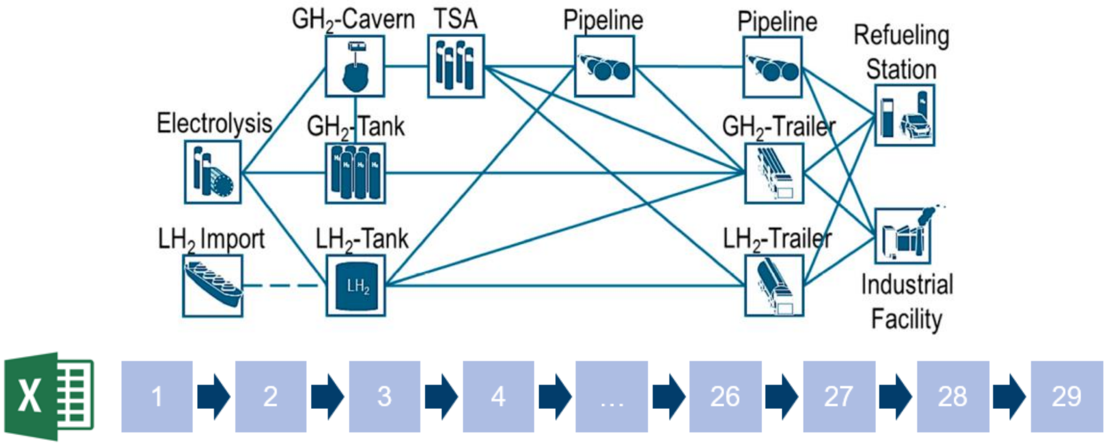


Figure 20 Overview of analyzed hydrogen supply chain pathways and schematic representation of their modelling within H2MIND [22]

Table 30 Processes and available H2MIND options withing HSC pathways [212]

HSC processes	**H2MIND options**
Electrolysis (H_2 production)	Centralized, Decentralized, Onsite at HRSs
H_2 purification	PSA, TSA
H_2 storage	GH_2 Tank, LH_2 Tank, Salt Cavern, LOHC Tank, NG-Grid
Blending (H_2 production)	SMR
H_2 import	LH_2 Port, GH_2 Port
Transport / Delivery	GH_2 Truck, LH_2 Truck, new H2 pipeline, reassigned NG pipeline, LOHC-Truck
Connectors	Compressors, Liquefaction, Evaporation, Hydrogenation, Dehydrogenation, LH_2 Pump, LOHC Pump
H_2 refuelling	HRSs divided by vehicle technology (buses, trains, MHVs, publicly- and non-publicly-refuelled cars or trucks) and size (S, M, L, XL, XXL – for publicly-refuelled cars and trucks)

In the end, the H2MIND tool builds the corresponding hydrogen infrastructure (the 'hydrogen grid') and performs its optimization of capacities and component costs. The grid is determined as a combination of pipeline and truck-covered tracks used for hydrogen transport and/or delivery to the refuelling locations. The grid optimization returns relevant information about the optimal infrastructure for the analysed HSC pathway – for example: overall length of the required pipelines (newly built or reassigned NG), pipeline diameters, required truck mileage and economics.

Most important result is the weighted average TOTEX [€/kg H_2]. It consists of the specific cost of covering a certain amount of hydrogen demand in a certain year t, if a hydrogen supply chain pathway is adopted. It descends from the sum of CAPEX and fixed and variable OPEX for each of the processes composing the supply chain (electrolysis, compression, storage, etc.). These terms are weighted for each single item within the hydrogen infrastructure based on the amount of hydrogen that it processes (that is, for example, the hydrogen produced by an electrolyser, the amount compressed for a compressor, the refuelling provided for a HRS, etc.). Being expressed in specific form (€/kg H_2), the weighted average TOTEX represents a valid tool for the comparison of different HSC pathways.

4.3 Model input

The data used for the present thesis work are derived from two different collection processes. The main batch of input data are derived from the results of the model developed by FZJ, used to orient the NRW H_2 Roadmap – *FINE-NESTOR*. In parallel to this, a search for data from external sources was also carried out, with the double purpose of i) complementing the H2MIND model where not ready to accommodate FINE-NESTOR results; and of ii) increasing the resolution in the geospatial description of the potential hydrogen refuelling stations for bus companies in NRW. In the following sections, more details are provided about the data collection.

4.3.1 FINE-NESTOR model

As previously stated, the FINE-NESTOR model was developed and implemented by Cerniauskas et al. at FZJ, as a way to analyse the national energy system of Germany. With this model, the scenario behind NRW H_2 Roadmap was set. The reader will find more detailed information about its structure and methodology in [211].

The FINE-NESTOR model provides a techno-economic representation of the energy supply from primary to final energy with more than 1,000 potential technologies for Germany. It makes it possible to calculate cost-optimal transformation paths for the entire energy system over a period up to 2050. The model is applied to investigate the German climate policy target of 'greenhouse gas neutrality' by the year 2050, meaning at least 95% reduction in greenhouse gas emissions compared to 1990. These greenhouse gas emission targets are matched with two other relevant existing initiatives in Germany: i) the phasing out of nuclear power plants by 2022 [217] and ii) the phasing out of coal-fired power plants by 2038 [218].

In such a scenario, for the year 2050, a hydrogen total demand of about 11 000 kt/yr is expected for Germany. Main share of it is on the mobility (44%) and industrial (27%) sectors. For the mobility, cars and heavy-duty vehicles play the major role – approximately 50% and 40% respectively of the mobility demand – compared to buses and trains. As for the industrial demand of hydrogen as raw material, steel production by direct reduction of iron is the main consumer (43% of industrial demand), followed by ammonia and methanol production. Relevant to mention for 2050 are also the generation of high temperature (> 500°C) process heat and electricity for the power system, whereas Fischer-Tropsch syngas production (as precursor of e-fuels and chemicals) and space heating of buildings are expected to play a subordinate role in Germany.

The timeframe within the scope of the present thesis (2025-2035) covers the short and medium time horizon. The corresponding hydrogen demand – already rearranged from H2MIND perspective – is reported in Table 31.

Table 31 FINE-NESTOR countrywide hydrogen demand for the timeframe 2025-2035 [211]

H_2 demand [kt/yr]	2025	2030	2035
Mobility			
Bus	6.75	46.85	92.54
Train	15.68	67.13	135.53
Cars	55.67	376.16	571.33
HDV and LCV	67.02	184.71	471.74
Industry			
Steel	0.01	0.04	101.73
Methanol	0.56	6.82	31.28
Ammonia	33.20	101.33	207.64
Chemicals (Fischer-Tropsch)	263.71	263.70	200.13
Energy – Heat and Power			
Re-electrification	238.76	552.26	1,082.69
High-Temp. industrial process heat	0.02	0.04	0.14
Buildings			
Space heating	36.48	40.29	59.01

It can be noticed that the market penetration of the mobility sector is in general much earlier than the industrial one. The industrial demand for hydrogen is first expected to undergo the replacement of conventional grey hydrogen for ammonia and methanol production with green hydrogen; in parallel, the gradual introduction of DRI steel production will boom starting 2035. Chemicals (syngas) are very significant in the short term, but FINE-NESTOR results show a reduction in their contribution to the demand for later years due to the limited internal generation potential for green hydrogen in Germany in the long run and, consequently, to the allocation of internal hydrogen production on other more strategical sectors.

The expected hydrogen supply to meet the demand described above is depicted Figure 21. Conventional systems (grey hydrogen) will primarily be used until 2030. The increase in domestic generation will then be possible by a significant expansion of electrolysis capacity, so that a total share of approx. 33% and 48% respectively of total supply will have to be achieved in 2040 and 2050. During the same period, the importance of conventional plants decreases sharply, so that by 2050 only existing plants without any significant production can be found. The optimization results make it clear that, for the year 2050, the total amount of hydrogen required in Germany will not be provided exclusively by domestic production. As early as 2030, imports will play an important role in the hydrogen supply. The import of blue hydrogen to Germany in the years 2030-2040 represents an important bridging technology in order to provide the necessary import quantities in the medium term. The blue hydrogen will be almost completely replaced by green hydrogen by 2050. After 2040, the role of green hydrogen imports will increase significantly, so that in 2050 more than half (approx. 52%) of the hydrogen will be imported into Germany. As for NRW, imported hydrogen is expected to enter the region either from the Netherlands via pipeline connection for gaseous hydrogen or from the ports in northern Germany in the form of liquefied hydrogen.

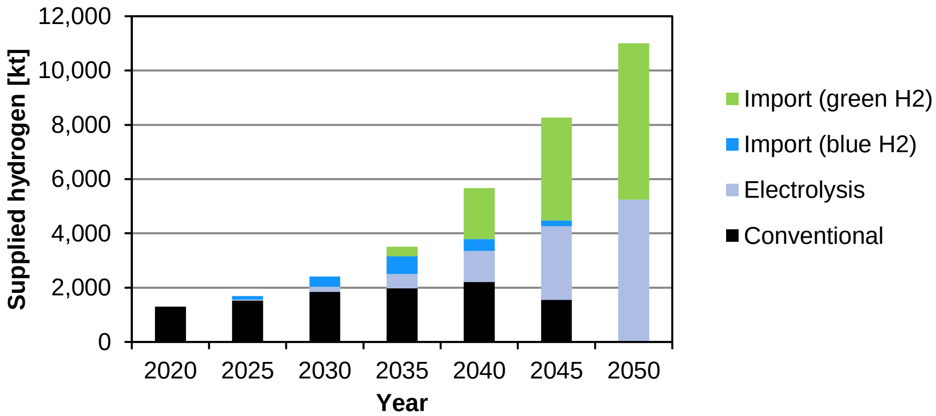


Figure 21 FINE-NESTOR supplied hydrogen up to year 2050 [211]

The expected hydrogen supply values for the timeframe within the scope of the present thesis is reported in Table 33.

Table 32 FINE-NESTOR countrywide hydrogen supply for the timeframe 2025-2035 [211]

H_2 supply [kt/yr]	**2025**	**2030**	**2035**
Electrolysis	37.31	185.51	527.10
Conventional	1,528.30	1,842.24	1,972.56
Import (blue H_2)	131.05	378.02	649.68
Import (green H_2)	-	-	364.64

The simulated scenario of demanded and supplied hydrogen requires a significant increase of installed capacity for renewable energy. According to FINE-NESTOR, Wind power and PV are expected to become the backbone of the future power supply in Germany, with a necessary average annual expansion of approx. 4.8 GW (onshore wind power) and 5.3 GW (photovoltaics) up to the year 2050. For onshore wind, the installed capacity during the timeframe within the scope of the present thesis, the electricity production and equivalent full-load hours are reported in Table 33.

Table 33 FINE-NESTOR Onshore wind 2025-2035 [211]

Onshore wind	2025	2030	2035
Installed capacity [GW]	73.5	84.5	94.0
Generated electricity [GWh/yr]	107,844	129,269	152,668
Equivalent full-load hours [hr/yr]	1,467	1,529	1,625

4.3.2 Integrative data collection

In parallel to the review of the FINE-NESTOR model optimization results, a search for data from external sources was also carried out, with the double purpose of i) complementing the H2MIND model where not ready to accommodate FINE-NESTOR results; and ii) increasing the resolution in the geospatial description NRW.

1. Existing bus depots for NRW population mobility

Firstly, existing bus depots in NRW were mapped, based on the list of bus mobility companies in the regions contained in [219]. Municipal companies for the mobility of NRW inhabitants were the focus of the task. This round of data collection aimed at gathering: 1) GIS coordinates of the existing bus depots; 2) Size of the specific fleet assigned to each depot. The assumption behind this data collection is that, at the end of the business day, buses return the assigned depot for refuelling: it seems reasonable to assume existing bus depots as good candidate locations for the construction of HRSs dedicated to bus fleets. The identified locations were integrated into the H2MIND input dataset of possible HRSs for buses, in order to improve the geospatial description of bus refuelling stations in NRW.

The complete list of existing bus depots in NRW is reported in Appendix B.

2. Existing steel production sites in Germany

Secondly, existing production sites for steel in Germany were mapped, based on the list of companies reported in [220]. Reported sites are listed in three categories according to the available technology and kind of product – blast furnace and basic oxygen furnace; electric arc furnace; stainless steel specialty. Steel production capacity [kt/yr] are provided: this information is relevant for a proportional allocation of the aggregated hydrogen demand for steel production. The purpose of this second data collection is to integrate the H2MIND model with a geospatial description of steel production sites. For each location, in analogy to bus depots, GIS coordinates were searched.

The complete list of existing steel production sites in Germany is reported in Appendix C.

4.4 Reliability and validity of the research tools and the input data

In the present section, the reliability and validity of the research tools and the input data are discussed. The H2MIND model by Cerniauskas et al. [22], [212] represents the only research tool applied for the purpose of the present thesis. The model was progressively developed and enhanced with the contribution of the research team within FZJ. Its application has been the source of various papers – [22], [221], [222] are examples: in consideration of the relevance and academic authority of the publications involved, the H2MIND model has been considered as an adequate tool for the present thesis. The present investigation, being developed with the direct support of FZJ, could also take advantage of the supervision of the main author of the simulation tool, facilitating the understanding of the tool in its meaning, purpose and capabilities.

As for the model input, two categories of data were considered: the results of an optimisation problem (FINE-NESTOR model) and the output of the mapping of existing geographic locations and their main features (bus depots in NRW, steel production sites in Germany). As for the FINE-NESTOR model, the reader can refer to Lopion [223] for validation; furthermore, the reliability and validity descend from the academic authority of the research institution (FZJ) who released the optimisation results: FZJ specialises in the research of hydrogen-based technologies, with particular reference to the mobility and industrial sectors. Moreover, the conclusions drawn from FINE-NESTOR served as the basis for the definition of the regional political agenda *H_2-Roadmap*. FZJ acts as a neutral agent, with no conflict of interests in pursing their investigation mission.

As for the collection of existing geographic locations, reliable sources were used. For the GIS coordinates, *Google Maps* webpage was consulted and various sources (mainly company websites) were reviewed for bus fleet sizes.

4.5 H2MIND model preparation

Figure 18 shows a schematic representation of the actions taken on H2MIND model in order to accommodate the information derived from FINE-NESTOR model.

In the first step, the aggregated amounts of FINE-NESTOR hydrogen demand were selected and adjusted to H2MIND model structure. Table 31 already reports these values in the H2MIND aggregation. For the purpose of the present thesis, only hydrogen demand for the sectors mobility and industry was selected for the analysis of the short- and medium-term timeframe. These two sectors reflect NRW key features the most (high population density of metropolitan areas and high intensity of energy-intensive companies). Other sectors are excluded from the scope of this thesis because of their limited relevance on the total hydrogen demand in the considered timeframe (space heating in buildings shrinking from 5% to 2%; high-temperature industrial process heat close to non-existent). The modelling of 're-electrification', that is the re-conversion of hydrogen into electricity through gas turbines and fuel cell power plants, requires taking into account the coordination between the hydrogen infrastructure and the development of the underlying power grid: sector coupling dynamics are not considered in H2MIND model (this could be recommended as area of research for future work): therefore, despite accounting for more than 30% of the expected hydrogen demand already in the short / medium term, re-electrification of hydrogen has not been included within the scope of the analysis. This demand sector is in any case expected to have a positive impact on the hydrogen infrastructure establishment, pushing towards higher rates of demanded hydrogen and thus to an acceleration in cost reduction for key infrastructural components.

Also, for the consistency of H2MIND model operation, two additional hydrogen demand sectors are kept within the scope of the simulation, even though they account for around 2% altogether: MHV mobility and refinery demand for non-mobility purposes. These two demands are calculated by H2MIND intrinsic methodology based on an improved version of the Bass model for technology innovation.

Table 34 shows the dataset used for the simulation in the present thesis. The demand repartition between 'private/public' and 'commercial' (being the definition provided in section 4.2 for these classes) descends from the market penetration coefficients available in H2MIND.

Table 34 Countrywide hydrogen demand for the timeframe 2025-2035 (H2MIND aggregation)

H_2 demand [kt/yr]	2025	2030	2035
Mobility			
Buses	6.75	46.85	92.54
Trains	15.68	67.13	135.53
Private cars	45.27	305.87	464.57
Commercial cars	10.40	70.29	106.76
Public HDVs and LCVs	46.98	123.31	296.30
Commercial HDVs and LCVs	20.04	61.40	175.44
MHVs	5.74	14.98	29.25
Industry			
Steel	0.01	0.04	101.73
Methanol	0.56	6.82	31.28
Ammonia	33.20	101.33	207.64
Chemicals	263.71	263.70	200.13
Refinery	2.39	7.50	21.15
TOTAL	450.72	1,069.24	1,862.33

After the setup of the aggregated demand values, the geospatial allocation of hydrogen consumption spots was adapted. As previously stated, the dataset of HRSs for buses was complemented with the existing bus depot locations in NRW. For the hydrogen demand allocation, the rule was adjusted for buses: for each of the 402 German districts, the consumption is concentrated at the centroid of the unit or, where available, it is distributed proportionally to the size of the corresponding bus fleet. For steel production centres in Germany, the hydrogen consumption was allocated on the dataset of locations described in the section above.

The hydrogen production modelling (the 'sources' within H2MIND) is setup in order to reflect the FINE-NESTOR scenario. FINE-Infrastructure provides a spatial allocation for hydrogen production based on a set of 80 clusters (Voronoi regions), centred around High Voltage stations in the German national power grid. These Voronoi centroids were complemented with the locations already available in H2MIND. The FINE-Infrastructure geospatial allocation profile for conventional fossil fuel-based processes, electrolysis and import for the year 2030 was used in the present thesis as reference for the geospatial allocation of hydrogen generation for the years 2025, 2030 and 2035. In order to define the contribution of each source location, for each of the 80 Voronoi regions, hydrogen production/import is concentrated at the centroid or, where available, it is distributed on the locations proportionally to the original max capacity indicated within H2MIND. The overall amount of hydrogen sourced through electrolysis, SMR or import are equally downsized in order to account only for the hydrogen demand within the scope of the present thesis. Figure 22 shows the set of locations used in the present thesis for the geospatial distribution of hydrogen sources – the map also shows the repartition of the German territory among the 80 Voronoi regions within the FINE-Infrastructure model. Table 35 shows the final composition of hydrogen sources after rescaling on the actual hydrogen demand within the scope of the present thesis.

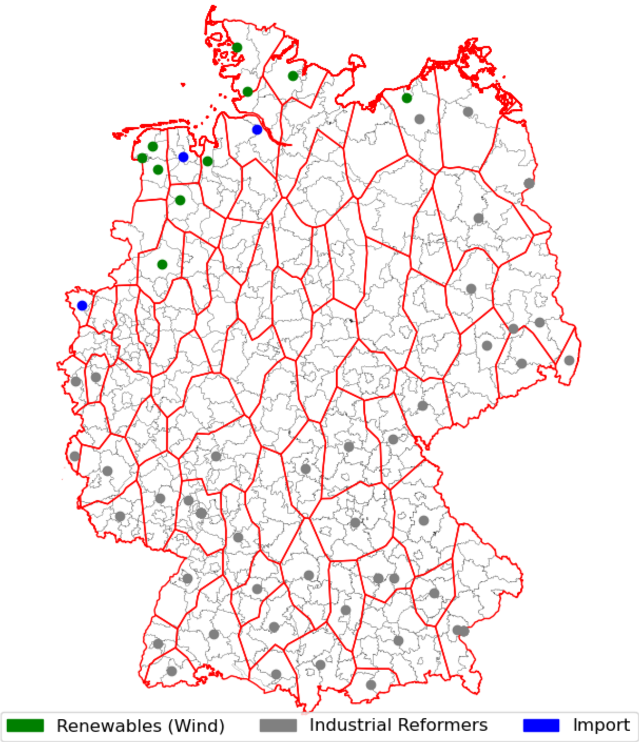


Figure 22 Map of source locations within adjusted H2MIND model

Table 35 Countrywide hydrogen supply for the timeframe 2025-2035 (H2MIND adaptation)

H2 supply [kt/yr]	2025	2030	2035
Electrolysis	27.71	129.76	344.72
Reformer (LS and SS)	327.93	680.42	863.57
Import	97.34	264.40	663.36

Lastly, the hydrogen supply chain pathways were selected for the simulation of the FINE-NESTOR optimal scenario – explanation of the pathway selection is provided in the next session of the present report.

4.6 Evaluation framework

The application of NRW H2 Roadmap scenario to the H2MIND model was carried out with respect to the following evaluation framework.

A preliminary level of evaluation is on the *geospatial allocation of hydrogen demand* from NRW H_2 Roadmap scenario – countrywide on the 402 German districts, as well as within NRW. This kind of analysis contributes to the identification of market sectors with an earlier penetration pace and possible synergies at local level, to be taken into consideration when planning on financial support for the development of a hydrogen infrastructure. The comparison of the geospatial distribution between different years (2025 – 2030 – 2035) is also source of insights about trends in the demand, both on national and local level. As already mentioned, H2MIND defines its own set of allocation factors, which may not result into the same spatial distribution as per the FINE-Infrastructure model. A comparison between the allocation within the two models can be carried out.

Another level of result evaluation is based on the *weighted average TOTEX* [€/kg H_2], introduced in section 4.2 In line with the conclusions by Cerniauskas et al. [22], [212], four combinations were chosen for the investigation, being appointed as the most interesting for shaping a national hydrogen infrastructure in Germany from a techno-economic point of view. They are listed in Table 36. On a general level, it can be said that all of them include the same components for hydrogen sourcing (centralized electrolysis, SMR and import by shipping and pipeline entry point) and they all end by HRSs and industrial consumption locations; what differs is represented by the configuration of transmission and distribution of hydrogen. Two pathways rely totally on hydrogen trailers for the connection of hydrogen source and sink locations. Trailers can be either used for the transport of gaseous or liquefied H_2. The other two pathways involve pipeline networks for the transmission and gaseous trailers for distribution– interesting is the comparison between dedicated hydrogen pipelines built as new and pipelines obtained from the reassignment of existing natural gas pipelines, for the identification of cost reductions in case of asset repurposing.

The four hydrogen supply chain pathways were compared according to their weighted average TOTEX: This comparison was carried out from global-cost perspective, then the cost breakdown was considered in order to identify specific features in the cost determination. The weighted average TOTEX was calculated also for the case of no demand from buses, in order to understand how these hydrogen-based vehicle category could impact the overall supply chain cost.

Table 36 Hydrogen supply chain pathways for H2MIND simulation [22], [212]

ID	Pathway name	Description
1	GH_2 trucks	Transport by gaseous hydrogen trailers
2	LH_2 trucks	Transport by liquefied hydrogen trailers
3	New pipelines	Transport by newly built hydrogen pipelines (transmission) and gaseous hydrogen trailers (distribution)
4	Reassigned NG pipelines	Transport by reassigned natural gas pipelines (transmission) and gaseous hydrogen trailers (distribution)

As last level or evaluation, not only is the weighted average TOTEX [€/kg H_2] useful for a comparison between different alternatives involving centralized electrolysis: it also provides an indicator for assessing the option of onsite hydrogen generation, that is electrolysis at HRS. The case of *onsite electrolysis* at bus depots (HRSs for buses) was selected as a case study of particular interest for this thesis. In such onsite electrolysis pathway, it was imagined that bus HRSs could count on locally installed electrolysers for covering a predefined share of hydrogen demand, ranging between 0% (no self-consumption) and 100% (complete independence). A minimum size of electrolysers onsite is set on 1 MW, in order to include techno-economic feasibility considerations into the simulation case; the rest would be provided by the complementary resulting national/regional centralized hydrogen infrastructure. For the simulation of such a scenario, the "GH_2 trucks" pathway is considered for the centralized hydrogen supply part. This is particularly relevant for the definition of the landscape of hydrogen sources (the triple "wind/RES", "SMR/blending" and "import" defined in section 4.5). Here, it is assumed that onsite electrolysis is 100% covered by RES; the rest of "GH_2 trucks" pathway sources (remaining "Electrolysis", "Reformer" and "Import") will cover for the complementing centralized hydrogen infrastructure. A TOTEX value is obtained for both onsite electrolysis pathway and for the complementary centralized pathway; the final global TOTEX value, to be used for scenario evaluation, is then obtained by combining the two single TOTEX and reweighing the averages on the overall hydrogen demand.

5 Chapter 5 – Results and Analysis

In the present Chapter, data and results are shown and analysed in order to highlight implications for the definition of deployment strategies for a hydrogen infrastructure. First step is the analysis of hydrogen demand on national level (Germany) and on the regional level of NRW. Second step is the economic implications from the point of view of cost comparisons. Specific considerations about hydrogen-based buses and their role in the creation of a hydrogen infrastructure in Germany and NRW are provided in the final section of the present Chapter.

5.1 Hydrogen demand distribution

5.1.1 Germany

Starting point of the present work is the analysis of the hydrogen demand resulting from the FINE-NESTOR model. Figure 23 shows the breakdown of the demand according to sector, for the years 2025 – 2030 – 2035.

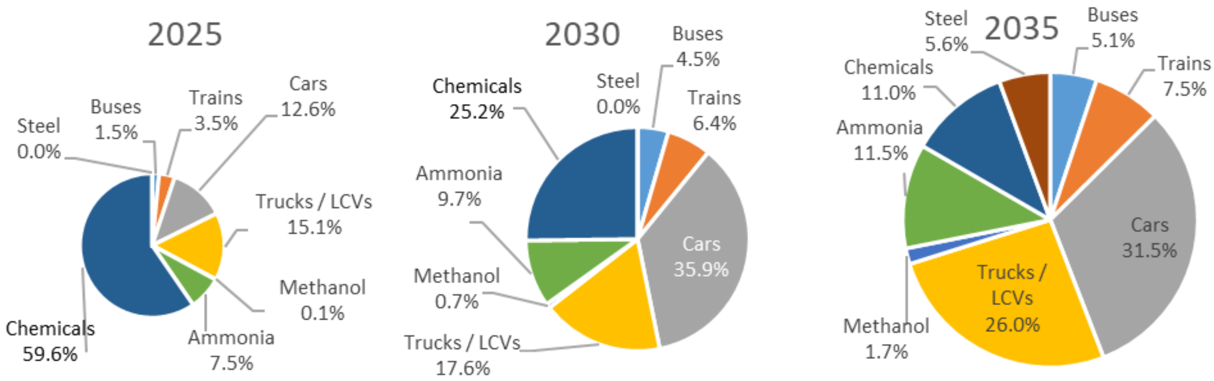


Figure 23 NRW H2-Roadmap hydrogen demand breakdown according to sector, for the years 2025 – 2030 – 2035 (Germany). The surface of the circles represents the total demand: the surface increase indicates the demand increase over time.

It can be noticed that, in the beginning of the observation period (2025), the industrial sector is expected to drive the demand – namely the production of chemicals, covering 60% alone. In the H_2 NRW Roadmap scenario, the importance of this demand is then gradually replaced by mobility so that, at the end of the observation period (2035) cars, trucks and light commercial vehicles are expected to play the role of primary contributors, accounting for 58% of demand altogether.

Looking to the spatial distribution of the national demand within Germany, the combination of FINE-NESTOR amounts with the allocation factors from H2MIND model, the resulting configuration is shown by Figure 24.

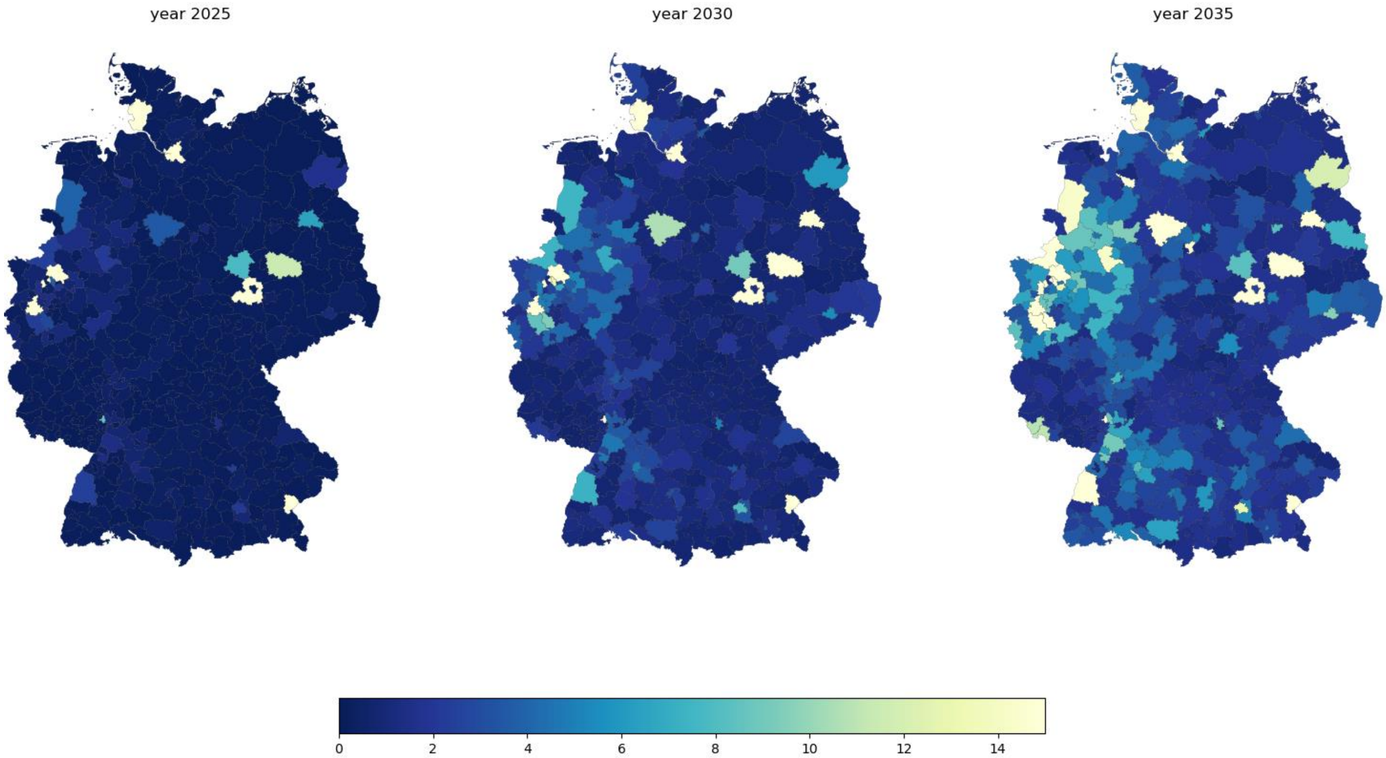


Figure 24 Spatial distribution of total hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

In 2025, for almost all German districts, the expected average hydrogen demand is very low (0.341 kt/yr on average), except for a few areas where hydrogen demand is expected to be concentrated. Out of the first 15 districts with highest demand in Germany, 5 are in NRW. These include the district with highest demand, Oberhausen (67.75 kt/yr), followed by Rhein-Kreis Neuss (52.06 kt/yr), Recklinghausen (15.81 kt/yr), Gelsenkirchen (3.77 kt/yr) and Köln (2.83 kt/yr). Other significant districts can be found in Sachsen-Anhalt – Saalekreis (64.24 kt/yr), the second highest, then Wittenberg (11.46 kt/yr) and Salzlandkreis (7.83 kt/yr). To be mentioned are also: Dithmarschen (28.40 kt/yr), Hamburg (21.77 kt/yr), Altötting (19.95 kt/yr), Ludwigshafen am Rhein (8.71 kt/yr), Berlin (6.54 kt/yr) Emsland (3.96 kt/yr) and Region Hannover (3.53 kt/yr). The main driver of this distribution is the presence of industry locations, as it could be noticed by observing the distribution of hydrogen demand for industry – see Appendix D for the graphical representation. As general indication, the districts where demand is at highest are located in the northern part of the country, especially North-West. By 10 years later, hydrogen demand is expected to develop and spread around the same initial main districts in the North. NRW and southern Niedersachsen represent the area with highest demand – 686 kt/yr both regions together, corresponding to 37% of the total national demand. By 2035, the South-West, namely Baden-Württemberg, will start to become another relevant hydrogen demand area (182 kt/yr, making 10% of total German demand).

Looking into the distribution of national hydrogen demand according to the consuming technology, the resulting configuration is reported in Figure 38 to Figure 45 inAppendix D. When it comes to mobility, buses and private cars seem to have a quite homogeneous technology penetration (thus, demand for hydrogen) over the country, though peaking on the most populated areas in the country – Berlin, München, Hamburg, Hannover, Frankfurt and NRW area (Köln and Düsseldorf in the first place). This can be explained considering the population distribution, which is the primary driver for hydrogen demand in this case of road-based mobility. To a certain extent, MHVs seem to have a quite similar diffusion: in this case, spatial allocation is directly connected with the extension of logistic areas, indicating that the most populated areas of the country are also the highest level of logistic services. On the other hand, it looks also clear that trains, commercial cars and HDVs have a marked trend over time towards localization in the north-western part of the country, namely NRW and southern Niedersachsen, close to the border with the Netherlands. In the case of trains, the reason lies in the combination of the spatial allocation drivers: NRW in particular has the highest share among federal regions for mileage and financial support for regional development, denoting a high intensity in the use of Diesel train lines and the support from the regional government to the enhancement of such lines. For commercial cars and public/commercial HDVs, it is mainly the extension of commercial area which drives the demand allocation: based on this factor, North-West Germany – namely NRW districts – play the major role, probably in connection with the fact that NRW represents the largest economy among the German states by GDP figures [224].

Industry hydrogen demand is at the extreme of such a distributional trend, with a demand concentrated on few districts only: 15 districts in 2025 (demand ranging from 1.5 to 66.7 kt/yr); 33 districts in 2035 (demand ranging from 1.5 to 69.6 kt/yr). In both cases, NRW is expected to cover the main share of the entire demand (46% in 2025, 33% in 2035).

5.1.2 North Rhine-Westphalia

In the present section, the regional hydrogen demand for NRW and its allocation on its districts is presented. Figure 25 and Table 38 shows the breakdown of the demand according to sector for the years 2025 – 2030 – 2035. Within the framework of an overall three-fold increase of the amount of demanded hydrogen, over the 10-year period under analysis, the initial primacy of the industrial sector gradually gives way to hydrogen mobility by cars, trucks and light commercial vehicles. If compared with Figure 23 in the previous section, it can be noticed that this is similar in trend and order of magnitude to the picture on country level; still, some slight differences can be pointed out. In the hydrogen demand evolution over time, industry plays a more relevant role for NRW than for the whole country (with a larger share by 8% on average). Within the mobility sector in NRW, buses and trains hold a smaller share than in the whole Germany over time; cars and trucks/LCVs play the main role, in line with the expected national trend, however cars have smaller shares on average (8.4%, 26.4% and 24.0% for NRW vs. 12.6%, 35.9% and 31.5% for Germany), whereas trucks/LCVs start by smaller shares compared to the national level (11.6% for NRW vs. 15.1% for Germany) and end up with a larger share (28.5% for NRW vs. 26.0% for Germany). Also, trucks/LCVs end up becoming the main contributors to hydrogen demand within transportation and this is opposite to the national trend where cars are more significant.

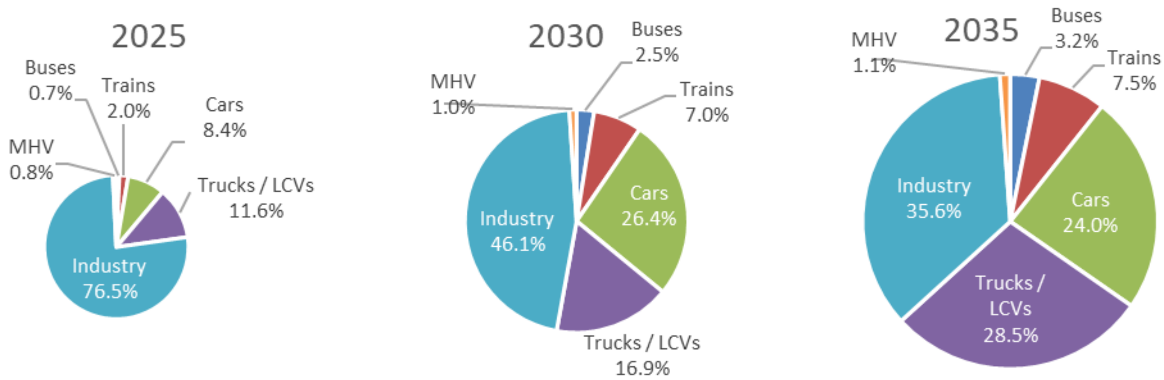


Figure 25 FINE-NESTOR hydrogen demand breakdown according to sector, for the years 2025 – 2030 – 2035 (NRW). The surface of the circles represents the total demand: the surface increase indicates the demand increase over time.

Table 37 NRW hydrogen demand for the timeframe 2025-2035 (H2MIND aggregation)

H_2 demand [kt/yr]	2025	2030	2035
Buses	1.21	8.42	16.63
Trains	3.55	23.32	38.84
Private cars	8.65	58.47	88.81
Commercial cars	6.36	29.11	35.77
Public HDVs and LCVs	10.38	27.23	65.44
Commercial HDVs and LCVs	10.35	28.97	82.78
MHVs	1.36	3.48	5.87
Industry	136.01	152.96	185.03
TOTAL NRW	**177.87**	**331.97**	**519.16**

Looking to the spatial distribution of the global demand within NRW, the combination of FINE-NESTOR amounts with the allocation factors from H2MIND model, the resulting configuration is shown by Figure 26.

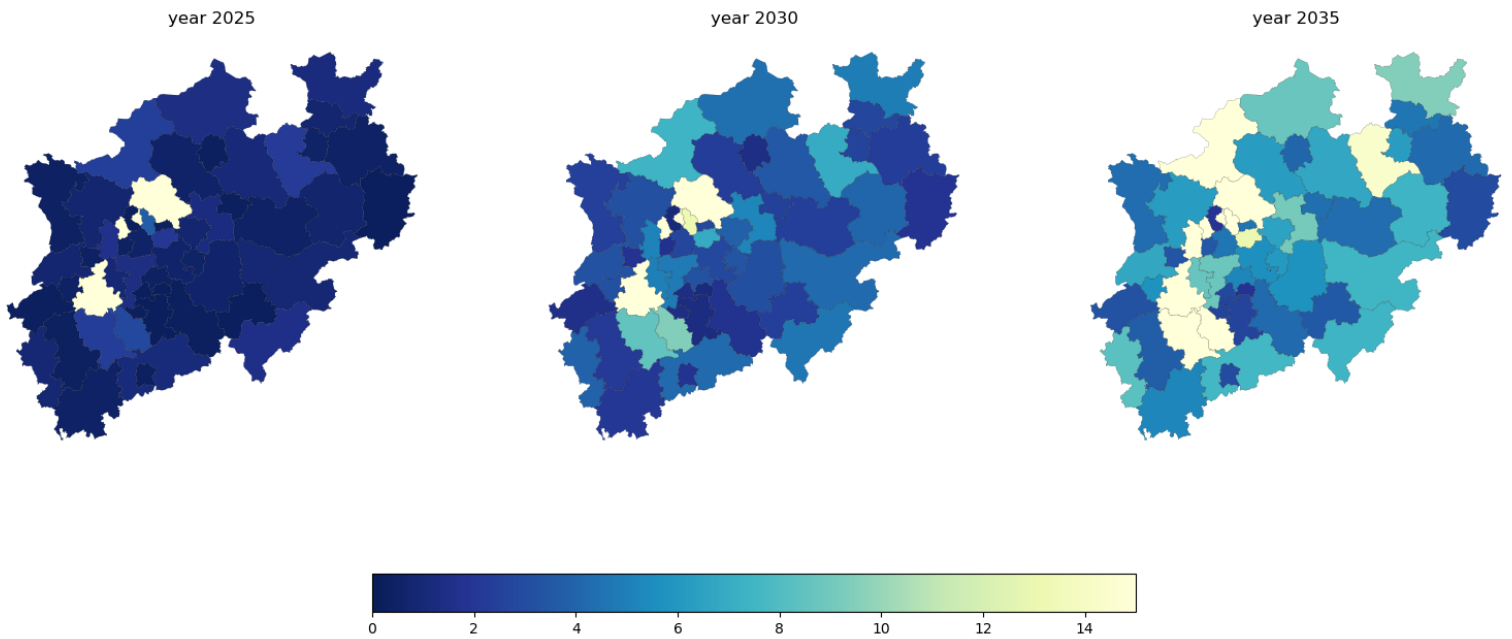


Figure 26 Spatial distribution of total hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

At the beginning of the investigation timeframe (2025), three districts are concentrating 76% of H_2 demand within the whole region: Oberhausen (67.7 kt/yr), Rhein-Kreis Neuss (52.1 kt/yr) and Recklinghausen (15.8 kt/yr). For these districts, driver is the industrial sector, being the sector represented in NRW by production of ammonia and chemicals in Oberhausen, Marl and Dormagen. Hydrogen demand is then expected to grow over this North-South direction within the region, gradually extending the list of major H_2-consuming districts to 10 in 2035: in addition to Rhein-Kreis Neuss (65.8 kt/yr), Oberhausen (56.3 kt/yr), and Recklinghausen (20.0 kt/yr), relevant are Duisburg (35.7 kt/yr), Gelsenkirchen (30.4 kt/yr), Rhein-Erft-Kreis (21.7 kt/yr), Köln (16.9 kt/yr), Borken (15.9 kt/yr), Bochum (13.1 kt/yr). Responsible for this is still the industrial sector, which sees the increase of importance of steel production and methanol – with plants in Duisburg (steel), Gelsenkirchen and Wesseling (methanol). Gütersloh (14.3 kt/yr), on the North-East part of the region, is to mention as well, in connection with mobility – commercial fleets of trucks and LCVs seem to play a relevant role there. On average, the demand in the remaining districts increases from 0.8 to 5.3 kt/yr over 10 years.

Looking into the distribution of NRW hydrogen demand according to the consuming technology, the resulting configuration is reported in Figure 46 to Figure 53 in Appendix E. A general comment can be made, that, regardless of the specific H_2-based technology taken into consideration, peak demand always occurs at districts of Metropolregion Rhein-Ruhr (MRR). Recurrent districts are: Köln, Bochum, Oberhausen and Rhein-Kreis Neuss. This can be explained by thinking that MRR is a very populated area concentrating alone around 55% of NRW inhabitants, with high density (1478 inhabitants/km² in MRR in comparison with 526 inhabitants/km² in NRW) [225], and population is a key factor for hydrogen demand in the case of passenger cars and public mobility (bus and trains). Aachen and Borken are also very relevant, for bus and commercial HDV/LCV demand, even if they lie outside the MRR region (Table 38): Aachen is reported to offer the largest bus fleet and the largest bus depot in NRW (ASEAG: 498 total vehicles, 300 vehicle in bus depot [226], [227]), this accounting for the highest ranking for bus demand. Borken shows the largest commercial area in NRW.

Table 38 Peak demand districts in NRW, years 2025 and 2035

	2025		2035	
Total demand	Oberhausen	67.7 kt/yr	Rhein-Kreis Neuss	65.8 kt/yr
Bus	Aachen (no MRR)	0.09 kt/yr	Aachen (no MRR)	1.2 kt/yr
Train	Köln	1.18 kt/yr	Köln	4.0 kt/yr
Private Car	Köln	0.36 kt/yr	Köln	3.0 kt/yr
Commercial Car	Bochum	0.8 kt/yr	Bochum	0.8 kt/yr
HDV	Köln	0.6 kt/yr	Köln	3.6 kt/yr
Commercial HDV	Borken (no MRR)	1.3 kt/yr	Borken (no MRR)	9.9 kt/yr
MHV	Köln	0.2 kt/yr	Köln	0.4 kt/yr
Industry	Oberhausen	66.7 kt/yr	Rhein-Kreis Neuss	55.3 kt/yr

5.2 Comparison between hydrogen supply chain pathways

As stated in section 4.6, in line with the conclusions by Cerniauskas et al. [22], [212], four hydrogen supply chain pathways were chosen for the investigation, being appointed as the most interesting for shaping a national hydrogen infrastructure in Germany from a techno-economic point of view and differing by the configuration of transport segment. Two totally based on trailers, for either gaseous or liquefied hydrogen; two including hydrogen pipelines, either built as new or obtained from reassignment of existing natural gas ones. They are listed in Table 36. The comparison of the weighted average TOTEX [€/kg H_2] and their trend over the period 2025-2035, calculated on nation-wide level, is shown in Figure 27 and Table 39.

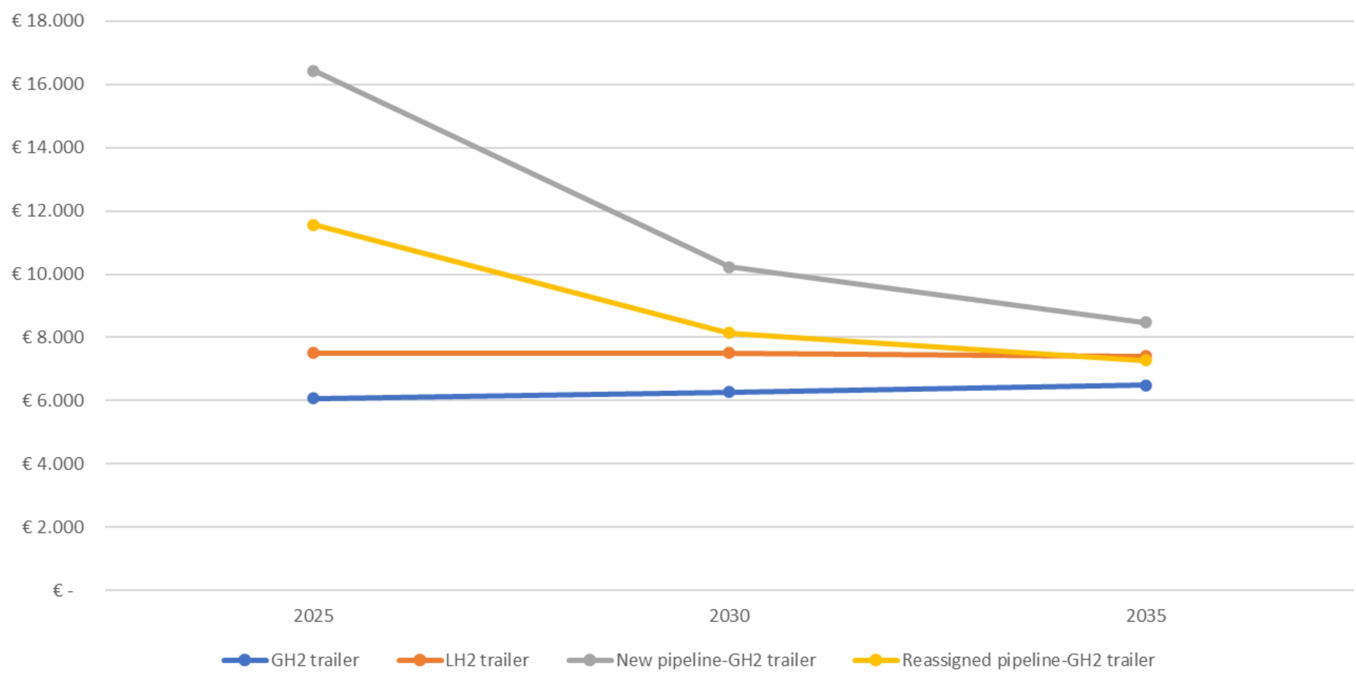


Figure 27 Weighted average TOTEX [€/kg H_2] trend over the period 2025-2035

Table 39 Weighted average TOTEX [€/kg H_2] trend over the period 2025-2035

Weighted TOTEX [€/kg]	2025	2030	2035
GH_2 trailer	6.070	6.270	6.490
LH_2 trailer	7.505	7.501	7.401
New pipeline-GH_2 trailer	16.441	10.222	8.481
Reassigned pipeline-GH_2 trailer	11.561	8.137	7.269

It can be noticed that, over the period under analysis (2025-2035), which still corresponds to the early stage of hydrogen infrastructure development and diffusion, trailers are the most economical solution. Gaseous hydrogen trailers are by far the cheapest solution for the whole transport segment over the period under analysis. This can be understood by considering that this supply chain pathway has the simplest configuration, meaning that critical capital-intensive assets are not required here, like pipelines or liquefaction units. An increasing trend can be notice for the gaseous hydrogen trailer option, shifting the cost between 6.0-6.5 €/kg. Liquefied hydrogen is the second most economical infrastructure configuration. Even if very slight, a decreasing trend can be notice for the liquefied hydrogen trailer option, with a cost moving 7.5-7.4 €/kg. Results show that, by 2035, LH_2 trailers are expected to enter competition with the pipeline-based configuration: both options show a net decreasing cost over time – new H_2 pipelines lowering from 16.4 to 8.5 €/kg and reassigned NG pipelines from 11.6 to 7.3 €/kg; still, only the NG pipeline reassignment strategy can reach real competition with trailer-based configuration within the observed timeframe.

For a better understanding of the resulting cost trends, it is necessary to look into the breakdown of the weighted average TOTEX among the single steps in the hydrogen supply chain pathway. Figure 28 and Table 40 shows the cost breakdown for the four investigated pathways and their evolution over time.

For *GH_2 trailer*, almost half of the cost is to be attributed to hydrogen sourcing. Electrolysis, SMR and import account for a share from 49% to 53% between 2025 and 2035. This relevance of hydrogen sourcing can be seen as the main responsible for the upward trend in weighted average TOTEX for GH_2 trailer pathway. Moving from 2025 to 2035, SMR, which is to date the consolidated conventional way of H_2 production, gradually reduces its share in final cost (from 1.5575 €/kg to 0.9995 €/kg), in favour to electrolysis and import (from 0.5360 €/kg to 1.0506 €/kg and from 0.8658 €/kg to 1.4184 €/kg, respectively), which have a higher marginal cost. This is due to the lower share of SMR within total H_2 production and increasing share of electrolysis (green H_2) and import (blue/green H_2), which is in line with the target of reducing CO_2 emissions Transport is also another relevant contributor to GH_2 trailer pathway cost , with a downward trend over time (1.6497 €/kg to 1.3263 €/kg) but not enough to offset the general cost increase. The cost of Transport mainly corresponds to the cost of trailer vehicles, and a decrease in corresponding TOTEX might be related to a higher utilization factor of the trailer fleet – for example, fixed costs related to the fleet could be beneficially allocated on a larger number of trucks and a larger overall hydrogen quantity. Fuelling seems to play a relevant role too, also showing an overall increase over time from 0.7584 €/kg to 1.0550 €/kg. As for Fuelling, it could be expected that the average size of the components of installed HRSs increases, taking advantage of economies of scale; still it might be that this effect is not enough to compensate the overall TOTEX cost increase due to the larger number of new HRSs to be installed; in such a situation, the prevailing effect is this second one of marginal cost.

Similar trends can be identified for *LH_2 trailer* – upward for Sourcing, downward for Transport, upward for Fuelling. In this case, however, the Liquefaction stage ("Connector") is particularly relevant for cost determination: it shows a dramatic downward trend over time (2.6205 €/kg to 1.5561 €/kg), which can be justified by a gradual increase of the asset utilization factor. The better use of liquefaction plants has a beneficial impact on overall pathway cost, so that in the end the global cost trend is slightly downward (7.5054 €/kg to 7.4012 €/kg).

Cost trends in the pipeline-based pathways – *New H_2 pipeline* and *Reassigned NG pipeline* – are very similar. Despite the above-described upward trend for Sourcing and Fuelling can be noticed in these cases as well, a sharp cost decrease over time is the main feature here. This is connected to the upstream part of Transport, based on pipeline network, which is expected to show an increased utilization factor over time (due to the expected higher H_2 volumes to be transported), thus a better use of the asset. The difference between the two pathway cost structures consists of the nature of the pipeline network: it is easy to understand that the case of reassignment of existing NG pipelines shows a more economical transport cost (6.7014 €/kg to 1.6406 €/kg) compared to the case of newly-built dedicated H_2 pipelines (11.5808 €/kg to 2.8518 €/kg) – 42% lower cost on average from 2025 to 2035.

From the point of view of hydrogen sources, all of the four cases result in a similar supply configuration for the period 2025-2030-2035. As an example, Figure 29 shows the source composition for the "GH_2 trucks" pathway: it can be noticed that RES-based electrolysis ("Wind") and Import ("Port") increase their importance over time, growing from 6% to 18% and from 21% to 35% respectively. On the opposite, SMR ("Blending") gradually reduces its role, falling from 72% to 46%.

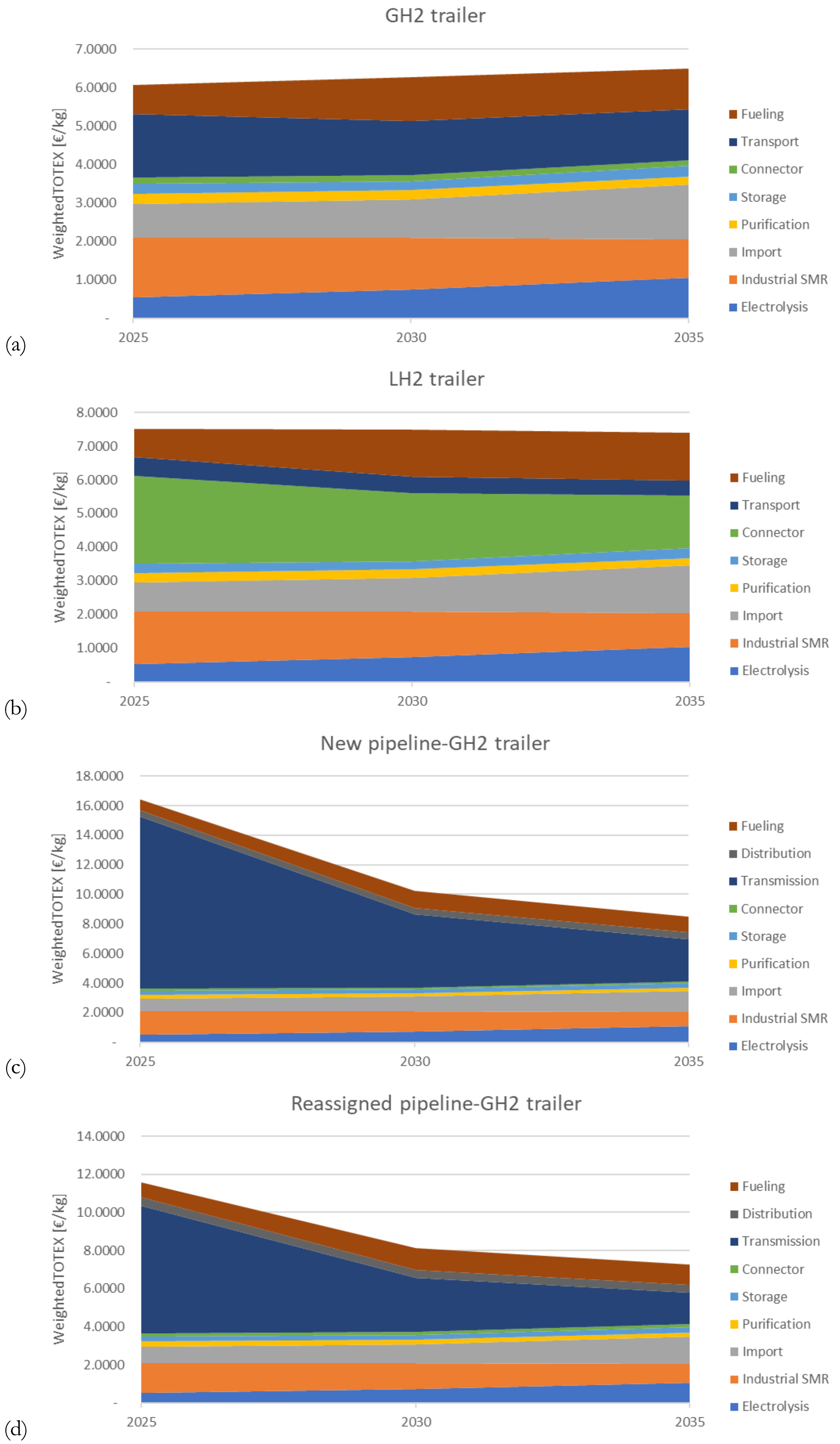


Figure 28 Weighted average TOTEX breakdown into single supply chain steps (a) GH_2 trailers; (b) LH_2 trailers; (c) New H_2 pipelines + GH_2 trailers; (d) Reassigned NG pipelines + GH_2 trailers.

Table 40 Weighted average TOTEX breakdown into single supply chain steps (a) GH2 trailers; (b) LH2 trailers; (c) New H2 pipelines + GH2 trailers; (d) Reassigned NG pipelines + GH2 trailers.

(a) GH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0506
Industrial SMR	1.5575	1.3608	0.9995
Import	0.8658	0.9904	1.4184
Purification	0.2664	0.2455	0.2100
Storage	0.2673	0.2292	0.2799
Connector	0.1687	0.1478	0.1499
Transport/Distribution	1.6497	1.4119	1.3263
Fueling	0.7584	1.1454	1.0550
weigh. TOTEX [€/kg]	**6.0698**	**6.2699**	**6.4896**

(b) LH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0506
Industrial SMR	1.5575	1.3608	0.9995
Import	0.8616	0.9857	1.4118
Purification	0.2736	0.2529	0.2159
Storage	0.2772	0.2379	0.2894
Connector	2.6205	2.0253	1.5561
Transport/Distribution	0.5481	0.4812	0.4571
Fueling	0.8309	1.4184	1.4208
weigh. TOTEX [€/kg]	**7.5054**	**7.5011**	**7.4012**

(c) New pipeline – GH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0729
Industrial SMR	1.5575	1.3608	0.9875
Import	0.8658	0.9904	1.4247
Purification	0.2664	0.2455	0.2100
Storage	0.2673	0.2292	0.2813
Connector	0.1632	0.1437	0.1465
Transport	11.5808	4.9272	2.8518
Distribution	0.4452	0.4407	0.4508
Fueling	0.7584	1.1454	1.0550
weigh. TOTEX [€/kg]	**16.4406**	**10.2218**	**8.4805**

(d) Reassigned pipeline – GH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0729
Industrial SMR	1.5575	1.3608	0.9875
Import	0.8658	0.9904	1.4247
Purification	0.2664	0.2455	0.2100
Storage	0.2673	0.2292	0.2813
Connector	0.1632	0.1437	0.1465
Transport	6.7014	2.8420	1.6406
Distribution	0.4452	0.4407	0.4508
Fueling	0.7584	1.1454	1.0550
weigh. TOTEX [€/kg]	**11.5612**	**8.1366**	**7.2693**

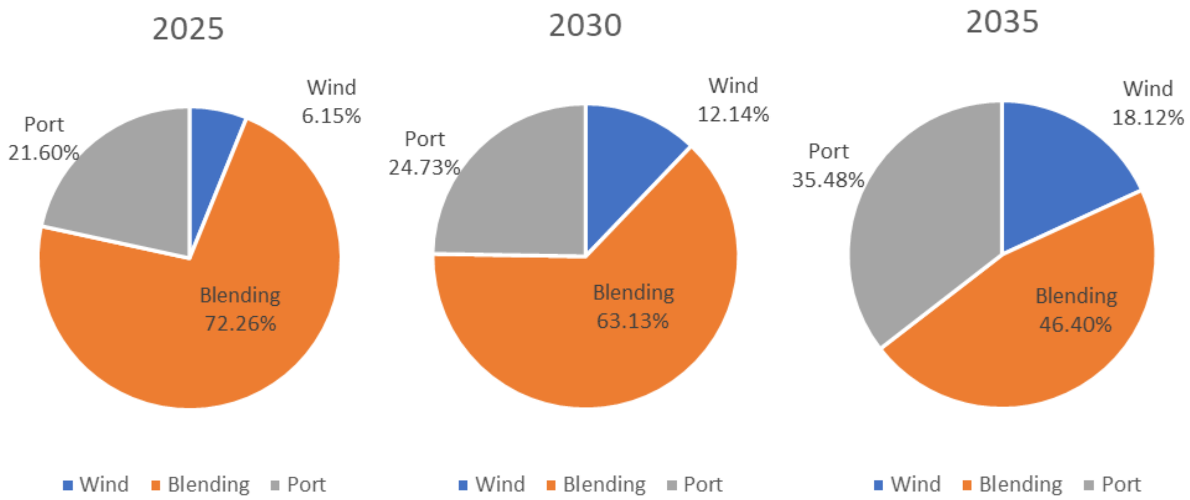


Figure 29 Hydrogen source composition for the period 2025-2030-2035 ("GH_2 trucks" pathway)

5.3 Focus: hydrogen buses

From Section 5.1, it could be noticed that hydrogen-based buses do not represent a very significant share of hydrogen demand over the investigated period: in 2035, they only get to exceed 5% of overall German demand and 3% in NRW. Thus, from the point of view of overall supply chain cost determination, the impact is also very limited. The difference between weighted average TOTEX for the cases (a) with hydrogen-based buses and (b) without buses can be calculated (Table 41): in terms of absolute values and percentage out of cost (a), such a difference does not exceed 0.7% over time for the fully trailer-based pathways (GH_2 and LH_2 trucks); it reaches higher values for the pipeline-based pathways (newly-built and NG-reassigned), even though it does not exceed 2.3%.

Even if the contribution to the whole hydrogen demand and infrastructure cost determination is not very relevant within the timeframe 2025-2035, the reader is to be reminded that this does not mean that hydrogen-based buses have no potential as drivers in the creation of a future hydrogen infrastructure. As reported already by Cerniauskas et al. [22], [212], thanks to the nature of the service they offer (public transportation) and the fixed structure of their schedules (tracks and timetable), if provided with dedicated HRSs at depots for refuelling at the end of the daily shift, buses can most likely ensure them high utilization factors (70% or more). This is an interesting aspect that buses share with all other fleet-based vehicles, such as trains, cars (e.g., taxis, commercial fleet of companies) or LCVs/HDVs (e.g. delivery services, road-cleaning vehicles): high utilization helps reduce the time to breakeven (thus, the risk) for the investment in HRSs, which is particularly critical in the very first stage of infrastructure development.

Table 41 Weighted average TOTEX for hydrogen supply chain pathways in the case (a) with and (b) without buses

Weighted average TOTEX [€/kg H_2]	(a) All technologies			(b) All technologies, excluding buses			% difference, ((a) – (b))/(a)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
GH_2 trucks	6.0698	6.2699	6.4896	6.0297	6.2852	6.5130	0.7%	-0.2%	-0.4%
LH_2 trucks	7.5054	7.5011	7.4012	7.4713	7.5209	7.4294	0.5%	-0.3%	-0.4%
New pipelines	16.4406	10.2218	8.4805	16.5712	10.4536	8.6471	-0.8%	-2.3%	-2.0%
Reassigned NG pipelines	11.5612	8.1366	7.2693	11.6184	8.2752	7.3751	-0.5%	-1.7%	-1.5%

For the simulated cases, the resulting size of bus-related HRSs was investigated. HRSs were classified according to their capacity into five size categories – S, M, L, XL, XXL. The comparison was done using the maximum yearly hydrogen demand [kt/yr] range of each class as reference (obtained by the assumption of utilization factor 70%). The daily capacity [t/day] range for each class is reported in Table 42.

Table 42 H2MIND classes for bus-related HRSs classification

HRS size	Capacity [t/day]	
	From:	**To:**
S	0	0.212
M	0.212	0.42
L	0.42	1
XL	1	1.5
XXL	1.5	3
XXL+	3	onwards

Figure 30 shows the frequency distribution of sizes of the HRSs simulated within the adapted H2MIND model. The reader can notice an expected average gradual increase in size for bus-related HRSs over the observed period 2025-2035. In 2025, almost the totality of HRSs is expected to range below a capacity of 0.212 t/day; in 2030, HRSs are distributed over M size – with 61%, net majority – and L size (35%); In 2035, 80% of HRSs are expected to have a capacity between 0.42 and 1 t/day (L size) and around 13% a capacity between 1 and 1.5 t/day (XL size). Looking into the geographical distribution of bus-related HRSs, maps are reported in Appendix F and Appendix G, for Germany and NRW respectively. A small replica of the maps for Germany is reported in Figure 31 as example. These maps show the location of the bus-related HRSs assumed for the simulation (i.e., existing bus depots in NRW, unit centroids in all other districts) and markers change in size and colour according to the expected size of HRS. NRW region (lighter orange) and MRR area (darker orange) are highlighted. These maps show that Berlin, Aachen, Hamburg, München, Köln and Hannover result in the largest HRSs for buses, even larger than XXL-size in 2035 – it is to be noticed that two out of these six districts are in NRW (Aachen and Köln).

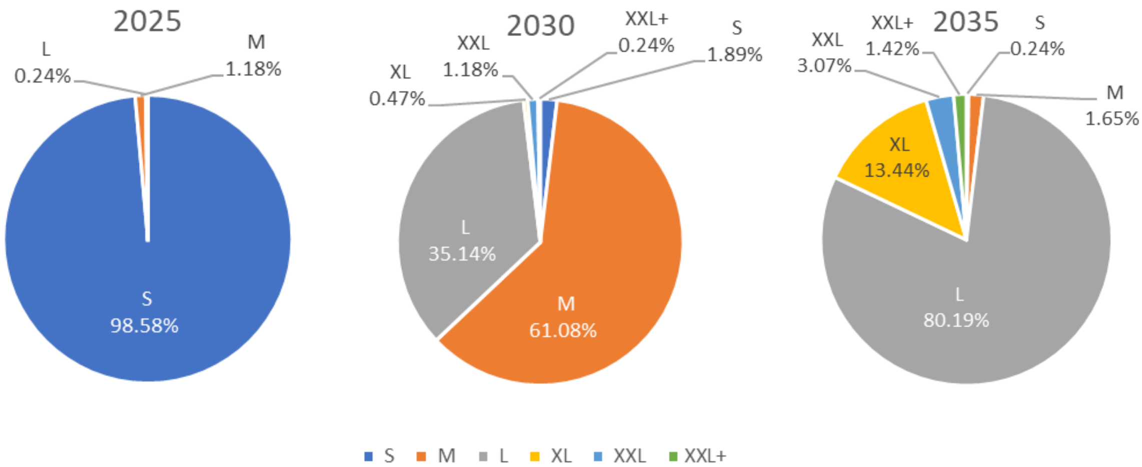


Figure 30 Frequency distribution of bus-related HRS in Germany, based on their capacity [kt/yr]

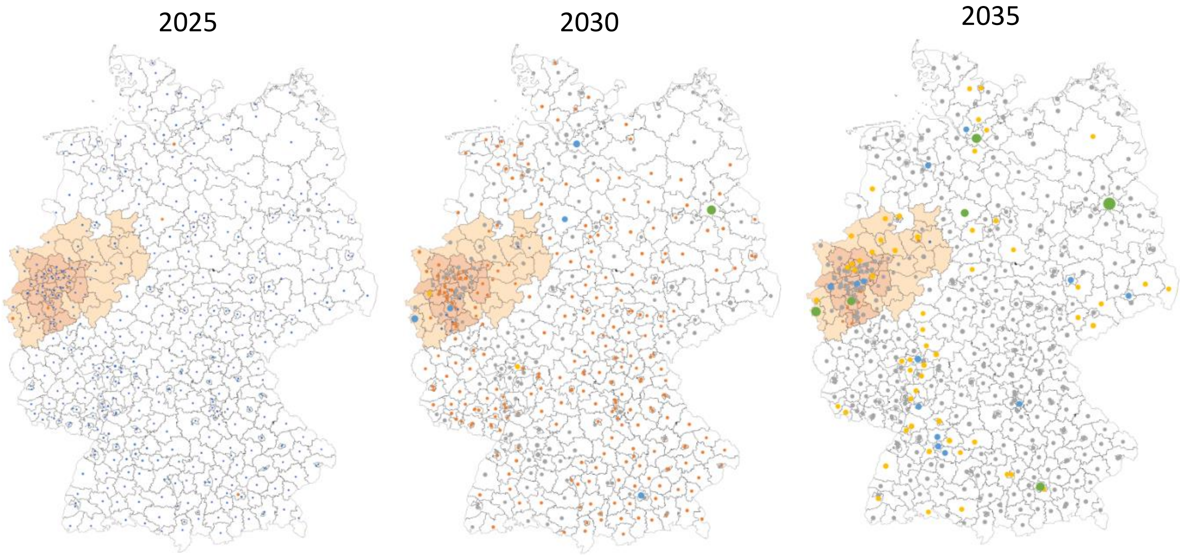


Figure 31 Spatial distribution of bus-dedicated HRSs in Germany, over time (2025 – 2030 – 2035).

Figure 32 and Figure 33 show the situation withing the sole NRW region. It can be noticed that all sizes of HRSs for buses are expected to develop within the region, with majority of L size expected for 2035 (62% of considered locations) and a significant share of even larger stations – from XL on (21%). Out of this latter category, Aachen and Köln are in the over-XXL class; Mönchengladbach and Wuppertal in XXL size class; Bielefeld, Hagen, Heinsberg, Borken, Coesfeld, Steinfurt, Warendorf, Oberhausen, Bottrop, Recklinghausen, Essen, Münster are in the XL size class.

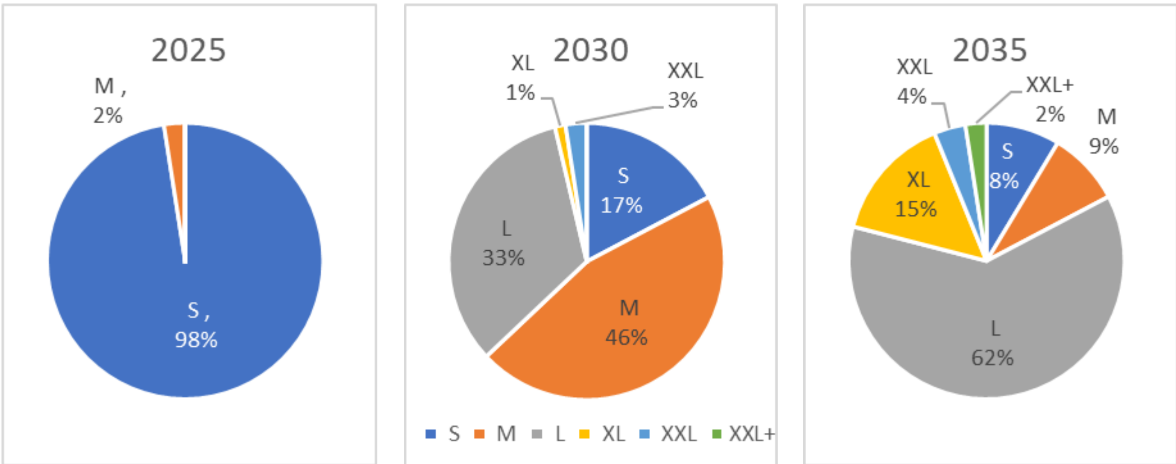


Figure 32 Frequency distribution of bus-related HRS in Germany, based on their capacity [kt/yr]

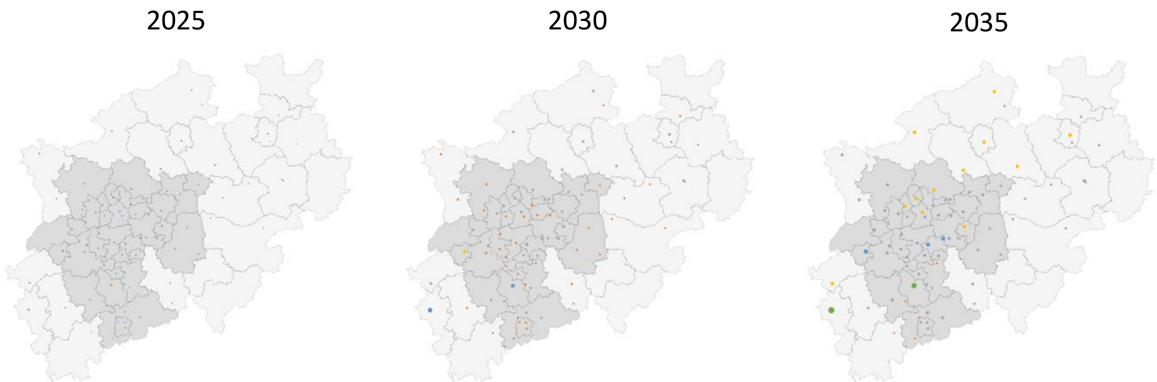


Figure 33 Spatial distribution of bus-dedicated HRSs in NRW, over time (2025 – 2030 – 2035).

5.4 Focus: onsite electrolysis for bus HRSs

The present thesis also considered the case of *onsite electrolysis* at bus depots (HRSs for buses), as anticipated in Section 4.6. As the reader will recall, the simulated scenario includes demand coverage by onsite electrolysis up to a certain target (from 25% to 100%) and compatibly with the constraint of 1 MW as minimum size for electrolysers; the rest of bus demand is complemented by the backing centralized infrastructure, shaped according to the supply chain pathway "GH_2 truck". The trend of the overall TOTEX over the period 2025-2035 for different shares of hydrogen self-sufficiency at bus HRSs (0% - 25% - 50% - 75% - 100%) is shown in Figure 34. It can be noticed that, in general, for the investigated timeframe, a fully centralized configuration is the most economical option (between 6 and 6.5 €/kg H_2). The 'onsite' options range on higher values over the investigated timeframe (between 6.8 and 8.4 €/kg H_2). In the beginning (2025), a decrease in TOTEX can be observed with increasing share of onsite electrolysis. Over time, though, an inversion in trends can be observed, with TOTEX increasing with increasing onsite hydrogen-generation component.

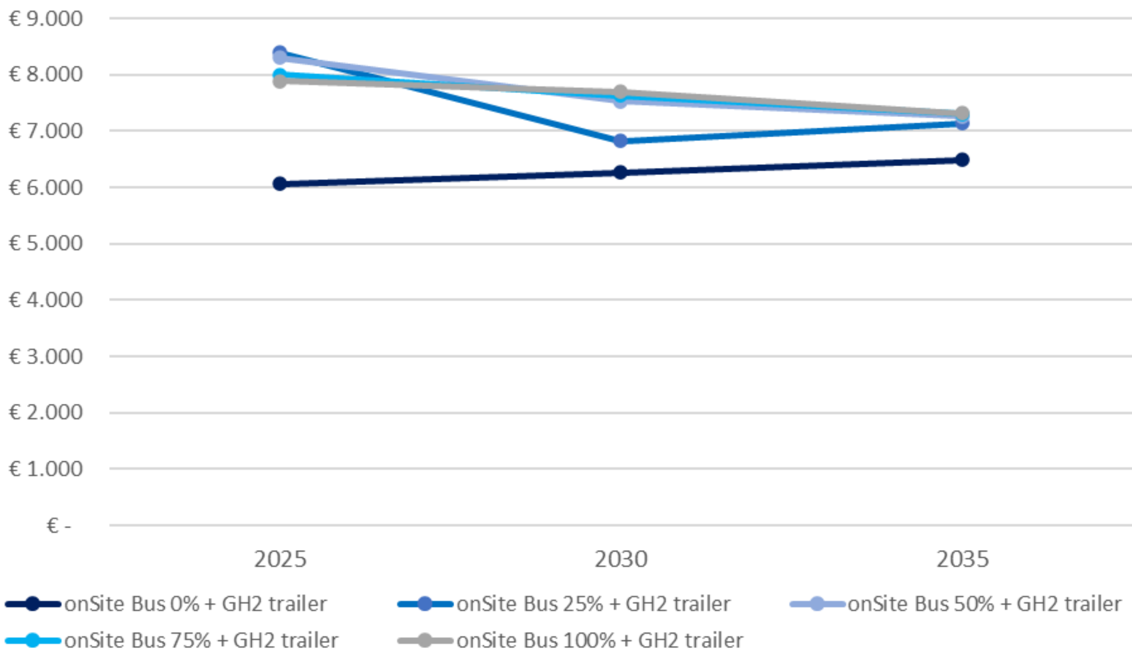


Figure 34 Weighted average TOTEX trend over the period 2025-2035 for the onsite electrolysis (bus HRS) scenario

In order to explain such a behaviour, the TOTEX trends of the single (a) 'onsite' and (b) 'complementary centralized' are reported in Figure 35.

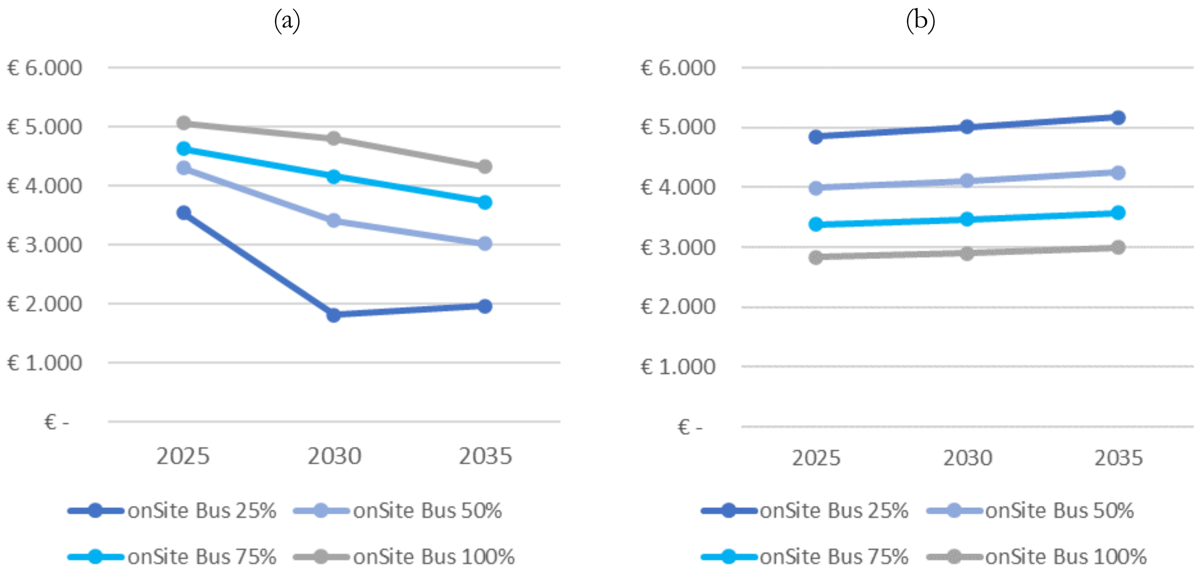


Figure 35 TOTEX trends of the single (a) 'onsite electrolysis' at bus HRSs and (b) 'complementary centralized' hydrogen pathway (GH_2 truck)

A clear behaviour can be identified for both (a) and (b). On the one hand, in the case of onsite electrolysis pathway, a reduction of supply chain cost is expected. This can be explained by positive effects of economy of scale, since the hydrogen demand for buses is expected to increase over time. However, increasing the share of bus-related H_2 demand has an expected opposite effect of increasing overall costs, since larger sizes are required in general. On the other hand, the case of complementary centralized pathway, is in line of what is presented in Section 5.2, that is an upward trend in overall hydrogen supply chain cost over time. From the point of view of the share of bus-related H_2 demand covered by onsite electrolysis, the behaviour in this case is opposite to case (a). The higher the share, the less is demanded to the centralized infrastructure, so lower costs are expected.

All in all, two opposite trends can be observed for the two cases (a) and (b) if taken individually; if combined, the cost-reducing effect of the introduction of onsite electrolysis is stronger than the cost-increasing drive of the centralized pathway, to the extent that an inversion in cost trends is expected – in other words, if in 2025 the case of 100% and 25% electrolysis onsite look, respectively, as the most and least economical configurations, in 2035 the scenario is completely subverted. As anticipated, over the timeframe 2025-2035, a completely GH_2 trailer-based hydrogen supply chain pathway looks undoubtedly as the most convenient option for a first-phase infrastructure in Germany; still, the downward trend in the 'onsite+centralized' configuration suggests the achievement of a cost parity after 2035: in the period 2025-2035, the benefit of onsite green hydrogen production does not look yet as an interesting option to harvest, however the market could push the national hydrogen ecosystem towards a gradual shift to bus station self-sufficiency in the future.

To complete the overview on bus-related HRSs, the expected hydrogen demand [kt/yr] for onsite and centralized cases, the expected electrolyser installed power capacity [MW], number of involved stations, and the cost breakdown [€/kg H_2] can be discussed.

Figure 36 and Table 43 show the split of the expected hydrogen demand [kt/yr] between onsite and centralised electrolysis over time in the different onsite production scenarios. The assumption of 1 MW as minimum size of electrolysers in terms of techno-economic feasibility affects the share of demand by buses fulfilled onsite. It can be noticed that bus demand is mainly covered by the backing centralized infrastructure in 2025 for all of the four scenarios, being the expected size of bus HRS still too small to afford to a dedicated onsite electrolyser; however, starting from 2030, the target of onsite production looks quite completely achievable by all scenarios (except for '25%'), with '75%' and '100%' meeting it fully in 2035. It is to be reminded that, for the simulated scenarios, both onsite and centralized contributions are sourced as green hydrogen, in line with the source composition foreseen for the pathway “GH_2 trucks” in Section 5.2.

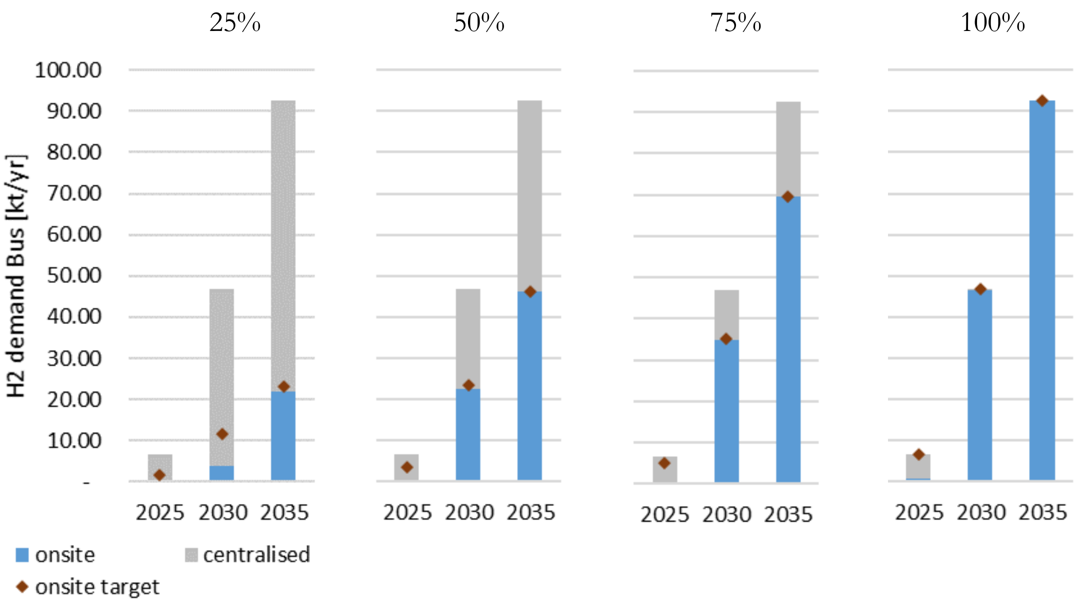


Figure 36 Split of bus-related hydrogen demand between onsite and centralized production, for the 4 simulated scenarios

Table 43 Split of bus-related hydrogen demand between onsite and centralized production, for the 4 simulated scenarios

H_2 demand Bus [kt/yr]		**2025**	**2030**	**2035**
onSite Bus 25%	onsite (target)	0.04 (1.69)	3.87 (11.71)	21.99 (23.14)
	centralised	6.71	42.98	70.55
onSite Bus 50%	Onsite (target)	0.23 (3.37)	22.60 (23.43)	46.07 (46.27)
	centralised	6.52	24.25	46.48
onSite Bus 75%	Onsite (target)	0.39 (5.06)	34.95 (35.14)	69.41 (69.41)
	centralised	6.36	11.90	23.14
onSite Bus 100%	Onsite (target)	0.83 (6.75)	46.64 (46.85)	92.54 (92.54)
	centralised	5.92	0.21	0.00
	Total	**6.75**	**46.85**	**92.54**

Table 44 show the total required capacity [MW] for onsite electrolysers, with detail of minimum and maximum expected size and the number of HRSs equipped with one. It is easy to notice that numbers increase with the increasing target share of onsite bus-related hydrogen demand coverage. Among all considered HRSs, Berlin is expected to show the largest installed capacity.

Table 44 Required capacity for onsite electrolysis at bus-related HRSs, according to the different cases: (a) 25%, (b) 50%, (c) 75%, (d) 100% onsite

onSite Bus 25%	2025	2030	2035
Total capacity onsite [MW]	1.2	120.4	644.3
Max [MW]	1.3	8.6	15.9
Min [MW]	1.3	1.0	1.0
Number of stations	1	79	383

onSite Bus 50%	2025	2030	2035
Total capacity onsite [MW]	7.53	703.5	1349.6
Max [MW]	2.6	17.1	31.8
Min [MW]	1.0	1.0	1.2
Number of stations	5	393	417

onSite Bus 75%	2025	2030	2035
Total capacity onsite [MW]	12.7	1087.9	2033.4
Max [MW]	3.9	25.7	47.8
Min [MW]	1.4	1.9	1.2
Number of stations	6	416	424

onSite Bus 100%	2025	2030	2035
Total capacity onsite [MW]	26.9	1451.8	2711.2
Max [MW]	5.1	34.3	63.7
Min [MW]	1.0	1.3	1.5
Number of stations	15	417	424

Figure 37 and Table 45 show the breakdown of the weighted average TOTEX for the 'GH_2 trailers' pathway according to the different cases of onsite electrolysis at bus-related HRSs. From the point of view of relevance, electrolysis and fuelling (both as results of onsite and centralized contributions) are the main cost components in 2025 for all the four considered cases; in 2035, electrolysis becomes the main cost component, becoming more and more significant with the increasing share of onsite production. For each of the supply chain steps except for electrolysis, a gradual decrease in costs can be observed when the share of onsite production is increased. Electrolysis shows the opposite trend, that is cost increase with increasing share of onsite hydrogen production due to the prevalence of onsite production costs over centralized electrolysis. The opposite trends in electrolysis can be explained considering two different effects – the reader can refer to Appendix H for the graphical detail of the cost trends: on the one hand, marginal costs are important for onsite production – that is, more dedicated electrolysers are to be installed in a larger number of HRSs with increasing bus-related demand over time, thus increasing the required investment; on the other hand, centralized electrolysis seems to require general non-dedicated electrolysers which reduce their specific cost with increasing hydrogen demand due to more intense utilization (larger utilization factors). Looking to the evolution of costs over time, detailed graphs (also making the distinction between onsite components and components within the centralized infrastructure) are provided in Appendix H. The combination of larger utilization factors of the installed/already existing components (responsible for a TOTEX cost decrease with demand increase over time) with the impact of marginal costs (responsible for a TOTEX cost increase with the increasing number of installed components from one year to the next one) can be identified as the driver of each single cost trend.

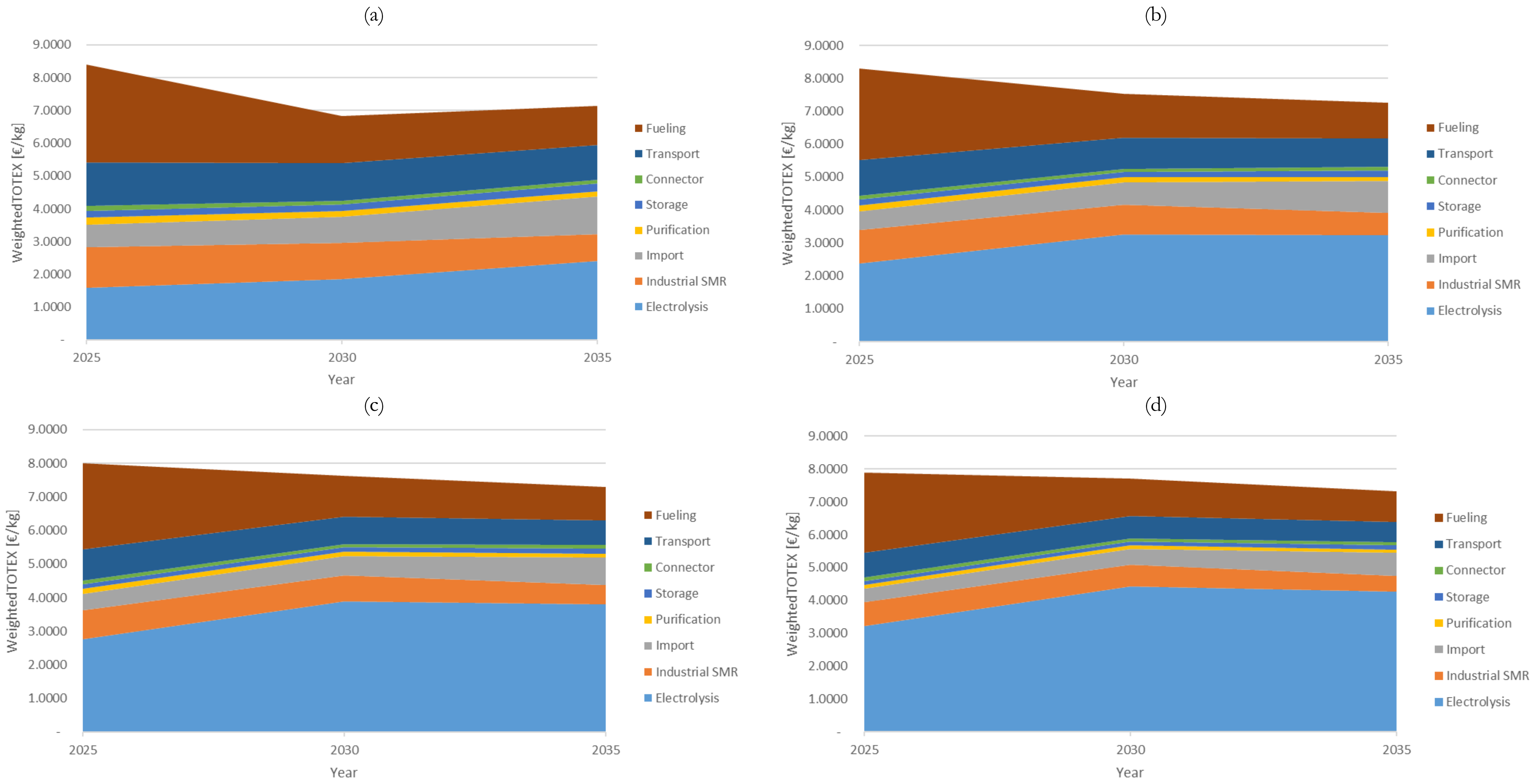


Figure 37 Weighted average TOTEX breakdown for 'GH$_2$ trailers' pathway according to the different cases of onsite electrolysis at bus-related HRSs: (a) 25%, (b) 50%, (c) 75%, (d) 100% onsite

Table 45 Weighted average TOTEX breakdown for 'GH$_2$ trailers' pathway according to the different cases of onsite electrolysis at bus-related HRSs: (a) 25%, (b) 50%, (c) 75%, (d) 100% onsite

(a) onSite Bus 25%	**2025**	**2030**	**2035**
Electrolysis	1.5814	1.8617	2.4177
Industrial SMR	1.2446	1.0910	0.8082
Import	0.6919	0.7947	1.1486
Purification	0.2128	0.1955	0.1657
Storage	0.2135	0.1832	0.2253
Connector	0.1406	0.1244	0.1279
Transport/Distribution	1.3199	1.1326	1.0607
Fueling	2.9887	1.4424	1.1839
weigh. TOTEX [€/kg]	**8.3933**	**6.8255**	**7.1380**

(b) onSite Bus 50%	**2025**	**2030**	**2035**
Electrolysis	2.3652	3.2524	3.2393
Industrial SMR	1.0267	0.9157	0.6753
Import	0.5708	0.6670	0.9582
Purification	0.1755	0.1592	0.1349
Storage	0.1758	0.1509	0.1870
Connector	0.1211	0.1104	0.1117
Transport/Distribution	1.0887	0.9460	0.8749
Fueling	2.7791	1.3274	1.0854
weigh. TOTEX [€/kg]	**8.3027**	**7.5292**	**7.2668**

(c) onSite Bus 75%	**2025**	**2030**	**2035**
Electrolysis	2.7575	3.8857	3.7953
Industrial SMR	0.8678	0.7830	0.5780
Import	0.4825	0.5704	0.8202
Purification	0.1482	0.1335	0.1125
Storage	0.1483	0.1273	0.1591
Connector	0.1061	0.0986	0.0998
Transport	0.9202	0.8065	0.7409
Distribution	2.7575	3.8857	3.7953
Fueling	2.5728	1.2240	0.9998
weigh. TOTEX [€/kg]	**8.0033**	**7.6291**	**7.3057**

(d) onSite Bus 100%	**2025**	**2030**	**2035**
Electrolysis	3.2138	4.4280	4.2624
Industrial SMR	0.7291	0.6647	0.4915
Import	0.4053	0.4842	0.6974
Purification	0.1243	0.1112	0.0933
Storage	0.1239	0.1065	0.1369
Connector	0.0935	0.0882	0.0891
Transport	0.7729	0.6828	0.6236
Distribution	3.2138	4.4280	4.2624
Fueling	2.4305	1.1334	0.9239
weigh. TOTEX [€/kg]	**7.8933**	**7.6989**	**7.3181**

6 Chapter 6 – Discussion

6.1 Recommendations for infrastructure deployment

In the light of the results shown in the previous Chapter, some considerations can be made around the strategies available for the deployment of a hydrogen infrastructure in Germany and, in particular, for the achievement of NRW targets to 2025 and 2030.

For the period 2025-2035 (start-up phase), investments should focus on high hydrogen-demand districts

The analysis of hydrogen demand distribution has highlighted some areas where the request for H_2 is expected to be concentrated. In order to minimize the risk associated to the investment in infrastructure components, it is highly recommended that financial support and initiatives should be oriented to these areas in the start-up phase, because they can offer higher levels of utilization of the infrastructural assets (e.g., new HRSs). NRW alone is expected to cover approximatively one third of the total German hydrogen demand. Within NRW, the relevance of a district depends on what hydrogen-consuming sector is considered. For *Mobility* and public transportation, based on the allocation factors used within H2MIND model, Köln ranks as the district with highest demand in many mobility sectors, looking as first priority region for mobility deployment initiatives. Other districts may result as relevant, depending on the kind of mobility in interest. For buses, Aachen, Wuppertal, Düsseldorf are the three top cities in the ranking (in addition to Köln).

For the period 2025-2035 (start-up phase), gaseous hydrogen trailers are the most convenient option for connecting production and consumption

As already discussed by Cerniauskas et al. [22], [212], pipelines will play a key role in the long-term hydrogen infrastructure. Looking into the weighted average TOTEX for the four analysed pathways, simulation results suggest that the cost curves will intersect after 2035, thanks to the increased hydrogen demand and the higher utilization factor for pipelines. In particular, the curve for NG pipeline reassignment will most likely reach the intersection point earlier than the curve for newly-built hydrogen pipelines, being this solution much more economical – it may cost up to 80% less than building new H_2 pipelines [222]. Still, H2MIND simulation results show that trailers for the transport of gaseous hydrogen represent the best option for the start-up phase of infrastructure deployment in Germany and NRW.

For the period 2025-2035 (start-up phase), a fully centralized green hydrogen production is to be preferred; onsite electrolysis will play a role in the longer term

Simulation results for different share of self-sufficiency at bus depots, from 0% (fully centralized configuration, no self-sufficiency) to 100% (total self-sufficiency, complete independent), show that the fully centralized hydrogen supply pathway is the best option for covering bus-related hydrogen demand in the introductory phase of hydrogen infrastructure creation. Nevertheless, cost curves for the cases with onsite electrolysis show a downward trend over time, which suggest that cost parity will be achieved in the future after 2035 – out of the scope of the present thesis. It is to be mentioned that the installation of local dedicated electrolysers at bus depots may be beneficial for cost recovery thanks to possible synergies with other energy services required by the bus depot – e.g., heat recovery. Similar virtuous effects can positively impact the cost curves, anticipating the moment for cost parity between a fully centralized green hydrogen generation pathway and the one with onsite installations. Indeed, onsite electrolysis could also bring advantages from the point of view of service promotion within the local community and of adoption by users, being it one way to achieve only green hydrogen being consumed by local bus fleet. Thus, it can be claimed that local public transport is carbon neutral (marketing).

6.2 Sustainability analysis

Considerations can be made about the sustainability of hydrogen supply chain and its possible pathways. When it comes to sustainability analysis, the three typical dimensions come into play: Environmental, Economic and Social. They can be related to the so-called 'Sustainable Development Goals' (SDGs) [228], a set of 17 interlinked global goals defined by the United Nations General Assembly in 2015 and intended to be achieved by 2030. They aim at ensuring a better and more sustainable future for all.

From the Environmental point of view, hydrogen could be an advantageous energy carrier. As already seen in the present thesis, its use can contribute to the decarbonization of hard-to-abate sectors, such as transports and certain industrial sectors. This aspect sounds particularly relevant for the contribution to *SDG7* and *SDG13*, which *'Ensure access to affordable, reliable, sustainable and modern energy for all'* and *'Take urgent action to combat climate change and its impacts'*. However, the real impact of hydrogen on CO_2 emissions depends on the specific pathway and on the specific technology adopted for each single step of the supply chain. This is particularly true for hydrogen generation. It can be considered completely carbon-free in the case of water electrolysis in combination of renewable energy ('green hydrogen'), not in the case of 'grey' and 'blue hydrogen' originated from fossil sources. It has been mentioned that green hydrogen represents only 1-2% of total hydrogen produced today: to promote decarbonization, it is therefore important to increase the share of clean green hydrogen. Not only would this mean covering for the already existing hydrogen uses, but also fulfilling the extra demand from new adoption of hydrogen technologies. The reader will agree that such a completely carbon-free scenario will not be a disruptive achievement, rather a gradual process. Green hydrogen is dependent on the diffusion of renewable energy capacity, which will need to raise from current levels. The need for more renewable energy for feeding electrolyzers will compete with the decarbonization process of the power system. Only about 30% of the electricity in Europe comes from renewables today [147]: it could be argued that new renewable capacities would first need to be deployed for the decarbonisation of the whole electricity sector, considering that injecting renewable electricity into the power grid for direct use will benefit from higher conversion efficiencies. In such a context, blue hydrogen may be a solution for the transitional phase, paving the way to green hydrogen. Although not completely carbon-free, it will generate lower emissions than traditional fossil-based hydrogen and it will foster adoption of hydrogen technologies. The need for a transition phase is recognized by the EU Commission in 2020 in the 'EU Hydrogen Strategy' [148]. In addition to this, increasing the renewable capacity to back the demand of green hydrogen will exacerbate the sustainability issues connected with the value chain of renewable sources – to make two examples: the environmental impact of the extaction of rare materials for wind and solar plants, the decommissioning of old installations and the recycling/disposing of their materials.

From the Economic point of view, it has been discussed that key to sustainability of the diffusion of hydrogen-based technologies may rise from the repurposing of existing infrastructure for Natural Gas. This may cost up to 80% less than building new H_2 pipelines [222] and may ensure a smoother transition to the cleaner gaseous commodity. Still, the problem lies in the cost of electrolysis, which is not yet competitive with traditional fossi-based technologies. Even assuming an average cost for unabated SMR hydrogen around 1.5-2 €/kg, electrolysis-hydrogen cost ranges between 3-5 €/kg (reference for Germany in [229]). Enough cost reductions and full maturity in technologies are still to be achieved, which is expected to happen no earlier than 2030. This justifies the role of public support in accelerating the adoption of hydrogen-based technologies, in order to foster the establishment of a self-sustaining market thorugh incentives, public projects and public-private business ventures. Although necessary in the initial stage, public initiatives and supporting mechanisms are to be designed in a way that facilitates gradual independence in order for hydrogen technologies to be sustainable economic wise in the long term.

From the Social point of view, Sustainability could be retraced in the fact that hydrogen infrastructure can build on the already existing infrastructure for Natural Gas. Not only may this be beneficial for the economic side of sustainability, it may also be accepted by the social community in consideration of the fact that job skills and competences will not different much from the one currently required (especially for the transportation and storage steps in the value chain, which would remain quite similar to the incumbent) or they can even expand and result in new job opportunities (in the areas of hydrogen production or of the numerous end-use applications, for example). The opportunity of rethinking the energy system, offered by the climate crisis and the strive for decarbonization, could also lead to rethinking social interactions on productive/economic level, experimenting models for commodity use which are 'more collective' and community-based. Renewable energies and their intrinsic modularity can leverage decentralization and promote the active role of consumers to so-called 'prosumers'. This is actually the key of 'hydrogen valleys': the creation of local ecosystems, with a community gathered and integrated around them, with a strong sense of ownership and commitment. More awareness from communities will for sure have positive implication on the environmental aspects as well. Various local ecosystems could then be connected together according to a bottom-up strategy: this would increase the flexibility of the energy system, its resilience, to respond to actual final needs of the community. From this point of view, these economic and social aspects of the deployment of hydrogen supply chains could contribute to achievement of *SDG 8, 9 and 10* (*'Promoting sustained, inclusive and sustainable economic growth, full and productive employment and decent work for all', 'Build resilient infrastructure, promote inclusive and sustainable industrialization and foster innovation', 'Reduce inequality within and among countries'*)

6.3 Key issues for continued work

The present thesis relies on a simulation model in order to draw techno-economic recommendations for future deployment of a hydrogen infrastructure in Germany and NRW. The quality and precision of the simulation results could be enhanced if the following aspects were included in the H2MIND model, thus representing areas for future work:

1. Modelling of *additional hydrogen-consuming technologies and sectors*, especially the ones mentioned within the H_2 Roadmap of NRW. This is the case of *re-electrification* (conversion of H_2 into electricity given back to the power grid) and *shipping*. Re-electrification in particular, it might be especially important for NRW due to current conversion process of lignite-based power plants to H_2 gas turbines using the available connection to the electricity grid.
2. Modelling of *system coupling* with *natural gas network* and *power network*. These systems have a critical influence on the evolution of a hydrogen infrastructure over time. To make some examples: the possibility of extending the H_2 network by repurposing existing NG lines depends on the status of the NG grid, plans for asset management and future development; as for the power system, it is relevant for the H_2 infrastructure since it provides access to the energy needed by electrolysers, affecting its availability in case of grid limitations (congestions, not enough power grid capacity to support the operation of hydrogen production plants, etc.), thus requiring a coherent power grid development plan. The availability of power grid connection points also affects the choice of locations for hydrogen production and / or hydrogen consumption.
3. Modelling of *LCVs as a self-standing hydrogen-consuming vehicle category*. In the existing version of H2MIND, these vehicles are approximated as a similar category to HDVs.
4. *Extension of renewable energies model*, by including other sources like *Offshore Wind* and *PV farms*. In the existing version of H2MIND, only Onshore Wind plants are considered.

7 Chapter 7 – Conclusions

The present thesis has investigated techno-economic strategies for the deployment of a hydrogen infrastructure in Germany and NRW in the period 2025-2035. The investigation is motivated by the recent publication (November 2020) of a 'hydrogen roadmap' for NRW region, containing a set of short- and medium-term targets (to 2025 and 2030, respectively) for the diffusion of hydrogen-based technologies in the sectors of mobility, industry and energy, and having the ultimate goal of contributing to decarbonization.

The analysis is set in continuation of the research work by Forschungszentrum Jülich (FZJ) on the topic. The institute has previously carried out a study to formulate and investigate the reference scenario for the definition of the targets included in NRW roadmap. This study was based on the results of two optimization models, *FINE-NESTOR* and *FINE-Infrastructure*. FZJ has also developed a simulation model (*H2MIND*) for the investigation of techno-economic strategies for hydrogen introduction within the German context.

In order to perform the analysis, H2MIND model was used and adapted to recreate the scenario set by FINE-NESTOR model for the period 2025-2030-2035 for the industry and mobility sector. Data were adapted in order to fit the technology categories considered by H2MIND: Buses, Trains, Private cars, Commercial cars, Public HDVs and LCVs, Commercial HDVs and LCVs, MHVs, Industry (as sum of hydrogen needs for production of Steel, Methanol, Ammonia, Chemicals and non-mobility Refinery). In such a scenario, on countrywide level, industry dominates hydrogen demand in 2025 – 67% on chemicals, ammonia and methanol, compared to 33% for buses, trains, cars and HDVs/LCVs. Such situation evolves over time to the point that mobility takes over in 2035 – 30% on chemicals, ammonia and methanol, compared to 70% for buses, trains, cars and HDVs/LCVs, with cars and HDVs/LCVs representing the highest shares. On NRW level, compositions of hydrogen demand over the years look very similar, with slight differences in the larger relative importance of HDVs/LCVs compared to cars.

FINE-NESTOR resulting hydrogen demand was distributed spatially according to H2MIND allocation criteria, which were complemented by the collection of locations of bus depots in NRW for the better detailing of the demand distribution of bus-related expected consumption in the region (also steel production sites in Germany were mapped in analogy to bus depots). NRW and, within the region, MRR show the largest amounts for hydrogen demand for all the technology sectors considered by H2MIND. The analysis of the spatial allocation of hydrogen demand over the period 2025-2035 (start-up phase), suggests the conclusion that investments should focus on high hydrogen-demand districts for the implementation of a virtuous cycle of demand/offer creation and consequent infrastructure development.

The comparison between four different hydrogen supply chain pathways was carried out – two totally relying on trucks, two including pipelines for hydrogen transport segment. The analysis of the weighted average TOTEX (weighted on the overall hydrogen demand), considered as global cost of the pathway and as cost breakdown into single steps of the supply chain, suggests pursuing a fully trailer-based infrastructure for the transport of gaseous hydrogen in the early stage of development. Pipeline networks are expected to reach cost parity with trailer-based options on a later stage only, after the period of analysis.

The option of installing dedicated electrolysers at bus-related HRSs, complementing the uncovered demand with centralized GH_2-trailer based infrastructure, also looks economically not convenient for the early stage of infrastructure development, regardless of the share of demand covered onsite (25%-50%-75%-100%). Although a fully centralized green hydrogen production is to be preferred for the period 2025-2035 (start-up phase); simulation results suggest that onsite electrolysis will play a role in the longer term. Possible collateral synergies – e.g., possible economic benefits from heat recovery at HRS/bus depot level or community acceptance of green hydrogen-based public transport – may speed up the achievement of the viability of onsite electrolysis business case.

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Appendix A

Input parameters of the H2MIND hydrogen supply chain pathways components

General

	General	Units
WACC	0.08	
electricityCostRES	0.06	€/kWh
storageDays	60	days
dieselCost	1.2	€/l
driverCost	35	€/h
NGCost	0.04	€/kWh
utilization Station	0.7	
waterCost	4	€/m³
storagePart	0.3	
heatGain	0	€/kWh
electricityDemandPrecooling	0.2	kWh/kg
distributionDistance	3	km
truckSpeed	50	km/h
eMultiplier	1	
h2concentraition	0.1	

Production

	ELC	ELD	ELO
form	1	1	1
pressureOut	30	30	30
investBase	1500	1500	1500
investCompare	1	1	1
investScale	0.925	0.925	0.925
investLifetime	10	10	10
boilOff	0	0	0
investOM	0.03	0.03	0.03
electricityDemand	47.6	47.6	47.6
waterDemand	0.01	0.01	0.01
installfactor	1.2	1.2	1.2
exp_rate	0.2	0.2	0.2
cap_now	20.5	20.5	20.5
lrpart	0.67	0.67	0.67

Purifying

	PSA	TSA
form	1	1
pressureOut	40	40
investLifetime	20	20
investOM	0.04	0.04
installfactor	1.2	1.2
O2 mole fraction	0.99985	0
SO2 mole fraction	0.98	0
CO mole fraction	0.98	0
H2O mole fraction	0.997175	0.99
CO2 mole fraction	0.8	0.8
efficiency	0.975	0.975
investBase	664864	197707
investCompare	16537771	23430
investScale	1	1
heatDemand	0	0.117
waterDemand	0	0.03293133

Blending

	SMR
form	1
pressureOut	30
investBase	170
investCompare	1
investScale	1
investLifetime	20
investOM	0.0514
methaneDemand	45.72
installfactor	1.92

Port

	PortGH2	PortLH2
system	21	22
form	21	22
investBase	33	30
investCompare	1	1
investScale	1	1
investLifetime	10	10
investOM	0.03	0.03
installationFactorPipe	1	1
installationFactorTruck	1	1
capacityMax	1	1
electricityDemandBase	0.7	0.1
electricityDemandCompare	1	1
electricityDemandScale	0	0
heatDemand	0	0
heatSupply	0	0
boilOffEff	0	0
pressureOut	1	1

Storage

	Cavern	GTank	LTank	LOHC-Tank	NG-Grid
form	1	1	2	3	1
pressureIn	150	150	1	1	1
pressureOut	60	60	1	1	1
investBase	81000000	250	30	50	0
investCompare	500000	1	1	1	1
investScale	0.28	1	1	1	1
investLifetime	30	20	20	20	40
boilOff	0	0	0.0003	0	0
investOM	0.02	0.02	0.02	0.02	0.08
efficiency	1	1	1	1	1

Transport

	Pipe	GHDV	LHDV	LOHC-Truck	PtG	PNG
form	1	1	2	3	1	1
pressureIn	100	500	1	1	40	100
pressureOut	70	15	1	1	70	70
pipeSystem	1	0	0	0	1	1
pipeInvestA	2.20E-03	0	0	0	2.20E-03	2.20E-03
pipeInvestB	0.86	0	0	0	0.86	0.86
pipeInvestC	247.5	0	0	0	247.5	247.5
pipeLifetime	40	1	1	1	40	40
pipeHours	8760	8760	8760	8760	8760	8760
pipeOM	0.04	0.04	0.04	0.04	0.04	0.04
pipeElectricityDemand	1	0	0	0	1	1
pipePressureHub	80	95	95	95	80	80
pipePressureStation	70	90	90	90	70	70
truckInvest	0	160000	160000	160000	0	0
truckLifetime	8	8	8	8	8	8
truckHours	2000	2000	2000	2000	2000	2000
truckOMfix	0.12	0.12	0.12	0.12	0.12	0.12
truckDriver	0	1	1	1	0	0
truckFuelDemandDiesel	0	34.5	34.5	34.5	0	0
truckFuelDemandH2	0	0	0	0	0	0
truckToll	0	0.13	0.13	0.13	0	0
trailerInvest	0	660000	860000	150000	0	0
trailerLifetime	12	12	12	12	12	12
trailerHours	2000	2000	2000	2000	2000	2000
trailerOM	0.02	0.02	0.02	0.02	0.02	0.02
trailerPayload	1	1200	4500	1800	1	1
trailerCapacity	1	1100	4300	1800	1	1
loadingtime	0	1.5	3	1.5	0	0
boilOffHourly	0	0	0	0	0	0

Connector

	Cmp	Lqf	Evaporation
system	11	12	21
form	11	12	21
investBase	15000	105000000	3
investCompare	1	50000	1
investScale	0.6089	0.66	1
investLifetime	15	20	10
investOM	0.04	0.08	0.03
installationFactorPipe	2.5	1	1
installationFactorTruck	3	1	1
capacityMax	10000	300000	1
electricityDemandBase	1	6.78	0.6
electricityDemandCompare	1	1	1
electricityDemandScale	0	0	0
heatDemand	0	0	0
heatSupply	0	0	0
boilOffEff	0.005	0.0165	0
H2 mole fraction	0	0	0

	Hydrogenation	Dehydrogenation	LH2Pump	LOHCPump	None	NGB
system	13	31	22	33	0	11
form	13	31	22	33	0	11
investBase	40000000	30000000	30	0.05	0	600000
investCompare	300000	300000	1	1	1	496.8
investScale	0.6	0.6	1	1	1	0.067
investLifetime	20	20	10	10	1	15
investOM	0.03	0.03	0.03	0.03	0	0.08
installationFactorPipe	1	1	1	1	0	1
installationFactorTruck	1	1	1	1	0	1
capacityMax	1000000	1000000	1	1	0	1
electricityDemandBase	0.37	0.37	0.1	0.1	0	1
electricityDemandCompare	1	1	1	1	0	1
electricityDemandScale	0	0	0	0	0	0
heatDemand	0	9.1	0	0	0	0
heatSupply	9.1	0	0	0	0	0
boilOffEff	0.03	0.01	0	0	0	0
H2 mole fraction	0	0	0	0	0	0

StationCarS

	PStationCarS	GStationCarS	LStationCarS	OStationCarS
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	kryo pump dispensing	cascade dispensing
pressureOut	700	700	700	700
lingeringTime	3	3	3	3
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	3	3	3	3
tanksize	5	5	5	5
form	1	1	2	1

StationCarM

	PStationCarM	GStationCarM	LStationCarM	OStationCarM
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	kryo pump dispensing	cascade dispensing
pressureOut	700	700	700	700
lingeringTime	3	3	3	3
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	3	3	3	3
tanksize	5	5	5	5
form	1	1	2	1

StationCarL

	PStationCarL	GStationCarL	LStationCarL	OStationCarL
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	kryo pump dispensing	cascade dispensing
pressureOut	700	700	700	700
lingeringTime	3	3	3	3
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	3	3	3	3
tanksize	5	5	5	5
form	1	1	2	1

StationCarXL

	PStationCarXL	GStationCarXL	LStationCarXL	OStationCarXL
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	kryo pump dispensing	cascade dispensing
pressureOut	700	700	700	700
lingeringTime	3	3	3	3
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	3	3	3	3
tanksize	5	5	5	5
form	1	1	2	1

StationCarXXL

	PStationCarXXL	GStationCarXXL	LStationCarXXL	OStationCarXXL
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	kryo pump dispensing	cascade dispensing
pressureOut	700	700	700	700
lingeringTime	3	3	3	3
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	3	3	3	3
tanksize	5	5	5	5
form	1	1	2	1

StationTrain

	PStationTrain	GStationTrain	LStationTrain	OStationTrain
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	30	30	30	30
operatingHours	12	12	12	12
utilizationRate	1	1	1	1
fillTime	30	30	30	30
tanksize	170	170	170	170
form	1	1	2	1

StationCCar

	PStationCCar	GStationCCar	LStationCCar	OStationCCar
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	kryo pump dispensing	cascade dispensing
pressureOut	700	700	700	700
lingeringTime	3	3	3	3
operatingHours	24	24	24	24
utilizationRate	1	1	1	1
fillTime	3	3	3	3
tanksize	5	5	5	5
form	1	1	2	1

StationBus

	PStationBus	GStationBus	LStationBus	OStationBus
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	5	5	5	5
operatingHours	12	12	12	12
utilizationRate	1	1	1	1
fillTime	10	10	10	10
tanksize	35	35	35	35
form	1	1	2	1

StationMHV

	PStationMhv	GStationMhv	LStationMhv	OStationMhv
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	1	1	1	1
operatingHours	3	3	3	3
utilizationRate	1	1	1	1
fillTime	1	1	1	1
tanksize	3.2	3.2	3.2	3.2
form	1	1	2	1

StationHdvS

	PStationHdvS	GStationHdvS	LStationHdvS	OStationHdvS
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	5	5	5	5
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	10	10	10	10
tanksize	35	35	35	35
form	1	1	2	1

StationHdvM

	PStationHdvM	GStationHdvM	LStationHdvM	OStationHdvM
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	5	5	5	5
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	10	10	10	10
tanksize	35	35	35	35
form	1	1	2	1

StationHdvL

	PStationHdvL	GStationHdvL	LStationHdvL	OStationHdvL
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	5	5	5	5
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	10	10	10	10
tanksize	35	35	35	35
form	1	1	2	1

StationHdvXL

	PStationHdvXL	GStationHdvXL	LStationHdvXL	OStationHdvXL
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	5	5	5	5
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	10	10	10	10
tanksize	35	35	35	35
form	1	1	2	1

StationHdvXXL

	PStationHdvXXL	GStationHdvXXL	LStationHdvXXL	OStationHdvXXL
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	5	5	5	5
operatingHours	24	24	24	24
utilizationRate	0.7	0.7	0.7	0.7
fillTime	10	10	10	10
tanksize	35	35	35	35
form	1	1	2	1

StationCHDV

	PStationCHDV	GStationCHDV	LStationCHDV	OStationCHDV
pressureIn	70	500	6	50
dispensingOption	cascade dispensing	cascade dispensing	cascade dispensing	cascade dispensing
pressureOut	350	350	350	350
lingeringTime	5	5	5	5
operatingHours	24	24	24	24
utilizationRate	1	1	1	1
fillTime	10	10	10	10
tanksize	35	35	35	35
form	1	1	2	1

Appendix B

Existing bus depots in NRW used within H2MIND

Company	Depot	Address	Postcode	City	X coordinate	Y coordinate	Number of Buses	Landkreis / kreisfreie Stadt	Landkreis-nummer
ASEAG	Aachener streetcar and power supply AG	Neuköllner Str. 1	52068	Aachen	50.78526564	6.12977462	498	Städteregion Aachen	05334
Kölner Verkehrs-Betriebe AG (KVB)	KVB Betriebshof Nord	Friedrich-Karl-Straße 261	50735	Köln	50.97530177	6.974010311	363	Köln, Stadt	05315
NEW MöBus	NEW mobile and active Mönchengladbach	Rheinstraße 70	41065	Mönchengladbach	51.18363649	6.452859695	227	Mönchengladbach, Stadt	05116
WSW	VGW Verkehrs-Gesellschaft Wuppertal mbH	Deutscher Ring 10	42327	Wuppertal	51.25057372	7.100405568	185	Wuppertal, Stadt	05124
MoBiel	moBiel	Otto-Brenner-Straße 242	33604	Bielefeld (Sieker)	52.00568988	8.559726085	154	Bielefeld, Stadt	05711
HST	Hagener Straßenbahn	Am Pfannenofen 5	58097	Hagen	51.37867462	7.473568237	138	Hagen, Stadt der FernUniversität	05914
West	WestVerkehr GmbH	Geilenkirchener Kreisbahn 1	52511	Geilenkirchen	50.96091286	6.123447741	135	Heinsberg	05370
RVM	RVM Regionalverkehr Münsterland GmbH	Boschstraße 7	48703	Stadtlohn	51.98413406	6.900595688	127	Borken	05554
RVM	RVM Regionalverkehr Münsterland GmbH	Rudolf-Diesel-Straße 8	59348	Lüdinghausen	51.75045457	7.436299408	127	Coesfeld	05558
RVM	RVM Regional Münsterland GmbH	Betriebshof und AboTeam, Laggenbecker Str. 90	49477	Ibbenbüren	52.27467441	7.733492607	127	Steinfurt	05566
RVM	Regional Münsterland GmbH	Kerkbrede 1	59269	Beckum	51.78833848	8.007411149	127	Warendorf	05570
STOAG	STOAG Stadtwerke Oberhausen GmbH	Max-Eyth-Straße 62	46149	Oberhausen	51.49578838	6.839267075	122	Oberhausen, Stadt	05119
VEST	Betriebshof Bottrop (Vestische Straßenbahnen GmbH)	Hiberniastraße 10	46240	Bottrop	51.54947575	6.950604389	121	Bottrop, Stadt	05512

VEST	Vestische Straßenbahnen GmbH	Westerholter Str. 550	45701	Herten	51.61063191	7.135649877	121	Recklinghausen	05562
EVAG	Essener Verkehrs AG, Betriebshof Stadtmitte	Barbarakirchgang 19	45139	Essen	51.46037695	7.025519671	120	Essen, Stadt	05113
SWMS	Stadtwerke Münster GmbH Verkehrsbetrieb	Rösnerstraße 11	48155	Münster	51.94025597	7.64495555	120	Münster, Stadt	05515
WSW	WSW mobil Betriebshof Nächstebreck	Hölker Feld ?	42279	Wuppertal	51.29334963	7.256173098	174	Wuppertal, Stadt	05124
Rhein-Erft-Verkehrsgesellschaft mbH (REVG)	REVG Rhein-Erft-Verkehrsgesellschaft mbH	Röntgenstraße 9	50169	Kerpen	50.87318971	6.756615076	101	Rhein-Erft-Kreis	05362
PaderSprinter GmbH	PaderSprinter	Barkhauser Str. 6	33106	Paderborn	51.70625126	8.720342393	101	Paderborn	05774
Verkehrsgesellschaft Ennepe-Ruhr mbH (VER)	Wuppermannshof	Hembecker Talstraße 5	58256	Ennepetal	51.29681196	7.31611071	100	Ennepe-Ruhr-Kreis	05954
RSVG	Rhein-Sieg Verkehrsgesellschaft mbH	Steinstraße 31	53844	Troisdorf-Sieglar	50.80285633	7.126334973	100	Rhein-Sieg-Kreis	05382
SWS	Stadtwerke Solingen - Verkehrsbetrieb	Weidenstraße 10	42655	Solingen	51.17820224	7.070563917	99	Solingen, Klingenstadt	05122
DVG	Betriebshof Unkelstein	Am Unkelstein 43	47059	Duisburg	51.44427087	6.772159281	96	Duisburg, Stadt	05112
SWK	SWK MOBIL GmbH	St. Töniser Str. 270	47804	Krefeld	51.32789068	6.532833185	96	Krefeld, Stadt	05114
VKU	VKU Verkehrsgesellschaft Kreis Unna mbH	Lünener Str. 13	59174	Kamen	51.59232389	7.652700403	93	Unna	05978
VKU	Verkehrsgesellschaft Kreis Unna Mbh	Kupferstraße 54	44532	Lünen	51.60671974	7.512506612	92	Unna	05978
DSW21	DSW21 depot Brünninghausen	Stockumer Str. 60	44225	Dortmund	51.47666905	7.453675421	91	Dortmund, Stadt	05913
DSW21	DSW21 depot Castrop Rauxel	Bahnhofstraße 14	44575	Castrop-Rauxel	51.55513781	7.311066923	90	Recklinghausen	05562
Stadtwerke Remscheid (SR)	Stadtwerke Remscheid GmbH	Neuenkamper Str. 81-87	42855	Remscheid	51.17900597	7.215657609	90	Remscheid, Stadt	05120
RSVG	RSVG-Servicepunkt Hennef	Bahnhofstraße 32	53773	Hennef (Sieg)	50.77388134	7.284811636	90	Rhein-Sieg-Kreis	05382
Rheinbahn AG	Rheinbahn Betriebshof Lierenfeld	Lierenfelder Str. 40	40231	Düsseldorf	51.21167119	6.81854684	86	Düsseldorf, Stadt	05111

Rheinbahn AG	Rheinbahn AG Betriebshof Heerdt	Eupener Str. 56	40549	Düsseldorf	51.22890967	6.69510882	86	Düsseldorf, Stadt	05111
Rheinbahn AG	Rheinbahn Betriebshof Benrath	Hildener Str. 72	40597	Düsseldorf	51.16058088	6.883733892	86	Düsseldorf, Stadt	05111
Rheinbahn AG	Rheinbahn depot Mettmann	Seibelstraße 9	40822	Mettmann	51.25611729	6.983904172	86	Mettmann	05158
Rheinbahn AG	Betriebshof Tiefenbroich	Sohlstättenstraße 40	40880	Ratingen	51.3095914	6.817761457	86	Mettmann	05158
NIAG	Niederrheinische Verkehrsbetriebe AG NIAG	Hammscher Weg 73	47533	Kleve	51.81094699	6.146178937	85	Kleve	05154
NIAG	Niederrheinische Verkehrsbetriebe AG NIAG	Marktweg 45	47608	Geldern	51.52159199	6.353475614	85	Kleve	05154
NIAG	Niederrhein.Verkehrsbetriebe AG NIAG	Rheinberger Str. 95	47441	Moers	51.45968652	6.630623498	85	Wesel	05170
NIAG	NIAG	Frankfurter Str. 59	46485	Wesel	51.63068714	6.642830238	85	Wesel	05170
BOGESTRA	Busbetrieb und Buswerkstatt Weitmar	Hattinger Straße 427	44795	Bochum	51.44606929	7.195484186	84	Bochum, Stadt	05911
BOGESTRA	Busbetrieb und Buswerkstatt Witten	Crengeldanzstraße 79	58455	Witten	51.44719864	7.326081959	84	Ennepe-Ruhr-Kreis	05954
SWN	SWN Verkehrs- und Service AG	Moselstraße 25	41464	Neuss	51.18221145	6.678127228	83	Rhein-Kreis Neuss	05162
BOGESTRA	Bogestra Betriebshof Ückendorf	Exterbruch 2	45886	Gelsenkirchen	51.51031707	7.13434204	83	Gelsenkirchen, Stadt	05513
OVAG / Verkehrsgesellschaft Bergisches Land mbH (VBL)	OVAG Oberbergische Verkehrgesellschaft mbH	Kölner Str. 237	51645	Gummersbach	51.00436551	7.583921954	79	Oberbergischer Kreis	05374
EVAG	Ruhrbahn GmbH Betriebshof Ruhrallee	Ruhrallee 354	45136	Essen	51.4310652	7.055068685	76	Essen, Stadt	05113
Wupsi	wupsi GmbH (Customer Center and headquarters)	Borsigstraße 18	51381	Leverkusen-Fixheide	51.05323789	7.019069716	74	Leverkusen, Stadt	05316
Wupsi	wupsi GmbH (Betriebshof Bergisch Gladbach)	Hermann-Löns-Straße 48A	51469	Bergisch Gladbach	50.9869407	7.103381205	74	Rheinisch-Bergischer Kreis	05378
DKB	Dürener Kreisbahn GmbH DKB	Kölner Landstraße 271	52351	Düren	50.81259504	6.510310012	70	Düren	05358
HCR	Straßenbahn Herne–Castrop-Rauxel	An der Linde 41	44627	Herne	51.54765361	7.261705249	66	Herne, Stadt	05916

SWB	SWB Bonn Betriebshof	Godesberger Allee 108	53175	Bonn	50.69856755	7.140200182	61	Bonn, Stadt	05314
SWB	Betriebshof Beuel Swb	Neustraße,	53225	Bonn	50.73567636	7.128237738	61	Bonn, Stadt	05314
SWB	SWB Betriebshof Dransdorf	Gerhart-Hauptmann-Straße 8	53121	Bonn	50.73775767	7.061803347	61	Bonn, Stadt	05314
MVG	Lüd., MVG - Verwaltung		58507	Lüdenscheid	51.22915589	7.62331707	58	Märkischer Kreis	05962
MVG	MVG Märkische Verkehrsgesellschaft GmbH Betriebsstelle Calle	Osemundstraße 10	58636	Iserlohn	51.37339517	7.739471708	58	Märkischer Kreis	05962
MVG	MVG Märkische Transport Company Ltd.	Posensche Str. 2	58840	Plettenberg	51.20421113	7.864845144	58	Märkischer Kreis	05962
Busverkehr Ostwestfalen GmbH (BVO)	Busverkehr Ostwestfalen GmbH (RegioCenter Herford)	Goebenstraße 75	32051	Herford	52.12737202	8.668993698	55	Herford	05758
Busverkehr Ostwestfalen GmbH (BVO)	BBH Bahnbus Hochstift GmbH Paderborn	Frankfurter Weg 43	33106	Paderborn	51.69767633	8.736101252	54	Paderborn	05774
Verkehrsgesellschaft Bergisches Land mbH (VBL)	Verkehrsgesellschaft Bergisches Land mbH Betriebshof Waldbröl	Brölbahnstraße 17	51545	Waldbröl	50.87416067	7.610741722	51	Oberbergischer Kreis	05374
RLG	RLG Regionalverkehr Ruhr-Lippe GmbH	Grabenstraße 30	59759	Arnsberg	51.43944531	7.980187029	51	Hochsauerlandkreis	05958
RLG	RLG regional transport Ruhr-Lippe GmbH	Altenbürener Str. 49	59929	Brilon	51.39018944	8.538530482	51	Hochsauerlandkreis	05958
RLG	RLG Regionalverkehr Ruhr-Lippe GmbH - Mobil Info	Am Bahnhof 10	59494	Soest	51.57739964	8.102503632	51	Soest	05974
RLG	RLG Regionalverkehr Ruhr-Lippe GmbH	Am Siek 5	59557	Lippstadt	51.67446097	8.369818871	51	Soest	05974
	Verkehrsbetrieb Hamm GmbH	Kampshege 7	59069	Hamm	51.65702205	7.8417032	50	Hamm, Stadt	05915
Verkehrsbetrieb Kipp GmbH (VBK)	VBK-Betriebshof Lengerich	Münsterstr. 58a	49525	Lengerich	52.18294731	7.848467772	50	Steinfurt	05566
BSM	Lanes of the city Monheim GmbH	Daimlerstraße 10A	40789	Monheim am Rhein	51.10211869	6.893054801	50	Mettmann	05158

LOOK Busreisen GmbH	LOOK Busreisen GmbH - Der vom Niederrhein	Wilhelm-Sinsteden-Straße 4	47533	Kleve	51.81164434	6.146187871	49	Kleve	05154
MVG	Mülheim transport company ltd	Duisburger Str. 78	45479	Mülheim an der Ruhr	51.42673545	6.866455404	47	Mülheim an der Ruhr, Stadt	05117
MoBiel	moBiel GmbH Betriebshof Süd	Lilienthalstraße 2-4	33689	Bielefeld (Sennestadt)	51.95582751	8.581517474	35	Bielefeld, Stadt	05711
Regionalverkehr Köln GmbH (RVK)	Regional traffic Cologne GmbH	Oststraße 2A	53879	Euskirchen	50.65801874	6.791987385	25	Euskirchen	05366
Regionalverkehr Köln GmbH (RVK)	Regionalverkehr Köln GmbH	Bonnstraße 260	50354	Hürth	50.87088116	6.890223398	25	Rhein-Erft-Kreis	05362
Regionalverkehr Köln GmbH (RVK)	Regionalverkehr Köln GmbH RVK-KundenCenter Glmobil	Steinstraße	51429	Bergisch Gladbach	50.9648744	7.160644758	25	Rheinisch-Bergischer Kreis	05378
Regionalverkehr Köln GmbH (RVK)	Regionalverkehr Köln GmbH NL Wermelskirchen	Braunsberger Str. 1	42929	Wermelskirchen	51.13008652	7.201478469	25	Rheinisch-Bergischer Kreis	05378
Regionalverkehr Köln GmbH (RVK)		Siemenacker 12	53332	Bornheim (Hersel)	50.76812381	7.041992305	25	Rhein-Sieg-Kreis	05382
Regionalverkehr Köln GmbH (RVK)	Regionalverkehr Köln GmbH RVK	Kalkofenstraße 1	53340	Meckenheim	50.62803919	7.010301481	25	Rhein-Sieg-Kreis	05382
SVD	Karl Köhne Omnibusbetriebe GmbH Detmold	Bahnhofstraße 33	32756	Detmold	51.94205422	8.866628298	22	Lippe	05766

Betriebssitz	Unternehmen	Sources
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Düren	DKB	- https://www.wer-zu-wem.de/firma/dkb-duerener.html
Düsseldorf	Rheinbahn AG	- https://de.wikipedia.org/wiki/Rheinbahn_(Unternehmen) - https://www.rheinbahn.de/unternehmen/Zahlen%20%20Berichte/Rheinbahn_in_Zahlen.pdf - https://de.wikipedia.org/wiki/Betriebshof_Lierenfeld (Lierenfeld) - https://www.rheinbahn.de/unternehmen/fuhrpark/Seiten/default.aspx (Lierenfeld)
Ennepetal	Verkehrsgesellschaft Ennepe-Ruhr mbH (VER)	- https://ver-kehr.de/wir-ueber-uns/ueber-die-ver/ - https://www.enkreis.de/aktuelles/news-detailansicht/news/ver-busse-gruen-weiss-rot-dominiert-erscheinungsbild.html
Essen	EVAG	- https://www.radioessen.de/artikel/essen-neuer-standort-fuer-busse-der-ruhrbahn-sie-machen-platz-fuer-neues-796742.html
Geilenkirchen	West	- https://de.wikipedia.org/wiki/WestVerkehr
Gummersbach	OVAG Oberbergische Verkehrsgesellschaft mbH (OVAG)	- https://de.wikipedia.org/wiki/Oberbergische_Verkehrsgesellschaft - https://www.ovaginfo.de/Pressemitteilungen/Pressemitteilung_FFP2-Maskenpflicht.pdf
Gummersbach	Verkehrsgesellschaft Bergisches Land mbH (VBL)	- https://de.wikipedia.org/wiki/Verkehrsgesellschaft_Bergisches_Land
Hagen	HST	- https://de.wikipedia.org/wiki/Hagener_Stra%C3%9Fenbahn_AG

Herne	Straßenbahn Herne–Castrop-Rauxel (HCR)	- https://de.wikipedia.org/wiki/Stra%C3%9Fenbahn_Herne%E2%80%93Castrop-Rauxel - https://www.halloherne.de/artikel/erster-e-bus-fuer-die-hcr-46468.htm - https://www.hcr-herne.de/de/betriebsbesichtigungen.html
Herten	Vestische Straßenbahnen GmbH (Vestische / VEST)	- https://www.vestische.de/die-vestische - https://de.wikipedia.org/wiki/Vestische_Stra%C3%9Fenbahnen
Kamen	VKU	- https://de.wikipedia.org/wiki/Verkehrsgesellschaft_Kreis_Unna
Kerpen-Türnich	Rhein-Erft-Verkehrsgesellschaft mbH (REVG)	- https://www.revg.de/ueber-uns.html - https://de.wikipedia.org/wiki/Rhein-Erft-Verkehrsgesellschaft
Köln	KVB	- https://www.kvb.koeln/unternehmen/kontakt/adressen.html - https://de.wikipedia.org/wiki/K%C3%B6lner_Verkehrs-Betriebe - https://www.kvb.koeln/unternehmen/die_kvb/zahlen_daten_fakten/index.html?INCLUDEMODUL=dokumente_einzeln2.mod/inc.download.php&downDokument=1830
Köln	Regionalverkehr Köln (RVK)	- https://www.rvk.de/die-rvk/ueber-uns - https://de.wikipedia.org/wiki/Regionalverkehr_K%C3%B6ln#cite_note-Fahrleistungen-1
Krefeld	SWK	- http://strassenbahn-bus.de/krefeld/betriebshof-krefeld/ - https://de.wikipedia.org/wiki/SWK_Mobil
Leverkusen	Wupsi	- https://de.wikipedia.org/wiki/Wupsi#cite_note-6
Lüdenscheid	MVG	- https://de.wikipedia.org/wiki/M%C3%A4rkische_Verkehrsgesellschaft - https://www.mvg-online.de/wir-ueber-uns/anfahrten/betriebshof-und-werkstatt-luedenscheid/ (Lüdenscheid) - https://www.mvg-online.de/wir-ueber-uns/anfahrten/betriebshof-und-werkstatt-iserlohn/ (Iserlohm) - https://www.mvg-online.de/wir-ueber-uns/anfahrten/betriebshof-plettenberg/ (Plettenberg)
Moers	NIAG	- https://de.wikipedia.org/wiki/Niederrheinische_Verkehrsbetriebe

Moers	LOOK Busreisen GmbH - Der vom Niederrhein	- https://de.wikipedia.org/wiki/Look_Busreisen
Mönchengladbach	NEW MöBus	- https://de.wikipedia.org/wiki/NEW_mobil_und_aktiv_M%C3%B6nchengladbach#cite_note-n.de-Fahrzeugliste-1
Monheim/Rhein	BSM	- https://de.wikipedia.org/wiki/Bahnen_der_Stadt_Monheim#cite_note-RP_Bordtechnik-2 - https://www.bahnen-monheim.de/unternehmen/ueber-uns
Mülheim an der Ruhr	MVG	- https://de.wikipedia.org/wiki/M%C3%BClheimer_VerkehrsGesellschaft
Münster (Ibbenbüren)	RVM	- https://de.wikipedia.org/wiki/Regionalverkehr_M%C3%BCnsterland#cite_note-5 - https://www.rvm-online.de/upload/36893470-RVM-Geschaftsbericht-2019-08-final.pdf - https://www.rvm-online.de/fahrplaene-fahrplanauskunft/anfahrt.php
Münster	SWMS	- https://www.stadtwerke-muenster.de/unternehmen/mobilitaet/unser-angebot-fuer-sie/betrieb/betriebshof-roesnerstrasse.html?o=1%25253Futm_source%252531%3D1%27A%3D0&cHash=27b432ff73a9d15c1fd5093ed679989e - https://www.stadtwerke-muenster.de/unternehmen/mobilitaet/unser-angebot-fuer-sie/betrieb/busflotte.html
Neuss	Stadtwerke Neuss (SWN)	- https://de.wikipedia.org/wiki/Stadtwerke_Neuss
Oberhausen	STOAG	- https://de.wikipedia.org/wiki/STOAG_Stadtwerke_Oberhausen
Paderborn	PaderSprinter GmbH	- https://de.wikipedia.org/wiki/PaderSprinter
Remscheid	Stadtwerke Remscheid (SR)	- https://de.wikipedia.org/wiki/Stadtwerke_Remscheid - https://www.stadtwerke-remscheid.de/unternehmen/zahlen-fakten/verkehrszahlen/

Soest	RLG	- https://de.wikipedia.org/wiki/Regionalverkehr_Ruhr-Lippe - https://www.rlg-online.de/regionalverkehr-ruhr-lippe/team.php - https://www.rlg-online.de/upload/34457628-FA20-0556-RLG-Geschaftsbericht-2019.pdf
Solingen	SWS	- https://de.wikipedia.org/wiki/Stadtwerke_Solingen_(Verkehrsbetrieb)#Fahrzeuge - https://www.stadtwerke-solingen.de/blog/fuehrung-neue-mitarbeiter-stadtwerken-solingen/
Troisdorf	Rhein-Sieg-Verkehrsgesellschaft (RSVG)	- https://de.wikipedia.org/wiki/Rhein-Sieg-Verkehrsgesellschaft - https://www.ksta.de/rsvg-busse-mit-direktem-draht-nach-oben-11912832?cb=1619548997458 (Hennef)
Wuppertal	WSW	- https://de.wikipedia.org/wiki/Betriebshof_Varresbeck

Appendix C

Existing steel production sites in Germany used within H2MIND

Plant name	Plant location	Plant location, Bundesland	H2 Demand, kt/year	Latitude	Longitude
Stahlwerk Bous GmbH	BOUS/SAAR	Saarland	32	49.275391	6.792489
Brandenburger Elektrostahlwerke GmbH (B.E.S.)	BRANDENBURG	Brandenburg	162	52.410777	12.501108
ArcelorMittal Bremen GmbH	BREMEN	Bremen	342	53.142378	8.692161
DHS - Dillinger Hütte Saarstahl AG	DILLINGEN	Saarland	248	49.355462	6.732577
thyssenkrupp Steel Europe AG	DUISBURG	Nordrhein-Westfalen	1,040	51.365653	6.719153
ArcelorMittal Eisenhüttenstadt GmbH	EISENHÜTTENSTADT	Brandenburg	216	52.161694	14.629954
BGH Edelstahl Freital GmbH	FREITAL	Sachsen	8	50.994096	13.639896
Georgsmarienhütte GmbH	GEORGSMARIENHÜTTE	Niedersachsen	90	52.211793	8.043663
Schmiedewerke Gröditz GmbH	GRÖDITZ	Sachsen	9	51.406444	13.443870
ArcelorMittal Hamburg GmbH	HAMBURG	Hamburg	99	53.524780	9.900199
H.E.S. Hennigsdorfer Elektrostahlwerke GmbH	HENNIGSDORF	Brandenburg	90	52.647407	13.211395
Lech-Stahlwerke GmbH	HERBERTSHOFEN	Bayern	106	48.512518	10.852271
Badische Stahlwerke GmbH	KEHL	Baden-Wurtemberg	225	48.600176	7.822539
BENTELER Steel/Tube GmbH	LINGEN	Niedersachsen	56	52.468448	7.315440
Stahlwerk Peine ein Unternehmen der SZAG	PEINE	Niedersachsen	90	52.317386	10.239396
ESF Elbe-Stahlwerke Feralpi GmbH	RIESA	Sachsen	81	51.313347	13.280407
Salzgitter AG	SALZGITTER	Niedersachsen	468	52.150546	10.443591
Deutsche Edelstahlwerke Specialty Steel GmbH & Co. KG	SIEGEN	Nordrhein-Westfalen	68	50.921999	8.025221
Stahlwerk Thüringen GmbH	UNTERWELLENBORN	Thüringen	99	50.655332	11.449473
Saarstahl LD Stahlwerk	VÖLKLINGEN	Saarland	292	49.243732	6.852550
Buderus Edelstahl GmbH	WETZLAR	Hessen	36	50.572838	8.485574
Besuchereingang Deutsche Edelstahlwerke	WITTEN	Nordrhein-Westfalen	43	51.433994	7.330121

Appendix D

Hydrogen demand geospatial distribution in Germany, according to technology

Buses

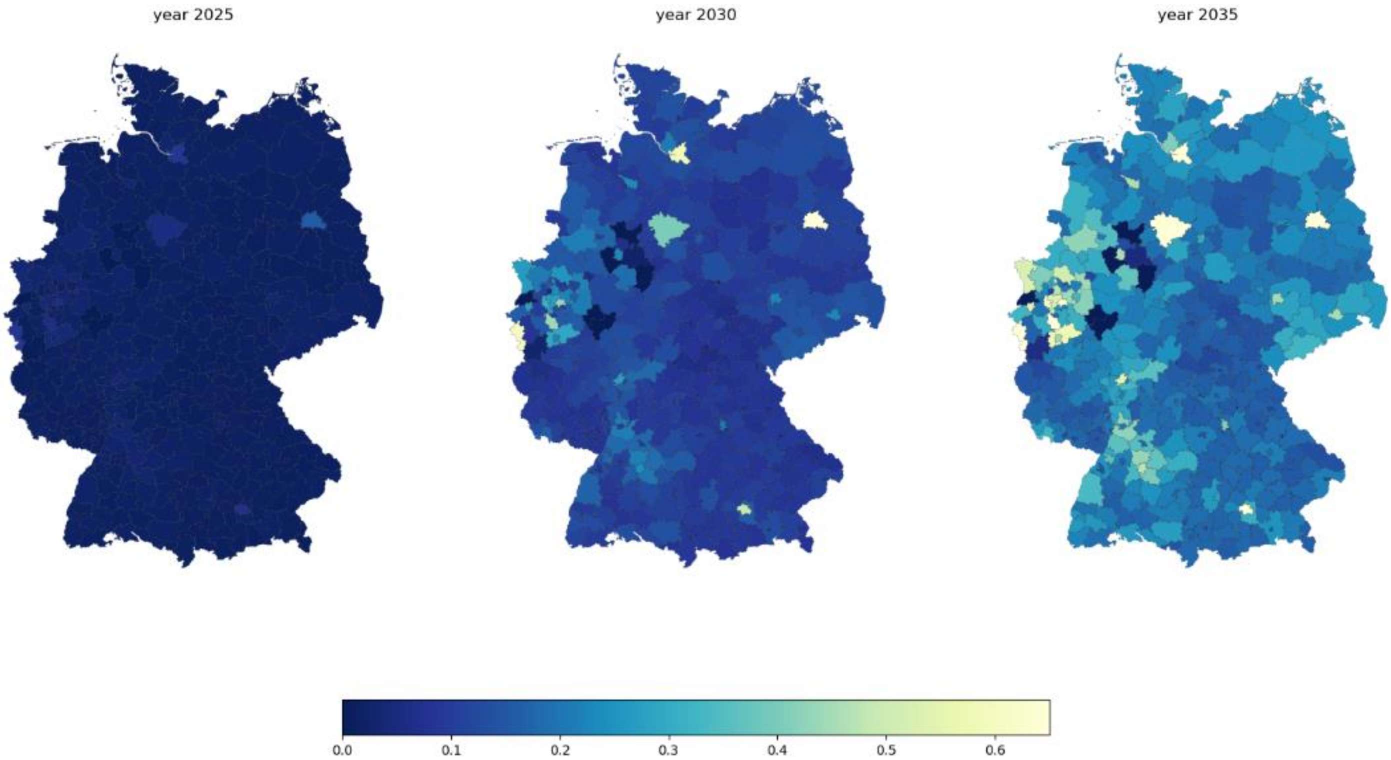


Figure 38 Spatial distribution of Bus hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

Trains

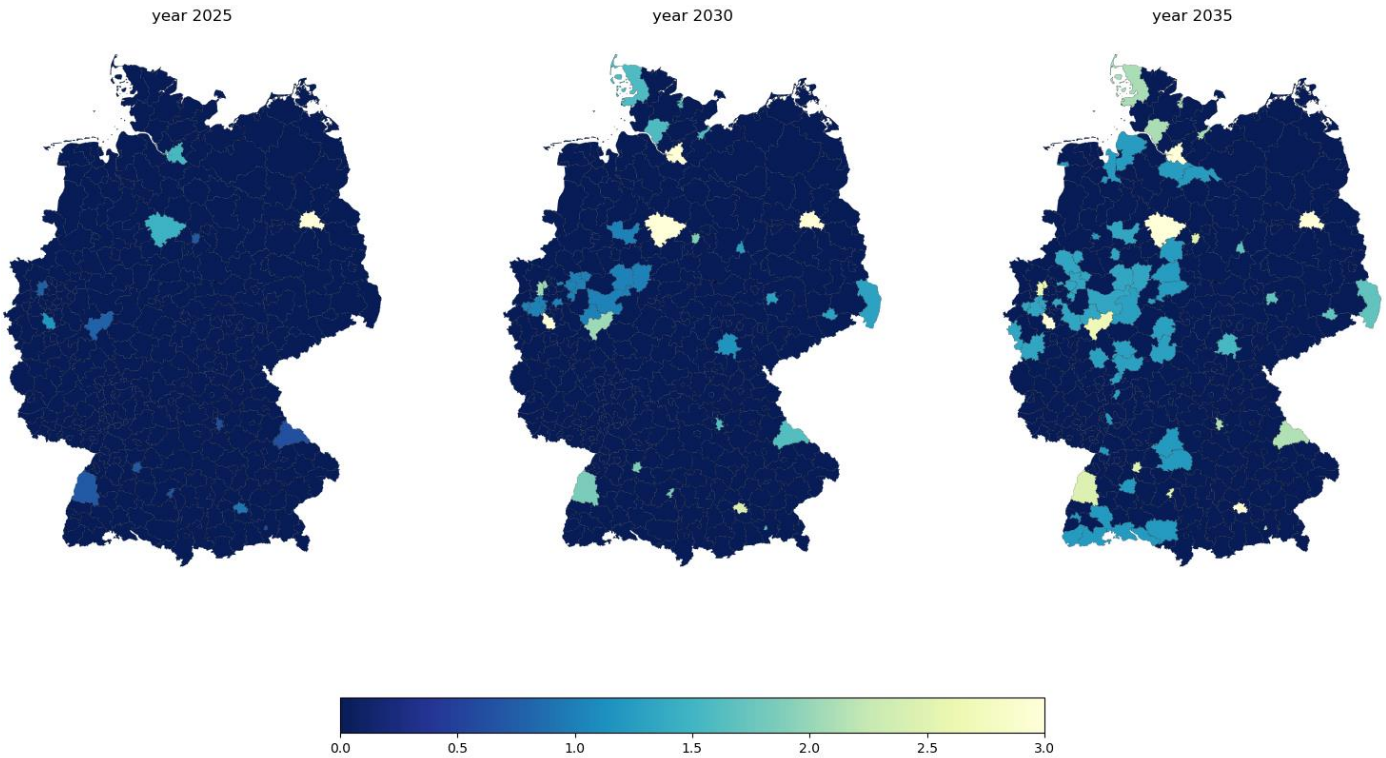


Figure 39 Spatial distribution of Train hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

<u>Private Cars</u>

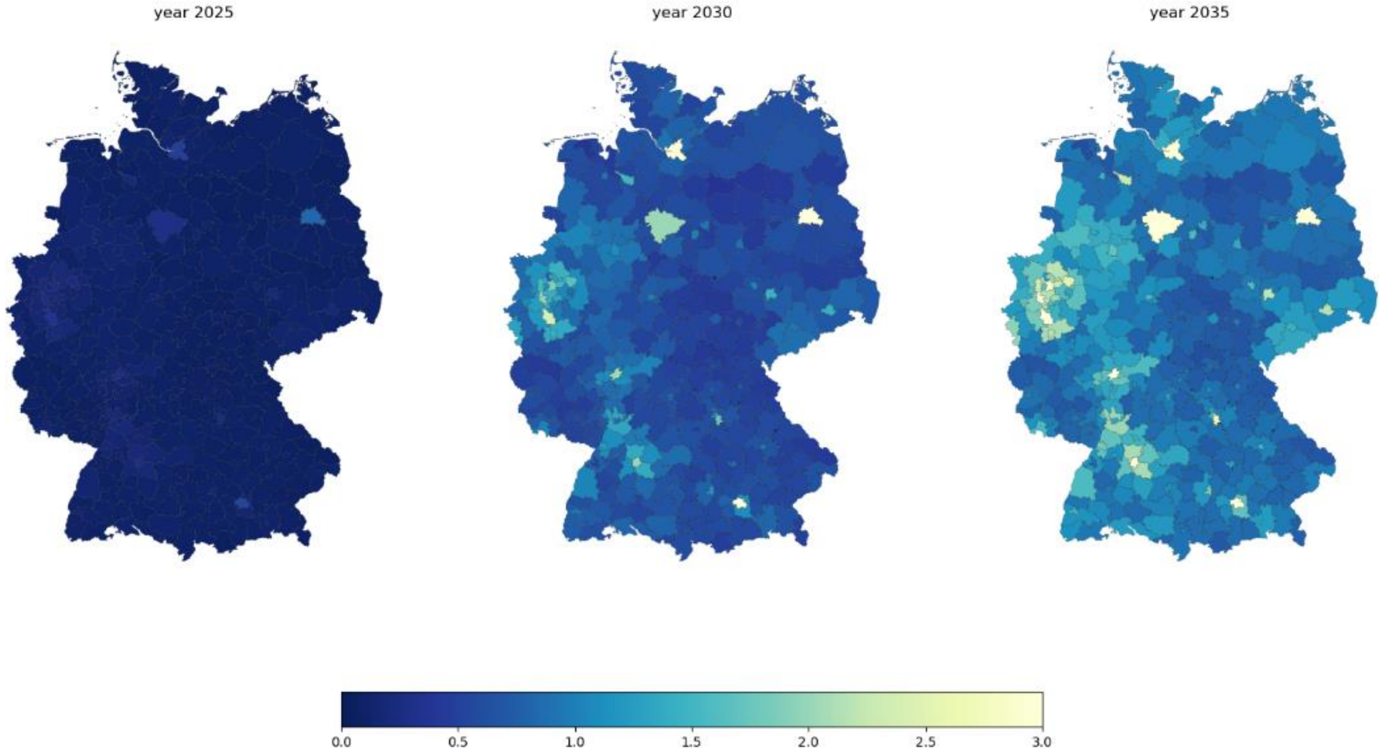


Figure 40 Spatial distribution of Private Car hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

<u>Commercial Cars</u>

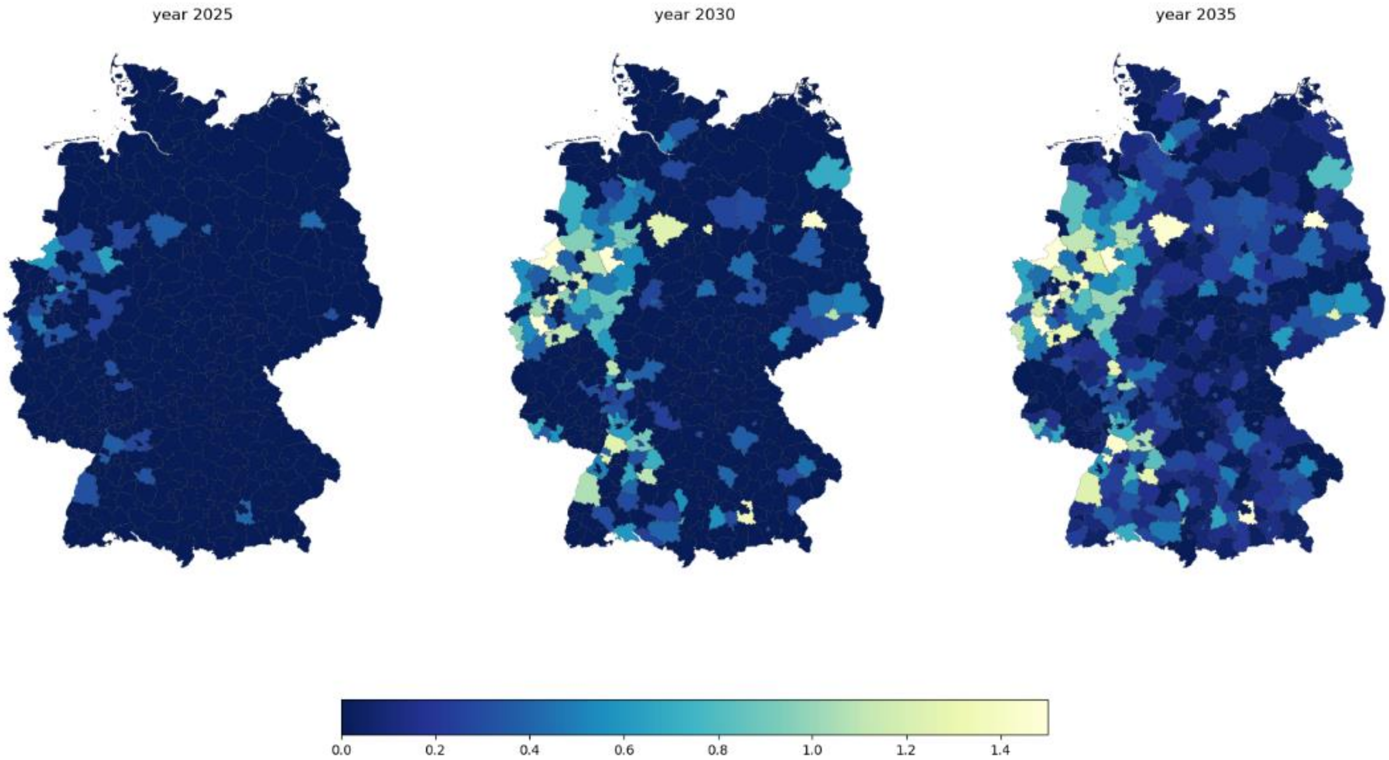


Figure 41 Spatial distribution of Commercial Car hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

Publicly-refuelled HDVs and LCVs

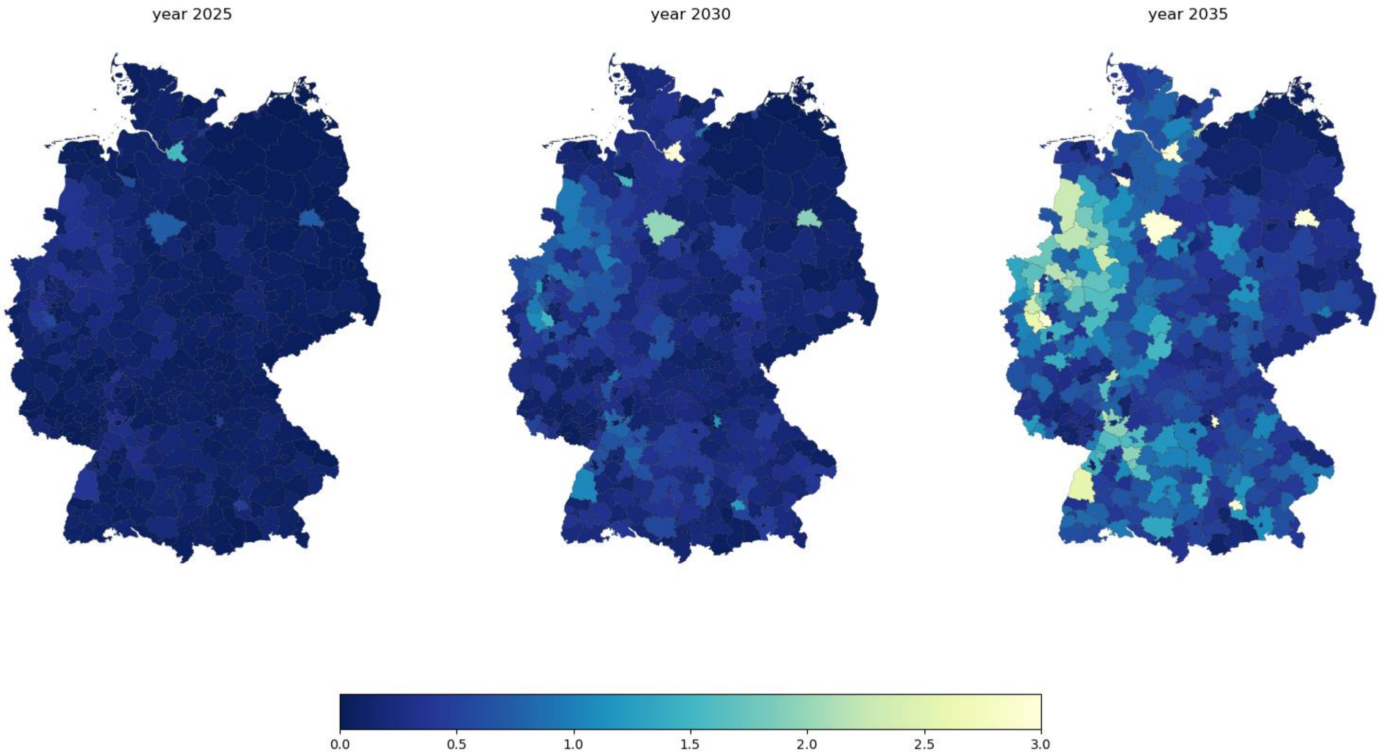


Figure 42 Spatial distribution of publicly-refuelled HDVs and LCVs hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

Privately-refuelled HDVs and LCVs

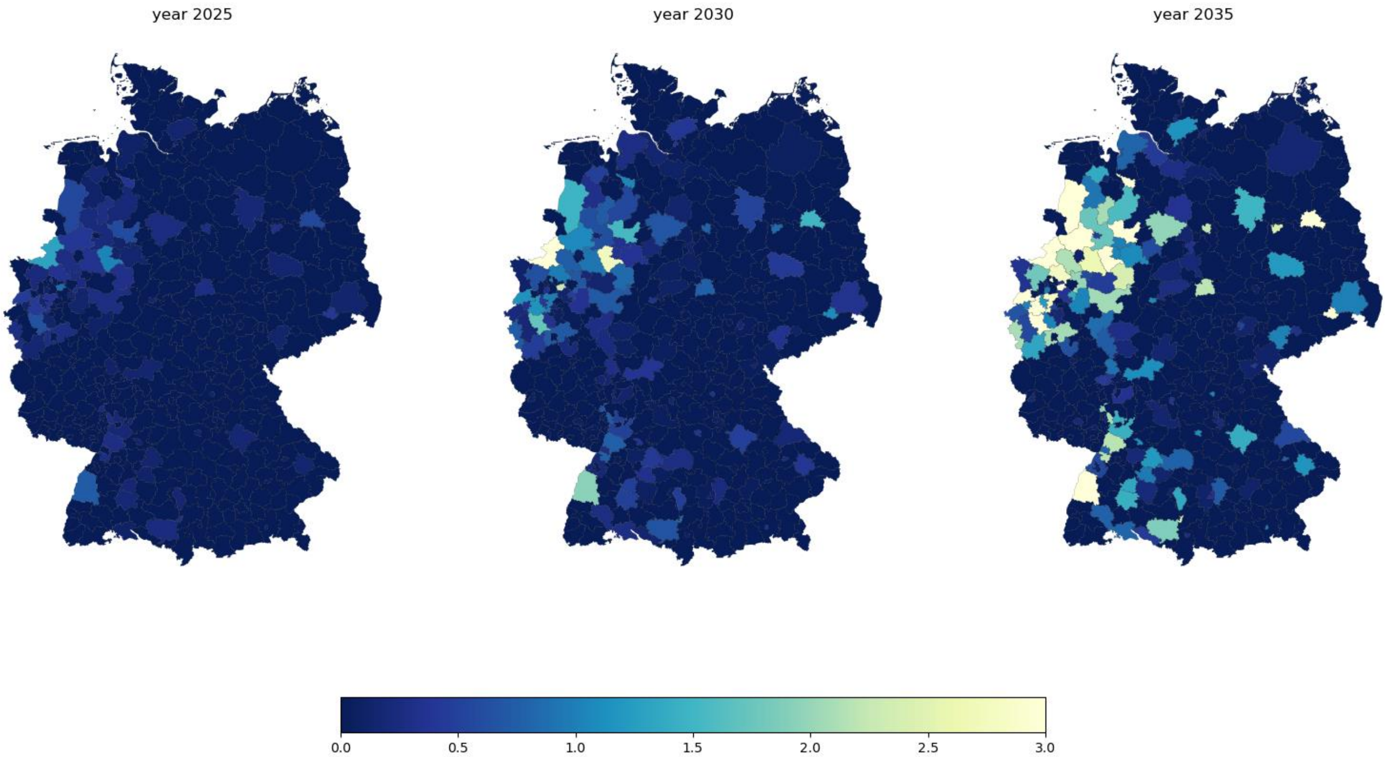


Figure 43 Spatial distribution of privately-refuelled HDVs and LCVs hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

MHVs

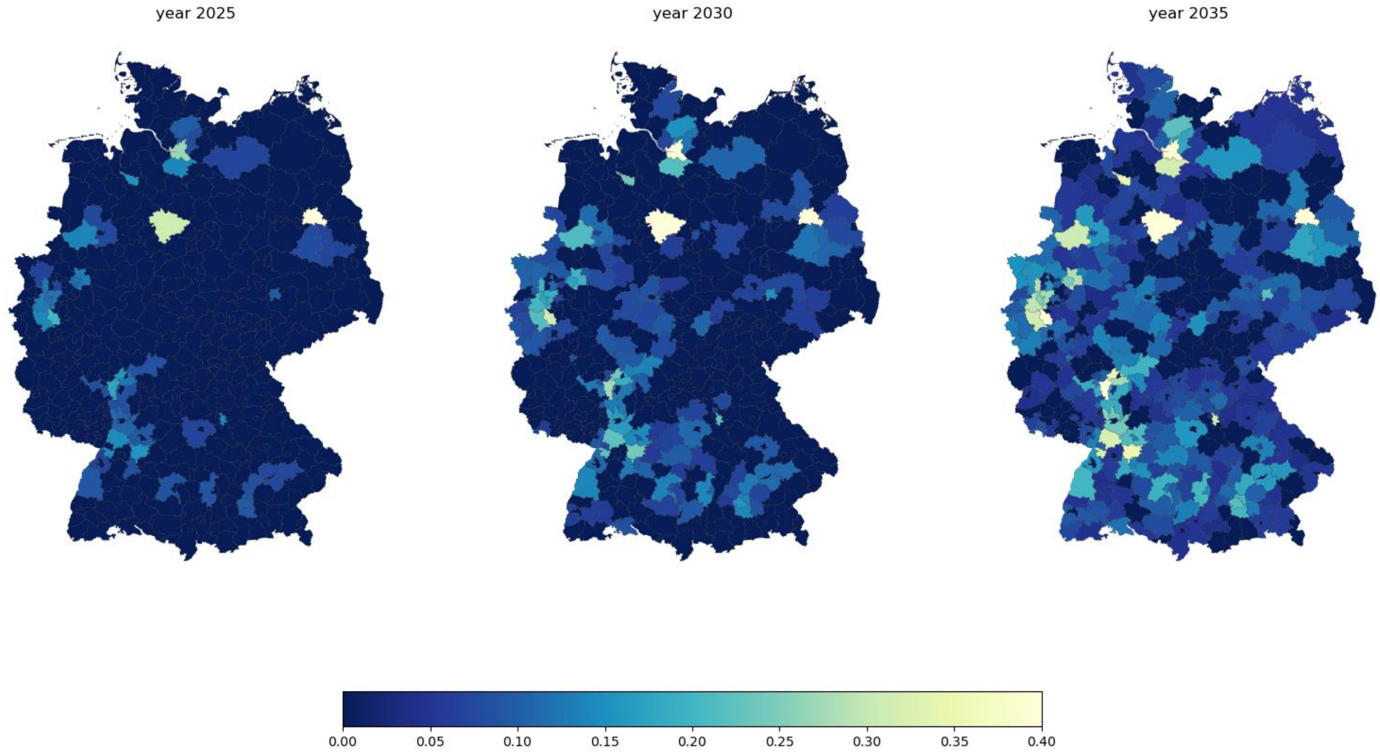


Figure 44 Spatial distribution of MHV hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

Industry

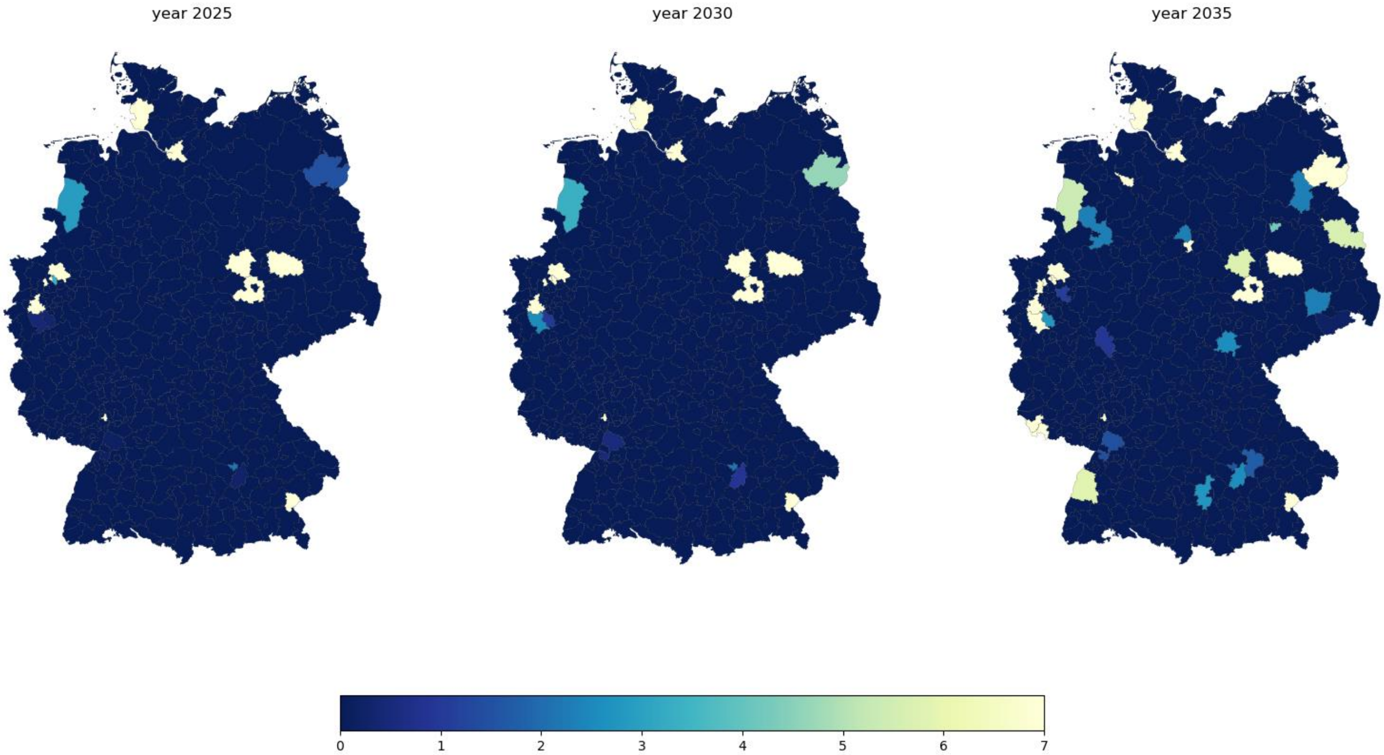


Figure 45 Spatial distribution of Industry hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (Germany)

Appendix E

Hydrogen demand geospatial distribution in NRW, according to technology

<u>Buses</u>

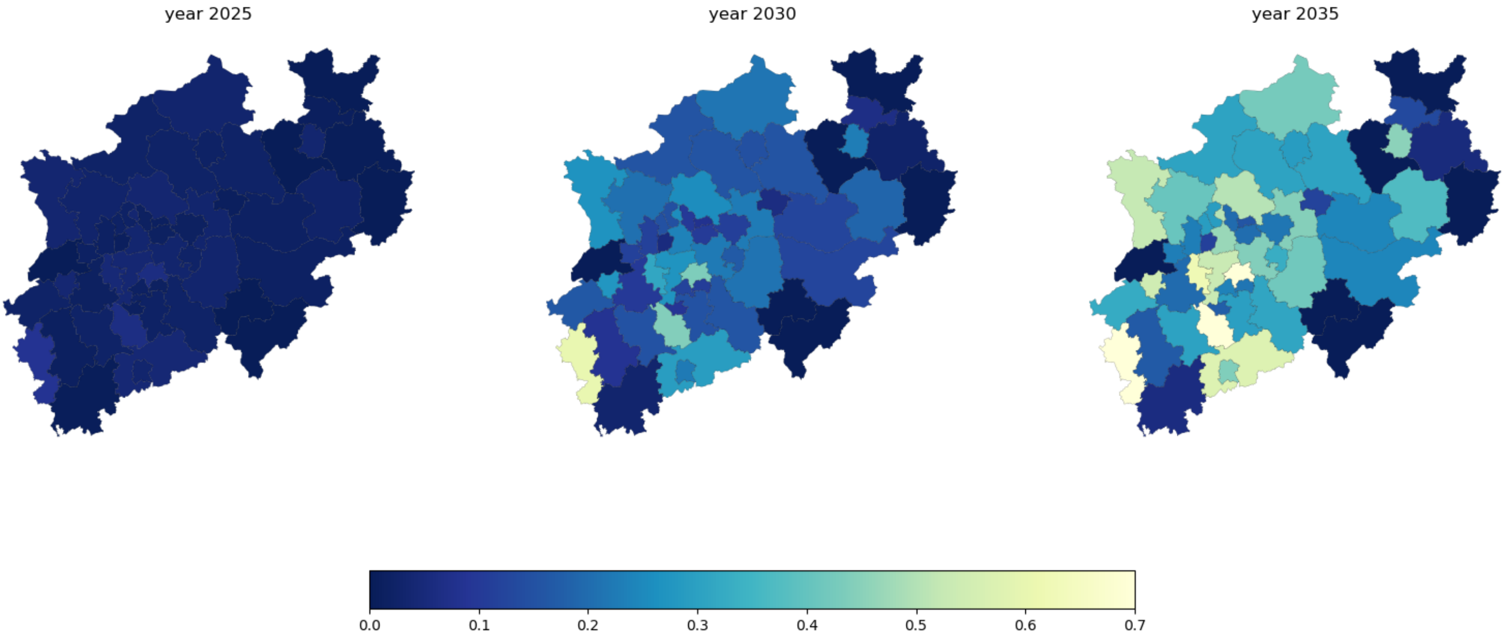


Figure 46 Spatial distribution of Bus hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

<u>Trains</u>

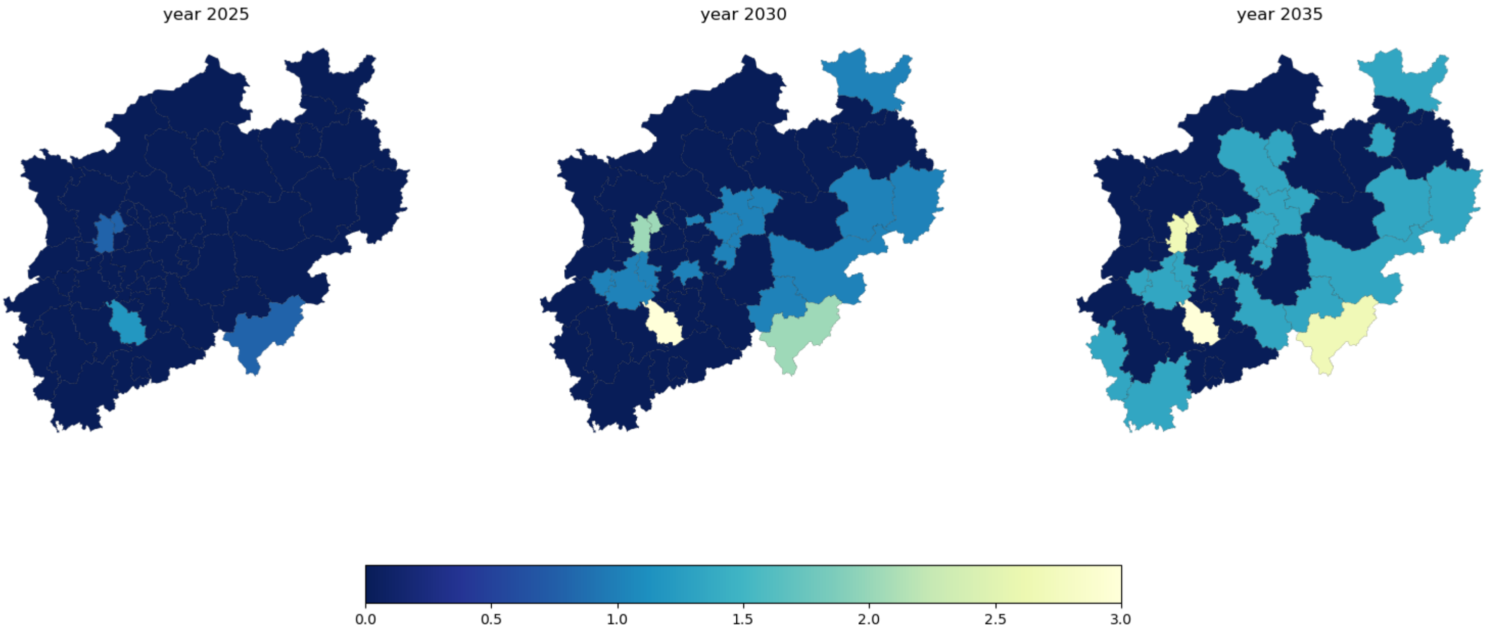


Figure 47 Spatial distribution of Train hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

Private Cars

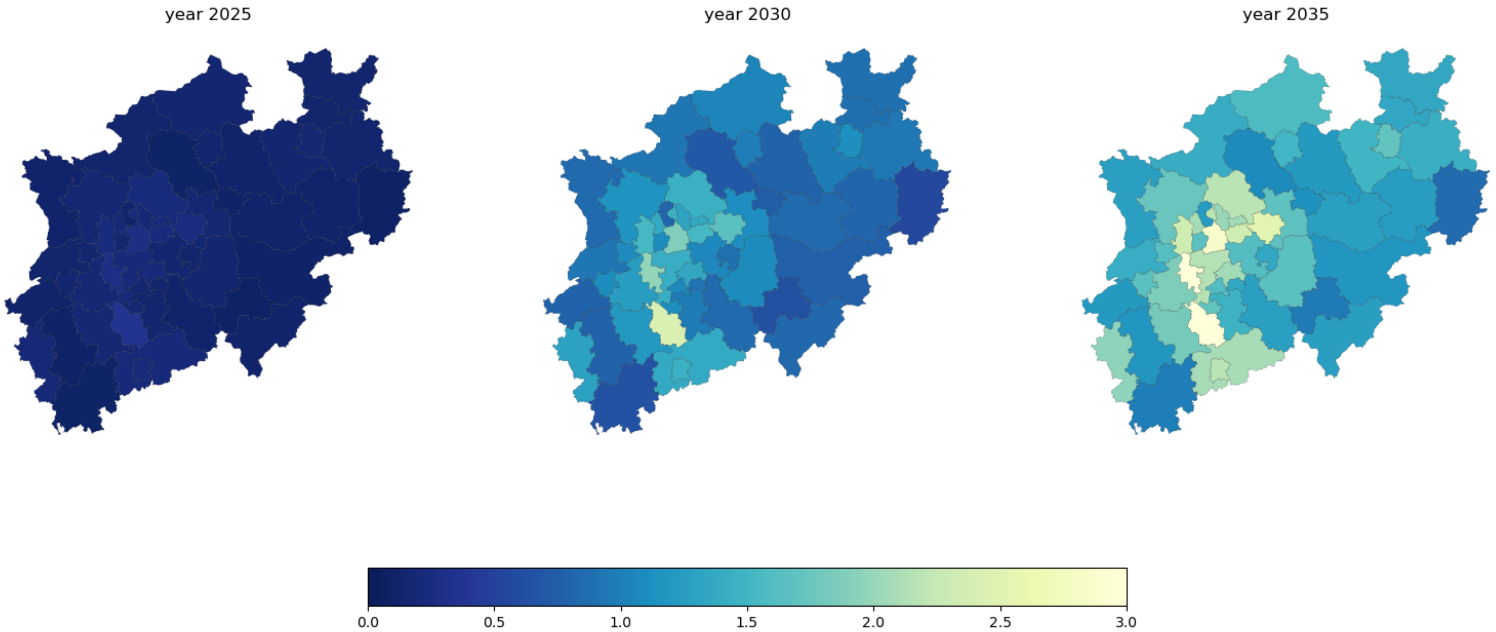


Figure 48 Spatial distribution of Private Car hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

Commercial Cars

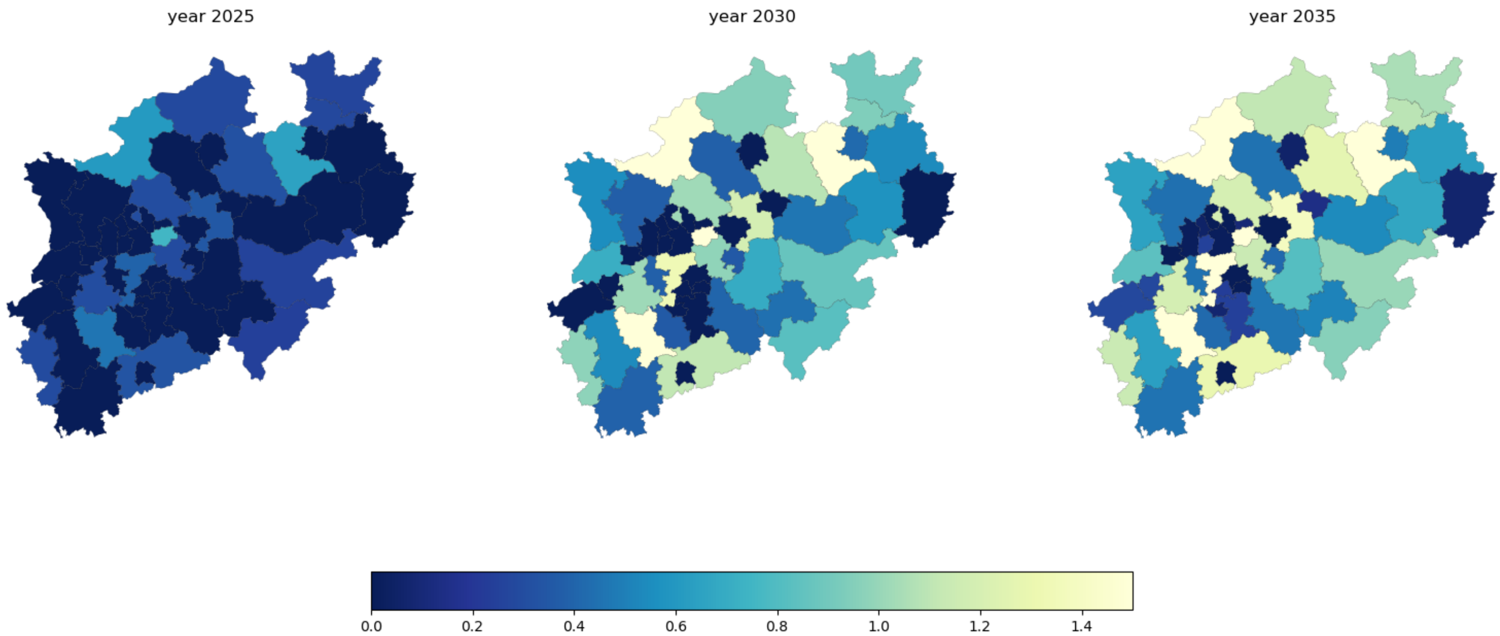


Figure 49 Spatial distribution of Commercial Car hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

Publicly-refuelled HDVs and LCVs

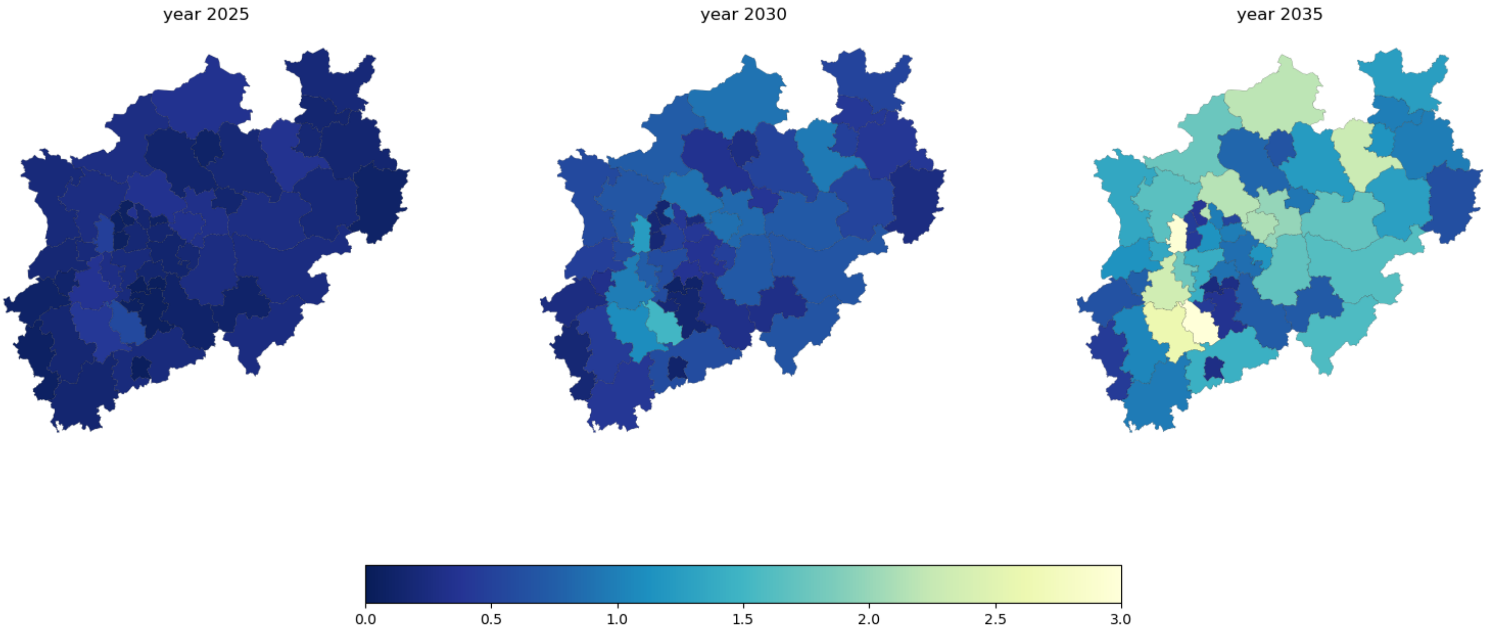


Figure 50 Spatial distribution of publicly-refuelled HDVs and LCVs hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

Privately-refuelled HDVs and LCVs

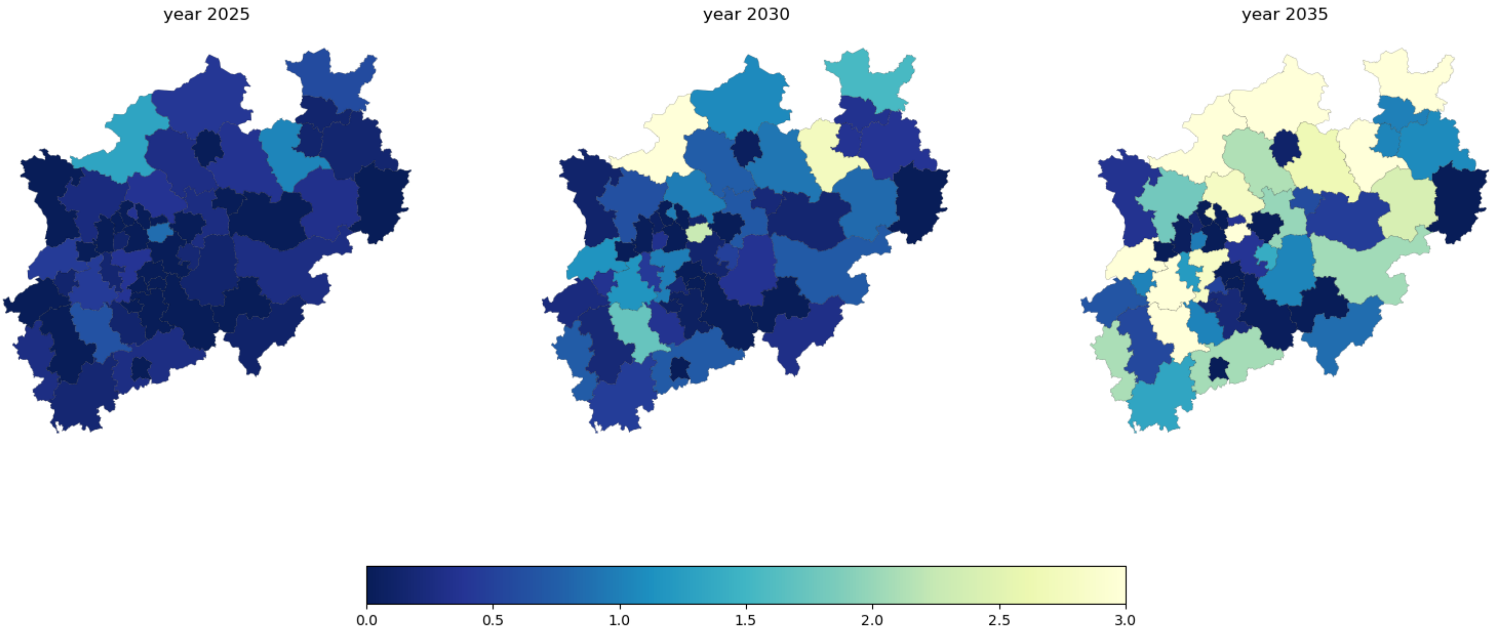


Figure 51 Spatial distribution of privately-refuelled HDVs and LCVs hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

MHVs

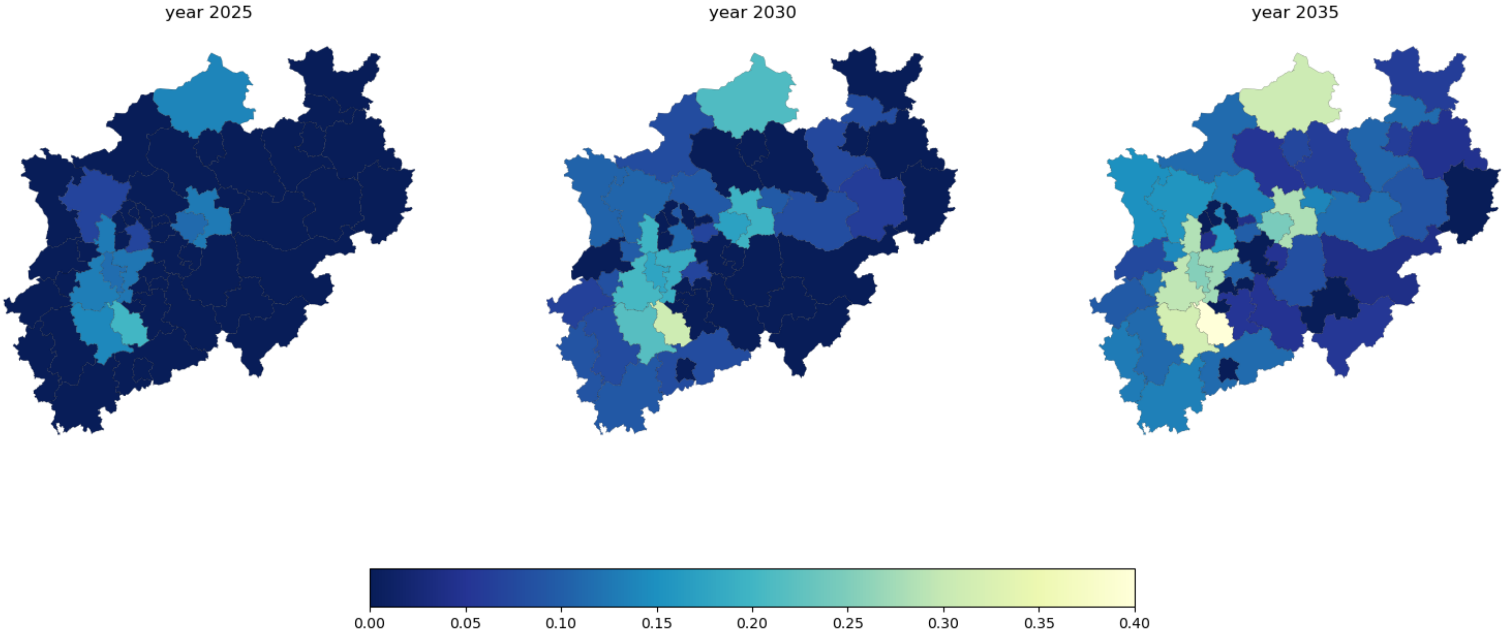


Figure 52 Spatial distribution of MHV hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

Industry

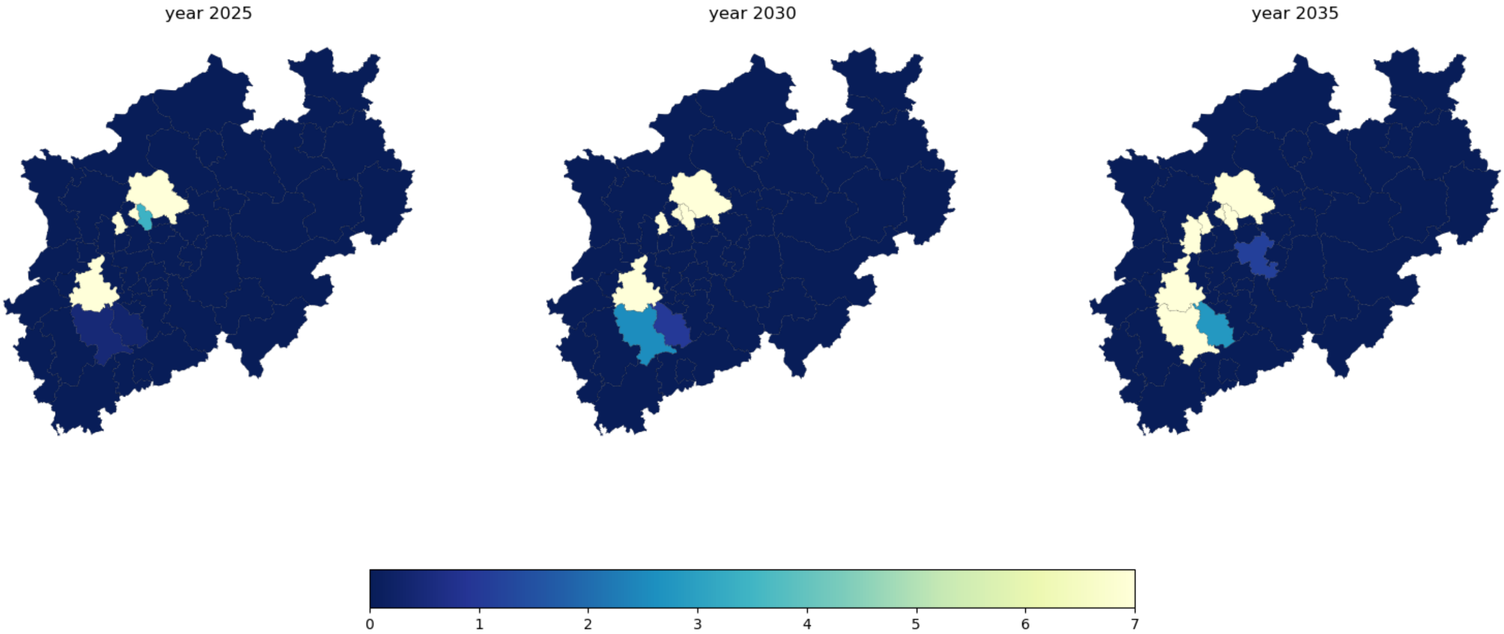


Figure 53 Spatial distribution of Industry hydrogen demand [kt/yr] for the years 2025, 2030, 2035 (NRW)

Appendix F

Spatial distribution of bus-dedicated HRSs in Germany, over time (2025 – 2030 – 2035) and by size. NRW region (lighter orange) and MRR area (darker orange) are highlighted. Marker size is proportional to the expected hydrogen throughput [kt/yr] for the HRS, the colour refers to the size class . according to the following legend:

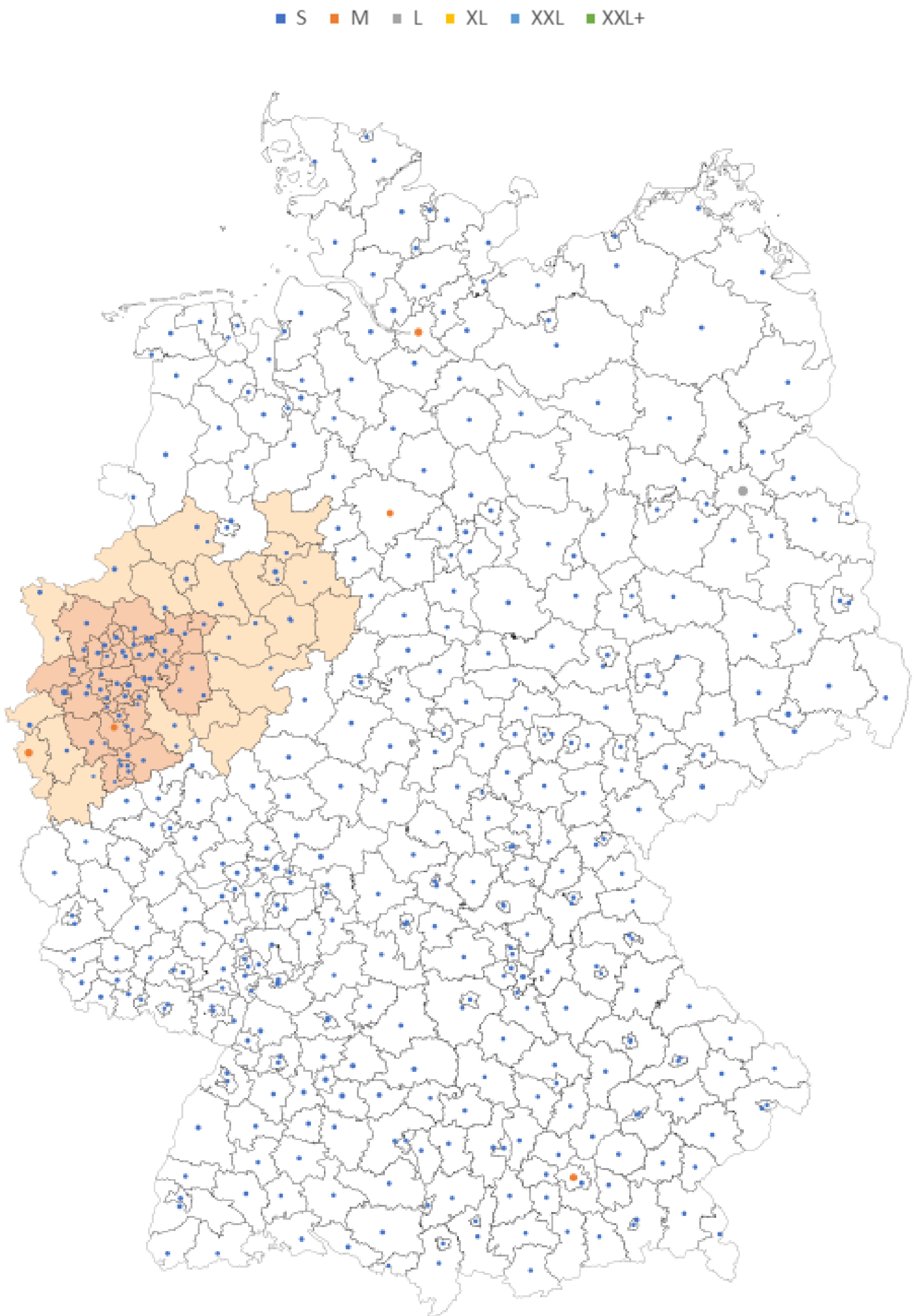


Figure 54 Spatial distribution of bus-dedicated HRSs in Germany, over time - 2025

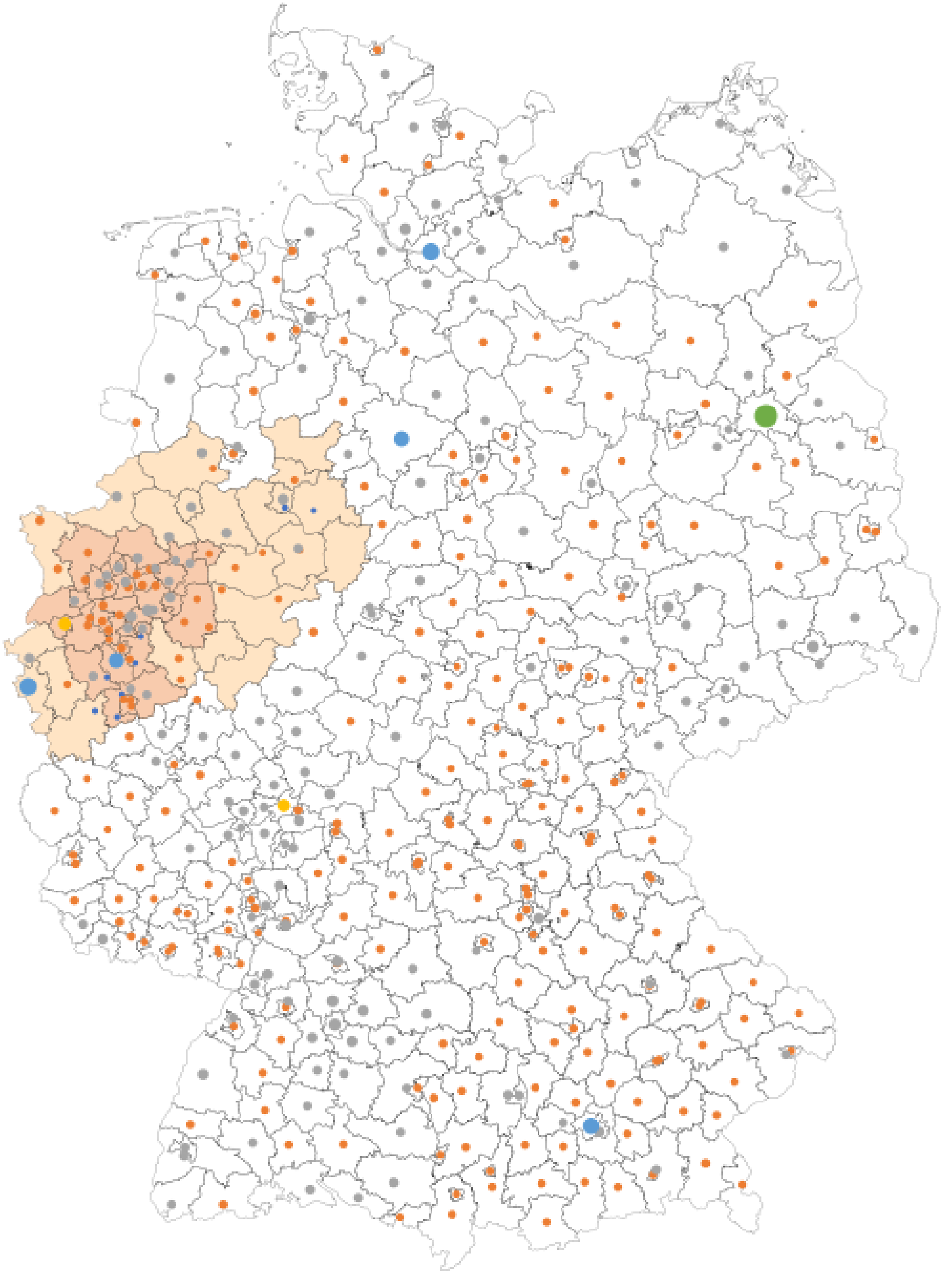


Figure 55 Spatial distribution of bus-dedicated HRSs in Germany, over time - 2030

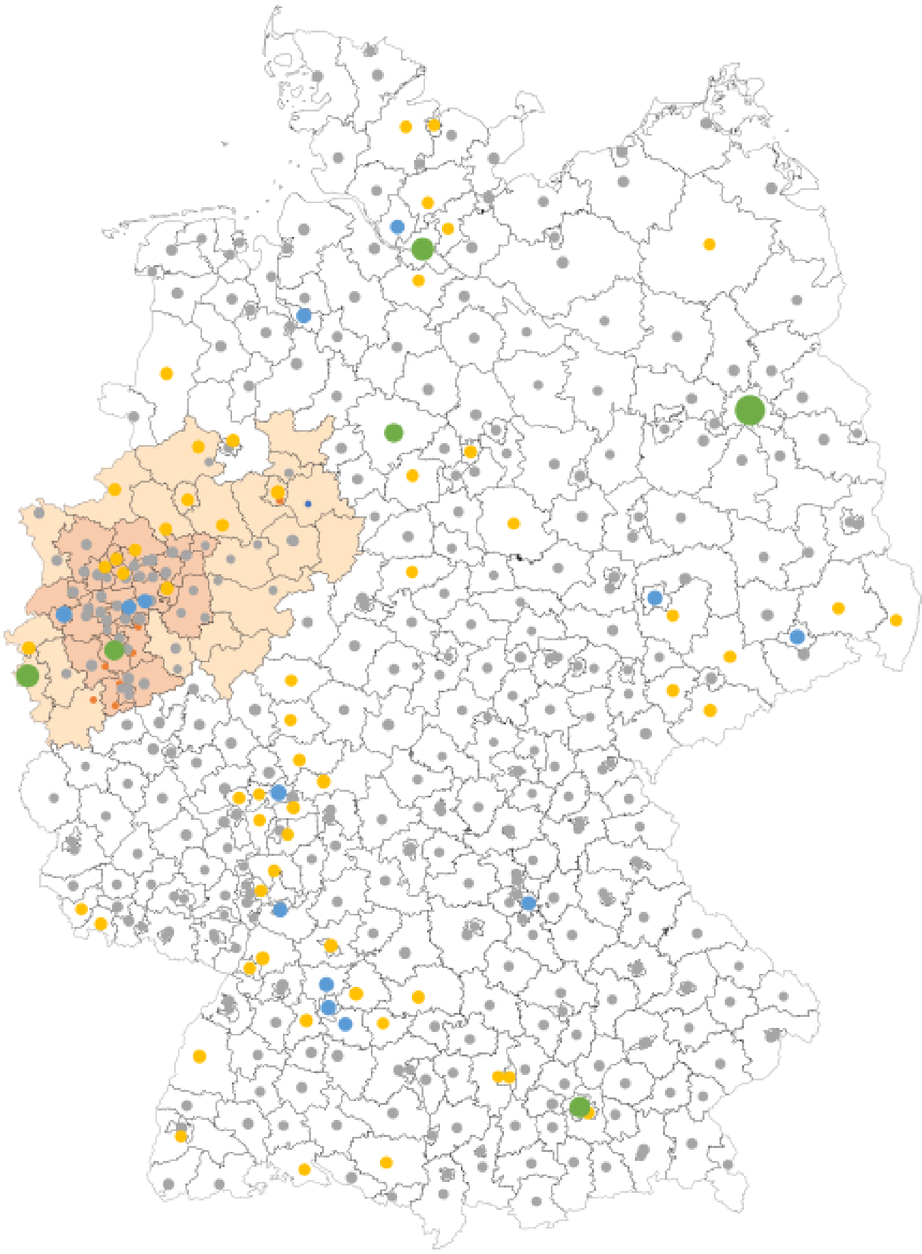


Figure 56 Spatial distribution of bus-dedicated HRSs in Germany, over time – 2035

Appendix G

Spatial distribution of bus-dedicated HRSs in NRW, over time (2025 – 2030 – 2035) and by size. MRR area (darker grey) is highlighted. Marker size is proportional to the expected hydrogen throughput [kt/yr] for the HRS, the colour refers to the size class according to the following legend:

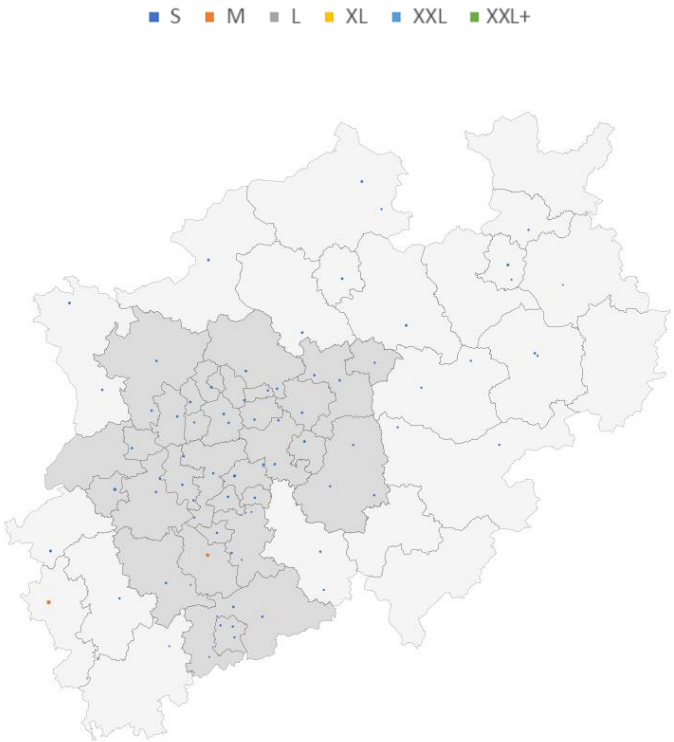


Figure 57 Spatial distribution of bus-dedicated HRSs in NRW, over time - 2025

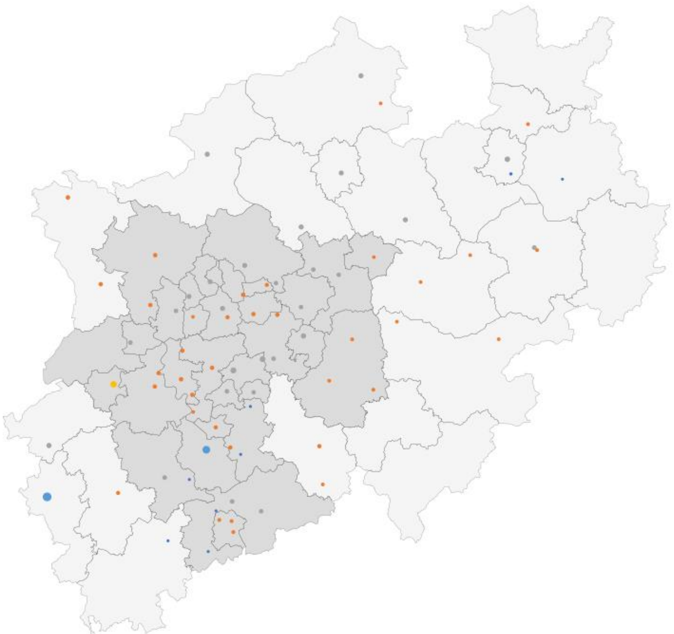


Figure 58 Spatial distribution of bus-dedicated HRSs in NRW, over time - 2030

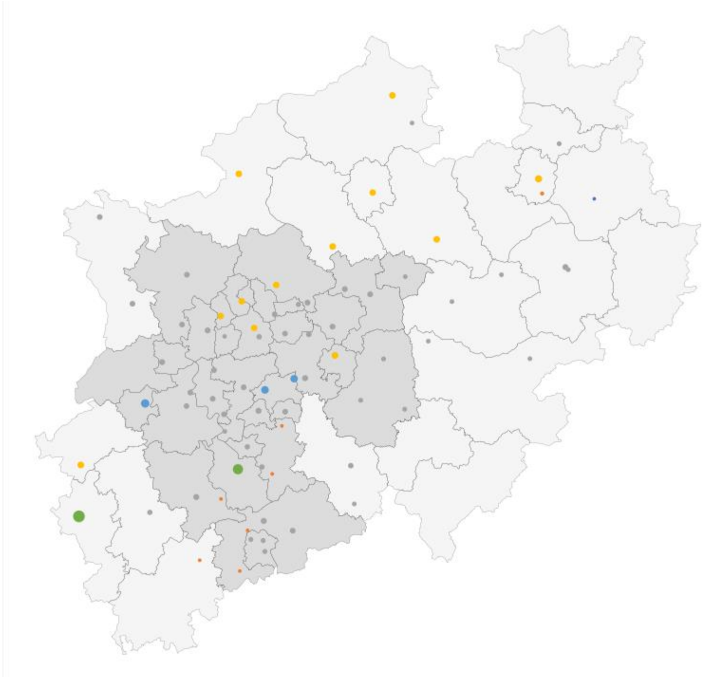
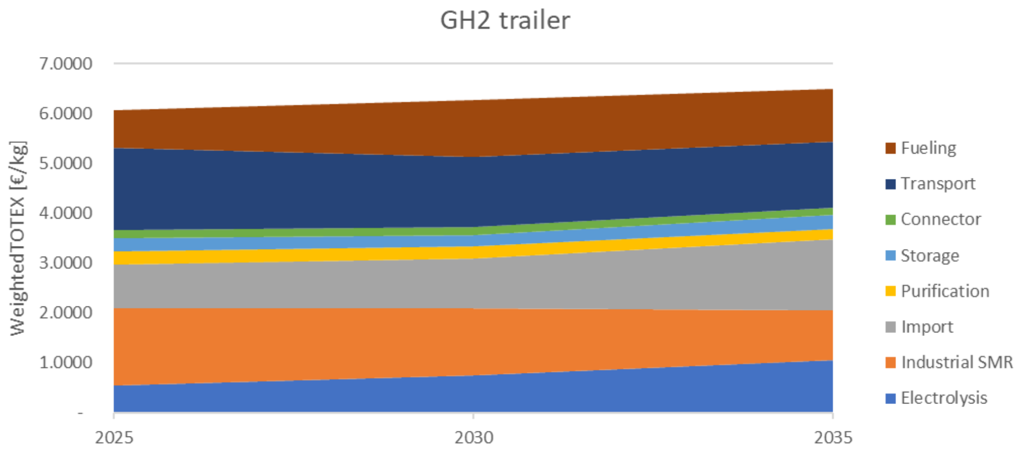


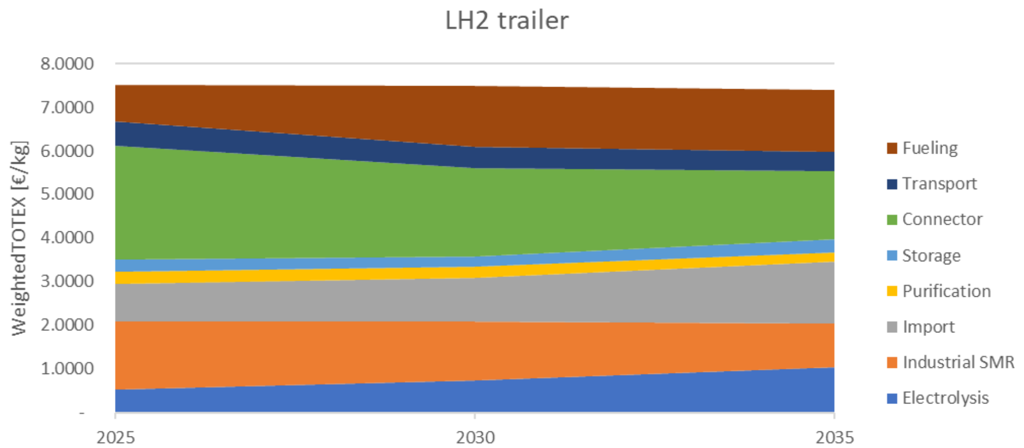
Figure 59 Spatial distribution of bus-dedicated HRSs in NRW, over time – 2035

Appendix H

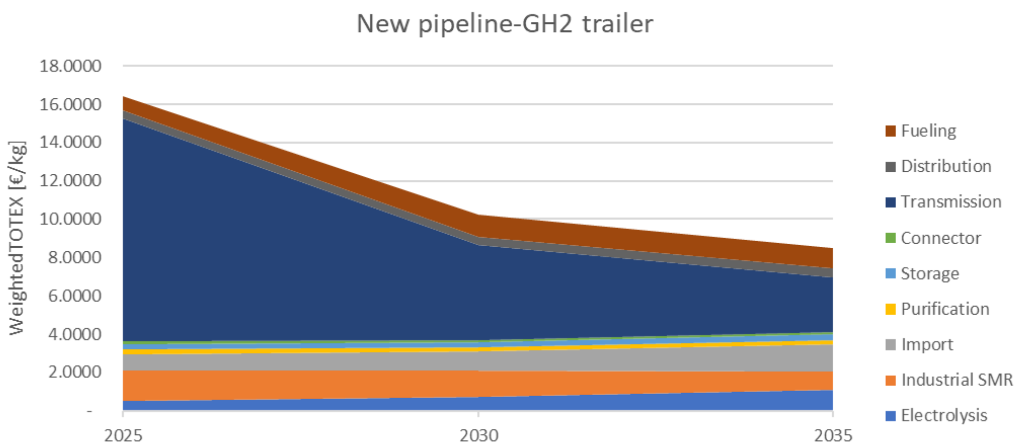
Onsite electrolysis for bus HRSs: expected hydrogen demand [kt/yr] for onsite and centralized cases, expected electrolyser installed power capacity [MW], number of involved stations, and cost breakdown [€/kg H_2].



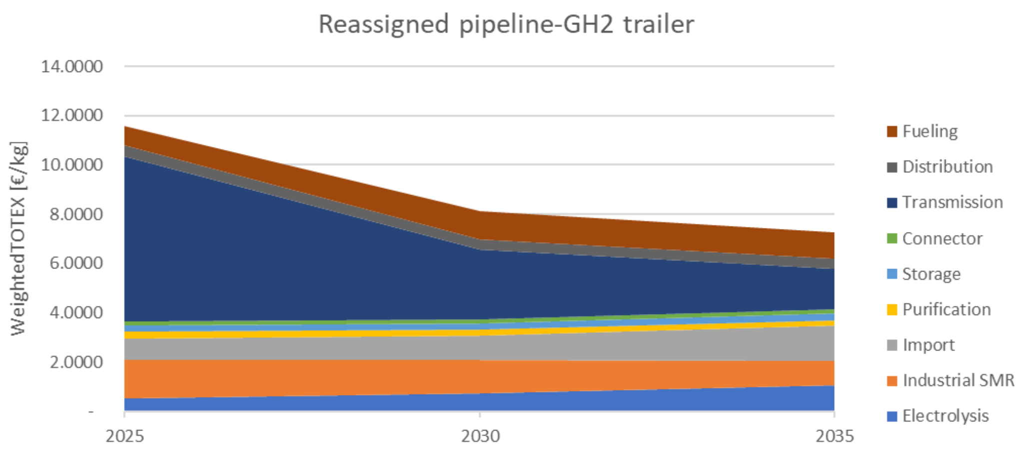
(a)



(b)



(c)



(d)

Figure 60 Weighted average TOTEX breakdown into single supply chain steps (a) GH_2 trailers; (b) LH_2 trailers; (c) New H_2 pipelines + GH_2 trailers; (d) Reassigned NG pipelines + GH_2 trailers.

GH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0506
Industrial SMR	1.5575	1.3608	0.9995
Import	0.8658	0.9904	1.4184
Purification	0.2664	0.2455	0.2100
Storage	0.2673	0.2292	0.2799
Connector	0.1687	0.1478	0.1499
Transport/Distribution	1.6497	1.4119	1.3263
Fueling	0.7584	1.1454	1.0550
weigh. TOTEX [€/kg]	**6.0698**	**6.2699**	**6.4896**

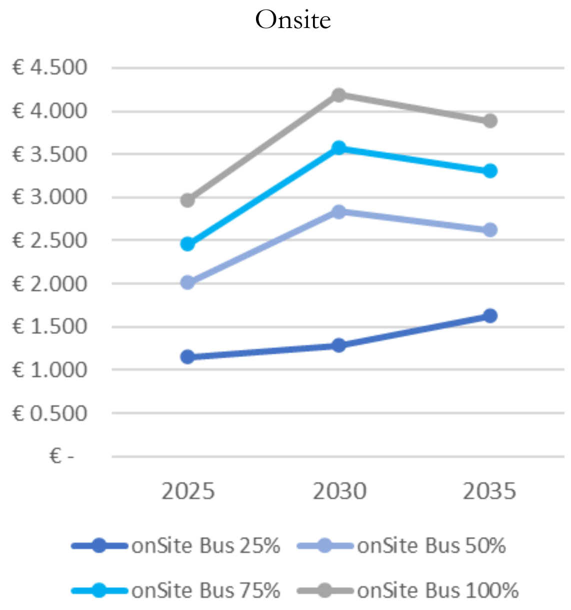
LH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0506
Industrial SMR	1.5575	1.3608	0.9995
Import	0.8616	0.9857	1.4118
Purification	0.2736	0.2529	0.2159
Storage	0.2772	0.2379	0.2894
Connector	2.6205	2.0253	1.5561
Transport/Distribution	0.5481	0.4812	0.4571
Fueling	0.8309	1.4184	1.4208
weigh. TOTEX [€/kg]	**7.5054**	**7.5011**	**7.4012**

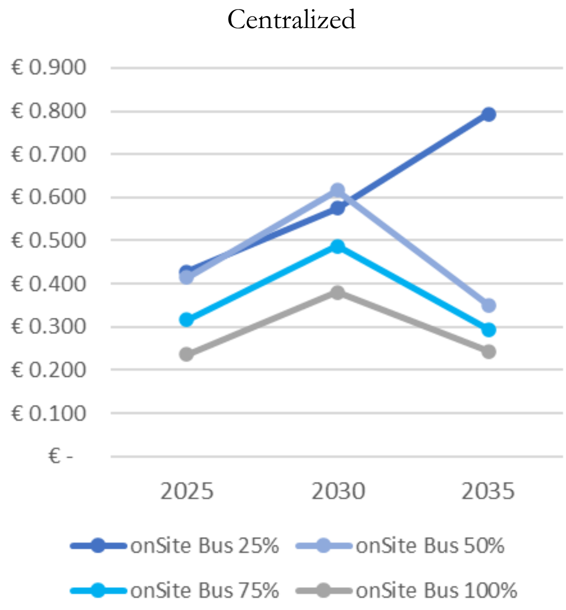
New pipeline – GH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0729
Industrial SMR	1.5575	1.3608	0.9875
Import	0.8658	0.9904	1.4247
Purification	0.2664	0.2455	0.2100
Storage	0.2673	0.2292	0.2813
Connector	0.1632	0.1437	0.1465
Transport	11.5808	4.9272	2.8518
Distribution	0.4452	0.4407	0.4508
Fueling	0.7584	1.1454	1.0550
weigh. TOTEX [€/kg]	**16.4406**	**10.2218**	**8.4805**

Reassigned pipeline – GH_2 trailer	**2025**	**2030**	**2035**
Electrolysis	0.5360	0.7389	1.0729
Industrial SMR	1.5575	1.3608	0.9875
Import	0.8658	0.9904	1.4247
Purification	0.2664	0.2455	0.2100
Storage	0.2673	0.2292	0.2813
Connector	0.1632	0.1437	0.1465
Transport	6.7014	2.8420	1.6406
Distribution	0.4452	0.4407	0.4508
Fueling	0.7584	1.1454	1.0550
weigh. TOTEX [€/kg]	**11.5612**	**8.1366**	**7.2693**

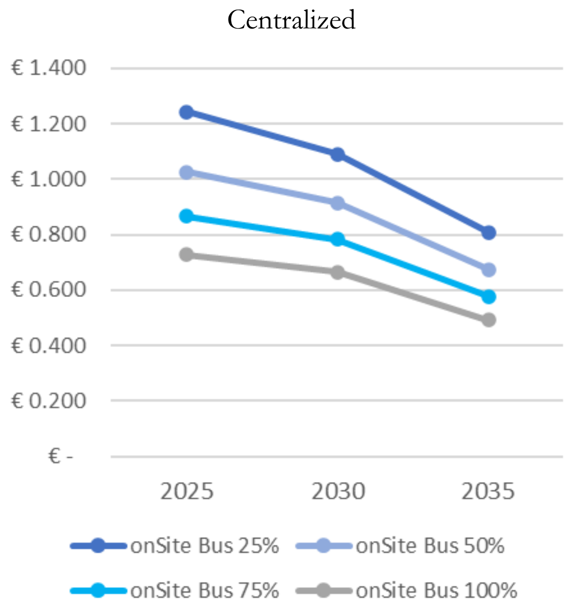
Table 46 Weighted average TOTEX breakdown into single supply chain steps (a) GH2 trailers; (b) LH2 trailers; (c) New H2 pipelines + GH2 trailers; (d) Reassigned NG pipelines + GH2 trailers.

Electrolysis

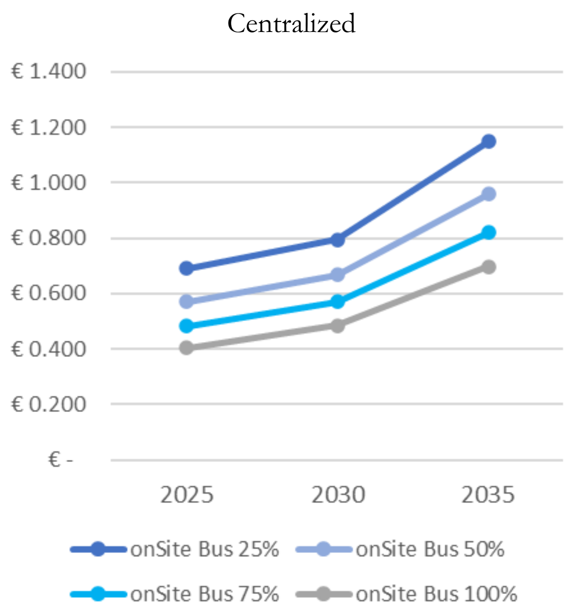




Industrial SMR



Import



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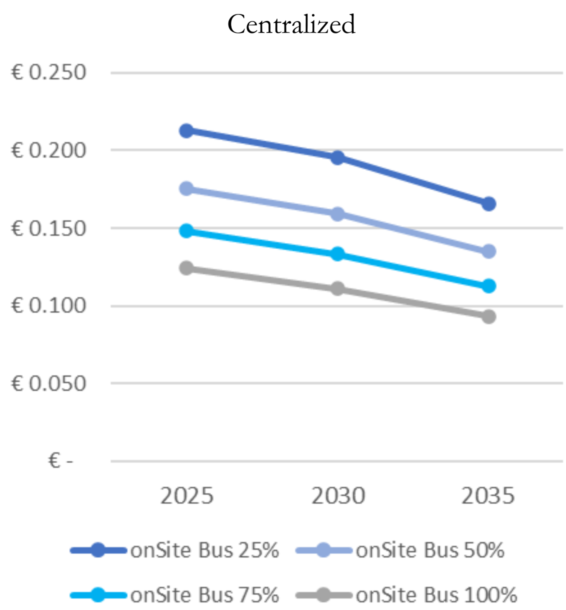

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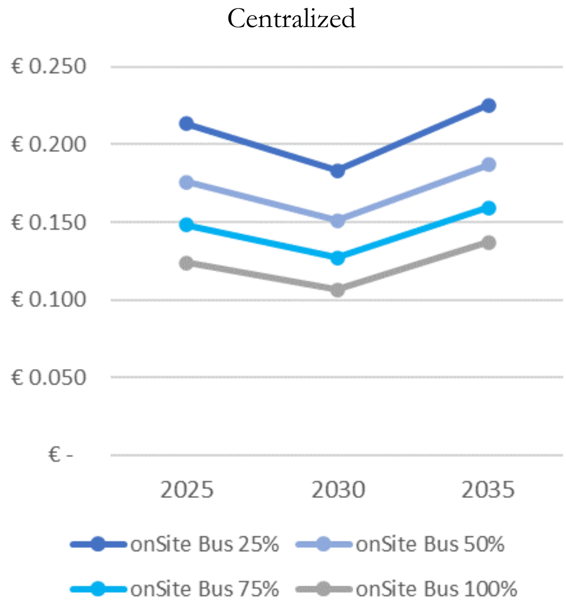
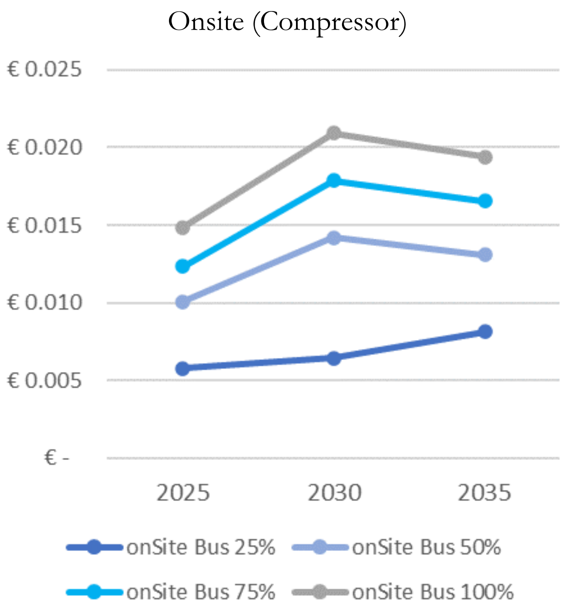
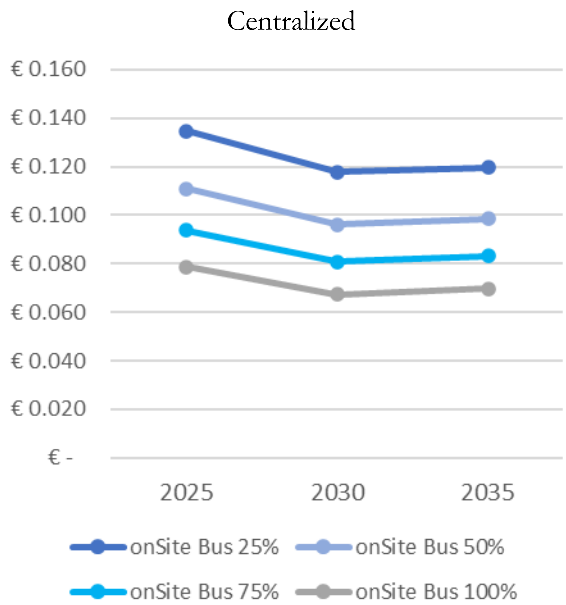


Connector





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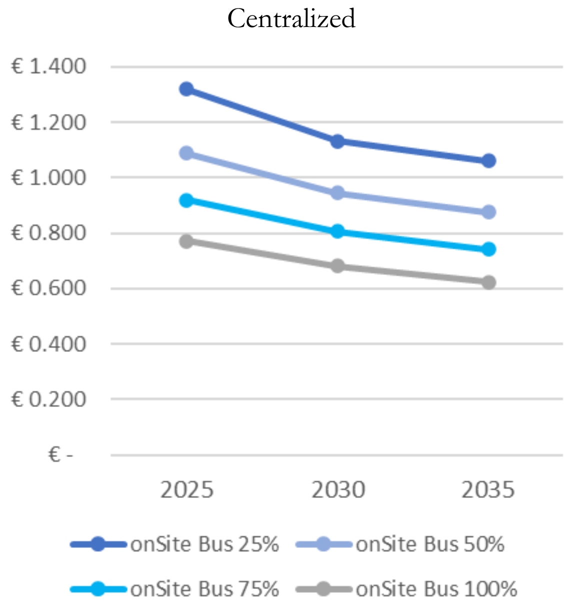
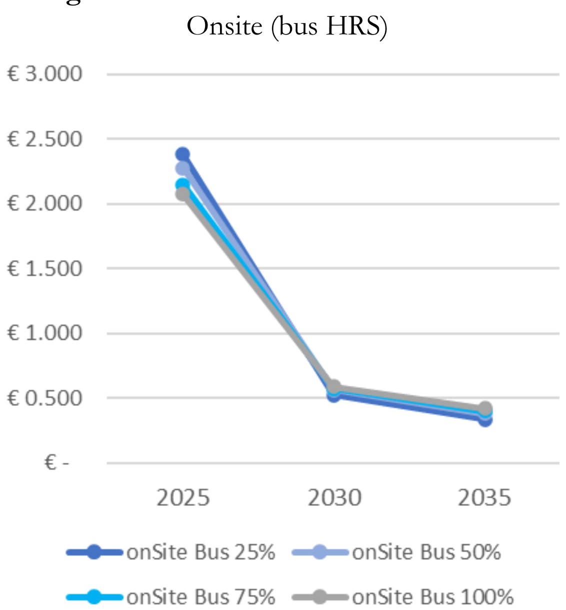
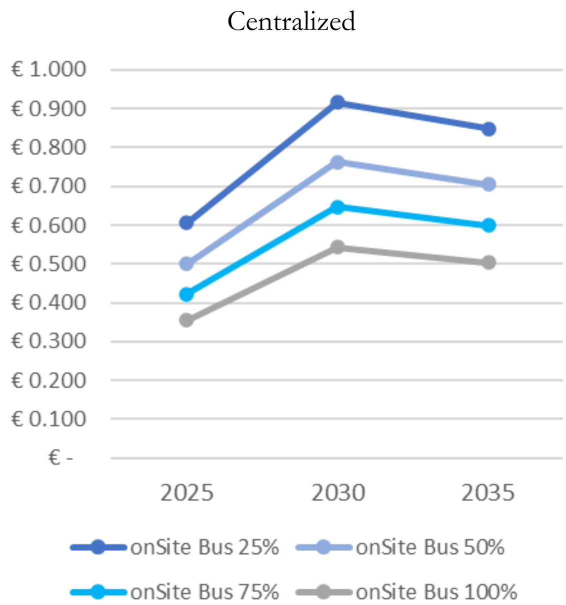


Fueling





TRITA – ITM-EX 2022:10