



European Hydrogen Infrastructure Planning

Latest Insights from TransHyDE System Analysis

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Imprint

Flagship Project TransHyDE

TransHyDE Project System Analysis

Sponsored by the Federal Ministry of Research, Technology and Space

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Table of Contents

	List of Figures	7
	List of Tables	10
1	Executive Summary	11
2	Introduction and objective	17
	2.1 Consideration of two approaches: stakeholders' and system's perspective	17
	2.2 Transport and Buildings	20
	2.2.1 How do the two modelled perspectives differ in the transport sector?	20
	2.2.2 How do the two modelled perspectives differ in the buildings sector?	22
	2.3 Industry	23
	2.3.1 How do the two modelled perspectives differ in the industry sector?	23
3	Transformation from the stakeholder perspective with focus on Industrial transformation	25
	3.1 What transformation pathways are anticipated from the stakeholder perspective?	26
	3.1.1 Iron & Steel Industry	27
	3.1.2 Chemical & Petrochemical Industry	27
	3.1.3 Paper & Pulp	28
	3.1.4 Non-metallic Minerals	29
	3.1.5 Other sectors and non-specified demand	30
	3.2 What industrial processes drive hydrogen demand in the stakeholder perspective?	30
	3.2.1 Iron & Steel Industry	32
	3.2.2 Chemical & Petrochemical Industry	32
	3.2.3 Non-metallic Minerals	33
	3.2.4 Industry-Wide Applications	34
	3.3 What is the European demand for a CO ₂ -Infrastructure?	35
	3.4 Is the CO ₂ price under the EU ETS sufficient to make hydrogen-based production cost-competitive?	37
	3.5 How will regional demand for hydrogen develop in the industrial sector?	39
	3.5.1 Regionalized industrial demand in 2030	39
	3.5.2 Regionalized industrial demand in 2050	39
	3.6 Summary of the industrial transformation from the stakeholder perspective	42
4	Imports	43
	4.1 What impact do different hydrogen import costs have on the European energy system?	43
	4.2 How does blue hydrogen impact the energy and hydrogen system?	46
	4.3 How does a delayed expansion of renewable energies influence the European need for hydrogen imports?	48
	4.4 How do alternative industrial value chains impact the energy system?	50
	4.5 Supply options for the steel industry in Germany?	51

5 Hydrogen infrastructures	56
5.1 What transport capacity can be expected by the approved German hydrogen core network?	56
5.2 How could a feasible transition path for the European natural gas infrastructure to green hydrogen look like?	58
5.3 What infrastructure is needed in addition to the EU hydrogen backbone?	60
5.4 Which existing and future infrastructure elements run the risk of ending up as stranded assets and how can this be counteracted?	62
5.5 Which transport vectors for hydrogen distribution are used under which conditions?	66
5.6 Electrolyzers and H ₂ -power plants: How do their locations influence the congestion management in the German power grid and what is the electrolyzers' potential for utilization of excess heat? Redispatch computations and an excursus to electrolyzer's excess heat analysis	69
5.6.1 Effects on the power transmission grid	69
5.6.2 Excursus – Modeling the heat production of a large-scale electrolyzer	71
5.6.3 Summary	73
6 Further Aspects of Hydrogen infrastructure	74
6.1 Meta Analysis on LCA of Hydrogen Infrastructure & Prospective LCA Methodology	74
6.1.1 Life Cycle Assessments of the Hydrogen Infrastructure – Key Insights	74
6.1.2 Outlook - Prospective Life Cycle Assessment	76
6.2 Drivers and Barriers of a European Hydrogen Infrastructure	76
6.2.1 Prerequisites and Resources	76
6.2.2 Regulatory Aspects	76
6.2.3 Economic Efficiency	76
6.2.4 Acceptance	76
6.3 A digital Roadmap	79

List of Figures

2.1	European hydrogen supply and demand in 2030 and 2050.	18
2.2	Installed electrolyser capacity geographical distribution in 2030.	19
2.3	Installed electrolyser capacity geographical distribution in 2050.	19
2.4	Installed electricity capacity for the different scenarios.	20
2.5	Electricity installed capacity per region in 2030.	21
2.6	Electricity installed capacity per region in 2050.	21
2.7	Final energy consumption of trucks in Germany 2019, 2030 and 2045.	22
2.8	Final energy consumption by energy carrier in the industry sector in Germany, according to the different scenario results. Gaseous and liquid hydrocarbons include both fossil and synthetic sources.	23
3.1	Development of modeled FEC in TWh per energy carrier in the sectors domestic & international transportation, buildings (private households + tertiary sector) and industry (including feedstock consumption) for the EU27+3.	26
3.2	Development of raw steel production compared to 2019 production levels (upper graph) and share of production per production process (lower graph) for the EU27+3.	27
3.3	Development of production levels compared to 2019 levels for pulp products (upper graph) and paper products (lower graph) for the EU27+3.	29
3.4	Development of glass production levels for all production processes compared to 2019 levels (upper graph) and the share of production of flat glass and hollow glass via conventional, hybrid and electric furnaces per year (lower graph) for the EU27+3.	29
3.5	Comparative development of energetic and feedstock consumption in the EU27+3 in the stakeholder perspective.	31
3.6	Development of energetic consumption (left) and feedstock consumption (right) per energy carrier in the EU27+3 in the stakeholder perspective.	31
3.7	Development of hydrogen demand (energetic and feedstock) per sector of industry for the EU27+3.	32
3.8	Development of demand for hydrogen in the steel sector per process and application for the EU27+3.	33
3.9	2050 demand for hydrogen in the chemical sector per process and application for the EU27+3.	33
3.10	2050 demand for hydrogen in the non-metallic minerals sector per sub-sector for the EU27+3.	34
3.11	Development of demand for hydrogen in the glass sector per process and application for the EU27+3.	35
3.12	Development of industrial demand for hydrogen per application in the EU27+3.	35
3.13	Cost-optimized pipeline infrastructure for captured CO ₂ in cement and lime sectors.	36
3.14	CO ₂ avoidance costs for primary steel (BF vs. NG-DRI (a), BF vs. H2-DRI (b), and NG-DRI vs. H2-DRI (c)) production (top) and for chemicals (ammonia (a), methanol (b) and HVC (c)) (bottom) in the four different hydrogen price sensitivities and comparison to the four defined CO ₂ price paths (Source: [22]).	38
3.15	Spatial development of hydrogen demand per product over time for low H ₂ and high CO ₂ price sensitivity (Price combination that is most favourable for hydrogen use) [22].	39
3.16	Regionalized hydrogen demand in 2030 in the industrial sector, NUTS-3 level.	40

3.17	Structure of total demand levels for hydrogen at the NUTS-3 level. Share of districts with a given demand range in 2030 and 2050 (left) and share of total demand represented by districts in a given demand range.	40
3.18	Regionalized hydrogen demand in 2050 in the industrial sector, NUTS-3 level.	41
4.1	Hourly hydrogen imports to Europe for the year 2050 in scenario Med Demand.	44
4.2	Costs for hydrogen imports to Europe via pipeline from MENA for variations of cavern cost and flexibility for gaseous (GH ₂) and liquid (LH ₂) hydrogen.	45
4.3	Hydrogen balance and renewable generation variations in Europe in 2050 (comparison of scenarios).	45
4.4	Optimized European hydrogen network and hydrogen production capacities - 2045.	47
4.5	Optimized hydrogen balance for Europe – 2045.	47
4.6	Hydrogen balance for the EU27+3 depicted for the four focus scenarios. The hydrogen generation and production need to be balanced for each hour.	49
4.7	Average hydrogen prices in the four focus scenarios in €2023/kg.	49
4.8	Scope, Final energy demand, and Specific Energy Consumption (SEC) of value chains for crude steel, High value chemical (HVC) and ammonia in the definition of scenarios S1 and S2.	51
4.9	Hydrogen Demand comparison between S1 and S2 illustrating the difference by value chain.	51
4.10	Hydrogen demand and hydrogen trade and installed capacity by source by 2050.	52
4.11	Value chain for green steelmaking based on direct reduction with hydrogen.	52
4.12	Final energy demand of crude steel production for different energy carriers.	53
4.13	Overview on the considered scenarios.	54
4.14	Comparison of Scenarios 1–4 for Australia as the iron-ore mining country.	55
5.1	Regional development of the Hydrogen Core Network (TUB ER, 2025).	57
5.2	Spatial allocation of the maximum load hours of the simulated years (TUB ER, 2025).	59
5.3	Flowrates in fluid dynamical simulation for both simulated years of S2_ChemSteel scenario (MYNTS, Fh SCAI).	59
5.4	Pressure in fluid dynamical simulation for both simulated years of S2_ChemSteel scenario (MYNTS, Fh SCAI), the values lie in the range of 15 to 60 bar (2030) and 12 to 98 bar (2045), which demonstrates that the core network, designed for 2032, cannot.	60
5.5	Modelled hydrogen network topology for 2030, 2040 and 2050 without adjustments [39].	61
5.6	Fluid-dynamic simulation results for the hydrogen network 2040 [39].	61
5.7	Results of the model Infracore for an optimized pipeline network in 2040. a) pipelines with a capacity of over 5 TWh in comparison to the plans of the European Hydrogen Backbone. b) Illustration of hydrogen flow per year.	62
5.8	Results of the model Infracore for an optimized pipeline network in 2050 with the constraint that the European Hydrogen Backbone will be implemented.	63
5.9	Contour plot indicating the least LCOH(T+S) as a function of hydrogen demand and transport distance.	66
5.10	Transport connections in all modelled scenarios of the Southern Upper Rhine Region in [66], plotted distance vs. transported mass. The color of the circle depicts the selected transport technology, and the size indicates the LCOHT. Pipelines are mostly selected for large transport volumes over short distances.	67
5.11	Transport connections in all modelled scenarios of the Southern Upper Rhine Region in [66], plotted transported mass vs. load factor. The color of the circle depicts the selected transport technology, and the size indicates the LCOHT. The load factor has less influence on the selected technology, but connections with low load factor have higher LCOHT.	68
5.12	Transport connections in all modelled scenarios of the Southern Upper Rhine Region in [66], plotted transported mass vs. load factor. The color of the circle depicts the selected transport technology, and the size indicates the LCOHT. The load factor has less influence on the selected technology, but connections with low load factor have higher LCOHT.	68
5.13	Electrolyzer locations and their relative change in annual electricity consumption due to redispatch measures in the Mid_Demand “copperplate” 2030 scenario. Only units > 10 MW are shown.	70
5.14	Hydrogen power plant locations and their relative change in annual electricity generation due to redispatch measures in the Mid_Demand “copperplate” 2030 scenario. Only units > 10 MW are shown.	70
5.15	Redispatch energy and costs for the modelled year 2030. inflex.: electrolyzers cannot be used for redispatch measures; flex.: electrolyzers can be used for redispatch measures. H2DO: electrolyzers at hydrogen-demand oriented locations, NRSO: electrolyser.	71

5.16	Redispatch results for the modelled year 2030: nodal annual volume of increase and decrease (generators and loads) ▲ Increase Generation ▲ Increase Consumption ▼ Decrease Generation ▼ Decrease Consumption; “Hydrogen demand oriented” allocation: (a) no electrolyzers in redispatch; (b) electrolyzers in redispatch; “Nodal renewable surplus oriented” allocation: (c) no electrolyzers in redispatch; (d) electrolyzers in redispatch; “Redispatch cost minimizing” allocation: (e) no electrolyzers in redispatch; (f) electrolyzers in redispatch;	72
5.17	The comprehensive overview of an electrolysis plant shows the current results of the project. The values represent the heat output at minimum and maximum level of the modeled 17.5 MWel Siemens Silyzer 300. Based on [73].	73
6.1	Life cycle emissions – system boundary: H ₂ production to reconversion, with different assumptions regarding transport distance, used fuel and energy mix (own illustration, based on data gained from [54, 76–83].	75
6.2	Perceived obstacles regarding the industrial use of green hydrogen.	77
6.3	Perceived opportunities regarding the industrial use of green hydrogen.	78
6.4	Availability of municipal resources for planning and approval processes.	79

List of Tables

1.1	Overview and description of scenarios.	16
2.1	Overview over the five scenarios analyzed within this publication. While scenarios Low_Demand, Mid_Demand, Mid_High_Demand and High_Demand follow a systematic increase of hydrogen demand within the different final energy consumption sectors, the stakeholder scenario 'MarketExp' focuses on the envisioned scale-up the different stakeholders involved in the European energy transition. Further details in [4, 5] and Chapter 3.	18
3.1	Scenario definitions and key assumptions [22].	38
5.1	Demands of the hydrogen core network scenario (based on the hydrogen core network application of July 2024).	57
5.2	Supply capacities of the hydrogen core network scenario (based on the core network application of July 2024).	58
5.3	Comparison of offtakes of maximum load hours in different scenarios [24, 46].	58
5.4	Scenario specific results for the cost-optimal hydrogen supply chain in Ostwestfalen-Lippe, modelled for 2030 in four different scenarios. The region would be a net hydrogen exporter for the assumed hydrogen prices at the core network, therefore the connection would lead to a larger local hydrogen system. Low risk of stranded assets from the connection, but high risk of stranded asset if no connection is happening and the demand development is low.	64
5.5	Scenario specific results for the Southern Upper Rhine Region, modelled for 2030. The region would be a net hydrogen importer for the assumed hydrogen prices at the core network, therefore the connection would lead to a smaller local hydrogen system. High risk of stranded assets for early investments in a local hydrogen supply chain.	64
6.1	Population size of surveyed municipalities.	77

1

Executive Summary

Introduction and objective

Hydrogen is expected to be a key contributor to the energy transition, especially in hard-to-abate sectors. The EU has recognized its role and aims for a comprehensive hydrogen ecosystem in Europe. Germany, as a central actor in Europe for its location, industrial base and renewable energy development, has set its own ambitious targets. The TransHyDE project aims to provide background information on crucial aspects of hydrogen infrastructure development.

Consideration of two approaches: stakeholders' and system's perspective

TransHyDE has taken a two-tier approach. The system's perspective allows a holistic understanding and identification of the most cost-efficient solutions, while the stakeholder's perspective complements with specific viewpoints from energy-intensive industries to identify constraints and incentives for the implementation of new technologies. Combining both perspectives allows for a more robust and comprehensive analysis. It ensures that systemic benefits are aligned with practical needs and constraints of stakeholders. A series of different scenarios map different implementation of technologies in various sectors and different regional renewable hydrogen generation capacities. The scenario results with respect to the end-users in the building and transport sector show a general agreement, reflecting the specific assumptions made. As for the use of hydrogen in the industrial sector, the scenario reflecting the stakeholder perspective is comparable with the system's scenario applying hydrogen for steel and chemicals

as well as high-temperature heat. The industry results are driven by the projected production volumes either from macroeconomic reports or bottom-up data provided by the sector-specific industrial research institutions. Differences are explained in terms of model assumptions and system barriers.

Transformation from the stakeholder perspective with focus on industrial transformation

The stakeholder perspective was implemented as a specific scenario. While transport and building demands were modelled in a conventional approach, industrial transformation pathways were based on the input provided by the sector-specific industrial research institutes. The final energy demand declines strongly in the transport (-40 %, all numbers in brackets for 2050 versus 2019) and building (-45 %) sectors due to electrification. While industry also substitutes conventional energy carriers over time, the overall decline of final energy use is more modest (-10 %). Some fossil-based energy carriers remain in the system for industry and transport and might need to be provided as synthetic fuels or compensated for based on carbon capture and negative emission technologies via DAC/CCS. The largest hydrogen demand for EU27+3 originates from industry (779 TWh), followed by transport (423 TWh) and by buildings (179 TWh), with additional demand from the transformation sector (e.g. power plants) not included. What transformation pathways are anticipated and which industrial processes drive hydrogen demand in the stakeholders' perspective?

Transformation pathways for the iron & steel industry,

while adjusting to an overall increase of production volume (+11 %), include expansion of the secondary route, which is limited by scrap availability and quality constraints, while the primary route can either be shifted to direct reduced iron (DRI) or combining the conventional blast furnace with carbon capture and storage (CCS). Over time in 2050, steel production by the secondary route is slightly increased (45 %), while the major shift happens towards DRI technology (50 %). A small conventional capacity (5 %) remains, while CCS is not implemented. The steel industry expects hydrogen demand to rise to 370 TWh in 2050 due to implementation of the direct iron reduction route, both as feed and fuel (296 TWh) and some contribution of unspecified process heat demand (70 TWh).

In the chemical and petrochemical industry, transformation options focus on the production of high-value chemicals, methanol, ammonia and urea. Production volumes are expected to remain constant at 2019 levels. Conventional ammonia production will be largely substituted by external hydrogen supply combined with Haber-Bosch synthesis (67 %), while the remaining conventional production is required for subsequent urea production. Methanol production is currently based on steam reforming of methane or partial oxidation of hydrocarbons. Both process routes will be replaced via syngas-based routes fed by biomass gasification (52 %) or CO₂ and hydrogen (48 %). High-value chemicals, i.e. olefines and BTX, are produced via steam cracking of naphtha. Future technology options include electrically heated steam crackers in combination with synthetic naphtha (44 %), recovering material via chemical recycling (12 %) and production via methanol-to-X processes (44 %). The chemical industry increases its hydrogen demand to 260 TWh in 2050, around 2/3 for the provision of process heat and 1/3 using hydrogen as feedstock for ammonia and methanol assuming the current market size. Demand will differ significantly if methanol and ammonia become energy carriers in their own right, rather than chemicals or in case of methanol, a platform chemical to produce Methanol-to-X products. The pulp and paper sector shows some variation in the expected production volumes for different products. Special and packaging paper production declines (-8 %) as does chemical and mechanical pulp (-11 %) and graphic paper (-85 %), while tissue paper is expected to increase (+14 %). Electric steam generation via heat pumps for low temperature applications, high-temperature heat pumps, electrode boilers and biomass for intermediate temperature applications will be dominant technologies and heat beyond 500 °C will be supplied by burning of biomass. Glass production is expected to slightly increase from 2019 levels by 5 % in 2050. Flat glass production transitions to hybrid furnaces, due to technical incompatibility with direct electrification while other glass products reach various levels of direct electrification: hollow glass (25 %), utility and special glass (33 %) and fiberglass (70 %), mineral fibers (100 %). Hydrogen demand is expected to increase as fuel (15 TWh), split between flat and hollow glass with minor contributions from other glass products.

Clinker production for cement is expected to decline (-30 %) with a slight decrease in overall cement production (-5 %). Energy carriers for clinker production shift from fossil fuels to burning waste from biogenic and fossil origin. Since a significant part of the CO₂-emissions is caused by using limestone as raw material, CCS will be a significant

contributor to reduce emissions in the cement sector, starting in 2028 and achieving universal coverage in 2045. This is supported by the implementation of oxyfuel technology to increase the CO₂-concentration in the flue gas and to improve capture efficiency. Cement and lime production use hydrogen in 2050 (17 TWh) exclusively to produce high-temperature heat. The overall demand for hydrogen from non-metallic minerals (NMM) include glass, cement and other industries amounts to around (101 TWh) in 2050. Next to those industries described in detail, the model covers other industrial sectors with a top-down approach. As cross-sectorial technology, industrial heat generation changes according to the required temperature. Process heat below 100 °C is provided by heat pumps and electric boilers, in the temperature range up to 500 °C high temperature heat pumps, electrical boilers as well as biomass and to a small extend hydrogen will be used. Beyond 500 °C, burning biomass and hydrogen become the main source of heat.

Overall, the industrial sector sees a slight decline (-9.5 %) in its final energy consumption combining feedstock and energy. However, the feedstock demand increases over time (+40 %) but is more than compensated for by the decline in energy use (-16 %). The picture is more complicated on closer inspection. Direct electrification, efficiency measures and sometimes lower energy demand by the transformative processes lead to reduced demand. On the other hand, economic growth, carbon capture in the cement industry and specifically chemical feedstock provision are responsible for contributions for higher demand. Fossil fuels are nearly eliminated in the future energy system. Some coke is still used in iron production, natural gas remains for ammonia coupled with urea production and some liquid hydrocarbons as well as natural gas for localized heat production and to fuel heavy equipment. Fossil feedstocks also decline significantly and could further be defossilized by synthetic feedstocks. Hydrogen demand can be covered by blue and green hydrogen in any combination. Hydrogen demand grows more than 7-fold until 2050 in industry with around 30 % as feedstock and 70 % as energetic use. Overall, the industry model predicts a demand of (779 TWh) hydrogen for 2050 with (239 TWh) for feedstock and the remainder to supply process heat.

What is the European demand for a CO₂-Infrastructure?

CCS becomes an important option for hard-to-abate emissions in the cement industry, thermal waste treatment, as well as capturing biogenic emissions from power plants. To facilitate CCS, a CO₂ infrastructure is required. Within our modelling framework emissions are collected on NUTS-3 level and combined for transport to export terminals and the respective storage sites, or in case of CCU, possible plant sites. The result is a south-western network collecting CO₂ from the Iberian Peninsula, Southern France and Italy leading to the Adriatic coast and a set of pipelines connecting Germany, Benelux, Northern France and Poland to storage sites in the North Sea. Other countries get access through local pipelines or export terminals to storage facilities. The predicted pipeline network of 37,000 km length is larger than what is foreseen in current EU plans.

Is the CO₂ price under the EU ETS sufficient to make hydrogen-based production cost competitive?

The EU ETS sets a price for CO₂ emissions. CO₂-avoidance cost for hydrogen-based technologies were analyzed using a variation of price parameters. In case of steel production, the substitution of blast furnace technology with hydrogen-based DRI strongly depends on the assumptions on the hydrogen price. Shifting from NG-based DRI to hydrogen-based DRI requires a CO₂-price of 250-300 €/t. Similar values are calculated for climate neutral ammonia production. Due to the lack of regulation regarding CO₂ as a feedstock within the EU-ETS, hydrogen does not become competitive even at high CO₂-prices for feedstock use. Due to an aging stock and investment cycles, hydrogen technologies might not be implemented due to cost reasons, resulting in a possible lock-in effect.

How will regional demand for hydrogen develop in the industrial sector?

Industry is the major user for hydrogen. However, its demand is highly localized at industrial centers and regions in Europe which need to be connected with the respective infrastructure. Industrial demand is expected to increase 7-fold from 2030 to 2050 and the number of districts requiring hydrogen supply increases accordingly all over Europe, while still a small number of districts (15) are responsible for a significant part (34 %) of the overall demand.

What impact do different hydrogen import costs have on the European energy system?

Previously, hydrogen imports were discussed predominantly with respect to import of gaseous hydrogen via pipelines, while shipping of e.g. green ammonia offers another degree of flexibility. Uncertainty about the overall amount of hydrogen required in 2050 is still large (697 TWh – 2897 TWh). This study estimated that 4 % - 10 % of pure hydrogen demands will be supplied via pipeline imports under the assumption of strong deployment of renewable energies in Europe. In case of slower deployment, import fractions are expected to rise to 10 % - 15 %. Ship transport of derivatives is uncompetitive for pure hydrogen demands with respect to domestic production. The imports have a seasonal dependence, since external hydrogen production is more competitive in winter due to more expensive domestic production and higher demands. Therefore, the pipeline networks need to be adjusted accordingly and there is a need for storage. We investigated the solution space by varying the degree of alignment between import and demand as well as storage cost assumptions. While there is a strong inverse dependence on cost with respect to alignment, due to underutilized equipment for long periods of time in case of strong alignment, storage cost features only a marginal influence on the overall cost and are therefore not expected to play an important role.

How does blue hydrogen impact the energy and hydrogen system?

Next to green hydrogen, produced by electrolysis with renewable electricity, blue hydrogen from SMR or POX in

combination with CCS is expected to play an important role, especially in the transition period, providing a stable, scalable supply. While our model had different options in locating a 10 GW blue hydrogen process chain, the lowest cost occurs with a central production in Northern Germany coupled with CCS in the North Sea. Next to this central plant, the model also installed smaller plants with an overall capacity of 21.2 GW at various locations. Due to the simplification of the model, transport of natural gas or CO₂ is treated as a copper plate. The assumed overall limitation of storage volume to 200 Mt/a leads to a shadow price of 252 €/t_{CO₂seq}. Overall, blue hydrogen would amount to 10 % of hydrogen used, limited by CO₂ sequestration. It also reduces the amount of green hydrogen import while requiring natural gas import. Hydrogen network costs are reduced with the use of blue hydrogen, since less transport of green hydrogen is required, as well as storage needs, since blue hydrogen is a more reliable supply.

How does a delayed expansion of renewable energies influence the European need for hydrogen imports?

Ramping up variable renewable power generation, PV and wind, is crucial in achieving the EU's climate goals. We evaluated the effects of a delayed ramp up versus an accelerated ramp up. The case of a slow ramp up results in higher imports and implementation of blue hydrogen to meet hydrogen demand and high hydrogen prices. In case of an accelerated ramp up, there is less import, an increase in storage capacity and lower hydrogen prices.

The pathway to a low carbon economy requires fundamental changes to industry sectors like the chemical and steel industry. The first energy-intensive steps to produce basic chemicals or iron with hydrogen are likely to be uncompetitive in Europe and the resulting products are easily transported. The scenario analysis indicates a strong cost benefit for external production of the energy/hydrogen-intensive step, leading to a much-reduced overall industrial energy demand with the corresponding impact on hydrogen infrastructure but also on infrastructure to import the intermediate products.

How do alternative industrial value chains impact the energy system?

Transformation of conventional iron & steel production to hydrogen-based pathways requires an infrastructure for stable and secure supply of hydrogen. While this might not be available from the onset, it is important to investigate alternative routes of hydrogen supply for a given site. One case study investigated the SALCOS® project in Salzgitter. Different hydrogen supply options include supply via pipeline, using ammonia or methanol as hydrogen carrier, local production via PEM or High-Temperature electrolyzer. In terms of energy demand, shorter process chains are advantageous and onsite conversion of precursors is favorable compared to central conversion. For carbon-based energy carriers, the transport of CO₂ or offsetting with DAC must be considered for circularity.

Supply options for the steel industry in Germany?

Since it might be favorable to spatially decouple the process steps of the DRI process chain, i.e. mining, reduction, melting, different scenarios were investigated and the energy demand as function of process chain integration. The energy demands are very similar with a slight benefit when being able to integrate the reduction process with the subsequent melting via electric arc furnace, avoiding the energy loss by DRI pellets cooling down. This limited assessment should not be overinterpreted, due to other factors coming into play like transport or site limitations.

Hydrogen infrastructures – What transport capacity can be expected by the approved German hydrogen core network?

An understanding of the development of the hydrogen network in Germany is crucial in describing the role of hydrogen in the energy transition. The final network will encompass 9040 km in 2032. The structure of the network, interconnecting demand and supply has been developed by the transmission system operators (TSO) based on market studies. It connects large consumers, e.g. power plants and energy intensive industries, with planned electrolyzers, cross-border interconnectors and marine terminals as well as storage sites. The main limitations of this approach are the missing link to the price sensitivity of demand of individual customers and the lack of model-based assessment of storage demand. Based on these aspects, an incremental and agile implementation of the core-grid is recommended.

Based on publicly available data on the network, a fluid-mechanical analysis was carried out, to validate the functionality of the network in different scenarios. Within the *T S2_chemSteel-scenario*, the maximum offtake during a “Dunkelflaute” of the grid is 26 GW in 2030 and 171 GW in 2045, both values are within the physical limit of flow velocity and pressure levels.

How could a feasible transition path for the European natural gas infrastructure to green hydrogen look like?

In order to investigate feasible transition pathways from a natural gas infrastructure to one supporting green hydrogen, repurposing of natural gas pipelines plays an important role, guaranteeing security of supply and preparing for future needs. The spatial and temporal grid development based on the *S2_chemSteel-scenario* was analyzed using an iterative process, peak load hours were identified and bottlenecks resolved, while active elements like compressors were introduced. A fluid dynamical calculation ensured operation within the physical limits and the network performance is simulated. The network starts growing from Northwestern Europe with a length of 3060 km and interconnects the entire continent by 2050 with 46,000 km, out of which 98 % are repurposed natural gas pipelines.

What infrastructure is needed in addition to the EU hydrogen backbone?

The infrastructure requirement originates from the transformation plans of the industry in combination with other

users, which implement a spatial and temporal demand profile. The supply of hydrogen was calculated from energy system analysis and both demand and supply are allocated on a district level. The infrastructure model adds information on natural gas pipelines, which may be repurposed. The optimization aims at minimizing the cost of the overall network with a yearly resolution and the result compares favorably with the European Hydrogen Backbone. A hydraulic simulation on the appropriate timescale would be necessary to judge the network's performance with daily and seasonal variation, which is beyond the scope of this study. An independent validation of the European Hydrogen Backbone revealed a potential demand for additional 4000 km pipelines in 2050 provided, pipelines remain the only transport option for hydrogen.

Which existing and future infrastructure elements run the risk of ending up as stranded assets and how can this be counteracted?

There is a substantial risk that the transformation to hydrogen as an energy carrier will lead to stranded assets, especially in the gas industry. Since hydrogen supply might have a strong local component, a detailed study on the regions Ostwestfalen-Lippe and Southern Upper Rhine has been carried out, varying the parameters of demand and grid connection. The former region has good wind power conditions and the potential to become a net exporter, provided the grid connection is in place. This indicates hydrogen production facilities are likely to remain competitive even after connection to the national backbone and further supply options. The latter region has less favorable conditions and investments into local hydrogen generation are at risk to become stranded investments, being uncompetitive with imports from outside the region.

Municipal heating supply by combined heat and power plants (CHP) is also at risk to become stranded assets if the future heat demand declines or competition by other forms of heat generation, e.g. geothermal, heat pumps become more technically advanced. Municipalities need to manage the transformation of their existing assets with quite some uncertainty. While converting waste incineration plants to hydrogen is relatively straightforward, converting a CHP plant to hydrogen comes with some technical challenges, which are outlined in detail.

Which transport vectors for hydrogen distribution are used under which conditions?

There are various storage and transport options for hydrogen available. A detailed analysis of different transport options based on their levelized cost of hydrogen transport and storage has been carried out to identify the most cost-efficient option for a given distribution task. On the example of different regions, different modes of hydrogen transport were analyzed with their levelized cost of transportation as function of distance and volume transported. Retrofitting existing gas pipelines the most cost-efficient pathway for large volumes, if available. New pipelines are cost-efficient for high volumes on short distances, while rail transport is more viable for longer distances. Truck transport offers the highest level of flexibility.

Electrolyzers and H₂-power plants: How do their locations influence the congestion management in the German power grid and what is the electrolyzers' potential for utilization of excess heat?

The location of electrolyzers and hydrogen power plants in the power grid have an impact on grid congestion and redispatch, thereby lowering overall cost. At the same time, they produce significant amounts of low temperature heat that need to be dealt with. Initially, electrolyzers were located within the power grid to minimize grid congestion before redispatch. Subsequently, this approach was extended to minimizing the actual cost of redispatch. Three strategies were analyzed: Hydrogen demand oriented, Nodal renewable surplus oriented and Redispatch cost minimizing. The chosen strategy has a profound impact on the effect of reducing redispatch cost. Next to its effect on redispatch, electrolyzers also reduce curtailment of renewable energy and provide additional hydrogen production.

Excess heat from electrolyzers might be usable, depending on the location, heat demand and technology to upgrade the heat, e.g. via heat pumps. As an example, an 17,3 MW PEM electrolyzer with a maximum heat generation of 3,8 MW was analyzed in detail. The stack itself generates around 23 % of the waste heat and the rectifier, depending on the mode of operation, 16 % - 22 %. The results indicate that the balance of plant should not be overlooked when assessing the potential for excess heat.

Meta Analysis on LCA of Hydrogen Infrastructure & Prospective LCA Methodology

Evaluating hydrogen infrastructure beyond economic parameters should include a sustainability assessment. A literature meta study on lifecycle assessment (LCA) studies on hydrogen infrastructure was carried out to assess the quality of data and derive recommendations. The studies vary in their selection of system boundaries, functional unit and scope. Specific tasks will require dedicated studies. Applying prospective LCA to address future developments is a particular challenge due to the need to adjust the background system in order to properly assess a future technology.

Drivers and Barriers of a European Hydrogen Infrastructure

Implementation of new technologies is subject to drivers and barriers which are categorized into four categories: Prerequisites and resources, Regulatory aspects, Economic efficiency, and Acceptance. A survey was carried out with employees of the steel industry to assess their view of obstacles and opportunities on the implementation of hydrogen technologies. The results show general support, coupled with a high degree of uncertainty, especially with respect to costs, security of supply and feasibility. Opportunities were perceived by the reduction of greenhouse gases, the potential for innovation and the associated competitive advantages. Another survey was conducted among employees in municipal administrations, who are located at a crucial intersection with the public and the infrastructure. The survey results suggest that while there is considerable awareness of hydrogen technology and its potential benefits, municipalities face significant challenges in terms of resources, knowledge, and planning. There is a limited base of well-founded knowledge, which should be addressed with transparent scientific communication, also with regard to possible limitations of the hydrogen transition, to provide a foundation for nuanced opinion-forming processes.

Additional content is provided to cover transportation cost of hydrogen as a function of volume and distance, effect of smart placements of electrolyzers on grid congestion in order to reduce redispatch cost, utilizing excess heat from electrolyzers, using LCA to evaluate the sustainability effect of a hydrogen infrastructure and surveys of acceptance of hydrogen technology with workers in the steel industry and in a municipal administration, to identify barriers and drivers for the transformation.

Table 1.1. Overview and description of scenarios.

Scenario	Abbreviation	Category	Short Description
Scenario 1 / Low_Demand	S1_newIndVC	System perspective	H ₂ use mainly for industrial process heating where electrification is technically challenging and for air and ship transport. Relocation of selected industrial products including H ₂ -based primary steel and H ₂ -based chemical feedstocks to outside Europe. This scenario reflects a conservative hydrogen deployment in demand sectors.
Scenario 1.5	S1.5_StrategicVC	System perspective	As S1, but with moderate relocation of industrial production.
Scenario 2	S2_ChemSteel	System perspective	As S1, but with fully domestic European green production of steel and chemical feedstocks (no relocation).
Scenario 3	S3_Ind	System perspective	As S2, but more extensive hydrogen use in process heating of industry.
Scenario 4 / Mid_High_Demand	S4_IndMob	System perspective	As S3, but more extensive hydrogen use in transport.
Scenario 5 / High_Demand	S5_allSec	System perspective	As S4, but including hydrogen use for space heating in selected areas/segments. This scenario reflects a very optimistic hydrogen deployment in demand sectors.
Scenario 6 / MarketExp	S6_MarketExp	Stakeholder Perspective	Cluster-based scenario reflecting stakeholder expectations; corresponds to MarketExp in the system-wide modelling framework.

2

Introduction and objective

The scale-up of a robust hydrogen (H₂) infrastructure is of strategic interest to the European Union (EU) to achieve its climate neutrality goals by 2050 [1]. Hydrogen is increasingly recognized as a key element in the EU's energy transition for hard-to-abate sectors. It offers a versatile and clean energy carrier that can be produced from various sources, including renewable electricity. The EU's Hydrogen Strategy aims to create a comprehensive hydrogen ecosystem that integrates production, storage, transport, distribution, and consumption across multiple sectors. This strategy is essential for reducing greenhouse gas emissions (GHG), enhancing energy security, and fostering economic growth. However, current progress on the scale-up of the European hydrogen economy is slow. ACER's current hydrogen monitoring report foresees that Europe is likely to miss its 2030 renewable hydrogen targets [2]. In this conflicting context, the FlagShip project TransHyDE provides important orientation knowledge so that decision-makers can make well-founded decisions in practice.

This flagship report presents results from the flagship project TransHyDE sponsored by the Federal Ministry of Research, Technology and Space (BMFTR) providing insights into the modeling and development of the EU H₂ infrastructure, with a particular focus on the German perspective within the broader EU context. Germany's role in this transition is particularly significant due to its advanced industrial base, strong renewable energy sector, potential storage sites, an adapted plan for the build-up of a hydrogen core network, and its strategic geographic location within Europe. The country has set ambitious targets for hydrogen production and usage, aiming to become a global leader in hydrogen technology and innovation. The German National

Hydrogen Strategy outlines specific measures to support the development of hydrogen infrastructure, including investments in research and development, pilot projects, and international cooperation.

Building on the foundational work presented in the preceding publication "European Hydrogen Infrastructure Planning" this document focuses on the new findings and results that have emerged since the first publication. The previous publication highlighted the significant potential for hydrogen to decarbonize various sectors, the technological advancements required, and the policy frameworks needed to support this transition.

In this publication (2.0), we present new findings and results that build on the previous work.

2.1. Consideration of two approaches: stakeholders' and system's perspective

One main aspect of the FlagShip Project TransHyDE is the concentration on both the stakeholder and system perspectives [3]. Since the results of an energy system modelling exercise are highly dependent on the initial scenario assumptions it is more important to understand all aspects of the upcoming transition. From a system perspective, it ensures a holistic understanding of the entire energy system, considering all elements and their interactions. This includes the entire value chain of energy vectors like electricity, hydrogen, and natural gas. By taking a system-wide view, it is possible to identify the most cost-effective and ef-

efficient pathways for infrastructure development, helping to avoid suboptimal outcomes and stranded investments. Additionally, the system perspective allows for the integration of different energy vectors, ensuring that the interactions between electricity, hydrogen, and natural gas infrastructures are fully represented. This is essential for balancing supply and demand and optimizing the use of renewable energy sources.

On the other hand, the stakeholder perspective provides valuable insights into the practical challenges and opportunities faced by different stakeholders in the energy system. This includes industrial stakeholders, policymakers, and grid operators. Understanding the needs and priorities of stakeholders helps in making informed decisions that are aligned with the interests of all parties involved, ensuring that the infrastructure development is feasible and supported by key stakeholders. Moreover, the stakeholder perspective highlights the specific requirements and constraints of different sectors, such as industrial processes, transportation, and energy production, helping to tailor the infrastructure planning to meet these needs effectively and identifying potential hurdles. Combining both perspectives allows for a more robust and comprehensive analysis. It ensures that the systemic benefits are aligned with the practical needs and constraints of stakeholders. This approach helps in identifying potential risks and challenges early on and developing strategies to mitigate them, reducing the likelihood of delays and cost overruns. Furthermore, a combined approach fosters collaboration between different stakeholders, promoting a shared understanding and coordinated efforts toward achieving the common goal of a sustainable hydrogen infrastructure.

Different scenarios were developed from both perspectives, as shown in Table 2.1. The system perspective scenarios are based on varying levels of hydrogen demand. The Low_Demand scenario assumes the relocation of industrial sectors, such as steel and chemical industries, outside Europe, resulting in low hydrogen demand. The Mid_Demand scenario focuses on hydrogen demand for high-temperature industrial processes and as a feedstock for the chemical and steel industries. The Mid_High_Demand scenario additionally includes demand from the transport sector and low-temperature industrial processes. The High_Demand scenario further incorporates hydrogen demand for heating in the building sector. The *MarketExp* scenario reflects stakeholders' expectations regarding hydrogen use. To compare both perspectives we selected the Mid_Demand, Mid_High_Demand to compare with the *MarketExp* scenario.

What this means can be seen in the market results of energy system analysis [4], where the inclusion of political goals significantly shapes the outcomes. Since energy system modelling relies on initial conditions such as demands and political objectives, these factors play a crucial role in defining the socio-political context of scenario analysis [6]. Hydrogen demands and how they are supplied differ greatly between the scenarios analysed within this report (see Table 2.1). When looking at the European hydrogen balance (see Figure 2.1, we can see, that while demands from the stakeholder (*MarketExp*) perspective fit a Mid_Demand scenario from the systems perspective, the provision of hydrogen strongly differs between the two perspectives. While from the systems perspective, hydrogen imports are a minor part of the hydrogen supply, hydrogen imports

Table 2.1. Overview over the five scenarios analyzed within this publication. While scenarios Low_Demand, Mid_Demand, Mid_High_Demand and High_Demand follow a systematic increase of hydrogen demand within the different final energy consumption sectors, the stakeholder scenario 'MarketExp' focuses on the envisioned scale-up the different stakeholders involved in the European energy transition. Further details in [4, 5] and Chapter 3.

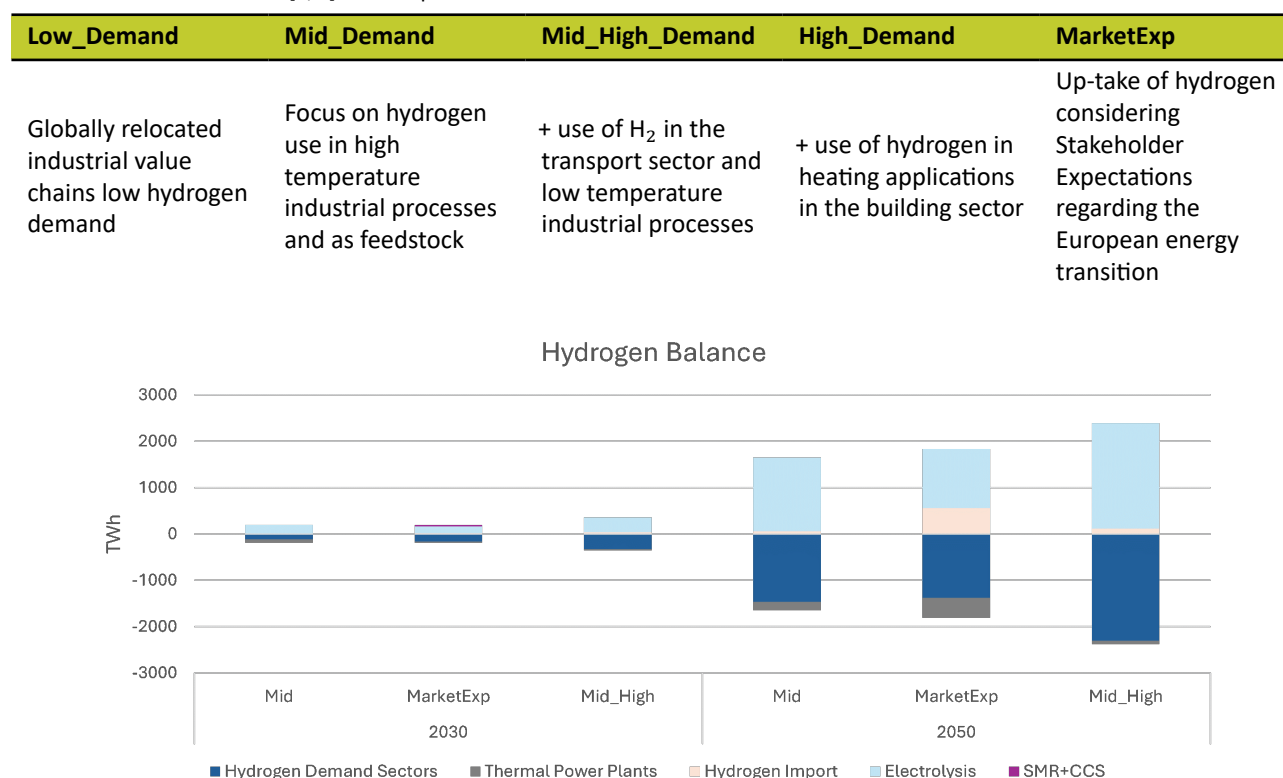


Figure 2.1. European hydrogen supply and demand in 2030 and 2050.

from non-European countries make up about one-third of demand from the stakeholder's perspective from 2030 onward in the MarketExp scenario.

The differences regarding domestic hydrogen provision, not only concern the total amount of installed electrolysis capacity within Europe, but also its distribution across the EU27 plus, Norway, Switzerland and the United Kingdom. Figure 2.3 shows the installed electrolyser capacity in Europe in 2030. For the low-demand and high demand-scenarios Germany, France and UK are dominant players having the higher electrolyser capacity. Northern Europe has also significant differences. In the case of the MarketExp scenario Finland has the highest electrolyser installed capacity with 12 GW while in the two system scenarios, low-demand and high-demand Finland has none and 1 GW installed capacity.

Figure 2.3 shows the geographical distribution of electrolyzers in 2050, highlighting clear differences between the scenarios. The total installed electrolysis capacity is 662 GW in the Mid_Demand scenario, 922 GW in Mid_High_Demand, and 413 GW in MarketExp. In the MarketExp scenario, most of the installed capacity is concentrated in Germany, the Netherlands, and the United Kingdom. In contrast, the system scenarios allocate more capacity to the United Kingdom and Southern Europe. A notable difference is observed in Poland and France, where both system scenarios have a high number of electrolyzers, whereas the MarketExp scenario reflects significantly lower installed capacity. A similar trend is seen in Spain and Portugal, where the MarketExp scenario has just over half the installed capacity (49 GW) compared to the Mid_Demand scenario

(91 GW).

One main reason behind the differences in the production of renewable hydrogen via electrolysis within Europe lays in the distinct expansion of renewable energy sources in the two compared scenario perspectives. While from the system's perspective (modelled with Enertile) renewable energies expansion within each country is mainly limited by the available renewable energy potentials, the stakeholder perspective (modelled with ISAaR) relies on stakeholder's expectations for the expansion of renewable energy sources (mainly TYNDP2024). Figure 2.4 shows the installed renewable capacity for three different scenarios in 2030 and 2050. In 2030, the installed capacities are similar in all scenarios. However, by 2050 there are significant differences. In the MarketExp scenario, higher hydrogen imports lead to lower total installed electricity capacity, as shown in Figure 2.4. This scenario has almost 700 GW less installed capacity, reflecting the difference in hydrogen imports between the cases. In addition, offshore wind capacity is higher in the MarketExp scenario due to fewer acceptance challenges. In contrast, offshore wind capacity is lower in the Systems scenarios, as installation decisions are primarily driven by higher costs rather than acceptance issues.

The differences among the scenarios are not only in the total installed electricity capacity for whole Europe but also in the installed capacity among different regions. Figure 2.5 shows the installed capacity for selected regions in 2030. We can see clear differences in the installed capacities between the MarketExp scenario and the system scenarios for Italy, Poland and France where the system scenarios in-

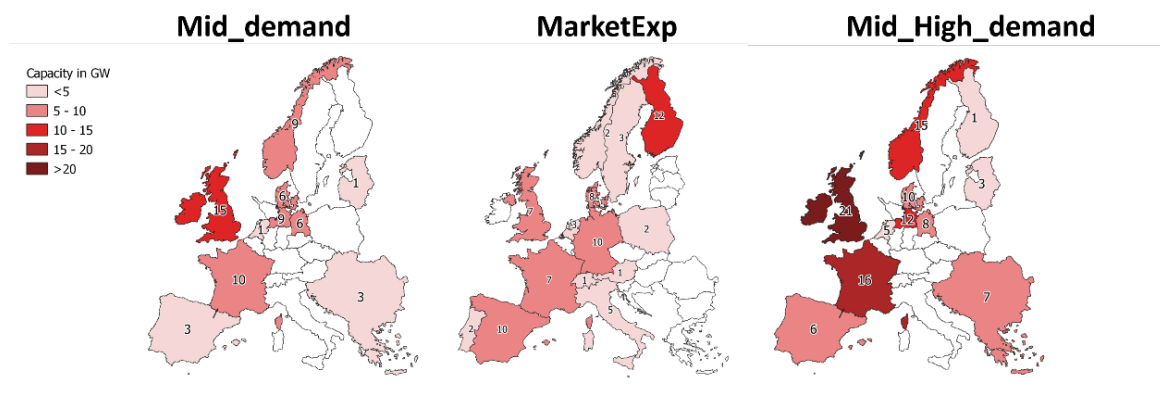


Figure 2.2. Installed electrolyser capacity geographical distribution in 2030.

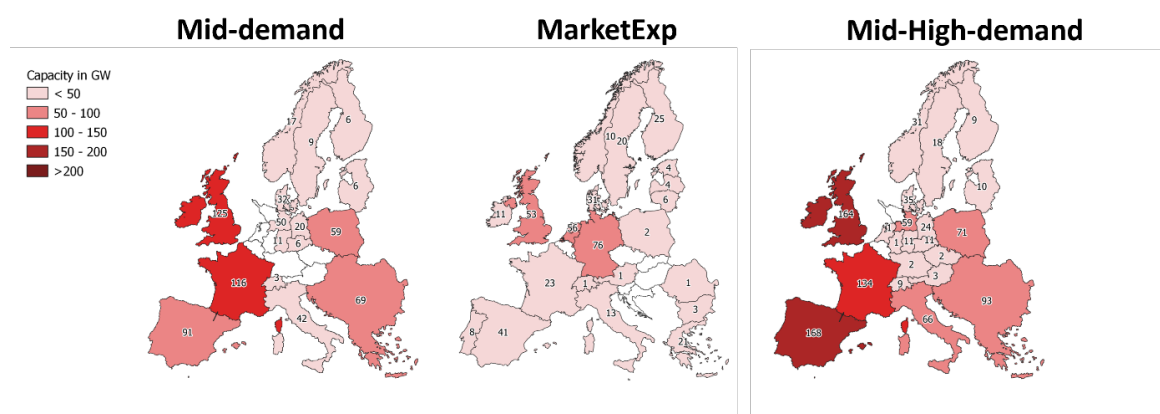


Figure 2.3. Installed electrolyser capacity geographical distribution in 2050.

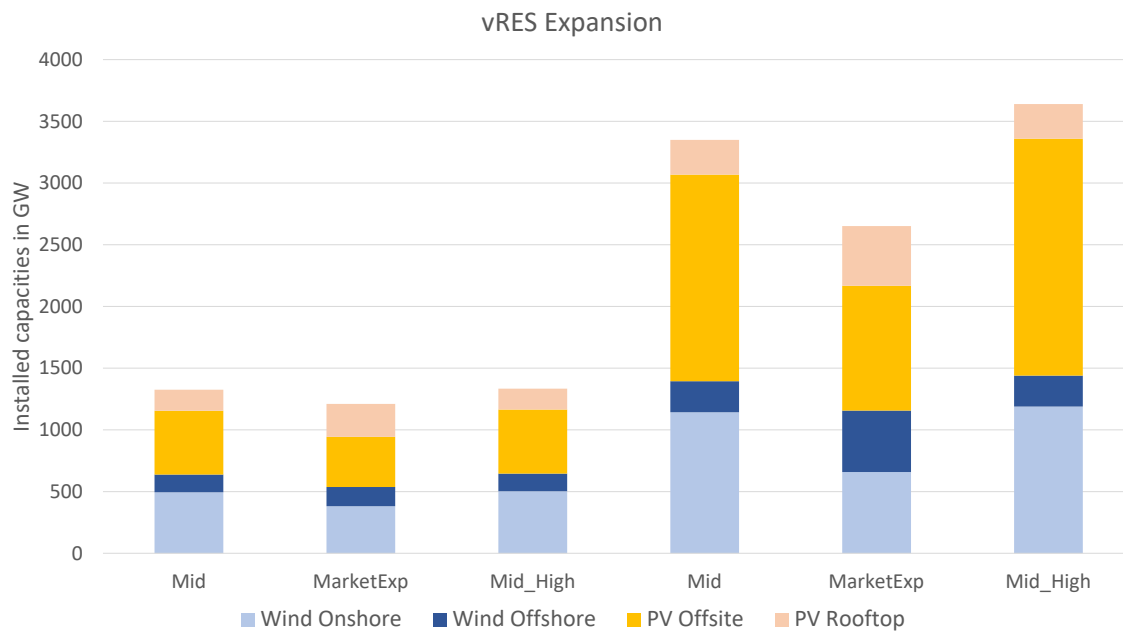


Figure 2.4. Installed electricity capacity for the different scenarios.

stalled a higher capacity in line with the higher electrolyser capacity. The opposite case is Finland where the Market-Exp scenario has a higher installed capacity coming mostly from additional PV. Germany and the United Kingdom have similar installed capacities for all the scenarios. In 2050 the differences follow the same pattern however they are accentuated due to the higher differences in hydrogen demand which lead to a higher installed capacity (Figure 2.6).

In conclusion, energy system scenarios are an important tool to obtain future perspectives of how the energy system will look. These perspectives are highly dependent on the initial constraints and assumptions that are given to the system as shown with the differences between our set of scenarios. The stakeholder perspective offers insights into the practical challenges and needs of various stakeholders, including policymakers and industrial stakeholders, ensuring that infrastructure development aligns with their interests and requirements. In contrast, the system perspective provides a holistic view of the energy ecosystem, encompassing all elements and their interactions, which is vital for identifying cost-effective and efficient pathways for infrastructure development. This dual approach not only helps in optimizing the use of renewable energy sources but also highlights the specific requirements and constraints of different sectors, enabling targeted infrastructure planning. Scenarios developed from both perspectives reveal significant differences in hydrogen demand and provision, particularly regarding the impact of political goals and stakeholder expectations on outcomes. These discrepancies emphasize the importance of long-term planning and collaboration among stakeholders to mitigate risks, address potential hurdles, and work towards a sustainable hydrogen infrastructure. The analysis also indicates that while

stakeholder perspectives may predict higher hydrogen imports, system perspectives emphasize domestic production capabilities influenced by renewable energy potentials, illustrating the complexities and interdependencies within the energy transition landscape.

2.2. Transport and Buildings

In addition to the extraordinary importance of hydrogen in industry, it is also used in other demand sectors. These are also modelled from a system's and stakeholder's perspective. The following sections are focused on the question of how the modelling varies between the two different perspectives and where the use of hydrogen and its derivatives appears to be feasible.

2.2.1. How do the two modelled perspectives differ in the transport sector?

The modelling of this sector includes both national and international transport in EU27+3. A version of the ALADIN model adapted for EU27+3 [7] is used for modelling from system's perspective, stakeholder's perspective is modelled with TraM [5]. Stakeholder's perspective is described in scenario *S6_MarketExp*. From a systemic perspective, the *S1_newIndVC*, *S2_ChemSteel* and *S3_Ind* scenarios do not differ in the transport sector, and the same assumptions are made in *S4_IndMob* and "*S5_allSec*". Scenarios *S1-S3*, *S4-S5* and *S6* are therefore regarded in this model comparison. Approximately, both models model road traffic using a bottom-up approach with integrated vehicle fleet. Rail, ship and air transport are each represented using a top-

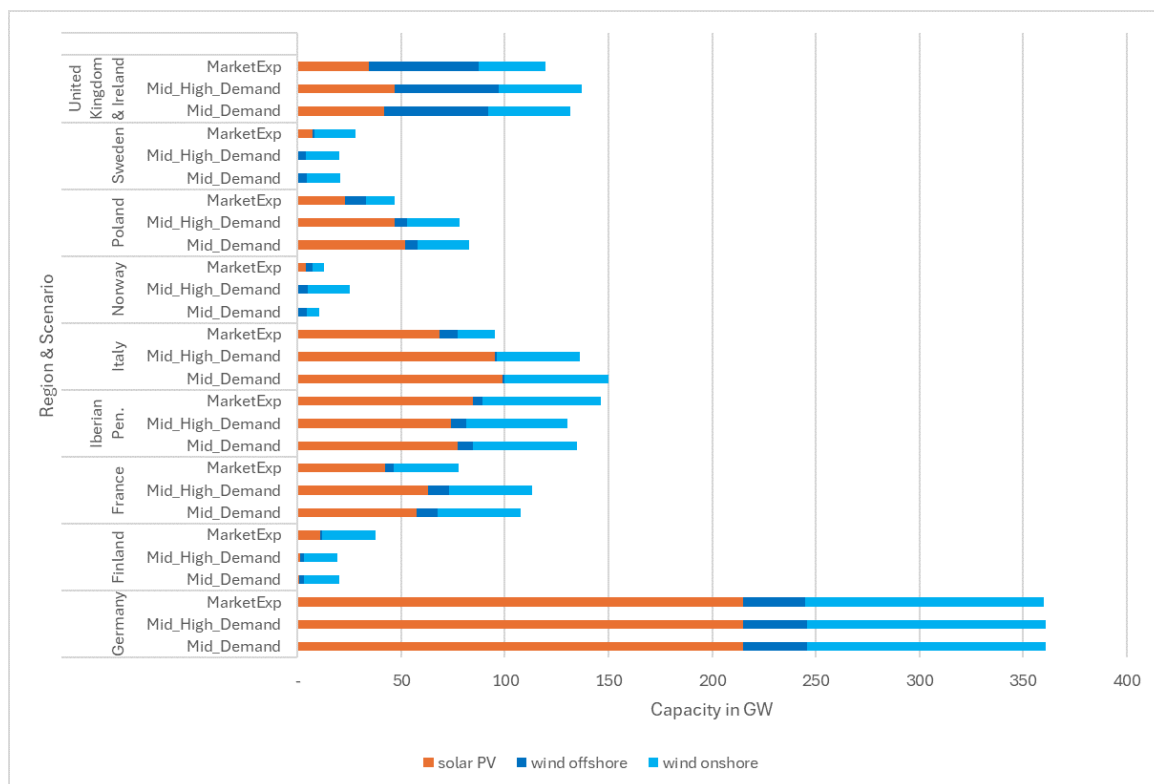


Figure 2.5. Electricity installed capacity per region in 2030.

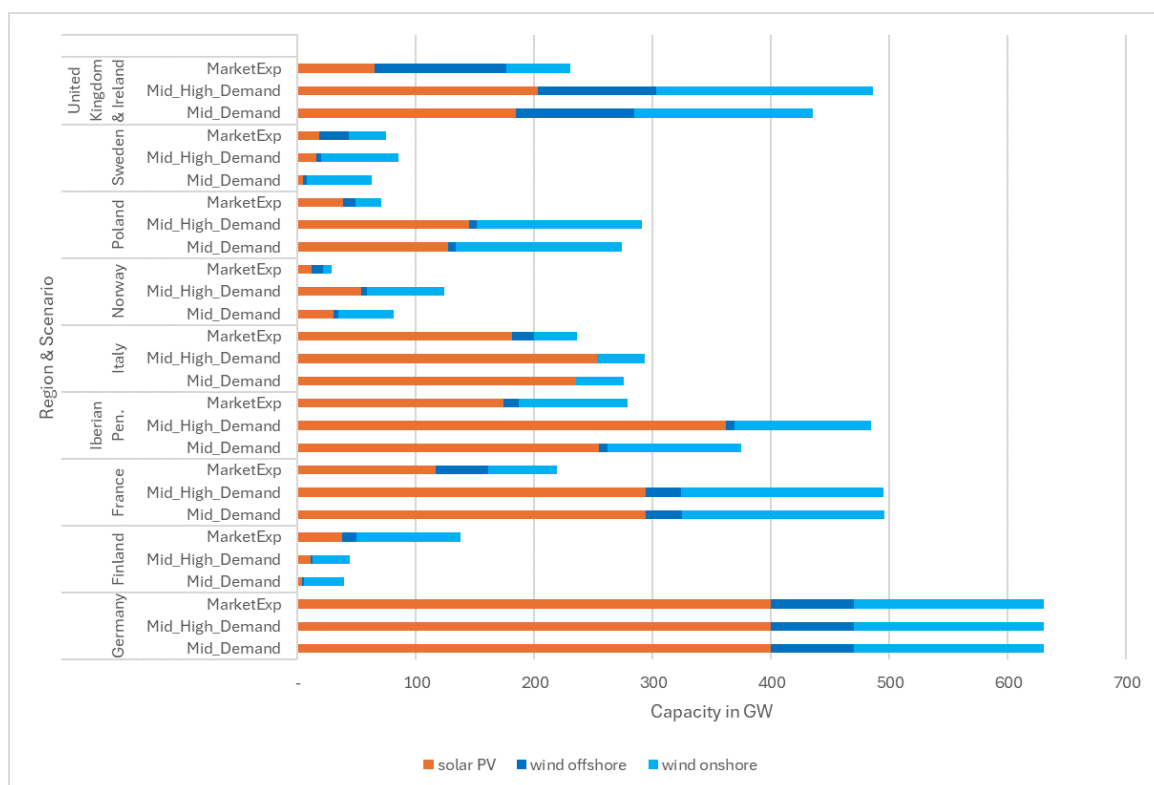


Figure 2.6. Electricity installed capacity per region in 2050.

down approach. The two perspectives differ with regard to the use of hydrogen in the various transport modes. In scenario *S6_MarketExp*, a small number of fuel cell cars are deployed, whereas these are not considered from system's perspective. The use of hydrogen also differs between the scenarios for air and ship transport. From a stakeholder perspective, it is used in national and international shipping and international air transport, and from a systemic perspective in national shipping and air transport. Here, however, the implementation options in the models are

more decisive than the influence of each scenario's perspective. In particular, the modelling of market development for cars and trucks differs between the perspectives. In scenario S1 to S5, the electrification of passenger car fleet was modelled using a country-specific logistic function based on a regression of real market development in the pioneering country of Norway and dependent on energy costs, charging infrastructure availability and subsidy levels. The annual market shares of the drive types in new truck registrations result from an agent-based simulation

of the truck fleet in Germany, in which the choice of drive is modelled on the basis of individual total cost of ownership. Different assumptions regarding costs and technology availability between scenarios S1-S3 and S4-S5 lead to divergent developments. For scenario S6, a cluster approach is chosen in which the entire area under consideration is divided into four clusters of countries with different development dynamics. Based on these dynamics, the energy carrier shares of new registrations are specified exogenously.

A key driver of the transformation is the development of transport demand in passenger and freight transport, as well as the corresponding final energy consumption. The GDP-driven development of freight transport demand is somewhat mitigated in *S6_MarketExp* due to the impact of the COVID-19 pandemic. Moreover, in the other scenarios, changes in car usage, such as car sharing, are assumed, which reduce energy consumption relative to transport performance. The specific consumption rates assumed for each vehicle type and propulsion system in the future years also have a decisive influence. In particular, for heavy-duty classes (trucks over 12 tons), the specific consumption rates of BEV trucks are lower and the efficiency improvements of diesel trucks are higher in Scenario S1-S5 compared to S6. This is also evident from Figure 2.7. There, the scenarios modeled in ALADIN, S1-S3 and S4-S5, have a lower final energy consumption for trucks in 2030, despite the higher transport demand compared to S6, which accounts for the aforementioned COVID-19 effect on freight transport demand. Thus, in S1-S5, higher transport demand is achieved with lower final energy consumption. An examination of the hydrogen demand by trucks shows that it is dependent on supply and the resulting costs of ownership. The scenario from the stakeholder's perspective, S6 falls between the two scenarios from the system perspective.

The divergent assumptions in the two perspectives regarding the use of hydrogen and its derivatives in (international) air and ship transport, combined with the fact that international transport has the second largest demand

from the stakeholder's perspective after industry, indicate that the scenarios are subject to certain uncertainties regarding future hydrogen demand and further research is needed. The comparison of transport scenarios reveals consistent developments across all scenarios, which can differ both due to the perspective taken and due to divergent general assumptions and implementations in the two models, ALADIN and TraM.

2.2.2. How do the two modelled perspectives differ in the buildings sector?

The buildings sector consists of private households and the services sector. For modelling the stakeholder's perspective, the models PriHM und TerM [5] are used. FORECAST [8] is used accordingly for the system's perspective. Similar to the transport sector, not all five scenarios from the system's perspective are considered individually in the buildings sector. The first four scenarios, *S1_newIndVC*, *S2_ChemSteel*, *S3_Ind*, and *S4_IndMob*, are identical regarding the transformation of the buildings sector and do not assume the use of hydrogen for heat supply. In contrast, *S5_allSec* considers the use of hydrogen for heating. Accordingly, a distinction is made between the two scenarios S1-S4 and S5. From the stakeholder's perspective, these are supplemented by scenario S6. The modelling approaches for heating system replacement differ between the two perspectives and models. From the stakeholder's perspective, a transformation of energy carriers occurs with exogenously specified replacement rates for five considered country clusters with similar development dynamics. From the system perspective, the heating stock is modeled using a cohort model, where heating systems are replaced at the end of their lifespan. The model results for Germany show that the final energy consumption of buildings in S6 is always higher than that in S1-S4 and S5. However, as the transformation is almost completed in all scenarios by the target year, the divergent modelling approach between the

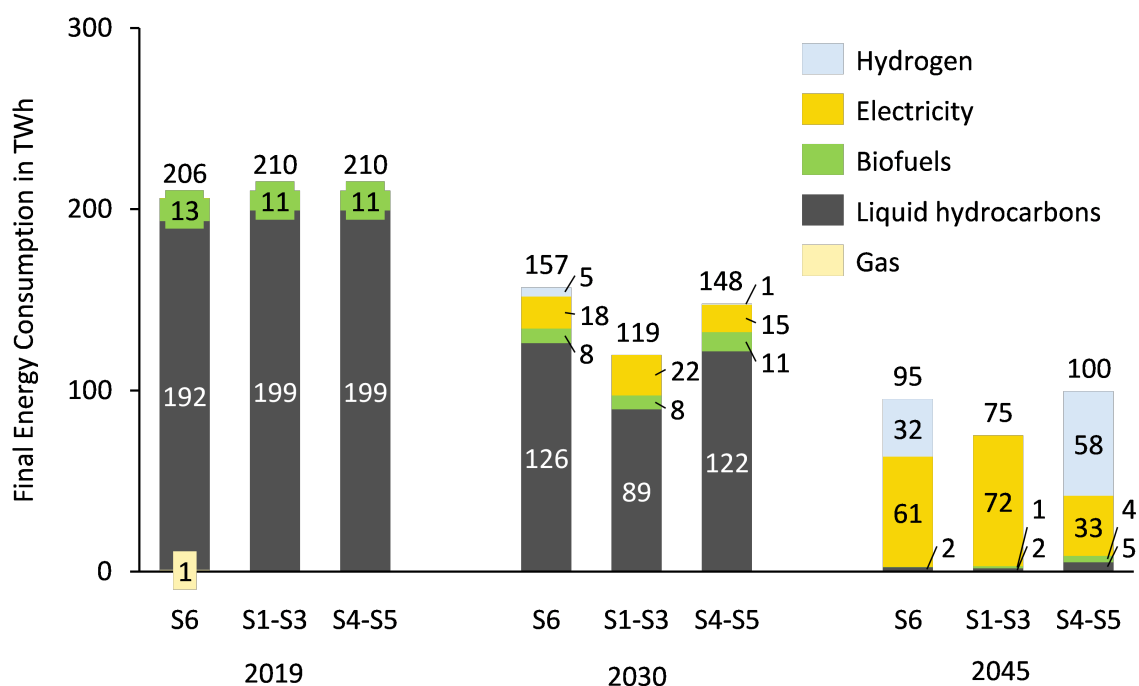


Figure 2.7. Final energy consumption of trucks in Germany 2019, 2030 and 2045.

perspectives is no explanation. Instead, the reason lies in the modelling of the two main factors influencing demand for space heating. There are differences in the development of residential and usable area as well as in the renovation rates. The residential area increases in both perspectives. In the modelling from the stakeholder's perspective, the usable floor area decreases, but in the modelling from the system perspective, it increases. Without the simultaneous development of renovation measures, this would lead to a higher final energy demand in space heating in S1-S4 and S5. This contradicts the results of the model comparison. However, the assumption of higher renovation rates in S1-S4 and S5 causes the useful energy demand for space heating to fall faster in these scenarios than in S6, despite the increase in residential and usable area. Another difference in the modelling that reinforces this fact is the consideration of the effects of climate change. As climate change progresses, the number of days requiring heating in Germany decreases, which reduces the demand for space heating. This effect is taken into account in FORECAST, in PriHM and TerM the assumption of heating degree days is constant. These varying assumptions are not only due to the different perspectives but are also attributable in part to the divergent modelling environments. The comparison of the potential use of hydrogen in the buildings sector shows that the scenario from the stakeholder perspective S6 is allocated between the two scenarios from the system perspective, of which no hydrogen is used by default in S1-S4. For Germany, the demand for hydrogen in S5 in 2045, in numbers 115 Wh, is more than three times as high as in S6.

To summarize, the model and perspective comparison in the buildings and transport sector shows the following key points. In segments with comparable conditions, hydrogen demand of the scenario from an stakeholder's perspective ranges between the scenarios characteristics from a system perspective. In addition to the transformation of energy carriers to electricity and hydrogen in particular, general assumptions, such as renovation rates, play an important role in the model comparison. These are heavily dependent on the modelling environment used and are not always a question of the perspective adopted. Furthermore, the results show that for future analyses of hydrogen demand from the demand sectors, in addition to industry, a glance at shipping and aviation is of interest.

2.3. Industry

2.3.1. How do the two modelled perspectives differ in the industry sector?

Two different models are used to represent the system and stakeholder perspective in the industry sector: The model SMIInd describes the industry sector from the stakeholder perspective. The system perspective is represented in the model FORECAST.

In order to compare the two models, identify their differences and find explanations in the modelled results, the five different demand scenarios of the system perspective – S1 to S5 – are contrasted with the stakeholder scenario S6: S1 to S5 assume increasing amounts of hydrogen use in the industry sector: In S1, hydrogen is only used for high-temperature heat and some steel generation, while a lot of steel and other high-energy materials are imported. S2 assumes the use of hydrogen for steel and chemistry, while in S3 hydrogen is used for all applications to varying degrees. S4 and S5 are identical to S3 in the industry sector.

Regarding hydrogen demand, the stakeholder scenario S6 lies between the scenarios S2 and S3-S5. This represents the assumptions and forecasts of industry stakeholders that were included in the design of the scenario. Figure 2.8 shows the total final energy consumption in the industry sector in Germany among the different models. As shown, scenario S3-S5 accounts for a significantly higher hydrogen consumption than the other scenarios. Assumptions for hydrogen use in S6 are comparable to those in S2: Hydrogen is used predominantly in steel and chemical industry as well as high-temperature heat supply, while only a limited amount of hydrogen is used for other applications, for example low-temperature heat, which are additionally considered in S6.

The development of the consumption of the other energy carriers does not differ as strongly between the different scenarios. In particular, coal as well as liquid and gaseous hydrocarbons are phased out of the system, while the importance of electrical energy increases. Biomass does not account for a large share of the energy consumption in either scenario, but its use increases in S6 – more than doubling between 2019 and 2045 – while it increases by only around 30 % in the other scenarios. This is because of the increased use of alternative decarbonization methods as assumed in the stakeholder scenario.

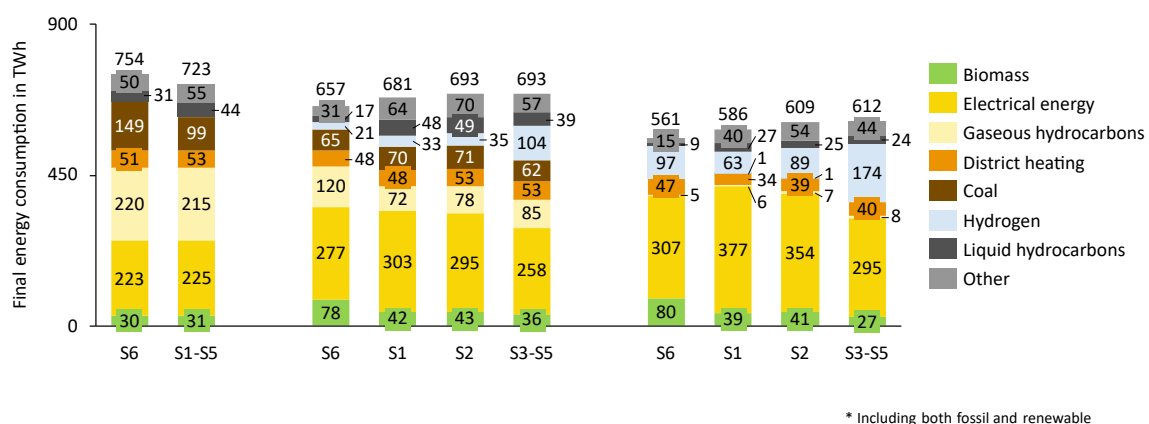


Figure 2.8. Final energy consumption by energy carrier in the industry sector in Germany, according to the different scenario results. Gaseous and liquid hydrocarbons include both fossil and synthetic sources.

In order to arrive at these results, both models follow a similar structure. Starting from the status quo of energy consumption, for which official statistics are available and used to calibrate the production volumes of the most important and energy intensive goods, the models assume a macroeconomic development based on the German and European projection reports [9] to compute a trajectory for the production volumes of these goods. The Stakeholder perspective additionally relies on production projections developed with the industrial sector institutes, as well as projection reports for remaining industrial sectors or where the partners could not provide further information. In both models, some of the energy consumption is not captured in this “bottom up” approach: A part of the energy consumption arises from cross-sectional technologies that are relevant in all sectors. For the development of this baseload of these technologies, the macroeconomic projections for each sector are considered.

After the computation of this baseload demand, both models assume the application of decarbonization measures, resulting in further changes in energy demand and carbon emissions. The applied measures are conceptionally identical between the two models: Energy efficiency measures, changes of production route, installation of new hot-water and steam-generating facilities, installation of new furnaces, changes in fuel and carbon capture. FORECAST additionally considers renovation works of the facility buildings, therefore reducing heating demand. While the modelled processes are the same, the exact implementation differs between the models. In particular, FORECAST’s highly-resolved building stock model allows for very detailed modelling of the building heating demand and of the industrial furnaces.

Nevertheless, the differences in final energy demand arise primarily from different system boundaries rather than differences in the transformation pathways. In particular, while the production volumes of steel and high-value chemicals do not differ by more than 10 % between the scenarios over the course of the transformation – with the exception of S1, where around 30 % of steel and almost all high-value chemicals are imported in 2050 – the reported final energy demands differ significantly. In the steel sector, this is explained by the different accounting of the off-gases that are created during blast-oven process: While FORECAST subtracts their energy content from the energy demand of the blast oven, Smlnd does not, resulting in a difference of almost 40 TWh in 2020. Meanwhile, in the chemical sector, FORECAST considers the use of refinery by-products as an additional energy consumption, whereas Smlnd does not, leading to higher reported material energy demand in the scenarios S1-S5. These examples highlight the difficulties that arise in the accounting of energy consumption between different models.

Potential for improvement was identified for both models during the model comparison. This includes more detailed consideration of refineries and integration of district heating systems in Smlnd, as well as improved modeling of process changes and the resolution of subsectors and locations in FORECAST.

3

Transformation from the stakeholder perspective with focus on Industrial transformation

In the 2024 TransHyDE-Sys Flagship Publication, *European Hydrogen Infrastructure Planning: Insights from the TransHyDE Project System Analysis*, multiple scenarios for future hydrogen demand from the energy system perspective were presented. In addition to these scenarios (Low_Demand, Mid_Demand and High_Demand), a complementary scenario was also modelled. Dubbed the stakeholder perspective, this additional scenario is intended to depict the transformation of the energy system based upon the plans and decisions of the individual and institutional actors that will be responsible for implementing various transformational measures. In turn, the results from the stakeholder perspective allow these plans to be placed into the context of the three scenarios modelled from the energy system perspective and provide insight into how the actively progressing transformation may continue to develop.

As described in the previous Flagship publication, the stakeholder perspective in the buildings and transportation sectors is represented by clusters of similar transformation pathways at the national level within each sector, with a detailed description of the methodology available in [5]. Meanwhile, the modelling of the stakeholder perspective in the industry sector was prepared in cooperation with the academic institutions of the steel, chemical, paper and glass industries, as well as consultation from their counterpart in the cement industry. Their input concerning the expected transformation pathways of their respective sectors of industry forms the core of the stakeholder perspective in the

industrial sector, which are described in more detail in the following chapter.

The energy demand of these sectors represents one side of the data provided as inputs to the integrated energy system model at the FfE, ISAaR¹, which also receives input from supply-side models of the expansion of renewable energies and in turn models the combined energy system at a detailed regional and temporal level. The following Figure 3.1 visualizes the results of these demand-side models for the final demand sectors, depicting the development of the energy demand for each energy carrier per sector from 2019 to 2050.

Three high-level conclusions can be taken from this graphic with regards to energy demand in 2050. Firstly, that final energy consumption (FEC) in all sectors declines in the scenario formed from the stakeholder perspective, without any major declines in transport performance (e.g., distances traveled, passenger numbers, and volume of goods), sufficiency measures in building operations, or sector-wide economic decline in industry. Instead, much of this decreased energy demand can be attributed to efficiency gains, with technologies for direct electrification representing a major lever in all sectors except international transportation.

Secondly, that despite significant electrification, demand for fossil energy carriers remains, particularly in the transportation sector but also in industry. As the demand-side models do not define the provenance of the demanded energy carrier (e.g., no direct differentiation between de-

¹ More information about ISAaR is available at <https://www.ffe.de/en/tools/isaar/> [10].

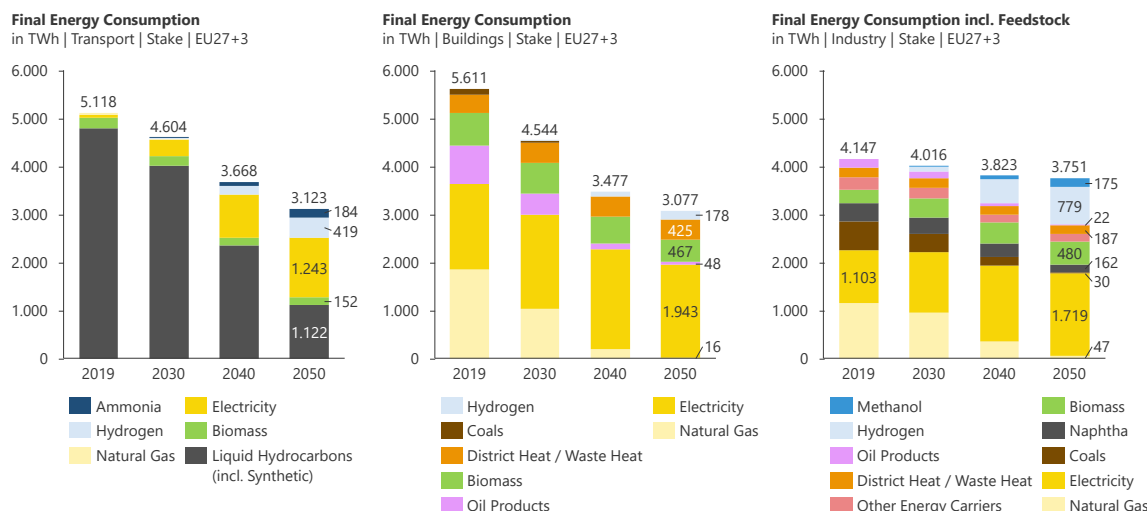


Figure 3.1. Development of modeled FEC in TWh per energy carrier in the sectors domestic & international transportation, buildings (private households + tertiary sector) and industry (including feedstock consumption) for the EU27+3.

mand for conventional gasoline vs. synthetic gasoline), these remaining fossil demands can be interpreted either as a demand for synthetic energy carriers or representing a potential need for carbon capture technologies to achieve climate neutrality. After these demands are passed from the demand-side models to the energy system model ISAaR, the resulting emissions are mitigated in one of two ways to achieve a net-zero energy system in 2050, after consideration of net negative emissions via LULUCF² in Europe. Emissions that would result from a demand for liquid hydrocarbons can be avoided by the import of synthetic fuels, or via limited European production of the same. Remaining emissions from fossil energy carriers or process emissions not captured from a single point source are mitigated using Direct Air Carbon Capture and Storage (DACCS).

Thirdly and finally, that demand for gaseous hydrogen in the stakeholder perspective's transformation of these final demand sectors is dominated by demand from the industrial sector. The 779 TWh demand for hydrogen in the industrial sector of the EU27+3 seen here is approximately 45 % higher than the 423 TWh demanded by the combined domestic and international transportation sectors, and more than four times higher than the 179 TWh demanded by the buildings sector (which includes tertiary sector demand). Additional demand for hydrogen stems from the transformation sector, where hydrogen is utilized in the processing of fossil fuels, and the energy supply sector, for example from hydrogen-fueled gas power plants, and is not included in the values depicted in this chapter.

Given the role of industry as the main source of demand for hydrogen among the final consumption sectors and the focus of TransHyDE-Sys on hydrogen and hydrogen infrastructure, the remainder of this chapter will concern the transformation of the industrial sector from the stakeholder perspective.

The next subsection describes the modeled transformation pathways in more detail, with a focus on those developed in cooperation with the aforementioned research institutions of the industrial sectors. This is followed by a brief presentation of the overarching results of industrial FEC as modeled by SMInd (Sector Model Industry) before focusing

on the main sources of industrial demand for hydrogen at the process and application level. A subsection devoted to the modelling of CO₂-Infrastructure follows, highlighting a necessary component for the successful transformation of the cement and lime, the cement and lime sectors, in which hydrogen plays a smaller role. After beginning to examine regional results in the frame of CO₂-infrastructure modelling, the final major subsection concerns the regionalized demand for hydrogen from the industrial sector before a conclusion to the chapter.

3.1. What transformation pathways are anticipated from the stakeholder perspective?

The transformation pathways that lead to the sectoral final energy consumption (FEC) previously depicted in Figure 3.1 are described in this chapter, focusing on the chosen technologies and considered trends. More detailed descriptions of the methodology of SMInd³ and its further development in TransHyDE-Sys, as well as the applied parameters will be available in forthcoming publications.

The participation of the industrial research institutions associated with the steel, chemical, paper, cement and glass industries provided a unique opportunity for shaping the stakeholder perspective of the industrial transformation modelled in TransHyDE-Sys. In addition to directly determining the transformation pathways of the represented sectors of industry, this cooperation enabled the expansion of SMInd to include new production processes by splitting previously aggregated processes into more precisely defined ones, as well as the opportunity to refresh update the technical parameters associated with specific energy consumption and the application-split of the energy consumption (e.g., n % of process fuel demand is for process heat > 500 °C). The transformation path defined for each of the sectors participating in TransHyDE-Sys will be described in turn, as well as the transformation measures applied to further sectors of industry, before turning to the resulting

² Land Use, Land Use Change, & Forestry

³ An overview of SMInd can be found at <https://www.ffe.de/en/tools/SMInd-sector-model-industry/> [11] or in more detail in [6]

demand for hydrogen in the following chapter.

3.1.1. Iron & Steel Industry

The transformation pathway in this sector of industry focuses on the production of raw steel and was developed together with VDEh-Betriebsforschungsinstitut (BFI). Raw steel production is split between primary steel production, performed today using blast furnaces, and secondary steel production via electric arc furnaces (EAF). A switch from primary steel production to secondary steel production would substitute the production of virgin raw steel with increased recycling of scrap steel but is not viable as the sole transformation option due to quality constraints and limited availability of scrap steel [12].

Two transformative processes have dominated the discussion surrounding the transformation of primary steel production in recent years, hydrogen-based direct reduction of iron and the use of carbon capture technology. Direct reduction uses hydrogen as the reduction agent, in place of coke, to remove oxygen from iron ore as well as for the provision of process heat. Lower temperatures are required compared to the blast furnace route, but the resulting sponge iron must be further processed in an EAF. Meanwhile, the application of carbon capture technology has considered both new proprietary processes for steelmaking, as well as retrofit carbon capture technology with existing blast furnaces [12].

The transformation pathway developed together with the BFI is characterized by an 11 % overall increase to European production in 2050 compared to the base year of 2019. A small shift towards more recycling of scrap steel via the secondary route is observed, with secondary steel representing 45 % of overall steel production in 2050 compared to a 43 % share in the base year. Steel production via the primary route is nearly completely produced via direct reduction (50 % of total production in 2050), although individual plants retain blast furnace production (5 % of total production in 2050). Figure 3.2 depicts the overall development of raw steel production levels as a bar chart, with the share of production per process in each year depicted by the area graph.

This transformation pathway takes advantage of the flexibility of the direct reduction process, initially using natural gas as a reduction agent after 2025 and steadily

increasing the share of hydrogen used for this purpose until it has replaced natural gas. A source of carbon remains necessary to the process to meet quality requirements and is provided in the modelled transformation via natural gas and biomass. Based upon the input of the BFI, carbon capture technologies are not implemented in the modelled transformation of steelmaking.

3.1.2. Chemical & Petrochemical Industry

The modelled transformation pathways developed with DECHEMA⁴ include multiple production processes within the chemical & petrochemical industry. These represent a further development of the scenarios presented in the VCI study *Working towards a greenhouse gas neutral chemical industry in Germany* [13]. Particularly relevant processes in the context of this hydrogen-focused project are ammonia production, the production of high-valued chemicals (HVC) such as ethylene and propylene, and methanol synthesis.

Ammonia

Production of ammonia has been based upon the Haber-Bosch process since the early 20th century. Prepared process gas reacts at 450-550 °C under high pressures (150-350 bar) to synthesize ammonia from the hydrogen and nitrogen present in the process gas. The hydrogen necessary for the synthesis is obtained today via steam reforming of natural gas or partial oxidation as an integrated step within the production process. Providing this chemically necessary hydrogen in another manner is key to the transformation of ammonia production, while production is expected to remain centered around the Haber-Bosch process itself for the foreseeable future [12].

The transformation pathway modeled here begins the shift from conventional ammonia synthesis, represented by both energy and feedstock demand for natural gas, to the Power-to-Ammonia route in 2025. In addition to the demand for hydrogen from an external source (for example, via electrolysis), this process is also characterized by an increased demand for electricity for the provision via air separation of the nitrogen used in ammonia synthesis. In terms of economic development, the crisis years surrounding the pandemic and Russian invasion of Ukraine are represented by a decline in overall production in the mod-

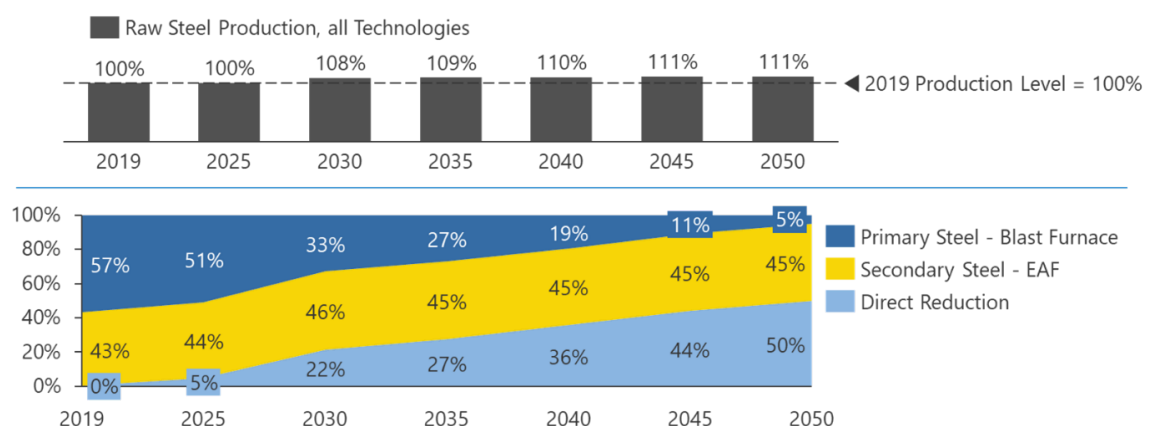


Figure 3.2. Development of raw steel production compared to 2019 production levels (upper graph) and share of production per production process (lower graph) for the EU27+3.

⁴ Gesellschaft für Chemische Technik und Biotechnologie e. V.

elled years 2019-2024, before stabilizing below its initial level by 2025 and remaining constant thereafter. Both production routes remain in the energy system in 2050, with power-to-ammonia featuring a 67 % share. The remaining conventional ammonia production is a result of integrated production of ammonia and urea.

Methanol

In TransHyDE-Sys the modelling of methanol synthesis was expanded from a single production pathway to differentiate between two separate conventional production processes and two transformative production processes. The conventional production of methanol is carried out via steam reforming of natural gas or the partial oxidation of byproducts of oil refining to produce process gas, followed in both cases by the catalytic synthesis of methanol [13]. Beginning from the modelled year 2025, production begins to shift to the power-to-methanol and the biomass gasification routes. Total production remains constant in 2050 compared to 2019 in this scenario, with the conventional processes completely replaced by transformative processes by 2045 across Europe.

Analog to ammonia production, the shift from methanol synthesis via steam reforming to the power-to-methanol route requires new sources for the synthesis components, hydrogen and CO₂ [13]. The CO₂ required for methanol synthesis via the power-to-methanol route could potentially be provided for example via carbon capture or the use of biomass, but this is not defined in the model [13]. In contrast, the source of both reactants is clearly defined in the biomass gasification route as woody biomass. Production in 2050 is split 52 % to 48 % between these two transformative production processes, with biomass gasification seeing the larger share.

High-value chemicals

High-value chemicals, an overarching term that includes olefines such as ethylene and propylene as well as aromatics such as benzene and toluene, form the starting point of many value chains in the chemical industry, for example plastics production [12]. Conventional production occurs via steam cracking, fueled by a mixture of naphtha and byproducts of the cracking process. The chemical bonds of naphtha are broken via high temperature heating within a steam cracker to obtain the desired HVC molecules [12]. An electrified steam cracker represents one of the transformative processes included in the modelled transformation pathway. Here, the standalone electric steam cracker retains naphtha as the primary demanded energy carrier. The provenance of the naphtha (e.g., fossil-based or synthetic) is not defined by SMIInd and occurs at a later stage of the model chain, as described in the introduction to this chapter.

A further transformative production process is explicitly characterized by the origin of the cracked feedstock. Plastic recycling via pyrolysis aims to reduce the production of plastics from new fossil-based feedstocks, instead re-using the chemical building blocks of plastic waste no longer suitable for mechanical recycling [13]. This process includes the thermal treatment of plastic waste to produce hydro-

carbons in liquid, gaseous, or solid form, which in turn can be processed in a steam cracker to obtain the desired HVC products [13]. In the modelled transformation pathway, the thermal energy for pyrolysis is provided both via the plastic feedstock and electrical energy, and the obtained hydrocarbons are then cracked in an electric steam cracker to obtain the desired products.

The two further transformative processes obtain HVC via chemical synthesis rather than the cracking of hydrocarbons. Both the Methanol-to-Olefines and Methanol-to-Aromatics (together, MtX) processes involve the catalytic synthesis of their desired target products from methanol, while the exact reactions vary between different proprietary processes [12]. In the modelled transformation pathways, the feedstock demand for these processes is depicted as a demand for methanol, with no further differentiation made regarding the production route used to obtain this feedstock or its geographic origin. As such, this demand for methanol does not influence the modelled demand for methanol production described previously.

Based upon the projected development of production levels developed by DECHEMA, overall HVC production levels remain constant until 2050, with the transformation characterized by a shift to the new production processes. Conventional production begins to be replaced by the transformative processes in 2025, with 50 % replaced by transformative processes in 2040 and the remaining 50 % by 2045. Electric steamcrackers and MtX represent the majority of production, each with a 44 % share of the final production, with plastic pyrolysis making up the remaining 12 % share of the individual processes.

3.1.3. Paper & Pulp

The cooperation with the PTS⁵ enabled the modelled paper production process to be split into separate processes for different paper types, each of which is characterized by different levels of energy consumption. In addition to packaging paper, tissue paper, graphic paper and special paper, the production of chemical pulp and mechanical pulp are also modelled. Transformation pathways were developed for each of these processes, with the main distinguishing factor between the processes being the development of production levels. The technologies that drive the transformation are broadly the same across the different processes.

A variety of trends are projected by the PTS analysis of the paper sector to lead to overall declines in the production levels of these products. These include increasing use of reusable packaging, increased resource efficiency, and the digitalization of newspapers and advertisements. Figure 3.3 depicts the development of production levels per product. Over the course of the modelled transformation, production of special and packaging papers declines to 92 % of 2019 levels by 2050, chemical and mechanical pulp to 89 % of 2019 levels, and graphic paper to 15 % of 2019 levels. Tissue paper represents the only product with projected increases in production levels, reaching 114 % of 2019 levels in 2050.

The technological transformation of these production processes is dominated by direct electrification. The provision of steam to the production process represents a

⁵ Institut für Fasern & Papier gGmbH; Until recently, Papiertechnische Stiftung / Forschungsstiftung der Papierindustrie

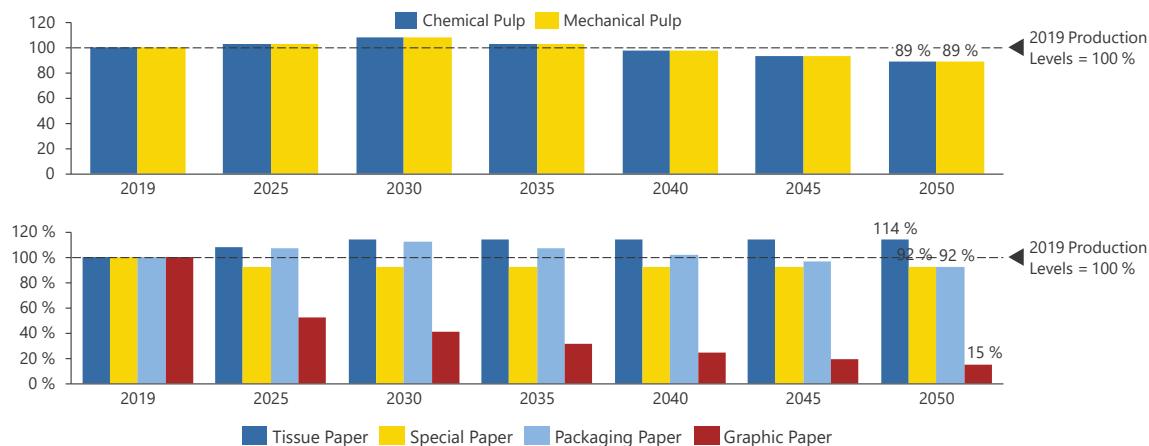


Figure 3.3. Development of production levels compared to 2019 levels for pulp products (upper graph) and paper products (lower graph) for the EU27+3.

large proportion of the demand for process heat in paper production, generally at temperatures below 200 °C [14]. Natural gas is the energy carrier used to meet much of this demand today, but is replaced in the modelled transformation by heat pumps for process heat below 100 °C, and high-temperature heat pumps, electrode boilers and biomass use for process heat between 100 °C and 500 °C. Demand for process heat above 500 °C is met largely by biomass, complemented by small amounts of hydrogen, and is primarily used for direct firing in the surface treatment of special papers [14].

3.1.4. Non-metallic Minerals

Glass

The creation of the transformation pathway in the glass sector was carried out with input from the HVG-DGG⁶. During TransHyDE-Sys, production processes for mineral fibers, utility and special glass, and fiberglass were newly defined and applied to Germany, in addition to the flat glass and hollow glass processes modelled in all countries. The modelled transformation pathways are based upon the mix-scenario of the BV Glas, featuring both hybrid furnaces and fully electrified furnaces. An increase in overall glass production

of 5 % by 2050 compared to 2019 levels was defined.

Flat glass transitions to solely hybrid furnaces, as the constraints of the production process for large sheets of glass is deemed incompatible with full electrification [15]. The remaining processes feature varying technology mixtures. 25 % of hollow glass furnaces are fully electrified, utility and special glass features a 33 % electrification rate, and fiberglass reaches 70 % electrification. In each of these cases, the remaining share of production is carried out using hybrid furnaces. The energy carrier split in the hybrid furnaces also develops over time, reaching 65 % electricity consumption and 35 % fuel consumption in 2050 for both flat and hollow glass production, from starting values of 13 % for electricity and 87 % fuels for flat glass and 23 % electricity and 77 % fuel for hollow glass.

The production of mineral fibers occurs solely in electric furnaces by 2050. By 2045, all fossil fuels have been replaced in the hybrid furnaces by hydrogen, which begins to be used in increasing amounts from 2030 onwards. Figure 3.4 depicts the development of overall production levels for glass products over time as well as the shares of conventional, hybrid and electric furnaces in the flat glass and hollow glass processes, which represent 95 % of total production.

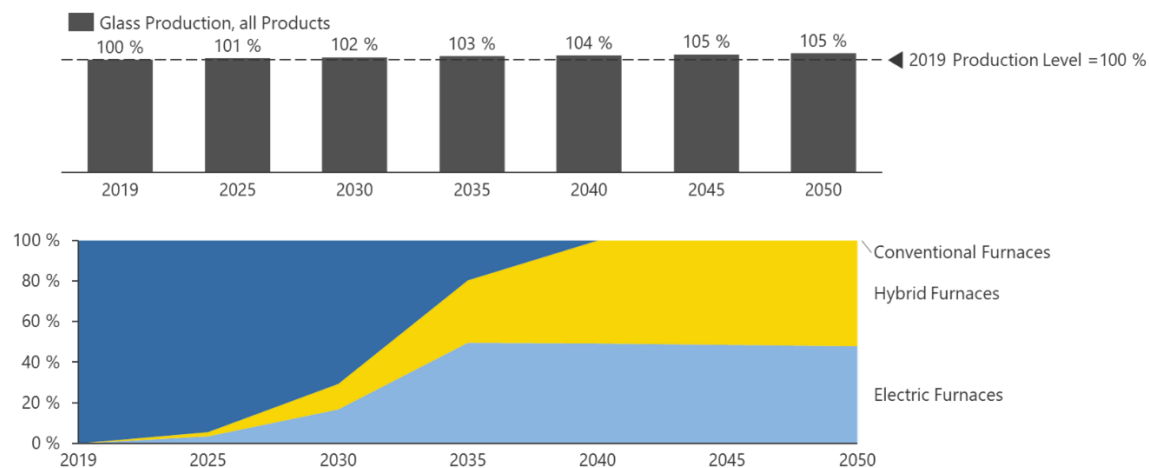


Figure 3.4. Development of glass production levels for all production processes compared to 2019 levels (upper graph) and the share of production of flat glass and hollow glass via conventional, hybrid and electric furnaces per year (lower graph) for the EU27+3.

⁶ Hüttentechnische Vereinigung der Deutschen Glasindustrie e. V.; Deutsche Glastechnische Gesellschaft e. V.

Cement

Consultations with the VDZ⁷ were valuable resources for validating individual parameters and determining the transformation pathways awaiting clinker and cement production. While the final production of cement in cement mills is already an electrified technology, the upstream process of clinker production consumes large amounts of fossil fuels to achieve the high temperatures required and features process emissions due to chemical changes in the raw materials during production.

The modeled transformation pathway includes a reduction in clinker production, both due to economic factors and as a result of targeted measures in the industry to decrease the share of clinker necessary in finished cement. Clinker production declines to 70 % of 2019 levels by 2050, while production of finished cement in cement mills remains at 95 % of initial production over the same timeframe.

The changes to clinker production levels is accompanied by a transformation of the energy carrier mix used for production. Coal, natural gas and oil use is reduced starting from 2020 and are fully replaced by 2045. In its transformed state, the energy carrier mix is made up of 90 % waste products and 10 % hydrogen. One-third of the waste products are designated as biogenic origin, while the remaining two-thirds are assumed to be fossil-based.

Beyond the transformation of the energy carrier mix, the key to the transformation of clinker production rests in the reduction of process emissions. Approximately 66 % of the emissions associated with clinker production are the result of the calcination of limestone, a chemical process which releases CO₂ from the raw materials independent of the energy carriers used in production. Until alternative binding materials can be developed that meet the technical requirements of cement, clinker will remain necessary for cement production and the resulting process emissions will need to be dealt with [16].

This makes the cement sector a prime candidate for the application of carbon capture technologies. In the modeled transformation, carbon capture is implemented starting in 2028 and installed across all clinker production locations by 2045. In a simplified approach agreed upon with the VDZ, a proportion of emissions is assumed to be captured at all production sites, which is linearly increased over time. In reality, individual production sites will use carbon capture technology to its full capacity once installed, barring limiting factors such as missing infrastructure, rather than this linear scale-up. While the approach used here impacts the results of the infrastructure modelling, no method for determining the beginning of carbon capture use at each individual production site was found that would not also significantly impact the results of the infrastructure modelling. A mix of technologies was applied, beginning with amine gas treatment and then with increasing use of Oxy-fuel technology. This was chosen based upon consultations with the VDZ in which the amine gas treatment technology was identified as near market-ready, while the Oxyfuel technology requires further development but is expected to be more efficient once technical maturity is reached. The resulting technology split is 80 % oxyfuel and 20 % amine gas treatment. The same use of carbon capture technology was also applied to the lime industry.

The consideration of carbon capture ends at the facility border in SMIInd, with no assumptions being made at this stage in the FfE Model Chain regarding the usage or storage of the resulting CO₂ or how it is transported to its final destination. The SMIInd results can be interpreted as a quantified yearly demand for carbon transportation infrastructure, and serve as input data for the remainder of the model chain and the InfracInt Model in particular. The modeling of CO₂-Infrastructure with InfracInt is presented in the later chapter.

3.1.5. Other sectors and non-specified demand

SMIInd models 46 production processes using a bottom-up approach, 44 of which were included in the transformation pathways developed by and with project partners. For the sectors of industry not represented by project partners and for the sectors of industry modeled top-down rather than via processes with a defined bottom-up parameters, transformation pathways were developed by the FfE based upon the results of previous projects and literature research.

A key aspect of the broader industrial transformation is the transformation of process heat. For those industrial production processes not directly modeled in the bottom-up approach, a general transformation was applied depending on the temperature level of the demanded process heat. Process heat below 100 °C is directly electrified via heat pumps and electrode boilers, with limited exceptions (for example, the food & tobacco sector and construction, where biomass continues to be used for this application). For process heat between 100 °C and 500 °C, a mix of direct electrification via electrode boilers and high-temperature heat pumps is applied together with biomass use and small shares of hydrogen (limited exceptions in the construction sector, where some natural gas and oil products continue to be used). At higher temperatures above 500 °C, process heat is provided by biomass and hydrogen. Biomass is more widely used until 2035, after which hydrogen becomes more important.

Where future projections of production levels could not be made in cooperation with project partners, an average increase in production was applied to represent growth in gross domestic product of approximately 1 % per year [6].

3.2. What industrial processes drive hydrogen demand in the stakeholder perspective?

The modeled transformation affects the overall demand for energy from the industrial sector as well as that of individual energy carriers. The overarching impact of the transformation will be briefly discussed before focusing on the processes that drive the future demand for hydrogen in the model results.

Beginning with overall final energy consumption (FEC), the modeled transformation pathways result in decreased energetic consumption of energy carriers in the industrial sector, but an increase in the use of energy carriers as feedstocks. The model results depicted in Figure 3.5 compare

⁷ VDZ Technology gGmbH

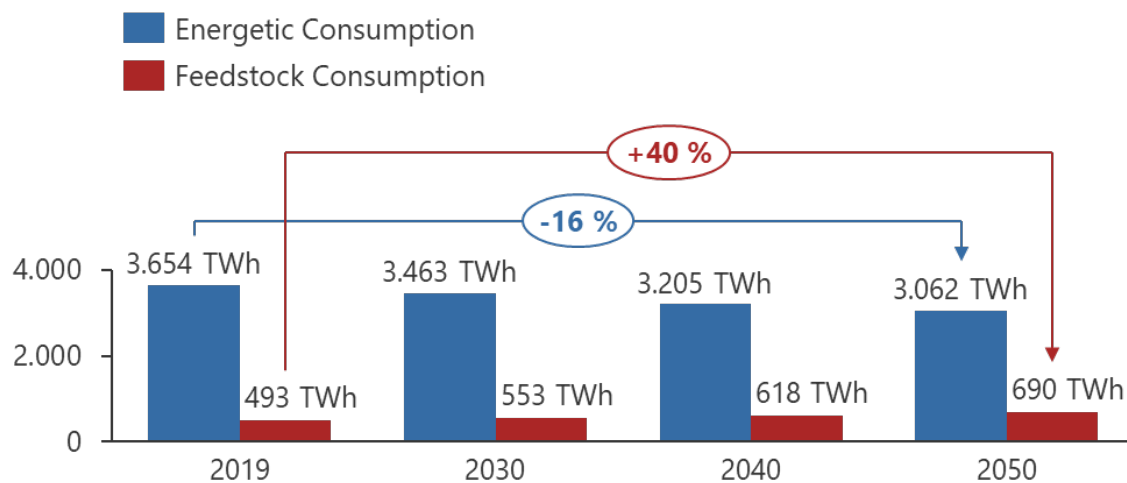


Figure 3.5. Comparative development of energetic and feedstock consumption in the EU27+3 in the stakeholder perspective.

the development of energy and feedstock consumption in the industrial sector of the EU27+3. Figure 3.6 then breaks the overall energy and feedstock consumption down by energy carrier.

Despite the rise in consumption of energy carriers as feedstocks, the FEC of the industrial sector declines in total by approximately 9,5 % between the base year 2019 and 2050.

The decline in energetic consumption is connected to several main effects. Increased demand for energy due to economic growth is outweighed by targeted energy efficiency measures and gains in efficiency of heat provision via direct electrification. This includes both the general shift in the provision of process heat described in the previous chapter, as well as the replacement of conventional processes by transformative processes. Several of these transformative processes are explicitly based on direct electrification, while others feature a lower specific final energy demand than the conventional counterparts they replace. The chemical industry features several exceptions to this, where demand for energy carriers as feedstocks increases. The use of carbon capture technology introduced in the model causes additional energy demand. However, in the development of the modelled transformation pathways, only the cement and lime industry indicated the use of carbon capture as a feature of their sectors' transformation plans at present. Therefore, the resulting increase in FEC is only seen in the cement and lime sectors and has a limited impact when considered at the larger sector level. Before

concentrating on the development of hydrogen's role in the industrial sector the changes to the other energy carriers will be described briefly.

Considering individual energy carriers, fossil fuels are nearly completely displaced from the energy mix, while demands for electricity and biomass increase markedly. Remaining fossil applications include the use of coke and natural gas in the steel industry (6 % of FEC of the steel sector), natural gas for ammonia production where integrated with urea production (2 % of FEC of the chemical sector), and natural gas and liquid hydrocarbons in the construction sector for decentralized process heat and fueling heavy equipment (18 % of sector FEC). As previously discussed, much of the current demand for these energy carriers for heat provision is replaced by electrification, driving the approximately 56 % increase in electricity demand between 2019 and 2050. Biomass enters the transforming energy mix relatively early as a source of non-fossil high temperature heat. Hydrogen is initially used only as feedstock, before beginning to also be used for high-temperature heat provision from 2028 onwards. Hydrogen's use as a feedstock also serves as an example to highlight increased demand for several other products caused by the adoption of transformative production processes.

The energy carriers currently in wide use as feedstocks, primarily natural gas and naphtha, both see declines in demand of more than 50 %. The remaining demand for these feedstocks in 2050, primarily in the steel and chemical industries, is based upon their chemical properties and could

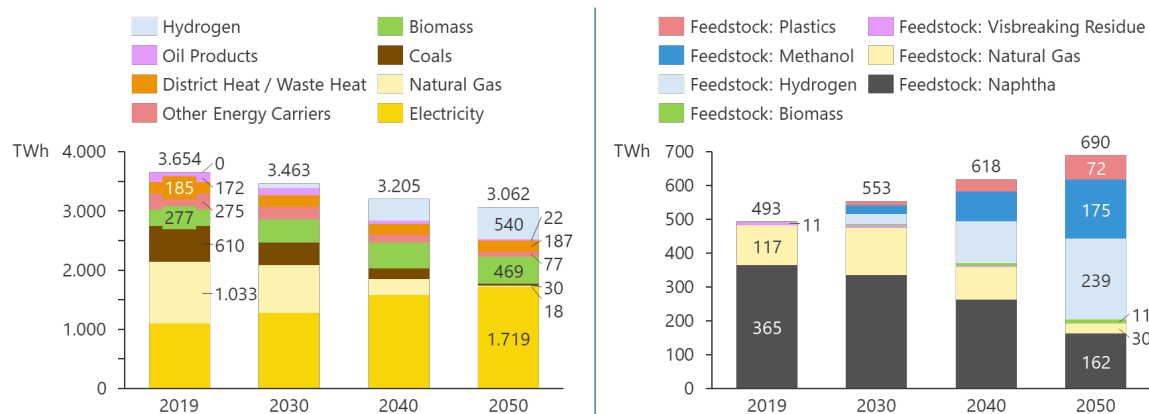


Figure 3.6. Development of energetic consumption (left) and feedstock consumption (right) per energy carrier in the EU27+3 in the stakeholder perspective.

be met by synthetic energy carriers as well as conventional fossil sources. In the case of naphtha for HVC production, much of the decline in demand is matched by increased demand for methanol as a feedstock in the MtX processes.

From the perspective of industrial demand, the 779 TWh of energy and feedstock demand for hydrogen in 2050 previously pictured in Figure 3.1 could originate from imported blue hydrogen, green hydrogen produced in Europe, or any combination of possible sources. This demand for hydrogen is for molecular hydrogen, rather than hydrogen derivatives or other energy carriers being used as a vector to transport hydrogen (for example, ammonia). Such questions of hydrogen production, transportation, and storage are considered in later chapters. The demand for hydrogen will now be examined more closely, highlighting the production processes from which the demand originates and how it is used in these processes.

As previously depicted in Figure 3.6, approximately 30 % of the demand for hydrogen is represented by feedstock demand, with energetic demand constituting the remaining 70 %. The temporal development of this demand was also on display in the previous graphic, with approximately 50 % of the total demand for hydrogen emerging in the decade between 2030 and 2040. Figure 3.7 offers a more detailed look at which sectors of industry are responsible for this increase in demand. In addition to the nearly five-fold increase in demand between 2030 and 2040 previously mentioned, the roles of the steel and chemical industries, and to a lesser extent the non-metallic minerals sectors, as the major drivers of demand become evident. The demand from these three sectors will be examined at the process level in the following subsections.

3.2.1. Iron & Steel Industry

Beginning the examination of these three sectors with the iron & steel industry, Figure 3.8 depicts the development of demand per process and application for steel production until 2050.

Demand for hydrogen in the iron & steel industry is dominated by the direct reduction process. As introduced in the previous chapter, hydrogen is needed here both as a feedstock, serving as a reduction agent to remove the oxygen atoms from crude iron in the process of creating steel, as well as the fuel source to provide the high temperatures necessary for this reaction. In the iron & steel industry the majority of demand not modeled bottom-up stems from the post-processing of raw steel in melting and reheating ovens. This is depicted here as the category “unspecified”. These processes operate at high temperatures above 500 °C and are consequently hard to electrify. Hence, it is assumed that these mainly natural gas fired furnaces are substituted by H₂ ready furnaces. The remaining fraction of demand stems from the provision of small shares of high-temperature heat in secondary steel production.

3.2.2. Chemical & Petrochemical Industry

As depicted in Figure 3.9, demand for hydrogen in the chemical sector is dominated by the provision of high temperature process heat.

While a proportion of this can be directly traced back to the modelled processes ammonia production and soda production, the majority of this demand originates from unspecified processes. After the direct reduction processes previously discussed in the steel sector, the use of hydrogen as a feedstock in the power-to-methanol and in particular power-to-ammonia processes represent the largest emerging demands for hydrogen as a feedstock from transformative processes. As discussed in the previous chapters Methanol and Ammonia, hydrogen is a chemical component needed in the synthesis of both of these products.

The level of hydrogen demand for these processes depicted here represents the demand for these final products in their current markets. However, other aspects of the industrial transformation could bring with them new uses and increases in demand. Ammonia may be used in the future as a vector for the transportation of hydrogen, and the methanol-to-olefines/aromatics processes modeled here

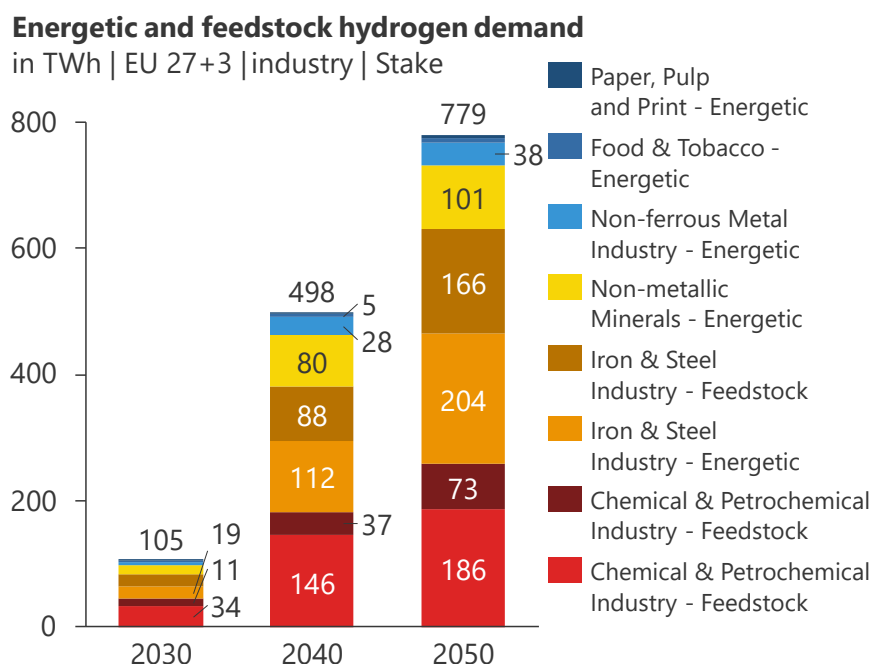
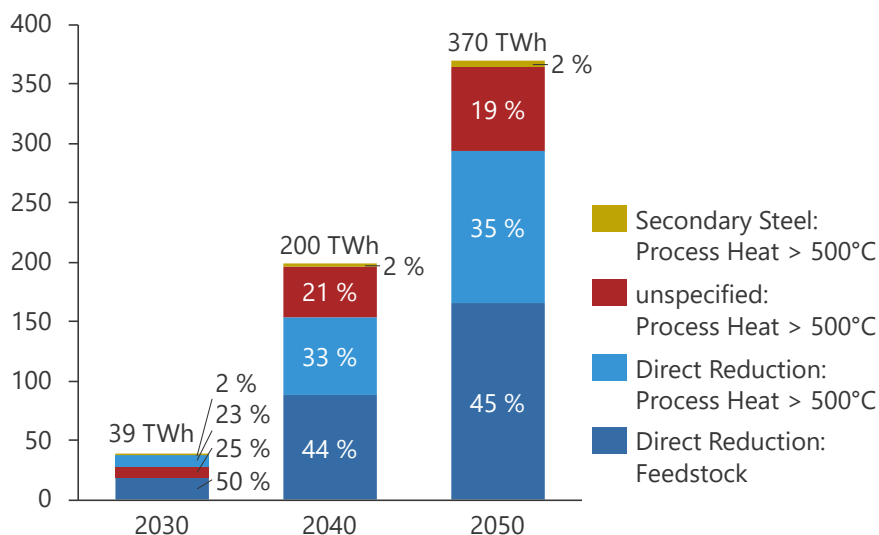


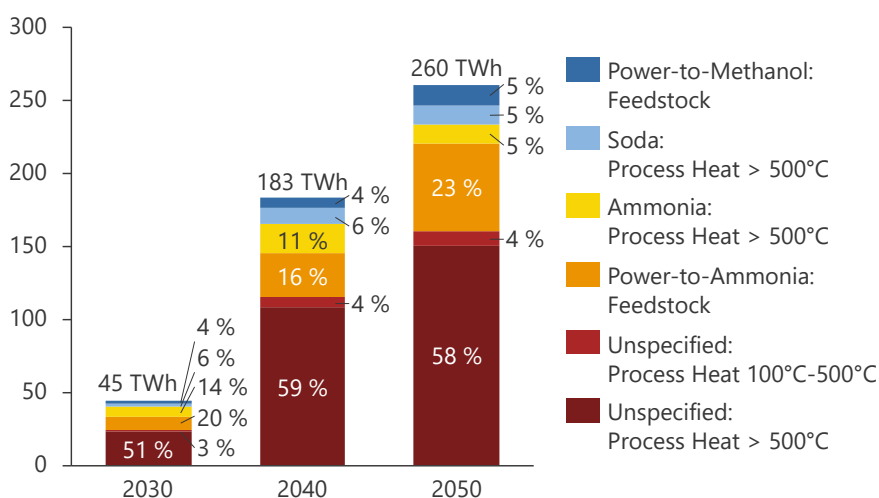
Figure 3.7. Development of hydrogen demand (energetic and feedstock) per sector of industry for the EU27+3.

Energetic and feedstock hydrogen demand

in TWh | EU 27+3 | Iron & Steel | Stake

**Figure 3.8.** Development of demand for hydrogen in the steel sector per process and application for the EU27+3.**Energetic and feedstock hydrogen demand**

in TWh | EU 27+3 | Chem. & Petrochem. | Stake

**Figure 3.9.** 2050 demand for hydrogen in the chemical sector per process and application for the EU27+3.

represent a new source of demand for methanol. Such emerging uses represent levers that could significantly increase the demand for hydrogen in the European chemical sector, should the production of these upstream products also be located in Europe.

Taking methanol production as an example, Figure 3.6 previously depicted a demand for methanol as a MtX feedstock of 175 TWh in 2050. While the hydrogen demand that this MtX production implies is not modelled in SMIInd, a simplified calculation demonstrates the importance of the “make or buy” decision to future industrial energy demand.

The demand for 0,2 tons of hydrogen per 1 ton of methanol produced via the power-to-methanol process as provided by DECHEMA is used here, as well as lower heating values of 33,33 MWh/t for hydrogen and 5,53 MWh/t for methanol. This results in a rounded demand of 1,25 MWh hydrogen per 1 MWh of methanol. In turn, the 175 TWh of methanol feedstock demand is re-cast as an additional 219 TWh demand for hydrogen feedstock using this simplified approach.

This represents a 91 % increase in the demand for hydrogen feedstock in the EU27+3 industry sector and would replace direct reduction as the process with the largest demand for hydrogen feedstock. Other hydrogen based synthetic energy carriers, such as synthetic naphtha in the industrial sector or synthetic fuels in the transportation sector, can have similar effects upon demand should the upstream production also be located in Europe. Even if located elsewhere, the overall impact on energy demand is worth bearing in mind regardless.

3.2.3. Non-metallic Minerals

The glass and cement sectors introduced earlier form part of the larger industry sector non-metallic minerals (NMM). The calcination of lime is also a process of this sector modeled using the bottom-up methodology. Other products, such as brickmaking or ceramics production, for example, are not yet included in the bottom-up modeling and fall into the category unspecified processes in SMIInd. As depicted

in Figure 3.10 a majority of the demand for hydrogen in the NMM sector originates from this category.

The entirety of this unspecified demand is demand for high-temperature (> 500 °C) process heat. The modeled processes from the glass, cement and lime sectors similarly demand hydrogen primarily for high-temperature process heat when considered at the application level. This will be demonstrated as these sectors are discussed in turn in the following sub-sections.

Glass

The glass sector represents the largest source of process-specific demand for hydrogen among non-metallic minerals. Flat glass production, which is expected by the DVG-HGG transformation pathway to remain difficult to completely electrify at the industrial scale, represents 50 % of this expected demand in 2050. Hollow glass meanwhile is expected to see both fully electric as well as hybrid production, and represents 46 % of hydrogen demand from the glass sector. In both of these processes, the demand for electricity significantly exceeds the demand for hydrogen in 2050, by approximately a factor of 3 for hollow glass production and a factor of 2 for flat glass production. The remaining “other glass” processes, representing newly modeled processes applied only in Germany as described in previous chapters, also mainly demand hydrogen for high-temperature process heat. Their expansion to the rest of the EU27+3 represents a future further development of SMIInd. Figure 3.11 depicts the development of hydrogen demand per process and application in the glass sector. The shift from conventional to hybrid production by 2040

is clearly visible in the strong increase in hydrogen demand between 2030 and 2040. The following decline in demand represents the continuing increase in the share of electricity in hybrid furnaces and the corresponding decrease in the share of hydrogen.

Cement and Lime

The cement and lime sectors similarly demand hydrogen for high-temperature process heat, as well as smaller amounts of middle-temperature process heat in the cement sector. The primary source of process heat remains waste streams, including biomass-based wastes, with only approximately 10 % of process heat being provided by hydrogen. The same fuel mix is also used for an application unique to these two sectors in this modeling, the carbon capture technology required to reduce the process-based emissions of these processes. The demand for CO₂ infrastructure resulting from this use of carbon capture technology is examined in the model Infracnt. The results of which will be discussed in the following chapter.

3.2.4. Industry-Wide Applications

As evident in the process-level description of hydrogen demand in the steel, chemical and non-metallic Mineral sectors, its main roles in the future energy system of the stakeholder perspective consist of use as a feedstock and for provision of high temperature heat. Examining the entire industry sector at the application level supports the evidence observed at the process level. Figure 3.12 depicts the EU27+3 hydrogen demand for each defined application

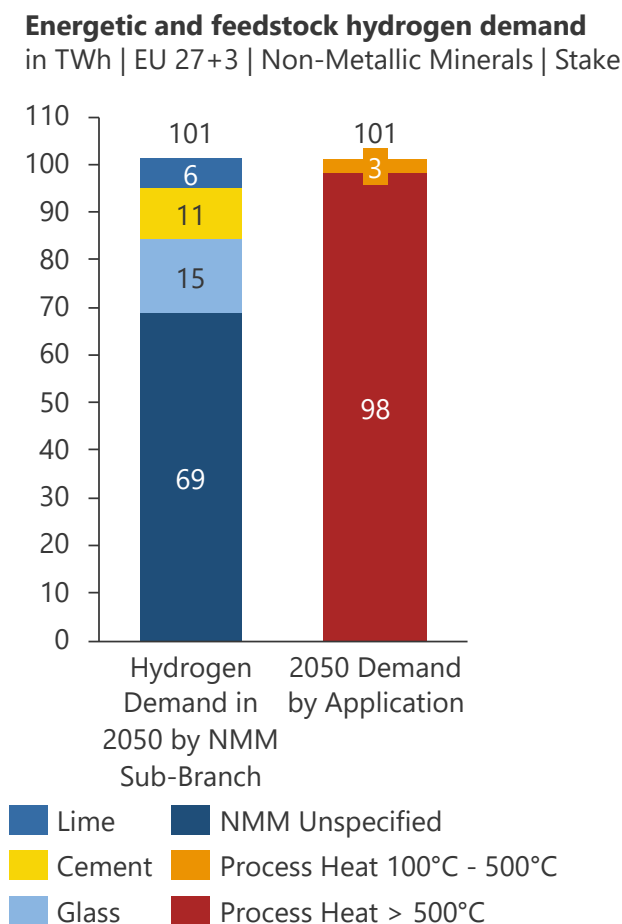


Figure 3.10. 2050 demand for hydrogen in the non-metallic minerals sector per sub-sector for the EU27+3.

Energetic and feedstock hydrogen demand

in TWh | EU 27+3 | Glass | Stake

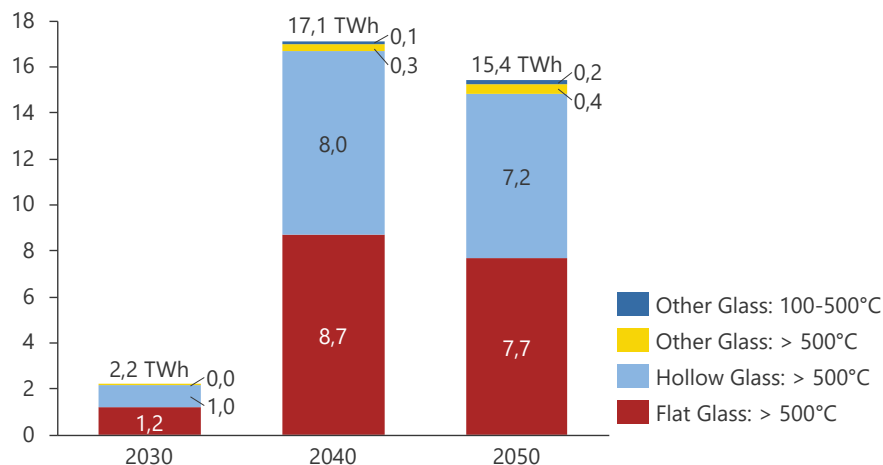


Figure 3.11. Development of demand for hydrogen in the glass sector per process and application for the EU27+3.

in the SMInd model. The energetic use of hydrogen for process heat applications represents 18 % of the 3.062 TWh of energetic FEC modeled in the year 2050. Hydrogen feedstock is the energy carrier with the largest source of feedstock demand, 35 % of the total 690 TWh of 2050 feedstock demand.

While detailed model comparisons are beyond the scope of this publication, the overall industrial demand in 2050 falls between the levels of industrial demand for hydrogen seen in the scenarios Low_Demand and Mid_Demand as modeled from the system perspective and presented in the 2024 flagship publication *European Hydrogen Infrastructure Planning: Insights from the TransHyDE Project System Analysis* (p.19). Initial comparison of results from the two perspectives for 2050 indicates that the widespread use of hydrogen to provide steam and hot water as modeled in scenario High_Demand is not reflected in the transformation pathways defined in the stakeholder perspective. Further model comparisons can provide insight into the resulting demand for high temperature process heat, represented as “furnaces” in the system perspective and as “process heat > 500 °C” in the stakeholder perspective, which is approximately 250 TWh across all system scenarios and 518 TWh in the stakeholder perspective. The differing geographical scopes of the models may have some influence, but are unlikely to be the sole explanation of the differing

results here. Ongoing work in TransHyDE-Sys is dedicated to comparing the models and model results of the two industry frameworks. The aim is to explain differences between the system and stakeholder perspective results where they arise. For a further description of the results of the model comparison, see the section How do the two modelled perspectives differ in the industry sector?.

The major driver of industrial demand in the system perspective scenarios is approximately 1.000 TWh of hydrogen as a feedstock for iron sponge (via direct reduction), ammonia, methanol and high-value chemicals. Different stages of the value chain and different technologies are modeled in the two perspectives, necessitating a detailed comparison if the resulting quantified demands are to be compared more closely or a “best guess” demand for feedstock is to be generated from the two. However, the earlier brief examination of the potential demand lever represented by the production of hydrogen-based feedstocks such as methanol aligns qualitatively with this result from the system perspective.

3.3. What is the European demand for a CO₂-Infrastructure?

Following the analysis of transformation measures within the industry, an energy system analysis was performed and

Hydrogen Demand by Application

in TWh | EU27+3 | Industry | Stake

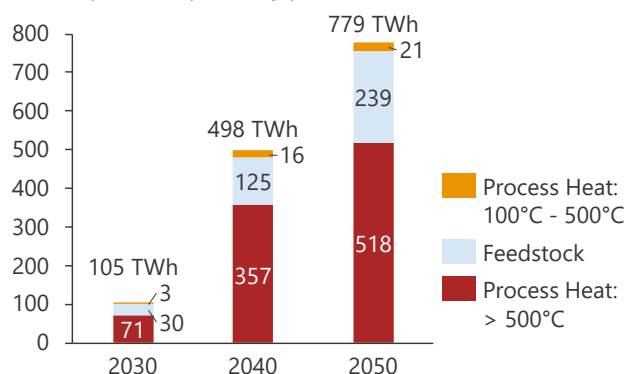


Figure 3.12. Development of industrial demand for hydrogen per application in the EU27+3.

finally the demand for a H₂ and CO₂ infrastructure was examined. Given that the CO₂ infrastructure is directly linked to the transformation pathways for the industry, the findings related to this aspect are presented in this section, whereas the results for the H₂ infrastructure are shown in Chapter 5.

The cement and lime sectors have indicated their intention to implement carbon capture and storage (CCS) to achieve net-zero emissions during the stakeholder interviews (see chapter Cement). However, other sectors are also suitable candidates for CCS. Notably, emissions from thermal waste treatment are classified as hard-to-abate, necessitating capture and storage solutions [17]. Furthermore, the capture of biogenic emissions, for example at biomass power plants, to generate negative emissions is an important tool for achieving climate goals.

The infrastructure model InfracInt used to determine the CO₂-infrastructure in Europe, however, only considers CO₂ sources from cement and lime sites. The results can therefore be understood as the minimal demand for a target infrastructure in 2050 based on hard-to-abate industrial emissions.

The regionalized CO₂ emissions captured from cement and lime serve as input for the infrastructure model InfracInt. A cost function describes the total costs for the construction of a CO₂ pipeline infrastructure, under the constraint that all captured CO₂ must either be utilized or stored. The amount of CO₂ per NUTS-3 district is illustrated in Figure 3.13 along with assumed available storage sites. The storage sites and export terminals are taken from the list of International Association of Oil & Gas Producers

(IOGP) for projects that are at least in the early development stage [18]. Given the abundance of additional sites with geological potential for CO₂ storage [19], the storage sites incorporated in the model can be viewed as a worst-case scenario for the exploitation of storage capacity. This conservative approach is used to highlight the distances over which the industry will have to transport CO₂ if no further storage sites are developed.

CO₂ can be transported through pipelines in both gaseous and liquid phases, depending on the pressure and temperature conditions. The gaseous phase has a low density, requiring larger pipeline diameters, which leads to increased costs. In contrast, transporting CO₂ in its liquid phase allows for greater transport capacity with smaller pipeline diameters due to its higher density, making it a more cost-effective solution for transporting large amounts of CO₂. However, maintaining the liquid phase at ambient temperature requires pressures of up to 150 bar within the pipeline. Since most existing natural gas pipelines are not designed to withstand such high pressures, a new infrastructure specifically for CO₂ pipelines will need to be constructed. For smaller quantities of CO₂, transportation via trains or ships is also a viable option; however, the developed infrastructure model InfracInt focuses solely on the demand for a pipeline transport network at district level, neglecting alternative transport methods for possible multimodal hub concepts.

The model optimizes the pipeline routes needed to transport CO₂ from source districts to storage sites by minimizing the overall construction costs. The result for the target year 2050 is shown in Figure 3.13, where the thick-

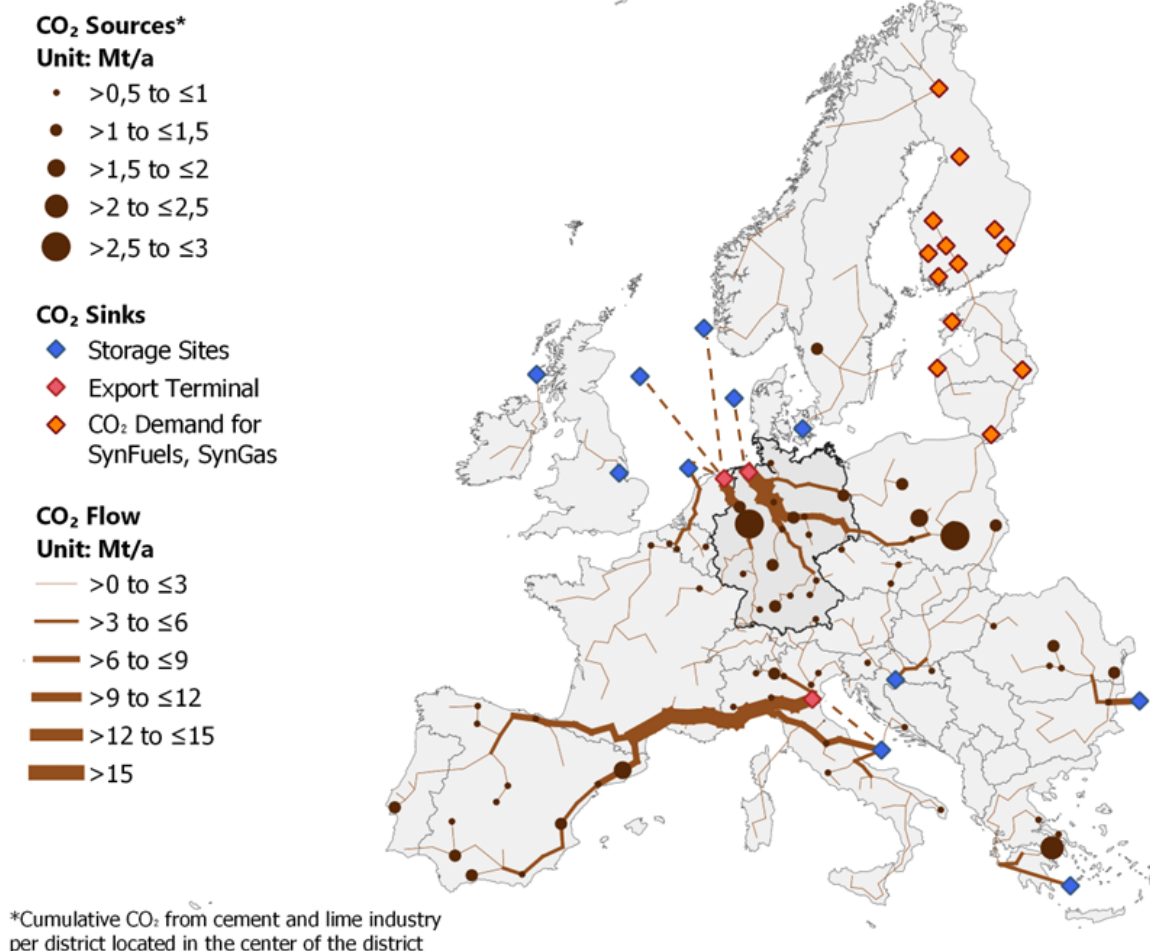


Figure 3.13. Cost-optimized pipeline infrastructure for captured CO₂ in cement and lime sectors.

ness of the lines represents the required capacity for each pipeline segment.

This model result shows the demand for an extensive collection network transporting CO₂ towards export terminals and storage sites. As the volume of collected CO₂ increases, so does the required pipeline capacity. Pipelines leading to the export terminals must have a capacity exceeding 15 Mt/a, which translates to a pipeline diameter of 800 mm when CO₂ is transported in a dense liquid phase.

Besides storing CO₂, the captured CO₂ can also be utilized (Carbon Capture and Utilization – CCU) for example to produce synthetic aviation fuels or synthetic methane. The demand for such synthetic fuels and gases was determined as part of the energy system analysis performed using the ISAAR model. The energy demands from the FEC sector models, such as the previously presented SMIInd results, are important inputs for this analysis. The results show that most demand is met by imports to Europe. Some production is also located in northern Europe, where the model forecasts large amounts of available electricity.

One possible production pathway for syngas or synfuel is a synthesis process that utilizes CO₂ and hydrogen [20]. The demand for CO₂ generated in this context serves as an input parameter to the infrastructure model Infracore. While the syngas and synfuel production capacity at the country level is a result of the energy system analysis, the regionalization to the district level is optimized parallel to the optimization of CO₂ and H₂ pipeline routing in the infrastructure model. This means that the utilization of CO₂ and H₂ is included as a sink in the infrastructure optimization. The resulting districts with CCU for the production of syngas and synfuel are illustrated in Figure 3.13 as orange diamonds. The sites intended for the production of synthetic fuels and gases are primarily supplied by CO₂ from industrial point sources that require a connection to the CO₂ pipeline network. Some production locations use Direct Air Capture to supply the required CO₂, which has higher costs compared to capture at industrial point sources but does not require a pipeline network.

The optimized CO₂ pipeline network has a length of 37,000 km, which is almost double the length that the EU is aiming for by 2040 according to its industrial carbon management strategy [21]. The main reason for this is the lower regional resolution used in the EU's modeling so that regional collection infrastructure requirements are not included in the estimation of pipeline lengths. Another reason is the greater availability of storage sites assumed in the EU's modeling, particularly in southern Europe, which can avoid additional pipeline kilometers. This suggests that further storage exploration is needed to reduce overall infrastructure costs.

Since the shown infrastructure model results consider only CO₂ sources from cement and lime sites, the required transport and storage capacities only show a minimal estimation of future infrastructure demands. By including CCS at other point sources, such as waste incineration plants and biomass power plants, the infrastructure requirements can change and will most likely be more extensive.

3.4. Is the CO₂ price under the EU ETS sufficient to make hydrogen-based production cost-competitive?

On the demand side, the EU ETS is the major instrument that improves the competitiveness of clean production technologies by increasing the cost for fossil fuel use. The production of DRI for steelmaking, methanol, HVCs and ammonia are among the potentially largest hydrogen consumers. [22] assessed the impact of the CO₂ price on the cost competitiveness of selected key technologies. A comprehensive market diffusion requires competitiveness of such hydrogen-based production routes compared to the current fossil fuel-based production.

Results in Figure 3.14 show CO₂ avoidance costs as an indicator of cost-competitiveness of hydrogen use for 16 variations of hydrogen and CO₂ prices (4 variations each). Table 3.1 lists the assumptions for fossil energy prices and the variations of hydrogen and CO₂ price projections.

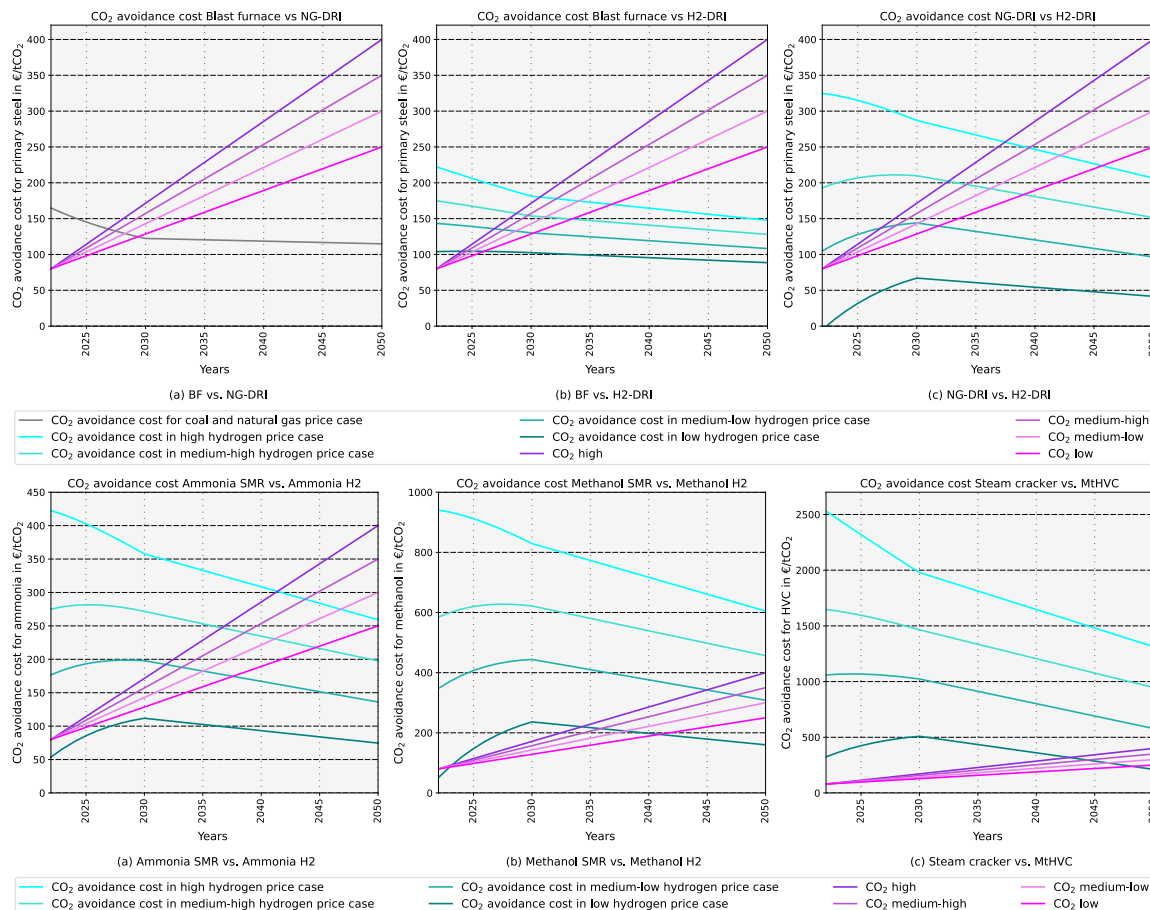
The y-axes in Figure 3.14 represents the required CO₂ prices to reach cost-competitiveness with the fossil-based status-quo processes considered under the assumed energy prices from Table 3.1. The horizontal lines in grey and turquoise indicate the development of the calculated CO₂ avoidance costs depending on the price developments of fossil energy carriers and green hydrogen, while the violet lines show the provided CO₂ price projections. The respective break-even prices reflect the year of competitive production and height of required CO₂ prices for cost parity.

Results differ substantially between the three products analysed. Switching from coal-fired blast furnaces (BF) to direct reduction of iron ore using natural gas (NG-DRI) could be competitive before 2030. The combination of a major emissions reduction of about 68 % for NG-DRI compared to BF and a moderate increase in energy costs only leads to relatively moderate CO₂ avoidance costs. The break-even point for switching from BF to hydrogen-based direct reduction (H₂-DRI) is highly dependent on the hydrogen price. For both options, the high CO₂ intensity of coal-fired BF and the resulting strong impact of the CO₂ price supports the early competitiveness of DRI. Comparing hydrogen use in DRI compared to natural gas use in DRI, the break-even point may increase to higher CO₂ prices up to 250-300 €/tCO₂. Abatement costs for the use of climate neutral H₂ in ammonia production compared to natural gas are in a similar order of magnitude, as also here, the price difference between natural gas and climate neutral hydrogen drives the abatement costs.

Substantially higher abatement costs are found for methanol and HVC, where H₂ is used as feedstock. One main reason is the fact that EU ETS does not price the carbon embedded in feedstocks, but only the share that is emitted during production. The carbon bound in e.g. plastics products is only covered in the EU ETS at the end of the products' lifecycle, in the form of waste incineration. These results underline how the current ETS design incentivises carbon capture at waste incineration sites, but not the replacement of fossil feedstocks in e.g. plastics production. This incentive-gap and huge cost-gap for H₂ as feedstock is in sharp contrast to its importance in scenarios

Table 3.1. Scenario definitions and key assumptions [22].

Indicator	Unit	Quantitative example: Germany			
		2022	2030	2040	2050
Description		<i>Medium short-term price shocks due to Covid pandemic and Russian invasion of Ukraine without huge long-term effects. This scenario reflects a realistic or best guess estimation concerning conventional energy prices.</i>			
Electricity price	€/GJ	62.7	41	37.6	34.2
Natural gas price	€/GJ _{LHV}	18	8.7	7.8	7
Naphtha price	€/GJ _{LHV}	22.6	13	12.7	12.4
Coal price	€/GJ _{LHV}	4.5	3.4	3.2	2.9
Fuel oil price	€/GJ _{LHV}	22.6	13	12.7	12.4
Energy availability	GJ _{LHV}	unrestricted	unrestricted	unrestricted	unrestricted
Production	ton	2019 calibration	2019 calibration	2019 calibration	2019 calibration
Sensitivities		<i>Sensitivities are conducted with same assumptions on electricity and fossil energy prices. They differ in hydrogen and CO₂ price assumptions (4 variations each) and thus result in 16 sensitivity combinations.</i>			
Variation		v1 / v2 / v3 / v4	v1 / v2 / v3 / v4	v1 / v2 / v3 / v4	v1 / v2 / v3 / v4
Hydrogen price	€/GJ _{LHV}	27 / 37 / 45 / 57	20 / 27 / 33 / 40	17.5 / 23.5 / 29 / 35	15 / 20 / 25 / 30
CO ₂ price	€/GJ	80 / 80 / 80 / 80	129 / 143 / 157 / 171	189 / 221 / 254 / 286	250 / 300 / 350 / 400

**Figure 3.14.** CO₂ avoidance costs for primary steel (BF vs. NG-DRI (a), BF vs. H2-DRI (b), and NG-DRI vs. H2-DRI (c)) production (top) and for chemicals (ammonia (a), methanol (b) and HVC (c)) (bottom) in the four different hydrogen price sensitivities and comparison to the four defined CO₂ price paths (Source: [22]).

and the high expectations that are related to it. Even relatively high CO₂ price assumptions are not sufficient to make hydrogen use in feedstocks cost competitive early enough, so that it is very likely that without additional

incentives, climate neutral hydrogen will not be used at large scale for chemical feedstocks by the year 2050.

The danger of lock-ins is highlighted by identified reinvestment needs of all European plants covered in the anal-

ysis of Neuwirth et al. [22]. For most plants only one investment opportunity is remaining until 2050, while already 36 % require reinvestment until 2030. Considering the age structure of the current plant stock, the theoretical reinvestment cycles, availability of hydrogen infrastructure based on the plans from the European Hydrogen Backbone initiative (EHB), and the cost-competitiveness per process the resulting market diffusion of hydrogen-based processes can be calculated as illustrated in Figure 3.14. On the spatial dimension, results show that the EHB grid topology fits well with the locations of large potential hydrogen users from the steel and chemicals industries (see Figure 3.15). On the other hand, the cost competitiveness does not match with the needs for re-investment for most plants, which results in a high danger of fossil lock-ins. Transitional technologies like the investment in natural gas-fired direct reduction can bridge the gap in cost competitiveness for a few years and mitigate the danger of technology lock-ins.

3.5. How will regional demand for hydrogen develop in the industrial sector?

In addition to the modelling of a future CO₂ infrastructure introduced in the previous chapter, Infracnt was also used to model a future hydrogen infrastructure in TransHyDE-Sys. As established in Chapter Transformation from the stakeholder perspective with focus on Industrial transformation, the industry sector is expected to become the largest source of hydrogen demand. For infrastructure modelling, the location of demand is arguably more important than the overall level of demand. In turn, regionalization of industrial demand plays a key role as input for Infracnt and will be discussed here.

3.5.1. Regionalized industrial demand in 2030

Regionalized demand for hydrogen in the earlier years of the EU27+3 industrial transformation modelled from the stakeholder perspective is dominated by a small number of NUTS-3 districts. In 2030, total industrial hydrogen demand in the EU27+3 is 104.600 GWh. 46 NUTS-3 districts feature a demand for hydrogen of 500 GWh or more, representing 57.800 GWh of hydrogen demand in total. This represents 55 % of total demand located in under 5 % of

NUTS-3 districts. 24 of these 46 districts have a demand above 1.000 GWh each and represent 43.200 GWh of total demand. The demand in these districts is heavily driven by direct reduction for the production of raw steel, with 12 districts featuring hydrogen demand over 1.000 GWh from this process alone. Three districts also feature more than 1.000 GWh of demand for high-temperature process heat in the chemical & petrochemical industry. The geographic distribution of the 24 districts with the highest demand in 2030 includes two demand clusters or corridors. One of these corridors stretches from the Baltic coast inland along the German-Polish border and includes three districts which represent a total of 4.390 GWh of hydrogen demand. The second follows the coast of the North Sea from the Seine-Maritime district in northern France to the city of Antwerp and consists of five NUTS-3 districts which together represent 10.715 GWh of hydrogen demand. Two adjacent districts to the south of Barcelona, Spain represent a further demand center. The remaining districts with a demand over 1.000 GWh each are spread across Germany, Finland, Sweden, Italy, France, Czechia, Romania, the Netherlands and Belgium. Several of these remaining Dutch, Belgian and western German districts could be viewed as extensions of the second cluster introduced above. Several of the districts separating this cluster from the more isolated high-demand districts themselves feature demands over 50 GWh in 2030. The visualization of these regions in Figure 3.16 offers indications of where the construction of infrastructure for transporting hydrogen could be prioritized.

3.5.2. Regionalized industrial demand in 2050

Due to the long lifetime of infrastructure, it is important to consider hydrogen demand further in the future as well as in the early years of the transformation. Total demand for hydrogen increases from 104 TWh in 2030 to 779 TWh in 2050. In turn, the regional demand levels increase as well. In both years considered, a small number of districts with high levels of demand each represent a majority of total demand, with this trend becoming stronger in 2050. Figure 3.17 depicts the development in the share of districts featuring different ranges of demand for hydrogen, as well as the share of total demand represented by the districts within each demand range.

The share of NUTS-3 districts with a yearly demand

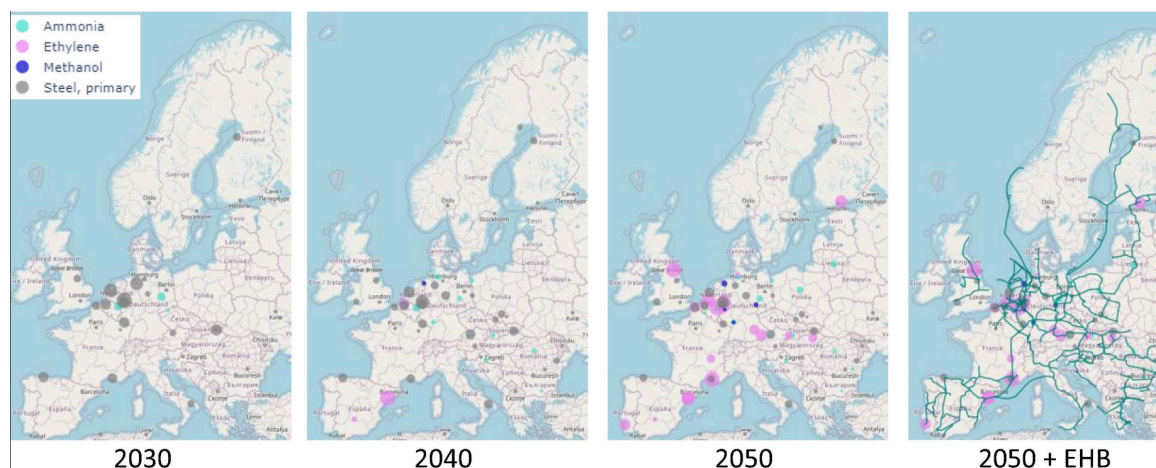


Figure 3.15. Spatial development of hydrogen demand per product over time for low H₂ and high CO₂ price sensitivity (Price combination that is most favourable for hydrogen use) [22].

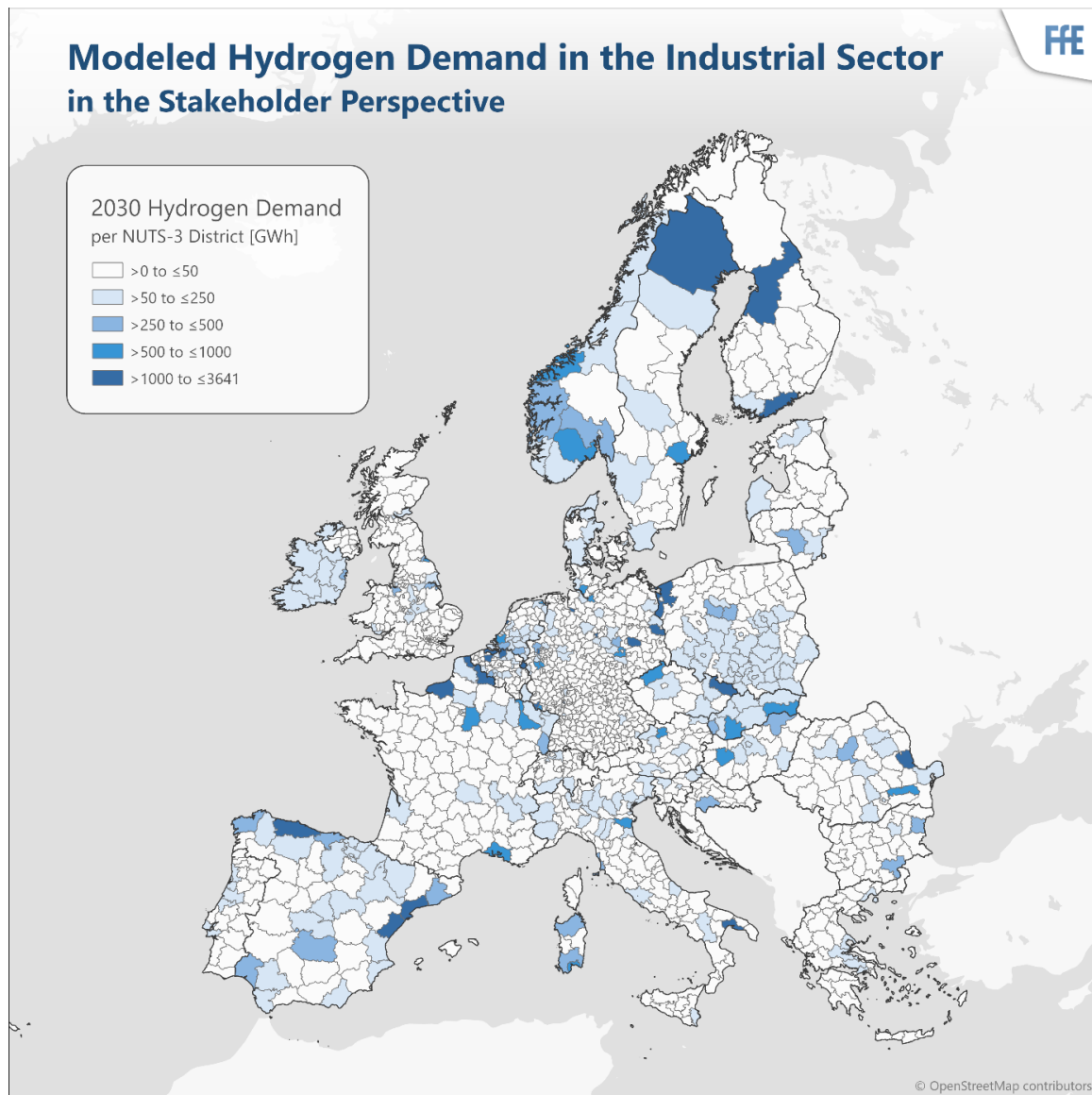


Figure 3.16. Regionalized hydrogen demand in 2030 in the industrial sector, NUTS-3 level.

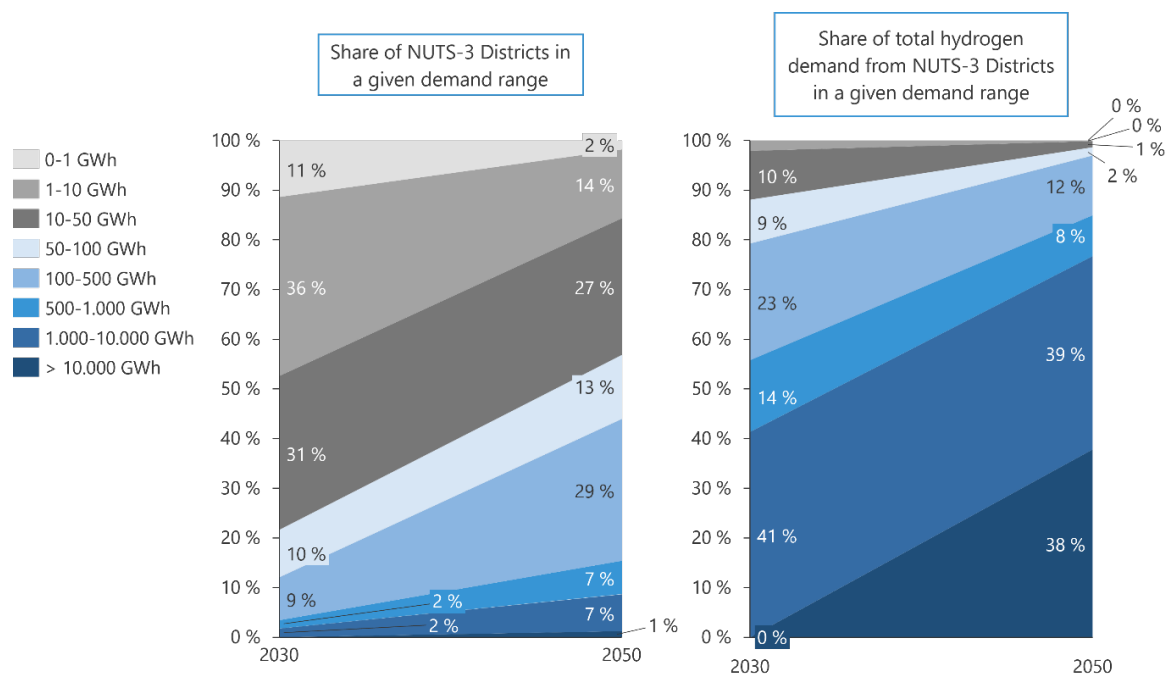


Figure 3.17. Structure of total demand levels for hydrogen at the NUTS-3 level. Share of districts with a given demand range in 2030 and 2050 (left) and share of total demand represented by districts in a given demand range.

over 1.000 GWh rises to 9 % from 2 % in 2030. Among the 111 districts with demand above this level, 15 feature a demand above 10.000 GWh. These two groups make up approximately 71 % of total demand for hydrogen in 2050, with 34 % of total demand originating in the 15 districts with the largest demand.

As depicted in Figure 3.18, each of the clusters observed in 2030 has expanded. In Germany and Poland, two additional German districts to the southwest of the existing cluster see demand above 1 TWh. These 5 districts represent a demand of 27,6 TWh. In Poland, an additional cluster emerges from four districts surrounding Wroclaw and a string of three districts straddling the Polish-Czech border, which includes two districts with more than 10 TWh of demand and represents a total demand of 34,6 TWh. To the south-east of this, seven districts across Slovakia and Hungary to the east of Bratislava feature an additional 28 TWh of demand. Additional districts around the western European cluster surrounding Antwerp also see levels of demand above 1 TWh, such that this cluster could now be said to extend as far as the German cities of Essen and Cologne to the east and southeast. Four districts of this cluster feature demand above 10 TWh per year, totaling 84,2 TWh between them. This includes the German city of Duisburg, whose demand of 39 TWh in 2050 represents

the highest NUTS-3 demand resulting from the regionalized modelling, primarily due to multiple production sites from the steel sector in the district featuring hydrogen-based direct reduction.

Each of the clusters observed in 2030 has expanded. In Germany and Poland, two additional German districts to the southwest of the existing cluster see demand above 1 TWh. These 5 districts represent a demand of 27,6 TWh. In Poland, an additional cluster emerges from four districts surrounding Wroclaw and a string of three districts straddling the Polish-Czech border, which includes two districts with more than 10 TWh of demand and represents a total demand of 34,6 TWh. To the south-east of this, seven districts across Slovakia and Hungary to the east of Bratislava feature an additional 28 TWh of demand. Additional districts around the western European cluster surrounding Antwerp also see levels of demand above 1 TWh, such that this cluster could now be said to extend as far as the German cities of Essen and Cologne to the east and southeast. Four districts of this cluster feature demand above 10 TWh per year, totaling 84,2 TWh between them. This includes the German city of Duisburg, whose demand of 39 TWh in 2050 represents the highest NUTS-3 demand resulting from the regionalized modelling due to the planned direct reduction plant of Thyssen Krupp.

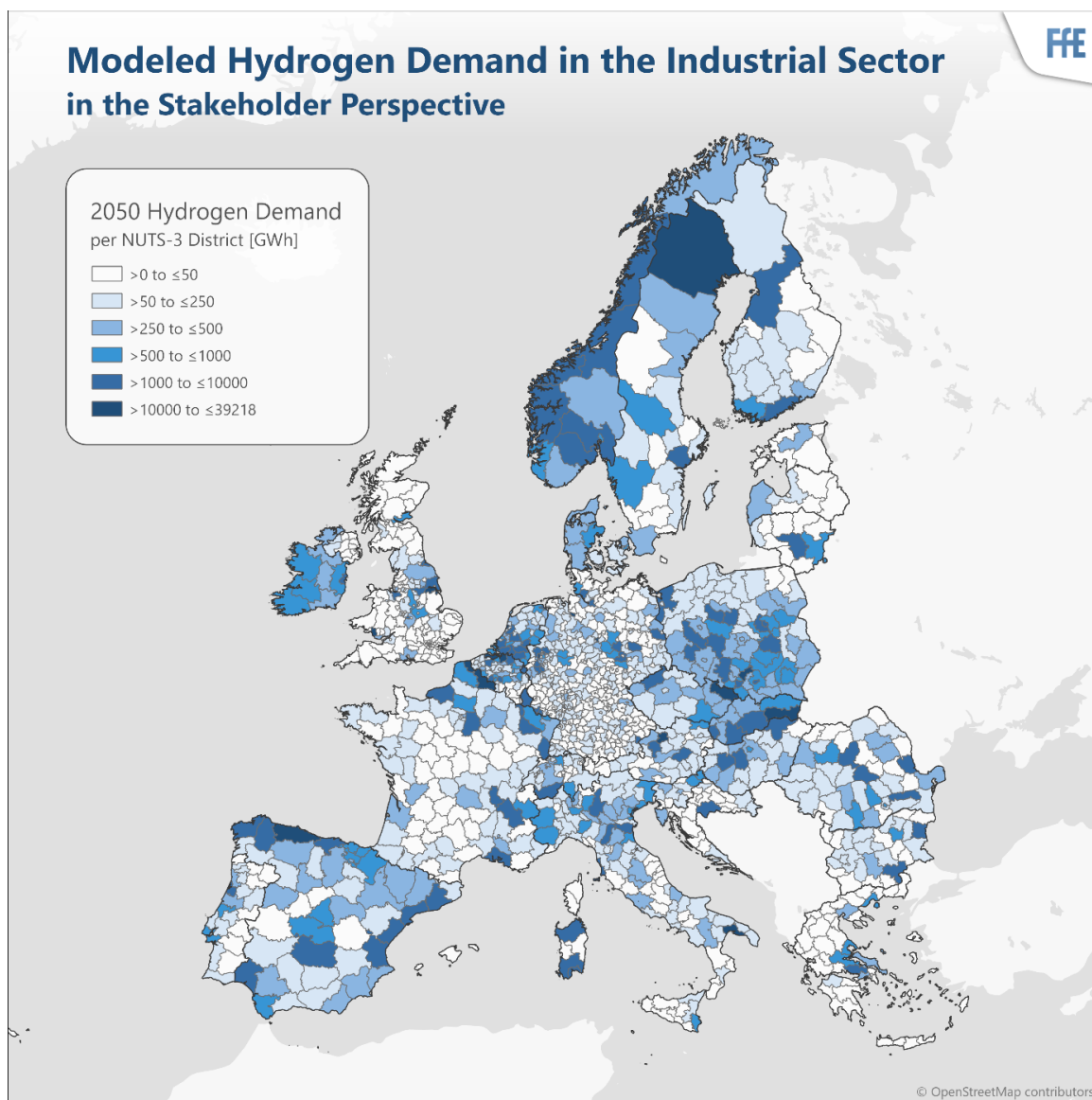


Figure 3.18. Regionalized hydrogen demand in 2050 in the industrial sector, NUTS-3 level.

Additional clusters of adjacent districts with more than 1 TWh of demand each are found on the north coast and east coast of Spain and the west coast of Norway. Individual districts with high demand can be found across the EU 27+3.

As this industrial demand is generally associated with production facilities, rather than spread across entire NUTS-3 districts as demand from the buildings or transportation sectors may be, additional local detail is important for the final planning of hydrogen infrastructure. However, the industrial demands at the district level presented here can serve as high-level indications for the planning of the large-scale networks necessary to transport hydrogen between countries and regions. As such, this data serves as a valuable input for the FfE infrastructure model Infracnt.

following chapter begins to explore these questions, considering the role of seasonal imports of hydrogen in the European energy system.

3.6. Summary of the industrial transformation from the stakeholder perspective

Developing industrial transformation pathways for the stakeholder perspective in cooperation with the respective research institutes of the participating industrial sectors enabled their expertise to be incorporated in the modeling performed in TransHyDE-Sys. Information regarding individual production locations and different production processes contributed to increasing the detail of the model SMInd. Focusing on this stakeholder perspective serves as a complement and additional context to the system perspective modeling, even if the technical differences of the two modes make direct comparisons difficult.

The industrial transformation modeled from the stakeholder perspective can be characterized in several ways. Total final energy consumption decreases over the course of the transformation, with increasing consumption of energy carriers as feedstocks outweighed by decreasing energetic consumption. This effect is driven by direct electrification of processes and of the provision of heat. This is key to the overall industrial transformation, with electricity in the most demanded energy carrier in 2050, with a share of 56 % of energetic FEC compared to 30 % in 2019. Demand for hydrogen in 2050 is approximately 18 % of total energetic demand, but is irreplaceable in the transformation of certain processes. While it is one of limited options for providing difficult to electrify high temperature process heat, use of hydrogen as a feedstock in the iron & steel and chemical & petrochemical sectors is unavoidable in the transformation pathways expected in these sectors. Of the modeled feedstock demand, 35 % is demand for hydrogen, the largest share of a single energy carrier. As presented previously, future decisions about where other feedstocks, such as methanol or synthetic hydrocarbons, are produced can have a significant impact on the level of hydrogen demand in Europe. This could see the demand for hydrogen as a feedstock exceeding its demand for energetic use.

The demand for hydrogen discussed in chapter Transformation from the stakeholder perspective with focus on Industrial transformation has referred almost exclusively to gaseous hydrogen. Beyond the level and location of demand, important questions remain regarding the geographic source of hydrogen needed to meet this demand, as well as in what form and via what infrastructure it will be transported from point of origin to demand centers. The

4

Imports

Europe is expected to become an importer of green hydrogen in the coming years. This is outlined in the REPowerEU strategy, which aims to produce 10 Mt of hydrogen domestically and import a further 10 Mt by 2030 [23]. While the total target of 20 Mt of hydrogen use will likely not be met by 2030 [2], it shows that the total demand for hydrogen is expected to increase significantly in the future.

In the initial TransHyDE flagship report [4], we found that Europe's hydrogen import needs were shaped by a strong preference for pipeline transportation over shipping at shorter distances, due to its lower conditioning costs, while shipping, although more expensive, provided essential flexibility for sourcing hydrogen carriers such as ammonia. The report also highlighted that production costs, rather than transportation, were the dominant cost driver, and that green chemical carriers like ammonia offered a promising pathway to meet future demand. These early insights, which also noted the potential for significant cost declines from 2030 to 2050 despite some uncertainties, have since informed more detailed analyses and refined modelling approaches. We estimated hydrogen demand in Europe to be between 697 TWh and 2,897 TWh by 2050, excluding derivatives. This bandwidth is based on five scenarios that range from a no-regret use of hydrogen in energy-intensive industries to a very broad use in all demand sectors (industry, transport and building). For more details, see Fleiter et al. (2024). Similarly, Riemer et al. (2022) identified an inner range of 300 to 1,000 TWh, with the outer range extending up to 3,000 TWh. Our study also suggests that part of this demand will be met by imports, estimated at between 29 TWh and 290 TWh (not counting derivatives), representing about 4 % to 10 % of total de-

mand for gaseous hydrogen. All imports come via pipeline, while ship imports are estimated to be more expensive than domestic production. These import shares assume a strong deployment of wind and solar energy in Europe at the most competitive locations in combination with the extension of pan-European of hydrogen and electricity infrastructure. With less optimal deployment of infrastructure and renewables, a higher share of imports would be cost-efficient. Other studies suggest that hydrogen imports could account for 10 % to 15 % of total demand by 2050.

4.1. What impact do different hydrogen import costs have on the European energy system?

Building on the projected growth of European hydrogen imports, our system optimization analysis reveals a pronounced seasonal pattern, with winter months showing significantly higher import volumes due to reduced renewable availability and elevated production costs. This chapter examines how strategic storage solutions in exporting regions can mitigate these fluctuations and enhance overall import competitiveness.

The results of our system optimization reveal a seasonal pattern of hydrogen imports into Europe. As shown in Figure 4.1, which presents the hydrogen import trends under the Med demand scenario, most imports occur during the winter months. This pattern is driven by the reduced availability of renewable energy sources in winter combined with a higher energy demand, which leads to higher hydro-

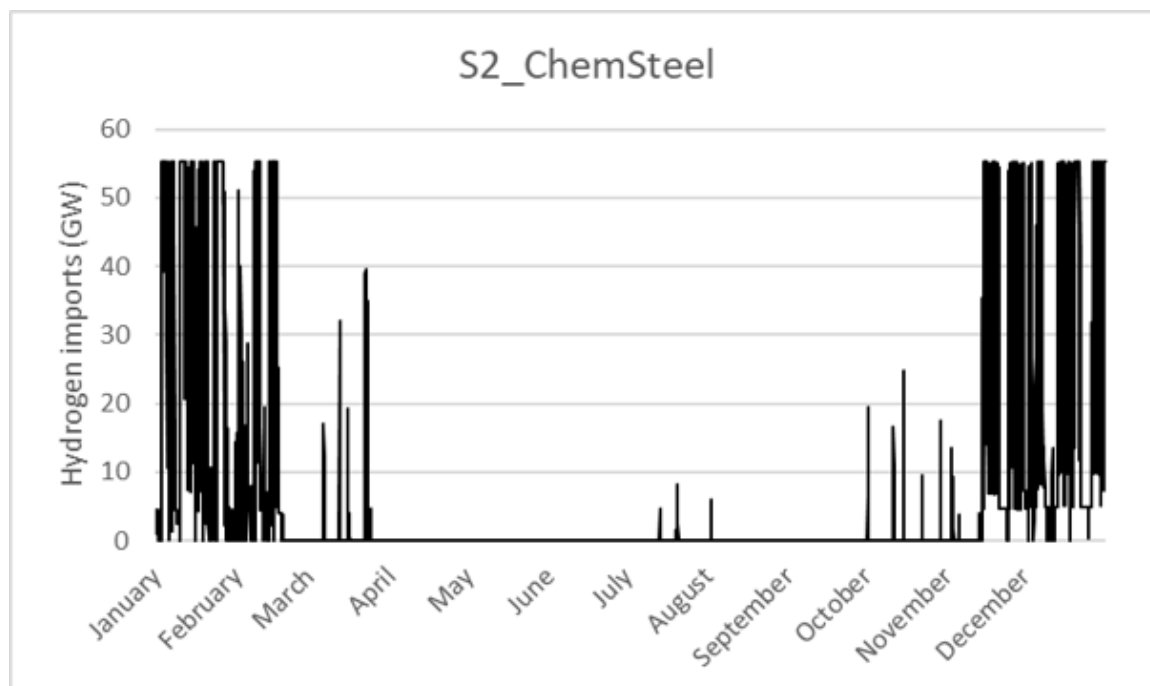


Figure 4.1. Hourly hydrogen imports to Europe for the year 2050 in scenario Med Demand.

gen production costs in Europe. Such import pattern would require adequate storage solutions in the exporting regions to match supply and demand. The following analysis will assess how seasonal storage in the exporting regions changes the competitiveness of imports and the resulting volumes.

Methodology

The analysis is structured into two main parts: first, the optimization of storage costs at export nodes, and second, the implications for the European energy system in 2050.

Given its proximity to Europe, the MENA region was modelled as a potential hydrogen export hub. The impact of storage was assessed using a soft-linking approach between two models. Initially, a linear optimization model minimizes total costs for importing gaseous and liquid hydrogen to Europe by optimizing capacities across hydrogen production, conversion, storage, and transportation processes. It integrates renewable energy sources (solar, wind), electrolysis facilities, liquefaction plants, underground storage caverns, pipelines, and shipping terminals. Annual modeling with daily steps captures renewable variability and import demands derived from PyPSA-EUR, considering socio-economic constraints. The model differentiates geographically and supports various import routes, with sensitivity analyses exploring the degree of demand alignment (0 %, 50 %, 75 % and 100 %) and two storage cost assumptions (550 and 1200 €/MWh)⁸ in the exporting countries. Demand Alignment describes the extent to which hydrogen production in exporting regions is synchronized with Europe's fluctuating import demand. In scenarios with high demand alignment (100 %), exporters dynamically adjust production to closely match Europe's varying hydrogen needs throughout the year, reducing the need for storage but requiring substantial production capacity fluctuations. Conversely, no demand alignment (0 %) implies constant hydrogen production independent of demand fluctuations, necessitating significant storage infrastructure to manage

seasonal variations. These cost estimates were then integrated into PyPSA as hydrogen import costs for Europe to analyze the effect in the European energy system.

We used the Med_demand scenario, which assumes that hydrogen demand is mainly driven by industry, in particular chemical feedstock, steel production and high temperature process heat. Further details can be found in [24]. All calculations are for the year 2045. In this section the short name S2 is used to refer to the Med_demand scenario.

Results: Seasonal Import Costs

This section examines eight import cost scenarios for gaseous and liquid hydrogen, which differ according to base (1200 €/MWh) and low (550 €/MWh) cavern investment costs as well as the degree of demand alignment (see Figure 4.2).

The findings indicate a substantial variation in import costs, ranging from 38 to 261 €/MWh, with gaseous hydrogen exhibiting, on average, a 45 % cost advantage over its liquid counterpart. A critical determinant of these costs is demand alignment. Scenarios characterized by reduced alignment tend to exhibit lower import costs, whereas higher demand alignments result in significantly higher costs. Specifically, an equal division (50/50) of demand alignment between importers and exporters leads to a cost increase of 120-135 % compared to export as needed. A further shift of 25 % to the exporter raises costs by an additional 29-31 %, while externalizing the final 25 % results in a more moderate increase of 23-24 %. These cost increases occur from the need for additional production capacity, including renewables, electrolysis, and liquefaction infrastructure, which remains underutilized during summer months. Notably, an increase from zero to 50 % demand alignment necessitates a 244 % expansion in production capacity, while further increments from 50 % to 75 % and 75 % to 100 % require additional expansions of 130 % and

⁸ Cavern costs variations have tested to validate the impact of storage on the resulting supply costs.

Imports

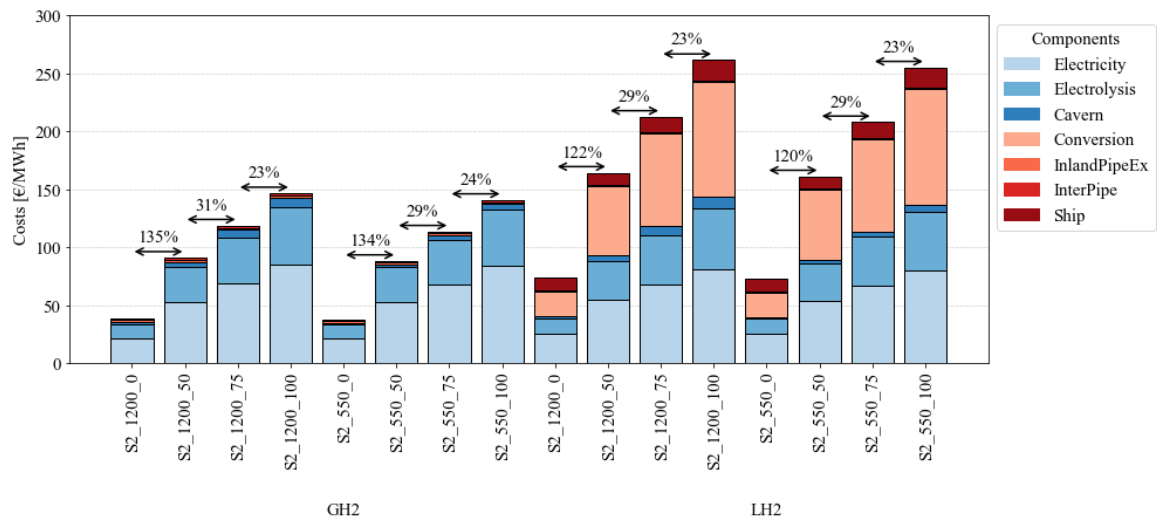


Figure 4.2. Costs for hydrogen imports to Europe via pipeline from MENA for variations of cavern cost and flexibility for gaseous (GH₂) and liquid (LH₂) hydrogen.

124 %, respectively. For instance, the S2_1200_0 scenario for gaseous hydrogen demands 142 GW of renewable capacity and 28 GW of electrolysis capacity by 2045, whereas the S2_1200_100 scenario necessitates 560 GW of renewables and 113 GW of electrolysis capacity. In contrast, variations in cavern storage costs exert only a marginal influence, leading to an average cost reduction of approximately 4 €/MWh (-4 %). These findings underscore the predominant role of seasonal demand alignment and production infrastructure in shaping import costs, with storage expenses playing a relatively minor role. How these resulting import costs affect the competitiveness of imports and volumes is shown in the next section.

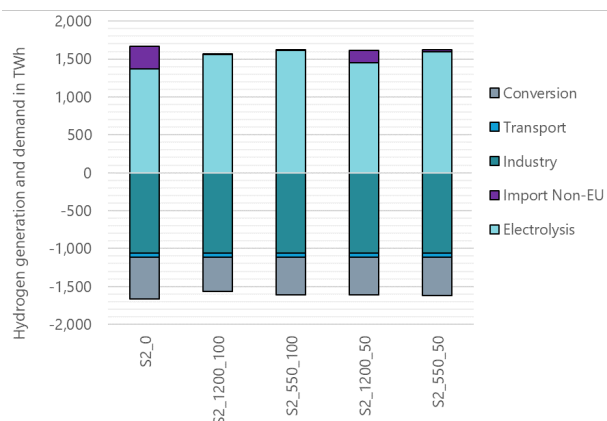
Results: System impact of different costs for storage and imports.

The impact on the European energy system was assessed using the PyPSA optimization model, evaluating demand alignment scenarios without demand alignment (S2_0), with alignment (S2_1200_100 and S2_550_100) and with 50 % alignment (S2_1200_50 and S2_550_50) (see Figure 4.3a).

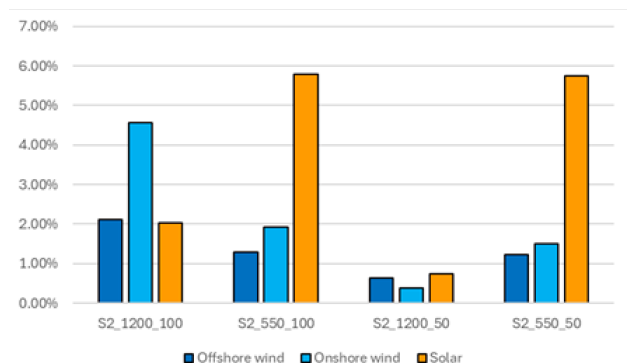
The results reveal that the S2_0 scenario exhibits the highest levels of hydrogen imports, attributable to the absence of demand alignment and, consequently, lower import costs. These lower costs facilitate increased utilization of hydrogen in the conversion sector, particularly for elec-

tricity generation. Conversely, scenarios lacking flexibility (suffix_100) demonstrate minimal hydrogen imports due to significantly elevated import costs, which constrain the system's ability to balance supply and demand and necessitate higher storage investments in Europe. A comparison between the S2_1200_50 and S2_550_50 scenarios indicates that while the former registers slightly higher hydrogen imports, the associated import cost differential remains negligible. This suggests that storage costs within the European energy system are a crucial determinant of domestic production costs. Additionally, all costs occur through pipeline connections, as pipeline-based hydrogen imports remain significantly more cost-effective than alternative import options via ship.

Furthermore, the analysis of electricity generation reveals distinct trends based on storage costs. Scenarios with lower storage costs (S2_550_100 and S2_550_50) exhibit a marked increase of over 5 % installed in electricity generation from solar sources in Europe, including utility-scale and rooftop photovoltaic systems. The storage costs significantly impact hydrogen import expenses. S2_1200_50 has the second-highest hydrogen import cost. Due to the high storage costs, the model favors importing hydrogen over domestic production. As a result, there are minimal differences in electricity generation when compared to S2_0. The S2_1200_100 scenario, characterized by high stor-



(a) Hydrogen balance in Europe in 2050 for the different scenarios.



(b) Variations in generation in 2050 for different renewable energy sources in the scenarios compared to S2_0.

Figure 4.3. Hydrogen balance and renewable generation variations in Europe in 2050 (comparison of scenarios).

age and hydrogen import costs, demonstrates the greatest increase in wind energy generation, encompassing both onshore and offshore capacities (see Figure 4.3b).

Finally, an assessment of hydrogen storage capacities across scenarios highlights significant disparities. Scenarios with lower storage costs (S50_€MWh_H2) correspond to the highest storage capacities in Europe, reaching up to 663 TWh. In contrast, the scenario with the highest storage and hydrogen import costs (S2_1200_100) exhibits the lowest storage capacity in Europe, at 337 TWh. These results underscore the role of storage costs in determining the overall hydrogen infrastructure in Europe, with cost-efficient storage solutions facilitating larger storage capacities and greater system flexibility.

Addressing the seasonal variability of hydrogen imports will require not only enhanced storage solutions but also a broader strategy for securing a stable hydrogen supply. While green hydrogen remains the long-term goal, the transition phase calls for alternative low-carbon solutions to bridge the gap. In this context, blue hydrogen emerges as a viable option, potentially leveraging existing infrastructure while significantly reducing emissions through carbon capture and storage. The next section will investigate the perspectives of blue hydrogen in the European system.

4.2. How does blue hydrogen impact the energy and hydrogen system?

Achieving climate neutrality requires a secure, sustainable, and scalable hydrogen supply. Green hydrogen, produced via electrolysis using renewable energy, is generally perceived as the main option for clean hydrogen supply and in many countries also as the long-term goal. Nonetheless, there are discussions whether the early transition phase, in which green hydrogen supply might be scarce, necessitates low-carbon hydrogen alternatives to ensure supply security and system stability. Blue hydrogen presents a viable solution for decarbonizing the energy system while leveraging existing infrastructure. Blue hydrogen is produced from natural gas via steam methane reforming (SMR) or autothermal reforming (ATR), with carbon capture and storage (CCS) to mitigate CO₂ emissions. Given that SMR is the predominant hydrogen production method globally and currently supplies nearly all of Germany's hydrogen demand (around 55 TWh/a), integrating CCS into this process could achieve CO₂ capture rates exceeding 90 %, substantially lowering emissions compared to conventional hydrogen production.

To explore the impacts of blue hydrogen on the European energy system, the PyPSA model was used to examine two scenarios for 2045: one scenario named S1.5 Green-only, in which hydrogen production in Europe is limited to electrolytic hydrogen and a second scenario referred to as S1.5 ColorMix, where both green and blue hydrogen are permitted. Both scenarios are constrained by the same emissions limit. The analysis was based on the S1.5 demand scenario which represents a balance between globally relocated industrial value chains and domestic production, with a projected total European hydrogen demand of 578 TWh in 2045. In this scenario, hydrogen demand is focused in

the industry sector, while transportation only uses small quantities and space heating does not use hydrogen at all.

There are two ways to supply blue hydrogen to Germany, either by importing it or producing it domestically, using SMR or ATR, with different options for storing the captured CO₂. Four different supply chains were analyzed in [25], assuming the use of Norwegian natural gas. The study concludes that the most cost-efficient option would be to produce blue hydrogen domestically and store the captured CO₂ onshore in Germany.⁹ This approach is used as the basis for the S1.5 ColorMix scenario setup. A base SMR production capacity of 10 GW with a 90 % emission capture rate was assumed in Germany, as an alternative to the currently halted plans to import blue hydrogen from Norway.

Hydrogen imports to Europe from the MENA region are allowed in both scenarios. The modelled import corridors through Italy and Spain are based on the European Hydrogen Backbone report [26], with an assumed import price of 84 €/MWh. Only pipeline imports are considered, as they are generally more cost-effective than imports via ship for transporting large amounts of hydrogen over short to medium distances [27]. The model setup covers the full ENTSO-E area and includes a clustered version of the German hydrogen core-network to fit the predefined regions. The optimization process follows a techno-economic approach to meet energy demands with the most cost-efficient solution while adhering to the technical boundaries of the system.

The model optimizes the capacities and locations of both electrolysis and SMR plants. The results indicate that the Green-only scenario sees higher installed electrolysis capacities, with the total network electrolysis capacity decreasing from 265 GW in the Green-only scenario to 241 GW in the ColorMix scenario. The optimized electrolysis locations for both cases are shown in Figure 4.4 (S1.5 Green-only to the left, and S1.5 ColorMix on the right), highlighting larger installations in northern regions with strong wind energy potential. While the availability of blue hydrogen reduces the need for electrolysis capacity, the location of larger electrolysis plants remains largely unchanged in both scenarios as their position is primarily driven by favorable renewable energy conditions.

In addition to the 10 GW of SMR capacity in northern Germany, the model deploys several smaller, distributed SMR plants across the network, resulting in a total system capacity of 21.2 GW to produce blue hydrogen in Europe. The model assumes a uniform natural gas price of 35 €/MWh [28] and simplifies the natural gas and CO₂ networks by treating them as copper-plated, meaning that factors such as proximity to import terminals and transport of captured CO₂ are not explicitly considered in the optimization of these smaller SMR plant locations. The overall use of SMR is constrained by the assumed 200 MtCO₂/a sequestration limit in Europe, which is also used for captured industry process emissions. A valuable indicator for the impact of the cap is shadow price of the constraint. It represents the marginal cost of increasing sequestration capacity and indicates the opportunity cost of allocating limited sequestration capacity among competing sectors.

⁹ It should be noted that, currently, storing CO₂ onshore in German territory is virtually prohibited, except for pilot projects. The case is selected to assess the fully economic potential of blue hydrogen.

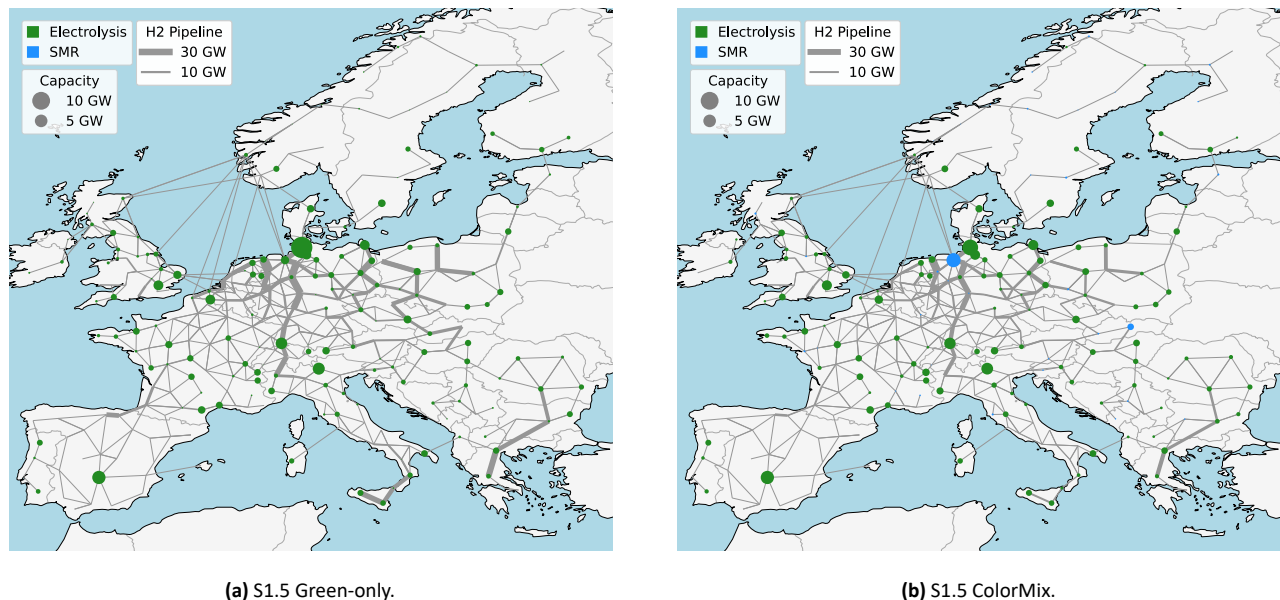


Figure 4.4. Optimized European hydrogen network and hydrogen production capacities - 2045.

In this scenario, the shadow price of the sequestration limit is 252 €/tCO₂, highlighting that expanding sequestration would be highly economic if more sequestration was allowed.

The hydrogen balance in Figure 4.5 breaks down the distribution of hydrogen sources and sinks in the system along the y-axis. The upper part of the graph, showing hydrogen supply, illustrates that the majority of hydrogen demand is met through electrolysis within Europe. In the ColorMix case, 10 % of the demand is supplied by blue hydrogen, while only 2 - 5 % is fulfilled by imports from the MENA region in both scenarios. As mentioned, the 10 % blue hydrogen is limited by the restricted annual sequestration capacity. Allowing for a higher sequestration threshold would result in higher shares of blue hydrogen. On the consumption side, the ColorMix scenario sees more hydrogen

use in the conversion sector, where the higher emissions from blue hydrogen are offset by increased utilization of green hydrogen for electricity generation to help balance the power system.

The availability of blue hydrogen reduces the reliance on direct hydrogen imports to meet Europe's hydrogen demand, while the import of natural gas increases. Imported hydrogen decreases from 48 TWh in the Green-only scenario to 21 TWh in the ColorMix scenario. While hydrogen imports remain a viable option, the optimization results show that their contribution to Europe's hydrogen supply is relatively small at a price of 84 €/MWh. This outcome subtly reflects the system's sensitivity to the assumed hydrogen import cost, suggesting that even slight cost differences can shift the balance between domestic production and imports as demonstrated in the previous section (system

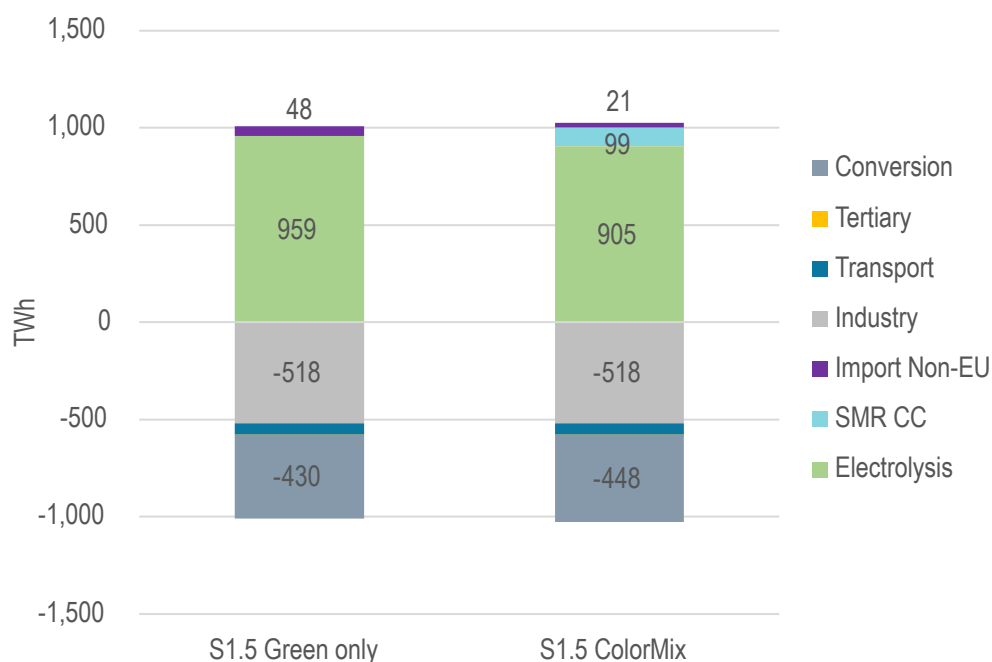


Figure 4.5. Optimized hydrogen balance for Europe – 2045.

impact of different costs for storage and imports).

The optimized network results in Figure 4.5 show that the hydrogen network capacity required in the Green-only scenario is higher than in the ColorMix scenario, with values of 184 TWkm and 151 TWkm, respectively. This is because the Green-only system requires transporting hydrogen over longer distances from remote renewable production sites to demand centers. In contrast, blue hydrogen production can occur closer to consumption areas, reducing transport distances and network capacity needs. Assuming a 60 % retrofitted pipeline share in the hydrogen network, the results see a 17.5 % reduction in network cost, dropping from 5.2 bn€/a in the Green-only case to 4.3 bn€/a in the ColorMix scenario. While more imports are needed in the Green-only scenario, import corridors through Italy and Spain appear less favorable in both scenarios due to their lower competitiveness at 84 €/MWh.

Similar findings were observed for the optimized hydrogen storage capacities in Europe. The required storage capacity drops from 319 TWh in the Green-only case to 290 TWh in the ColorMix scenario. This decrease is primarily due to the more reliable and steady production of blue hydrogen, which occurs mainly in the winter season and helps mitigate the supply fluctuations seen in renewable electrolysis, thereby lowering the need for extensive seasonal storage. These changes in hydrogen infrastructure requirements are also reflected in the resulting average hydrogen price in the system, which drops from 78 €/MWh in the Green-only case to 73 €/MWh in the ColorMix scenario.

In summary, blue hydrogen contributes to the European energy and hydrogen system by providing a lower-carbon alternative to conventional hydrogen production while infrastructure and renewable capacities scale up. However, its long-term viability depends on sequestration possibilities and carbon capture efficiencies, regulatory frameworks, and cost competitiveness with green hydrogen. The transition to green hydrogen, however, depends on the timely expansion of renewable energy. Delays in this expansion could affect Europe's reliance on hydrogen imports, raising concerns about energy security and supply diversification, which the following section examines in detail.

4.3. How does a delayed expansion of renewable energies influence the European need for hydrogen imports?

As a result of the climate targets set in the European Green Deal, the urgency to accelerate the transition towards carbon-neutral energy system is increasing. Consequently, countries set ambitious objectives for the ramp-up of volatile renewable energy sources (vRES). However, their expansion is subject to great uncertainty. Delays compared to current expansion plans may necessitate further import measures, such as hydrogen imports from outside Europe, to satisfy the growing energy demand in Europe. To shed light upon these consequences, we explore the impact of delayed and accelerated expansion of volatile renewable energy sources on Europe's hydrogen import needs. The following contents are based on the publication by [29].

Methodology

Using the multi-energy system model ISAaR, which optimizes the total system costs while meeting constraints such as GHG emission targets, the European energy system is simulated in an hourly resolution. The model features various energy carriers including electricity, hydrogen, biomass, gaseous and liquid hydrocarbons and district heating as well as sector-coupling technologies that link the different energy carriers. The period until the target year 2050 is modelled in 5-year steps starting from 2025.

To study the impact of different vRES expansion rates on the energy system, we design a European transformation scenario S6_MarketExp in line with the visions of the different stakeholders involved in the energy transition. The expansion of renewable energies in this scenario is fixed based on the capacities from the TYNDP 2024 scenarios "Best estimate" and "High", which take into account national expansion targets. To systematically quantify the impact of vRES expansion uncertainties, we vary the ramp-up of vRES capacities in comparison to the S6_MarketExp scenario after 2025. The variations range from -30 % total vRES expansion up to +30 % vRES expansion and further include variation of single technologies such as wind onshore. In the following, we focus on the -30 % and +30 % variation, which represent the more extreme variations within the analyzed solution space, in comparison to the S6_MarketExp scenario and a scenario with endogenous vRES expansion (vRESend). More details on the scenario definitions and techno-economic parameters such as investment and operating costs can be found in [3].

Results

Starting with the European hydrogen generation and provision, Figure 4.6 shows the hydrogen balance of the EU27+3 for the four focus scenarios from 2025-2050. The hydrogen load from the final energy carrier (FEC) sectors is the same for all scenarios and increases steadily until 2050. In scenarios with higher vRES capacity (+30 % and endogenous expansion), electrolyzers are utilized to cover the FEC sector hydrogen demand almost completely. Additionally, hydrogen storages are expanded, mostly comprising cavern storages as they are less expensive than above-ground tank storages. These storages are used to store hydrogen produced by electrolyzers in hours with electricity surplus from vRES and utilize the hydrogen for electricity generation in H₂-ready thermal power plants when electricity production from vRES is low. For lower vRES capacities, we observe higher imports from Extra-EU countries, as local hydrogen production through electrolysis is lower. In the -30 % scenario, hydrogen is furthermore produced through steam reforming as the cost-effective import potentials are exhausted. In the later years, steam reforming is combined with CCS to meet the GHG reduction goals.

The hydrogen prices are a model output of the hydrogen balance, where consumption and production need to be met at all hours of the year. These prices represent the lowest possible costs necessary to cover an additional MWh of hydrogen and can thus be interpreted as marginal costs of hydrogen production. Figure 4.7 shows the resulting hydrogen prices (mean hydrogen prices of the EU27+3 weighted by the hydrogen load per country) in the four focus scenarios. The prices generally depend on the cost

Hydrogen Balance in TWh

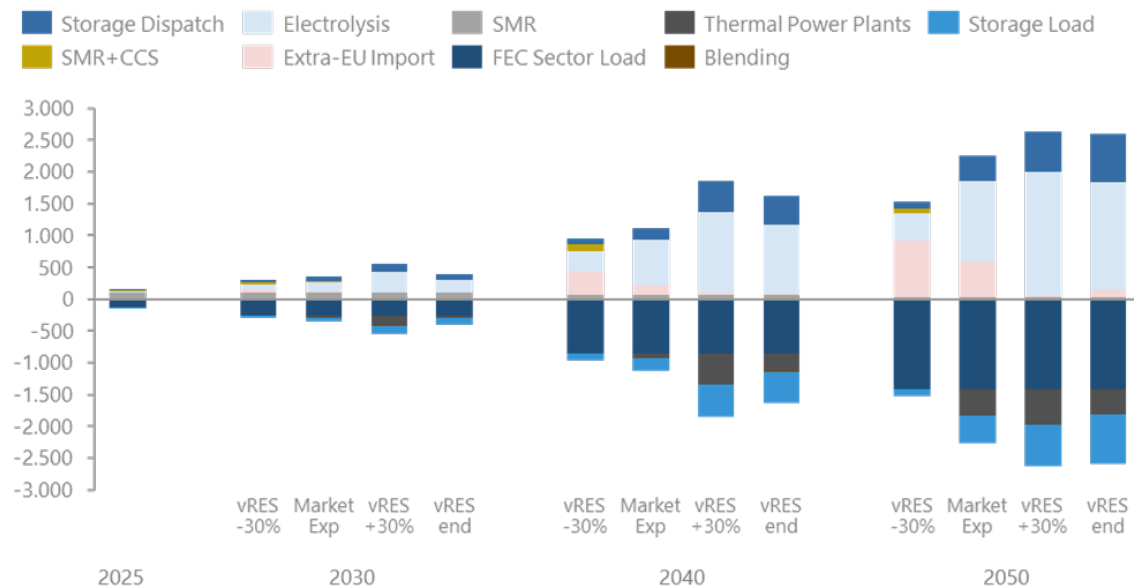


Figure 4.6. Hydrogen balance for the EU27+3 depicted for the four focus scenarios. The hydrogen generation and production need to be balanced for each hour.

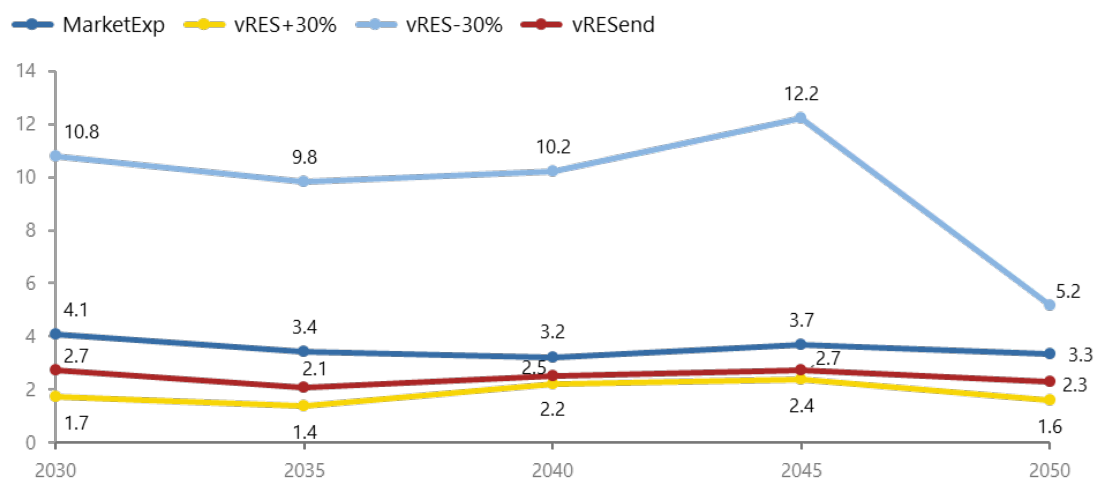
Load-Weighted Average Hydrogen Prices in the EU27+3 in €₂₀₂₃ per kg of Hydrogen

Figure 4.7. Average hydrogen prices in the four focus scenarios in €₂₀₂₃/kg.

of hydrogen production and imports compared to the uptake of the hydrogen demand from the final energy sectors. Thus, the prices towards 2050 do not linearly decrease, but show effects such as the phase-out of emissions allowed in the European emission trading system from 2040 onwards, which in turn leads to an increase in hydrogen prices. Finally in 2050, the transformation in the final energy sectors is almost complete, while vRES capacities further increase, relieving the energy system and yielding lower hydrogen prices.

The prices strongly vary depending on the vRES expansion. Especially, the scenario with very low vRES expansion (-30%) shows average hydrogen prices that are significantly higher compared to the other scenarios. In this scenario, only very little hydrogen can be produced through electrolysis. Additionally, SMR+CCS and the hydrogen import options are at capacity in order to cover the demand. Thus, more expensive options, such as importing green methane for deployment in thermal power plants to produce more electricity for electrolyzers, would be necessary to cover

more hydrogen demand, which leads to much higher prices than in all the other scenarios. Allowing endogenous vRES expansion (vRESend) yields prices, that lie beneath the S6_MarketExp scenario. In this scenario, the installed capacities of vRES can be freely expanded, yielding higher resulting capacities than in the S6_MarketExp, which allows for more electrolysis and consequently leads to lower prices. Even lower prices shows vRES+30 %. Here, however, the vRES capacities were not expanded freely to minimize the total system costs as in vRESend, but were exogenously fixed. While the hydrogen prices are lower due to more electricity generated from vRES, that can be utilized in electrolyzers, the total systems costs, including all operational and investments costs, are higher compared to vRESend.

In conclusion, our study of both delayed on accelerated vRES expansion highlights the relevance of a fast and considerable expansion of vRES. Failing to do so increases the dependency of hydrogen imports from extra-EU countries and thus leads to higher risks in terms of supply security through geopolitical and supply chain disruptions.

Moreover, a slower expansion of vRES causes higher hydrogen prices within the EU27+3 as more expensive hydrogen production options such as importing hydrogen or steam reforming with CCS are necessary to cover the demand while complying with the GHG-reduction goals. Altogether, the findings stress the need to prioritize and accelerate vRES expansion to ensure a robust and economically sound transition towards a carbon-neutral energy system.

4.4. How do alternative industrial value chains impact the energy system?

The transition to a low-carbon economy will likely induce fundamental changes in industrial production technologies and value chains in many sectors. Hydrogen can play a key role in the transformation to a net-zero industry sector, both as a fuel and as a feedstock (see Chapter 3). Particularly, the chemical industry and the steel industry can potentially require large quantities of hydrogen to replace fossil fuels. The production of high-value chemicals like ethylene (HVCs) and ammonia alone could require up to 1000 TWh of hydrogen by 2050 in the EU27 [24]. Primary steel production could add another 150 TWh if a major share of today's blast furnaces are replaced by direct reduction or iron ore. While the potential scale of hydrogen demand is enormous, the cost-efficiency of a fully domestic production is at least uncertain and highly depends on the future price of climate-neutral hydrogen.

This raises fundamental questions about how these industries will structure their future climate-neutral value chains and where they will localize which production step. Regions with favorable renewable energy conditions offer the potential for large-scale, cost-efficient hydrogen production, which could provide a competitive advantage in producing hydrogen-intensive products. At the same time, transporting hydrogen-based products such as hot briquetted iron (HBI), methanol or ammonia is relatively straightforward compared to gaseous or liquid hydrogen. This makes it feasible to establish global climate neutral supply chains where energy-intensive processing steps are located in regions with abundant renewable energy potentials, while further processing and product manufacturing take place in industrial centers in today's steel and chemicals sites. This global split of the supply chains has a large potential to improve cost efficiency of future climate neutral products and is referred to as "renewable pull" in the literature [30, 31]. Verpoort et al. assess the cost potential cost savings of importing intermediate products like HBI, methanol and ammonia for Germany and find large potential cost savings compared to a fully domestic production. From the perspective of hydrogen infrastructure planning, this brings a huge uncertainty regarding future hydrogen demand and infrastructure needs.

Here, we assess the impact of alternative industry value chains on the energy system and the resulting needs for hydrogen infrastructure. The results are based on the energy system analysis by [24]. We first run a detailed simulations model for the industry sector, which projects energy demand and CO₂ emissions as a result of technological change

in individual industrial processes.¹⁰ The projected energy demand is then used as input to the energy system model Enertile, which evaluates the broader implications for the energy system, including renewable energy deployment, and infrastructure requirements. To assess the impact of different value chain configurations on industry hydrogen demand and the energy system, we compare two scenarios:

1. **S1_NewIndVC:** Key energy-intensive intermediate products—sponge iron, ammonia, and methanol are largely imported, while further value chains remain in Europe.
2. **S2_ChemSteel:** The above mentioned products are produced in Europe at today's sites with climate-neutral hydrogen, while the hydrogen supply is left to the system optimization.

The results reveal significant differences in hydrogen demand and the reliance on imported methanol, synthetic naphtha, ammonia and further products between the two scenarios. By 2030, hydrogen demand is still relatively low in both scenarios but starts to increase as industrial sectors begin to integrate hydrogen into their processes. The difference between the two scenarios widens significantly towards 2050, with hydrogen demand in S1_NewIndVC reaching 227 TWh, whereas in S2_ChemSteel, demand rises sharply to 1355 TWh. In S1_NewIndVC, intermediate products are largely imported, reducing domestic hydrogen demand but increasing reliance on imports, which total 1,169 TWh by 2050. In contrast, S2_ChemSteel reduces the need for imports, with total imported volumes decreasing to 419 TWh, as domestic production covers a larger share of the demand. The breakdown of hydrogen demand in S2_ChemSteel shows that 1181 TWh is concentrated in three key industrial products. Specifically, 146 TWh is required for H₂-DRI iron production in the steel sector, 951 TWh is required for HVC and 85 TWh for ammonia synthesis (see Figure 4.8 and Figure 4.9).

The extent to which hydrogen demand is met by domestic production or imports introduces systemic uncertainties, as it directly affects infrastructure planning for transport networks, electrolysis deployment, and storage capacity. The chemical and steel clusters in North-West Europe, particularly North-Rhine Westphalia in Germany, Western Netherlands, and Flanders in Belgium, are among the most exposed to shifts in industrial hydrogen supply chains, with hydrogen demand in S2_ChemSteel exceeding 100 TWh in these regions by 2050.

If the entire value chain remains within Europe, these industrial clusters would primarily depend on long-distance hydrogen transport networks, increasing the need for pipeline infrastructure to accommodate large-scale hydrogen flows. The results indicate that hydrogen is transported from both northern and southern Europe to central industrial regions, with trade volumes varying significantly between the scenarios. In S1_NewIndVC, intra-EU hydrogen trade reaches 365 TWh by 2050, whereas in S2_ChemSteel intra-EU trade increases to 917 TWh. Electrolysis capacity requirements further differentiate the two scenarios. In S1_NewIndVC, electrolyzer capacity

¹⁰ A description of the model FORECAST is available in Fleiter et al. [32].

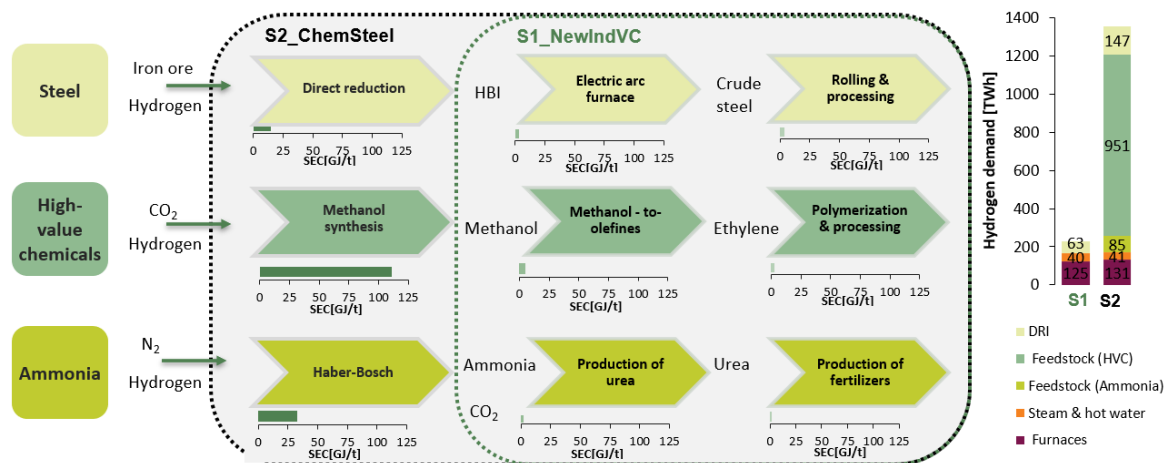


Figure 4.8. Scope, Final energy demand, and Specific Energy Consumption (SEC) of value chains for crude steel, High value chemical (HVC) and ammonia in the definition of scenarios S1 and S2.

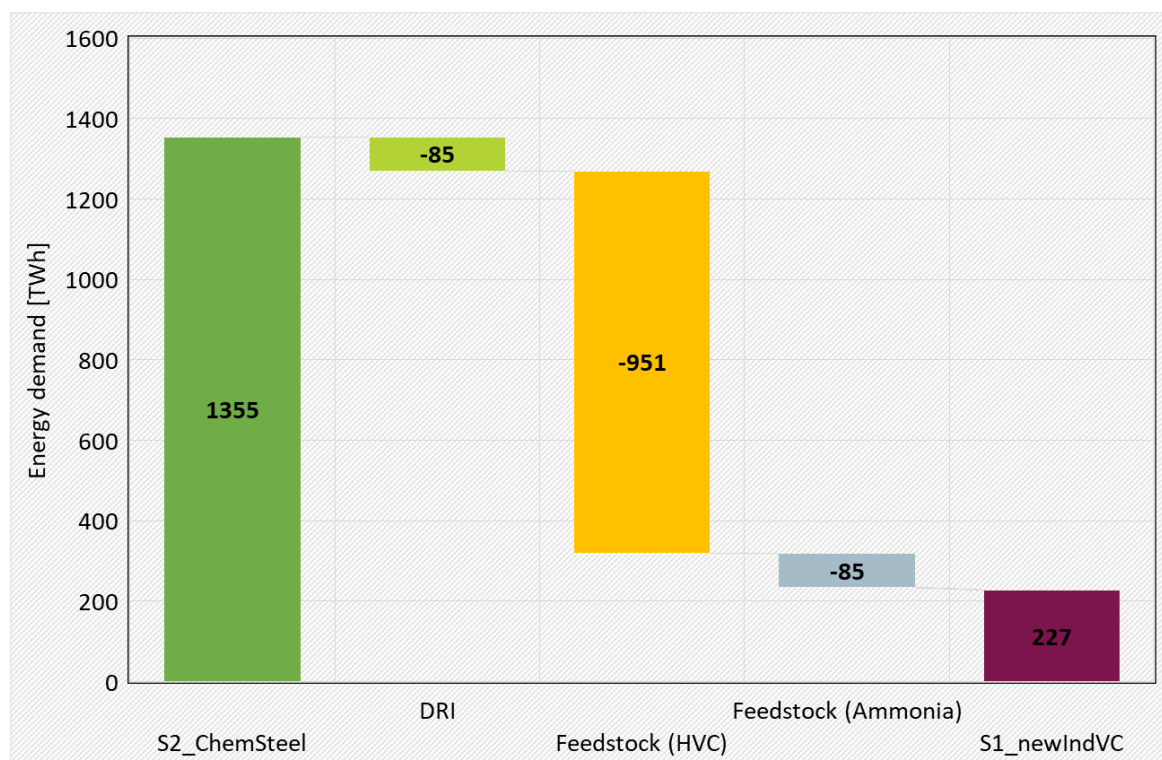


Figure 4.9. Hydrogen Demand comparison between S1 and S2 illustrating the difference by value chain.

reaches 662 GW by 2050, whereas in S2_ChemSteel, it expands to 992 GW, aligning with the higher domestic hydrogen production required in this scenario.

Infrastructure requirements also vary significantly. The moderate electrolysis deployment in S1 reduces the need for domestic hydrogen pipelines and storage systems, as hydrogen is primarily imported in the form of intermediate products. In S1_New IndVC, the main infrastructure requirement arises from the need for import terminals, storage facilities, and logistical hubs to handle hydrogen-based imports. In S2_ChemSteel, the infrastructure requirements shift toward electrolysis expansion, and an extensive European hydrogen transport network. The higher electrolyzer capacity (992 GW) necessitates significant expansion of renewable energy generation, with total installed renewable energy capacity reaching 6546 GW, compared to 5693 GW in S1_New_IndVC (see Figure 4.10).

4.5. Supply options for the steel industry in Germany?

Steel is one of the fundamentals of a highly industrialized society and, therefore, one of the most important industrial products worldwide. Germany is the largest steel-producing country in Europe. The production of crude steel via the established blast furnace/basic oxygen furnace route nearly completely relies on the import of the necessary raw materials coal and iron ore. The latter one is generally imported from countries like Sweden, Canada, Brazil, and Australia. In the course of the transition of the industrial sector, steelmaking with reduced CO₂ emissions is gaining increasing importance. Frequently discussed is the application of the direct reduction process [33]. Here, pelletized iron ore is reduced with natural gas or hydrogen. The produced direct reduced iron (DRI) is converted into crude steel in an electric arc furnace (EAF). The resulting value chain starting from iron ore mining is given in

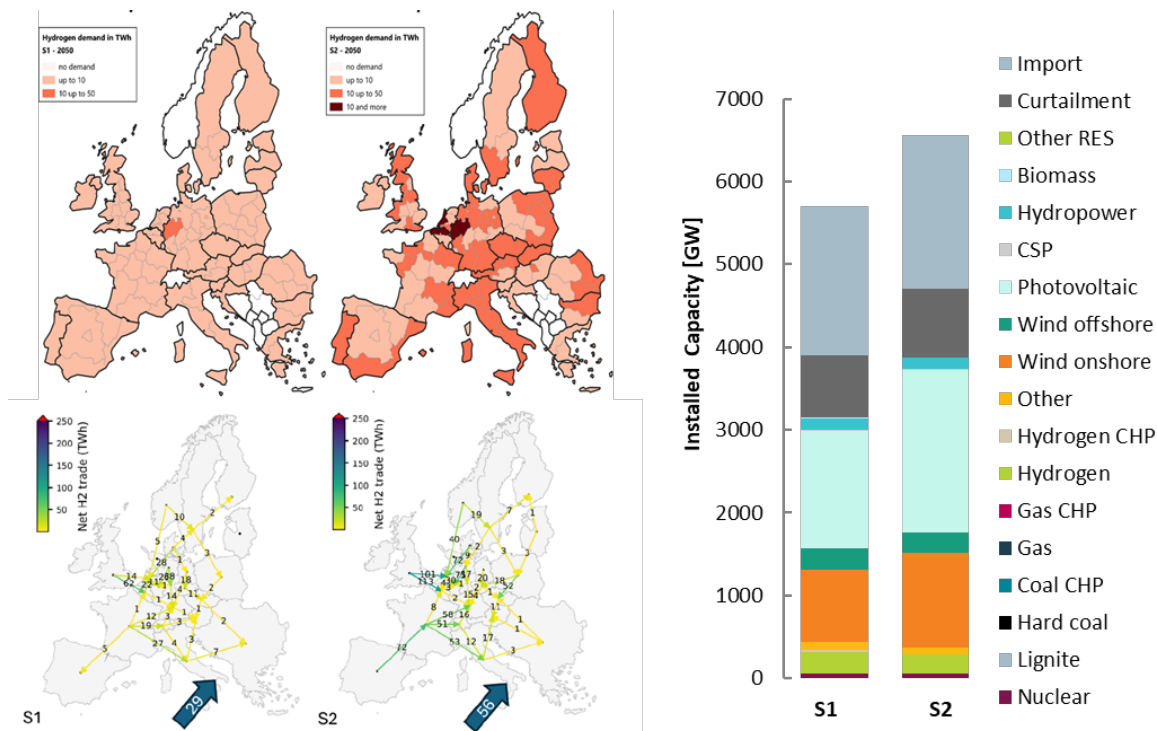


Figure 4.10. Hydrogen demand and hydrogen trade and installed capacity by source by 2050.

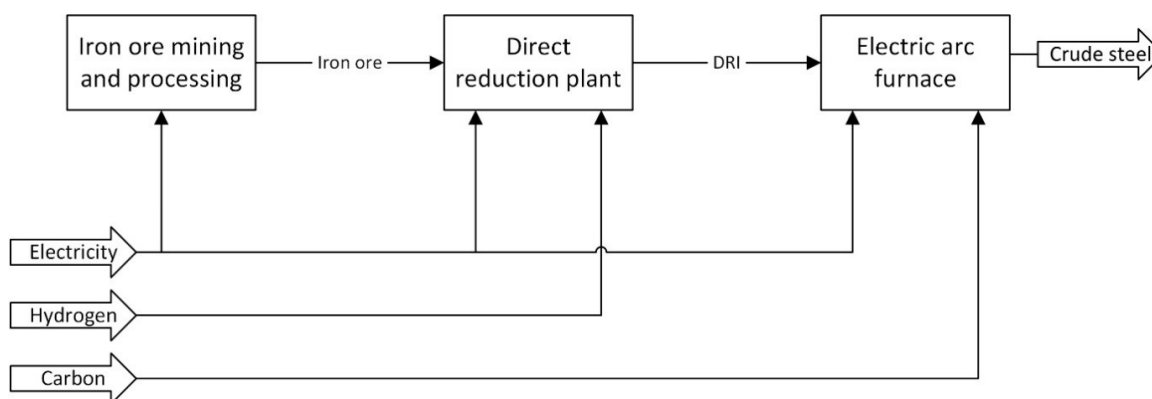


Figure 4.11. Value chain for green steelmaking based on direct reduction with hydrogen.

Figure 4.11.

For the transition towards climate neutral steel mills using the DRP/EAF route hydrogen is necessary in large quantities at the respective sites. As the renewable energy potential of Germany is limited, import of hydrogen is an important option to be assessed in the course of developing a roadmap for the transition of the steel sector. At the same time, there is the challenge that the supply and the infrastructure, in particular the hydrogen production plants, the hydrogen transport system and the hydrogen storage facilities, for climate-neutral gases still have to be established. Many studies investigate the import options of hydrogen from a country perspective and neglect e. g. the domestic transport or the condition of the respective applications. Given this background, a case study addressed the question: What are the supply options for a domestic steel plant with its own hot metal production, especially if a hydrogen network has not yet been established?

The case study is the Salzgitter steelworks, which is actively involved in the SALCOS® project to gradually replace conventional primary steel production with a direct reduction (DR) process using hydrogen. [34] The focus on this study is the investigation of different supply options including onsite electrolysis, importing synthetic natural gas (SNG)

via the existing natural gas infrastructure, methanol and ammonia. Both, ammonia and methanol, have been considered as hydrogen carriers that cannot be used directly in the steelmaking process and thus have to be reconverted to hydrogen. As the reversion step of cracking the ammonia, respectively reforming the methanol into hydrogen is an energy intensive step, two sub-scenarios have been considered. First, the reversion process is done directly after the import at the port and the resulting hydrogen would be transported by pipeline (central case). Second, the ammonia and methanol are transported directly to the industry site and the reversion is done onsite (decentral case).

There are large differences in literature when considering conversion efficiencies. Drivers are the system condition for the energy required for conversion processes was obtained from the energy carrier itself (e. g. autothermal processes) or from external sources (e. g. heat or renewables). It is important to fully account for all energy flows, as the substitution of fossil fuels by the respective alternative supply options involves a more complex upstream chain with various conversion processes, whose incomplete accounting would distort the consideration of the transformation. This can be illustrated by the example of direct

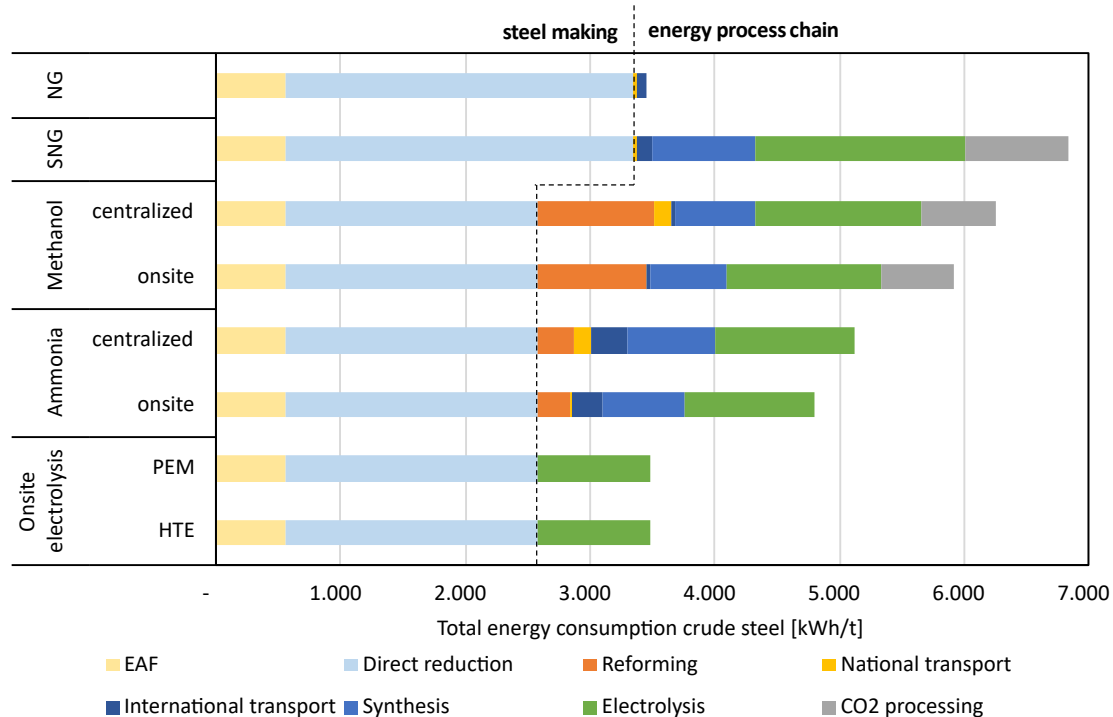


Figure 4.12. Final energy demand of crude steel production for different energy carriers.

reduction. In the simplest case, the required hydrogen is obtained by electrolysis of water at the production site, where the PEM (Proton Exchange Membrane Electrolysis) and HTE (High Temperature Electrolysis) processes can be compared. Looking only at the electrical energy required, HTE has a significantly higher efficiency, which may suggest a lower energy requirement for steel production. However, in the case of HTE, the electrical energy saved is provided by heat, so that both electrolysis processes require approximately the same amount of energy overall. An energy gain in steel production can therefore only be achieved if the HTE is fed with unused waste heat on site.

The particular added value of this case study therefore lies in analysing all the relevant energy flows in the process chain as precisely as possible in order to obtain a differentiated perspective on the environmental and economic aspects of the Salzgitter steelworks. The data is based on publicly available sources. In many areas, reference is made to the comprehensive compilations of [35].

The total energy demands for the different supply options shown in Figure 4.12 follow the value chain upwards from left to right. As the DRI has to be melted in the EAF regardless of the direct reduction process, all options have the same melting energy. However, there are already differences in direct reduction, as direct use of hydrogen is more efficient than reduction with natural gas or SNG. Methane must first be reformed internally to CO and H₂ before it is reactive, so additional energy is required. The energy chain consists of possible reconversion of the hydrogen carrier, national and international transport, synthesis of the energy carrier molecule, hydrogen electrolysis and possible processing of CO₂. The balancing logic shows the energy demands, including auxiliary energy, for each step. If this results in higher hydrogen production requirements, for example because molecules are lost during transport, this additional need is shown with the electrolysis. In other words, energy losses are tracked along the process chain

and allocated to each step to balance the processes. The shorter the process chain, the lower the efficiency losses, which is why the onsite electrolysis options show the lowest total energy demand alongside the natural gas reference case. Among the H₂ carrier molecules, SNG has the highest total energy demand, although savings can be achieved by using it directly in the DRP. This is partly due to the assumption that SNG is used as a material energy supplier at several points in the process chain, e.g. as a fuel for ship transport, while the other supply options only use fossil auxiliary energy. This means that the production of the auxiliary energy is included in the upstream chain and increases the total energy demand. Despite this difference with methanol and ammonia, the upstream chain of NH₃ is more efficient, resulting in a lower total energy demand. It should be noted that centralized cracking or reforming of NH₃ and methanol requires significantly more energy than on-site reconversion. The very energy-intensive transport of H₂ offsets the energy savings of a centralized, larger and therefore more efficient reconversion plant of the carrier molecules, even over short national transport distances.

In the absence of a hydrogen network, NH₃ supply appears to have an efficiency advantage. In the long term, however, this will change in favour of direct supply of H₂, regardless of the electrolyser process used. Direct on-site generation would be preferable, although the available renewable electricity generation capacity usually requires more distant sites connected by pipeline. The emission analysis comes to similar conclusions and reinforces these views, as a short efficiency chain is generally associated with a short upstream emission chain. For carbon-based energy sources, the transport of carbon back to create a circular economy also plays a role. However, in the case of efficient direct carbon capture from air at the production site of the carbon-based energy carrier, a balance with the emission source at the demand site should be sufficient and make return transport unnecessary. Estimating costs

is difficult, especially in the start-up phase with different existing infrastructures, as an efficient market cannot yet be assumed and project costs can therefore vary widely. In principle, however, costs are based on the energy required. Higher losses in the supply phases also lead to higher costs, as these have to be compensated by higher infrastructure capacities at the beginning of the supply chain. This does not fundamentally change the previous assessment of energy carriers. However, it should be considered that the infrastructure for e.g. SNG is largely in place and therefore cost advantages can be achieved as long as other infrastructures need to be built and their utilisation rates increased.

Besides importing hydrogen or hydrogen carriers as well as iron ore for the operation of the entire DRP/EAF route in Germany, the import of DRI is also a viable option to be assessed. In contrast to hydrogen, DRI can easily be transported in bulk carriers in form of hot-briquetted iron (HBI). As many iron ore-mining countries also offer a high potential for renewable electricity generation, the realization of hydrogen production and direct reduction in these countries could offer advantages. The different scenarios regarding localization of the process steps of green steel-making were evaluated from a technical and economical perspective.

In order to understand the implications of the different scenarios, a deeper look into the process chain is necessary. The DRP/EAF process is already established on an industrial scale based on natural gas as reducing agent for iron ore [36]. As the production costs are heavily dependent on the availability of cheap natural gas, the existing plants are generally built close to existing natural gas resources. Therefore, already in the state-of-the-art process based on natural gas, iron ore mining and direct reduction are most often decoupled. However, direct reduction plant and electric arc furnace are often operated close to each other. The reason is an improved thermal integration. The DRI leaves the shaft furnace of the DRP with 600–700 °C and it is possible to feed this hot DRI (HDRI) directly into the EAF. The alternative would be hot briquetting and cooling of the produced iron. Thus, in case DRP and EAF would be operated at different locations, the same is to be expected for the hydrogen-resulting HBI would need to be reheated in the EAF causing an additional energy demand. This influences the overall energy demand of the steelmaking process. In order to compare the energy demand of the available options, four different scenarios were defined, given in Figure 4.13.

For all scenarios it was considered that the final process step, the production of crude steel in the EAF, is situated in Germany, as molten steel is necessary as input material for secondary metallurgy. For Scenario 1 the DRP is placed in close proximity to the iron ore mine, while for Scenario 2 it is situated at the coast of the iron ore mining country. These two scenarios potentially differ in availability of electricity and water for hydrogen generation as well as in workforce potential. If the DRP is constructed in Germany, in general, also two options result. The first would be to place the DRP at the German coast, close to a port (Scenario 3). This would offer some advantages. If hydrogen for the DRP is to be supplied via electrolysis, this region offers the highest potential for renewable energy generation as well as a good availability of water. Also, if imported hydrogen is considered, this region would ensure short transport distances from the port. For Scenario 4 the DRP is operated directly at the steel mill. This is close to the current situation, where the relevant steps of primary metallurgy are implemented at the same site. Scenario 4 is the only scenario, where the above-described heat integration between DRP and EAF can be realized.

Regarding the technical dimension of the assessment, the energy demand for crude steel production via the four different scenarios was calculated. In this context, for all process steps from mining via transport to actual steel-making the energy demand for a CO₂-free realization was calculated, reflecting the long-term future transition of the whole value chain. For example, for ship transport the electric energy demand of fuel production for an ammonia-fuelled ship was considered. The results of the comparison of the different scenarios are given in Figure 4.14.

The comparison shows that the overall energy demand is comparable for most of the cases. For Scenario 4 the electric energy of the EAF can be reduced in comparison to the other scenarios, as discussed above. In contrast Scenarios 1 and 2 offer a reduced energy demand for ship transport. This is due to the lower mass of reduced iron in comparison to iron ore pellets. This effect is of course most relevant for the Australian case considered in Figure 4.14, as the transport distance was the highest among the considered countries. Scenario 3 consequently showed the highest energy demand as none of the advantages of the other scenarios applied.

Having in mind that from a technical perspective also other factors are of importance (e.g. water supply, availability of electricity, land and workforce), the negligible differ-

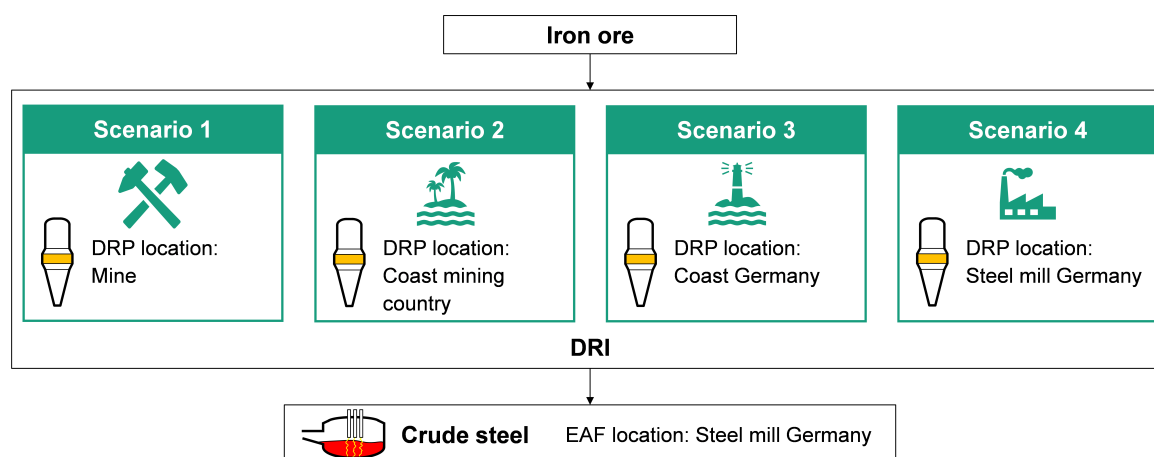


Figure 4.13. Overview on the considered scenarios.

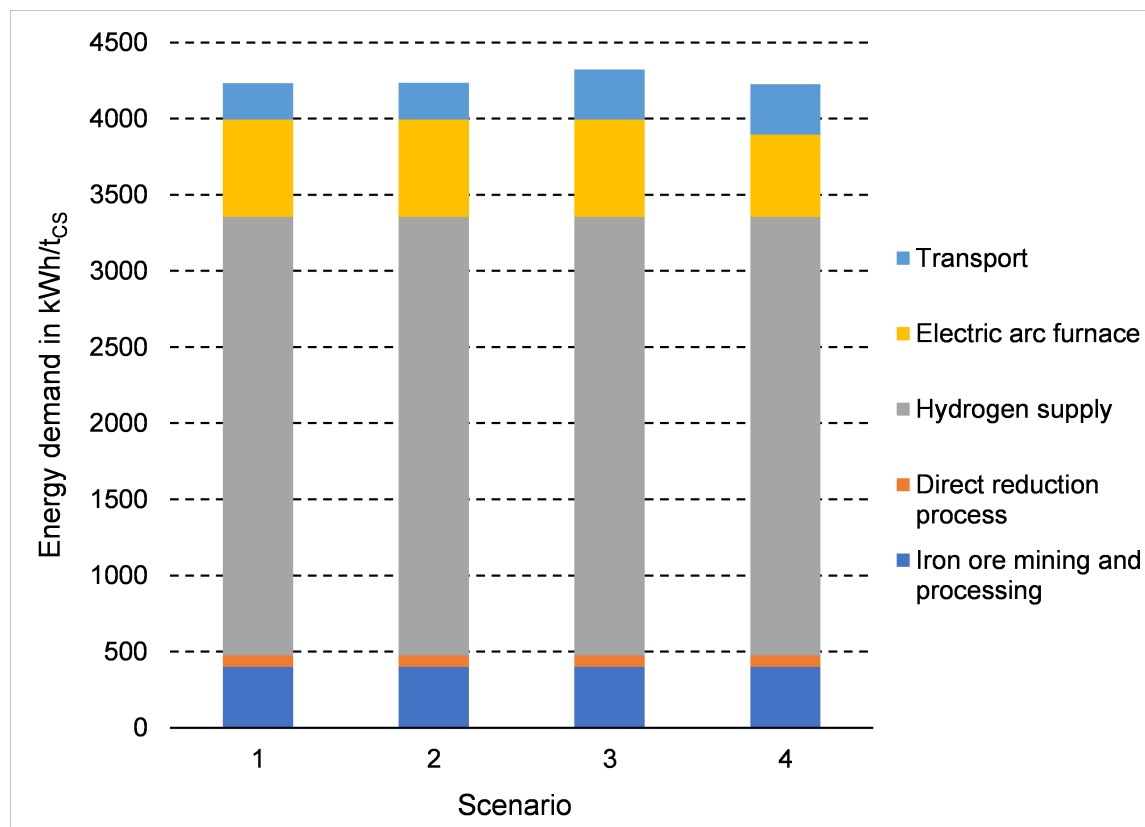


Figure 4.14. Comparison of Scenarios 1–4 for Australia as the iron-ore mining country.

ence between the energy demands given in Figure 4.14 do not allow to identify a preferred option solely on this basis. The more relevant factor are the process economics. However, the difference between the different scenarios can already be assessed qualitatively on the basis of the data given in Figure 4.14. The by far largest fraction of electric energy is to be supplied for hydrogen production. For all considered countries costs for renewable energy or hydrogen generation are expected to be lower than in Germany. So, from an economic perspective, the direct import of DRI in form of HBI would be advantageous in comparison to the production in Germany. The results presented above are based on the assumption that hydrogen is produced at site of the direct reduction plant. However, as transport of hydrogen – and potentially reconversion of hydrogen – are expected to have higher costs than the transport of DRP, the same conclusion can be drawn for imported hydrogen. The import of DRI in form of HBI would not only reduce costs but would considerably reduce the demand for renewable energy or imported hydrogen. This would, of course, be a change to the current situation, where all steps of primary metallurgy are realized in Germany. Therefore, this option would also need to be assessed from an industrial policy perspective. However, the resulting decrease in production costs of green steel from Germany would increase international competitiveness.

5

Hydrogen infrastructures

To answer questions regarding hydrogen network infrastructures, transitioning from energy system models to energy network models is necessary and consequently the complex interconnections within energy infrastructures need to be captured. Network models represent key components—such as energy sources, technologies, and demand sectors—as nodes, while edges illustrate their relationships and energy flows. These models serve diverse purposes, from high-level political decision-making to detailed technical and economic analyses for network operation and control [37]. When network development paths based on existing topologies are analysed, ensuring the simultaneous security of supply for both natural gas and hydrogen is crucial. This requires a foundational “base topology” of the existing methane transport network, incorporating theoretical pipeline repurposing and ongoing infrastructure projects [38]. A network topology for the existing methane network based on the “System Capacity Map 2024” of ENTSO-G complemented with additional information can be found on <https://nemosys.de/>. Additional information can be found in [39].

Within this project, a potential future hydrogen infrastructure is developed based on the existing methane network through a combination of automated and manual method. To answer the questions of this chapter, hydrogen topologies are either based on planned projects like the German hydrogen core network, optimization models or graph algorithms.

5.1. What transport capacity can be expected by the approved German hydrogen core network?

A Germany-wide, efficient and quickly realizable hydrogen core network is to be built for an expandable hydrogen ramp-up. As a hydrogen infrastructure is both essential and a matter of course for Germany’s climate neutrality and security of supply, the German transmission system operators submitted a joint application for the hydrogen core network to the Federal Network Agency in July 2024. [40, 41] The approved hydrogen core network from October 2024 includes a total of 9040 km with a new construction share of 44 %. Including the compressor stations, the investment for the network should be around 18.8 billion euros, which should be completed by 2032 and connect all federal states. The planning for the pipeline sections, which are to be completed by the end of 2027, is enshrined in the energy industry act (§ 28q (8) [42]. These pipeline sections have a total length of around 2,200 km. In 2030, the hydrogen core network will reach a length of around 6,250 km [43]. Figure 5.1 shows the regional development of the hydrogen core network.

As a starting point for the German hydrogen core network and the identification of the relevant connected regions, the transmission system operators defined a scenario based on the hydrogen market partner survey conducted as part of the Gas Network Development Plan 2020-2030. The potential market partners of the transmission system operators (producers and consumers of hydrogen) were asked whether or how much hydrogen connection capac-

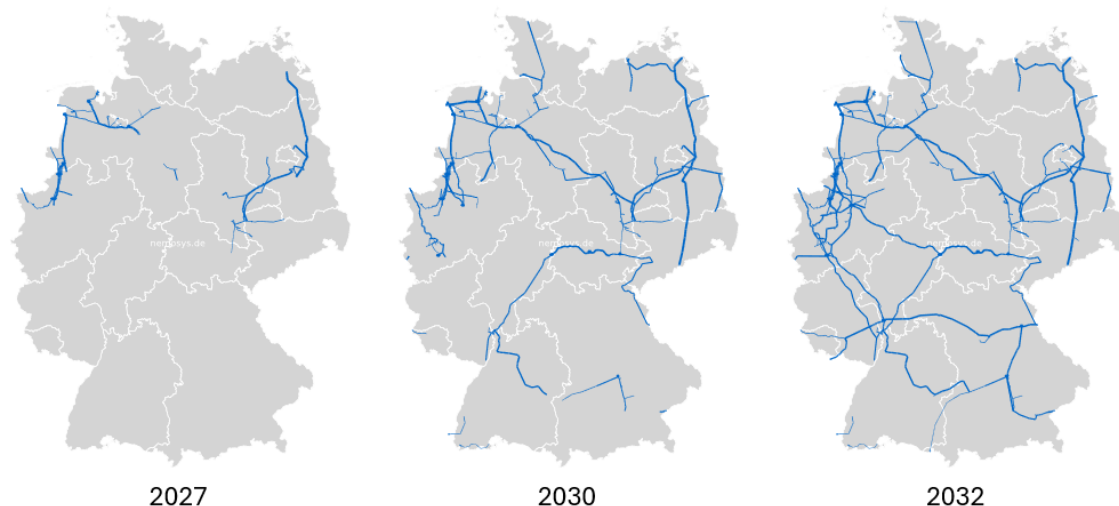


Figure 5.1. Regional development of the Hydrogen Core Network (TUB ER, 2025).

ity they would need in the future [40]. The scenario on which the joint application for the hydrogen core network is based was completed on this basis with more up-to-date project information and hydrogen strategies from the federal states and adjusted for projects that were no longer being pursued in 2023 according to the transmission system operators' state of knowledge [44]. The core network therefore considers the needs of power plants and energy-intensive industries such as the iron & steel, chemical, glass and ceramics industries and refineries on the demand side. On the supply side, there are onshore and offshore electrolysis projects, cross-border interconnection points and other entries, which include imports via marine terminals where hydrogen can be landed in various forms like liquid hydrogen, ammonia or methanol. In addition to Important Projects of Common European Interest (IPCEI), the scenario also includes Projects of Common European Interest (PCI), real-world laboratory projects funded by the BMWK and projects that are intended to serve the European integration of the hydrogen core network in the future [44]. An overview of the supply and demand projects of the hydrogen core network scenario can be found in Table 5.1 and Table 5.2 [45].

On the supply side, in addition to imports from 10 countries, German demand is covered by domestic production through electrolysis and other supplies via shipping terminals, including in the form of LOHC and ammonia. In the approval process for the German hydrogen core network, the network was validated in terms of fluid mechanics using the specified scenario data.

The assessment of the capacity of the approved hydrogen core network requires comprehensive testing of the network and its validation with more demanding scenario data [38]. The basis for this validation is the detailed reconstruction of the hydrogen core network based on publicly available data from the German transmission system operators (TSOs), the Federal Network Agency (BNetzA) and the "base topology". The methodological approach is based on [38]. Further details on the creation of the network topologies and the modeling of the core network are documented in the first flagship publication [4].

As part of our analysis, the reconstruction of the hydrogen core network was validated in terms of fluid mechanics not only with the scenario of the transmission system operators (TSOs), but also with the TransHyDE scenarios. The S2_ChemSteel scenario was selected for a representative re-

Table 5.1. Demands of the hydrogen core network scenario (based on the hydrogen core network application of July 2024).

	Exit capacity (GW _{th})	Exit quantity (TWh _{th} , gross calorific value)	Areas of application & Explanations
IPCEI, PCI and real laboratory projects	10.3	49	
Iron & steel industry	7.8	50	Crude steel from primary route, heating and annealing furnaces, forming technology
Chemical industry	5.2	32	Ammonia synthesis, basic chemistry
Refineries	4.2	30	Desulphurization, hydrocracking, e-kerosene
Glass industry	0.4	2	Continuous melting of container and flat glass
Ceramics industry	0.2	1	Medium and large production sites
Power plants	62.0	157	Power plants with more than 100 MW _{el} (approx. 235 MW _{th} thermal firing capacity) according to the BNetzA's "Market Master Data Register"
Storages	7.6	11	Storage locations with IPCEI funding
Total	86.5	279	Double counting of projects possible

Table 5.2. Supply capacities of the hydrogen core network scenario (based on the core network application of July 2024).

Supply capacity (GW _{th})		Areas of application & explanations
Border crossing points		
North Sea	2.0	
Norway	5.0	AquaDuctus (Offshore)
Netherlands	11.7	Oude Statenzijl/Bunde and Vliegghuis
Belgium	3.8	Eynatten
France	8.5	Medelsheim, Freiburg
Austria	6.3	Überackern
Czech republic	6.0	Waidhaus, Deutschneudorf
Poland	2.8	Oder-Spree, Uckermark
Denmark	14.3	Bornholm, Lubmin
Electrolysis	15	The National Hydrogen Strategy's target of 10 GW in 2030 and subsequent ramp-up considers
Storage	7.6	Storage locations with IPCEI funding
Other supplies	19	Imports via ship terminals in the form of LOHC and ammonia, among others
Summe	101	

view of the network capacity, as it places a special focus on energy-intensive industrial sectors and takes power plants into account. The underlying scenario data comprises supply and demand volumes for a total of five simulated years. The years 2030 and 2045 were used as test cases for our investigations, as they represent the widest possible and most realistic range of potential future developments. An overview of the specific demand volumes of the individual scenarios is shown in Table 5.3.

Table 5.3. Comparison of offtakes of maximum load hours in different scenarios [24, 46].

Scenario	2030 (GW)	2032 (GW)	2045 (GW)
S1	24	-	149
S2	26	-	171
S5	42	-	192
H ₂ Core Network	-	87	-

These simulated years can be broken down into individual hours for a detailed investigation of the interesting or particularly challenging network usage cases. In particular, the hours with the highest cumulative hydrogen demand across all sectors are identified and analyzed to investigate the “*Dunkelflaute*”, potential periods with minimum RE production and therefore maximum hydrogen demand in power plants. The following table shows an overview of the offtakes of the maximum load hours of different scenarios. A comprehensive documentation of the methodology for the temporal and spatial resolution as well as the allocation of the scenario data is available in [38]. Figure 5.2 shows the results of the spatial allocation of the maximum load hours for the base years 2030 and 2045, which serve as the basis for further simulation-based investigations.

The peak load hour of the S2_ChemSteel scenario reaches a maximum offtake capacity of 26 GW in 2030, which corresponds to around 30 % of the total offtake

capacity of the core network scenario. As the hydrogen core network was designed for a more demanding scenario, the validation of the *Dunkelflaute* situation in 2030 takes place within the physical limits of flow velocity and pressure level. Due to the low network load, hydrogen transport in this scenario can even take place without the use of active compressor stations, if hydrogen is imported via border crossing points at around 45 bar.

A fluid-mechanical validation of the approved hydrogen core network with the S2_ChemSteel scenario data is possible up to an offtake capacity of around 110 GW while maintaining the physical limits of pressure and speed in the hydrogen transport network - including the compressor stations. For the year 2045, the maximum offtake capacity in the *Dunkelflaute* situation of the S2 scenario increases to 171 GW. A simulation and validation of this network usage case with the existing hydrogen core network shows that the physical limits of fluid mechanics are exceeded, particularly in north-western Germany. However, it would be possible to comply with these limits through additional line capacities and targeted network expansions. Since the core network is designed for the year 2032, it is to be expected that it does not seamlessly accommodate a later network usage case in 2045. Figures 5.3 and 5.4 provide an overview of flow rates and pressure levels of the pipelines in both simulated years.

5.2. How could a feasible transition path for the European natural gas infrastructure to green hydrogen look like?

Preliminary concepts for a European hydrogen infrastructure have been developed through energy system modeling. However, many of these plans lack transparency regarding their methodology and underlying data. Additionally, due to the low temporal and spatial resolution of these

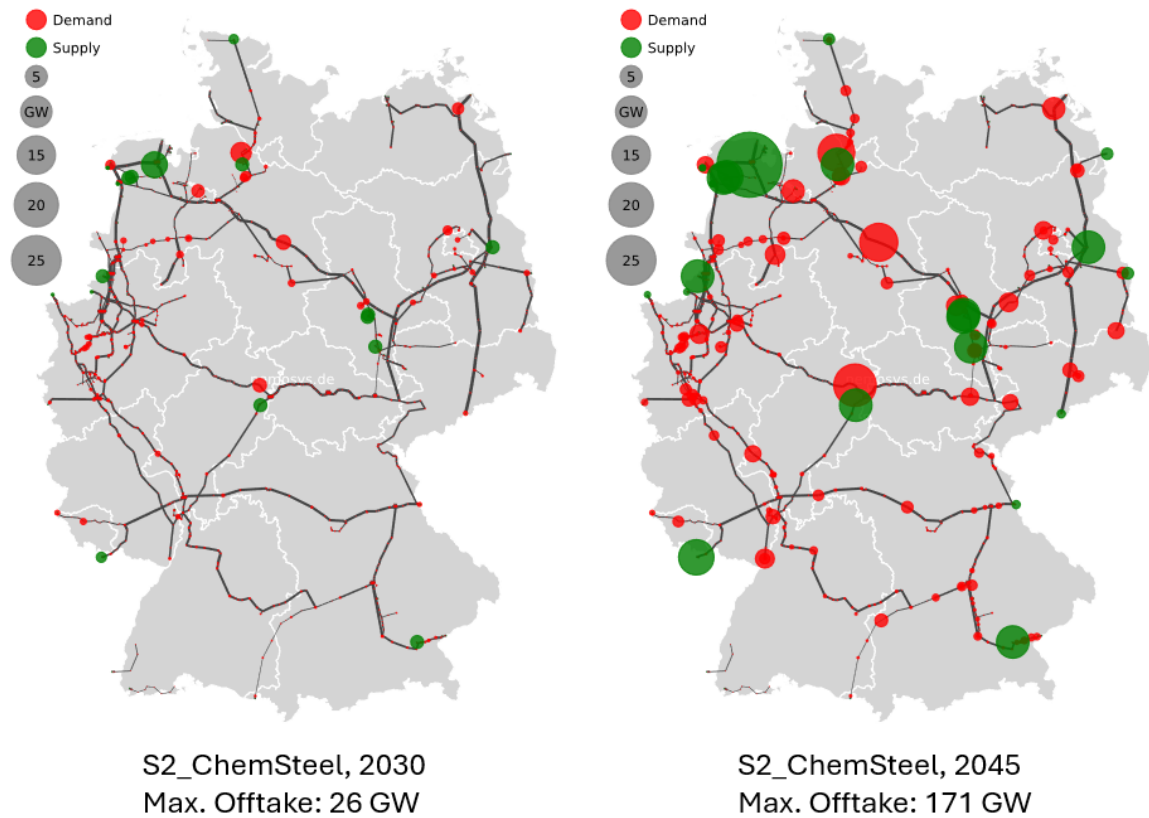


Figure 5.2. Spatial allocation of the maximum load hours of the simulated years (TUB ER, 2025).

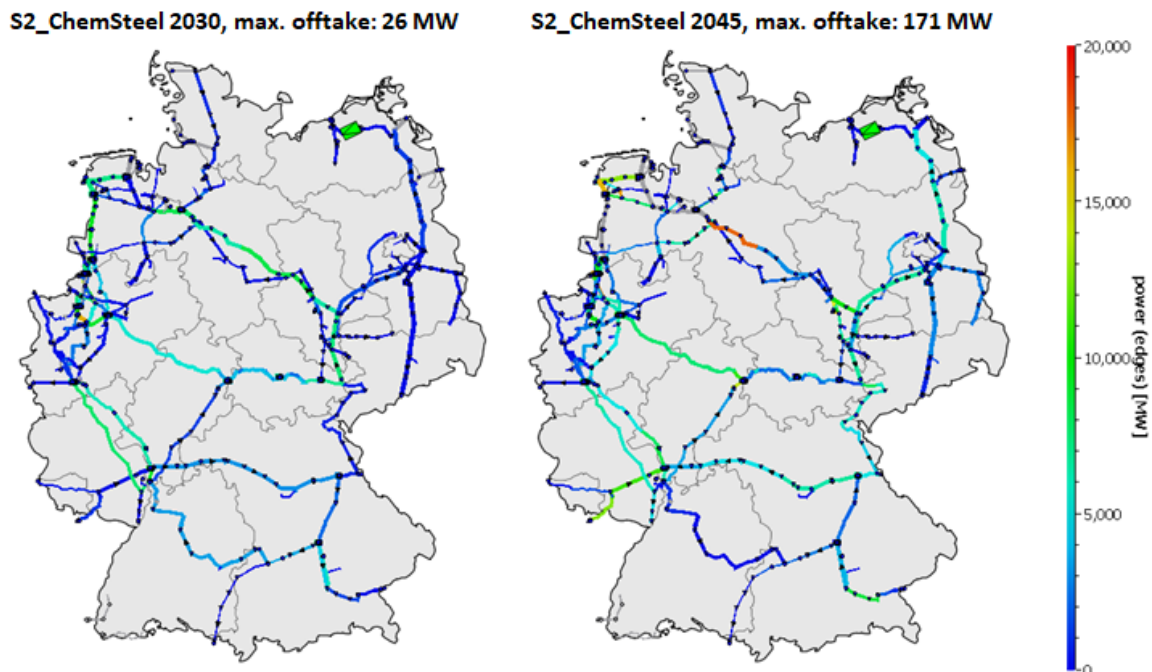


Figure 5.3. Flowrates in fluid dynamical simulation for both simulated years of S2_ChemSteel scenario (MYNTS, Fh SCAI).

models, they provide only limited insights into the actual development of pipeline infrastructure. While some studies have examined network constraints between European regions by integrating market and network analyses, clear hydrogen network expansion pathways are still missing. The following paragraphs are based on a study by [39].

Our methodological framework [37, 38] enables the optimization of hydrogen infrastructure by leveraging the existing natural gas network. By repurposing natural gas pipelines for hydrogen transport and constructing new hy-

drogen pipelines, the goal is to meet future hydrogen demand while ensuring the continued security of natural gas supply. This approach allows for high-resolution spatial and temporal modeling. Consequently, a possible expansion pathway for the European hydrogen transport network for the years 2030, 2040, and 2050 using the Steiner tree algorithm was modeled, ensuring a high level of spatial and temporal resolution. Based on data from the “S2_ChemSteel” scenario of the TransHyDE project, hydrogen supply and demand data were further spatially disaggregated. The re-

S2_ChemSteel 2030, max. offtake: 26 MW

S2_ChemSteel 2045, max. offtake: 171 MW

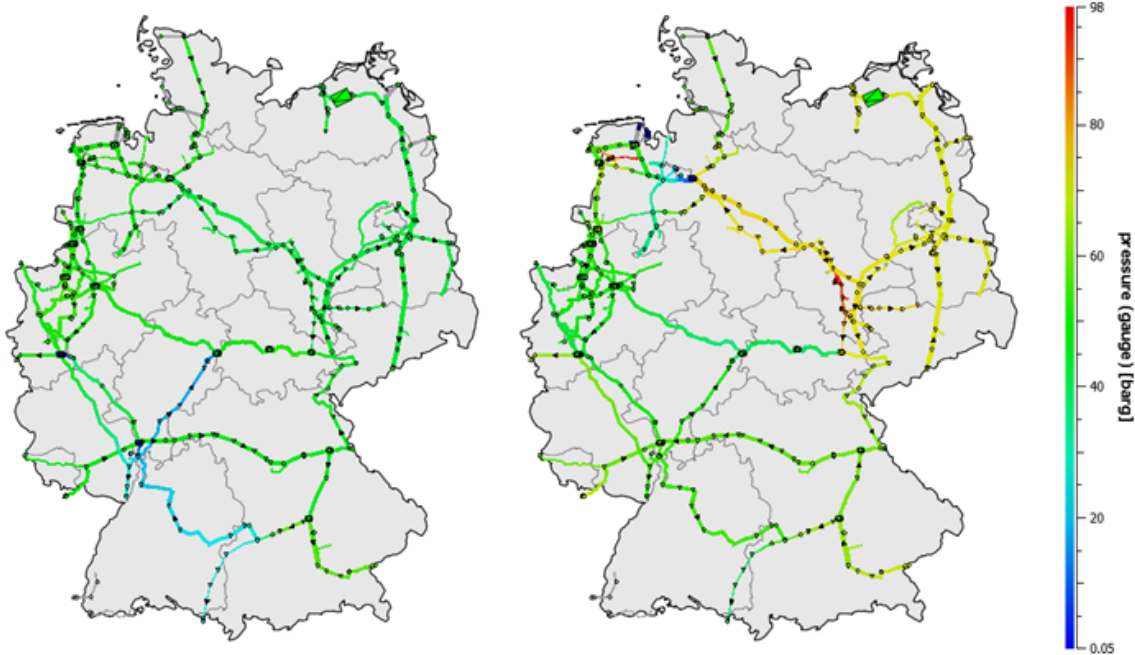


Figure 5.4. Pressure in fluid dynamical simulation for both simulated years of S2_ChemSteel scenario (MYNTS, Fh SCAI), the values lie in the range of 15 to 60 bar (2030) and 12 to 98 bar (2045), which demonstrates that the core network, designed for 2032, cannot.

sulting high-resolution hydrogen network topology serves as the foundation for fluid-dynamic simulations, providing a more realistic representation of the European transport infrastructure's future design.

To ensure reliable modeling of hydrogen infrastructure, results must align with recent developments. Various reports and studies show the slow adoption of hydrogen and implementation gaps limiting infrastructure expansion, with many projects being unrealized. Current network plans rely on projections rather than market needs, risking overinvestment and underutilization. Consequently, a phased, market-driven approach is recommended.

For this study, in 2030, the Steiner tree algorithm models only northwestern Germany, the Netherlands, and Belgium, aligning with ACER's assessment of key hydrogen regions until 2030. While growth will also continue elsewhere, a fully interconnected European network by 2030 remains unlikely. The herein applied algorithm optimizes for shortest paths, creating a minimum spanning tree with single-line connections. While suitable for fluid-dynamic simulations, the lack of redundancy may challenge real-world reliability.

To ensure the hydrogen network is properly dimensioned, the peak load network usage case is identified, and an iterative approach is used to detect and resolve bottlenecks. The European-scale network requires configuring compressor stations and other active elements, which are strategically placed in 2030, 2040, and 2050. A divide-and-conquer strategy simplifies the network by splitting it at compressor stations, treating them as virtual sources or sinks. An initial simulation with a 10% flow correction factor determines flow patterns. Since minimum spanning tree networks lack meshing, a single valid flow pattern is derived. Compressor stations are closed during this step, allowing the network to be solved in trivial subnetworks with predefined pressure settings. A global configuration is created by assigning a defined pressure to the lowest pressure sink nodes, ensuring safe pressure levels throughout the network. A final simulation checks for bottlenecks,

identifying excessive pressure drops that may require additional pipelines or compressor stations. This process is repeated iteratively until the network is stable and meets peak load requirements efficiently.

Figure 5.5 illustrates the gradual expansion of the hydrogen network over time and contains the additional pipeline connections determined by the iterative process. In 2030, the network is limited to northwestern Europe, covering regions in Germany, the Netherlands, and Belgium. By 2040, the infrastructure expands significantly, extending across the EU25+3 region and connecting a broader range of demand and supply centers. By 2050, the network evolves into a comprehensive, interconnected system, integrating additional regions to support increased hydrogen transport and distribution.

The hydrogen networks with manual adjustments span around 3,180 kilometers in 2030, with 3,060 kilometers being repurposed pipelines and 120 kilometers newly built. Until 2040 a significant expansion of the network takes place spanning all over Europe with around 38.000 kilometers and a share of repurposed pipelines of 98 %. By 2050 the hydrogen network has a length of 52.900 kilometers with 1500 kilometers being newly built.

Figure 5.6 shows the fluid-dynamic simulation results for the modeled European hydrogen network for the year 2040. A detailed description of the topology development, the scenario data allocation and the fluid-dynamic simulation results for the years 2030, 2040 and 2050 for the hydrogen and the methane network can be found in [39].

5.3. What infrastructure is needed in addition to the EU hydrogen backbone?

The future demand for hydrogen in Europe will be met through a combination of imports and domestic electrolysis. To ensure a steady supply to end consumers, it is crucial to

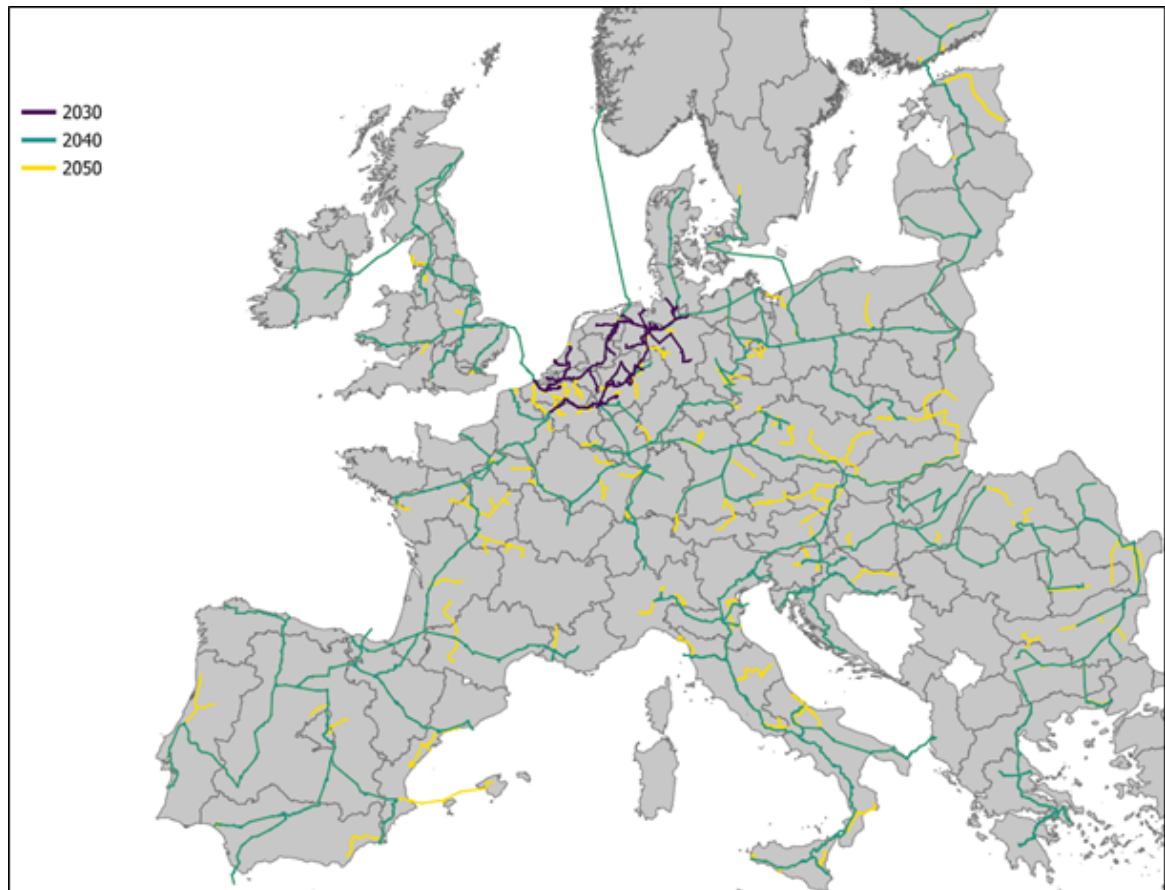


Figure 5.5. Modelled hydrogen network topology for 2030, 2040 and 2050 without adjustments [39].

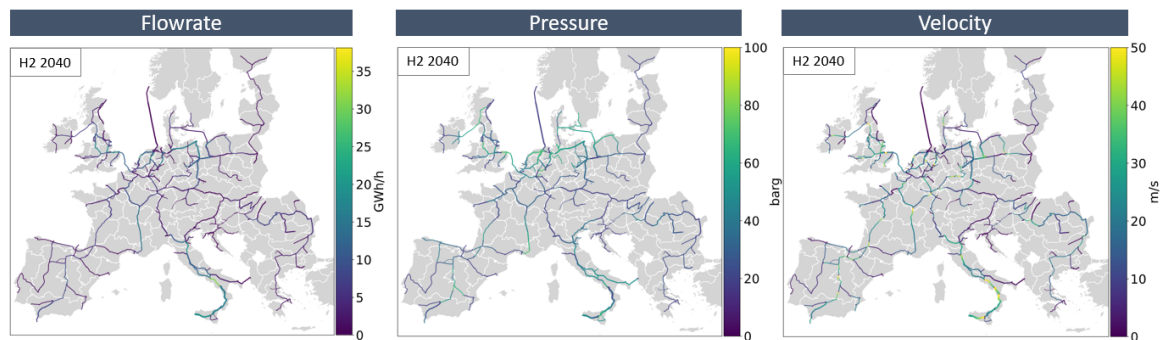


Figure 5.6. Fluid-dynamic simulation results for the hydrogen network 2040 [39].

connect production and imports with demand. To address this, a consortium of 33 energy infrastructure operators has developed the European Hydrogen Backbone (EHB) as a dedicated hydrogen transport network [47].

For the project TransHyDE, an infrastructure model was developed to determine a cost-optimized European pipeline network. The model results were then compared with the EHB to evaluate its cost-effectiveness and possible need for expansion.

The infrastructure model is the last analysis from a model chain. First, the future hydrogen demand is modelled by analyzing transformation plans across various industries (see Chapter 3), as well as the sectors of transportation, commerce, trade, services, and private households. An energy system analysis was then conducted, taking into account the potential for renewable energy expansion. This analysis assesses the hydrogen demand for power generation and electrolysis capacity within Europe. The resulting overall future hydrogen demands were calculated for each district, providing a distribution of hydrogen demands on

district level.

The regionalized hydrogen demands serve as input to the infrastructure model. Additionally, the infrastructure model takes into account the existing natural gas pipelines that can be repurposed for hydrogen transport. Hydrogen production is modeled based on the electrolysis capacities available in each country which is resulting from the energy system analysis. The model operates on a temporal resolution of one year, which means that variations in hydrogen demand and the corresponding storage requirements are not factored into the analysis. By applying a defined set of constraints, the model aims to minimize the overall costs for a European pipeline infrastructure that effectively connects hydrogen sources to demand centers at the district level. The resulting optimized pipeline network for the year 2040 is illustrated in Figure 5.7 a), where blue lines represent repurposed natural gas pipelines and red lines indicate newly constructed hydrogen pipelines. There remains an optimality gap of about one percent in the optimization which means that the total optimum may differ slightly to

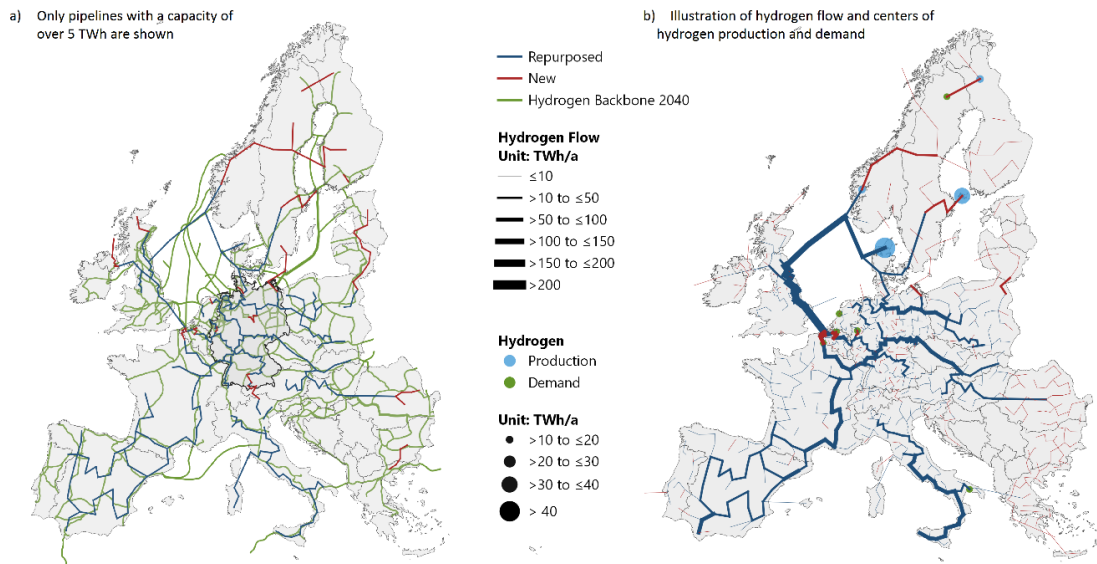


Figure 5.7. Results of the model Infracore for an optimized pipeline network in 2040. a) pipelines with a capacity of over 5 TWh in comparison to the plans of the European Hydrogen Backbone. b) Illustration of hydrogen flow per year.

the shown pipeline routing. For a comparison of the model results to the plans of the EHB, the EHB is highlighted in green on the same map.

Figure 5.7 a) shows that the optimized pipeline network has many similarities to the plans of the European Hydrogen Backbone (EHB). In particular, the routes through Germany, Spain, and France match well with the model results. This suggests that the developed modeling framework captures the infrastructure requirements driven by stakeholders, showcasing its capacity to represent the planning for hydrogen distribution and transportation.

In Figure 5.7 b), the same model results for 2040 are shown, highlighting the hydrogen flow for each pipeline section. It is important to note that the temporal resolution is one year, so the overall demand for hydrogen transport in one year is depicted. The overall annual hydrogen flow indicates a significant need for high transport capacity from import countries (Italy, Spain) to Central Europe. Furthermore, there is a notable demand for hydrogen transport from production centers located in Northern Europe across Great Britain to Central Europe. This highlights the critical role of transport infrastructure in facilitating the movement of hydrogen to meet the growing energy needs across regions. Since the model performs no hydraulic modeling, there is no guarantee that the pipeline network can withstand daily and seasonal demand and production variations. To ensure the resilience of the network, subsequent hydraulic modeling must be performed.

To shed light on the question of whether the EHB is sufficiently dimensioned, a scenario was modelled where the EHB is treated as a fixed element. To achieve this, the routing of the EHB is modeled at NUTS-3 level and incorporated into the infrastructure optimization as a fixed constraint. The modelled EHB is depicted in green in Figure 5.8 alongside the results of additional infrastructure requirements.

The analysis reveals that an additional 4000 km of pipelines are required to meet all demand in 2050. Those mostly consist of pipelines with capacities of less than 1 GW, which are illustrated in light blue (for repurposed pipelines) and light red (for newly constructed pipelines). Since the infrastructure model only considers transportation via pipelines, every district with some

hydrogen demand is connected by pipeline. However, other transport modalities like trucks, trains or ships may be more cost-effective for small transport capacities.

5.4. Which existing and future infrastructure elements run the risk of ending up as stranded assets and how can this be counteracted?

The development of the hydrogen economy is poised to disrupt numerous industries, particularly those within the gas sector, thereby impacting significant components of the existing infrastructure. The retrofitting of existing natural gas infrastructure emerges as a pivotal element in the advancement of the hydrogen economy, particularly transmission pipelines for the hydrogen core network. The German Bundesnetzagentur recognizes this by planning the German core network based to almost 60 % on retrofitted transmission pipelines [41]. The development stages of the European hydrogen network optimized within the TransHyDESys project even foresee a substantially higher share of repurposed pipelines, above 90 % (see chapter How could a feasible transition path for the European natural gas infrastructure to green hydrogen look like?). However, on local levels not all components of contemporary gas infrastructure are anticipated to be converted to hydrogen, owing to economic or technical constraints, particularly with regard to pipelines and current gas consumers within the distribution network. The feasibility of retrofitting pipeline sections or gas consumers is depending on numerous factors, including technical suitability, the availability of alternative technologies (particularly direct electrification), the projected demand for hydrogen, and the accessibility of hydrogen resources. Model-based analyses can assist in determining which existing infrastructure will remain essential in future hydrogen-based systems and which may become obsolete before the end of their originally planned utilization period, therefore labelled as stranded assets.

The risk of stranded assets further needs to be analyzed

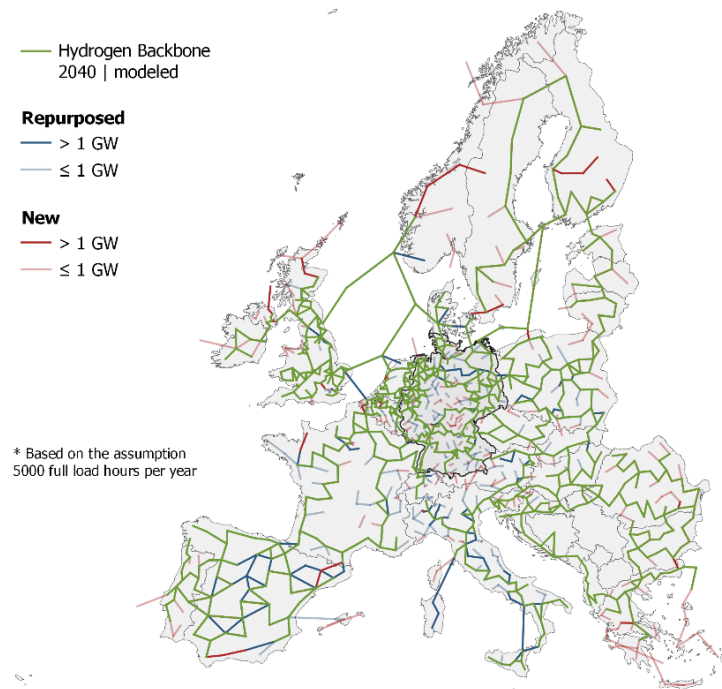


Figure 5.8. Results of the model Infracore for an optimized pipeline network in 2050 with the constraint that the European Hydrogen Backbone will be implemented.

for infrastructure currently under development or construction as part of the early hydrogen economy. Hydrogen supply chains, e.g. consisting of electrolyzers, hydrogen storage, truck trailers, or pipelines, that are established to supply local demands might not be economically viable if boundary conditions change. To analyze this, the Fraunhofer ISE is optimizing regional hydrogen supply chains under different boundary conditions as part of the project TransHyDE-Sys. A new modelling framework *HYSCOPE* has been developed as part of the project, its methodology is presented in [48]. Two boundary conditions of substantial influence are the implementation of the hydrogen core network and the development of the hydrogen demand. The subsequent section will present the resulting effects on the local hydrogen supply chains in two German hydrogen valleys, Ostwestfalen-Lippe as studied in the *Hydrive-OWL* project [49] and the Southern Upper Rhine as studied in the H2-SO project [50]. Both regions are modeled for a supply of hydrogen demands projected for 2030 from the *S2_ChemSteel* and *S4_IndMob* scenario developed in TransHyDE-Sys [24]) once with only local hydrogen production possible (no core network) and once with an established hydrogen core network that can be used for imports and exports of hydrogen into/from the region. The specific prices and revenues for hydrogen imports and exports are resulting from an energy system optimization for a defossilized European energy system conducted within TransHyDE-Sys.

Table 5.4 presents selected results for the cost-optimal

hydrogen supply chain in two demand projections in Ostwestfalen-Lippe, optimized with and without availability of the hydrogen core network. The region boasts excellent local potential for wind power plants, enabling low local hydrogen production costs. Consequently, when connected to the core network, Ostwestfalen-Lippe has the potential to become a net hydrogen exporter, based on the assumed specific hydrogen revenues for export. Hydrogen supply chains established for supply of local demands have low risk of becoming stranded assets after core network connection, the capacities are increasing for export. If the region gets connected to the core network the development of local hydrogen demands has only a minor effect, because large production sites are used for export in both demand projections. Lower local levelized cost of hydrogen (LCOH) are even possible for the low demand projection, as better RE potentials can be used for export¹¹. Only the scenario with low demand and without core network results in substantially smaller installations and higher LCOH due to the lack of economies of scale.

The scenarios of the Southern Upper Rhine Region show substantially different results, presented in Table 5.5. Large scale installations are only selected if no hydrogen imports from the core network are available. Therefore, investments made in a local hydrogen supply chain before the hydrogen core network connection are under high risk of becoming stranded assets. This also applies on the two projects for local electrolysis with a total capacity of 56 MW that are currently under development [51], and therefore

¹¹ This conclusion only applies to local hydrogen cost, which benefit from the export revenues. Furthermore, the denominator in the LCOH calculation is smaller with less local demand. The prices of local hydrogen supply would not be below backbone prices because of market mechanisms, that are out of scope of these analyses.

Table 5.4. Scenario specific results for the cost-optimal hydrogen supply chain in Ostwestfalen-Lippe, modelled for 2030 in four different scenarios. The region would be a net hydrogen exporter for the assumed hydrogen prices at the core network, therefore the connection would lead to a larger local hydrogen system. Low risk of stranded assets from the connection, but high risk of stranded asset if no connection is happening and the demand development is low.

	Unit	S2_ChemSteel No Core Network	S2_ChemSteel With Core Network	S4_IndMob No Core Network	S4_IndMob With Core Network
Internal LCOH	€/kg	7.05	4.91	6.48	6.20
Mean export price	€/kg	N/A	5.46	N/A	5.68
Mean import price	€/kg	N/A	6.01	N/A	6.23
Installed electrolysis	MW	39	312	269	423
Installed pipeline length	km	0.0	16.6	21.4	12.0
Necessary truck trailers	-	6	47	5	52
H ₂ production	t/a	4,188	27,715	33,240	43,228
H ₂ demand	t/a	3,975	3,975	33,240	33,240
H ₂ import	t/a	N/A	2	N/A	37
H ₂ export	t/a	N/A	23,741	N/A	10,025

Table 5.5. Scenario specific results for the Southern Upper Rhine Region, modelled for 2030. The region would be a net hydrogen importer for the assumed hydrogen prices at the core network, therefore the connection would lead to a smaller local hydrogen system. High risk of stranded assets for early investments in a local hydrogen supply chain.

	Unit	S2_ChemSteel No Core Network	S2_ChemSteel With Core Network	S4_IndMob No Core Network	S4_IndMob With Core Network
Internal LCOH	€/kg	8.82	7.80	7.90	6.80
Mean export price	€/kg	N/A	5.58	N/A	5.79
Mean import price	€/kg	N/A	6.13	N/A	6.34
Installed electrolysis	MW	117	56	266	56
Installed pipeline length	km	0.0	0.5	61.0	16.6
Necessary truck trailers	-	8	15	9	17
H ₂ production	t/a	11,517	9,804	46,461	9,806
H ₂ demand	t/a	11,267	11,267	46,429	46,429
H ₂ import	t/a	N/A	1,464	N/A	36,623
H ₂ export	t/a	N/A	1	N/A	1

set as lower boundary in the optimisation. They would not be selected in a greenfield optimization, as demonstrated in Mendler et al. [48] which also shows additional scenarios. The scenarios with high demand projections result in a LCOH decrease of 1 €/kg due to economies of scale. Resulting maps of the optimized hydrogen supply chain can be seen in the roadmap developed within TransHyDE-Sys [52].

Another sector that faces both opportunities and challenges, including the risk of stranded assets, as a result of the development of the hydrogen economy is the heating sector. Many municipalities are investing in district heating networks and planning for future hydrogen integration to prevent economic losses from outdated infrastructure. This shift is especially relevant for gas turbine combined heat and power (CHP-CCGT) plants, which play a crucial role in the urban heating supply system of district heating networks. The risk of stranded assets is particularly rel-

evant in cities, which rely heavily on CHP-CCGT for their district heating supply. If the planned hydrogen connection is not economically viable or the demand for hydrogen is lower than expected, the expensive conversion of the power plants could remain unutilized. To minimize the risk of stranded assets, knowledge of the technical challenges of switching to hydrogen and the necessary conversions of CHP plants is required. This was assessed from a technical perspective within the TransHyDE-Sys-MechaMod at Bonn-Rhein-Sieg University of Applied Sciences.

As combined heat and power plants are operated seasonally - with high capacity utilization in winter and reduced or none use in summer - the question arises as to whether the investment in such a hydrogen supply scheme is justified. In addition, district heating networks are long-term infrastructure projects with high fixed costs. If hydrogen is not consistently available as an energy source or is too

expensive, the economic risk could increase.

In the strategic municipal heat planning, many cities continue to plan with their heating networks and are expanding some of them. While the total network length is increasing, overall heat demand is expected to rise only slightly due to high renovation rates [53]. Large-scale heat pumps, such as geothermal and river heat pumps, will play a crucial role in the heating transition. However, they are not yet capable of fully supporting the current temperature levels required by district heating networks. Currently, most district heating networks in Germany are classified as second- or third-generation, operating at supply temperatures between 100 °C and 130 °C or between 70 °C and 100 °C, respectively [54]. Until the transformation to lower supply temperatures is complete, CHP-CCGT plants remain a necessary transitional solution, particularly in cities where large-scale heat storage facilities cannot be implemented due to space constraints. Additionally, waste incineration plants (WIP) remain essential components of urban heating systems, as they provide consistent heat output, but they also currently rely on natural gas for a stabilization of the unsteady energy content of the feed. The cities of Bonn and Cologne are currently working on converting their power plants to hydrogen.

The city of Bonn expects that by winter 2035, approximately 117 tons of hydrogen per day will be needed to operate existing waste incineration and combined cycle power plants [53]. Looking ahead, the CHP plants are expected to operate primarily in a heat-driven mode, with higher full-load hours during the heating season. The waste incineration plant (WIP) in contrast, is likely to operate year-round at more constant output levels, driven by continuous waste input. This difference in operating patterns will strongly influence the temporal distribution of hydrogen demand and should be taken into account when planning supply and storage systems. However, on-site electrolysis is only partially viable due to space limitations. Consequently, a connection to the national hydrogen backbone is crucial. Municipal utilities are currently coordinating with grid operators to secure this connection and are also exploring partnerships with additional hydrogen offtakers to make the investment more cost-effective. However, even in the absence of additional consumers, municipal utilities would proceed with the connection to ensure their power plants remain viable and avoid stranded assets related to hydrogen pipeline infrastructure.

The following key technical challenges have been identified through literature review and an own quantitative analysis within TransHyDE-Sys-MechaMod.

The operational patterns of different heat-generating plants vary significantly. WIPs run continuously year-round as a stable energy source, whereas district heating power plants operate at full capacity only in the winter months, reducing to partial or zero load in summer [53]. Transitioning WIPs from natural gas to hydrogen is comparatively straightforward, as the Wobbe Index difference is not substantial. However, the full conversion of GT-CHP plants requires careful consideration of multiple subsystems. The following subsystems were analyzed in several studies: fuel gas supply, gas turbines and the downstream systems, in particular: the heat recovery steam generator (HRSG) and flue gas aftertreatment [55–58].

Key technical challenges in the transition from natural gas to hydrogen in the fuel gas system include:

- Higher volume flows required for the same energy output. This results in higher velocities, which may require pipe diameters adjustments [59].
- Pressure loss plays a minor role [59].
- Material considerations, though low-pressure levels pose fewer challenges in hydrogen embrittlement, but higher maintenance intervals could arise.
- Preheating requirements, as with 100 % hydrogen at a pressure drop of 8 bar, for example, there is no cooling but slight heating due to the Joule-Thomson effect. At the same time, the heat capacity increases compared to natural gas. The preheaters must therefore be larger than for natural gas to achieve the temperatures required for turbine operation [59].

The gas turbine itself represents the most critical and costly component in the conversion process [58]. Dry Low Emission (DLE) gas turbines, which are commonly used, face a heightened risk of flashbacks when operating with hydrogen.

Additional challenges for gas turbines and the downstream parts include:

- **Higher combustion temperatures**, which can lead to material degradation.
 - **NOx emissions**, as hydrogen combustion reduces CO₂ output but increases combustion temperatures, potentially leading to elevated NOx emissions. If manufacturers do not resolve this issue, greater amounts of ammonia will be required in the flue gas treatment process to meet environmental regulation [60].
- **Increased water vapor content**, affecting HRSG efficiency and flue gas aftertreatment.
 - **Increased Dew Point** leading to higher corrosion and maintenance intervals of the HRSG and flue gas aftertreatment [59].

In many cases, the retrofit process is constrained by the gas turbines themselves. But manufacturers want to make large scale gas turbines capable of 100 % hydrogen by the 2030s. Efficiency losses in the HRSG and steam turbine can be offset by efficiency gains in the gas turbine due to higher combustion temperatures [61, 62]. This compensation is beneficial for electricity-demand driven plants. However, for heat-demand-driven plants such as the Bonn North CHP-CCGT plant, this results in a reduction of district heating output. Therefore, in heat-prioritized plants, the performance of the HRSG must be considered a limiting factor, and the impact of changes in flue gas composition must be thoroughly analyzed. Fluctuations in the hydrogen mixing ratio can be problematic during the cold and hot start of a gas turbine, as they influence the combustion properties [63]. A blending station and a hydrogen storage tank could regulate these fluctuations, whereby the Wobbe index is a decisive control variable in the case of direct pipeline supply. In addition, safety measures such as purging the HRSG before start-up and adjustments to explosion safety must be taken to minimize hydrogen build-up and the associated risks.

In the case of dynamic behavior with hydrogen combustion, the use of a bypass can help to avoid pressure and temperature peaks. The control of the gas turbine can be stabilized and uniform combustion ensured through the targeted redirection of exhaust gas flows. This helps to minimize undesirable effects such as incomplete combustion or safety risks due to hydrogen build-up [57].

In conclusion, while hydrogen integration in district heating networks presents technical and economic challenges, securing access to the hydrogen backbone and addressing turbine limitations are crucial steps in ensuring a successful transition. The development of hydrogen-capable turbines, optimized heat recovery steam generator designs, and effective NO_x mitigation strategies will determine the feasibility and sustainability of hydrogen as a primary energy source for district heating systems in the coming decades.

5.5. Which transport vectors for hydrogen distribution are used under which conditions?

An analysis presented in the previous flagship report compared the cost-effectiveness of hydrogen transportation through gaseous trailers and newly installed pipelines, focusing on compressed hydrogen gas [4]. The findings highlighted how factors such as pressure level, transported capacity, trailer capacity, pipeline diameter, pressure drop, and transport distance influence the levelized cost of hydrogen transportation (LCOHT). Gas trailers were found to be cost-effective for hydrogen demands of up to 30–40 t/day, while pipelines demonstrated cost advantages for shorter distances at similar demand levels and for larger demands across all distances. Additionally, investment costs, compressor expenses, and fuel costs played significant roles in determining the overall economic feasibility of each mode of transport. To further explore these calculations, a cutting-edge online tool is available at <https://websites.fraunhofer.de/iff-lcoh-t-calculator/>. This advanced tool helps users to optimize their hydrogen supply chain by identifying the most cost-effective

transportation methods and routes. With its ability to provide in-depth insights into levelized costs for hydrogen, the tool enables users to enhance decision-making through comprehensive cost analysis. While this analysis focuses on compressed gaseous hydrogen transport via trailers and pipelines, it is important to note that liquid hydrogen (LH₂) distribution is widely used in practice, particularly for moderate transport volumes over longer distances. The exclusion of LH₂ in the present study reflects the defined analytical scope, which was limited to gaseous hydrogen transport. Nonetheless, the potential relevance of LH₂ distribution should be considered when interpreting the results, especially for scenarios involving medium-scale demand and extended transport distances.

Building on this foundation, a new analysis extends the cost assessment by incorporating primary storage tanks (200 bar), which could also be utilized for various storage functions, including balancing supply fluctuations. This expanded evaluation covers up to 10 t/day of storage capacity, providing a more comprehensive understanding of hydrogen infrastructure [64]. By integrating storage costs with transport costs, the updated results offer a clearer picture of the total investment and operational expenses involved in hydrogen distribution. The following section explores these findings in detail, shedding light on the impact of storage on cost optimization and infrastructure planning.

Figure 5.9 presents the combined levelized cost of hydrogen transportation and storage (LCOH(T+S)) in €/kg. This value is derived by integrating transportation costs from [65] for distances up to 500 km with updated storage costs for hydrogen demands of up to 10 t/day [64]. The storage costs account for CAPEX and OPEX of storage tanks, as well as the compressor costs required for transferring gaseous hydrogen from trailers or pipelines to storage tanks. The contour map illustrates the least levelized cost of hydrogen for transportation and storage across various scenarios, comparing three options: 350-bar trailers, 540-bar trailers, and 100-mm pipelines.

The graph shows that for all hydrogen demand levels and transport distances up to 400 km, the 350 bar trailer emerges as the most cost-effective option for hydrogen transportation and storage. While its compressor energy costs during transfer of hydrogen to storage tanks

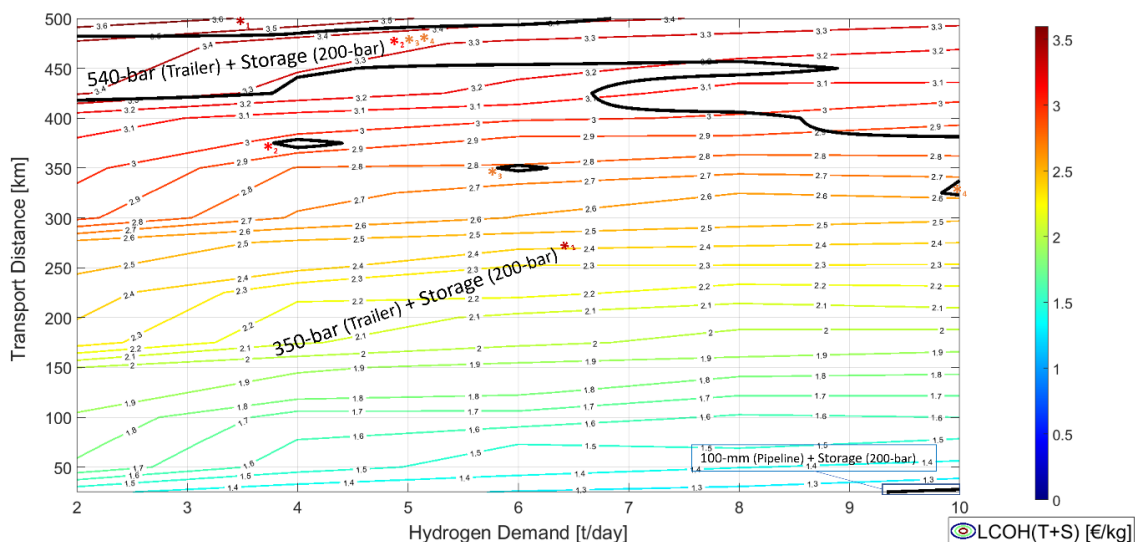


Figure 5.9. Contour plot indicating the least LCOH(T+S) as a function of hydrogen demand and transport distance.

are slightly higher than those of the 540-bar trailer, its lower transport-related costs make it the preferred choice. With longer distances, the 540-bar trailer becomes the optimal choice due to its ability to handle larger volumes more efficiently at higher pressures, while also benefiting from lower compressor energy costs during transfer to storage tanks. The few anomalies in the figure arise from transportation cost variations driven by the more efficient utilization of trailer capacity [65]. For longer distances and higher hydrogen demand, pipelines emerge as the cost-effective option. These insights provide valuable guidance for selecting optimal hydrogen distribution and storage infrastructure based on specific demand and distance requirements.

To complement the generic transport cost evaluation, a comprehensive analysis of specific hydrogen transport connections in selected and modelled hydrogen valleys in Germany is conducted. The analyzed regions consist of the Southern Upper Rhine Region, Ostwestfalen-Lippe, Emsland, Frankfurt (Main), and Nordhessen as funded within the HyLand project series [67]. Results for the Southern Upper Rhine Region are examined in detail. This analysis encompasses the levelized cost of hydrogen transport (LCOHT) and the most cost-efficient transport technologies. This analysis is part of a broader study of hydrogen valleys. The integration of this analysis within a spatially resolved, dynamic optimization framework offers numerous advantages. Firstly, the hourly pattern of hydrogen deliveries can be taken into account. This hourly pattern is influenced by fluctuations in hydrogen supply and demand. Secondly, the analysis of multiple connections within a region allows for the consideration of shared infrastructure and facilities. For instance, truck trailers can be shared flexibly between connections and filling stations, and compressors and filling stations can be utilized for multiple connections starting from the same location. Furthermore, the analysis can account for specific infrastructural and geographic conditions, such as existing connections to railway networks, highways, or natural gas grids. However, a limitation arises due to the paucity of public data for natural gas grids. Only transmis-

sion grid data is available, and it only covers parts of the analyzed regions. Additionally, the diameters of these grids are often too large for efficient hydrogen transportation within hydrogen valleys.

A comparative analysis is conducted for each transport connection within the modeled region, encompassing next to gaseous truck trailer, newly constructed pipelines and the retrofitting of existing natural gas pipelines also liquid hydrogen (LH₂) truck trailer and railway transport, contrary to the generic analysis at the beginning of this chapter. It should be noted that the retrofitting of pipelines and rail transport are exclusively available in locations that are connected to the existing respective grids. The construction of new pipelines involves an optimization of pipeline diameter and input pressure. The analysis of all scenarios calculated in Mender et al. [66] for the Southern Upper Rhine Region is focused on identifying the most cost-efficient transport technology and the resulting LCOHT. The resulting connections, visualized regarding distance and total transported mass in Figure 5.10, indicate that pipeline transport is predominantly selected for connections up to 30 km and with more than 10 t/day, with some exceptions. When the results are graphed based on transported mass and load factor (a ratio of average transported mass and maximum hourly transport capacity) in Figure 5.11, it becomes evident that the load factor exerts a lesser influence on technology selection, although connections characterized by low load factors are usually not conducive to pipeline transport. Very few connections over short distances are exception, on which a transport via pipelines is even viable for low load factors. The correlation between load factor and LCOHT (low load factor results in high LCOHT) is stronger than the one to the selected technology. The modeling of other regions within TransHyDE, specifically Ostwestfalen-Lippe [49], Emsland [68], Frankfurt am Main [69], and Nordhessen [70], substantiates the observed trends regarding technology selection. As illustrated in Figure 5.12, the strategic retrofitting of pipelines and the augmentation of railway transport infrastructure can emerge as cost-

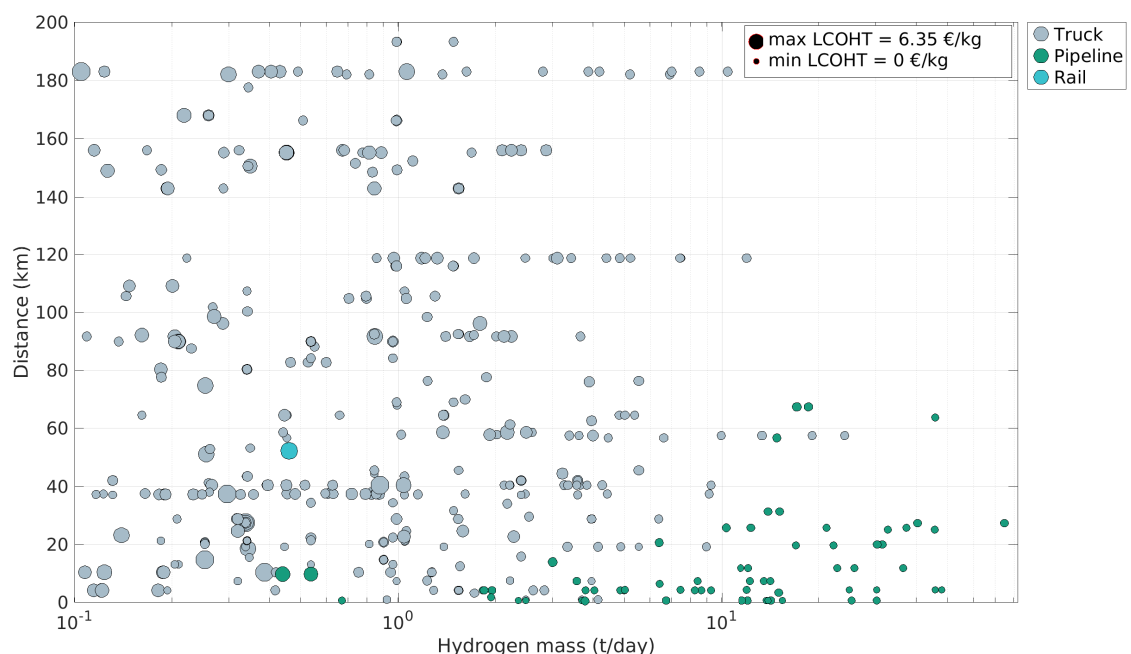


Figure 5.10. Transport connections in all modelled scenarios of the Southern Upper Rhine Region in [66], plotted distance vs. transported mass. The color of the circle depicts the selected transport technology, and the size indicates the LCOHT. Pipelines are mostly selected for large transport volumes over short distances.

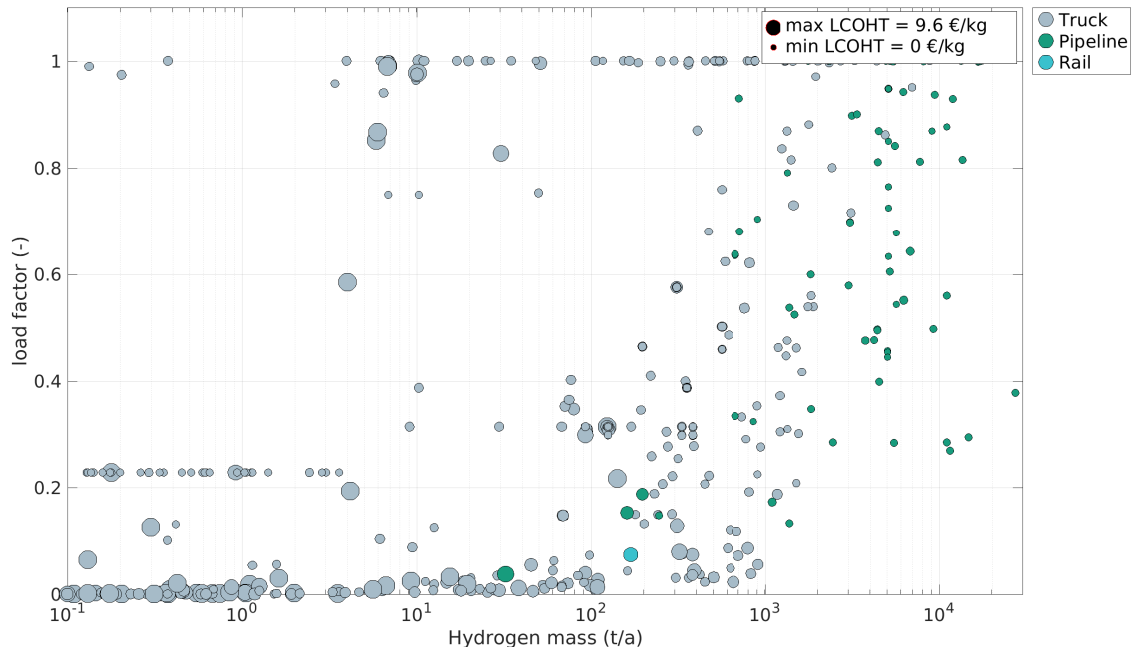


Figure 5.11. Transport connections in all modelled scenarios of the Southern Upper Rhine Region in [66], plotted transported mass vs. load factor. The color of the circle depicts the selected transport technology, and the size indicates the LCOHT. The load factor has less influence on the selected technology, but connections with low load factor have higher LCOHT.

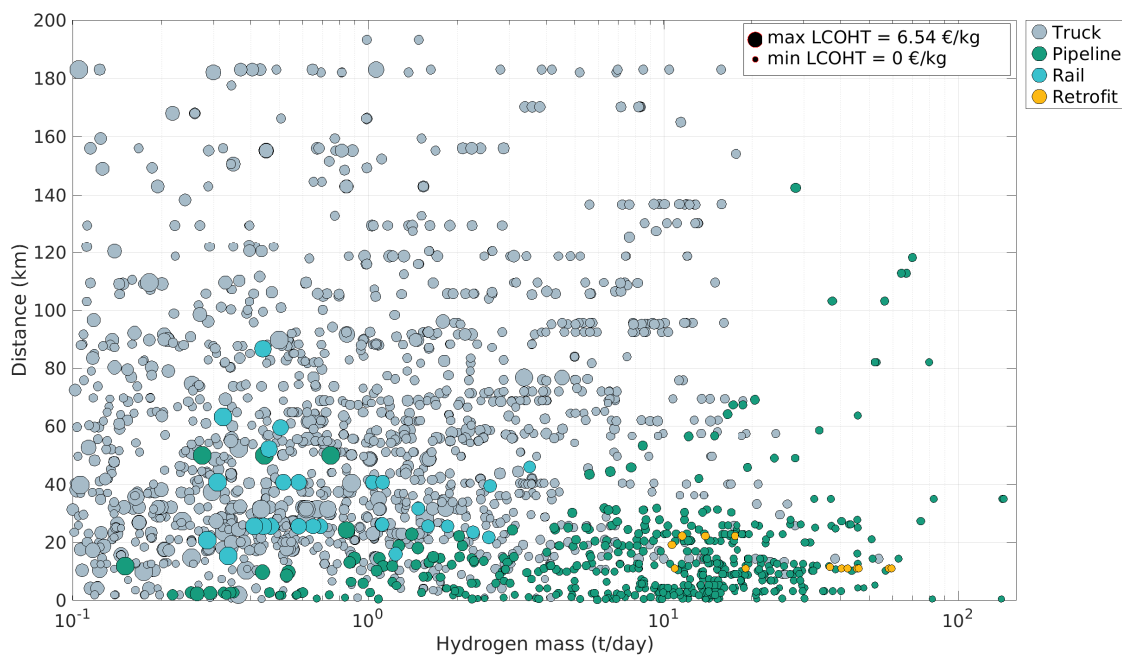


Figure 5.12. Transport connections in all modelled scenarios of the Southern Upper Rhine Region in [66], plotted transported mass vs. load factor. The color of the circle depicts the selected transport technology, and the size indicates the LCOHT. The load factor has less influence on the selected technology, but connections with low load factor have higher LCOHT.

effective solutions, provided that local conditions are conducive to such endeavors. The retrofitting of pipelines might even be substantially more valuable in reality, given the condition that no data on existing distribution grids was available and only transmission grids could be considered. Liquid hydrogen transport was not selected for any connection as the higher transport capacity per trailer cannot compensate the high investments for liquefaction and storage on shorter distances as seen within hydrogen valleys. This does not correspond to current practice, in which hydrogen is predominantly transported in liquid form. In addition to the high purity enabled by LH_2 , which is not taken into account in the modeling, the high flexibility between short and long distances (over 1000 km) is also crucial for today's hydrogen distribution, as the same fleet is used

for various types of applications. Further analysis within regional projects in cooperation with local gas grid and gas distribution operators should be carried out to improve the validity of the results, including the combination of intraregional transport with national or even international transport. It is expected that the relevance of rail and LH_2 transport increases under these requirements.

5.6. Electrolyzers and H₂-power plants: How do their locations influence the congestion management in the German power grid and what is the electrolyzers' potential for utilization of excess heat? Redispatch computations and an excursus to electrolyzer's excess heat analysis

The localization of electrolyzers and H₂-power plants plays a crucial role in the establishment of a sustainable and cost-efficient hydrogen economy. In particular, large-scale electrolyzers are very demanding as they consume significant amounts of electrical energy and water and produce heat that must be dealt with. These factors must be considered when selecting a location.

This section addresses the key criteria and challenges associated with electrolyzer and H₂-power plant allocation from a cross-sectoral perspective. Several strategies for site selection are examined and compared based on the operation of the power transmission grid. More precisely, the impact of the selection strategies on the operational redispatch measures are investigated. While the effects on the power transmission grid affect the overall system cost, other factors can have favorable effects from a project developer's point of view. Next to the availability requirements for water supply, space, and grid infrastructure, one of these factors is the locations of heat consumers that can utilize the electrolyzer's excess heat to enable additional value chains. To this end, detailed knowledge of the excess heat generated by an electrolyzer and its auxiliary units is required. The conducted simulations are summarized as an excursus in this chapter.

5.6.1. Effects on the power transmission grid

The integration of renewable energy sources (RES) and the ramping up of the German and European hydrogen market heavily impact future power systems. This includes plans for a substantial increase in domestic H₂-production via electrolysis and consumption by H₂-power plants. While large scale energy system optimizations can provide solutions to determine capacity installation goals for large regions (c.f. energy system models Enertile and PyPSA), it cannot capture all grid infrastructures in detail. Considering the power transmission grid, the actual spatial distribution of electrolyzers and H₂-power plants can have a significant impact on the congestions occurring in the grid, the cost associated with the management of such congestions (redispatch) and finally the integration as well as the use of RES.

Typically, allocating electrolyzers is done heuristically. Ideas include reducing renewable energy curtailments or leaving all investment decisions to market participants which can lead to a broad distribution of utilities that are not interconnected via a hydrogen network. To assess and compare these "rule of thumb" solutions, a mathematical optimization model based on a redispatch model has been developed. In a first step, locations were chosen in

such a way that the power transmission grid congestion before redispatch is minimized. This method delivers improved locations with respect to redispatch cost and energy volume. The results of this approach can be found in [71]. Subsequently, the method has been extended in such a way that the locations are chosen by minimizing the actual cost of resolving the power transmission grid congestions (redispatch) lowering the total redispatch cost furthermore. In summary, we have examined the effects of three different allocation methods for electrolyzers and H₂-power plants on the redispatch cost within Germany. They can be summarized as follows:

1. Hydrogen demand oriented ("H2DO"): Electrolyzers close to future H₂-consumers, hydrogen power plants close to today's natural gas power plant sites.
2. Nodal renewable surplus oriented ("NRSO"): Electrolyzers close to power transmission grid substations with renewable energy surplus avoiding power transport, hydrogen power plants at locations with least renewable energy coverage of load.
3. Redispatch cost minimizing ("RCM"): Least redispatch cost in the power transmission grid operation

The capacity installation targets are gained from an energy system optimization (system model Enertile). More specifically, a modified version ("copperplate") of the *Mid_Demand* scenario for the year 2030 is used as input data (See scenario results in [24]). This modification of *Mid_Demand* assumes a uniform power price zone in Germany represented by a congestion-free "copperplate" (i.e., unlimited power transmission capacity) within Germany. First, the load and generation data not corresponding to electrolyzers or H₂-power plants are disaggregated and allocated to substations to match the detailed model of the German extra high voltage power grid of the year 2030. Then, the goal is to allocate electrolyzers (13.5 GWel in total) and H₂-power plants (15.4 GWel) to the substations. While H2DO does not rely on an operating H₂-grid by 2030 and places all units where they are needed, the NRSO and RCM methods rely on the planned German backbone H₂-grid [44] and assume a maximum distance of 30 km for the allocation of electrolyzers and H₂-power plants. In this way, it can be assured that the units can be connected to the H₂-grid without excessive cost. The results of the respective methods are evaluated using a power redispatch model. The redispatch volumes as well as the overall costs are used to compare the outcomes.

The allocations gained by the three methods are shown in Figure 5.13 and Figure 5.14. The H2DO-allocation leads to high electrolyzer allocation in western and southern Germany and at a few industry sites in central and northern Germany. NRSO and RCM select locations in northern Germany, with NRSO having a strong focus on wind dominated regions in Lower Saxony at the coast and Dutch border. For RCM, a few locations more south are also favorable due to local power transmission grid congestions. Hydrogen power plants are placed only in southern and western Germany by RCM, while NRSO also selects locations in metropolitan areas in northern Germany.

Based on the different allocations, a redispatch optimization is performed to mitigate all relevant congestion

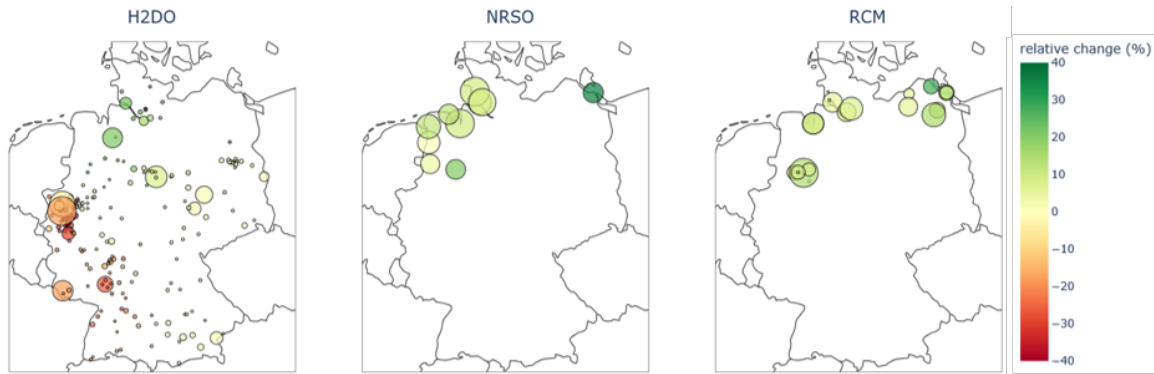


Figure 5.13. Electrolyzer locations and their relative change in annual electricity consumption due to redispatch measures in the Mid_Demand “copperplate” 2030 scenario. Only units > 10 MW are shown.

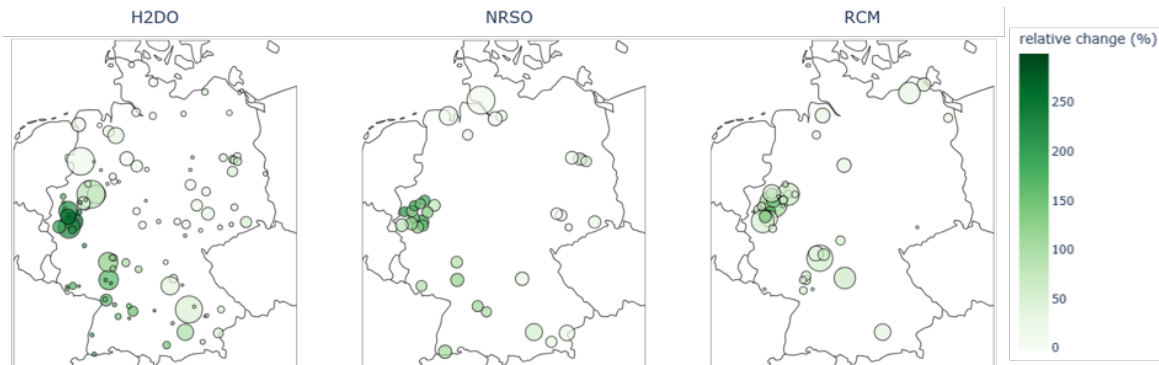


Figure 5.14. Hydrogen power plant locations and their relative change in annual electricity generation due to redispatch measures in the Mid_Demand “copperplate” 2030 scenario. Only units > 10 MW are shown.

in the power transmission grid. Electrolyzers are theoretically capable and - depending on the technology - flexible enough to adjust their power consumption if requested by the grid operator. However, they are currently not obliged to participate in the redispatch process. Therefore, the redispatch optimization has been conducted in two variants, without and with participation of electrolyzers in the redispatch. The results include the redispatch work for the different flexible categories applicable in the redispatch optimization as well as the redispatch cost based on the given costs assumptions. As illustrated in Figure 5.15, the use of electrolyzers in the redispatch can reduce the cost for each allocation method (based on the applied cost assumptions¹²).

The different allocation strategies have a high impact on the redispatch costs. As shown in Figure 5.15, redispatch costs can be reduced by around 51 % (around 1.8 billion Euro in the modelled year and based on the applied cost assumptions) by choosing electrolyzer locations with high renewable energy surplus (NRSO) instead of those with high hydrogen demand (H2DO). In RCM, the redispatch costs are around 71 % (2.3 billion Euro) lower than in H2DO. Note that this cost assessment focuses on the redispatch costs only and disregards other costs, e.g. related to different hydrogen infrastructures.

Additionally, it is found that the participation of electrolyzers in redispatch affects redispatch energy volume only slightly. The location of electrolyzers and hydrogen power plants, however, have a strong influence on the

required redispatch energy. Nonetheless, the participation of electrolyzers in the redispatch reduces renewable curtailment by 6 % (1.4 TWh) regarding H2DO, 33 % (4.1 TWh) for NRSO and 48 % (4.4 TWh) regarding RCM¹³. The corresponding additional hydrogen production in the considered year would result in around 27,700 tH₂ regarding H2DO, 82,500 tH₂ for NRSO and 87,000 tH₂ regarding RCM, based on an estimated efficiency of 50 MWh/tH₂ for PEM-electrolysis.

The geographical distribution of the redispatch measures is illustrated in Figure 5.16. In all cases, the generation decrease mainly takes place in northern Germany - especially in the North-West, where large scale offshore wind is connected to the power transmission grid. In the RCM cases (subplots e and f), the reduction of generation is less pronounced compared to the H2DO (a and b) and NRSO (c and d) cases, corresponding to their lower total sums of redispatch volume.

The increase in generation consistently takes place in western and southwestern Germany, in all cases. Focusing on the NRSO allocation, it can be seen that an additional decrease of consumption is used and needed (Figure 5.16c and Figure 5.16f). Independent of the allocation H2DO, NRSO or RCM, when electrolyzers participate in the redispatch, the increase of consumption is higher than in the cases where they are not allowed to participate. Consequently, the generation decrease nearby (i.e., curtailment of renewable energy feed-in) is lower. When looking at the locations of the electrolyzers, the increase of consumption

¹² The cost assumptions can be found in: J. M. Kisse, P. Hahn, Y. Harms, and M. Braun, “Flexible Electrolysers as a Tool for Renewable Energy Integration and Congestion Management: Comparison of Different Allocation Methods in a Transmission System Case Study for Germany 2030,” [71].

¹³ Compared to the curtailment that occurs in redispatch if the electrolyzers’ flexibility cannot be utilized for redispatch measures.

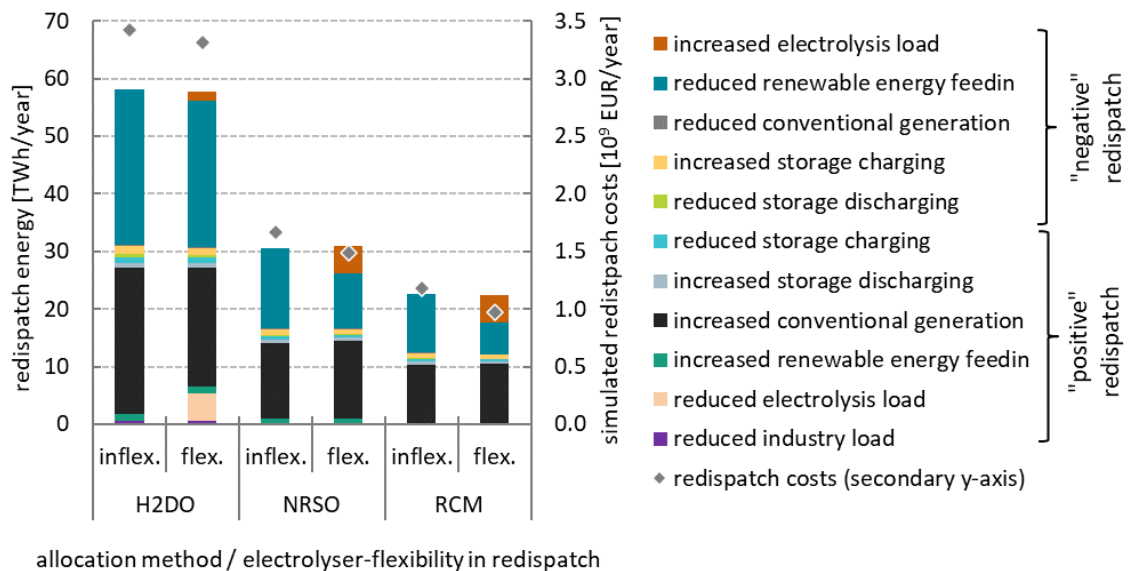


Figure 5.15. Redispatch energy and costs for the modelled year 2030. inflex.: electrolyzers cannot be used for redispatch measures; flex.: electrolyzers can be used for redispatch measures. H2DO: electrolyzers at hydrogen-demand oriented locations, NRSO: electrolyser.

takes place in the locations where the electrolyzers are allocated, other load flexibilities are only used to an almost neglectable extend. This also leads to a higher amount of H₂-production after the redispatch optimization. In summary, it can be concluded that the usage of electrolyzers in congestion management provides a potential for cost savings and reduces RES curtailment up to 48 % in the modelled scenario and year. A coordinated approach of electrolyzer site selection will reduce redispatch costs. Already heuristic schemes which incentivize electrolyzer investments in areas with high local renewable energy surplus (correlated to the electrolyzers' dispatch) lead to savings of 51 %. This coordination could be implemented in different ways, the instrument "use instead of curtailment" (§13k, German Energy Industry Act, EnWG) is going in the right direction. Even more precise location assessments can increase the savings to 71 % but require a deeper analysis and carry a higher computational burden. The earlier discussed other allocation factors play a key role as well.

5.6.2. Excursus – Modeling the heat production of a large-scale electrolyzer

The electrolyzer's primary function is hydrogen production, and in large-scale applications, the by-product heat can be utilized for district heating, thereby enhancing overall efficiency. The local supply of hydrogen and waste heat has the additional benefit of increasing local security and safety of energy supply. The location of an electrolyzer plant will be beneficial if it is close to heat consumers, such as a district heating network or a company that requires heat for buildings or industrial processes. However, the utilization of excess heat for additional purposes necessitates additional components, such as a heat pump to elevate the temperature level. Notably, old generation district heating networks mandate a feed forward temperature of 100 °C or higher [72], whereas the electrolyzer's output temperature is approximately 60 °C [73]. The optimal location for an electrolyzer plant is decided by factors specific to the local infrastructure and requirements. The primary concern in determining the location of an electrolyzer plant is the power grid connectivity, and the use of excess heat is an ad-

ditional benefit which could potentially reduce operational costs.

In order to analyze the heat production, a system model of a 17.5 MW electrolyzer was constructed. This system model is based on traditional models found in literature; however, the issue of heat is rarely addressed in these models, particularly with regard to heat from additional components such as power converters, gas dryers, and other components of the so-called balance of plant. This project involves the construction of a system model that has been exemplarily adapted to a Siemens Silyzer 300 stack and a power converter. The model will be employed to compare and scale the heat production to that of the entire 17.5 MW plant. Figure 5.17 shows the comprehensive overview of the Siemens Silyzer 300.

First, a model of the primary component, the electrolyzer stack, was developed based on equations derived from existing literature. During the development process, inconsistencies in the literature were identified and addressed in the publication [73]. Furthermore, an equation was identified that can reduce the computational effort required for stack models. With regard to the heat production of a stack, the results indicate that under optimal conditions, the stack generates approximately 23 % of the total heat. However, the utilization of heat for district heating is expected to be diminished due to the efficiencies of the heat exchangers and losses to the environment. The Siemens Silyzer 300 is an air-cooled model, resulting in elevated losses to the environment. Due to the numerous unknowns associated with the air-cooled model, the calculation of heat losses proved to be unfeasible. Nevertheless, under optimal conditions and assuming water-cooled stacks, calculations indicate a maximum extraction of 3.8 MW_{th} from the Silyzer 300.

Furthermore, the heat generation of the power supply (particularly the rectifier) was calculated and compared with that of the stack. The rectifier contributes between 14 % and 18 % of the total heat generation from the entire electrolyzer plant, with the actual value depending on the type of rectifier and the operating conditions. Different technologies of rectifiers are used in real applications, and further research is still being conducted. In this study, a

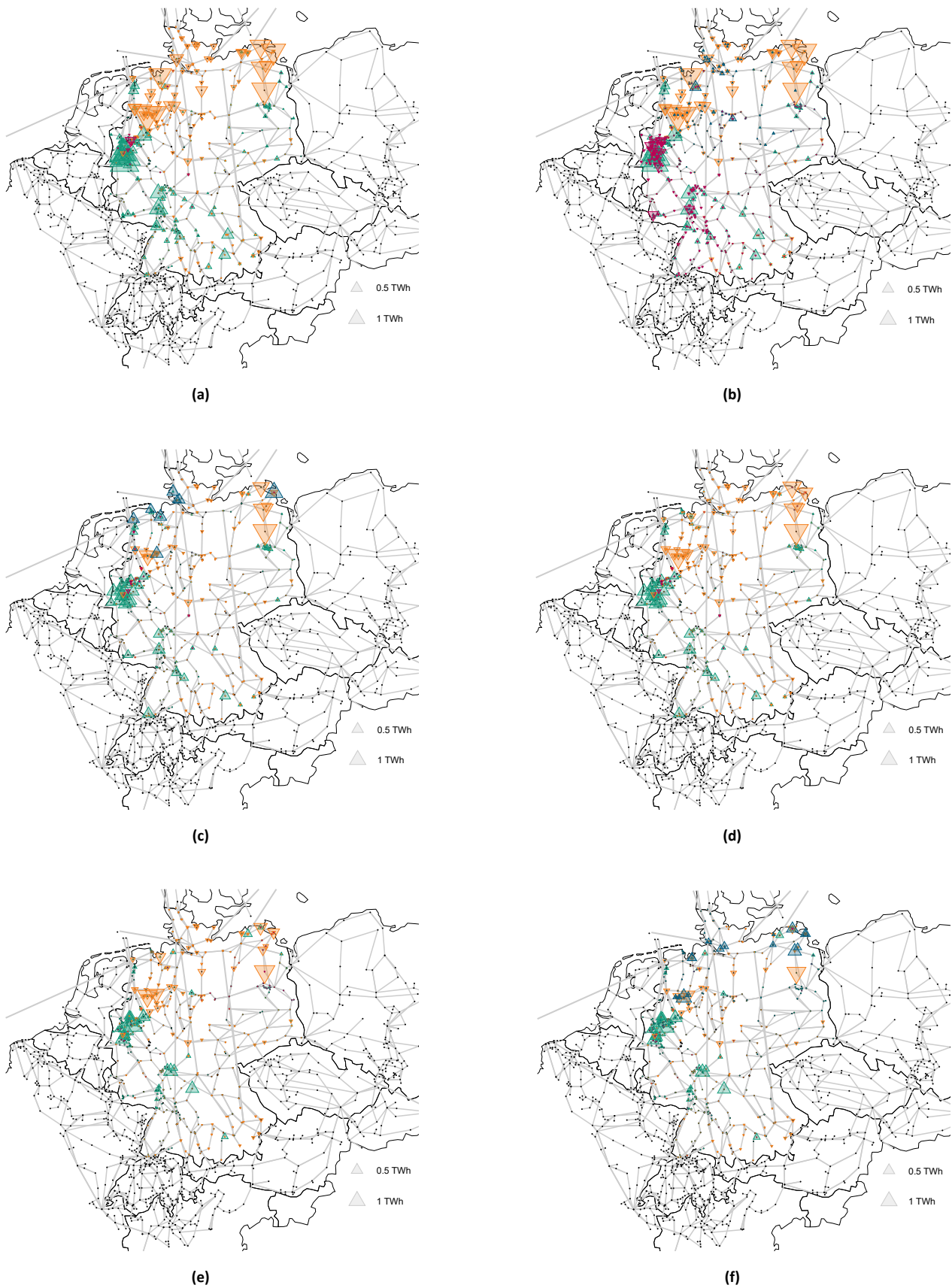


Figure 5.16. Redispach results for the modelled year 2030: nodal annual volume of increase and decrease (generators and loads) ▲ Increase Generation ▲ Increase Consumption ▼ Decrease Generation ▼ Decrease Consumption; "Hydrogen demand oriented" allocation: (a) no electrolyzers in redispach; (b) electrolyzers in redispach; "Nodal renewable surplus oriented" allocation: (c) no electrolyzers in redispach; (d) electrolyzers in redispach; "Redispach cost minimizing" allocation: (e) no electrolyzers in redispach; (f) electrolyzers in redispach;

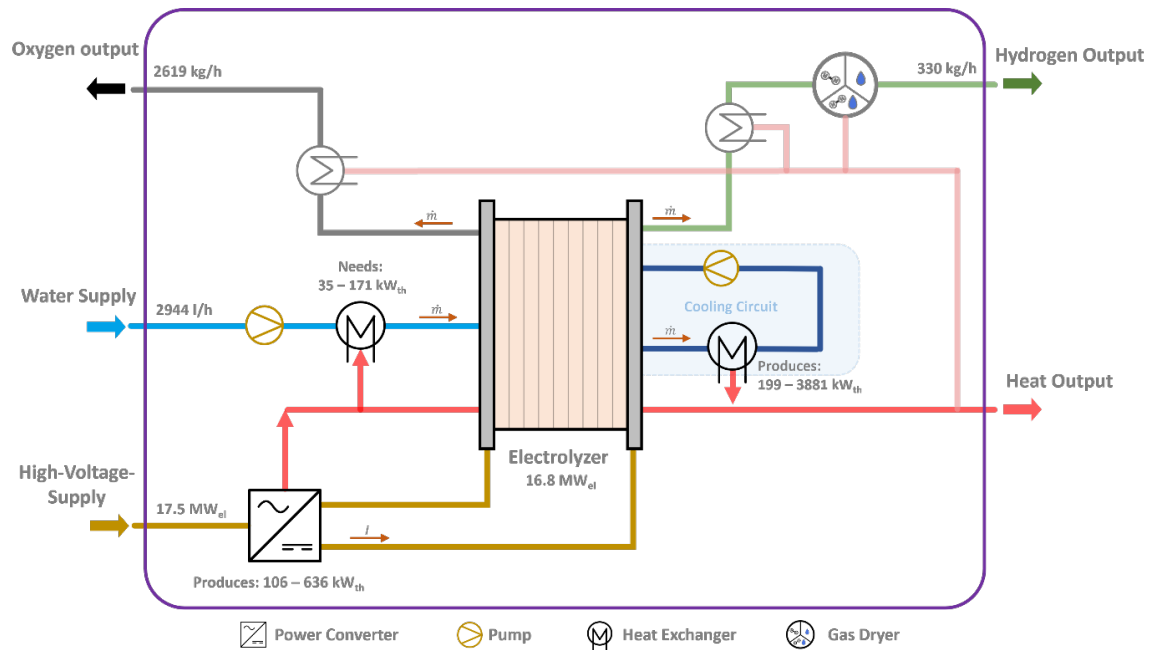


Figure 5.17. The comprehensive overview of an electrolysis plant shows the current results of the project. The values represent the heat output at minimum and maximum level of the modeled 17.5 MW_{el} Siemens Silyzer 300. Based on [73].

B6C thyristor-based rectifier was analyzed. The heat output of the rectifier was compared to that of the stack, and it was found that the rectifier produced 22 % (285 kW_{th}) of heat at partial load and 16 % (635 kW_{th}) at full load [74]. Extracting heat from megawatt-scaled rectifiers is typically accomplished via water cooling, due to its superior heat extraction capabilities. There is a lack of literature on the use of rectifier heat for electrolyzer stack applications, underscoring the need for further research in this area.

In consideration of the findings, it has been demonstrated that the heat from the balance of plant should be given greater consideration in the calculation of the total heat output of the electrolyzer plant. Nevertheless, other components, such as a gas dryer or the preheating of process water, necessitate heat, which are not included in these calculations. The development of a comprehensive model of an electrolyzer plant incorporating multiple balance of plant components is currently underway.

5.6.3. Summary

The strategic localization of electrolyzers, in combination with their role in redispatch mechanisms and the utilization of waste heat, offers significant potential for improving both energy efficiency and grid stability. By placing electrolyzers in regions with high renewable energy generation and integrating them into redispatch strategies, surplus electricity can be effectively used to produce hydrogen, reducing curtailment and balancing the grid.

The main factor for the choice of the electrolyzer is the redispatch mechanism. Moreover, utilizing the waste heat generated during electrolysis can enhance overall system efficiency by supplying nearby industrial processes, district heating networks, or other heat-demanding applications. This holistic approach not only increases the economic viability of hydrogen production but also strengthens sector coupling by linking the electricity, hydrogen, and heat markets.

6

Further Aspects of Hydrogen infrastructure

6.1. Meta Analysis on LCA of Hydrogen Infrastructure & Prospective LCA Methodology

6.1.1. Life Cycle Assessments of the Hydrogen Infrastructure – Key Insights

There are several ways to transport hydrogen (H_2) from its production to its application. It can be transported by pipeline in gaseous form (GH_2) or as a hydrogen carrier, for instance as liquid hydrogen (LH_2), ammonia (NH_3) or as a liquid organic hydrogen carrier (LOHC). To ensure a sustainable development of the hydrogen infrastructure, it is necessary to consider not only technological, financial, regulatory and social aspects but also environmental aspects. This raises the question of the environmental impact of these hydrogen transport options.

As previously reported by FfE [75], a literature review of Life Cycle Assessments (LCAs) of hydrogen infrastructure has been carried out as part of the TransHyDE Project System Analysis. The aim of the review is to investigate the life cycle greenhouse gas (GHG) emissions of hydrogen transport for each carrier (GH_2 , LH_2 , NH_3 and LOHC), identifying hotspots and mitigation potentials. The focus here is on studies conducting assessments based on LCA methodology as this method is suitable for assessing the environmental impacts of a product, a process or a service over its entire life cycle, from raw material extraction to disposal. In the course of this research, existing LCA studies were evaluated with regard to the system boundaries, the functional unit, the hydrogen carrier and the transport

mode. These publications were analyzed in terms of the GHG potential ($kg\ CO_2$ -equivalent (eq.)) for the different combinations of the hydrogen carrier and transport mode. Additionally, hotspots, influencing factors and reduction potential along the value chain were evaluated.

The review examined 17 publications published between 2017 and 2024. Studies that do not apply the LCA as a method or do not focus on green hydrogen are already excluded. The review shows that within these studies, both the system boundaries and the functional units differ, making it particularly challenging for a comparison of the results. More specifically, most of the studies (79 %) start with the H_2 production process and while 39 % end with the H_2 delivery process for end use, 36 % end with the reconversion process. Furthermore, in 62 % of the studies, the functional unit refers to an amount (usually kg) of hydrogen at a certain purity and pressure. The remaining studies refer to other functional units such as transported energy (in MJ). In addition, various combinations of carrier medium and transport mode were investigated within these studies. The most frequently evaluated combination is LH_2 transported by ship, closely followed by GH_2 transported by pipeline.

Figure 6.1 summarizes the results of the literature review. It shows the GHG potential ($kg\ CO_2$ -eq.) of a combination of different hydrogen carriers and transport modes examined for the functional unit of one kilogram of hydrogen. The considered system boundary starts with the production of green H_2 and ends with reconversion, regardless of the transport distance. The figure displays a boxplot illustrating the distribution of the dataset. The box represents the middle 50 % of the values. The line within the box denotes the median, that is, the value dividing the

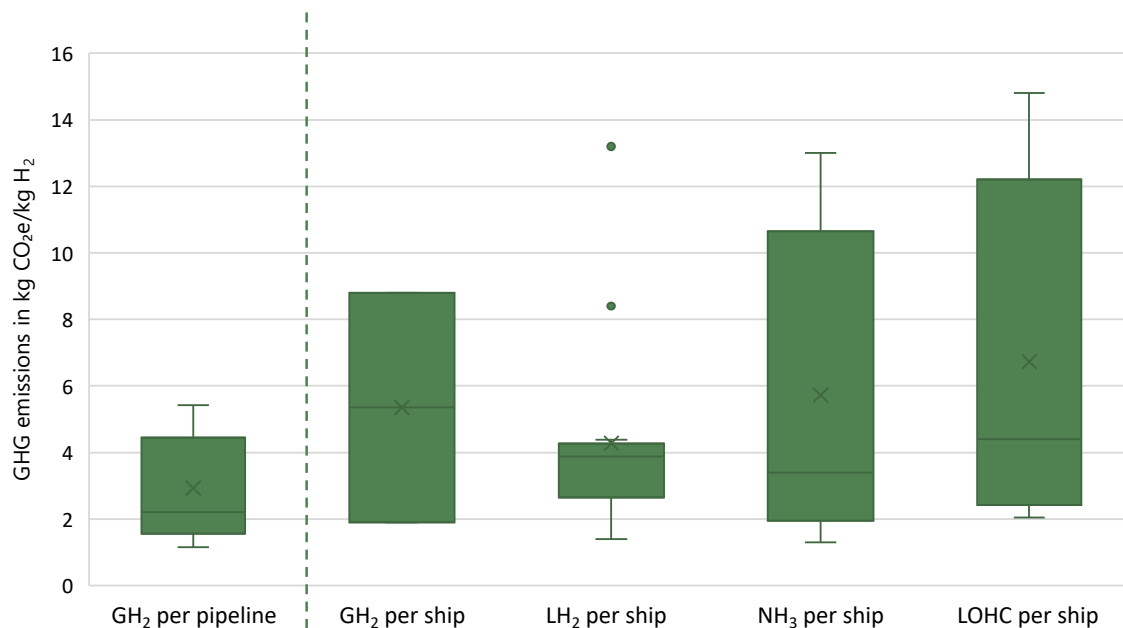


Figure 6.1. Life cycle emissions – system boundary: H₂ production to reconversion, with different assumptions regarding transport distance, used fuel and energy mix (own illustration, based on data gained from [54, 76–83]).

data into two equal halves. The cross indicates the mean of the dataset, whereas the dots represent outliers

The results show a wide range of data points, caused by differing assumptions of the publications, especially regarding transport distance, transport mode combinations and used fuel, assumed energy mix as well as regarding the functional unit in terms of purity and pressure of H₂. Although Figure 6.1 does not provide a clear answer to the question of the most environmentally friendly transport option, it is possible to derive general indications from the individual publications:

- For distances over 1000 km, LH₂ transport tends to have the lowest environmental impact [76, 77, 80, 84]
- The GHG emissions of the GH₂ transport are comparable to the LH₂ transport. Regarding shorter distances, the GH₂ transport is associated with lower GHG emissions than the LH₂ transport. [78, 84, 85]
- The transport of hydrogen via chemical carriers such as LOHC and NH₃ is associated with higher GHG emissions LCA [76, 77, 83, 86]. When considering the publications separately, the respective results show that the NH₃ transport tends to have a lower environmental impact than the LOHC transport. [76, 77, 80]

The emission hotspots vary depending on the carrier medium. For shorter transport distances, energy-intensive conversion or reconversion steps are the main cause of GHG emissions. The following hotspots were identified for the respective combination of hydrogen carrier and transport mode:

- GH₂ by truck: Transport emissions, which are particularly influenced by the transport distance [82, 84].
- GH₂ by pipeline: Electrical energy for the operation of compressor stations for injection and transport [77, 84].

- LH₂: Energy-intensive liquefaction, especially when fossil grid electricity is used [81, 84]. The use of wind power for liquefaction can reduce overall emissions [83, 84]. In ship transport, the use of boil-off gas as a fuel offers the potential for reducing the total emissions [76, 84, 87]
- LOHC: Heat demand of dehydrogenation (reconversion to H₂), especially if the heat demand is covered by natural gas [76, 84]. Using part of the transported hydrogen for dehydrogenation can reduce GHG emissions [77, 83, 84].
- NH₃: Ammonia cracking for reconversion into H₂ [77, 84]. Direct use of ammonia (without reconversion) can reduce the total emissions [77, 84, 88].

Studies conducting sensitivity analyses show that the transport distance has a significant impact on the results of the environmental impact of hydrogen transport. Total emissions increase with increasing transport distance, regardless of the carrier medium and transport mode [77, 78, 80, 84, 85]. This is due to the use of fuels and the electrical energy required for pipeline transport. The influence of transport distance on GHG emissions varies depending on the energy content and transport capacity of the hydrogen carrier. For example, due to the higher energy content of LH₂, emissions from LH₂ transport increase more slowly with distance than GH₂ transported by truck. The longer the transport distance, the more advantageous liquefaction is. [78, 84, 85]

Additionally, the composition of the assumed energy mix represents an influencing factor. The use of renewable energy, especially wind power, significantly reduces transport emissions compared to grid electricity [79, 80, 83, 84, 87]. Electricity supply is particularly relevant for hydrogen carriers, which have a high energy demand. For example, the GHG emissions per kg of H₂ transported for the hydrogen carriers LOHC and NH₃ are 2.4 to 5 times higher when grid electricity is used than when wind power is used [80, 84].

In conclusion, the environmental impacts of H₂ transport vary in the literature due to different system boundaries and data quality. Individual case studies are necessary for decision-making. A comprehensive sustainability assessment in the sense of a Life Cycle Assessment requires the consideration of other environmental impact categories such as eutrophication or water consumption.

6.1.2. Outlook - Prospective Life Cycle Assessment

Future scenarios play a central role in the evaluation of hydrogen technologies, since the entire economy is undergoing a transformation process towards climate neutrality. A well-founded evaluation must take these developments into account. *Prospective* Life Cycle Assessments help to quantify relevant future environmental indicators, such as material requirements, and take into account future energy and technology scenarios along the entire value chain, e.g. an increasing share of renewable electricity, the use of green steel or more efficient manufacturing and utilization in the case of e.g. next generation batteries, PV cells or electrolysis stacks.

Ideally, prospective LCA considers future scenarios for the foreground and background system. However, considering future scenarios for the background system is particularly challenging because LCA practitioners usually use a life cycle inventory (LCI) database with several thousand processes as background system. For example, the LCI database ecoinvent (version 3.10) includes over 23,000 interlinked processes. Hence, the consideration of future technological improvements for each technology relevant along the hydrogen value chain under study can therefore be correspondingly complex. Therefore, for example at Fraunhofer ISE 'premise', a Python-based tool is applied allowing an update of the entire LCI database ecoinvent for sectors like electricity supply, cement production, steel production, transport, and fuel supply. Future production mixes are derived from Integrated Assessment Models (IAM), which model climate change scenarios. Premise includes scenarios from the two IAMs 'REMIND' and 'IMAGE' up to the year 2100. The outputs are LCI databases with over 30,000 interlinked processes, reflecting updated production mixes.

This approach allows the environmental impacts to be modelled not only based on the state-of-the-art but also taking into account future efficiency improvements and progress in defossilisation. This is essential in the case of electricity-intensive green hydrogen and Power-to-X processes, where not only the efficiency of the electrolyser, for example, can have a direct influence on the ecological footprint, but also the background processes such as the provision of steel for wind turbines and DAC systems, the electricity intensity of silicon PV cell production and the use of green polymers and plastics for the production of required components.

6.2. Drivers and Barriers of a European Hydrogen Infrastructure

Within the TransHyDE Project System Analysis framework conditions which affect the development of the hydro-

gen infrastructure today and in the future were identified and collected through workshops, interviews, and a survey. These framework conditions were then assigned into drivers and barriers along a timeline. Many could not be clearly classified and represent different sides of the same coin. For example, CO₂ pricing is an important mechanism to even out the odds for emerging technologies that are often more expensive than existing fossil-based ones. At its core, however, this mechanism leads to a general increase in prices for consumers on the interim. This can yield lower overall acceptance for the overarching energy transition within society, if no social compensation schemes follow.

In general, the assigned drivers and barriers fall into four broad categories which are described in the following: *Prerequisites and resources, Regulatory aspects, Economic efficiency, and Acceptance.*

6.2.1. Prerequisites and Resources

Hydrogen adaption and infrastructure development is dependent on prerequisites and a broad range of resources. For example, a prerequisite for a hydrogen future is a large-scale production of hydrogen. In order to produce green hydrogen by water electrolysis, renewable energies and water is needed. There is also demand for materials e.g., for production plants and infrastructure construction.

Additionally, rules and regulations, as well as economic feasibility could be considered prerequisites for a hydrogen economy ramp-up.

6.2.2. Regulatory Aspects

Rules and regulations govern a potential hydrogen economy. On the one hand, guidelines are needed to implement products and to estimate costs, for example. On the other hand, detailed regulations may hinder fast ramp-up, as these are often correlated with higher costs. Higher costs lead to higher prices that might not meet buyers' expectations.

6.2.3. Economic Efficiency

Economic efficiency and viability are the lynchpins of large-scale implementation. Without them, technological readiness will likely not rise above demonstration projects. Short-term solutions, such as subsidies, may help bridge initial differences in costs of grey and green technologies. However, it is no sustainable long-term option.

6.2.4. Acceptance

In addition to the technical and economic challenges, the ramp-up of the hydrogen economy and the associated development and expansion of the necessary infrastructure is also connected to social issues. These social perspectives exist at various levels, including the perception of the general public and the ongoing media discourse concerning opportunities and risks of the hydrogen economy [4, 89, 90], as well as, for example, the views of employees within industries affected by the transformation, such as the steel and glass industries. Municipalities also represent a crucial societal level of consideration: They are where the concrete implementation of the hydrogen transformation occurs and becomes tangible, i.e. electrolysers, pipelines, storage facilities and refueling stations are approved and built, making

them perceptible to a broad range of stakeholders and the public. Experience from other energy infrastructures, such as renewable energy and transmission lines, indicates that uncertainty often exists among municipal stakeholders, which can sometimes lead to delays in approval processes. Therefore, it is essential to address these aspects early in the implementation of hydrogen projects to mitigate potential obstacles proactively.

In order to reflect these different perspectives, TransHyDE conducted several surveys within the transformation industries (steel, glass, refineries) as well as a Germany-wide municipal survey. In the following, selected results from the survey in the steel industry and a nationwide poll of municipalities will be presented.

From February 20, 2024, to March 20, 2024, a survey was conducted to gain insights into the perspectives of employees in the steel industry regarding the H₂ transformation. The survey was conducted in cooperation with both the workers council and the strategy department of the steel company and completed by 228 participants, who provided their responses through an online questionnaire. The survey consisted of 24 items to capture the employees' views on the adoption and implementation of hydrogen technologies (H₂ transformation). The survey provided valuable insights into employees' perceptions of the potential benefits and challenges associated with the H₂ transformation. In this context, the results show a general support, coupled with a high degree of uncertainty. Particularly, when asked about potential obstacles, concerns were raised regarding the costs, security of supply and feasibility. In summary, the perceived hurdles mainly pertain to the feasibility of implementing the H₂ transformation in terms of technology, costs and available quantities (Figure 6.2).

Regarding potential opportunities, the results indicate that the main focus is on ecological benefits, i.e. the reduction of greenhouse gases. The potential for innovation and the associated competitive advantages are also seen as opportunities (Figure 6.3).

The results underline the importance of successful ex-

amples in real industrial operations to demonstrate technical feasibility and economic viability. This concrete experience is an important signal not only for the public but also for employees in the transformation industries.

Another relevant role for a successful transformation is at the municipal level. Therefore, a nationwide survey was conducted to explore the perspectives of municipalities and municipal stakeholders regarding hydrogen (H₂) transport infrastructure. The survey aimed to assess the level of knowledge, involvement, needs, and concerns of local authorities regarding the development of hydrogen transport networks and their role in the energy transition. The survey was distributed through municipal umbrella organizations (DStGB, DLT) and included 20 items. A total of 174 municipal actors participated in the survey from December 8, 2023 – April 24, 2024. The municipalities were categorized based on their population size. The data show that more than 50 % of the answers come from municipalities with fewer than 25.000 inhabitants, as shown in Table 6.1.

Table 6.1. Population size of surveyed municipalities.

Population Size (inhabitants)	Percentage
fewer than 10,000	20.5 %
between 10,000 and 25,000	36.3 %
between 25,000 and 50,000	11.7 %
between 50,000 and 100,000	7.0 %
between 100,000 and 200,000	14.6 %
between 200,000 and 400,000	7.6 %
exceeding 400,000	2.3 %

The survey explored the extent to which municipal actors are informed about the H₂ core network and the role of municipalities in its development. It also examined the level of involvement of these actors in planning and decision-making processes related to hydrogen infrastructure. In



Figure 6.2. Perceived obstacles regarding the industrial use of green hydrogen.

From your perspective, what are the main chances regarding the industrial use of green hydrogen?"

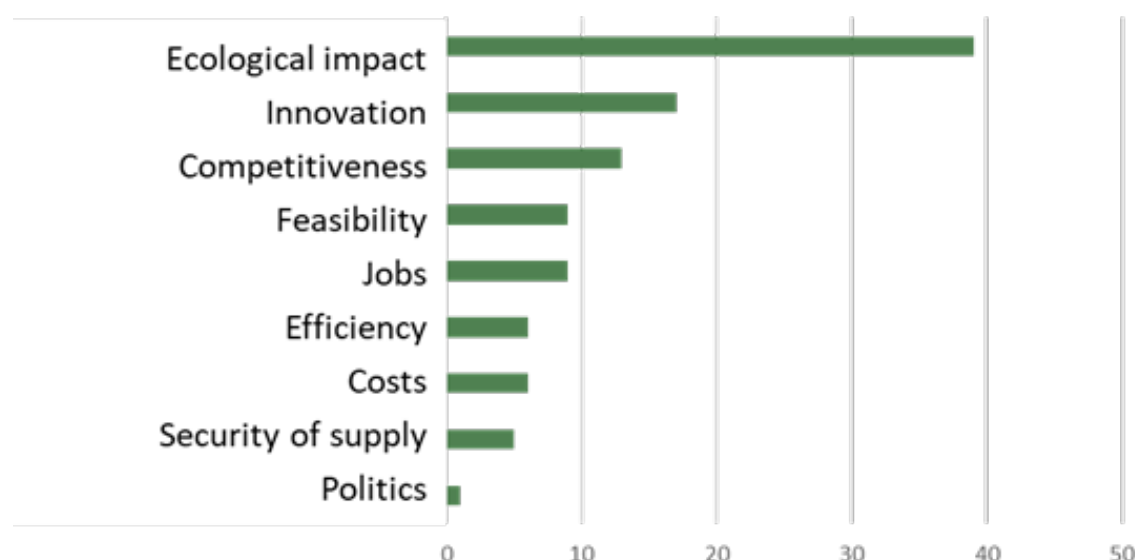


Figure 6.3. Perceived opportunities regarding the industrial use of green hydrogen.

In addition, respondents were asked about the general acceptance of hydrogen transport infrastructure within their municipalities, as well as their views on the broader energy transition, the potential conflicts that could arise, and potential concerns about various risks associated with hydrogen infrastructure. These risks included financial risks, the possibility of accidents, and other operational or regulatory challenges. Furthermore, the survey identified the potential benefits of hydrogen infrastructure for municipalities, such as boosting local economies, creating regional value chains, and securing regional energy supply. Finally, municipal actors were asked about the availability of resources required for the planning and permitting of hydrogen projects. This included factors such as the availability of knowledge and expertise, financial resources, personnel, and a clear strategic vision for hydrogen development in their municipality, as well as their experiences with hydrogen projects to date, as well as any barriers they had encountered. The survey also sought to identify areas where municipal actors needed additional support or resources to facilitate the expansion of hydrogen infrastructure.

The survey on hydrogen (H_2) infrastructure expansion in municipalities revealed important insights into local knowledge, perceptions, and the potential impact of hydrogen projects. The responses indicated varying levels of awareness, acceptance, and readiness for the integration of hydrogen transport networks within local energy systems. The survey results provide detailed insights into the perception and acceptance of hydrogen infrastructure and projects across various municipalities. First, the awareness of the H_2 Core network was examined: 65,8 % of respondents had already heard of this network, indicating a moderate awareness of hydrogen infrastructure development. However, only 31,8 % of respondents knew whether their municipality would be directly affected by the expansion of the network, indicating a lack of information. In terms of acceptance of the energy transition, the survey showed that 80,6 % of respondents rated the acceptance of the energy transition within their community as high. For hy-

drogen projects in particular, 55,9 % of respondents stated that acceptance of such initiatives was high, while 23,5 % were unable to give an assessment. Another finding of the survey relates to previous conflicts arising from infrastructure projects. In 40 % of the municipalities, past projects related to renewable energy or network expansion had led to conflicts, which indicates potential resistance that could also accompany future hydrogen projects. Concerning the impact of hydrogen transportation infrastructure, 75,5 % of respondents agreed with the statement that the expansion of hydrogen infrastructure would positively affect the local economy. 77,2 % believed that this infrastructure could contribute to regional value creation, and 73,1 % stated that it would contribute to securing the regional energy supply. In terms of priority sectors for hydrogen use, the municipal stakeholders identified the following: the mobility sector (60,3 %), the industrial sector (64,4 %), and the heating sector (51,7 %).

When asked about their municipality's preparedness for hydrogen infrastructure development, the survey revealed that only 20,4 % of respondents felt their municipality was sufficiently informed about the hydrogen core network. A mere 11,7 % stated that their municipality possessed sufficient knowledge and expertise regarding hydrogen technologies. Only 7 % indicated that they had adequate financial resources to support hydrogen infrastructure projects. In addition, just 7,6 % reported having sufficient personnel resources for such initiatives. Finally, only 15,8 % of respondents stated that their municipality had a clear vision and strategy for establishing hydrogen infrastructure (Figure 6.4). The survey results suggest that while there is considerable awareness of hydrogen technology and its potential benefits, municipalities face significant challenges in terms of resources, knowledge, and planning. While most respondents acknowledged the positive impacts that hydrogen infrastructure could have on the local economy, regional value creation, and energy security, the lack of adequate resources, such as funding, expertise, and personnel, remains a major barrier. Furthermore, despite

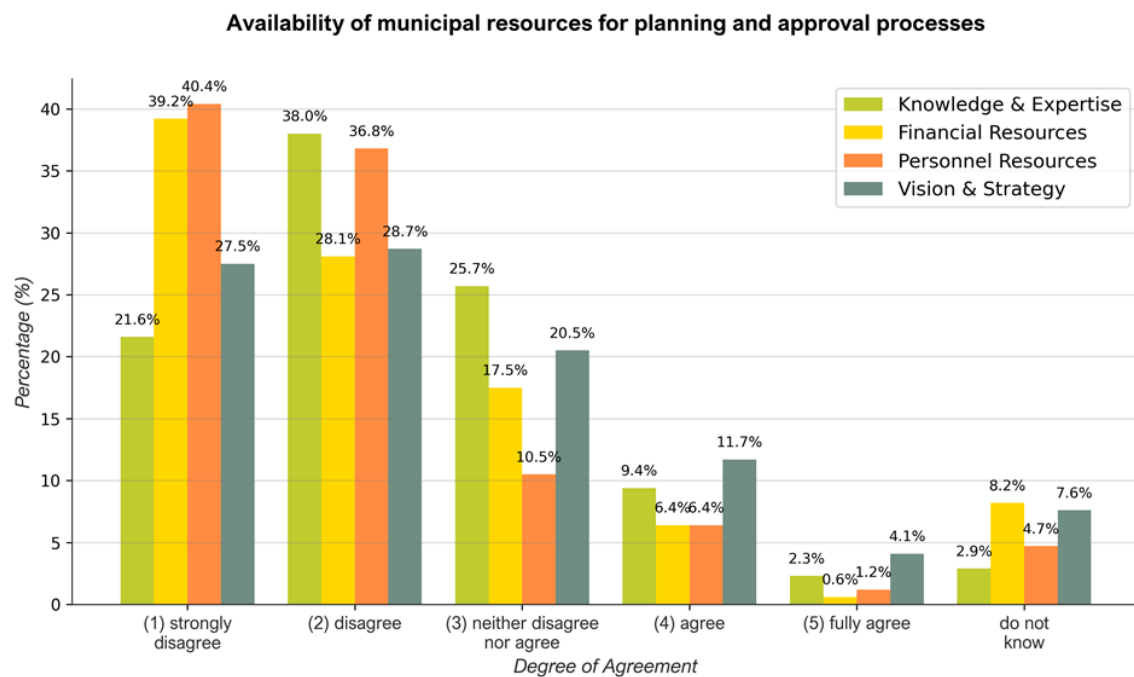


Figure 6.4. Availability of municipal resources for planning and approval processes.

the generally high acceptance of the energy transition, hydrogen projects encounter varying levels of local support, with a significant portion of respondents unable to assess or clearly support these initiatives. Prior conflicts related to other infrastructure projects also highlight the need for careful planning and community engagement to ensure the successful implementation of hydrogen transport infrastructure. These findings emphasize the importance of providing municipalities with the necessary resources, information, and strategic guidance to effectively integrate hydrogen solutions into their local energy frameworks.

All in all, the results of both the industry survey and the nationwide poll indicate a high level of social acceptance for H₂ in principle. However, they also reveal a still limited base of well-founded knowledge. Consequently, transparent scientific communication is necessary, also with regard to possible limitations of the hydrogen transition, to provide a foundation for nuanced opinion-forming processes. This is especially pertinent at the municipal level, where implementation occurs. Here, the results show that even such core infrastructures as the core network are not yet widely known, necessitating increased information and communication measures. Similarly, targeted communication measures combined with further education and training strategies within the transforming industries are needed to develop transformation competencies. When it comes to acceptance, the most important factors are the expected positive environmental impacts (“green electricity”) and the potential economic benefits for regional transformation. These factors should be enabled and made tangible accordingly. In summary, the results emphasize that a successful development of the hydrogen economy requires a holistic approach integrating technical, economic, ecological and social perspectives.

while others influence the establishment of the hydrogen infrastructure in the long term, such as funding measures supporting the ramp-up of a hydrogen economy. Based on these drivers and barriers, options for action were developed within a stakeholder dialogue involving various representatives from politics, business, society, and science and allocated to a time scale from today until 2050. All of the above are part of the TransHyDE digital roadmap, which is available in German. In addition, the digital roadmap shows modelling results of the TransHyDE Project System Analysis for hydrogen production, infrastructure, and consumption. Also, in-depth fact sheets on different energy carriers can be found on the website.



6.3. A digital Roadmap

Some of these drivers and barriers are particularly relevant in the short term, such as the first mover disadvantage,

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