Global Alliance POWERFUELS

LUT University

POWERFUELS
in a Renewable Energy World

Global Volumes, Costs, and Trading 2030 to 2050

powered by

dena
German Energy Agency

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Content

Executive Summary

Aligned to the Paris Agreement's goals, this study by Lappeenranta-Lahti University of Technology (LUT) and the Global Alliance Powerfuels explores the role of powerfuels in a global carbon-neutral energy system based on renewable energy sources.

Powerfuels – i. e. green hydrogen and derived gaseous and liquid energy carriers and feedstocks such as synthetic kerosene, methane or ammonia – will play an important role in a carbon-neutral energy system. They will be essential for defossilising sectors that are hard to electrify such as aviation, maritime transport, and specific industrial processes. In addition, they will play an important role in replacing fossil resources employed as process feedstocks[a]. Furthermore, even in sectors with high electrification shares, there will be numerous applications relying on gaseous or liquid energy carriers. Here too, renewable liquid and gaseous energy carriers such as powerfuels will be essential for their defossilisation.

Most current global energy scenarios and studies significantly underestimate the role of power-to-X technologies in their full spectrum of future energy systems[17, 28]. In response, as a first, this research study builds upon an energy system model that includes all Power-to-x products. It quantifies the presence of powerfuels across the global energy mix in 2030, 2040, and 2050. By analysing 145 distinct geographical regions covering the whole world, the study explores the potential of producing powerfuels in each region, examines the resulting cost levels, and quantifies how trade of powerfuels develops in a cost-optimised global market. It further quantifies the reductions of levelised costs resulting from international trade of powerfuels and the greenhouse gas emission reductions resulting from their adoption. The results are mainly reported as demand volumes for powerfuels and CO_2 as raw material, costs, and trade volumes. Costs are reported for two distinct cases: one where powerfuels are traded globally and one where powerfuels are only traded within the producing regions. A dedicated focus chapter on Europe is included in this study.

[a] Such is the case in the chemical industry, where renewable electricity-based chemicals are the only technologically viable option for defossilising the entire product chain.

This study is based on the LUT Energy System Transition model. The model considers energy demand from the power, heat, industry, transport, chemical, and desalination sectors as well as an estimation of the non-energetic feedstock demand of the chemical sector.

The fundamental assumptions and modelling choices of the model are:

- The global energy system in 2050 is carbon-neutral.
- Projections for energy demand and the underlying assumptions are aligned with the IEA's World Energy Outlook.[83]
- Final energy demand is characterised by high levels of direct electrification, mainly based on Ram et al.[54] This leads to a final electricity demand of 13,000 TWh_{el} in the transport sector and 20,400 TWh_{el} in the heat sector in 2050 (up from 6,000 TWh_{el} in transport and 10,000 TWh_{el} in heat in 2030), thus reducing 2050 end energy demand in fuels and chemicals to about 44,700 TWh in 2050 (down from 50,100 TWh in 2030)[b].
- The study assumes the technical availability of all power-to-X processes known to date and therefore the availability of the resulting energy carriers and feedstocks.
- Renewable electricity based synthetic fuels are complemented by biofuels and bio-chemicals in meeting the demand for molecule-based renewable energy carriers and feedstocks. The use of biofuels other than waste, residues and by-products is limited at 2020 levels due to sustainability constraints[c].
- The shares of powerfuels as well as shares of global trade emerge from analysing the production potential and the costs in 145 geographical regions covering the whole world.
- Based on today's perspective and taking into account most recent forecasts on technological development, some industrial processes and specific energy uses can only become carbon-neutral by the use of renewable energy carriers such as synthetic methane or ammonia.

[b] Data extracted from Figure 8, under consideration of a coefficient of performance for heat pumps of 2.7.

[c] The cap results from an optimisation of the energy-specific land use efficiency of different energy carriers and the assumption of limited land availability for the installation of renewable energy generation infrastructure needed to cover final energy demand. The quantity of biofuels and thus energy crops is capped, as those deliver less final energy per unit of occupied land compared to powerfuels. A further factor influencing this modelling choice is the projected competition for arable land resulting from a growing global population, growing global GDP, and the resulting increase in demand for food crops.

Key Findings

- Powerfuels will play an important role in a carbon-neutral energy system in 2050, covering about 28 % of the final energy demand globally[d] (43,200 TWh of 152,200 TWh in 2050) with significant demands in all sectors (see Figures ES1 and ES3), despite a strong uptake of electric vehicles in the transport sector and strong electrification in the heat sector.

- The demand for carbon-neutral fuels leads to a significant demand for sustainable CO_2. In 2050, 6,000 Mt of CO_2 as raw material will be needed for the production of renewable hydrocarbon energy carriers and feedstocks. Unavoidable CO_2 point sources can almost entirely meet demand in the 2020s (in this study mainly waste incinerators, pulp and paper plants and non-fuel emissions of cement mills). These cannot further meet the growing demand from 2030 onwards. Direct air capture (DAC) is thus necessary as a long-term sustainable and cost-effective option to provide carbon employed in the production of renewable fuels (see Figure ES2). Further, DAC makes it possible to close the carbon loop of powerfuels by recapturing CO_2 that is emitted throughout their use phase.

- Global trade will reduce the levelised cost of powerfuels by up to 30 % in some regions compared to a self-supply scenario. In a scenario with international trade, the global average equilibrium cost levels for synthetic renewable ammonia, methanol, methane, and Fischer-Tropsch fuels range from about 45 to 75 €/MWh in 2050 (down from approximately 120 to 140 €/MWh in 2030), after trade, pre-shipping. The resulting global trade flows lead to considerable economic benefits for both producers and users. Total global cost savings from international trade versus domestic-only powerfuels production amount to almost 140 b€ per year in 2050 (after having peaked in 2040), or a relative global average cost reduction of 10 % in 2040 and 6 % in 2050 compared to the market volume (pre-trade) in 2040 and 2050 (of 1,550 b€ and 2,200 b€ respectively). In Europe, global powerfuels trade can reduce costs by 15 % to 30 % compared to a domestic self-supply scenario, resulting in 75 b€ cost savings per year in 2050 (see Figure ES4).

- Global powerfuels markets are more diverse than today's markets for fossil fuels, both in variety of supplying countries as well as in distribution of internationally traded energy carriers and feedstocks. South America, sub-Saharan Africa and, to a lesser extent, the Middle East and North Africa emerge as key exporters, while Europe, Eurasia, Northeast Asia, and Canada (within North America) emerge as key importing regions. The market shares for synthetic renewable fuels in 2050 break down to 28 % methanol, 23 % Fischer-Tropsch fuels, 21 % hydrogen, 20 % methane (SNG/LNG), and 8 % ammonia. Methanol is expected to become the new central bulk chemical in the global chemical industry, and is traded globally.

- Powerfuels trade volumes will be lower than present trading of fossil fuels, especially crude oil. The globally traded market volume of synthetic renewable methane, Fischer-Tropsch fuels, ammonia and methanol will reach 563 b€ in 2050, corresponding to 23 % to 33 % of global demand for the respective fuels (the share of fossil fuels traded in 2019 was 43 % of total fossil fuel consumption[e]). This development follows from the availability of excellent solar and wind resources in most regions, resulting in higher domestic production capacities, lower import demand and higher export capabilities. This allows for significant economic benefits resulting from global trade, as well as further benefits resulting from domestic powerfuels production, such as job creation and higher tax revenues.

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[d] The global final energy demand in 2050 is based on Ram et al.[54]. The value for 2050 is aligned with the IEA WEO Stated Policies Scenario[124]. IEA defines total final energy consumption as the sum of the energy consumption in the end-use sectors and for non-energy use. Energy used for transformation processes and for own use of the energy-producing industries is excluded.

[e] Globally traded shares differ strongly between fossil fuels: fossil oil is heavily traded globally (74 % of total demand) while fossil gas (25 %) and hard coal with (21 %) are traded to significantly lower volumes on global markets but produced and used more domestically.

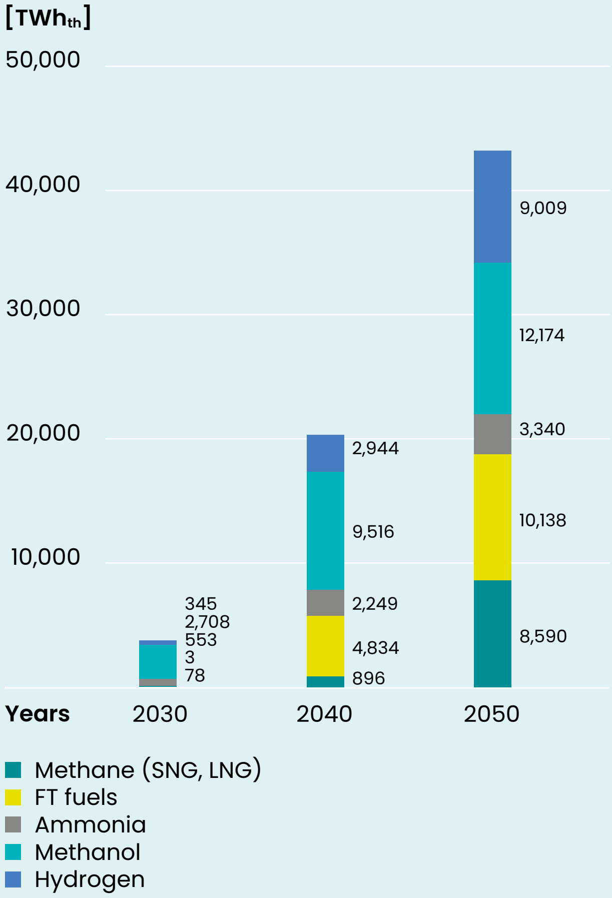


Figure ES1: Global powerfuels demand across the transition.

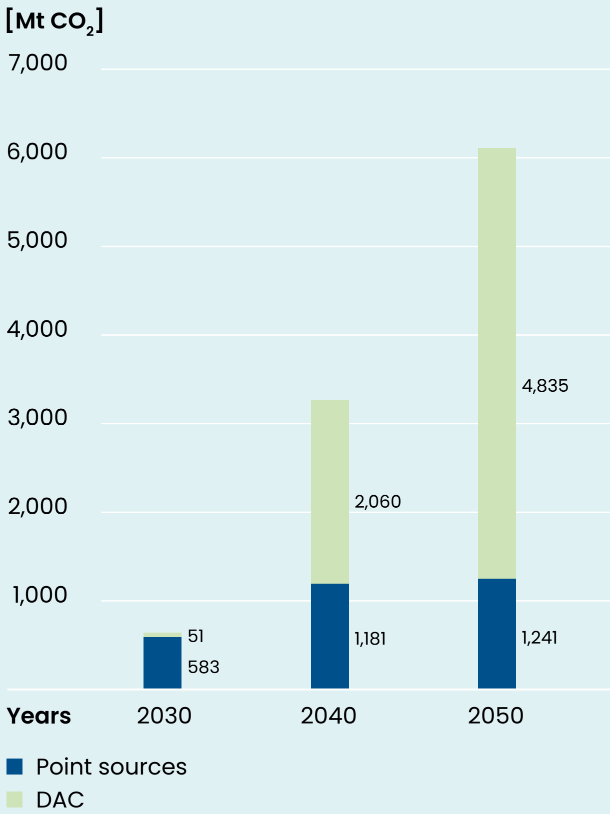


Figure ES2: Global CO_2 demand for powerfuels production across the transition.

- The global investment needs for the transition from fossil-based to powerfuels are comparable to currently projected upstream investments in the oil and gas industry. The study deduces that upstream investments in powerfuels production amount to approximately 18,000 b€[f] between 2020 and 2050, including dedicated renewable energy generation plants. For comparison, projected annual upstream investments of the global oil and gas industries from OPEC and GECF amount to approximately 17,450 b€ in the time frame 2020 to 2045/2050[g]. The investments needed for meeting powerfuels demand in a carbon-neutral energy system fully based on renewable sources as described in this study therefore appear to be both reasonable and feasible.

[f] At an assumed exchange rate of 1.1 €/$, the post-trade market volume of powerfuels amounts to 2,070 b€ in 2050. The annualised capital expenditure amounts to approximately 70 % of the levelised cost of fuel, and thus 1,449 b€. As the WACC is assumed at 7 % and the average lifetime of assets at 30 years, the required capital expenditure for powerfuels in 2050 totals at about 17,980 b€.

[g] According to OPEC's 2020 World Oil Outlook, projected upstream investments in oil products will amount to approximately 9,900 b$ in the period 2019 and 2045[125]. The global upstream investments in natural gas are projected to amount to approximately 9,300 b$ in the period 2020 – 2050[126]. With a total of 19,200 b$, this translates to 17,450 b€ for the exchange rate of 1.1 €/$ assumed in this study.

- Powerfuels are an indispensable contribution to climate mitigation in a sustainable, cost-optimised scenario. By using renewable electricity and sustainable carbon for production of powerfuels, these renewable synthetic fuels counterbalance emissions from utilisation already in advance (during production), thus having a net-zero carbon footprint. Global use of powerfuels thereby results in avoiding 13 Gt CO_2eq in 2050 compared to a scenario with continued use of fossil fuels. More importantly, powerfuels achieve this necessary reduction of greenhouse gas emissions without further increasing pressure on highly vulnerable ecosystems (e. g. for increasing biomass supply) as the required primary energy and production feedstocks can be sourced from installations on non-arable land. When realising the uptake of powerfuels in the second half of the 2020s and following a linear ramping-up for powerfuels as described in this study, a cumulative total of 140 Gt CO_2eq would be avoided by 2050, thereby making a substantial contribution to the Paris Agreement's goal of limiting global warming.

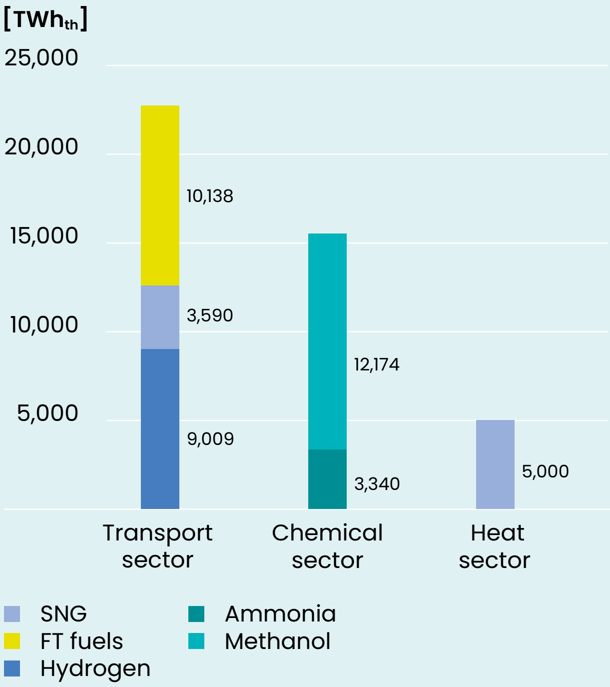


Figure ES3: Global powerfuels demand by sector in 2050.

Conclusions and recommendations

- Powerfuels are a risk- and cost-optimised solution needed to achieve a fully decarbonised energy system in 2050. In order to produce the volumes required in a defossilised energy system, a powerfuels market needs to be developed starting today. To facilitate this development, powerfuels must be addressed in the renewable energy frameworks of regional, national and supranational bodies such as the European Commission's Hydrogen Strategy and its Renewable Energy Directive[h]. The paradigm must shift from "Hydrogen Strategies" to "Powerfuels Strategies".

- Powerfuels will play a fundamental role in defossilising applications that will continue to require hydrocarbons, hydrogen, and ammonia as non-energy feedstocks, especially in the chemical sector. This is not currently being reflected strongly enough in the global discourse on defossilisation. Defossilising the non-energy use of chemicals, especially in the chemical sector, must be included in the political agendas of regional, national and supranational bodies in order to support the industry's shift toward these solutions.

[h] As one example in place today, the Renewable Energy Directive (RED II) includes powerfuels as one option to fulfil renewable energy targets in the European transport sector.

- Large-scale sourcing of CO_2 via direct air capture is necessary to produce the volumes of powerfuels required in a defossilised energy system. DAC plants have just reached the commercial scale. It is therefore imperative that policy frameworks incentivise their technological development with the aim of ramping up their production while driving down their cost. Governments and supranational entities must therefore set incentives for developing a DAC economy as the backbone of a powerfuels economy. To this end, one central measure is to define the environmental sustainability of CO_2 sources eligible for powerfuels production in policy frameworks.

- Investments in the early adoption of powerfuels can lead to a long-term, stable business case. The private sector is already investing in a renewable hydrogen based economy. In order to increase and accelerate investments, the global actors of the energy sector should develop ambitious transition strategies with a specific transformation path that diverts planned upstream investments from fossil fuels to renewable fuels. This would significantly contribute in providing the necessary investment in powerfuels production capacities. Further, non-governmental bodies within energy politics as well as within the global oil and gas industry should coordinate regarding standardisation and funding schemes in order to support the development of global markets for powerfuels.

- Both powerfuels importers and exporters benefit from global trade in terms of reduced costs of energy transition, increased employment opportunities, and in turn political stability. Dedicated standards and sustainability certification must be developed to enable global trade of powerfuels. This is a necessary precondition for financing of projects and facilitating public trading in international financial markets. Similarly, infrastructural challenges should be addressed, such as creating necessary port and pipeline infrastructure.

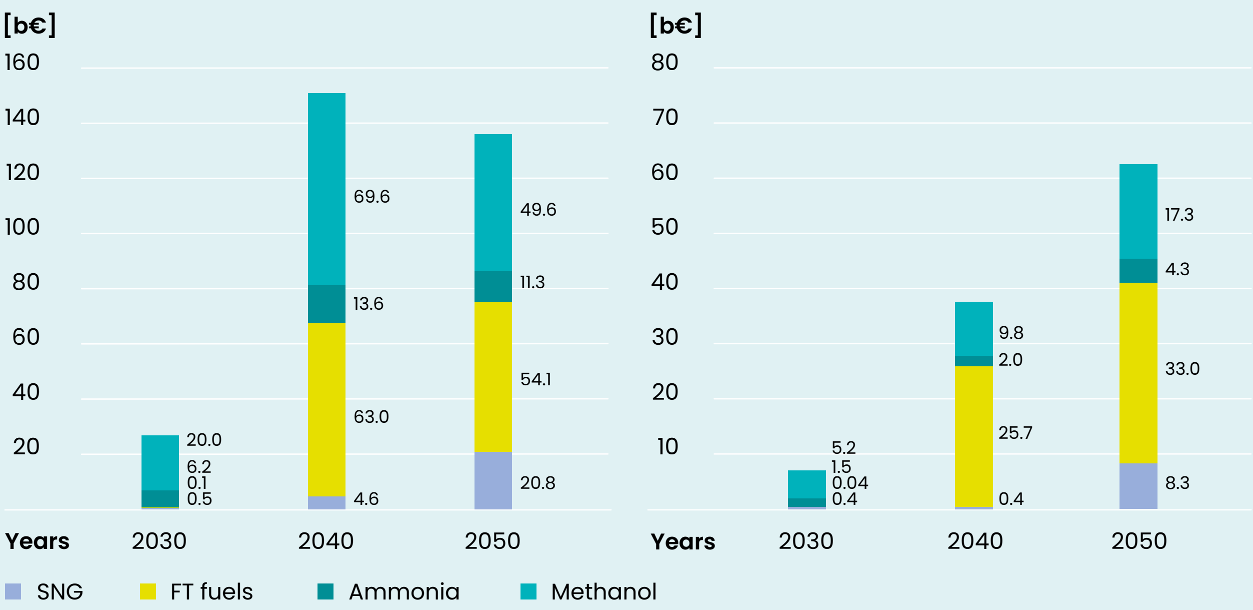


Figure ES4: Development of cost reductions from powerfuels trading globally (left), and in Europe (right).

1 Introduction

Climate mitigation is the most important issue of current times. The urgency was heightened by the findings of the IPCC[4], which stated that extra warming on top of the approximately 1 °C we have seen so far would amplify the risks and associated impacts, with implications for the world and its inhabitants. Additionally, latest research indicates a coupling of major global climate change tipping points[5], which further stresses the importance of not violating the 1.5 °C target. The daunting task of limiting warming to 1.5 °C would require transformative systemic changes, integrated with sustainable development across the world. Over the past decade, the energy transition from its niche beginnings, primarily in Europe, has become a global phenomenon affecting energy markets and disrupting fundamental structures[6–8]. The massive uptake of renewable energy in Europe and across the world, with 77 % of new power capacity being renewables in 2019[7], has opened new avenues with increased participation of citizens and companies in shaping energy choices, owing to the decentralised nature of renewables particularly solar photovoltaics (PV) and wind energy. The power sector is leading the way through the transition as solar and wind power increasingly replace coal, fossil gas, and nuclear energy as the world's most preferred energy sources[6]. The key driver is the rapidly declining costs for renewable energy technologies in the last few years. Cost reductions, particularly for solar PV and wind power, have been consistent over the last decade and are set to continue into the next decade. In the case of solar PV, costs between 30 – 40 euro per megawatt-hour are already prevalent in regions with good resources and enabling regulatory and institutional frameworks[9]. For example, record-low auction prices for solar PV in Chile, Mexico, Peru, Saudi Arabia, the United Arab Emirates, India and recently in Germany have seen a levelised cost of electricity as low as 25 €/MWh[10], while the present low is at 15.7 USD/MWh[11], and further development to below 10 €/MWh will be the next major milestone, thus paving the way for the solar age[8, 12]. Wind energy costs have been declining across the world with record low tariffs in the UK for both onshore and offshore, with trends in Asia also indicating low tariffs in the near future[13].

Definitions for fuels and chemicals adopted in this study

Powerfuels:

renewable electricity based - synthetic natural gas (SNG), liquified natural gas (LNG), Fischer-Tropsch fuels (FT fuels), hydrogen (H_2), ammonia, methanol, and naphtha

FT fuels:

renewable electricity based - diesel, gasoline, kerosene, and naphtha

Liquid hydrocarbons:

fossil fuels, biofuels, and FT fuels

Chemicals:

ammonia, methanol, and naphtha (either renewable electricity based or of fossil origin)

Despite the growth of renewables in the power sector across the world, the remaining energy sectors are still dawdling. Heat consumption remains heavily based on fossil fuels, primarily natural gas, while just about 10.3 % of the heat used worldwide in 2015 was produced from new renewable energy technologies, including renewable electricity[14]. However, there is increasing application of renewables in various heating processes. Renewable energy can serve thermal demand when supplied by electricity, either directly or using heat pumps[15]. Furthermore, electrification of heating is on the rise, using mainly wind electricity for power-to-heat applications, heat pumps in district heating networks and increasingly using electricity from solar PV for heat to increase self-consumption rates in the face of reductions in feed-in tariffs and growing retail electricity prices[15]. District heat systems supply about 11 % of global space and domestic hot water heating and are particularly suitable for use in densely populated regions that have an annual heating demand of four or more months, such as in the northern latitudes of Asia, Europe and North America[16]. In many regions in the world, renewable based district heating with seasonal storage is already a viable option[15].

Energy for the transport sector makes up nearly 40 % of the final energy demand. The transport sector comprises several modes, namely road, rail, marine and aviation across passenger and freight categories[17, 18]. Despite gains in efficiency, the sector accounted for two-thirds of overall oil consumption, since all the dominant transport technologies rely on fossil oil-based fuels. A significant rise in passenger-kilometre and tonne-kilometre demand has seen GHG emissions from international aviation more than double from 1990 levels (129 %), followed by increases in international shipping (32 %) and road transportation (23 %) emissions[19]. Transport emissions are dominated by road transport; in 2017, road transport was responsible for almost 72 % of total GHG emissions from transport (including international aviation and shipping). Of these emissions, 44 % were from passenger cars, 9 % from light commercial vehicles and 19 % came from heavy-duty vehicles[19]. However, there is a movement towards electrification in the transport sector with the evolution of the global electric car market. Battery-electric car deployment has been growing rapidly over the past ten years, with the global stock of electric passenger cars passing 5 million in 2018, an increase of 63 % from the previous year[20]. Around 45 % of electric cars on the road in 2018 were in China – 2.3 million – compared to 39 % in 2017 and in comparison, Europe accounted for 24 % of the global fleet, and the United States 22 %[20]. The penetration of this technology in the transport sector could reach the same level as the PV penetration in the power sector, in the coming years and possibly evolve even faster[21]. The global EV sales has reached over 2.2 million in 2019 and translates into an average of 2.5 % market share (1 in 40 new cars), indicating that the growth of EV sales is accelerating[22]. Likewise, the marine sector has options with increasing availability of alternative fuels such as biofuels in existing engines, which could be an immediate option, thereafter use of electricity-based powerfuels[23], such as synthetic natural gas, Fischer-Tropsch based fuels or hydrogen[24]. The production and use of sustainable aviation fuels, specifically bio-based jet fuel or synthetic jet fuel apart from direct electrification for short-distance flights can propel the aviation sector towards being more sustainable[25]. Whereas, the rail sector with already a high share of electricity use is well underway for maximum electrification[16]. In addition, powerfuels, including hydrogen and biofuels, could cover the non-electrified rail transport.

Many global energy scenarios have tried to project the future transition of energy systems based on a wide-ranging set of assumptions, methods and targets from a national as well as global perspective[26]. The report from the Centre for Alternative Technology[27] outlines scenarios at global, regional, national and sub-national scales that illustrate how the Paris Agreement targets could be realised. Moreover, conclusions are drawn from analyses of over 130 scenarios that demonstrate how deep defossilisation or net-zero GHG emissions can be achieved before mid century using prevailing technologies, whilst supporting social and economic development[27]. Most of the studies lay out pathways to phase out non-sustainable technologies, such as nuclear energy and fossil fuel based energy conversion, while integrating sustainable renewable energy options to satisfy an increasing energy demand of the future global society. However, most global energy scenarios lack in acknowledging the role of storage and power-to-X technologies in future energy systems, with inherent methodological limitations[17, 28]. For the most part, power, heat and transport have traditionally relied on separate infrastructures and different fuels. As a result, separate regulations and policy regimes govern each energy use. Electrification is tearing down these sectoral barriers, mainly due to high technical efficiencies, comparably lower costs and the availability of prospective power-to-X technologies. These power-to-X technologies include power-to-heat (electric heat pumps[29, 30]), power-to-hydrocarbons (hydrogen[31, 32], methanation[31–34], synthetic fuels[34–36], synthetic chemical feedstock[37–40]), a directly or indirectly electrified transport sector[17, 18] (battery-electric vehicles[41, 42], marine[43, 44], aviation[35]), power-to-water (reverse osmosis desalination[45]), and power-to-CO_2 for negative emission technologies[46, 47], but also sustainable or non-avoidable carbon capture and utilisation (CCU)[48].

Despite direct use of renewable electricity being the most economical and sustainable form of energy utilisation, the hard-to-abate sectors[49] very much need the range of power-to-X technologies. Heavy industry (cement, iron & steel, chemicals, aluminium, and pulp & paper) and heavy-duty transport (trucking, shipping, and aviation) are together responsible for nearly one-third of global CO_2 emissions[49]. Powerfuels, which are synthetic gaseous or liquid energy carriers and feedstocks, based on renewable electricity, deliver energy or basic materials for many use cases and are a renewable alternative to fossil resources in avoiding GHG emissions[23]. Powerfuels could be a game changer in accelerating the energy transition. By transforming electrons into molecules, they enable renewable energy to be stored over long periods and transported over long distances[23]. In addition, powerfuels can be chemically identical to their respective fossil counterparts and can thus be used in any application area where fossil resources are consumed today. The chemical industry's use of petroleum products accounts for 14 % of all GHG emissions[50]. However, almost all chemicals can be produced by initial synthesis with electricity, water and air[51, 52]. The major feedstock chemicals for a sustainable chemical industry are ammonia and methanol, which can be converted to almost all other hydrocarbon-based chemicals. As chlorine synthesis is already electricity-based, it will be decarbonised when the power sector is decarbonised. Naphtha as a major by-product of synthetic FT fuels is another valuable feedstock chemical for the chemical industry and can be converted into many hydrocarbon-based chemicals. Along these lines, this research study by LUT University and Global Alliance Powerfuels explores the role of powerfuels in enabling an energy system transition pathway towards climate neutrality by 2050, across the world.

2 Methods and Data

Modelling the global energy system transition with powerfuels

The LUT Energy System Transition model[53,54] is applied across an integrated energy system covering the demand from power, heat, transport and desalination in a Best Policy Scenario (BPS), as highlighted in Ram et al.[54], which forms the basis for the estimation of powerfuels. The unique features of the model enable cost-optimal energy system transition pathways on high levels of geospatial and temporal resolutions. Furthermore, the capability to model in an hourly resolution for an entire year enables uncovering of crucial insights particularly with respect to storage and flexibility options, most relevant to future energy systems. The model includes the industry sector, which is comprised of industrial fuel production and utilisation in all sectors, desalination and industrial process heat. However, the inclusion of further exclusive industry sectors, such as cement[48], iron & steel, chemicals, metal refining (in particular aluminium), pulp & paper, and remaining sectors is planned in the future. Energy demand of these sectors is included in the existing sectors of power, heat and transport. The non-energetic fuel demand of chemicals is not included in the model but is estimated with a separate method for this research study, as highlighted by Figure 1. The details of the model along with all the assumptions are presented in Ram et al.[54] and Bogdanov et al.[53].

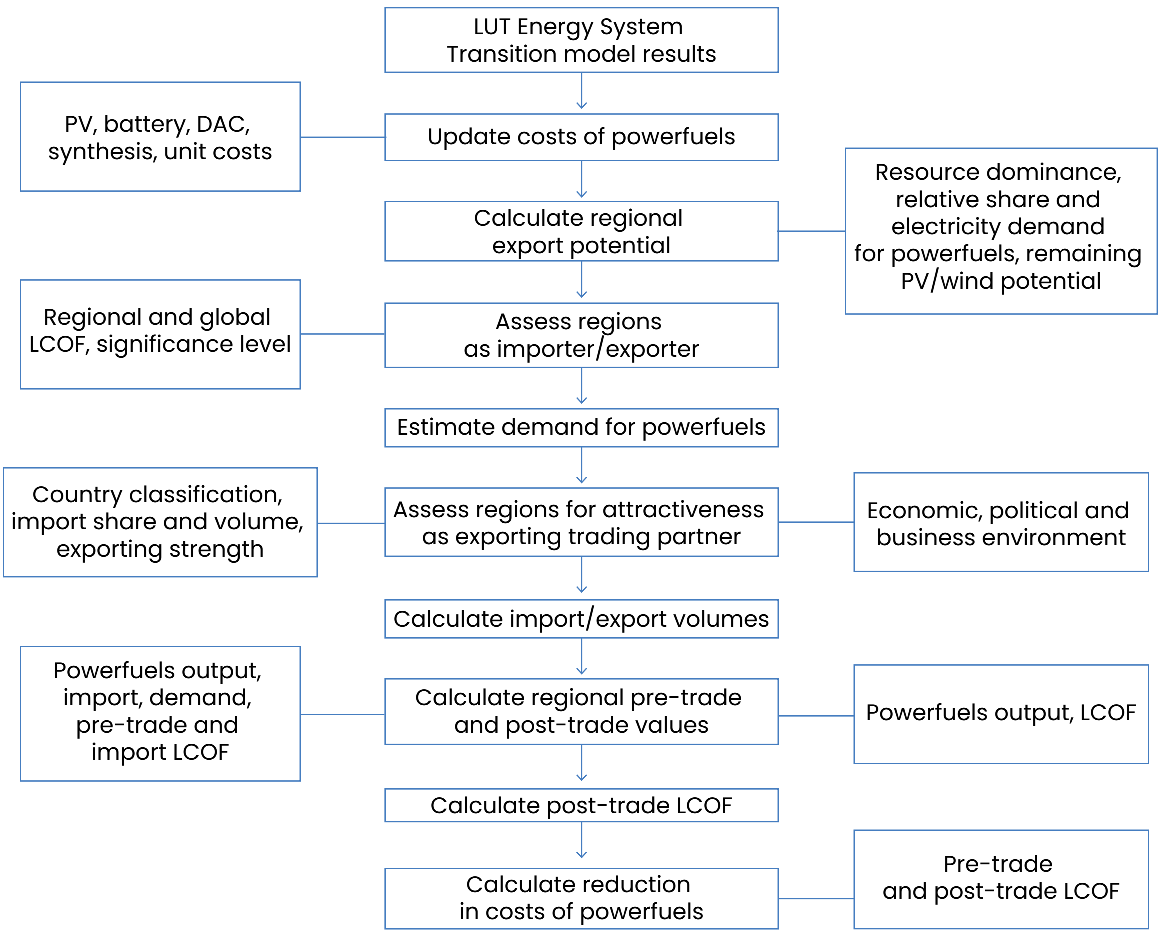


Figure 1: Process for estimating the potential of powerfuels.

In this research study, the results of Ram et al.[54] are post-processed as indicated in Figure 1. Costs of solar PV, battery and some further parameters are updated so that the latest insights are applied for powerfuels and corresponding regional demands are estimated. A global trading analogy is applied to assess the regional export/import capabilities, based on which export and import potentials for every region globally is determined. Further, export and import volumes to be traded globally are estimated, which allows for determining pre- and post-traded costs on a levelised basis. In addition, the reduction in costs globally is estimated to analyse the benefits of trading in powerfuels. The detailed methods of the LUT Energy System Transition model are presented in section A of the Annex, followed by the technical and financial assumptions in section B of the Annex. Section C in the Annex presents the detailed methods adopted for the global trading of powerfuels. Lastly, section D in the Annex highlights the limitations, uncertainties and possible improvements in the methods of this research.

Industrial fuel production

The energy system undergoes a transition away from fossil fuels, mainly coal, oil, natural gas and nuclear energy, towards production and adoption of renewable electricity based synthetic fuels complemented by some conversion of biomass to biofuels for use in the power, heat and transport sectors. This transition is captured in a 5-year time interval between 2015 to 2050 across 145 regions of the world. These 145 regions are considered in a 92 regions resolution for which all regions of one country are aggregated to one region.

Hydrogen, methane and liquid hydrocarbon production units are integrated in the model. Methane is also produced from biogas purification/upgrading. Tthis biomethane is used in gas-based power and heat generation and can also be used as RE-based liquefied natural gas (LNG) for marine transportation. However, the share of biogas that can be upgraded is limited due to infrastructure requirements and the levels of urbanisation in the region, which does not exceed 70 % despite high levels of urbanisation. The other form of gas is synthetic natural gas (SNG), which is methane produced from methanation reactors with hydrogen and CO_2 as input. The entire power-to-gas (PtG) process includes water electrolysis (assumptions are based on alkaline technology) producing hydrogen from water, CO_2 direct air capture (DAC) units[55] collecting CO_2 from ambient air, and methanation units producing SNG. Water electrolysers and DAC units consume electricity and heat from the system in order to produce H_2 and CO_2, while, methanation units convert H_2 and CO_2 to synthetic CH_4[47] as shown in Figure 1. Furthermore, liquid hydrocarbons are either produced from biomass by biorefineries or synthesised from H_2 and CO_2 using the Fischer-Tropsch process (see Figure 2).

Crude oil refineries are not directly included in the model and existing capacities of refineries are assumed to be enough to satisfy local consumption of fossil fuels. However, the cost of refineries to convert crude oil into refined fuels for the transport sector is included. The fuel shares of the transportation modes in the road segment are based directly or indirectly on levelised cost of mobility (LCOM) considerations for newly sold vehicles, which change the stock of vehicles according to the lifetime composition of the existing stock. Vehicle stock and overall demand data are then linked to specific energy demand values to estimate the demand of fuels and electricity for the transport sector. A more detailed description of the methods is provided in Khalili et al.[17].

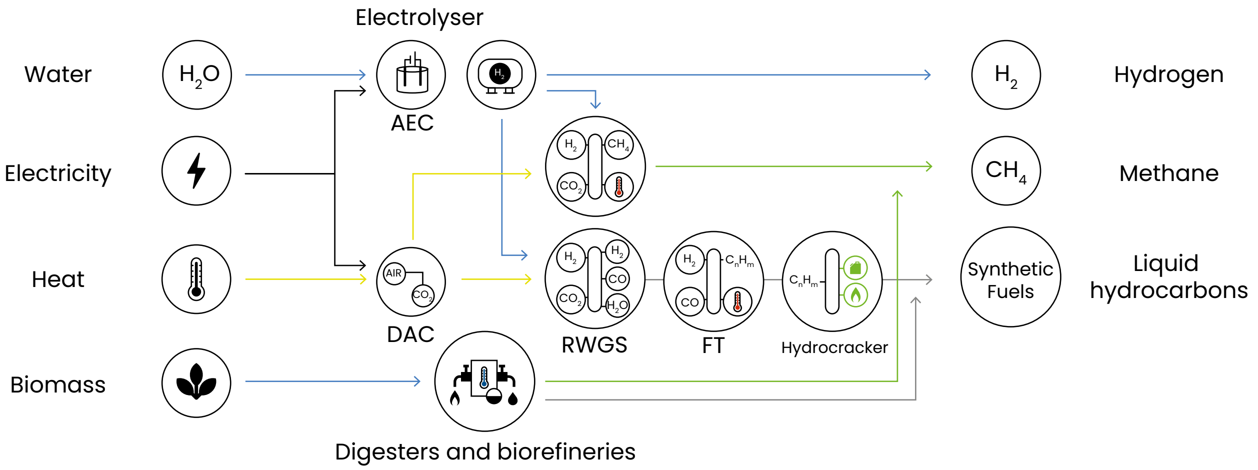


Figure 2: Schematic of the value chain elements in the production of sustainable fuels.

CO_2 from direct air capture

CO_2 direct air capture (DAC) demand is determined for each region in tonnes of CO_2 per year. This amount of CO_2 will be captured from the atmosphere by DAC units for the synthetic fuels production. Heat and electricity needed for DAC operation is supplied from waste heat, electricity-based heat pumps and direct electricity consumption. The simplified structure of the CO_2 supply by DAC units is presented in Figure 3. A more detailed description of the methods, data, and assumptions can be found in Breyer et al.[47].

In this research study, CO_2 from sustainable or unavoidable point sources with substantial operating hours, which are mainly waste incinerators, pulp and paper mills, and the limestone fraction of cement mills is considered. In line with current trends, CO_2 capture efficiency of 87 % and CO_2 captured utilisation of 70 % are considered. The capture efficiency of CO_2 from exhaust stream at point sources varies between 80 % and 90 % for most point sources, while 87 % is assumed for this analysis[48]. The utilisation rate of the CO_2 capture potential is assumed to be 70 %, since not all potential sites of CO_2 supply match with requirements for synthesis demand sites, while long-term investment stability may be limited, or other exclusion reasons may apply. CO_2 as a raw material is needed for the production of SNG, FT fuels, and methanol.

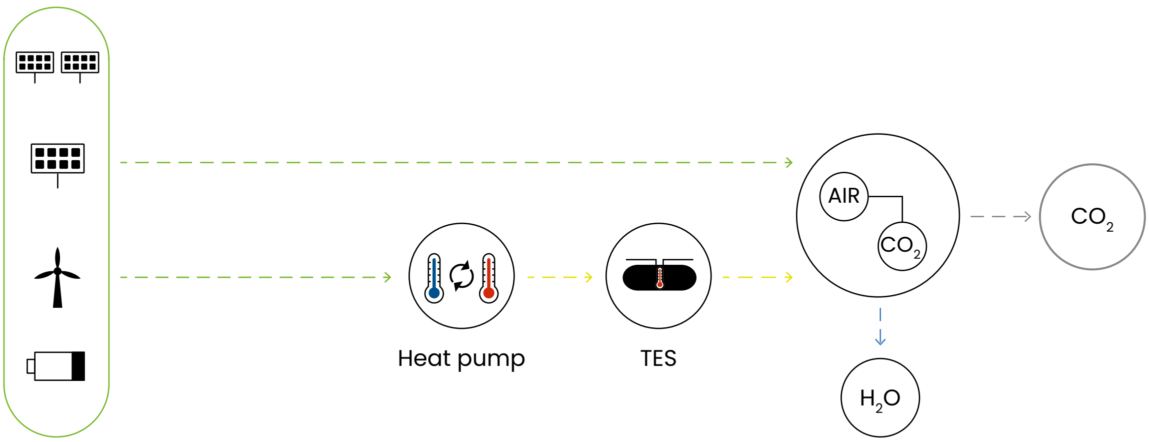


Figure 3: CO_2 supply structure of direct air capture (DAC) units. Abbreviation: TES - thermal energy storage.

Power-to-chemicals

Supply-side technical production potential volumes and costs of RE-based chemicals (methanol, ammonia) are derived from modelling insights applied in the highly resolved modelling environment on 50-km and 1-h resolutions, as highlighted in Fasihi and Breyer[40, 56]. RE-based chemicals are not considered in Ram et al.[54], which is the basis for the powerfuels analysis. However, the same data basis is used in the structured 145 regions resolution as in Ram et al.[54] so that further processing is enabled in an analogue manner and produces comparable result structures. Full results for the period up to 2050 in 10-year time intervals for RE-based ammonia on a comparable cost basis are adopted from Fasihi and Breyer[40, 56], and similarly for methanol in 2030, which are further extrapolated for the period 2020 to 2050, following the fundamental trend line of ammonia, which is applicable due to close technological structures and trends.

The process for RE-chemicals, methanol and ammonia production is highlighted in Figures 4 and 5. Methanol, which is a bulk chemical for further chemicals to be developed, is produced with a completely renewable electricity and storage base, as highlighted in Figure 4.

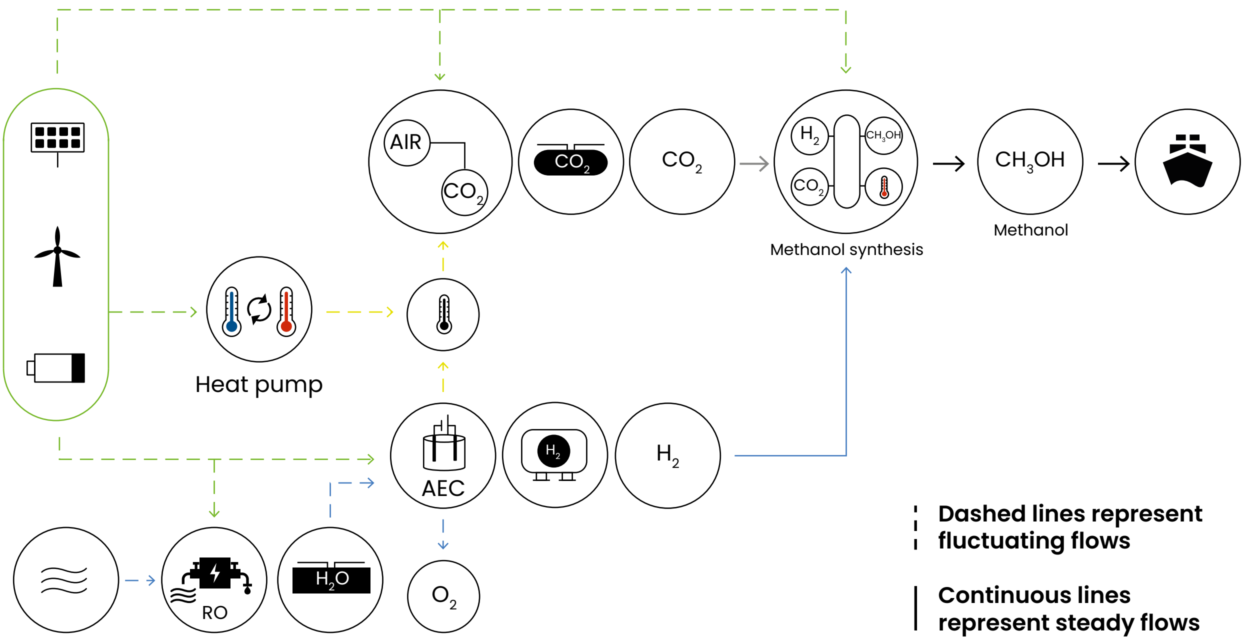


Figure 4: Schematic of the value chain elements in the production of renewable electricity based methanol.

A complete renewable electricity generation and storage base is assumed along with the air separation unit (ASU) delivering the nitrogen and ammonia synthesis plants for the production of RE-based ammonia, as highlighted in Figure 5.

Demands for methanol and ammonia are derived on the basis of demand projection for ammonia and the fundamental assumption that methanol is expected to become the new central bulk chemical in the global chemicals industry for the period until 2050.

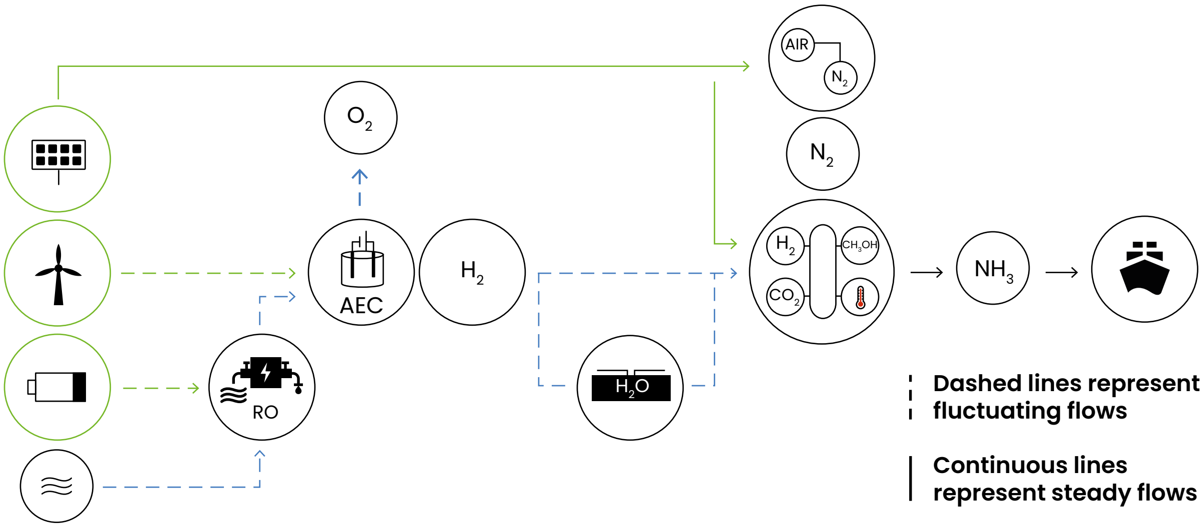


Figure 5: Schematic of the value chain elements in the production of renewable electricity based ammonia.

Growth trajectory of powerfuels

The development of the global fuels and chemicals demand shares covered by powerfuels follows from Ram et al.[54]. The shares of RE-chemicals (i. e. powerfuels used as chemicals) are assumed to follow a progressive development curve from 2030 to 2050, aligned to the 1.5 °C target of the Paris Agreement, as indicated in Figure 6. The global weighted powerfuels shares are 7 % (2030), 48 % (2040) and 96 % (2050). The shares of synthetic methane/synthetic liquid hydrocarbons is 1 %/0 % (2030), 18 %/28 % (2040) and 90 %/94 % (2050) respectively, as shown in Figure 6. The shares of RE-chemicals (RE-ammonia and RE-methanol) are assumed to be 26 % (2030), 85 % (2040) and 100 % (2050). The phase-in of RE-based LNG (marine) and FT fuels occurs rather late and is quite rapid thereafter. A steadier phase-in could occur with 3 % (2030), 43 % (2040) and 94 % (2050), as highlighted in Ram et al.[54]. Concomitantly, the share of fossil fuels declines steadily from its current dominant share of over 90 % in the initial phase of the transition. Beyond 2030, the decline in the shares of fossil fuels is rather rapid, with complete defossilisation by 2050.

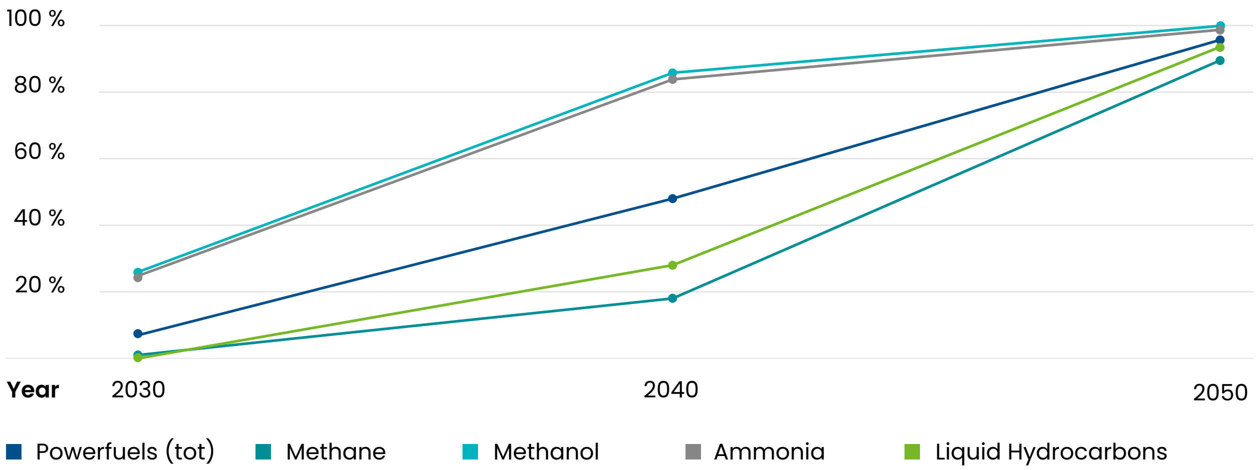


Figure 6: Global fuels and chemicals demand shares covered by powerfuels from 2030 to 2050.

Global trading of powerfuels

Along with the production of powerfuels, the global trading of these is considered in this research. In line with global trade trends, the trading framework is primarily built on the cost of production of powerfuels along with a few other factors.

Initially, the global demand volume weighted average cost is obtained for the respective year in the transition period until 2050. Thereafter, the 145 regions are aggregated into countries and larger regions, which results in 92 regions across the world that are further grouped into nine major regions. The 92 regions are also grouped into importers, exporters and neutral with a buffer of 1 to 5 % around the global volume weighted average cost per powerfuel and RE-chemical to reflect respective trading interests.

Classifying export regions does pose challenges, as regions with good renewable resources and low costs of generation are not necessarily ideal as export bases, since factors such as political stability, technological advancement, access to finance, ease of doing business among others constitute the attractiveness of a region to become a potential export hub. On this basis, the 92 regions are grouped according to their export attractiveness and classified as: attractive, moderate, risky and deterrent. This export attractiveness is expected to have an impact on the relative world market share for exports, i.e. an attractive-rated country is expected to gain a larger relative share than a risky-rated country, while a deterrent-rated country would be blocked form exporting. A more detailed explanation of the methods (section C in the Annex) along with the regional classification of the 92 countries and regions globally according to the import export attractiveness is highlighted in Figure C1 in section C of the Annex. The exportable volume for the 92 regions is obtained based on a combination of available area after meeting the regional domestic needs for all energy demand and the solar PV/wind generation mix, while the relative export shares are estimated as a function of export attractiveness, cost attractiveness and available area for higher capacities of solar PV and wind.

Correspondingly, the import demand is estimated as a function of relative cost levels, i.e. whether the domestic pre-trading costs are higher than global average pre-trading costs, and the resulting import shares of the different regions. Finally, the global import demand is covered by the global export volume, according to relative export shares. The global export cost is estimated from the volume-weighted costs from exporter regions, whereas import costs are estimated as the volume-weighted costs from importer regions, which includes shipping costs for LNG, FT fuels, ammonia and methanol that is covered by the importing regions in line with current trade practices.

Additional background data for powerfuels

The hourly solar irradiation and wind speed in 0.45 ° x 0.45 ° spatial resolutions are taken from NASA databases[57, 58] and are partly reprocessed by the German Aerospace Center[59]. Feed-in time series for fixed optimally tilted PV systems are calculated based on Gerlach et al.[60] and Huld et al.[61] to maximise the annual generation by considering the optimal PV module angle at each node, taking into account the irradiance angle, temperature and the impact of clouds on the hourly generation. Feed-in time series for single-axis tracking PV are based on Afanasyeva et al.[62], which considers a horizontal north-south-orientated single-axis continuously tracking system and global horizontal irradiation (GHI), direct normal irradiation (DNI), other environmental conditions (e. g. ambient temperature), and PV system components, such as cabling, inverters, and transformers. Feed-in time series of wind power plants are calculated for ENERCON (2014) standard 3MW wind turbines (E-101) with hub heights of 150 m, according to Gerlach et al.[60].

Demand data for powerfuels is adopted from Ram et al.[54], while the transport sector is based on the detailed analyses by Khalili et al.[17], for the power sector by Bogdanov et al.[53] and for the heat sector by the methods presented in Bogdanov et al.[63].

Chemicals are categorised into ammonia, methanol and naphtha, as the chemical industry can be fully reliant on these feedstock chemicals[52, 64]. Naphtha is a valuable by-product from Fischer-Tropsch synthesis and represents about 20 % of the total output[65] and within the LUT model is reallocated from the transport sector to the industry sector. Electricity demand, hydrogen demand and CO_2 for renewable electricity based methanol is as listed in Table 1.

Table 1: Electricity, H_2 and CO_2 demand for the production of RE-chemicals.

Demand	Ammonia	Methanol
Electricity	0.123 $kWh_{el}/kWh_{th,NH3}$	0.034 $kWh_{el}/kWh_{th,MeOH}$
Hydrogen	1.131 $kWh_{th,H2}/kWh_{th,NH3}$	1.246 $kWh_{th,H2}/kWh_{th,MeOH}$
Carbon dioxide	-	0.230 kg $CO_2/kWh_{th,MeOH}$

The financial and technical assumptions for ammonia are taken from Fasihi et al.[56] and for methanol from Fasihi and Breyer[40]. The total chemicals demand is projected according to Fasihi et al.[55], of which the ammonia demand projection is used from Fasihi et al.[56], and the naphtha by-product from FT synthesis is used first, while the remaining chemicals demand is supplied by methanol, as the fundamental chemical feedstock. The global chemicals demand is distributed on a country level according to the relative gross domestic product (GDP) share of a country in the global value, based on the GDP data from Toktarova et al.[66]. The shares of current chemicals to be phased out and the corresponding RE-chemicals ammonia and methanol to be phased in are according to Figure 6. The fossil feedstock for the chemical industry for the initial period is based on the IEA database[67].

Data for available CO_2 streams from point sources are taken for cement mills from Farfan et al.[48], for pulp and paper mills from Kuparinen et al.[68] and for waste incinerators according to Ram et al.[54]. The GHG emissions avoided due to the phase-in of powerfuels are calculated on the basis of the well-to-wheel approach[17], which includes all emissions from extracting fossil fuels to the final use. The parameters for this research are taken from Khalili et al.[17], which are listed in Table 2. The assumed fossil feedstock mix for chemical products is 6.0 % coal, 75.1 % oil, and 18.8 % natural gas, as in the IEA database[67].

Table 2: Emission factors of the various elements in the production of fuels and chemicals.

Elements	Emission Factors
Hydrogen (fossil based steam methane reforming)	380 g CO_2/kWh_{H2}
Fossil natural gas	300 g CO_2/kWh_{th}
Fossil oil products	368 g CO_2/kWh_{th}
Hard coal	390 g CO_2/kWh_{th}
Chemicals (fossil based)	356 g CO_2/kWh_{th}

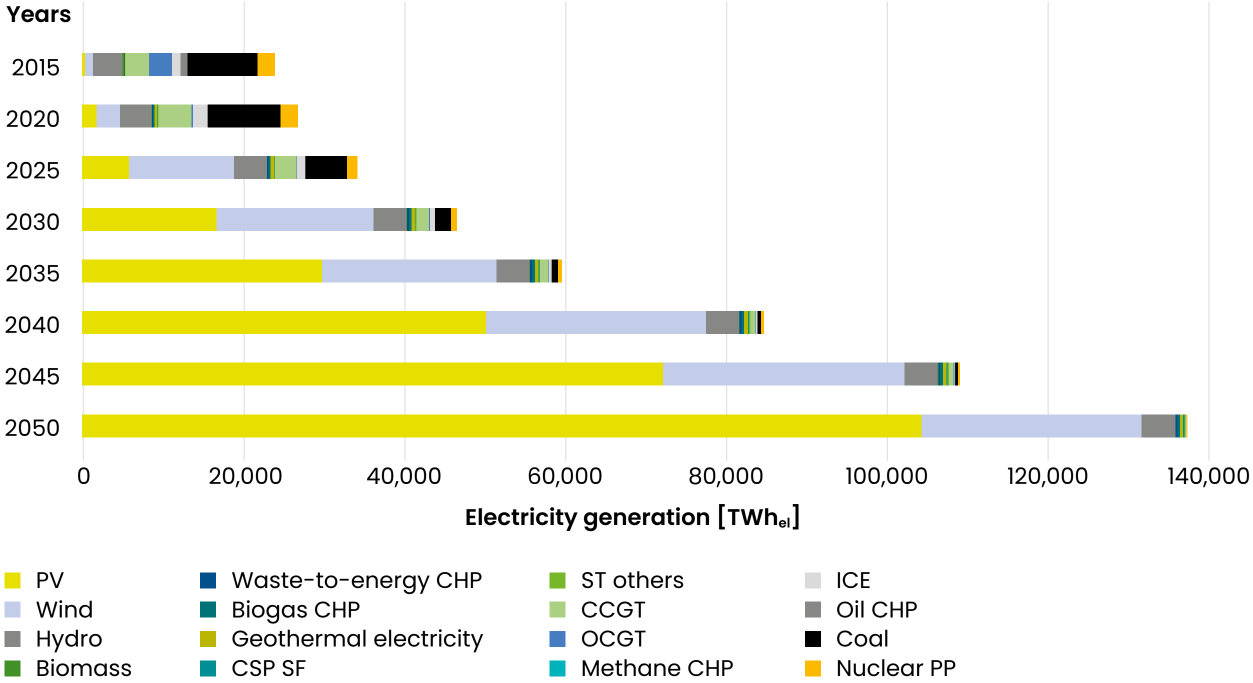
3 Results

Powerfuels in the global energy system transition

There is no place for fossil fuels in a fully sustainable energy system, if the goals of the Paris Agreement are to be realised. As highlighted by the results in Ram et al.[54] a zero GHG emissions global energy system can be achieved across the power, heat, transport and desalination sectors. Additionally, it is evident that a complete direct substitution of hydrocarbons by renewable electricity is not possible, as electricity cannot be directly used in some sectors such as in aviation for long-distance flights or marine and in other cases such as in the chemical industry. Thus, renewable electricity based synthetic fuels and chemicals are essential to fulfil this demand. Renewable electricity based FT fuels, hydrogen and liquefied gases (methane and hydrogen) are a viable alternative to fossil fuels by 2040 and have a vital role through the transition.

Electrification and defossilisation across the power, heat, transport and desalination sectors

Renewable electricity, which is a primary source of energy, emerges as the key energy carrier through the transition as highlighted by Ram et al.[54] and shown in Figure 7. Electricity is utilised directly in the power sector, for generating heat applicable in the heat sector and providing electricity for direct use as well as production of synthetic fuels (hydrogen, methane and FT fuels) in the transport sector and high-temperature applications in the heat sector. Natural heat from the environment in the form of geothermal heat and bioenergy from biomass and organic waste provides some shares of primary energy for electricity, heat and transport use. High levels of efficiency gains from electrification and sector coupling enable a decrease in the primary energy demand of an integrated energy system by 2050. This is captured by the final energy demand, which represents the energy demand at the consumption end.



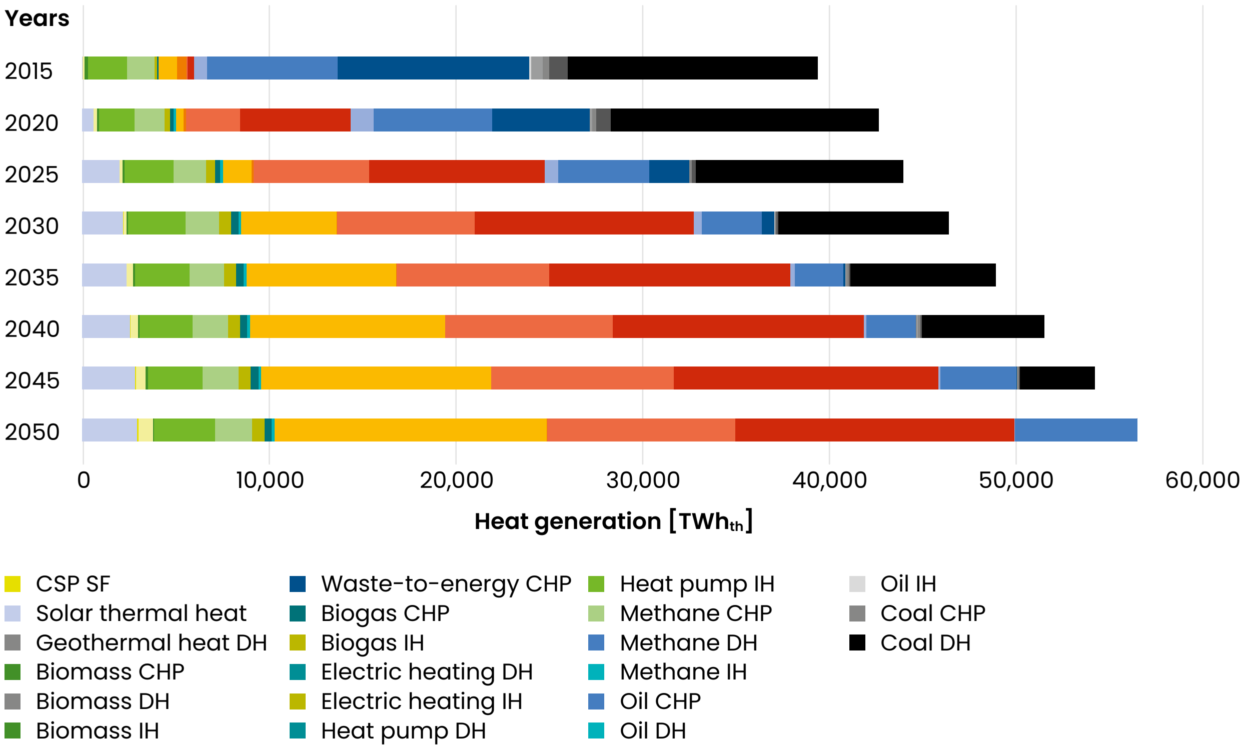
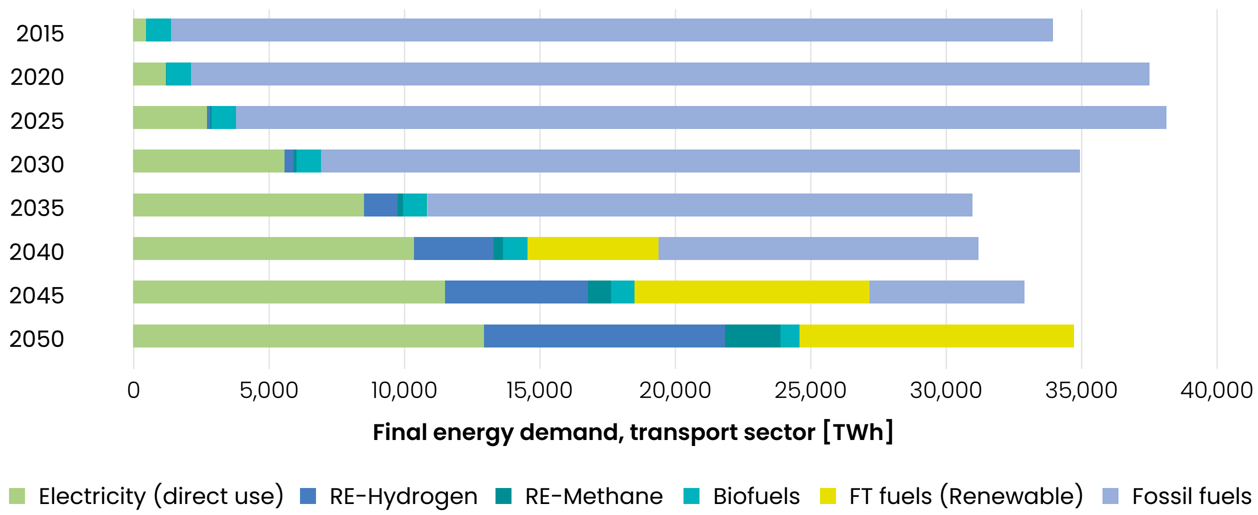


Figure 7: Technology-wise electricity generation (above) and technology-wise heat generation (below) during the energy transition from 2015 to 2050. Results according to Ram et al[54].

In the current decoupled and fossil fuels heavy energy system, a higher level of primary energy is required to meet the final energy demand, whereas in a highly electrified and sector-coupled energy system a lower level of primary energy is required to meet the final energy demand, which is almost the same by 2050.

Renewable electricity based hydrogen emerges as the other most important energy carrier through the transition, mainly in the production of synthetic fuels as shown in Figure 8. The transport and heat sectors utilise renewable electricity based fuels to a large extent from 2040 onwards. In 2050, a major portion of the electricity is used in the production of powerfuels, as highlighted in Figure 8.

The chemical industry can transition to being more sustainable by switching from fossil fuels to renewable electricity based power-to-chemicals solutions. The two main chemicals that can serve as the feedstock chemicals by 2050 are ammonia and methanol. Naphtha, a by-product from FT fuels production, can also be used as a very valuable feedstock for the chemical industry. It can be assumed that the present production of fossil fuels based chemicals can be gradually substituted by these two feedstock chemicals. The distribution of the additional growth share is assumed to be according to the relative global gross domestic product increase, resulting in non-energetic fuels demand for the chemical industry from 2030 to 2050.



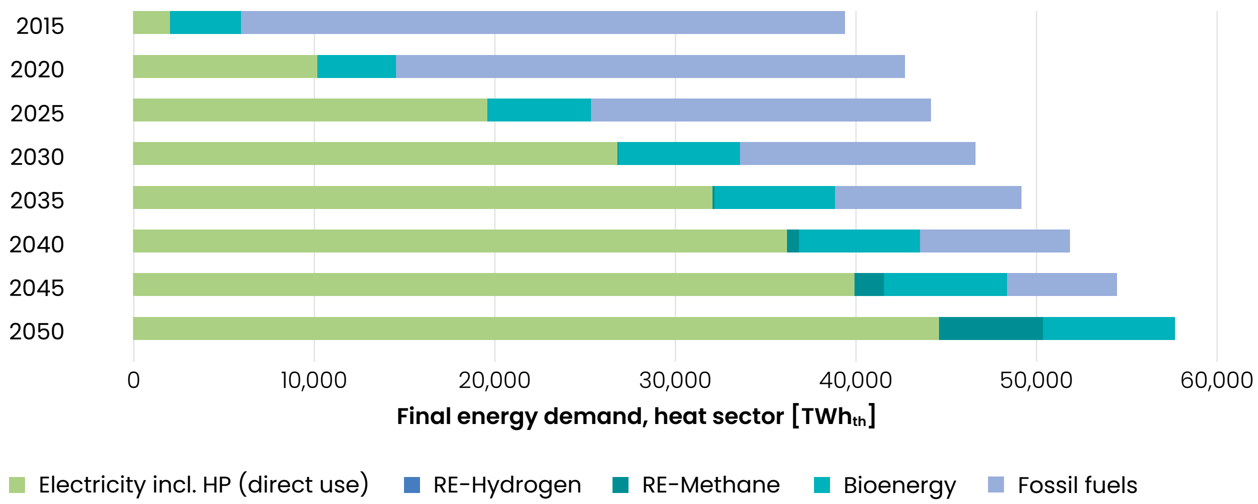


Figure 8: Final energy demand for the transport sector (above) and the heat sector (below) during the energy transition from 2015 to 2050. Results according to Ram et al[54].

Energetic demand development for fuels and chemicals

The results from this research indicate an interesting trend in terms of final energy demand for fuels and chemicals. As the energy system transits from fossil fuels towards renewables the final energy demand for fuels and chemicals declines from nearly 50,000 TWh in 2030 to just above 35,000 TWh by 2050 as shown in Figure 9.

The shift towards higher levels of electrification, especially in the transport sector, induces a lower demand for fossil fuels as highlighted in Ram et al.[54] in more detail. However, there is a growing demand for powerfuels from 2030 onwards as shown in Figure 10. This is mainly due to the necessity to phase out fossil fuel based emissions, but also to the cost-effectiveness of powerfuels with declining costs of renewable electricity. Methane demand declines initially owing to the declining shares of fossil fuels, while the demand for methane increases up to 2050 as shown in Figure 10. There could be further possibilities of methane being substituted with renewable electricity based hydrogen in this period, while some shares of sustainable bioenergy also contribute. A steady growth in the demand for chemicals is observed until 2050, where the demand for methanol represents the remaining chemical feedstock, which is not covered by the naphtha by-product from FT fuels and demand for ammonia.

The first markets for powerfuels, including their use as chemicals, begin to take shape by 2030 and thereafter grow significantly up to 2050, as highlighted in Figure 10.

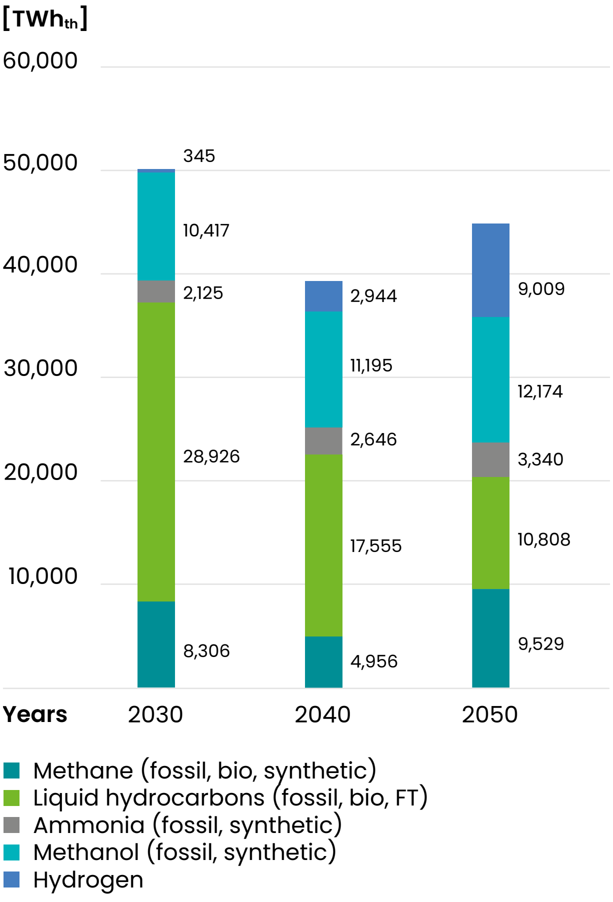


Figure 9: Development of final energy demand of all fuels and chemicals through the transition. The energy content of fuels and chemicals is displayed.

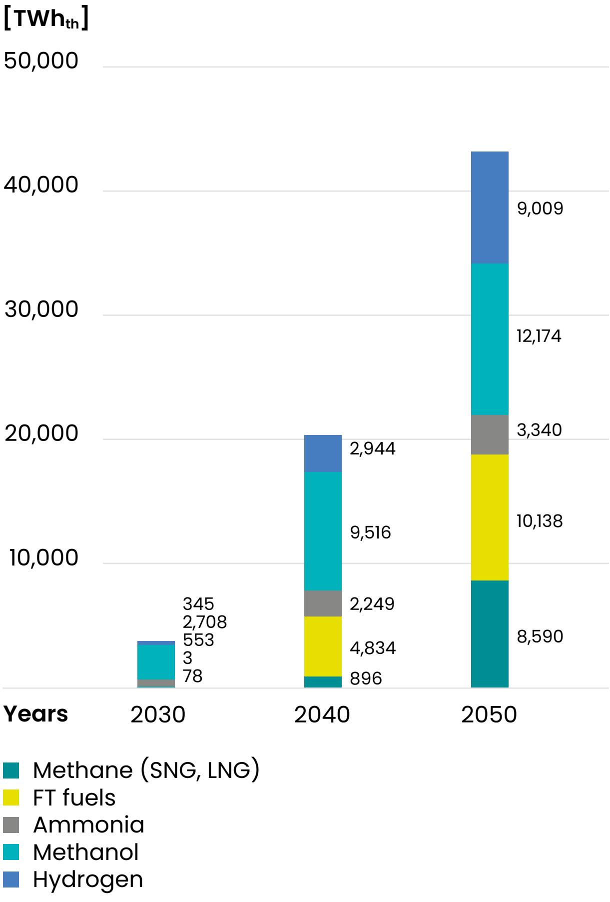


Figure 10: Development of final energy demand of powerfuels through the transition.

RE-chemicals have the potential for massive growth from 2030 onwards, as shown in Figure 10. Similarly, FT fuels witness massive demand from 2040 onwards, as it is expected to emerge as the prime alternative powerfuel with a dominating role in the hard-to-abate sector aviation. While there is significant demand for synthetic methane by 2050, there are possibilities of substitution with renewable electricity based hydrogen. Hydrogen is expected to play an increasing role in the heat sector in providing industrial process heat, and RE-chemicals may face additional demand as fuels for the marine sector. This would reduce the role of FT fuels, RE-LNG and hydrogen in that respect. The global market shares in 2050 are for SNG 25 %, for FT fuels 30 %, for RE-based ammonia 10 %, and for RE-based methanol 35 %, comprising a global market volume of about 35,000 TWh, which indicates a substantial potential for powerfuels in a 100 % renewable energy future.

The demand for powerfuels on a sectoral basis is shown in Figure 11. Interestingly, almost no powerfuels are required for the power sector, even within a 100 % renewable energy system, since daily variations can be balanced by low-cost batteries and dispatchable renewables such as sustainable bioenergy plants along with hydropower. Some biogas is upgraded to biomethane and can provide seasonal balancing, whereas the overall volume for methane in a 100 % renewable energy system remains comparably low, even if hydrogen is not used as a seasonal balancing option, as in the underlying study by Ram et al.[54]. Most of the SNG is used in the heat sector, in particular for high-temperature industrial processes, such as for cement or steel production. In the short to mid term, methane is the most suitable technical drop-in option, while in the mid to long term much of these processes may be finally managed through direct electrification, or at least by hydrogen. A substantial methane demand is expected in the transport sector, for RE-LNG based shipping. The uncertainty in this demand is very high, since several fuel options are available, and the marine industry has not yet favoured one option over the others. In principle, any of these powerfuels could be used: RE-LNG, liquefied hydrogen, FT fuels, RE-ammonia and RE-methanol. In the underlying study of Ram et al.[54], the fuel options were RE-LNG, liquefied hydrogen and FT fuels, while most recently the options of using RE-ammonia and RE-methanol are increasingly being discussed. Not yet widely discussed is the massive increase in sustainable water supply, which may require the same amount of SNG as in the power sector for stable water supply, by balancing seasonal effects in a least cost operation mode, as detailed by Caldera and Breyer[45].

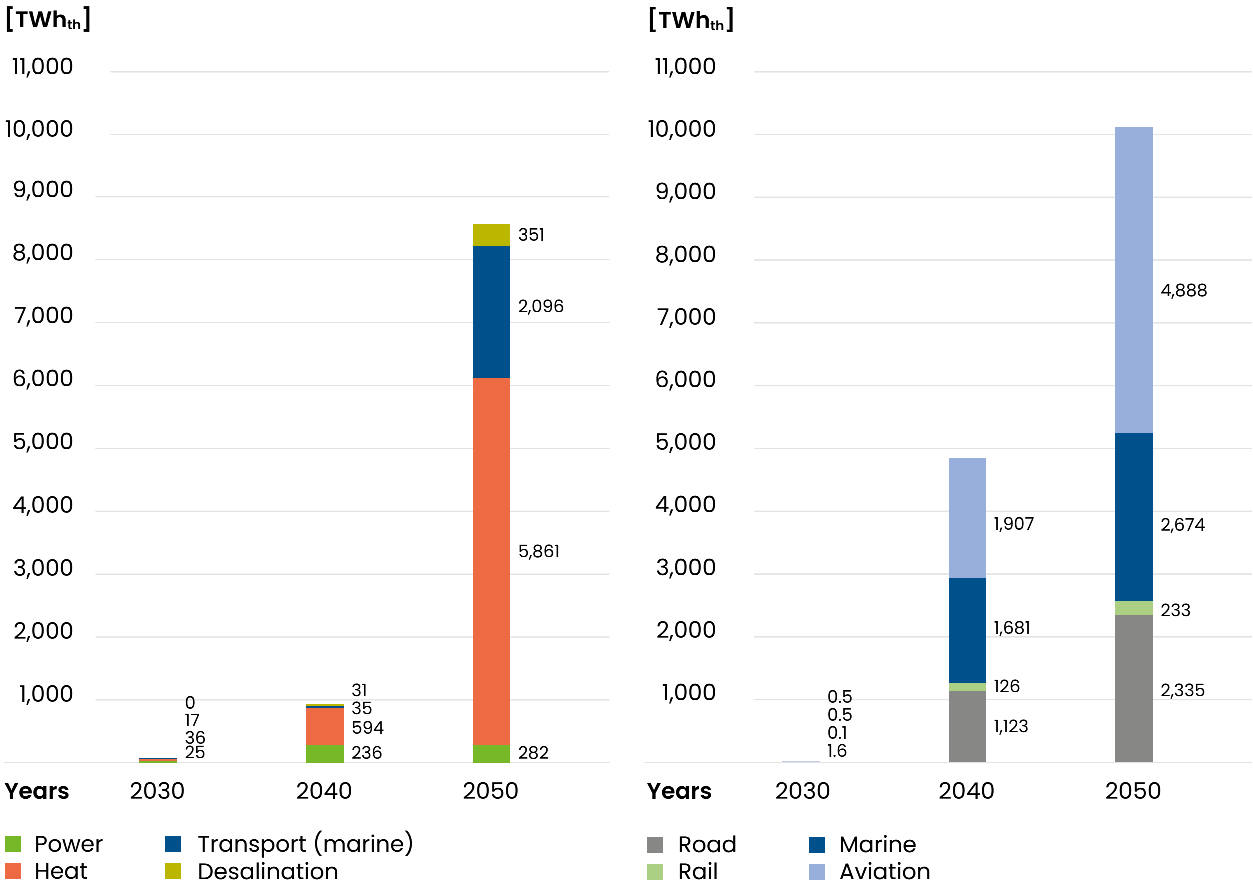


Figure 11: Development of final energy demand of powerfuels on a sectoral basis for SNG (left) and FT fuels (right) through the transition. Results according to Ram et al.[54].

FT fuels are found to be required only in the transport sector, however across all transport modes. The highest share with almost 50 % is required by the aviation mode, and the remaining is demanded by the transport modes of road and marine with roughly equal shares. In Ram et al.[54], a massive direct electrification via battery-electric vehicles is assumed, but smaller shares for conventional internal combustion engines and plug-in hybrids are assumed, which leads to demand of liquid hydrocarbon fuel that is covered by FT fuels. Biofuels are assumed to be highly restricted due to sustainability constraints, so that only wastes, residues and by-products can be utilised, with arable land primarily for food production and preserving valuable ecosystems. RE-chemicals are solely used in the chemical industry, while RE-naphtha as a by-product of FT fuels production can be used as a valuable feedstock chemical.

Demand for powerfuels

As the demand for fossil fuels wanes through the transition, mainly with the increasing trend of electrification of road transport, markets for powerfuels emerge across the world from 2030 onwards. The global distribution of demand for methane and liquid hydrocarbons in 2030, 2040 and 2050 is presented in Figures 12 – 14.

In 2030, the global share of synthetic methane is 0.9 % of 8,306 TWh_{th} and that of FT fuels is 0.01 % of 28,926 TWh_{th}, as indicated by Figure 12. The demand is fairly well distributed across the world for both methane and liquid hydrocarbons.

In 2040, the global share of synthetic methane is 18.1 % of 4,955 TWh_{th} and that of FT fuels is 28 % of 17,555 TWh_{th}, as indicated by Figure 13. Some of the African countries now begin to develop demand for methane and FT fuels.

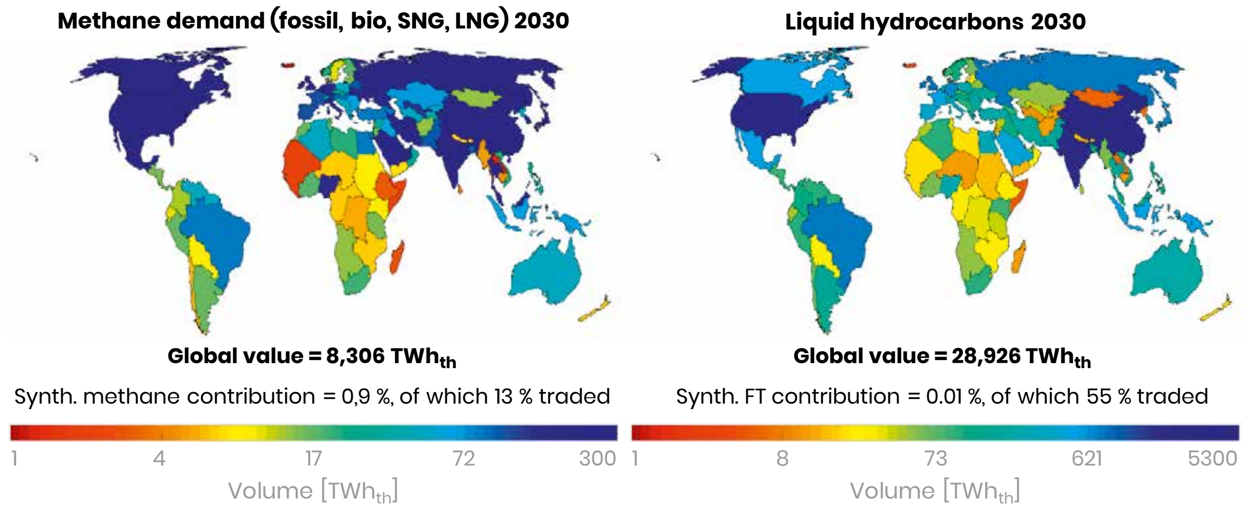


Figure 12: Global distribution of demand for methane (left) and liquid hydrocarbons (right) in 2030.

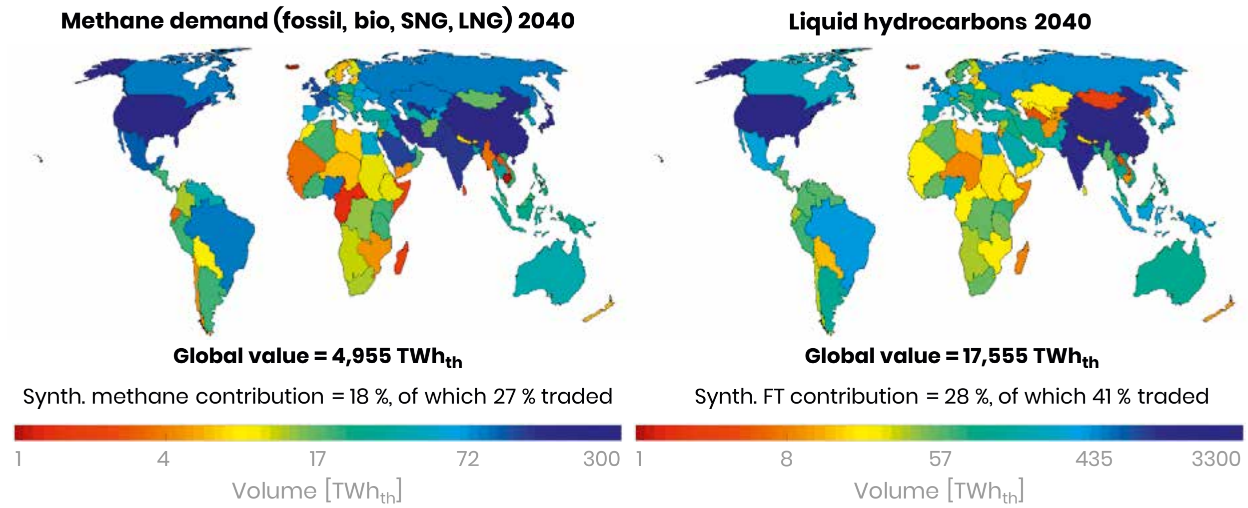


Figure 13: Global distribution of demand for methane (left) and liquid hydrocarbons (right) in 2040.

In 2050, the global share of synthetic methane is 90.1 % of 9,529 TWh_{th} and that of FT fuels is 94 % of 10,808 TWh_{th}, as indicated by Figure 14.

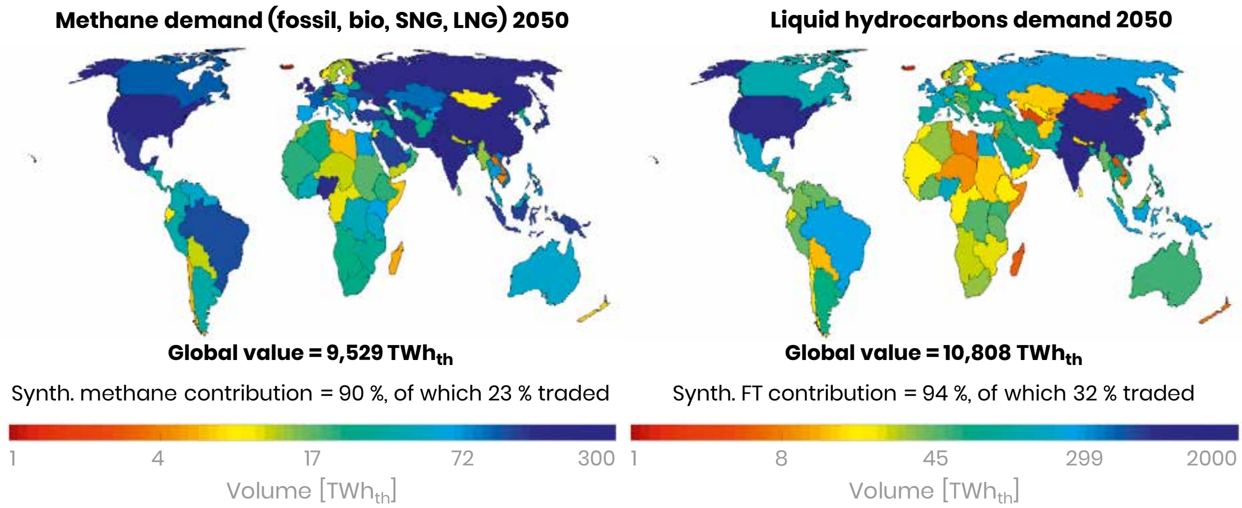


Figure 14: Global distribution of demand for methane (left) and liquid hydrocarbons (right) in 2050.

The demand for ammonia and methanol is well distributed, more so among the developed and emerging economies. African and South American countries still have a low demand in 2030 as shown in Figure 15. Synthetic ammonia has a share of 26 % of 2,125 TWh_{th} of total global demand, while synthetic methanol contributes 26 % of 10,417 TWh_{th} of global demand in 2030.

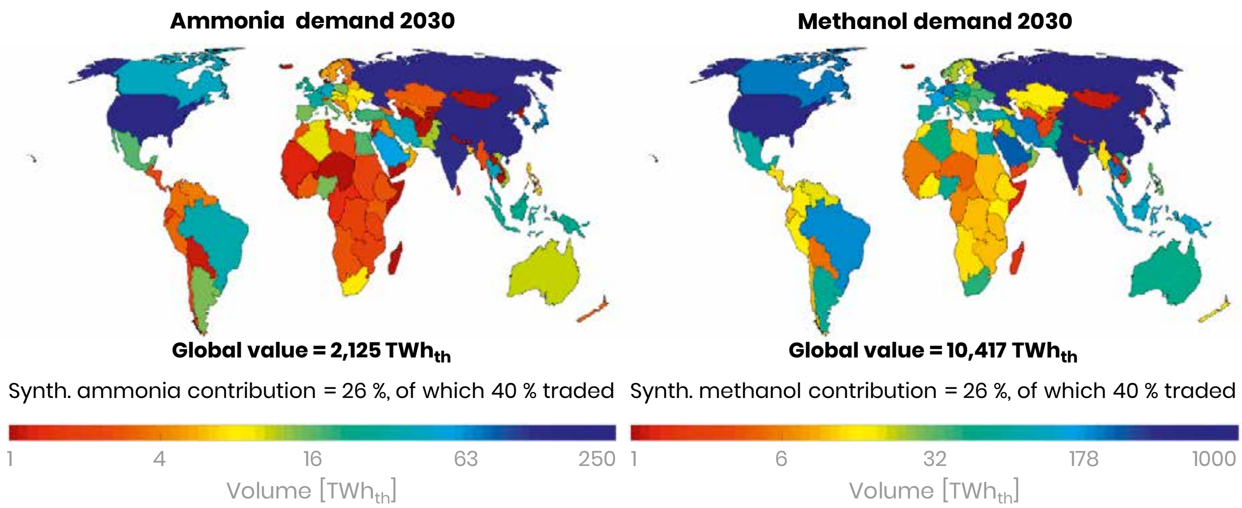


Figure 15: Global distribution of demand for ammonia (left) and methanol (right) in 2030.

In 2040, synthetic ammonia has a share of 85 % of 2,646 TWh_{th} of total global demand, while synthetic methanol contributes 85 % of 11,195 TWh_{th} of global demand as shown in Figure 16. The demand for methanol, which is representative of the non-ammonia chemical feedstock has increasing shares across Africa and South American countries.

In 2050, synthetic ammonia has a share of 100 % of 3,340 TWh_{th} of total global demand, while synthetic methanol contributes 100 % of 12,174 TWh_{th} of global demand as shown in Figure 17. In line with the trend, African and South American countries continue to gain higher shares, while the demand remains high in countries such as China, India and the USA through the transition.

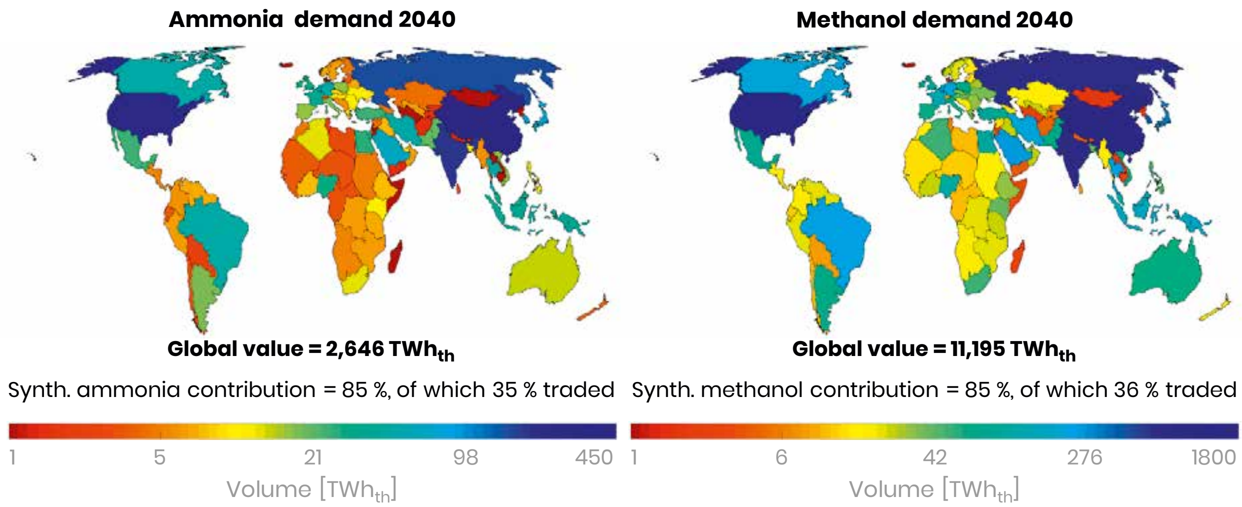


Figure 16: Global distribution of demand for ammonia (left) and methanol (right) in 2040.

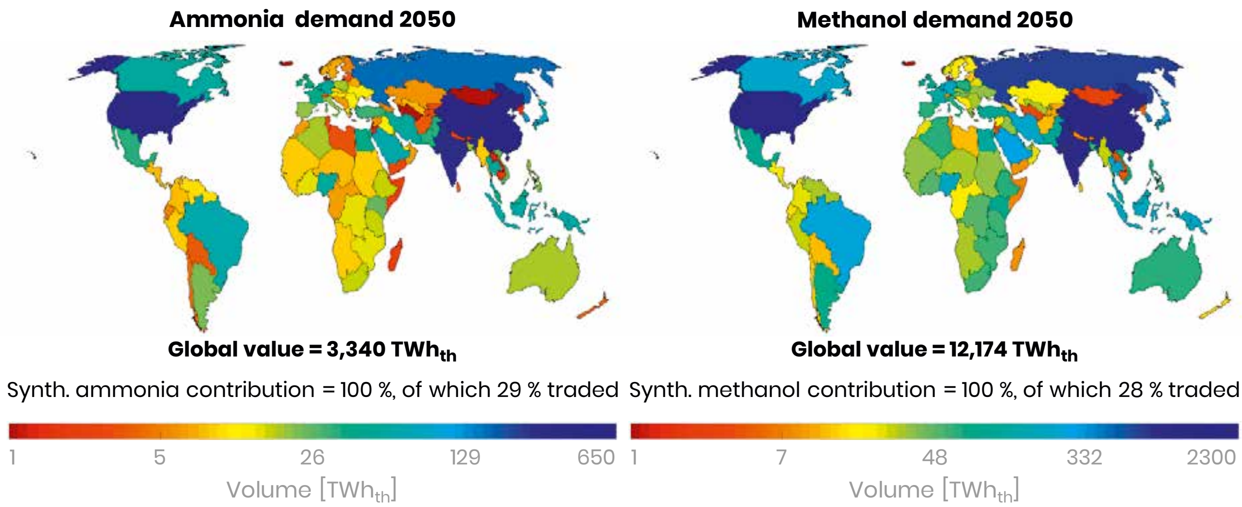


Figure 17: Global distribution of demand for ammonia (left) and methanol (right) in 2050.

Demand for CO_2 as raw material input

Sustainable CO_2 demand is mainly covered by point sources and DAC through the transition. In the initial period of the transition, point sources supply most of the CO_2, whereas DAC grows through the transition, providing most of the CO_2 in the later part of the transition.

Point sources are mainly considered from three major sources, which are limestone related process emissions of cement mills, pulp and paper production and waste incinerators. The share of CO_2 captured from these three sources through the transition is highlighted in Figure 18. Cement mills contribute majorly towards supplying CO_2 through the transition, with 65 % in 2050 as highlighted in Figure 18, while pulp and paper contribute 19 % of the CO_2 and waste incinerators supply 17 % in 2050.

DAC is an essential technology for any sustainable energy scenario as highlighted by Breyer et al.[47]. 80 % of all CO_2 raw material in 2050 will be provided by DAC, as highlighted in Figure 19. DAC technology phases in first for carbon capture and utilisation (DACCU), then from 2040 onwards also for carbon capture and storage with enhanced weathering in the form of carbon mineralisation (DACCS-EW)[47].

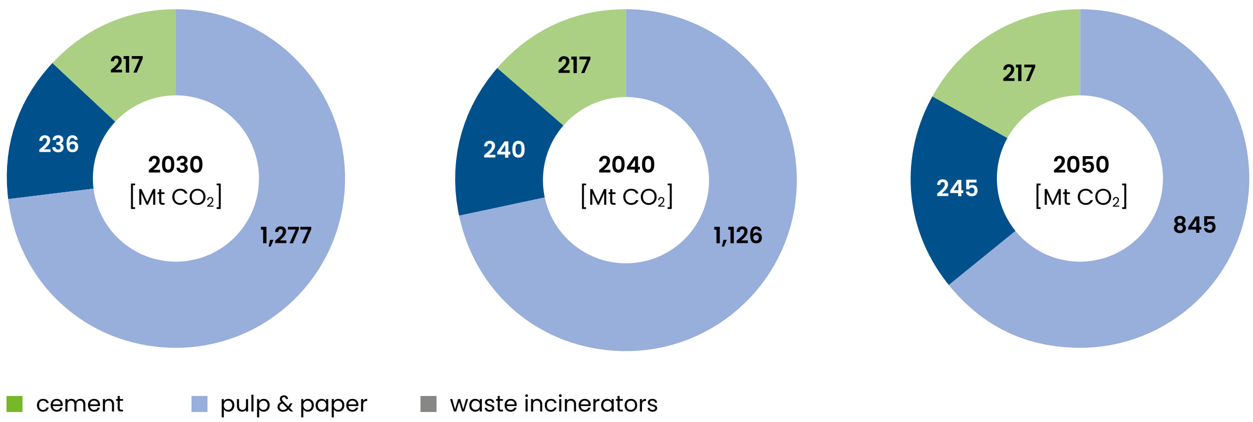


Figure 18: Shares of captured CO_2 from different point sources through the transition

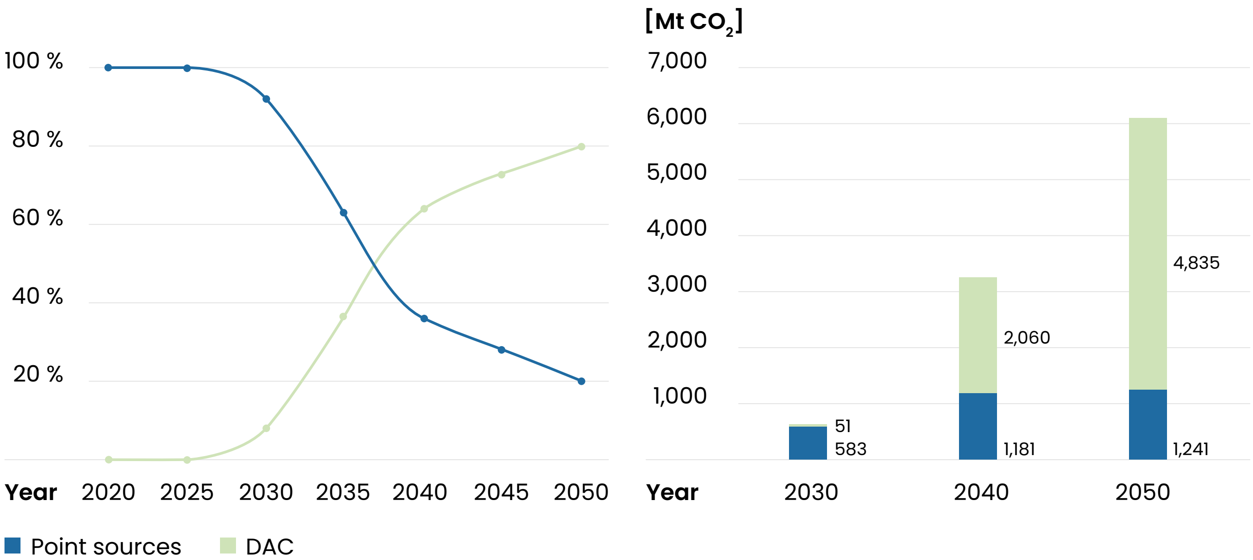


Figure 19: CO_2 demand covered by point sources and DAC through the transition from 2020 to 2050: relative shares (left) and absolute volumes (right).

High reliance on CO_2 point sources in RE-based systems will demand installations of gaseous CO_2 storage for short- and long-term buffering, since point source CO_2 will be captured continuously from processes with very high operation hours, while H_2 will be mostly produced during energy surplus periods. In addition, special transportation infrastructure will be needed to collect CO_2 from smaller point sources. Consequently, to enable synthetic fuels production mostly with point source CO_2, significant capacities of CO_2 and H_2 storage along with transportation infrastructure will be needed. Underground storage is not always available due to specific geological structure requirements, while on ground storage and CO_2 transportation infrastructure will demand area and additional costs for installations. Moreover, in RE-based systems, biomass capacities are expected to become a very valuable energy source, which is mostly used for sustainable liquid biofuels production or for heat and electricity generation during energy deficit periods. Therefore, taking into account cost reduction with learning effects, DAC emerges as the long-term sustainable option for capturing CO_2.

Sustainable or unavoidable CO_2 point sources, mainly waste incinerators, pulp and paper plants and non-fuel emissions of cement mills, meet the demand in the 2020s, whereas from 2030 onwards these CO_2 point sources cannot meet the demand and the market for DAC takes shape. In 2030, 92 % of global CO_2 demand can be covered by point sources, while DAC contributes 51 Mt CO_2, as shown in Figure 20.

Since DAC and point sources are the only two sources of CO_2 analysed in this work, the complementary values for shares and absolute values in Figures 20 – 22 apply to the respective CO_2 source, e.g. the global average CO_2 demand covered by DAC in 2030 amounts to 8 %.

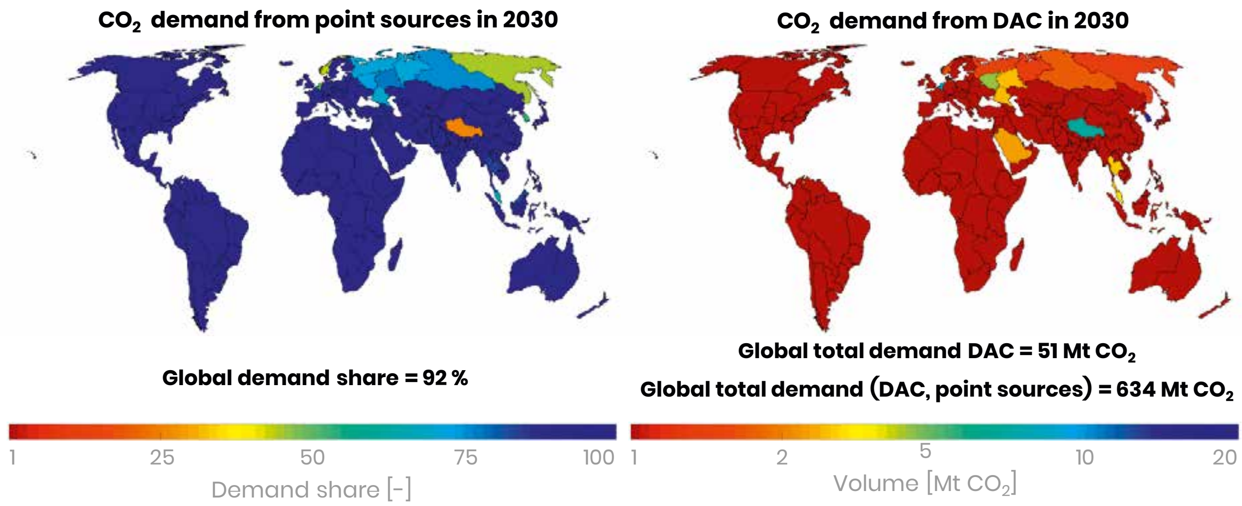


Figure 20: Global distribution of CO_2 demand covered by point sources (left) and DAC (right) in 2030.

In 2040, 36 % of global CO_2 demand is covered by point sources, while DAC contributes 2,060 Mt CO_2, as shown in Figure 21. Mostly, industrialised and developed regions of the world have a higher DAC demand, while point sources are distributed across the world.

In 2050, 20 % of global CO_2 demand is covered by point sources, while DAC contributes 4,835 Mt CO_2, as shown in Figure 22. In line with the trends, point sources are distributed across the world, with higher shares only in exceptional regions which have enough CO_2 point sources with strong pulp and paper industry, or late industrialisation (thus late cement demand) and low CO_2 for synthesis demand. By contrast DAC has higher shares in developed and emerging economies.

CO_2 DAC is the main sustainable source of CO_2 supply from 2030 onwards. It also becomes cost-effective in the long run.

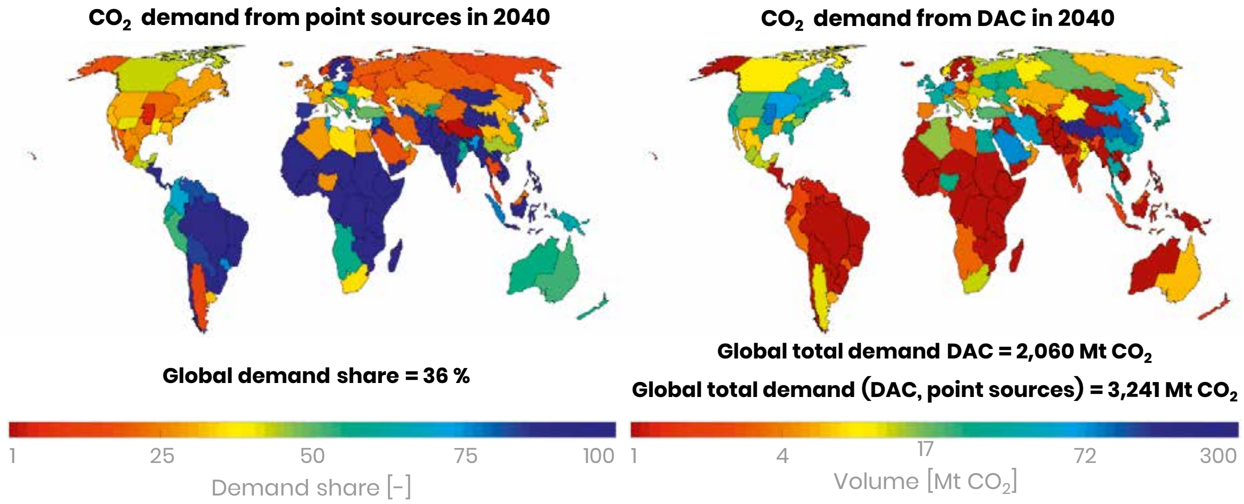


Figure 21: Global distribution of CO_2 demand covered by point sources (left) and DAC (right) in 2040.

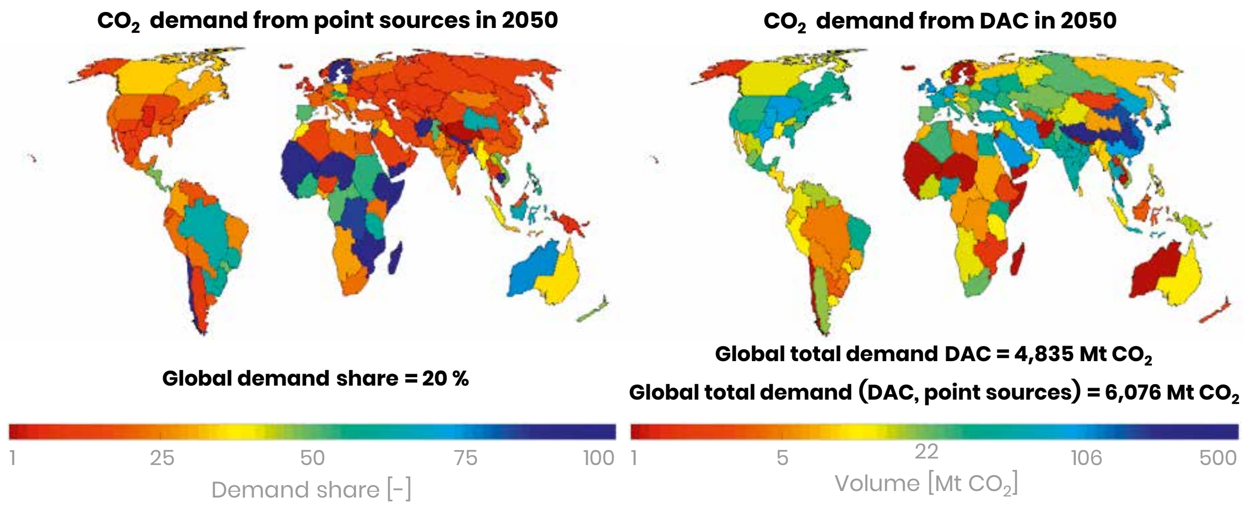


Figure 22: Global distribution of CO_2 demand covered by point sources (left) and DAC (right) in 2050.

Global trading of powerfuels

Initial insights into global trading of powerfuels are obtained by analysing the pre-trade demand curve and the unconstrained supply curve, only factoring in the economics, regional resources and available area. It is assumed that 4 % of total area can be utilised for wind energy and 6 % for solar PV. Figures 23 and 24 show the classical market equilibrium for such a simplified approach for the results in 2050. All volumes at a higher LCOF than the equilibrium would be supplied by imports and not by domestic production, while the volumes below the equilibrium cost level would remain as domestic supplies. Such a theoretical approach ignores several issues, such as stability and attractiveness of least-cost exporters, but also other positive effects of domestic supply such as energy security, domestic jobs, value creation and high domestic tax incomes, which may justify a marginally higher domestic cost level than achievable on a pure import basis, as it is current practice of most countries to tax value creation and further income for social security systems.

The global average equilibrium cost levels for SNG and FT fuels are around 51 €/MWh and 75 €/MWh in 2050 respectively, as shown in Figure 23.

Similarly, the global average equilibrium cost levels for RE-ammonia and RE-methanol are 46 €/MWh and 52 €/MWh in 2050 respectively, as shown in Figure 24.

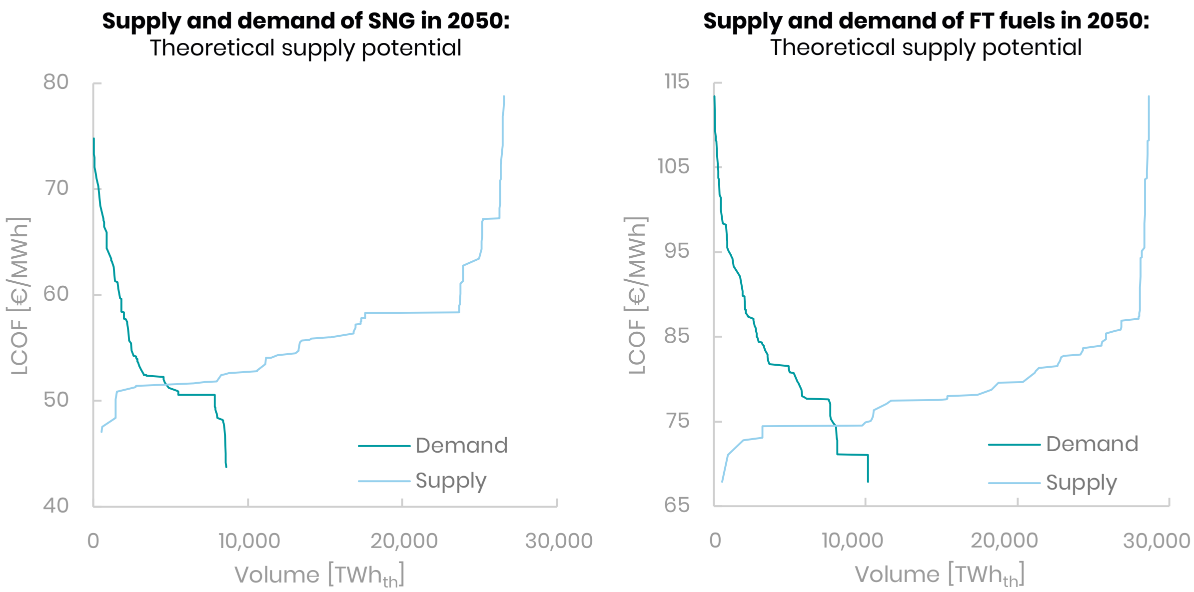


Figure 23: Global average supply and demand curves of SNG (left) and FT fuels (right) in 2050.

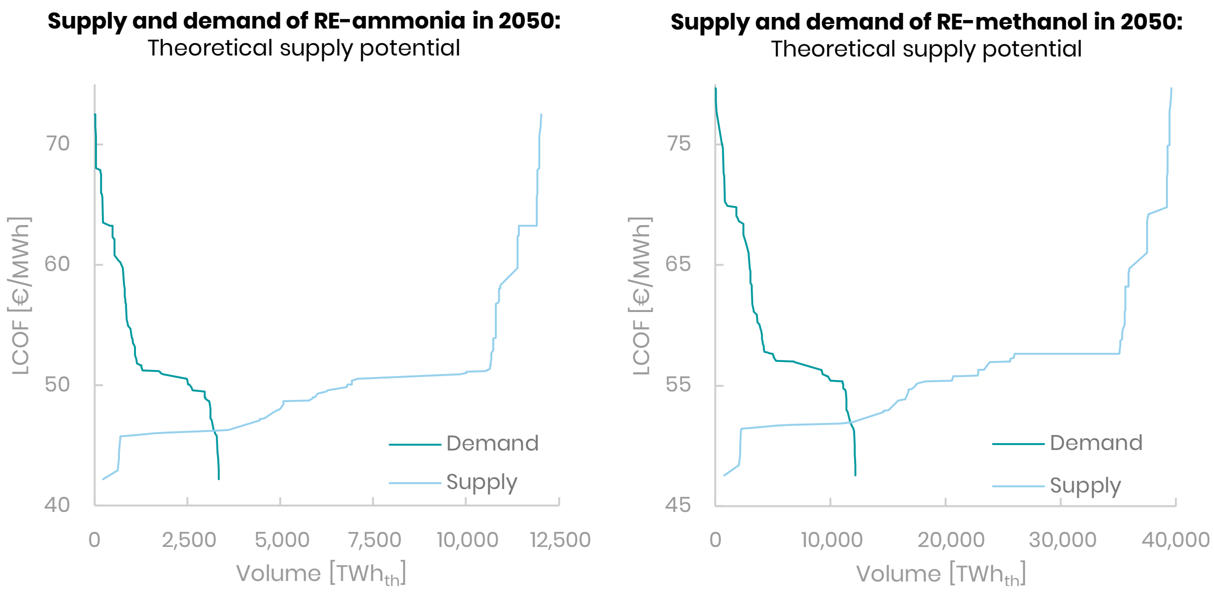


Figure 24: Global average supply and demand curves of RE-ammonia (left) and RE-methanol (right) in 2050.

In the following, some of the effects mentioned that are relevant for balanced decision-making are taken into account, as is detailed in the Methods section and the related Appendix section. The results are shown in Figures 25-28 for the corresponding powerfuels. In Figure 25 the demand curve for SNG is shown as the pre-trade demand curve, while the supply curve is transformed to not only consider the conversion to LNG, but in particularly also to consider the attractiveness of a specific region for importers, since regions in turmoil such as Yemen and Somalia show most attractive economics, but pose immense risks for doing business and creating value for investors. The supply curve strongly factors in the regional attractiveness, but also the benefits of low production costs to the extent possible. The average pre-trade LCOF is displayed as a benchmark to distinguish cost and volumes of importers, indicated by the blue area, and the volumes of self-supplying and exporting regions in dark red. It is assumed that importing countries follow a portfolio approach, which allows mixing of least-cost supply options with other low-cost supplies from other regions, resulting in a balanced and stable long-term trade for both exporters and importers. The average LCOF of the traded volume is also displayed.

In Figure 25 (right), the consequences for the post-trade demand curve are highlighted, which maintains the demand volumes that are assumed to be inelastic, but for the adjusted cost due to trading, which moves all importing countries on the cost level of the traded LCOF plus the cost for shipping fuels. As a consequence, the global market is split into three main fractions: first, an attractive domestic volume, which is still at a slightly higher cost level than globally traded volumes, but also linked to benefits such as higher energy security, jobs, and higher tax revenues, so that up to 15 % higher cost levels may be well justified. Second, the traded volume for all may be importers, which improves their cost structure as further detailed in the following figures. Third, a low-cost volume of the total market, which is below the cost level of the traded volumes and which generates further benefits for these self-supplying regions, but which also indicates the regions with the best possible export opportunities due to global least-cost production possibilities.

The average LCOF of globally traded SNG is around 50 €/MWh and the corresponding globally traded volume is around 2,000 TWh_{th} in 2050, as shown in Figure 25.

The average LCOF of globally traded FT fuels is around 75 €/MWh and corresponding globally traded volume is around 3,300 TWh_{th} in 2050, as shown in Figure 26.

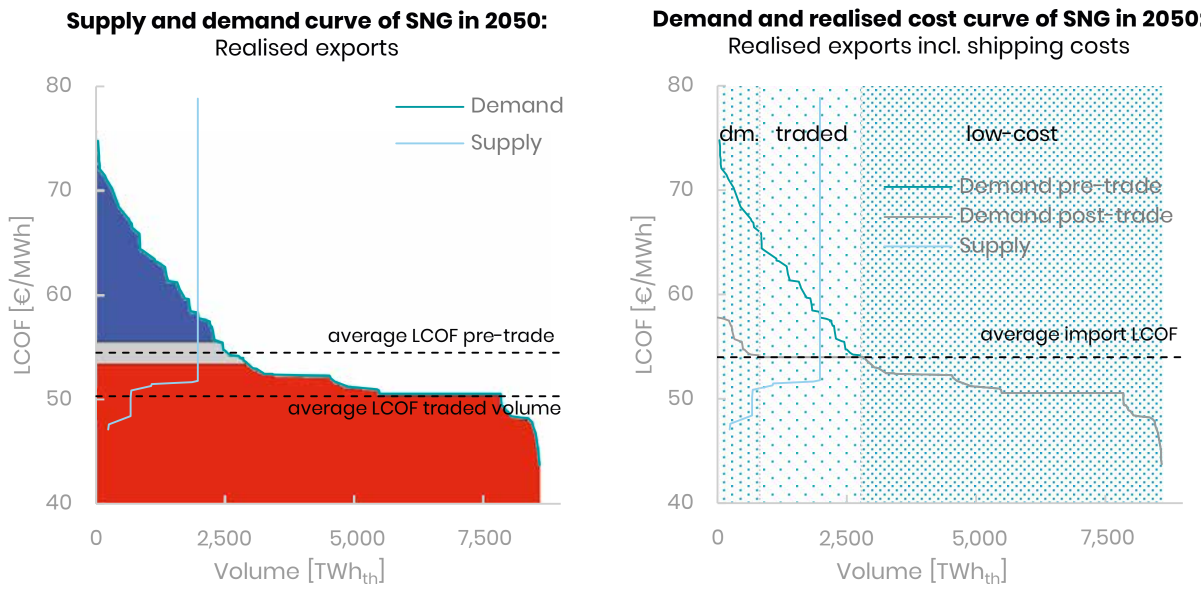


Figure 25: Global average supply and demand curves of SNG, pre-trade (left) and with exports (right) in 2050.

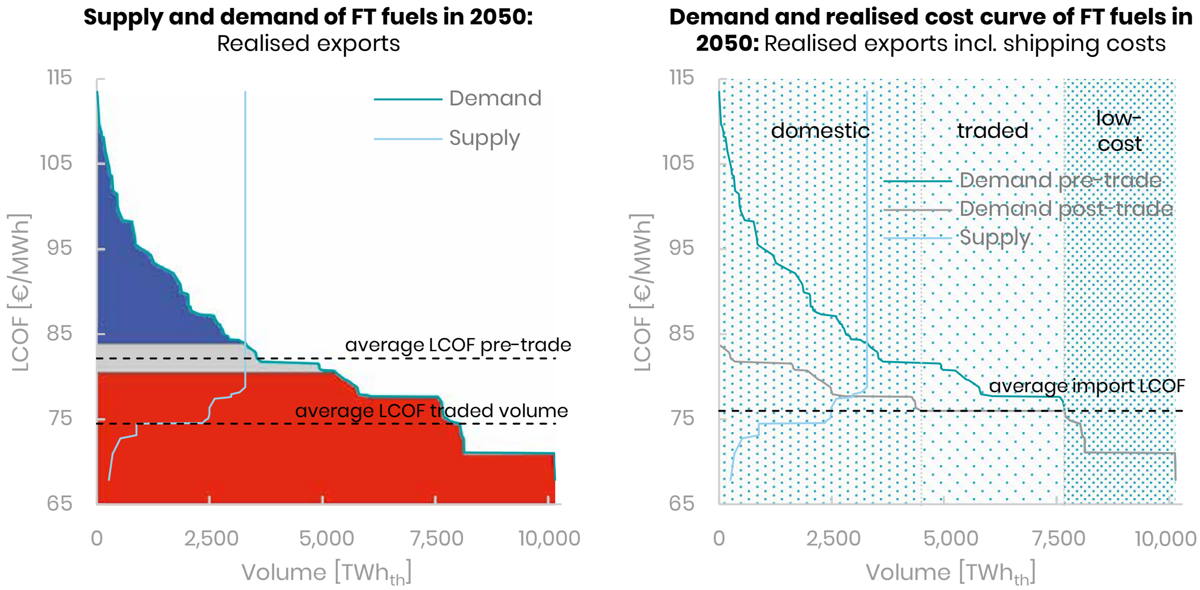


Figure 26: Global average demand and supply curves of FT fuels, pre-trade (left) and with exports (right) in 2050.

The average LCOF of globally traded RE-ammonia is around 45 €/MWh and corresponding globally traded volume is around 1,000 TWh_{th} in 2050, as shown in Figure 27. Comparatively, lower volumes of RE-ammonia are traded globally.

The average LCOF of globally traded RE-methanol is around 51 €/MWh and corresponding globally traded volume is around 3,400 TWh_{th} in 2050, as shown in Figure 28. RE-methanol seems to be the most suitable for global trade with high volumes.

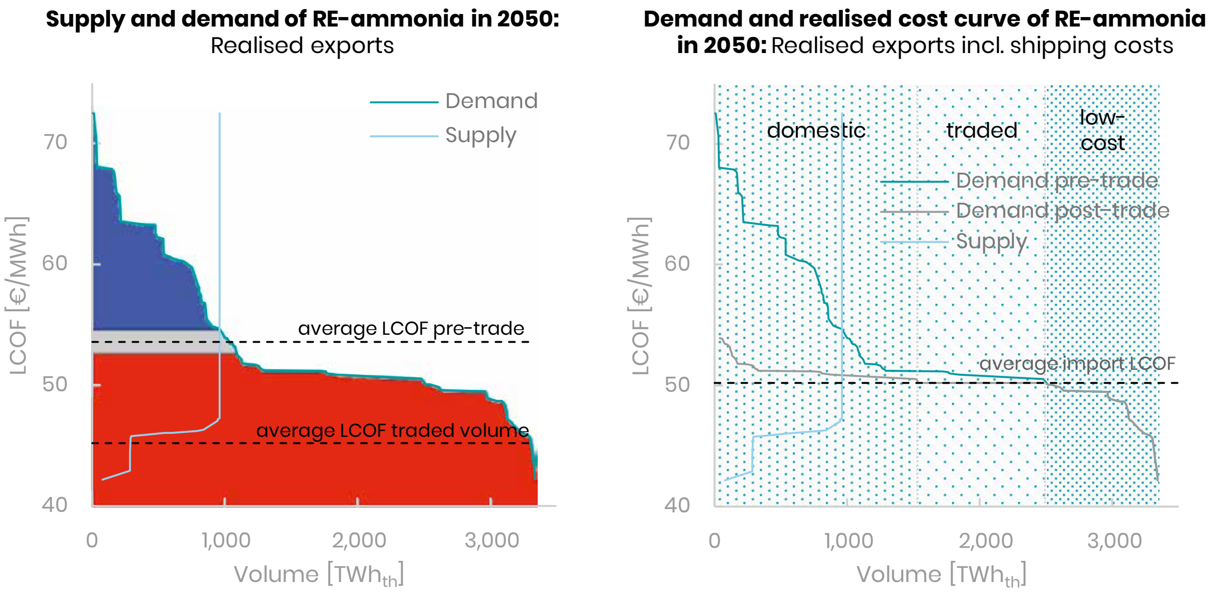


Figure 27: Global average demand and supply curves of RE-ammonia, pre-trade (left) and with exports (right) in 2050.

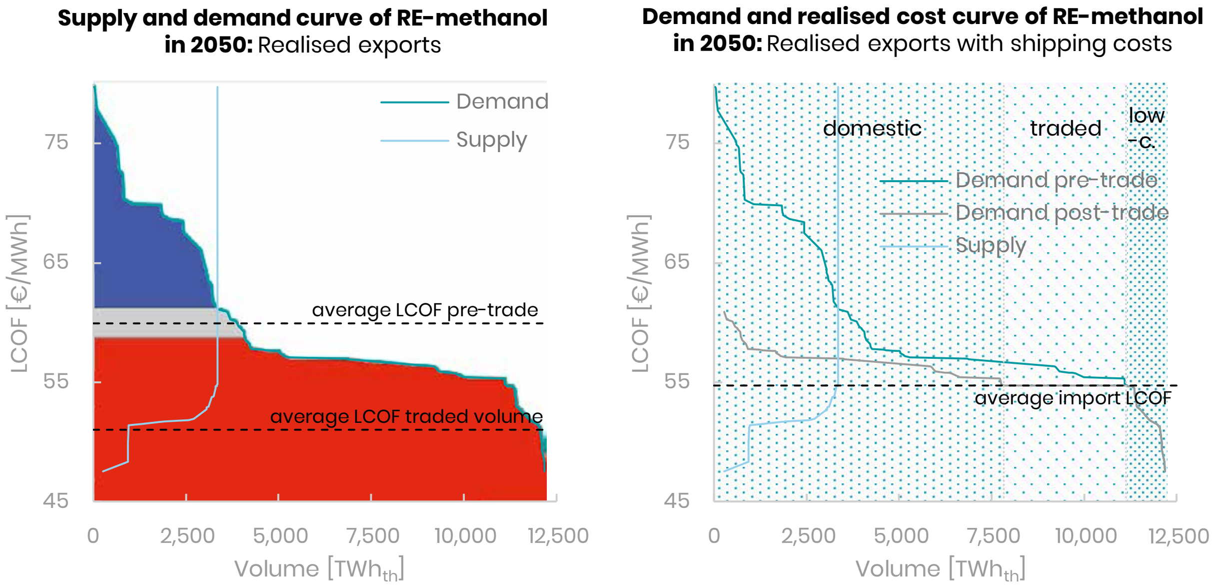


Figure 28: Global average demand and supply curves of RE-methanol, pre-trade (left) and with exports (right) in 2050.

Global trading of powerfuels has been established based on several factors with costs of production being critical. Countries and regions are classified based on their preference to be export-oriented, import-oriented or neutral. More details in section C and Figure C1 of the Annex.

In 2030, the global trade preferences for LNG and FT fuels are highlighted in Figure 29. In the case of LNG, North America and southern parts of South America, along with Australia, China and some parts of Africa are export-oriented, while Central Europe, South Asia and some parts of Africa are import-oriented and the rest neutral. By contrast, for FT fuels, most of the world is import-oriented as costs are still comparatively higher.

In 2040, trade preferences begin to diversify for LNG and FT fuels, as shown in Figure 30. LNG is exported mainly by Canada, Chile, southern parts of Argentina, China and some African countries, while the USA, parts of South America and Europe are importers with the rest being neutral. In the case of FT fuels, India, China, the USA and the southern parts of South America become exporters, while the rest are mostly importers or neutral.

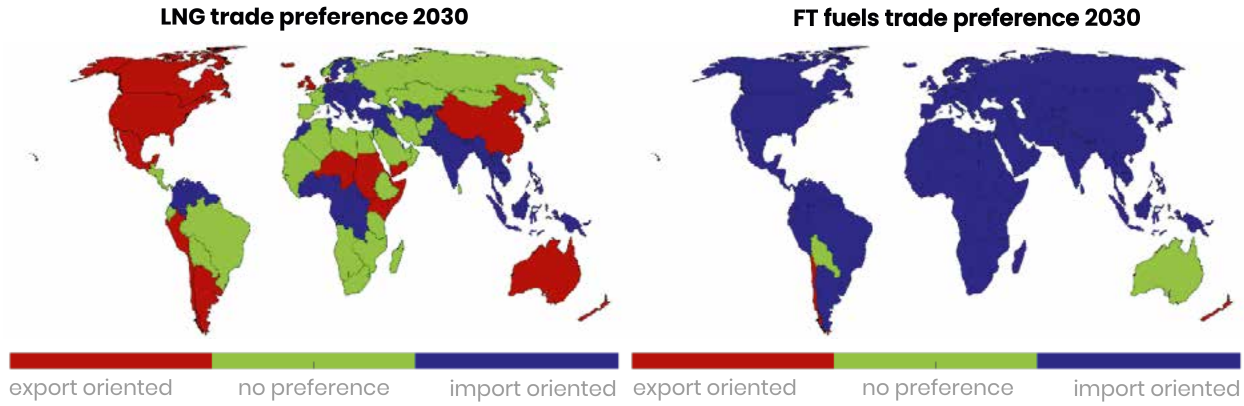


Figure 29: Global trade preference of LNG (left) and FT fuels (right) in 2030.

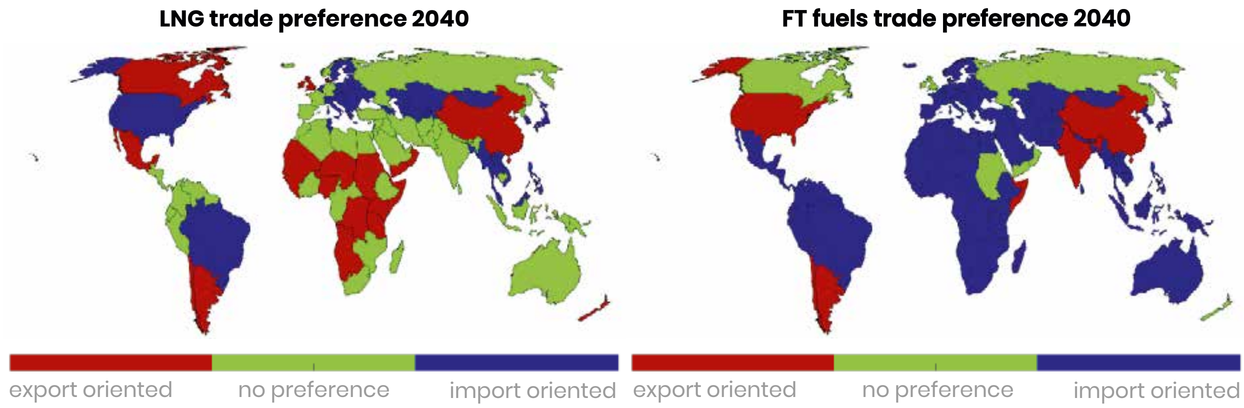


Figure 30: Global trade preference of LNG (left) and FT fuels (right) in 2040.

In 2050, further diversification of trade preferences for LNG and FT-fuel is highlighted by Figure 31. LNG import is mainly in the northern hemisphere with Canada, Europe and Eurasia, while exports are mainly from African countries and Mexico along with Peru. The rest of the world is neutral. In the case of FT fuels, India, China, Australia as well as most parts of South America and Africa are export-oriented, while Europe, Eurasia and MENA are import-oriented and the rest of the world is neutral.

Similarly, the global trade preferences for RE-chemicals are mapped for ammonia and methanol as shown in Figures 32 – 33. In 2030, mainly North America, Australia and southern parts of South America are export-oriented, while the rest of the world is mostly import-oriented or neutral.

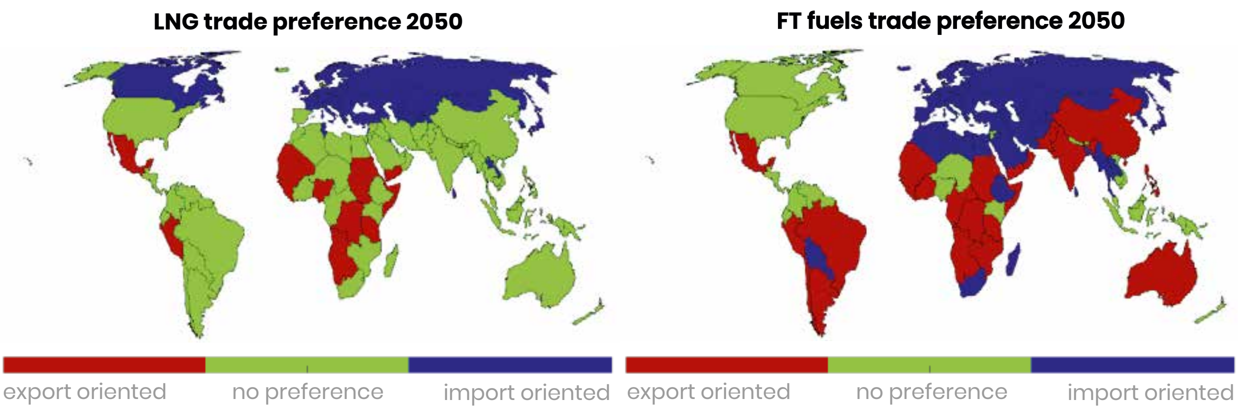


Figure 31: Global trade preference of LNG (left) and FT fuels (right) in 2050.

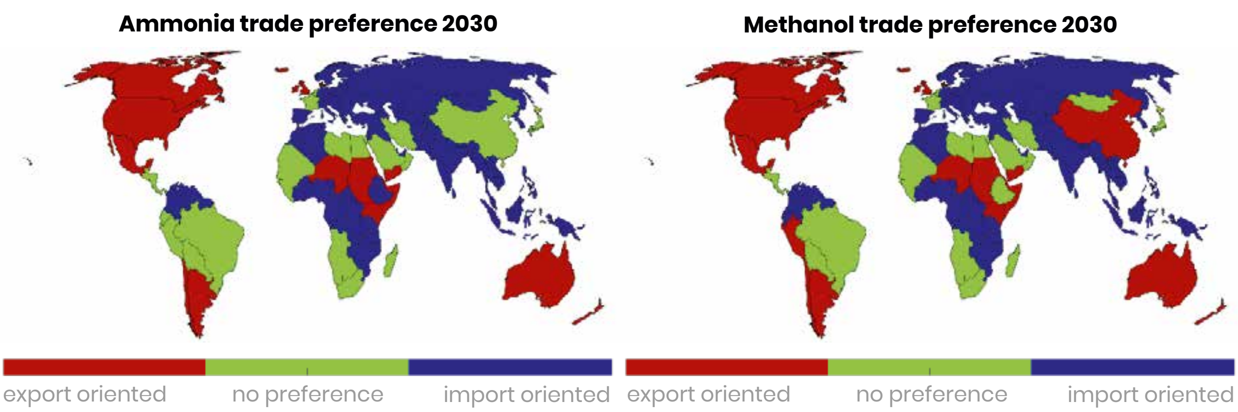


Figure 32: Global trade preference of ammonia (left) and methanol (right) in 2030.

In 2040, Canada, China, southern parts of South America and parts of Africa are export-oriented, while the USA, Central Europe and parts of South America are import-oriented and the rest are largely neutral as shown in Figure 33.

In 2050, mostly the northern hemisphere with Canada, Europe and Eurasia are import-oriented, while most of Africa, along with Mexico and Peru are export-oriented. The rest of the world is mostly neutral, as highlighted in Figure 34.

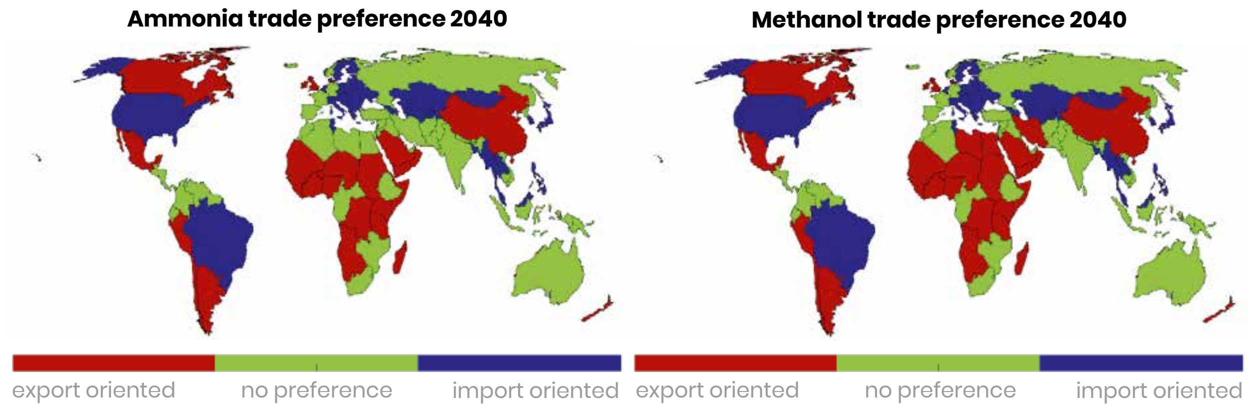


Figure 33: Global trade preference of ammonia (left) and methanol (right) in 2040.

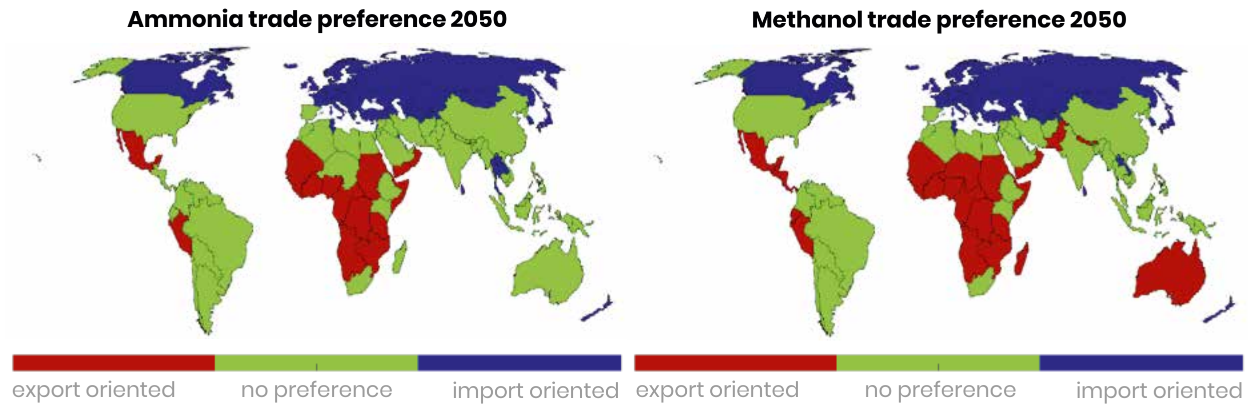


Figure 34: Global trade preference of ammonia (left) and methanol (right) in 2050.

The trade volumes for powerfuels increase through the transition period as shown in Figure 35. Europe shows continued and increasing import demand, while South America has a growing export base and remains in the market with high shares until 2050, owing to the excellent solar and wind resources across the world. North America can balance the trade within its region and remain largely self-sufficient. Sub-Saharan Africa continuously gains exporter market shares, benefiting from solar PV cost declines and large available areas with high resource availability. The MENA region has significant export attractiveness, but less than generally expected meeting the surrounding demand. SAARC shows strong domestic supply, while Northeast Asia relies on some shares of imports by 2050. Eurasia will rely on significant imports by 2050.

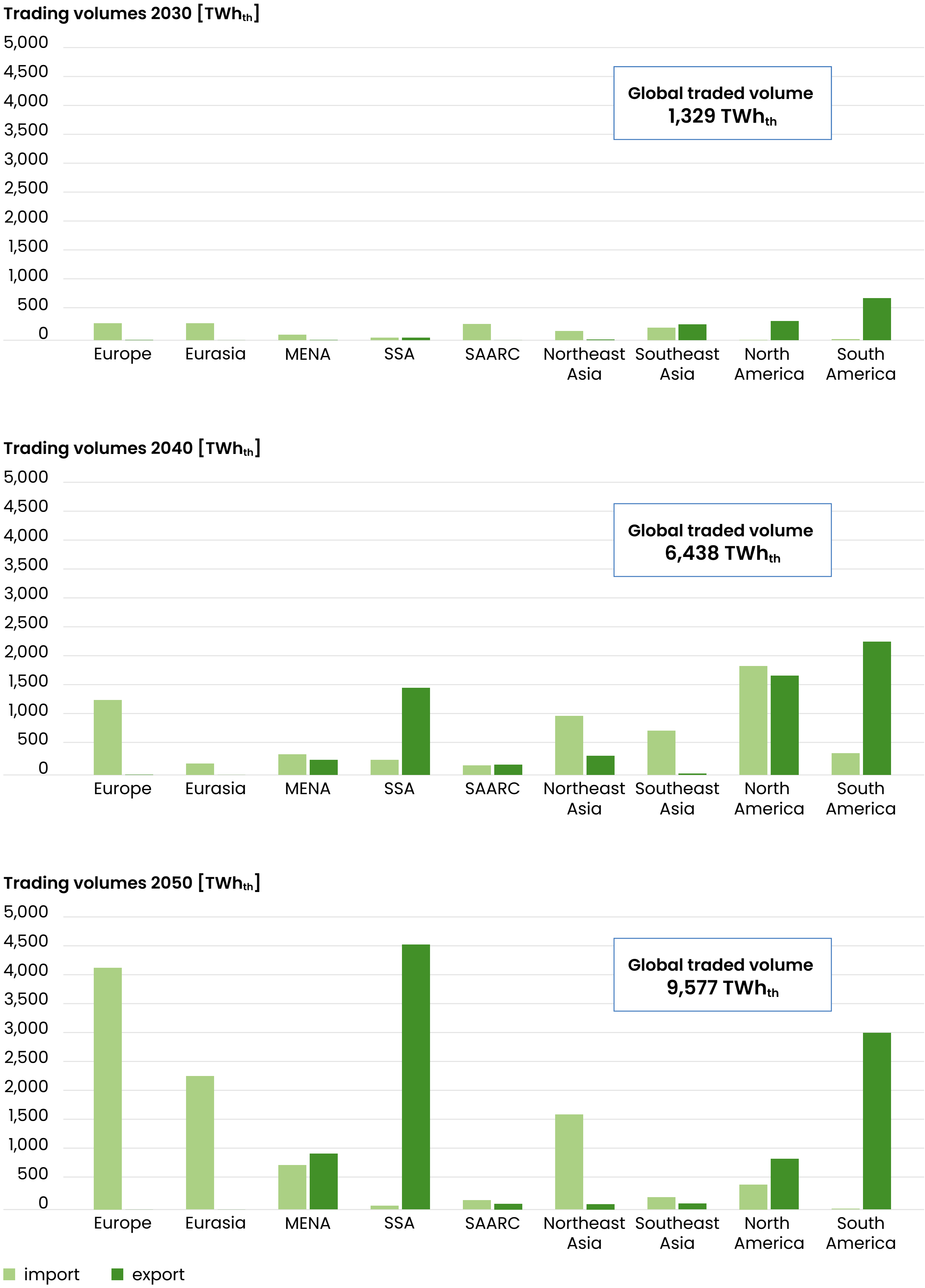


Figure 35: Trading volumes of powerfuels across the nine major regions in 2030 (above), in 2040 (centre) and in 2050 (below).

The trading volumes of imports and exports across the nine major regions in powerfuels is shown in Figures 36 – 38.

In 2030, around 1,330 TWh_{th} of powerfuels are traded across the world and well distributed, as shown in Figure 36.

In 2040, the traded volume of powerfuels increases to 6,438 TWh_{th} across the world, with Europe and North America having higher import volumes and the Americas with sub-Saharan Africa having higher export volumes, as shown in Figure 37.

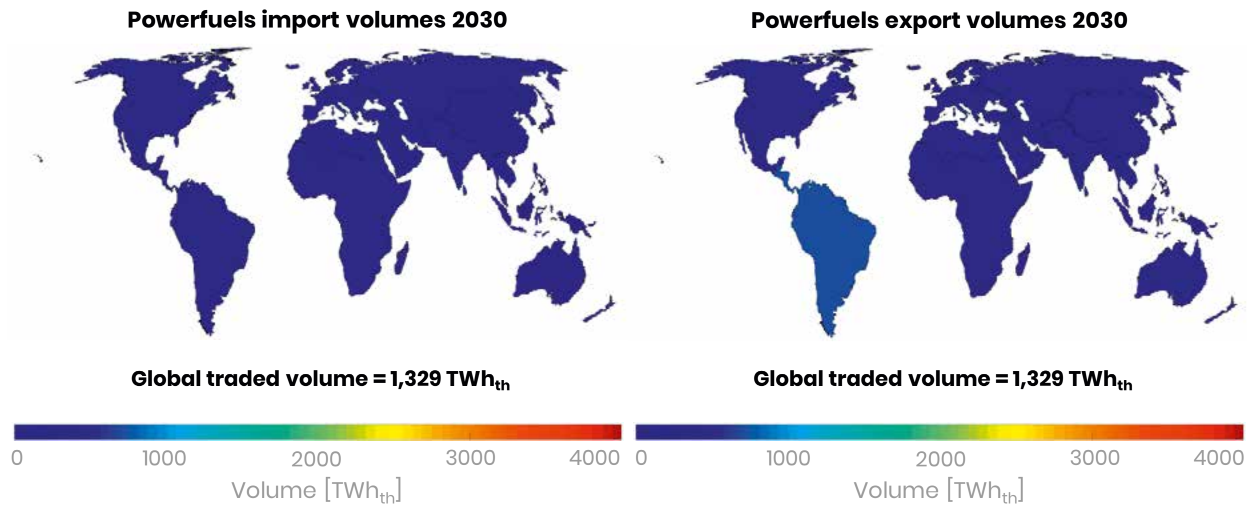


Figure 36: Global distribution of import volumes (left) and export volumes (right) of powerfuels in 2030.

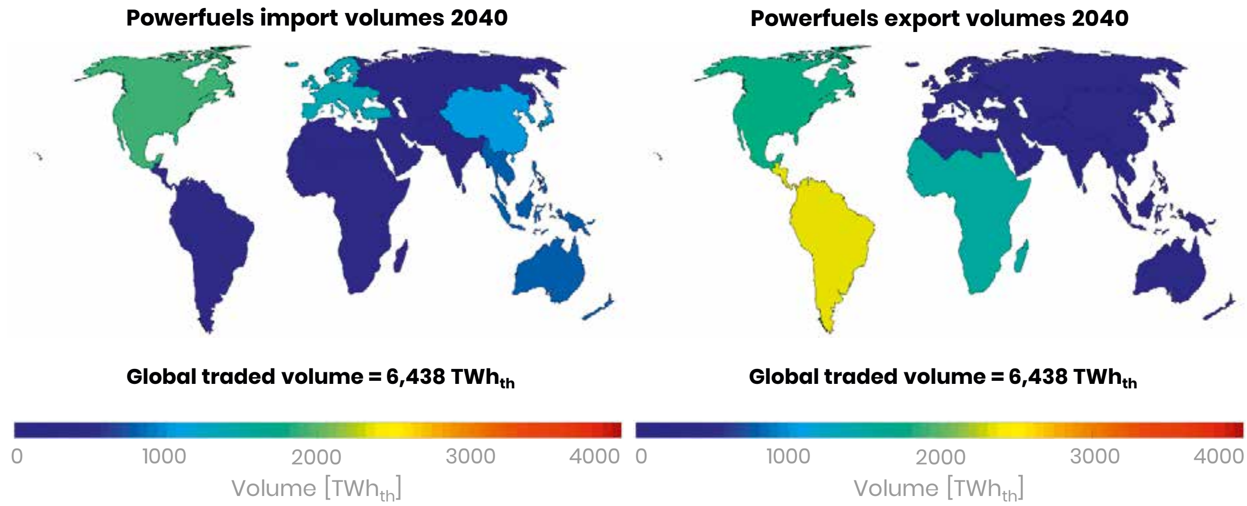


Figure 37: Global distribution of import volumes (left) and export volumes (right) of powerfuels in 2040.

In 2050, the traded volume of powerfuels further increases to 9,577 TWh_{th} across the world, with Europe, Eurasia and Northeast Asia dominating the import volumes. On the other hand, South America and sub-Saharan Africa emerge as the global export hubs with the highest volumes, as shown in Figure 38.

A more in-depth view of the trading of powerfuels is presented in Figures 39 – 42, highlighting the top importing and exporting regions across the world for LNG, FT fuels, RE-ammonia and RE-methanol in 2050.

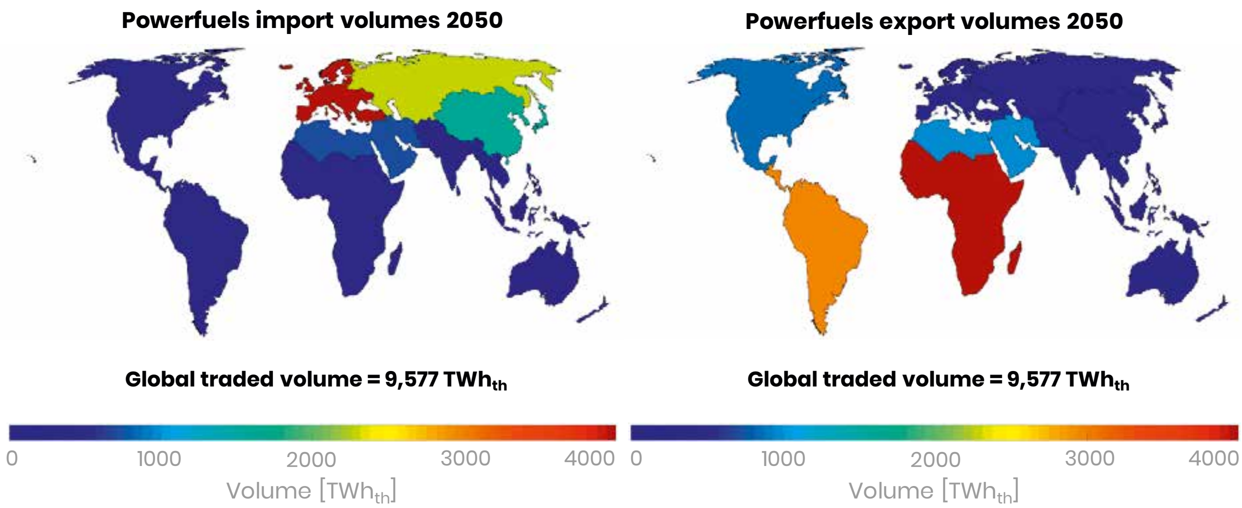


Figure 38: Global distribution of import volumes (left) and export volumes (right) of powerfuels in 2050.

The top importing regions for LNG are mainly in Eurasia and Europe, while the top exporting regions are mostly in Africa and South America, as shown in Figure 39. Import volumes of LNG in 2050 are well spread across different regions, while export volumes are from fewer regions with more than 50 % export volume coming from just three regions.

In the case of FT fuels, the top importing regions in 2050 are again regions in Eurasia and Europe along with Japan and others, while the top exporters are Brazil, China and Australia as shown in Figure 40. Export and import volumes of FT fuels are well spread across the different regions, with more than 50 % of export dominated by the top three countries.

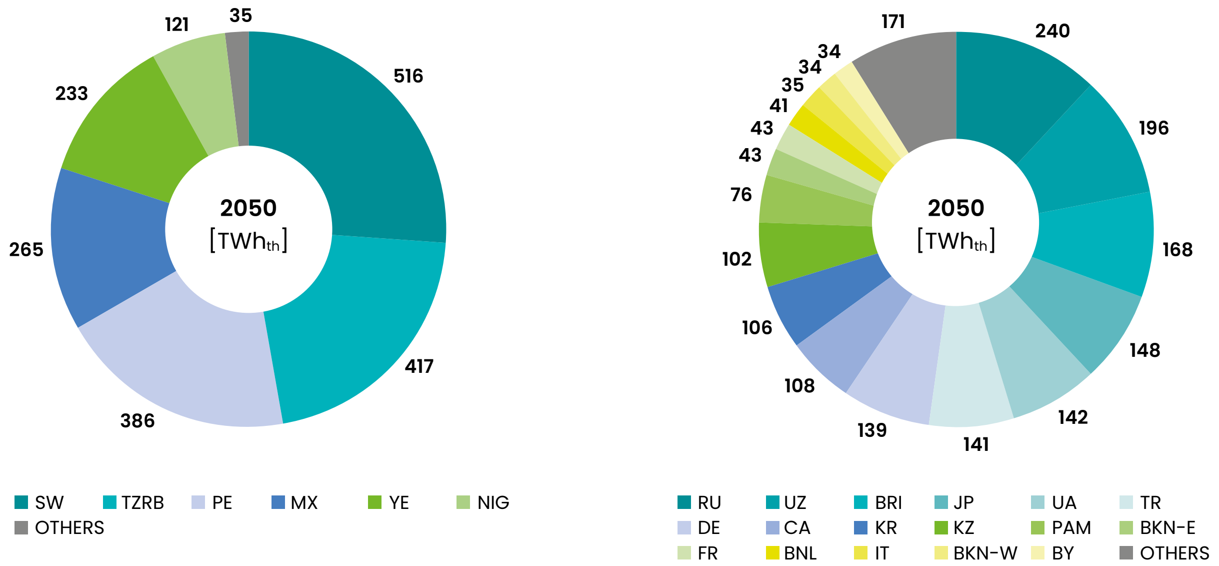


Figure 39: Exporting (left) and importing (right) regions with corresponding volumes for LNG in 2050. The abbreviations for the regions are listed in the appendix.

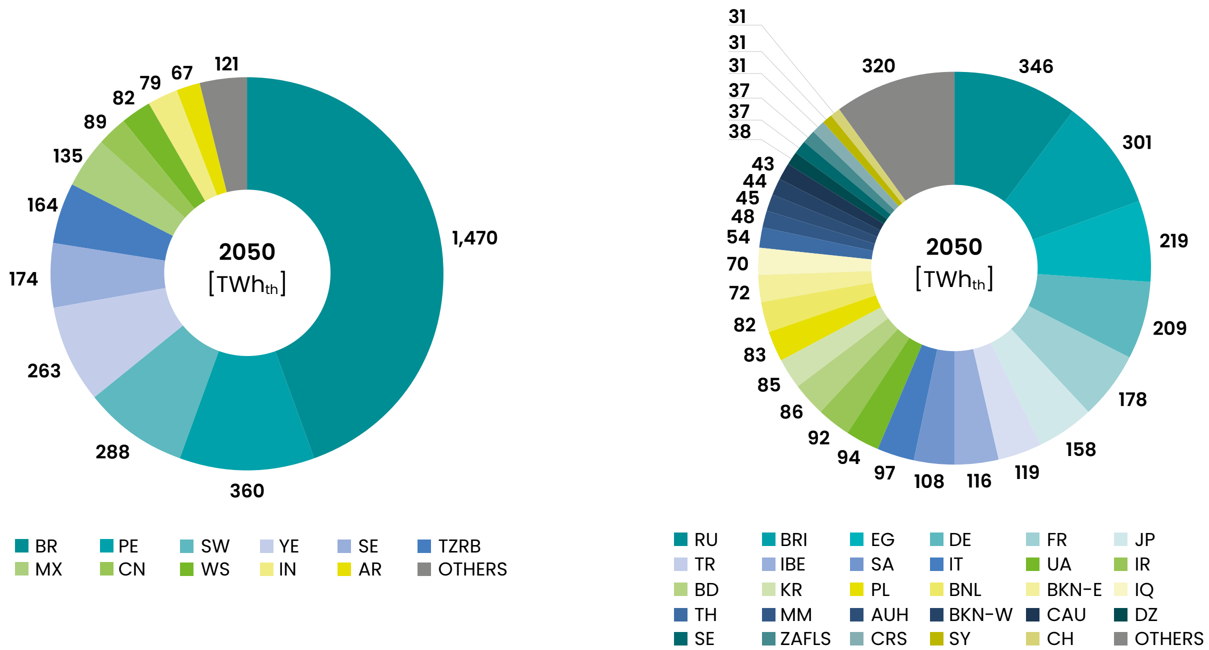


Figure 40: Exporting (left) and importing (right) regions with corresponding volumes for FT fuels in 2050. The abbreviations for the regions are listed in the appendix.

Russia, Korea and Japan are top importers of RE-ammonia in 2050, while most of the exporting regions are in Africa as shown in Figure 41. Nearly 50 % of import volume is from the top four regions, while the top six exporting regions contribute to more than 75 % of the export volume for RE-ammonia in 2050.

In the case of RE-methanol, Russia, Korea and Japan are the top importers, while the exporting regions are mostly from Africa and South America, as shown in Figure 42. The top three importing regions have a combined share of nearly 50 % of the import volume for RE-methanol in 2050, whereas the top four exporting regions contribute to more than 50 % of the export volume for RE-methanol in 2050.

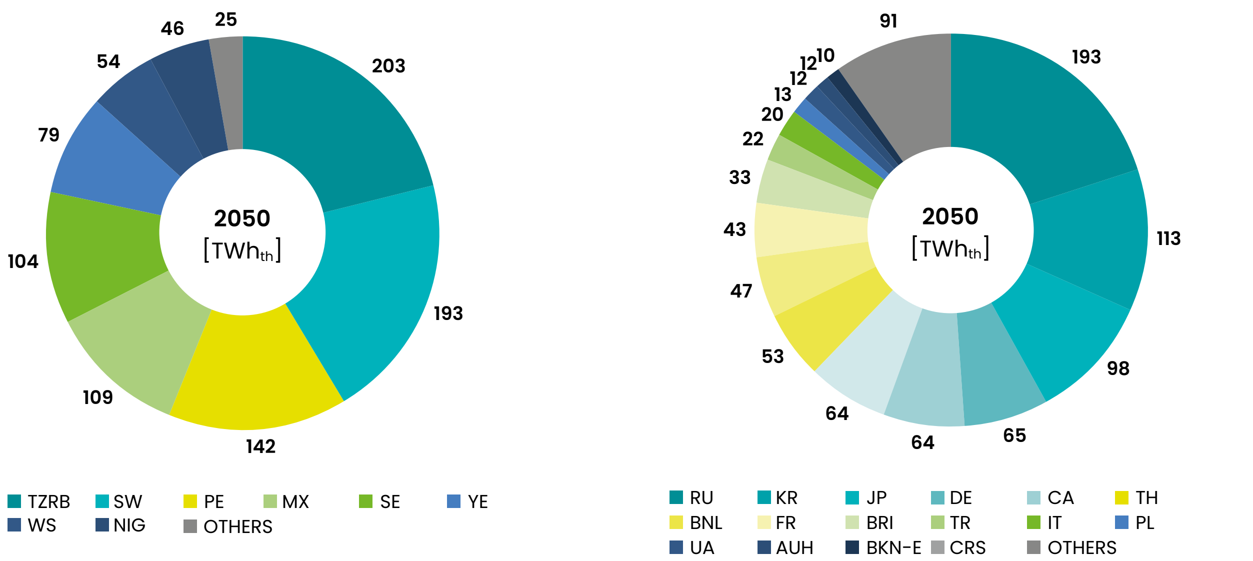


Figure 41: Exporting (left) and importing (right) regions with corresponding volumes for RE-ammonia in 2050. The abbreviations for the regions are listed in the appendix.

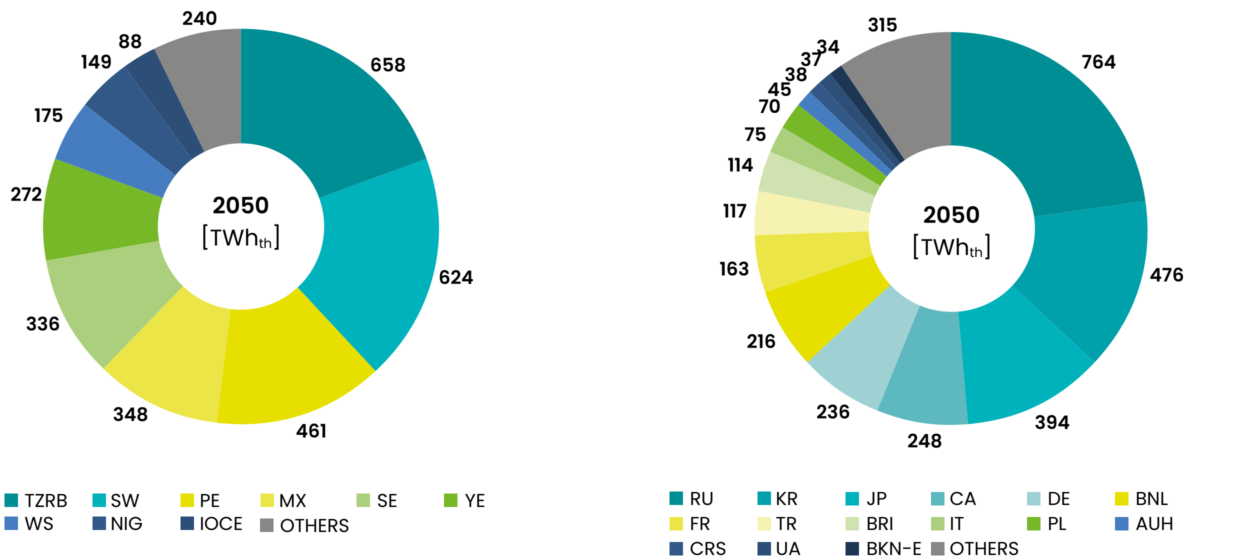


Figure 42: Exporting (left) and importing (right) regions with corresponding volumes for RE-methanol in 2050. The abbreviations for the regions are listed in the appendix.

Cost analysis of powerfuels

As costs are critical to economies, having access to low-cost powerfuels could be a vital advantage in the future for robust industrial development. The global average levelised cost of fuel (LCOF) for powerfuels is observed to decline through the transition, which is further reduced with global trading.

The global average LCOF of pre-traded and post-traded LNG and FT fuels declines through the transition, as highlighted in Figure 43. A reduction of around 60 % in the LCOF of LNG and around 40 % reduction in FT fuels occurs by 2050, in comparison to the cost levels of 2030.

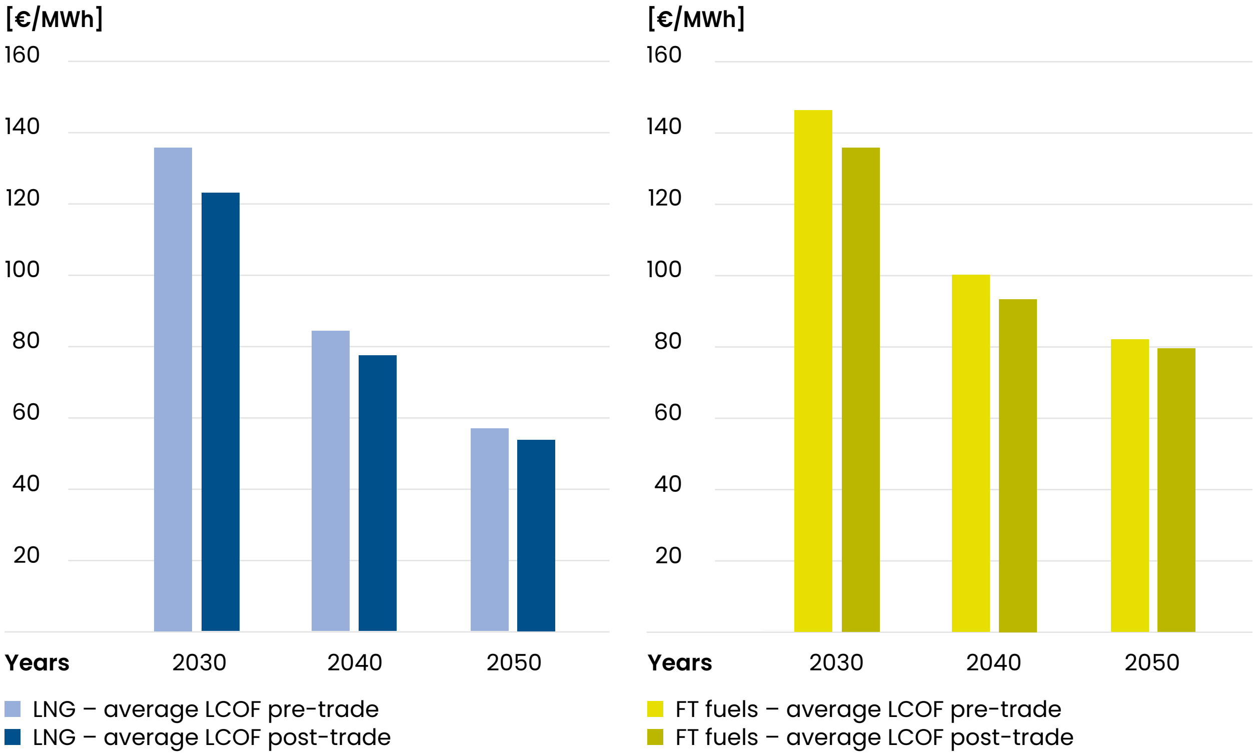


Figure 43: Global average pre-trade and post-trade levelised cost of fuel for LNG (left) and FT fuels (right) through the transition from 2030 to 2050.

Similarly, the global average LCOF of pre-traded and post-traded ammonia and methanol decline through the transition, as highlighted in Figure 44. A reduction of around 55 % in the LCOF of ammonia and around 50 % in methanol occurs by 2050, in comparison to the cost levels of 2030.

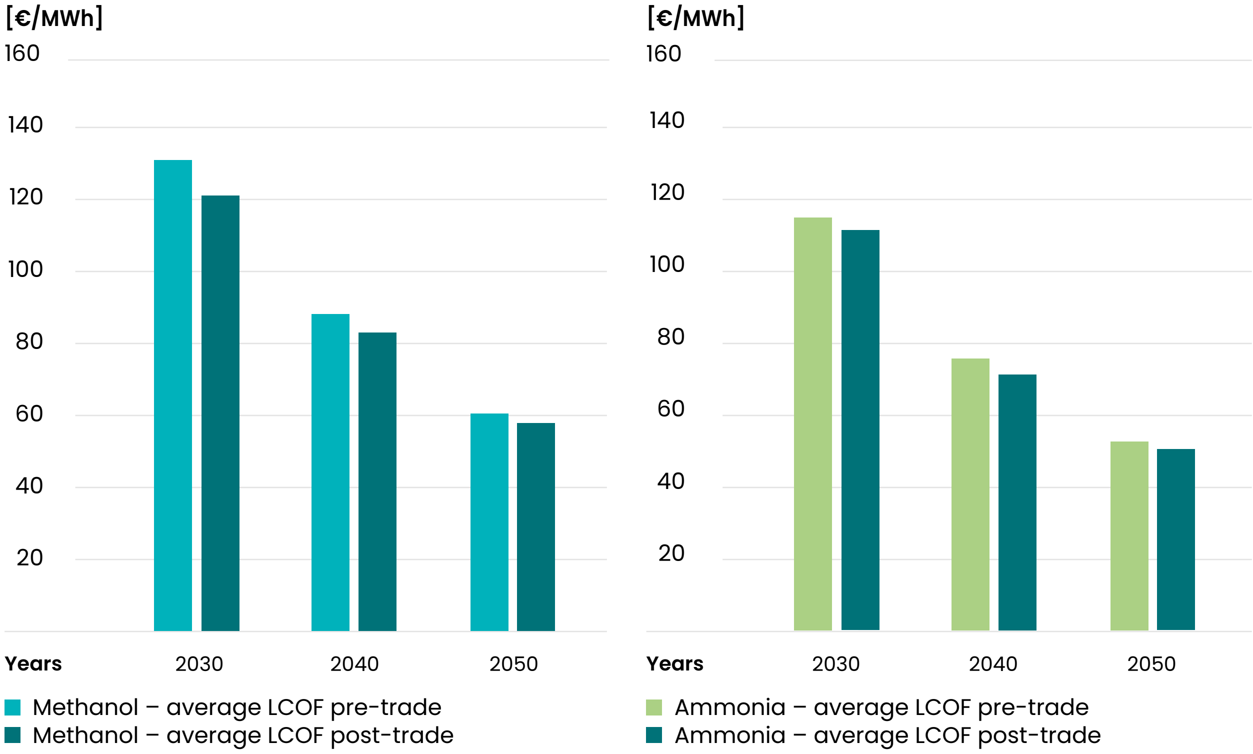


Figure 44: Global average pre-trade and post-trade levelised cost of fuel for methanol (left) and ammonia (right) through the transition from 2030 to 2050.

From a global trading perspective, the LCOF has a significant trading-induced decline potential in 2030 across powerfuels. While the transition progresses towards 2050, the global average LCOF does not reduce significantly from pre-traded to post-traded cost levels for both powerfuels. This is mainly attributed to the significant decline in the cost of renewable electricity that makes it economically viable for domestic production. However, there are still regions and countries that significantly benefit from trading and this emerges for the regional LCOF for powerfuels.

The global distribution of the levelised cost of fuel for SNG in 2050 is highlighted in Figure 45. Pre-trading costs are higher in the northern hemisphere, while the post-trading costs are more fairly distributed across the world, in particular in reducing the high LCOF in North America, Europe and Eurasia, with a slight reduction in the global volume weighted average LCOF.

The global distribution of the levelised costs of FT fuels in 2050 is highlighted in Figure 46. Globally, there is a slight reduction in costs for pre-traded and post-traded FT fuels, however, Europe and other high-cost regions in Central Asia gain quite significantly from the trading.

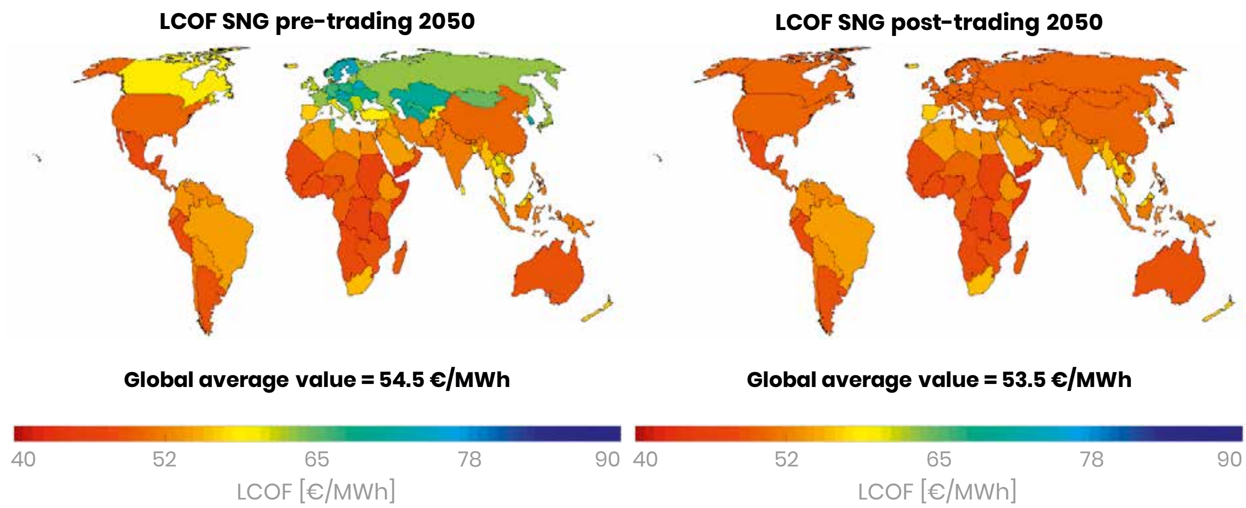


Figure 45: Global distribution of LCOF for SNG pre-trading (left) and post-trading (right) in 2050.

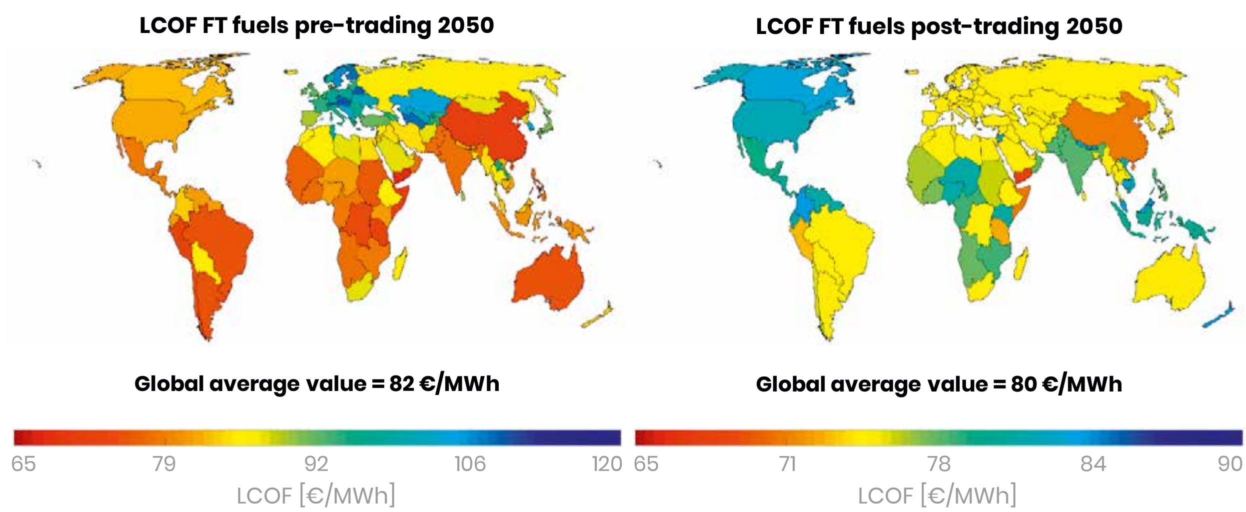


Figure 46: Global distribution of LCOF for FT fuels pre-trading (left) and post-trading (right) in 2050.

Importing countries, mainly in the northern hemisphere, benefit from cost reductions of around 15 – 30 % for powerfuels from the pre-traded to the post-traded cost level in 2050, as highlighted in Figure 47. However countries in the global Sun Belt can predominantly switch to domestic self-supply.

Similarly, the global distribution of the levelised cost of chemicals is analysed. The levelised cost of ammonia in 2050 across the world, has a slight decrease from pre-trading to post trading, as shown in Figure 48. Europe and Eurasia gain the most from trading as costs are reduced.

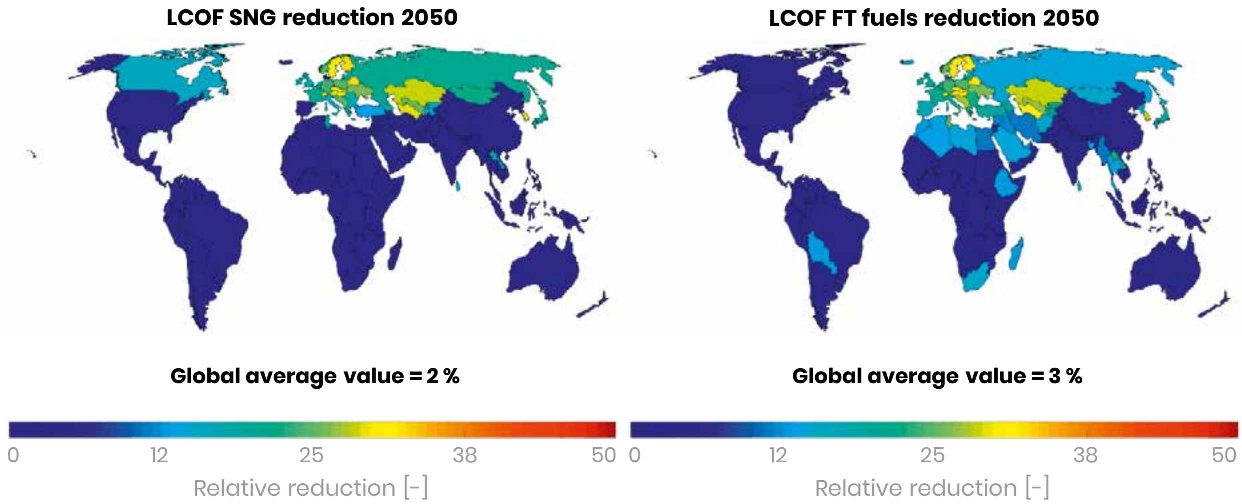


Figure 47: Global distribution of LCOF reduction in SNG (left) and FT fuels (right) in 2050.

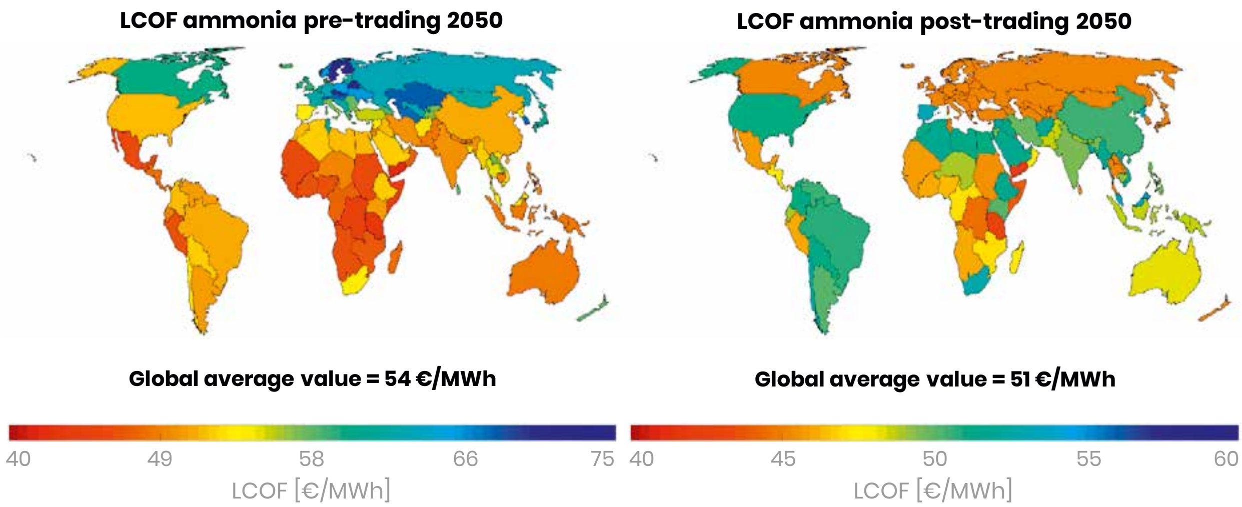


Figure 48: Global distribution of LCOF for ammonia pre-trading (left) and post-trading (right) in 2050.

The global distribution of the levelised cost of methanol is shown in Figure 49. The northern hemisphere sees the most benefits from pre-trading to post-trading cost levels. The costs are marginally reduced from a global perspective.

Importing countries, mainly in the northern hemisphere, benefit from cost reductions of around 15 – 30 % for RE-chemicals, as highlighted in Figure 50. However countries in the global Sun Belt can predominantly switch to domestic self-supply.

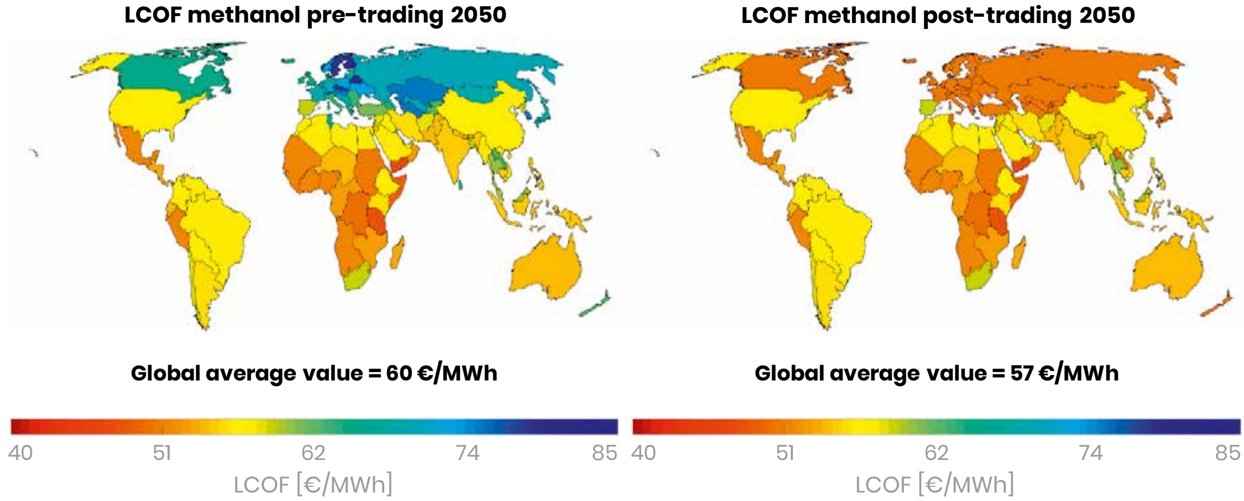


Figure 49: Global distribution of LCOF for methanol pre-trading (left) and post-trading (right) in 2050.

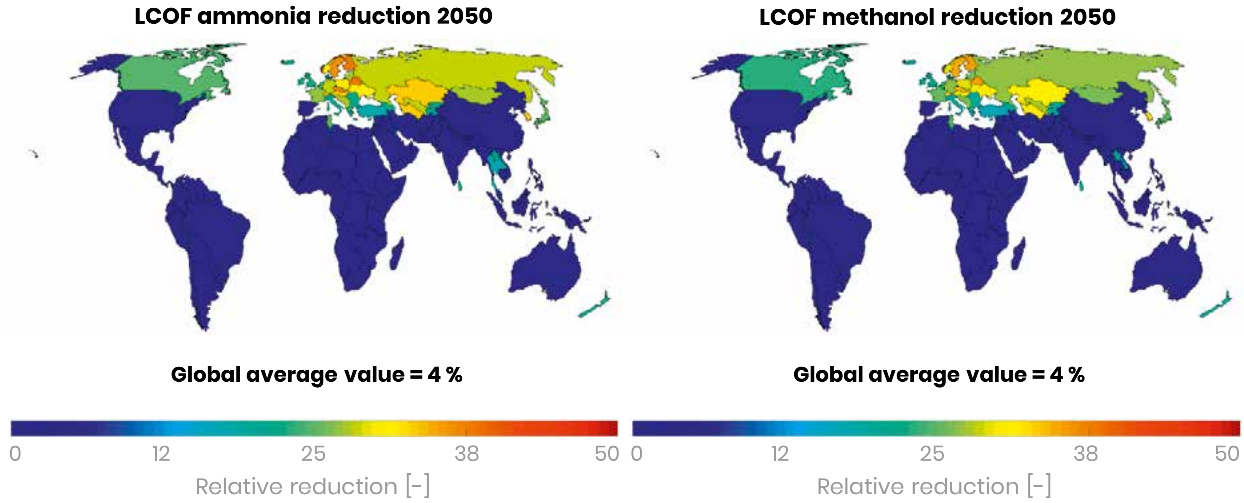


Figure 50: Global distribution of LCOF reduction in ammonia (left) and methanol (right) in 2050.

The global market volume of trading is 99 b€ and 244 b€ for LNG and FT fuels in 2050, which translates to traded market volumes of 23 % and 33 % respectively, as indicated by Figure 51. A global shipping cost of 3.7 €/MWh for LNG and 1.5 €/MWh for FT fuels is considered, which is generally borne by the importing region. The shipping cost assumes an overseas distance of up to 18,000 km. The globally traded market volume of powerfuels is substantially lower compared to fossil fuels trading, which is a direct consequence of highly concentrated fossil fuel resources compared to the excellent solar and wind resources all around the world, more exclusively in the Sun Belt region that is home to a large majority of the global population. Globally, the share of fossil fuels traded was at 43 % of total fossil fuel consumption in 2019. The major contribution was from fossil oil with 74 % of the total traded fossil fuels, fossil gas with 25 % and hard coal with 21 %[69]. This indicates significantly higher shares of global trade prevalent in fossil fuels, particularly fossil oil, as the availability is limited to a few geological locations.

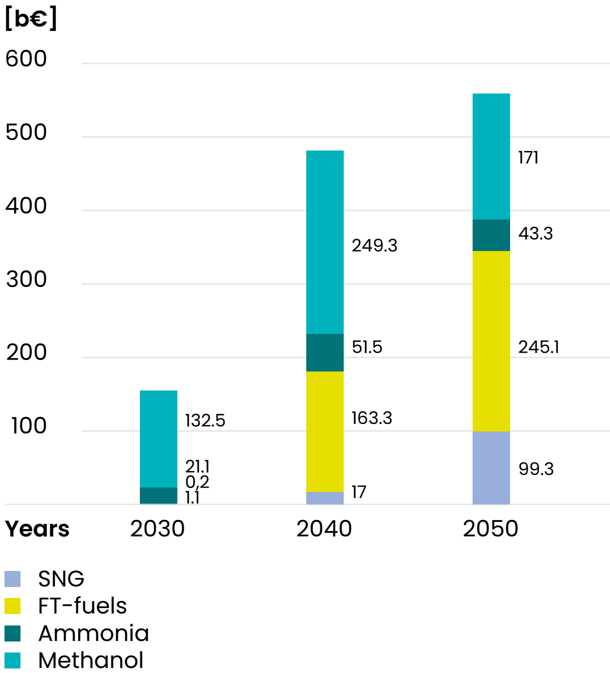


Figure 51: Development of traded import value for powerfuels through the transition.

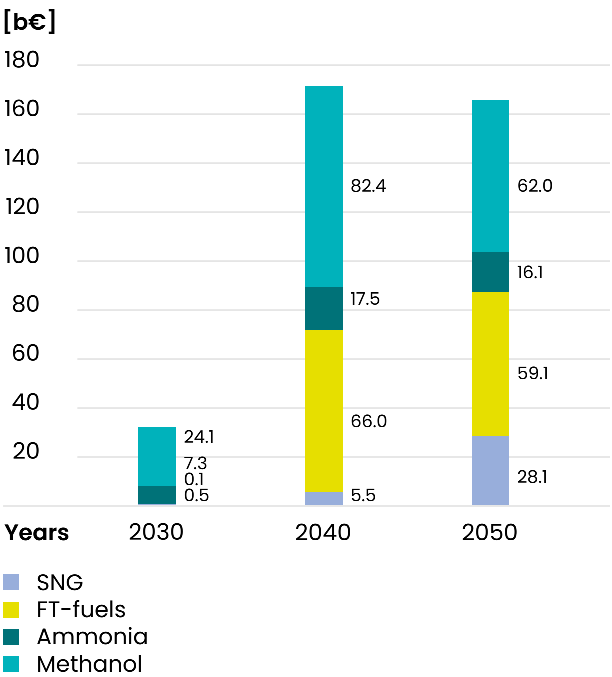


Figure 52: Development of global cost reductions pre-shipping for powerfuels through the transition.

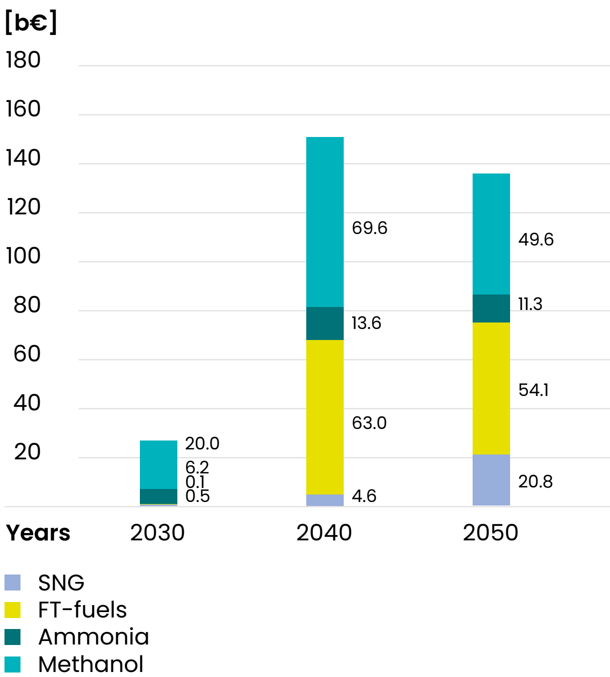


Figure 53: Development of global cost reductions post-shipping for powerfuels through the transition.

The global market volume of trading is 49 b€ and 171 b€ for ammonia and methanol, which translates to traded volumes of 29 % and 28 % respectively, as highlighted by Figure 51. A global shipping cost of 5 €/MWh for ammonia and 3.7 €/MWh for methanol is considered, which is generally borne by the importing region. The shipping cost assumes an overseas distance of up to 18,000 km.

The benefits of global trading can be assessed by the cost reductions attained across the world for powerfuels. The total cost reductions pre-shipping for powerfuels across the world from 2030 to 2050 are highlighted in Figure 52.

The benefits from global trading reach a peak in 2040 with close to 180 b€ in cost reductions globally. However, the benefits from trading reduce to about 160 b€ in 2050. This is predominantly due to the decline in costs of renewables, which favour domestic production of powerfuels over imports.

The benefits further reduce by taking into account the costs for shipping powerfuels around the world, as indicated by Figure 53. The global cost reductions reduce from a peak of close to 160 b€ in 2040, to about 130 b€ in 2050.

Greenhouse gas emissions savings

The energy transition is a highly complex endeavour, which is central along with several key actions and drivers for phasing out GHG emissions. The avoided GHG emissions due to powerfuels are interlinked with other measures, such as the focussed phase-in of renewable electricity solutions, battery-electric vehicles and low-cost electrolysers. The avoided GHG emissions due to powerfuels are considered in a simplified way in this research. The volumes of powerfuels are presented in Figure 10, and due to sustainable production approaches no GHG emissions are induced. The present production approaches are based on fossil fuels, such as crude oil based liquid hydrocarbons for the transport sector, fossil fuels based chemicals for the chemical industry and fossil gas for methane applications. Zero GHG emitting powerfuels are compared to counterpart products based on fossil fuels, which is current practice. This makes it possible to highlight the avoided GHG emissions on an annual basis for the entire transition pathway until 2050.

The role of powerfuels cannot be underestimated in achieving ambitious climate targets, since there are typically no other options, or highly unsustainable, risky and high-cost options, which involve balancing GHG emissions with negative emission technologies, such as BECCS (while DAC remains crucial and central). Already by 2030, 1.2 Gt CO_2eq emissions could be avoided if the uptake of powerfuels occurs in the second half of the 2020s, while by 2040 already 6.8 t CO_2eq emissions could be avoided and by 2050, almost 13 Gt CO_2eq could be avoided with powerfuels, as shown in Figure 54. This positions powerfuels as central and indispensable climate mitigation technologies of prime importance. The contribution of powerfuels to avoidable GHG emissions is roughly equal, with the contribution shares being 20 %, 29 %, 11 %, 33 % and 7 % for SNG, FT fuels, RE-ammonia, RE-methanol and RE-naphtha, respectively.

The pathway related cumulative avoided GHG emissions of powerfuels are shown in Figure 55. Assuming a ramp-up of powerfuels production capacities in the second half of the 2020s and a continued linear ramping from 2030 to 2040, and from 2040 to 2050, this leads to avoided GHG emissions of 42 Gt CO_2eq by 2040 and 140 Gt CO_2eq by 2050, which suggests the enormous role of powerfuels in realising ambitious climate policies.

A delay in the phase-in of powerfuels would lead to enormous GHG emissions, which cannot be mitigated otherwise. In a business-as-usual scenario without powerfuels, the options would be either around 13 Gt CO_2eq emissions per year around 2050, or massive pressure on already highly vulnerable ecosystems for large-scale biofuel and bio-chemical production, or risky and high-cost considerations of negative emission technologies, or even worse, massively risky geo-engineering options. Among all these options, powerfuels are low-cost, sustainable and the most feasible option.

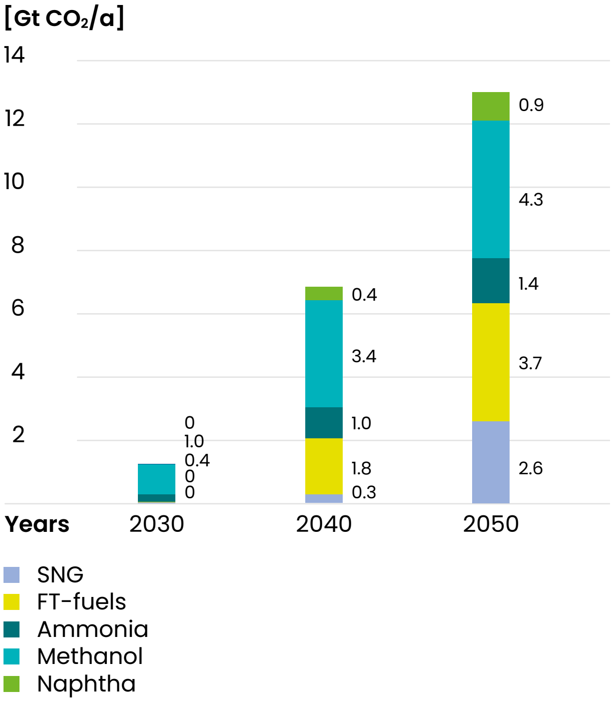


Figure 54: Avoided annual GHG emissions for powerfuels through the transition.

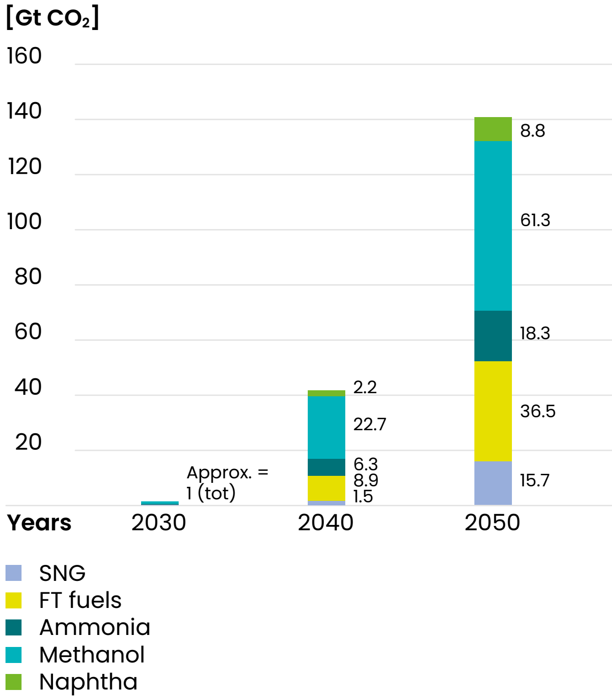


Figure 55: Avoided cumulative GHG emissions for powerfuels through the transition.

4 Outlook for Europe

Europe is amongst the most interconnected regions in the world, with robust energy infrastructure connecting the different countries and the members of the EU pursuing a common goal of creating an Energy Union. As far as renewable energy resources are concerned, Europe has a good mix of significant wind potential in the northern and western regions (including the United Kingdom and Ireland) complemented with excellent solar potential in the southern regions. Other forms of renewable resources are also well distributed throughout the continent, which influence the regional energy mix of the various countries and regions within Europe. Europe is well equipped with technological advancements and is the most prominent in terms of achieving the ambitious climate mitigation targets as indicated by the European Green Deal[70]. However, whether the region benefits from trading in powerfuels is further explored. A recent study[71] showed that with an ambitious scenario, Europe can achieve 100 % renewables by 2040 and with an early mover advantage could be one of the first exporters of powerfuels. It has been shown that self-supply on a national basis is possible within Europe[54], while recently this has been expanded to a cooperation strategy for Europe[71]. The question remains: what would be the benefit of importing powerfuels in comparison to a national and regional self-supply strategy. This research question is detailed in the following.

The regional distribution of the levelised cost of fuel for SNG in 2050 across Europe is highlighted in Figure 56. Pre-trading costs are higher in the central and northern parts of Europe with an average of 64 €/MWh, while the post-trading costs are more fairly distributed across Europe with a significant reduction to an average LCOF of 50 €/MWh.

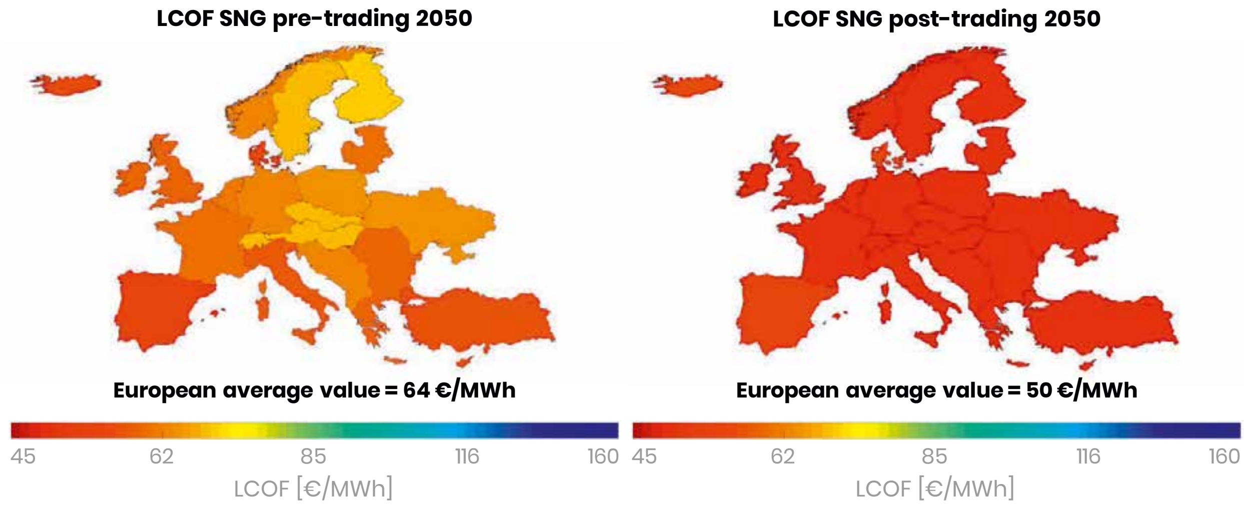


Figure 56: Regional distribution of LCOF for SNG pre-trading (left) and post-trading (right) across Europe in 2050.

The regional distribution of the levelised costs of FT fuels in 2050 across Europe is highlighted in Figure 57. The costs are fairly distributed across Europe with a pre-traded average of 96 €/MWh and a post-traded average for the LCOF of FT fuels at 74 €/MWh. However, Europe gains quite significantly from global trading as indicated by the average LCOF.

Northern and Central Europe benefit the most with average cost reductions of 21 % for SNG and 23 % for FT fuels, as highlighted in Figure 58. By contrast, Southern Europe and the UK benefit less from trading, but with higher cost reductions in comparison to average global cost reductions in 2050.

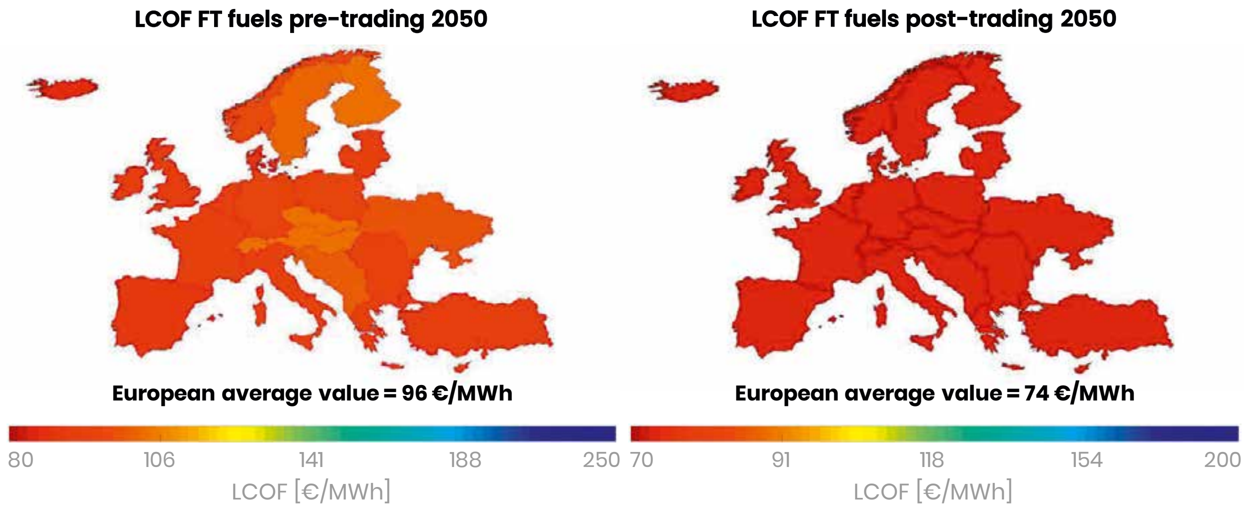


Figure 57: Regional distribution of LCOF for FT fuels pre-trading (left) and post-trading (right) across Europe in 2050.

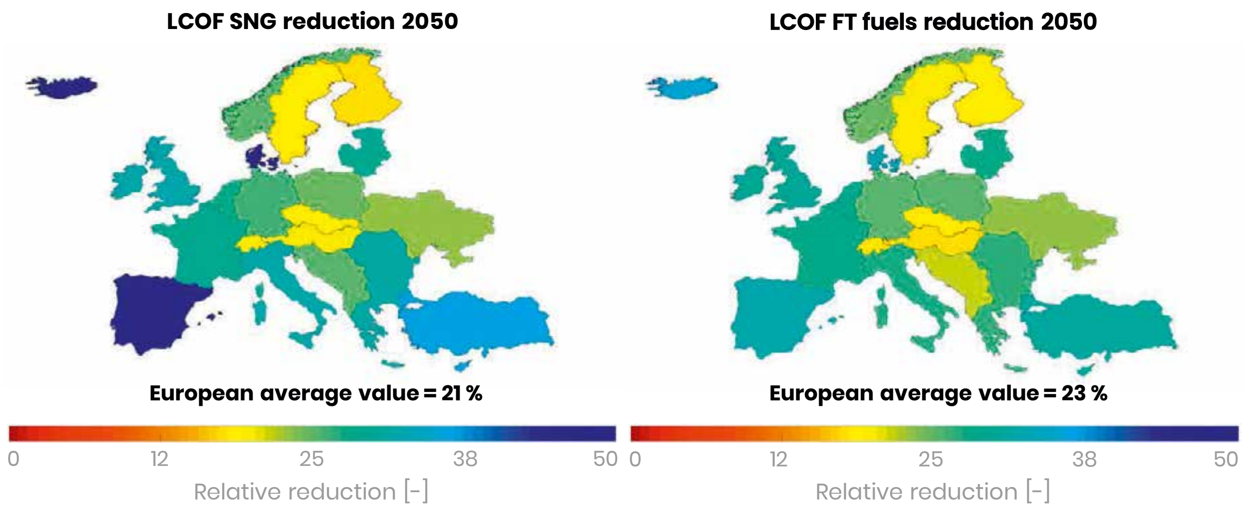


Figure 58: Regional distribution of LCOF reduction in SNG (left) and FT fuels (right) across Europe in 2050.

Similarly, the regional distribution of the levelised cost of RE-chemicals across Europe is analysed. The levelised cost of ammonia in 2050 across Europe decreases substantially from an average pre-trading LCOF of 61 €/MWh to an average post trading LCOF of 46 €/MWh, as shown in Figure 59. The costs are quite fairly distributed across Europe with minimal regional variation.

The regional distribution of the levelised cost of methanol across Europe in 2050 is shown in Figure 60. The northern and central parts of Europe have slightly higher pre-trading costs with an average LCOF of 68 €/MWh, while the post-trading cost levels are evenly distributed across Europe with an average LCOF of 52 €/MWh. The costs are significantly reduced and gain from global trading of methanol.

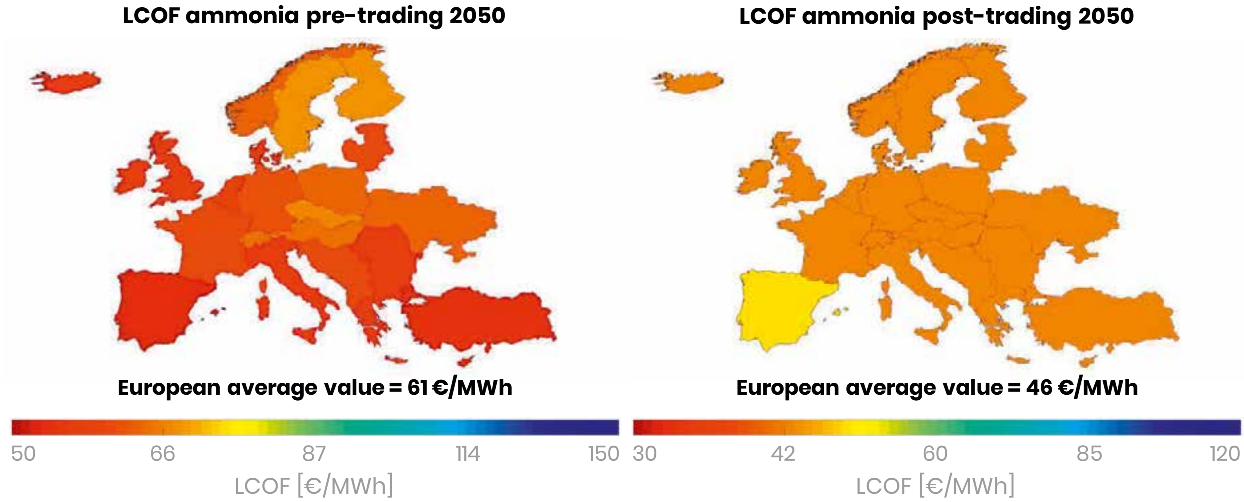


Figure 59: Regional distribution of LCOF for ammonia pre-trading (left) and post-trading (right) across Europe in 2050.

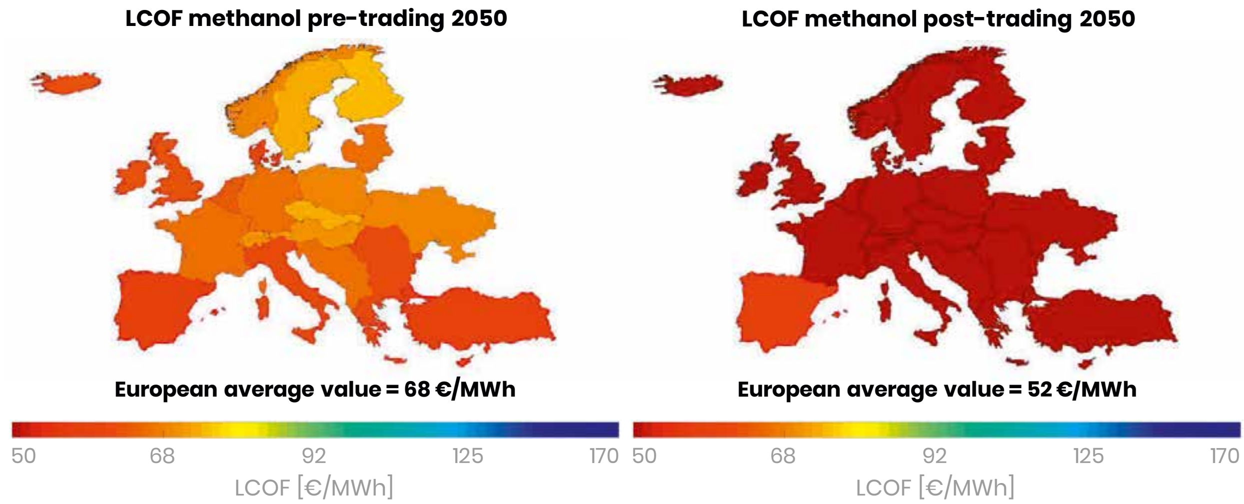


Figure 60: Regional distribution of LCOF for methanol pre-trading (left) and post-trading (right) across Europe in 2050.

Northern and central parts of Europe benefit the most from cost reductions of 16 % for RE-ammonia and 24 % for RE-methanol in 2050, as highlighted in Figure 61. By contrast, southern parts of Europe and the UK have lesser cost reductions but are much higher in comparison to average global cost reductions for RE-chemicals.

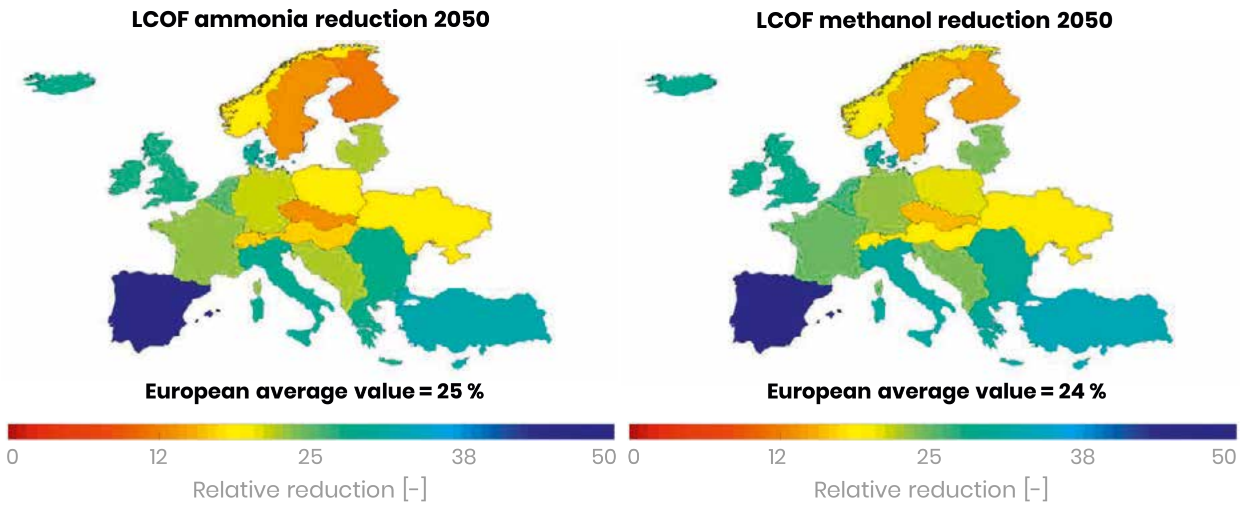


Figure 61: Regional distribution of LCOF reduction in ammonia (left) and methanol (right) across Europe in 2050.

Contrary to global trading trends, Europe stands to benefit from trading as the cost reductions attained in powerfuels grow through the transition as shown in Figure 62. The total cost reductions for pre-shipping of powerfuels increase from about 10 b€ in 2030 to around 73 b€ in 2050. Even with declining costs of renewable electricity, it benefits Europe to develop a long-term trading strategy with key regional partners around the world.

However, with consideration of shipping costs, the overall cost reductions are in the range of 60 b€ in 2050, as highlighted in Figure 63. This is still a valuable outcome for the whole of Europe and could be more beneficial for some countries within Europe to trade in powerfuels.

Powerfuels have a vital role in achieving the ambitious European Green Deal targets, as these are the most feasible options for complete defossilisation. The other options are highly unsustainable, risky and expensive, for example balancing GHG emissions with negative emission technologies, such as BECCS. Already by 2030, 170 Mt CO_2eq emissions could be avoided across Europe if powerfuels are part of the energy system in the second half of the 2020s, while by 2040 around 925 Mt CO_2eq emissions could be avoided, and by 2050 almost 1,650 Mt CO_2eq could be avoided with powerfuels, as shown in Figure 64. This positions powerfuels as key enablers and indispensable climate mitigation technologies of significant importance in Europe. The contribution of powerfuels in avoidable GHG emissions is roughly equal, as the contribution shares are 20 %, 29 %, 11 %, 33 % and 7 % for SNG, FT fuels, RE-ammonia, RE-methano and RE-naphtha, respectively.

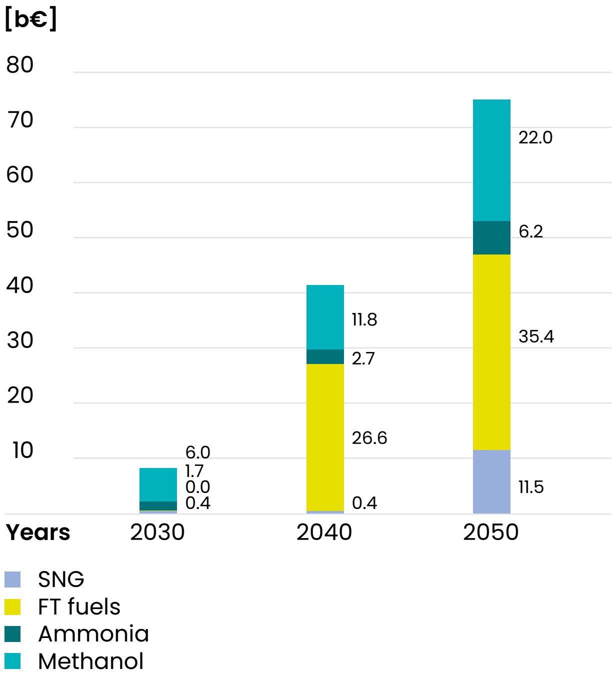


Figure 62: Development of cost reductions pre-shipping for powerfuels through the transition in Europe.

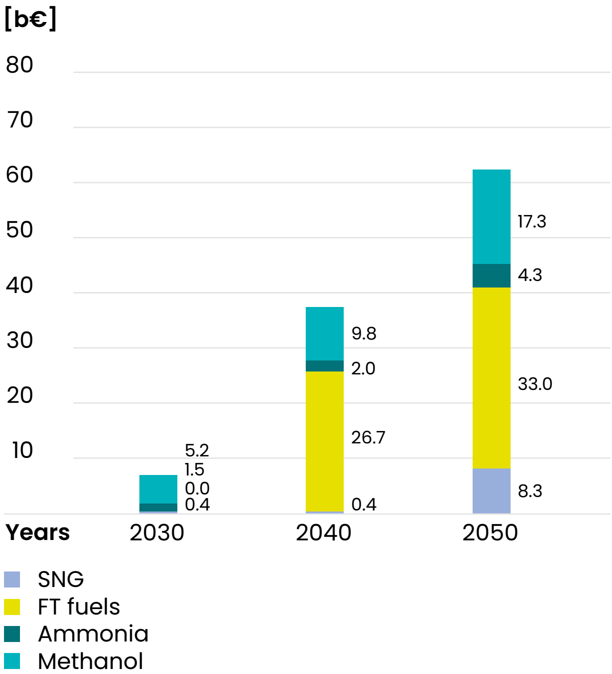


Figure 63: Development of cost reductions post-shipping for powerfuels through the transition in Europe.

The pathway related cumulative avoided GHG emissions of powerfuels are shown in Figure 65. Assuming the ramp-up of powerfuels production capacities in the second half of the 2020s and continued linear ramping from 2030 to 2040, and from 2040 to 2050, this leads to avoided GHG emissions of 5.6 Gt CO_2eq by 2040 and 18.5 Gt CO_2eq by 2050 across Europe. This highlights the essential role of powerfuels in realising the ambitious European Green Deal to be climate neutral by mid century.

Delaying the phase-in of powerfuels would lead to enormous GHG emissions, which cannot be mitigated otherwise, andwould jeopardise efforts of achieving climate neutrality. A business-as-usual scenario without powerfuels would result in around 1.65 Gt CO_2eq emissions per year by 2050, or lead to massive pressure on already highly vulnerable ecosystems for the production of huge volumes of biofuel and bio-chemicals, or rely on risky and high-cost negative emission technologies. Among all these options, powerfuels are low-cost, sustainable and the most feasible option for Europe.

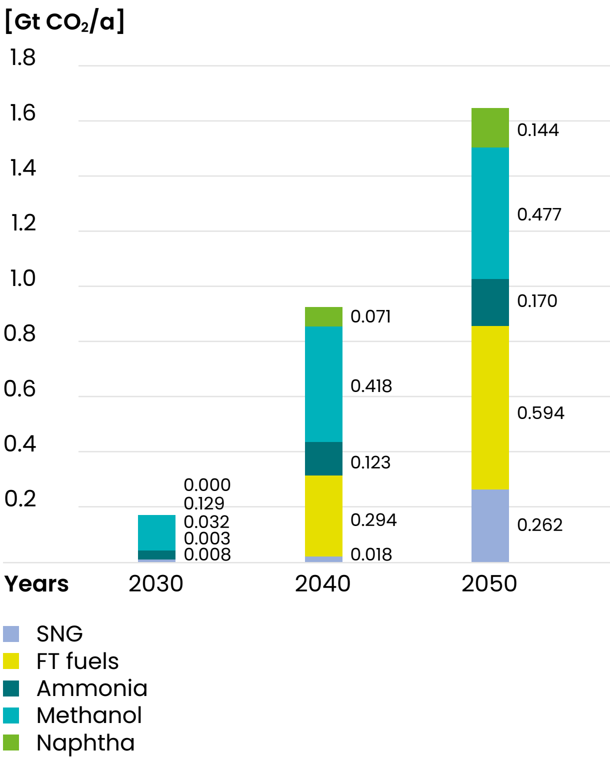


Figure 64: Avoided annual GHG emissions for powerfuels through the transition in Europe.

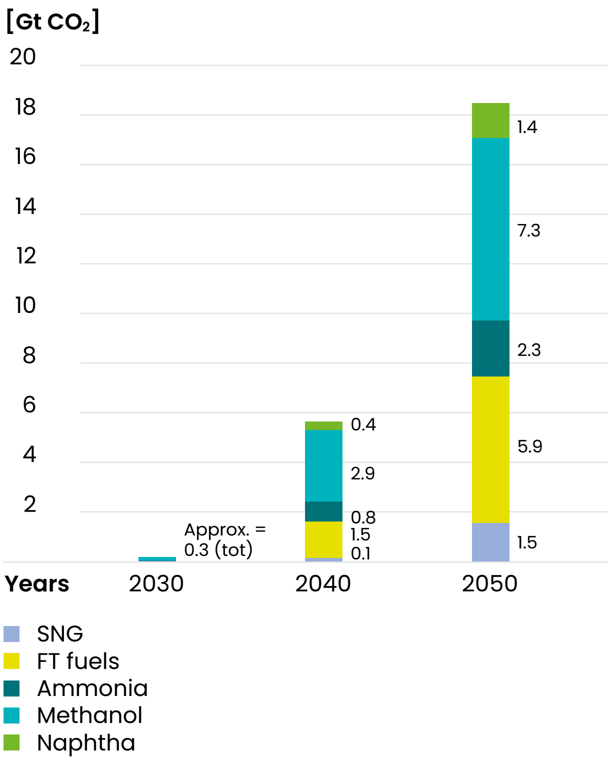


Figure 65: Avoided cumulative GHG emissions for powerfuels through the transition in Europe.

5 Discussion and conclusions

The future of powerfuels

A rapid increase in the supplies of solar, wind, and other forms of renewable electricity has been disrupting industries. Even petroleum companies such as Shell and Chevron are looking for ways to turn renewable power into fuels[50]. In 2018, the global installed capacity of solar and wind surpassed 1 terawatt (TW). The second TW is expected to follow soon and more importantly at just half the cost of the first, and the pace is likely to accelerate thereafter. A recent study suggests that the lower cost of renewable generation could trigger the development of 30-70 TW of solar PV capacity alone, enough to supply the majority of global energy needs by 2050[8]. This research, which is fundamentally based on a cost-optimised renewable energy system, is dominated by solar PV, as it emerges to be the most cost-effective energy source that is also abundantly available across the world[54]. Direct and indirect electrification emerges as a growing trend with umpteen benefits for the energy system as a whole. It is in this context that powerfuels have a vital role in not only delivering sustainable solutions, but also enabling better integration of the different sectors of power, heat, transport and industry while providing the necessary flexibility to the system.

Powerfuels enhance the penetration of renewables in a cost-effective manner and are therefore critical to 100 % renewable energy systems.

Powerfuels for system flexibility

Powerfuels, having high energy density, can be transported conveniently over long distances and stored on a large scale over extended periods, allowing them to compensate even seasonal supply fluctuations and thus contribute to the overall flexibility of the energy system. As highlighted in Ram et al.[54] as well as this research, powerfuels can provide cost-effective storage solutions especially with the power-to-Gas approach, which is already taking shape across several countries as a balancing option with high shares of renewable electricity. Moreover, existing fossil fuel infrastructure such as pipelines and gas stations with the vast supply networks could be utilised for powerfuels, thereby reducing costs further and avoiding stranded assets.

One of the critical components in the production of powerfuels that has immense value proposition for integration and increasing sector coupling is electrolysers. As highlighted by other studies[54, 71], electrolysers are essential in not only producing valuable hydrogen, which is then utilised to produce powerfuels, but also in providing flexibility to the energy system. Electrolysers help in reducing curtailed renewable electricity and assist in increasing the penetration levels of renewables in energy systems, especially in regions with high solar potential, which become the lowest-cost sites for energy systems due to very low-cost solar PV.

Powerfuels for an integrated energy sector

The chemical industry is globally the industrial sector with the highest demand for energy and feedstock fuels, accounting for approximately 10 % of the total final energy consumption and almost 30 % of the industrial final energy consumption[23]. In addition, it is also the largest industrial consumer of both oil and gas, accounting for 14 % and 8 % of total primary demand for each fuel respectively[23]. The chemical industry is unique as about half the sector's energy input is not combusted but is consumed as feedstock, which is the raw material for production of other chemical products. The other half is used to provide direct heat and electricity to drive the sector's processes. A direct substitution of renewable electricity for energy use is quite straightforward and is already happening in many cases around the world. As highlighted in this research for the feedstock chemicals ammonia and methanol, the production processes switch energy and feedstock input from predominantly fossil fuels to renewable electricity, which is then converted to ammonia and methanol as the new sustainable feedstock chemicals. Additionally, as the chemical industry develops new reactors and finds ever more charmed combinations of catalysts, and as renewable energy continues to surge, the plants that churn out chemical staples will inevitably become green, i. e. fully sustained by renewable electricity[50]. This enables further integration of the industry into the larger energy system, which increases the flexibility and stability of the system.

CO_2 from being a pollutant to a sustainable feedstock

Carbon is one of the key components in most chemical products and fuels used widely, such as in transportation and heating as fuels, while as a chemical in products such as plastics, packaging, furniture, clothing, pharmaceuticals, and many others. Currently, more than 90 % of the carbon demand in the chemical sector is satisfied by fossil resources[72]. The chemical industry results in direct CO_2 emissions from fossil fuels consumed in its manufacturing processes, as well as indirect CO_2 emissions generated when fossil fuels are burnt to provide energy and the chemicals with by-products incinerated at the end of their lifetimes. For the chemical industry to reduce both its direct and indirect CO_2 emissions and to decrease its dependence on fossil resources, it requires a constant supply of sustainable carbon. As highlighted in this research, sustainable and unavoidable point sources in the initial period of the transition and DAC in the mid- to long-term duration of the transition can supply carbon in a sustainable and cost-effective manner. Therefore, CO_2 can be transformed from an undesirable pollutant to a valuable and sustainable feedstock for the production of powerfuels.

Powerfuels in major global energy transition scenarios

The projected merits of powerfuels have been presented in previous sections. However, these insights are not reflected in global energy transition studies, as there are different perspectives leading to different approaches and outcomes. The future role of powerfuels is controversially discussed in global energy scenarios, as there are mainly four perspectives:

- First, low ambition scenarios simply ignore powerfuels and base their findings still reliant on fossil fuels, which leads to either failing in any sort of ambitious climate targets or the requirement of massive negative CO_2 emission technologies. This is a prevalent approach in most climate scenarios and scenarios in the proximity of the fossil fuel industry.

- Second, climate targets are taken seriously and negative CO_2 emission technologies are regarded sceptically. However, this requires a massive scale-up of bioenergy, which dramatically violates sustainability limits and further endangers fragile ecosystems. This is a classic approach in climate scenarios and also some 100 % renewable energy scenarios.

- Third, powerfuels are acknowledged, biofuels are limited and negative CO_2 emission technologies are restricted, but assuming a high-sufficiency strategy leading to unrealistically low demand levels, in particular for international transportation of freight and passengers. This is partly coupled with the assumption of phasing out any hydrocarbon demands, irrespective of their origin, which may be achievable throughout the second half of the 21st century, but might be unlikely until 2050. This is a rather favoured approach in most 100 % renewable energy scenarios.

- Fourth, considering all major sustainability limitations in a fair way, leading to the phase-out of all fossil fuels, direct electrictrification to the extent possible, massive phase-in of powerfuels, very high sustainability standards for bioenergy, and envisioning prosperous economic development according to the Sustainable Development Goals of the United Nations. No restrictions in international transportation or industrial expansion, but based on a 100 % renewable energy system and comprehensive direct and indirect electrification across the different energy sectors. This is finally enabled by the massive cost decline in solar PV, wind energy, battery technology, electrolysers and synthesis processes. Currently, the only global energy system analysis exploring this approach is covered by the publications of Breyer et al., further highlighted in Ram et al.[54], and as presented in this study.

Ram et al.[54] clearly showed the technical feasibility and economic viability of the fourth approach and is one of the very few global energy transition scenarios describing a 1.5 °C pathway in a cost-neutral way for all energy sectors. The fundamental differences of Ram et al.[54] to other 100 % renewable energy studies are the consideration of the latest insights on cost trends for solar PV and other renewables, storage with battery technology and system flexibility with various power-to-X options for all energy sectors. The system stability is guaranteed by high temporal resolution with full hourly modelling and high geospatial resolution with 145 regions across the world.

The transport sector is explored and presented in more detail in Table 3 for the present status in global energy transition studies and the relative role of fossil fuels, biofuels, powerfuels, and direct electrification. Table 3 is based on Khalili et al.[17], but is updated with the latest study results, where available. Representatives of all the four main categories can be identified. Hydrogen is grouped into powerfuels, and in several studies is the only considered powerfuel, while ignoring SNG and FT fuels. Not a single global energy transition study has considered the roles of RE-ammonia or RE-methanol so far, while this may change with the current developments in the marine industry.

Table 3: Total global final energy demand of the transport sector for the years 2015 to 2050 in the referenced scenarios. (Various kinds of energy units are converted to TWh for comparability. Total final energy fuel demand shares in 2050 of all transport sectors are listed in the right-hand part of the table. For International Energy Agency (IEA), BP, ExxonMobil, and US DoE EIA scenarios the fuel-share values for 2040 are considered.)

Source	Publ. Year	Final energy demand of transport sector in TWh/a			
		2015	2020	2025	2030
Khalili et al.[17]	2019	31,613	34,799	35,848	35,609
Greenpeace [E]R[73]	2015	-	26,129	25,599	25,070
Greenpeace [E]R adv.[73]	2015	-	25,850	24,897	23,207
Teske, 1.5 °C[74]	2019	30,752	-	29,411	25,606
Teske, 2 °C[74]	2019	30,752	-	26,142	20,371
Jacobson et al.[75]	2018	-	-	-	-
Löffler et al.[76]	2017	31,298	32,434	28,910	24,069
Pursiheimo et al.[77]	2019	-	-	-	-
García-Olivares et al.[78]	2018	-	-	-	-
WWF[79]/Deng et al.[80]	2011	29,102	29,598	28,714	25,940
World Energy Council[81]	2019	34,203	-	33,820	33,413
DNV GL[82]	2019	29,861	33,333	35,416	34,027
IEA, WEO StPS[83]	2019	31,308	-	36,704	38,693
IEA, WEO SDS[83]	2019	31,308	-	34,250	34,378
Luderer et al. B200[84]	2018	-	-	-	-
Luderer et al. B800[84]	2018	-	-	-	-
Shell, Sky[85]	2018	30,812	33,019	34,989	34,611
BP Energy Outlook[86]	2019	29,656	32,564	34,890	36,053
ExxonMobil[87]	2017	32,530	-	36,633	-
US DoE EIA[88]	2017	32,823	33,703	35,168	37,806

The findings of Khalili et al.[17], which are used for the transport sector in Ram et al.[54], find the highest shares of powerfuels by 2050 among all global energy transition studies. This is mainly due to two fundamental restrictions: first, strict adherence to sustainability limitations of biofuels, and second, a prosperous economic environment leading to increasing demand for international transportation, which requires chemically high energy density fuels on a large scale.

There is a severe gap in research of RE-chemicals, as there seems to be a lack of studies that include RE-chemicals as part of the global energy transition. Leading 100 % renewable energy research has explicitly excluded the chemical industry from global energy transition studies, as explicitly mentioned in publications, such as Jacobson et al.[75], Teske et al.[74], Ram et al.[54], and summarised in Hansen et al.[89]. In less ambitious studies, the chemical industry is based on fossil feedstocks by default, such as in the Shell Sky[85], in all scenarios of the World Energy Outlook of the IEA[83] and the World Energy Council[81]. The same is also true for the climate scenarios of the IPCC[4, 90], and it is documented by Pursiheimo et al.[77] that leading models such as TIMES are technically not able to use RE-chemicals. However, it is projected that RE-ammonia can become cost-competitive from the late 2020s onwards[56], while RE-methanol may follow fast[40]. This severe gap needs to be addressed by the energy modelling community so that more realistic scenarios can be discussed[89], which is also supported by the chemical industry[91].

				final energy fuel shares in 2050 in %			
2035	2040	2045	2050	fossil fuels	biofuel	powerfuels	electricity
33,761	32,177	31,758	32,542	0	1	63	35
-	21,808	-	19,159	29	14	20	38
-	18,020	-	14,836	0	14	35	51
-	19,604	-	17,001	0	16	36	48
-	15,919	-	14,279	0	25	29	46
-	-	-	13,113	0	0	33	67
20,258	16,706	13,326	10,414	0	15	44	41
-	-	-	23,480	0	30	33	37
-	-	-	28,383	n/a	n/a	n/a	n/a
24,420	19,533	17,998	17,741	0	74	0	26
-	34,448	-	33,134	62	12	9	17
32,638	31,250	30,555	30,000	49	12	6	33
40,228	41,938	-	-	89	6	0	5
-	30,412	-	-	71	14	1	14
-	-	-	31,945	32	29	18	21
-	-	-	36,110	47	26	12	15
36,290	37,686	38,837	40,630	67	13	2	18
37,216	37,099	-	-	89	7	0	4
-	40,736	-	-	94	4	0	2
40,736	44,400	-	-	98	0	0	2

Future for global trading of powerfuels

Powerfuels, owing to their properties, can be stored, transported and traded around the world. The deciding factor is the costs of producing powerfuels and as the findings of this research indicate, global average LCOF for FT fuels and RE-chemicals are comparable to fossil fuels from 2030 onward and are more cost-competitive by 2050. SNG and LNG as powerfuels may be competitive in niche markets, but hardly compete with fossil methane, while renewable electricity based hydrogen may be able to substitute most of the energy applications of fossil methane in the mid to long term. However, ambitious GHG emission pricing may tilt the economics from fossil methane to favour SNG and LNG powerfuels. As highlighted in this research, different countries and regions benefit on varying levels from the global trade of powerfuels. The findings indicate that regions with excellent renewable resources, mainly solar, such as countries and regions in South America and Africa, become exporters. These countries have the opportunity to develop ecosystems that will foster the growth of producing powerfuels, which will bring about positive socio-economic impacts. While, countries in the northern latitudes, especially Canada, Europe and Eurasia, benefit in the short to mid term from access to low-cost wind sites, in the mid to long term they turn into importers and benefit from lower-cost production sites in the exporting regions. The closer excellent solar resource sites are located to the equator, the more attractive options arise for producing powerfuels, since cost-inducing seasonal variations are at a minimum level. The key aspects are leveraging the potential of renewable energy sources, materialising economic production of powerfuels, along with fostering of international trade. The findings of this research show that the overall trading volumes of powerfuels in comparison to current trading volumes of fossil fuels and chemicals are rather low, in the order of 25 – 35 % of the global demand. This is a result of the fair and wide distribution of renewable resources across the world and economic incentives for countries to produce powerfuels domestically for increased self-sufficiency and security. However, the option of international trade does bring about benefits for countries in the northern latitudes such as Canada, Europe and Eurasia, which witness cost reductions of around 15 - 30 % by 2050.

Shipping costs of powerfuels do play a role in influencing trading and in line with current practices shipping costs are borne by importing regions in this research. An interesting finding suggests that the highest-costing powerfuel (FT fuels) has the lowest shipping cost, therefore it is the easiest tradable powerfuel. By contrast, the lowest-costing chemical (RE-ammonia) has the highest shipping cost and is therefore more limited in trading.

Powerfuels are fully tradeable on the global scale at relatively low costs of transportation. As findings of this research show, the current globally unequitable fossil fuels and chemicals trade structure will transition into a more globally equitable trade in powerfuels by 2050. This further presents options for countries with high energy needs, but limited area and potential for renewable energy sources, to diversify supply as energy importers. This is the case for regions such as Europe, which can benefit with high volumes of import and some volumes of domestic production, as highlighted in the findings of this research. The global trade also provides new carbon-neutral export opportunities for countries with high renewable energy potential and sound business environments. As highlighted in the research, more stable countries in Africa and South America can transform into exporters of powerfuels with their excellent renewable resources. Furthermore, it presents technologically advanced countries, such as Australia, Japan and North America along with Europe, twith the opportunity to open avenues of exporting technology and know-how to regions with excellent renewable sources all year round and to create global partnerships for mutual benefits. It seems that the much discussed powerfuels export potential for countries in the Middle East and North Africa may be more limited, as these countries have not been found to be the leading exporters in this research. All the MENA countries tend to become self-suppliers, including countries that currently cannot export fossil with the opportunity to is also a result of world market shares in powerfuels exports being rather limited. Further research is required with the consideration of comprehensive export options, for instance exporting renewable electricity based hydrogen through pipelines from North Africa to Europe[92]. Such options have not been considered in this research.

Powerfuels for climate neutrality

Climate change is one of the most, if not the most pressing issue that the global community is confronted with, as it has repercussions for the very existence of future generations. This has compelled countries around the world to agree on the common goals of the Paris Agreement[93], and if the goals are to be achieved, a complete overhaul of the current highly polluting energy system to a sustainable one has to happen before the middle of this century. The power sector has taken the lead with the direct switch to renewable electricity generation, which is fast becoming the most preferred source of electricity across the world, as renewables had a 77 % share of all new power capacities added in 2019[6, 7]. However, the other sectors of heat, transport and the hard-to-abate industries pose a challenge to this transformation. Here is where powerfuels emerge as the most effective options to accelerate the transition and increase the adoption of renewable electricity. As highlighted by this research, powerfuels have the potential to avoid global cumulative GHG emissions of around 140 Gt CO_2eq by 2050. This is quite significant in the pursuit of achieving climate neutrality for countries across the world, even more so for Europe, which has recently agreed on the European Green Deal[70] for the region to achieve climate neutrality by 2050.

Global political consensus for advancing powerfuels

Political support for powerfuels is expected to differ with the market development and market maturity levels of the production technologies. Current trends indicate that powerfuel and RE-chemical production technologies, while gaining traction, still have to be commercialised on a large scale. But at the same time, there are already technology leaders in the global market who need further support to scale up production, thereby gaining valuable experience in these processes and enabling reduction in production costs.

It also seems important to investigate the short- and long-term socioeconomic impacts of powerfuels deployment on a large scale, globally. In the early market phase, it will be important to develop market environments around the world which lead to steady rise in demand, while the phase of commercialisation and expansion should progress with robust regulatory development for long-term investments in a sustainable future. Fossil fuel importing countries and regions in particular have massive incentives to pursue energy self-sufficiency with the promotion of powerfuels, which will lead to economic benefits by reducing import bills and importantly by helping in mitigating climate change.

To deploy and scale up powerfuels on a global level,

- it is crucial that important market players, policymakers and experts from the research sector cooperate and coordinate future activities;
- a global GHG emissions pricing mechanism is vital for ensuring cost competitiveness of powerfuels;
- international support with multilateral exchanges and knowledge transfers, as well as campaigns to raise awareness for powerfuels are required globally;
- a global body responsible for dialogue processes regarding standardisation, funding schemes, policy and regulatory instruments has to take shape.

Annex A

LUT Energy System Transition model

The LUT Energy System Transition model[94] has integrated all crucial aspects of the power, heat and transport sectors into an integrated energy system. Moreover, the model includes prosumers, both power and heat, as part of the energy system. The industrial energy demand is considered in the power and heat sectors. The fundamental approach is shown in Figure A1.

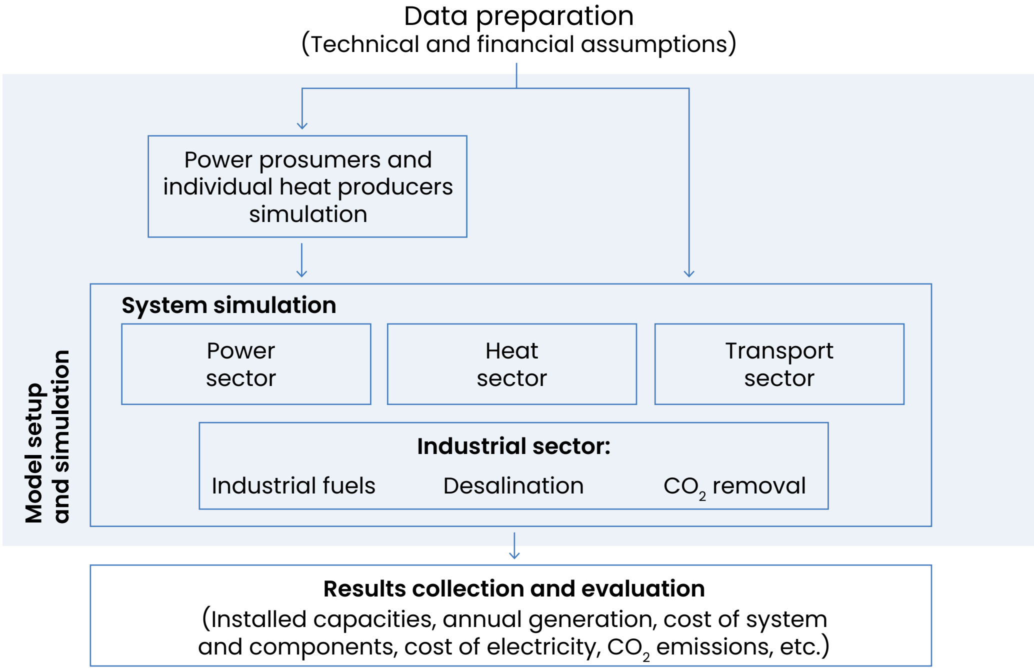


Figure A1: Fundamental structure of the LUT Energy System Transition model.

The optimisation model of the energy system is based on a linear optimisation of the system parameters under a set of applied constraints with the assumption of a perfect foresight of renewable energy generation and energy demand. A multi-node approach enables the description of any desired configuration of sub-regions and power transmission interconnections. The main constraint for the optimisation is the matching of total energy generation and total energy demand values for every hour of the applied year, and the optimisation criterion is the minimum of the total annual cost of the system. The hourly resolution of the model significantly increases the computation time. However, it guarantees that for every hour of the year the total supply within a sub-region covers the local demand and enables a more precise system description including synergy effects of different system components.

The optimisation is performed in a third-party solver. Currently, the main option is MOSEK ver. 7, but other solvers (Gurobi, CPLEX, etc.) can also be used. The model is compiled in the Matlab environment in the LP file format, so that the model can be read by most of the available solvers. After the simulation, results are parsed back to the Matlab data structure and post-processed. A detailed description is provided in Bogdanov et al.[53].

Power and heat sectors

The LUT model simulates an energy system development under specific given conditions as shown in Figure A2. For every time step the model defines a cost-optimal energy system structure and operation mode for the given set of constraints: power demand, heat demand for industry, space and domestic water heating, available generation and storage technologies, financial and technical parameters, and limits on installed capacity for all available technologies. The target of the optimisation is the minimisation of total system cost. Costs of the system are calculated as a sum of the annual capital and operational expenditures (including ramping costs) for all available technologies. The transition simulation was performed for the period from 2015 to 2050 in five-year time intervals.

The distributed generation and self-consumption of residential, commercial, and industrial prosumers are included in the energy system analysis and defined with a special model describing the development of the individual power and heat generation capacities. Prosumers can install their own rooftop PV systems, lithium-ion batteries, buy power from the grid, or sell surplus electricity in order to fulfil their demand. At the same time prosumers can install individual heaters for space and water heating. The target function for prosumers is minimisation of the cost of consumed electricity and heat, calculated as a sum of self-generation equipment annual costs, costs of fuels, and costs of electricity consumed from the grid. The share of consumers that is expected to be interested in self-generation gradually increases from 3 % in 2015 to an in-built limit of 20 % by 2050.

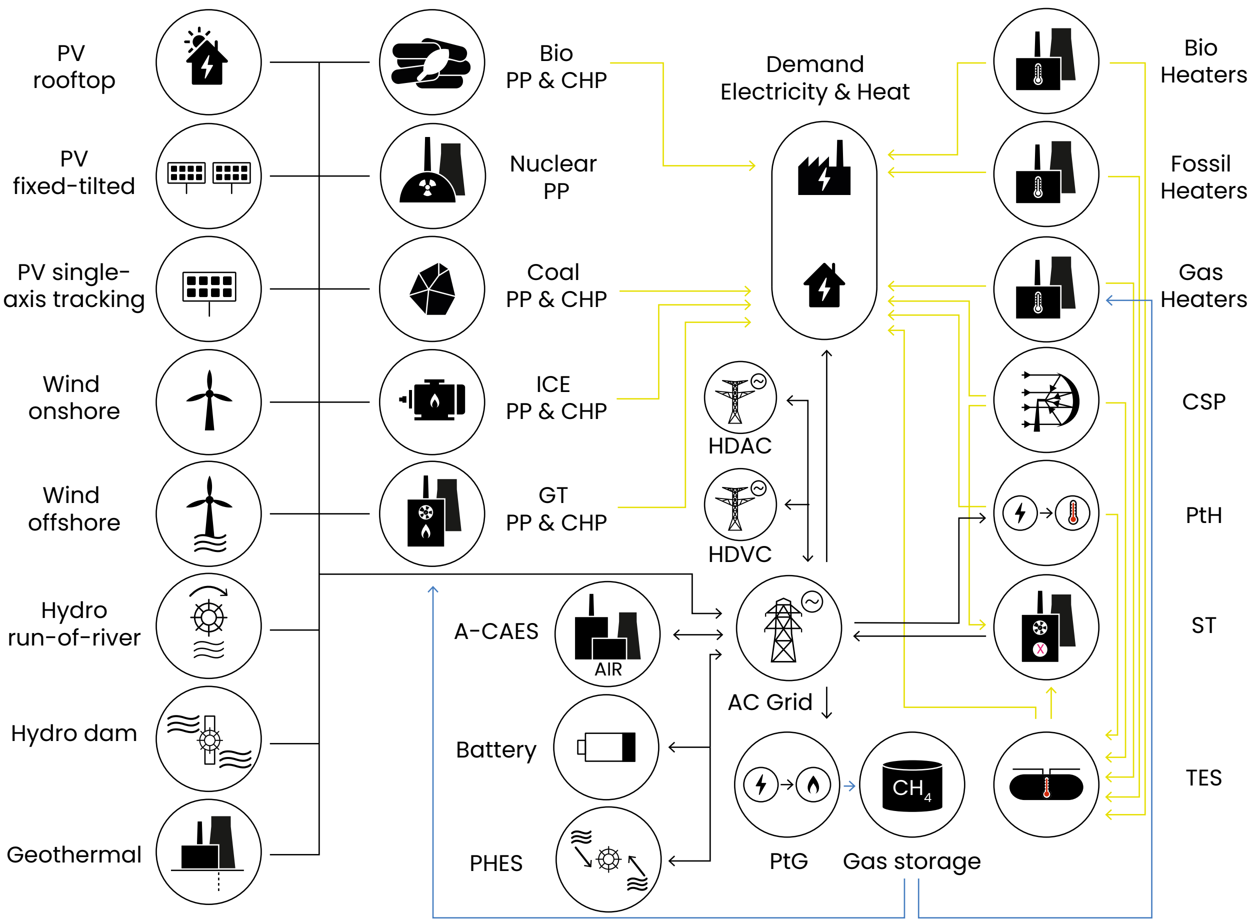


Figure A2: Schematic of the LUT Energy System Transition model comprised of energy converters for power and heat, storage technologies, transmission options, and demand sectors.

The model has integrated all crucial aspects of an energy system. Technologies introduced to the model can be classified into five main categories:

- Electricity generation: fossil, nuclear, and RE technologies
- Heat generation: fossil and RE technologies
- Energy storage
- Energy sector bridging
- Electricity transmission

Fossil electricity generation technologies are coal power plants, combined heat and power (CHP), oil-based internal combustion engine (ICE) and CHP, open cycle (OCGT) and combined cycle gas turbines (CCGT), and gas-based CHP. RE electricity generation technologies are solar PV (optimally fixed-tilted, single-axis north-south tracking, and rooftop), wind turbines, hydropower (run-of-river and reservoir), geothermal, and bio energy (solid biomass, biogas, waste-to-energy power plants, and CHP). Fossil heat generation technologies are coal-based district heating, oil-based district and individual scale boilers, and gas-based district and individual scale boilers. RE-based heat generation technologies are concentrated solar thermal power (CSP) parabolic fields, individual solar thermal water heaters, geothermal district heaters, and bioenergy (solid biomass, biogas district heat, and individual boilers).

Storage technologies can be divided into three main categories: short-term storage – lithium-ion batteries and pumped hydro energy storage (PHES); medium-term storage – adiabatic compressed air energy storage (A-CAES), and high and medium temperature thermal energy storage (TES) technologies; and long-term gas storage including power-to-gas (PtG) technology, which allows the production of synthetic methane to be utilised in the system.

Bridging technologies are power-to-gas, steam turbines, electrical heaters, district and individual scale heat pumps, and direct electrical heaters. These technologies convert energy from one sector into valuable products for another sector in order to increase total system flexibility, efficiency, and decrease overall costs. A detailed overview can be found in Bogdanov et al.[53].

Transport sector

Transportation demand is derived for the modes: road, rail, marine, and aviation for passenger and freight transportation. The road segment is subdivided into passenger LDV, passenger 2W/3W, passenger bus, freight MDV, and freight HDV. The other transportation modes are comprised of demand for freight and passengers. The demand is estimated in passenger kilometres (p-km) for passenger transportation and in (metric) ton kilometres (t-km) for freight transportation. Further information and data for transportation demand along with fuel shares and specific energy demand are provided in Khalili et al.[17].

The transportation demand is converted into energy demand by assuming an energy transition from current fuels to fully sustainable fuels by 2050, whereas the following principal fuel types are taken into account and visualised in Figure A3:

- Road: electricity, hydrogen, liquid fuels
- Rail: electricity, liquid fuels
- Marine: electricity, hydrogen, methane, liquid fuels
- Aviation: electricity, hydrogen, liquid fuels

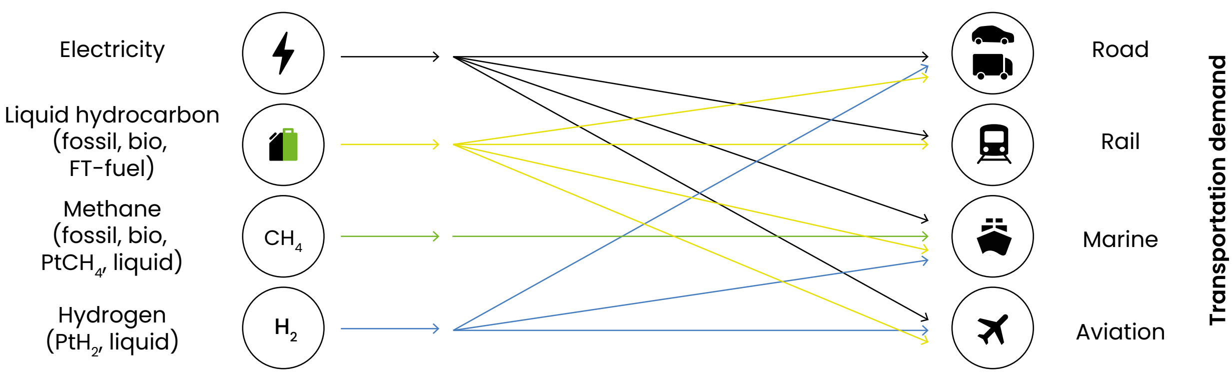


Figure A3: Schematic of the transport modes and corresponding fuels utilised during the energy transition from 2015 - 2050.

Desalination sector

The LUT Energy System Transition model is used to identify the lowest cost configuration of 100 % RE hybrid power plants to enable a low water production cost. The levelised cost of water includes the water production cost as well as the pumping of water from the coastline to the sites with desalination demand. An hourly simulation is performed as part of the LUT Energy System Transition model as indicated in Figure A4.

The desalination demand is estimated for regions with water stress greater than 40 % and is a function of the water stress and total water demand for a specific year. The water stress we refer to is explained in more detail in Caldera et al.[95]. The total water demand is the sum of the projected demand from the municipal, industrial and agricultural sectors. Irrigated agriculture accounts for 70 % of the global water withdrawals. However, the average global irrigation efficiency is estimated to be as low as 33 % and experience a maximum relative growth rate of 0.3 % per annum. In Caldera et al.[96], a scenario is presented where the irrigation efficiencies are increased using a maximum relative growth rate of 1 % per annum. The irrigation efficiency growth rate per annum varies with water stress, based on a logistic expression. It is assumed that irrigation sites with water stress higher than 80 % have a maximum growth rate of 1 % per annum. The improved irrigation efficiency results in reduction in water demand, water stress and consequently desalination demand for a given year. This method, the data and assumptions used to project the desalination demand from 2015 to 2050 are discussed in Caldera and Breyer[45, 96]. Therefore, the desalination demand presented in the report addresses the demands of the municipal, industrial and agricultural sector with improved irrigation efficiency.

Other details including the mathematical equations can be found in Bogdanov et al.[94], and Ram et al.[54].

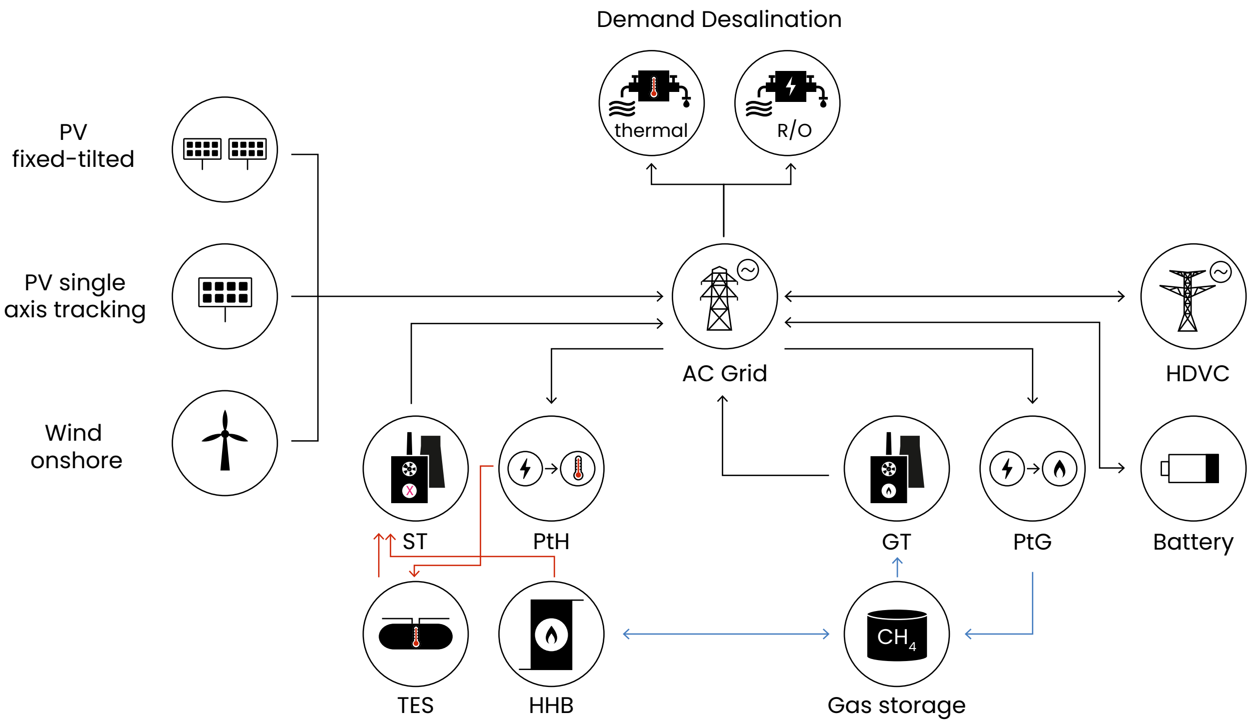


Figure A4: Schematic of the LUT Energy System Transition model to determine the optimal combination of components that meet the hourly electricity demand of SWRO desalination capacities.

Annex B

Technical and financial assumptions

The following tables show the various technical and financial assumptions that were factored into the modelling of the global energy transition.

Table B1: Technical and financial assumptions of energy system technologies used in the energy transition from 2015 to 2050.

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
PV rooftop - residential	Capex	€/kW_{el}	1,360	1,169	966	826	725	650	589	537	[97]
	Opex fix	€/(kW_{el} a)	20	17.6	15.7	14.2	12.8	11.7	10.7	9.8	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	35	35	35	40	40	40	
PV rooftop - commercial	Capex	€/kW_{el}	1,360	907	737	623	542	484	437	397	[97]
	Opex fix	€/(kW_{el} a)	20	17.6	15.7	14.2	12.8	11.7	10.7	9.8	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	35	35	35	40	40	40	
PV rooftop - industrial	Capex	€/kW_{el}	1,360	682	548	459	397	353	318	289	[97]
	Opex fix	€/(kW_{el} a)	20	17.6	15.7	14.2	12.8	11.7	10.7	9.8	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	35	35	35	40	40	40	
PV optimally tilted	Capex	€/kW_{el}	1,000	432	336	278	237	207	184	166	[12]
	Opex fix	€/(kW_{el} a)	15	7.8	6.5	5.7	5	4.5	4.04	3.7	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	35	35	35	40	40	40	
PV single-axis tracking	Capex	€/kW_{el}	1,150	475	370	306	261	228	202	183	[12, 98]
	Opex fix	€/(kW_{el} a)	17.3	8.5	7.2	6.2	5.5	4.9	4.4	4.1	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	35	35	35	40	40	40	
Wind onshore	Capex	€/kW_{el}	1,250	1,150	1,060	1,000	965	940	915	900	[99]
	Opex fix	€/(kW_{el} a)	25	23	21	20	19	19	18	18	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	25	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
Wind offshore	Capex	€/kW_{el}	3,220	2,880	2,700	2,580	2,460	2,380	2,320	2,280	[100]
	Opex fix	€/(kW_{el} a)	112.7	92.16	83.7	77.4	71.34	66.64	58	52.44	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	20	25	25	25	25	25	25	25	
Hydro reservoir/dam	Capex	€/kW_{el}	1,650	1,650	1,650	1,650	1,650	1,650	1,650	1,650	[100]
	Opex fix	€/(kW_{el} a)	49.5	49.5	49.5	49.5	49.5	49.5	49.5	49.5	
	Opex var	€/(kWh_{el})	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	
	Lifetime	years	50	50	50	50	50	50	50	50	
Hydro run-of-river	Capex	€/kW_{el}	2,560	2,560	2,560	2,560	2,560	2,560	2,560	2,560	[100]
	Opex fix	€/(kW_{el} a)	76.8	76.8	76.8	76.8	76.8	76.8	76.8	76.8	
	Opex var	€/(kWh_{el})	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	
	Lifetime	years	50	50	50	50	50	50	50	50	
Geothermal power	Capex	€/kW_{el}	5,250	4,970	4,720	4,470	4,245	4,020	3,815	3,610	[100, 101]
	Opex fix	€/(kW_{el} a)	80	80	80	80	80	80	80	80	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	40	
Coal PP	Capex	€/kW_{el}	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	[102, 103]
	Opex fix	€/(kW_{el} a)	20	20	20	20	20	20	20	20	
	Opex var	€/(kWh_{el})	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Lifetime	years	40	40	40	40	40	40	40	40	
Nuclear PP	Capex	€/kW_{el}	6,210	6,003	6,003	5,658	5,658	5,244	5,244	5,175	[102, 104, 105]
	Opex fix	€/(kW_{el} a)	162	157	157	137	137	116	116	109	
	Opex var	€/(kWh_{el})	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	
	Lifetime	years	40	40	40	40	40	40	40	40	
CCGT	Capex	€/kW_{el}	775	775	775	775	775	775	775	775	[102]
	Opex fix	€/(kW_{el} a)	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	35	35	35	35	35	35	35	35	
OCGT	Capex	€/kW_{el}	475	475	475	475	475	475	475	475	[106]
	Opex fix	€/(kW_{el} a)	14.25	14.25	14.25	14.25	14.25	14.25	14.25	14.25	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	35	35	35	35	35	35	35	35	
Steam turbine (CSP)	Capex	€/kW_{el}	760	740	720	700	670	640	615	600	[54]
	Opex fix	€/(kW_{el} a)	15.2	14.8	14.4	14	13.4	12.8	12.3	12	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	30	30	30	30	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
CHP NG heating	Capex	€/kW_{el}	880	880	880	880	880	880	880	880	[100]
	Opex fix	€/(kW_{el} a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	
	Opex var	€/(kWh_{el})	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
	Lifetime	years	30	30	30	30	30	30	30	30	
CHP oil heating	Capex	€/kW_{el}	880	880	880	880	880	880	880	880	[100]
	Opex fix	€/(kW_{el} a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	
	Opex var	€/(kWh_{el})	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
	Lifetime	years	30	30	30	30	30	30	30	30	
CHP coal heating	Capex	€/kW_{el}	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	[100]
	Opex fix	€/(kW_{el} a)	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	
	Opex var	€/(kWh_{el})	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	
	Lifetime	years	40	40	40	40	40	40	40	40	
CHP biomass heating	Capex	€/kW_{el}	3,560	3,300	3,145	2,990	2,870	2,750	2,645	2,540	[54]
	Opex fix	€/(kW_{el} a)	81.9	75.9	72.3	68.8	66	63.3	60.8	58.4	
	Opex var	€/(kWh_{el})	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	
	Lifetime	years	25	25	25	25	25	25	25	25	
CHP biogas	Capex	€/kW_{el}	503	429	400	370	340	326	311	296	[54]
	Opex fix	€/(kW_{el} a)	20.1	17.2	16	14.8	13.6	13	12.4	11.8	
	Opex var	€/(kWh_{el})	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Lifetime	years	30	30	30	30	30	30	30	30	
Waste incinerator	Capex	€/kW_{el}	5,940	5,630	5,440	5,240	5,030	4,870	4,690	4,540	[100]
	Opex fix	€/(kW_{el} a)	267.3	253.4	244.8	235.8	226.4	219.2	211.1	204.3	
	Opex var	€/(kWh_{el})	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	
	Lifetime	years	30	30	30	30	30	30	30	30	
Biogas digester	Capex	€/kW_{th}	771	731	706	680	653	632	609	589	[54]
	Opex fix	€/(kW_{th} a)	30.8	29.2	28.2	27.2	26.1	25.3	24.3	23.6	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	25	25	25	25	
Biogas upgrade	Capex	€/kW_{th}	340	290	270	250	230	220	210	200	[107]
	Opex fix	€/(kW_{th} a)	27.2	23.2	21.6	20	18.4	17.6	16.8	16	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	25	25	25	25	
CSP (solar field, parabolic trough)	Capex	€/kW_{th}	438.3	344.5	303.6	274.7	251.1	230.2	211.9	196	[108, 109]
	Opex fix	€/(kW_{th} a)	10.1	7.9	7	6.3	5.8	5.3	4.9	4.5	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	25	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
Residential solar heat collectors - space heating	Capex	€/kW$_{th}$	1,286	1,214	1,179	1,143	1,071	1,000	929	857	[54]
	Opex fix	€/(kW$_{th}$ a)	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	
	Opex var	€/(kW$_{th}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	20	25	25	30	30	30	30	30	
Residential solar heat collectors - hot water	Capex	€/kW$_{th}$	485	485	485	485	485	485	485	485	[54]
	Opex fix	€/(kW$_{th}$ a)	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	
	Opex var	€/(kWh$_{th}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	15	
DH rod heating	Capex	€/kW$_{th}$	100	100	100	75	75	75	75	75	[54]
	Opex fix	€/(kW$_{th}$ a)	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	
	Opex var	€/(kWh$_{th}$)	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Lifetime	years	35	35	35	35	35	35	35	35	
DH heat pump	Capex	€/kW$_{th}$	700	660	618	590	568	554	540	530	[120]
	Opex fix	€/(kW$_{th}$ a)	2	2	2	2	2	2	2	2	
	Opex var	€/(kWh$_{th}$)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
	Lifetime	years	25	25	25	25	25	25	25	25	
DH natural gas heating	Capex	€/kW$_{th}$	75	75	75	100	100	100	100	100	[120]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/(kWh$_{th}$)	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	35	
DH oil heating	Capex	€/kW$_{th}$	75	75	75	100	100	100	100	100	[54]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/(kWh$_{th}$)	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	35	
DH coal heating	Capex	€/kW$_{th}$	75	75	75	100	100	100	100	100	[54]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/(kWh$_{th}$)	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	35	
DH biomass heating	Capex	€/kW$_{th}$	75	75	75	100	100	100	100	100	[54]
	Opex fix	€/(kW$_{th}$ a)	2.8	2.8	2.8	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/(kWh$_{th}$)	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	35	
DH geothermal heat	Capex	€/kW$_{th}$	3,936	3,642	3,384	3,200	3,180	3,160	3,150	3,146	[54]
	Opex fix	€/(kW$_{th}$ a)	144	133	124	117	116	115	115	115	
	Opex var	€/(kWh$_{th}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	22	22	22	22	22	22	22	22	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
Local rod heating	Capex	€/kW_{th}	800	800	800	800	800	800	800	800	[54]
	Opex fix	€/(kW_{th} a)	10	10	10	10	10	10	10	10	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	30	
Local heat pump	Capex	€/kW_{th}	800	780	750	730	706	690	666	650	[100]
	Opex fix	€/(kW_{th} a)	16	15.6	15	7.3	7.1	6.9	6.7	6.5	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	20	
Local natural gas heating	Capex	€/kW_{th}	800	800	800	800	800	800	800	800	[54]
	Opex fix	€/(kW_{th} a)	27	27	27	27	27	27	27	27	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	22	22	22	22	22	22	22	22	
Local oil heating	Capex	€/kW_{th}	440	440	440	440	440	440	440	440	[54]
	Opex fix	€/(kW_{th} a)	18	18	18	18	18	18	18	18	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	20	
Local coal heating	Capex	€/kW_{th}	500	500	500	500	500	500	500	500	[54]
	Opex fix	€/(kW_{th} a)	10	10	10	10	10	10	10	10	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	15	
Local biomass heating	Capex	€/kW_{th}	675	675	675	750	750	750	750	675	[54]
	Opex fix	€/(kW_{th} a)	2	2	2	3	3	3	3	2	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	20	
Local biogas heating	Capex	€/kW_{th}	800	800	800	800	800	800	800	800	[54]
	Opex fix	€/(kW_{th} a)	27	27	27	27	27	27	27	27	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	22	22	22	22	22	22	22	22	
Water electrolysis	Capex	€/kW_{H2}	800	685	500	363	325	296	267	248	[110, 111]
	Opex fix	€/(kW_{H2} a)	32	27	20	12.7	11.4	10.4	9.4	8.7	
	Opex var	€/(kWh_{H2})	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Lifetime	years	30	30	30	30	30	30	30	30	
Methanation	Capex	€/kW_{CH4}	547	502	368	278	247	226	204	190	[110, 111]
	Opex fix	€/(kW_{CH4} a)	25.16	23.09	16.93	12.79	11.36	10.4	9.38	8.74	
	Opex var	€/(kWh_{CH4})	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
	Lifetime	years	30	30	30	30	30	30	30	30	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
CO_2 direct air capture	Capex	€/t_{CO2} a	1,000	730	493	335	274.4	234	210.6	195	[55, 121]
	Opex fix	€/t_{CO2} a	40	29.2	19.7	13.4	11	9.4	8.4	7.8	
	Opex var	€/t_{CO2}	0	0	0	0	0	0	0	0	
	Lifetime	years	20	20	30	25	30	30	30	30	
Fischer-Tropsch unit	Capex	€/kW, $FT_{Liq,output}$	947	947	947	947	947	852.3	852.3	852.3	[121]
	Opex fix	€/kW, $FT_{Liq,output}$	28.41	28.41	28.41	28.41	28.41	25.57	25.57	25.57	
	Opex var	€/kW, $FT_{Liq,output}$	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	30	
Battery storage	Capex	€/kW_{el}	400	234	153	110	89	76	68	61	[12]
	Opex fix	€/(kW_{el} a)	24	3.3	2.6	2.2	2.1	1.9	1.8	1.7	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	
Battery interface	Capex	€/kW_{el}	200	117	76	55	44	37	33	30	[12, 122, 123]
	Opex fix	€/(kW_{el} a)	0	1.5	1.3	1.1	1.01	0.9	0.9	0.8	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	
Battery PV prosumer - residential storage	Capex	€/kW_{el}	603	407	280	209	170	146	124	111	[97]
	Opex fix	€/(kW_{el} a)	36.2	13.6	7.7	5.8	4.7	4	3.4	3	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	
Battery PV prosumer - residential interface	Capex	€/kW_{el}	302	204	140	104	85	73	62	56	[97]
	Opex fix	€/(kW_{el} a)	0	0	0	0	0	0	0	0	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	
Battery PV prosumer - commercial storage	Capex	€/kW_{el}	513	346	235	174	141	120	102	91	[97]
	Opex fix	€/(kW_{el} a)	30.8	11.5	6.5	4.9	3.9	3.3	2.8	2.5	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	
Battery PV prosumer - commercial interface	Capex	€/kW_{el}	256	173	117	87	70	60	51	46	[97]
	Opex fix	€/(kW_{el} a)	0	0	0	0	0	0	0	0	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	
Battery PV prosumer - industrial storage	Capex	€/kW_{el}	435	294	198	146	118	100	85	76	[97]
	Opex fix	€/(kW_{el} a)	26.1	9.8	5.4	4.1	3.3	2.7	2.3	2	
	Opex var	€/(kWh_{el})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
Battery PV prosumer - industrial interface	Capex	€/kW$_{el}$	218	147	99	73	59	50	42	38	[97]
	Opex fix	€/(kW$_{el}$ a)	0	0	0	0	0	0	0	0	
	Opex var	€/(kWh$_{el}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	15	20	20	20	20	20	20	20	
PHES storage	Capex	€/kW$_{el}$	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	[100]
	Opex fix	€/(kW$_{el}$ a)	1.335	1.335	1.335	1.335	1.335	1.335	1.335	1.335	
	Opex var	€/(kWh$_{el}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	50	
PHES interface	Capex	€/kW$_{el}$	650	650	650	650	650	650	650	650	[100]
	Opex fix	€/(kW$_{el}$ a)	0	0	0	0	0	0	0	0	
	Opex var	€/(kWh$_{el}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	50	
A-CAES	Capex	€/kW$_{el}$	35	35	32.6	31.1	30.3	29.8	27.7	26.3	[100]
	Opex fix	€/(kW$_{el}$ a)	0.53	0.53	0.50	0.47	0.46	0.45	0.42	0.40	
	Opex var	€/(kWh$_{el}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	40	55	55	55	55	55	55	55	
A-CAES interface	Capex	€/kW$_{el}$	600	600	558	530	518	510	474	450	[100]
	Opex fix	€/(kW$_{el}$ a)	0	0	0	0	0	0	0	0	
	Opex var	€/(kWh$_{el}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	40	55	55	55	55	55	55	55	
Gas storage	Capex	€/kW$_{el}$	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	[54]
	Opex fix	€/(kW$_{el}$ a)	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Opex var	€/(kWh$_{el}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	50	
Gas storage interface	Capex	€/kWh$_{th}$	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	[54]
	Opex fix	€/(kWh$_{th}$ a)	31	31	31	31	31	31	31	31	
	Opex var	€/(kWh$_{th}$)	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2	
	Lifetime	years	41.4	41.4	41.4	41.4	41.4	41.4	41.4	41.4	
Hot heat storage	Capex	€/kWh$_{th}$	50.8	41.8	32.7	26.8	23.3	21	19.3	17.5	[54]
	Opex fix	€/(kWh$_{th}$ a)	0.76	0.63	0.49	0.4	0.35	0.32	0.29	0.26	
	Opex var	€/(kWh$_{th}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	30	30	30	30	
District heat storage	Capex	€/kWh$_{th}$	50	40	30	30	25	20	20	20	[54]
	Opex fix	€/(kWh$_{th}$ a)	0.8	0.6	0.5	0.5	0.4	0.3	0.3	0.3	
	Opex var	€/(kWh$_{th}$)	0	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	30	30	30	30	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
Hydrogen storage	Capex	€/kWh_{th}	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	[112]
	Opex fix	€/(kWh_{th} a)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	15	
Hydrogen storage interface	Capex	€/kWh_{th}	255.9	255.9	255.9	255.9	255.9	255.9	255.9	255.9	[112]
	Opex fix	€/(kWh_{th} a)	10.23	10.23	10.23	10.23	10.23	10.23	10.23	10.23	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	15	
CO_2 storage	Capex	€/ton	142	142	142	142	142	142	142	142	[113]
	Opex fix	€/(ton a)	9.94	9.94	9.94	9.94	9.94	9.94	9.94	9.94	
	Opex var	€/ton	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	30	
Reverse osmosis seawater desalination	Capex	€/(m^3/day)	1,150	960	835	725	630	550	480	415	[114]
	Opex fix	€/(m^3/day a)	46	38.4	33.4	29	25.2	22	19.2	16.6	
	Consumption	kWh_{th}/m^3	0	0	0	0	0	0	0	0	
	Lifetime	years	25	25	30	30	30	30	30	30	
	Consumption	kWh_{el}/m^3	4.1	3.6	3.35	3.15	3	2.85	2.7	2.6	
Multi-stage flash standalone	Capex	€/(m^3/day)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	[114]
	Opex fix	€/(m^3/day a)	100	100	100	100	100	100	100	100	
	Consumption	kWh_{th}/m^3	85	85	85	85	85	85	85	85	
	Lifetime	years	25	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Multi-stage flash cogeneration	Capex	€/(m^3/day)	3,069	3,069	3,069	3,069	3,069	3,069	3,069	3,069	[54]
	Opex fix	€/(m^3/day a)	121.4	121.4	121.4	121.4	121.4	121.4	121.4	121.4	
	Consumption	kWh_{th}/m^3	202.5	202.5	202.5	202.5	202.5	202.5	202.5	202.5	
	Lifetime	years	25	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Multi-effect distillation standalone	Capex	€/(m^3/day)	1,438	1,200	1,044	906.3	787.5	687.5	600	518.8	[114]
	Opex fix	€/(m^3/day a)	47.44	39.60	34.44	29.91	25.99	22.69	19.80	17.12	
	Consumption	kWh_{th}/m^3	68	51	44	38	32	28	28	28	
	Lifetime	years	25	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Multi-effect distillation cogeneration	Capex	€/(m^3/day)	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	[54]
	Opex fix	€/(m^3/day a)	61.69	61.69	61.69	61.69	61.69	61.69	61.69	68.81	
	Consumption	kWh_{th}/m^3	168	168	168	168	168	168	168	168	
	Lifetime	years	25	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	

Technologies		Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
Water storage	Capex	€/m³	64.59	64.59	64.59	64.59	64.59	64.59	64.59	64.59	[114]
	Opex fix	€/(m³ a)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	
	Opex var	€/m³	0	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	50	
Ammonia synthesis	Capex	€/MWh_{th}	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	[56]
	Opex fix	€/(MWh_{th} a)	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	
	Opex var	€/(kWh)	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	30	
Methanol synthesis	Capex	€/kW_{th}	52.6	52.6	52.6	52.6	52.6	52.6	52.6	52.6	[40]
	Opex fix	€/(kW_{th} a)	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	
	Opex var	€/(kWh_{th})	0	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	30	

Table B2: Energy-to-power ratio and self-discharge rates of storage technologies.

Technology	Efficiency (%)	Energy/Power ratio (h)	Self-discharge (%/h)	Ref.
Battery	90	6	0	[115]
PHES	85	8	0	[115]
A-CAES	70	100	0.1	[115]
TES	90	8	0.2	[115]
Gas storage	100	8,024	0	[115]

Table B3: Financial assumptions for the fossil-nuclear fuel prices and GHG emission cost. The referenced values are all till 2040 and are kept stable for later periods (fuels) or are assumed to further increase to match the Paris Agreement (GHG emissions).

Name of component	Unit	2015	2020	2025	2030	2035	2040	2045	2050	Ref.
Coal	€/MWh_{th}	7.7	7.7	8.4	9.2	10.2	11.1	11.1	11.1	[116]
Fuel oil	€/MWh_{th}	52.5	35.2	39.8	44.4	43.9	43.5	43.5	43.5	[106]
Fossil gas	€/MWh_{th}	21.8	22.2	30.0	32.7	36.1	40.2	40.2	40.2	[116]
Uranium	€/MWh_{th}	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	[105]
GHG emissions	€/t CO_2eq	9	28	52	61	68	75	100	150	[116]

GHG emissions by fuel type in t CO_2eq/MWh_{th}		
Coal[117]	Oil[117]	Fossil gas[118]
0.34	0.25	0.21

Table B4: Efficiency assumptions for HVDC transmission lines[119].

Component	Power losses
HVDC line	1.6 %/1,000 km
HVDC converter pair	1.4 %

Annex C

Assumptions for powerfuels and their trading

Cost basis for powerfuels

First, the LCOF for powerfuels needed to be updated. Ram et al.[54] results were taken as a base, then the costs were updated as follows:

- The Solar PV and battery cost have been updated according to Vartiainen et al.[12], without adjusting the relative shares of electricity generation of PV and wind or relative shares of storage options.
- The FT fuels production cost from Ram et al.[54] was adjusted to a CO_2 input of 0.2839 kg CO_2/kWh$_{FT,HHV}$ including respective DAC capacities and thermal and electric energy demand.
- LNG and SNG production costs are taken from Ram et al.[54], without further adjustment, except the solar PV and battery cost.
- Ammonia and methanol production costs are based on Ram et al.[54], for all regional conditions, in particular all utilisation of plants, LCOE and relative component sizing. In addition, the product-specific synthesis units are applied as listed in technical and financial assumptions.

Key parameters for powerfuels

Total **electricity demand** for powerfuels for the year 2050 is assumed to be:

- RE-LNG: 1.6952 kWh$_{el}$/kWh$_{LNG,HHV}$ equivalent of 59 % overall efficiency;
- FT fuels: 1.8868 kWh$_{el}$/kWh$_{FT,HHV}$ equivalent of 53 % overall efficiency;
- Ammonia: 1.4990 kW$_{hel}$/kWh$_{NH3,HHV}$ equivalent of 66.7 % overall efficiency;
- Methanol: 1.5921 kWh$_{el}$/kWh$_{MeOH,HHV}$ equivalent of 62.8 % overall efficiency.

These values include the full process chain for the power-to-fuel/chemical process, including external water supply and CO_2/N_2 DAC, while assuming heat recovery of waste heat for CO_2 DAC.

Total **CO_2 demand** as raw material input for the powerfuels and hydrocarbon-based chemical for the year 2050 is assumed to be:

- RE-LNG: 0.1779 kg CO_2/kWh$_{LNG,HHV}$;
- FT fuels: 0.2839 kg CO_2/kW$_{hFT,HHV}$;
- Methanol: 0.2299 kg CO_2/kWh$_{MeOH,HHV}$.

Regional export potential for powerfuels

A total upper limit for area utilisation is assumed to be 6 % of the entire area of a region for solar PV and 4 % for onshore wind energy, respectively. The area demand of a region for own energy supply for the sectors power, heat, transport and desalination is considered as a priority. Remaining area potential for solar PV and onshore wind energy is considered as the maximum potential for export production. The regional cost-optimised electricity generation mix of solar PV and wind energy as obtained for the transport sector in Ram et al.[54] has been used for the renewable electricity supply for powerfuels and RE-based chemicals, independent of domestic demand or export.

If one of the electricity sources (PV or wind) is dominant in the region with more than 98 % of total supply, then the potential for RE-LNG, FT fuels, ammonia and methanol were found using Eq. 1 for the dominant source with potentials expressed in energy units ($TWh_{th,fuel}$; $TWh_{el,PV}$), the relative share per powerfuel/chemical and electricity demand for the powerfuel/chemical ($TWh_{el}/TWh_{th,fuel}$):

Powerfuel/chemical potential
= remaining PV/wind potential
× share of PV/wind electricity
× relative share for powerfuel/chemical
÷ electricity demand for powerfuel/chemical

Eq. (1)

The relative share for LNG, FT fuels, ammonia, and methanol are assumed to be 25 %, 30 %, 10 %, and 35 %, respectively, as these values express roughly the expected 2050 shares of the powerfuels.

If none of the electricity sources is dominant, then the source which is more limited in remaining electricity supply potential is considered for the remaining total production potential of the regions, as expressed in Eq. 2:

Powerfuel/chemical potential
= remaining PV/wind potential
× share of PV/wind electricity
× relative share for powerfuel/chemical
÷ electricity demand for powerfuel/chemical

Eq. (2)

Eq. (2) is identical to Eq. (1), however, the applied basis of the values is different, as mentioned, therefore it has been duplicated here.

Import and export attractiveness assessment

In the following, a region in the 92 regions resolution is called country, since most of them are single countries. Others represent a group of countries, for instance Iberia for Portugal and Spain. Country i is assessed as an importer if the LCOF powerfuel/chemical in the country is higher than the global volume weighted average pre-trade value of the LCOF powerfuel/chemical. The significance level for import attractiveness is set at 2 %, i.e. imports are considered to be attractive if the cost of producing the powerfuel/chemical in country **i** is higher than the global average by more than 2 %.

Country i is assessed as an exporter if the LCOF powerfuel/chemical in country **i** plus the shipping cost is lower than the global volume weighted average pre-trade value of the LCOF powerfuel/chemical. The significance level is set at 2 % also for exporters.

In the event that none of the applied limits lead to the classification of being an importer or exporter, then the country is assessed as neutral. Exporters and neutral countries fulfil their powerfuel/chemical demand with domestic resources.

If country **i** is found to be an importer, then 100 % of demand is assumed to be imported from the group of exporters. If country i is found to be an exporter, then the country's exporting volume of the powerfuel/chemical is assumed to be equal to its potential for producing that powerfuel/chemical, if no further adjustment is applied.

Higher significance margins and lower import quotas could be assumed, which would lead automatically to a lower globally traded volume of powerfuels/chemicals. The set parameters make it possible to test the limits of a maximum global trade of powerfuels/chemicals based on pure economics and area availability, while other factors such as employment, energy security, political aspects, etc., may also play a substantial role for respective decision-making. The resulting regional classification of countries and regions in respect to their import/export attractiveness is highlighted in Figure C1.

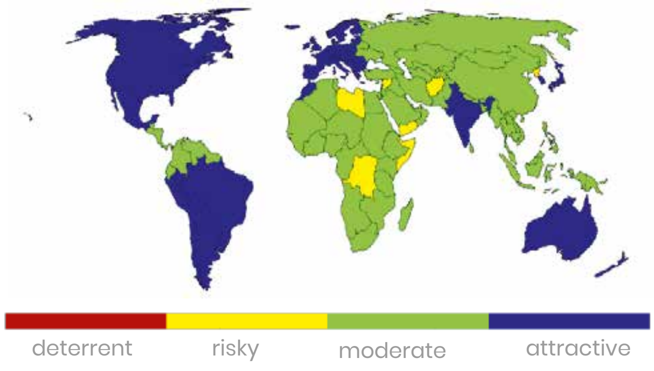


Figure C1: Global mapping of the import/export attractiveness of countries and regions across the world.

As highlighted in Figure C1, the most attractive regions are in blue, the moderately attractive regions are in light green, regions considered risky are in yellow and no region globally is found to be a deterrent.

Distribution towards exporter attractiveness

All countries are rated for their attractiveness as a trading partner on a scale of 0 (least attractive) to 3 (most attractive) based on political environment, economic stability and considerations of doing business in the country. An exporting strength for an exporting country j is obtained based on the maximum export volume, the exporter attractiveness level, and the LCOF powerfuel/chemical, as shown in Eq. (3):

$$\begin{aligned}&\textbf{exporting strength}_j\\&= \text{maximum export volume}_j\\&\times (1 + \text{weighting of exporter attractiveness}_j)\\&\times (\text{LCOF}_{average} - \text{LCOF}_{min})\\&\div (\text{LCOF}_j - \text{LCOF}_{min} + \text{minimum cost buffer})\end{aligned}$$

Eq. (3)

Weighting of exporter attractiveness is set to be +0.7, 0, -0.7 for exporters classified as top, acceptable, and risky, respectively. The minimum cost buffer is set at 0.6 (on a scale 0.1 to 5).

The impact of this exporting strength shaping leads to higher shares for countries of the lowest LCOF, while the impact of exporting attractiveness is factored in strongly. The cost buffer parameter is used to control the exporting strength to appropriate values. The set parameters are obtained due to empiric parameter variations.

Import and export volumes

The trading structure on volumes of import of a powerfuel/chemical to country **i** from country **j** is obtained by taking into consideration:

- country **i** is classified as an importer;
- import volume of a powerfuel/chemical due to domestic demand;
- import share, which is set to 100 % for this study;
- world market export share of exporter country **j** as the share on the exporting strength;
- global import volume is distributed to exporters according to their world market export shares.

The total import value of a powerfuel/chemical **k** of country **i** is the sum of import values from all other regions, which is found by multiplying the energy volume of imports from a country **j** by the $LCOF_{j,k}$ powerfuel/chemical **k** in country **j**. The weighted average import LCOF is found by dividing the total import value by the total imported volume of a powerfuel/chemical. The cost of shipping is considered as a reduction in economic post-trade benefit.

The Post-trading LCOF for country **i** for a powerfuel/chemical **k** is found by applying Eq. (4):

$$LCOF_{post\text{-}trade,i,k} = \frac{(output_{i,k} - import_{i,k}) \times LCOF_{pre\text{-}trade,i,k} + import_{i,k} \times import\ LCOF_{i,k}}{demand_{i,k}}$$

Eq. (4a)

$$demand_{i,k} = output_{i,k} + import_{i,k}$$

Eq. (4b)

The Powerfuel/chemical pre-trade market value is found as the product of the powerfuel/chemical output and pre-trade LCOF. The Post-trade market value is a product of the powerfuel/chemical output and post-trade LCOF as summarised in Eq. 4. The difference between the two is the obtainable cost reduction excluding shipping costs.

Shipping costs are found by multiplying total imported volume by powerfuel/chemical shipping costs. Assumed shipping costs of powerfuels/chemicals are as follows:

- LNG: 3.7 €/MWh;
- FT fuels: 1.5 €/MWh;
- Ammonia: 5 €/MWh;
- Methanol: 3.7 €/MWh.

The shipping costs are based on estimates for long-distance shipping of up to 18,000 km, as discussed for LNG in Fasihi et al.[33], FT fuels in Fasihi et al.[65], methanol in Fasihi and Breyer[40], and an estimation for ammonia based on the other three powerfuels/chemicals.

Annex D

Limitations, uncertainties and possible improvements

This research on the global trading of powerfuels is the first of its kind, and therefore it not only presents new insights, but also identifies areas for further improvement.

This study estimates the average cost of powerfuels production in a region by considering weighted averaged solar PV and wind yield profiles. This approach assumes the existence of a power grid connecting generation sites across the country and providing the electricity supply to powerfuels synthesis units. Distributed grids make it possible to significantly decrease the variability of renewable electricity generation and in turn reduce storage demand. At the same time, with this approach the cost of powerfuels production at the best sites of a region is not defined. The best sites within a region could be better identified by using higher spatial resolution, possibly resulting in a lower LCOF, if the least-cost sites are available for installing solar PV or wind turbines. However, this uncertainty could be lower than the uncertainty regarding the cost of synthesis units assumed for all powerfuels.

The powerfuels demand assumption also has a significant impact on the calculated LCOF. Slower growth of the production of powerfuels would result in lower LCOF due to a lower share of synthesis capacities installed in early periods, while the cost of all equipment involved is higher. However, a slower uptake of powerfuels would lead to unrealistically rapid installation rates in later periods or failing to achieve the target of defossilising the energy system by 2050.

The transportation costs of powerfuels are equalised based on one of the longest possible shipping routes in the world. In addition, the shipping cost of ammonia and methanol could be further reduced if larger energy carriers were used, realising further economies of scale. Applying the case-specific marine distance of each exporting and importing region, fuel/chemicals-specific loading/unloading costs, as well as considering large-scale energy carriers could lower the shipping costs. However, the impact on the results is not expected to be significant, as shipping costs assumed are already low.

The impact of pipeline delivery is not considered in this research, which could lower the costs of traded fuels among neighbouring countries and regions. However, in a solar PV dominated world, most of the countries within a broader region are expected to have less variation in LCOF, thus the case may not be particularly relevant from a cost perspective, while area availability aspects may factor in. The substitution of SNG/LNG demand by hydrogen may drastically reduce the demand for SNG/LNG. This is expected to increase the share of self-production and consumption, since hydrogen has a relatively higher shipping cost but lower production cost, while technological uncertainty is still high. Hydrogen shipping is therefore not considered in this research. Demand-wise, the considered LNG and FT fuels for marine transportation may be too high, since ammonia and methanol are increasingly discussed as a major future fuel for marine transportation. While this could change the relative share of each powerfuel and RE-chemical, it would have almost no impact on the relevance of powerfuels, and the aggregated demand.

The uniformly considered WACC imposes some uncertainties. However, the attractiveness factor reflects the localised WACC to some extent for exporting countries. In addition, large international investors would equalise the WACC, in reality via various financing tools.

Locally deployed large-scale electrolysers could provide additional flexibility and value in energy systems with further improved sector coupling. As a result, some currently importing countries may prefer more local production, while reducing their balancing fuel demand or curtailed electricity.

Annex E

Regions

The 92 regions/countries in this study are based on Bogdanov et al.[53] and listed below, further structured into nine major regions, with the abbreviation for respective country and countries for regions with more than one country.

Abbr	Countries
Europe	
NO	Norway
DK	Denmark
SE	Sweden
FI	Finland
BLT	Baltic: Estonia, Latvia, Lithuania
PL	Poland
IBE	Iberia: Portugal, Spain, Gibraltar
FR	France, Monaco, Andorra
BNL	Belgium, Netherlands, Luxembourg
BRI	British Isles: Ireland, United Kingdom, Isle of Man, Guernsey, Jersey
DE	Germany
CRS	Czech Republic, Slovakia
AUH	Austria, Hungary
BKN-W	Balkan-West: Slovenia, Croatia, Bosnia and Herzegovina, Serbia, Montenegro, Macedonia, Albania
BKN-E	Balkan-East: Romania, Bulgaria, Greece
IT	Italy, San Marino, Vatican, Malta
CH	Switzerland, Liechtenstein
TR	Turkey, Cyprus
UA	Ukraine, Moldova
IS	Iceland
Eurasia	
RU	Russia
BY	Belarus
CAU	Armenia, Azerbaijan, Georgia
KZ	Kazakhstan

Abbr	Countries
PAM	Tajikistan, Kyrgyzstan
UZ	Uzbekistan
TM	Turkmenistan
MENA	
DZ	Algeria
BHQ	Bahrain and Qatar
EG	Egypt
IR	Iran
IQ	Iraq
IL	Israel
JWG	Jordan (incl. West Bank & Gaza Strip = State of Palestine)
KW	Kuwait
LB	Lebanon
LY	Libya
MA	Morocco
OM	Oman
SA	Saudi Arabia
TN	Tunisia
AE	United Arab Emirates
YE	Yemen
SY	Syria
Sub-Saharan Africa (SSA)	
WW	Senegal, Gambia, Cape Verde Islands, Guinea Bissau, Guinea, Sierra Leone, Liberia, Mali, Mauritania, Western Sahara
WS	Ghana, Côte d'Ivoire, Benin, Burkina Faso (Upper Volta), Togo
WN	Niger, Chad

Abbr	Countries
NIG	Nigeria
SER	Sudan, Eritrea
ETH	Ethiopia
SOMDJ	Djibouti, Somalia
KENUG	Kenya, Uganda
TZRB	Rwanda, Burundi, Tanzania
CAR	Central African Republic, Cameroon, Equatorial Guinea, Sao Tome and Principe, Congo, Republic of Gabon
COG	Congo, Democratic Republic
SW	Angola, Namibia, Botswana
ZAFLS	Republic of South Africa, Lesotho
SE	Malawi, Mozambique, Zambia, Zimbabwe, Swaziland
IOCE	Comoros Islands, Mauritius, Mayotte, Madagascar, Seychelles
SAARC	
IN	India
BD	Bangladesh
NP + BT	Nepal and Bhutan
PK	Pakistan
AF	Afghanistan
LK	Sri Lanka
Northeast Asia	
JP	Japan
KR	South Korea (Republic of Korea)
KP	North Korea (DPR of Korea)
CN	China
MN	Mongolia

Abbr	Countries
Southeast Asia	
NZ	New Zealand
AU	Australia
ID + PNG + TL	Indonesia, Papua New Guinea and Timor Leste
MY+SG+BN	Malaysia, Singapore and Brunei
PH	Philippines
MM	Myanmar
TH	Thailand
LA	Laos
VN	Vietnam
KH	Cambodia
North America	
CA	Canada
US	United States of America
MX	Mexico
South America	
CAM	Panama, Costa Rica, Nicaragua, Honduras, El Salvador, Guatemala and Belize
CO	Colombia
VE	Venezuela, Guyana, French Guiana, Suriname
EC	Ecuador
PE	Peru
CSA	Bolivia and Paraguay
BR	Brazil
AR + UR	Argentina and Uruguay
CL	Chile

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Abbreviations

A-CAES	Adiabatic compressed air energy storage
BECCS	Bioenergy carbon capture and storage
BEV	Battery electric vehicle
CAES	Compressed air energy storage
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CSP	Concentrated solar thermal power
DAC	CO_2 direct air capture
DACCS	Direct air carbon capture and storage
DH	District heating
DME	Dimethyl ether
FCEV	Fuel cell electric vehicle
FLH	Full load hours
FT	Fischer-Tropsch
GECF	Gas Exporting Countries Forum
GHG	Greenhouse gas
GT	Gas turbine
GW	Gigawatt
HDV	Heavy-duty vehicle
HHB	Hot heat burner
HT	High temperature
HVAC	High voltage alternating current
HVDC	High voltage direct current
ICE	Internal combustion engine
IEA	International Energy Agency
IH	Individual heating
LCOC	Levelised cost of curtailment
LCOE	Levelised cost of electricity
LCOH	Levelised cost of heat
LCOS	Levelised cost of storage
LCOT	Levelised cost of transmission
LCOW	Levelised cost of water
LDV	Light-duty vehicle
LNG	Liquefied natural gas
LT	Low temperature
MDV	Medium-duty vehicle
MED	Multiple-effect distillation
MSF	Multi-stage flash
MT	Medium temperature
MW	Megawatt
OCGT	Open cycle gas turbine
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operational expenditures
PHEV	Plug-in hybrid electric vehicle
PHES	Pumped hydro energy storage
PP	Power plant
PtG	Power-to-gas
PtH	Power-to-heat
PtL	Power-to-liquids
PtX	Power-to-X
PV	Photovoltaics
RE	Renewable energy
R/O	Reverse osmosis (seawater)
SNG	Synthetic natural gas
ST	Steam turbine
TES	Thermal energy storage
TPED	Total primary energy demand
TW	Terawatt
TTW	Tank-to-wheels

German Energy Agency