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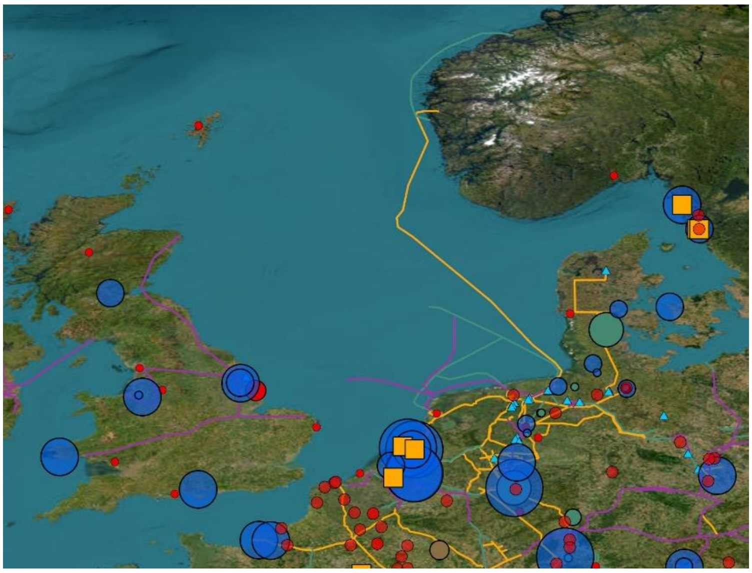
Case study report: Regional transitions in existing bioenergy markets 2.0

IEA Bioenergy: Task 40

February 2026



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Case study report: Regional transitions in existing bioenergy markets 2.0

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Summary

The global energy transition is shifting from centralized fossil fuels to a more decentralized system, with an increasing focus on regionalized energy supply for improved supply security. Commoditization, on the other hand, is promoted as a way to connect regionally available, diverse biomass with global markets. The "Regional Transitions 2.0" project explores whether regionalization and commoditization strategies are mutually exclusive for sustainable bioenergy. The main finding is that both strategies present unique opportunities and risks, and that the regional context is crucial to the sustainability of biobased supply chains. The Regional Transitions 2.0 project has evaluated five different case studies on both regionalization and commodization strategies in Austria, Germany, Sweden, the US, and the North Sea region.

This case study evaluates **the North Sea region** for its critical role as a major hub for energy-intensive industries and trade, and for its extensive energy infrastructure. A key challenge facing this region is the so-called re-emergence of distance, where the high cost of transporting dispersed, low-energy-density renewable resources, such as biomass and hydrogen, replaces the low transport costs of centralized fossil fuel supply chains that have shaped its past development.

The clustering of advanced biofuel production and renewable hydrogen supply could become increasingly important for cost-effective decarbonization, particularly in hard-to-abate sectors such as aviation and maritime transport. Hydrogen is already crucial for producing Sustainable Aviation Fuels (SAF) through pathways like hydrotreated esters and fatty acids (HEFA). Looking ahead, electrofuels (e-fuels) consistently show very high hydrogen requirements, while advanced biofuels like Alcohol-to-Jet (ATJ) and Hydro-processing of bio-based waste oil and fats require moderate amounts. This difference highlights a trade-off: pathways with high carbon efficiency often require significant hydrogen input.

The planned European Hydrogen Backbone (EHB) network and associated electrolyzer projects could connect production hubs with industrial consumers and support climate-neutrality targets. However, it demonstrates significant spatial disparity. The network is densest in Western Europe (Germany, the Netherlands, and Belgium), leveraging repurposed natural gas pipelines and large-scale salt cavern storage. In contrast, regions like Scandinavia and the UK have much less developed infrastructure, suggesting that decentralized, on-site hydrogen production may become a competitive necessity there. Furthermore, a detailed cost analysis in Denmark (Jutland) showed that, while centralized pipeline delivery is currently the most cost-effective option, onsite hydrogen production with storage could become the most competitive option by 2050. This suggests that access to low-cost green electricity may become as important as access to hydrogen infrastructure.

Finally, a significant misalignment exists between the large projected hydrogen demand for advanced biofuels and synfuels by 2050 and the minimal designated allocation for these sectors in current electrolyzer projects, which overwhelmingly prioritize other industries, including chemicals, steel, and power. This misalignment, alongside uncertainty stemming from feedstock availability, green hydrogen supply, and policy efficacy, constitutes a major threat to the successful scale-up of the renewable fuel sector and the energy transition in the North Sea region.

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1. Introduction

1.1 BACKGROUND

The global energy transition towards carbon neutrality is complex and uncertain, but key trends are emerging. These include the increasing cost-effectiveness of solar and PV electricity, the electrification of road transport, and the future potential of a "green" hydrogen economy alongside a circular carbon economy. There is also a shift from centralized fossil-fuel-based energy supply to decentralized, distributed renewable energy systems. Recent conflicts and climate change-driven events have heightened the urgency of this transition, sparking interest in regionalizing energy supply for improved security of supply.

Bioenergy, part of the larger bioeconomy, plays a significant role in this transition, with both regional and global supply chains contributing to sustainable energy. While international bioenergy trade has been crucial for the development of the bioenergy sector and the deployment of renewable energy (Junginger et al. 2019), it also faces criticism for potentially hindering the move towards decentralized, renewable energy and for possibly lacking ecological sustainability (McGovern and Klenke 2016). IEA Bioenergy Task 40 supports the deployment of viable, efficient, and profitable biobased value chains, especially bioenergy, as part of a sustainable energy system and circular economy. Thus, regionalization of bioenergy supply chains is encouraged where it offers clear advantages.

1.2 REGIONAL TRANSITIONS 2.0

The future size and viability of the bioenergy sector, as part of biobased value chains, depends on both its adaptability to the dynamic context of the energy transition and on its role in securing a reliable and sustainable energy system. In the Regional Transitions 1.0 project, experts from IEA Bioenergy Task 40 explored possible strategies to develop sustainable feedstock supply chains in a regional dynamic market context to deliver biomass for different end-use markets (Hoefnagels et al. 2023). **The Regional Transitions 2.0 project aims to demonstrate that regionalization and commoditization strategies are not mutually exclusive to the energy transition.** Their common denominator is that the regional context is important for the sustainability performance of bioenergy supply chains (O'Keeffe et al. 2016). To this end, the Regional Transitions 2.0 project has evaluated five case studies on regionalization and commodization strategies in Austria, Germany, Sweden, the US, and the North Sea region.

- Case study 1: An evaluation of integrating bioenergy communities for the production of renewable natural gas in Austria
- Case study 2: Ecosystem of innovation in the region: Bio-based Innovations from the region of Zeitz and Central Germany
- Case study 3: The role of sugar depots in enabling regionalized supply with commoditized intermediates for commercial-scale biorefineries in the US.
- Case study 4: Cost-effective supply chain configurations for the production of bioelectro- and electrofuels in Sweden
- Case study 5: Hydrogen supply and biofuel production in the North Sea region.

This case study evaluates integration options for advanced biofuel production and renewable hydrogen supply in the North Sea region.

2 Case study description

The clustering of advanced biofuel production and renewable hydrogen supply could reduce transportation costs and improve supply chain efficiencies. The North Sea region was selected as a case study[1] because it covers the largest industrial ports in Europe, hosts energy-intensive industries, and is connected by an extensive energy and transport infrastructure network (IEA 2021).

2.1 THE NORTH SEA REGION

The North Sea Region is an international area situated in northwestern Europe and bordered by Belgium, Denmark, France, Germany, the Netherlands, Norway, Sweden, and the United Kingdom (Figure 1). The strategic importance of this region is underpinned by its ecological and economic functions. It is a biodiversity-rich ecosystem while also functioning as a major hub for fishing, shipping, and logistics, making it one of the world's busiest areas for international trade. Furthermore, it plays a critical role in the European energy supply system, including production and reserves of natural gas and oil, refining, energy trade, and, increasingly, renewable energy supply, particularly offshore wind (DNV 2024, NSE 2024).

The region also hosts major industrial hubs, many of which are concentrated around port areas. These industrial hubs include both energy-intensive industries, such as primary steel, oil refining, and (organic) chemicals, as well as light industries, such as food and feed processing and automotive.

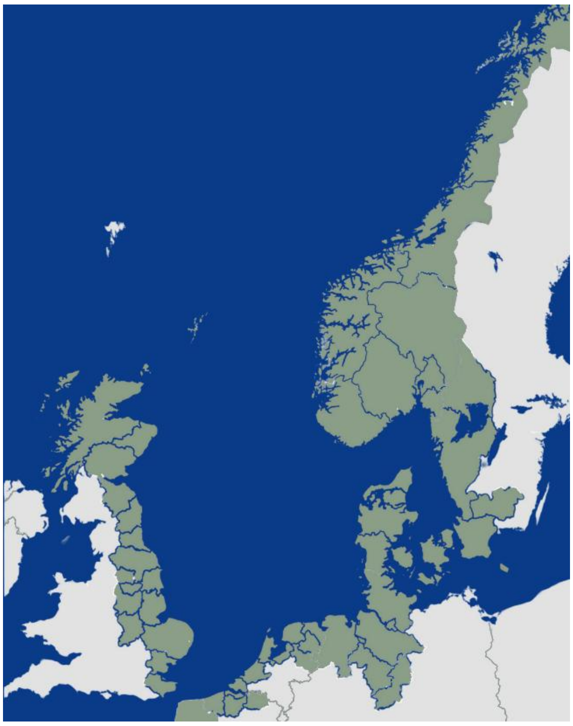


Figure 1 The North Sea region (adapted from Interreg North Sea, 2025)

2.2 CHALLENGES AND OPPORTUNITIES IN THE NORTH SEA REGION FROM THE RE-EMERGENCE OF DISTANCE IN THE CONTEXT OF THE ENERGY TRANSITION

Although regional natural gas and oil supply are important, many industrial clusters in the North Sea region have developed independently of the direct proximity to the resources required, enabled by very low transport costs and well-developed transportation and energy infrastructure. This has led to the concentration of large, centralized production agglomerations independent from resource locations. This so-called ‘death of distance’ for resources and goods (Day, 2022) is an important driver for the historic development of these large industrial agglomerations[2] in the North Sea region. Energy-intensive energy and manufacturing industries, such as oil refineries, iron and steel, chemicals, and non-metallic mineral production (cement, ceramic & glass), have benefited from access to cheap resources, low energy costs and downstream markets.

[1] Part of the analysis is also available in more detail in a master’s thesis report (Alempiew, 2025).

[2] Agglomeration theory refers to the beneficial aspects that firms in an industrial setting can obtain through locating in near proximity of one another. These benefits include aspects such as, knowledge spill over, shared infrastructure, and access to a skilled labour pool.

In contrast to fossil fuels, renewable resources are more dispersed, and transport is relatively expensive. Moving electricity over long distances requires high-voltage transmission lines, which are expensive to build and maintain. The cost of transporting hydrogen is a major factor in its viability as a future energy source, largely due to its low volumetric energy density (IRENA, 2019). Also, biomass has a low energy density, making it more expensive to transport in its raw form. The transport cost can be reduced by processing biomass early in the supply chain, for example, by pelletization, but it will still remain significant. As a consequence, when moving towards green supply chains, distance will become a decisive factor again (Figure 2). In this context, many industrial sectors in the North Sea region will therefore be challenged.

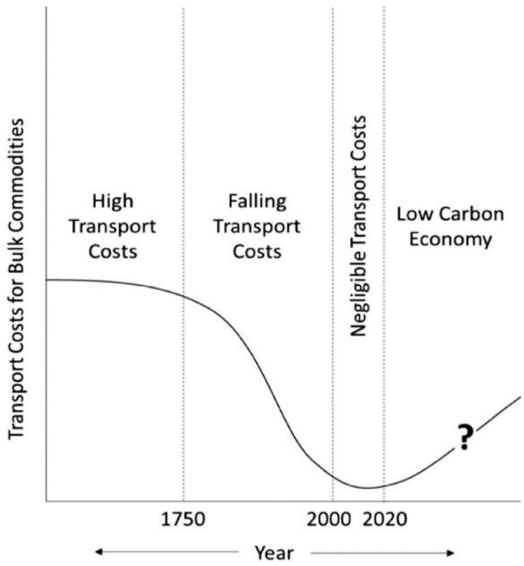


Figure 2 Development of transport cost of bulk commodities, including energy (Day, 2022)

2.3 RENEWABLE FUEL PRODUCTION AND THE ROLE OF HYDROGEN

Both biomass and hydrogen are projected to play a critical role in decarbonizing hard-to-abate or hard-to-electrify sectors, including transport and energy industries such as steel, ammonia, and other high-temperature industrial processes. Despite its promise, the widespread adoption of green hydrogen faces significant logistical challenges concerning supply, storage, and transportation. The interconnected development of biomass and hydrogen applications across transport and industry will significantly impact their deployment.

Hydrogen is already crucial for producing biodiesel and sustainable aviation fuels (SAF), specifically for hydrogenation-derived renewable diesel (HDRD) and Hydro-processed Esters and Fatty Acids (HEFA). The HDRD/HEFA process involves hydrotreating, which uses hydrogen and catalysts to convert fats and oils, such as used cooking oil, into drop-in fuels, including renewable diesel and SAF. The total production capacity of HDRD/HEFA was 7.6 million liters (ML) in 2024, producing 4.2 ML of fuel (USDA FAS, 2024). Many of these plants that are in operation or planned[3] are located in the North Sea region and are located near existing oil refineries or blending terminals in port areas (Figure 3). Today, hydrogen is mainly supplied through the steam reforming of natural gas, but if it were replaced with green hydrogen, it could reduce the GHG intensity of HEFA by 20% (Pavlenko and Searle 2021).

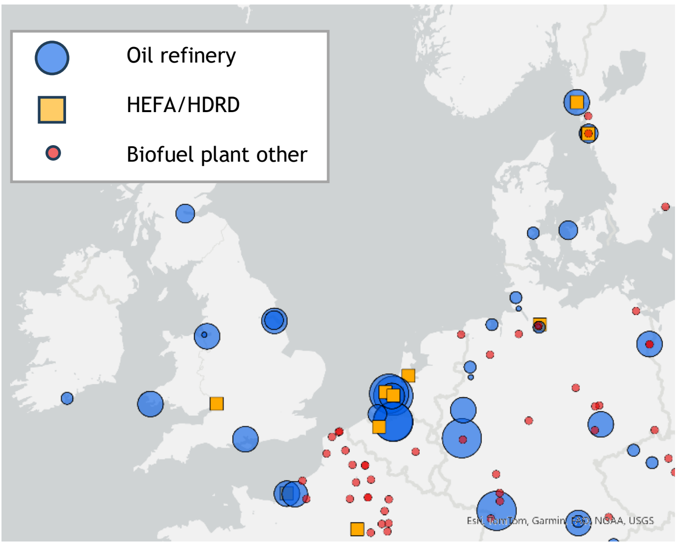


Figure 3 Existing and planned HDRD/HEFA plants, oil refineries, and other biofuel plants in the North Sea region (biofuel plant locations from RISE (2024) and IEA Bioenergy Task 42 (2024). Oil refineries: CONCAWE (2025).

[3] The planned capacity also includes the Rotterdam biofuel plant located in the Shell Energy and Chemicals Park in Rotterdam, which was recently cancelled (Shell 2025).

Next to existing biofuel plants, the hydrogen integration potential could grow substantially with the deployment of advanced biofuels, electrofuel, and hybrid bio-electrofuel production systems. Many of these pathways require or could be combined with hydrogen to produce renewable liquid fuels. Figure 4 illustrates the hydrogen requirement per unit of liquid renewable fuel produced across different pathways.

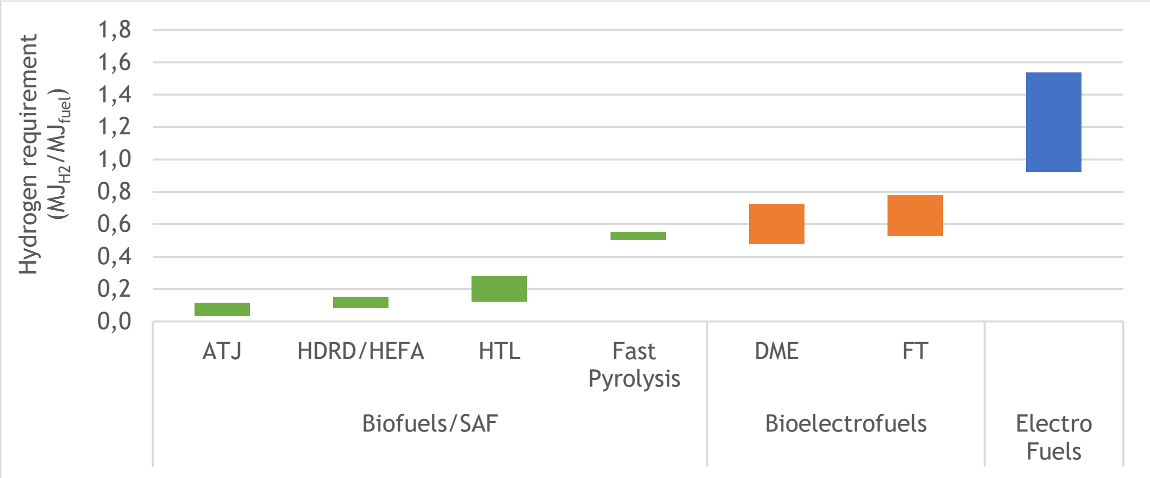


Figure 4 Hydrogen requirement for biofuels, bioelectrofuels, and electrofuels in a selection of different production pathways (in MJ_{H2}/MJ_{fuel}). A detailed overview of the individual systems is provided in Appendix 1.

Among biofuel conversion routes, ATJ (Alcohol-to-Jet) has the lowest hydrogen requirement, followed by HDRD/HEFA, with values between 0.082 and 0.153 MJ/MJ. Hydrothermal Liquefaction (HTL) displays moderately higher hydrogen demands, spanning from 0.12 to 0.28 MJ/MJ, while fast pyrolysis exhibits relatively high values of 0.50–0.55 MJ/MJ, mainly resulting from the higher O/C ratio in pyrolysis oil compared to HTL. Biomass gasification followed by DME or Fischer-Tropsch (FT) synthesis does not need hydrogen, but hydrogen and oxygen from electrolysis could be used to improve the overall energy and carbon efficiency of these systems (Section 3.2). The ranges shown in Figure 3 represent different configurations (see Appendix 1 for details).

Hydrogen is also a key input for Renewable Fuels of Non-Biological Origin (RFNBOs), also known as electrofuels or e-fuels, particularly for the aviation sector, where it is critical for reducing rising carbon emissions (Uslu, 2020). Electrofuel pathways (e-fuels) consistently show hydrogen-to-fuel energy ratios above 0.9, with e-FT kerosene ranging between 0.92 (co-electrolysis) and 1.40 (alkaline electrolysis). Other e-fuels, such as e-Methane (1.19), e-Methanol (1.16), and e-MTK Kerosene (1.25), display comparable values, whereas e-OME (3-5) demonstrates the highest requirement at 1.54.

In the context of the rollout of renewable liquid fuel production using hydrogen, agglomeration will likely play a significant role, as refineries can benefit from locating near hydrogen access hubs, together with other hydrogen demand industries, thus sharing infrastructure costs, associated with hydrogen transport and storage (Riera et al., 2023). This act of co-location, referred to as clustering, has the potential to foster innovation through the exchange of expertise and technological advancement and can also be a helpful factor in facilitating regulatory compliance policies. This will be pertinent not only to the development of hydrogen demand industrial facilities, such as renewable liquid fuel refineries, but also likely to the emergence of hydrogen supply facilities (Nunes et al., 2020).

2.4 HYDROGEN INFRASTRUCTURE

The EU currently consumes approximately 8 Mt of hydrogen annually, primarily in ammonia production, chemicals, and refining. Most of this hydrogen is produced via natural gas reforming, a process that generates substantial CO_2 emissions unless coupled with carbon capture and storage. Only a small fraction is currently produced by electrolysis powered by renewable energy, known as "green hydrogen" (European Commission, 2020a). Green hydrogen is central to future sustainable fuel strategies, including sustainable liquid fuels (European Parliament and Council, 2023a; European Parliament and Council, 2023b).

The EU's initial 2020 hydrogen strategy aimed for at least 6 GW of renewable hydrogen electrolyzers by 2024, producing up to 1 million tonnes of renewable hydrogen, and increasing to 40 GW and 10 million tonnes annually by 2030 (European Commission, 2020a). Geopolitical events, notably the 2022 invasion of Ukraine, intensified the urgency to reduce reliance on Russian fossil fuels. In response, the REPowerEU plan amplified the EU's hydrogen ambitions, targeting an additional 15 million tonnes of renewable hydrogen capacity by 2030 (10 million tonnes domestic, 5 million tonnes imported) (European Commission, 2023).

The European Hydrogen Backbone (EHB)

The European Hydrogen Backbone (EHB) initiative is a collaborative effort by 33 energy companies across 28 countries to create a comprehensive hydrogen network throughout Europe. The plans were updated in 2022 to respond to the European Commission's RePowerEU proposal, which aims to reduce the continent's reliance on energy imports from Russia (Sagdur et al.,2023). Key aspects of the EHB include:

- **Corridors**: The initiative anticipates the development of five pan-European hydrogen supply and import corridors, connecting industrial hubs, ports, and regions with significant hydrogen production capacity.
- **Production**: By 2030, the EHB aims to facilitate the production of over 20 million megatons of renewable and low-carbon hydrogen.
- **Infrastructure**: The network is projected to reach nearly **53,000 kilometers by 2040**, with over 60% of the pipelines repurposed from existing natural gas infrastructure.
- **Demand**: By 2040, the network is expected to meet a forecasted demand of 1,640 TWh per year, serving industrial needs first and then expanding to other sectors like heavy transport, buildings, and long-term energy storage.

3 Economic and ecological viability

3.1 ECONOMIC VIABILITY

Large-scale hydrogen infrastructure, such as the EHB Initiative, could become crucial to developing renewable liquid fuels by providing cost-effective access to hydrogen. A key challenge is the uneven geographic distribution of the planned infrastructure. The planned hydrogen infrastructure varies significantly across the region, as shown in Figure 5. Germany, the Netherlands, and Belgium already have a well-developed network with dense pipelines, numerous electrolyzer projects, and access to salt cavern storage options, which could act as key hubs. In contrast, regions like Scandinavia, Eastern Europe, and the UK have a much less developed infrastructure, with fewer pipelines, limited electrolyzer projects, and little to no large-scale storage, especially in inland areas of the UK, Sweden, and Norway. While electrolyzer projects are strong in the UK and Western Europe, they are scarce in the north and east.

Advanced biofuel plants tend to cluster near proposed pipelines, with notable exceptions in Scandinavia, and show signs of co-location, forming clusters in places like the Netherlands. In regions like Sweden, where large pipelines are limited, smaller-scale onsite hydrogen production could become a viable and competitive alternative (Pettersson and Axelsson, 2025). In these regions, advances in electrolyzer technology could make this decentralized approach more feasible, potentially creating localized hydrogen demand clusters separate from the main network.

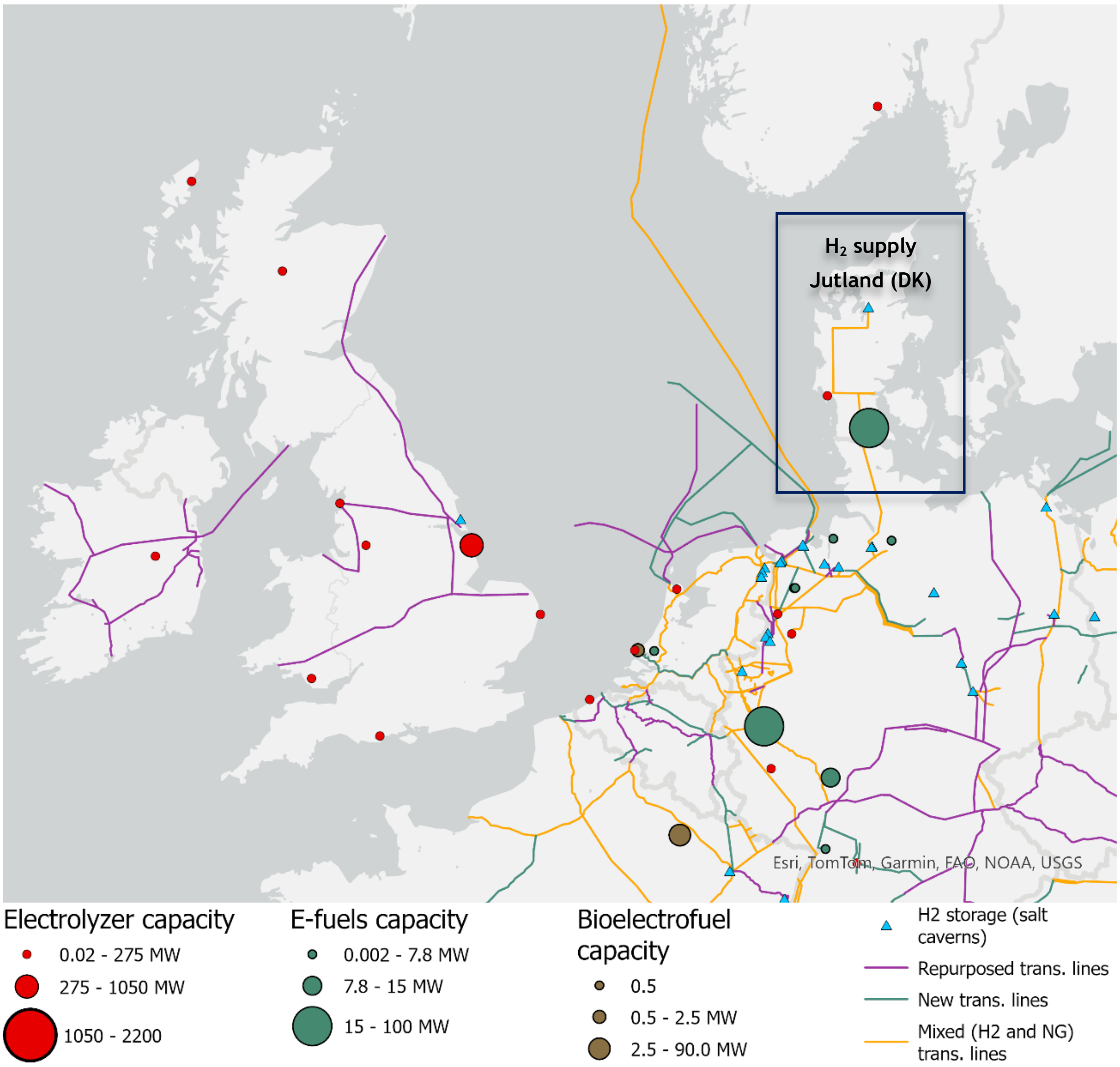


Figure 5 Potential deployment of hydrogen Infrastructure in the North Sea region, including electrolyzers, pipelines, salt cavern storage, and planned electrofuel and bioelectrofuel capacities. Close up for hydrogen supply: North Jutland, Denmark (DK). A detailed description is provided in Appendix 3.

To demonstrate the economic viability of hydrogen supply to a biorefinery, Jutland in Denmark was selected for a detailed analysis (see Figure 5). Five different hydrogen supply chain configurations were analysed for 2030 and 2050:

- Scenario 1: Pipeline and Salt cavern storage
- Scenario 2: Pipeline and Compressed storage
- Scenario 3: Truck and Salt cavern storage
- Scenario 4: Truck and Compressed storage
- Scenario 5: On-site production and Compressed storage

The detailed assumptions for transport distances, costs, and system performance are provided in Appendix 2; the calculated hydrogen supply costs for these scenarios are shown in Figure 6. The most cost-effective option is centralized production with pipeline transport, yielding the lowest levelized cost of €5.3 per kg (€3.5/kg for production and €1.7/kg for transport). On-site production is slightly more expensive at €5.8 per kg, with almost all of that cost attributed to production. Centralized production using truck transport is the least feasible, with total levelized costs ranging from €6.2 to €6.6 per kg, largely because transport costs account for nearly half the total. By 2050, onsite production with onsite storage becomes the most competitive option, achieving the lowest levelized cost of €3.4 per kg. Centralized production with pipeline transport remains viable but is less competitive, with costs ranging from €4.3 to €4.4 per kg. Truck transport for high daily demand remains unfeasible, resulting in high levelized costs of €5.2-€5.7 per kg, with transport alone accounting for over half the total cost.

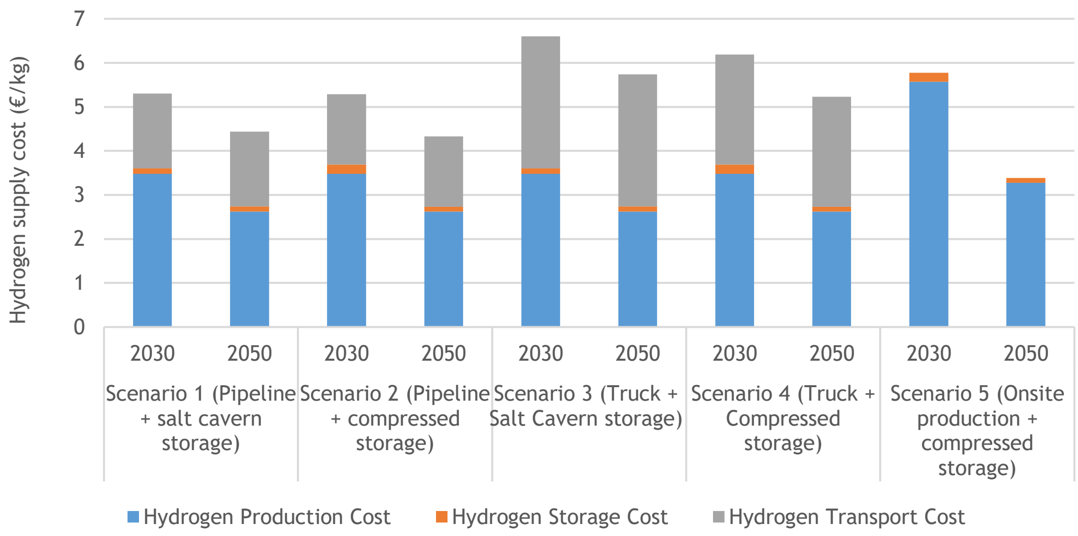


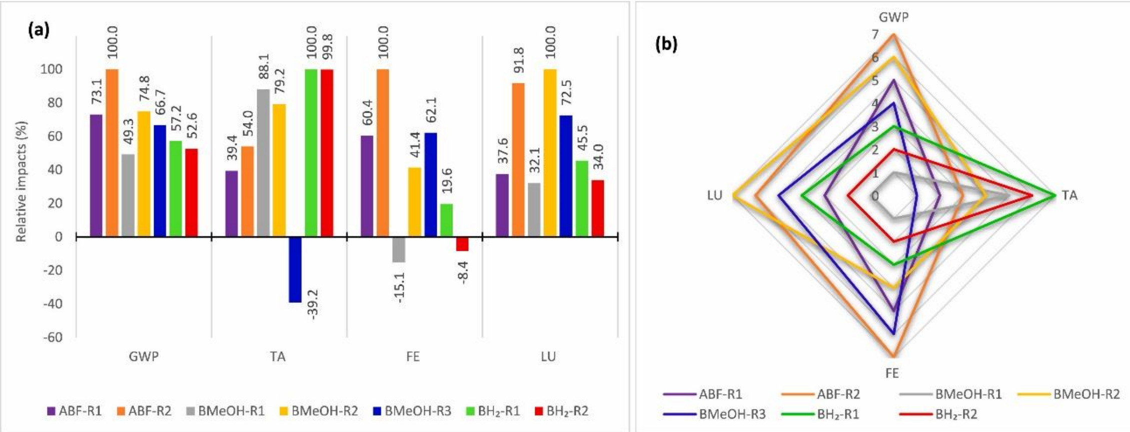
Figure 6 Hydrogen supply cost for different supply chain configurations at 36.5 kt/y capacity. Adapted from Alempiew (2025).

These cost estimates for 2030 and 2050 are higher than some studies because of the assumed use of Solid Oxide Electrolysis Cell (SOEC) technologies rather than the cheaper, more mature alkaline electrolyzers. Despite this, the 2030 cost projections align with the broad, uncertain range reported in recent publications (Scott, 2024). Furthermore, these projections support the scientific consensus that by 2050, advancements in electrolyzer technology and the high capital expenditure of new pipelines will likely make local production more competitive than centralized production (Galimova et al., 2023).

3.2 ECOLOGICAL VIABILITY

3.2.1 Life cycle assessment

The ecological viability of electrofuels and biofuels as separate pathways is evaluated in multiple studies using life cycle assessment (LCA). Few studies have examined the ecological implications of integrating green hydrogen and biofuel supply chains. A recent study from IEA Bioenergy ITP (Padi et al. 2025) compared 7 biofuel case studies to identify best practices over global warming potential (GWP), terrestrial acidification (TA), freshwater eutrophication (FU), and land use (LU) (Figure 7). The geographic scope of Western Europe aligns with the North Sea region and provides insights into potential synergies and trade-offs arising from biofuel and green hydrogen integration strategies. The results show that biofuel systems without hydrogen integration outperform those with hydrogen integration, due to the assumed upstream emissions from the electricity supply (marginal mix, Western Europe, 2030). These results highlight the need for a cleaner electricity supply to benefit from the improved product yields, reduced land use, and improved carbon efficiency of these integrated supply chains.



ABF-R1: hydrothermal liquefaction of wood chips followed by biorude hydrotreating using hydrogen from electrolysis. **ABF-R2:** ABF-R1 route combined with CO_2 capture and hydrogen from electrolysis for conversion to methanol. **BMeOH-R1**: gasification of torrefied wood chips followed by methanol synthesis. **BMeOH-R2:** adds hydrogen to the syngas and oxygen to the gasifier from electrolysis to the BMeOH-R1 route. **BMeOH-R3**: similar to ABF-R2, but with synthetic methanol as the main output and biocucrude and biochar as by-product outputs, **BH2-R1:** hydrogen production from multi-stage biomass gasification (pyrolysis followed by gasification and water-gas-shift). **BH2-R2:** hydrogen production from biomass gasification, Torrgas two-step system.

Figure 7 Comparison of the seven-case study biofuel process routes. (a) Percentage relative impacts, and (b) Rankings of the biofuel routes on an equal impact weighting basis (NB: 1 and 7 represent best and worst performances, respectively) (Padi et al. 2025).

3.2.2 Carbon efficiency, energy efficiency, and hydrogen requirement

Figure 8 presents a radar chart comparing advanced biofuel production pathways across three performance metrics: hydrogen demand, carbon efficiency, and energy efficiency. Hydrogen demand is expressed as MJ H_2 input per unit of fuel output, while carbon and Energy efficiency show the percentage of feedstock input per unit of fuel output (e.g., 0.8 = 80%). Carbon efficiency represents the proportion of carbon in the final fuel (kerosene, gasoline, diesel, etc.) relative to the carbon initially present in the feedstock.

Bio-DME and Bio-FT clearly outperform the other pathways in carbon utilization (92.5% and 85.1%, respectively), converting more than 85% of feedstock carbon into final fuel. In contrast, ATJ achieves only 21.8% carbon efficiency due to the carbon losses occurring during the conversion of raw biomass to alcohol. Although ATJ is at unfavorable points in terms of carbon efficiency, among all pathways, ATJ stands out for its exceptionally low hydrogen requirement (0.076 MJ/MJ), whereas Bio-DME and Bio-FT are at the opposite extreme. The HDRD/HEFA pathway sits between these extremes: it achieves the highest reported energy efficiency (69.1%) and a moderate carbon efficiency (58.9%), making it a relatively balanced option with lower hydrogen demand than gasification-based pathways. HTL and fast pyrolysis offer a mid-range profile, with hydrogen demands of 0.19 MJ/MJ and 0.53 MJ/MJ, and strong energy efficiency (56.3% and 64.5%) and carbon efficiency (62.0% and 62.5%). Taken together, the chart highlights a clear trade-off. Pathways with high carbon efficiency require significant hydrogen input, while pathways with low hydrogen demand compromise on carbon or energy efficiency. It should be noted that direct comparison across pathways is challenging, as the underlying feedstocks vary in type and quality, and the range of final fuel products (e.g., jet fuel only versus DME) differs significantly.

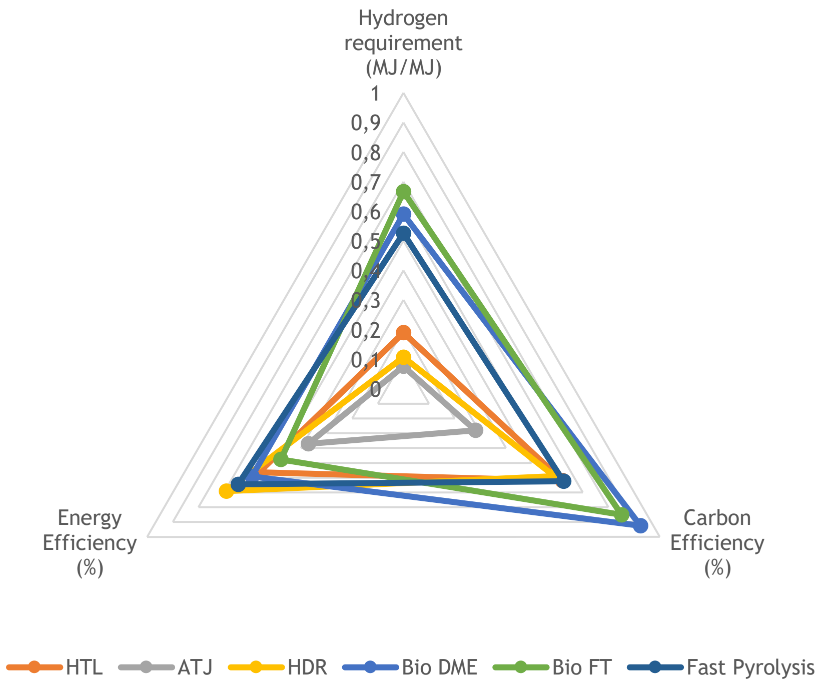


Figure 8 Comparison of conversion efficiencies and hydrogen demand across selected biofuel and bioeelectrofuel production pathways. Details from the individual supply chains and references are provided in Appendix 1.

4 Regional development/community building

Industries, and in particular energy-intensive industries, are challenged by increased global competition, (geo)political developments and uncertainties, high energy costs, especially in the context of the energy transition. As an example, the combination of declining demand resulting from the shift to renewable energy in transport and supply disruptions has already led to the closure of multiple oil refineries, particularly in Europe (IEA 2024a, S&P 2024). According to the IEA (2024b), capacity of 1.0 to 1.5 barrels/day could close by 2030. However, the transition to a climate-neutral economy presents a major regional development opportunity for the North Sea region, such as converting existing oil refineries to renewable fuel production facilities, including biorefineries (S&P 2024).

Offshore wind power is at the core of the energy transition in the North Sea region (Gusatu et al. 2020). Industry must be able to rely on this clean power for direct electrification and for producing green hydrogen via electrolysis. Furthermore, sustainable bioenergy and potentially bioenergy with carbon capture and storage (BECCS) must be strategically integrated for hard-to-abate sectors like maritime and aviation, and high-temperature processes where electrification or hydrogen use is less feasible. Developing this new energy architecture, including vast infrastructure for hydrogen pipelines, CO_2 transport networks, and facilities for sustainable bioenergy supply chains, could potentially create new high-value jobs and revitalize port-adjacent economies (Wyns and Khandekar, 2023).

The European Hydrogen Backbone’s proposed hydrogen network utilizes a combination of new pipelines, repurposed natural gas pipelines, and mixed pipelines (Figure 5). The proposed network is densest in Germany, the Netherlands, and Belgium, forming a robust core network that heavily leverages existing natural gas infrastructure. Advanced biofuel production facilities, such as hydrotreatment plants, are distributed throughout the region and often in proximity to the proposed hydrogen pipelines. However, there are exceptions, particularly in Sweden and Norway, where plants are located far from the projected network. Salt cavern hydrogen storage, which provides large-scale, long-term hydrogen storage, is concentrated in northwestern Germany and the eastern Netherlands. The UK and northern Europe have few large-scale storage options.

The analysis of the hydrogen network and biofuel plant locations reveals a significant **spatial disparity**. Electrolyzer projects are most concentrated in Western Europe, with a high density in Germany and the Netherlands. In contrast, the Nordic and Eastern Baltic countries have very few projects. Most electrolyzers are, however, small-scale (0-25 MW). While many projects are dedicated to producing hydrogen for synthetic fuels, only one project was identified for biofuel production.

5 Markets: opportunities and threats

The integration of green hydrogen into renewable fuel pathways provides both promising and challenging market prospects. Emerging technologies like Alcohol-to-Jet and Hydrothermal Liquefaction, as well as the more mature technology of Hydro-processing of bio-based waste oil and fats, require relatively low hydrogen consumption per unit of produced fuel. The development of advanced biofuels and bioelectrofuels offers additional market opportunities to integrate green hydrogen.

5.1 OPPORTUNITIES

The RED III, ReFuelEU Aviation, and FuelEU Maritime Regulation are driving significant projected growth in sustainable liquid fuels, which are crucial for decarbonizing hard-to-abate transport sectors such as aviation, maritime, and freight by 2050. Projections indicate that advanced biofuels and synthetic fuels (synfuels) will play a crucial role, with pathways like Bio Fischer-Tropsch (FT) and Hydrothermal Liquefaction (HTL) showing the greatest potential, though their scale-up requires substantial investment. Technologies such as Bio FT, Fast Pyrolysis, and Bio DME could all be integrated with green hydrogen.

The levelized cost of hydrogen production via electrolysis is projected to become a more competitive solution, as anticipated reductions in capital expenses and renewable electricity prices are expected to lead to significant cuts in overall levelized costs. Nevertheless, the cost competitiveness of green hydrogen remains a challenge, as it is still more expensive than grey hydrogen produced from natural gas (IRENA, 2021).

5.2 THREATS

A significant misalignment exists between the projected demand for green hydrogen in the renewable fuel sector and the planned hydrogen supply infrastructure (Alempiew 2025). While hydrogen demand for producing advanced biofuels and synfuels is projected to reach tens of petajoules per year by 2050, current and future hydrogen production facilities, particularly electrolyzer projects, show minimal designated allocation for these end uses, overwhelmingly prioritizing other sectors like traditional refining, steel production, grid injections, power, and direct use in mobility. The gap between projected demand for hydrogen, green electricity, and allocated designated supply of these energy sources underscores the importance of aligning the joint energy-industry transition (Wyns and Khandekar, 2023).

Analysed projections of advanced biofuel deployment show wide variation across scenarios, both in the scale of total sustainable liquid fuel production and in the distribution and fuel type (Alempiew 2025, Chiaramonti 2021). The high degree of uncertainty stems from multiple drivers across the value chain, specifically feedstock availability, the pace of technological advancement, and the effectiveness of policy implementation.

Similarly, while the integration of green electricity and advanced biofuels offers opportunities, competition with electrification for light-duty road transport is also a barrier to the development of advanced biofuels needed for heavy-duty road transport, maritime, and aviation.

6 Conclusions

The transformation of the energy and industry sectors from largely fossil-based to carbon-neutrality creates both challenges and opportunities for industrial agglomerations. Many large, centralized industrial hubs were developed as a result of relatively low transport costs of energy and raw materials. The North Sea region hosts many of these major industry and transport hubs. However, dispersed renewable resources like renewable electricity, biomass, and hydrogen are replacing the historically low costs of fossil fuel supply chains. The location and supply chain cost of clean energy will therefore drive a new form of industrial clustering around renewable power hubs, but they are also influenced by existing infrastructure and industrial capital. The integration options of advanced biofuel production and renewable hydrogen supply for the North Sea region is an example of these emerging clustering options.

The scale-up and commercialization of advanced biofuels and renewable fuels of non-biological origin require supply chain and process optimization that strategically balance biomass resource efficiency, net carbon utilization efficiency, and energy efficiency against established metrics, including carbon intensity (GHG footprint) and supply chain economics. This case study compares these performance indicators across different integrated hydrogen and advanced biofuel systems.

The comparison of different pathways in this study shows a clear trade-off: high-carbon-efficient pathways often require significant hydrogen input, while lower-hydrogen-intensive options commonly achieve moderate carbon efficiency. Further extending the evaluation with life cycle assessment shows that the improved product yields, reduced land use, and improved carbon efficiency of these integrated hydrogen and biofuel value chains could still lead to burden shifting if hydrogen is produced from the average electricity mix for 2030 in Western Europe, resulting from upstream emissions of electricity supply. The integration of hydrogen into biofuel production is therefore only environmentally advantageous if the hydrogen is sourced from low-carbon pathways, such as green hydrogen. A reliable, high-volume supply of sustainably produced hydrogen is therefore a critical enabler for achieving commercial-scale production of these renewable fuels.

The deployment of the European Hydrogen Backbone (EHB) could provide access to (green) hydrogen at cluster locations, but there are some major hurdles. First, it shows significant spatial disparity, concentrating infrastructure (pipelines, storage) in Western Europe (Belgium, Germany, Netherlands). In regions with sparser networks, such as Sweden, Norway, and the UK, decentralized, on-site hydrogen production might remain the preferred option. Secondly, there is a substantial misalignment between the projected hydrogen demand for advanced fuels by 2050 and the minimal designated capacity in current electrolyzer projects, which heavily prioritize energy-intensive manufacturing industries (steel, chemicals, power). And finally, onsite hydrogen production appears to become the most competitive solution by 2050, despite centralized pipelines being cheapest today. Note, however, that the most viable option depends on multiple context and location-specific factors that were not included in this evaluation.

The results of this case study are therefore exploratory and limited to a selected number of integrated hydrogen and advanced biofuel systems, with only the hydrogen supply modeled in the region. The possible synergies and trade-offs of hydrogen and advanced biofuel integration options are location and context-specific. Furthermore, other integration benefits, such as shared infrastructure and excess heat used by other industries, were not assessed in this report. Integrated supply chain modeling could provide further insights into the North Sea region's energy transition by quantitatively evaluating the economic, logistical, and spatial viability of integrating green hydrogen and biofuel pathways across different centralized and decentralized supply chain configurations.

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Appendices

Appendix 1 - Hydrogen demand, carbon efficiency, and energy efficiency

Table 1 Hydrogen demand, carbon efficiency, and fuel yield of HTL, fast pyrolysis and ATJ pathways.

Fuel type	Pathway(s)	H_2 requirement (MJ_{H2}/MJ_{fuel})	Carbon Efficiency	Enery efficiency	Source
HTL	Sewage sludge to upgraded fuel; Catalytic upgrading of biocrude; HTL 350◦C and a pressure of 22 Mpa.	0.279	0.424	0.405	Penke et al., 2021
	Pine wood to upgraded fuel; Fe-assisted lignocellulosic biomass; 330 ◦C, 200 bar; The waste streams, soluble organic in the water phase and the gases coming from the red mud reduction, are converted into H2 needed for the hydrotreating unit	0.203	0.800	0.674	Mousavi et al., 2024
	Sewage sludge to upgraded fuel (diesel, naptha); Catalytic upgrading of biocrude; HTL at 347 ˚C - 20,5 Mpa	0.123	0.641		Snowden-Swan et al., 2017
	Woody biomass to gasoline and diesel; HTL at 20.4 MPa and preheated to 327-355 ˚C; upgrading (hydrotreating and hydrocracking)	0.140	0.437	0.520	Zhu et al., 2014
Fast Pyrolysis	Forest residue feedstock to Gasoline, diesel and heavy hydrocarbons. Thermal fast pyrolysis (TFP) at 520 ◦C	0.501	0.663	0.657	Onarheim et al., 2020
	Forest residue feedstock to Gasoline, diesel and heavy hydrocarbons. Catalytic pyrolysis (CAT) based on a spray-dried HZSM-5 catalyst	0.550	0.586	0.633	
ATJ	Corn stover to SAF, gasoline and diesel (via biological and catalytic conversions)	0.081			Han et al., 2017
	Corn stower to SAF, gasoline, diesel; ethanol pathway without solid combustion; The general procedure specified in ASTM D7566 was used to obtain jet fuel from alcohol.	0.036	0.810	0.800	Voß et al., 2023
	Corn stower to SAF, gasoline, diesel; ethanol pathway with solid phase combustion; The general procedure specified in ASTM D7566 was used to obtain jet fuel from alcohol.	0.034	0.810	0.798	
	Ethanol to SAF and diesel; dehidration at 340 ˚C- 55 psig, oligomerization at 250 ˚C -300 psig and hydrogenation at 100 ˚C-250 psig (1 psig=6.89kPa)	0.115			Geleynse et al., 2018
	Isobutanol to SAF and gasoline; dehidration at 325 ˚C- 60 psig, oligomerization at 100 ˚C -250 psig and hydrogenation at 100 ˚C-250 psig (1 psig=6.89kPa)	0.113			

Table 2 Hydrogen demand, carbon efficiency, and energy efficiency of HDRD/HEFA pathways.

Fuel type	Pathway(s)	H_2 requirement (MJ_{H2}/MJ_{fuel})	Carbon Efficiency	Energy efficiency	Source
HDRD/HEFA	Soybean oil to SAF and Diesel	0.094			Pearlson et al., 2013
	Camelina oil to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.123		0.620	Chu et al., 2017
	Carinata oil to SAF and Diese;l hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.108		0.630	
	UCO(used cooking oil) to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.108		0.668	
	Soyoil to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.153		0.576	
	Soybean oil to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.101		0.660	
	Palm oil to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.082		0.816	
	Rapeseed oil to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.098		0.760	
	Jatropha oil to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.093		0.747	
	Camelina oil to SAF and Diesel; hydrodeoxygenation at 400 ◦C and 92 bar, Residence time 2 h, NiMo catalyst	0.110		0.744	
	Used cooking oil (UCO) to HEFA SPK, hydrotreating at 420 ◦C		0,589 (varying between 0.541 and 0.632 depending on feedstock composition)		Mannion et al., 2024

Table 3 Hydrogen demand, carbon efficiency, and energy efficiency of DME and FT pathways.

Fuel type	Pathway(s)	H_2 requirement (MJ_{H2}/MJ_{fuel})	Carbon Efficiency	Energy efficiency	Source
DME	Wheat straw gasification to DME via methanol intermediate; Catalysts: methanol synthesis (Cu/ZnO/Al2O3), dehydration catalyst (γ-Al2O3); the amount of hydrogen added through the electrolyzers= 0,4 kg/s	0.725	ranging from 90 to 95%	highest total energy efficiency is 59.1% and achieved at between 0.28 and 0.32 kg/s of hydrogen addition.	Kofler et al., 2023
	Wheat straw gasification to DME via methanol intermediate; Catalysts: methanol synthesis (Cu/ZnO/Al2O3), dehydration catalyst (γ-Al2O3); the amount of hydrogen added through the electrolyzers= 0,35 kg/s	0.634			
	Wheat straw gasification to DME via methanol intermediate; Catalysts: methanol synthesis (Cu/ZnO/Al2O3), dehydration catalyst (γ-Al2O3); the amount of hydrogen added through the electrolyzers= 0,3 kg/s	0.581			
	Wheat straw gasification to DME via methanol intermediate; Catalysts: methanol synthesis (Cu/ZnO/Al2O3), dehydration catalyst (γ-Al2O3); the amount of hydrogen added through the electrolyzers= 0,25 kg/s	0.534			
	Wheat straw gasification to DME via methanol intermediate; Catalysts: methanol synthesis (Cu/ZnO/Al2O3), dehydration catalyst (γ-Al2O3); the amount of hydrogen added through the electrolyzers= 0,2 kg/s	0.476			
FT liquids (BTL)	Lignocelluosic biomass to SAF, diesel and gasoline; Power-and-Biomass-to-Liquid; Gasification + Fischer-Tropsch (Slurry bubble column, Co catalyst)+ SOEL/ PEMEL; WGS reactor is used	0.778	0.970	0,4785 (SOEL= 0,494 , PEMEL = 0,463)	Dossow et al., 2021
	Lignocelluosic biomass to SAF, diesel and gasoline; Power-and-Biomass-to-Liquid; Gasification + Fischer-Tropsch (Slurry bubble column, Co catalyst)+ SOEL/ PEMEL; No WGS reactor is used	0.528	0.673	0,477 (SOEL= 0,493 , PEMEL = 0,461)	
	Lignocelluosic biomass to SAF, diesel and gasoline; Power-and-Biomass-to-Liquid; Gasification + Fischer-Tropsch (Slurry bubble column, Co catalyst)+ SOEL/ PEMEL; r-WGS reactor is used	0.667	0.789	0,479 (SOEL= 0,499 , PEMEL = 0,458)	
	Lignocelluosic biomass to SAF, diesel and gasoline; 1 stage FT model ; Power+Biomass-to-Liquid (PBtL); Gasification + Fischer-Tropsch; SOEC for hydrogen production	0.763	0.910		Hillestad et al., 2018
	Lignocelluosic biomass to SAF, diesel and gasoline; 3 stage FT model; Power+Biomass-to-Liquid (PBtL); Gasification + Fischer-Tropsch; SOEC for hydrogen production	0.597	0.913		

Table 4 Hydrogen demand of eletrofuel pathways.

Fuel type	Pathway(s)	H_2 requirement (MJ_{H2}/MJ_{fuel})	Source
Electro Fuels	e-FT SAF; Alkaline Electrolysis Cells (AEC); 20-40% solution of KOH is used and the electrodes coated with Ni as catalyst;	1.404	Concawe. (2024).
	E-FT SAF; Co-electrolysis via high- temperature Solid-Oxide Electrolysis Cells at 700-1000°C	0.924	
	e-Methane; methanation at 400°C - 30 bar and the presence of a nickel or ruthenium catalyst	1.188	
	e-Methanol	1.162	
	e-Methanol-to- Gasoline; at 300-400°C and 15-20 bar	1.228	
	e-Methanol-to- SAF	1.248	
	e-OME (3-5); synthesized from methanol	1.536	
	e-Ammonia; high pressure (100-1,000 atm), and elevated temperatures (400-550°C) via catalyst	1.140	

Appendix 2 – Techno-economic parameters of the hydrogen case study

A detailed description of the hydrogen case study and parameters is provided in Alempiew (2025). The following scenarios were made to evaluate different supply chain configurations for hydrogen supply:

- Scenario 1: Pipeline and Salt cavern storage
- Scenario 2: Pipeline and Compressed storage
- Scenario 3: Truck and Salt cavern storage
- Scenario 4: Truck and Compressed storage
- Scenario 5: On-site production and Compressed storage

Assumptions for Electrolyzer Parameters

- **Electrolyzer Type**: The analysis used an SOEC electrolyzer for hydrogen production, chosen for its higher efficiencies at scale.
- **Scale-Dependent Parameters**:
  - **Capital Costs**: Decrease as system size increases due to economies of scale.
  - **Efficiency**: Improves with system size, reflecting advancements in technology and scale efficiencies.
  - **Stack Lifetime**: Increases with scale, reflecting improved durability and reduced replacement frequency.

System Size Assumptions for On-Site Production

- Medium-large 500 MW SOEC (solid oxide electrolyzer cell) electrolyzer
- Efficiency:
  - 2030: 81%
  - 2050: 83%
- CAPEX
  - 2030: 1.5 M€/MW
  - 2050: 0.7 M€/MW
- Stack lifetime:
  - 2030: 55 000 hours
  - 2050: 95 000 hours
- Plant Lifetime: 25 years.
- Utilization Rate: 90% of capacity.
- Fixed O&M Costs: 2% of capital costs annually.
- Electricity Price: Static at 66 €/MWh across all scenarios.
- Discount Rate: 8%.

Levelized Cost of Transport and Storage

The levelized cost of transport was taken from Solomon et al. (2024) and calculated for the assumed transport distances per mode of transport in the different scenarios in Table 5.

Table 5 Transport modes and distances for the different scenarios.

Connection	Transport Mode	Distance (km)
Salt Cavern to Refinery	Pipeline	33.5
	Road	63
Electrolyzer to Salt Cavern	Pipeline	490
	Road	350
Electrolyzer to plant	Pipeline	480
	Road	340

The levelized cost of storage were obtained from the European Commisions 2020 Hydrogen generation in Europe; Overview of cost and key benefits report (European Commission, 2021).

Appendix 3 - Detailed description of Figure 5 on Potential deployment of hydrogen Infrastructure in the North Sea region, including electrolyzers, pipelines, salt cavern storage, and planned electrofuel and bioelectrofuel capacities.

Hydrogen pipeline distribution	The proposed network includes three types: new dedicated hydrogen pipelines, repurposed natural gas pipelines, and mixed pipelines carrying both hydrogen and natural gas. Each serves a distinct purpose in hydrogen transport across Europe.
Spatial Coverage and Density	New pipelines are densest in Western Europe (Germany, Netherlands, Belgium), forming a strong backbone, with significant development also in Finland, the east coast of Norway, the Baltics, and the North Sea (for energy islands). Repurposed pipelines form the backbone of the UK's sparse network and are prevalent in south-central Europe and East Germany. Mixed pipelines are expected to be the most common, forming most of the dense European network (West Germany, East Netherlands, France) and solely supplying Denmark and mostly supplying Poland (which also has one dedicated new line). The network relies heavily on existing infrastructure, using new lines to connect regions lacking expansive natural gas networks.
Electrolyzer Capacity and Distribution	Electrolyzer plants are categorized by end-use: biofuel production (brown circles), synthetic fuel production (green circles), and non-dedicated end-use (white circles). Capacity is visualized in 5 size categories, ranging from the smallest (0-25 MW) to the largest (100-2500 MW).
Regional Trends in Electrolyzer Capacity	Central and Western Europe (especially Germany and the Netherlands) have the highest density of projects. Nordic and eastern Baltic countries show a remarkably sparse collection (less than 5 identified). Most projects are small-scale (0 to 25 MW), and the locations of electrolyzers heavily overlap with the proposed pipeline network (few projects are >50 km away). The largest project is located near London in the UK.
Distribution of Synfuel and Biofuel dedicated electrolyzers.	Only one small-scale electrolyzer project was identified as dedicated to biofuel production (located in France). Many projects were identified for synthetic fuel (synfuel) production, distributed evenly across Western Europe, including three larger-scale projects (two 75-100 MW in West Germany and Northern Norway, and one 50-75 MW in Denmark).
Advanced Biofuel Production Facilities	Facilities are categorized by technology: Fischer-Tropsch (red), hydrothermal liquefaction (black), hydrotreatment (orange), hydrolysis (green), and alcohol-to-jet (purple). Each technology has a unique hydrogen-to-fuel energy ratio, impacting integration into the hydrogen network.
Advanced Biofuel Production Facilities distribution by fuel type	Bio Fischer-Tropsch (Bio FT): 6 plants (2 UK, 1 France, 1 Germany, 1 Norway, 1 Sweden). Three are near the pipeline network, one is at the end of a standalone pipeline (Sweden), and two are far from any projected pipelines. Only one is near large-scale underground storage.
	Hydrothermal Liquefaction (HTL): 4 plants (2 North Denmark, 1 near Newcastle UK, 1 near Oslo Norway). Danish plants are near the pipeline network, large storage, and centralized electrolysis. The UK plant is near the pipeline and large-scale electrolysis but no large storage. The Oslo plant lacks access to the pipeline or storage but is near an electrolyzer.
	Hydrotreatment Plants: The most common (15 plants) distributed across Northern and Western Europe, often forming clusters (4 in total: West Netherlands, Southwest Sweden, South Finland, North Sweden).
	Alcohol-to-Jet: 5 plants. Three are near or directly on the connected pipeline network and decentralized electrolyzers. Two are close to each other in East-Central Sweden but are far from the network and electrolyzers.
Salt-Cavern Storage	22 large-scale underground salt cavern storage locations were identified. They are heavily concentrated in North-West Germany and the East Netherlands, with smaller concentrations in Central and East Germany extending into Poland. France has two, and North Denmark has one. The UK and the very north of Europe have no large-scale storage connected to their networks.

Source: Alempiew (2025).

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