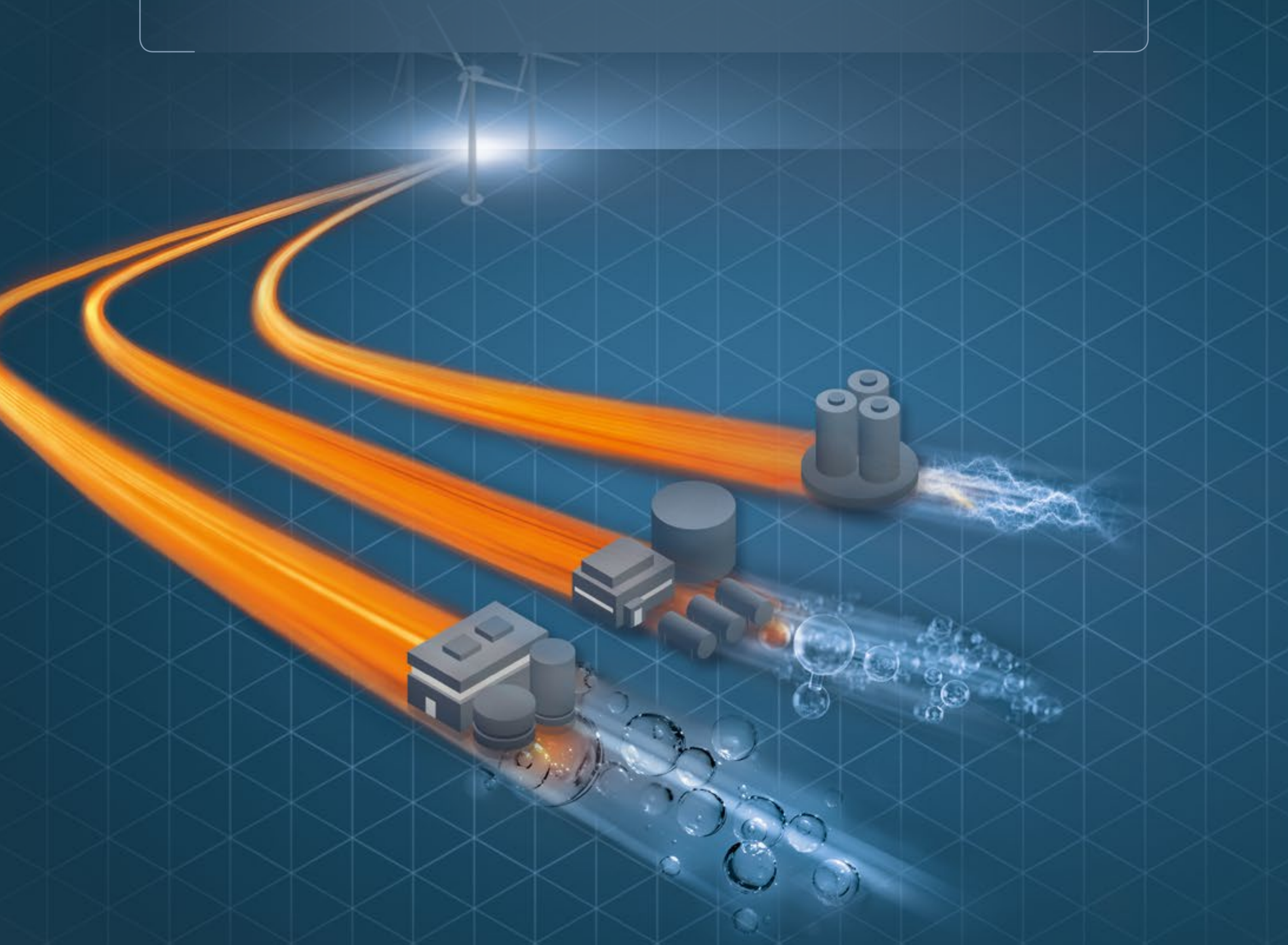
FVV PRIME MOVERS. TECHNOLOGIES.

Defossilizing the transportation sector

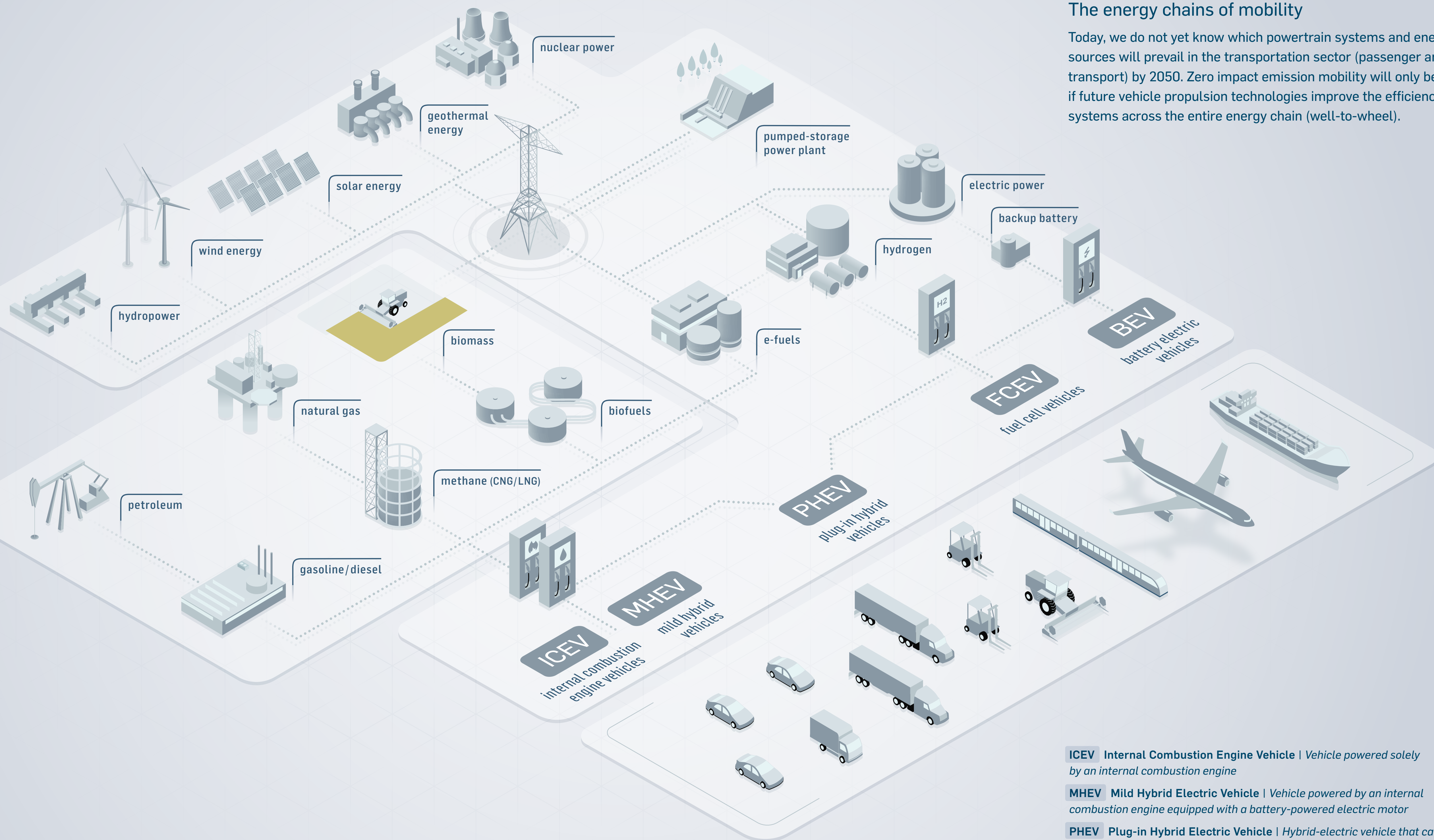
Options and requirements for Germany



FVV

The energy chains of mobility

Today, we do not yet know which powertrain systems and energy sources will prevail in the transportation sector (passenger and freight transport) by 2050. Zero impact emission mobility will only be achieved if future vehicle propulsion technologies improve the efficiency of the systems across the entire energy chain (well-to-wheel).



ICEV **Internal Combustion Engine Vehicle** | *Vehicle powered solely by an internal combustion engine*

MHEV **Mild Hybrid Electric Vehicle** | *Vehicle powered by an internal combustion engine equipped with a battery-powered electric motor*

PHEV **Plug-in Hybrid Electric Vehicle** | *Hybrid-electric vehicle that can travel up to approx. 15–20 km without using its combustion engine*

FCEV **Fuel Cell Electric Vehicle** | *Vehicle that uses a fuel cell to power an electric propulsion system*

BEV **Battery Electric Vehicle** | *All-electric vehicle that derives its propulsion power from an on-board rechargeable battery pack*

Author

Dr. Ulrich Kramer | Ford-Werke GmbH

Contributing authors

Felix Ortloff | DVGW Research Centre at the Engler-Bunte-Institute (EBI) of the Karlsruhe Institute of Technology (KIT), Gas Technology
Stephan Stollenwerk | innogy SE
Ralf Thee | Research Association for Combustion Engines (FVV) eV

Project support

Reinhard Otten | Audi AG
Dr. Xavier Sava | BASF New Business GmbH
Dr. Claudia Spang | BASF SE
Dr. Lars Menger | BMW AG
Dr. Jörg Ullmann | Robert Bosch GmbH
Steffen Eppler | Robert Bosch GmbH
Andreas Schleiffer | BP Europa SE
Harry Schüle | Continental Automotive GmbH
Dr. Dietrich Gerstein | DVGW Deutscher Verein des Gas- und Wasserfaches eV
Dr. Claudia Herudek | Ford-Werke GmbH
Dr. Werner Willems | Ford-Werke GmbH
Sebastian Barth | Honda R&D Europe (Deutschland) GmbH
Dr. Michael Hönl | MTU Friedrichshafen GmbH
Dr. Andreas Janssen | Shell Global Solutions (Deutschland) GmbH
Dr. Martin Lohrmann | Volkswagen AG
Werner Kübler | MAN Truck & Bus AG

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A brief overview of the study

In accordance with the Climate Action Plan 2050, Germany is to become predominantly greenhouse gas-neutral by 2050. However, it is not possible to fully decarbonize the transportation sector when vehicles are powered by combustion engines that use fossil fuels. This is also the case if the entire remaining potential for optimizing combustion engines and vehicles is exhausted. In order to achieve the CO_2 emission targets, suitable concepts are therefore necessary.

Against this background, the Fuels working group of the Research Association for Combustion Engines (FVV) worked together with relevant partners from the automotive, chemical, mineral oil and supplier industries and an energy provider to compare and assess various mobility scenarios, which would all enable **fully CO_2-free mobility** (well-to-wheel) and the energy requirements of which can be completely covered by realistically exploitable renewable energies (solar and wind energy).

All of these 100 % scenarios, as they are known, involve complete "defossilization" of energy provision, meaning that fossil fuels are no longer used. Local CO_2 emissions from vehicles are permitted here if they are fully compensated during the course of energy provision (closed CO_2 cycle). Although these are theoretical and relatively unrealistic scenarios, they are very useful tools for analyzing potential and comparing technical and economic suitability. The described conclusions do not merely reflect the opinion of a single industry partner here, but are rather to be viewed as the cross-industry synthesis of this joint study.

The study focuses on a quantitative economic comparison of mobility costs (fuel production, expansion of distribution infrastructure, vehicle costs) and the primary energy requirement of various fuel-powertrain systems selected in a previous step, which when considered as a whole, can enable complete defossilization by 2050.

In all of these scenarios, energy is provided by solar and wind power and is exclusively CO_2-neutral. The use of electricity is compared in three fundamentally different scenarios:

1. Direct use of electrical energy obtained through regeneration in electric vehicles (battery electric vehicle, or BEV).

2. Generation of hydrogen via electrolysis using electrical energy obtained through regeneration and water and the subsequent use of the hydrogen in vehicles using a fuel cell (fuel cell electric vehicle, or FCEV).

3. Generation of what are known as PtX fuels (e-fuels) using regenerative, electrolytically produced hydrogen by means of various fuel-specific treatment processes using CO_2 from the ambient air (closed CO_2 cycle). These are subsequently used in the combustion engine (spark ignition or compression ignition combustion process depending on the fuel).

The energy requirement is based on the real fuel amount used in Germany in 2015 (560 TWh, of which 440 TWh was used in cars and 120 TWh was used in trucks). This energy requirement is used to calculate a "wheel energy requirement" on the basis of an assumed degree of efficiency for vehicles in the field. In turn, this is determined as the new (tank-to-wheel) energy consumption for each of the concepts examined using the best degree of efficiency that is currently possible, which is based on one reference vehicle each for cars and trucks. This ensures that the results for the individual paths are comparable.

This consumption is used in conjunction with the respective process efficiency values to calculate a primary energy requirement. This in turn serves as the basis for calculating the fuel costs (investment and production) as well as infrastructure costs. When these costs and the vehicle costs are applied to the driving distance, the results are designated as mobility costs.

A minimum and maximum cost scenario has been calculated for all costs. This also applies to the costs of the electricity used to produce fuel, which is generated in the Middle East and North Africa (MENA) in the minimum cost scenario, and in the North Sea off the German coast with offshore wind turbines in the maximum cost scenario. However, this does not apply for electric vehicles (BEVs). For these – as well as for the fuel cell scenario with fuel produced locally at the filling station through electrolysis – it is assumed that electrical energy must be permanently available (constant electrical power supply scenarios). This is necessary because electrical energy cannot be stored at the charge point in a sufficient quantity to satisfy the wish of customers to charge their vehicles at any time; i. e. also at times when there is no wind and the sun is not shining in Germany (dark periods). In accordance with [ISE 2015] it is assumed that energy suppliers have to store and reconvert 20 % of energy in the background due to the necessity of guaranteeing permanent energy provision. This is taken into account accordingly in the price of electricity for these two scenarios. For all scenarios in which fuel is produced centrally, the storage of energy in the fuel itself is possible, thus enabling discontinuous production.

The "100 % mobility scenarios" (100 % of vehicles using the same powertrain type) used as a prerequisite here are neither desirable nor realistic, but are suitable for facilitating a comparison of fuel/powertrain paths on the assumption of mass and industrial-scale utilization. In a second step, more realistic mixed scenarios with a broad range of possible synergies (parallel use of different energy sources with variable market shares, mixed powertrains with various degrees of hybridization or fuel blending) can be derived from the results. The second step is not examined in this study.

Here is an overview of the most important results

It is unlikely that electrification (using batteries) will be able to cover all applications on its own. Quickly replenishable fuels with a high energy density are probably necessary – in particular for heavy commercial vehicles for cargo transportation, cars that cover high mileages and plug-in hybrid vehicles.

Synthetic fuels (e-fuels) and electromobility complement each other. E-fuels can be employed as a necessary and sensible element to support an electromobility strategy. It is also feasible to produce, distribute and use electricity-based fuels from a technological standpoint. The costs and customer acceptance of these are decisive to the success and the ecological leverage of all energy sources and powertrain forms. Owing to the greater availability of renewable energy (predominantly wind and solar energy), production costs in the MENA region or in the Mediterranean region are generally considerably lower than in Germany.

Energy requirement

The necessary electrical energy for BEVs must be available to cover the demands at all times. It is therefore necessary for the energy suppliers to provide these vehicles with "buffered electricity". As a result, the average degree of efficiency when supplying electricity for e-vehicles is lower and the electricity purchase costs are significantly higher than when 100 % of the produced electricity is used directly. In the scenario entailing 100 % renewable electricity generated predominantly from wind and solar energy in Germany (and also in the EU), which is assumed in this case, it is estimated that buffering of approximately 20 % of generated energy in stores (seasonal stores such as power-to-x) will be indispensable [ISE 2015].

As a result of the buffering of 20 % of generated electrical energy, the electricity price doubles in the domestic constant electrical power supply scenarios. For example, volatile wind electricity from the North Sea cost just € 88 per MW h in 2017, while a figure of around € 180 per MW h is expected for a constant electrical power supply. Volatile electricity produced in Germany and MENA can be used in all central e-fuel scenarios. At approximately € 24 per MW h, from 2030 MENA electricity is anticipated to be cheaper than the volatile North Sea electricity generated in 2017 by a factor of 3 to 4.

For a 100 % BEV scenario (battery electric car, hybrid-overhead line truck) the primary energy requirement is between 249 and 325 TW h per year, which corresponds to around half of today's total electricity requirement in Germany (515 TW h per year in 2015). Around 11,000 to 15,000 new offshore wind turbines (5 MW) would have to be installed to cover this. By way of comparison, almost 30,000 wind turbines are being operated with a significantly lower capacity in Germany today. This number can therefore be halved by building turbines with a capacity of up to 10 MW (up to 8 MW is already possible today in offshore turbines).

For a 100 % FCEV scenario with centrally produced hydrogen, around 1.8 to 2.0 times more energy would be required than for the 100 % BEV scenario. The number of 5 MW wind turbines in the North Sea would rise to between 23,000 and 26,000.

If combustion engines are operated with synthetic fuels (PtX), the primary energy requirement in the best case (methane) is around 2.7 to 3.1 times greater than the energy requirement for a BEV scenario only (corresponding to 35,000 to 40,000 5 MW offshore wind turbines); in the worst case (OME) it can be up to 4.7 times greater (corresponding to up to 60,000 5 MW offshore wind turbines).

The well-to-wheel (WtW) degrees of efficiency for electromobility are between approximately 58 and 80 % (without taking air conditioning in BEVs into account, which reduces the degree of efficiency), while those for FCEVs are between 25 and 32 %, and the equivalent values for PtX-driven vehicles with combustion engines are in the region of 10 to 17 % for cars and 14 to 24 % for trucks. Further increases in efficiency, for example through hybridization, were not yet taken into consideration here.

Energy and fuel costs

In the most favorable case, the energy costs for the BEV scenario amount to € 0.11 per kW h (constant electrical power supply costs); these are higher than the pure production costs due to the buffer storage costs and losses and include transfer and charging losses.

If PtX fuels are produced centrally in Germany under the least favorable conditions (maximum cost scenario), at € 0.22 per kW h, the central production of H_2 appears to be the variant with the lowest costs per unit of energy, followed by methane (€ 0.23 per kW h), DME (€ 0.26 per kW h) and methanol (€ 0.27 per kW h). Fischer-Tropsch (FT) fuels can cost up to € 0.32 per kW h and OME up to € 0.37 per kW h. By way of comparison, in this maximum cost scenario the reliably available electricity for BEVs will cost € 0.25 per kW h on average. Unlike the energy used in electric vehicles, all fuels can also be produced in MENA instead of Germany, and under significantly more favorable conditions. Under favorable conditions (minimum cost scenario, MENA), hydrogen can be produced for € 0.08 per kW h, followed by methane and DME (€ 0.09 per kW h), methanol (€ 0.10 per kW h), FT fuels (€ 0.12 per kW h) and OME (€ 0.14 per kW h).

Due to the higher degree of efficiency in vehicles with electric powertrains, the distance-based energy costs are lowest for the purely electric variants, i. e. BEVs (electric cars and hybrid-overhead line trucks).

Mobility costs for cars

For cars in particular, mobility costs are dominated by vehicle costs (vehicle depreciation + proportion of infrastructure costs + fuel before tax). For cars from the compact vehicle segment (Ford Focus, Volkswagen Golf, Opel Astra, etc., costing around € 20,000), the acquisition costs including depreciation are many times higher than the costs for the energy source (before tax) and for infrastructure.

Because future surcharges for vehicles, in particular for BEVs and FCEVs, are very difficult to predict compared to diesel and gasoline variants, there is a significant degree of uncertainty in the assessment of future mobility costs. For BEVs there is also considerable uncertainty regarding the grid expansion costs required for providing the required charge current. The expansion will be predominantly determined by the charging behavior of customers, which is difficult to predict. If cost parity is assumed between BEVs, FCEVs and vehicles with diesel powertrains (minimum cost scenario), similar mobility costs are achieved for all scenarios.

When considering the maximum mobility costs for cars, the use of the PtX fuels methanol and methane in an optimized combustion engine is the cheapest variant (around € 38 per 100 km). At approximately € 40 to € 42 per 100 km, FT fuels are also significantly below the BEV cost risk (around € 45 per 100 km). Mobility with hydrogen produced centrally in Germany is more expensive still (approximately € 47 per 100 km). Locally generated hydrogen used in an FCEV is the most expensive solution in the maximum cost scenario by a great margin (around € 53 per 100 km).

Attainability of TtW CO_2 emissions

Although the CO_2 emissions of a vehicle may appear unimportant in a closed CO_2 circuit, a tank-to-wheel (TtW) assessment is relevant in line with current European legislation.

Low-carbon fuels (fuels with a favorable C/H ratio) can contribute to a reduction of TtW CO_2 emissions. With methane, for example, CO_2 emissions can be improved by around 25 % compared to vehicles with gasoline powertrains purely because of the C/H ratio. By further optimizing the engine, a total reduction in CO_2 emissions of 29 % is possible. On the other hand, using OME fuels (from C2) in a diesel engine brings about an increase in TtW CO_2 emissions, for example of 13 to 15 % for OME 3 – 4 compared to diesel or of 2 to 4 % compared to gasoline in a spark ignition (SI) engine. However, the full effect of synthetic fuels only becomes apparent from a WtW perspective. Zero-impact emission mobility is achievable with all examined combustion engine concepts (concentration of emissions below permitted limit values).

Handling safety of fuels

As a general rule, the use, storage, transport and distribution of all energy sources have been fully mastered, albeit with different levels of risk.

Fueling/charging time

End users are used to refueling their cars or trucks within just a few minutes. This is also possible for FCEVs.

In contrast, the charging times of BEVs necessitate a change in customer behavior (at a 150-kW quick-charge point, the charging time for a car in the compact segment is 40 to 45 minutes for 500 km; even the currently planned high-performance concepts with up to 350 kW would require around 15 to 20 minutes for 500 km). Today, the prerequisites for charging at home are not in place everywhere. The number of charging points required is significantly higher than for the other concepts.

Compatibility with existing stock

Six of the observed PtX fuels can already be used as blended components in the existing infrastructure and in vehicles that are available today. A high proportion of FT gasoline can be admixed to gasoline in compliance with EN 228. The EN 228 standard also allows the admixture of up to 3 % methanol. FT diesel can be blended with diesel fuel up to a proportion of around 35 % on the condition that EN 590 is met (14,000 filling stations for gasoline and diesel).

Furthermore, pure FT diesel corresponding to the requirements laid down in EN 15940 can be used in vehicles that are approved for this. FT propane/butane can be used as liquefied petroleum gas if the conditions specified in EN 589 are met (6,800 existing filling stations). Up to 100 % PtG methane and up to 2 % H_2 can be admixed with natural gas (DIN 51 624 and EN 16723-2) (900 existing filling stations).

To quickly launch a new fuel, it is essential to standardize the fuel and filling stations at an early stage. If availability is sufficient, a quick market launch (< 3 years) is possible within the scope of existing standards and in significant quantities with the following blended components: FT gasoline, FT diesel, FT propane and PtG methane.

Investment costs

The full decarbonization of the transportation sector in Germany requires an enormous financial commitment. Depending on the path, the total investment costs amount to between just under € 270 billion and in excess of € 1,740 billion. This large range is less a result of the chosen fuel path than of the additional vehicle costs that may be incurred for battery electric vehicles and fuel cell vehicles. The minimum required investment costs for the three main paths of PtX, H_2 and BEVs are between € 270 billion and € 550 billion. The maximum required investment costs for all PtX paths are between € 800 billion and € 1,190 billion. Methane has the lowest investment costs (in Germany) at approximately € 800 billion, while power-to-OME requires the highest investment at almost € 1,190 billion. For a hydrogen scenario, on the other hand, investments of up to € 1,740 billion could be necessary. The investment risk for a purely electric scenario is up to € 1,320 billion.

Alongside the uncertainties in predicting future vehicle costs, there is also a serious degree of uncertainty when forecasting the level of grid expansion required for the universal use of BEVs. These costs are highly dependent on customer usage behavior (charging behavior).

The decisive difference between the three main paths of PtX, H_2 and BEVs is the sector in which the investments need to be made. While for decarbonization through hydrogen all involved partners (energy suppliers, the fuel industry, infrastructure operators and the automotive industry, i. e. vehicle buyers) will have to make significant additional investments, for all PtX paths the additional costs are almost exclusively incurred in electricity generation and fuel production. In the BEV scenario, there are only investment costs in the infrastructure and possibly for the vehicles. Investment in expanding renewable energy plants is necessary in every scenario.

For the carbon-based fuels, CO_2 separation from the air is an expensive plant component. For simple synthesis processes, such as for CH_4, separation of CO_2 from the ambient air makes up 40 % of the total investment costs for the fuel synthesis plant. There is a significant need for research in this area to reduce plant costs and the amount of energy required. Furthermore, emitters of CO_2 can be used as CO_2 sources, in particular during the transition period from a fossil fuel-based to a completely sustainable energy sector. In this case, CO_2 is obtained without any significant energy expenditure and is virtually free. Even in a world in which no energy is generated from fossil sources, it is likely that there will still be industry sectors that emit large amounts of CO_2 for process-related reasons (for example, production of steel, cement or biogas). This CO_2 can be used to produce PtX fuels while keeping costs to a minimum.

Assumptions and approach

Within the scope of the Fuels working group of the FVV, a team made up of relevant partners from the automotive, chemical, mineral oil and supplier industries, as well as an energy supplier, was brought together with the aim of defining realistic fuel-powertrain paths and assessing these on the basis of key criteria (which were also to be defined). This was to be performed on the basis of a "fuel matrix" to be created by the working group. The companies involved are shown in **Figure 1**.

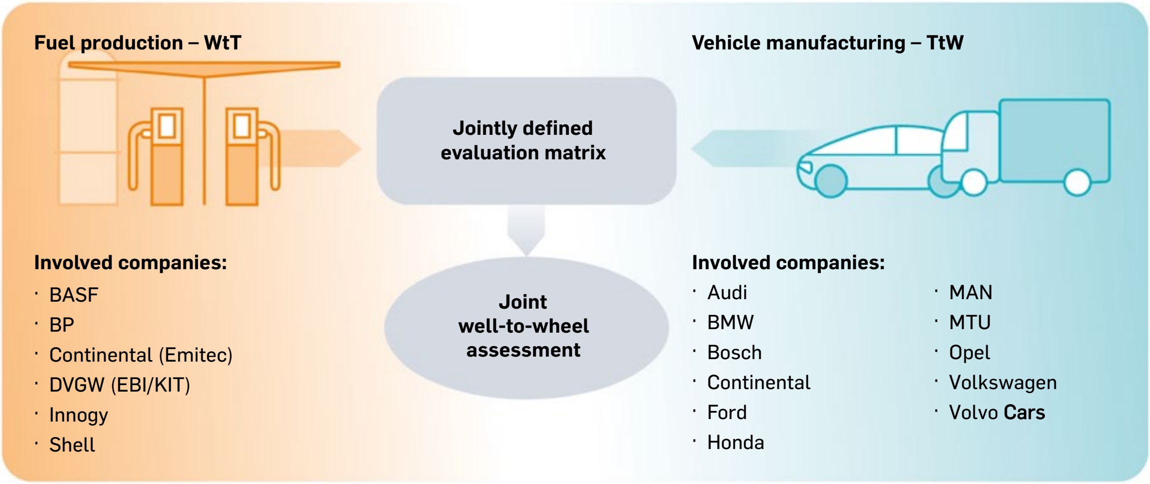

Figure 1: Members of the "Fuels" working group and authors of the briefing paper

Considered fuel-powertrain options

The assessment focuses on various fuel-powertrain systems, which were selected jointly and can enable complete defossilization by 2050 when considered in a holistic manner. In all of these scenarios, energy is provided by solar and wind power and is exclusively CO_2-neutral. The use of electricity is compared in three fundamentally different scenarios (as shown in **Figure 2**):

1. Direct use of electrical energy obtained through regeneration in electric vehicles (BEV) (reference scenario).

2. Generation of hydrogen via electrolysis using electrical energy obtained from renewable sources and water. The hydrogen is subsequently used in vehicles with fuel cells (FCEVs).

3. Generation of so-called power-to-x (PtX) fuels using regenerative, electrolytically produced hydrogen by means of various fuel-specific treatment processes using CO_2 from the ambient air or from sources that would otherwise release CO_2 into the environment (closed CO_2 cycle). These are subsequently used in the combustion engine (spark ignition or diesel process depending on the fuel).

A detailed overview of the investigated fuel-powertrain paths and a summary of the framework conditions can be found in **Table 1.** Here it is assumed that for the first two fuel-powertrain paths – “BEV” and “H_2 FCEV local” – electrical power must be constantly available (designated here as constant electrical power supply scenarios). This is necessary because it is not economically viable to store electrical energy or locally produced hydrogen at the filling station in a sufficient quantity to satisfy the wish of customers to charge their vehicles at any time, i.e. also at times when there is no wind and the sun is not shining in Germany (dark periods). In accordance with [ISE 2015] it is assumed that, due to the necessity of guaranteeing permanent energy provision, energy suppliers have to store and reconvert 20 % of energy in the background in the form of CH_4 (degree of efficiency of 60 % for both storage and reconversion). This is taken into account accordingly in the price of electricity for these two scenarios. A DC line through the Mediterranean Sea from MENA (Middle East and North Africa region), with which a constant energy supply would be conceivable without power-to-gas (PtG) buffering when worldwide wind power and PV plants are connected and expanded, is currently viewed as being difficult to realize from a political standpoint and is not taken into account in this scenario. Therefore, for the two constant electrical power supply scenarios, it is assumed that electrical energy is generated in Germany in both the minimum cost scenario and the maximum cost scenario.

For all other scenarios, energy can be stored in the fuel itself. The electrolysis is performed discontinuously, with a hydrogen storage tank being filled in the process. In order to enable discontinuous operation, the degrees of efficiency of alkaline electrolyses are taken as the basis.

PtX synthesis is also done in a discontinuous manner where possible. In order to homogenize PtX synthesis, an H_2 pressure tank is used which, depending on the design, can even enable continuous operation of the PtX plant if this appears economically viable. With regard to their power capacity, both electrolysis and PtX syntheses are overdimensioned in accordance with downtimes.

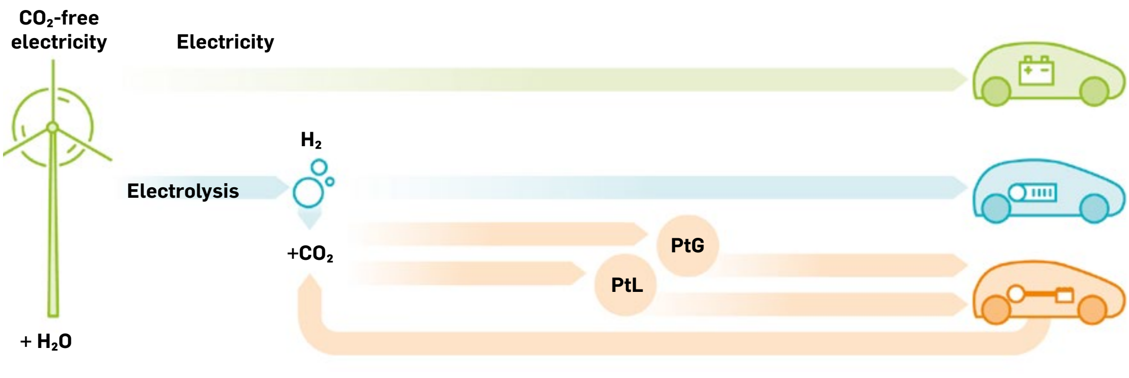

Figure 2: Examined fuel-powertrain paths (100 % defossilization)

<table>
<tr><th>Fuel</th><th>Powertrain</th><th>Electricity supply</th><th>Energy storage</th><th>Energy distribution</th></tr>
<tr><td>Electricity (benchmark)</td><td>Battery electric vehicle (BEV)</td><td>Permanently available electrical energy, Germany</td><td>20 % energy buffer (Pt-CH_4 reconversion) for buffering during dark periods</td><td>Electricity distribution grid, Germany</td></tr>
<tr><td>E-H_2 (pressure tank in vehicle) (local production at the filling station)</td><td>Fuel cell (FCEV)</td><td>Permanently available electrical energy, Germany</td><td>20 % energy buffer (Pt-CH_4 reconversion) for buffering during dark periods</td><td>Electricity distribution grid, Germany</td></tr>
<tr><td>E-H_2 (pressure tank in vehicle) (central production, liquefied for transport)</td><td>Fuel cell (FCEV)</td><td rowspan="9">Intermittent electricity supply (fuel only produced when solar/wind power is available)

Minimum cost scenario: production in MENA* (2030)

Maximum cost scenario: production in Germany (2017)</td><td rowspan="9">No additional energy storage. Energy storage for dark periods in the fuel itself (surplus production when solar/wind power is available)</td><td rowspan="9">Local liquefaction (for CH_4 and H_2)

Transport of liquid fuel by ship (from MENA)

+ 500 km truck transport in Germany (for fuel from MENA and Germany)</td></tr>
<tr><td>E-methane (vehicle: pressure tank)</td><td>SI engine (λ=1)</td></tr>
<tr><td>E-methane (car: pressure tank, truck > 3.5t: liquefied methane (LNG))</td><td>SI engine (λ=1)

HPDI CI engine (> 3.5t)</td></tr>
<tr><td>E-methanol (M100)</td><td>SI engine (λ=1)</td></tr>
<tr><td>E-gasoline (Fischer-Tropsch)</td><td>SI engine (λ=1)</td></tr>
<tr><td>E-propane (LPG) (Fischer-Tropsch)</td><td>SI engine (λ=1)</td></tr>
<tr><td>E-diesel (Fischer-Tropsch)</td><td>CI engine</td></tr>
<tr><td>E-OME</td><td>CI engine</td></tr>
<tr><td>E-DME</td><td>CI engine</td></tr>
</table>

*MENA = Middle East North Africa

Table 1: Framework conditions of the investigated fuel-powertrain paths (100 % defossilization)

Today, large FT plants (Fischer-Tropsch synthesis) are not run discontinuously in regular operation, as the primary energy source is continuously available. However, possible power-to-liquid (PtL) plants would be optimized for discontinuous operation, for which reason a start-up time from standby mode of 24 hours was assumed for this study. For OME synthesis, the working group did not have any reliable data on the ability to start up the processes quickly. It is assumed that an OME plant displays the same characteristics as FT plants (with a start-up time of 24 hours). To ensure a robust PtX synthesis process, FT and OME plants were therefore equipped with an H_2 pressure tank designed for a duration of 24 hours. Although larger H_2 pressure tanks would increase the usable full load hours of the PtX plant, they are so expensive that their enlargement is not expected to be economically viable. An economic consideration and optimization of the H_2 pressure tank size was not feasible within the scope of this brief study and was therefore not performed. In addition, for the further optimization of H_2 storage tank size with regard to full load hours for PtX synthesis, it would also have been necessary to examine solutions for replacing or supplementing the very expensive H_2 pressure tanks which are conceivable in the future. For instance, solutions such as the use of storage caverns (where geographically possible), liquid storage of H_2 or the reconversion of the synthesis product for covering dark periods would be imaginable. However, the process of optimizing such a plant is not part of this briefing paper.

In contrast to complex FT PtX plants, simple PtX plants for generating methane, methanol and DME are easier to run on a discontinuous basis. According to the experts from the working group, a power-to-methane synthesis can be started up from standby in around ten minutes. For starting up production of methanol and DME, the working group estimates approximately half a day to a day. Therefore, it is estimated that an H_2 pressure tank storage duration of one hour is needed to start up the methane synthesis process, while 12 hours is assumed for starting up the methanol and DME synthesis (both for Germany and MENA). After consulting representatives from the H_2 liquefaction industry, an H_2 pressure tank storage duration of six hours was assumed for starting up the liquefaction plant for H_2.

The various H_2 storage tank sizes are to be viewed as minimum sizes and are primarily for the purpose of reliable operation of the PtX synthesis plant. They were dimensioned to the precise size required for starting up the plant without any faults when the tank is full. However, for brief dark periods these storage tanks also allow an increase in the number of full load hours for PtX synthesis. These were estimated using data from the Fraunhofer Institute; for MENA on the basis of [IWES 2017], for Germany based on the 2016 offshore wind power statistics [ISE 2015]. A summary of the assumptions made can be found in **Table 2** and **Table 3**.

Degrees of efficiency of electrolysis (max.)	0.73	–
Pressure tank storage duration of H_2 (FT, OME)	24	h
Pressure tank storage duration of H_2 (methanol, DME)	12	h
Pressure tank storage duration of H_2 (H_2, central)	6	h
Pressure tank storage duration of H_2 (methane)	1	h
Imputed interest	0.04	–
Staff, maintenance, repair	0.05	–
Service life of the plants	20	a
ROI	0.06	–
Residual value	0	euros
Electrolysis full load hours (EL FLh)	5,782	h/a
PtX full load hours (PtX FLh) per annum (use in percent during dark period through installation of H_2 pressure tank)		h/a
FT, OME	7,813 (68.2 %)	
Methanol, DME	7,149 (45.9 %)	
Methane, H_2, central	5,782 (0 %)	

Table 2: Assumptions for “minimum cost scenario”, production in MENA, solar/wind mix

Degree of efficiency of electrolysis (min.)	0.62	–
Pressure tank storage duration of H_2 (FT, OME)	24	h
Pressure tank storage duration (methanol, DME)	12	h
Pressure tank storage duration of H_2 (H_2, central)	6	h
Pressure tank storage duration (methane, H_2, central)	1	h
Imputed interest	0.04	–
Staff, maintenance, repair	0.05	–
Service life of the plants	20	a
ROI	0.06	–
Residual value	0	–
Electrolysis full load hours (EL FLh)	5,623	h/a
PtX full load hours (PtX FLh) per annum (use in percent during dark period through installation of H_2 pressure tank)		h/a
FT, OME MtG	5,758 (4.3 %)	
Methanol, DME	5,692 (2.2 %)	
Methane, H_2, central	5,623 (0 %)	

Table 3: Assumptions for “maximum cost scenario”, production in DE, offshore wind power (North Sea)

Assumptions for 100 % scenarios regarding the availability of electricity from renewable sources

When comparing various options for the utilization of electricity in the transport sector – either as a direct (electromobility) or an indirect energy source (PtX, hydrogen) – the assumed electricity generation costs are of decisive importance. These costs can be influenced by many factors, including the chosen technology, the availability of the input energy used by this (wind, solar, water), the concurrence of use and production and the physical distance. For example, due to the higher availability of solar radiation, in sunny regions a PV plant can provide electricity far more cheaply than in Germany when the other assumptions remain the same. In order to cover this variation in energy provision, maximum and minimum costs for two different scenarios have been determined in this study.

The “supply follows load” scenario (aka the “constant electrical power supply scenario”) assumes that electricity is generally available when it is required. This also means that to a certain extent the costs for electricity comprise the intermediate storage of electricity in batteries or an energy source (hydrogen, methane, liquid fuels). For example, this is the case when cars are directly charged with electricity. Although it is fundamentally possible to control the recharging of a car over a defined period (several hours), it must also be possible to charge and use the car during an extended dark period. This is also generally the case for electrolyzers that provide hydrogen locally in the immediate vicinity of the filling station, as the installation of very expensive and complex H_2 pressure tanks will probably be dispensed with for cost reasons.

In this scenario, the minimum costs are derived from an estimate in the study "Flexibilitätskonzepte für die Stromversorgung 2050" ("Flexibility concepts for the electricity supply in 2050") [Elsner 2015]. Here, the average electricity supply costs of between € 87 and € 114 per MW h are defined in a scenario with very high CO_2 reduction objectives. The median value (€ 100 per MW h) was used for this investigation. This scenario includes the intermediate storage of around 20 % of the electricity quantity [Fraunhofer ISE 2015]. The maximum costs are derived from a combination of technical solutions in the ESYS study [ESYS 2015] taking into account today's technology costs (PV, wind, storage).

The "load follows supply" scenario (intermittent electricity supply) describes a case in which the demand for electricity can generally follow supply, meaning that no (or very little) intermediate storage is necessary. For instance, this is the case for the "centralized" production (i. e. not at the filling station) of hydrogen, methane and all liquid energy sources.

The minimum costs are based on an estimate of the further reduction in the cost of PV systems and wind turbines by 2030. Costs of 1.5 ct per kW h for PV and 2.5 ct per kW h for wind turbines at good locations (for example in the MENA region) appear to be realistic. Even today, electricity generated by PV systems costs less than 3 ct per kWh[1]. These figures were used to derive the electricity delivery costs on the basis of the full load hours for wind and PV from the Fraunhofer IWES study[2] [IWES 2017]. The maximum costs are based on the results of the Fraunhofer IWES study for the scenario covering offshore wind power in Germany in 2017.

€ /MW h	Min. costs		Max. costs	
	€ /MW h	FLh (electrolysis) h/a	€ /MW h	FLh (electrolysis) h/a
Supply follows load	100	8,760	180	8760
Load follows supply	24	5,877	88[3]	5,623

Table 4: Cost assumptions for electricity (Innogy; based on [IWES 2017], [Elsner 2015], [ESYS 2015], [Fraunhofer ISE 2015])

1 https://renewablesnow.com/news/update-abu-dhabi-confirms-usd-24-2-mwh-bid-in-solar-tender-540324/, https://www.pv-tech.org/news/lowest-ever-solar-bids-submitted-in-abu-dhabi

2 The annual electricity generation costs (LCOE * annual quantity of electricity) have been applied to the quantity of electricity that was actually used (curtailment 9 %). The scenario entailing LH_2 production in Morocco in 2050 was used as a basis. [IWES 2017]

3 For comparison: LCOE in 2020 between USD 120 and 180 per MW h, source: page 63 [IRENA 2012]

Investment costs for expanding the electricity infrastructure

The costs for the necessary expansion of the grid infrastructure were estimated on the basis of the calculated consumption for electromobility in the car and truck segment. It should be taken into account that both the parallel expansion of decentralized generation plants and the use of intelligent charge control can heavily influence the costs specified here. At the same time, regional differences, which can also influence costs, were not initially taken into consideration in this simple assessment. As a first approximation, a simplified approach is selected here, in which the costs for the necessary additional infrastructure are estimated based on the additional burdens and lump-sum costs and investments from various grid studies.

On the basis of the lump-sum costs specified in the distribution grid study by the German Federal Ministry for Economic Affairs and Energy (BMWi) in 2014 [BMWi 2014], a replacement value approach can be used to determine the investment that would be needed to build the currently available infrastructure while taking into account the currently installed capacities on all grid levels. Today's grid is designed for a peak load of around 84 GW, which means that the average cost per GW is € 2.4 billion to € 3.5 billion[4]. At the same time, the costs for expanding the grid infrastructure for additional generation plants can be estimated at € 1.0 billion per GW. This figure results from an examination of the costs from the Grid Development Plan 2030 [BNetzA 2017] for the expansion of the transmission grid (€ 32 billion to € 34 million for expansion of renewable energies totaling 70 GW: € 0.5 billion per GW of transmission grid capacity) in addition to the figures from the dena distribution grid study [dena 2012] (€ 28 billion for expansion of 78 GW: € 0.5 billion per GW in the distribution grid[5]). Due to the compensatory effect when expanding renewable energies and additional demand, an across-the-board value of € 2.0 billion per GW should be assumed for cars. For overhead line trucks, only an expansion of the high- and extra-high voltage grid (transmission grid plus the 110-kV distribution grid level) is necessary, meaning that € 1.2 billion per GW should be taken as an estimate[6].

For electric cars, the concurrence of charging is a significant factor in the infrastructure costs. If the charging cycles are highly concurrent (all cars are charging at the same time), the demand would entail a peak load of 500 GW (44 million vehicles * 10 to 12 kW per vehicle) and thus necessitate investment running into the trillions. However, with a natural distribution of charging cycles and simple control, a considerable reduction of this peak load is conceivable without causing any inconvenience. For the maximum cost scenario of this study, 5,000 full load hours per year were assumed, which parts of the working group viewed as quite realistic. At a calculated demand of 135 to 175 TWh, this would reduce the peak load to 27 to 35 GW, thus lowering the necessary investment to between € 54 billion and € 70 billion. If intelligent control is also used (cars as interruptible loads), the required level of investment could be reduced further. In addition,

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4 Numerical data as per BDEW and in accordance with replacement values [DENA 2010].

5 Expansion from 61 GW (in 2012) to 139 GW in 2032; in 2016: 97 GW, meaning that € 28 billion now amounts to € 0.6 billion per GW (not taking into account the investments already made in the further expansion of renewable energies). Therefore, for reasons of simplification, € 0.5 billion per GW is also assumed here.

6 Excluding the 110-kV level, the distribution grid is responsible for approximately one third of the costs, as a result of which around two thirds of the total costs (€ 2 billion per GW) have been estimated here.

7 Estimate based on installed capacities for diesel and gasoline refueling at service stations and truck stops (approx. 23 GW) and taking into account the reduced consumption (50 %) and assumption of 50 % of capacities by already installed infrastructure, e. g. simultaneous reduction in demand in industry and households.

a required grid expansion of 6 GW[7] is estimated for the quick-charging infrastructure. Because such stations are installed at higher voltage levels, the additional capacities reach a similar figure to the specific investment costs for expanding the grid for overhead line trucks. The result is a total investment of around € 77 billion.

Taking into account the information from the study "Machbarkeitsstudie zur Ermittlung der Potenziale des Hybrid-Oberleitungs-Lkw" ("Feasibility study for determining the potential of the hybrid-overhead line truck") [ISI 2017][8], the calculated demand (52 to 69 TWh) would lead to additional expansion of approximately 13 to 17 GW. This would correspond to an investment of € 15 billion to € 21 billion.

Overall, the selected approach indicates that an additional investment of € 92 billion to € 98 billion would be necessary. Due to the reasons explained above, the figures chosen here are towards the higher end of the actual costs, primarily because the influence of simultaneously expanding plants for renewable energies and utilizing the possibilities held through digitalizing the energy sector are not yet taken into consideration. At the same time, today's infrastructure still offers free capacity, further reducing new investments.

The installation of decentralized electrolysis units in the "decentralized hydrogen supply" scenario also requires a corresponding expansion in the electricity infrastructure. Because the electrolysis units will also be connected to higher voltage levels, the estimated investment in high- and extra-high voltage grids given above (€ 1.2 billion per GW) will also be used here as an approximation. On the condition that the demand for electrolysis units is evenly distributed throughout the year (8,000 h/a), an electricity demand of 528 TWh would result in additional grid expansion of 66 GW. As is the case for quick-charging infrastructure for e-vehicles, provision at peak times must also be guaranteed. Using an identical approach, a capacity of 15 GW[9] was calculated for peak load supply. The total investment is therefore € 90 billion.

The investment volumes calculated here are seen as the "upper limit" of the necessary investments, as some of the investment costs in a grid infrastructure are already contained in the costs of the underlying studies for estimating the electricity generation costs; cf. [ISE 2015]. This results in the investment costs shown in **Table 5** for the respective scenarios.

Alongside the transport distance, losses in the transmission and distribution grid are also dependent on further factors such as the operating point, the weather and the technology used. Therefore, the currently observable grid losses are initially used in this paper. A total of 23.9 TWh of grid losses were recorded in 2014. Of these, 6.4 TWh are attributable to the transmission grid. As such, at an overall consumption of 487.5 TWh, there were losses of 4.9 %. For the transmission system operator (TSO) level, this results in a loss factor of 1.3 % [BNetzA 2016].

Scenario	Min. investment costs	Max. investment costs
Electric car	€ 0 billion	€ 77 billion
Overhead line truck	€ 0 billion	€ 21 billion
Decentralized hydrogen supply	€ 0 billion	€ 90 billion

Table 5: Investment costs for expanding the electricity grid for the respective scenarios

8 Grid expansion of 1 GW is required for every 4 TWh of consumption.

9 Taking into account higher consumption compared to BEVs, better utilization due to 24-hour production on peak days and substitution of 6 GW through the existing infrastructure.

Approach for estimating fuel demand for 2050

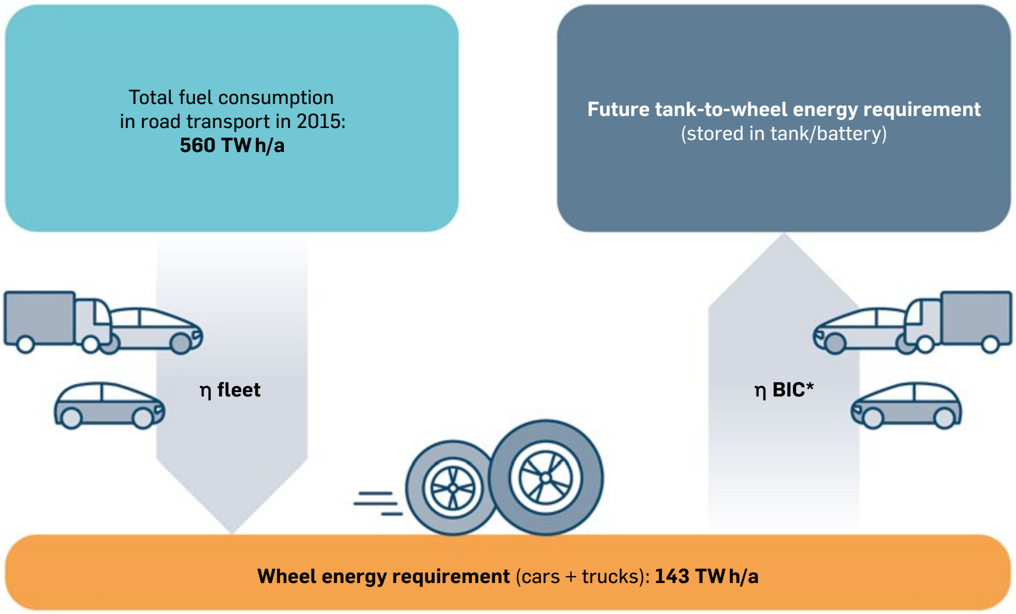
In order to ensure that all scenarios are comparable, the real amount of fuel consumed in cars and trucks in Germany in 2015 was used as a basis. Consumption in cars (up to 3.5 t gross vehicle weight, including motorcycles) was around 440 TWh per annum in 2015, while consumption in trucks (gross vehicle weight of over 3.5 t, including buses) was 120 TWh per annum [Destatis 2017; KBA 2017].

Tank-to-wheel assessment

Using this consumption as a starting point, the “energy requirement to wheel” was calculated for the existing fleet of cars and trucks. The method is shown in **Figure 3**.

For cars the NEDC degree of efficiency of 23 % for a typical compact-class vehicle (e. g. Volkswagen Golf, Opel Astra/Kadett, Ford Focus/Escort) of an average age was used as a basis here, with a degree of efficiency at constant travel of 35 % being assumed for trucks. This results in “wheel energy consumption” of around 143 TWh per annum, of which 101 TWh per annum are attributable to cars and 42 TWh per annum were consumed by trucks. The method used to derive the degree of efficiency of the car fleet is explained in the following chapter.

For cars, the best possible NEDC vehicle efficiency that is achievable today for every powertrain in the same vehicle (compact segment, gasoline vehicle with 99 g/km CO_2 and diesel vehicle with 88 g/km CO_2) was then used to calculate a new total energy consumption value for each scenario, once again on the basis of the NEDC. A degree of efficiency of



* BIC (best in class): car – most efficient compact-segment vehicle 2017; truck – degree of efficiency up to 42 % (for details, see p. 24).

Figure 3: Approach for estimating the “real” fuel requirement for 2050 on the basis of NEDC degrees of efficiency.

up to 42 % is assumed (for details, see p. 24) for trucks at constant. The newly calculated total energy consumption is then divided by the total number of kilometers driven in 2015. The future "real consumption" determined using this method (without hybridization) forms the basis for the tank-to-wheel (TtW) energy requirement calculation. These basic assumptions are used to create a calculation table, with which all scenarios can be compared with regard to their primary energy requirement and total economic cost. In doing so, the change in annual kilometers covered by 2050, the change in the fleet mix by 2050 (e. g. more SUVs) and technological leaps that significantly increase the degree of efficiency that is achievable today are not taken into account. Because these changes are expected to take a similar course for all technologies, the comparability of the scenarios is ensured. Likewise, no hybridization is taken into consideration for all concepts with a combustion engine. For electric vehicles, the required heat energy for operation during winter is not considered.

All of these influences on energy consumption and costs can be adjusted on the basis of various factors in order to perform a sensitivity analysis.

Assumptions for cars (degrees of efficiency, range, vehicle costs)

As outlined previously, for cars the NEDC degree of efficiency of 23 % is used for a typical compact-class vehicle (e. g. Volkswagen Golf, Opel Astra/Kadett, Ford Focus/Escort) of an average age.

This can be verified by observing the vehicle stock of 2015 and the NEDC consumption of compact cars of the corresponding construction years.

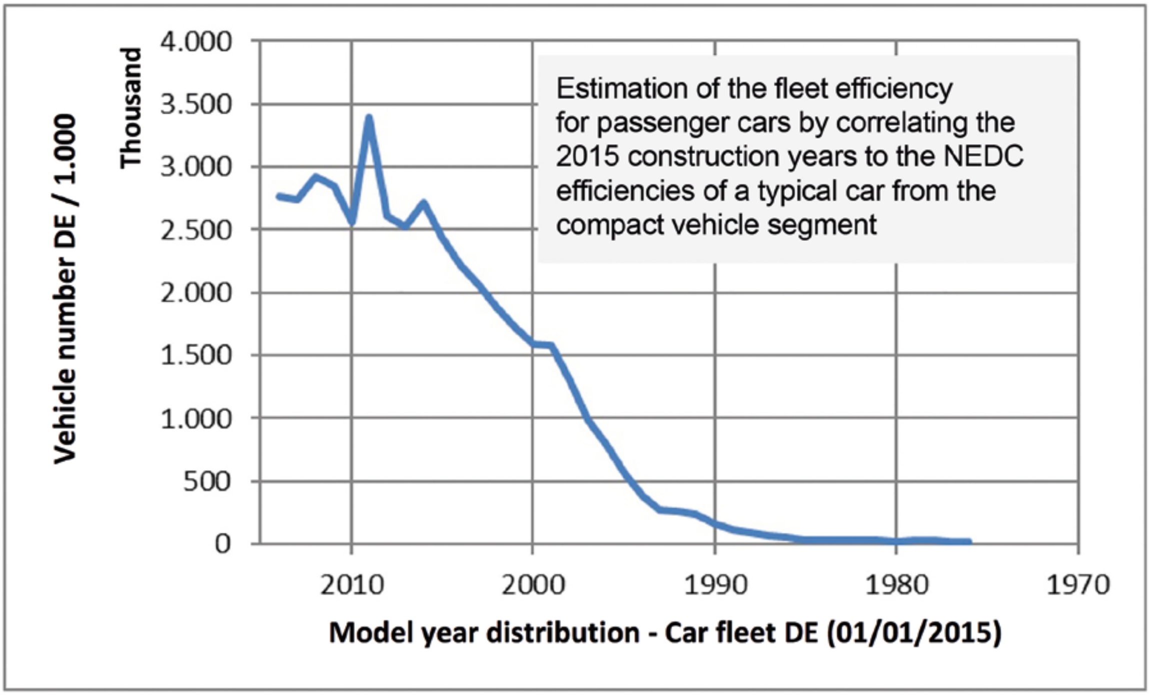


Figure 4: Model year distribution in car fleet in Germany in 2015 [KBA 2015], [KBA 2017].

All degrees of efficiency for vehicles with a combustion engine are calculated on the basis of a Ford Focus, model year 2017. A turbocharged, direct-injection three-cylinder 1.0 l gasoline powertrain with 74 kW in an optimized eco version with CO_2 emissions of 99 g per km (NEDC) was chosen as the basis for the combustion process in a spark ignition engine. For the auto-ignition combustion process, a turbocharged, direct-injection four-cylinder 1.6 l diesel powertrain with 77 kW in an optimized eco version with CO_2 emissions of 88 g per km (NEDC) was chosen as the basis for the assumed fleet consumption.

For all other combustion engine powertrains, the improvements in the degree of efficiency brought about by the potential of the respective alternative fuels were taken into account. The additional weight of the fuels and tank systems was also considered. Here it was assumed that every vehicle has a NEDC range of at least 500 km. This also applies for the fuel cell vehicle and the electric vehicle. The energy consumption for these two concepts was oriented toward the best possible level of technology at the given time (BEV: Opel Ampera / VW Golf; FCEV: Toyota Mirai). For fuel cell vehicles, an additional weight compared to the gasoline vehicle (base weight: 1276 kg) of just 300 kg was assumed and not the real weight of the Toyota Mirai (1930 kg), as the Toyota is above the compact vehicle segment examined here. Due to the reduction in weight, the consumption of the FCEV is reduced from 91.15 MJ per 100 km (homologated consumption of the Mirai) to 80.61 MJ per 100 km.

Vehicle	NEDC energy requirement MJ/100 km
BEV	47.17
E-H_2 (FCEV)	80.61
E-DME (CI engine)	124.79
E-OME 3-5 (CI engine)	124.30
E-methane – CH_4 (SI engine, direct injection)	127.53
E-methanol (M100) (SI engine, direct injection)	126.01
E-gasoline FT (SI engine, direct injection)	131.48
E-diesel (CI engine)	123.37
E-propane/butane (SI engine, direct injection)	126.73

Table 6: Future energy consumption of car powertrain concepts

A compact-class vehicle with a gasoline spark ignition engine for a basic price of € 20,000 was taken as the basis for the cost analysis. The depreciation was calculated in accordance with tables from the ADAC for a kilometrage of 15,000 km per annum and a running time of four years. [ADAC 2016]

Examples of compact-class vehicles, approx. € 20,000	List price [€]	Depreciation/ month [€]	Depreciation/ year [€]	Depreciation / 4 years [€]
Seat Leon SC 1.4 TSI Start&Stop Style	20,940	314	3768	15,072
Seat Leon 1.0 TSI Ecomotive Reference	20,110	288	3456	13,824
Skoda Octavia 1.4 TSI Green tec Active	20,830	307	3684	14,736
VW Golf 1.2 TSI BMT Comfortline	19,675	299	3588	14,352
VW Golf 1.0 TSI BlueMotion Trendline	20,450	327	3924	15,696
Average	20,401	307	3684	14,736
based on price of € 20,000	20,000	301	3612	14,446
Assumption for study	**20,000**	**300**	**3600**	**14,400**
			Depreciation in € per 100 km	**24**

Table 7: Basis for depreciation calculation for cars; 15,000 km per year [ADAC 2016]

Assumptions for commercial vehicles (degrees of efficiency and costs; energy density/range)
To estimate the driving consumption or the degree of efficiency of the powertrain, today's average values are used as the basis, future improvements are also incorporated and changes due to altered fuels are taken into account accordingly. According to Lastauto & Omnibus Katalog 2017 [LastOm 2017], the average consumption of commercial vehicles over long distances (40 t) is around 33 l per 100 km. If the WHTC cycle of a 40-t truck-trailer combination is taken into account, this results in approximately 430 MJ per 100 km. As such, the degree of efficiency of the powertrain in a commercial vehicle is around 36 %. The degree of efficiency in the vehicle fleet as a whole is slightly lower, as consumption for construction site vehicles and buses is higher and in some cases utilization is also lower. A value of 35 % is used for the entire fleet (see above). For the time frame of 2030 to 2050 examined here, an optimistic total of 20 % is assumed for the potential for improvement with regard to losses during driving and powertrain improvements. As such, a degree of efficiency of 42 % and an average fuel consumption of approximately 28.6 l per 100 km is forecast. This value is all the more optimistic as the diverse use of commercial vehicles not only covers long-distance travel, but also comprises trucks for construction sites and distributions, the application profiles of which are considerably more difficult to optimize.

This base degree of efficiency of 42 % for the conventional diesel engine is applied to other fuels which can be burned using the compression ignition procedure. These include methane in the HPDI process (high-pressure direct injection: a diesel combustion process with gas and ignition oil), DME, OME and synthetic diesel. For the combustion method in spark ignition engines with spark plug, i. e. combustion of premixed methane or methanol, a reduction of 10 to 15 % is assumed, thereby resulting in an estimated degree of efficiency of 37 %. For gasoline, a degree of efficiency of just 36 % is estimated due to the higher knocking tendency. The average of gasoline and methane is used for operation with propane/butane, i. e. 36.5 %. A degree of efficiency of 55 % is assumed for a fuel cell stack. This is an optimistic, but realistic, value for future PEMFCs (polymer electrolyte fuel cells), although the long-term durability for commercial vehicle applications is not yet proven, as experience has only been gathered with buses to date. Furthermore, a degree of efficiency of 85 % is assumed for the electrical system consisting of battery, electric motor and power electronics. The battery is necessary as the fuel cell does not respond quickly enough for highly transient processes. Thus, there is an overall degree of efficiency of around 46 %, a figure which includes necessary cooling. As is the case for the electrical component of the fuel cell powertrain, a degree of efficiency of 85 % is estimated for the purely electrical overhead line solution. Here, too, it must be assumed that a sufficiently large battery will be installed to cover routes where no overhead line is provided.

The costs for the individual technologies required for the respective fuel are estimated as additional costs to the existing diesel engine. Values from the Lastauto & Omnibus Katalog 2017 for long-distance applications were used for the basic costs [LastOm 2017]. For the operating costs specified in the catalog and calculated by DEKRA (excluding staff costs), the average of the data for commercial long-distance goods traffic with 120,000 km per year and 330 kW ± 10 kW was used. The values are simulated via a formula in accordance with the DEKRA comments in the catalog. This allows the additional costs arising from the technologies needed for other fuels to be estimated within the operating costs. For synthetic diesel, OME and combustion processes with methanol and gasoline in a spark ignition engine, the additional costs compared to diesel technology are estimated to be zero. Today's spark ignition engines still produce additional costs compared to the diesel engine, from which they are generally derived. With the corresponding batch sizes and cost optimization, however, there should no longer be any additional costs.

The costs for the tank technology (pressure tank) must be included for DME and LPG. Literature values on additional costs are not known. An estimate can be made on the basis of the prices for commercially available pressure tanks for LPG, which vary between USD 1.00 per liter (2,000 l) and USD 2.60 per liter (75 l) depending on the size. Accordingly, an optimistic figure of € 1.00 per liter is assumed, which in turn appears realistic at correspondingly large batch sizes. As such, for the case of LPG and DME there is an additional cost of € 1,000 for a 1,000-liter tank.

For the other fuels, the figures from the report "Erarbeitung einer fachlichen Strategie zur Energieversorgung des Verkehrs bis zum Jahr 2050" ("Drawing up a specialist strategy for the energy supply for transport up to 2050") [UBA 2016] financed by the German Environment Agency and the "Working Paper" [Institute for Applied Ecology, 2016] often used therein are mainly used for the respective technologies with the framework conditions described in the following. The purchasing costs in the aforementioned source are for the years 2010 and 2050 and are averaged. This results in additional costs for an LNG tank (LNG: liquid natural gas) of around € 14,000. LNG is assumed for every type of methane combustion, as the ranges for long-distance transport with CNG (CNG: compressed natural gas) and the refueling duration are not acceptable. For the HPDI system, another source [Rittich 2014] assumes additional costs of € 10,000 without a tank, as a result of which a pessimistic € 24,000 is estimated for the HPDI process with gas in a diesel engine. A figure of € 150 / kW_{el} is assumed for the fuel cell in the maximum cost scenario in 2030, which results in a fuel cell price of € 49,500 for 330 kW. In the same manner, the required hydrogen tank is estimated at € 1,320 per kg, resulting in around € 75,000 for a 57 kg tank. The packaging of a tank like this has not yet been resolved. With 57 kg, the vehicle could travel approximately 800 km – roughly the maximum daily distance of a long-distance truck today. In total, the additional costs for a fuel cell vehicle in the maximum cost scenario amount to around € 125,000. In the minimum cost scenario, a cost reduction for fuel cell and tank systems in accordance with the US Department of Energy is assumed [US Energy 2009] [US Energy 2012]. The additional price for a fuel cell truck compared to a diesel truck is thus around € 37,000 in the minimum cost scenario.

In order to estimate the additional costs for the overhead line technology, the "Machbarkeitsstudie zur Ermittlung der Potenziale des Hybrid-Oberleitungs-Lkw" ("Feasibility study for determining the potential of the hybrid-overhead line truck") was used [ISI 2017]. The study specifies costs of between € 10,000 and € 15,000 for the electric motor; a figure of € 12,500 is therefore adopted here. An examination of the German highway network shows that there are many areas with a linear distance of 100 km where an overhead line cannot be installed, thus necessitating the use of a battery to cover these distances. In order to cover this distance with a 40-t truck-trailer combination solely using a battery, a battery size of 300 kWh has to be taken into account. The packaging for a battery of this size has not yet been resolved. The costs for the battery are estimated at € 250 per kWh, a value higher than the equivalent value for applications in cars due to the more heavy-duty mode of operation that is expected. The mechanical loads (acceleration, in particular vertical) and electrical loads (large power and energy range) are considerably higher than in car applications.

Assumptions for the energy requirement and costs of producing synthetic fuels

In order to perform a technology-neutral assessment of fuel manufacturing, rhe assessment is divided into four main subprocess steps. This allows assumptions to be made regarding constant framework conditions as well as enabling a transparent technical assessment of all production paths (see **Figure 5**).

1. Electrolysis
2. CO_2 separation including liquefaction for storage
3. Fuel production including auxiliary energies, use of waste heat and effort for fuel preparation
4. Fuel distribution including liquefaction, transport, distribution and provision at the filling station.

The enthalpy flows released through exothermic reactions in many processes during synthesis can be used as an energy source within the process chain. Alongside internal use for product preparation (for example for the separation of substances through distillation), the heat can also be utilized when obtaining CO_2 from the air. This concerns the E-DME, e-methane and e-gasoline/e-diesel fuels through Fischer-Tropsch. Here, the energy is used to expel the CO_2 from the amine-based filter material. Furthermore, it is also conceivable to use part of the reaction heat from CO_2 hydrogenation (synthesis) for water evaporation in the solid oxide electrolysis. This increases the electrical degree of efficiency of the SOEC. However, this is only relevant if CO_2 is not captured from the air, as in this case the synthesis heat is already used to a great extent. For central production, the times in which no electrical energy is available for the operation of ancillary units and product liquefaction (e.g. during the night) is bridged through the reconversion of hydrogen via fuel cells. Four scenarios are used to provide a separate assessment of how the various subprocesses influence the energy requirement and the costs of possible e-fuel production in the future (see **Table 8**).

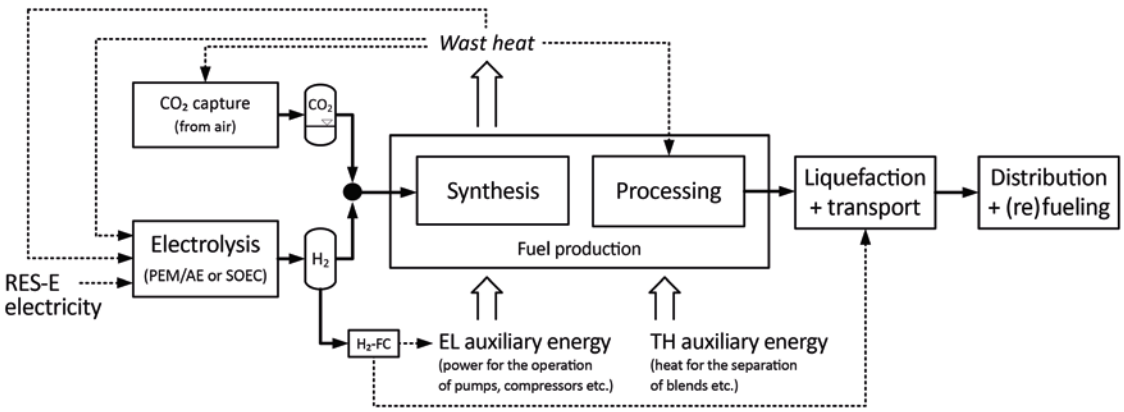


Figure 5: Schematic representation of the main process steps in the production and distribution of e-fuels

	Scenarios	Framework conditions
1	**MENA, max. degree of efficiency/ min. costs (best-case e-fuel)**	• Fuel production in MENA* • High degree of efficiency of electrolysis • CO_2 is captured from the air (cheap)
2	**MENA, min. degree of efficien-cy/max. costs**	• Fuel production in MENA* • Low degree of efficiency of electrolysis • CO_2 is captured from the air (expensive)
3	**DE, max. degree of efficiency/ min. costs**	• Fuel production in DE* • High degree of efficiency of electrolysis • CO_2 is captured from the air (cheap)
4	**DE, min. degree of efficiency/ max. costs (worst-case e-fuel)**	• Fuel production in DE* • Low degree of efficiency of electrolysis • CO_2 is captured from the air (expensive)

*For electricity prices, see Table 12

Table 8: Possible scenarios for the future production of e-fuels

Based on the aforementioned scenarios, a "best-case e-fuel" (MENA, max. degree of efficiency/min. costs) and a "worst-case e-fuel" (DE, min. degree of efficiency/max. costs) are defined, which will be referred to throughout the rest of the study.

Data from the company Climeworks is used regarding CO_2 provision from the air. Furthermore, the energy required for CO_2 liquefaction/intermediate storage is taken into account in all scenarios.

The calculation of the usable waste heat resulting from fuel synthesis is based on a thermodynamic observation of the respective reaction pathways. The waste heat is generated at the temperature level of the corresponding syntheses and, if it is >120° C, can be used for CO_2 capture. The additional auxiliary energy required to run pumps, compressors, recycling streams, etc., must be coupled to the fuel production process from external sources (as electricity). The expenditure involved in preparing the product comprises losses through the formation of unwanted by-products and the energy used for product preparation.

The future production capacity per plant is defined as 2 million tons of fuel per year for all scenarios. This corresponds to a gasoline production output of around 2.5 to 3 GW.

The assumptions shown in **Table 9** regarding degrees of efficiency and costs are used as the basis for the investigated subprocesses.

For reasons of simplification, it was assumed that auxiliary energy of any type is exclusively coupled in the process chains in the form of electrical energy.

The fuel syntheses were analyzed separately for the individual paths. In reality, each individual path is selected or optimized regarding the size, operating method, location, available investment capital and business strategy, feedback into existing infrastructure, etc.

Subprocess	Energy expenditure	Investment costs
CO_2 capture from the air	P_{el} = 0.3 kWh/kg_{CO2} P_{th} = 1.5 kWh/kg_{CO2} [LBST 2016]	Max. scenario: € 4,560 h / kg_{CO2} [LBST 2016] Source: Climeworks, 2018 Min. scenario: € 2,700 h / kg_{CO2} Source: Climeworks, 2018
CO_2 liquefaction	P_{el} = 0.2 kWh / kg_{CO2} (adiabatic methods, polytropic compression to 57 bar)	-
Electrolysis	P_{el} = 45.61 - 53.40 kWh / kg_{H2} [NOW 2011]	€ 750 / kW (1 MW, decentralized prod.) € 250 / kW (GW, central prod.) (average values from forecast for 2040 and 2050: [LBST 2016])
H_2 pressure tank		€ 16.4 / kWh_{H2} [expertise from the working group]
Syntheses		
Fischer-Tropsch synthesis	Usable waste heat: 0.19 kWh / kWh_{Prod} Auxiliary energy for synthesis: 0.03 kWh / kWh_{Prod} Energy for preparation of product: 0.1 kWh / kWh_{Prod}	€ 1,030 / $kW_{Prod.}$ [de Klerk 2011]
Methane synthesis	Usable waste heat: 0.31 kWh / kWh_{Prod} Auxiliary energy for synthesis: 0.005 kWh / kWh_{Prod} Energy for preparation of product: 0.001 kWh / kWh_{Prod}	€ 100 / $kW_{Prod.}$ (TREMP technology, based on costs for CO methanation)[10]
Methanol synthesis	Usable waste heat: 0.07 kWh / kWh_{Prod} Auxiliary energy for synthesis: 0.002 kWh / kWh_{Prod} Energy for preparation of product: 0.12 kWh / kWh_{Prod}	€ 290 / $kW_{Prod.}$
DME synthesis	Usable waste heat: 0.09 kWh / kWh_{Prod} Auxiliary energy for synthesis: 0.003 kWh / kWh_{Prod} Energy for preparation of product: 0.05 kWh / kWh_{Prod}	€ 190 / $kW_{Prod.}$
OME synthesis	Usable waste heat: 0.07 kWh / kWh_{Prod} Auxiliary energy for synthesis: 0.05 kWh / kWh_{Prod} Energy for preparation of product: 0.34 kWh / kWh_{Prod}	€ 760 / $kW_{Prod.}$

10 1.6 GW coal-to-SNG: € 1.5 billion, of which 10 % is attributable to the TREMP component [Topsøe 2012]

Liquefaction		
H_2 liquefaction	$P_{el} = 0.21\ kWh/kWh_{Prod}$	€ 900 – € 1,090 / $kW_{Prod.}$ [LBST 2016]
CH_4 liquefaction	$P_{el} = 0.04\ kWh/kWh_{Prod}$	€ 270 – € 600 / $kW_{Prod.}$ [LBST 2016]

Table 9: Energy expenditure and costs for process steps in the production of alternative fuels

Detailed assumptions on the synthesis plants

In addition, the following assumptions are made regarding the **Fischer-Tropsch plant**:

- The existing CtL/GtL technology can also be used for PtL technologies without any restrictions.
- The proportion of investment costs for fuel preparation is comparatively low (approximately 10 % of the total costs), but is taken into account. If the existing refineries are used for synthetic Fischer-Tropsch crude, the corresponding investment costs are no longer incurred.
- One of the main cost drivers for Fischer-Tropsch plants is eliminated when used in a PtL plant: the need to capture oxygen for the production of synthesis gas. According to [de Klerk 2011], capital costs can thus be reduced by up to ~30 %, however, as no further information is provided on this, this possible cost reduction is not taken into further consideration in the course of this study.

The following additional assumptions are made regarding **methane synthesis**:

- The TREMP methanation technology for the methanation of biomass- or coal-based input is used as the basis for calculating the energy requirement and cost.
- The costs for CO_2 methanation tend to be lower (omission of recycling compressor due to reduced amounts of heat released, etc.).
- The auxiliary energies include operation of the recycling compressor. It is assumed that liquid CO_2 can be obtained from a tank.
- The product preparation includes drying the product gas.

In addition, the following assumptions are made regarding **DME synthesis**:

- DME synthesis is based on a direct hydrogenation of CO_2 to DME (70 bar, 240°C) in line with the JFE process, in which DME is produced from CO and H_2 in a single stage [ProEcPro 2005]. It is then prepared through distillation.
- The auxiliary energies include operation of the recycling compressor. It is assumed that liquid CO_2 can be obtained from a tank.

In addition, the following assumptions are made regarding **OME synthesis**:

- The OME synthesis [Schmitz 2017] requires three reaction steps:
  - Hydrogenation of CO_2 to methanol
  - Oxidation of part of the methanol to form aqueous formaldehyde
  - Acid-catalyzed condensation of formaldehyde and methanol to form OME 3-5 mixture
- The preparation is performed over two distillation steps and one phase separation.

In addition, the following assumptions are made regarding **methanol synthesis**:

- The methanol synthesis is based on a direct hydrogenation of CO_2 to methanol (70 bar, 250°C).
- The auxiliary energies include operation of the recycling compressor. It is assumed that liquid CO_2 can be obtained from a tank.
- The product preparation includes thermal energy for the complex process of separating methanol from the reaction water.

The investment costs for DME and methanol are determined on the basis of calculations using a thermodynamic simulator (like ASPEN+) and specific investments as per [Lange 2001]. World-scale plants with annual capacities of 1.7 million tons of MeOH or 1.5 million tons of DME respectively were used as a basis. For these large capacities, output-specific investment costs of € 250 per kW of heat transfer capacity are assumed.

Degrees of efficiency in fuel production and provision

The overall degrees of efficiency in fuel production for the individual scenarios are given in **Table 10**.

PtX fuels	Assumptions			
	Max. ELY efficiency, CO_2 available	Min. ELY efficiency, CO_2 available	Max. ELY efficiency, CO_2 from air	Min. ELY efficiency, CO_2 from air
BEV	94 %*	72 %*	94 %*	72 %*
E-H_2 (FCEV), local prod., DE	67 %	58 %	67 %	58 %
E-H_2 (FCEV), centralized prod., MENA	61 %	53 %	61 %	53 %
E-DME	65 %	56 %	51 %	45 %
E-OME	45 %	39 %	37 %	33 %
E-methane	71 %	60 %	57 %	50 %
E-methanol	60 %	52 %	48 %	43 %
E-gasoline (FT)	61 %	52 %	47 %	42 %
E-diesel (FT)	62 %	53 %	49 %	43 %
E-propane (FT)	62 %	53 %	50 %	44 %

* The differences in the degree of efficiency are due to the charging speed (quick charge yes/no).

Table 10: Degrees of efficiency in the production of PtX fuels

Energy requirement and costs of fuel distribution

It is assumed that all centrally produced fuels are distributed in Germany via truck. As such, an average distribution distance of 500 km is assumed regardless of the production location (MENA and DE). The additional energy used when compared to the transport of diesel or gasoline, which results from the lower energy density of some fuels, is taken into account here. It is assumed that methane and H_2 are transported as liquids. The energy required for liquefaction is taken into consideration.

For the two constant electrical power supply scenarios (BEV and local H_2), no additional energy requirement for fuel distribution is considered, as no fuel needs to be transported in either of the scenarios.

As only few reliable sources of information on the costs of LNG and LH_2 tankers are available, the costs for transportation by ship from MENA to Germany are assumed to be negligible and are therefore not taken into account when comparing the scenarios; the same applies to investment costs for a new fleet of tankers (for transportation of LNG and LH_2 from MENA) and for converting the existing tanker fleets (e.g. for transporting methanol, DME or OME from MENA). The following cost estimation for a fleet of LH_2 and LNG tankers demonstrates that these costs are negligible.

The carrying capacity of a typical LNG tanker is approximately 250,000 m^3 [Wachtmeister et. al 2012] [Wiki Tanker 2017]. As the liquid density of LNG is around 425 kg per m^3 [LNG Calc 2017], this results in a load quantity of 106,250,000 kg = 106,250 t. This corresponds to an energy content of 5,312.5 * 1e6 MJ = 1475.7 * 1e6 kWh per load (CV = 50 MJ/kg). Assuming a transport duration of two weeks, every ship can transport 24 loads per year. This results in an annual transport capacity of 24 * 1475.7 * 1e6 kWh = 3.542 * 1e10 kWh = 35.42 TWh per tanker.

According to these calculations, around 20 tankers will be needed ((700 / 35.42) TWh = 19.76) to transport the required amount of primary energy of approximately 700 TWh per year. The investment costs for one LNG tanker are around USD 200 million [Wiki Tanker 2017], which translates to roughly € 170 million, resulting in an investment sum of € 3.4 billion for the requisite 20 tankers. As the amortization of tankers is generally carried out over a period of 40 years [Wiki Tanker 2017], the annual depreciation costs are relatively low. Due to existing tankers also being subject to conversion costs for transporting liquids from MENA, which are however expected to be lower (but are unfortunately not known), the differences in investment costs for tankers in the LNG scenario compared to liquid fuel scenarios are considered to be even smaller.

A liquid hydrogen tanker has a transport capacity of around 11,400 t [Abe et. al 1998]. This roughly corresponds to an energy quantity of 1,368 * 1e6 MJ (CV = 120 MJ/kg), or 380 * 1e6 kWh = 0.38 TWh per load. At 24 loads per year, this results in an annual transport capacity of 24 * 0.38 TWh = 9.12 TWh per tanker. In order to transport the required amount of primary energy of approximately 502 TWh per year, according to these calculations around 55 tankers will be needed ((502 / 9.12) TWh).

There is very little literature on the investment costs for an LH_2 tanker. According to [Abe et. al 1998] these amount to around GBP 3 to 27 / (GJ*a), which equates to around USD 140 million to USD 2,200 million per tanker when applied to the tankers described above, with the smaller values applying for larger ships. When investment costs of USD 360 million are assumed (three times the minimum value [UKSHEC 2012], corresponding to around € 310 million), the result is an investment sum of around € 17 billion for a fleet of LH_2 tankers, which – as is the case for the LNG fleet – are generally amortized over 40 years. These costs are not considered either.

Assumptions on the infrastructure for fuel distribution

For all fuels produced in MENA, liquid transport (including for LNG and LH_2) via ship and subsequent distribution by truck are assumed. The investment costs for the fleet of ships and their energy consumption are not considered, as these values are not significant and few exact figures are available for investment costs for LH_2 tankers (see above for estimate).

For transportation through Germany, a truck running on the respective target fuel is assumed (100 % scenarios). The energy consumption during transport is included in the total degrees of efficiency for production. An average delivery distance of 1,000 km is assumed (2 * 500 km: MENA terminal, e. g. seaport in Hamburg, Antwerp, etc., to a location in central Germany, plus return journey of empty truck). The different energy densities and thereby transport capacities of the trucks are taken into account according to **Table 11**. The investment costs for the trucks are not considered.

Additional costs for transporting e-fuels through Germany (DE) by truck	Gasoline/ diesel	H_2	CH_4	MeOH	DME	OME	FT	FT	
	(Reference)	Liquid	Liquid				Gasoline/ diesel	Propane/ butane	
Load capacity	28	2.5	15.8	27.7	23.1	37.7	28.0	18.9	t
Density	800	71	450	790	660	1078	800	540	kg/m³
Transport volume	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	m³
Calorific value	42.00	119.97	50.01	19.90	28.40	18.97	42.00	46.00	MJ/kg
Energy content per journey	1,176,000	298,125	787,658	550,235	656,040	715,738	1,176,000	869,400	MJ
Number of journeys	1	3.94	1.49	2.14	1.79	1.64	1.00	1.35	-
Number of extra journeys (vs. diesel)	0.00	2.94	0.49	1.14	0.79	0.64	0.00	0.35	-
Fuel consumption for trucks	1,220.10	1,220.10	1,220.10	1,220.10	1,220.10	1,220.10	1,220.10	1,220.10	MJ/100 km
MJ fuel consumption / 100 km/ MJ fuel transported	0.0010	0.0041	0.0015	0.0022	0.0019	0.0017	0.0010	0.0014	MJ / MJ / 100 km
MJ fuel consumption/delivery distance/MJ fuel transported	0.0104	0.0409	0.0155	0.0222	0.0186	0.0170	0.0104	0.0140	MJ / MJ (2 x delivery distance)
MJ fuel consumption/delivery distance/MJ fuel transported vs. diesel	0.0000	0.0306	0.0051	0.0118	0.0082	0.0067	0.0000	0.0037	MJ / MJ (2 x delivery distance)
Additional energy used	0.00000	0.03055	0.00512	0.01180	0.00822	0.00667	0.00000	0.00366	kWh / kWh
Distance	1,000	km							
Consumption diesel truck	35	l diesel/100 km							
Consumption diesel truck	29.05	kg diesel/100 km							
Transport requirement basic	0.01038	kg diesel consumed / kg diesel transported							
	0.01038	kWh diesel consumed / kWh diesel transported							

Table 11: Energy expenditure for transport in Germany

For supplying fuels produced centrally in Germany, the same assumptions were made for transport by truck within Germany. There are no transport costs for electric vehicles and decentrally produced H_2.

The energy expenditure and costs for H_2 and methane liquefaction are described in **Table 9** in the previous chapter. Furthermore, the energy expenditure for operating filling stations is taken into account. For reasons of simplification, the same energy expenditure is assumed for all liquid fuels as for diesel fuel, i.e. 0.0034 kWh per 1 kWh of final fuel [BMVBS 2013].

For a methane filling station, 0.005 kWh per 1 kWh of final fuel is estimated. These figures arise from the assumption of a mix of compressed methane evaporated from liquid methane and direct sales of compressed methane. For compressed methane, a figure of 0.01 kWh per 1 kWh of final fuel is defined (this applies for compression to 300 bar from the natural gas grid), while this value is close to zero for methane distributed in liquid form. This produces an average value of 0.005 kWh per 1 kWh of final fuel.

For running an H_2 filling station supplied with liquid fuel (central H_2 scenario), 0.41 kWh per 1 kg of H_2 (0.0124 kWh per 1 kWh of H_2) of operating energy is defined [EFCF 2004]. These figures primarily result from the energy required for cooling (energy requirement of 100 kg per day at approx. 5 kWh per kg). A value of 3.51 kWh per 1 kg of H_2 (0.106 kWh per 1 kWh of H_2) is assumed for the operation of a decentralized H_2 filling station [CEP 2015].

Assumptions on the infrastructure for vehicles with combustion engines and fuel cells – cars

In Germany there are currently around 14,000 filling stations which sell diesel and gasoline. Most of these filling stations have eight or more fueling points where all types of gasoline and diesel are generally available. The number of filling stations in existence is the result of market development spanning decades. These filling stations are not used to their full capacities at all times, but solely peak times. It can also be assumed that fewer filling stations would be sufficient for the basic supply of fuel. Moreover, filling station operators are currently facing a period of consolidation.

There are around 6,800 LPG filling stations in Germany and approximately 900 natural gas filling stations. While the filling station infrastructure for natural gas is often viewed as insufficient in customer surveys, this is not known to be the case for the number of LPG filling stations. On this basis, the working group determined that the minimum number of filling stations for full coverage (100 % scenario) must be somewhere between 900 and 6,800. In the light of this and the current market situation, two realistic guiding scenarios are adopted for a 100 % scenario. The “minimum cost scenario” assumes that there will be 5,000 filling stations, while the “maximum cost scenario” incorporates a total of 10,000 filling stations. In these scenarios, all filling stations are equipped with eight filling points for the respective fuel type.

According to the experiences of filling station operators, the average stay of a customer when fueling their car is around ten minutes. The actual fueling time per 100 km for a gasoline and diesel vehicle is usually below ten seconds. Accordingly, fewer than 50 seconds are required to fill a quantity of fuel sufficient for 500 km. The pure fueling time therefore only makes up a fraction of the average stay at the filling station (< 10 %). Methane, LPG and fuel cell vehicles generally have a fueling time of less than 30 seconds per 100 km. Therefore, less than 2½ minutes of actual fueling time are needed to fill enough fuel to cover 500 km. As such, the pure fueling time only makes up a small part of the average stay at the filling station for these vehicles, too (< 25 %). The same number of filling stations and filling points is thus used for all fuel-powertrain combinations, apart from electric vehicles. As they have a charging duration ranging between 500 seconds and 6 to 7 hours for 100 km (150 kW quick-charge station or household socket at a consumption of 60 MJ per 100 km; e.g. NEDC Ford Focus or 1.5 * NEDC Opel Ampera), electric vehicles require a significantly different infrastructure, the assumptions for which are described in detail below.

The existing infrastructure can be used for **FT diesel** and **FT gasoline**, meaning that no costs arise.

For **OME**, the experts of the working group assume that the existing diesel and gasoline infrastructure (conversion of four diesel and four gasoline filling points at each filling station) can be used after fitting new seals. Here it is also assumed that vapor recovery will probably not be required for the conversion (unresolved for OME 3). The underlying conversion costs are € 1,250 per filling point.

For **methanol** it is assumed that only filling stations adapted for ethanol, i.e. equipped with an ethanol-compatible plastic tank coating and without copper lines, are converted. This comprises all filling stations in Germany that were built or modernized after 2005, totaling around 95 % of the available stations. Apart from the hoses and seals, these filling stations are generally compatible with methanol. Furthermore, it is assumed that four gasoline and four diesel filling points are converted in each case. In addition, a vapor recovery system needs to be installed at the diesel dispensers. According to the estimate of the experts from the working group, the average conversion costs should be around € 2,250 per filling point.

As the current **LPG** infrastructure only comprises small tanks with a low capacity and in most cases only one to two filling points per filling station, this infrastructure can only be used during a transition period. For 100 % supply at all 10,000 or 5,000 filling stations, the infrastructure would have to be replaced by new tanks of a sufficient size (even at the filling stations that already sell LPG). Therefore, existing tanks are not included in the calculation. For the new installation, a fully installed, aboveground tank with a capacity of 100 m^3 was used as a basis. The experts from the working group estimate that the costs for the new LPG tanks amount to € 6,250 per filling point.

The old LPG dispensers can still be used, which means that the existing filling points (assumption: 6,800 * 2) can be deducted from the costs for the installation of new LPG nozzles. A sum of € 7,500 is projected for each LPG filling point.

In principle, the same infrastructure costs are estimated for **DME** as for LPG (at € 9,500 per filling point for the installation of new tanks and € 7,500 for each filling point nozzle), with the difference that the existing LPG fuel filling pumps are not taken into account for DME as these cannot be used without modification. The experts from the working group believe that at least new seals and hoses have to be installed to distribute DME.

For **methane** it is assumed that the current infrastructure can be used, as it is generally fed from the gas grid and no insufficiently dimensioned tanks have to be replaced, as is the case for LPG. A total of 900 filling stations, each with two filling points only per filling station (estimate), were taken into account as the current infrastructure. This means that 900 quarter-size filling stations were subtracted from the 10,000 or 5,000 filling stations to be built. For cars and trucks weighing up to 3.5 t, only compressed methane (CNG) is assumed as a fuel with the corresponding tank facilities. The filling station costs were postulated on the basis of discussions with numerous established companies that install CNG filling stations. These discussions also revealed that two filling points can be assumed at more than 90 % of filling stations in today's infrastructure. Furthermore, these existing filling points are able to fuel around eight to ten vehicles per filling point per hour, which appears sufficient in light of the hypothetical gross fueling time of ten minutes per vehicle.

Today, a complete CNG filling station with two filling points costs around € 270,000. On the basis of this, the fully fledged filling station with eight filling points is upscaled as follows: two compressors including storage for four fuel filling pumps costing € 350,000. Costs of € 35,000 for each filling point are then added to this figure for the installation of the fuel fulling pump. Therefore, the overall installation costs for each filling point are € 61,000.

Today, there is practically no infrastructure that would be sufficient to distribute the required quantities of **hydrogen**. The approximately 30 existing filling stations and the planned filling stations only have one or two filling points. Here it is generally not possible to fuel more than four vehicles per hour back-to-back. This infrastructure is therefore not included in the calculation.

For the scenario **with central hydrogen production**, only liquid hydrogen delivered to filling stations by truck was considered. The filling station costs are based on discussions with numerous established companies that install hydrogen filling stations on the one hand, and on the study by [Mayer et. al 2017] on the other. On this basis, a sum of € 3.3 million per filling station (min. 700 kg H_2 per day, eight filling points) was estimated.

For the scenario **with local hydrogen production** at the filling station, the same assumptions apply for the tank and fuel filling pumps (€ 3.3 million per filling station; at least 700 kg H_2 per day, eight filling points). The infrastructure costs for connections to the local electrolysis system, which are described in the chapter "Investment costs for expanding the electricity infrastructure", are added to this.

Assumptions on the infrastructure for vehicles with combustion engines and fuel cells – trucks

Trucks are generally not fueled at car filling stations, but rather have their own infrastructure that predominantly consists of depot filling stations and separate filling points at highway filling stations. The study [UBA 2016] estimates that there are 48,572 fuel filling pumps for trucks and assumes that 61 % of trucks are fueled at their own depot. The working group believes that the present number of filling stations will fall when a new infrastructure is built, and that haulage companies would be more likely to dispense with their own filling station and instead use public filling stations in the case of expensive installations (for example H_2). The fueling capacity at public fuel filling pumps (for a partial acquisition of depot customers) is available. According to the expertise of the working group, the dispensers are currently utilized less than 10 % of the time, meaning that a reduction is possible without further ado. Therefore, the working group assumed that only "large" haulage companies/depots can afford their own filling station, where "large" is defined as "more than ten trucks". In Germany, 18 % of haulage companies have more than ten trucks [BAG 2009].

The experts from the working group estimate that there are 4,500 public filling points for trucks. This figure is based on the number of public truck filling stations (665) with an estimated six to eight filling points each.

Applying the same parameters as for cars (reduction of the total number of filling stations from 14,000 to 10,000 or 5,000), a total number of 3,000 public filling stations with four filling points each (12,000 filling points) is assumed in the maximum cost scenario; for the minimum cost scenario, these figures are halved, with a total of 1,500 filling stations and 6,000 filling points.

As is the case for cars, the existing infrastructure can be used for **FT diesel**, meaning that no costs arise.

For **FT gasoline**, the experts from the working group expect that all diesel filling pumps currently in use will have to be converted for gasoline by fitting a vapor recovery system. These costs amount to approximately € 2,500 per filling point.

For **OME**, the experts of the working group assume that the existing diesel infrastructure can be used following conversion. The suitability of filters and seals is not currently known, resulting in the assumption for conversion costs of around € 1,000 per filling point.

For **methanol**, the experts of the working group assume that all diesel filling points can be converted. Like gasoline, fueling with methanol requires a vapor recovery system (costing around € 2,500 per filling point) and an additional upgrade of the hose and seal (approximately € 500 per filling point).

For the **LPG** infrastructure for trucks, similar assumptions apply as for cars. For the new installation, a fully-installed, above-ground storage tank with a capacity of 100 m^3 is used as a basis. The costs for the new LPG tanks amount to € 6,250 per filling point. The experts from the working group estimate a sum of € 7,500 for an actual LPG filling point (fuel filling pump). As there is no existing infrastructure, this cannot be included in the calculation.

In principle, the working group adopts the same infrastructure costs for **DME** as for LPG (€ 6,250 per filling point for installation of new tank + € 7500 per filling point nozzle).

For the **methane** filling stations (for trucks weighing more than 3.5 t), a mix of liquid methane and compressed methane filling stations was assumed. The working group estimates that there is a total of 400 liquid methane filling points. The number of compressed methane filling points was calculated as follows:

number of compressed methane filling points = total number of methane filling points – 400

As with cars, total installation costs of € 61,000 per filling point were calculated for the pure compressed methane filling stations. For **liquid methane filling stations**, costs of € 500,000 are estimated for each fuel filling point with one LNG and two CNG dispensers. The costs of two compressed methane filling pumps are subtracted from this number, resulting in net costs of € 382,000 per LNG filling point. The filling station costs were postulated on the basis of discussions with numerous established companies that install **CNG** and **LNG filling stations**.

As is the case for cars, only liquid hydrogen delivered to filling stations by truck is considered for the scenario **with central hydrogen production**. The filling station costs are based on discussions with numerous established companies that install hydrogen filling stations on the one hand, and on the study by [Mayer et. al 2017] on the other. On this basis, a sum of € 3.3 million per filling station (min. 700 kg H_2 per day, eight filling points) was estimated.

For the scenario **with local hydrogen production** at the filling station, the same assumptions apply for the tank and fuel filling pumps (€ 3.3 million per filling station; at least 700 kg H_2 per day, eight filling points). The infrastructure costs for connections to the local electrolysis system, which are described in the chapter “Investment costs for expanding the electricity infrastructure”, are added to this.

Assumptions on the infrastructure for electric vehicles – charging stations for cars (BEVs)

Due to the long charging times, the charging infrastructure for BEVs needs to be far more comprehensive and installed in line with different concepts. In 2017, the following charging infrastructure was available for cars in Germany [EAFO 2017]:

- Up to 22 kW: 22,857
- More than 22 kW: 1,810
- 2AC type: 341
- CHAdeMO: 444
- CCS: 638
- Tesla: 387

The working group views the following charging infrastructure as sufficient:

- Quick-charge stations:
  € 62,500 x 160,000 charging stations
- Charging at home:
  Wall box (including installation costs)
  € 950 x 25,000,000 charging stations
- Charging at work:
  As with charging at home,
  € 950 x 10,000,000 charging stations

These numbers of charging stations are halved in the minimum cost scenario.

The costs for the additionally required expansion of infrastructure are explained in the chapter “Investment costs for expanding the electricity infrastructure”.

Assumptions on the infrastructure for electric vehicles – trucks (hybrid-overhead line BEVs)

The purely electric scenario assumes that hybrid-overhead line trucks are primarily supplied with energy via a high-voltage power line, but that also possess a battery so that they can run in areas without overhead lines (delivery traffic).

Scenario 2B from [ISI 2017] is used for the minimum cost scenario. The network coverage with overhead lines comprises an accessible distance of 3,900 km (max. transformer station capacity 25 MVA). According to this study, the accessible distance when using a battery is 13,000 km, which corresponds to the entire German highway network. This concept requires trucks to be fitted with a 300 kWh battery, resulting in total costs of € 16 billion.

For the maximum cost scenario, an overhead line length of 13,000 km (complete German highway network) is assumed while retaining a 300 kWh battery in trucks. The costs for the overhead lines outlined in [ISI 2017] total between € 3.883 and € 4.35 million per km. Assuming the higher value, the total cost is € 56.55 billion. The higher figure is assumed here. The costs for the additionally required expansion of infrastructure are explained in the chapter “Investment costs for expanding the electricity infrastructure”.

Further assessment criteria

Alongside the main focus on comparing the operating costs of the examined fuel-powertrain combinations, further criteria are also used for the assessment.

a) Primary energy requirement for fuel production
b) Safety, handling
c) Attainability of zero emissions (TtW), and TtW-CO_2 emissions
d) Market introduction potential, customer acceptance and lead time to market
    i. Fueling/charging time
    ii. Compatibility with existing stock/drop-in ability in fossil fuels
    iii. Number of compatible cars in the market/existing infrastructure
    iv. Availability of technology
    v. Bi-fuel capacity (with gasoline/diesel powertrain)
    vi. Availability of fuel standards
    vii. Retrofitting capability
e) Functional temperature range
f) Risks, potential/advantages
g) Compatibility of vehicles with rest of world.

Results

Electrical energy requirement

The TtW energy requirement [TWh per annum] for the various powertrain concepts is shown in **Figure 6**. The BEV has the lowest TtW energy requirement at 176 TWh/a. FCEVs need almost twice the amount (307 TW h/a), while concepts with combustion engines require around two-and-a-half times as much (431 to 469 TWh/a).

The WtW energy requirement [TWh/a) resulting from this can be found in **Figure 7** in the form of a minimum and maximum value, which are respectively produced from a combination of the most and least favorable framework conditions assumed for PtX production. Details on the most favorable assumptions (minimum cost scenario) and the least favorable assumptions (maximum cost scenario) can be found in **Table 12.**

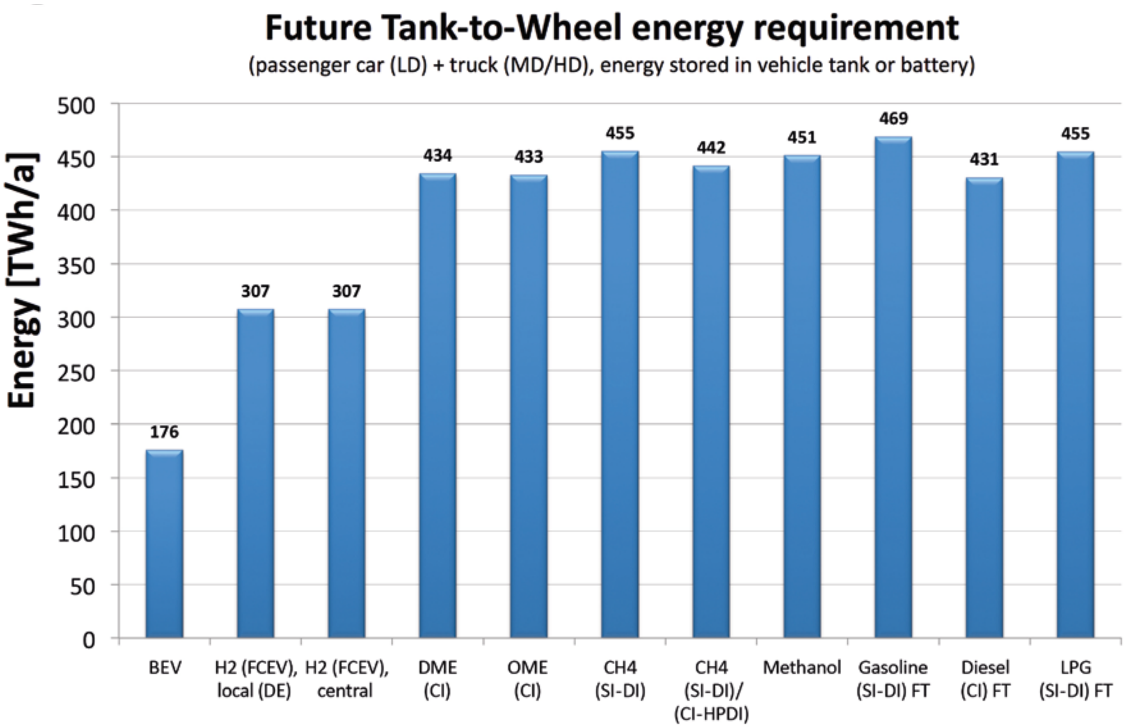


Figure 6: TtW energy requirement [TWh/a]

Scenario	Min. costs (max. efficiency)	Max. costs (min. efficiency)
Electrolysis energy requirement PtX production (incl. H_2)	Alkaline electrolysis 45.61 kWh / kg H_2 (degree of efficiency: 0.73)	Alkaline electrolysis 53.40 kWh / kg H_2 (degree of efficiency: 0.62)
CO_2 source for PtX production	From ambient air (€124.50 / t CO_2)	From ambient air (€ 292.80 / t CO_2)
Electricity price BEV and FCEV / H_2 local	Permanently available Germany 2030: € 100/MWh	Permanently available Germany 2015: € 180/MWh
Electricity price FCEV / H_2 central and all other PtX processes	Alternating, MENA PV + wind 2030: € 24.26 / MWh (€ 15 / MWh PV, € 25 / MWh wind)	Alternating offshore wind, Germany 2015: € 88.10/MWh
Amortization of investment in fuel production	20 years, ROI 6 %, interest 4 %, maintenance 5 %, residual value 0	20 years, ROI 6 %, interest 4 %, maintenance 5 %, residual value 0
Degree of efficiency for transmission/charging for BEVs	Maximum: 0.94	Minimum: 0.72
Infrastructure	Filling stations: - Car: 40,000 filling points - Truck: 6,000 filling points Car - BEV charging stations: - 80,000 quick-charge stations - 12.5 million home charging stations - 5 million workplace charging stations Hybrid-overhead line truck: Overhead line 4,000 km Assumption: NO electricity grid expansion required for BEV / connection of local H_2 electrolysis	Filling stations: - Car: 80,000 filling points - Truck: 12,000 filling points Car - BEV charging stations: - 160,000 quick-charge stations - 25 million home charging stations - 10 million workplace charging stations Hybrid-overhead line truck: Overhead line 13,000 km Electricity grid expansion for BEV charging stations: € 77.4 billion, costs for connecting overhead lines for trucks: € 21 billion, connection of local H_2 electrolysis: € 90 billion
Amortization of investment in infrastructure	40 years, ROI 6 %, interest 4 %, maintenance 5 %, residual value 0	40 years, ROI 6 %, interest 4 %, maintenance 5 %, residual value 0
Vehicle costs for cars	No surcharge for all SI concepts (based on gasoline vehicle for € 20,000) + € 2,400 for all CI concepts compared to SI (taken from current manufacturers' price lists) Assumption (QED) for BEVs and FCEV: Same price as for diesel vehicle will be possible in 2050	[Berger 2016]: (forecasts for 2030) + current manufacturers' price lists (based on gasoline vehicle for € 20,000): BEV 500 + € 11,300, FCEV + € 12,500, DME + € 3,400, diesel/OME + € 2,400, methane + € 1,800, propane + € 1,500, methanol + € 300
Vehicle costs for trucks	From [LastOm 2017], p. 293 ff. (DEKRA), (basis: trailer truck € 90,400): Red. price FCEV and BEV from "Update DOE - Fuel Cell Technologies Office, chapter 3.3 + 3.4" hybrid-overhead line EV + € 51,978, FCEV + € 36,538, DME/propane + € 1,000, diesel/OME/gasoline + 0, methane + € 14,000 or € 24,000 (HPDI)	From [LastOm 2017], p. 293 ff. (DEKRA), (basis: trailer truck € 90,400): hybrid-overhead line + € 87,500, FCEV + € 124,740, DME/propane + € 1,000, diesel/OME/gasoline + 0, methane + € 14,000 or € 24,000 (HPDI)

Table 12: Assumptions for the minimum and maximum cost scenarios

For the FCEV and combustion engine powertrains, low degrees of efficiency for electrolysis were assumed in the worst-case e-fuel scenario (DE, min. degree of efficiency / max. costs) and the highest degrees of efficiency for electrolysis were assumed in the best-case e-fuel scenario (MENA, max. degree of efficiency / min. costs). Furthermore, the minimum and maximum efficiency scenarios for the combustion engine powertrains differ with regard to the assumed investment costs for CO_2 separation from the air.

The described minimum and maximum values are to be viewed as guiding figures, while the range between them covers the lack of prediction accuracy. Therefore, calculating an average value to compare the scenarios would lead to incorrect conclusions being drawn and should be avoided.

The assumptions for the charging losses of BEVs are shown in **Table 13**. The charging losses of the battery in the maximum efficiency scenario when consumption is calculated according to the applicable standard [ECE R101.01] were already included on the TtW side. Therefore, a degree of efficiency of 100 % is used as the basis on the WtT side. This applies for slow charging with an optimal degree of efficiency. The degree of efficiency of 72 % for the minimum efficiency scenario is taken from the current VDA-dena-LBST study [LBST 2017]; this applies for fast charging and includes the distribution losses of quick-charge stations with up to six sockets with 120 kW per charging unit and battery electric buffer storage (two hours) for charging a battery from 30 % charge to 100 % charge. Transmission losses from the wind turbine to the BEV are specified separately and make up a total of 6 % in the minimum efficiency scenario and 0 % in the maximum efficiency scenario, as the latter figure is already included in the degree of efficiency for charging batteries in the LBST study [LBST 2017].

In order to evaluate the scenarios with regard to the primary energy requirement, it is necessary to consider the electrical energy that needs to be used as a buffer for dark periods in the two scenarios in which electricity needs to be supplied on a continuous basis, BEV and local H_2 (referred to in the following as the constant electrical power supply scenarios). In doing so it is assumed that 20 % of the volatile electrical energy is stored as PtG [ISE 2015] and is then reconverted in a gas power station. A degree of efficiency of 60 % is assumed in each case for the PtG generation and the reconversion.

On the other hand, central H_2 generation, H_2 generation for the PtX plants and the PtX plants themselves (in some cases limited by relatively long start-up times of up to 24 hours) can be operated on an alternating basis so that the energy is stored in the fuel itself or in hydrogen as an intermediate product.

An often discussed approach of using the BEV fleet as a buffer for volatile wind and solar energy is pursued ad absurdum in **Table 14**. This shows how much more the battery for each vehicle would weigh and cost if all 45 million BEVs were used for the intermediate storage of the primary energy requirement for operating the vehicle fleet over a two-week dark period. In two weeks, 204 kWh would have to be stored per vehicle. On the basis of today's battery technology (specific weight 6 kg per kWh) and specific battery costs that have not yet been reached (€ 150 per kWh), the battery of each and every vehicle would weigh around 1,200 kg and cost more than € 30,000, which appears unrealistic.

Degree of efficiency for charging BEV	Min. efficiency	Max. efficiency
Transport of energy to charging cable	1	0.94
Charging of battery	0.72	1
Total EV charging:	**0.72**	**0.94**

Table 13: Assumptions regarding degree of efficiency for BEV charging losses

Annual WtW energy requirement for BEVs: 244 TWh	Energy storage quantity for two-week dark period	
Total BEV energy requirement per day in TWh/d	**TWh total**	**kWh per vehicle**
0.67	9.37	204
Additional costs for battery per vehicle	€ 30,672	
Weight of battery	1,227 kg	

Table 14: Theoretical additional battery weight (basis: 6 kg/kWh) and additional costs (basis: € 150/kWh) if all vehicles have to buffer a sufficient energy quantity for a two-week dark period in addition to normal operation

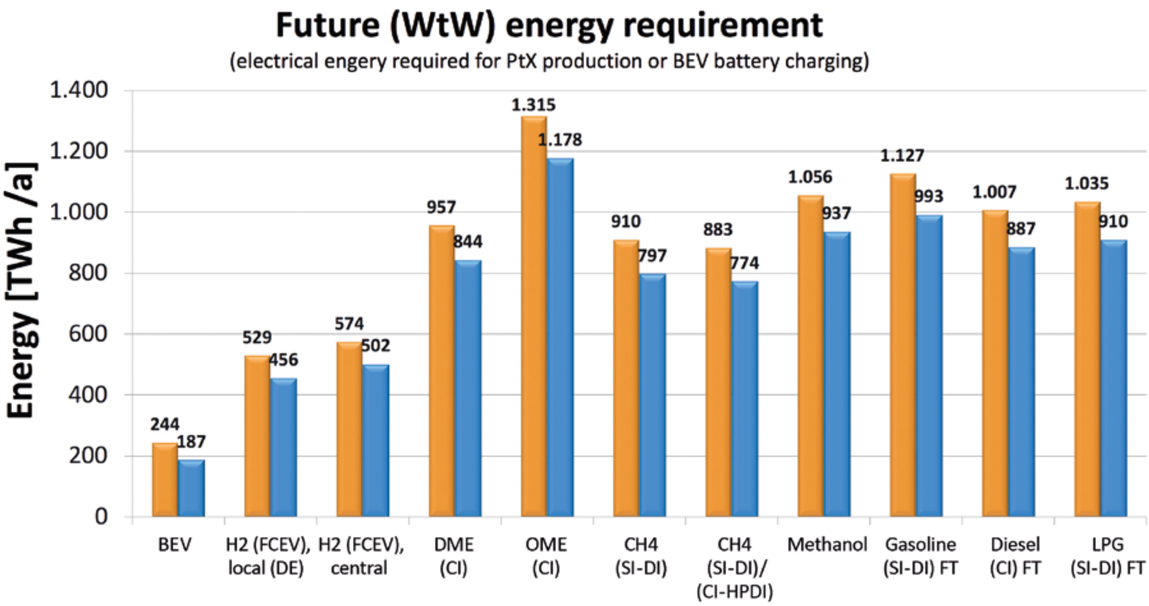


Figure 7: WtW energy requirement (min./max.) [TWh/a] – under the framework conditions specified in **Table 12**

Under the conditions described above, the WtW energy requirement (**Figure 7**) results in the primary energy requirement shown in **Figure 8**. In contrast to the WtW energy requirement, this contains the buffer losses of the BEV and local H_2 scenario, which arise as a result of the 20 % Pt-CH_4 intermediate storage and reconversion. For a 100 % BEV scenario this would be between 249 and 325 TWh per year, which corresponds to around half of today's total electricity requirement in Germany. In the case of locally produced hydrogen used in an FCEV, approximately 2.2 to 2.4 times as much energy would be needed, while only around 1.8 to 2.0 times as much would be required in the central H_2 scenario. The prediction accuracy is much lower for all combustion engine concepts, as the fuel production chain is longer and is thus subject to greater uncertainty. In the best case (CH_4) the primary energy requirement is around 50 % higher than with central H_2 production and thus approximately 2.7 to 3.1 times greater than the energy requirement for a pure BEV scenario. In the least favorable case (OME), the primary energy requirement for the BEV scenario is exceeded by a factor of up to 4.7. During this evaluation it should be noted that the FT fuels cannot be produced individually, but rather together as a mix. A realistic distribution of these would be 60 % FT diesel, 20 % FT gasoline, 10 % FT LPG and 10 % other products (e. g. engine oil).

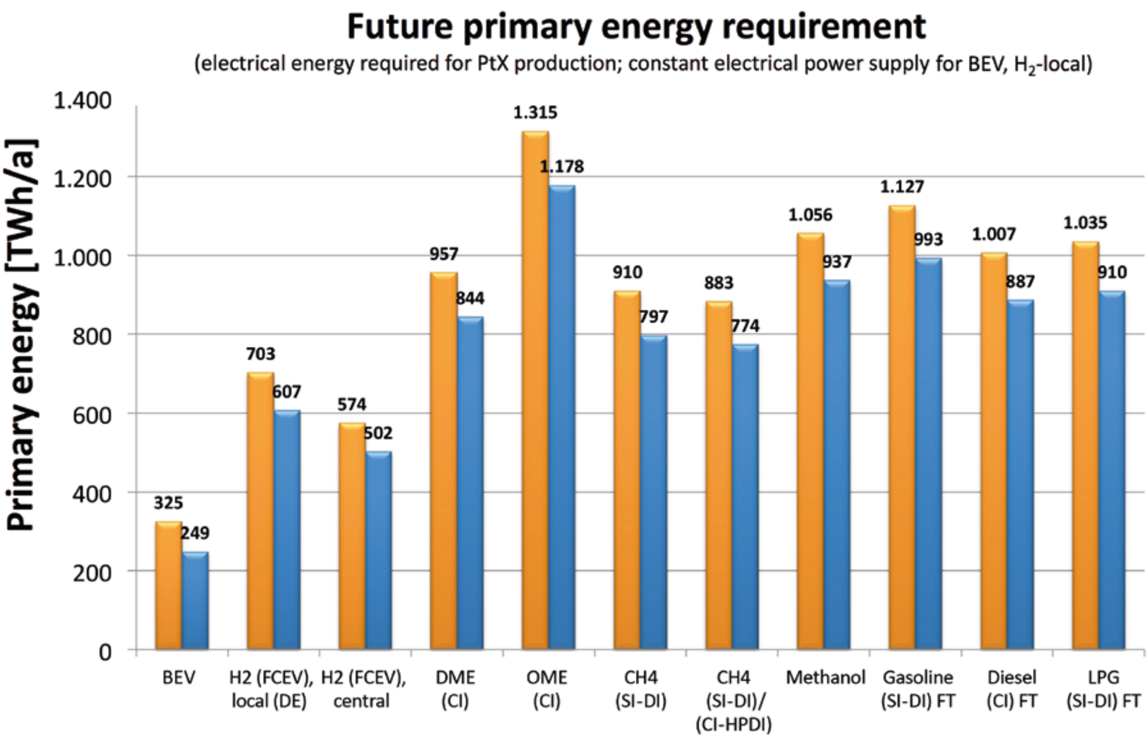


Figure 8: Primary energy requirement (min./max.) [TWh/a] – under the framework conditions specified in **Table 12**

Since there will still be significant sources of CO_2 in the future which can be made directly available for PtX production, both when the energy sector is 100 % sustainable (cement and steel manufacturing, biogas production) and, in particular, during the transition period from a fossil-based to a fully sustainable energy sector (coal, gas, oil-fired power stations), it is prudent to consider the total energy requirement without taking the energy for CO_2 separation from the air into account. This is shown in **Figure 9**. If CO_2 is available from existing sources, the primary energy requirement for the PtX paths is reduced by around 15 to 20 %. In the most favorable case (CH_4), the primary energy requirement would then only be around 25 to 30 % higher than with central H_2 production and approximately 2.2 to 2.5 times greater than the energy requirement for a pure BEV scenario.

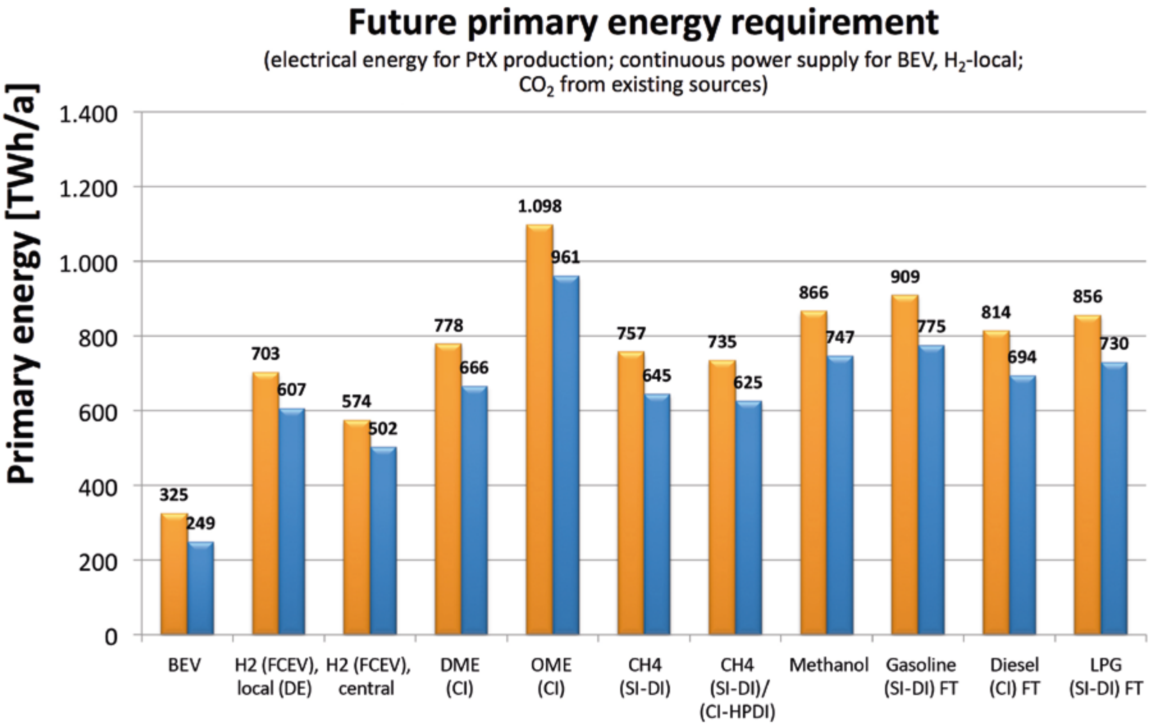


Figure 9: Primary energy requirement (min./max.) [TW h/a] – under the framework conditions specified in **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

The respective WtT degrees of efficiency for fuel production are shown in **Figure 10**, while the WtW degrees of efficiency are presented in **Figure 11** (for cars) and **Figure 13** (for trucks). While the total degree of efficiency (WtW) for electromobility is between just under 58 and roughly 80 %, the equivalent figure for a fuel cell vehicle is in the region of 25 to 32 %. For PtX-driven vehicles with combustion engines, the WtW degrees of efficiency for cars are between 10 and 17 % and in the region of 14 to 24 % for trucks. Under favorable conditions, PtX-driven vehicles with combustion engines can almost reach the level of FCEVs (truck: 25 to 31 %) (e. g. truck with methane HPDI: 21 to 24 %). Of all the PtX fuels, methane tends to achieve the highest degrees of efficiency.

If one assumes that CO_2 is available, the WtW degrees of efficiency for the PtX paths are significantly higher, as is shown in **Figure 12** (for cars) and **Figure 14** (for trucks). For PtX-driven vehicles with combustion engines, the WtW degrees of efficiency for cars are then between 12 and 21 % and in the region of 17 to 30 % for trucks. Under favorable conditions (truck with methane HPDI: 25 to 30 %), PtX-driven vehicles with combustion engines then reach the level of FCEVs (truck: 25 to 31 %).

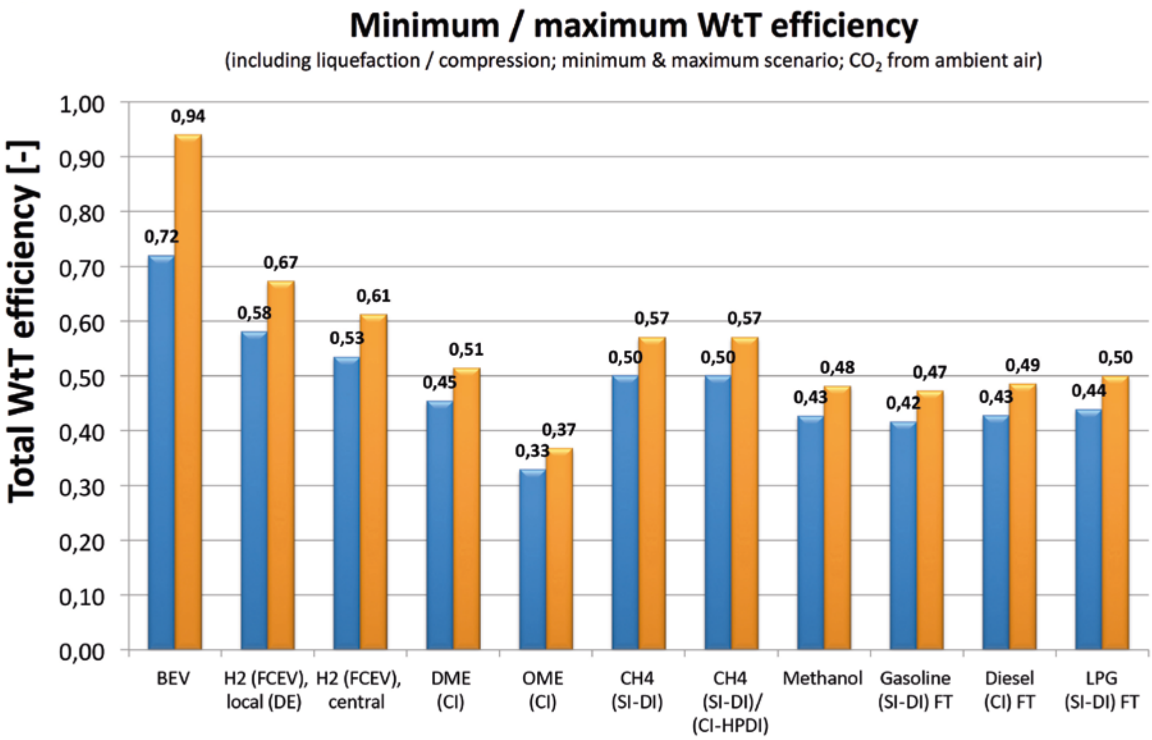


Figure 10: WtT degrees of efficiency for fuel production – under the framework conditions specified in **Table 12**

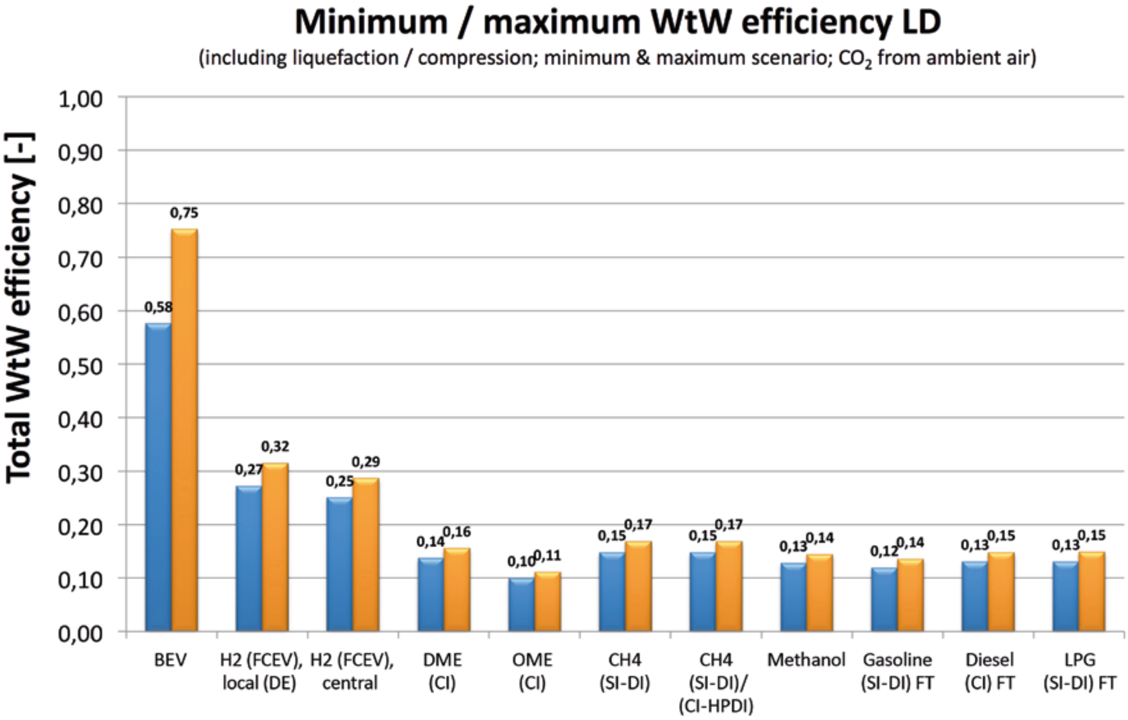


Figure 11: WtW degrees of efficiency (fuel production * car (NEDC)) – under framework conditions specified in **Table 12**

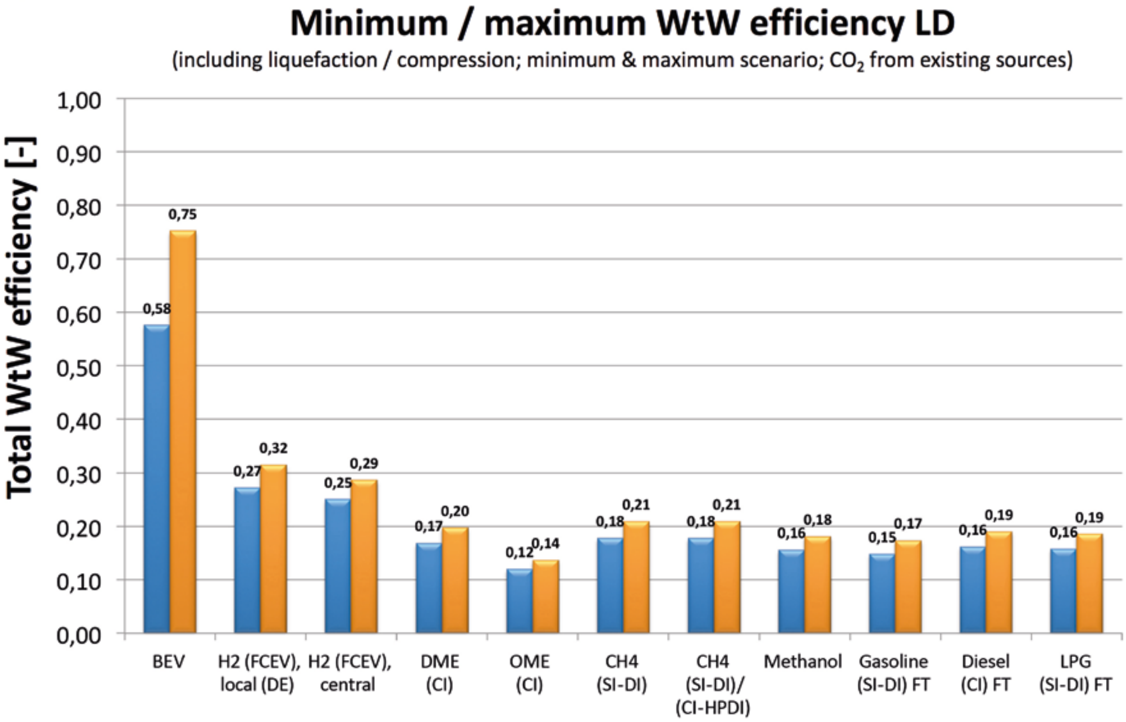


Figure 12: WtW degrees of efficiency (fuel production * car (NEDC)) – under framework conditions specified in **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

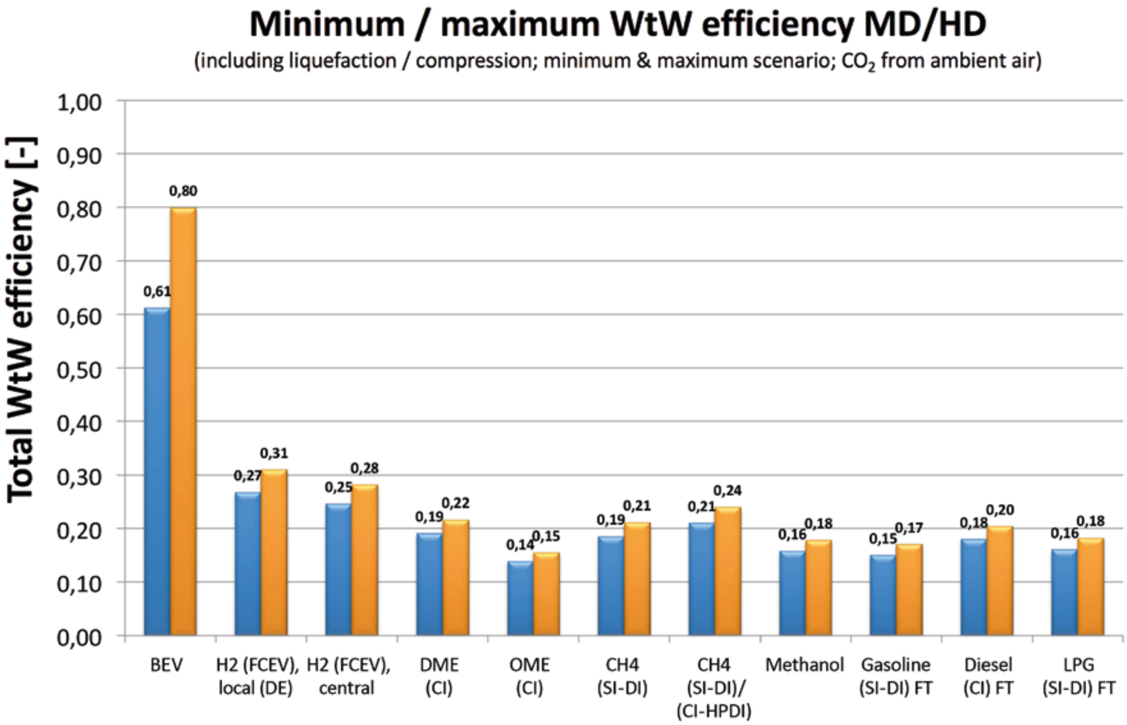


Figure 13: WtW degrees of efficiency (fuel production ⋆ truck) – under framework conditions specified in **Table 12**

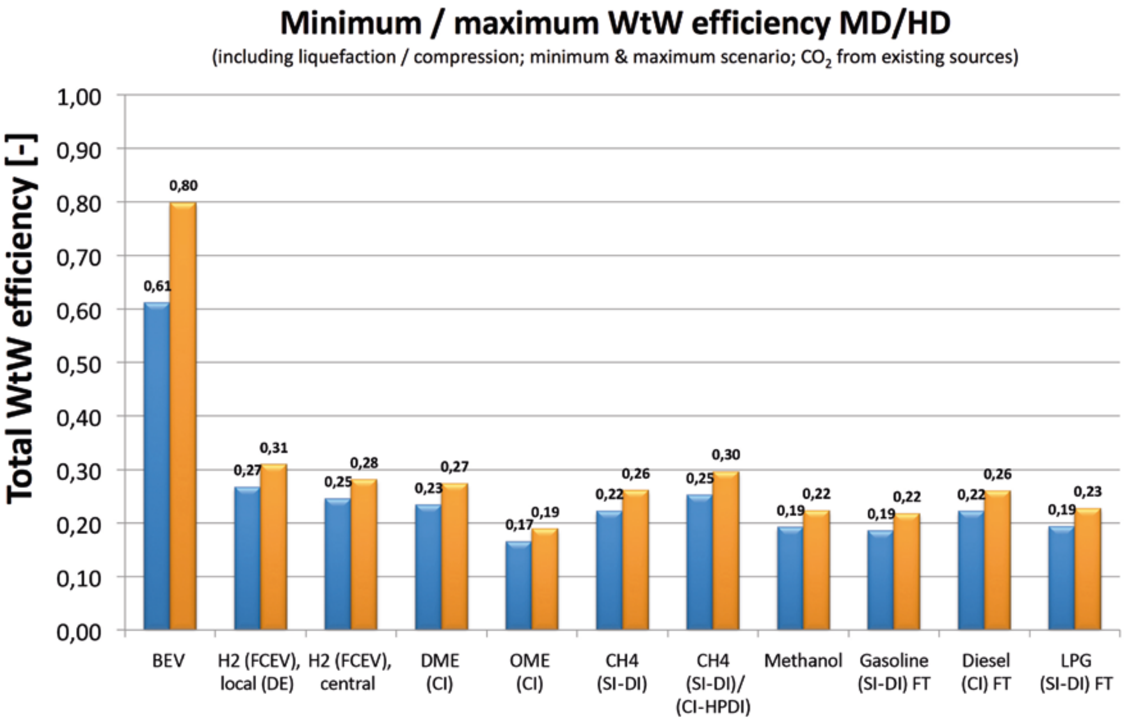


Figure 14: WtW degrees of efficiency (fuel production ⋆ truck) – under framework conditions specified in **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

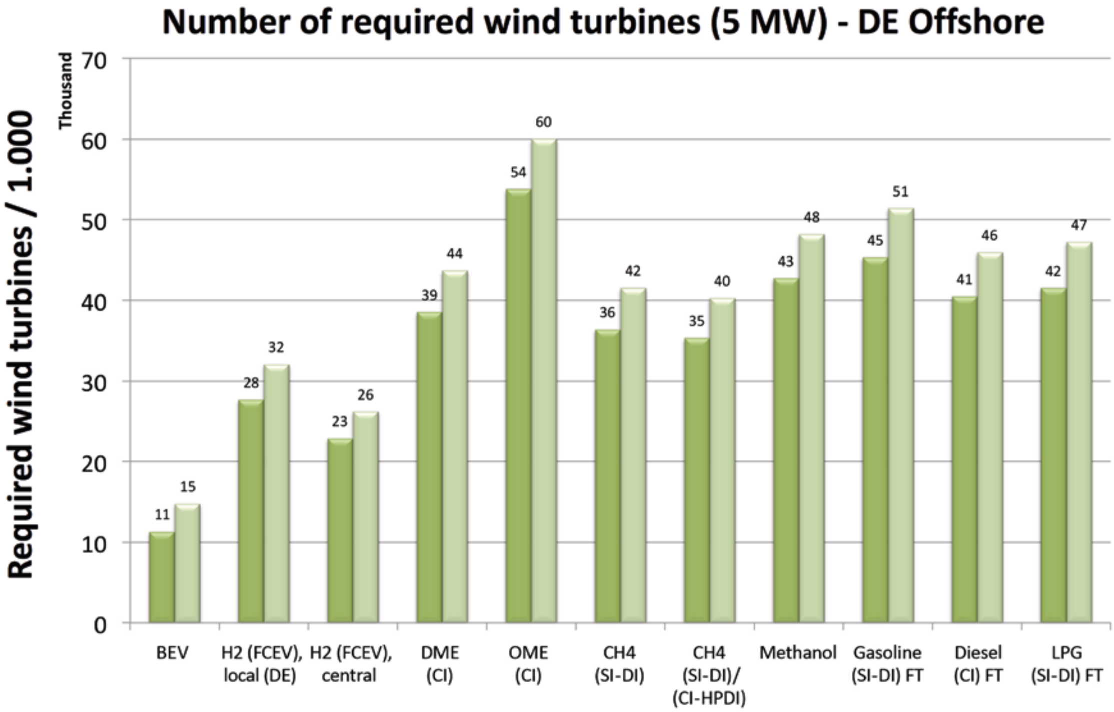


Figure 15: Theoretically required number of wind turbines (5 MW) for offshore wind power from Germany (North Sea) – comparison: max. EL degree of efficiency + CO_2 from existing sources vs. min. EL degree of efficiency + CO_2 from the air

On the basis of the primary energy requirement it is possible to estimate the theoretical number of 5-MW wind turbines that would be required to power all vehicles in Germany CO_2-neutrally and using renewable energy. **Figure 15** exclusively portrays the scenario with purely offshore wind in Germany for wind turbines with a capacity of 5 MW in two cases: a maximum electrolysis degree of efficiency and a minimum electrolysis degree of efficiency. According to this, in a pure BEV scenario almost 15,000 new wind turbines would have to be installed just to run the German fleet of cars and trucks. By way of comparison, almost 30,000 wind turbines are being operated with a significantly lower capacity in Germany today. While around 25,000 new wind turbines would be required for a central H_2 scenario, local hydrogen production would necessitate approximately 30,000 new wind turbines. In the PtX scenarios, between 35,000 to 40,000 (methane) and 55,000 to 60,000 (OME) new wind turbines would need to be installed depending on the fuel and assumed degree of efficiency.

For the FT fuels it should be taken into consideration that these can only be produced together (diesel, gasoline, LPG plus by-products). An average range will therefore establish itself between the various FT fuels.

INTERIM CONCLUSION

- For a 100 % BEV scenario (car: BEV, truck: hybrid-overhead line) the primary energy requirement would be between 249 and 325 TWh per year, which corresponds to around half of today's total electricity requirement in Germany. Around 11,000 to 15,000 new offshore wind turbines (5 MW) would have to be installed to cover this. By way of comparison, almost 30,000 wind turbines are being operated with a significantly lower capacity in Germany today. This number could be halved by building turbines with a capacity of up to 10 MW (up to 8 MW is already customary today in offshore turbines).

- For a 100 % FCEV scenario with centrally produced hydrogen, around 1.8 to 2.0 times more energy would be required than for the 100 % BEV scenario. The number of 5 MW offshore wind turbines in the North Sea would rise to between 23,000 and 26,000.

- If PtX fuels are used in combustion engines, the primary energy requirement in the best case (methane) is around 2.7 to 3.1 times greater than the energy requirement for a pure BEV scenario (corresponding to 35,000 to 40,000 5-MW offshore wind turbines); in the worst case (OME) it can be up to 4.7 times greater (corresponding to up to 60,000 5-MW offshore wind turbines).

- The well-to-wheel (WtW) degrees of efficiency for electromobility are between approximately 58 and 80 % (without taking air conditioning in BEVs into account, which reduces the degree of efficiency), while those for FCEVs are between 25 and 32 %, and the equivalent values for PtX-driven vehicles with combustion engines are in the region of 10 to 17 % for cars and 14 to 24 % for trucks. Further increases in efficiency, for example through hybridization, have not yet been taken into consideration here.

Costs (fuel, infrastructure, vehicle, operating costs)

As mentioned in the previous chapter and described in detail in **Table 12**, two scenarios are examined. In the minimum cost scenario, high degrees of efficiency are assumed – cheap CO_2 from available sources (€ 124.50 per t), a low electricity price for 2030 from MENA for an intermittent electricity supply and low purchasing costs (car costs for BEVs and FCEVs at same level as diesel, costs for equivalent spark ignition engine-powered vehicle classes € 2,400 cheaper than CI engine-powered ICEV/FCEV/BEV). In the maximum cost scenario, on the other hand, the least favorable degrees of efficiency – expensive CO_2 from the air (€ 292.80 per t), a high electricity price from Germany corresponding to that for 2015 and vehicle costs from [Berger 2016] – were assumed.

These scenarios are to be viewed as guiding figures. Both extremes are possible, while the range between them covers the lack of prediction accuracy. Therefore, no average values should be used to compare the scenarios as this would lead to false conclusions.

The same applies in principle for the fleet of trucks, although the experts from the working group did not have access to any literature sources on minimum and maximum costs for some PtX scenarios. In these cases, only one value was used. The above applies here, too: The minimum and maximum scenarios are to be viewed as aids for orientation, the direct comparison of which can lead to incorrect conclusions. A "probable" scenario was consciously omitted.

The costs for PtX production depend to a significant degree on the H_2 storage costs (pressure tanks). Today, large FT plants are not run discontinuously in regular operation, as the primary energy source is continuously available. Should electrical energy for the production of PtX fuels only be available on a volatile basis, PtX plants would also be optimized for discontinuous operation, for which reason a start-up time from standby mode of 1 to 24 hours depending on the fuel was assumed for this study. In the case of FT fuels, 24 hours was used as a basis.

For OME synthesis, the working group does not have any reliable data on the ability to start up the processes quickly. It is assumed that an OME plant displays the same characteristics as FT plants (with a start-up time of 24 hours). To ensure a robust PtX synthesis process, FT and OME plants are therefore equipped with a H_2 pressure tank designed for a duration of 24 hours. Although larger H_2 pressure tanks would increase the usable full load hours of the PtX plant, they are so expensive that their enlargement is not expected to be economically viable. An economic optimization of the H_2 tank size was not feasible within the scope of this brief study and was therefore not performed. In addition, for the further optimization of H_2 storage tank size with regard to full load hours for PtX synthesis, it would also have been necessary to examine possible solutions for replacing or supplementing the very expensive H_2 pressure tanks. For instance, solutions such as the use of storage caverns (where geographically possible), liquid storage of H_2 or the reconversion of the synthesis product for covering dark periods would be imaginable. However, the process of optimizing such a plant is not part of this study.

In contrast to complex FT PtX plants, simple PtX plants for generating methane, methanol and DME are easier to run on a discontinuous basis. A power-to-methane synthesis can be started up from standby in around 10 minutes. In the case of methanol and DME production, the experts from the working group estimate that around ½ to 1 day will be required for startup. Therefore, it is estimated that a H_2 tank storage duration of one hour is needed to start up the methane synthesis process, while 12 hours are assumed for starting up methanol and DME synthesis (both for Germany and MENA). An H_2 storage duration of six hours is assumed for H_2 liquefaction. The various H_2 storage tank sizes are to be viewed as minimum sizes and are primarily for the purpose of reliable operation of the PtX synthesis plant. They were dimensioned at precisely the size at which the plant can be started up without any faults when the tank is full. However, for brief dark periods these storage tanks also allow an increase in the number of full load hours for PtX synthesis. These were estimated using data from the Fraunhofer Institute, for MENA on the basis of [IWES 2017] and for Germany based on the offshore wind power statistics [ISE 2016].

Figure 16 contains the energy-related fuel costs in € per kWh under PtX production conditions that are currently viewed as being realistic. Due to the need to continuously provide locally produced electrical energy for electric vehicles (car: BEV, truck: hybrid-overhead line BEV) and as a result of the relatively expensive electricity price associated with this, the energy costs for the BEV scenario are € 0.11 per kWh in the cheapest case. The prices per kWh displayed for the BEV are higher than the assumed electricity prices for buffered wind energy, as transmission losses and losses relating to quick charging are included for the BEV.

In relation to the energy content, PtX fuels produced in MENA are cheaper than energy for electromobility: -27 % for hydrogen generated decentrally in MENA (€ 0.08 per kWh) and -18 % for methane produced decentrally in MENA (€ 0.09 per kWh). Locally generated hydrogen (€ 0.18 per kWh in the best case) has the lowest potential with regard to the energy-related costs: +82 % compared to BEVs.

If PtX fuels are produced centrally in Germany under the least favorable conditions (maximum cost scenario), at € 0.22 per kWh the central production of H_2 appears to be the variant with the lowest costs, followed by CH_4 (€ 0.23 per kWh) and BEVs (€ 0.25 per kWh, constant electrical power supply). FT fuels can cost up to € 0.32 per kWh and OME up to € 0.37 per kWh.

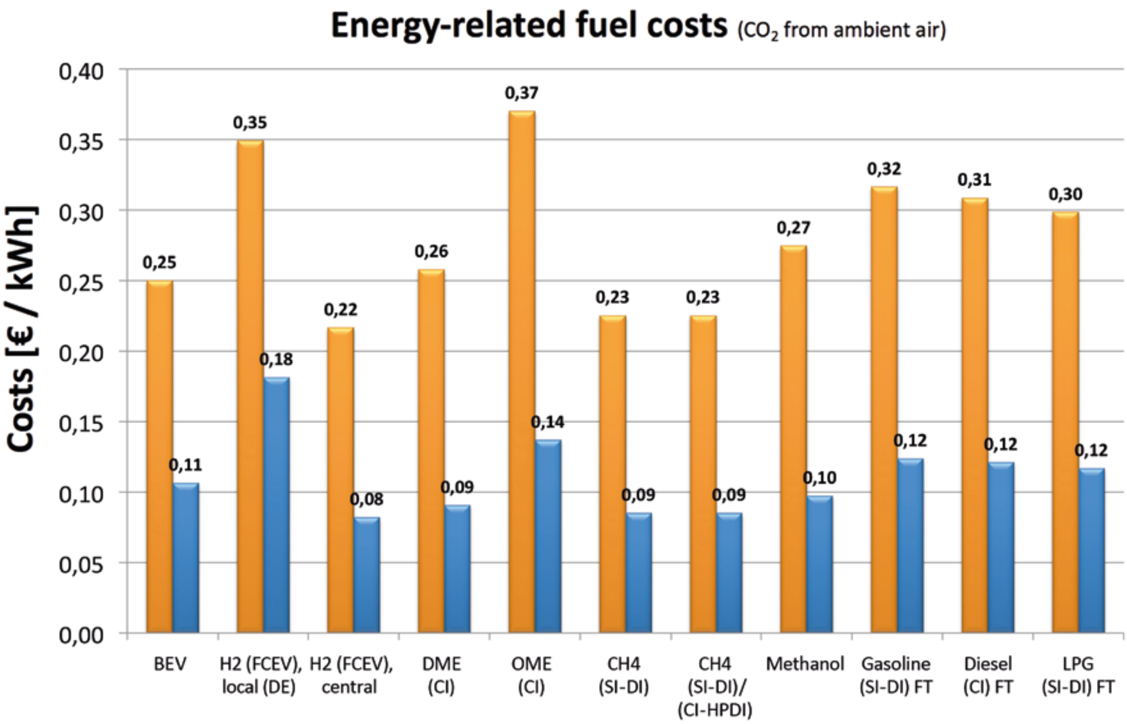


Figure 16: Energy-related fuel costs (min./max.) [€/kWh] – under the framework conditions specified in **Table 12**

Figure 17 contains the energy-related fuel costs in € per kWh under the assumption that CO_2 from industrial processes is available for free and without any additional energy expenditure. This would reduce the costs for PtX fuels by around € 0.04 to € 0.09 per kWh. As a result, at € 0.06 per kWh, methane and DME produced in MENA would be significantly cheaper than a constant electrical power supply produced in Germany (€ 0.11 per kWh).

Figure 18 and **Figure 20** show the distance-related fuel costs for cars and trucks in € per 100 km. Due to the better degree of efficiency in BEVs, the purely electric variants, i. e. BEVs (cars) and HO-BEVs (trucks), are the cheapest solution with regard to distance-related fuel costs.

When H_2 is produced centrally, the distance-related fuel costs for FCEVs are higher than those for BEVs; by 32 % (car) to 42 % (truck) for production in MENA (minimum cost scenario), and by 48 % (car) to 60 % (truck) for central H_2 production in Germany (maximum cost scenario).

With cheap PtX fuels for combustion engines, the distance-related fuel costs are slightly higher than with an FCEV. Methane appears to be the cheapest variant here. When methane is produced centrally in MENA (minimum cost scenario), the fuel costs are 62 % (HPDI truck) and 116 % (car) higher than those for the BEV; when methane is produced centrally in Germany (maximum cost scenario) they are 85 % (HPDI truck) and 146 % (car) higher.

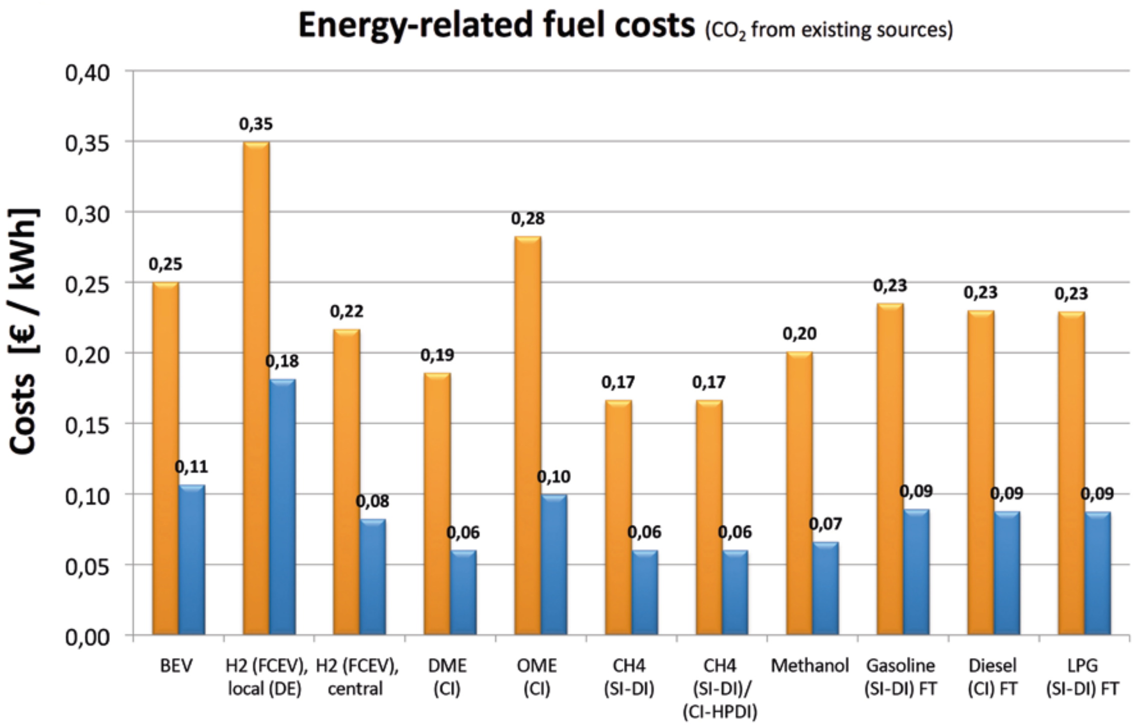


Figure 17: Energy-related fuel costs (min./max.) [€/kWh] – under the framework conditions specified in **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

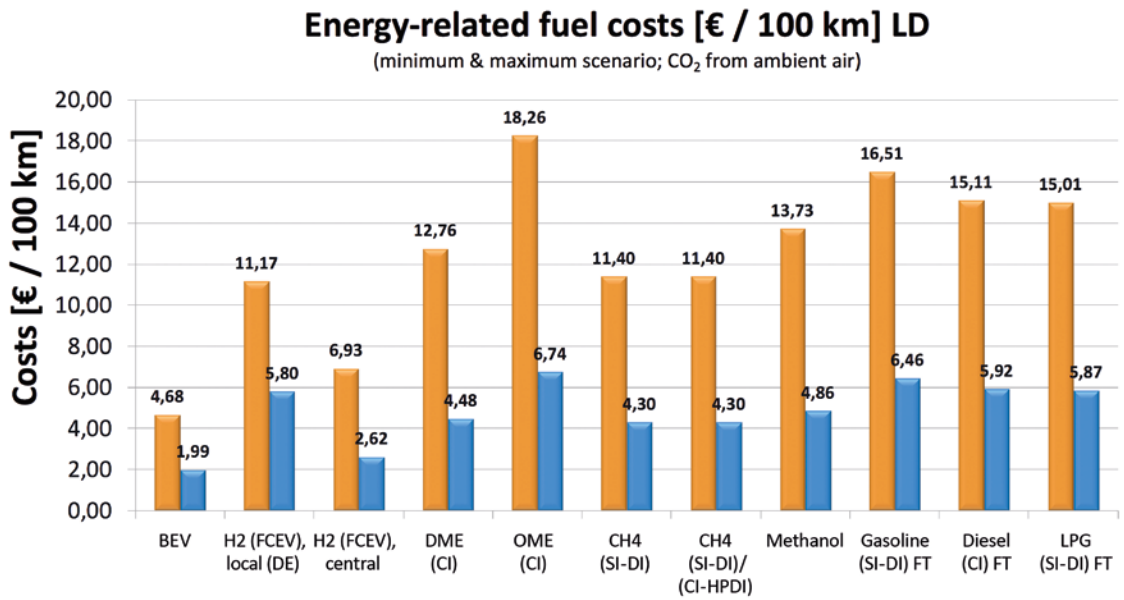


Figure 18: Min./max. fuel costs for cars [€/100 km] – under the framework conditions specified in **Table 12**

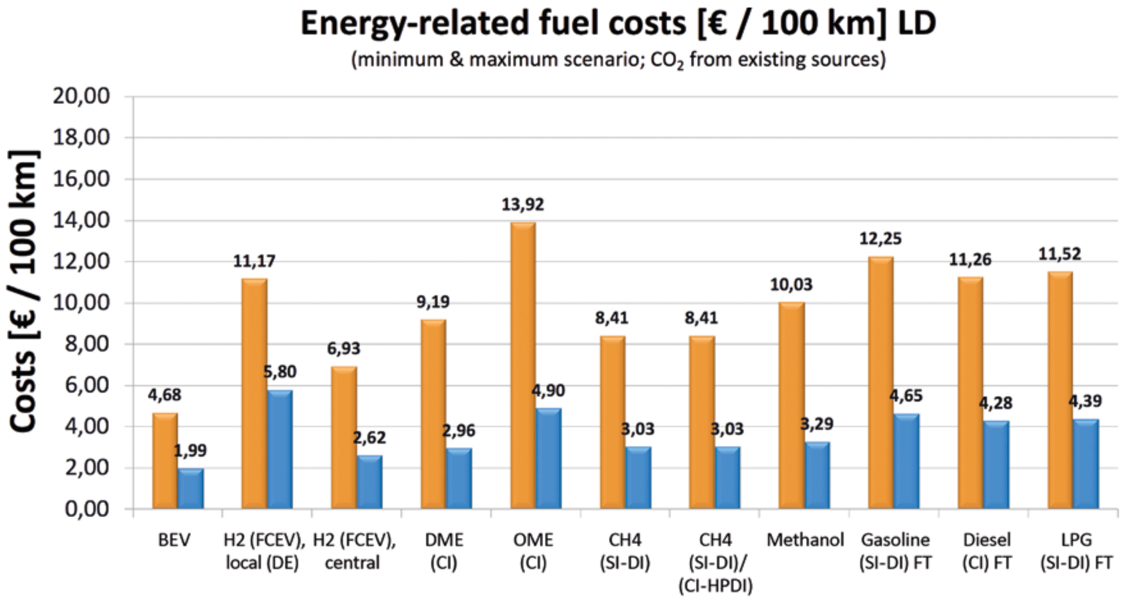


Figure 19: Min./max. fuel costs for cars [€/100 km] – under the framework conditions specified in **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

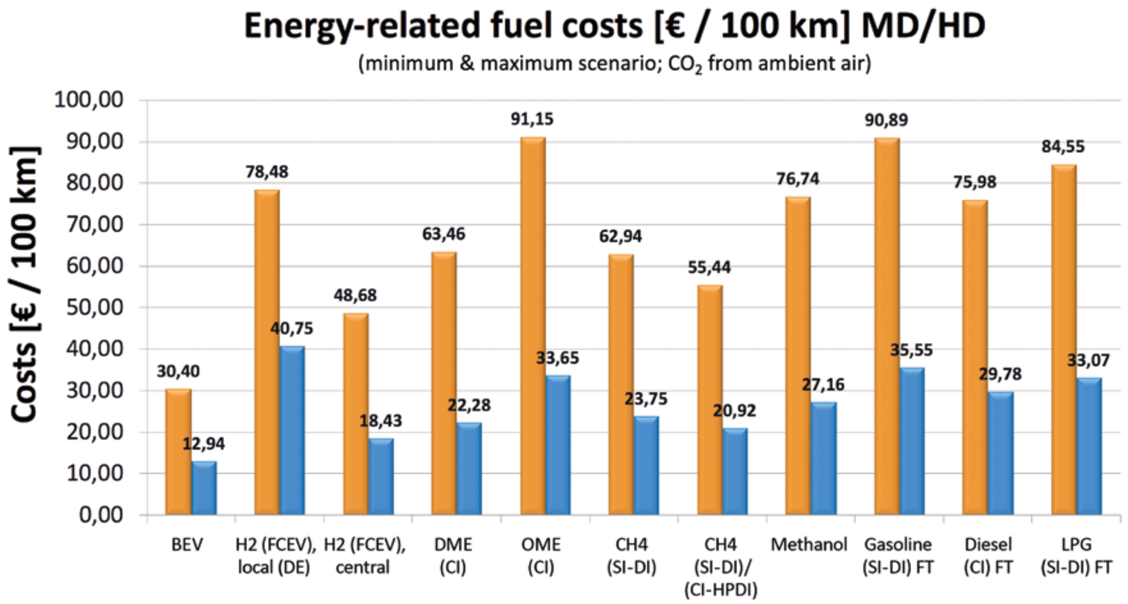


Figure 20: Min./max. fuel costs for trucks [€/100 km] – under the framework conditions specified in **Table 12**

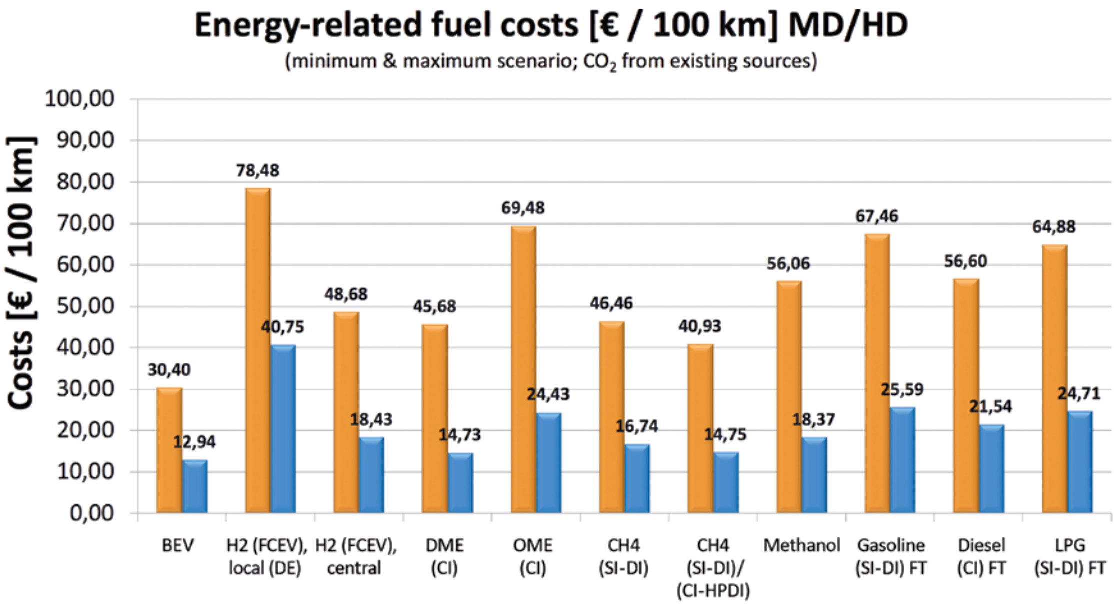


Figure 21: Min./max. fuel costs for trucks [€/100 km] – under the framework conditions specified in **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

Figure 19 and **Figure 21** show the distance-related fuel costs for cars and trucks in € per 100 km in the case that no CO_2 separation from the air is necessary. The fuel costs are significantly reduced.

A truck run on e-methane or E-DME would be cheaper to operate per kilometer than a fuel cell vehicle. The fuel costs would be only 10 to 50 % higher than those for a hybrid-overhead line truck.

Figure 22 and **Figure 23** show the total distance-related fuel costs plus infrastructure costs for cars and trucks. The assumptions made for the infrastructure are shown in **Table 12**. The distribution infrastructure for electrical energy and for fuel is amortized over 40 years, with the total costs for building the infrastructure being distributed among all vehicles in Germany (this is performed separately for trucks and cars with their own fueling infrastructures). Due to the uncertainty in predicting the costs for expanding the electricity grid, the forecast for electric vehicles also becomes less precise when infrastructure costs are taken into account.

When infrastructure costs are added to fuel costs for cars, the cost potential (i. e. assuming the most favorable conditions) for the methane, DME and methanol variants are in a similar range from between € 4.36 to € 4.86 per 100 km. At € 2.50 per 100 km, BEVs have far greater potential. FCEVs (centrally produced H_2) are in between the two at € 3.01 per 100 km, while the minimum costs for the other fuels are significantly higher (> € 5.89 per 100 km).

When infrastructure costs are added to fuel costs for trucks, the scenarios HO-BEV, FCEV (central H_2), methane (HPDI) and DME display similar cost potential (€ 19.26 to € 22.32 per 100 km). The minimum costs for liquid fuels are considerably higher (> € 27.17 per 100 km).

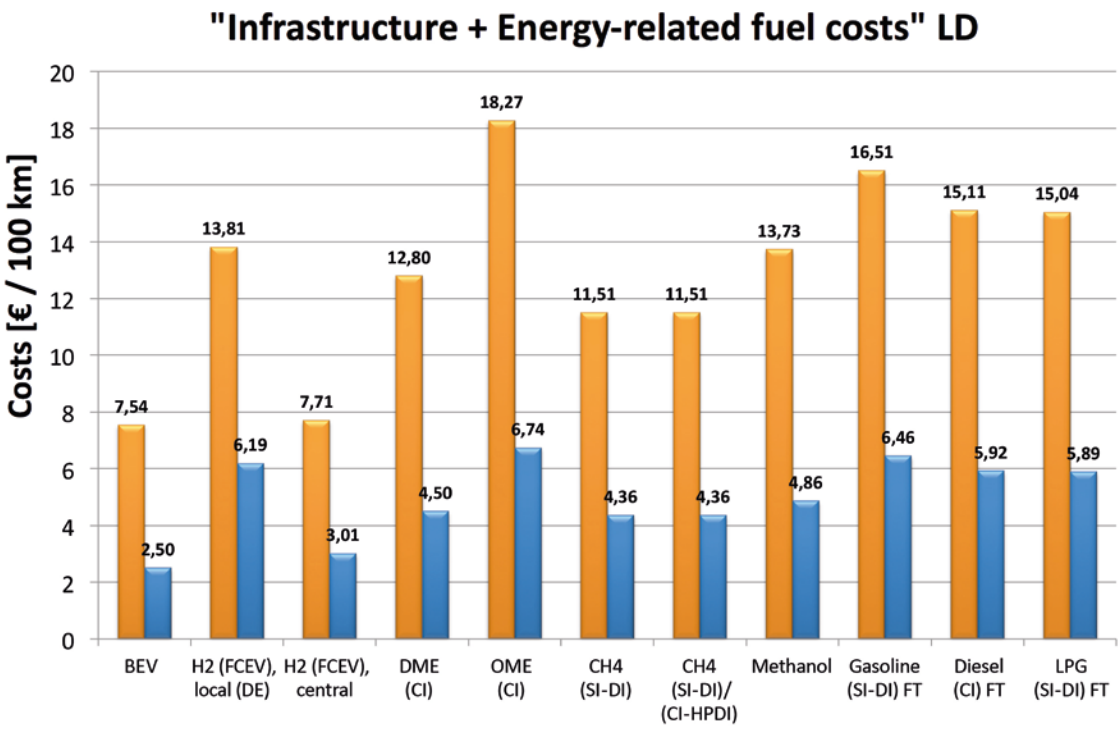


Figure 22: Min./max. total: fuel and infrastructure costs for cars [€ /100 km] – framework conditions as per **Table 12**

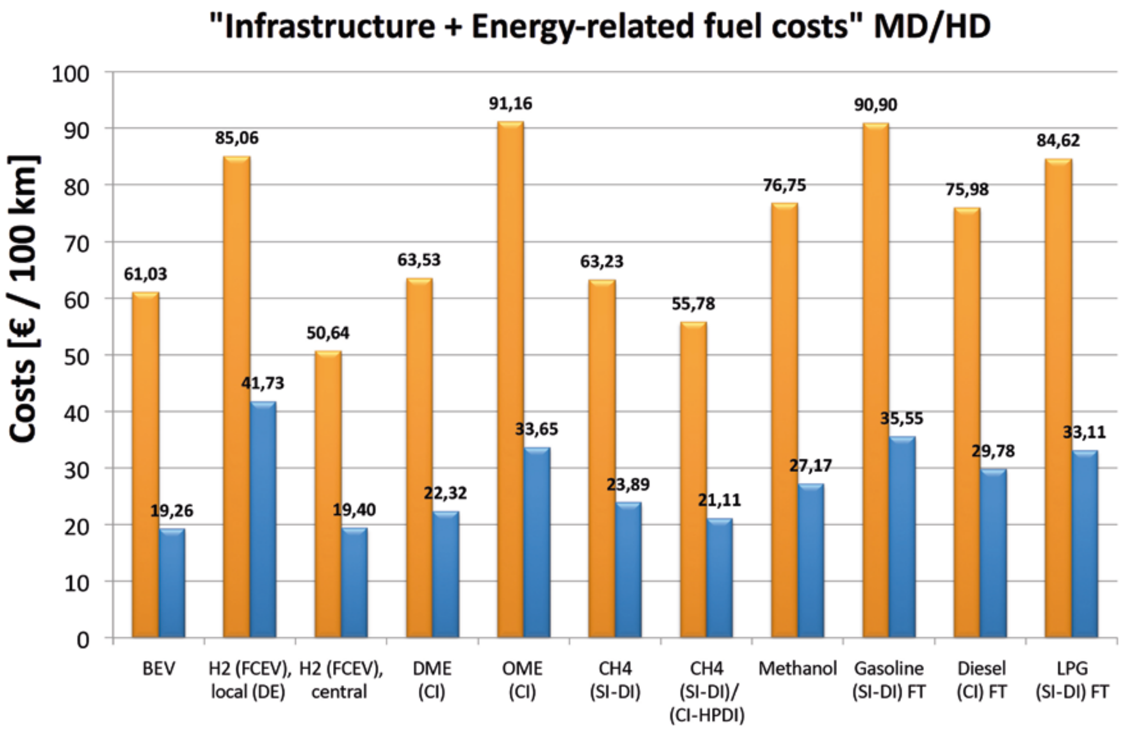


Figure 23: Min./max. total: fuel and infrastructure costs for trucks [€/100 km] – framework conditions as per **Table 12**

Figure 24 shows the mobility costs for the various car scenarios, while **Figure 26** illustrates those for the truck scenarios.

The mobility costs consist of the total fuel costs, the applied infrastructure costs and the vehicle costs. For calculating the car costs, a typical compact segment vehicle was assumed (e.g. Volkswagen Golf, Opel Astra, Ford Focus) costing €20,000 and the depreciation was calculated according to [ADAC 2016]. The depreciation was determined in € per 100 km on the basis of an ownership period of four years and an annual kilometrage of 15,000 km. For truck costs, a long-distance trailer truck for a selling price of €90,400 was taken as the basis. Further assumptions on the vehicle costs can be found in **Table 12**. As can be seen in the cost comparisons "fuel + infrastructure (**Figure 22** and **Figure 23**) vs. mobility costs (**Figure 24** and **Figure 26**)", mobility costs are dominated by vehicle costs, particularly when it comes to cars.

Because future surcharges for vehicles, in particular those for BEVs and FCEVs compared to diesel and gasoline variants, are very difficult to predict, there is a significant degree of uncertainty in the assessment of future mobility costs.

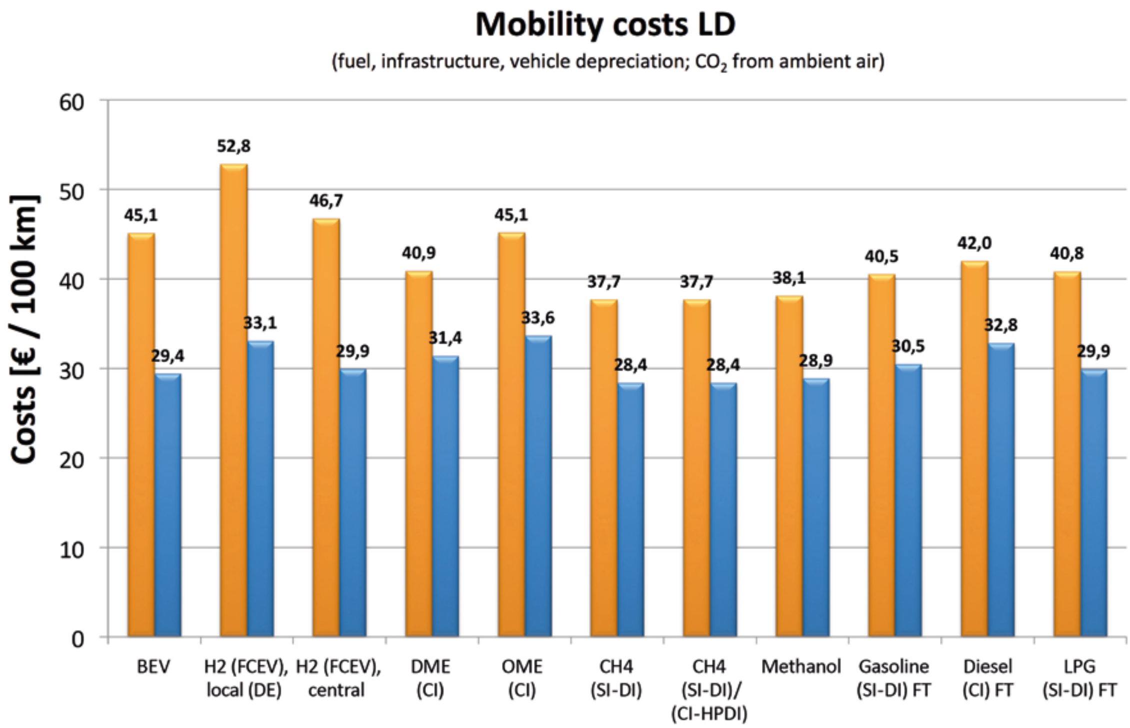


Figure 24: Min./max. mobility costs for cars [€ / 100 km] – framework conditions as per **Table 12**

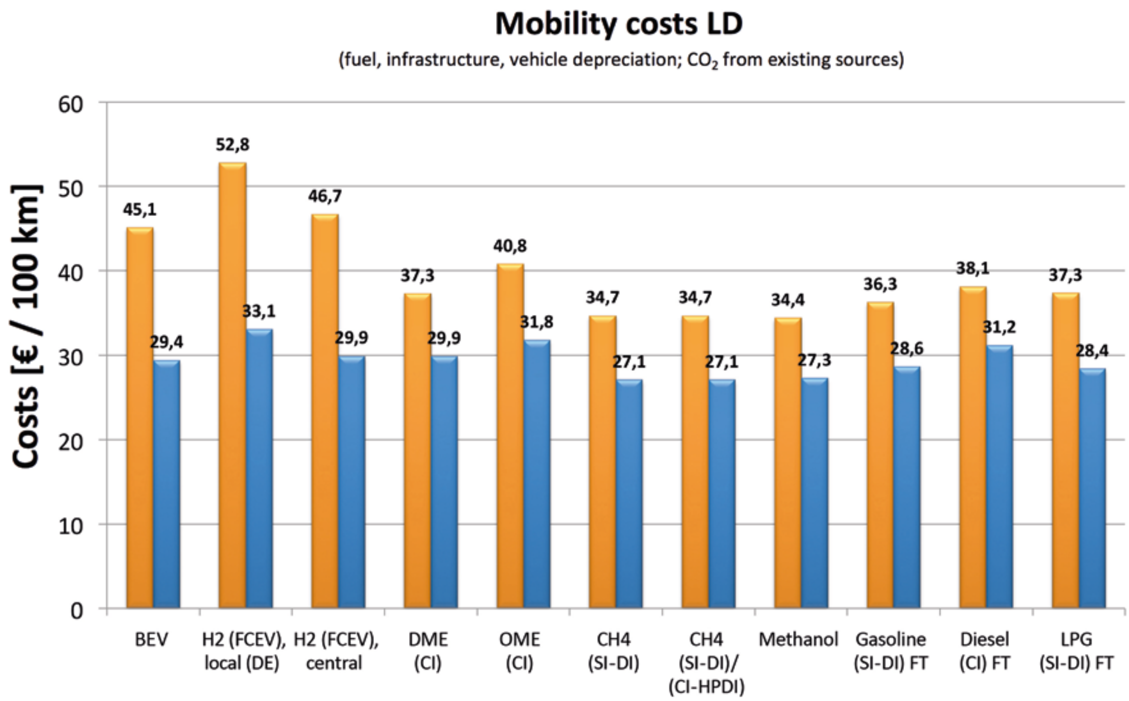


Figure 25: Min./max. mobility costs for cars [€ /100 km] – framework conditions as per **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

The minimum car mobility costs (minimum cost scenario) for cheap PtX fuels for combustion engines produced centrally in MENA (CH_4, methanol: € 28.40 to € 28.90 per 100 km) and H_2 (central: € 29.90 per 100 km) are on the same level for FCEVs as for BEVs (central: € 29.40 per 100 km).

When examining the maximum mobility costs for cars (maximum cost scenario: production in Germany, minimum degree of efficiency for electrolysis, maximum estimated additional vehicle costs), use of the PtX fuels methanol and methane in an optimized combustion engine is the cheapest variant (around € 38 per 100 km). At approximately € 40 to € 42 per 100 km, FT fuels are also significantly below the BEV cost risk (around € 45 per 100 km). H_2 produced centrally in Germany and used in FCEVs is still slightly more expensive than BEVs (approximately € 47 per 100 km).

In this assessment (maximum cost scenario), locally generated H_2 used in an FCEV is also the most expensive solution (around € 53 per 100 km).

When observing the **minimum mobility costs for trucks** (minimum cost scenario), DME produced in MENA (approximately € 70 per 100 km) is the most advantageous solution, followed by methane (HPDI) and centrally produced H_2 (FCEV) from MENA (approximately € 74 per 100 km). Methane (λ=1) and methanol were slightly more expensive (around € 74 and € 75 per 100 km respectively). BEVs come behind these at around € 76 per 100 km. Locally generated hydrogen used in an FCEV is the most expensive solution by far (around € 96 per 100 km).

When observing the **maximum mobility costs for trucks** (maximum cost scenario), the HPDI truck run on methane (€ 108 per 100 km) was the most cost-effective solution, followed by the DME truck (around € 111 per 100 km) and the fuel cell truck (H_2 produced centrally in Germany) (approximately € 121 per 100 km). The hybrid-overhead line truck follows these (around € 124 per 100 km). FT diesel is at virtually the same level (around € 123 per 100 km), but can only be produced together with other components, which are significantly more expensive when calculated separately (FT gasoline approximately € 139 per 100 km, FT LPG approximately € 132 per 100 km). OME is more expensive again (around € 139 per 100 km).

Locally generated hydrogen used in an FCEV (maximum cost scenario) harbors the greatest cost risk (around € 155 per 100 km).

Figure 25 and **Figure 27** show the mobility costs for cars and trucks in € per 100 km in the case that no CO_2 separation from the air is necessary. For cars, the mobility costs for the PtX scenarios would fall by around 5 to 10 %, while those for trucks would fall by approximately 10 to 15 %. In both cases, the mobility costs with cheap PtX fuels tend to appear lower than in the BEV and FCEV scenarios.

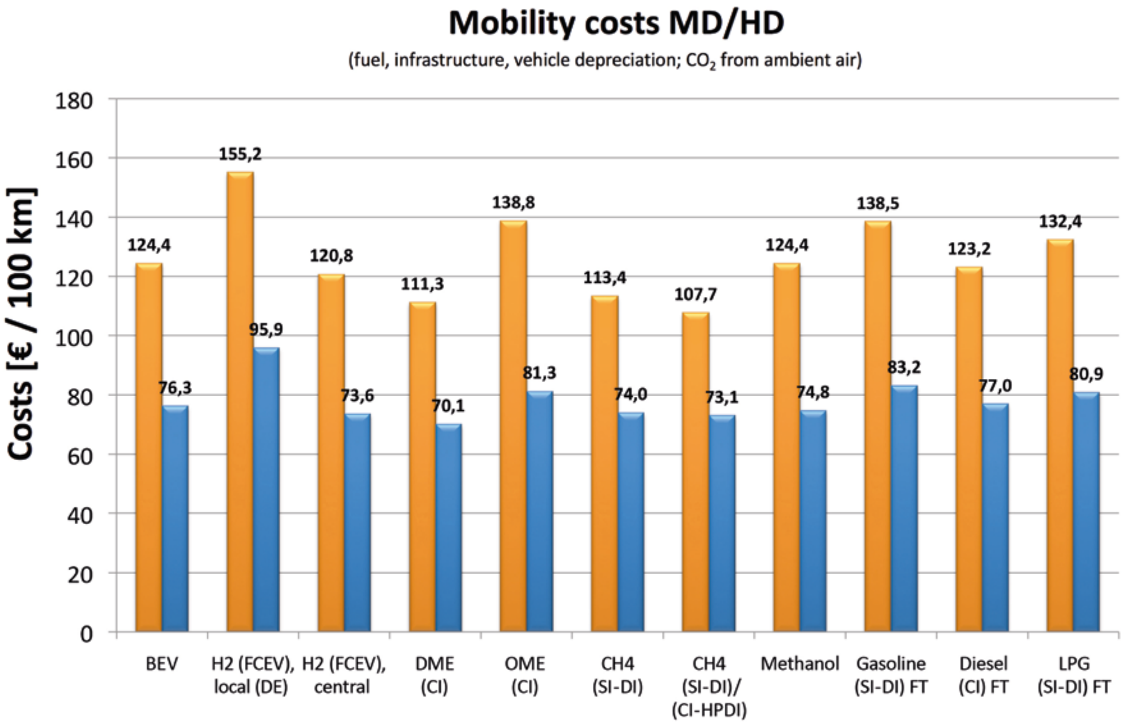


Figure 26: Min./max. mobility costs for trucks [€/100 km] – framework conditions as per **Table 12**

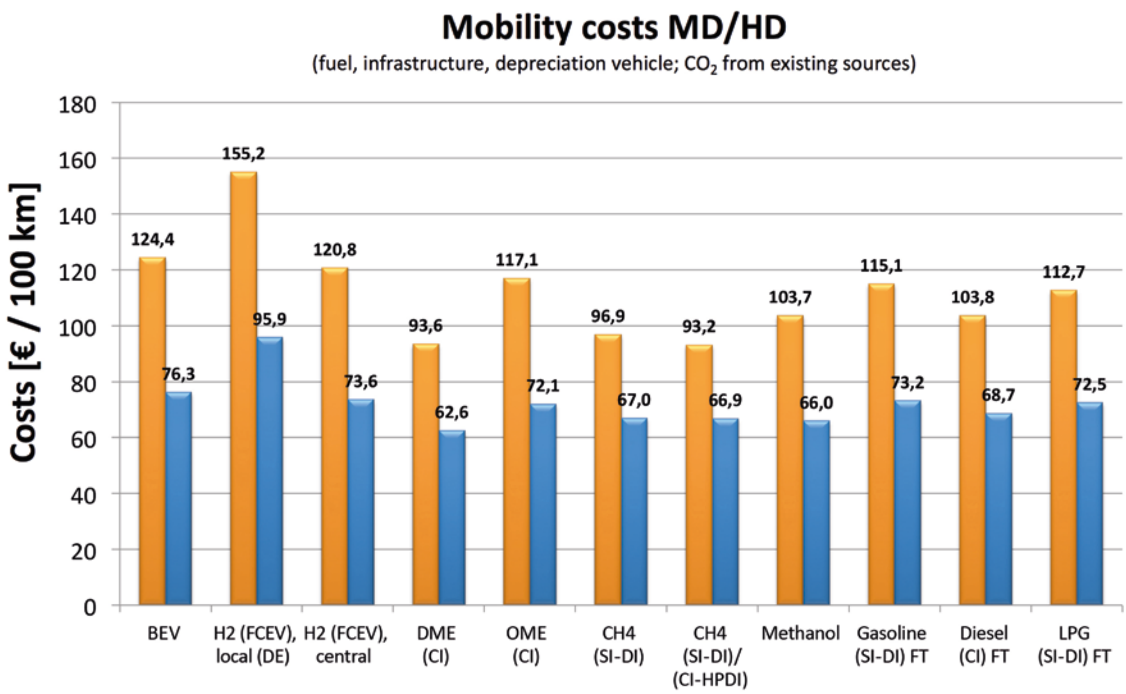


Figure 27: Min./max. mobility costs for trucks [€/100 km] – framework conditions as per **Table 12**, but without taking into account the energy requirement for CO_2 separation (assumption: CO_2 from existing sources)

SUMMARY **costs for electricity**

- The necessary electrical energy for BEVs must be available as required at any time. Therefore, it is necessary for the energy supplier to provide these vehicles with "buffered electricity". As a result, the average degree of efficiency when supplying electricity for e-vehicles is lower and the electricity purchase costs are significantly higher than when 100 % of the produced electricity is used directly. In the scenario entailing 100 % renewable electricity generated predominantly from wind and solar energy in Germany (and also in the EU), which is assumed in this case, it is predicted that buffering of approximately 20 % of generated energy in stores (including seasonal stores such as PtX) will be indispensable.

- As a result of the buffering of 20 % of electrical energy, the electricity price doubles in the domestic constant electrical power supply scenarios. For example, volatile wind electricity from the North Sea cost just € 88 per MWh in 2017, while a figure of around € 180 per MWhs is expected for a constant electrical power supply. Volatile electricity produced in MENA can also be used in all central e-fuel scenarios. At approximately € 24 per MWh, in the future this is anticipated to be cheaper than the volatile North Sea electricity generated in 2017 by a factor of 3 to 4.

SUMMARY **energy and fuel costs**

- In the most favorable case the energy costs for the BEV scenario amount to € 0.11 per kWh (constant electrical power supply costs); these are higher than the pure production costs due to the buffer storage costs and losses and include transmission and charging losses.

- If PtX fuels are produced centrally in Germany under the least favorable conditions (maximum cost scenario), at € 0.22 per kWh the central production of H_2 appears to be the variant with the lowest costs per unit of energy, followed by methane (€ 0.23 per kWh), DME (€ 0.26 per kWh) and methanol (€ 0.27 per kWh). FT fuels can cost up to € 0.32 per kWh and OME up to € 0.37 per kWh. By way of comparison, in this maximum cost scenario, the reliably available electricity for BEVs, including losses during quick charging, will cost € 0.25 per kWh on average. Unlike the energy used in electric vehicles, all fuels can also be produced in MENA instead of Germany, and under significantly more favorable conditions. Under the most favorable conditions (minimum cost scenario, MENA), hydrogen can be produced for € 0.08 per kWh, followed by methane and DME (€ 0.09 per kWh), methanol (€ 0.10 per kWh), FT fuels (€ 0.12 per kWh) and OME (€ 0.14 per kWh). By way of comparison, a constant electrical power supply for BEVs produced in Germany under the most favorable circumstances would cost € 0.11 per kWh.

- Due to the better degree of efficiency in electric vehicles, the purely electric variants, i.e. BEVs (cars) and HO-BEVs (trucks), are the cheapest solution with regard to distance-related operating costs.

- When H_2 is produced centrally in MENA (minimum cost scenario), the distance-related fuel costs for FCEVs are 42 % (truck) or 32 % (car) higher than those for BEVs; when H_2 is produced centrally in Germany (maximum cost scenario) they are 60 % (truck) and 48 % (car) higher.

- Even with the cheap PtX fuels for combustion engines, the distance-related fuel costs are higher than with a BEV or FCEV. Methane appears to be the cheapest variant here. When methane is produced centrally in MENA (minimum cost scenario), the fuel costs are 62 % (HPDI truck) and 116 % (car) higher than those for the BEV; when methane is produced centrally in Germany (maximum cost scenario) they are 85 % (HPDI truck) and 146 % (car) higher.

SUMMARY fuel costs and proportion of distribution infrastructure

- If the distribution infrastructure costs are considered for cars in addition to the fuel costs, the BEV scenario remains the cheapest scenario: BEV (€ 2.50 per 100 km), followed by centrally produced H_2 (€ 3.01 per 100 km), methane (€ 4.36 per 100 km), DME (€ 4.50 per 100 km) and methanol (€ 4.86 per 100 km).

- When infrastructure costs are added to fuel costs for trucks, the BEV and central H_2 variants display similar cost potential (around € 19 per 100 km). Methane (HPDI, around € 21 per 100 km) and DME (around € 22 per 100 km) are slightly more expensive.

SUMMARY mobility costs

- For cars in particular, mobility costs are dominated by vehicle costs (vehicle depreciation + proportion of infrastructure costs + fuel before tax). For cars from the compact vehicle segment (Ford Focus, Volkswagen Golf, Opel Astra, etc., costing around € 20,000), the acquisition costs including depreciation are many times higher than the costs for the energy source (before tax) and for infrastructure.

- Because future surcharges for vehicles, in particular for BEVs and FCEVs, are very difficult to predict compared to diesel and gasoline variants, there is a significant degree of uncertainty in the assessment of future mobility costs.

- If cost parity is assumed between BEVs, FCEVs and diesel-driven vehicles (minimum cost scenario), similar mobility costs are achieved for all scenarios.

- When examining the maximum mobility costs for cars (maximum cost scenario: production in Germany, minimum degree of efficiency for electrolysis, maximum estimated additional vehicle costs for 2030 according to [Berger 2016], high estimate of infrastructure costs for expansion of electricity grid), use of the PtX fuels methanol and methane in an optimized combustion engine is the cheapest variant (around € 38 per 100 km). At approximately € 40 to € 42 per 100 km, FT fuels are also significantly below the BEV cost risk (around € 45 per 100 km). Mobility with hydrogen produced centrally in Germany can be even more expensive (approximately € 47 per 100 km). Locally generated hydrogen used in an FCEV is the most expensive solution in the maximum cost scenario by a great margin (around € 53 per 100 km).

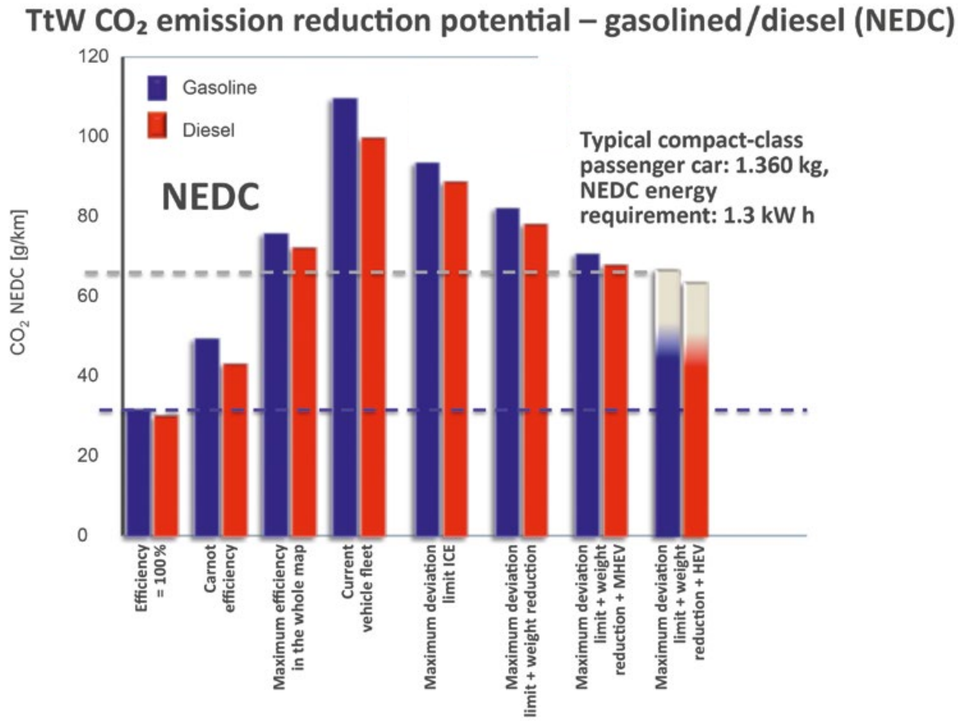


Figure 28: TtW CO_2 emission limits with gasoline and diesel powertrains [Kramer 2017] [Maas et. al. 2016]

Attainability of TtW CO_2 emissions

Based on the current state of the art, the CO_2 efficiency was assessed for each of the observed scenarios on the basis of a tank-to-wheel efficiency analysis. The currently valid NEDC test cycle is used for these efficiency analyses. Information on this cycle is freely available.

The most important results from the individual analyses can be classified in three main scenarios and evaluated:

a) BEV – purely battery electric mobility: Battery electric vehicles (BEVs) are classified as being CO_2-neutral in line with current TtW legislation. Furthermore, purely battery electric vehicles do not produce any local emissions.
b) FCEV – hydrogen-based fuel cell vehicles: Due to the technology used, fuel cell vehicles also produce no local emissions. They enable CO_2-neutral mobility on the basis of current legislation.
c) Vehicles with combustion engines: Vehicles with combustion engines emit CO_2 due to the system used. According to the TtW assessment used as a legal basis, this form of mobility cannot be described as CO_2-neutral, as shown in **Figure 28**. It should be noted that Figure 28 only shows the technologically attainable CO_2 emission limits for a compact segment vehicle in the NEDC. Considerably higher limits must be set for the WLTP cycle and for larger vehicles (e.g. SUVs).

Low-carbon fuels (LCF) can also contribute to a reduction of TtW CO_2 emissions. The TtW CO_2 advantages of various fuels are shown in **Figure 29**.

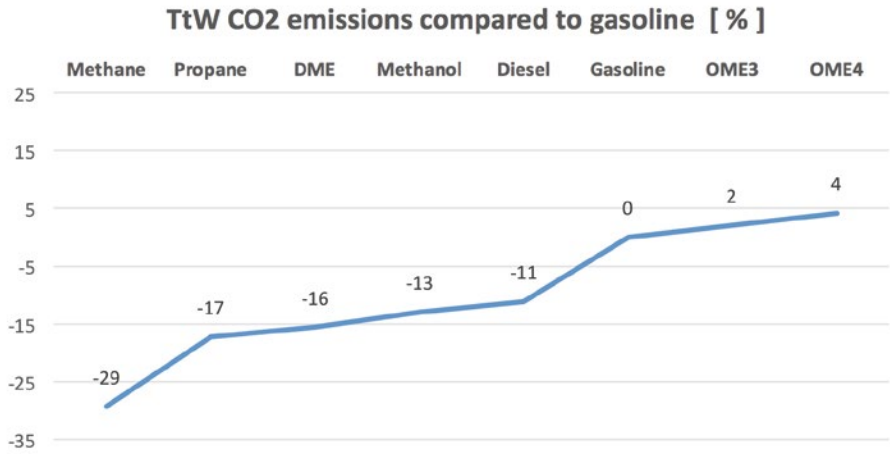


Figure 29: TtW CO_2 emissions of various fuel-powertrain paths compared to the spark ignition engine run on gasoline

SUMMARY attainability of TtW CO_2 emission reduction objectives

- Although the CO_2 emitted by a vehicle may appear irrelevant in a closed CO_2 cycle, a TtW assessment is relevant according to current European legislation (tank-to-wheel (TtW) objective), in particular because fossil energy sources are still used during the transition period – in contrast to the scenarios with 100 % renewable energies described in this study.
- Fuels with a favorable C/H ratio for reducing CO_2 emissions (low-carbon fuels, LCF) can contribute toward lowering TtW CO_2 emissions.
- With methane, for example, CO_2 emissions can be improved by around 29 % compared to gasoline-driven vehicles because of the optimal C/H ratio and the possibilities for optimizing the engine that are offered by the fuel's high degree of knock resistance.
- On the other hand, using OME fuels (from C2) in an auto-ignition engine brings about an increase in TtW CO_2 emissions, for example of 13 to 15 % for OME 3-4 compared to diesel or 2 to 4 % compared to gasoline in a spark ignition engine.

Attainability of zero-impact emissions

Driving without producing any local emissions is only possible with BEVs, FCEVs and combustion powertrains in plug-in hybrid form. Pollutant emissions can be reduced to a great extent through engine optimization and new developments in exhaust gas treatment. New vehicle concepts enable mobility with zero-impact emissions regardless of the fuel. This means that the exhaust emissions of vehicles with combustion engines are at the boundary of metrological detectability and that the environmental impact is below the permitted limit values specified in the German Federal Immission Control Act (BImSchG).

	NOx	Soot PM	Soot PN	NMHCs/VOCs
BEV				
H_2 (FCEV)				
DME (CI)	Lower raw emissions than diesel (no NOx-soot tradeoff) R&D required Low temperature	Non-critical Technology known	Technology known With current measurement technology Particles < 23 nm R&D required	R&D required Low temperature and at extremely high EGR rate
OME (CI)	Lower raw emissions than diesel (no NOx-soot tradeoff) R&D required Low temperature	Non-critical Technology known	Technology known With current measurement technology Particles < 23 nm R&D required	R&D required Low temperature and at extremely high EGR rate
Methane - CH_4 (SI, DI)	Non-critical Technology known	Non-critical Technology known	Non-critical with current measurement technology Particles < 23 nm R&D required	Non-critical Technology known
Methane - CH_4 (CI truck + SI, DI car)	Lower raw emissions than diesel (no NOx-soot tradeoff) R&D required Low-temperature technology	Non-critical Technology known	Technology known With current measurement technology Particles < 23 nm R&D required	R&D required Low temperature and at extremely high EGR rate
Methanol (M100) (SI)	Non-critical Technology known	Non-critical Technology known	Technology known With current measurement technology Particles < 23 nm R&D required	Increased R&D requirement Cold start
Gasoline (SI) FT and MeOH synthesis	Non-critical (up to E10) Technology known	Non-critical (up to E10) Technology known	Technology known With current measurement technology Particles < 23 nm R&D required	Non-critical (up to E10) Technology known
Diesel (CI) (max. B7)	R&D required Low temperature NOx for soot filter regeneration	Non-critical Technology known	Technology known With current measurement technology Particles < 23 nm R&D required	R&D required Low temperature
Propane (SI)	Non-critical Technology known	Non-critical Technology known	Technology known With current measurement technology Particles < 23 nm R&D required	Non-critical Technology known

Table 15: Evaluation of attainability and maturity of technology for zero-impact emissions

Color coding	Green = suitable (technically solved, economically viable, non-hazardous)	Orange = not suitable

Table 16: Color coding for evaluation matrices

	CO	N_2O	NH_3	CH_4	Formaldehyde
	R&D required Low temperature	R&D required Low temperature	R&D required AMOX catalyst	Non-critical Technology known	R&D required Low temperature, close to lambda 1
	R&D required Low temperature	R&D required Low temperature	R&D required AMOX catalyst	Non-critical Technology known	R&D required Low temperature, close to lambda 1
	Non-critical Technology known	Non-critical Technology known	Non-critical Technology known	Non-critical Technology known	Non-critical Technology known
	R&D required Low temperature	R&D required Low temperature	R&D required AMOX catalyst	R&D required CH_4 catalyst for lean-burn gasoline engines with long-term stability	R&D required Low temperature, close to lambda 1
	Increased R&D requirement Cold start	Non-critical Technology known	Non-critical Technology known	Non-critical Technology known	R&D required
	Non-critical (up to E10) Technology known	Non-critical (up to E10) Technology known	Non-critical (up to E10) Technology known	Non-critical (up to E10) Technology known	Non-critical (up to E10) Technology known
	R&D required Low temperature, soot filter regeneration	R&D required Low-temperature technology	R&D required AMOX catalyst	Non-critical Technology known	Non-critical Technology known
	Non-critical Technology known	Non-critical Technology known	Non-critical Technology known	Non-critical Technology known	Non-critical Technology known

	Yellow = increased need for further research (possibly critical)	Blue = need for further research (not critical)

An estimate of the level of technological maturity and research required for achieving the goal of zero-impact emissions with the various combustion engine paths is shown in **Table 15**. An explanation of the color coding can be found in **Table 16**.

SUMMARY attainability of zero-impact emissions:

- Zero-impact emission mobility is achievable with all examined combustion engine concepts (concentration of emissions below permitted limit values).

Safety in transport and handling

Safety aspects when transporting and handling liquid and gaseous fuels

For this examination of the safety aspects of storage, transportation and distribution, the hazard potential of the substance, the storage and transport conditions and the resulting hazards will be taken into account, as well as aspects relating to the fueling process. The fueling process is a particular hazard source in this connection, as it has to be performed safely by people who are not trained or experienced.

The potential dangers of fuel production and energy generation are not part of this assessment. This also applies for the quantities of fuel in the vehicle tank which may escape in the event of an accident. In this context, it should be noted that vehicles are specially designed and manufactured in accordance with relevant standards and guidelines in order to minimize the risk even in the event of an accident.

The handling of electricity requires a separate assessment, as this form of energy has fundamentally different properties to the other liquid and gaseous fuels.

The hazard potentials inherent to the fuels are listed in full in the safety data sheets. The provisions laid down in the German Chemicals Act (ChemG) and in particular the REACH regulation apply for placing these substances on the market, handling them and for consumer protection. Furthermore, the provisions of the German Ordinance on Industrial Safety and Health (BetrSichV) and the European Agreement concerning the International Carriage of Dangerous Goods by Road (ADR) also apply.

There is also a multitude of technical rules that substantiate the legal regulations and thereby describe the requirements that enable safe handling of these substances on an everyday basis.

The hazard potential of individual fuels is described in more detail in the “Safety” appendix. This describes the factors that could influence the probability of an incident occurring and that thus require particular attention when filling the respective fuel.

To sum up, the assessment shows that liquid fuels such as methanol or e-gasoline can harbor significant hazard potential. This is mainly due to the fact that such substances are flammable or highly flammable, have toxic or health-endangering characteristics and are also hazardous to the environment. Depending on the type, the hazards can spread via the liquid or gas path, or both. Compared to gases, however, their rate and radius of spread is lower. Liquefied gases such as LNG or LPG also have a high hazard potential with regard to fire and explosion. In particular, the enormous increase in volume during the transition from the liquid to the gaseous state increases this potential. On the other hand, the potential threat to the environment is far lower than with liquid fuels. Pressurized gases such as hydrogen or CNG are also highly flammable but present no direct hazard to health or the environment. Moreover, their characteristic of dissipating quickly in a free atmosphere reduces their hazard potential. Conversely, storage and handling of these substances under very high pressures or at very low temperatures also harbors dangers.

SUMMARY safety of fuels:

- All examined fuels harbor an approximately equal, albeit different, hazard potential.
- As a general rule, the storage, transport and distribution of all fuels have been fully mastered from a technical perspective.
- The real risk for all fuels is to be seen as very low.

Battery electric energy

Although the transportation of electricity holds a high hazard potential, it has been fully mastered from a technical perspective, meaning that there is only a very low risk from electricity transmission today.

In order to "store" electricity, it has to be converted into other media. Depending on the type of process, this can entail significant hazard potential.

The hazards that arise from batteries are of a fundamentally different nature to those of gaseous and liquid energy sources. Leaking or escaping from containers/tanks and the associated fire and explosion hazards can generally be excluded. Nevertheless, batteries can catch fire due to technical defects. The substances produced by this fire are generally assessed as toxic. Electrolytes with a corrosive effect may escape from some types of batteries. There is a risk of injury in the event of unprotected contact with these substances. Damage to vehicles or a hazard to the environment cannot be excluded. If electric vehicles catch fire, it must also be considered that the fire department and rescue workers cannot approach the burning e-vehicle due to the danger of electric shock or can only do so after determining that no voltage is present, and that it also may only be possible to use extinguishing agents following a corresponding delay.

When handling electricity, the dangers posed by an electrical short circuit are a key issue. A short circuit can be caused by aging electrical equipment, faulty installations or improper actions such as using unsuitable extension cables. Atmospheric effects such as heavy rain or a lightning strike can also present a danger. Furthermore, manipulative interventions are a conceivable risk factor.

In the event of contact with defective electrical devices there is a risk of electric shock, which may be fatal.

The dangers of electricity are generally known. Comprehensive rules and standards describe the equipment for protecting users from electrical hazards, and electrical installations are designed in accordance with these requirements. However, defective or overloaded electrical equipment is one of the most common causes of accidents and fire incidents. It should be assumed that such events cannot be completely ruled out in electromobility either.

SUMMARY safety:

As a general rule, the use, storage, transport and distribution of all energy sources have been fully mastered, albeit with different levels of risk. A detailed analysis of this can be found in the appendix of this study.

Market introduction potential, customer acceptance and lead time to market

In order to assess the market introduction potential, the level of customer acceptance and the possibility of placing technologies on the market quickly, the following criteria will be examined:

- Fueling/charging time
- Compatibility with existing stock/drop-in capability with fossil fuels/number of compatible cars on the market/existing infrastructure/bi-fuel capacity/availability of fuel standards
- Availability of technology
- Retrofitting capability
- Functional temperature range
- Risks, potential/advantages
- Compatibility of vehicles with rest of world
- Potential of biofuel in addition to PtX
- Investment risk (minimum plant size)

Fueling/charging time

	Charging time [s] for 100 km
BEV	500
H_2 (FCEV)	< 30
DME (CI engine)	< 30
OME (CI engine)	< 20
Methane – CH_4 (SI engine, direct injection)	< 30
Methanol (M100) (SI engine, direct injection)	< 20
FT gasoline (SI engine, direct injection)	< 10
FT diesel (CI engine)	< 10
FT propane (SI engine, direct injection)	< 30

Table 17: Time to fuel cars for 100 km in seconds (assumptions for SI/CI concepts and FCEVs: NEDC; assumptions for BEVs: 80 % charge at 150-kW quick-charge station, at consumption of 60 MJ per 100 km, e. g. NEDC Ford Focus or 1.5 x NEDC Opel Ampera)

An estimation of the fueling or charging time for a car journey over 100 km (calculated on the basis of NEDC consumption) is shown in **Table 17**. An explanation of the color coding can be found in **Table 16**.

The fueling time for all combustion engine concepts and FCEVs is calculated on the basis of NEDC consumption. All of them are assessed as being admissible with regard to customer acceptance. Fueling for a range of 500 km would be possible in less than 2.5 minutes in all cases. Even when an increase in NEDC consumption of 50 % is projected for the real consumption of the vehicles, the fueling time is still under four minutes, which still appears acceptable. Even under the good conditions assumed in the table, the charging time for a BEV is significantly longer (80 % charge at a 150-kW quick-charge station, at a consumption of 60 MJ per 100 km – for example NEDC Ford Focus or 1.5 x NEDC Opel Ampera), especially taking into consideration that the real consumption and NEDC consumption deviate more strongly in a BEV than is the case for combustion engine concepts. The charging duration is therefore at least 500 seconds per 100 km, or even six to seven hours using a conventional household socket. Under optimal conditions, it would take around 40 to 45 minutes to charge a car sufficiently for a range of 500 km, which is seen as unacceptable for long-distance drivers.

The picture for truck applications is similar to that for cars. Only pressurized gas, i. e. CNG applications, displays significantly longer fueling times than liquid (and cryogenic liquid) fuels due to the size of the tank. Due to the lack of experience with tanks that would be sufficiently dimensioned for long-distance travel, customer acceptance was not examined in this case. Liquid fuels or cryogenic gases are expected to establish themselves here.

SUMMARY fueling or charging time:

- End users are used to refueling cars and trucks within just a few minutes. This is also possible for FCEVs. In contrast, the charging times of BEVs necessitate a change in customer behavior (at a 150-kW quick-charge point, the charging time for a Golf-class car is 40 to 45 minutes for 500 km; even the currently planned high-performance concepts with up to 350 kW would require around 15 to 20 minutes for 500 km). Today, the prerequisites for charging at home are not in place everywhere. The number of charging points required is significantly higher than for the other concepts.

Compatibility with existing stock

An estimation of the compatibility of existing vehicles, or the “drop in” ability of various fuels in fossil fuels, is described in **Table 18**. An explanation of the color coding can be found in **Table 16**.

	Compatibility with existing stock (max. blended proportion in %)				Number of compatible cars on the market in 2017 (Number of filling stations in Germany in 2017)	Bi-/flex-fuel capability with existing gasoline/diesel powertrains	Suitable fuel standards available
	Gasoline	Diesel	LPG	CNG			
BEV	–	–	–	–	Approx. 25,000 (EAFO 2017) (< 22 kW: 22,857) (> 22 kW: 1,810) (2AC type: 341) (CHAdeMO: 444) (CCS: 638) (Tesla: 387)	Bi-fuel with gasoline/diesel as a plug-in hybrid (retrofitting very difficult)	N/A
H_2 (FCEV)	–	–	–	2	< 100 (approx. 30)	Difficult packaging and cost situation	Fuel: ISO 14687-2 Filling stations: EN 17127
DME (CI)	–	–	–	–	0 (0)	Research required	ISO 16861
OME (CI)	–	–	–	–	0 (0)	Research required	Proposed standard available
Methane – compressed (LD/HD)	–	–	–	100	80,000 (approx. 900)	Bi-fuel with gasoline (retrofitting possible)	DIN 51624 EN 16726-2 Sulfur reduction advisable
Methane – liquid (HD)	–	–	–	2	< 100 (1)	Dual-fuel with diesel (retrofitting possible)	DIN 51624 EN 16723-2 Sulfur reduction advisable
Methanol (M100)	3	–	–	–	0 (0)	Flex-fuel with gasoline (retrofitting possible)	For introduction: Chinese M85 standard available
Gasoline FT	100	–	–	–	29.8 million (approx. 14,000)	Not necessary, as compatible	EN 228
Diesel (CI) FT	–	100	–	–	14.5 million (approx. 14,000)	Not necessary, as compatible	EN 15940 (approx. 30 – 35 %, also in EN 590)
Propane (SI)	–	–	100	–	480,000 (approx. 6,800)	Bi-fuel with gasoline (retrofitting possible)	EN 589 Sulfur reduction advisable

Table 18: Compatibility with existing vehicle stock, ability to use as drop-in fuels, bi-fuels or flex-fuels, availability of fuel standards

Aside from the charging infrastructure for BEVs, which is still rudimentary and is currently undergoing expansion, in Germany there is only an appreciable infrastructure for four fuels. For gasoline as per EN 228 and diesel as per EN 590 there are more than 14,000 filling stations, which should each have around eight filling points on average. This infrastructure is absolutely sufficient. Indeed, a consolidation of the market is expected in the medium term. For LPG (a propane/butane mixture as per EN 589) there are approximately 6,800 filling stations in Germany, which corresponds to coverage of around 48 %. LPG filling stations are generally only equipped with two filling points. The density of the LPG filling station network is viewed as acceptable. Furthermore, there is also a CNG network with around 900 filling stations (6 % coverage). The size of this network is seen as insufficient for significant market development with regard to customer acceptance; however, it is certainly capable of development. In addition, there are a few E85 fuel pumps (< 100, not a relevant fuel here) and around 30 hydrogen filling stations.

Apart from FT gasoline, FT diesel, FT propane (butane) and, to a certain extent, also PtG methane, practically none of the fuels examined here can be distributed immediately without first building up an infrastructure. Accordingly, all other fuels must be drop-in-capable to enable a quick market introduction. In this context, drop-in capability means that the respective fuel is compatible with a large proportion of the existing vehicle fleet and the current infrastructure. In addition, the drop-in capability of a fuel is to be assessed in relation to each of the four existing filling station networks.

Along with FT gasoline, a high proportion of which can be admixed with fossil-based gasoline while adhering to EN 228, it is also possible to admix methanol. However, the admixture of methanol is highly limited (up to 3 % as per EN 228). Due to the additional limitation of oxygen content specified in EN 228, however, the admixture of methanol limits the amount of biofuel (ethanol) that can be added. No more than 35 % of paraffinic FT diesel can be admixed with fossil diesel in accordance with EN 590, as otherwise the lower limit for fuel density would not be adhered to. Discussions on lowering the minimum density threshold in EN 590 are currently ongoing. For purely paraffinic diesel (FT diesel and HVO) the EN 15940 standard applies, according to which an increasing number of new vehicles are approved. Up to 100 % FT propane can be admixed with fossil LPG in compliance with EN 589, while up to 100 % PtG methane can be admixed with CNG. Furthermore, natural gas may contain up to 2 % hydrogen. DME has no drop-in capability, and more research is required for OME. Even when only low proportions of fuels are admixed, the compatibility of materials, such as seals in existing vehicles, must be checked.

If a sufficient filling station network does not exist and the use as a drop-in fuel is only possible to a limited degree or not at all, the bi-fuel capability of a concept can be of great assistance when launching a technology on the market, particularly when simple retrofitting options are offered [Kramer 2012]. This is evident when examining the German and European LPG and CNG market. The bi-fuel capability of each concept is also listed in **Table 18**. Bi-fuel vehicle concepts are not necessary for fuels that are fully compatible with existing fuels or that can be admixed in high proportions (FT gasoline, FT diesel, FT propane and, to a limited extent, also PtG methane). Plug-in hybrids (BEVs with gasoline or diesel powertrain) can be viewed as bi-fuel-capable vehicles. Bi-fuel vehicles with a gasoline powertrain are also available on the market for PtG methane and FT propane/butane. Flex-fuel vehicles (mixture of gasoline with up to 85 % methanol in one tank) have been in existence since the 1980s. This technology is relatively simple and affordable.

On the other hand, the realization of an FCEV with an additional gasoline or diesel powertrain is very difficult for packaging and cost reasons. Vehicles of this kind are not available.

A bi-fuel DME vehicle (in combination with diesel) is not yet technically possible. The different requirements of the fuels with regard to the injection system is a technical challenge that has not yet been solved. However, research projects on this subject are ongoing.

OME has not yet been investigated with regard to its bi-fuel capability. Research is needed in this area.

For heavy-duty commercial vehicles in fleets there is a slightly different picture – in Germany at least – as most fueling takes place in depots. The costs for the haulage companies must be compensated by cheaper purchasing conditions for large quantities. In this respect, the introduction of a new fuel is likely to be easier. However, the same principles apply as for cars. Bi-fuel capability is rare among heavy-duty commercial vehicles, and as a result there is a lack of experience in this area.

In order to launch a new fuel quickly, early standardization of the fuel is essential; this then guarantees the quality of the fuel in the field. Reliable European/German fuel standards already exist for gasoline, diesel, paraffinic diesel, LPG and natural gas.

For H_2 and DME, however, only ISO standards are in existence. These would have to be transferred to a European and German standard – a process that would take at least three years. For OME there is currently only a proposal, meaning that an even longer period would be required for the OME standardization process.

SUMMARY compatibility with existing vehicle stock:

- Six of the observed PtX fuels can already be used as blended components in the existing infrastructure and in vehicles that are available today and can make a significant contribution to lowering CO_2. A high proportion of FT gasoline can be admixed to gasoline in compliance with EN 228. The EN 228 standard also allows the admixture of up to 3 % methanol. FT diesel can be blended with diesel fuel with a proportion of around 30 to 35 % on the condition that EN 590 is met (14,000 filling stations for gasoline and diesel). Furthermore, pure FT diesel corresponding to the requirements laid down in EN 15940 can be used in vehicles that are approved for this. FT propane/butane can be used as liquefied petroleum gas if the conditions specified in EN 589 are met (6,800 filling stations). Up to 100 % PtG methane and up to 2 % H_2 can be admixed with natural gas (DIN 51624 and EN 16723-2) (900 filling stations).

- The bi-fuel capability of a concept with gasoline/diesel powertrains can play a key role in supporting the market introduction of a technology, at least for cars. The following concepts are already bi-fuel-capable today: plug-in hybrid with combustion engine, methane and gasoline in natural gas vehicles, propane/butane and gasoline in LPG vehicles, methanol or ethanol and gasoline in flex-fuel vehicles.

- In order to launch a new fuel quickly, early standardization of the fuel and filling stations is essential. If availability is sufficient, a quick market launch (< 3 years) is possible within the scope of existing standards and in significant quantities with the following blended components: FT gasoline, FT diesel, FT propane and PtG methane.

Further risks and potential

Scenario	Risks	Potential/advantages
BEV	• Raw material availability and recycling for current battery technologies in 100 % scenario not resolved • Real consumption considerably higher than normal consumption, especially at cold temperatures • Resale difficult outside EU (in particular for hybrid-overhead line trucks) • Financing of infrastructure for hybrid-overhead line trucks unresolved	• Technology available (vehicles in series production) • Compatible with BEV strategy in China
H_2 (FCEV)	• Liquid H_2 blow-off in enclosed buildings (not suitable for cars, parking garages, etc.) • Blow-off of compressed H_2 (700 bar pressure containers) may be necessary in special situations • Only limited use of parking garages, tunnels and ferries may be possible • Resale difficult outside EU • Research may be required on reducing platinum consumption • No cost-effective fossil-based H_2 and no bio-H_2 available (fossil-based H_2 must be extracted from natural gas) with which the infrastructure could be expanded cheaply	• Technology available (vehicles in series production) • Compatible with FCEV strategy in California and Japan
DME (CI)	• Only limited use of parking garages, tunnels and ferries may be possible • Carrying of AdBlue necessary (less than for diesel) • Resale difficult outside EU • No cost-effective fossil-based DME and only small quantities of bio-DME available (fossil-based DME must be extracted from natural gas, bio-DME from black liquor waste from the paper industry) with which the infrastructure could be expanded cheaply	
OME (CI)	• Carrying of AdBlue necessary (less than for diesel) • Resale difficult outside EU • No cost-effective fossil-based OME and no bio-OME available (fossil-based OME must be extracted from natural gas) with which the infrastructure could be expanded cheaply	• Non-toxic • Possibly compatible with China: OME from coal (truck)

Scenario	Risks	Potential/advantages
Methane – CH_4 (SI, DI)	• Only limited use of parking garages, tunnels and ferries may be possible • Prevention of methane slip in vehicle and infrastructure necessary (GHG potential, climate-relevant emissions) • Solutions to be developed for LNG vent-off in event of heating up	• Technology available (vehicles in series production) • Fully developed gas distribution grid (400,000 km) and gas storage available • Expected to be compatible with electricity storage technology • Basic filling station infrastructure (900 filling stations, 1800 filling points) available. Expansion of further infrastructure with cost-effective CNG possible (with later conversion to e-fuels) • 100 % compatibility with CNG, bio-methane, PtG methane → Blending of any quantity of CNG with bio- and/or PtG methane can be controlled through corresponding legislation/tax incentives • Compatible with niche markets: Iran, Pakistan, Thailand, China ...
Methane – CH_4 (CI, truck)	• Only limited use of parking garages, tunnels and ferries may be possible • Truck (LNG): cryogenic high-pressure pump: function/durability questionable • Truck: carrying of a second e-fuel as an ignition oil (e. g. E-OME) necessary • Truck: carrying of AdBlue necessary • Prevention of methane slip necessary in vehicle and infrastructure (GHG potential, climate-relevant emissions) • Truck: • Resale difficult outside EU	• Technology available (vehicles in series production) • Fully developed gas distribution grid (400,000 km) and gas storage available • Expected to be compatible with electricity storage technology • Basic filling station infrastructure (900 filling stations, 1800 filling points) available. Expansion of further infrastructure with cost-effective C NG possible (with later conversion to e-fuels) • 100 % compatibility with CNG, bio-methane, PtG methane → Blending of any quantity of CNG with bio- and/or PtG methane can be controlled through corresponding legislation/tax incentives • Compatible with niche markets: Iran, Pakistan, Thailand, China (alongside CNG, also LNG) ...

Scenario	Risks	Potential/advantages
Methanol (M100) (SI)	• Carrying of a second e-fuel (e. g. e-gasoline) expected to be necessary for cold start • Resale difficult outside EU • Economically producible bio-methanol as a cost-effective, sustainable supplement to e-methanol only available in very small quantities (glycerin from waste from bio-diesel production)	• Technology available (very similar ethanol vehicles in series production) • Economically available for the introduction of fossil-based methanol in large quantities (from natural gas) • May be compatible with electricity storage technology • Methanol is suitable for the chemical industry as a “new” base material
Gasoline (SI) FT/ MeOH synthesis	• Can only be produced as FT gasoline in connection with FT diesel, FT propane/butane and further by-products. Downstream refinery necessary • Economically producible bio-gasoline not available as a cost-effective, sustainable supplement to e-gasoline • Bio components as a cost-effective, sustainable supplement to e-gasoline can only be admixed in small quantities (10 % ethanol, 3 % methanol)	• Technology available (vehicles in series production) • Fully developed infrastructure available • High degree of compatibility with fossil-based gasoline. Proportional blending with PtG gasoline can be controlled through corresponding legislation/tax incentives • Fully compatible with all world markets
Diesel (CI)	• Carrying of AdBlue necessary • FT diesel can only be produced in connection with FT gasoline, FT propane/butane and further by-products. Downstream refinery necessary • Economically producible bio-diesel as a cost-effective, sustainable supplement to e-diesel (HVO) only available in small quantities (availability of sustainable vegetable oil) • Bio components as a cost-effective, sustainable supplement to e-diesel can only be admixed in small quantities (7 % FAME/FAEE)	• Technology available (vehicles in series production) • Fully developed infrastructure available • 100 % compatibility with fossil-based diesel. Any desired blending with PtG diesel can be controlled through corresponding legislation/ tax incentives • Fully compatible with all world markets (trucks) or European markets (cars)
Propane (SI)	• Only limited use of parking garages, tunnels and ferries may be possible • FT propane/butane can only be produced in connection with FT gasoline, FT diesel and further by-products. Downstream refinery necessary • Economically producible bio-propane as a cost-effective, sustainable supplement to e-gasoline virtually unavailable (only approx. 4 % as a by-product of HVO production)	• Technology available (vehicles in series production) • Extensive basic infrastructure available in Germany (6,800 filling stations, approx. 13,600 filling points, small tanks) and also to a great extent in Europe • Niche markets available worldwide

Table 19: Further risks and potential of the investigated fuel-powertrain scenarios

Further risks and potential of the investigated fuel-powertrain scenarios are listed in **Table 19**.

Once a corresponding new standard has been completed and the infrastructure and vehicles have been modified accordingly, fuels and fuel blends that have not yet been standardized can be admixed to fossil fuels, even in large quantities where possible (similar to the use of E10 in gasoline), and thereby make a contribution toward reducing CO_2. This concerns e-methanol and E-OME in particular.

Investment requirement

The full decarbonization of the transport sector in Germany requires an enormous financial commitment regardless of the chosen solution. As shown in **Figure 30** and **Table 20**, the total investment costs are between almost € 270 billion and around € 1,740 billion depending on the path. This large range is due to the additional vehicle costs that may be incurred for battery electric vehicles and fuel cell vehicles on the one hand, and the range of necessary power plant investments on the other.

The figures in **Figure 30** and **Table 20** are based on a fuel matrix developed during the course of this study. All fuel paths containing hydrocarbons are summarized under PtX (combustion engines with e-fuels). The range of PtX costs is a result of the different fuels as well as the observed minimum and maximum cost scenarios. The additional costs compared to vehicles driven by a spark-ignition engine were used for the additional vehicle costs of cars. The additional costs of trucks are based on a comparison with compressed ignition engine driven vehicles. The additional total investments are based on the assumption that 3.4 million cars and 50,000 trucks are sold in Germany per year (figures for Germany in 2015). These figures are accumulated over a period of 20 years, which corresponds to the estimated amortization period of PtX plants.

	1 **Investment costs for power plants***	2 **Investment costs for fuel production**	3 **Investment costs for infrastructure**	4 **Cumul. add. vehicle costs** car (vs. gasoline) + truck (vs. diesel)**
PtX	€ 137 – 526 bn (Pt-CH_4)	€ 102 – 118 bn (Pt-CH_4)	€ 3 – 6 bn (Pt-CH_4)	€ 0 – 122 bn + € 24 bn (CH_4)
	€ 166 – 629 bn (Pt-MeOH)	€ 115 – 168 bn (Pt-MeOH)	< € 1 bn (Pt-MeOH)	€ 0 – 20 bn + € 0 bn (MeOH)
	€ 166 – 635 bn (Pt-FT)	€ 176 – 254 bn (Pt-FT)	€ 0 bn (Pt-FT)	€ 82 bn + € 0 bn (FT)
	€ 149 – 570 bn (Pt-DME)	€ 103 – 151 bn (Pt-DME)	€ 1 – 2 bn (Pt-DME)	€ 163 – 231 bn + € 1 bn (DME)
	€ 208 – 783 bn (Pt-OME)	€ 167 – 243 bn (Pt-OME)	< € 1 bn (Pt-OME)	€ 163 bn + € 0 bn (OME)
H_2	€ 89 – 342 bn (central)	€ 71 – 87 bn (central)	€ 19 – 38 bn (central)	€ 163 – 850 bn (car)
	€ 273 – 568 bn (local)*	€ 55 – 66 bn (local)	€ 19 – 128 bn (local)	+ € 37 – 125 bn (truck)
BEV	€ 112 – 262 bn*	0	€ 38 – 198 bn	€ 163 – 768 bn (car) + € 52 – 88 bn (truck)
	Energy supplier	**Fuel industry**	**Fuel industry**	**Automotive industry**

* Including investment costs for Pt-CH_4 plants for reconversion and provision of a constant electrical power supply

** Cumulative additional vehicle costs (car vs. gasoline; truck vs. diesel) over 20 years: 3.4 million cars and 50,000 trucks per annum; assumption FT: (½ gasoline + ½ diesel)

Figure 30: Distribution of investment requirement by sector

Scenario (cars + trucks)	Min. investment costs in € billion	Max. investment costs in € billion
$Pt\text{-}CH_4$	270	800
Pt-MeOH	280	820
Pt-FT	420	970
Pt-DME	420	960
Pt-OME	540	1,190
$Pt\text{-}H_2$ (central)	380	1,440
$Pt\text{-}H_2$ (local)	550	1,740
BEV	360	1,320

Table 20: Minimum investment requirement and maximum investment risk in total

The investment costs for providing renewable electricity were estimated in accordance with the electricity costs used as a basis for this study (cf. p. 16). Correspondingly, highlighted values from this study (full load hours for electrolysis, interest rate and ROI, service life and operating costs for the "supply follows load" scenarios) as well as values from the study "What Will the Energy Transformation Cost?" ["Was kostet die Energiewende?", ISE 2015] (service life and operating costs for variable electricity scenarios) were taken as a basis here. This retrograde calculation thus delivers investment costs of € 1,000 to € 3,400 per kW for a variable electricity supply and € 5,200 to € 9,400 per kW for a constant electricity supply. It should be noted that this does not correspond to the investment costs for a technology (e. g. offshore wind power in the maximum scenario for variable electricity), but rather the investment costs for entire systems that meet the respective requirements (e. g. € 24/MWh at 5,877 h/a when produced in MENA). In addition, this means that the investment costs given here must also cover all investments for the stabilization of the electricity supply in the "supply follows load" scenarios.

Although the accuracy of this estimation is certainly questionable, it does deliver a first indication of the total investments that can be necessary for such an electricity supply.

As demonstrated in the minimum and maximum cost scenario for cars in **Figure 31** and **Figure 32**, mobility costs are dominated by vehicle costs. When observing the cheaper case for each of the three main paths (PtX, H_2 and BEVs) (**Table 20**), the minimum investment costs required are between € 270 and 550 billion and are thus in the same order of magnitude. A comparison of the maximum investment costs required for the three main paths of PtX, H_2 and BEVs shows that these are below € 1,190 billion for all PtX scenarios. For a hydrogen scenario, on the other hand, investment of up to € 1,740 billion could be necessary. The investment risk for a purely electric scenario is up to € 1,320 billion.

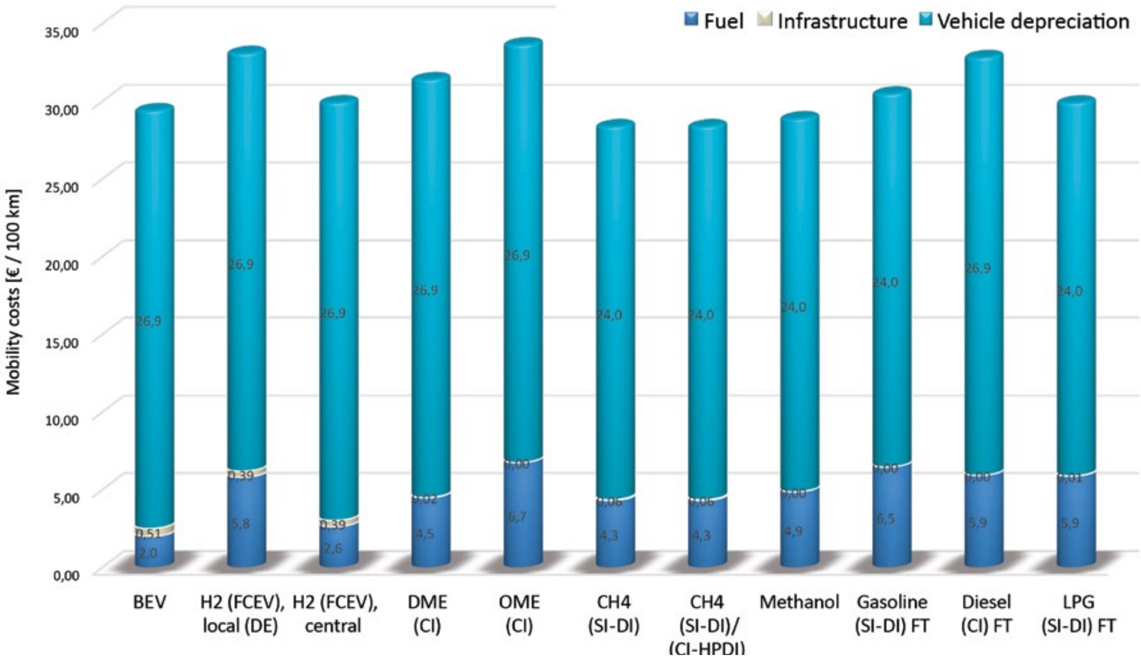


Figure 31: Cost breakdown: minimum mobility costs for cars

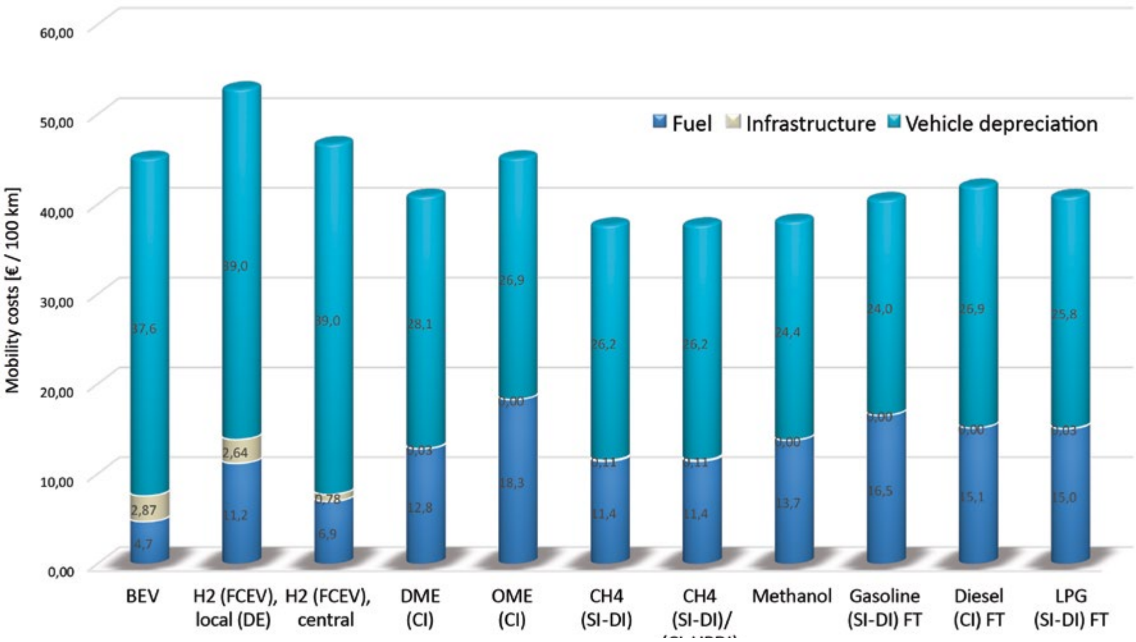


Figure 32: Cost breakdown: maximum mobility costs for cars

The decisive difference is the sector in which the required investments must be made; see **Figure 30**. While all involved partners (energy suppliers, the fuel industry, infrastructure operators and the automotive industry) will have to make significant additional investments for decarbonization through hydrogen, the additional costs for all PtX paths are almost exclusively incurred through power plants and fuel production. There are practically no additional costs on the vehicle side. In the event of full decarbonization through BEVs, however, investment costs are only necessary in electricity production, the infrastructure and possibly in the vehicles themselves, although this can be on a significant scale.

Investment costs of the PtX plant components

Figure 33 and **Figure 34** show the minimum investment requirement for plants installed in MENA and in Germany. Both figures show the plant components for electrolysis, H_2 storage, CO_2 separation, PtX synthesis and gas liquefaction plants.

Minimum costs in MENA

When estimating the minimum plant size and the investment costs required for this, according to **Figure 33**, PtX synthesis with 31 % (FT gasoline) and CO_2 separation from the air with 38 % (FT gasoline) represent procedurally complex and limiting plant components. When producing CH_4 in particular, separation of CO_2 from the ambient air makes up a share of 40 %. An electrolysis stack or an H_2 storage facility can be duplicated and scaled easily. This means that CO_2 separation is a financially costly plant component for carbon-based fuels. In order to reduce the cost risk for this plant component, there is a significant need for further research. It is predicted that emitters of CO_2 can be used as CO_2 sources, in particular during the transition period from a fossil fuel-based to a completely sustainable energy sector. In this case, CO_2 is obtained without any significant energy expenditure and is virtually free. Even in a world in which no energy is generated from fossil sources, it is likely that there will still be industry sectors that emit large amounts of CO_2 for process-related reasons (for example, production of steel, cement or biogas), which can then be used for the cheap production of PtX fuels.

For plants that solely produce H_2 in MENA, the minimum plant size and the investment costs thus required are geared towards the most economically prudent size of the H_2 liquefaction process, which can comprise up to 68 % of the plant costs. At € 47.4 billion, the costs of the H_2 liquefaction plants reach about 40 % of the level of PtX plants for FT diesel and FT gasoline.

Due to the additional costs for CO_2 separation in MENA, the carbon-based fuels are 2.9 times (FT gasoline) and 1.6 times (e-methane) as expensive as centrally produced H_2.

Minimum costs in Germany

There is a similar picture when estimating the minimum plant size in Germany. Here, CO_2 separation is also the main cost driver for the whole plant, making up a total of 34 % in the example of FT gasoline. The sensible approach whereby PtX plants are installed close to CO_2 sources that will also be unavoidable in the future, such as cement or biogas plants, is derived from this.

Using the example of e-methane, the use of locally available CO_2 could prevent costs being incurred for CO_2 separation. Furthermore, the investment required for liquefaction could be lowered by feeding e-methane into the gas grid, thereby reducing the total investment costs for e-methane to € 43.4 billion. These costs would then be € 74.6 billion lower than the minimum costs in MENA which lie at € 117.9 billion.

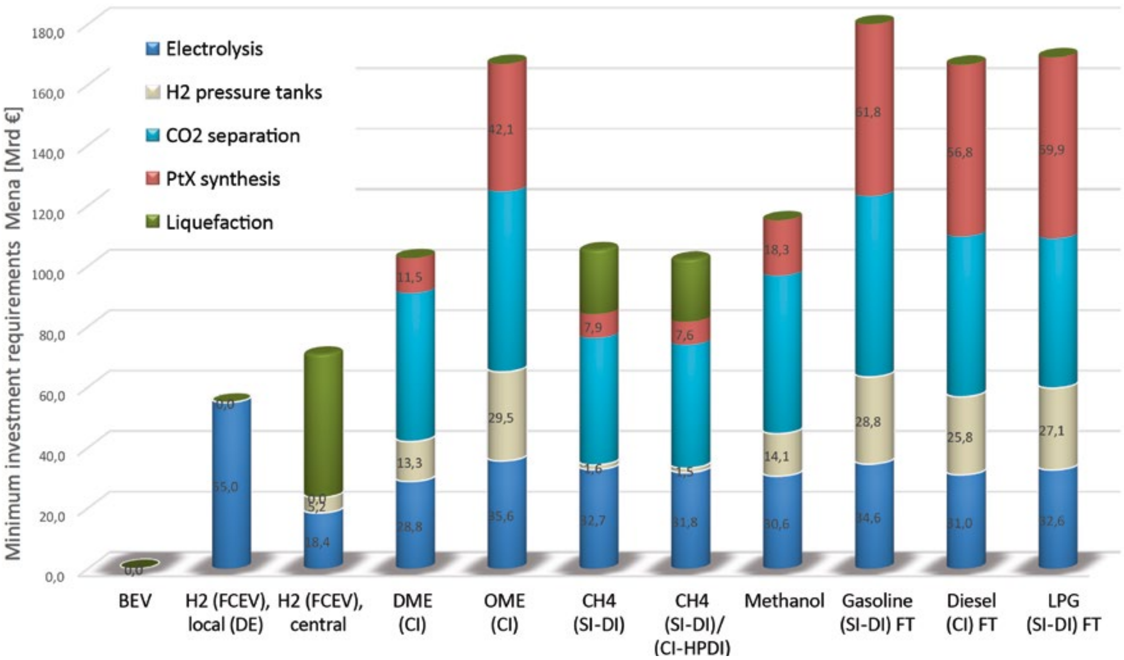


Figure 33: Minimum investment requirement for PtX plants in MENA (CO_2 from air)

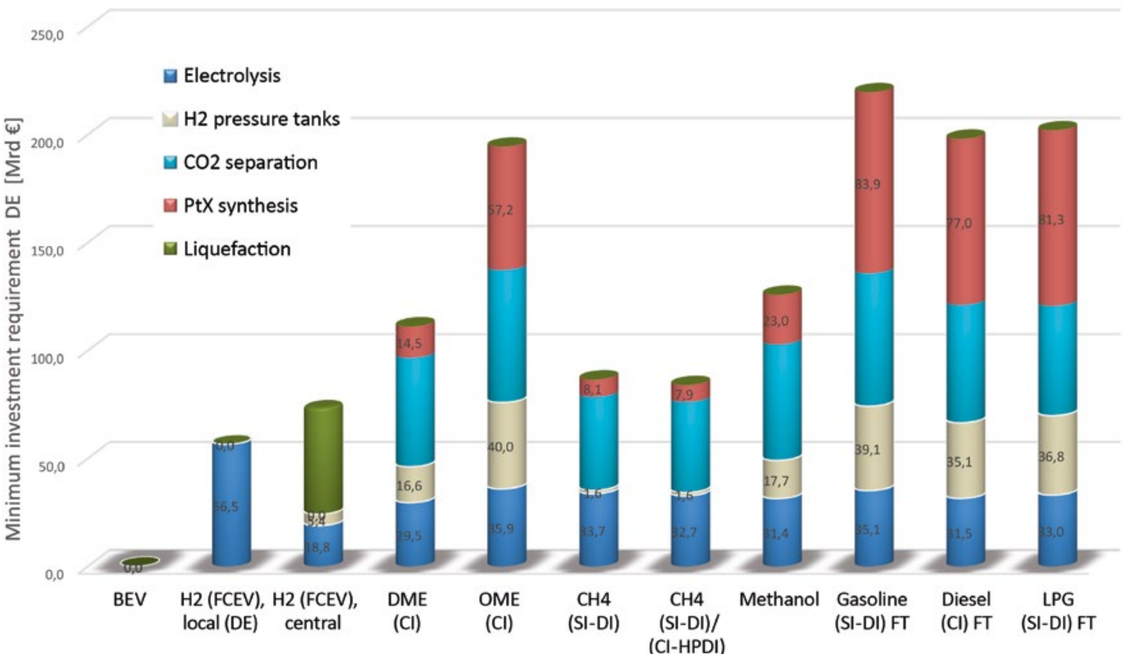


Figure 34: Minimum investment requirement for PtX plants in Germany (CO_2 from air)

SUMMARY investment requirement:

- The full decarbonization of the transportation sector in Germany requires an enormous financial commitment. Depending on the path, the total investment costs amount to between just under € 270 billion and in excess of € 1,740 billion. This large range is less a result of the chosen fuel path than the additional vehicle costs that may be incurred for battery electric vehicles and fuel cell vehicles. Mobility costs are dominated by the vehicle costs.

- The minimum required investment costs for the three main paths of PtX, H_2 and BEVs are between € 270 billion and € 550 billion.

- The maximum required investment costs for all PtX paths are between € 800 billion and € 1,190 billion. Methane is the most affordable fuel (in Germany) at approximately € 800 billion, while power-to-OME requires the highest investment at almost € 1,190 billion. For a hydrogen scenario, on the other hand, investment of up to € 1,740 billion could be necessary. The investment risk for a purely electric scenario is up to € 1,320 billion.

- Alongside the uncertainties in predicting future vehicle costs, there is also a serious degree of uncertainty when forecasting the level of grid expansion required for the universal use of BEVs. These costs are highly dependent on customer usage behavior (charging behavior).

- The decisive difference between the three main paths of PtX, H_2 and BEVs is the sector in which the investments need to be made. While all involved partners (energy suppliers, the fuel industry, infrastructure operators and the automotive industry, i. e. vehicle buyers) will have to make significant additional investments for decarbonization through hydrogen, the additional costs for all PtX paths are almost exclusively incurred in electricity generation and fuel production. In the BEV scenario, there are only investment costs in the infrastructure and possibly for the vehicles, alongside the costs for building wind/solar power plants.

- For the carbon-based fuels, CO_2 separation from the air is an expensive plant component. For simple synthesis processes such as for CH_4, separation of CO_2 from the ambient air makes up 40 % of the total investment costs for the fuel synthesis plant. There is a significant need for research in this area to reduce plant costs. It is predicted that emitters of CO_2 can be used as CO_2 sources, in particular during the transition from a fossil fuel-based to a completely sustainable energy sector. In this case, CO_2 is obtained without any significant energy expenditure and is virtually free. Even in a world in which no energy is generated from fossil sources, it is likely that there will still be industry sectors that emit large amounts of CO_2 for process-related reasons (for example, production of steel, cement or biogas), which can then be used for the cheap production of PtX fuels.

Investment risk

Under the current legal framework conditions, there is no commercial reason to invest in expensive PtX plants. Alongside the high investment costs, current legislation is a hindrance to the introduction of PtX fuels. As automotive manufacturers must meet stringent TtW CO_2 targets without the favorable CO_2 balance of PtX fuels during fuel production being taken into account, BEV and fuel cell technologies are given preferential treatment ahead of PtX processes. While FCEVs and BEVs do not emit CO_2 on the TtW side, the entire WtW chain is CO_2-neutral for PtX fuels.

In order to incentivize investment in PtX production, it is therefore necessary to define political framework conditions that sufficiently honor the production of sustainable PtX fuels as soon as possible and on a European level. On the basis of technology-neutral conditions, investors could then decide which fuel they wish to produce and supply when and on what scale. The political and legal framework must provide a reliable long-term scenario regarding CO_2 and environmental targets within the EU, which should then be valid until 2050.

A legal framework must also be devised for plants that are to be installed outside the EU, for instance in MENA, in order to create clarity and stability for investments in these often politically unstable countries. However, these investment costs will not be incurred in a single year, but in successive portions.

On the condition that the statutory framework conditions are defined by 2025, a further 25 years will then remain to reduce CO_2 emissions by 2050 in accordance with the targets set in the Paris Agreement. The high investment costs that have been determined for some of the various energy sources will thus be spread across 25 years. The implementation of a 100 % scenario during the course of 25 years thereby means growth of 4 % per year. These investment costs would correspond to an annual CO_2 saving of 4 % on the condition that there are enough vehicles on the market for the respective fuel.

In order to reduce the investment risk, mixed scenarios between MENA and Germany are conceivable, whereby the initial plants would be installed in Germany. This would allow the potential of existing CO_2 sources to be utilized. Further investments would then be made in MENA at a later stage.

Conclusions

The "100 % mobility scenarios" (100 % of vehicles using the same powertrain type) used as a prerequisite here are neither desirable nor realistic, but are suitable for facilitating a comparison of fuel/powertrain paths on the assumption of mass and industrial-scale utilization. In a second step, more realistic mixed scenarios with a broad range of possible synergies (parallel use of different energy sources with variable market shares, mixed drives with various degrees of hybridization or fuel blending) can be derived from the results. However, the second step is not examined in this study.

It is unlikely that electrification (using batteries) will be able to cover all applications on its own. In particular, it is highly likely that commercial vehicles, cars used to cover long distances (fleet cars) and plug-in hybrids will remain dependent on quickly refillable fuels with a high energy density.

Synthetic fuels (e-fuels) and e-mobility complement each other. E-fuels can be employed as a necessary and sensible element for supporting an electromobility strategy.

The production, distribution and use of sustainable, electricity-based fuels is technically feasible; costs and customer acceptance play a decisive role in the success and ecological leverage of all energy sources and powertrain types. Due to the higher availability of renewable energy (primarily wind and solar), costs for production in MENA or in the Mediterranean region are generally considerably lower than in Germany.

Framework conditions

The necessary electrical energy for BEVs must be available as required at any time. As a result, these vehicles need to be provided with "buffered electricity" by the energy suppliers, the average degree of efficiency when supplying electricity for e-vehicles is lower and the electricity purchase costs are significantly higher than when 100 % of the produced electricity is used directly. In the scenario entailing 100 % renewable electricity generated predominantly from wind and solar energy in Germany (and also in the EU), which is assumed in this case, it is predicted that buffering of approximately 20 % of generated energy in stores (including seasonal stores such as PtX) will be indispensable [ISE 2017].

The intermediate storage of electrical energy in a constant electrical power supply scenario results in a higher electricity price. For example, volatile wind electricity from the North Sea cost just € 88 per MWh in 2017, while a figure of around € 180 per MWh is expected for a constant electrical power supply. Volatile electricity produced in MENA can also be used in all central e-fuel scenarios. At approximately € 24 per MWh in the future (2030), this is anticipated to be cheaper than the volatile North Sea electricity generated in 2017 by a factor of 3 to 4. A decentralized fuel cell scenario is expected to need on-site electrolysis that can cope with requirements. Electrolysis is thus connected to the "constant electricity grid". Central provision of hydrogen – preferably produced in MENA – is a cost-effective alternative here.

The electrical power for the two scenarios named above (BEV and local H_2) must come from Germany or Europe, as there are currently no long-distance lines from MENA and their planning and installation appears complex.

At least a holistic consideration of the energy chain (WtW: Well-to-wheel) is necessary as a basis for evaluating the various fuel/energy paths. A final assessment is only possible with a cradle-to-grave (CtG) approach (LCA – life cycle assessment) which also includes the production and maintenance of vehicles, plants and infrastructure. A CtG approach of this ilk was not taken into account when compiling this study; further research is required in this area.

Energy requirement

For a 100 % BEV scenario (car: BEV, truck: hybrid-overhead line BEV) the primary energy requirement would be between 249 and 325 TWh per year, which corresponds to around half of today's total electricity requirement in Germany. Around 11,000 to 15,000 new offshore wind turbines (5 MW) would have to be installed to cover this. By way of comparison, almost 30,000 wind turbines are being operated with a significantly lower capacity in Germany today. This number can therefore be halved by building turbines with a capacity of up to 10 MW (up to 8 MW is already customary today in offshore turbines).

For a 100 % FCEV scenario with centrally produced hydrogen, around 1.8 to 2.0 times more energy would be required than for the 100 % BEV scenario. The number of 5 MW offshore wind turbines in the North Sea would rise to between 23,000 and 26,000.

If PtX fuels are used in combustion engines, the primary energy requirement in the best case (methane) is around 2.7 to 3.1 times greater than the energy requirement for a pure BEV scenario (corresponding to 35,000 to 40,000 5-MW offshore wind turbines); in the worst case (OME) it can be up to 4.7 times greater (corresponding to up to 60,000 5 MW offshore wind turbines).

The well-to-wheel (WtW) degrees of efficiency for electromobility are between approximately 58 and 80 % (without taking air conditioning in BEVs into account, which reduces the degree of efficiency), while those for FCEVs are between 25 and 32 %, and the equivalent values for PtX-driven vehicles with combustion engines are in the region of 10 to 17 % for cars and 14 to 24 % for trucks. Further increases in efficiency, for example through hybridization, are not yet taken into consideration here.

Energy and fuel costs

The energy costs for the BEV scenario are € 0.11 per kWh in the cheapest case (constant electrical power supply costs). These are higher than the pure production costs due to the buffer storage costs and losses and include transmission and charging losses.

Under the most favorable conditions (minimum cost scenario, MENA), hydrogen can be produced for € 0.08 per kWh, followed by methane and DME (€ 0.09 per kWh), methanol (€ 0.10 per kWh), FT fuels (€ 0.12 per kWh) and OME (€ 0.14 per kWh). If PtX fuels are produced centrally in Germany under the least favorable conditions (maximum cost scenario), at € 0.22 per kWh the central production of H_2 appears to be the variant with the lowest costs per unit of energy, followed by methane (€ 0.23 per kWh), DME (€ 0.26 per kWh) and methanol (€ 0.27 per kWh). FT fuels can cost up to € 0.32 per kWh and OME up to € 0.37 per kWh. By way of comparison, in this maximum cost scenario, the reliably available electricity for BEVs, including losses during quick charging, will cost € 0.25 per kWh on average. Unlike the energy used in electric vehicles, all fuels can also be produced in MENA instead of Germany, and under significantly more favorable conditions.

Due to the better degree of efficiency in electric vehicles, the purely electric variants, i. e. cars (BEVs) and trucks (hybrid-overhead line BEVs), are the cheapest solution with regard to distance-related operating costs.

The distance-related fuel costs for FCEVs are 42 % (truck) or 32 % (car) higher than those for BEVs when H_2 is produced centrally in MENA (minimum cost scenario); when H_2 is produced centrally in Germany (maximum cost scenario) they are 60 % (truck) or 48 % (car) higher.

Even with cheap PtX fuels for combustion engines, the distance-related fuel costs are higher than with a BEV or FCEV. Methane appears to be the cheapest variant here. When methane is produced centrally in MENA (minimum cost scenario), the fuel costs are 62 % (HPDI truck) and 116 % (car) higher than those for the BEV; when methane is produced centrally in Germany (maximum cost scenario) they are 85 % (HPDI truck) and 146 % (car) higher.

Fuel costs and share of distribution infrastructure costs

If the distribution infrastructure costs are considered for cars in addition to the fuel costs, the BEV scenario remains the cheapest scenario: BEV (€ 2.50 per 100 km) is followed by centrally produced H_2 (€ 3.01 per 100 km), methane (€ 4.36 per 100 km), DME (€ 4.50 per 100 km) and methanol (€ 4.86 per 100 km).

When infrastructure costs are added to fuel costs for trucks, the BEV and central H_2 variants display similar cost potential (around € 19 per 100 km). Methane (HPDI, around € 21 per 100 km) and DME (around € 22 per 100 km) are slightly more expensive.

Mobility costs for cars

For cars in particular, mobility costs are dominated by vehicle costs (vehicle depreciation + proportion of infrastructure costs + fuel before tax). For cars from the compact vehicle segment (Ford Focus, Volkswagen Golf, Opel Astra, etc., costing around € 20,000), the acquisition costs including depreciation are many times higher than the costs for the energy source (before tax) and for infrastructure.

Because future surcharges for vehicles, in particular those for BEVs and FCEVs compared to diesel and gasoline variants, are very difficult to predict, there is a significant degree of uncertainty in the assessment of future mobility costs.

If cost parity is assumed between BEVs, FCEVs and diesel-driven vehicles (minimum cost scenario), similar mobility costs are achieved for all scenarios (€ 28 - 33 for cars; € 73 - 95 for trucks). The lower of these values is methane for cars and DME for trucks.

The cheapest variant is to use the PtX fuels methanol and methane in an optimized combustion engine (around € 38 per 100 km). This becomes evident when observing the maximum mobility costs for cars (maximum cost scenario: production in Germany, minimum degree of efficiency for electrolysis, maximum estimated additional vehicle costs, high estimated infrastructure costs for expanding the electricity grid). At € 40 to 42 per 100 km, FT fuels are also below the BEV cost risk (around € 45 per 100 km). Mobility with hydrogen produced centrally in Germany can be even more expensive (approximately € 47 per 100 km). Locally generated hydrogen used in an FCEV is the most expensive solution in the maximum cost scenario by a large margin (around € 53 per 100 km).

Attainability of TtW CO_2 emissions

Although the CO_2 emissions of a vehicle may appear irrelevant in a closed CO_2 circuit, a TtW assessment is relevant in line with current European legislation (TtW objective).

Low-carbon fuels (fuels with a favorable C/H ratio for decreasing CO_2 emissions) can contribute to a reduction of TtW CO_2 emissions. With methane, for example, CO_2 emissions can be improved by around 25 % compared to gasoline-driven vehicles purely because of the C/H ratio. By further optimizing the engine, a reduction of 29 % is possible. On the other hand, using OME fuels (from C2) in an auto-ignition engine brings about an increase in TtW CO_2 emissions, for example of 13 to 15 % for OME 3-4 compared to diesel or of 2 to 4 % compared to gasoline in a spark ignition engine.

Attainability of zero-impact emissions

Zero-impact emission mobility is achievable with all examined combustion engine concepts (concentration of emissions below permitted limit values).

Handling safety of fuels

As a general rule, the use, storage, transport and distribution of all energy sources have been fully mastered, albeit with different levels of risk.

Fueling/charging time

End users are used to refueling cars and trucks within just a few minutes. This is also possible for FCEVs. In contrast, the charging times of BEVs necessitate a change in customer behavior (at a 150-kW quick-charge point, the charging time for a Golf-class car is 40 to 45 minutes for 500 km; even the currently planned high-performance concepts with up to 350 kW would require around 15 to 20 minutes for 500 km). Today, the prerequisites for charging at home are not in place everywhere. The number of charging points required is significantly higher than for the other concepts.

Compatibility with existing stock

Six of the observed PtX fuels can already be used as blended components in the existing infrastructure and in vehicles that are available today. A high proportion of FT gasoline can be admixed to gasoline in compliance with EN 228. The EN 228 standard also allows the admixture of up to 3 % methanol. FT diesel can be blended with diesel fuel with a proportion of around 30 to 35 % on the condition that EN 590 is met (14,000 filling stations for gasoline and diesel). Furthermore, pure FT diesel corresponding to the requirements laid down in EN 15940 can be used in vehicles that are approved for this. FT propane/butane can be used as liquefied petroleum gas if the conditions specified in EN 589 are met (6,800 filling stations). Up to 100 % PtG methane and up to 2 % H_2 can be admixed with natural gas (DIN 51624 and EN 16723-2) (900 filling stations).

The bi-fuel capability of a concept with gasoline/diesel powertrains can play a key role in supporting the market introduction of a technology, at least for cars. The following concepts are already bi-fuel-capable today: plug-in hybrid with combustion engine, methane and gasoline in natural gas vehicles, propane/butane and gasoline in LPG vehicles, methanol or ethanol and gasoline in flex-fuel vehicles.

Fuels and fuel blends that have not yet been standardized require their own standard, provided that they are not covered by existing standards. Whether and to what extent OME may be blended in diesel fuel is currently the subject of research. The compatibility of elastomers in the existing vehicle stock is to be considered in particular here.

Investment costs

The full decarbonization of the transportation sector in Germany requires an enormous financial commitment. Depending on the path, the total investment costs amount to between just under € 270 billion and in excess of € 1,740 billion. This large range is due to the additional vehicle costs that may be incurred for battery electric vehicles and fuel cell vehicles, as well as the range of investment costs for power plants. Mobility costs are dominated by the vehicle costs.

The maximum required investment costs for all PtX paths are between € 800 billion and € 1,190 billion. Methane is the most affordable fuel (in Germany) at approximately € 800 billion, while power-to-OME requires the highest investment at almost € 1,190 billion. For a hydrogen scenario, on the other hand, investments of up to € 1,740 billion could be necessary. The investment risk for a purely electric scenario is up to € 1,320 billion.

The minimum required investment costs for the three main paths of PtX, H_2 and BEVs are between € 270 billion and € 550 billion.

Alongside the uncertainties in predicting future vehicle costs, there is also a serious degree of uncertainty when forecasting the level of grid expansion required for the universal use of BEVs. These costs are highly dependent on the usage behavior of customers (charging behavior).

The decisive difference between the three main paths of PtX, H_2 and BEVs is the sector in which investments need to be made. While all involved partners (energy suppliers, the fuel industry, infrastructure operators and the automotive industry, i. e. vehicle buyers) will have to make significant additional investments for decarbonization through hydrogen, the additional costs for all PtX paths almost exclusively arise in electricity generation and fuel production. In the BEV scenario, there are only investment costs in the infrastructure and possibly for the vehicles.

For the carbon-based fuels, CO_2 separation from the air is an expensive plant component. For simple synthesis processes such as for CH_4, separation of CO_2 from the ambient air makes up 40 % of the total investment costs for the fuel synthesis plant. There is a significant need for research in this area to reduce plant costs. Furthermore, emitters of CO_2 can be used as CO_2 sources, in particular during the transition period from a fossil fuel-based to a completely sustainable energy sector. In this case, CO_2 is obtained without any significant energy expenditure and is virtually free. Even in a world in which no energy is generated from fossil sources, it is likely that there will still be industry sectors that emit large amounts of CO_2 for process-related reasons (for example, production of steel, cement or biogas), which can then be used for the cheap production of PtX fuels.

Identified need for research

General research requirement

This study is not the only one to conclude that the future structure of mobility will be more complex and diverse than it is today. New fuels are appearing on the horizon or are already being tested. Battery electric and fuel cell vehicles are already demonstrating their readiness for the market, but at the same time are posing questions regarding their mass-market suitability that go beyond technical feasibility.

Largely CO_2-neutral mobility is dependent on forms of energy generation that are currently not existent in anywhere near the required scale. Furthermore, there is a competitive situation between the individual sectors of renewable energy, which are not covered in this study – the issues associated with this need to be resolved on a societal level. There must also be sufficient acceptance among the population for the installation of more plants for generating renewable energy. The installation of additional wind turbines in the countryside is currently the subject of protest and resistance. If Germany is to produce fuel in a self-sufficient manner, this study estimates that, depending on the powertrain/fuel, 11,000 to 60,000 more offshore wind turbines with a capacity of 5 MW will be needed in the North Sea solely to operate Germany's fleet of cars and trucks (based on consumption for 2015). Whether it is more prudent to produce the energy needed for mobility in Germany or, for instance, to import it as fuel from other countries is a question that this study cannot answer. These are politically far-reaching questions.

This study concentrates on comparing 100 % scenarios (100 % CO_2-free mobility with zero-impact emissions and one powertrain type in each case), in particular with regard to the energy requirement and mobility costs. A need for technical research stems from this investigation.

The technology costs are of significant importance here. This is one of the topics which will require more research in the future: on the one hand in order to reduce general technology costs, on the other to initially quantify these costs in order to compare them with other paths. After all, only mobility paths that are affordable will ultimately prove successful in the long term.

Just as overall emissions (well-to-wheel) are examined and assessed in well-to-tank and tank-to-wheel emissions, it is also possible to divide the corresponding research requirement into these categories.

Need for research on the manufacturers' side

It has already been mentioned that renewable energy in Germany is expected to be a limited commodity and therefore also expensive. For this reason, it is important to reduce energy consumption as well as expanding energy generation. To do so, the degrees of efficiency of fuel production must be increased, for example through better integration of process heat or by coupling the syntheses with the utilization of biomass. However, electrolysis processes must also be highly dynamic in order to ensure a quick reaction to the volatile nature of renewable energy generation and its typical load changes. Generation peaks with "surplus" electricity can therefore be sensibly converted into fuel, the full load hours of the corresponding plants increased and the capacity of H_2 pressure tanks reduced. There is still a great need for research in these areas.

For the same reason, the liquefaction of hydrogen must take place in a highly dynamic manner and the electricity used in this process reduced. Reducing the electricity input brings down costs while increasing the degree of efficiency. For hydrogen storage, alternatives or supplements for the very expensive H_2 pressure tanks need to be found in order to keep the complete process within an economically sensible framework. With the expansion of renewable electricity generation, the question of how to prudently use production peaks will arise frequently. Alongside the aforementioned highly dynamic electrolysis and hydrogen liquefaction processes, further storage technologies need to be researched and tested. Efficient and cost-effective storage (caverns, product reconversion) is important here, as is the recovery of this energy.

The production process is just one aspect of supplying energy for mobility, however; the two others are the distribution and the supply of raw materials.

The existing cost estimations diverge greatly with regard to expanding the grid to enable the requirements-based distribution of electricity. In addition to a charging infrastructure for BEVs, overhead lines for trucks also play a role in the considerations of this study. More accurate figures result in a more precise estimate of the costs of mobility based on this. Important factors include user behavior when charging electric vehicles (distribution of charging times, which could be controlled via different pricing) and also the legal framework conditions of the grid expansion. The route taken (overhead line, underground cable) influences the costs and thereby results in different electricity prices.

In terms of liquid and gaseous fuels, in Germany there is currently only a fully developed infrastructure for gasoline and diesel, partially for propane/butane (LPG) and a rudimentary infrastructure for methane (CNG); an infrastructure would have to be built up for all other fuels. Standards, costs and a legal framework must be clarified and defined here.

In addition to the costs and availability of renewable energy, CO_2 as a raw material plays a particularly crucial role in the input values for e-fuels. The industrial sources of CO_2 capture, such as waste gas from the cement or steel industries, do not seem sufficient for a full supply in a 100 % scenario. Another source is the separation of CO_2 from the ambient air. Further research is required in this area in order to raise efficiency; in turn, this will allow costs to be lowered significantly and a realistic cost estimation to be made.

The materials used for the battery are of fundamental importance in BEVs. The questions to be answered here are which quantities of lithium or cobalt, for example, can be mined economically, how they are distributed throughout the world and whether German companies can access these. The same applies for the supply of platinum for fuel cells. Accordingly, geopolitical questions are posed alongside technical ones: Which countries are we becoming dependent on? The large-scale recycling of batteries must also be resolved (life cycle assessment).

Once the questions regarding production have been answered with sufficient accuracy, the focus will then move on to developing introduction scenarios and providing scientific support for these.

Need for research on the vehicle side

The required research on the part of the automotive manufacturers and their suppliers primarily focuses on the efficient conversion of energy in the vehicle as well as economy and the sparing use of (in some cases new) materials and material combinations.

It may be necessary to adapt and replace seals and all fuel-carrying parts in the vehicle. In the case of (e-)methane vehicles, the question arises as to the long-term stability of the catalyst for lean-burn gas engines and the associated methane slip (cf. FVV projects “Methan katalytisch I” (no. 1134) and “II” (no. 1177)). For trucks, the durability and function of cryogenic high-pressure pumps must be guaranteed when running continuously on LNG.

A successful market introduction of fuel concepts for cars is supported both by an option to use them as a bi-/flex-fuel in gasoline and diesel engines and by the ability to drop in new fuels. Concepts must be developed in this area and the limits to the drop-in capacity alongside existing fossil fuels investigated. There is a particular need for research with regard to the bi-/flex-fuel capacity for the fuels DME and OME. An FVV research project on this subject is currently in progress (XME Diesel, no. 1005). The ability to retrofit the existing vehicle stock should also be examined, as this could also have a positive effect on the introduction of new fuels, particularly in the light of possible vehicle bans.

Research is required in the area of cold starts at very low temperatures, both for fuel systems with a particular focus on emissions (FVV project “Abgaszusammensetzung bei niedrigen Temperaturen” (no. 1316)) and for BEVs with regard to realistic consumption and thereby an acceptable range.

One important question for customers – but also for the purposes of achieving a better comparison – relates to the expected costs for vehicles in the future. The corresponding assumptions are explained in this study. A more detailed discussion on this was not possible due to antitrust law. The FVV compliance rules were observed in all interviews.

The opposite effects are expected for BEVs. On the one hand, positive economies of scale with growing production numbers will result in falling marginal costs (and thus also falling unit costs); on the other, growing production figures will diminish raw material supplies due to increasing demand (see above) and will thereby cause battery – and ultimately vehicle – costs to increase. Increasing production figures are not only expected to bring about a price increase due to greater demand, however, but also a price increase for technical reasons, as raw materials need to be derived from less and less cost-effective sources.

There are also open questions with regard to operation using gaseous fuels. It has not been resolved whether tunnels, ferries and parking garages can be readily used despite a possible LNG/liquid H_2 vent-off. It needs to be determined whether these locations can initially be made suitable through special conversion measures and approved for such vehicles.

At the end of a vehicle’s useful life for a customer, the question of selling the vehicle will arise – within or outside of Europe. The following questions will also have to be answered: What predictions can be made regarding the durability and thus the intrinsic value of the battery? Which markets will remain closed because they lack the corresponding (energy) infrastructure? Here, too, an exact assessment is not possible with the current level of knowledge; research should be undertaken to this end.

The identified need for research can be summarized as follows:

- Highly dynamic electrolysis
- Improvement of electrolysis: optimized integration of process exhaust heat, increase of degrees of efficiency of electrolysis by using high-temperature electrolysis
- Highly dynamic hydrogen liquefaction
- Costs of H_2 pressure tanks
- Storage requirement for renewable electricity compared to intermittently operated chemical complexes
- Storage technologies in general (caverns, power plants, etc.)
- Costs and energy requirement for CO_2 separation from the air
- Coupling of syntheses with use of biomass: By using residual material and waste as input for e-fuel syntheses, the amount of CO_2 required, including the need for CO_2 separation from the air, can be reduced significantly. Furthermore, coupling allows synergies to be utilized within the production process chains and facilitates a considerable increase in the energy efficiency of the fuel production process
- Utilization of other CO_2 sources
- Infrastructure requirement and costs of the grid expansion for electric vehicles
- Realistic consumption (even at low temperatures) and costs for BEVs
- Customer acceptance for comparatively long charging times
- Required raw materials, technical availability and geopolitical dependencies (life cycle assessment)
- Sub-zero emissions potential
- CH_4 catalyst for lean-burn gas engines with long-term stability
- Durability and function of cryogenic high-pressure pumps (for trucks running on LNG)
- Engine modifications
- Bi-fuel, flex-fuel and drop-in capability (compatibility with fossil fuels and biofuels)
- Retrofitting capability

- Behavior at very low temperatures (fuels, battery)
- Operation of gas-driven (liquid H_2, liquid CH_4) vehicles in enclosed buildings
- Suitability and costs of other PtX fuels, such as DMC+ (DMC+ MeFo), MtG (methanol-to-gasoline)

Political recommendations from various studies

The results of this study lead to the conclusion that many options are available from an economic point of view and under the condition that the individual “renewable” energy paths achieve a high market penetration rate. Under technology-neutral political framework conditions solely geared toward the climate targets, purely battery electric vehicles are just as likely to prevail as those that use electricity-based, gaseous or liquid fuels depending on the area of application and customer preferences. In this case the result in the field would be “mixed scenarios” with regard to market penetration (taking the example of commercial vehicles: fleets comprising overhead line, FCEV and FT diesel vehicles), but also technically “mixed concepts” (for cars these would be plug-in hybrids with green electricity and renewable methane as an energy source or with blends made up of fossil-based and renewable fuels during the transition phase). The systemic synergies that would result from such mixed scenarios and hybrid concepts are consciously excluded from this study by assuming 100 % penetration for each fuel, but would certainly be existent. Above all, such mixed scenarios would be more resistant to external influences (for example power failures or supply bottlenecks for certain fuels or raw materials). However, the development of synthetic hydrocarbons and their manufacture on an industrial scale are essential if the climate objectives are to be achieved, regardless of their use in road transport examined here. Completely different investigations conducted independently of one another come to this conclusion, such as energy studies by dena [dena 2010] [dena 2018] or by the BDI [BDI 2018]. After all, these are necessary for the defossilization of sectors such as aviation, marine transport or the chemical industry. Furthermore, when a very large proportion of the electricity supply is made up of renewable energies, synthetic methane and hydrogen from PtG plants will also be needed for reconversion in order to overcome electricity shortages.

In addition, the authors of these studies urge an immediate market launch on the basis of appropriate political framework conditions, so that the corresponding technologies are available at a high level of technical maturity and are highly efficient should they become essential components of an energy and transport transformation.

However, it is still debatable as to how such a market launch can be initiated. Institutions such as the BDI, the DWV, Agora and dena specify growing quotas (via the Renewable Energy Directive, or RED) for sustainable synthetic fuels as a suitable method for forcing fossil fuels off the market in a targeted way and guaranteeing the security of investment for possible producers (upstream approach).

The VDA and NGVA believe it is necessary to allow CO_2 reductions achieved using e-fuels to be credited towards fleet emissions for cars on a voluntary basis (downstream approach) as they view the actual progress in the RED to be minimal. Owing to the necessity of excluding double marketing, this would enable the producers of e-fuels to choose whether to earn revenue for achieved CO_2 reduction on the upstream (quota) or the downstream side (ability to credit fleet emissions).

According to the reasoning of these stakeholders, this would bring about additional flexibility for market participants: For an identical reduction in CO_2, they could choose the most sensible option for them at the respective point in time – whether portfolio adjustments (different vehicles), technical measures or the use of different energy sources – which could lead to lower economic costs. On the basis of these options, the producers of electricity-based fuels would be motivated to develop more and cheaper renewable energy sources in larger amounts in order to serve the expanded market.

Due to the high opportunity costs in a car market regulated with penalty fees amounting to around € 500 per t CO_2, the VDA and NGVA argue that in many cases the manufacturing of e-fuels would require no subsidies whatsoever. Corresponding legislation is already planned in Switzerland [BUNDESVERSAMMLUNG 2016]. Independently of these proposals, which are aimed at the possible revenue from these fuels, institutions such as dena, the DVGW, DWV, BDEW and many more point to regulatory measures in Germany that they believe are necessary and that affect the cost when producing e-fuels. In their view, a further measure needs to be realized concerning e-fuels produced in Germany, without which it would not be possible to achieve profitability even in the event of good opportunities in terms of revenue. Due to the currently applicable ultimate consumer status of PtX plants, they argue that the electricity that could be obtained at very cheap prices at times of surplus is many times more expensive due to the levy specified in the German Renewable Energy Sources Act.

The aforementioned stakeholders therefore propose lifting the in their view systemically questionable ultimate consumer status. After all, the ultimate consumer is the customer at the filling station. Should this not be possible for formal or political reasons – according to the argument of a PtX alliance founded in 2017 [DVGW 2018] – it would be prudent to compensate this artificial disadvantage compared to conventional biofuels through an adequate CO_2-based “innovation bonus” within the scope of a “market introduction program”.

Detailed observation of the safety of individual fuels

Hydrogen

Hydrogen is highly flammable (F+, R12), but it is not toxic or dangerous to health in any other way.

Hydrogen is much lighter than air and thus dissipates into the atmosphere very quickly. Therefore, diffuse leakages outdoors pose a comparatively low safety risk. When it escapes into the environment, for example through a leaky pipe, there is a risk of ignition. This is highly likely in the event of the gas escaping from a high-pressure storage tank or pipe due to the very low ignition energy. With a span of between approximately 4 to 78 vol %, the ignition range is very large. In the event of ignition, it should be noted that hydrogen flames are barely visible, particularly in daylight, and can be up to 30 m long depending on the pressure at the point of escape (jet fire). This type of fire can act like a burner on neighboring objects and cause their destruction. No health-damaging products are created when hydrogen burns.

When hydrogen is released in an enclosed space (e.g. garage), there is an acute risk of explosion. Enclosed spaces/areas are therefore not suitable for handling hydrogen, unless the spaces/areas have been fitted with safety equipment for this purpose (good ventilation) and, if necessary, approved. At high concentrations, hydrogen has a suffocating effect in enclosed spaces.

If hydrogen is stored at low temperatures, direct contact with liquid hydrogen can cause severe frostbite. This danger exists both in the event of liquid hydrogen escaping and when touching non-insulated components.

The safe storage and handling of hydrogen has been known for a long time from the process industry and is comprehensively covered in rules and standards. No scents are generally added to hydrogen, making it difficult to immediately determine when it escapes through a leak. Corresponding hydrogen sensors are therefore stipulated in storage areas, vehicles and garages.

Hydrogen is stored cold (typically at approximately -253°C and 16.5 bar) as a liquid or under high pressure (200, 350 or 700 bar are typical at 20°C).

If hydrogen is stored under high pressure as a gas, this generally takes place in bundles of extremely robust high-pressure containers (high-pressure gas cylinders). This ensures that neither internal overpressure nor external influence endangers the secure enclosure, meaning that its transport and storage can be viewed as being highly safe. Destruction of these high-pressure cylinders is unlikely even in the event of a traffic accident. Release of the entire volume can virtually be ruled out, as only part of the total transport volume is contained in each cylinder.

During transport and storage in liquid form, a failure of the cooling equipment can cause an impermissible increase in pressure. This must be reduced via safety equipment by releasing hydrogen into the environment in a safe place. The container walls for liquid storage are designed to withstand considerably lower pressures than high-pressure gas storage. In contrast to high-pressure gas cylinders, the containers for liquid storage are comparatively easy to damage through external influences. If it is taken into account that the enclosed quantity in such a container is far greater than in a single high-pressure gas cylinder, the danger resulting from these liquid storage and transport containers is significantly higher than that inherent in high-pressure gas cylinders.

Hydrogen storage facilities and filling stations require special monitoring according to the German Ordinance on Industrial Safety and Health (BetrSichV). Depending on the quantity stored, they may be subject to the requirements set in the German Major Accidents Ordinance (StörfallV, from 5t). There are relevant regulations on transporting hydrogen by road and rail (cf. ADR/RID). It should be noted that not all tunnels can be used when transporting hydrogen (cf. Tunnel Restriction Code categories B to E).

In order to handle hydrogen safely, it must be ensured that the technical equipment is completely leak-tight at all times. This places high demands on the fueling process in particular, which must be performed using valves developed and approved specifically for this purpose and matching tank nozzles to be used on the vehicle. For this reason, a high degree of standardization is required for the fueling technology.

E-CNG

Like fossil natural gas, E-CNG is highly flammable (F+, R12). Although E-CNG is classified as non-toxic, it can cause drowsiness and light-headedness upon exposure. In the case of fire or an explosion, however, incomplete combustion can create toxic products such as carbon monoxide. At high concentrations, E-CNG can have a suffocating effect in enclosed spaces.

E-CNG is lighter than air and therefore dissipates into the atmosphere very quickly. Therefore, diffuse leakages outdoors generally do not pose a high safety risk.

Upon release, E-CNG only ignites if an ignition source is available and it has gathered in a flammable concentration range (4-17 vol%). In the event of ignition, explosive combustion is then possible. In this case, there is a high pressure development in enclosed spaces, which can cause massive damage. As it is stored under high pressure, when E-CNG escapes from a hole-like opening it can produce very long flames, which can act like a burner on neighboring objects and cause their destruction.

In contrast to hydrogen, scents are generally added to E-CNG, meaning that it is noticed when it escapes through a leak. For this reason, no additional sensors are stipulated in vehicles or garages.

E-CNG is typically stored under high pressure (pressure of 200 bar at 15°C is normal). For pumping into the tank, E-CNG filling stations work with pressures that are higher than this, for example 300 bar. Therefore, storage containers/tanks are designed accordingly and are to be classified as safe to operate. To avoid freezing and the associated safety problems, E-CNG must be dried to a dew point of -20°C at 200 bar.

The technology for storing, loading and transporting CNG is already available, as is the technology for fueling vehicles. CNG has been used as a fuel for around 15 years in Germany. It should be noted that E-CNG does not generally need to be transported by road or rail, as it is distributed in the existing pipeline system for natural gas. This allows E-NG to be compressed into E-CNG at the filling station as needed and made available in high-pressure buffer tanks. As a result, the distribution of E-CNG is generally extremely safe.

Nevertheless, should it be necessary to transport CNG by road and rail, the applicable regulations must be observed (cf. ADR/RID). It should be noted that not all tunnels can be used when transporting CNG (cf. Tunnel Restriction Code categories B to E).

When installing natural gas compressors at filling stations, suitable spaces must be provided that comply with explosion and fire protection requirements. Depending on the surroundings, noise protection requirements must also be adhered to.

CNG storage facilities and filling stations require special monitoring according to the German Ordinance on Industrial Safety and Health (BetrSichV). Depending on the quantity stored, they may be subject to the requirements set in the German Major Accidents Ordinance (StörfallV, from 50 t). However, CNG filling stations are generally designed for smaller quantities.

In order to handle E-CNG safely, it must be ensured that the technical equipment is completely leak-tight at all times. This places high demands on the fueling process in particular, which must be performed using valves developed and approved specifically for this purpose and matching tank nozzles to be used on the vehicle.

E-LNG

As a general rule, E-LNG has the same hazard characteristics as E-CNG, which are described above. The additional hazards presented by E-LNG are closely connected to the transformation from the liquid to the gaseous state. In its liquid state, E-LNG is neither flammable nor explosive; the vapors/gases, on the other hand, are highly flammable. E-LNG is therefore classified as a highly flammable substance with the identification F+, R12. E-LNG is classified as non-toxic. In the case of fire or an explosion, however, incomplete combustion can create toxic products such as carbon monoxide. At high concentrations, E-LNG vapors can have a suffocating effect in enclosed spaces.

Cold, liquid E-LNG that escapes in the event of a leak initially spreads on the floor in the same manner as a liquid. If it reaches an ignition source (e.g. a hot engine or an exhaust pipe), a pool fire can occur. When large quantities of E-LNG suddenly escape, there is a danger of a gas explosion (“BLEVE”). Owing to the low storage temperatures for E-LNG, direct contact with E-LNG can cause severe frostbite. There is also a risk of frostbite injuries when touching non-insulated components.

Evaporated E-LNG behaves in the same manner as gaseous natural gas; cf. E-CNG. It ignites if an ignition source is available and it has gathered in a flammable concentration range (4-17 vol %). In the event of ignition, explosive combustion is then possible. In this case, there is a high pressure development in enclosed spaces, which can cause massive damage.

No scents are generally added to E-LNG, for which reason it would not immediately be noticed were it to escape through a leak. The use of corresponding E-LNG sensors is recommended for this reason.

E-LNG is typically stored at a low temperature (-162° C or higher) and at pressures of 1 to 30 bar (3 to 8 bar is normal in the vehicle tank). When storing E-LNG, the low storage temperature must be maintained permanently. The storage tanks are thus equipped with the appropriate insulation. The LNG in the tank is always sufficiently cold during regular operation. If it should heat up despite this, E-LNG expands into the gaseous state due to the transition, causing an increase in internal pressure in closed containers. Storage containers are equipped with pressure relief devices (safety valves), which must discharge the vaporous gas in a safe place.

E-LNG can be distributed via existing import terminals or through decentralized generation plants. It can then be distributed to filling stations via water, rail and road. For road transport, the remarks made above apply (cf. ADR/RID provisions).

E-LNG storage facilities and filling stations require special monitoring according to the German Ordinance on Industrial Safety and Health (BetrSichV). Depending on the quantity stored, they may be subject to the requirements set in the German Major Accidents Ordinance (StörfallV, from 50 t).

In order to handle E-LNG safely, it must be ensured that the technical equipment is completely leak-tight at all times. This places high demands on the fueling process in particular, which must be performed using valves developed and approved specifically for this purpose. matching tank nozzles to be used on the vehicle.

Note:
In Germany, there is no technical code for handling E-LNG comparable to that for LPG. Should other rules describing how to handle liquefied gases not be sufficient, the Dutch rules for E-LNG can be referred to as a source of information. E-LNG is currently a little-used fuel in Germany. It is also not commonly used for industrial purposes. Therefore, no standardization has been implemented in the same way as for LPG or hydrogen. However, large volumes of E-LNG are used as a fuel in European countries. The international LNG industry has thus already established very high safety standards.

E-propane/butane (E-LPG)

E-LPG is a highly flammable substance with the identification F+, R12. It is classified as non-toxic and slightly hazardous to water (water hazard classification 1). In its liquid state, however, E-LPG is neither flammable nor explosive; only the vapors/gases are highly flammable. In the case of fire, incomplete combustion can create toxic products such as carbon monoxide. At high concentrations, it poses a risk of suffocation in enclosed spaces. Direct contact with E-LPG can cause local frostbite injuries due to evaporation/vaporization.

E-LPG is also heavier than air in its gaseous form, can spread on the floor and may collect in dangerous concentrations at low points. Therefore, vehicles that transport LPG or carry it as a fuel may not be allowed to use underground parking garages or sensitive tunnel systems.

In its gaseous form, LPG ignites if an ignition source is available and it has gathered in a flammable concentration range (approx. 1.5 to 10 vol %). In the event of ignition, explosive combustion is then possible. In this case, there is a high pressure development in enclosed spaces, which can cause massive damage. If E-LPG escapes into the environment, for example in the case of a vehicle defect or incorrect fueling, a zone with an explosive atmosphere quickly forms. If it catches fire, this can result in a vehicle fire – with a correspondingly hazardous situation for occupants and the surroundings.

The safe handling of LPG has been known for a long time from the process industry and it has also long been used as a fuel for vehicles. As such, there is a comprehensive set of rules describing the technical devices and equipment needed to handle LPG safely. These rules can be directly applied to the handling of E-LPG.

Scents are added to E-LPG, meaning it would be noticed immediately were it to escape through a leak. The use of corresponding E-LPG sensors is not required for this reason.

E-LPG is typically stored at the ambient temperature and at pressures of 6 to 10 bar. Depending on the design, storage containers are secure to up to 30 bar. Transport containers, such as those on fuel tankers, usually have no pressure relief device and therefore have an intrinsically safe design. Due to the type of container design, the hazard potential of transporting E-LPG can be classified as low.

E-LPG storage facilities and filling stations require special monitoring according to the German Ordinance on Industrial Safety and Health (BetrSichV). Depending on the quantity stored, they may be subject to the requirements set in the German Major Accidents Ordinance (StörfallV, from 50 t).

In order to handle E-LPG safely, it must be ensured that the technical equipment is completely leak-tight at all times. This places high demands on the fueling process in particular, which must be performed using valves developed and approved specifically for this purpose and matching tank nozzles to be used on the vehicle. For this reason, a high degree of standardization is required for the fueling technology.

DME

Like LPG, DME is a highly flammable substance with the identification F+, R12. Due to its characteristics, DME is handled in the same manner as LPG. The same rules and requirements apply with regard to storage, transport and filling.

However, it should be noted that DME is not compatible with all materials that are currently used for handling LPG. This is the case for NBR, for instance. It is thus clear that LPG systems cannot be used for storing and transporting DME without adaptation.

The method for handling DME has been known for a long time, as it is used as a propellant either in its pure form or as a mixture with other hydrocarbons.

E-gasoline

E-gasoline behaves in the same manner as conventional gasoline fuel and is classified as a highly flammable substance with the identification F+, R12. E-gasoline takes a liquid form at ambient pressure and temperature. Therefore, hazards through this distribution path must be observed, such as the hazard to bodies of water and groundwater (water hazard classification 3, severe hazard to water).

If e-gasoline escapes, for example in the case of a vehicle defect or incorrect fueling, a pool of liquid forms with an explosive atmosphere above it. If it catches fire, this can result in a vehicle fire – with a correspondingly hazardous situation for occupants and the surroundings. E-gasoline vapors have immediate effects on exposed persons, such as lightheadedness and irritation of the eyes or respiratory system. At high concentrations, it poses a risk of suffocation.

E-gasoline can be handled in the same manner as conventional gasoline fuel. The handling of gasoline fuels is common worldwide and the existing equipment and systems guarantee a high standard for the safe handling of this hazardous substance. Furthermore, consumers are also knowledgeable about the hazards and are sufficiently practiced in handling gasoline fuel on a day-to-day basis.

E-gasoline is stored and transported at ambient pressure and temperature. Directed emission of tank gases containing e-gasoline must be avoided or reduced by means of gas collection and recovery equipment, while diffuse emissions are to be minimized by using approved seals. Further leak-tightness requirements relate to the avoidance of liquid leaks. In the case of containers and piping installed underground, this is conventionally ensured through double walls.

Gasoline/e-gasoline storage facilities and filling stations require monitoring according to the German Ordinance on Industrial Safety and Health (BetrSichV). Depending on the quantity stored, they may be subject to the requirements set in the German Major Accidents Ordinance (StörfallV, from 2500 t).

Unlike the gaseous fuels examined above, no hermetically sealed valves are to be used when fueling a vehicle. The atmosphere displaced from the vehicle tank is fed into the storage tank of the filling station through suction.

E-methanol

Like fossil methanol, e-methanol is highly flammable (F, R11) and has a toxic effect in the event of inhalation, oral intake or skin contact. It is water-soluble and slightly hazardous to water (water hazard classification 1).

If methanol escapes, for example in the case of a vehicle defect or incorrect fueling, a pool of liquid forms with an explosive atmosphere above it. If it catches fire, this can result in a vehicle fire – with a correspondingly hazardous situation for occupants and the surroundings. Furthermore, e-methanol vapors have immediate health-damaging effects on exposed persons. There is a hazard to health in the event of inhalation, swallowing and skin contact. At high concentrations, it poses a risk of suffocation. In the case of fire or an explosion, incomplete combustion can create toxic products such as carbon monoxide. Formaldehyde should also be considered as a product of decomposition.

The safe handling of e-methanol has been known for a long time in the process industry. Safety requirements and equipment are described in existing rules and standards. As a general rule, the requirements are comparable to those for conventional gasoline.

E-methanol is corrosive. This especially applies to aluminum, zinc, copper, brass and iron, for example. In the presence of air, unalloyed or low-alloyed steels in particular can sustain severe corrosion damage when they temporarily come into contact with e-methanol (risk of stress corrosion). Elastomers such as NBR are not suitable for operation with e-methanol.

E-methanol is stored and transported at ambient pressure and temperature. Due to the toxic effect of e-methanol and the toxic combustion products it can form, there is significant danger in the event of e-methanol escaping. Therefore, e-methanol must be completely sealed during transport and storage. During filling it must be ensured that no atmosphere containing e-methanol is released, which is realized through hermetically sealed systems.

Unlike gasoline, methanol is not commonly handled at filling stations; this has only been realized within the scope of pilot projects.

E-methanol storage facilities and filling stations require monitoring according to the German Ordinance on Industrial Safety and Health (BetrSichV). Depending on the quantity stored, they may be subject to the requirements set in the German Major Accidents Ordinance (StörfallV, from 500 t).

Overall, methanol is to be considered a substance with a high hazard potential, in particular due to its toxic effect. It has to be assumed that methanol cannot be handled in the existing distribution and filling station infrastructure without considerable modifications.

E-diesel

In this assessment, e-diesel is understood to be diesel that is gained through the Fischer-Tropsch (FT) process. FT diesel generally has the same properties as conventional diesel and can be handled in the same manner. The same regulations apply.

Diesel has been given water hazard classification 2.

Diesel is stored and transported at ambient temperature and pressure. Under these conditions, diesel does not present a risk of explosion or fire (non-flammable according to the German Ordinance on Hazardous Substances (GefStoffV)). There is also no risk of a dangerous atmosphere forming. Therefore, diesel can be handled in open systems. Filling stations at which only diesel is filled do not require monitoring according to the German Ordinance on Industrial Safety and Health (BetrSichV). As per the German Major Accidents Ordinance (StörfallV), the quantity threshold for diesel is 2500 t.

E-diesel can be handled in the existing infrastructure without restriction.

E-diesel can be stored in systems which are open to the atmosphere. This also applies for fueling vehicles. If diesel escapes during fueling, a pool of diesel can form. In an open environment, e-diesel does not ignite at ambient pressure and temperature due to its own characteristics. Should it escape, diesel only catches fire if it is heated to more than 55°C through hot surfaces or the influence of burning objects, causing a flammable air/diesel mixture (approximately 0.6 to 6.5 vol %) to be formed. As such, e-diesel can be regarded as a substance with a low hazard potential.

OME 3-5

The physical data of this group of substances largely corresponds to that of diesel with regard to ignition and fire behavior. It has a water hazard classification of 1. OME 3-5 is considered non-toxic. The same applies for vapors and aerosols.

OME 3-5 is a group of substances that has not previously been placed on the market as a fuel. OME 3-5 has merely been used in research and pilot projects.

A comprehensive assessment and classification of OME 3-5 has not yet been performed. However, on the basis of the known data it is clear that OME 3-5 has a significantly lower hazard potential than e-gasoline or e-methanol, for example. Its water hazard classification of 1 also implies that the hazard potential is lower than that of e-diesel. As a result, in this comparison OME is the fuel with the lowest hazard potential.

OME 3-5 can be handled in the existing infrastructure. It is also known that OME does not have a corrosive effect. However, it is to be assumed that modifications are necessary, as it is not compatible with all previously installed materials.

List of abbreviations

a	annum
AE	Alkaline electrolysis
BDEW	Bundesverband der Energie- und Wasserwirtschaft | Federal Association of the Energy and Water Industries
BEV	Battery electric vehicle
BImSchG	German Federal Immission Control Act
BLEVE	Boiling liquid expanding vapor explosion
BtL	Biomass-to-liquid
C	Carbon
C-methane	Compressed methane gas
CH_4	Methane
CI	Compression ignition
CNG	Compressed natural gas
CO_2	Carbon dioxide
CtL	Coal-to-liquid
CV	Calorific value
DE	Germany
DENA	Deutsche Energie-Agentur | German Energy Agency
DI	Direct injection
DIN	Deutsches Institut für Normung | German Institute for Standardization
DME	Dimethyl ether
DVGW	Deutscher Verein des Gas- und Wasserfaches | German Association for Gas and Water
DWV	Deutscher Wasserstoff- und Brennstoffzellen-Verband | German Hydrogen and Fuel Cell Association
EEG	German Renewable Energy Sources Act
EGR	Exhaust gas recirculation
ELY	Electrolysis
EN	European standard
FAEE	Fatty acid ethyl esters
FAME	Fatty acid methyl esters
FCEV	Fuel cell electric vehicle
FLh	Full load hours
FT	Fischer-Tropsch (synthesis)
g	Gram
GHG	Greenhouse gas
GJ	Gigajoule
GtL	Gas-to-liquid
GW	Gigawatt
H	Hydrogen
h	Hours
H_2	Molecular hydrogen
H_2O	Water
HD	Heavy-duty vehicle
HO-BEV	Electric hybrid-overhead line truck
HPDI	High-pressure direct injection
HVO	Hydrotreated vegetable oils
ISO	International Standardization Organisation
k	Thousand
kg	Kilogram
km	Kilometer
kW	Kilowatt

kW h	Kilowatt hour
l	Liter
L-methane	Liquefied methane gas
LCF	Low-carbon fuel
LCOE	Levelized cost of energy
LD	Light-duty vehicle / passenger car
LH_2	Liquefied hydrogen
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MD	Medium-duty vehicle
MENA	Middle East & North Africa
MeOH	Methanol
min	Minutes
MJ	Megajoule
MtG	Methanol-to-gasoline
MVA	Megavolt ampere
MW	Megawatt
NBR	Nitrile Butadiene Rubber
NEDC	New European Driving Cycle
NOX	Nitrogen oxide
OME	Oxymethylene ether
PEM	Proton exchange membrane
PEMFC	Proton exchange membrane fuel cell
PHEV	Plug-in hybrid electric vehicle
Prod.	Production
PtL	Power-to-liquid
PtX	Power-to-x
PV system	Photovoltaic system
R&D	Research and development
RED	Renewable Energy Directive (EU)
RES-E	Electricity from renewable energy sources
ROI	Return on investment
s	Seconds
SI	Spark ignition
SOEC	Solid oxide electrolysis cells
SUV	Sport utility vehicle
t	Tons
TREMP	Topsoe recycle energy-efficient methanation process
TSO	Transmission system operator
TtW	Tank-to-wheel
TW h	Terawatt hours
UNECE	United Nations Economic Commission for Europe
WHTC	World Harmonized Heavy-duty Transient Cycle (UNECE)
WLTP	World Harmonized Light-duty Vehicles Test Procedure (UNECE)
WtT	Well-to-tank
WtW	Well-to-wheel

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The study ›Defossilizing the transportation sector – Options and requirements for Germany‹ has been prepared for general guidance only. The reader should not act on any information provided in this study without receiving specific professional advice. FVV does not guarantee the correctness, accuracy and completeness of the information and shall not be liable for any damage resulting from the use of information contained in this study.s

A briefing paper summarises the most important results of the study: **›Energy paths for road transport in the future – Options for climate-neutral mobility in 2050‹.**

Both publications are available online:

→ www.fvv-net.de/en | Media

→ www.themis-wissen.de

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AUTHOR

Dr. Ulrich Kramer, Ford-Werke GmbH

EDITORS

Johannes Winterhagen, delta eta
Petra Tutsch and Ralf Thee, FVV

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The goal is ambitious: Road transport is to be climate-neutral by 2050. However, this objective can only be achieved if energy generated from renewable sources is used in the transport sector. A working group at the Research Association for Combustion Engines (FVV) has therefore analyzed various mobility scenarios for Germany from both a technical and an economic viewpoint within the scope of this study. The scenarios present completely CO_2-free mobility in 2050, the required energy for which is covered in full by renewable and realistically exploitable sources. The use of electricity, hydrogen and synthetic e-fuels is analyzed in detail in this FVV study, for which experts from automotive manufacturers and suppliers, energy and mineral oil companies, the chemical industry and various associations pooled their knowledge. The results of the study aim to enable a fact-based dialog on the energy sources and powertrains of the future.

Forschungsvereinigung Verbrennungskraftmaschinen e.V.
Research Association for Combustion Engines

Lyoner Strasse 18 | 60528 Frankfurt/M. | Germany
T +49 69 6603 1345 | F +49 69 6603 2345 | info@fvv-net.de

www.fvv-net.de