The Future Cost of Electricity-Based Synthetic Fuels

STUDY

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Preface

Dear readers,

In the decarbonised energy system of the future, synthetic fuels from renewable electricity will be an important supplement to the (more energy-efficient) direct use of electricity from renewables. Lately, there has been increased interest in scenarios that rely on the wide-scale use of synthetic fuels at greatly reduced cost. What assumptions inform these projected cost reductions? To create more transparency in future discussions, Agora Verkehrswende and Agora Energiewende commissioned Frontier Economics to analyse cost reduction paths for synthetic fuels and investigate favourable locations in Germany and abroad for generating the renewable power needed to produce them. This study – together with the Excel tool available on our websites – presents the findings. A further aim of this study is to encourage discussion about how to make synthetic fuel production sustainable and which measures are mostly likely to achieve it.

We hope you find the study to be an inspiring and enjoyable read!

Yours sincerely,
Patrick Graichen,
Executive Director of Agora Energiewende
Christian Hochfeld,
Executive Director of Agora Verkehrswende

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1 **Synthetic fuels will play an important role in decarbonising the chemicals sector, the industrial sector, and parts of the transport sector.** Synthetic fuel production technologies can be used to manufacture chemical precursors, produce high-temperature process heat, as well as to power air, sea and possibly road transport. Because synthetic fuels are more expensive than the direct use of electricity, their eventual importance in other sectors is still uncertain.

2 **To be economically efficient, power-to-gas and power-to-liquid facilities require inexpensive renewable electricity and high full load hours. Excess renewable power will not be enough to cover the power demands of synthetic fuel production.** Instead, renewable power plants must be built explicity for the purpose of producing synthetic fuels, either in Germany (i.e. as offshore wind) or in North Africa and the Middle East (i.e. as onshore wind and/or PV). The development of synthetic fuel plants in oil- and gas-exporting countries would provide those nations with a post-fossil business model.

3 **In the beginning, synthetic methane and oil will cost between 20 and 30 cents per kilowatt hour in Europe. Costs can fall to 10 cents per kilowatt hour by 2050 if global *Power-to-Gas (PtG)* and *Power-to-Liquid (PtL)* capacity reaches around 100 gigawatts.** The aimed-for cost reductions require considerable, early and continuous investments in electrolysers and CO_2 absorbers. Without political intervention or high CO_2 pricing, however, this is unlikely, because the cost of producing synthetic fuels will remain greater than the cost of extracting conventional fossil fuels.

4 **We need a political consensus on the future of oil and gas that commits to the phase-out of fossil fuels, prioritises efficient replacement technologies, introduces sustainability regulations, and creates incentives for synthetic fuel production.** Electricity-based fuels are not an alternative to fossil fuels but they can supplement technologies with lower conversion losses, such as electric vehicles and heat pumps. Application-specific adoption targets and binding sustainability regulations can help to ensure that PtG and PtL fuels benefit the climate while also providing a reliable foundation for long-term planning.

Content

The Future Cost of Electricity-Based Synthetic Fuels

Conclusions Drawn by
Agora Verkehrswende and
Agora Energiewende

1 Synthetic fuels will play an important role in decarbonising the chemicals sector, the industrial sector and parts of the transport sector.

Meeting greenhouse gas reduction targets will require the large-scale use of synthetic fuels.

Numerous sectors of the German economy depend on fossil fuels. As illustrated in Figure 1, the German transport and heating sectors are particularly dependent on oil. Oil is also important for non-energy use in the industrial sector. Road transport is the subsector with the largest consumption of oil. Natural gas is used first and foremost for heating and power generation.

Germany aims to achieve a 55% reduction in greenhouse gas emissions in relation to 1990 levels by 2030. Furthermore, by 2050, the country hopes to achieve greenhouse gas reductions of 80% to 95%.

The Climate Protection Plan 2050, which was adopted by the federal government in 2016, represents the first German policy to set forth reduction targets for each sector of the economy. Specifically, the Climate Protection Plan calls for reducing emissions in the building sector from 119 million tonnes of CO_2 equivalents in 2014 to between 70 and 72 million tonnes of CO_2 equivalents by 2030. In the transport sector, emissions are to be reduced from 160 million tonnes of CO_2 equivalents in 2014 to 95–98 million tonnes of CO_2 equivalents in 2030.[1] The most important energy policy measures for achieving these reductions by 2030 include improving energy efficiency, electrifying the building and transport sector, increasing the share of

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1   Bundesregierung (2016).

Use of fossil oil and gas in Germany in 2015 (terawatt hours)   Figure 1

* Includes power uses in commercial and sea transport sectors (bunkering)
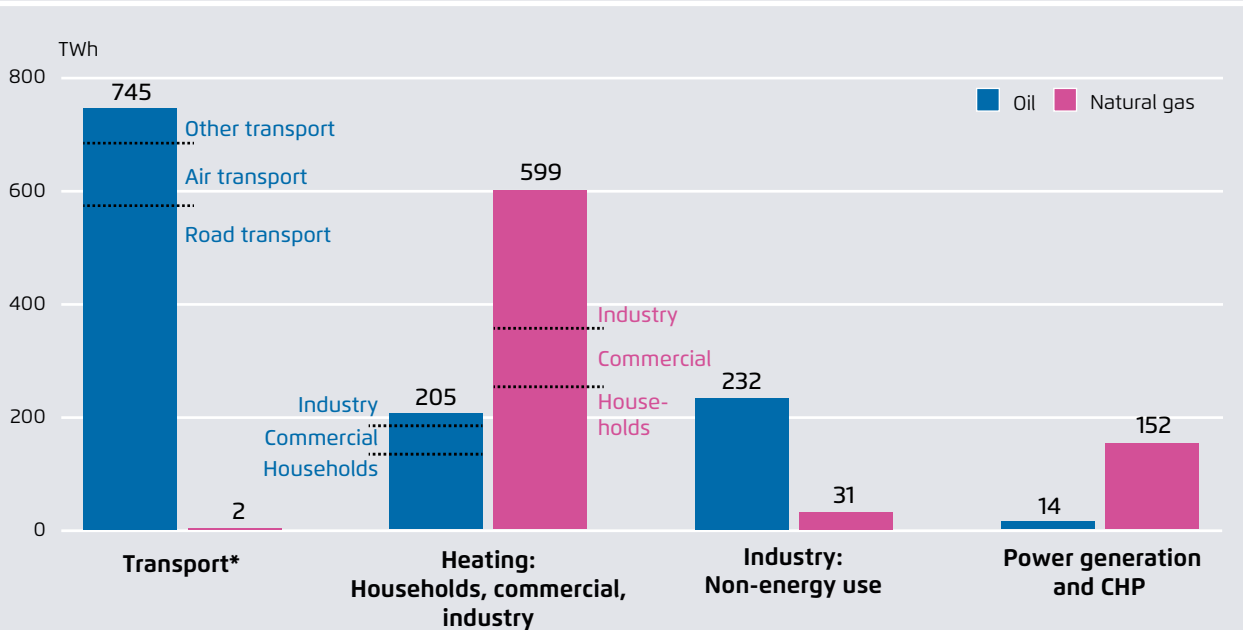
Own illustration based on AGEB (2017)

renewables in the power mix, and reducing the use of carbon-intensive energy sources such as coal and oil.[2] As natural gas is the fossil fuel associated with the lowest carbon emissions, for some applications, it will play an important role as a bridge technology until 2030 on the road to decarbonisation.[3]

In numerous scenarios that model the successful achievement of carbon abatement targets between 2030 and 2050, synthetic fuels cover a significant share of demand. Indeed, higher levels of political ambition are directly associated with a greater reliance on *power-to-gas* (PtG) and *power-to-liquid* (PtL). Significant quantities of these fuels are needed to meet demand in the transport sector, even in scenarios that model a mid-range carbon reduction path of 87.5% by 2050. In addition to the synthetic fuel needed to decarbonise domestically, international air and sea transport will require significant production volumes.

PtG and PtL will be particularly important as fuel sources because sustainably produced biomass – including wood, biogas and biofuels – is not available in sufficient quantities to replace coal, oil and natural gas in applications that rely on thermal combustion. Due to the fact that biomass displaces croplands for growing food and animal feed, there are strong limitations to expanding its production, both in Germany and globally. And while land-use competition can be avoided by producing biofuels from waste and agricultural residues, the growth potential for this class of biofuels is far too limited to cover the energy needs of the transport sector.[4]

Electricity-based synthetic fuels[5] – referred to in the following as "synthetic fuels" – can promote decarbonisation if they are produced with renewable power and if carbon inputs (when required) are climate-neutral.[6] The most important synthetic fuel is hydrogen as the basic molecule, followed by methane and synthetic liquid fuels. The precise role that these fuels will play in the energy system of the future is still unclear, however. The answer to this question depends in large part on when and at what cost conventional fuels can be replaced with climate-friendly alternatives.[7] From a present-day perspective it appears that technological advancements could make it possible to produce large volumes of synthetic fuels at reasonable cost levels, thus allowing synthetic fuels to play a significant role in decarbonisation.

Synthetic fuels offer a number of benefits over direct use of electricity: synthetic fuels are energy-dense, can be stored and transported, and are also compatible in numerous respects with existing power systems. In this way, synthetic fuels display the same positive features as fossil fuels. Industrial societies have developed far-reaching technological dependencies and routines in everyday life. The compatibility of synthetic fuels with existing infrastructure is a clear argument in their favour, for their adoption does not entail large changes in existing routines and systems.

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2   Agora Energiewende (2017b). Furthermore, in the transport sector, a greater share of demand must be met by rail and bus, and *shared mobility* must be strengthened (Agora Verkehrswende 2017). See Langenheld & Graichen (2017) on the role of energy efficiency.

3   See IEA (2017b) on the methane emissions released by natural gas production that cannot be ignored.

4   Worldwide, second generation biofuels produced from agricultural and forestry waste have a maximum potential to cover energy demand of 13 to 19 exajoules. By contrast,

global transport sector energy demand in 2050 has been estimated at 100 to 170 exajoules (INFRAS, Quantis 2015).

5   Synthetic fuels are used to produce heat and power vehicles. In both of these areas of application, fuel options include liquid fuels (such as heating oil, gasoline, diesel) and gaseous fuels (hydrogen, natural gas, synthetic methane).

6   Solar-thermal processes that do not produce electricity (DLR 2017) are not taken into consideration here.

7   BDEW et al. (2016)

Synthetic fuels have a large disadvantage, however: low energy efficiency. Large volumes of electricity are needed for their production due to conversion losses.

Compared to the direct use of electricity, the production of synthetic fuels is associated with high conversion losses. This has two immediate consequences: First, *power-to-gas* and *power-to-liquid* fuels will always be considerably more expensive than the direct consumption of electricity. Second, reliance on synthetic fuels significantly increases demand for electricity from wind and solar energy, and, by extension, increases the geographic area occupied by renewable energy systems.[8] Accordingly, if synthetic fuels are deployed on a wide-scale, the high volumes of renewable energy that are required for synthetic fuel production cannot be generated in Germany, but rather must be imported. Estimating the global potential for synthetic fuel development is not an aim of this study.[9]

Figure 2 illustrates the conversion losses that are associated with three different **passenger vehicle drive technologies,** assuming the underlying source of energy is renewable electricity:[10] battery-driven electric vehicles, fuel-cell vehicles and combustion-engine vehicles. The overall efficiency of the system declines with each additional conversion step. The battery-driven electric vehicle has the highest efficiency rating (69%), because the incurred conversion losses are relatively low. The fuel cell vehicle ranks second with an efficiency rating of 26%. In this case, the intermediate step of generating hydrogen using electrolysis leads to a significant efficiency

reduction. The least efficient solution is to use synthetic fuels in a combustion engine, as the two-step chemical conversion in combination with the inefficiency of the combustion engine leads to an overall efficiency rating of 13%. Battery-driven vehicles are thus five times more efficient than combustion engines that run on renewable synthetic fuels. This means that a combustion-engine vehicle would need five times as much renewable electricity as a battery-driven vehicle to travel the same distance. In comparison to direct electricity usage, scenarios that foresee widespread adoption of synthetic fuels thus require a considerably expanded renewable energy generation fleet, with the land use that this entails. High costs also result from constructing synthetic fuel production facilities.

Figure 3 compares the efficiency of various **heating systems,** assuming the underlying power source is renewable electricity. The electric heat pump is the technology with the highest overall efficiency rating, as it comes with as special leverage effect that other technologies do not have. Its 285% efficiency rating is attributable to its ability to withdraw more energy from the environment (whether the air, soil or water) than required in terms of operational power. In the example presented here, the heat pump can provide heating energy three times[11] greater than the required input power. The second most efficient technology is the gas condensing boiler, with an efficiency rating of 50%. While transport in this case has only low losses, the production of hydrogen is associated with high conversion losses. At the end of the process is the hydrogen fuel cell, with an efficiency rating of 45%, composed in nearly equal shares of heat (24%) and electricity (21%). Accordingly, the overall efficiency of the heat pump is six times higher than that of the hydrogen fuel cell. If one takes only the heat production of the hydrogen fuel cell into account (24%), then the efficiency rating of the heat pump is 12 times higher.

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8   FENES et al. (2015). In the case of *power-to-gas* only 0.24 to 0.84 kilowatt-hours of fuel are produced from 1 kilowatt-hour of renewable electricity. This efficiency range includes various conversion techniques (from pure electrolysis to methanisation) and gas grid pressure levels. The harnessing of waste heat in *power-to-gas* facilities can help to improve efficiency levels (dena 2016).

9   More research is needed in this area. See Fh-IWES (2017).

10   These example figures do not consider upstream processes.

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11   This presupposes an annual performance factor of 3 minus 5% transmission losses = 2.85.

Both figures demonstrate the relatively high conversion losses associated with the use of synthetic fuels.

In the absence of clear evidence that this indisputable, physics-based disadvantage of synthetic fuels is more than offset by other advantages – i.e. avoidance of infrastructure costs – then the obvious strategy would be to first pursue technological solutions with lower conversion losses.[12]

In the heating and transport sectors, synthetic fuels should predominantly be used in areas in which the direct and efficient use of electricity is not possible.

In the **transport sector,** electric motors are the best solution in terms of efficiency and cost for powering trains, cars, light utility vehicles, municipal buses, and trucks operating over short distances and with good charging options. With respect to heavy trucks operating over extended distances, one needs to make distinctions. This is because the vehicle batteries in mass production are not sufficiently strong as a single source of power, nor are they expected to become strong enough in the coming years. As a result, heavy trucks operating over long distances will need to be operated with overhead power lines – or, alternatively,

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12 Additional research is needed, particularly concerning infrastructure costs. Initial work in this area has been undertaken by FNB Gas (2017).

Individual and overall efficiencies for cars with different vehicle drive technologies, starting from renewable electricity   Figure 2
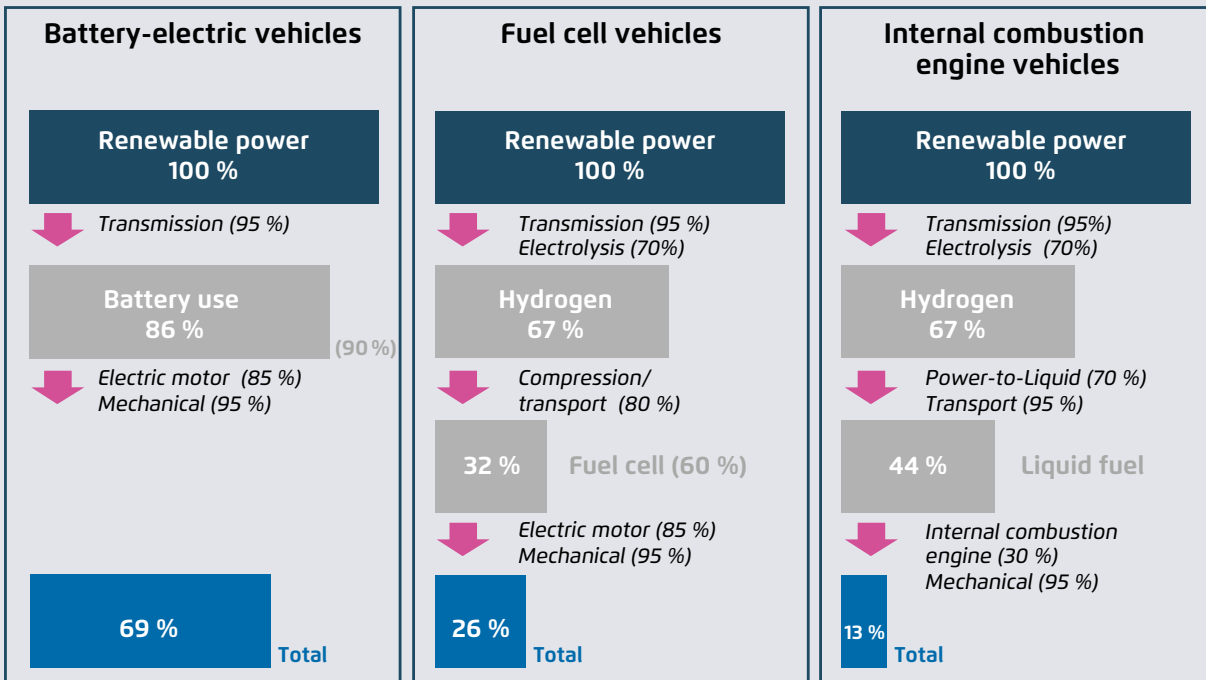
Battery-electric vehicles	Fuel cell vehicles	Internal combustion engine vehicles
Renewable power 100 %	Renewable power 100 %	Renewable power 100 %
Transmission (95 %)	Transmission (95 %) Electrolysis (70%)	Transmission (95%) Electrolysis (70%)
Battery use 86 % (90 %)	Hydrogen 67 %	Hydrogen 67 %
Electric motor (85 %) Mechanical (95 %)	Compression/ transport (80 %)	Power-to-Liquid (70 %) Transport (95 %)
	32 % Fuel cell (60 %)	44 % Liquid fuel
	Electric motor (85 %) Mechanical (95 %)	Internal combustion engine (30 %) Mechanical (95 %)
69 % Total	26 % Total	13 % Total

Note: Individual efficiencies are indicated in parentheses. Multiplied together, the individual efficiencies yield the overall cumulative efficiencies in the boxes.

Authors' illustration, based on acatech et al. (2017a), Figure 5

Individual and overall efficiencies for different heating systems, starting from renewable electricity — Figure 3

Electric heat pump

Renewable power 100 %

Transmission (95 %)

Total 285 %

Fuel cell heating

Renewable power 100 %

Transmission (95 %)
Electrolysis (70 %)

Hydrogen 67 %

Compression/transport/ fuel cell*

Heating 24 % | Power 21 %

Total 45 %

Gas condensing boiler

Renewable power 100 %

Transmission (95%)
Electrolysis (70%)

Hydrogen 67 %

Power-to-Gas (80 %)
Transport (99 %)

Methane 53 %

Gas condensing boiler (95 %)

Total 50 %

* Efficiencies: 80% (compression/transport) and 85% (total fuel cells; 45% heating, 40% power)

Note: Individual efficiencies are indicated in parentheses. Multiplied together, the individual efficiencies yield the overall cumulative efficiencies in the boxes. For heat pumps, we have assumed an annual performance factor of 3.

Authors' calculations based on acatech et al. (2017 a,b), Köppel (2015), FENES et al. (2015)

with combustion engines or fuel cells. A combination of various propulsion technologies might make sense to handle geographic areas in which overhead wires have not yet been installed. In the absence of a comprehensive overhead wire network, the decarbonised transport system of the future will necessarily contain long-distance trucks that are reliant on synthetic fuels. According to current expert opinion, direct electricity use is also not an option for air or maritime transport, except on an extremely limited basis.[13] These two subsectors will thus require climate-neutral synthetic

fuels, namely hydrogen to power fuel cells as well as CO_2-based synthetic methane or liquid fuel to power combustion engines (see rows 2 and 3 in Table 1). Synthetic fuels will also be required to operate construction equipment and heavy agricultural vehicles, as it will only be possible in select cases to directly power these vehicle types with electricity.[14]

In the **heating sector for buildings** the most efficient option is to directly use renewable energy (e.g. by installing deep geothermal and solar thermal

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13 Agora Verkehrswende (2017), p. 60; Umweltbundesamt (2016), p. 1; see *Flugrevue* (2017), *Maritime Journal* (2017); acatech et al. (2017b).

14 See Electrive (2017).

energy systems)[15] as well as to operate heat pumps with renewable power. One limitation in this area is that existing buildings must be sufficiently insulated to make the installation of a heat pump effective. If this requirement presents a problem – for whatever reason –, then reliance on synthetic fuels could be an alternative, either in combination with a fuel-cell combined heat and power (CHP) system, condensing boiler, or heat pump operating as a hybrid heating system.[16]

Industrial process heating is the primary form of **heating demand in the industrial sector**. Heat pumps are the most effective means of meeting heating demand at low temperatures (which currently means approximately 75 degrees Celsius, but could mean up to 140 degrees Celsius with the development of new refrigerants).[17] However, in 2014 some 60% of the demand for industrial process heating was for temperatures above 200 degrees Celsius.[18] Heat pumps are unable to serve demand at this temperature level. While solutions that rely on the direct conversion of electricity[19] can be adopted in some areas, combustion processes will invariably be needed to cover a considerable share

of future demand for high-temperature process heating.[20] Synthetic fuels will have to be used here if decarbonisation targets are to be met.

Due to their low conversion efficiency, synthetic fuels are generally only taken into account in scenarios that model decarbonisation pathways up to 2050 in areas of the energy system for which no realistic, more efficient alternative is foreseeable.

Table 1 provides and overview of sectors and applications for the direct use of electricity and for synthetic fuels.

Besides their role in the transport and heating sectors, synthetic fuels will be important for the long-term storage of electricity and for the climate-neutral production of input materials needed by industry.

Hydrogen is required for numerous **industrial** processes, including the synthesis of ammonia and the direct reduction of iron ore.[21] In general, the hydrogen needed for industrial applications is produced using fossil fuels. In the decarbonised power system of the future, these fuels will need to be produced using electricity. Furthermore, carbon is required as an input material to manufacture numerous **organic basic chemicals** such as methanol and ethylene. While such carbon is primarily obtained today from petroleum and natural gas, climate-neutral alternatives are needed for the future. Carbon obtained from synthetic fuels could be a viable option. It is estimated that through 2050, the European chemicals industry will require some 50 to 300 million tons of CO_2 annually as an input material for the manufacture of the most important organic compounds. A similar level of demand is expected for manufacturing combustible

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15 While the direct use of renewable energy is no longer explicitly discussed in the following, it should – where relevant – always be considered as a preferable alternative to the use of renewable electricity and synthetic fuels.

16 In the absence of investment in improved energy efficiency, heating poorly insulated buildings with 100% synthetic fuels is likely to make little economic sense over the long-term – particularly if demand from other sectors with a higher willingness to pay leads to higher synthetic fuel prices. The significance of *power-to-gas* as a solution for heating buildings and the role played by building efficiency are being explored in a study by IFEU et al. (forthcoming).

17 This is particularly relevant for the food, paper and chemical industries (VDE-ETG 2015).

18 Fh-IWES & IBP (2017)

19 These processes involve various methods, including the use of resistance heating, induction, radiation, and plasmas. An electric arc furnace, for example, can generate temperatures of up to 3,500 degree Celsius (VDE-ETG 2015).

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20 Blesl et al. (2015) estimates this at 200 terawatt-hours for Germany in 2050.

21 IEA (2017)

Prioritised decarbonisation options, by sector and application			Table 1
Decarbonisa-tion options	**First priority Direct use of electricity***	**Supplemental approaches Synthetic fuels****	
		Hydrogen***	CO_2-based PtG and PtL
Transport	Trains, buses, short-haul trucks, long-haul trolley-trucks and -buses, cars, motorcycles, inland waterway transport (depending on the purpose)	Long-haul trucks and buses without overhead lines, inland waterway transport (depending on the purpose)	Air and sea transport, long-haul trucks and buses without overhead lines, inland waterway transport (depending on the purpose)
Heating	Low-temperature heat with heat pumps in well-insulated buildings and in the industry	Fuel cell CHP in existing buildings with significant insulation restrictions	Existing buildings with significant insulation restrictions and hybrid heating systems with back-up boilers
	High-temperature heat with direct electricity use (resistance heating, plasma, etc.)	High-temperature process heat for hard-to-electrify applications	High-temperature process heat for hard-to-electrify applications
Industry		Ammonia production; direct reduction of iron ore in steel production	Carbon source for organic basic chemicals
Power	Short-term storage	Long-term storage and reconversion in gas-fired power plants and hydrogen combustion motors	Long-term storage and reconversion in gas-fired power plants
Commerce, trade, services	Stationary and some mobile power applications in construction, agriculture, and logistics	Mobile power applications in construction, agriculture, logistics, and military	Mobile power applications in construction, agriculture, logistics, and military

* May include some direct renewables such as solar thermal power.
** May include some direct renewable energy use by means of biomass.
***For use in fuel cells unless otherwise specified.

Note: Some approaches are still in development. This table does not contain all possible applications.

Own summary based on acatech et al. (2017b); Blesl et al. (2015); DECHEMA (2017a); dena (2017a:8); dena (2017c); IEA (2015); IEA (2017); ifeu et al. (2016); Larfeldt et al. (2017); Öko-Institut et al. (2015); Steward et a. (2009); FENES et al. (2014); Fh-ISI et al. (2017a); Fh-ISI et al. (2017b); Fh-IWES/IBP (2017); UBA (2016).

fuels, yielding an annual CO_2 demand of some 670 million tons annually in the EU.[22]

In the **power sector,** high shares of renewable energy will make it very important to store synthetic methane as a backup source of energy to cover demand when wind and solar power generation are low. [23]

22   DECHEMA (2017b)

23   FENES et al. (2014)

At present, experts primarily envision the reconversion of hydrogen into electricity through combustion in gas-fired power plants, either as an additive to natural gas or in the form of ammonia.[24] The use of hydrogen combustion engines represents another option.[25]

24   Depending on the gas turbine technology, experts discuss a hydrogen blending of 25 to 45%. In this regard, see Larfeldt et al (2017).

25   IEA (2017); Steward (2009).

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2   To be economically efficient, power-to-gas and power-to-liquid facilities require inexpensive renewable electricity and high full load hours. Excess renewable power will not be enough to cover the power demands of synthetic fuel production.

Two conditions must be fulfilled to allow the economically viable operation of power-to-gas and power-to-liquid production facilities: annual full load hours must be high, and renewable power must be cheap.

→ *High full load hours:* PtG and PtL facilities are capital intensive and have high fixed costs. Accordingly, each additional operational hour has a strong impact on the cost of synthetic fuels, as this defrays the high fixed costs. In order to be operated in an economically efficient manner, *PtG and PtL* facilities need to achieve 3,000 to 4,000 full load hours annually.[26]

→ *Inexpensive renewable electricity:* Due to conversion losses, the price of electricity is the major determinant of PtG and PtL variable costs. As a rule of thumb, the energy costs of producing synthetic methane are twice as high as the cost of the input electricity. In other words, if electricity procurement costs are 5 cents per kilowatt hour, then the synthetic methane produced with this electric-

26   acatech et al. (2015)

ity has an energy production cost of 10 cents per kilowatt hour. To arrive at a final cost figure, one must add capital costs as well as the input cost of water and CO_2. Inexpensive renewable power is thus essential for the economically viable operation of *power-to-gas* and *power-to-liquid* production facilities.

In light of the foregoing, inexpensive renewable power must be available during 3,000 to 4,000 hours each year to achieve economically efficient operation. Consequently, it will not be possible to operate PtG and PtL facilities with the "excess" renewable power – a hope that has been voiced by many experts.[27] Indeed, estimates of renewable power generation in coming years and decades do not foresee sufficient power volumes for the operation of synthetic fuel facilities on "excess production" alone.

27   For instance, Shell (2017) notes that "electrolysis using excess power production from renewables has a huge potential for the future." (Own translation) See also DVGW (2017), GP JOULE (2017), VKU (2017).

→ In the case of **system-wide balance surplus,** renewable energy generation exceeds demand at a given point in time when looking at the market area as a whole. Accordingly, the residual load – that is, the difference between demand and fluctuating renewable generation – is negative.[28] At no point in time to date has Germany managed to cover 100% of demand with power from renewable sources.[29] As the share of variable renewables in the power mix continues to grow, however, there will often be hours when renewable energy covers more than 100% of demand. With a share of 55% wind and solar energy, we can expect excess production of approximately 1,000 hours per year. When wind and solar energy reach a 65% share, we can expect excess production of approximately 2,000 hours per year, and when they reach at 90% share, we can expect nearly 4,000 hours per year of excess production (see Figure 4).[30]

→ In the event of **local and regional grid bottlenecks,** it may not be possible to use available renewable power locally or to transport it to other regions because the transmission network has not been sufficiently extended yet. What happens frequently instead is that renewable energy production must be curtailed. Though the renewable facilities are usually connected to the distribution network, in most cases the problems lie in the transmission network. The power losses from curtailment have increased dramatically in recent years. In 2015, Germany's total loss of power output was just under 4.4 terawatt hours, with 3 of those terawatt hours in Schleswig-Holstein alone.[31] If Schleswig Holstein's government meets its 2025 wind energy targets without expanding its transmission network, state facilities may have to curtail production for up to 1,600 hours annually because of their inability to transport excess electricity elsewhere.[32]

Based on this initial assessment, the amount of available excess power does not justify the operation of PtG and PtL production facilities in Germany.[33] Moreover, these facilities, if built, would compete in the market for flexibility with local switchable loads that often cost considerably less, such as power-to-heat, energy storage and industrial applications.[34]

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28 Negative power prices are often seen as an indicator of negative residual load. But so far negative power prices in Germany have primarily been the result of the inflexibility of conventional "must-run" power plants (Energy Brainpool 2014).

29 In 2016 and 2017 negative power prices occurred for 97 and 146 hours, respectively. But the highest share of renewables in power consumption amounted to 86% and 88.6%, respectively (Agora Energiewende 2017a, 2018).

30 acatech et al. (2015) determine the share of variable renewable power from 8 scenarios and, using the meteorological year 2008 with uniform loads, calculate the number of hours with excess electricity. Their approach does not take into account a Europe-wide power exchange.

31 Agora Energiewende (2017c)

32 Once the planned network expansion is complete, however, this curtailment will no longer occur. See GP JOULE (2017); Ecofys/Fh-IWES (2014); see also ChemCoast (2013).

33 The supplemental use of grey electricity or certified renewable power from existing facilities would considerably worsen the overall climate footprint of synthetic fuels. For more, see the following section.

34 *GP JOULE (2017); acatech et al.* (2015); Michaelis et al. (2016). High levels of flexibility will nevertheless be needed in the future. Whether and how PtG facilities can play a role – in multi-use applications, if needed (BTU 2017) – requires further investigation.

Excess renewables production in Germany versus the full-load
hours of renewable electricity generation   Figure 4

* System balance surplus (negative residual load); based on 8 scenarios without a European power exchange by acatech et al. (2015).
  To reach the renewable production expansion targets in this period, wind and PV energy will have to be supplemented by biomass and
  hydropower.
** Maximum curtailment from grid bottlenecks through 2025 according to the wind power expansion targets of Schleswig-Holstein.
   This curtailment will cease after implementation of the planned grid expansion measures (ecofys/IWES 2014).
*** PV tracking systems.

Own illustration

The use of excess renewable energy, therefore, does not suffice as a decarbonisation strategy.

Additional renewable power must be generated if the heating and transport sectors are to be decarbonised through greater integration between sectors (i.e. "sector coupling") in combination with increased reliance on renewables. Otherwise, renewable power will simply get moved from one sector to another. The excess used in the heating and transport sectors would be accompanied by a renewable deficit in the power sector.[35] A true clean-energy transition, however,

requires the decarbonisation of all sectors. The main assumption of this study is that the production of synthetic fuels is only possible if additional investment is made in renewable energy facilities. These fuels must cover the total cost of added renewable power generation.

Renewable power plants must be built explicitly for the purpose of producing synthetic fuels, either in Germany as offshore wind parks or, for example, in North Africa or the Middle East as onshore wind turbines and/or PV installations.

35 Fh-IWES/IBP (2017); Schill (2016); Öko-Institut et al. (2016); acatech et al. (2015); Brunner et al. (2016).

Figure 4 shows the annual full-load-hour production ranges that can be reached with renewable power generation in Germany and abroad. While PV tracking systems in North Africa and in the Middle East could generate more than 2,000 full load hours, combined PV/wind farms in these regions could guarantee around 4,000 to 5,000 full load hours. Offshore wind power from the North and Baltic Seas lies in a similar range (around 3,500 to 4,400 full load hours). These facilities would operate more than twice as many hours as could be expected from excess production in Germany generally or in Schleswig-Holstein in particular for the next 10 to 15 years.[36] The highest full-load-hour production

is possible with combined geothermal/hydropower plants in Iceland, which run almost the entire year.

In various parts of the world, combined PV/wind farms can provide sufficient full load hours for operating PtG and PtL facilities. Beyond the Mediterranean regions closely examined in this study, there are also very good locations, for example, in Brazil, Patagonia, and Somalia.[37] The problem, however, is that numerous promising sites are not only far away from Germany but they also lack the appropriate infrastructure.

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36 Two current scenarios estimate that electrolyser use in 2050 will reach 3,457 and 4,131 full load hours, respectively ("Strom und grünes Gas" in FNB Gas (2017) and "90 offen" in acatech et al. (2017)).

37 Fh-IWES (2017); for a global overview, see Fasihi et al. (2016).

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3 **In the beginning, synthetic methane and oil will cost between 20 and 30 cents per kilowatt hour in Europe. Costs can fall to 10 cents per kilowatt hour by 2050 if global PtG and PtL capacity reaches around 100 gigawatts.**

The production of synthetic methane and oil in Europe will begin at around 20 to 30 cents per kilowatt hour.

Were construction to begin on PtG or PtL plants today, they would not go online until 2022. But because PtG and PtL technologies are still in their infancy, any new facilities would be run as pilot projects as part of a market launch programme and hence likely to be based in Europe. This, in turn, would require energy from offshore wind farms in the North and Baltic Seas. Based on the facilities planned today, synthetic methane and oil would cost between 20 and 30 cents per kilowatt hour (Figure 5). If these facilities were built in sun- or wind-rich areas of North Africa and

the Middle East, costs would decrease by 40%.[38] The only way fuels could be produced for less is if they were made in Iceland using geothermal power and hydropower. In this case, around 10 cents per kilowatt hour could be feasible by 2022. The reason is the comparatively low costs for power production and the high capacity utilisation of conversion technologies. The potential for generating synthetic fuels in Iceland is limited to 50 terawatt hours in total.

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38 This assumes that the same cost of capital apply for facilities in North Africa as for facilities in Europe. As there are no concrete projects for exporting PtG methane or PtL to Germany (cf. Reuters 2017), these values are rather theoretical.

Cost of synthetic methane and liquid fuels in cent$_{2017}$ per kilowatt hour final product (without network charges and distribution cost)   Figure 5

Note: Prices of natural gas and premium petrol are based on average values from scenarios by the World Bank and the IEA. Other cost reductions for PtG / PtL may result from advancements in PV, from battery storage that increases full load hours, and from especially large electrolysis facilities. Cost increases may result from higher cost of capital due to higher country risks.

*   Offshore wind power
**   PV and PV / wind systems
*** Geothermal / hydropower (total potential limited to 50 terawatt hours)

Note: 10 cents per kilowatt hour is equivalent to around 90 cents per liter of liquid fuel.

Own calculations based on Frontier Economics (2018), with weighted average cost of capital of 6% (values rounded).

Costs could sink to around 15 cents per kilowatt hour by 2030 and to around 10 cents per kilowatt hour by 2050.

The costs of synthetic fuels may sink considerably during this period. This is mainly because of the degression of the investment costs for renewable energy power stations and conversion facilities due to the learning effect of a growing global market. In addition, the efficiency of water electrolysis is likely to increase over time, further cutting costs.

In the medium and long term, the import of synthetic fuels from all export regions will be cheaper than producing them in Germany with offshore wind energy. But the costs for these options tend to converge over time. The savings from importing synthetic fuels depend on the investment costs for offshore wind

and the full load hours at each site.[39] Another factor are the differences in cost of capital. For simplicity's sake, we have assumed weighted average cost of capital of 6%. In real-life situations, however, the exporting countries are subject to country-specific risk premiums on account of political or regulatory instability, and these premiums could increase the costs of imported synthetic fuels. For instance, cost of capital rates of 12% would raise the 2050 reference cost of PtG produced in North Africa using power from combined PV/wind facilities from 11 cents to 15 cents per kilowatt hour. This is a higher kilowatt hour value than the average projected cost for the production of synthetic fuels in Europe using offshore wind power with a cost of capital rate of 6%.[40]

The sought-after cost decreases can be reached if the global PtG/PtL capacity reaches some 100 gigawatts. But this would also require considerable, early and continuous investment in electrolysers and CO_2 absorbers.

The most important determining factors for the future cost of synthetic fuels are the costs of power generation, investment in production facilities, and the capacity utilization of conversion facilities. Transport costs play a less significant role, especially when it comes to liquid fuels.

While global investment in renewables is increasing, and the costs of solar and wind energy are likely to continue to fall,[41] similar levels of investment in PtG and PtL facilities are not in the offing. And considerable investment is needed to generate the economies of scale and learning effects that will decrease costs.[42] To achieve the cost reductions projected in this study, global electrolysis capacity must reach an order of magnitude of 100 gigawatts (Figure 6). A comparison with scenarios for Germany shows the following: For instance, acatech et al. (2017b) project 108 gigawatts of domestic electrolysis capacity in a scenario for 2050 that reduces greenhouse gases by 90% relative to a base year of 1990. By contrast, INES et al. (2017) provide an "optimised system" scenario with complete greenhouse gas neutrality that implies around 350 gigawatts of electrolysis capacity. Many scenarios project that PtG use in Germany will not be significant prior to 2030.[43] The exception here is acatech et al. (2017b), who estimate that the installation of 35 gigawatts of electrolysis capacity by 2030 will inaugurate an era of large-scale hydrogen production, and a new phase in the clean-energy transition.[44]

The 100 gigawatts of electrolysis capacity needed for affordable synthetic fuels corresponds to a fivefold increase in the world's current installed capacity of about 20 gigawatts.[45] Such an increase in capacity would cost between 10 and 100 billion euros by 2050. This broad range is indicative of the uncer-

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39 On the import side, additional cost reductions are foreseeable for PV and battery storage, further increasing full load hours. But these go beyond the scope of this study. A similar cost-cutting phenomenon can be observed in very large electrolysis plants. This study assumes specific investment costs of around 660 to 770 euros per kilowatt for 2020. However, investment costs as low as 400 to 500 euros per kilowatt can be achieved today in facilities with capacities of 100 megawatt or greater (DLR et al. 2014; IEA 2017a). In a 5-megawatt facility, the share of costs not related to the electrolyser stack would amount to 58%; in a 100-megawatt facility, the share would be 23% (DLR et al. 2014).

40 Projected cost of capital rates have a decisive impact on profitability estimates. They can be adjusted using the Excel tool on the Agora website. Ondraczek et al. (2015) calculate weighted average cost of capital rates of 11.8% for Morocco, 10.5% for Algeria, and 8.6% for Saudi Arabia. In practice, state guarantees such as the Hermes cover can help lower cost of capital (Temperton 2016). Current studies on the import of synthetic fuels usually assume cost of capital of less than 8%. MWV et al. (2017) project either 2% or 7%, while dena (2017b) put the number at 4%.

41 IRENA (2016).
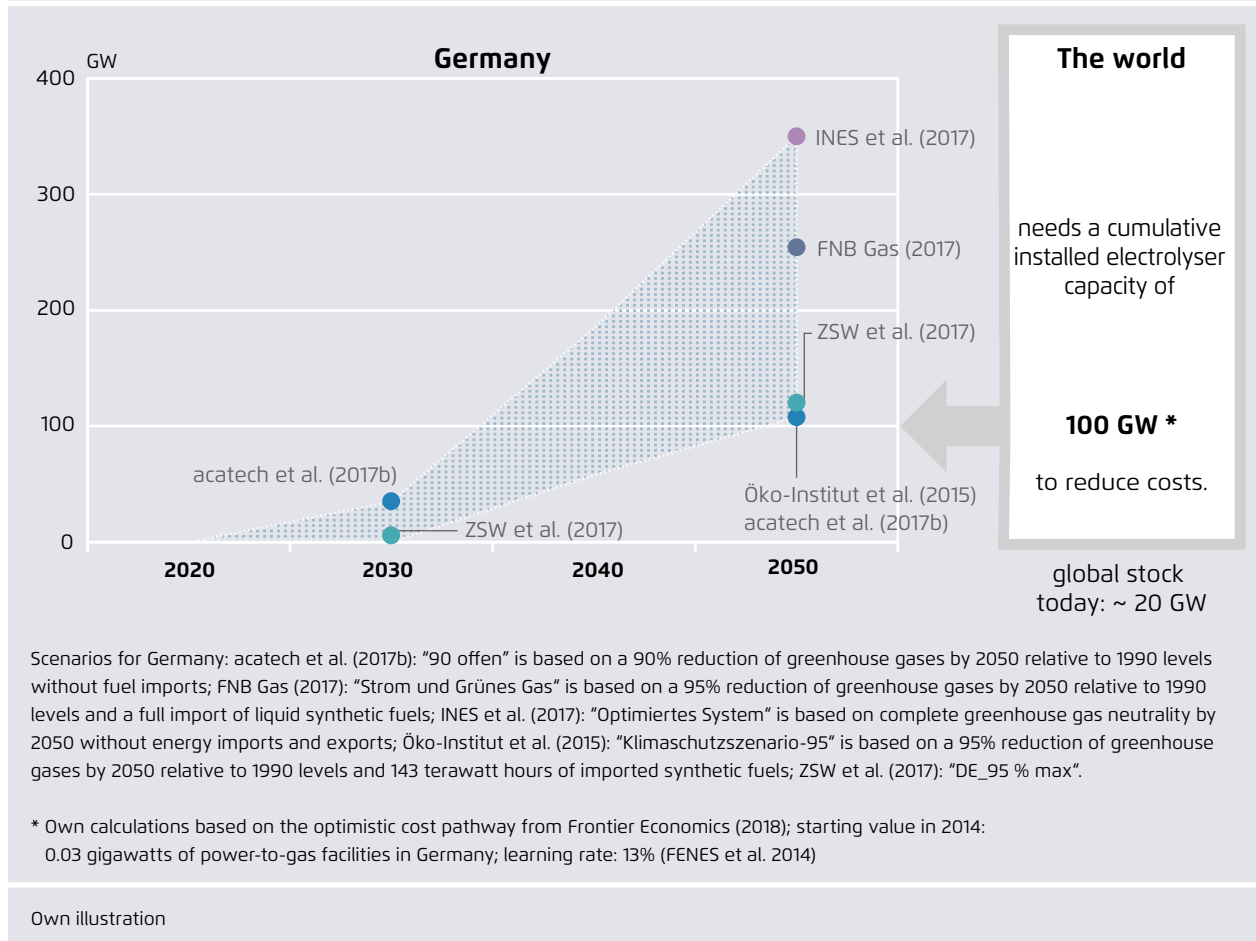
42 Schmidt et al. (2017a).

43 See AEE (2016).

44 See also ZSW et al. (2017), who project a demand of 5 to 10 gigawatts in 2030, and dena (2017a), who project a demand of around 40 terawatt hours.

45 This mostly involves alkaline electrolysis.

Installed electrolysis capacity for PtG and PtL in scenarios for Germany,
and cumulative installed global electrolysis capacity for cost reduction in gigawatts   Figure 6

Scenarios for Germany: acatech et al. (2017b): "90 offen" is based on a 90% reduction of greenhouse gases by 2050 relative to 1990 levels without fuel imports; FNB Gas (2017): "Strom und Grünes Gas" is based on a 95% reduction of greenhouse gases by 2050 relative to 1990 levels and a full import of liquid synthetic fuels; INES et al. (2017): "Optimiertes System" is based on complete greenhouse gas neutrality by 2050 without energy imports and exports; Öko-Institut et al. (2015): "Klimaschutzszenario-95" is based on a 95% reduction of greenhouse gases by 2050 relative to 1990 levels and 143 terawatt hours of imported synthetic fuels; ZSW et al. (2017): "DE_95 % max".

* Own calculations based on the optimistic cost pathway from Frontier Economics (2018); starting value in 2014:
0.03 gigawatts of power-to-gas facilities in Germany; learning rate: 13% (FENES et al. 2014)

Own illustration

tainty surrounding technological advancements.[46] Adding to the costs of electrolysis are the investment costs for the construction of methanisation and PtL facilities. And if methanisation and PtL production is

to rely on a sustainable carbon source, carbon capture from air (Direct Air Capture) technology must become commercially viable.[47] Since the Direct Air Capture pilot facilities are still in their early testing stages, current cost assumptions for these technologies are fraught with uncertainty. In sum, if synthetic fuels are to become affordable, the world must reach the 100-gigawatt mark. This challenge has multiple technological and financial hurdles. But as the following paragraphs explain, the largest hurdle is the political one.

46 The broad range of possible paths and costs arises, among other reasons, because of the variety of learning rates and starting values. While discussions in Germany typically use starting values based on the few existing PtG electrolysis plants in Germany (< 0.1 gigawatts), Schmidt et al. (2017b) compare global learning curves and use global electrolysis capacity (~ 20 gigawatts) as a starting value. It is also uncertain whether learning curves gained from past data on alkaline electrolysis can be applied to new technologies such as PEM electrolysis (Schmidt 2017a) or potentially also membraneless electrolysis (Esposito 2017).

47 See Section 4.

STUDY | The Future Cost of Electricity-Based Synthetic Fuels

Smaller and more decentralised approaches to generating synthetic fuels in Germany are not the focus of this study.[48] Though they too are likely to benefit from middle-to-long-term cost reductions in conversion technologies, they are not projected to add significant capacity. The cost reductions depend primarily on the world's total cumulative electrolysis capacity.

But without political intervention or high CO_2 pricing, investment in synthetic fuel production is unlikely, as are the resulting cost reductions. This is because the cost of producing synthetic fuels is higher than the cost of extracting fossil fuels.

PtG and PtL are decarbonisation technologies for areas of the energy economy in which gas or liquid fuels are more suitable than renewable electricity. Unlike wind and solar power, which today can be produced for less than fossil-based electricity in many parts of the world, PtL and PtG are unlikely to be more affordable than petroleum and natural gas without the right political framework, as can be seen in the World Bank and IEA price scenarios in Figure 5. The reason lies with existing reserves of petroleum and natural gas, which are still plentiful and easy to extract. If global demand for petroleum and natural gas remains the same or even falls as wind and PV power stations bring more and more electricity to the market, then fossil fuels won't be in short supply any time soon.

PtG and PtL will see widespread use only if the right political measures are in place. One of those measures is raising the price of carbon emission credits to, currently, between 80 and 100 euros per tonne of CO_2 so as to reflect the actual harm caused by the burning of fossil fuels. Other measures include the introduction of fuel additive guidelines[49] or market acceleration programmes.[50] These instruments are needed to get synthetic fuels out of the pilot stage and reduce the cost of their production.

Hydrogen costs almost 50% less than synthetic methane to produce, yet requires new infrastructure and hydrogen-powered end-use applications.

An alternative to synthetic methane or liquid fuel is their common chemical precursor: hydrogen. Hydrogen is significantly easier to produce and far more efficient than methane or liquid fuels. Consider: the cost of generating hydrogen is about 50% less than synthetic methane produced at the same site. Initially, hydrogen could be produced in North Africa at 10 cents per kilowatt hour. By 2050, the cost could fall to 5 cents (Figure 7).

The downside of hydrogen is that its use requires more changes to the energy system than do synthetic methane or other synthetic liquid fuels. This is because existing infrastructure has limited application when it comes to hydrogen. Costly changes would need to be made not only to infrastructure but also to gas- and fuel-fired end-use applications.[51] Germany's current gas supply network can tolerate hydrogen totalling 10% by volume.[52] In the future, there is talk of increasing system tolerance to 15% by volume.[53] Anything higher is likely to demand either expensive retrofitting or the installation of local or regional infrastructures specifically for hydrogen.[54]

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48 "Small" is a vague concept here. In reality, it can describe many differently sized facilities, which may even include very small generators designed for single-family homes. See Energiezukunft (2015) and dena (2016).

49 See section 7.2.

50 See section 4.

51 Gas turbines, storage, and CNG vehicles are especially critical with respect to their hydrogen tolerance. See Müller-Syring et al. (2014).
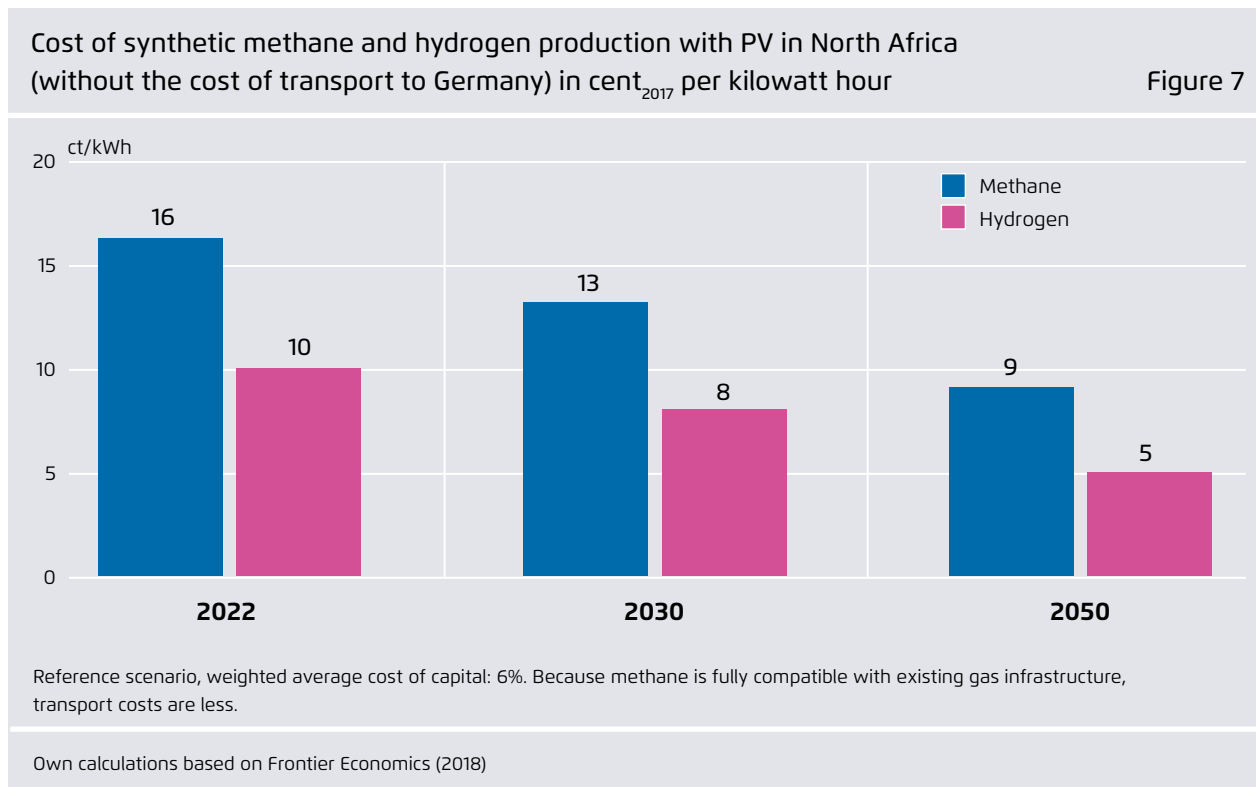
52 In the past, city gas contained over 50% hydrogen, and it was distributed to households using infrastructure that in part probably still exists today. But this experience does not include long-distance transport pipelines (Shell 2017).

53 DBI-GUT et al. (2017).

54 Regional pipelines exclusively for hydrogen are rare in Germany and currently under study. Once built, local hydrogen networks could be interlinked (Dena 2016;

Cost of synthetic methane and hydrogen production with PV in North Africa (without the cost of transport to Germany) in cent$_{2017}$ per kilowatt hour　　　Figure 7

Reference scenario, weighted average cost of capital: 6%. Because methane is fully compatible with existing gas infrastructure, transport costs are less.

Own calculations based on Frontier Economics (2018)

But before hydrogen can be distributed and used, it must reach Germany. It is still unclear how to organise the blending of hydrogen to natural gas to be then transported through pipelines of transmission system operators in foreign countries. Alternative options under consideration involve converting hydrogen gas to a liquid,[55] mixing it with organic carrier fluids,[56] or turning it into ammonia [57] and then transport-

ing it with tankers. At any rate, the wide-scale use of hydrogen would require a global hydrogen infrastructure. The argument for building such an infrastructure improves as international cooperation for global decarbonisation grows.[58] Though a separate infrastructure for hydrogen will cost more than using gas pipelines already in place, the elimination of fossil fuels will obviate the need for carbon capture from air and the lingering questions about its viability.

The question is how best to develop a pathway from fossil fuels over synthetic hydrogen, synthetic methane, and liquid fuels to make the most of existing assets while keeping total system costs to a minimum.

DVGW 2017; Shell 2017). FNB Gas (2017) describes a scenario with separate lines, one for transporting hydrogen to industry and transport companies and one for distributing methane to households.

55　Kawasaki Heavy Industries plans to introduce such ships by 2020 (LNG World Shipping 2017). On the conversion losses of liquefying hydrogen, see Fh-IWES (2017).

56　Preuster et al. (2017).

57　Turner (2017). Grinberg Dana et al. (2016) provide an in-depth analysis of how nitrogen can be used as a liquid carrier of hydrogen and argue that as fuel it delivers the best energy balance. See also IEA (2017a).

58　DBI-GUT et al. (2017). The government in South Australia proposed a hydrogen roadmap for making the region a hydrogen exporter (Government of South Australia 2017).

In the long-term, global market prices will emerge for synthetic fuels.

Based on developments in other markets, it is likely that the prices will exceed the generation costs described in this study. The willingness of a sector to pay for synthetic fuels depends on the CO_2 pricing of fossil fuels and on the availability and cost of direct-renewable or direct-electric alternatives,

which vary considerably from sector to sector.[59] The greater the pressure to decarbonise the individual sectors, the greater the long-term competition for synthetic fuels.[60]

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59 See Table 1 above.

60 dena (2016).

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4   **We need a consensus on the future of oil and natural gas that commits to the phase-out of fossil fuels, prioritises efficient replacement technologies, introduces sustainability regulations, and creates incentives for synthetic fuel production.**

Synthetic fuels are not an alternative energy source but a supplement for technologies with lower conversion losses such as electric vehicles and heat pumps. In this regard, application-specific targets are key.

The phase-out of petroleum and natural gas is critical for mitigating climate change and bringing about a clean-energy transition. In light of the enormous challenges associated with such a phase-out, government and industry leaders must come to a consensus and commit themselves to undertaking action.[61] Rules must be introduced for phasing out petroleum and natural gas and for substituting them with carbon-neutral alternatives. It is important to stress here that this substitution cannot occur one-to-one using carbon-neutral fuels. Due to the significant conversion losses, this approach would bring major disadvantages in terms of efficiency, energy needs, land requirements, costs, and the success of the global clean-energy transition. Though they are not a viable alternative to direct electricity and renewable power, synthetic carbon-neutral fuels will most likely

become an indispensable supplemental energy source for some areas.[62] Hence, it is important to furnish a basis for the medium- and long-term availability of competitive costs. This can only succeed if regulative instruments are implemented that allow long-term planning for investment in PtL and PtG facilities. The creation of a reliable foundation for planning decisions will hinge on three factors: namely, the adoption of a clear phase-out path, transparent directives, and incentives for using the most efficient technology in each sector. Moreover, a reliable market acceleration programme must be in place for sustainably produced synthetic fuels.

Existing instruments for lowering the specific CO_2 emissions of fuels such as the EU Fuel Quality Directive or for increasing the share of renewables such as the EU Renewable Energy Directive, are already fostering the phase-out of fossil fuels and the introduction of carbon-neutral alternatives. Both direct power and synthetic fuels are specifically mentioned in the revised version of the Renewable Energy Direc-

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61 Agora Energiewende (2016).

62 See Table 1.

tive. Table 2 provides an overview of relevant German and European legislation on the reduction of CO_2 emissions in fuels. At the international level, efforts to curtail CO_2 emissions must be increased as well, especially those of the International Civil Aviation Organization (ICAO)[63] and the International Maritime Organization (IMO). And the German government needs to put more pressure on international actors to cut fuel emissions.

Below we describe some points of orientation for establishing a consensus on the future of oil and natural gas, though a more detailed analysis goes beyond the scope of this study. We focus here on the sustainability requirements of synthetic fuels.

The first step in phasing out petroleum and natural gas is to reduce fossil fuel use.
Petroleum and natural gas still exist in abundant quantities, but in order to reach the climate targets set down in the Paris Agreement, a large share of fossil fuel reserves must remain in the ground.[64] Accordingly, it will be essential to introduce policy measures that gradually decrease total fossil fuel use and the overall emissions they release. The agreement the German government made with nuclear power plant operators in 2000 can serve as an example. That agreement allotted each plant a certain amont of energy it could produce before shutting down, giving operators flexibility in managing the phase-out.[65]

Incentives to drive the efficient replacement of petroleum and natural gas

As we pointed out, synthetic fuels cannot replace petroleum and natural gas on a one-to-one basis. Even if it drove the demand for synthetic fuels, it would not make sense to incentivise their use in personal vehicles. In terms of climate change mitigation, electric engines are a more efficient and, in the medium term, more affordable option. It is important not to weaken existing efficiency legislation such as the EU directive on reducing CO_2 emissions in cars and light utility vehicles[66] by counting synthetic fuels towards the CO_2 fleet targets of car manufacturers.[67] It is already likely that by 2030 the total cost of battery-electric vehicles will be more affordable than vehicles with internal combustion engines[68], pushing consumers to buy electric cars. This trend would be reinforced if governments make good on their plans to outlaw internal combustion engine vehicles for the sake of air quality and carbon reduction.[69]

In the building sector, it would be counterproductive if the possibility of using synthetic fuels in gas- and oil-fired boilers decreased the number of buildings that receive green retrofits.[70] This is especially true given the long lifespans of buildings. For one, synthetic fuels require much more power than heat pumps.[71] For another, future demand competition on

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63   For more on the ICAO climate change mitigation instrument CORSIA and the ETS system in aviation, see Cerulogy (2017) and ICCT (2017)

64   IPCC (2013).

65   See Agora Energiewende (2016) for more on how the nuclear consensus can serve as a role model for a coal consensus.

66   In the context of the EU directive on the reduction of CO_2 emissions of cars and light utility vehicles, counting carbon-neutral fuels towards climate goals would slow the electrification of vehicles and thus be counterproductive for climate change mitigation (EU 2009a).

67   For more about the future of CO_2 regulation for cars and light utility vehicles, see Agora Verkehrswende (2018).

68   Cf. Öko-Institut (2018).

69   For instance, a recent legislative proposal in California would require all new cars and light utility vehicles sold in the state to be emission-free by 2040 (Kane 2018).

70   Langenheld/Graichen (2017); Fraunhofer IWES/IBP (2017).

71   The example in Figure 3 shows a gas-fueled condensing

Relevant European and German norms for reducing CO_2 emissions from fuel	Table 2

Regulation	Specifications
Revised EU Renewable Energy Directive (RED II)	At least a 27% share of renewable power by 2030 in the transport, heating/cooling, and industrial sectors; 6.8% minimum share in transport of advanced biofuels including electricity-based synthetic fuels by 2030; At least a 70% reduction of greenhouse gases of modern biofuels relative to fossil reference fuels
Fuel Quality Directive (FQD; 2009/30/EG)	6% specific greenhouse gas reduction by 2020 relative to fossil reference fuels
German Federal Immission Control Act for implementing FQD and RED (BImSchG)	Greenhouse gas reduction targets for market sale of fossil and biogenic fuels: 3.5% from 2015; 4% from 2017; 6% from 2020
37th German Federal Immission Control Ordinance (37. BImSchV)	Counts electricity-based fuels towards greenhouse gas targets starting in 2018 under the following conditions: power does not have a biogenic source; not coupled with grid; alternatively grid coupling to prevent the curtailment of renewable energy power stations
38th German Federal Immission Control Ordinance (38. BImSchV)	Sets the minimum share of advanced fuels (including electricity-based fuels) for market sale: 0.5% starting in 2025 and 0.05% starting in 2020 with more than 20PJ
Biofuel Sustainability Ordinance (Biokraft-NachV)	Defines minimum standards for greenhouse gas reductions from biofuels
Energy Industry Act (EnWG)	Defines synthetic methane and hydrogen as "biogas" if at least 80% of power, carbonmonoxide, and carbondioxide come from renewable sources

Own overview

the global market and between sectors make it uncertain whether synthetic fuels for gas- or oil-fired boilers will be cheaper than the direct use of electricity or renewable energy. Green retrofitting keeps the options open when it comes to heating technology, and offers more flexibility in the event that hopes of cost reductions do not pan out.[72]

Application-specific targets for increasing the share of synthetic fuels

For applications that do not lend themselves to wide-scale use of direct electricity or direct renewable energy, synthetic fuels can act as an important supplement. Politicians should discuss introducing quotas for synthetic fuels based on the area. For instance, two cases where it would make a good deal of sense to raise synthetic fuel levels are air and maritime transport.

Application-specific targets for electricity-based fuels enable long-term planning for investors and reduce costs through research, development and scaling.[73] The ideal investors for synthetic fuels could be those actors that are financially strong and still turning a considerable profit with fossil fuels. Well-balanced political instruments for phasing out petroleum and natural gas and introducing carbon-neutral substitutes should be used to send the right signals to investors[74] for cross-branch activity.[75] At the same time, the government must promote technology by funding pilot facilities. The creation of facilities that

adhere to strict sustainability regulations would create a basis for subsequent investment and provide an opportunity to gather important experience.

Incentives to introduce synthetic fuels must be accompanied by binding sustainability standards. Most of all, legislation is needed to guarantee a minimum level of greenhouse gas reduction against a fossil fuel baseline.

Binding sustainability regulations would ensure that PtG and PtL fuels benefit the climate and encourage long-term planning

Market incentives for synthetic fuels only make sense for climate policy if they are tied to mandatory sustainability regulations. This was the lesson from the EU's experience with biofuels from food crops. At first, quotas increased demand and made possible massive increases in production capacity. Only later did worry about the environmental and societal effects lead to the introduction of stricter sustainability standards.[76] A critical analysis of indirect land use changes on greenhouse gas levels of biodiesel and bioethanol found that the benefit of these fuels on the environment was much less than initially supposed.[77] To assess the global decarbonisation potential of PtG and PtL fuels, binding sustainability standards are needed in five areas (Table 3). Sustainability standards are also needed for the launch of applications that use direct electricity, especially for the manufacture of batteries and the excavation of their raw materials.[78]

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boiler that requires six times as much renewable power for synthetic methane as a heat pump with an annual performance factor of 3.

72 ifeu et al. (in progress).

73 Schmidt et al. (2017a).

74 In an ideal world, carbon pricing would incentivise a shift from fossil to renewable energy sources in the non-ETS sector as well. See Agora Energiewende (2017d). In view of innovation externalities, it should be assumed that carbon pricing alone will not create the research, development, and long-term investment needed for building PtG and PtL facilities (Mitchell et al. 2011).

75 DECHEMA (2017a).

76 A comparison of the EU Commission's reform proposals for the renewable energy directive (EU 2018), the current guideline 2009/28/EG (EU 2009b), and its earlier version 2003/30/EG (EU 2003) shows that sustainability requirements have increased and conventional biofuel allowances have decreased.

77 Other critical factors are the ecological and societal consequences of biofuel production from agricultural waste products. On the emissions of various biogenic energy use scenarios, see, ifeu (2016).

78 Öko-Institut (2017a) and Cerulogy (2017).

Minimum level of greenhouse gas reduction

To be ecologically viable, the entire production chain of synthetic fuels should emit at least 70% less greenhouse gas than fossil fuels. 100% greenhouse gas neutrality is impossible. Even the production of wind and solar power releases tiny amounts of greenhouse gas. The EU Commission's proposed reforms to its renewable energy directive uses the 70% mark. Synthetic fuels, too, should meet these minimum requirements. The emission reduction is calculated based on greenhouse gas intensity of the electricity used and the carbon dioxide source.

More renewable power

To get greenhouse gas emissions close to neutral, the power for the entire production process (including water treatment) must come from renewable sources. And this means adding renewable energy power stations specifically for fuel production. These stations should not be coupled with the power grid and the power they produce should not count toward the share of renewables in the power mix.[79] When it comes to producing synthetic fuels in developing countries for export to industrial nations, a key question arises: How to prevent the slowdown of decarbonisation that occurs when the best wind and solar power sites are used for generating PtG and PtL exports while domestic demand is met with less favourable and possibly more expensive renewable energy power stations or with fossil fuel-fired plants?[80]

CO$_2$ from sustainable atmospheric sources

Another factor in greenhouse gas neutrality is the use of direct air capture or sustainable biogenic sources when acquiring the CO$_2$ needed for generating PtL and PtG fuels. Of these two approaches, direct air capture is the most promising for the future of synthetic fuels. Sustainable biogenic CO$_2$ is available only in limited quantities and is particularly scarce in dry regions best suited for wind and PV power generation. Fossil CO$_2$ from cement and steel production is a poor choice for PtL and PtG generation as well, even if regarded by many as a temporary solution.[81]

Several reasons speak against the use of fossil CO$_2$. First, *German climate targets seek to limit carbon emissions*. The reduction goals for 2050 restrict greenhouse gas emissions to a minimum. And the levels that are permitted have been reserved for hard-to-avoid emissions in the industrial and agricultural sectors. Whereby however, today's carbon capture technology is only suitable for industrial sites. Here, it's point sources and not diffuse sources like in agriculture.

Will the CO$_2$ provided by the industry be able to cover the CO$_2$ needed for synthetic fuels production in Germany in 2050? This question is important because international greenhouse gas reporting requires that fossil CO$_2$ be covered by a country's emission budget even if CO$_2$ capture and fuel production occurs abroad. Otherwise, CO$_2$ from burning fossil fuels in Germany would exceed emission budgets.

Second, *the decreased availability of captured CO$_2$*. On the basis of current reduction measures, the world is unlikely to achieve the Paris Agreement's goal of limiting global warming to 1.5 degrees Celsius above preindustrial levels. In the future, therefore, green-

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79   As explained in section 1.2, excess power does not provide a reliable foundation for PtG and PtL production. Additional power needed from the grid to increase the number of full load hours must be balanced with power mix emissions. A high power demand can quickly offset climate benefits and ultimately release more emissions than fossil fuels.

80   Future studies need to compare global supply and demand scenarios for synthetic fuels. For instance, what would happen if most EU member states were to rely on the import of synthetic fuels? See IEA (2017a).

81   Christensen & Petrenko (2017) point out the risk of "double counting" emission reductions. This occurs when, say, cement industry CO$_2$ used for vehicle fuel production counts toward individual greenhouse gas reduction goals of multiple interlinked sectors – the cement industry, fuel producers, and car manufacturers, say.

house gas emissions will need to be eliminated in the industrial sector or captured and placed underground through carbon capture and storage (CCS).[82]

Third, *investment in direct air capture is a must.* As long as low-cost CO_2 is available from the cement and steel industries, investment in direct air capture (DAC) technology will not reach the scale needed for rapid cost reductions. The study projects DAC costs of 145 euros per tonne of CO_2 through 2030 and 100 euros per tonne thereafter (Figure 8).[83]

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82   ZEP (2017).

83   See also section 6.2.3.4 and the downloadable Excel tool, which allows cost estimation for CO_2 capture from the cement industry. The DAC technology cited by Climeworks (2017) became known to a wider public as part of the project Nordic Blue Crude. Dena (2017b) relies on the same technology but projects greater costs, from around 200 to 400 euros per tonne of CO_2.

Another question is whether shifting greenhouse gas emissions from one sector to another will just reduce the pressure to decarbonise. As a result, the sectors that benefit – for example, the buildings materials sector – have less incentive to innovate.

There is a third risk associated with direct air capture: DAC plants have a large geographical footprint, and this must figure into the earliest planning stages. (Converting plants producing PtG and PtL from CO_2 emissions for DAC is costly, besides.) Though space may play a minor role in North Africa and the Middle East, the same cannot be said for the densely populated areas of Europe. Say a PtG or PtL plant draws a nominal load of one gigawatt from a large offshore wind park in the North Sea or Baltic Sea. The CO_2 from DAC would require a surface area of between

Overview of relevant sustainability aspects in the production of synthetic fuels	Table 3
Minimum greenhouse gas reduction	Entire production chain of synthetic fuels must emit 70% less greenhouse gas than conventional fossil fuels.
Additional renewable electricity generation	Power for the entire production process (including water processing, etc.) must come from additional renewable energy power stations. If this cannot be achieved, the emissions of each power mix must be balanced.
CO_2 from sustainable atmospheric sources	Only CO_2 capture from the air or sustainable biogenic sources create a closed carbon-neutral CO_2 cycle. If this cannot be achieved, all CO_2 emissions are to be counted.
Sustainable use of water and land	Water processing for electrolysis may not negatively impact water supply. Production sites may not be located in nature reserves or in other vulnerable areas (such as habitats with high levels of biodiversity).
Social sustainability of fuel production	Synthetic fuel production may not negatively impact local communities. When fuel is produced in developing countries, a portion of the revenues must go towards sustainable local development.

Own illustration, modified as per Öko-Institut (2017b)

Cost assumptions for CO_2 production in euros$_{2017}$ per tonne of CO_2			Figure 8
	Today	**2030**	**2050**
Direct air capture **for PtG***	145	102	100
German cement industry	33		
Iceland cement industry	17		
* PV, North Africa, reference			
Frontier Economics (2018)			

0.19 and 1.28 square kilometres (Table 4),[84] roughly 27 to 180 football fields.

Sustainable water and land use

By contrast, many areas favourable for PV and wind generation have land but lack fresh water. And fresh water is needed for electrolysis in fuel production, so desalination plants must be built as well. In this regard, producer countries must take care that development is sustainable. It would not be acceptable for fuel plants in developing regions to use large quantities of fresh water while local communities do not have enough to drink. Moreover, attention must be paid so that large industrial facilities do not displace existing or less lucrative forms of land use. This is especially true of land used for food production, but it also includes space for settlements and nature reserves to protect endangered animals and plants.

Socially sustainable fuel production

It is important that fuel production dos not negatively impact local communities. In developing countries, a portion of production revenues must go toward sustainable development. When countries in North Africa and in the Middle East produce synthetic fuels for Germany, efforts should be made to ensure inclusive benefits for local populations.

Synthetic fuel as a possible post-fossil business model for oil and natural-gas exporters

If the sustainability standards reached as part of the oil and natural gas consensus are adhered to, the export of synthetic fuels can bring important benefits for producer countries whose economies rely primarily on fossil fuel exports. This is because fossil revenues are likely to decline amid global efforts to stay within the two-degree warming limit. The drop in revenues will have significant effects on jobs, state budgets, existing subsidies for fossil fuels, on the relationship between government and society, and on the political stability of entire regions.[85] In the Southern Mediterranean the situation is exacerbated by a rapidly growing population, high unemployment, and the increasing immediate effects of global warming.[86]

Though these discussions are just starting to gain momentum now,[87] almost ten years' worth of thinking has already gone into *Desertec*.[88] Designed to harness sustainable power from sun-rich deserts, *Desertec* wanted to create a transmission system to bring solar power from the Southern Mediterranean to Europe.[89]

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84 This range is due to the differing data provided by researchers (APS 2011; Climeworks 2017). We assume here 4,400 full load hours and that the efficiency of electricity→H2: 67% and that H2→methane/PtL: 80%.

85 Today's low oil prices have put significant pressure on the state budgets of oil exporters. See Jalilvand (2017).

86 Dii (2013); Lelieveld et al. (2016).

87 Fasihi et al. (2017); dena (2017a, b); MWV et al. (2017).

88 Werenfels/Westphal (2010)

89 The first concepts for *Desertec* had the choice of trans-

But the system of high-voltage direct current transmission lines envisioned by the project has yet to materialise.

The production of synthetic fuels in the Southern Mediterranean offers similar benefits to those of Desertec. For export countries, the largest benefit comes from added economic productivity through the manufacture of components for renewable energy generation and through the construction and operation of renewable energy power stations.[90] A similar boost is likely to come from the construction of additional PtG and PtL production plants. Import countries, for their part, will receive the synthetic fuels they need at relatively cheap cost. And the lack of high-voltage transmission lines to Europe does not pose a problem for synthetic fuels, as it did for the Desertec project. This is because synthetic fuels can be transported using existing pipelines and infrastructure. The only exception here is hydrogen, for which existing infrastructure will suffice only in part.[91]

But as the enormous challenge of decarbonisation becomes increasingly clear, so does the urgent need for synthetic fuel use in some areas. And this is precisely where renewable energy production in the Southern Mediterranean comes in: offering a sensible approach to a global division of labour while helping secure geopolitical stability.

Land requirements for CO_2 capture from the air for PtG or PtL production using a 1-gigawatt offshore wind park   Table 4

km²	PtG methane	PtL
min*	0.19	0.35
max**	0.70	1.28

*   0.4 km² for 1 Mt CO_2/year; Climeworks (2017)
** 1.5 km² for 1 Mt CO_2/year; APS (2011)

Own calculations

Summary

In the future, *power-to-gas* and *power-to-liquid* fuels will be needed for applications where direct electricity or direct renewable energy is not an option. But conversion plants require affordable renewable energy, a great deal of full load hours, and direct air carbon capture. To reduce the costs of operating the plants, early, large-scale investment will be needed. Owing to the size of this investment, government and industry must act in concert. This means reaching a consensus on the gradual phase-out of petroleum and natural gas, the prioritisation of efficient replacement measures, binding sustainability regulations, and the creation of incentives to introduce synthetic fuels. To make this happen, we need to start developing suitable energy policy instruments now.

porting electricity or hydrogen. The decision was made for power because of the conversion losses associated with turning hydrogen back in to electricity. (Düren 2017).

90   Dii (2013).

91   Düren (2017).

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The Future Cost of Electricity-Based Synthetic Fuels

frontier
economics

3. Summary

Background, objective and focus of the study

The German government aims to reduce CO_2 emissions by 80% to 95% in relation to 1990 levels by 2050. Achieving this target will require CO_2 reductions across all sectors, including the heating and transport sectors.

One option for decarbonising the heating and transport sectors is to rely on synthetic fuels from renewable electricity, including hydrogen and synthetic methane, methanol, gasoline, and diesel. A key advantage of this approach is that it would be relatively easy to import synthetic fuels from other countries, thereby indirectly importing electricity from renewable energy sources. This would enable the use of highly favourable locations for generating electricity from renewables (i.e. locations with excellent wind and solar resources). As a result, the cost of producing synthetic fuels would be cheaper than producing in Germany. Foreign production would also address the problem of dwindling domestic site availability for new renewable generation plants, such as wind turbines.

In light of current discussions concerning the potential for expanding the use of synthetic fuels, Agora Energiewende and Agora Verkehrswende commissioned Frontier Economics to estimate the costs associated with importing synthetic fuels up to 2050. The study places a particular focus on the costs associated with importing synthetic methane and synthetic liquid fuels. For the purpose of comparison, it also estimates the costs associated with producing these fuels using offshore wind turbines in the North and Baltic Seas.

The value chain for generating synthetic methane and synthetic liquid fuels

The starting point for the production of synthetic methane and synthetic liquid fuels is the generation of electricity. Hydrogen is produced from electricity and water using electrolysis, releasing oxygen as a by-product. In a second conversion step, hydrogen and carbon dioxide are used as inputs to produce either synthetic methane (via methanisation) or synthetic liquid fuels (via Fischer-Tropsch synthesis or methanol synthesis).

Six different site/technology options for the electricity generation were considered as part of the study:
→ Offshore wind power in the North and Baltic Seas (used as a reference point to assess the potential cost advantage of importing synthetic fuels)
→ Geothermal/hydropower in Iceland
→ Photovoltaic power in North Africa
→ Hybrid photovoltaic power/onshore wind power in North Africa
→ Photovoltaic power in the Middle East
→ Hybrid photovoltaic power/onshore wind power in the Middle East

The cost estimates assume that the CO_2 required for methanisation or the production of synthetic liquid fuels is extracted from the air (*direct air capture*). We also assume in this study that the conversion plants are constructed on a large scale explicitly for exporting synthetic fuels to Germany. With a view to offshore wind turbines in the North and Baltic Seas, the investment costs of the plants are explicitly taken into account, rather than simply the short-term marginal costs (i.e. the study does not assume that synthethic fuel production is based on excess electricity in the system ("surplus electricty").
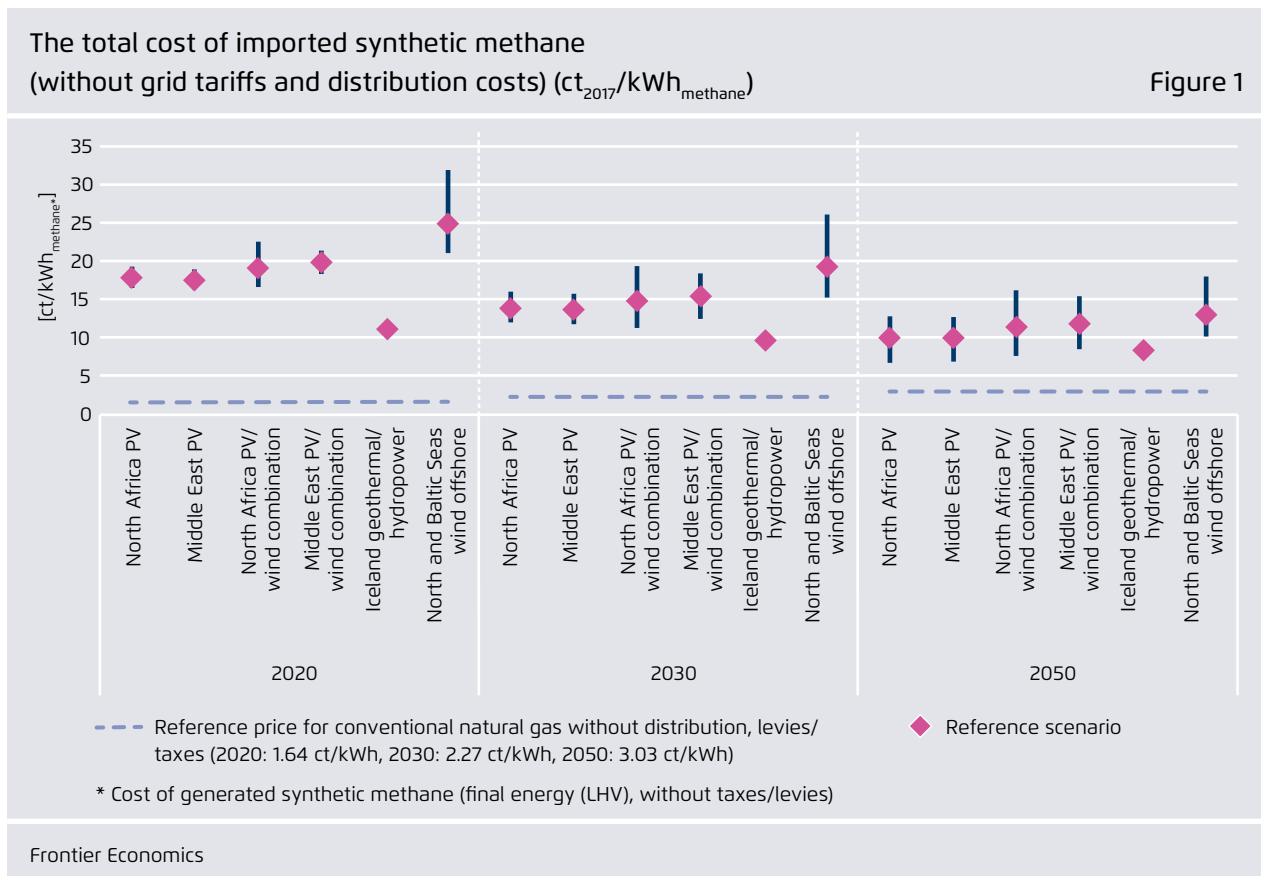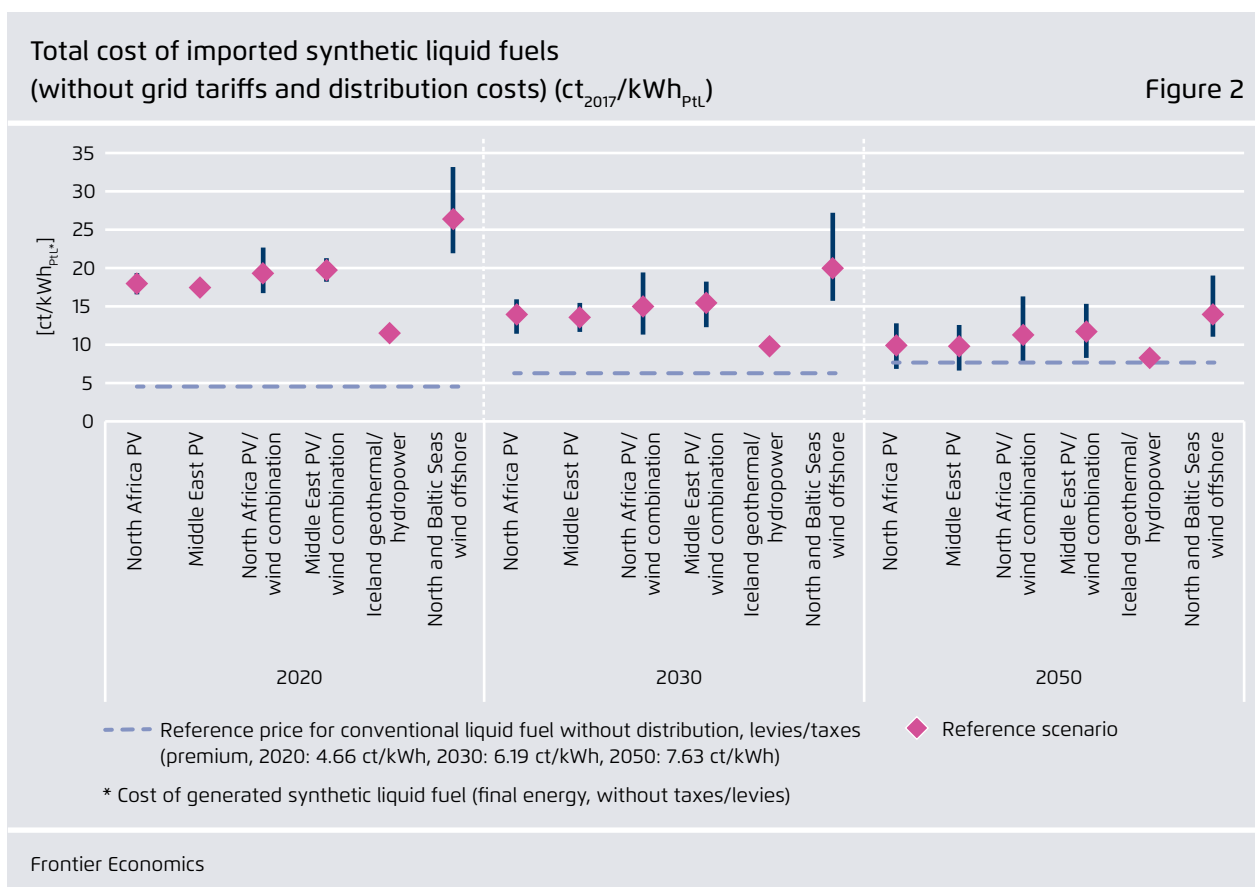
Key findings

Our cost estimates reveal the following:

→ **The cost of synthetic methane/synthetic liquid fuels declines considerably over time** (see Figures 1 and 2). This cost decline is driven first and foremost by the assumed decline of investment costs of renewable electricity generation plants and conversion plants due to economies of scale and learning effects. The efficiency of hydrogen electrolysis is also assumed to increase over time. Our estimated cost reductions mean that in the medium to long term, the cost of synthetic fuels approaches that of fossil fuels.

→ **The cost of the individual site and technology options converges over time.** This is because the investment costs for photovoltaic power plants and offshore wind turbines are assumed to fall more

sharply than the investment costs for established technologies such as onshore wind, geothermal and hydropower.

→ **The costs of generating electricity as fundamental driver of synthetic fuel costs** (see Figure 3). Electricity generation costs make up a significant fraction of the total costs of synthetic methane and synthetic liquid fuels. In 2020 electricity generation costs are by far the largest cost component. Although electricity generation costs are expected to fall until 2050 due to assumed reductions in investment costs for renewable energy, they will continue to make up a significant fraction of total costs in 2050. The strong influence of electricity generation costs on the cost of synthetic methane and synthetic liquid fuels can be attributed to the conversion losses that occur during hydrogen electrolysis, methanisation and methanol synthesis or Fischer-Tropsch synthesis.

The total cost of imported synthetic methane
(without grid tariffs and distribution costs) ($ct_{2017}/kWh_{methane}$) Figure 1

Reference price for conventional natural gas without distribution, levies/taxes (2020: 1.64 ct/kWh, 2030: 2.27 ct/kWh, 2050: 3.03 ct/kWh)

◆ Reference scenario

* Cost of generated synthetic methane (final energy (LHV), without taxes/levies)

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Total cost of imported synthetic liquid fuels (without grid tariffs and distribution costs) (ct_{2017}/kWh_{PtL}) Figure 2

Reference price for conventional liquid fuel without distribution, levies/taxes (premium, 2020: 4.66 ct/kWh, 2030: 6.19 ct/kWh, 2050: 7.63 ct/kWh)

◆ Reference scenario

* Cost of generated synthetic liquid fuel (final energy, without taxes/levies)

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→ **Conversion plants utilisation rates and investment costs are also a considerable cost driver** (see Figure 4) These represent the second most important cost component after electricity generation costs.

→ **The costs of procuring CO_2:** The production of synthetic methane and synthetic liquid fuels from hydrogen requires carbon dioxide which can be obtained from various sources, including biomass, industrial processes, and geothermal boreholes, but can also be captured directly from the air. The cost of procurement varies considerably depending on the source of the CO_2. In our cost estimates we assume that the required CO_2 is extracted from the air in all countries. Our estimates are thus based on the method with the highest relative costs but also the greatest possibility for large-scale use. Direct air capture also complies with the sustainability requirement of a closed CO_2 cycle (see below).

Sustainability aspects

If synthetic fuels are to be imported with the aim of achieving emission reduction targets of these synthetic fuels in Germany, then the fuel production of these synthetic fuels in the countries of origin must meet certain sustainability criteria. The following sustainability aspects are of considerable importance in this regard:

→ **Additionality of renewable electricity generation:** Additionality considers the question of whether the renewable electricity generated in the countries of origin for producing fuels is in addition to or displaces renewable electricity generated for other purposes.

→ **Sustainable use of space:** Another sustainability criterion refers to the competitive use of land area, e.g. for building renewable energy plants and conversion facilities. The displacement of food pro-

Comparison of the generation and transport costs of synthetic methane in North Africa (photovoltaic) and in the North and Baltic Seas (offshore wind) in the reference case (ct$_{2017}$/kWh$_{methane}$)

Figure 3

North Africa

Source: PV

North and Baltic Seas

Source: wind offshore

- Transport
- Conversion to methane (including H$_2$ storage)
- Conversion via hydrogen electrolysis
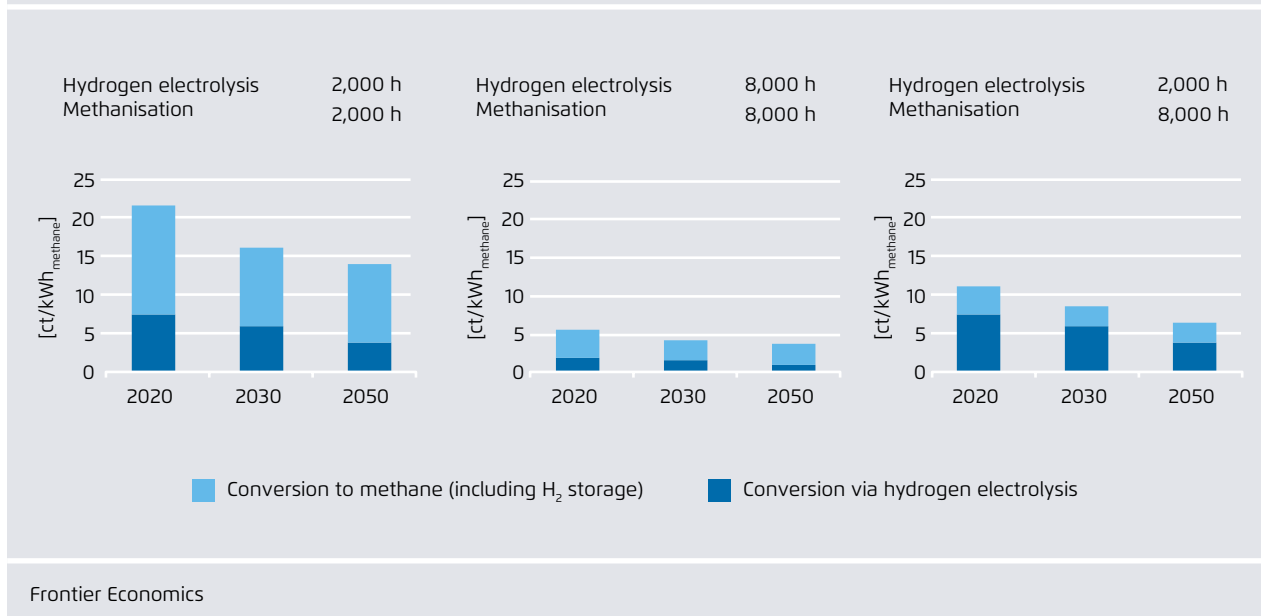- Electricity costs of hydrogen electrolysis
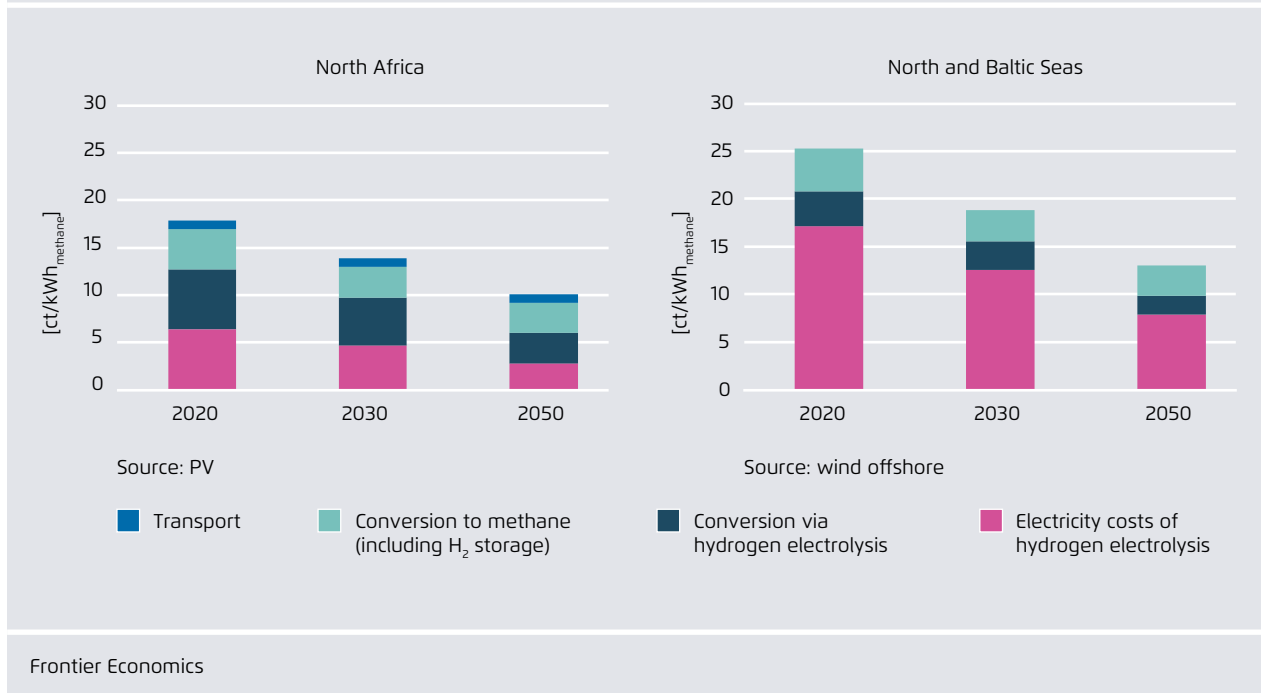
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Impact of conversion plants load factors and investment costs on the cost of conversion (exemplary values for hydrogen electrolysis and methanisation)

Figure 4

Hydrogen electrolysis   2,000 h
Methanisation   2,000 h

Hydrogen electrolysis   8,000 h
Methanisation   8,000 h

Hydrogen electrolysis   2,000 h
Methanisation   8,000 h

- Conversion to methane (including H$_2$ storage)
- Conversion via hydrogen electrolysis

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duction and forested areas is of particular concern in this regard. However, in very dry regions, such as North Africa and the Middle East, this is not expected to be a major problem. The extent to which there is competition between uses needs to be investigated specifically for each site/country being considered.

→ **Sustainable economic development in the production countries:** In some cases it is a requirement that CO_2 reduction measures are implemented in in a manner that encourages sustainable economic development in the production countries. Investment in renewable energy and synthetic fuel production technology is likely to have a positive effect on economic development and may be of particular interest to countries that currently generate a high proportion of their national income from the export of fossil fuels, and - at the same time - have a high renewable energy potential. However, it must be ensured that the exported synthetic fuels are genuinely produced from renewable sources, e.g. by introducing a certification system.

→ **Existing water supply must not be used in dry climate zones:** In dry climate zones such as North Africa and the Middle East, it must be ensured that the water required for the electrolysis is sourced from seawater desalination plants and not from the existing water supply.

→ **Closed CO_2 cycle**: To created a closed CO_2 cycle, the CO_2 must be captured from the air, biomass or biogas. In our cost estimates we have assumed that the required CO_2 is extracted from the air in all countries.

Summary and prospects

Our estimates suggest that there are cost benefits associated with importing synthetic fuels. These benefits are primarily attributable to the more favourable site conditions for generating electricity in foreign countries, compared to the production in Germany. Our estimates additionally suggest that in the medium to long term, the costs of synthetic and conventional fuels will converge.

The literature on which our cost estimates are based indicate that there is a great deal of uncertainty concerning future cost trends. These uncertainties are reflected in the broad divergence in costs between the different scenarios. We refer the reader to the Excel tool provided at the Agora website which enables users to investigate how divergent underlying assumptions impact the cost calculations.

4. Background, objective and methodological approach of the study

In this section we describe the background of the study (Section 4.1), its objectives (Section 4.2), and its methodological approach and structure (Section 4.3).

4.1 Background of the study

The German government aims to reduce greenhouse gas emissions by 80% to 95% in relation to 1990 levels by 2050. Achieving this target will require carbon reductions across all sectors, including the heating and transport sectors. For the period up to 2030,

the German government has defined sector-specific targets in its Climate Action Plan 2050. According to this policy document, emissions in the building sector are to be reduced from 119 million metric tonnes of CO_2 equivalents in 2014 to 70 to 72 million tonnes of CO_2 equivalents by 2030. At the same time, transport sector emissions are to be reduced from 160 million metric tonnes of CO_2 equivalents in 2014 to 95 to 98 million metric tonnes of CO_2 equivalents by 2030.[92]

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92   German Federal Government (2016)

German decarbonisation targets requires significant expansion of renewable energy, also in the heating and transport sectors   Figure 5
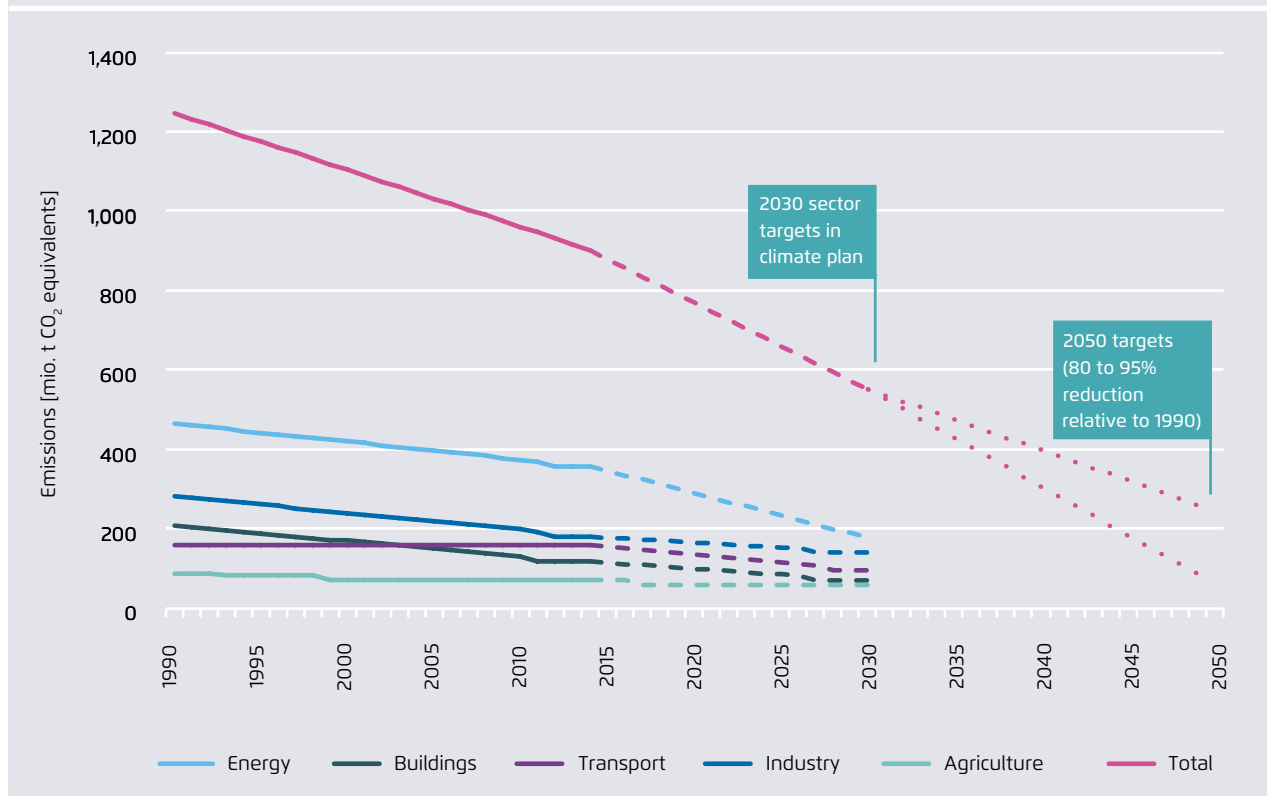
Frontier Economics based on the *Climate Action Plan 2050* (German Federal Government 2016)

There are currently two fundamental strategies being considered for the long-term complete decarbonisation of the heating and transport sectors in Germany,[93] although combining elements of the two strategies is also a conceivable option:[94]

→ On the one hand, decarbonisation can be achieved through the direct electrification of the heating and transport sectors (for example, using electricity-based heating systems and electric vehicles).

→ On the other hand, decarbonisation can be achieved by using synthetic fuels[95] that are produced from renewable electricity (synthetic gaseous fuels such as hydrogen, synthetic methane or methanol and synthetic liquid fuels such as synthetic gasoline and diesel).

Direct electrification of the heating and transport sectors would allow the direct use of renewable electricity to meet heating and transportation energy demands in the heating and transportation sectors. The advantage of this approach is that electricity does not have to be converted into another type of energy, which entails considerable conversion losses. Another advantage is that many electricity-based technologies are highly efficient such as heat pumps. The disadvantage of this approach is that there are losses associated with transporting, distributing and particularly with storing electricity. Furthermore, beyond the costs that would arise from constructing new renewable generation capacity, widespread electrification would entail significant investment in additional electricity transport grids, distribution grids and electricity storage infrastructure.

Under the second option, electricity generated using renewable sources is converted to synthetic fuels which are then used in the heating and transport sectors. The main drawback of this option are the conversion losses that occur when producing synthetic fuels. As a result under this strategy, a far greater number of renewable generation plants are required to meet the same volume of end consumer demand, as compared to the option of using electricity directly. In addition, significant investments would be required to construct conversion plants. Widespread end-use applications such as combustion engines are in some cases also less efficient than corresponding electrical drive technologies. However, this approach has numerous advantages:

→ existing infrastructure can remain in use (for example, gas transport networks, distribution infrastructure, fuel-based vehicle fleets);

→ synthetic fuels are easy (and relatively inexpensive) to store compared to electricity;

→ synthetic fuels have a higher energy density compared to electricity, and can thus be be used in aviation and shipping sectors; and

→ the import of synthetic fuels from abroad is relatively simple.

The focus of this study is the option of importing synthetic fuels to cover demand in the heating and transport sectors. Importing synthetic fuels could become an important element of the energy transition if the availability of renewable energy produced in Germany cannot keep up with demand over the long term. This is a clear risk, as very high demand for renewable electricity is predicted by models that forecast the effects of greater integration between energy sectors. The import of synthetic fuels also has the advantage of allowing the use of highly favourable sites for generating renewable electricity (i.e. locations with excellent wind and solar resources). This would reduce cost of generating synthetic fuels when compared to production in Germany.

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93 The direct use of renewable energy sources such as biomass and solar energy can also contribute to the decarbonisation of the heating sector (see Fh-IWES/IBP, 2017).

94 Identifying the decarbonisation pathway that is the most economically favourable does not form part of this study.

95 Both liquid fuels (such as heating oil, gasoline, diesel) and gaseous fuels (natural gas, synthetic methane) can be used as fuels in the heating and transportation sectors. In our cost estimate we focus on the costs associated with synthetic methane and synthetic liquid fuels.

4.2 Objective of the study

The objective of this study is to estimate the costs associated with importing synthetic fuels up to 2050. We specifically focus on the costs associated with importing synthetic methane and synthetic liquid fuels. As described in more detail in Section 4.3, our cost estimates are based on an analysis of the existing literature, discussions with experts, and our own indicative cost assumptions. It should be noted that the cost estimates for specific technologies encountered in the literature and voiced by experts are subject to significant variance. According to statements from experts, for example, there have been very large decreases in the cost of PEMEC electrolysis over the past few years, meaning that the figures taken from studies published just a few years ago may already be outdated (see Section 6.1).

For this reason, this study provides cost ranges in line with three scenarios: an optimistic scenario, a pessimistic scenario, and a reference scenario. This study does not claim to make a precise point forecast of cost and technological developments up to 2050. Our calculations are available as a user-friendly Excel tool that can be downloaded from the Agora Energiewende/Agora Verkehrswende website (www.agora-energiewende.de/en/PtG-PtL-Tool/). The tool quickly elucidates the cost effects of changing assumptions in a transparent manner.

4.3 Methodological approach and organisation

We estimate the costs of importing synthetic fuels based on the following steps along the value chain:
→ **Electricity generation:** We first estimate the electricity generation costs associated with selected technology and site options up to 2050 (see Section 5 for details).
→ **Conversion:** In this step, we estimate the costs of conversion, that is, the costs associated with converting electricity into synthetic fuels via hydro-

gen electrolysis, methanisation, methanol or Fischer-Tropsch synthesis (see Section 6 for details).
→ **Transport:** In addition to generation and conversion costs, we must factor in the cost of transporting the synthetic fuels to Germany (see Section 7.1 for details).
→ **Blending/distribution:** To determine costs at the end customer level, grid tariffs and distribution costs must be taken into account.[96] Furthermore, if synthetic fuels are used as an additive to fossil-based natural gas or liquid fuels, then the blending ratio must be considered for costs at the customer level (see Section 7.2 for details).

Our cost estimates for the conversion processes are based on our review of the literature, the input provided by experts during a dedicated project workshop, and, in certain areas, our own assumptions (see Section 6). Conversion costs are estimated in detail based on investment costs, operating costs, and efficiency improvements over time given expected technological progress. These same factors are considered in our assessment of electricity generation costs while assumptions for renewable energy investment costs and plant load factors are estimated based on literature and current market trends.

Our assumptions regarding transport costs and blending ratios are based on information from the literature. These costs are modelled in less detail, however, because of their relatively minor role in the overall cost structure.

With a view to our cost estimates, we assume that synthetic fuel production plants are constructed exlusively for the export of synthetic fuels to Germany. This necessitates a full cost accounting approach for each plant. Similarly, we explicitly take

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96 Levies and taxes would also have to be taken into account. It is not currently clear how the system of levies and taxes will develop until 2050 (see Agora Energiewende, 2017d), so we abstract from levies and taxes for the purpose of this study.

into account the cost of constructing offshore wind turbines in the North and Baltic Seas, rather than simply considering short-term marginal costs. In other words, our cost estimates are not based on the assumption that synthetic fuels are only produced when power production from renewables exceeds demand (surplus electricity).

We also assume that synthetic fuels are produced and transported to Europe in the form of methane and synthetic liquid fuels. While it would be possible to conduct a separate analysis of the costs associated with producing and transporting hydrogen, the costs of hydrogen production are only included in our calculations as an interim step. This is because the use of hydrogen on a large scale – that is, beyond simply adding small quantities of hydrogen to natural gas – would require significant changes to Germany's energy system (e.g. new transport and distribution infrastructure, the adoption of new consumer technologies, etc.). Calculating such a comprehensive change to the nation's energy system is simply beyond the scope of this study.

This report is structured according to the aforementioned steps along the value chain:
→ In Section 5 we explain which electricity generation options we consider and which assumptions we make in terms of individual renewable energy technologies.
→ In Section 6 we describe conversion technologies and the assumptions made regarding their costs.
→ In Section 7 we explain the assumptions we have made for transport costs and the costs associated with blending/distribution.
→ In Section 8 we present the results of the cost estimates.
→ In Section 9 we discuss the sustainability criteria that are relevant for importing synthetic fuels from a policy perspective.
→ In Section 10 we summarise our results and describe options for further discussion about the decarbonisation of the heating and transport sectors.

5. Electricity generation

In this section we explain the electricity generation options that are considered as part of this study (Section 5.1); the assumptions we make regarding costs, full-load hours, and the lifetime of renewable energy plants (Section 5.2); and the electricity generation costs that result from our assumptions (Section 5.3).

5.1 Countries and electricity generation technologies considered

5.1.1 Summary of the site and technology options considered as part of the study

By way of example, the study considers six different locations and generation technology variants for producing synthetic fuels. These variants differ in terms of the available renewable resources and the resulting assumed degree of plant utilisation (i.e. load factor):

→ **Offshore wind power in the North and Baltic Seas** (3,500 to 4,400 full-load hours): The costs associated with producing synthetic fuels using offshore wind power in the North and Baltic Seas serve as a point of reference for assessing the costs of importing synthetic fuels from abroad.

→ **Geothermal/hydropower in Iceland** (8,000 full-load hours): The costs of generating electricity using geothermal power and large hydroelectric plants are very low compared to other electricity generation options (see Figure 7). At the same time, geothermal and hydropower plants generate power while operating essentially at base load. In such plants, the high level of full-load operation impacts the level of full-load hours of the hydrogen electrolysis and therefore lowers the specific conversion costs.[97] Iceland consequently has highly favourable conditions from a cost perspective as a potential exporter of synthetic fuels. It must be pointed out, however, that the country's potential for electricity generation based on geothermal and hydropower is relatively low at about 50 terawatt hours per year,[98] implying that imports from Iceland alone are not a solution for the German energy transition. Accordingly, Iceland mainly serves as an example for countries with highly favourable locational conditions for renewabes-based synthetic fuel production in this study.

→ **Photovoltaic power plants in North Africa** (2,100 to 2,500 full-load hours): Photovoltaic power plants are associated with relatively low electricty generation costs when constructed in locations with ample solar resources, such as North Africa. The investment costs for photovoltaic plants are also expected to fall further until 2050, thus contributing to lower electricity generation costs over the long term. We assume that ground-mounted PV power plants with *single-axis tracking* systems will be constructed.[99] We also assume that the water required for hydrogen electrolysis will be produced in seawater desalination plants.

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97 The CO_2 required in Iceland for methanisation or the production of liquid fuels could be captured from geothermal boreholes, which is comparably cost effective. However, it is a matter of debate, how carbon neutral this would be. We therefore assume in this study that the CO_2 in Iceland is also captured from the air.

98 See Askja Energy (no year).

99 The percentage of tracking photovoltaic systems in global ground-mounted solar parks is increasing (GTM 2016). If fixed photovoltaic power plants were constructed instead of plants with tracking systems (e.g. because the use of plants with tracking systems is too expensive, due to the mechanism being affected by sand), somewhat lower full-load hours would be achieved (Breyer [2016] states 1,790 hours for fixed plants and 2,344 hours for plants with tracking systems in the case of Morocco, for example). At the same time, the use of fixed power plants would be associated with lower investment costs compared to the use of plants with tracking systems.

→ **Hybrid photovoltaic power plants/onshore wind power electricity generation in North Africa** (3,485 to 5,015 full-load hours): To test the effect of higher full-load hours on the cost of fuels, we consider the option of hybrid PV/onshore wind power plants. The investment costs for such plants are correspondingly higher, however, because of the expenditures necessary for two different technologies.[100]

→ **Photovoltaic power plants in the Middle East** (2,200 to 2,600 full-load hours): The Middle East, like North Africa, has favourable local conditions for renewable energy from PV. As is the case for North Africa, we assume that the necessary water is produced using seawater desalination plants.

→ **Hybrid PV/onshore wind generation in the Middle East** (3,910 to 4,335 full-load hours): The option of hybrid PV/onshore wind power is also considered for the Middle East.

For all countries/regions, we assume that the CO_2 input required for conversion is collected from the air (*direct air capture*).

5.2 Assumptions regarding costs, full-load hours and lifetime of renewable energy plants

Table 1 shows the renewable energy investment costs estimated by the study for the snapshot years 2020, 2030 and 2050.[101] The assumed investment costs in the reference scenario and the optimistic and pessimistic scenarios are given for each snapshot year.

The cost assumptions for onshore wind power, geothermal power and large hydropower are based on the New Policies Scenario and the 450 Scenario contained in the *World Energy Outlook (*IEA, 2016). To estimate the possible future cost reduction for onshore wind power plants, data from Wiser et al. (2016) were also incorporated.

Because the cost predictions contained in the *World Energy Outlook f*or offshore wind power and photovoltaic systems are considerably higher than the figures contained in other studies, we consider additional sources for these two technologies: Our assumptions for the current cost of offshore wind power are based on Fichtner/Prognos (2013). We estimate future cost trends for offshore wind by drawing on the interim results of an analysis carried out by Prognos/Fichtner (2017). Our assumptions for PV investment cost are based on data from Fraunhofer ISE (2015) and scaled up by ten percent to take into account the higher costs of single-axis systems.[102]

To determine the investment costs required for hybrid PV/onshore wind, we add together the investment costs for each technology. By contrast, to determine the investment costs for hybrid geothermal/

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100 Other options to increase the full-load hours would be to generate electricity using *concentrating solar power (CSP)* plants or using battery storage. Neither option has been examined as part of this study: CSP in North Africa and the Middle East achieves full-load hours of between 2,300 and 3,500 hours (Brand/Zingerle, 2010; Breyer, 2016; Caldera et al., 2016). This is considerably less than the full-load hours that can be generated in the two regions using hybrid PV/onshore wind (see Section 5.2). At the same time, the investment costs for CSP plants are greater than the sum of the investment costs required for photovoltaic and onshore wind power plants. (In the *World Energy Outlook* 2016 report published by the IEA, CSP investment costs in 2020 are estimated to be 5,000 to 5,100 euro per kilowatt. This is considerably higher than the sum of the investment costs for photovoltaic and onshore wind power – see Table 1 in Section 5.2). A rough calculation of the costs and benefits of using battery storage has also shown that even with optimistic assumptions for the costs of the storage units (Ghorbani et al. [2017] assume investment costs of 300 euro per kilowatt hour for lithium ion batteries by 2020), the costs would outweigh the benefits.

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101 Cost assumptions for the interim years can be calculated using the Excel tool available on the Agora website.

102 The investment costs reported by Fraunhofer ISE (2015) refer to non-tracking systems. According to Fasihi et al. (2016), the investment costs of tracking systems are about ten to eleven percent higher than those for non-tracking systems.

hydropower, we use the mean of the investment costs for geothermal and hydropower.[103]

The investment costs for offshore wind power stated in Table 1 do not include the costs of grid connection. To calculate the electricity generation costs associated with offshore wind power, we therefore consider falling grid connection costs of 1.5 cents per kilowatt hour in 2020, 1.16 cents per kilowatt hour in 2030 and 0.7 cents per kilowatt hour in 2050.[104]

It must, however, be noted that grid connection with the development of offshore grids is associated with considerable scale effects and the specific costs are also likely to decline over the next few decades due to technological progress. To be able to model this simply and approximately, we made a separate assumption that the costs of grid connection decrease from 2020 onwards on average by 2.5 percent per year.

In terms of the operating costs of renewable energies, it is assumed that these correspond to a percentage of the investment costs and remain constant over time. The percentage rates are guided by the operating costs indicated in the *World Energy Outlook 2016* published by the IEA (Table 2). For hybrid photovol-

taic / onshore wind power plants and for geothermal / hydroelectric plants, the mean for the particular plants is used.

Table 3 describes the assumptions for full-load hours for the renewable energies in the particular regions considered in this study.

Considered countries/regions and technology for producing synthetic fuels   Figure 6

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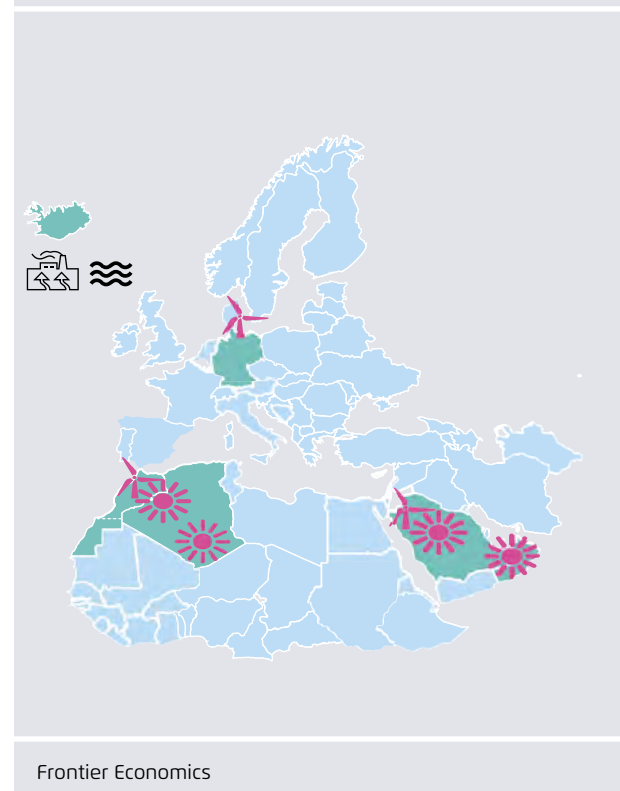
103 As can be seen in Table 3, the full-load hours for hybrid photovoltaic/onshore wind generation are higher than for photovoltaic systems alone or onshore wind electricity generation alone. The full-load hours for hybrid geothermal/hydroelectric electricity generation, on the other hand, are identical to the full-load hours for geothermal electricity generation alone or hydroelectricity generation alone.

104 The assumptions for the grid connection costs are based on information available from tenders for offshore wind parks in the Netherlands. The Dutch government compensates the costs of grid connection at 1.4 cents per kilowatt hour. However, the actual grid connection costs are probably about 1.4 to 1.6 cents per kilowatt hour. See offshore Wind.biz (2016) for details. It must be taken into account that in the Netherlands, AC power is used, whereas Germany uses DC connections, which could lead to different costs. Most countries bordering the North and Baltic Seas currently use AC connections.

Assumed renewable energy investment costs [€₂₀₁₇/kW] Table 1

	Optimistic			Reference			Pessimistic		
Year	2020	2030	2050	2020	2030	2050	2020	2030	2050
Onshore wind	1,415	929	780	1,526	1,260	1,078	1,604	1,550	1,478
Offshore wind	2,250	1,720	1,400	2,800	2,200	1,600	3,502	3,067	2,196
Photovoltaic	833	608	306	908	718	486	981	828	667
Geothermal	2,524	2,389	2,118	2,524	2,434	2,254	2,577	2,502	2,353
Large hydropower	2,389	2,389	2,389	2,389	2,389	2,389	2,389	2,389	2,389

Frontier Economics based on IEA (2016), Fraunhofer ISE (2015), Fichtner/Prognos (2013), and Wiser et al. (2016).

Assumed operating costs and lifetime of renewable energy plants Table 2

	Operating costs (% of the investment costs)	Service lifetime (years)
Onshore wind	2.5	20
Offshore wind	3.2	25
Photovoltaic	1.5	25
Geothermal	2.0	30
Large hydropower	2.5	50
Hybrid PV/onshore wind plants	2.0	22.5
Hybrid geothermal/hydropower plants	2.3	40

Frontier Economics based on IEA (2016) and Prognos/Fichtner (2017) for operating costs; Fraunhofer ISE (2013) for the lifetime of on-shore wind power plants and photovoltaic technology; IEA (2010a) for the lifetimes of hydropower plants; IEA (2010b) for the service lifetime of geothermal power plants; and Prognos/Fichtner (2017) for the lifetime of offshore wind power plants.

| Assumed full-load hours of renewable energy plants [hours/year]					Table 3
Region	**Technology**	**Optimistic**	**Reference**	**Pessimistic**	**Key literature sources / comments**
North Africa	Photovoltaic systems (single-axis tracking)	2,500	2,344	2,100	Breyer (2016) for the reference case
	Onshore wind	3,400	2,700	2,000	Brand/Zingerle (2010) and Breyer (2016)
	Hybrid photovoltaic/ wind power	5,015	4,287	3,485	Full-load hours correspond to the sum of the full-load hours for photovoltaic systems and onshore wind power with a deduction of 15%[105]
Middle East	Photovoltaic systems (single-axis tracking)	2,600	2,440	2,200	Caldera et al. (2016) for the reference case
	Onshore wind	2,500	2,450	2,400	Caldera et al (2016) and Norton Rose Fulbright (2013)
	Hybrid photovoltaic/ wind power	4,335	4,157	3,910	Full-load hours correspond to the sum of the full-load hours for photovoltaic systems and onshore wind power with a deduction of 15%.
Iceland	Hybrid geothermal/large hydropower	8,000	8,000	8,000	It is assumed that the generated electricity is suitable for covering base load demand.
North and Baltic Seas	Offshore wind	4,400	4,000	3,500	Fh IWES Wind Monitor (no year) (pessimistic value), Prognos/ Fichtner (2017) (reference value and optimistic value)

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105 The 15% deduction reflects the fact that wind power and PV power are partially correlated. It is is based on the "overlap full load hours" such as those described in Breyer (2012). The 15% deduction assumed here is higher and thus more conservative than Breyer's. If we used the "critical overlap full load hours" as a basis, which Breyer recommends, the deduction would range between 1 and 8% and for many regions would only be around 2% (Breyer 2012). This would result in 10% less power generation costs for hybrid PV/wind power stations than assumed in this study.

Frontier Economics based on Breyer (2012), Breyer (2016), Caldera et al. (2016), Norton Rose Fulbright (2013), Fh-IWES Windmonitor (no year), Prognos/Fichtner (2017)

5.3 Electricity generation costs

Figure 7 shows the electricity generation costs resulting from the assumptions discussed in Section 5.2 for the different technologies. The electricity generation costs of offshore wind power vary enormously between the optimistic and the pessimistic scenarios because of the assumed full-load hours and investment costs.

Electricity generation costs in 2020, 2030 and 2050 [ct_{2017}/kWh_{el}]   Figure 7

Frontier Economics
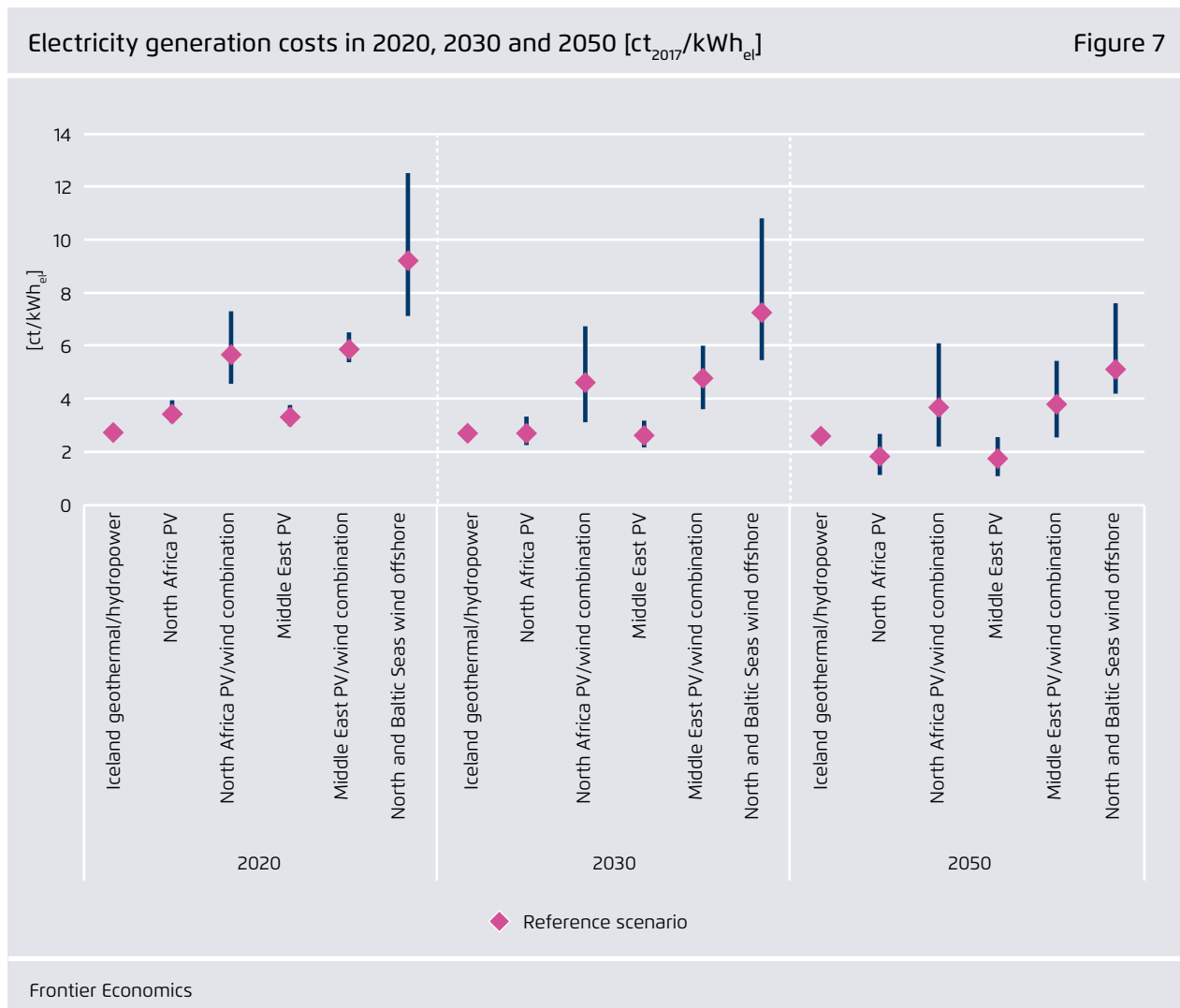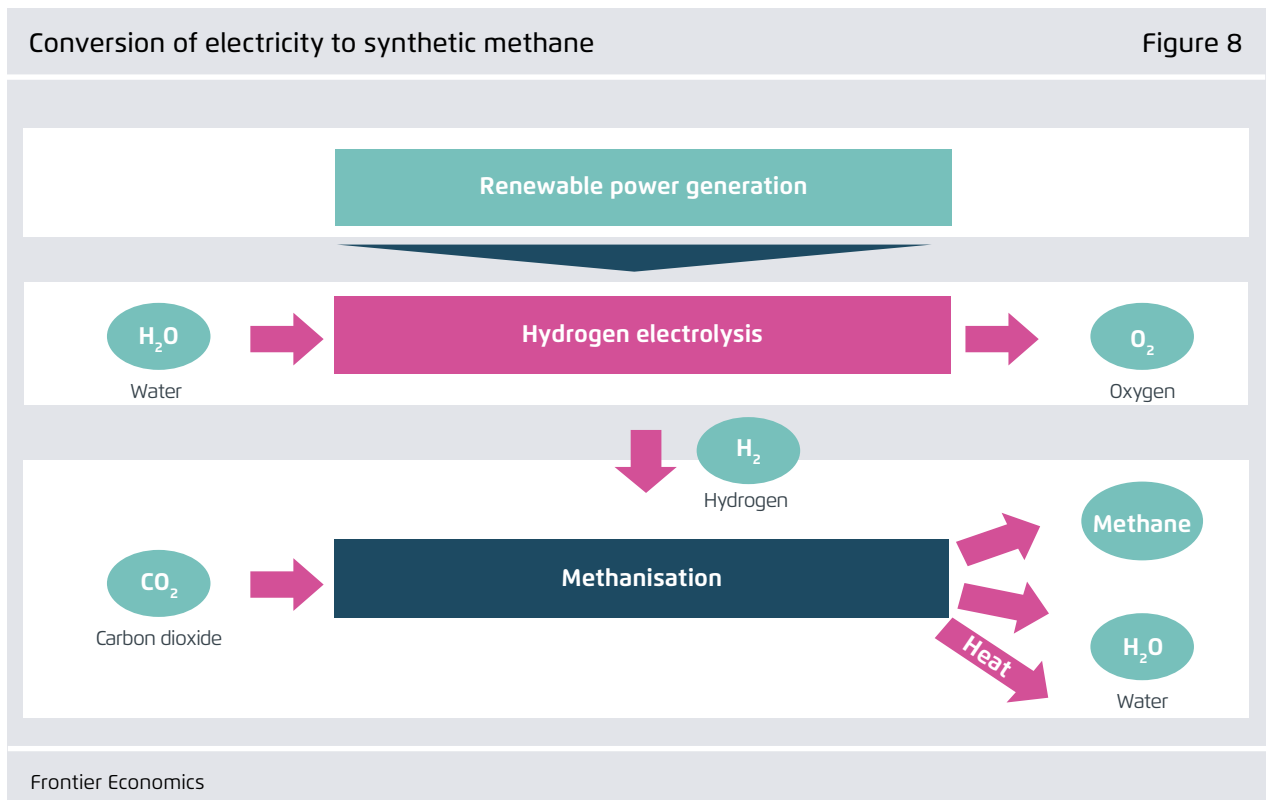
6. Conversion processes

In this section we describe the processes used to convert electricity to synthetic fuels as well as the associated cost components. Figures 8 and 9 summarise the processes for converting electricity to synthetic methane and synthetic liquid fuels. In both cases, electricity and water are first converted to hydrogen (and oxygen) using hydrogen electrolysis. In a second step, either synthetic methane is produced via methanisation or synthetic liquid fuels are generated via methanol or Fischer-Tropsch synthesis.[106]
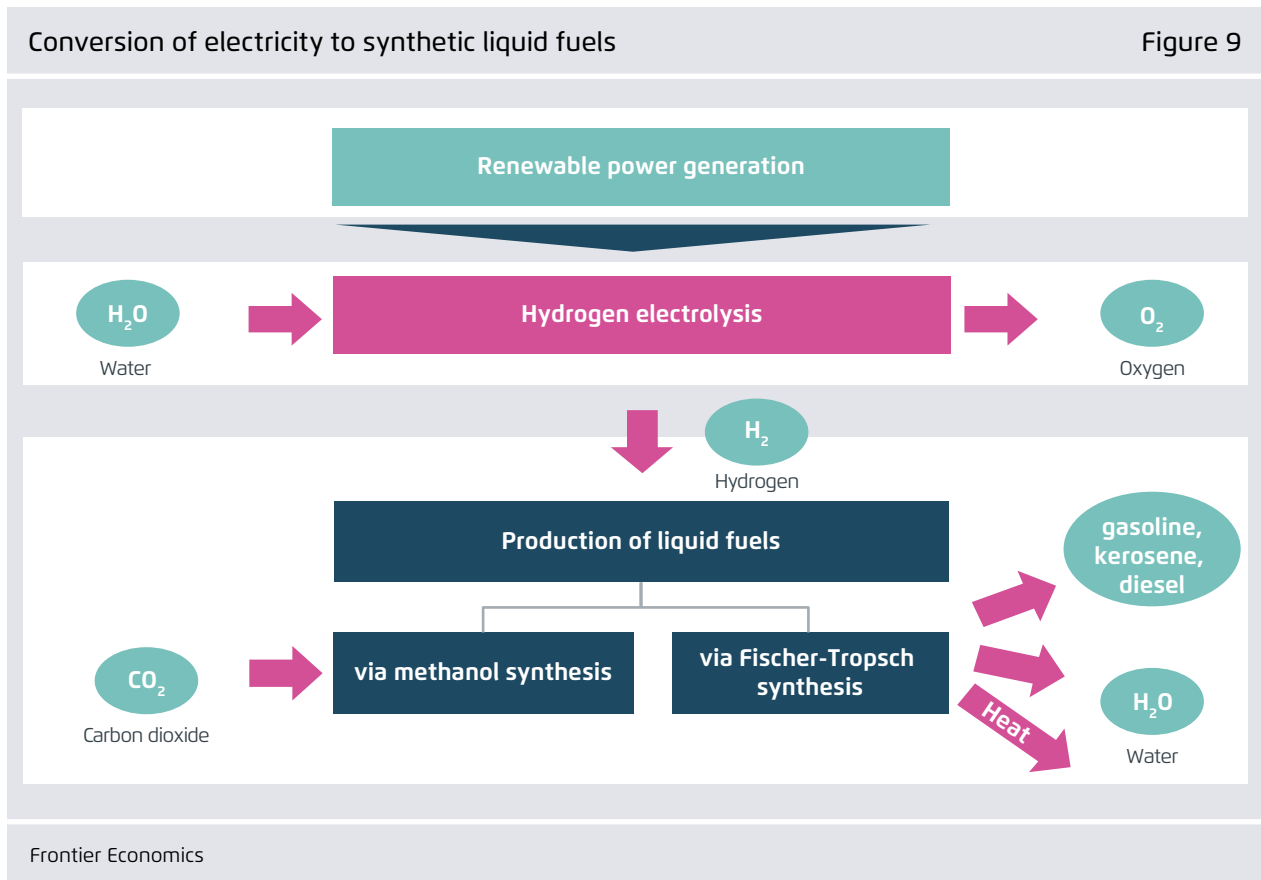
We assume as part of this study that the conversion plants are constructed on a large scale explicitly for exporting fuels to Germany. This implies on the one

hand that, we draw on the low-range figures reported in the literature when estimating costs, because large plants are associated with lower costs, and current cost statistics are based to a large extent on small plants that are intended primarily for demonstration and research purposes. The implication on the other hand is that we assume that high market penetration rates will be achieved in the future, thus allowing further economies of scale to be realised. The assumption of declining future costs applies in particular to hydrogen electrolysis; by contrast, methanisation, methanol synthesis, and Fischer-Tropsch synthesis are already well-established technologies.

In the following we describe the processes and costs associated with hydrogen electrolysis (Section 6.1), methanisation (Section 6.2) and the production of liquid fuels (Section 6.3).

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106 Methanol and Fischer-Tropsch synthesis are different processes from a technical perspective but the costs associated with them are very similar. Accordingly, we have not distinguished between them in our the cost estimation.

Conversion of electricity to synthetic methane — Figure 8

Frontier Economics

Conversion of electricity to synthetic liquid fuels	Figure 9

Renewable power generation

H₂O — Water → **Hydrogen electrolysis** → O₂ — Oxygen

H₂ — Hydrogen

Production of liquid fuels

CO₂ — Carbon dioxide → **via methanol synthesis** / **via Fischer-Tropsch synthesis** → gasoline, kerosene, diesel / Heat / H₂O — Water

Frontier Economics

6.1 Hydrogen electrolysis

Hydrogen electrolysis involves the production of hydrogen and oxygen from electricity and water (see Figure 10). The cost components for hydrogen electrolysis therefore include the cost of supplying water as well as the investment and operating costs of the electrolysis plants. In practice, however, the costs of supplying water are negligibly low (see Section 6.1.3.1 for details).

When converting electricity to hydrogen, the efficiency losses, which vary depending on the hydrogen electrolysis technology used, must be taken into account (see Section 6.1.1 for details).

6.1.1 Hydrogen electrolysis technologies

Hydrogen electrolysis can be carried out using low-temperature processes (at 50 degrees Celsius to 80 degrees Celsius) or high-temperature processes (700 degrees Celsius to 1000 degrees Celsius).

Low-temperature processes include alkaline electrolysis (AEC) and proton exchange membrane electrolysis (PEMEC). Both technologies are sold commercially and are well advanced compared to high-temperature electrolysis. PEMEC electrolysis has a somewhat higher efficiency than AEC electrolysis.

High-temperature electrolysis (SOEC – ion conducting solid oxide electrolysis) is still in the development phase, but there are a number of pilot projects, including the Sunfire plant in Dresden. SOEC electrolysis is a highly efficient process with low levels of conversion losses. An additional advantage of SOEC electrolysis is that it has a potentially lower electricity requirement compared to low-temperature electrolysis because energy needs can be covered

Hydrogen electrolysis process — Figure 10

Frontier Economics
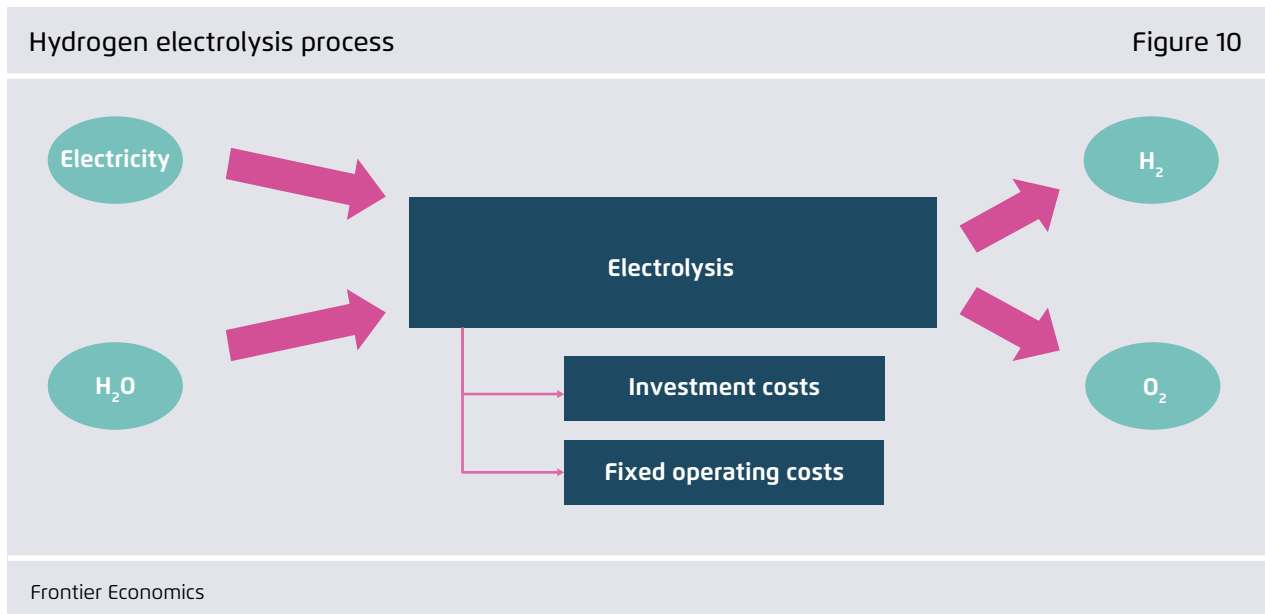
in part by heat input. In the case of methanisation, methanol synthesis and Fischer-Tropsch synthesis, heat is generated as a by-product, which can be used as an input for SOEC electrolysis. Capturing the CO_2 input for the conversion from the air, however, also requires heat input, leading to competition for heat resources.

A fundamental drawback of high-temperature electrolysis is its lack of flexibility compared to low-temperature electrolysis. This impairs the use of the SOEC electrolysis in combination with fluctuating renewable energy.[107] For this reason, we assume in this study that hydrogen is produced using low-temperature electrolysis. However, because SOEC electrolysis is, as previously discussed, still in the development phase and future options for use cannot yet be assessed, we also provide cost estimates and degrees of efficiency for this process, whenever available.[108]

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107 See Fasihi et al. (2016).

108 These data are useful because SOEC can be manually selected in the Excel tool, allowing the effects on the costs of hydrogen electrolysis to be illustrated.

6.1.2 Literature review:Investment costs of hydrogen electrolysis plants

Figure 11 shows the wide range of investment costs cited in the literature. This broad range can be attributed in part to the following three factors:

1. **Cost figures relate in part to different plant sizes:** Some of the studies evaluated explicitly state the plant size to which the investment cost figures refer. In some studies, cost figures are also given for several plant sizes (for example, in LBST, 2016; and Enea Consulting, 2016). These studies show that investment costs fall with increasing plant sizeGiven that as part of this study we assume that large plants will be constructed for the export of synthetic fuels (see the introduction to Section 6), we base our cost estimate on the figures for large plants.

2. **Cost figures refer in part to different electrolysis technologies:** Some studies indicate whether the cost figures refer to AEC, PEMEC or SOEC electrolysis, while other studies state cost figures without specifying the technology. Most of the cost figures that can be found refer to the AEC process, while explicit cost figures for PEMEC are only cited in ISE (2011), Enea Consulting (2016) and Fasihi et al. (2016). In Fasihi et al. (2016), it is apparent that the

cost trend for PEMEC is more uncertain than that for AEC: The lower end of the range for PEMEC costs is below that of the costs for AEC in 2030, while the upper end of the range is greater than the costs for AEC.

Only one cost estimate could be found for SOEC in the studies analysed (namely, in Fasihi et al., 2016). According to these figures, which pertain to 2030, SOEC will continue to be more expensive than AEC over the medium term. However, the cost trend for SOEC is subject to significant uncertainty, as demonstrated by the wide range of SOEC investment costs cited in Fasihi et al. (2016).

3. **Studies were published at different points in time (2011 to 2016):** The evaluation shown in Figure 11 includes estimates from studies that were published between 2011 and 2016. As previously explained in Section 4.2, there has been a sharp downward trend in the costs associated with PEM electrolysis (according to the experts consulted), implying that figures reported in earlier studies already appear to be outdated.

6.1.3 Assumptions as part of the study

In this section we describe the assumptions made as part of the study regarding the costs and efficiency of hydrogen electrolysis. We differentiate between the assumptions made for low-temperature and high-temperature electrolysis but not between the two low-temperature electrolysis procedures AEC and PEMEC. As described in the previous section, arriving at a reliable cost comparison between the two technologies is very difficult. The differences in the efficiency are also lower than between low-temperature and high-temperature electrolysis, meaning that differentiating between the two for the cost estimate is not necessary in this study.

The results of the study shown in Section 8 assume the use of low-temperature electrolysis. As explained in Section 6.1.1, the waste heat from the methanisation process (or the process of converting electricity to liquid fuels) can either be used as input for high-temperature electrolysis or as input for capturing CO_2 from the air. We assumed as part of this study that the waste heat is used for capturing CO_2 from the air and is therefore not available for the electrolysis.

6.1.3.1 Plant investment and operating costs

The following Table 4 shows the assumed investment costs of low-temperature and high-temperature hydrogen electrolysis. We assume that the annual operating costs correspond to a fixed percentage of the investment costs – namely, 3 per cent per year for low-temperature electrolysis, and 3.5 per cent per year for high-temperature electrolysis.

6.1.3.2 Degree of efficiency

Table 5 shows the the assumed degree of efficiency LHV when converting electricity to hydrogen.

Overview of studies that address investment costs for hydrogen electrolysis   Figure 11
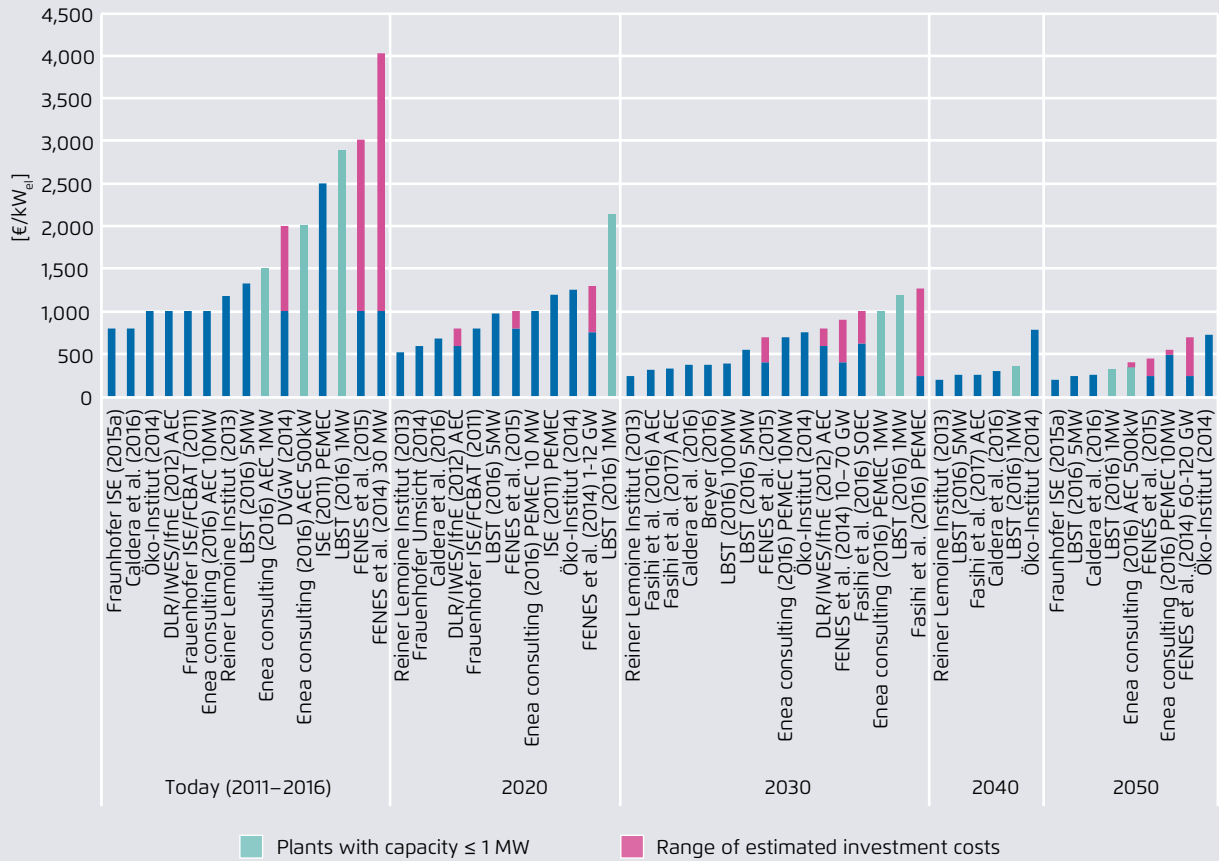
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6.1.3.3 Degree of utilisation for hydrogen electrolysis plants

Another important factor influencing hydrogen electrolysis costs is the degree to which the electrolysis plants are utilised: The higher the degree of utilisation (i.e. load factor), the lower the share of the investment costs as part of overall conversion costs. We assume that the degree of utilisation of hydrogen electrolysis plants corresponds to the full-load hours for the particular electricity generation technology. As described in Section 5.1, although the degree of utilisation can

in principle be increased by using electricity storage systems, rough estimates indicate that the associated costs considerably outweigh the benefits of a higher degree of utilisation, even with optimistic assumptions about progressive cost reductions.

Assumed investment costs for hydrogen electrolysis [€$_{2017}$/kW$_{el}$]									Table 4
	2020			**2030**			**2050**		
	Opt.	**Ref.**	**Pess.**	**Opt.**	**Ref.**	**Pess.**	**Opt.**	**Ref.**	**Pess.**
Low-temperature electrolysis	656	737	768	442	625	707	200	450	600
High-temperature electrolysis	877	930	969	675	804	909	400	600	800

Frontier Economics based on the literature review described in Section 6.1.3 and based on expert input.

Assumed degree of efficiency LHV for converting electricity to hydrogen			Table 5
	2020	**2030**	**2050**
Low-temperature electrolysis	67%	71%	80%
High-temperature electrolysis	81%	84%	90%

Frontier Economics based on the literature review described in Section 6.1.3 and based on expert input.[109]

6.1.3.4 Costs of water supply

The costs of supplying water are negligibly low, even in countries in which the water must be obtained from desalination plants.[110] The costs of supplying water using seawater desalination plants are calculated using data from Caldera et al. (2016). According to these figures, the investment costs of desalination plants are 1,150 euro/(m³ per day); the operating costs are four per cent of the investment costs ; and the electricity consumption is 4.1 kWh$_{el}$/m³.

6.2 Methanisation

In the process of methanisation, methane (CH_4) and the by-products water (H_2O) and heat are generated from carbon dioxide (CO_2) and hydrogen (H_2) (Figure 12). In addition to the investment and operating costs of the methanisation plants, there are also costs associated with capturing the CO_2 needed for the methanisation process. The waste heat from methanisation can be used as the input for capturing CO_2 from the air (Section 6.2.3.4). We assume in our cost calculation that this waste heat is sufficient to cover all of the heat requirements for *direct air capture* plants (see Section 6.2.3.4). The water generated as a by-product of methanisation can be used as input for hydrogen electrolysis.

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109 LBST (2016), p. 69, Fasihi et al. (2017), p. 249 and Fasihi et al. (2017), p. 4

110 In Enea Consulting (2016), the costs of supplying water are completely omitted because it is considered to be of little relevance: "Based on previous ENEA studies, the water consumption was neglected given its low impact on the overall LCOX" (p. 19).

6.2.1 Methanisation technologies

Today, the methanisation process is largely based on catalytic (thermochemical) methanisation. In addition, biological methanisation is also currently under development.

6.2.1.1 Catalytic methanisation

Catalytic methanisation is carried out at 300 to 550 degrees Celsius, usually using a nickel-based catalyst. Good heat recovery is possible for catalytic methanisation. Even in stand-by mode, the temperature of the methanisation plant must always exceed about 200 degrees Celsius.[111]

6.2.1.2 Biological methanisation

Biological methanisation is carried out at 30 to 70 degrees Celsius via micro-organisms suspended in an aqueous solution. These micro-organisms absorb CO_2 and hydrogen through their cell walls and convert

them to water and methane. Biological methanisation has a lower overall efficiency than catalytic methanisation. Due to lower rates of methane formation, larger reactors are also required, thus making biological methanisation primarily suitable for small-sized production plants.[112]

Due to the fact that biological methanisation is still under development, has a lower degree of efficiency, and is also more suited to small-scale production (at least for the time being), we do not consider this option further in our cost calculations.

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111 Bär et al. (2015)

112 ibid.

Methanisation process   Figure 12

Frontier Economics
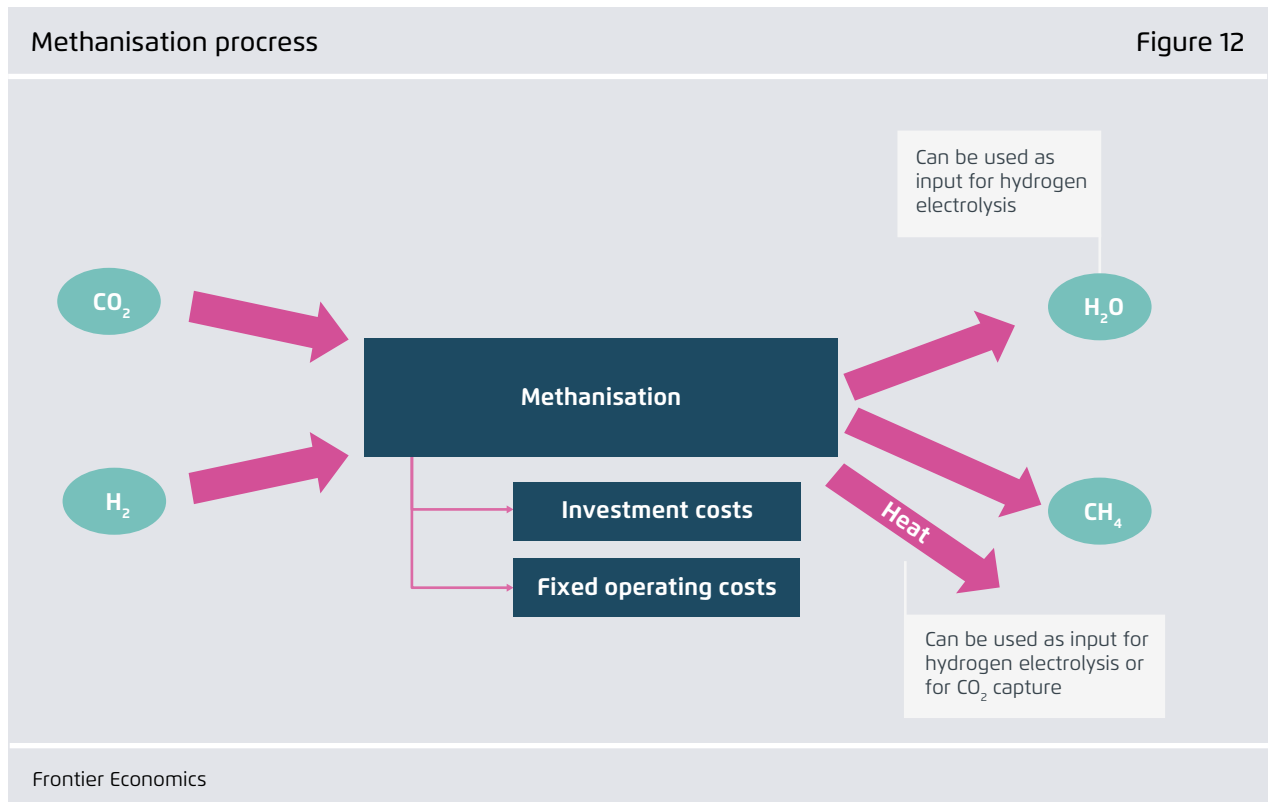
6.2.2 Literature review: Investment costs of methanisation

To estimate the investment costs associated with methanisation, we first carried out an analysis of the literature. Figure 13 shows the large divergence in cost figures across the various studies.

Information about the size of the conversion plant to which the costs refer to is only available in DVGW (2014). This information indicates that investment costs decrease sharply with increasing plant size.

Literature review: Investment costs of methanisation[113]   Figure 13

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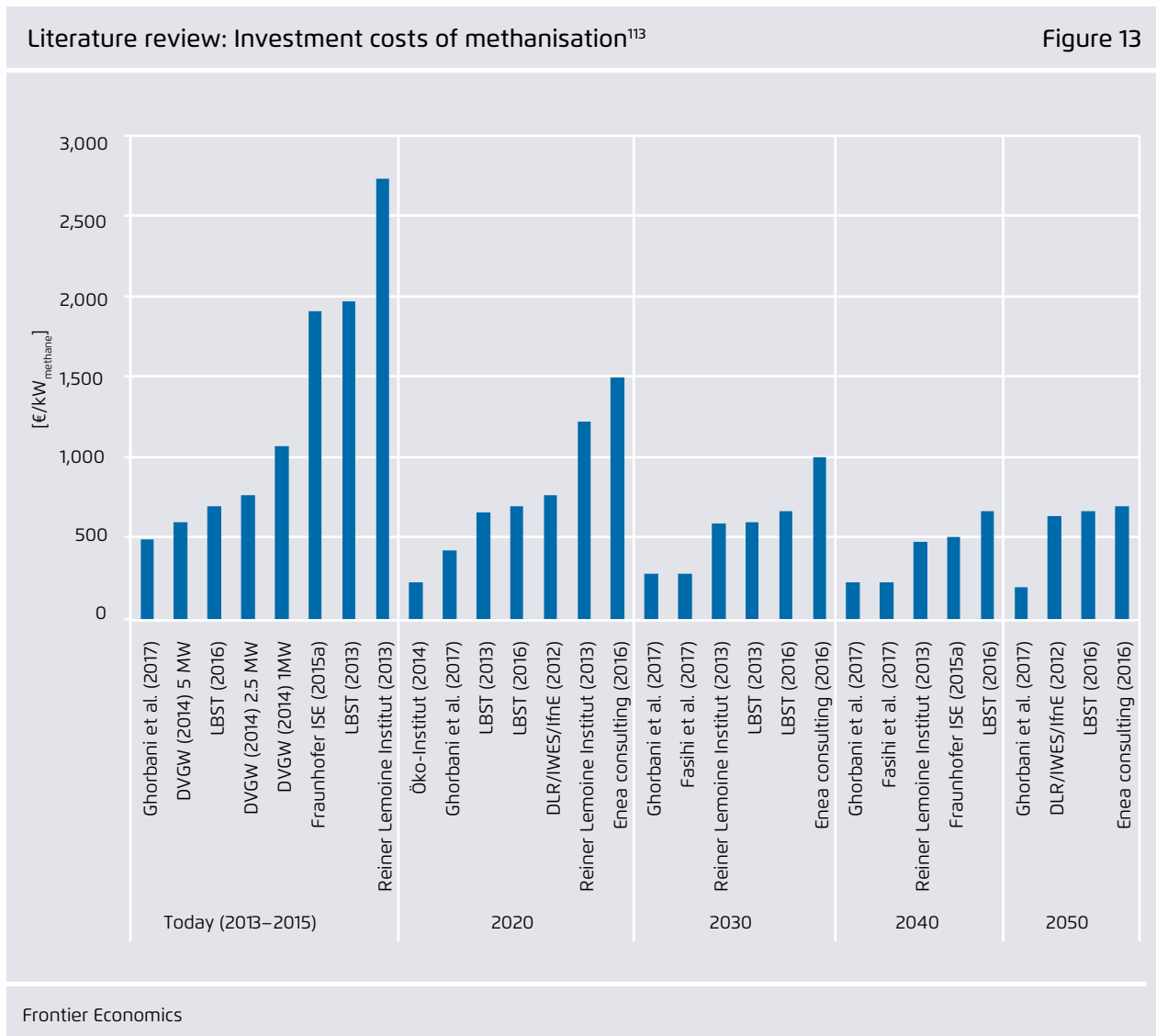
113   In some studies the costs are give in euro/kW_{el}. In these cases the costs were converted using the factor 1.57 kW_{el}/kW_{gas} for simplicity (factor derived from Fasihi et al., 2017): Based on the assumption made about the degree of efficiency, 1000 kWh_{el} is required to produce 637 $kWh_{methane}$.

6.2.3 Assumptions as part of the study

6.2.3.1 Investment and operating costs

As described in the introduction to Section 6, as part of this study we assumed that large production plants will be specifically constructed for the export of synthetic fuels. Furthermore, we have drawne on the lower ranges of figures reported for current costs, due to expected economies of scale. In addition, we assumed operating costs correspond to a fixed rate of three per cent of investment costs per year.

6.2.3.2 Degree of efficiency

The assumed degree of efficiency for converting hydrogen to methane is 80 per cent. Schütz and Härtel (2016) assume a degree of efficiency of 80 per cent in their study; Fasihi et al. (2016) and Fasihi and Breyer (2017) base their assumptions on a conversion efficiency of about 78 per cent for 2030/2040; and LBST assume in a 2016 study that about 83 per cent of processed hydrogen can be converted to methane. Because the methanisation technology is already extensively developed, the efficiency is assumed to not increase over time. These assumptions were also approved by the experts who were surveyed as part of the project workshop.

6.2.3.3 Plant utilisation rates

Methanisation plant utilisation rates can be increased by using hydrogen storage. The costs associated with storing hydrogen are considerably lower than those associated with storing electricity.

To achieve an 8,000-hour utilisation rate (i.e. load factor) for the methanisation plants, we assume that the hydrogen is stored temporarily. The size of the hydrogen storage required depends on the full-load hours that have been achieved for the electricity generated from renewable sources (and therefore also for hydrogen electrolysis). In Iceland, 8,000 hours have already been achieved for electricity generated from renewable sources, meaning that hydrogen storage is not required to reach a degree of utilisation of 8,000 hours for methanisation plants. The highest

hydrogen storage costs are incurred if the renewable electricity is generated using photovoltaics (Table 7).[114]

Although the storage of hydrogen (at least in steel tanks) is an established technology, the figures cited in the literature for the investment costs of the storage systems are inconsistent. This may be attributable to divergent technology costs (for example, underground storage versus storage in steel tanks), the size of the plant, steel prices, fluctuating exchange rates, or other factors. In this study, we apply a figure of 27 euros/kWh$_{H2}$ as investment costs.[115]

6.2.3.4 CO_2 capture and requirement

The CO_2 required for the methanisation plant could theoretically be captured from industrial processes, power stations, biogas or biomass plants, geothermal boreholes or from the air. As described in Section 5.1.1 we assumed as part of the study that CO_2 is captured from the air in all countries. This ensures a closed CO_2 cycle. The CO_2 can also be captured from the air in all

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114 To simplify the estimation of hydrogen storage costs, we assumed concerning the full-load hours for the particular renewable generation technologies in the reference scenario. It must be noted that in Germany the plants would be integrated into the power grid, creating system benefits for supplying renewable electricity that would lead to a considerably lower need for hydrogen storage. In northern Germany, cavern storage would also be available at considerably lower costs. These benefits are not included in our analysis.

115 Ramsden, Krpopovski, Levene (2008) assume investment costs in the near term of $30.7 million for a storage system with a steel tank with a storage capacity of 28,600 kilogram hydrogen (corresponding to about 27 euros per kilowatt hour). Since mid to late 2008, steel prices have been falling, which would suggest that storage systems have become cheaper. The authors assume costs of only $19.1 million (cited in Steward et al., 2009) in the medium term (corresponding to about 20 euros per kilowatt hour) or $12.3 million (about 13 euros per kilowatt hour) in the long term. LBST (2013) assume a converted value of about 66 euros per kilowatt hour with no economies of scale (for example, due to the purchase of large numbers of steel tanks). We use a mean value derived from the available ranges.

Assumed investment costs for methanisation plants [$€_{2017}/kW_{methane}$]			Table 6
	2020	**2030**	**2050**
Optimistic scenario	652	432	190
Reference scenario	748	654	500
Pessimistic scenario	785	756	700

Frontier Economics, based on the literature review described in Section 6.2.2 and based on expert input.

Assumed costs for hydrogen storage [ct_{2017}/kWh_{H2}]						Table 7
	North Africa		**Middle East**		**Iceland**	**Germany**
	PV	PV/Wind	PV	PV/Wind	Geothermal/ Hydroelectric	Offshore wind
ct/kWh$_{H2}$	0.43	0.28	0.42	0.29	0	0.34

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considered sites while harnessing CO_2 from industrial processes would be site-specific. In such a case, the necessary infrastructure for transporting the CO_2 with its associated costs would also have to be considered.

The production of one kilowatt hour of methane requires 0.198 kilogram of CO_2.[116]

Costs of CO_2 capture from the air
Capturing CO_2 from the air (*direct air capture*) is assumed to take place using temperature swing adsorption (TSA) technology. This involves capturing the CO_2 in a filter and then releasing it from the filter using heat. Investment costs for TSA plants are currently about 1,800 euro/kW$_{methane}$ and it is

assumed that they will drop to 1,278 euro/kW$_{methane}$ until 2050.[117]

Operating costs were set at four per cent of the investment costs. The electricity consumption of the plant is, on average, 0.9 MJ/kg (CO_2).[118] The electricity costs correspond to the particular electricity production costs of the renewable energy technologies.

The TSA process requires heat in addition to electricity. As described in Section 6.2, we assume that the required heat is available as waste heat from the methanisation (or from the process for producing liquid fuels) and is therefore not associated with any costs.
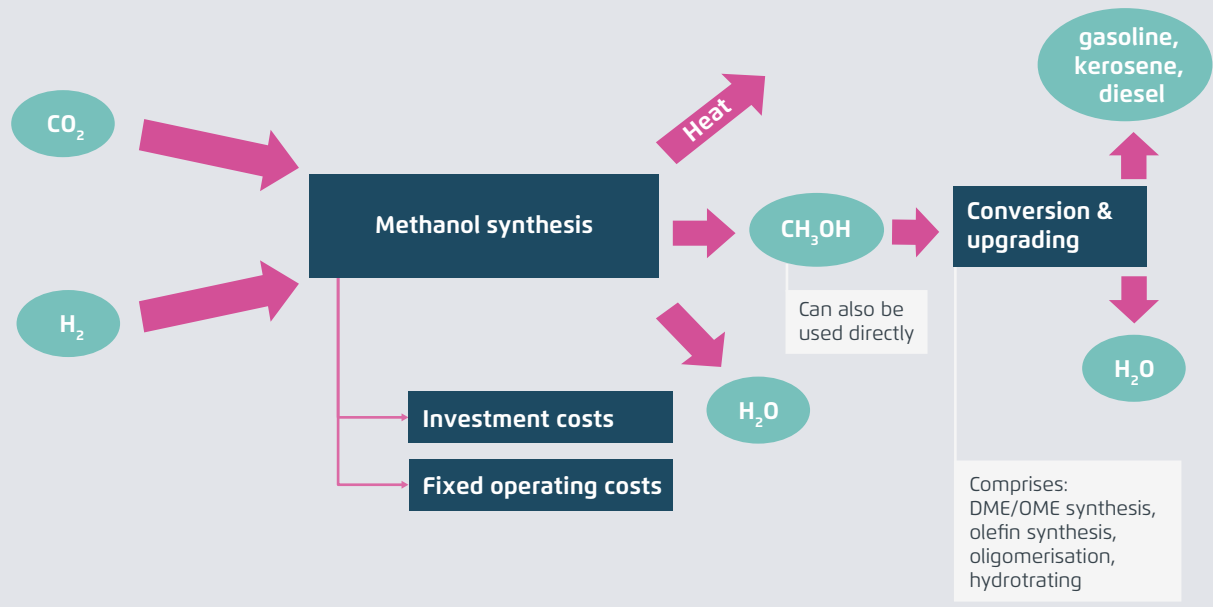
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116 LBST (2013), p. 26 and LBST (2016), p. 97

117 LBST (2016), p. 82

118 LBST (2016), p. 97. This is the average of the range from 0.72 to 1.08 MJ/kilogram CO_2.
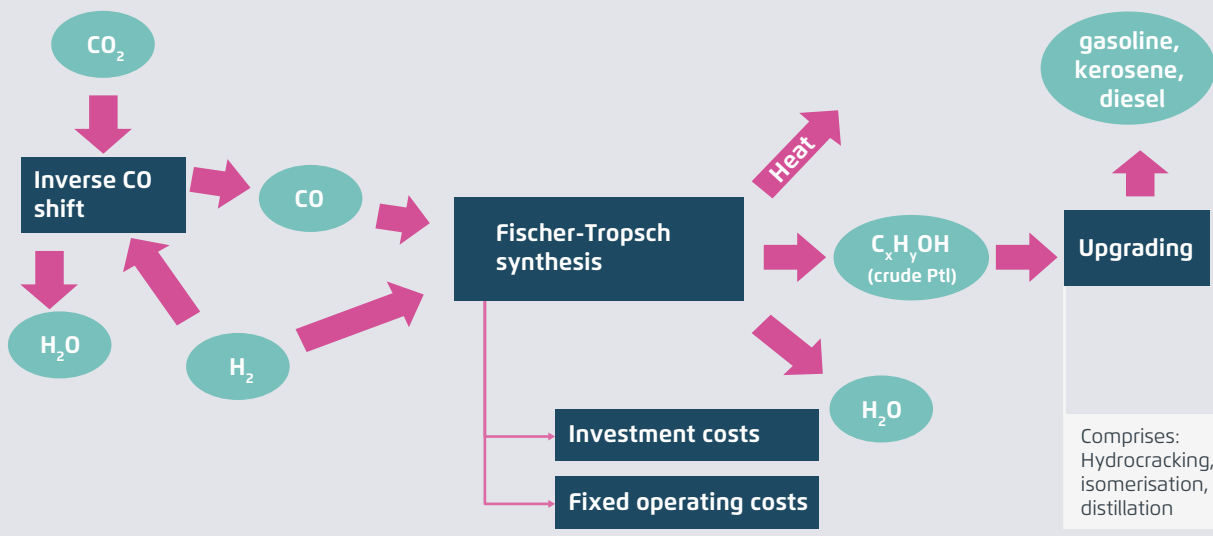
Liquid fuel production via methanol synthesis — Figure 14
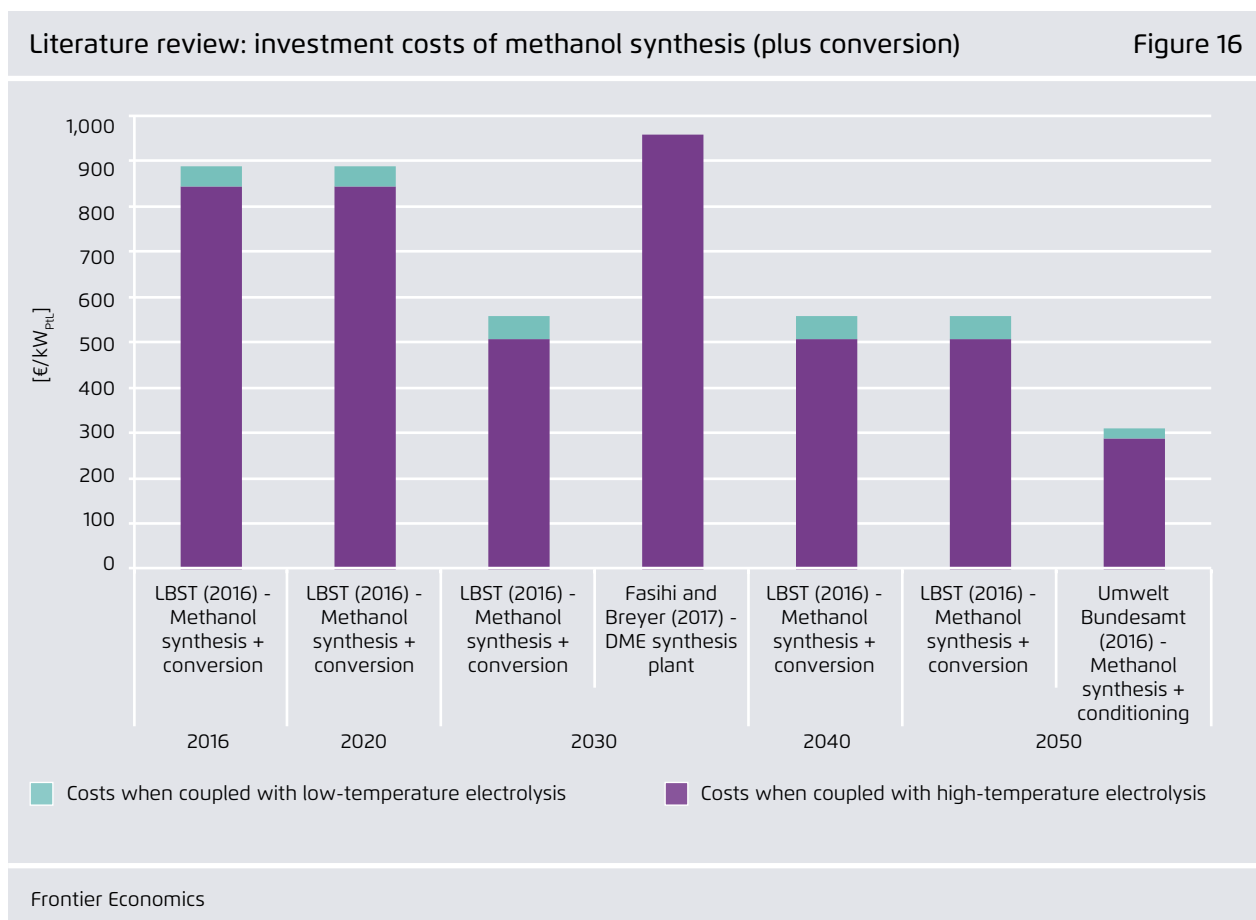

Liquid fuel production via methanol synthesis

- CO_2
- H_2
- Methanol synthesis
  - Investment costs
  - Fixed operating costs
- Heat
- CH_3OH — Can also be used directly
- H_2O
- Conversion & upgrading
  - gasoline, kerosene, diesel
  - H_2O
  - Comprises: DME/OME synthesis, olefin synthesis, oligomerisation, hydrotrating

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Liquid fuel production via Fischer-Tropsch synthesis — Figure 15

Liquid fuel production via Fischer-Tropsch synthesis

- CO_2
- Inverse CO shift
  - H_2O
  - H_2
- CO
- Fischer-Tropsch synthesis
  - Investment costs
  - Fixed operating costs
- Heat
- C_xH_yOH (crude Ptl)
- H_2O
- Upgrading
  - gasoline, kerosene, diesel
  - Comprises: Hydrocracking, isomerisation, distillation

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Literature review: investment costs of methanol synthesis (plus conversion)   Figure 16

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6.3 Production of liquid fuels (methanol synthesis and Fischer-Tropsch synthesis)

Synthetic liquid fuels are produced from hydrogen and carbon dioxide or carbon monoxide using methanol synthesis or Fischer-Tropsch synthesis.

In the case of methanol synthesis, methanol is produced in a first step from hydrogen and carbon dioxide or carbon monoxide. The methanol can either be used directly (see Section 7.2.1 for limitations on direct use) or converted further to synthetic petrol, diesel or monomolecular fuels such as OME (oxymethylene ether) and DME (dimethyl ether) (Figure 14).

The largest methanol synthesis plant is currently in operation in Iceland and generates more than five million litres of methanol per year.[119]

In the production of synthetic liquid fuels using Fischer-Tropsch synthesis, carbon monoxide and hydrogen are used to produce a raw liquid fuel (C_XH_YOH) that is then refined (Figure 15). The carbon monoxide is obtained from carbon dioxide using a reverse water-gas shift reaction.[120] Fischer-Tropsch synthesis is currently used, for example, in the Sunfire demonstration plant in Dresden. Nordic Blue Crude plans to use Fischer-Tropsch synthesis to

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119 Carbon Recycling International.

120 If Fischer-Tropsch synthesis is coupled with high-temperature electrolysis, the production of hydrogen and carbon monoxide can also be carried out using co-electrolysis in a single step.

Literature review: Investment costs of Fischer-Tropsch synthesis (plus upgrading)   Figure 17

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produce synthetic diesel in Norway.[121] The Fischer-Tropsch process is a relatively established technology that is already used on a larger scale to obtain synthetic fuels from coal.

6.3.1 Literature review: Investment costs of liquid fuel production

Figures 16 and 17 show the findings of our literature review on the investment costs required to construct liquid fuel production plants that are based on methanol synthesis or Fischer-Tropsch synthesis. The costs refer to methanol synthesis and further conversion of the methanol to petrol/diesel or DME. Alternatively, they refer to the costs of Fischer-Tropsch synthesis and subsequent conversion to a refined fuel.

Compared to the literature on hydrogen electrolysis and methanisation, a much smaller number of studies address the costs of the production of synthetic liquid fuels. For this reason, the cost ranges are far narrower than for the other conversion techniques. At the same time, the processes for producing liquid fuels are comparably well-established, so that smaller progressive cost reductions are expected than for hydrogen electrolysis or methanisation.

Even if higher progressive cost reductions are not expected because of technological progress, investment costs could sink in the years up to 2050 due to standardisation effects and the use of large-scale plants, among other possible factors. A study conducted by the Federal Environmental Agency (2016)

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121 Nordic Blue Crude (no year).

Assumed investment costs for liquid fuels conversion plants [€$_{2017}$/kW$_{PtL}$]			Table 8
	2020	**2030**	**2050**
Optimistic scenario	732	544	300
Reference scenario	788	677	500
Pessimistic scenario	843	828	800

Frontier Economics based on the literature review described in Section 6.3.1 and based on expert input.

highlights the size of the cost effect that may be associated with the use of large plants.[122]

6.3.2 Assumptions as part of the study

6.3.2.1 Investment and operating costs

The literature review of the investment costs of plants used to produce synthetic liquid fuels shows that the costs of Fischer-Tropsch synthesis and methanol synthesis do not differ fundamentally. For this reason, we have not differentiated the costs between the two processes.

We have assumed that the operating costs correspond to a fixed rate of three per cent of the investment costs.

6.3.2.2 Degree of efficiency

For the conversion of hydrogen to a liquid fuel, a degree of efficiency of 79.9 per cent is assumed on the basis of Fasihi and Breher (2017).

6.3.2.3 Plant utilisation rates

As for the methanisation plants (see Section 6.2.3.3), we assume that hydrogen storage is used, which means that a utilisation rate (i.e. load factor) of 8,000 hours for liquid fuels production can be assumed.

6.3.2.4 CO_2 capture and requirement

The production of one kilowatt hour of liquid fuel requires 2.033 kilogrammes of CO_2.[123] We assumed that the CO_2 is captured from the air for all countries.

This CO_2 capture from the air uses *temperature swing adsorption (TSA)*, as described in Section 6.2.3.4. The investment costs are currently about 2,231 euros/kW$_{PtL}$ and it is assumed that they will drop to 1,635 euros/kW$_{PtL}$[124] until 2050. Operating costs were set at four per cent of the investment costs. The electricity consumption of the plant is, on average, 0.9 MJ/kg (CO_2).[125]

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122 See Federal Environmental Agency (2016), "For the purpose of this study, the technical and economic data for the PtL plant as per LBST (2016) have been scaled up to a production capacity of 100 kt of liquid hydrocarbons per year. Thanks to economies of scale, this leads to lower specific investment for the direct air capture plant for CO_2 supply and the synthesis step compared to LBST (2016)" (p. 19).

123 Fasihi and Breyer (2017). The figure for the CO_2 requirement refers to the production of DME.

124 LBST (2016), p. 95

125 LBST (2016), p. 97. This is the average of the range from 0.72 to 1.08 MJ/kilogram (CO_2).

7. Transport, blending and distribution

In this section we describe the costs that are incurred along the value chain after the production of synthetic fuels in the roduction countries: First, costs arise for the transport of the synthetic fuels from the production country to Germany (Section 7.1). Second, costs arise at the end customer level, such as distribution costs and grid tariffs. (Section 7.2).[126]

7.1 Transport

This study takes into account the cost of transport from production countries to Germany. The costs of domestic distribution within Germany are also considered through inclusion of distribution costs and grid tariffs (see Section 7.2 for details).

7.1.1 Transport options

There are two basic options available for transporting synthetic methane from the production countries to Germany: Transport using natural gas pipelines or transport as LNG. Distribution via pipelines is only possible for countries that are connected to the European gas network, which means transport would be possible from North Africa, for example, but not from Iceland or (presumably) the Middle East. Furthermore, in the case of a pipeline transport from North Africa, it would not be possible to ensure that the synthetic methane physically reaches Germany – instead, it would be fed into the European gas network, and then credited to Germany.

If the synthetic methane is transported by tanker, then synthetic methane could directly be transported to Germany or to neighbouring countries such as the Netherlands or Belgium, where LNG terminals are located.

7.1.2 Assumptions as part of the study regarding transport costs

In this study we did not estimate the costs associated with pipeline transport but instead assumed that synthetic fuels will be transported to Germany using tankers.

7.1.2.1 Transport costs of synthetic methane

The LNG transport costs of synthetic methane include the costs of liquefying the gas in the production country, the direct transport costs, and the costs of regasification in Germany. Our estimate of current liquefaction costs are based on the lower values given in Ripple (2016) that are cited for Sabine Pass.[127] The costs of liquefaction have increased sharply in the last ten years and are currently at a high level.[128] As a potential means of reducing costs, Songburst (2014) suggests increasing competition for the production of LNG plants and components, as well as the exploitation of synergy effects between projects in a single region. Considering these cost reduction strategies, we assume a slight decrease in costs by 2050.

Our direct transport and regasification costs are based on Henderson (2016). The direct transport costs are scaled according to the distances between

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126 There are also levies and surcharges that are incurred at the end customer level. It is currently not clear how the system of levies and taxes system will develop until 2050, so we abstracted from levies and taxes for the purpose of this study.

127 Ripple (2016) specifies liquefaction costs but these differ (at the same site) depending on the buyer and the contractually agreed volume. From an economic perspective, these costs are not the costs of the liquefaction from the producer's perspective but rather the costs from the buyer's perspective, that is, the prices. Under the premise that even at the lowest price the costs will still be covered from the producer's perspective, this reflects an approximation of the costs from the producer's perspective.

128 Seeliger (2006) reported marginal costs of LNG transport (including liquefaction costs) between Algeria and Italy of an order of magnitude from 0.85 to 1.68 $/MMBtu.

the production countries considered in the study and Germany.

7.1.2.2 Transport costs for liquid fuels

The cost of transporting liquid fuels to Germany are estimated on the basis of the cost figures found in Fasihi et al. (2016), who report costs of 0.82 euros/MWh_{th} for a transport distance of 13,400 kilometres.[129] When this figure is adjusted for the distance between the production countries considered in this study and Germany, this yields the transport costs shown in Table 10.

7.2 Blending and distribution

We assume that synthetic fuels will also be used as an additive to fossil-based fuels. There are also additional costs at the end customer level, such as distribution costs and grid tariffs. Levies and taxes would also have to be taken into account. It is currently not clear how the system of levies and taxes will develop until 2050, so we abstracted from levies and taxes for the purpose of this study.[130]

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129 Fasihi et al. (2016), p. 254

130 For a summary of the discussion about levies and taxes in the energy sector, see Agora Energiewende (2017d).

LNG transport costs			Table 9
	Figures in US $/MMBtu (real)		
	2020	**2030**	**2050**
Liquefaction	2.25	2.2	2.0
Sea transport from Iceland	0.25	0.25	0.25
Sea transport from North Africa	0.38	0.38	0.38
Sea transport from the Middle East	1.17	1.17	1.17
Regasification	0.5	0.5	0.5
Total	3.0–3.92	2.95–3.87	2.75–3.67
	Figures in euro cents/kWh (real)		
Liquefaction	0.69	0.67	0.61
Transport from Iceland	0.08	0.08	0.08
Transport from North Africa	0.12	0.12	0.12
Transport from the Middle East	0.36	0.36	0.36
Regasification	0.15	0.15	0.15
Total	0.91–1.19	0.9–1.18	0.84–1.12

Frontier Economics based on Henderson (2016), Ripple (2016) and www.SeaRates.com (determination of the transport distance). Conversion factors: 1 MMBtu = 293.297 kWh; and 1 USD = 0.89 euro.

7.2.1 Variations in the blending/distribution of synthetic fuels

7.2.1.1 Gases (hydrogen, methane)

In the natural gas sector, either synthetic hydrogen or synthetic methane can be used. Using hydrogen is more cost effective than using methane because there are lower conversion losses associated with the production of hydrogen compared to the production of methane. However, technical restrictions place a cap on the hydrogen blending ratio (i.e. the permissible ratio that requires no fundamental adjustments to natural gas network infrastructure or end-use applications), whereas a blending ratio of up to 100 per cent is possible when adding methane to natural gas.

7.2.1.2 Liquid fuels

In the transport sector, synthetic liquid fuels can in principle be blended up to 100 percent with petrol and diesel. Alternatively, monomolecular fuels (such as methanol, DME and OME) can be used in the transport sector.[131] The latter option has the advantage of reducing local emissions, such as fine particulate matter. However, the blending of monomolecular fuels with diesel and petrol is only possible to a lim-

ited degree because at higher blending ratios, end-use applications would have to be converted.

7.2.2 Assumptions made as part of the study regarding blending and distribution

7.2.2.1 Blending ratios

The end customer prices are calculated for blending ratios of 0 to 100 per cent synthetic natural gas to methane and 0 to 100 per cent synthetic liquid fuels to diesel or petrol.

7.2.2.2 Costs of fossil fuels

The natural gas price of the World Bank, which was set at about 1.5 cents per kilowatt hour in 2017, is used as the basis for gaseous fossil fuel procurement prices.[132] For the projection of prices up to 2050, the natural gas price trend identified by the World Bank up to 2030 is used as the basis for the optimistic scenario and extrapolated for the period after 2030. In the pessimistic scenario the natural gas price up to 2040 is based on the Current Policies Scenario of the IEA (2016) (this trend is extrapolated for the years between 2040 and 2050). The values for the reference scenario correspond to the mean of the values in the optimistic and pessimistic scenarios.

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131 Synthetic methane can also be used in the transport sector in natural gas vehicles.

132 See World Bank (2017)

Assumed transport costs for liquid fuels			Table 10
Production country	**Port of departure**	**Sea distance to Hamburg (km)**	**Transport costs ct/kWh$_{th}$ (real)**
Iceland	Reykjavik	2,332	0.014
North Africa	Algiers, Annaba, Agadir, Casablanca, Nador	approx. 3,600	0.022
Middle East	Muscat, Dammam, Jeddah/ King Abdullah Port, Dubai	approx. 11,000	0.067

Frontier Economics based on www.SeaRates.com (determination of the sea distance) and Fasihi et al (2016) (estimation of the transport costs per kilometre).

The purchase price for liquid fossil fuels in April 2017 is 3.9 cents per kilowatt hour for premium petrol and 3.7 cents per kilowatt hour for diesel.[133] For the projection of prices up to 2050, the trend for the crude oil price of the World Bank up to 2030 is used as the basis for the optimistic scenario and extrapolated for the period after 2030. In the pessimistic scenario the trend for petrol and diesel prices is derived from the crude oil price trend contained in the Current Policy Scenario of the IEA (2016). The values for the reference scenario correspond to the mean of the values in the optimistic and pessimistic scenarios.

7.2.2.3 Grid tariffs / distribution costs

As part of the study it is assumed that grid tariffs and distribution costs remain constant between today and 2050 and the costs incurred are the same for natural gas and synthetic methane and for fossil diesel/petrol and synthetic liquid fuels. The following values are used in our calculations:

→ Grid tariffs for gas (natural gas/synthetic methane) of 1.59 cents per kilowatt hour.[134]

→ Distribution costs for gas (natural gas/synthetic methane) of 0.43 cents per kilowatt hour. [135]

→ Costs of (domestic) transport, storage, stockholding, administration and distribution for liquid fuels (fossil diesel/petrol or synthetic liquid fuels) of 10 cents per litre.[136]

Assumed product procurement prices for fossil fuels: natural gas, premium gasoline and diesel (ct$_{2017}$/kWh)			Tabele 11
Scenario	**2020**	**2030**	**2050**
Natural gas			
Optimistic	1.42	1.70	2.25
Reference	1.64	2.27	3.03
Pessimistic	1.87	2.84	3.81
Premium gasoline			
Optimistic	4.17	4.42	4.91
Reference	4.66	6.19	7.63
Pessimistic	5.14	7.96	10.34
Diesel			
Optimistic	4.01	4.25	4.73
Reference	4.48	5.95	7.34
Pessimistic	4.94	7.66	9.95

Frontier Economics based on Petroleum Industry Association (2017) and IEA (2016).

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133 See Petroleum Industry Association (no year)

134 Grid tariffs for natural gas at the household level, including costs of measurement and billing as per BDEW: 'Natural gas price for households (single-family households) in ct/kWh' (as of 02/2017)

135 Purchase and distribution costs as per BDEW (2017), minus purchase costs that were approximated using the mean of the BAFA cross-border price in the last five years.

136 Data for the distribution costs of petrol and diesel are not publicly available. The Petroleum Industry Association only publishes data that cover the contribution margins, the costs of transport, storage, stockholding, administration and distribution as well as the profit margins. The contribution margins also fluctuate over time. In the period from January to April 2017, the contribution margin for petrol/diesel was about 12 to 14 cents per litre.

According to statements from the Petroleum Industry Association, the profit margin is expected to be 1 to 2 cents per litre (Boerse.Ard.de , 2015; sueddeutsche.de, 2014). We therefore assume that about 10 cents per litre are incurred for the cost of transport, storage, stockholding, administration and distribution.

8. Summary of results for synthetic fuel cost estimates up to 2050

This chapter summarises the results of the cost estimate:

→ Section 8.1 provides an overview of the estimated costs and
→ Section 8.2 identifies the main cost drivers.

All results are based on the assumption of a WACC of six percent (for all technologies and sites).[137]

8.1 Overview of the cost estimates

The total costs of imported synthetic fuels are explained below – first as final energy costs at the German border (that is, without considering grid tariffs and distribution costs) (Section 8.1.1), then at the end customer level (that is, considering grid tariffs and distribution costs but without considering levies and taxes[138]) (Section 8.1.2).

8.1.1 Total production and transport costs for imported synthetic fuels (without grid tariffs/distribution costs)

8.1.1.1 Total costs of imported synthetic methane

Figure 18 shows the estimated costs for the production and transport of imported synthetic methane for the snapshot years 2020, 2030 and 2050. The costs in the reference scenario are shown in pink; the purple line indicates the cost range between the optimistic scenario (low costs) and the pessimistic scenario (high costs).

The purchase costs for conventional natural gas assumed in the reference scenario are also shown in Figure 18 as a dashed line. It is worth mentioning that a comparison between the costs of synthetic methane and the price for conventional natural gas is inadequate because, unlike conventional natural gas, synthetic methane is carbon neutral.

Looking at the results for 2020 shows:

→ **The most favourable production option for synthetic methane is based on geothermal power and hydropower in Iceland.** This is due to the country's comparably low electricity generation costs and high load factors of the conversion technologies rates.
→ **The production of synthetic methane based on offshore wind power in the North and Baltic Seas is associated with higher costs than the import of synthetic methane** under all of the import options considered.
→ The cost of methane imported from North Africa and the Middle East lies between the cost of methane imported from Iceland and the generation costs in the North and Baltic Seas.

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137 The WACC can, just as for the other assumptions made, be adjusted in the Excel tool on the Agora website. The WACC has noticeable influence on the total costs (see also Fh-ISE 2015b).

138 It is currently not clear how the system of levies and taxes will develop until 2050 – as described in Chapter 7 – so we abstracted from levies and taxes for the purpose of this study.

→ **The cost of producing synthetic methane is at a similar level when based on photovoltaic technology or on hybrid PV/onshore wind power. This is attributable to two** countervailing effects: For one, hybrid photovoltaic/onshore wind power generation achieves higher full-load hours than electricity generated using photovoltaic technology alone. The degree of utilisation of the hydrogen electrolysis plant increases as a result, reducing the significance of investment costs. However, the electricity generation costs are higher than for photovoltaic generation alone.

A comparison of the results for 2020 with the results for 2050 reveals the following:

→ **The cost of synthetic methane declines considerably over time.** This is due to progressive investment cost reductions for the construction of renewable electricity generation plants (see Section 5) and conversion plants (see Section 6). The efficiency of

hydrogen electrolysis is also assumed to increase over time (see Section 6).

→ **The costs of the different site and technology options converge over time.** The reason for this is that the investment costs for photovoltaic power plants and offshore wind turbines are assumed to fall more sharply than the investment costs for more established technologies such as onshore wind, geothermal and hydropower (see Section 5);

→ **Even in the long term, importing synthetic methane is associated with lower costs than generating synthetic methane based on offshore wind energy in the North and Baltic Seas, regardless of the production country considered.** However, the costs converge appreciably. The size of the potential cost advantage of importing synthetic methane depends fundamentally on the development of the investment costs of offshore wind energy up to 2050 and on what full-load hours can be achieved at individual wind farm sites (see Section 5 on the

Total cost of synthetic methane (without grid tariffs and distribution costs) (ct$_{2017}$/kWh$_{methane}$) Figure 18

cost ranges that inform the optimistic and pessimistic scenarios).

Overall, the cost benefit due to more favourable electricity generation costs in potential import countries more than offsets the transport costs to Germany, thus creating a cost benefit for importing synthetic methane. How high this cost benefit is depends significantly on how the investment costs of offshore wind energy develop compared to the costs of other renewable energy generation technologies, particularly photovoltaic technology.
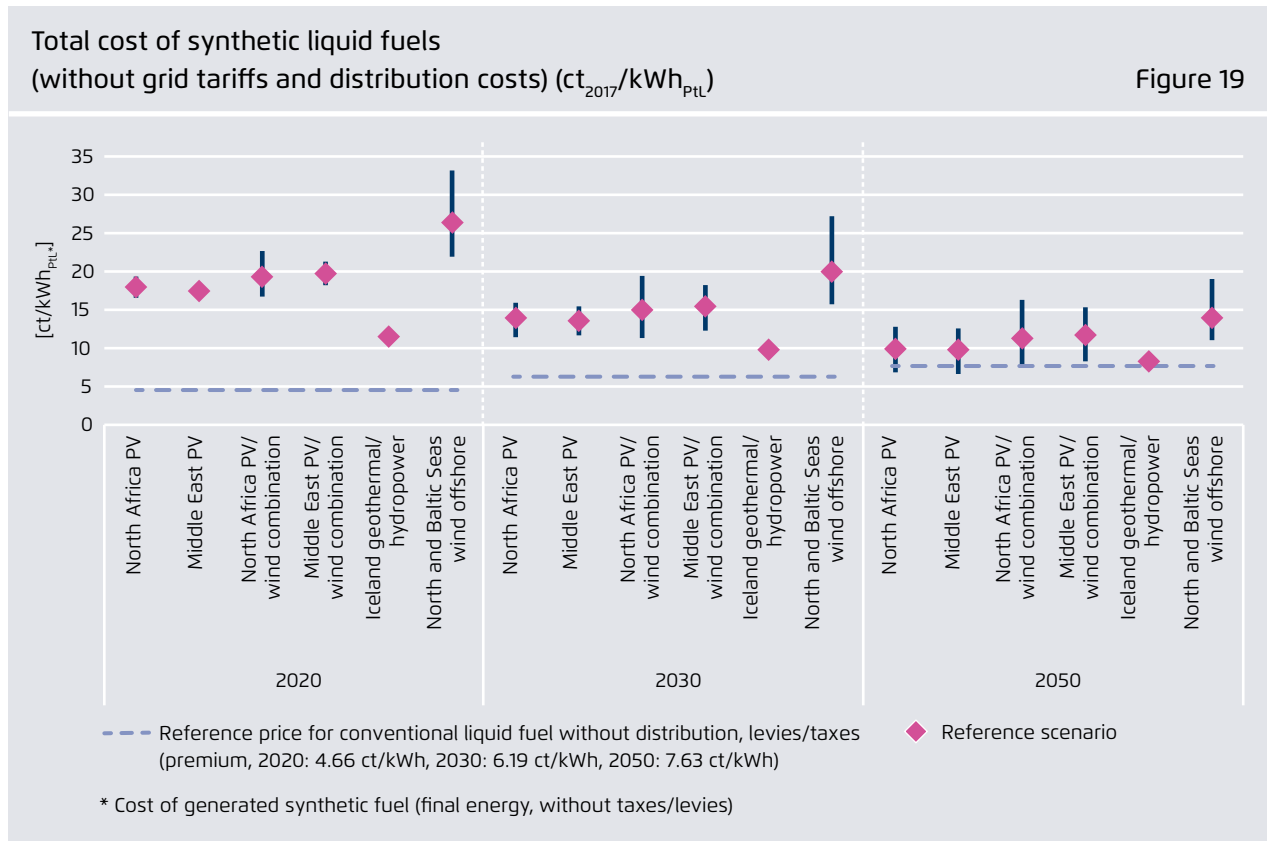
8.1.1.2 Total costs of imported synthetic liquid fuels

The generation and transport costs associated with imported synthetic liquid fuels (Figure 19) are similar to that of synthetic methane. Because both synthetic methane and synthetic liquid fuels are produced using hydrogen, a large share of the generation costs

are identical. Furthermore, there is only a marginal difference in the assumed efficiency of methanisation and of conversion to liquid fuels, and production plant investment costs are of a similar order of magnitude (Section 6). Although the transport costs of liquid fuels are lower than those of synthetic methane,[139] synthetic liquid fuels incur somewhat higher CO_2 input costs, meaning that the results of the cost estimates are comparable.

This demonstrates that, there are also possible cost benefits associated with importing synthetic liquid fuels. However, as is the case for synthetic methane, the extent of the cost benefit depends crucially on how the investment costs for offshore wind energy develop over time.

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139 While liquid fuels have direct transport costs only, LNG transport of methane additionally includes cost of liquefaction and regasification (see Section 7).

Total cost of synthetic liquid fuels
(without grid tariffs and distribution costs) (ct$_{2017}$/kWh$_{PtL}$)   Figure 19

Reference price for conventional liquid fuel without distribution, levies/taxes (premium, 2020: 4.66 ct/kWh, 2030: 6.19 ct/kWh, 2050: 7.63 ct/kWh)

◆ Reference scenario

* Cost of generated synthetic fuel (final energy, without taxes/levies)

8.1.2 Total cost of imported synthetic fuels at the end customer level (including grid tariffs and distribution costs)

The total cost of methane at the (household) end customer level is shown in Figure 20. In addition to generation and transport, we consider the costs of, distribution, grid tariffs and fossil/synthetic natural gas blend.

Costs at the end customer level depend on the synthetic methane blending ratio: With a blending of 0 per cent, the costs are based exclusively on procurement costs for conventional natural gas, and with a blending of 100 per cent, the costs are based exclusively on procurement costs for synthetic methane.[140]

_____

140 The cost of synthetic methane in Figure 20 corresponds to the cost of imported synthetic gas from North Africa that is generated using photovoltaic technology. In the Excel tool provided on the Agora website, the figure can also be calculated for other import options.

In 2020 the costs of synthetic and conventional methane are expected to remain highly divergent. Accordingly, the end customer costs of 100 per cent blending are more than four times the costs of 0 per cent blending.

As the cost of synthetic and conventional methane converges until 2050, the cost differential narrows between blending ratios. This convergence is driven on the one hand by the assumption of increased prices for conventional natural gas (in the reference scenario from a current level of 1.72 ct_{2017}/kWh to 2.36 ct_{2017}/kWh in 2030 and to 3.16 ct_{2017}/kWh in 2050). On the other hand, the generation costs of synthetic methane are expected to fall, as shown in Figure 18.

Total cost of methane depending on the proportion of blended synthetic methane (including grid tariffs and distribution costs) – costs of synthetic methane given for the import option "PV from North Africa" (ct_{2017}/kWh$_{methane}$)　　　Figure 20

Source: PV; interest rate: 6%
Note: 0% – only fossil natural gas; 100% – only synthetic natural gas

* Costs for generating methane (final energy (LHV), without levies/taxes)

Total cost of liquid fuels depending on the proportion of blended synthetic fuel (including distribution costs) – costs of synthetic liquid fuels given for the import option "PV from North Africa" (ct$_{2017}$/kWh$_{PtL}$)
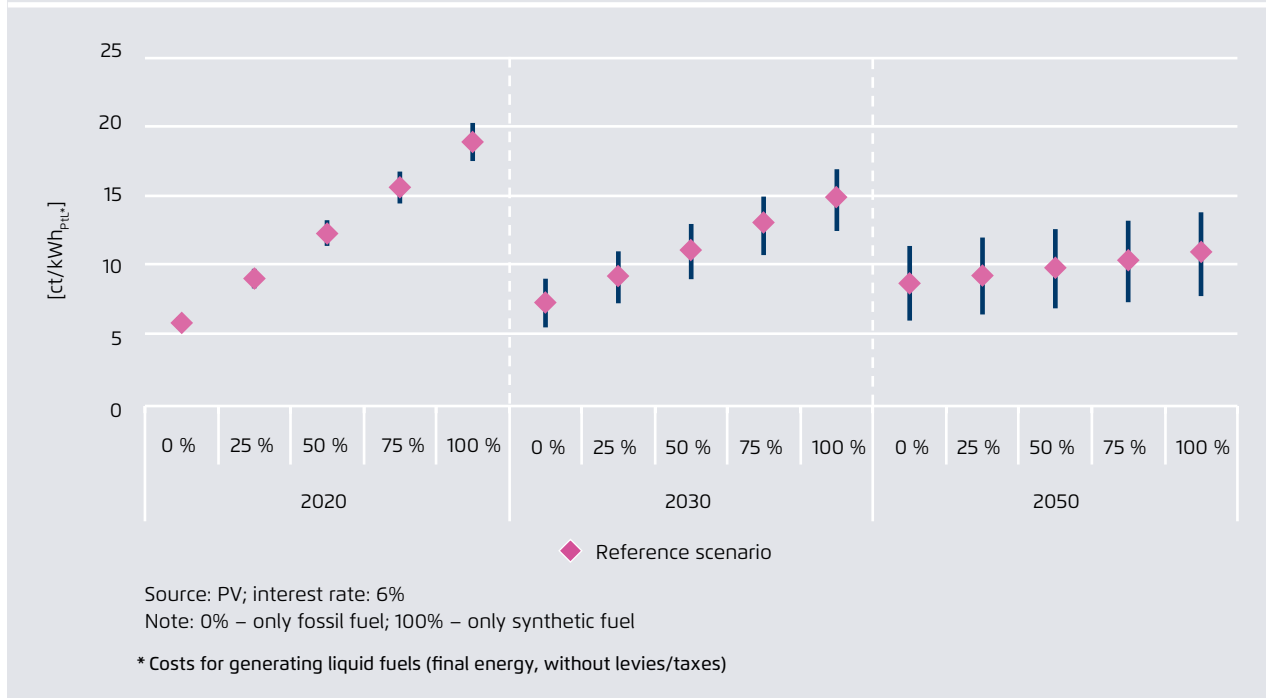
Figure 21

Source: PV; interest rate: 6%
Note: 0% – only fossil fuel; 100% – only synthetic fuel

* Costs for generating liquid fuels (final energy, without levies/taxes)

Figure 21 shows the total cost of liquid fuels at the end customer level. Similar to methane, the costs of synthetic liquid fuels are higher than the costs of conventional fuels in 2020. The costs of synthetic and conventional liquid fuels largely converge until 2050. This convergence is driven, on the one hand, by the assumption of increased prices for conventional fuels (for premium petrol in the reference scenario from a current level of 4.66 ct$_{2017}$/kWh to 6.19 ct$_{2017}$/kWh in 2030 and to 7.63 ct$_{2017}$/kWh in 2050) and, on the other hand, the assumption that generation costs of synthetic fuels are expected to fall, as shown in Figure 19.
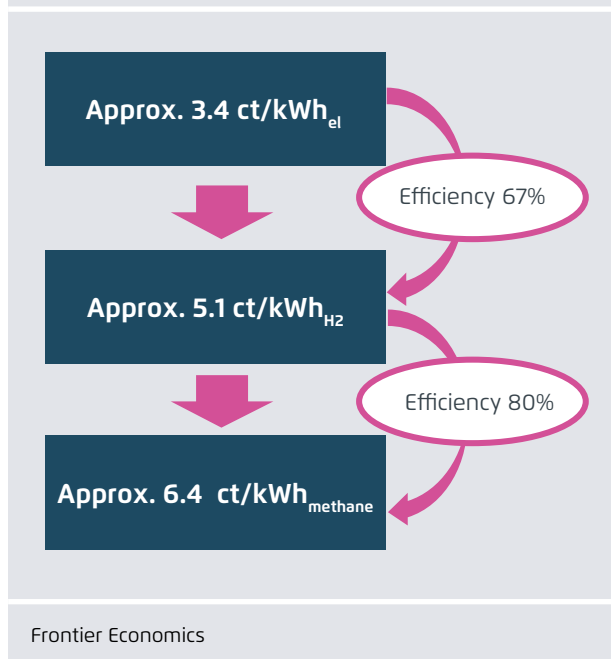
8.2 Fundamental cost drivers

The primary drivers of the cost trends for imported synthetic methane and synthetic liquid fuels are described below. These drivers are: electricity generation costs (Section 8.2.1); conversion plant utilisation rates (load factors); and conversion plant investment costs (Section 8.2.2). Transport costs are of secondary importance which is particularly true for synthetic liquid fuels.

8.2.1 Cost driver: Electricity generation costs

Electricity generation costs make up a significant fraction of the total cost of synthetic methane and synthetic liquid fuels, as shown in Figures 23 and 24. In 2020 electricity generation costs are by far the largest cost component. Although electricity generation costs fall by 2050 due to the assumption of

Increase in electricity generation costs due to conversion losses – illustration of the electricity generation costs and efficiencies in the production of synthetic methane for the import option "PV from North Africa" in the reference scenario   Figure 22

Approx. 3.4 ct/kWh$_{el}$

Efficiency 67%

Approx. 5.1 ct/kWh$_{H2}$

Efficiency 80%

Approx. 6.4 ct/kWh$_{methane}$

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decreasing investment costs for renewable energy, they continue to make up a significant fraction of the total costs in 2050.

The strong impact exerted by the electricity generation costs on the cost of synthetic methane and synthetic liquid fuels can be attributed to the inefficiency of the conversion process, as illustrated by the following example (Figure 22): The electricity generation costs of photovoltaic technology in North Africa are 3.43 ct/kWh$_{el}$ in 2020 (reference scenario). With an efficiency of 67 per cent for hydrogen electrolysis, electricity costs of 5.12 ct/kWh$_{H2}$ are incurred. In the case of methanisation, methanol synthesis, or Fischer-Tropsch synthesis, there are additional conversion losses, so that the electricity costs for the

final product in this illustrative example are 6.39 ct/kWh$_{methane}$ and 6.39 ct/kWh$_{PtL}$.

The importance of the electricity generation costs can be seen in Figures 23 and 24 when comparing the electricity generation costs between different countries and between different years. Due to the multiplier effect of the conversion losses described above, differences in the investment costs and full-load hours between different regions and at different times exert a strong effect on the total costs.

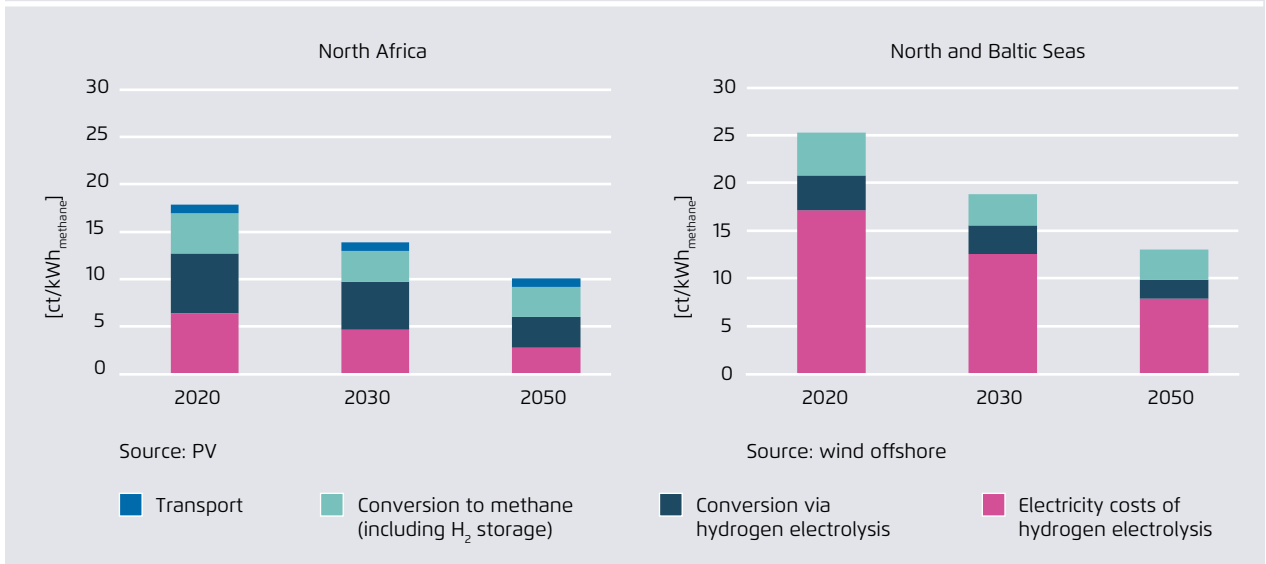### 8.2.2 Cost driver: Plant utilisation rates and investment costs

The costs associated with developing the synthetic fuel conversion plants (hydrogen electrolysis, methanisation and methanol or Fischer-Tropsch synthesis) are the second most important cost component. In this connection, plant costs are primarily driven by initial investment costs and subsequent utilisation rates.

The impact exerted by investment costs is clearly evident in Figure 24 when comparing the costs in 2020 and 2050. As described in Section 6, the costs of all the conversion plants are assumed to fall over time.

The effect exerted by plant utilisation rates can be seen in Figure 25: On the left-hand side, a utilisation rate of 2,000 hours is assumed for both hydrogen electrolysis and methanisation. The resulting conversion costs are more than three times higher than that of the centre figure, in which the utilisation rates are set at 8,000 hours. In the right-hand figure an average case is also shown in which the utilisation rate for hydrogen electrolysis is assumed to be 2,000 hours per year while the methanisation plant runs 8,000 hours per year. This final case illustrates a situation in which

Comparison of the generation and transport costs of synthetic methane in North Africa (photovoltaic) and in the North and Baltic Seas (offshore wind) in the reference scenario (ct$_{2017}$/kWh$_{methane}$)
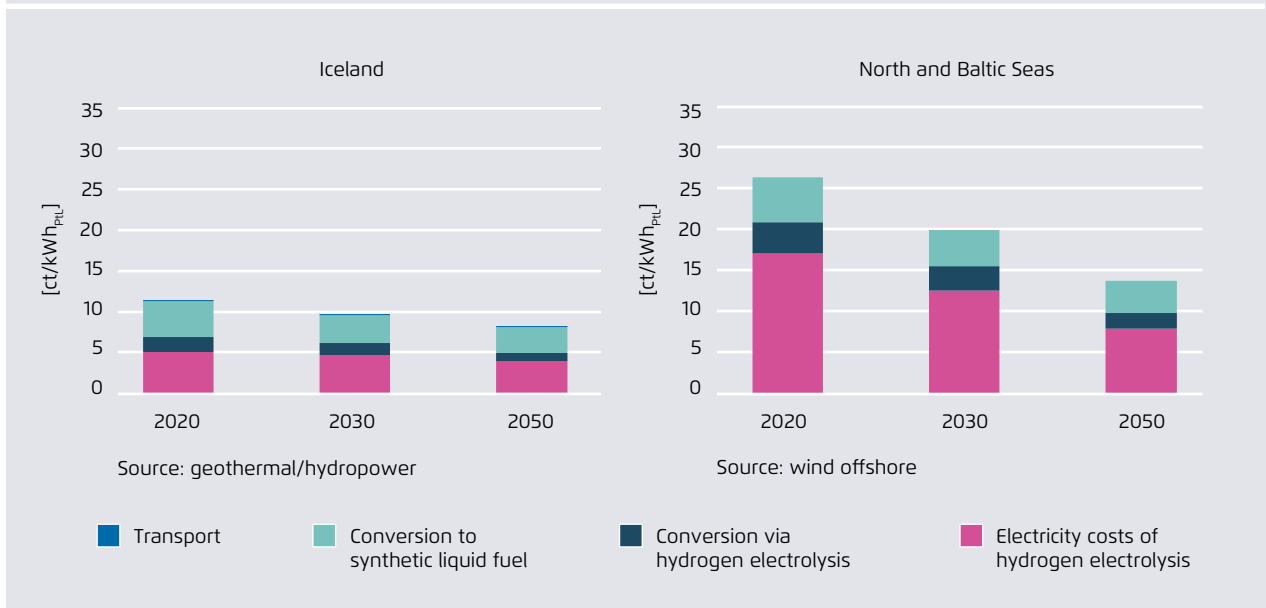
Figure 23

North Africa

Source: PV

North and Baltic Seas

Source: wind offshore

- Transport
- Conversion to methane (including H$_2$ storage)
- Conversion via hydrogen electrolysis
- Electricity costs of hydrogen electrolysis

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Comparison of the generation and transport costs of synthetic liquid fuels in Iceland (geothermal/hydropower) and in the North and Baltic Seas (offshore wind) in the reference scenario (ct$_{2017}$/kWh$_{PtL}$)

Figure 24

Iceland

Source: geothermal/hydropower

North and Baltic Seas

Source: wind offshore

- Transport
- Conversion to synthetic liquid fuel
- Conversion via hydrogen electrolysis
- Electricity costs of hydrogen electrolysis

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Cost impacts of production plant utilisation rates and investment costs on
the cost of conversion (indicative values for hydrogen electrolysis and methanisation)　　Figure 25

Frontier Economics
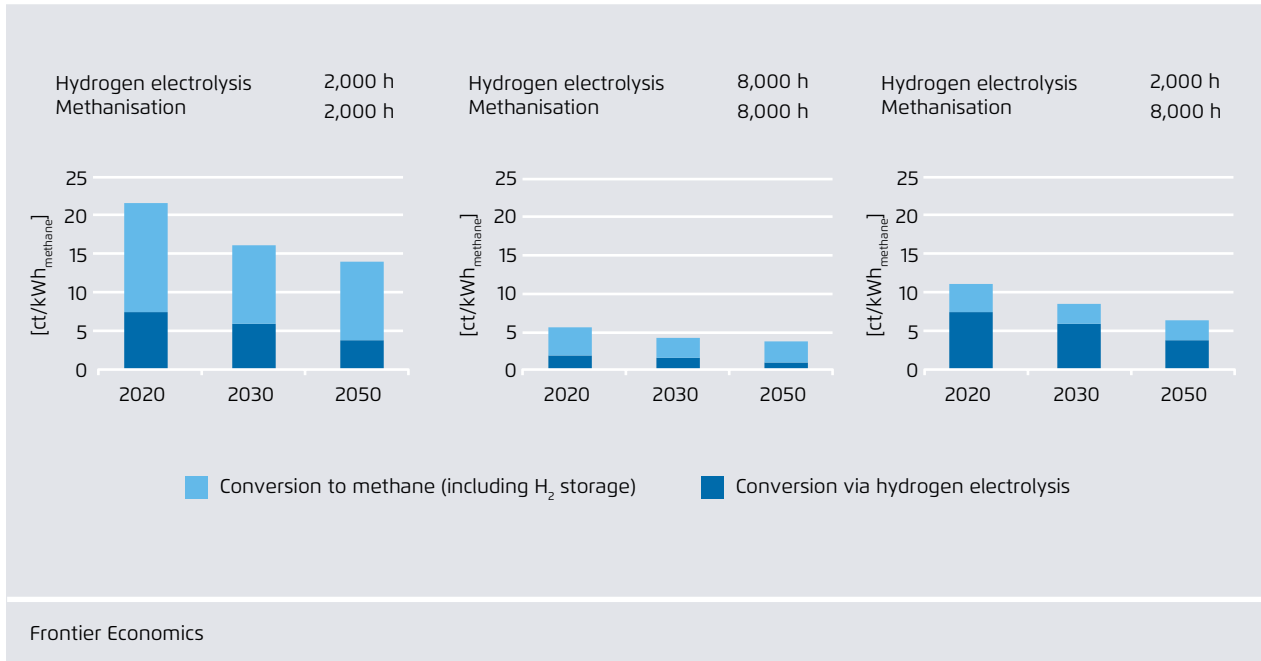
hydrogen electrolysis has fewer full-load hours
because the electricity is generated using fluctuat-
ing renewable sources (and without using electricity
storage) but the methanisation has upstream hydrogen
storage, which increases utilisation.

8.2.3 The role of costs for CO_2 and seawater desalination

The costs of capturing CO_2 within the methanisation
process are not irrelevant. The costs of capturing CO_2
from the air (direct air capture) make up about 10 to
15 percent of the total costs of methane production.

On the other hand, the costs of seawater desalination
as a part of the electrolysis are negligible. Based on the
figures available in the literature, these costs are orders
of magnitude that are not apparent in the figures (see
the tool).

9. Sustainability criteria

If synthetic fuels are to be imported to Germany for the purpose of achieving emission reduction goals, then political considerations dictate that the production of synthetic fuels in the countries of origin must satisfy certain sustainability criteria. The following sustainability criterias may be of considerable importance in this regard:

→ **The additionality of renewable electricity generation:** The concept of additionality considers whether renewable electricity generation in the countries of origin occurs in addition to or displaces other renewable electricity generation. One challenge in analysing the additionality of electricity generated from renewable sources lies in defining the reference base relative to which the generation is supplemental. In this regard, one could adopt the criterion that renewable electricity generated for the purpose of producing synthetic fuels for export must occur on a supplemental basis to renewable electricity generation

  → that would in any case be generated on the basis of purely economic criteria in the production country;

  → that is required to satisfy the renewable energy targets in the production countries; and/or

  → that is required to cover the entire electricity (or even energy) demand of the production country.

This conception of additionality thus mirrors the definition of additionality for greenhouse gas reduction measures that was adopted as part of the Clean Development Mechanism (CDM).[141] Additionality was defined such that CDM measures must lead to emissions reductions that would not have been achieved without the CDM measures. Providing evidence of additionality is difficult in practice, however. Schneider (2009) concludes that additionality can never be demonstrated with complete certainty because additionality has to be demonstrated relative to a hypothetical situation (namely, that in which the CDM measures were not implemented). Research into the additionality of CDM measures has come to the conclusion that for the majority of the projects considered, it is questionable whether the measures actually satisfy the additionality criterion.[142] In light of this problem, Schneider (2009) has urged that evidence of additivity should be provided using objective criteria and in a transparent manner. However, Schneider has also highlighted the trade-off between eliminating non-additional projects, on the one hand, and not excluding projects that are additional as a result of criteria that are too stringent, on the other.

With regard to the production of synthetic methane/synthetic liquid fuels in other countries, this means that the additionality criterion should be defined to prevent the displacement of local renewable electricity generation while also avoiding insurmountable bureaucratic hurdles for implementing environmentally and economically useful measures. However, a very strict definition of additionality (for example: "It must first be ensured that electricity demand in the production country is already covered by renewable energy") would be almost impossible to satisfy in almost all the potential production countries in the short to medium term. Iceland would represent a sole exception, because domestic electricity demand (of about 17 terawatt hours) is already almost entirely covered by renewable energy and Iceland's renewable

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141 As part of the CDM mechanism, developing countries can make use of measures to reduce greenhouse gases and have these certified. In this way, they acquire Certified Emission Reductions (CER) or Emission Reduction Units (ERU). Industrial countries can acquire these certificates in order to meet their own reduction targets. These can be also be submitted in the EU ETS as reduction certificates.

142 See Schneider (2009) and the literature evaluated in this paper (Schneider (2009), p. 250f). A critical analysis is also available from the Oeko Institute (2016). The additionality of the expansion of renewable energies in non-EU countries as part of the CDM as an additional measure is questionable.

energy potential is more than twice that of domestic electricity demand.[143] However, in most other countries there is the risk that a very strict interpretation of additionality would prevent investment in renewable energy that would otherwise occur. As a result, a strict interpretation could be counter-productive from an environmental policy perspective.

→ **Sustainable use of space:** Another sustainability criterion relates to competition between various land uses. Competition with the use of land for food production and with forested areas are of particular importance in this regard. Renewable power facilities, synthetic fuel production plants and, as necessary, plants for obtaining water and CO_2 all require space. Each local and regional situation has to be examined individually to determine how the space necessary for synthetic fuel production has been used to date, and which uses could potentially be displaced. In the context of the debate surrounding biofuels, Fargione et al. (2008) argue that converting forested areas to cropland for biofuel production can lead to significant increases in CO_2 emissions compared to the use of conventional fuels. Unlike the production of biofuels, it is not necessary to make use of agricultural land or fertile forests to produce synthetic methane/synthetic liquid fuels. Desert areas can be just as easily used, for example.

→ **Sustainable economic development in production countries:** In some cases, it may be a requirement to ensure that CO_2 reduction measures in foreign countries are implemented in a manner that encourages sustainable economic development. Criteria for sustainable development could include the requirement to make additional investment, reduce poverty levels, and/or transfer new technologies.[144] A study conducted as part of the Desert Power 2050 project, which aims to cover a considerable share of energy demand in Europe, North Africa and the Middle East with renewables by 2050, determined that successful economic development depends heavily on political and regulatory factors. Model-based calculations indicate positive growth in real incomes when international climate policy is implemented that internalises the negative consequences of CO_2 emissions.[145]

→ Export countries could benefit economically in the long term from investment in renewable energy and the infrastructure needed for exporting synthetic fuels. It must still be investigated to what extent the export countries can create the political and economic conditions needed to establish lasting domestic value creation. Synthetic fuel production could be of considerable interest to countries that to date have generated a considerable share of their national income by exporting fossil fuels, including countries in North Africa and the Middle East. However, it is essential that certification systems are established in such countries to ensure that the fuels are produced by synthesis processes and not from fossil sources. Such certification is already in place for bioethanol, the sustainability of which must be verified.[146] To this end, the EU has enacted appropriate legislation in the *Renewable Energy Directive*. The EU's sustainability criteria specify that it must be demonstrated that the biofuels used in the member states since 2011 are associated with at least a 35 per cent reduction in greenhouse gases compared to fossil fuels. Furthermore, from 2018 onward this reduction must be 50 per cent. Bioethanol producers are certified by an independent body in accordance with a state-approved certification system. Regular independent audits conducted by experts verify the origin of the

143 Askja Energy (no year).

144 Schneider (2007)

145 Calzadilla et. al (2014)

146 The EU stipulates that 10 percent of the energy used in the transport sector come from renewable sources by 2020; see Directive 2009/28/EC of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC

raw materials and their processing in the bioetha-nol plants. The producers must document the sus-tainability of the raw materials that they cultivate.

→ **Existing water supply must not be used in dry climate zones:** In dry climate zones such as North Africa and the Middle East, it must be ensured that the water required for the electrolysis is sourced from seawater desalination plants and not from the existing water supply. In our cost estimates we have therefore assumed that in dry climate zones water will have to be supplied from desalination plants. A critical situation would emerge in this case if, for example, sites for seawater desalina-tion plants are otherwise neeeded for supplying the local population. However, this situation has not been investigated; that is, it is not known if there is a scarcity of sites for seawater desalination plants in regions that can be potentially be used for pro-ducing synthetic fuels.

→ **Closed CO_2 cycle:** To created a closed CO_2 cycle, the CO_2 must be captured from the air, biomass or biogas.[147] In our cost estimates we have assumed that the required CO_2 is extracted from the air in all countries. Accordingly, our calculations are based on a carbon-neutral carbon dioxide cycle. An appropriately closed carbon dioxide cycle would have to be confirmed for the import of synthetic fuels. Unlike the additionality of the measures (see above), evidence of a closed carbon dioxide cycle is comparably simple to provide, for example, by comparing the CO_2 quantities captured in direct air capture plants with the quantity of CO_2 used in the conversion processes.

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147   What must be noted is that synthetic methane produced using electricity from renewable sources has the same environmental effect as fossil methane when it escapes unburnt (methane slip). We assume in our analysis that methane slip can be controlled using technology and is accordingly not included.

10. Summary and prospects

Our estimates of the costs associated with import-ing synthetic fuels shows that there is a possible cost benefit associated with importing synthetic fuels from countries with favourable sites for generating electricity from renewable sources as compared to production that includes offshore wind power in the North and Baltic Seas. Our cost estimates also reveal that in the medium to long term, it can be assumed that the costs of synthetic and conventional fuels converge.

We have evaluated literature that indicates a high degree of uncertainty with regard to future cost trends for fuel production technologies. These uncer-tainties are reflected in the broad cost ranges associ-ated with the different scenarios. In this context, we refer the reader once again to the Excel tool provided on the Agora website that enables users to test the consequences of varying underlying assumptions.

Overall, this study provides an important contri-bution to the current debate about decarbonisation strategies in the heating and transport sectors. For a comprehensive economic assessment of the various decarbonisation strategies being considered, addi-tional analysis is necessary, e.g. to compare the costs of synthetic fuels with the costs of different electrifi-cation options.

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