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Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities

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HIGHLIGHTS

- Comprehensive database for global production and supply costs with projections until 2050.
- Production costs are the significant cost component for liquid or easily liquefiable energy commodities.
- Green hydrogen might be traded regionally via pipeline rather than shipped globally via LH_2.
- Importing green ammonia is more cost-efficient than importing green hydrogen for domestic ammonia production in Germany.
- Germany: Only if a low-cost European H_2 pipeline grid exists could ammonia production from imported H_2 be cost-effective.

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ABSTRACT

Green energy commodities are expected to be central in decarbonising the global energy system. Such green energy commodities could be hydrogen or other hydrogen-based energy commodities produced from renewable energy sources (RES) such as solar or wind energy. We quantify the production cost and potentials of hydrogen and hydrogen-based energy commodities ammonia, methane, methanol, gasoline, diesel and kerosene in 113 countries. Moreover, we evaluate total supply costs to Germany, considering both pipeline-based and maritime transport. We determine production costs by optimising the investment and operation of commodity production from dedicated RES based on country-level RES potentials and country-specific weighted average costs of capital. Analysing the geographic distribution of production and supply costs, we find that production costs dominate the supply cost composition for liquid or easily liquefiable commodities, while transport costs dominate for gaseous commodities. In the case of Germany, importing green ammonia could be more cost-efficient than domestic production from locally produced or imported hydrogen. Green ammonia could be supplied to Germany from many regions worldwide at below the cost of domestic production, with costs ranging from 624 to 874 \$/t NH_3 and Norway being the cheapest supplier. Ammonia production using imported hydrogen from Spain could be cost-effective if a pan-European hydrogen pipeline grid based on repurposed natural gas pipelines exists.

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Introduction

Many countries decarbonise their energy systems by using renewable energies to mitigate climate change and achieve a sustainable energy supply. Renewable energy sources (RES), in particular wind and solar energy, can be used to produce green electricity. In addition to green electricity, hydrogen and hydrogen-based green energy commodities are projected to play a significant role in the decarbonisation of so-called hard-to-abate sectors, where direct electrification is difficult. Applications for synthetic green energy commodities could be long-term energy storage, feedstock for industrial processes and use as fuel in heavy duty transport or aviation [1].

Production potentials for green energy commodities are distributed unevenly around the globe. Countries with a high energy demand do not necessarily have access to large RES potentials. Germany, for example, would have to continue to rely on energy imports as part of a cost-effective decarbonisation strategy [2–7]. Even in the long term, Germany will probably have to cover up to half of its energy demand using molecule-based energy carriers [3]. A considerable part of these molecule-based energy carriers might be synthetic green energy commodities due to limited sustainable biomass potentials. Green hydrogen plays a central role. Hydrogen can be used energetically or as a feedstock for hydrogen-based commodities such as ammonia, methane, methanol or Fischer-Tropsch fuels like synthetic kerosene, gasoline or diesel.

Many hydrogen-based energy commodities have physical properties that make them easier to transport and store than hydrogen. At ambient conditions, gaseous energy carriers such as hydrogen and methane are more difficult to transport than liquid, or easily liquefiable energy carriers such as methanol, kerosene, or ammonia. In addition, hydrogen has a volumetric energy density three times lower than methane. Both methane and hydrogen can be liquefied for maritime transport. However, the temperatures required to liquefy hydrogen are significantly lower than for methane, making the shipping of liquid hydrogen more energy-intensive and expensive. Furthermore, hydrogen-based commodities such as methane, methanol, ammonia or Fischer-Tropsch products are substitutes for fossil energy carriers and can use existing infrastructure for transport.

The quantification of supply costs requires an assessment of the entire supply chain. Several studies have analysed production and transport costs for hydrogen and hydrogen-based energy carriers. Fasihi et al. [8] investigate costs for renewable power-to-liquid (PtL) fuels from PV wind hybrid sources in 2030. They evaluate production costs by modelling approach an integrated 5 GW_e plant consisting of electrolysis, direct air capture (DAC) as CO_2 source, Fischer-tropsch synthesis and battery storage. In a first step, the capacities of the plant components are optimised. Based on these optimal capacities, the operation of the plant is then optimised to minimise the production costs. The authors analyse a potential PtL supply chain from Patagonia to Rotterdam and find that PtL supply costs are 84 $/MWh. They also investigate the sensitivity of investment risks on production costs: changing the weighted average costs of capital (WACC) from 5% to 7% increases the overall supply costs by 14.5%.

Agora Verkehrswende, Agora Energiewende and Frontier Economics [9] published a study estimating supply costs for power-to-methane and PtL-fuels from North Africa, the Middle East, Iceland and the North and Baltic Seas to Germany until 2050 for three different scenarios. While the study considers direct air capture (DAC) as a CO_2 source, the corresponding spreadsheet model by Frontier Economics [10] also considers carbon capture from the cement industry as an alternative option.

Another study by Frontier Economics [11] analyses global production and export potentials of hydrogen and hydrogen-based commodities. Countries are assessed based on three criteria: firstly, costs of generating RES electricity, secondly area-specific resource potentials, and thirdly political stability, energy political framework and trade. The study identifies promising exporting countries to Europe and Germany based on these criteria. Detailed case studies are carried out for the exporter countries Norway, Chile, Morocco, Saudi Arabia, Australia and China. The study does not provide production or supply cost estimates.

Hank et al. [12] investigate the costs and energy efficiency of hydrogen and hydrogen-based commodities methane, methanol and ammonia while also considering liquefied hydrogen (LH_2) and hydrogen bound in liquid organic hydrogen carriers (LOHC) for transport for a baseline and an optimistic scenario in 2030. The paper provides energy efficiencies of the respective supply chains, including production from integrated plants (including excess heat integration) and long-distance maritime transport. Moreover, production and maritime transport costs from Morocco to Germany are evaluated in detail. They find that commodities with high energy efficiencies and low production costs are LH_2 (52–60%, 149 $/MWh) and ammonia (48–52%, 146 $/MWh). All other analysed commodities are more costly in production and have a lower energy efficiency.

Brändle et al. [13] estimate the development of global production and supply cost of low-carbon hydrogen from wind and solar energy sources as well as from natural gas with carbon capture and storage (CCS) and methane pyrolysis in 90 countries. An optimisation model minimises hydrogen production costs by determining optimal capacity ratios for electrolyse-RES systems. The results are accessible and customisable in a comprehensive spreadsheet model [14]. The authors find that hydrogen supply costs are likely to vary substantially from country to country, depending on natural gas prices, RES potentials and access to existing pipeline networks which may be retrofitted to carry hydrogen. They conclude that due to the high costs of maritime hydrogen transport, international trade in pure hydrogen is more likely to develop along pipeline networks.

Pfennig et al. [15] use a geospatial information system (GIS)-based approach to estimate production costs and potentials and their geographical location. The study covers hydrogen and hydrogen-based methanol, methane and PtL fuels. The authors use GIS to identify suitable areas for low-cost solar and wind energy production. Potentials are further refined by applying criteria relating to land use, distance to settlements and infrastructure, and ecological restrictions. The authors evaluate cost-optimal production systems, including battery storage in exporting countries and the

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supply costs to the EU. Moreover, the study contains a socio-economic analysis of exporting countries. The results are available in a comprehensive and customisable web application [16].

Various publications deal with the estimation of transport costs for hydrogen and hydrogen-based energy commodities. Raab et al. [17] provide a techno-economic evaluation of large-scale hydrogen transport, comparing liquid hydrogen and two LOHC, namely methyl cyclohexane and hydrogenated dibenzyl toluene. They estimate hydrogen transport costs from Australia to Germany in the range of 1.58–4.30 $/kg$_{H2}$. Johnston et al. [18] conduct a detailed cost analysis of the supply chain of hydrogen, methane, ammonia, and methanol from Australia to various destinations. The analysis considers liquid hydrogen and LOHC (methyl cyclohexane and hydrogenated dibenzyl toluene) as transport options for pure hydrogen. They estimate transport costs from Australia to the Netherlands of 2.09 $/kg$_{H2}$ via liquid hydrogen transport and 0.56 $/kg$_{H2}$ via transporting ammonia as a hydrogen carrier. They do not include costs for the reconversion of ammonia to hydrogen in the destination country. Di Lullo et al. [19] estimate land transportation costs of hydrogen for various systems. These systems include hydrogen pipelines, blending hydrogen into the natural gas grid, ammonia pipeline transport, LOHC transport via pipeline, trucks, and trailers, as well as compressed or liquid hydrogen transport via trucks. They put transport costs in relation to the GHG emission intensity of the transport route, showing that pipeline transport might be the most suitable option for large-scale land transportation of hydrogen.

There are considerable differences between the scope, the level of detail and the number of hydrogen-based energy commodities covered in the existing literature. None of the reviewed publications apply country-specific WACC, despite the production cost's high sensitivity towards the WACC [8] and significant socio-economic differences between countries [15]. Only two studies provide energy balances of the production- and transport routes [8,12]. Some studies contain detailed production- and supply costs but for a limited amount of countries [8,10]. All works consider DAC, but only one study assesses additional CO2 sources [10]. Just two of the reviewed studies provide production cost and the corresponding potentials i.e., producible quantities [13,16].

We add to and expand on the existing literature by quantifying the production cost and potentials of hydrogen, ammonia, methane, methanol, and Fischer-Tropsch based fuels for 113 countries globally. We combine this with an assessment of transport costs and derive a cost-based ranking of suppliers for each commodity for Germany as a case study.

We determine production costs by optimising the investment and operation of green energy commodity production from dedicated renewables based on a country-specific RES time series and country-specific weighted average costs of capital. Moreover, we quantify supply costs to Germany. Key results are presented in this paper. Our entire set of results is available for download in a spreadsheet tool (Microsoft Excel).[1]

[1] Check here for updates: https://www.ewi.uni-koeln.de/en/publications/globales-ptx-produktions-und-importkostentool/.

The paper is structured as follows: Section 2 describes key assumptions and explains the underlying methodology. Section 3 presents a sensitivity analysis, as well as an assessment of the production costs and the supply costs to Germany for the commodities hydrogen, ammonia, methanol and methane in 2030. The analysis focuses on mid-term supply options of green ammonia for Germany. Subsequently, we discuss the limitations of our study. Overall conclusions are presented in section 4.

Methodology

The model presented in the paper at hand is an extension of the model developed by Brändle et al. [13], which minimises the levelised cost of hydrogen produced from a combination of an intermittent RES with an electrolyser and is applied to estimate levelised cost of hydrogen (LCOH) ranges for different combinations of RES and electrolysers for 89 countries. We expand the model to optimise the production of four synthetic hydrogen-based energy commodities: ammonia, methanol, methane and Fischer-Tropsch liquids. In addition to a RES and an electrolyser, the model now incorporates hydrogen storage, and further conversion of hydrogen to a hydrogen-based energy commodity such as methane or ammonia.

Furthermore, we extend the dataset built by Brändle et al. [13] to 113 countries and introduce country-specific weighted average costs of capital estimates to analyse the impact of differences in financing costs and country risk on the respective green energy commodities' levelised production cost (LCOF).

Model

We calculate the minimum LCOF for all combinations of commodity *i*, country *n*, RES *res*, RES resource class *r* and year *y* by applying a linear optimisation model that optimises the ratio of the capacity of the individual components of a given production process, considering CAPEX and OPEX of the electrolyser, CAPEX and OPEX of a pressurised hydrogen tank storage to exploit flexible operation of the electrolyser and the hydrogen conversion plant, the CAPEX and OPEX of the green hydrogen-based commodity synthesis plant, CAPEX and OPEX cost of the RES, as well as the load profile and capacity factor of the RES. Fig. 1 shows a flowsheet of the links between the individual components of the plant optimised in the model.

The model is described by equations (1)–(8).

$$\min_{C^{el}_{n,r,y},C^{sto}_{n,r,y},C^{con}_{n,r,y},C^{res}_{n,r,y}} TC^{el,sto,con,res}_{n,r,y} \tag{1}$$

s.t.

$$Q^{H2}_{n,r,y,h} + Q^{con}_{n,r,y,h} * e^{con} \le C^{res}_{n,r,y} * CF^{res}_{n,r,h} * \eta^{el}_{y} \tag{2}$$

$$Q^{H2}_{n,r,y,h} \le C^{el}_{n,r,y} * \eta^{el}_{y} \tag{3}$$

$$L^{H2}_{n,r,y,h} \le C^{sto}_{n,r,y} \tag{4}$$

$$Q^{con}_{n,r,y,h} \le C^{con}_{n,r,y} * \eta^{con}_{y} \tag{5}$$

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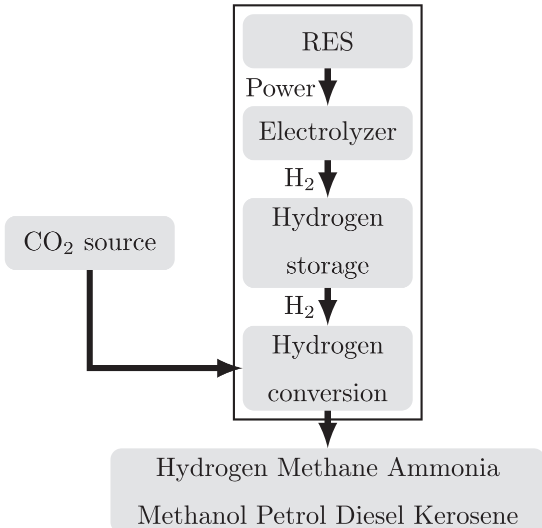

Fig. 1 – Flowsheet of the links between the individual components in the optimisation model for the production of green hydrogen and hydrogen-based energy commodities. The capacity and operation of components inside of the box is endogenously optimised.

$$Q^{con}_{n,r,y,h} \leq (Q^{H2}_{n,r,y,h} + F^{H2}_{n,r,y,h})*\eta^{con}_{y} \tag{6}$$

$$L^{H2}_{n,r,y,h} = L^{H2}_{n,r,y,h-1} + F^{H2}_{n,r,y,h} \tag{7}$$

$$\sum_{n=h}^{8760} Q^{con}_{n,r,y,h} = D^{i}_{n,r,y} \tag{8}$$

$TC^{i,el,sto,con,res}_{n,r,y}$ is the total cost of production of commodity i by the combination of electrolyser el, hydrogen storage sto, hydrogen conversion process con and RES technology res in year y, country n and resource class r, defined by:

$$\begin{aligned} TC^{el,sto,con,res}_{n,r,y} = {} & \underbrace{(CAPEX^{res}_{n,y}*a^{res}_{n} + OPEX^{res}_{n,y})*C^{res}_{n,r,y}}_{\text{RES cost}} \\ & \underbrace{+(CAPEX^{el}_{y}*a^{el} + OPEX^{el}_{y})*C^{el}_{n,r,y}}_{\text{Electrolysis cost}} \\ & \underbrace{+(CAPEX^{sto}_{y}*a^{sto})*C^{sto}_{n,r,y}}_{H_2\ \text{storage cost}} \\ & \underbrace{+(CAPEX^{con}_{y}*a^{con} + OPEX^{con}_{y})*C^{con}_{n,r,y}}_{H_2\ \text{conversion cost}} \end{aligned} \tag{9}$$

where.

$a^{res,el,sto,con}$ is the capital recovery factor used to convert renewable energy generator (res) electrolyser (el), hydrogen storage (sto) or hydrogen conversion process (con) investment costs into annual costs,
$C^{el}_{n,r,y}$ is the installed electrolyser (el) capacity in year y, country n and resource class r (expressed in kW-electric),
$C^{sto}_{n,r,y}$ is the installed hydrogen storage (sto) capacity in year y, country n and resource class r (expressed in kW-H_2),
$C^{con}_{n,r,y}$ is the installed hydrogen conversion (con) capacity in year y, country n and resource class r (expressed in kW-H_2),
$C^{res}_{n,r,y}$ is the installed RES (res) capacity in year y, country n and resource class r (expressed in kW-electric),
η^{el}_{y} is the efficiency of electrolyser el in year y in %,
η^{con}_{y} is the efficiency of the hydrogen conversion process con in year y in %,
e^{con} is the electricity consumption of the hydrogen conversion process,
$CF^{res}_{n,r,h}$ is the capacity factor of RES type res in hour h, country n and resource class r, with $h = \{1, 2, \ldots, 8760\}$, the generation of hourly profiles is described in Ref. [13],
$Q^{H2}_{n,r,y,h}$ is the H_2 production of the respective combination of RES technology res, and electrolyser el in country n, resource class r, year y and hour h.
$Q^{con}_{n,r,y,h}$ is the fuel production of the respective combination of RES technology res, electrolyser el, hydrogen conversion process con, and hydrogen storage sto in country n, resource class r, year y and hour h.
$F^{H2}_{n,r,y,h}$ are the net storage flows of the respective combination of RES technology res, electrolyser el, hydrogen conversion process con, and hydrogen storage sto in country n, resource class r, year y and hour h,
$L^{H2}_{n,r,y,h}$ is the hydrogen storage level in country n, resource class r, year y and hour h and
$D^{i}_{n,r,y}$ is the demand in country i, resource class r and year y. Since all investment cost functions are linear functions of the capacity, $D^{i}_{n,r,y}$ can be any positive number.

The optimal ratio of RES-to-electrolyser capacity $S^{*el,res}_{n,r,y}$ that yields the lowest LCOH ($LCOH^{*el,res}_{n,r,y}$) for a combination of res and el in country i, resource class r and year y is given as

$$S^{*el,res}_{n,r,y} = \frac{C^{*res}_{n,r,y}}{C^{*el}_{n,r,y}}, \tag{10}$$

where $C^{*el}_{n,r,y}$ is the optimal installed el capacity in year y, country n and resource class r and $C^{*res}_{n,r,y}$ is the optimal installed res capacity in year y, country n and resource class r. The $LCOH^{*el,res}_{n,r,y}$, expressed in \$/kg of hydrogen, is computed as

$$LCOH^{*el,res}_{n,r,y} = LHV*\frac{TC^{*el,res}_{n,r,y}}{\sum_{n=h}^{8760} Q^{*res,el}_{n,r,y,h}} \tag{11}$$

where LHV is the lower heating value of hydrogen (33.33 kWh/kg). The mean yearly capacity factor of the electrolyser el in optimum is obtained by

$$CF^{*el}_{n,r} = \frac{\sum_{n=h}^{8760} Q^{*res,el}_{n,r,y,h}}{C^{*el}_{n,r,y}*8760} \tag{12}$$

Assumptions and data

This section provides a detailed description of assumptions and data. Country-specific assumptions are hourly RES profiles, RES potentials and WACC. A detailed description of the methodology for hourly RES profiles and potentials can be found in Brändle et al. [13]. Country-specific WACC are taken from Finance 3.1 [20]. We use WACC data for the oil & gas

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sector as we prospect that the oil & gas sector might be the most similar existing sector to a future hydrogen and hydrogen-based green energy commodities sector. A detailed description of the transport cost calculation can be found in Appendix A. Fig. 2 gives an overview of the methodology. What follows is a description of the techno-economic assumptions for production cost calculation.

Table 1 displays the techno-economic assumptions used for hydrogen and hydrogen conversion plants. All costs are given in $\$_{2019}$ and all calorific units refer to the lower heating value. CAPEX and the specific hydrogen demand for hydrogen-to-methane plants based on catalytic methanation are taken from Brynolf et al. [21], the power demand for compression is adopted from Tremel et al. [22]. The Fischer-Tropsch (FT) process produces several products (synthetic petrol, kerosene and diesel) and is therefore subsumed as a hydrogen-to-liquid plant. CO-FT processes utilise syngas consisting of carbon monoxide and hydrogen as feed. With a suitable catalyst, the FT process can directly convert a feed of hydrogen and carbon dioxide without major process modifications [31,32]. CO_2-FT process require less upstream processing than a CO-FT process, since no feedstock pretreatment, gasification, air separation unit (ASU) and gas cleaning unit are necessary. Hannula and Kurkela [23] provide detailed capital costs for a CO-FT process based on biomass feedstock. We estimate the CAPEX for a CO_2-FT process by deducting the investment costs for equipment required for the upstream processing of syngas. Moreover, Hannula and Kurkela [23] present five different FT process designs, of which four produce surplus electricity. Thus, we assume an external electricity demand of zero for the FT process. The specific CO_2 demand of a FT process cannot be estimated from stoichiometry alone, as the process conditions influence which chemical reaction is predominant. We adopt an estimate by Ram et al. [25] for this work. For other hydrogen conversion processes in Table 1 we estimate the specific CO_2 demand by stoichiometry and assume that 1 mol-% of the stoichiometric CO_2 demand is purged. In the case of hydrogen-to-methanol, we adopt CAPEX, power demand and efficiency from Pérez-Fortes et al. [26] who provide a detailed quasi-isothermal methanol synthesis process design utilising CO_2 as raw material. To estimate CAPEX, efficiency and power demand of the Haber-Bosch process used to produce ammonia from hydrogen, we take the plant model developed by Moritz et al. [27]. Unlike hydrocarbons, the stoichiometry of ammonia does not contain carbon but nitrogen. The combustion or chemical conversion of ammonia thus does not lead to CO_2-emissions. We assume that nitrogen for ammonia production is extracted from the air by an ASU. CAPEX for the ASU is taken from Dry [28] while the electricity demand of the ASU is adopted from Bazzanella and Ausfelder [29]. Synthetic hydrocarbons are only carbon-neutral if the carbon required for synthesis is biogenic or has been removed from the air by direct air capture (DAC). Due to the low concentration of CO_2 in the air, DAC is more energy and cost-intensive than nitrogen production by ASU. We consider low-temperature solid sorbent direct air capture as carbon capture technology. All technical and economical parameters, as well as CAPEX reduction pathways, are adopted from Fasihi et al. [30]. For all the aforementioned processes, we assume fixed operation and maintenance (FOM) costs of 4% of the annual CAPEX in accordance with literature [1, 21, 29].

Except for electrolysis and DAC, CAPEX values for 2021 are taken from peer-reviewed literature and scaled to a plant capacity of 50 $MW_{product}$ for the baseline scenario and 100 $MW_{product}$ for the optimistic scenario. We estimate the influence of plant scale on capital costs by the seven-tenth rule [33]:

$$\text{Cost of plant A} = \text{Cost of plant B}\left(\frac{\text{Capacity of plant A}}{\text{Capacity of plant B}}\right)^{0.7} \qquad (13)$$

We assume that CAPEX declines for all technologies except DAC and electrolysis are mainly due to scale effects. The typical scale of plants is expected to increase over time due to

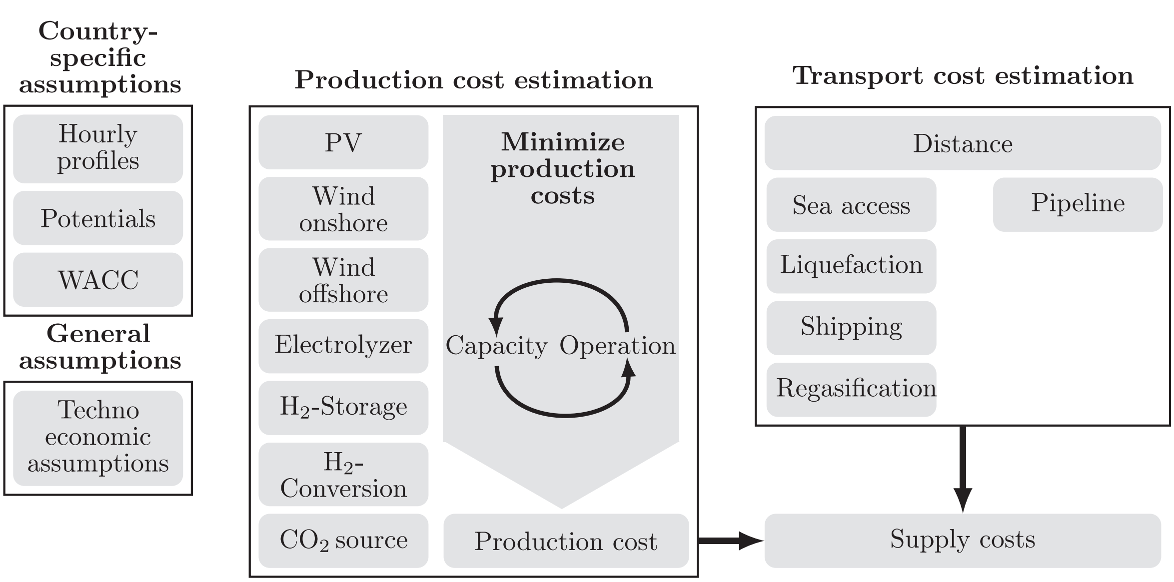

Fig. 2 – Methodology for estimating the long-term supply cost of the green energy commodities hydrogen, ammonia, methane, methanol and FT-products.

Table 1 – Techno-economic assumptions for hydrogen generation and hydrogen conversion plants. CAPEX are given for scenarios baseline/optimistic, respectively.

			2021	2030	2040	2050	
Power-to-hydrogen							
by low temperature	CAPEX	$\$_{2019}/kW_{H_2}$	1429/752	919/588	752/420	600/267	[13]
water electrolysis	FOM	% of CAPEX/a	2	2	2	2	[13]
	Power demand	kW_{H_2}/kW_{el}	0.67	0.68	0.72	0.75	[13]
	Lifetime	a	25	25	25	25	[13]
Hydrogen-to-methane							
by cathalytic methanation	CAPEX	$\$_{2019}/kW_{CH_4}$	400/325	310/214	271/181	247/163	[21]
	FOM	% of CAPEX/a	4	4	4	4	
	Power demand	kW_{el}/kW_{CH_4}	0.01	0.01	0.01	0.01	[22]
	Hydrogen demand	kW_{CH_4}/kW_{H_2}	0.75	0.75	0.76	0.77	[21]
	Lifetime	a	25	25	25	25	
	CO_2 demand	kg_{co_2}/kWh_{CH_4}	0.2	0.2	0.2	0.2	
Hydrogen-to-liquid*							
by Fischer-Tropsch process	CAPEX	$\$_{2019}/kW_{liquid}$	1630/1324	1264/873	1104/738	1006/664	[23]
*petrol, diesel, kerosene	FOM	% of CAPEX/a	4	4	4	4	
	Hydrogen demand	kW_{liquid}/kW_{H_2}	0.71	0.71	0.72	0.73	[22,24]
	Lifetime	a	25	25	25	25	
	CO_2 demand	kg_{co_2}/kWh_{liquid}	0.27	0.27	0.27	0.27	[25]
Hydrogen-to-methanol							
by quasi-isothermal	CAPEX	$\$_{2019}/kW_{MeOH}$	1130/918	876/606	765/512	697/460	[26]
methanol synthesis	FOM	% of CAPEX/a	4	4	4	4	
	Power demand	kW_{el}/kW_{MeOH}	0.27	0.27	0.27	0.27	[26]
	Hydrogen demand	kW_{MeOH}/kW_{H_2}	0.83	0.83	0.84	0.85	[26]
	Lifetime	a	25	25	25	25	
	CO_2 demand	kg_{co_2}/kWh_{MeOH}	0.25	0.25	0.25	0.25	
Hydrogen-to-ammonia							
by Haber-Bosch process	CAPEX	$\$_{2019}/kW_{NH_3}$	1332/1082	1033/714	902/603	822/542	[27, 28]
	FOM	% of CAPEX/a	4	4	4	4	
	Power demand	kW_{el}/kW_{NH_3}	0.29	0.29	0.29	0.29	[27, 29]
	Hydrogen demand	kW_{NH_3}/kW_{H_2}	0.85	0.85	0.85	0.85	[27]
	Lifetime	a	25	25	25	25	
CO_2 Direct Air Capture							
by temperature swing adsorption	CAPEX	$\$_{2019}/(t_{CO_2}/a)$	7793/7793	3608/2018	2914/1174	2124/897	[30]
(low-temperature solid	FOM	% of CAPEX/a	4	4	4	4	
sorbent)	Power demand	kW_{el}/t_{CO_2}	250	225	203	182	[30]
	Heat demand	kW_{th}/t_{CO_2}	1850	1500	1286	1102	[30]
	Lifetime	a	25	25	25	25	

the market ramp-up for synthetic fuels. We assume the typical plant capacity to increase from 50 $MW_{product}$ in 2021 to 250 $MW_{product}$ in 2050 in the baseline scenario and from 100 $MW_{product}$ to 1000 $MW_{product}$ in the optimistic scenario. A capacity of 1000 $MW_{product}$ corresponds to 10% of an average refineries' capacity in the present [34] and is chosen based on the authors' assessment that the global production of synthetic fuels is unlikely to reach the scale of present-day fossil fuel production.

Results & discussion

In this section, we present the key results of our cost analysis. Section 3.1 provides an overview of the global production costs of the green energy commodities hydrogen, ammonia, methanol and methane in 113 countries. Section 3.2 describes supply costs (including transport) from these origin countries to Germany. Section 3.3 provides more details on the supply costs of ammonia to Germany. Finally, section 3.4 discusses the limitations of our analysis, which could be addressed through further research.

It is important to note that the green energy commodities analysed in the following are not compared against each other in terms of the absolute level of costs since they are not substitutes. Each of the four commodities have different uses. However, comparing relative characteristics like the relation between production and supply costs helps to gain an understanding what commodities are more likely to be traded regionally or globally and what countries are possible suppliers.

Global green energy commodity production costs

The analysis at hand compares two scenarios for the development of future green energy commodity production costs, a baseline and an optimistic scenario. We analyse the LCOF for hydrogen, ammonia, methanol and methane in 113 countries. As mentioned before, each of the four commodities has different physical characteristics and addresses different markets in terms of demand, hence absolute costs are not comparable. However, a comparison of relative cost characteristics helps to understand differences between the commodities and the respective countries. The LCOF shown in this

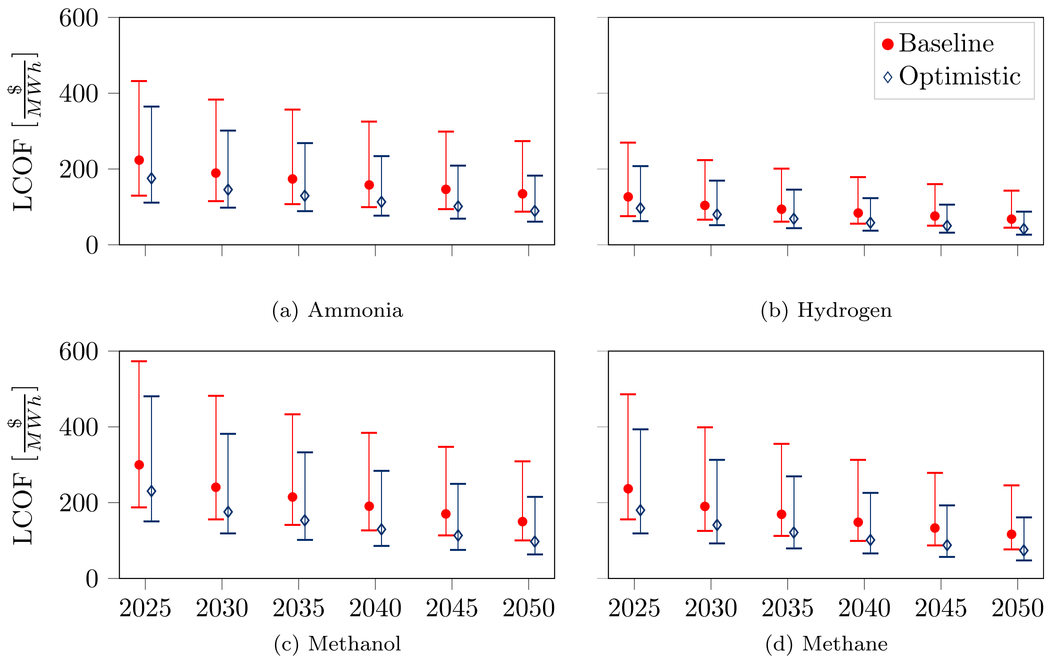

Fig. 3 – Comparison of the LCOF for 113 countries for the baseline and optimistic scenarios. The whiskers represent the minimum and maximum of the distribution, marks denote the average.

section is the weighted average cost of producing a quantity of 100 TWh/a of a commodity (assuming that the most economical RES potentials are used to cover a countries historical electricity consumption and are thus not available for the production of green energy commodities, see Appendix B. If not stated otherwise, Figures in the section show results for the year 2030 and the baseline scenario and for hydrogen pipeline transport by retrofitted natural gas pipeline. Countries which have a production potential of less than 100 TWh/a or that are not included in our analysis are greyed out.

Fig. 3 compares the LCOF in the two scenarios for different years. We observe that, on average, methanol has the highest and hydrogen has the lowest LCOF. In the case of methanol, the high LCOF are due to the investment costs and energy consumption of methanol production, which are the highest among the analysed commodities. Thus, WACC and capacity factors for renewables significantly impact the LCOF, leading to a wide range in the distribution of costs across countries. Furthermore, methanol, but also methane, require carbon that is not from a fossil source. With DAC, it is produced by a comparably cost-intensive process.[2] Hydrogen has the lowest energy demand and investment cost of the four commodities shown in Fig. 3 since only electrolysis is required to produce it.

We observe a general decrease in the LCOF over time for all commodities in both scenarios. This trend reflects the reduction of the investment costs for RES, electrolysis and the main components of subsequent hydrogen conversion plants, and hence the respective learning curve of each technology. This is further reinforced by increasing energy efficiency in electrolysis and most hydrogen conversion plants. However, no further learning is anticipated for technologically mature peripheral equipment like piping and instruments, as well as the construction of buildings.

Fig. 4 presents the LCOF of the green energy commodities hydrogen, ammonia, methanol and methane in 2030 in a separate map for each commodity. The LCOF is referenced to a colour code, where green to yellow denotes the lower half and yellow to red is the upper half of the cost distribution. We cluster the countries into classes using the Fischer-Jenks method for visual presentation. Using eight classes provides a meaningful illustration of the global cost range. The intervals of the classes and the related colour is given on the left-hand side of each map. Moreover, the distribution of the global LCOF of the respective green energy commodity is presented by a boxplot diagram on the right-hand side of each map.

The analysis shows that countries with good RES potentials and a low WACC are best suited for the production of RES-based green energy commodities, as the capacity factor and the hourly profiles of the RES as well as the WACC are the primary cost drivers. Fig. 4 shows that Norway, Morocco, and France have the lowest LCOF for all presented green commodities. While Norway and France have good access to wind energy and a low WACC, the WACC in Morocco is slightly higher, which is compensated for by better wind energy potentials. Additionally, we can see that the United States, Saudi Arabia, South Africa, Namibia, Australia, China and Spain are all at least in the second lowest class for all presented commodities, since they combine good renewable energy potentials with comparably low WACCs of 8% or less. Regions which belong to the upper half of the LCOF classes for hydrogen are Central Africa, southern South America, Central Asia and Eastern Europe, mainly due to a high local WACC, combined with less favourable wind or solar energy potentials in some of

[2] Costs could be lower if low-cost biogenic carbon is available locally.

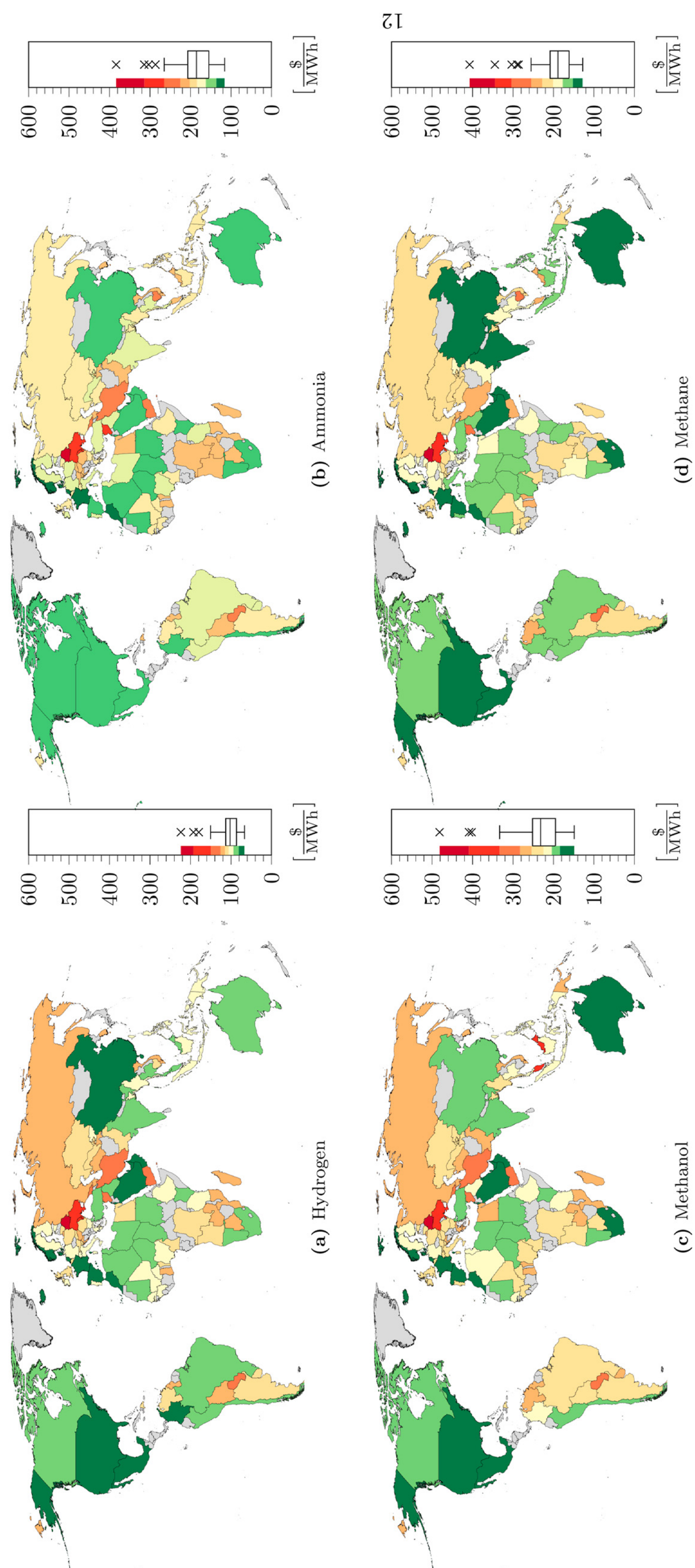

Fig. 4 – Levelised costs of fuel production (LCOF) for a production volume of 100 TWh/a in the baseline scenario and the year 2030.

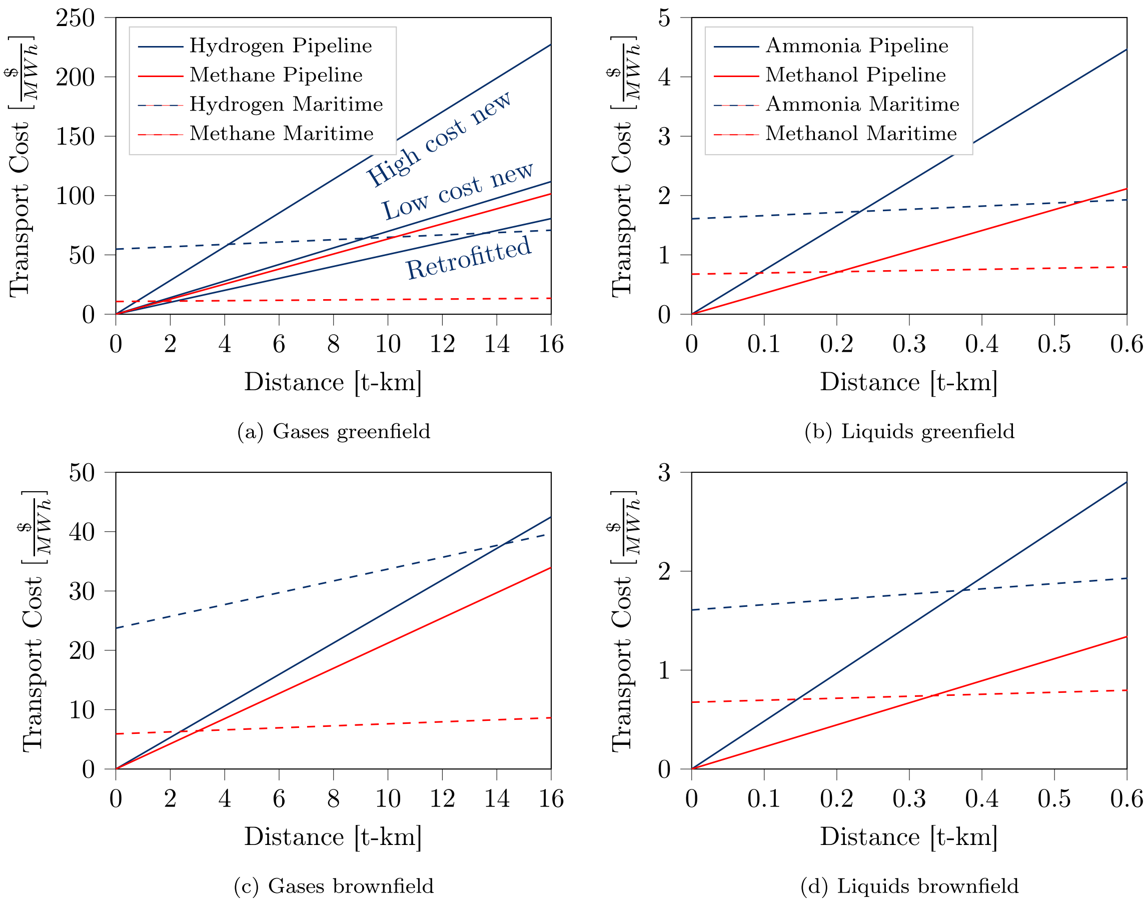

Fig. 5 – Transport costs for liquid and gaseous commodities for greenfield investments in infrastructure or brownfield use of existing infrastructure in the year 2030. This figure shows exemplary transport costs from Algeria to Germany assuming electricity costs of 40 $/MWh in the origin country and 45 $/MWh in the destination country.

these regions. The LCOF for hydrogen as the lowest-cost commodity range from 67 $/MWh to 224 $/MWh with a median of 103 $/MWh. The LCOF for methanol as the highest-cost commodity span from 156 $/MWh to 481 $/MWh with a median of 238 $/MWh.

Transport and supply costs to Germany

This section assesses the transport costs of the different green energy commodities and presents overall supply costs, looking at the example of Germany as the importing country.

Fig. 5 displays the costs for the maritime and pipeline-based transport of the commodities hydrogen, ammonia, methanol and methane over the transport distance. A distinction is made according to the physical state of the commodity transported as well as to brownfield and greenfield costs.[3] Gaseous commodities represent hydrogen and methane, which are gaseous at standard conditions and not easily liquefiable. Methane and hydrogen are liquefied for shipping but are transported in the gaseous state in pipelines. Liquid commodities denote methanol or any Fischer-Tropsch products which are liquid at standard conditions, or ammonia which is easily liquefiable and generally transported in the liquid state. Pipeline transport costs are linear functions of the transport distance. Maritime transport costs are affine linear functions of the transport distance, with the height of the y-axis intersection primarily defined by regasification and liquefaction costs. Fig. 5a and b shows greenfield transport costs, which are the sum of CAPEX and OPEX. Fig. 5c and d shows brownfield transport costs, which are assumed to consist of OPEX only. Details on the transport cost calculation can be found in Appendix A. Moreover, Fig. 5a contains three different cost scenarios for hydrogen pipelines. Comparing maritime and pipeline transport costs, we can see that the intersection of pipeline transport costs and maritime transport costs is at around 200–300 km for liquid commodities. In comparison, the intersection is at about 1700 km for methane and between 4000 and 14,000 km for hydrogen, depending on the pipeline cost scenario. It is important to note that the viable length of a pipeline is not only defined by economics but also by geography, terrain, politics or right of way. Therefore, we only consider already existing pipeline routes as viable options. Moreover, we assume that the chemical state at standard conditions is the end-use state of each commodity. Hence, liquid hydrogen and liquid methane are regasified after maritime transport. This assumption might not cover all

[3] In the brownfield case, the necessary infrastructure is already available and its costs are thus sunk, while the greenfield case looks at the total costs including investment.

use cases, as there might be a demand for liquefied gases in heavy-duty transport [35]. Comparing magnitudes, the pipeline transport costs for gaseous fuels are two to four times higher than for methanol. The pipeline transport costs for ammonia are similar to other gaseous commodities. Cost differences are more significant in maritime transport. The transport costs for methane are up to 16 times higher than for methanol and up to 7 times higher than for ammonia. The maritime transport costs for hydrogen are up to 80 times higher than for methanol and up to 34 times higher than for ammonia, depending on the distance. We observe that transport costs correlate strongly with a commodities' liquefiability. The more easily a commodity is liquefiable, the shorter the distance over which shipping is cheaper than pipeline-based transport. Thus, shipping dominates the transport of liquid commodities. Conversely, the more challenging it is to liquefy a commodity, the more favourable it is to use pipelines. From the comparison of the brownfield and greenfield scenarios, we observe that pipeline and maritime transport costs intersect at greater distances in the brownfield scenarios than in the greenfield scenarios, since pipeline-based transport is more CAPEX but less OPEX-intensive than shipping.

Fig. 6 shows the supply costs of the four analysed green energy commodities to Germany. They are the sum of LCOF in the origin country and the transport cost from the origin country to Germany. Appendix A provides a detailed overview of the calculations. We use greenfield transport costs for hydrogen and ammonia, considering that only little developed transport infrastructure exists for these commodities today. While there are existing pipelines and terminals for the transport of ammonia, the existing port-based ammonia import capacity in the EU, for example, amounts to only around 0.65 Mt per year [36]. Existing capacity may not be large enough to handle the high volumes of green ammonia that would be shipped in the future, in particular if ammonia is used as a hydrogen carrier. Therefore, in- and export capacities require expansion, for example by construction of additional terminals. Today existing ammonia and hydrogen pipeline networks connect sites of the chemical industry and ports for example in France, Belgium, the Netherlands, Germany and the US. However, these pipeline grids are regional and not comparable in size and capacity to the existing infrastructure of e.g. the natural gas grid in Europe or North America [37–39]. We assume that hydrogen pipeline grids would emerge from existing natural gas pipeline grids and therefore assume the retrofitted natural gas pipeline scenario for hydrogen pipeline transport costs. Further, we use brownfield transport costs for methane and methanol assuming that these commodities are transported using existing natural gas or oil infrastructure.

Import costs vary greatly depending on the country of origin, as Fig. 6b shows. This variation is due to differences in production and transport costs. Production costs are influenced by the country-specific RES potential, which affects the capacity ratios between RES power plants, electrolyser and hydrogen conversion plant as well as the hydrogen storage capacity. The WACC is another important factor. Countries in which investments are deemed more risky due to local economic or political circumstances generally have higher capital costs. The analysis shows that, based on current WACC estimates, importing hydrogen and hydrogen-derived products from many African countries, for example, is unlikely to be economically viable despite suitable RES potentials.[4]

Depending on the energy commodity and mode of transport, transport costs from the origin country to Germany are also an important cost driver.

Fig. 6a displays hydrogen supply costs from the respective origin country to Germany. Compared to the hydrogen production costs in Fig. 4 the significance of hydrogen transport costs becomes apparent. Countries that are integrated into the European natural gas transmission system would benefit from a conversion of natural gas pipelines to hydrogen pipelines which could offer lower supply costs. That applies especially to imports from European countries with good wind and PV potentials, like Norway, France, Denmark Spain or Italy, with supply costs to Germany ranging from 74 $/MWh to 101 $/MWh, but also eastern European countries like Poland or Hungary with supply costs of 113 $/MWh and 119 $/MWh. Ukraine and Belarus cannot benefit from their pipeline connection to Germany. Due to their high WACC they have high supply costs of 229 $/MWh and 199 $/MWh. Countries outside Europe, but with a connection to the European gas transmission grid, particularly in North Africa, could also offer low total hydrogen supply costs to Germany: Estimated supply costs from Morocco, Lybia, Tunesia and Algeria range from 89 $/MWh to 106 $/MWh.

A pipeline connection is crucial: many countries with large and suitable RES potentials and a very low LCOH nevertheless feature high supply costs to Germany since they are distant and not connected by pipeline. The main cost driver are the high transport costs for pure hydrogen, especially for the shipping of liquefied hydrogen. Reflected in Fig. 4 this can be observed, e.g., for Saudi Arabia (140 $/MWh), the US (145 $/MWh), or Australia (159 $/MWh). For ammonia, production costs in the origin country make up most of the total supply cost and transport costs are less significant. As a result, not only Germany's neighbours, but also more distant regions offer supply costs that are lower than the ammonia production costs in Germany. In addition to North and Southwest Europe, North Africa, North America, and the Middle East stand out as low-cost sources of green ammonia.

However, access to the sea is crucial, since the least-cost option of transporting ammonia over large distances is by ship. Landlocked countries like Kazakhstan, Chad or Bolivia thus are at a cost disadvantage when it comes to exporting ammonia, since the ammonia has to be first piped to the nearest port. Hence, ammonia supply from landlocked countries would not be competitive. However, for countries with sea access, green ammonia is a good option to jump start green energy exports/imports, especially in the short-to medium-term. This is discussed in more detail in section 3.3.

From the energy commodities analysed in the paper at hand, methanol has the lowest transport costs. Methanol is

[4] It should be noted that the WACC could be lower if the investment were, for example, backed by governments or financial institutions.

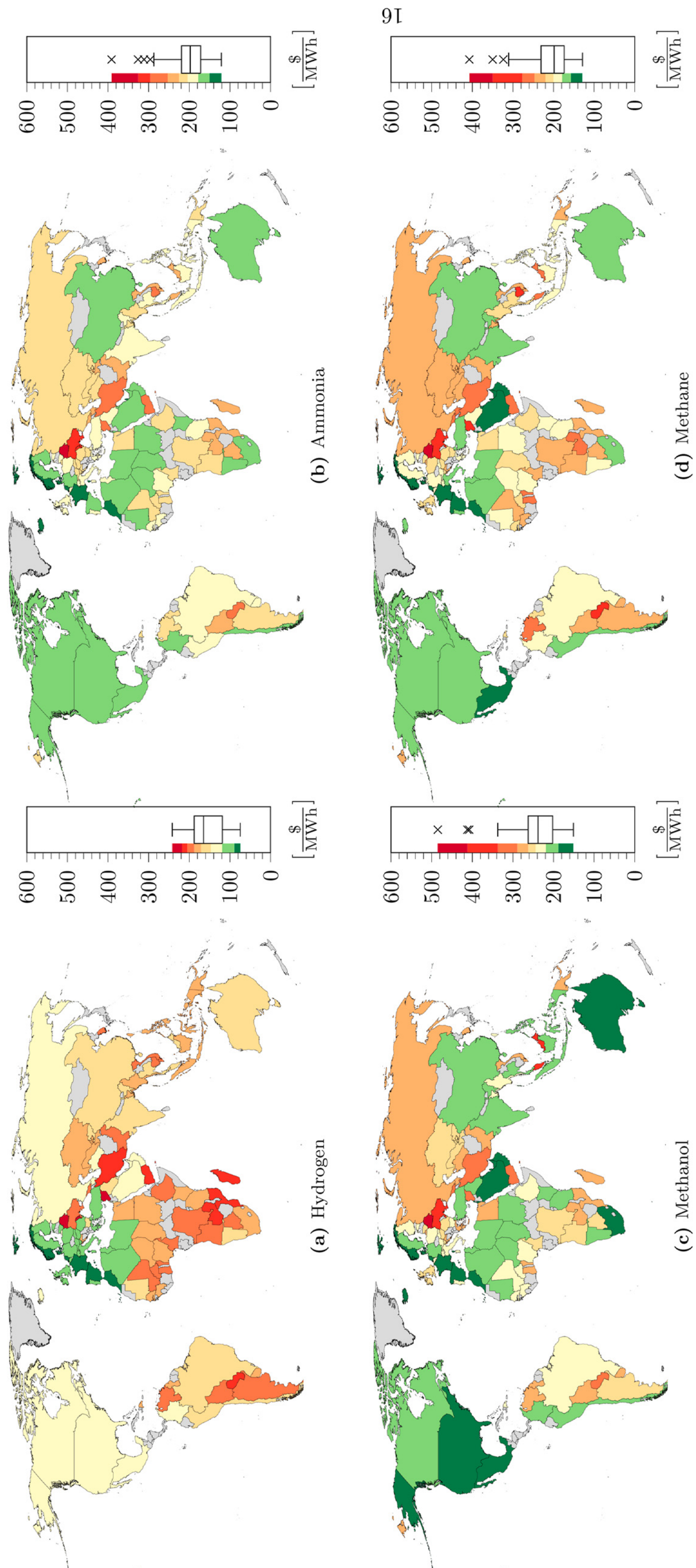

Fig. 6 — Supply cost to Germany for an import volume of 100 TWh/a in the baseline scenario and the year 2030.

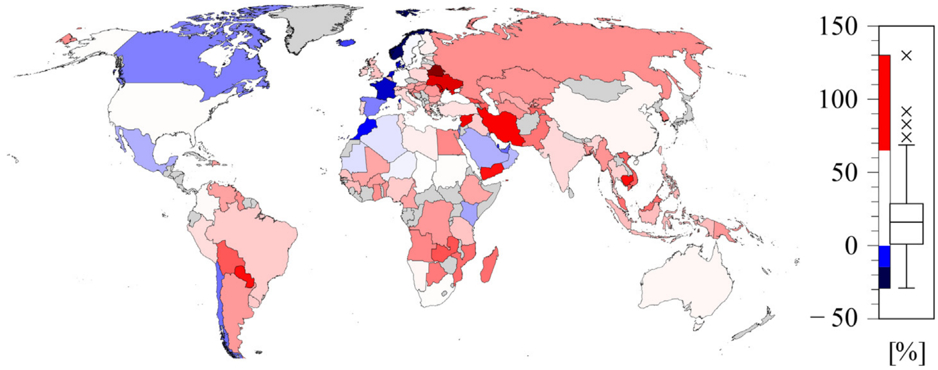

Fig. 7 — Deviation of import costs of green ammonia to Germany from the production cost of green ammonia in Germany in the baseline scenario for an import volume of 100 TWh in 2030. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

the second biggest liquid commodity traded globally today, next to crude oil. Ships are already in service as methanol transport is possible with oil tankers. This is also reflected when comparing production and supply costs of methanol (Figs. 4c and 6c) that exhibit the smallest difference compared to the other three energy commodities. Hence, countries that have the lowest green methanol production costs like Norway, Qatar, Spain or Saudi Arabia (149–167 $/MWh) would be, from a purely economic perspective, the optimal sources of supply for Germany. Even a doubling of methanol transport costs would not fundamentally change the picture, as shown in Fig. 5. However, compared to the other green energy commodities analysed in this study methanol is the most expensive since its production requires a climate neutral carbon source. In our assumptions, carbon dioxide is provided by DAC, which is a comparably expensive technology, especially in the short-to medium-term. Costs could be less if a low-cost biogenic carbon source were available[5]

Green ammonia - comparison of domestic production and imports

In the following section, we present a case study analysing supply options of green ammonia for Germany in 2030 and the baseline scenario. The case study focuses on ammonia for several reasons. On the one hand, ammonia is most likely to become the primary hydrogen transport carrier in the near-to medium-term since a pan-European hydrogen pipeline infrastructure might not be realised before the medium to long term. Existing natural gas pipelines might not be available for retrofitting before the 2030s [40], and the construction of new pipelines takes time and has significant investment costs. Hence, large-scale hydrogen supply to Germany is only possible via ship in the near term. Ammonia is likely to be the hydrogen carrier of choice. While today, shipping pure hydrogen via liquid hydrogen or LOHCs is only at the stage of pilot projects, ammonia is traded and transported on a large scale (e.g. in LPG carriers) and many ports in Europe can handle ammonia [36]. Hence, importing ammonia might be a near term option because it is not necessary to set up new infrastructure entirely, although scaling up ammonia imports to larger volumes will likely require an expansion of the existing infrastructure. To meet the demand for green ammonia in Germany, the following options are thus available in the short to medium term: (1) domestic production from locally produced green hydrogen, (2) domestic production from imported hydrogen, or (3) direct imports of green ammonia from abroad. Assuming that a pan-European pipeline grid for hydrogen based on retrofitted natural gas pipelines does not exist by 2030, we observe 21 potential origin countries that can supply at least 100 TWh ammonia, for which the supply costs of green ammonia to Germany are lower than the green ammonia production costs in Germany. The comparison of options (1), (2) and (3) shows that the maritime supply of green ammonia from many regions of the world is more economical than the domestic production of green ammonia. This holds even when the production of ammonia in Germany is based on green hydrogen from domestic production, as well as when imported green hydrogen from the lowest-cost hydrogen supplier is used for ammonia production.[6]

In Fig. 7, supply costs to Germany by country of origin are displayed relative to production costs in Germany. Negative values mean that the supply costs from the origin country are lower than the domestic production costs in Germany and vice versa. We observe that supplying green ammonia from northern and western Europe, North Africa, North America, Chile, the Arabian peninsula, and central Africa is cost-effective against domestic green ammonia production in Germany. All countries with supply costs below production costs in Germany are examined individually in Fig. 8. The figure shows that the most economical supply options for Germany are European countries. With a cost range of 624–874 $/t NH_3 and an average of 743 $/t NH_3, supplies from seven European countries are more economical than producing green ammonia in Germany. Supplies from Norway, the Netherlands, Denmark, and France are the most economical. Onshore wind is the lowest-cost RES that can be used for ammonia production in these countries. While

[5] The spreadsheet tool in the supplementary material provides the option to adjust the cost of the carbon source and analyse the impact on methanol supply costs.

[6] As noted above, the lack of infrastructure might not make hydrogen supply via pipeline a near-term option.

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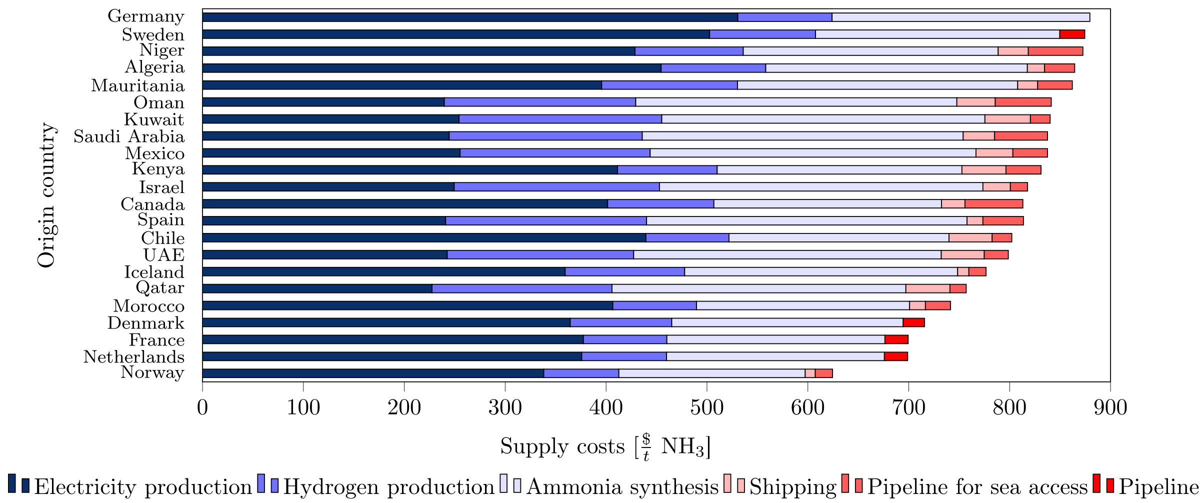

Fig. 8 – Green ammonia supply costs in Germany by origin. Only origin countries with lower supply costs than production costs in Germany are shown. The values represent levelised supply costs in the baseline scenario in 2030 for a supplied quantity of 100 TWh. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

ammonia is supplied via ship from the majority of the origin countries, pipeline transport is the most economical from the Netherlands, France, Denmark, and Sweden, as these countries are in close proximity to Germany. Supply costs from North Africa are 802 \$/t NH_3 on average. Morocco is the cheapest supplier in the region with supply costs of 741 \$/t NH_3 based on onshore wind energy. Further afield, supply costs of green ammonia from the Middle East range between 757 and 841 \$/t NH_3. The lowest-cost production is based on solar PV in the entire region. Qatar is the cheapest supplier from the Middle East and the sixth-cheapest supplier overall. From South America, ammonia from Chile costs 802 \$/t NH_3 and is based on offshore and onshore wind. From North America, Canada can supply green ammonia based on onshore wind at 813 \$/t NH_3. Mexico can supply green ammonia at a cost of 838 \$/t NH_3, based on PV.

The difference between wind and PV can be observed in the cost structure in Fig. 8. PV has lower investment costs but also lower capacity factors than wind energy. The lower capacity factor of PV increases levelised hydrogen production costs as the electrolysers' CAPEX is levelised over a smaller amount of produced hydrogen. In the cost structure, ammonia production from PV has lower electricity production costs but higher hydrogen production costs compared to ammonia production based on wind energy.

The finding that importing green ammonia tends to be more economical than producing green ammonia in Germany holds even when assuming the existence of a hydrogen pipeline grid based on repurposed natural gas pipelines in Europe and North Africa. We observe that even in that case, direct imports of ammonia are still more cost-effective for 20 out of 21 importing countries. Only from Spain, importing hydrogen for domestic ammonia production in Germany is less costly than importing ammonia directly - at the cost of 755 \$/t NH_3.

Production costs for conventional ammonia based on grey hydrogen are highly dependent on the price of natural gas and range from 300 to 700 \$/t NH_3 in Europe [27,39,41]. Accordingly, there is a cost gap that must be closed for green ammonia to become competitive. Compared to the typical production costs of grey ammonia in Germany, the supply costs of green ammonia are 20–80% higher, depending on the origin country.

In addition to its direct use, ammonia can also be employed as a carrier for transporting hydrogen. To recover the hydrogen, ammonia needs to be cracked. The process of ammonia cracking recovers 0.78 kWh H_2/kWh NH_3 [42]. However, using ammonia as a transport medium for hydrogen is relatively cost-intensive due to the associated conversion losses. To compare, hydrogen supplied to Germany from the cheapest supplier, Norway, costs 2.2 \$/t H_2 using a retrofitted natural gas pipeline, 3.6 \$/t H_2 using LH2 maritime transport, and 4.7 \$/t H_2 via ammonia cracking. Nevertheless, as mentioned above, an infrastructure for the large-scale transport of liquid hydrogen or an international hydrogen pipeline grid does not yet exist. Therefore, the supply of hydrogen via ammonia as a carrier might be the only option available to import hydrogen in the short to medium term. Infrastructure for importing ammonia already exists in Germany, for instance, in the ports of Brunsbüttel and Rostock [36].

Limitations

In the previous section, we presented levelised production and supply cost projections for green energy commodities from 113 countries for the years 2021–2050 for a baseline and an optimistic scenario. The costs were calculated for greenfield investments of integrated plants comprising a dedicated RES, an electrolyser, hydrogen storage, synthesis units for the respective commodity, and, if applicable, an ASU or CO_2 DAC unit. However, there are some limitations to the analysis presented above, opening up opportunities for further research.

First, the RES considered in the context of this work are solar PV, onshore wind and offshore wind only. We do not consider hydropower. Since hydropower may currently yield lower hydrogen production costs than wind or solar energy [43], we may overestimate the LCOF for countries with significant hydropower potentials, such as many central African countries [44]. Nevertheless, wind and solar energy sources have a broader geographical distribution and far greater potentials than hydropower and are thus better suited for large-scale production of green energy commodities.

Secondly, we estimate the LCOF of using only a single RES. In the right circumstances, solar/wind hybrids could allow for higher combined capacity factors and lower RES-to-electrolyser capacity ratios. Thus, we may overestimate the LCOF in some cases. This study uses country-level data on RES potentials and synthetic hourly profiles. Therefore, we cannot determine whether suitable, geographically overlapping solar/wind hybrid energy potentials exist within a country. However, as shown by Brändle et al. [13], hybrid systems only have a cost advantage when both good solar and good wind potentials overlap geographically. For most combinations of solar/wind energy resource classes, single RES systems perform better because they are less capital-intensive. Accordingly, we do not consider solar/wind hybrids.

Thirdly, because of the country-level resolution, we use a generalised approach for domestic transport cost estimation. In maritime transport, we consider the transport from the capital to the relevant port. However, the capital might neither represent the economic heart of a country nor where the best RES potentials are located. The chosen geographical resolution could lead to a distorted estimation of the cost of transporting a commodity, especially inside very large countries such as China, Russia or the United States.

Fourthly, various country-specific parameters influence production costs in reality. Our model accounts for RES potentials, hourly RES profiles, WACC, and differences in labour costs for renewables (see Ref. [13]). Due to a lack of data, we were not able to account for the impact of differences in labour costs between countries on the cost of hydrogen production and hydrogen conversion technologies.

Lastly, other factors potentially influencing the LCOF from RES are disregarded. These factors include interaction of RES and the local electricity market. The installed RES is assumed to produce electricity for the electrolysis and hydrogen conversion plant only. Potential revenues from feeding excess electricity to the grid are disregarded. Moreover, costs of water supply are not considered. Electrolysis needs large amounts of demineralised water, which may first have to be transported to the RES production site. However, the impact of water supply on the LCOH is very small [45–47] and therefore excluded in this study for the sake of model simplicity.

Furthermore, potential changes in RES capacity factors over time are not taken into account. Climate change and increasing RES efficiency could lead to changing capacity factors in the future. However, since there are no uniform factors to project changes in capacity factors globally, a detailed capacity factor assessment would go beyond the scope of this study and is therefore only recommended as a possibility for future research.

Regarding the optimality of the results, the optimisation of the integrated plants for hydrocarbon commodities does not include the DAC plant for CO_2 production. We may overestimate the LCOF of hydrocarbon commodities, as the DAC to hydrogen conversion plant capacity ratio is estimated heuristically. We assume that the DAC unit operates identically to the electrolyser. Accordingly, the capacity ratio between the hydrogen conversion plant and DAC plant is identical to that between the electrolyser and the hydrogen conversion plant, which might not be optimal.

Conclusion

We determine the levelised production costs of green hydrogen and green hydrogen-based energy commodities as well as their supply costs to Germany. The costs are projected for greenfield investments in 113 countries from 2021 to 2050 for a baseline and an optimistic scenario. All data, results and calculations are available for download in a spreadsheet tool. Since each of the four commodities have different physical characteristics and address different markets in terms of demand, total costs are not comparable. However, comparing relative cost characteristics helps to understand differences along the commodity's supply chains. We find that while pure hydrogen has the lowest production costs, its transportation costs are the highest, especially in maritime transport. Thus, hydrogen is likely to be traded mostly regionally by pipeline, for instance, within Europe and North Africa. In the supply cost structure of green ammonia, methanol and methane, by contrast, production costs are the dominant cost component. This would potentially allow for the emergence of global maritime trade in these commodities. In the case of green ammonia supplied to Germany, the direct import of green ammonia by ship is cost-efficient compared to domestic production of ammonia from domestically produced or imported hydrogen in 2030. Only if a European hydrogen pipeline grid based on repurposed natural gas pipelines exists could ammonia production from imported hydrogen in Germany potentially be cost-effective from Spain.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2022.12.046.

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