

# Report

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## **E-Fuels: A techno-economic assessment of European domestic production and imports towards 2050 - Update**



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## EXECUTIVE SUMMARY

Concawe and Aramco have jointly commissioned this study, aiming to conduct a techno-environmental (Part 1) and economic (Part 2) analysis of different e-fuels pathways produced in different regions of the world (North, Centre, and South of Europe, as well as Middle East and North Africa) in 2020, 2030 and 2050, with assessments of sensitivities to multiple key techno-economic parameters.

The e-fuels pathways included in the scope of this study are: e-hydrogen (liquefied and compressed), e-methane (liquefied and compressed), e-methanol, e-polyoxymethylene dimethyl ethers (abbreviated as OME<sub>3-5</sub>), e-methanol to gasoline, e-methanol to kerosene, e-ammonia, and e-Fischer-Tropsch kerosene/diesel (low temperature reaction). The e-hydrogen is considered a final fuel but also as a feedstock for producing other e-fuels.

The study also includes:

- An assessment of stand-alone units versus e-plants integrated with oil refineries
- A comparison of e-fuels production costs versus fossil fuels / biofuels / e-fuels produced from nuclear electricity,
- An assessment of the impact of intermittency and seasonality of renewable energy supply on storage requirements, synthesis plant sizing and production costs,
- An analysis of the context of e-fuels in the future in Europe (potential demand, CAPEX, renewable electricity potential, land requirement, feedstocks requirements)
- A deep dive into the safety and environmental considerations, societal acceptance, barriers to deployment and regulation

The e-fuels techno-environmental assessment (Part 1) has been developed by Concawe and Aramco, using the Sphera GaBi platform as modelling tool, and the e-fuels economical and context assessment (Part 2) has been conducted by the consultants LBST and E4tech, under the supervision of Concawe and Aramco. All the assumptions are fully aligned between both parts of the study.

For the base cases, it is assumed that the e-fuel plant produces 1 million t of e-diesel equivalent<sup>1</sup> per year. Hence, the nameplate capacities of hydrogen generation via water electrolysis and downstream processes depends on the characteristics of regional renewable electricity supply.

### Techno-environmental assessment

In Part 1, a detailed analysis of the e-fuels production efficiency, energy consumption, mass balance and carbon intensity of the produced e-fuels has been conducted in the different regions and timeframes. In addition, sensitivity analyses to relevant technical parameters, such as technology development, electricity power sources (including the grid), carbon sources, carbon capturing location and hydrogen transportation via hydrogen vectors have been included (section 1.7).

The detailed mass and energy balances per type of e-fuel and source of CO<sub>2</sub> is included in Chapter 8.

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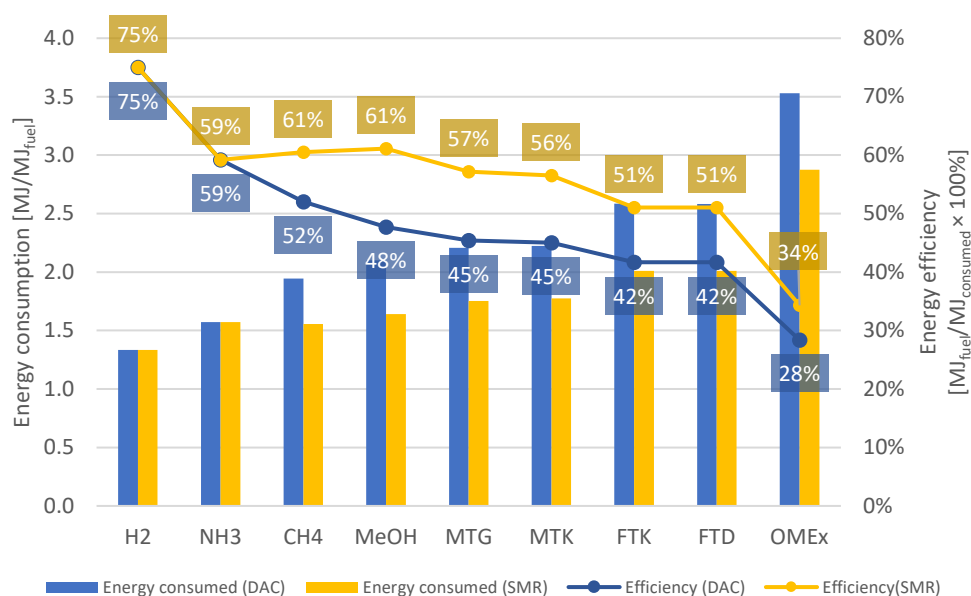
<sup>1</sup> Based on conventional diesel EN 590

For the base cases, a 100% concentrated (point) unavoidable CO<sub>2</sub> source is considered in 2020 and 2030, while only direct air capture (DAC) is considered in 2050. The choice of 100% DAC in 2050 was made for the sake of compliance with announced restrictions concerning the origin of CO<sub>2</sub> for e-fuels [EC 2022], and assuming that the unavoidable and sustainable CO<sub>2</sub> sources in 2050 would be limited. The summary of the assumptions made are included in section 1.5. Sensitivities to a mix of concentrated CO<sub>2</sub> source and DAC are included in section 1.7.

Figure I shows that the energy consumption for e-fuels production increases depending on the length and complexity of the synthesised molecules. The simplest molecules, like hydrogen, require less energy consumption for their production than the more complex ones. As an example, for fuels synthesised from air-captured CO<sub>2</sub> (DAC), 1 MJ of FT e-diesel requires 2.4 times the energy needed to produce 1 MJ of e-hydrogen, while 1 MJ of the more complex molecule e-OME<sub>3-5</sub> needs 3.6 times that amount.

Accordingly, the opposite trend is observed for the e-fuel efficiency, defined as the ratio between the energy contained in the fuel and the energy used to produce the fuel. The simplest molecule, e-hydrogen, has an energy efficiency of 75% driven by the electrolysis efficiency (alkaline electrolyser). The efficiency continues to drop as hydrogen is combined with nitrogen, carbon or oxygen to produce larger fuel molecules. The reduction in efficiency from shorter to longer carbon chains does not increase proportionally: **The energy efficiency of the simplest fuel containing a carbon atom, e-methane, is 52% when produced from air-captured CO<sub>2</sub> (DAC), but it drops to 42% for more complex molecules like FT e-diesel or FT e-kerosene. The lowest efficiency comes from to the e-OME<sub>3-5</sub> (OMEx), a non drop-in fuel and exception compared to the other molecules, estimated at 28%.**

**Figure I:** Comparison of energy consumption and energy efficiency for e-fuels production when using CO<sub>2</sub> from Direct Air Capture (DAC) and a Concentrated CO<sub>2</sub> source (SMR) (Timeline: 2050)



Note: E-fuels production includes electrolysis, carbon capture and fuel synthesis. Upstream power transmission/distribution nor downstream fuel distribution are excluded.

These values correspond to the cases with carbon capture from DAC in the 2050 timeline. If the carbon capture is obtained from a concentrated source, the Fischer-Tropsch diesel and kerosene (FTD and FTK) efficiencies increase up to 51%, and for polyoxymethyl dimethyl ethers (OME<sub>3-5</sub>) they increase to 34%. The energy efficiencies of the production pathways were improved by assuming heat integration between the fuel synthesis and the carbon capture process, whenever possible. Additional potential efficiency improvements, like heat recovery from low temperature electrolysis, were not considered in the base cases.

In Figure II we can observe that, taking North Europe as an example, the net GHG emissions of the different e-fuels pathways in a Cradle-to-grave (CTG) basis are around 4.3-6 gCO<sub>2</sub>eq/MJ (except from the e-OME<sub>3-5</sub>) and around 0.5 gCO<sub>2</sub>eq/MJ if we only count emissions from Operation & Maintenance (O&M). The Well-to-Wheels (WTW) emissions are almost zero because of the use of renewable energy for all operations except power for distribution. These values are in the same order of magnitude for all the e-fuels pathways, as e-fuels that are less energy-intensive to produce (such as e-hydrogen) are more energy-intensive to transport than drop-in fuels such as e-gasoline or e-diesel. The opposite can be observed when comparing the costs of drop-in and non-drop-in e-fuel costs (see Part 2: Economic assessment), because the cost of new infrastructure is relatively more impactful over the total cost than their environmental impact over the lifetime GHG emissions.

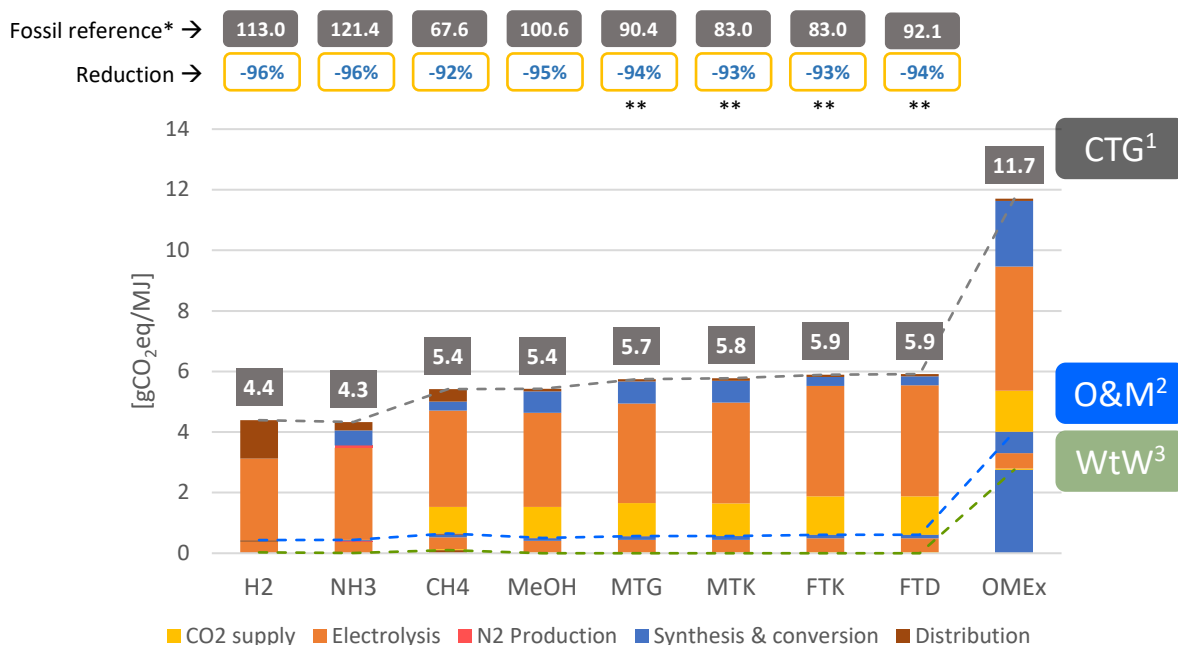
In Figure II we can also observe that GHG emissions are coming mainly from the Electrolysis, with a share of roughly 65-80% of the CTG impact (except for OME<sub>3-5</sub>, where it accounts for around 40%). The emissions from Operation & Maintenance (O&M) represent between 9-12% of the total CTG emissions (around 35% for OME<sub>3-5</sub>). This means that roughly 90% of the total emissions from e-fuels are associated to the infrastructure required, mainly for renewable electricity.

**All the e-fuels pathways (except e-OME<sub>3-5</sub>) achieve a GHG reduction higher than 92% versus the fossil alternative (without emission reductions).** All the e-fuels pathways comply with the RED II limit for ReFuNoBio (28.2 gCO<sub>2</sub>eq/MJ), which mandates a 70% reduction in GHG versus the fossil reference defined in the RED II (94 gCO<sub>2</sub>eq/MJ). This reduction is reached even considering a CTG basis. This might suggest that some more economical schemes might be possible, which are not 100% dependent on green power as the sole energy input but accept some use of fossil energy while staying within the limit. **However, any kind of fossil-green mixed versions of e-fuels is out of the scope of this study. It is important to note that the reduction rates assumed in the present study consider CTG emissions from all feedstocks, including renewable electricity.** If emissions from manufacturing solar panels or wind turbines are excluded (i.e. not CTG basis), the GHG reduction would be even higher.

e-OME<sub>3-5</sub> GHG emissions are around 11.7 gCO<sub>2</sub>eq/MJ. The emissions are more than twice the rest of e-fuels due to the higher complexity of the process that requires more energy consumption, while still being compliant by far to the RED II criteria for sustainable e-fuels (28.2 gCO<sub>2</sub>eq/MJ). OME<sub>3-5</sub> presents other benefits when blending with diesel components such as the low soot and NO<sub>x</sub> emissions [Lumpp et al. 2011] that could be considered for commercial fuel blending.



**Figure II:** Cradle-to-grave (CTG) GHG emissions of different e-fuel pathways (Case: North EU, 2050 as an example. Rest of regions and timelines are included in section 1.6.)



#### Notes:

\* JEC WtT Study v5, GaBi Database / \*\*Additional reduction if RED II fossil fuel comparator (94 gCO<sub>2</sub>eq/MJ) is used

<sup>1</sup>Cradle-to-Grave (CTG) includes Operation & Maintenance emissions plus emissions from building the infrastructure to produce the e-fuels, their feedstocks and their energy requirements

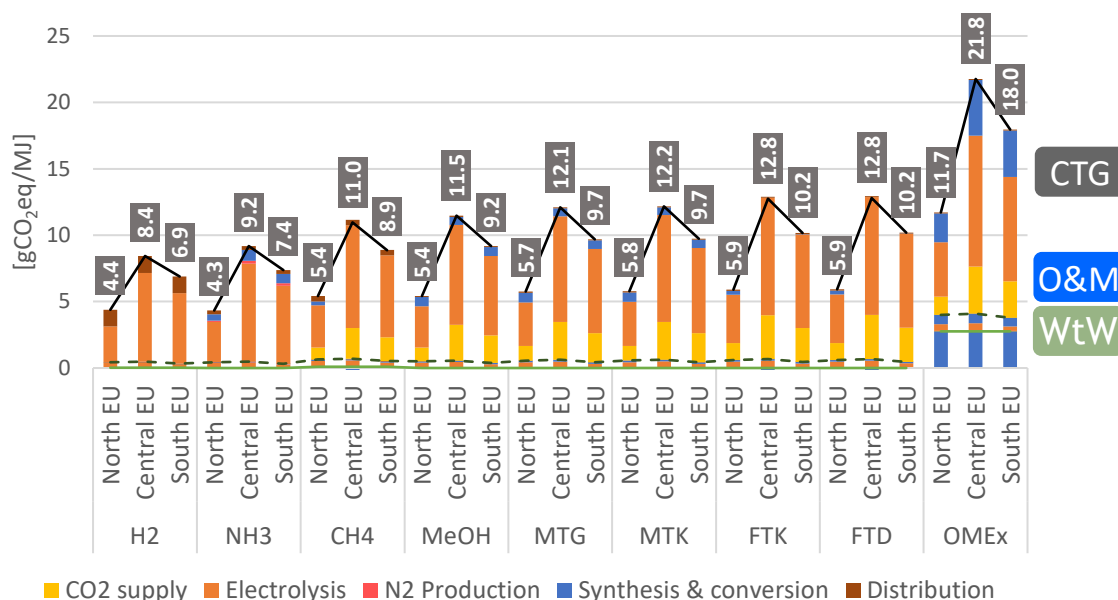
<sup>2</sup>Operation & Maintenance (O&M) includes Well-to-Wheels emissions plus emissions from maintaining the infrastructure to produce the e-fuels, their feedstocks and their energy requirements

<sup>3</sup>Well-to-Wheels (WTW) includes emissions from production, transport and use of the e-fuels, their feedstocks and their energy requirements

In Figure III we show that the GHG emissions from Operation & Maintenance are very similar among regions for all the e-fuels pathways in 2050 (around 0.5 gCO<sub>2</sub>eq/MJ for Northern Europe). However, the CTG values show lower levels in North Europe (around 5.5 gCO<sub>2</sub>eq/MJ), followed by South (around 10 gCO<sub>2</sub>eq/MJ) and Central Europe (around 12.5 gCO<sub>2</sub>eq/MJ) in 2050 for all the e-fuels pathways. The highest values observed for Central Europe are due to the higher carbon intensity of the available renewable power in the region. This results from the lower full load hours of renewable electricity and the higher contribution of photovoltaic renewable electricity (PV) versus wind renewable electricity. PV presents higher CTG carbon emissions than wind electricity (2.6 to 6 times higher depending on the region).

Long distance transport of fuels is mostly subject to the carbon intensity of the fuel used for ship propulsion and is not expected to increase significantly the GHG emissions of e-fuels. The carbon intensity of the electricity used for e-fuel production will still be the most dominant factor.

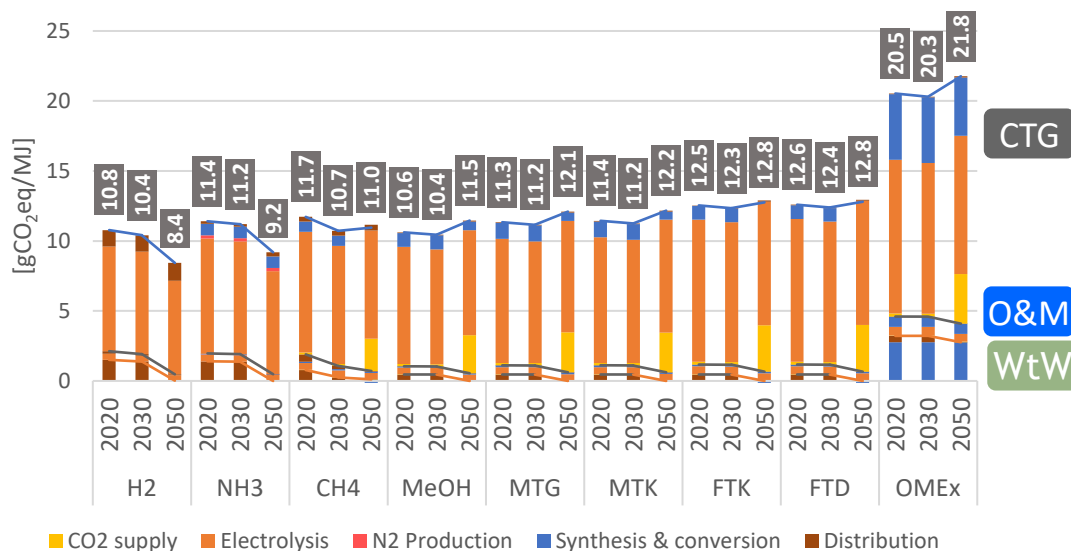
**Figure III:** Cradle-to-Grave (CTG) GHG Emissions from e-fuels production by region in Europe in 2050



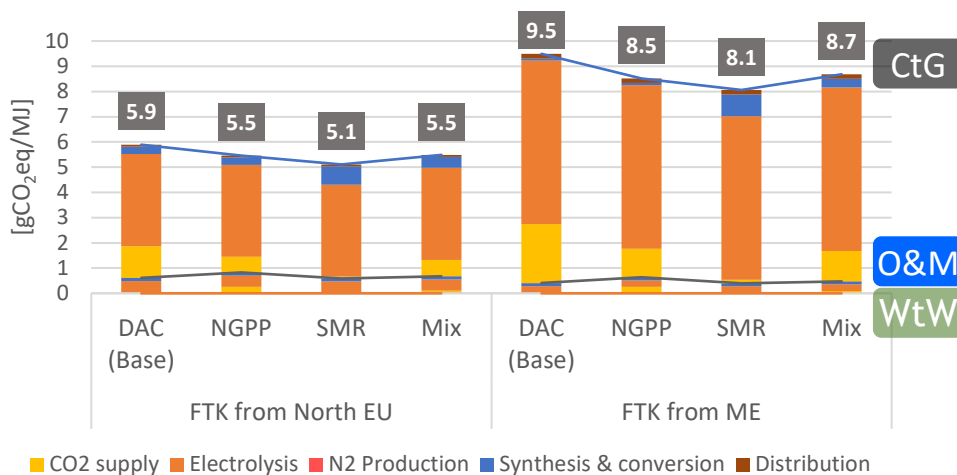
In Figure IV we see that a progressive reduction of CTG GHG emissions is observed over time only for hydrogen and ammonia, while for carbon-based fuels they first drop and then increase. As an example, for FT Kerosene the CTG GHG emissions in gCO<sub>2</sub>eq/MJ for the FT Kerosene go from 12.5 in 2020 down to 12.3 in 2030 and then up to 12.8 in 2050. This is due to opposite effects overlapping: On one side, an improvement in electrolyser efficiencies and the generalization of the use of e-fuels for maritime and truck transport, which favour a decrease over time of H<sub>2</sub> supply and distribution emissions. On the other hand, the displacement of concentrated sources of CO<sub>2</sub> by the use of DAC, which requires more energy-intensive operations to capture CO<sub>2</sub> from the atmosphere and results in a net increase of emissions by 2050. The contribution of Operation & Maintenance remains stable over time (around 0.5 gCO<sub>2</sub>eq/MJ for FT kero) until 2050. The WTW GHG emissions drop steadily until 2050 for all fuels as the emissions from the additional renewable electricity required for DAC is assumed to be 0 on a WTW basis. Sensitivities to this assumption are included in section 1.7.



**Figure IV:** Cradle-to-Grave (CTG) GHG Emissions from e-fuels production in Central Europe in 2020, 2030 and 2050



**Figure VI:** Comparison of GHG emissions from Fischer-Tropsch kerosene production from different CO<sub>2</sub> sources and different production locations in 2050



Note: NGPP = Natural Gas Power Plant

Figure VI depicts the impact of switching to different CO<sub>2</sub> sources for e-fuel synthesis. In the Fischer-Tropsch kerosene pathway, the utilisation of a high CO<sub>2</sub> concentration like steam methane reforming (SMR) pre-combustion off-gases instead of CO<sub>2</sub> captured from the atmosphere via direct air capture (DAC), reduces the GHG impact by 0.8 to 1.4  $\text{gCO}_2\text{eq/MJ}$  depending on the geographical location. The use of flue gases from a natural gas power plant (NGPP), less concentrated than SMR off-gases but more concentrated than air, also reduces the GHG emissions by 0.4 to 1.0  $\text{gCO}_2\text{eq/MJ}$ .

Other sensitivities are further analysed in the body of the report, such as the use of different renewable energy sources, the use of CO<sub>2</sub> captured in Europe for e-fuel synthesis in MENA, and the impact of using energy carriers to transport H<sub>2</sub> instead of liquefaction, in a case where e-fuels are produced in Europe with hydrogen coming from MENA (see Section 1.7.).

## Economic assessment

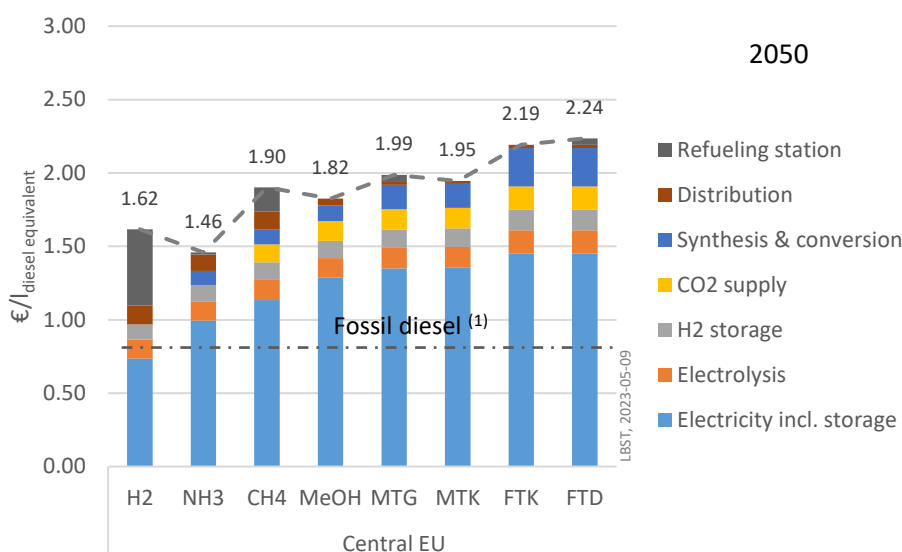
In Part 2, a detailed analysis of the costs for e-fuel supply for 9 e-fuels for 4 geographies (North, Central, South of EU and MENA) and 3 timeframes (2020, 2030 and 2050) plus a series of key sensitivities have been taken into account, leading to more than 100 assessments.

Figure VII shows the costs of e-fuels produced in Central Europe and Figure VIII the ones produced in MENA and transported to EU in 2050, as an example (for the other regions and timeframes, see Chapter 2). The figures show that between 40% and 80% of the cost including electricity storage is coming from the renewable electricity cost.

It also shows the strong correlation between energy requirements for e-fuel production and associated costs. E-fuels that are less energy-intensive to produce generally lead to lower costs of fuel production, such as e-hydrogen and e-methane. However, subject to transport distance and mode, e-hydrogen and e-methane need to be liquefied, thus increasing to the transportation efforts.

Based on the assumptions taken, this economic assessment of e-fuels towards 2050 shows that fuel supply costs across all regions (see Chapter 2) range between 1.7 and 4.6 € per litre of diesel-equivalent in the short term and between 1.4 and 2.8 € per litre in the long term if the outlier OME<sub>x</sub> is excluded. For OME<sub>x</sub> the fuel supply costs range between 3.2 and 6.8 € per l of diesel equivalent in the short term and between 2.7 and 4.3 € per l of diesel equivalent in the long term.

**Figure VII:** Costs of e-fuels produced in Central Europe in 2050



(1) Diesel price: 0.3 €/l (2020) - 0.8 €/l (2050), with crude-oil prices 40 €/bbl (2020) - 110 €/bbl (2050) taken from the EU Commission Impact Assessment [EU COM 2020]

**Figure VIII:** Costs of e-fuels produced in MENA and transported to Rotterdam in 2050

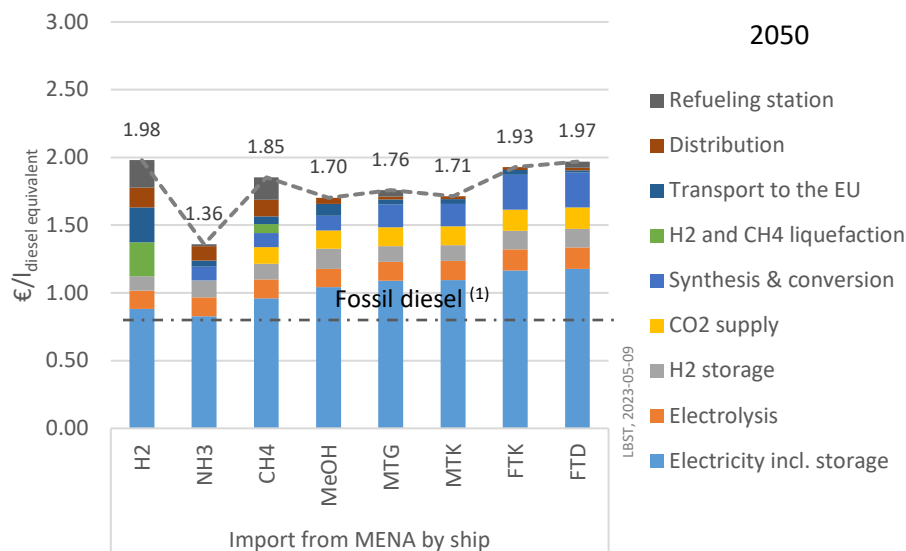
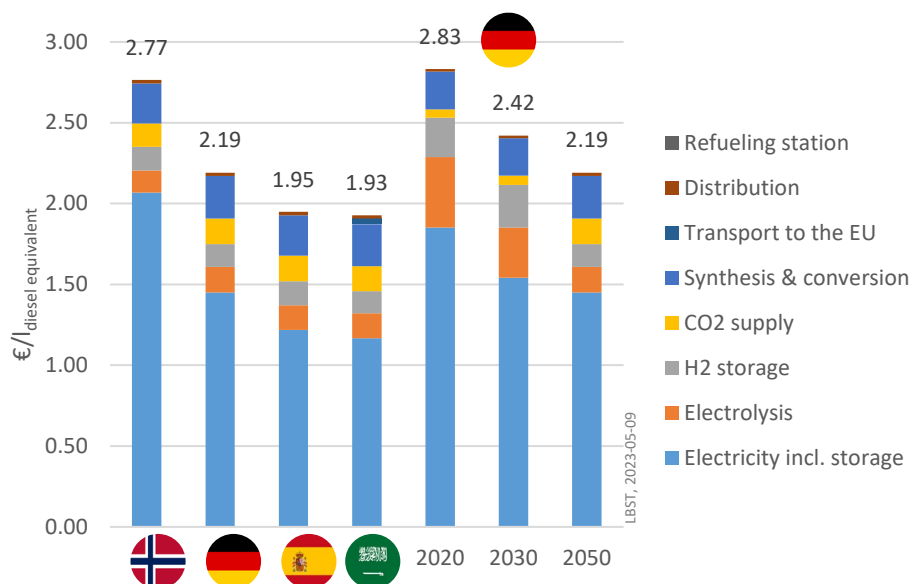


Figure IX shows that Fischer-Tropsch e-kerosene (FTK) produced in MENA and South Europe represent the lowest fuel costs, followed by Central and North Europe. This is directly linked to the full load hours and the renewable electricity cost.

Note that for North Europe, 100% offshore wind has been taken into account assuming that new additional e-fuels plants would rely on this source. In case of using hydropower as primary electricity source, the e-fuel production cost in North Europe would be lower.

Figure IX also shows that e-fuels costs produced in Central Europe are reduced with time (20%) due to decreasing CAPEX for wind & PV plants, electrolysis, and improvement of electrolysis efficiency despite lower availability of concentrated CO<sub>2</sub> sources.

**Figure IX:** Costs of Fischer-Tropsch e-kerosene, first part of the chart refers to 2050 and the second to EU Central (as an example, see the rest of the timeframes and regions in Chapter 2)

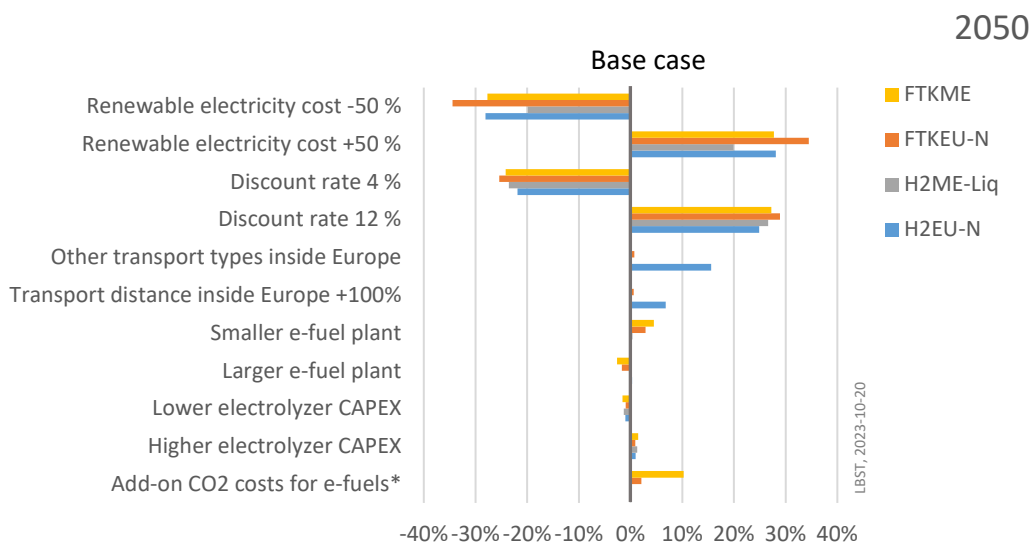


In this chapter, the same H<sub>2</sub> and CO<sub>2</sub> buffer storage capacities have been assumed for all regions. An evaluation of the impact of the regional weather conditions on the size of the buffer capacities, and its cost, is conducted in chapter 4.

### Sensitivities to key economic parameters

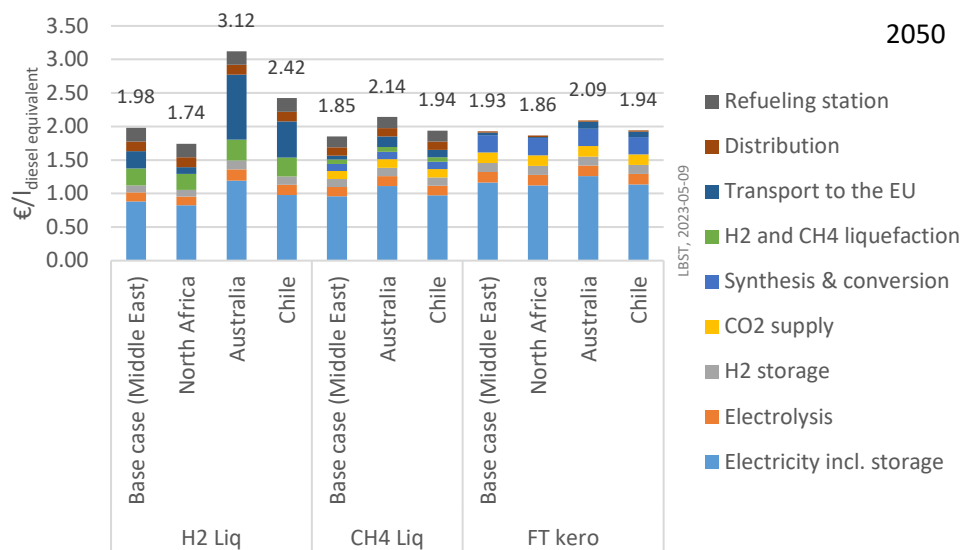
Figure X shows the sensitivities conducted. Electricity costs and discount rate have a significant impact on overall fuel supply costs. 50% change of electricity supply costs or discount rate assumptions resulted in about 25% supply cost. Other factors investigated, such as transport type and distance inside or outside Europe, or e-fuel plant size, have only marginal impacts (single-digit percentage points). The cost impacts relative to the final production costs are very similar for 2020 and 2050 except in case of add-on CO<sub>2</sub> costs for CO<sub>2</sub> for e-fuels. In 2050 CO<sub>2</sub> from concentrated CO<sub>2</sub> sources with CO<sub>2</sub> add-on costs have been applied as sensitivity compared to CO<sub>2</sub> from direct air capture without CO<sub>2</sub> ad-on costs in the base case.

**Figure X:** Sensitivity: impact of variation of selected parameters



A deep dive into the e-fuels production cost when produced and imported to Europe from further regions in the world, such as Australia and Chile, has been conducted and is shown in Figure XI. The results show that for liquid e-fuels, even very long transport distances lead to minor changes of e-fuel production costs, of similar ranges as e-fuels produced domestically in South Europe. For e-hydrogen, long distance transport of many thousands of kilometres significantly increases the production costs.

**Figure XI:** Impact of geography. Imports of e-fuels to EU from further regions



Another relevant sensitivity analysis is the use of alternative carriers for H<sub>2</sub> import to feed synthesis processes. The use of ammonia, methylcyclohexane and methanol as H<sub>2</sub> carrier to feed synthesis processes leads to higher e-fuels production costs (3.20 € per l of diesel equivalent for ammonia, 4.52 per l of diesel equivalent for methylcyclohexane, and 2.93 per l of diesel equivalent for methanol as H<sub>2</sub> carrier compared to 3.14 € per l of diesel equivalent in the base case).

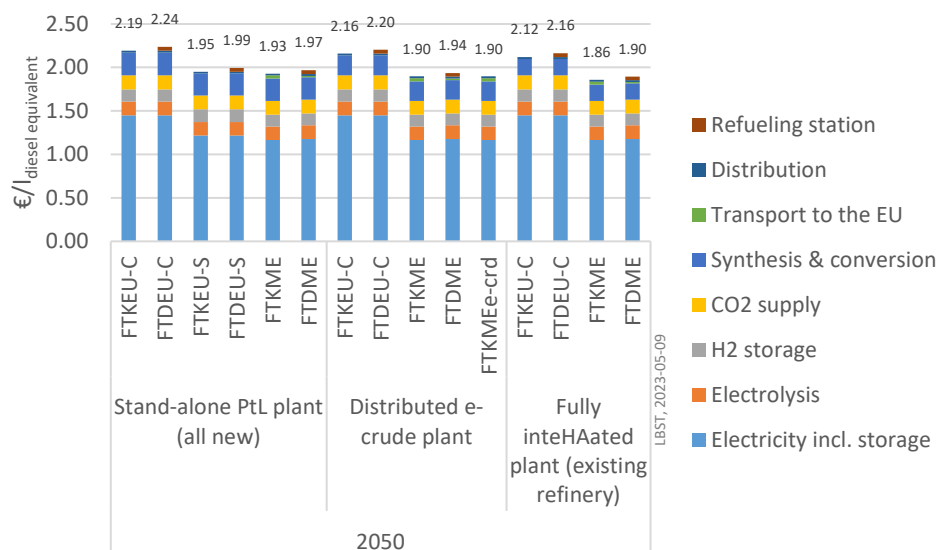
#### Stand-alone plants vs. distributed e-crude plants vs. fully integrated plants

The comparison between a **stand-alone e-fuel plant** (all-new integrated plants for hydrogen production, synthesis to e-crude, and final upgrading), a **distributed e-fuel plants** (new hydrogen production and synthesis to e-crude units, and e-crude upgraded in existing refineries) and a **full integrated e-fuel plant** (the hydrogen production, synthesis to e-crude, and final upgrading is all fully integrated into an existing refinery) is also reported.

Existing **refineries** can play a facilitating role in the energy transition to e-fuels. These have been bulk consumers of hydrogen for decades and offer valuable knowledge in many aspects of hydrogen infrastructure, storage and end-use. Switching natural gas-based hydrogen production at refineries to hydrogen from on-site electrolysis and/or supply via pipeline allows for an accelerated cost reduction path of electrolyser capex and/or deployment of H<sub>2</sub> pipelines. The additional costs for deploying several hundreds of megawatts of electrolyser capacity per average refinery site are amortised over a product output of many gigawatts resulting in marginal additional final product costs in the order of 0.005 €/l<sub>Diesel-eq</sub> [LBST 02/2016]. Furthermore, the existing refining assets can, in part, be used to upgrade Fischer-Tropsch syncrude, allowing an efficient use of existing investments. Since refineries are complex, have diverse configurations, and differ in terms of supply infrastructure and products mix, refinery-specific feasibility studies are recommended to assess opportunities in the field.

The difference between stand-alone and fully integrated plant into a refinery is that there are no capital costs for hydrocracking, fractionation (upgrading), utilities, and logistics in case of the fully integrated plant. Only OPEX is taken into account for these processes. However, these capital cost elements in the total e-fuel production costs have a low contribution (~3%). In 2050 the e-fuel production costs range between 1.93 and 2.24 € per l of diesel equivalent for stand-alone e-fuel plants and between 1.86 and 2.16 € per l of diesel equivalent for e-fuel plants fully integrated into an existing refinery.

**Figure XII:** E-fuels production costs comparison in a stand-alone, distributed and fully integrated plant



In the short to medium term there may be advantages in utilizing existing refineries to minimize capital expenditure. There is a potential advantage of co-processing in the early e-fuel development. The lower the CAPEX, the higher the probability for a company to invest, aiming to have a return of invest in a shorter time.

In 2050, the CAPEX for the stand-alone FT plant without H<sub>2</sub> and CO<sub>2</sub> supply amounts to about 1800-2000 million € including indirect cost. The CAPEX for the distributed FT e-crude plant without H<sub>2</sub> and CO<sub>2</sub> supply amounts to about 1400-1500 million €. The CAPEX of the FT plant fully integrated into an existing refinery without H<sub>2</sub> and CO<sub>2</sub> supply amounts to about 1000-1100 million €<sup>2</sup>.

### Comparison of e-fuel production costs versus fossil fuels, fuels produced from nuclear electricity and biofuels

Based on the assumptions taken, the costs of e-fuel supply are higher than those for fossil crude oil-based fuels, even in 2050 taking into account the improvement in technology and the decrease in electricity costs. In 2050 the costs of e-fuels supply ranges between 1.5 € per l of diesel equivalent for e-hydrogen and 2.8 € per l of diesel equivalent for FT kerosene. The costs of crude oil-based diesel amount to about 0.8 € per l of diesel equivalent in 2050 (for a crude oil price of 110 euro/boe)<sup>3</sup>.

Based on the assumptions taken<sup>4</sup>, nuclear electricity would result in higher e-fuels production costs in 2020 versus PV or wind on-shore electricity if new nuclear plants have to be built (except wind off-shore).

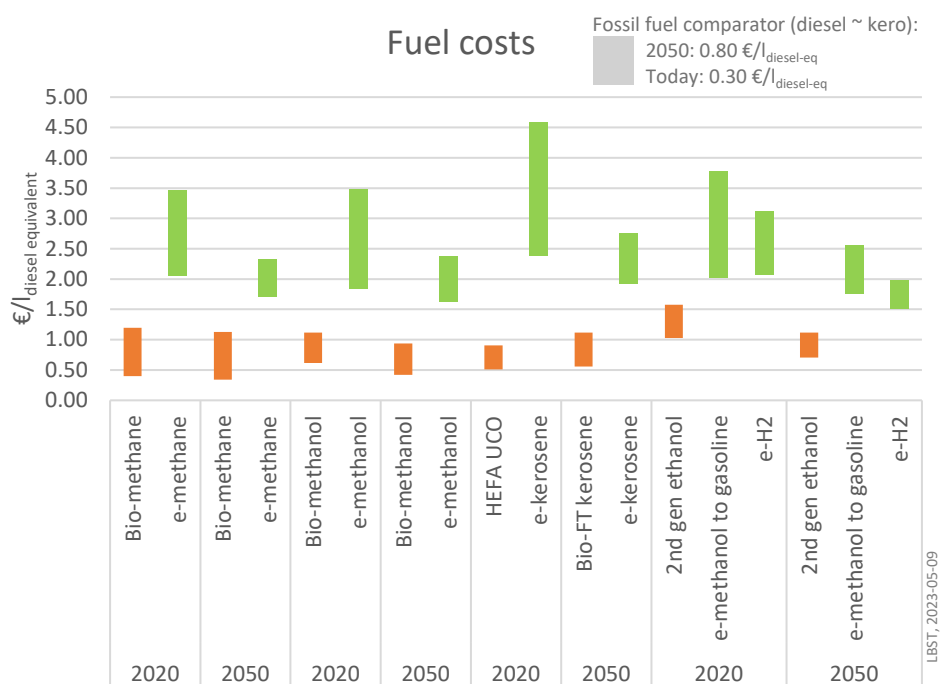
<sup>2</sup> No learning curve has been applied to Fischer-Tropsch plant as the technology can be considered mature. However, the capacity of the plants changes between 2030 and 2050 due to an increase of flexibility of the FT plant leading to a higher CAPEX of the FT plants in 2050 than in 2020 and 2030.

<sup>3</sup> According to crude oil price estimations in the EU Commission Impact Assessment SWD (2020) 177 final [EU 2020]

<sup>4</sup> [Areva 2014], [WNA 2018], [WNN 2018], [CourDeComptes 2012]

Based on biofuel cost data in [IEA 2020], the **production costs** and **GHG abatement costs** for biofuels are lower than those for e-fuels. In 2050, the production costs of **biofuels** are expected to range between 0.3 € per l of diesel equivalent (lower limit for bio-methane) and 1.1 € per l of diesel equivalent (upper limit for bio-methane, Bio-FT kerosene, and 2<sup>nd</sup> generation ethanol). The higher cost for e-fuels is attributable primarily to the cost of green hydrogen production as compared with biomass gasification. The FT process step is broadly the same for the e-fuel and biofuel cases while the cost of producing green hydrogen is high owing to high input electricity costs and, to a lesser extent, high capex (electrolysis). By contrast, the capex of gasification plant is high while the input feedstock costs are relatively low. Over time electrolyser capex is likely to fall (perhaps more quickly than gasification plant capex), but while the cost of renewable electricity will also fall it is not expected to match the lower costs of biofuel feedstock. However, this report provides a high-level cost comparison between e-fuels and biofuels based on acknowledged literature sources. It is neither designed to assess their cost differentials nor differentials between costs and prices.

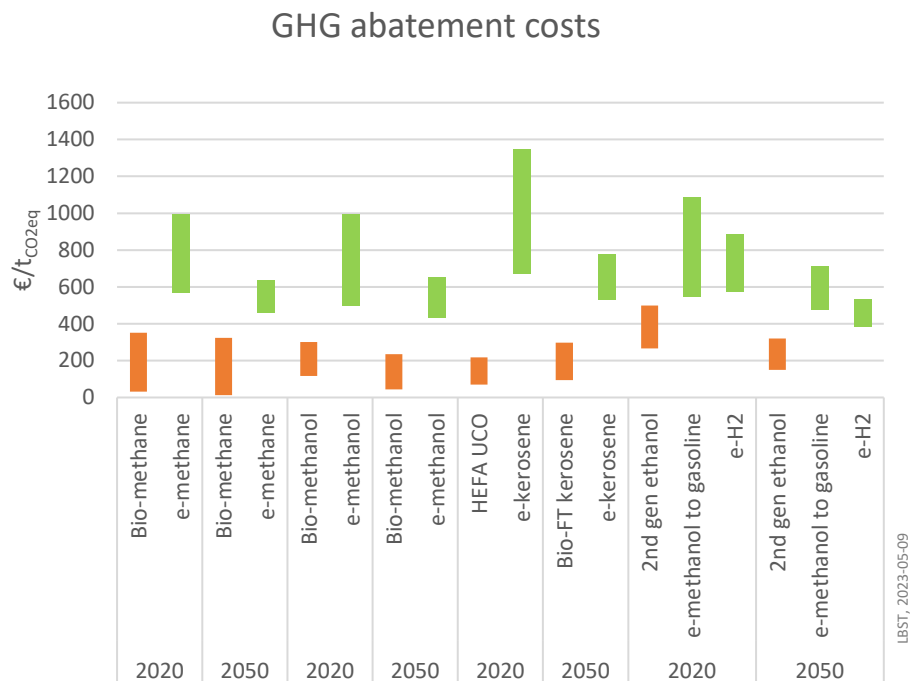
**Figure XIII:** E-fuels versus biofuels production costs



The GHG abatement costs for e-fuels are expected to decrease from about 480-1350 in 2020 to some 390-780 €/t of avoided CO<sub>2</sub>-equivalent in 2050. The GHG abatement costs for biofuels are expected to decrease from 30-500 €/t of avoided CO<sub>2</sub> equivalent in 2020 to some 10-320 €/t of avoided CO<sub>2</sub> equivalent in 2050.



**Figure XIV:** E-fuels versus biofuels GHG abatement costs



It should be noted that these abatement costs refer only to fuel supply (including embedded carbon), without accounting for use-case efficiencies. For example, fuel cell electric vehicles (FCEV) have a higher efficiency than internal combustion engine (ICE) vehicles leading to lower abatement costs for hydrogen fuel. The powertrain assessment has not been included as part of the scope.

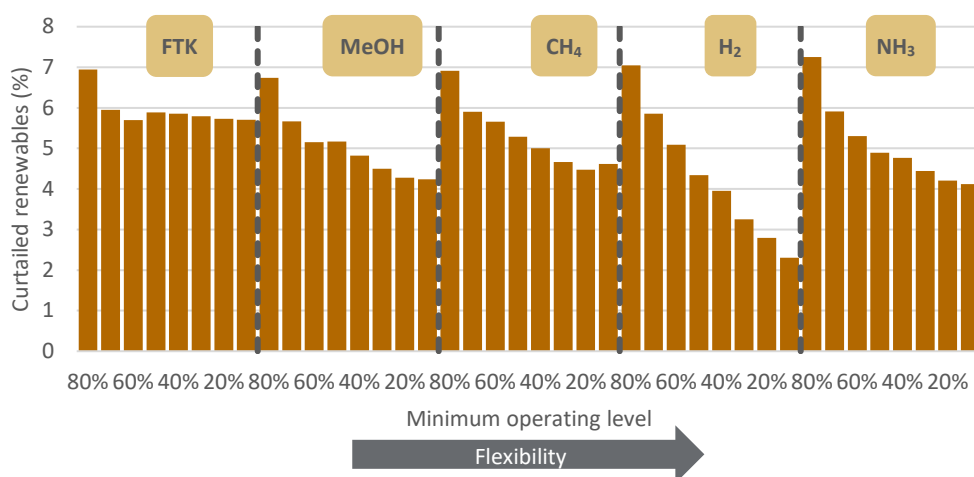
### Intermittency & seasonality of renewable energy supply

The intermittency of renewable electricity sources and the operational flexibility of fuel production processes have a direct impact on the costs of e-fuel production. In this study the degree of variability in renewable power supplies was explored with focus on wind and solar power. The results of this analysis provided inputs for the broad assumptions used in chapters 1 and 2 including the mix of PV and wind, the amount of renewable curtailment, and the size of storage elements. These include electricity storage based on battery systems, hydrogen storage, and CO<sub>2</sub> storage necessary for e-fuels production along with the cost impacts of production flexibility.

PV and wind are intermittent, but complementary to a large extent. Site-specific co-optimization allows to smooth the electricity supply. The PV/wind ratio for least-cost production is driven by the combination of multiple parameters, including CAPEX for the different system facilities (PV and Wind power plants, buffer storage of electricity, H<sub>2</sub> and CO<sub>2</sub>, electrolysis plants and synthesis processes) and the equivalent full load hours. The CAPEX values for renewable electricity and for various components of the e-fuel plant change over time, leading to different PV/wind ratios also evolving over time.

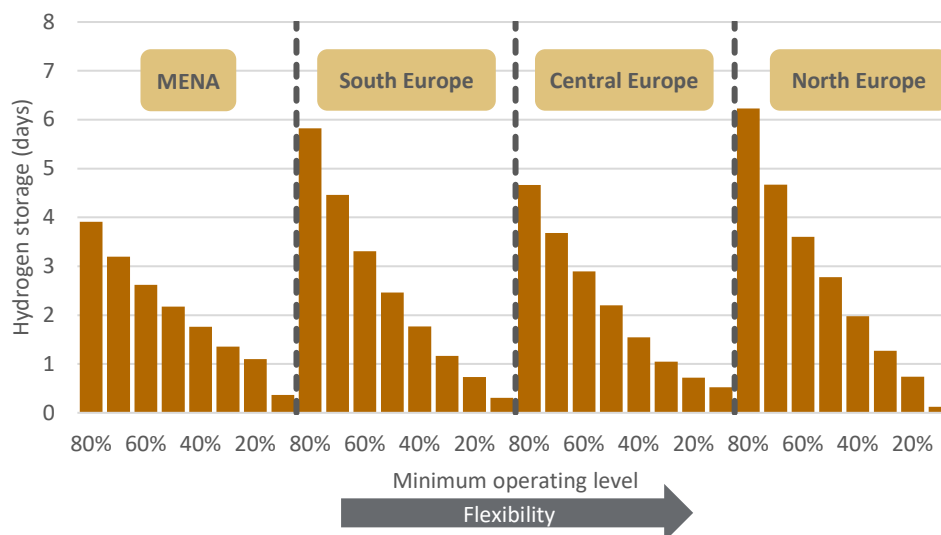
Figure XV shows, for Central Europe, the average amount of curtailed electricity across all operational points and fuels, which is about 5.8%. The level of curtailment decreases when the operational flexibility of the synthesis units increases. The study shows also that in North Europe the curtailment amounts to only 2.6% on average across the range of fuel and conditions modelled. In MENA, the average electricity curtailment across all fuels and all operational conditions is around 6.6%. In South Europe the inflexible cases see a much higher degree of curtailment due to the impacts of periods with low wind speed and low solar irradiation in renewable production leading to overbuilding of assets, with an average of around 6.7% electricity curtailed across all fuels below a minimum part load of 60%.

**Figure XV:** Electricity curtailment in Central Europe (2050)



As shown in Figure XVI, the hydrogen storage capacity required depends on the flexibility of the downstream synthesis processes, such as the maximum change rate in hourly production and the minimum part load. This is also valid for the CO<sub>2</sub> storage capacity. The higher the flexibility of the downstream synthesis process, the lower the hydrogen and CO<sub>2</sub> storage requirements. Furthermore, the characteristics of renewable electricity supply over time also influence the H<sub>2</sub> and CO<sub>2</sub> storage requirements. The study shows that a higher PV share is related to higher H<sub>2</sub> and CO<sub>2</sub> storage requirements, except in regions with regular daily irradiation (batteries for day/night balancing). In most regions, increasing flexibility by 30%-points reduces the storage capacity requirements to less than a half.

**Figure XVI:** H<sub>2</sub> storage requirements (Fischer-Tropsch Kerosene, 2050)



The study shows that, in general, as operational constraints become more flexible, the capacity of the synthesis plant increases with its load factor correspondingly decreasing. This is because the plants need to be oversized to allow higher production in times of high renewable energy availability, and compensate for lower production in times of lower renewable energy production in order to achieve the targeted annual production volume. The final capacity of the plant is a result of the balance between costs and load factors on all the different components in the system.

The study also demonstrates that a significant cost reduction in fuel production can be achieved with moderate flexibility of synthesis technologies. In case of Central Europe 70-85% of the cost reduction potential can be achieved by moving the minimum part load from 80% down to 40%.

### Context of e-fuels in the future of Europe - potential demand and feasibility

Technical **potentials for renewable power production** in Europe (>22,000 TWh/yr, as estimated in Section 5.1) is a factor of seven of today's (~3000 TWh/yr) electricity demand and thus exceeds the foreseeable energy demand for all energy uses in a carbon-neutral future in principle. However, this is subject to social acceptance of the significant infrastructure that would have to be built. The technical potential in other regions of the world such as MENA is even greater but bring with it geopolitical and energy dependency risks.

High and low explorative **scenarios** for e-fuels developed for this project suggest that demand for e-fuels in Europe could be in the range between 63 and 115 million tons of oil-equivalents (or 733 and 1337 TWh<sub>fuel,LHV</sub>, respectively). The low case is in line with the IEA World Energy Outlook 2022 estimates for e-fuels while the high case assumes that the remaining fossil fuels and biofuels in the IEA WEO scenario are also replaced with e-fuels. This would require the deployment of 278 to 1,531 GW of newly installed renewable generation capacity depending on the geographic distribution, generation mix, and demand scenario chosen. Gross land use requirement for this is significant, around 0.1 million km<sup>2</sup>, but it represents only around 2% of the total usable European land area (a little over 4 million km<sup>2</sup>). The

CAPEX required to deliver this amount of e-fuels process plant and associated renewables would lie in the range €1 - 2.3 trillion or the equivalent of an annual investment of between 0.2 and 0.6% of EU GDP. This level of expenditure is consistent with other estimates (e.g. [McKinsey 2020]) of the investment required to achieve net zero, and also with that of other major infrastructures (e.g. the 5G mobile network is estimated at €0.3-0.5 trillion).

**The challenge involved in meeting e-fuels demand in both the high and low explorative scenarios is significant.** Vast amounts of investment are required, and sizable amounts of resources must be mobilised, but it seems to be technically feasible. For example, the low and high explorative scenarios derived from IEA in this study result in a renewable electricity demand of 1319 TWh (low scenario) to 2805 TWh<sub>e</sub>, respectively, which compares to a technical renewable electricity production potential of some 22,000 TWh/a in Europe. The main limitation to exploit the significant renewable electricity potentials in Europe may be social acceptance of mass deployment of wind and solar power plants, but not the technical renewable power production potentials. Besides this, suitable sources of CO<sub>2</sub> are needed as feedstock for electricity-derived synthesised hydro-carbonaceous fuels. Use of concentrated CO<sub>2</sub> sources lead to lower overall fuel costs and higher e-fuel production efficiency, making it an interesting option until 2030 when technologies for direct air capture (DAC) are not yet available at-scale and availability of unavoidable CO<sub>2</sub> sources is foreseen [Concawe 2019, p 46f]. Availability of industrial CO<sub>2</sub> sources, such as from steel production or cement, is set to change with novel production pathways, increased recycling efforts, and a general move towards a more circular economy towards 2050. By then, direct air capture is to take a higher contribution.

Specific **water** demand for electricity-based fuels is negligible compared to water demand for energy crops (few litres versus several thousand litres of water per litre energy-equivalent [UBA 2022]). The use of dry cooling towers and/or closed-loop water cycling is recommended (where needed) to minimise net water demand. Some direct air capture technologies also provide water that can further reduce the net water demand from PtX plants. For regions that are prone to, or already face, water-supply stress, such as MENA region, the net water demand of the e-fuel plant must be supplied by seawater desalination plants (less than 1% of e-fuel total costs). Despite the low specific water footprint, PtX production plants at-scale are significant point water consumers. Diligent assessment of water supply, demand, and reservoir characteristics are a relevant part in the preparation of environmental and social impact assessments (ESIA) accompanying plant approval processes.

A deep dive into the safety and environmental considerations, societal acceptance, barriers to deployment, regulation and new technologies is also included as part of the study (see Chapter 5).

## 1. TECHNO-ENVIRONMENTAL ASSESSMENT

### 1.1. BACKGROUND

Climate change and environmental degradation are an existential threat to Europe and the world. To overcome these challenges, the European Green Deal<sup>5</sup> will transform the European Union into a modern, resource-efficient, and competitive economy, ensuring zero net emissions of greenhouse gases by 2050.

Concawe, in partnership with Aramco, aims to assess the technology developments across different transport sectors and the EU refining system with the potential to contribute to these EU long-term decarbonisation goals, where the potential role of e-fuels was identified as one of several promising technologies.

A series of reports in this area was published in 2019 by Concawe:

- [Concawe 2019 Refinery 2050] Exploring the potential replacement of crude oil in EU refineries by Low Carbon Feedstocks, such as lipids, biomass, and e-fuels  
<https://www.concawe.eu/publication/refinery-2050-conceptual-assessment-exploring-opportunities-and-challenges-for-the-eu-refining-industry-to-transition-towards-a-low-co2-intensive-economy/>
- [Concawe 2019 Role of e-fuels in the European transport system - Literature review] [https://www.concawe.eu/wp-content/uploads/Rpt\\_19-14.pdf](https://www.concawe.eu/wp-content/uploads/Rpt_19-14.pdf)

However, Concawe and Aramco identified some missing points that motivated taking a further step to better understand the e-fuel technologies and the economic impact of their domestic production compared to the option of importing them from other regions in the world.

Concawe and Aramco have jointly commissioned this study. It proposes a techno-environmental (Part 1) and economic (Part 2) analysis of different e-fuels pathways produced in different regions of the world (North, Centre and South of Europe, Middle East, and North Africa (MENA)) with assessments of sensitivities to multiple key techno-economic parameters. The study also includes an assessment of stand-alone units versus e-plants integrated with oil refineries.

The study also includes (Part 2) a comparison of e-fuels production costs versus fossil fuels and biofuels, and an analysis of the context of e-fuels in the future in Europe (potential demand, feasibility, opportunities, and challenges).

The E-fuels techno-environmental assessment (Part 1) has been developed by Concawe and Aramco, using the Sphera GaBi platform (LCA for Experts, as of March 2023) as modelling tool, and E-fuels economical assessment (Part 2) has been conducted by the consultants LBST and E4tech, under the supervision of Concawe and Aramco.

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<sup>5</sup> [https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal\\_en](https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en)

## 1.2. SCOPE OF PART 1: TECHNICAL ASSESSMENT

The main objective of Part 1 is to estimate for the timeframes **2020**, **2030** and **2050**, the following technical parameters:

- **Energy efficiency** based on the **energy consumption** of each e-fuels production pathway, in the form of electricity and heat requirements.
- **Mass balances** of the different e-fuels pathways, to determine the amount of hydrogen, carbon dioxide, water, oxygen, and other feedstock streams needed for their production.
- **Carbon intensities** expressed in grams of CO<sub>2</sub> equivalent per unit of energy for each e-fuel of the scope.

The e-fuels pathways considered in the scope are:

- **e-hydrogen**, in both liquefied and compressed form, used as a final product for fuel cell hydrogen **electric** vehicles, and also as feedstock for producing other e-fuels, abbreviated as **H<sub>2</sub>**;
- **e-methane**, in both liquefied and compressed form, produced by methanation of syngas, abbreviated as **CH<sub>4</sub>**;
- **e-methanol**, produced by single-step reaction of hydrogen and carbon dioxide, used as a final product for **internal** combustion engine vehicles and also as feedstock for producing other e-fuels, abbreviated as **MeOH**;
- **e-polyoxymethylene dimethyl ethers**, produced from **methanol** and oxygen via formaldehyde, abbreviated as **OME<sub>3-5</sub>** or **OME<sub>x</sub>**;
- **e-gasoline** and **e-kerosene** produced from the methanol-to-gasoline and methanol-to-middle distillates reactions, abbreviated as **MTG** and **MTK** respectively;
- **e-ammonia** produced from the Haber-Bosch reaction of **e-hydrogen** and nitrogen, abbreviated as **NH<sub>3</sub>**;
- **e-kerosene** and **e-diesel** produced from syngas via low-temperature Fischer-Tropsch reaction, abbreviated as **FTK** and **FTD** respectively.

The parameters of the e-fuels cited above were analysed in the context of different regions in the world, including:

- Domestic production in Europe in three regions:
  - **North Europe** (taking Norway as the reference)
  - **Central Europe**, inland (taking Germany as the reference)
  - **South Europe** (taking Spain as the reference)
- Production in **Middle East** (Saudi Arabia) / **North Africa** (Morocco), and then imported to the EU, considering two different possibilities:
  - e-Hydrogen import to Europe as final product (hydrogen transported in liquefied form)
  - e-Fuel import to Europe as final products (as drop-in fuels)

Besides the base cases, key sensitivity analyses have been also included to the following relevant parameters:

- **Technology development:** An accelerated scenario is included, taking into account learning curves, improvement in technology (e.g. e-fuels efficiency increase, utilization as fuel for trucks & ships), new technologies penetration (e.g. co-electrolysis).
- **Electricity power sources:** A 100% use of each individual electricity source is considered:
  - 100% Wind: Offshore and onshore (anchored offshore windmills, no floating ones)
  - 100% Solar: Photovoltaic (PV) / Concentrated solar power (CSP)
  - 100% Geothermal
  - 100% Hydro
- **Carbon sources (CO/CO<sub>2</sub>)** (taking into account the extraction/purification process, storage and transportation)
  - From a diluted source, taking as proxy a low temperature Direct Air Capture
  - From combustion off-gases, taking as proxy a natural gas power plant
  - From a concentrated source, taking as proxy Steam Methane Reforming (SMR) off-gas or Autothermal reforming (ATR)
- **Carbon capturing location:** Assuming a CO<sub>2</sub> stream captured in EU and shipped from Europe to MENA to produce the e-fuels
- **Hydrogen transported as chemicals** (as hydrogen vectors in order to facilitate transport), such as:
  - e-Methanol (via methanol cracking)
  - Methylcyclohexane (via toluene)
  - e-Ammonia (via ammonia cracking)

The battery limits of the study include:

- Facilities needed to produce the fuels and their feedstocks (hydrogen, CO<sub>2</sub>, electricity, thermal energy, etc).
- Sea transmission cables from the offshore wind to the coast in the case of North Europe and high-voltage transmission cables from the in the cases of South Europe and MENA.
- The distribution network from the production facilities to the e-fuel service station. Storage of hydrogen has been taken into account to produce e-fuels on a continuous basis, limited to the maximum available full load hours for each specific region (see section 1.5.2).
- Fuel use in the form of combustion emission factors per unit of energy.

The fuel combustion in the engine taking into account specific efficiencies for different powertrain options is not included in the scope.



### 1.3. METHODOLOGY

#### 1.3.1. General methodology

The present study follows the standard of ISO 14040 [ISO1 2006] and 14044 [ISO2 2006] to evaluate the lifecycle impacts of fuels, electricity, batteries and vehicles.

Foreground data, including material and energy inventory balances of fuel and electricity production, plant construction and end-of-life treatments for streams and materials were based on various sources from public literature and available industry data.

Background data, in particular life-cycle inventory (LCI) data for energy and material supply were taken from the 2021 version of Sphera's GaBi LCI databases [Sphera 2021] (GaBi databases renamed as "Managed LCA Content" as of March 2023). The same methodology was applied, and the same data requirements were defined for both the foreground and background data, ensuring their mutual consistency.

The LCA modelling platform used was the GaBi software system for life-cycle engineering [Sphera 2021] (GaBi software renamed as "LCA for Experts" as of March 2023).

#### 1.3.2. System boundaries and scope

The life cycle of a fuel includes the following stages:

- Production of the raw materials: Electricity, hydrogen, carbon dioxide/monoxide, water, oxygen, etc.
- Fuel synthesis: Methanation reaction, Fischer-Tropsch reaction, Haber-Bosch reaction, etc.
- Fuel distribution: Transportation by ship, truck, pipelines required to transfer the fuels from the production sites to the service stations, including storage systems.
- Fuel utilisation: Expressed only as a combustion emission factor per unit of energy, excluding the efficiency of the vehicle engine.
- Manufacturing, use and end-of-life of the facilities and equipment needed to produce and transport the e-fuels and their feedstock streams: Reactors, compressors, pipelines, storage, etc.

The CO<sub>2</sub> emissions of the fuels are all expressed on a "Cradle-to-Grave" basis. This incorporates:

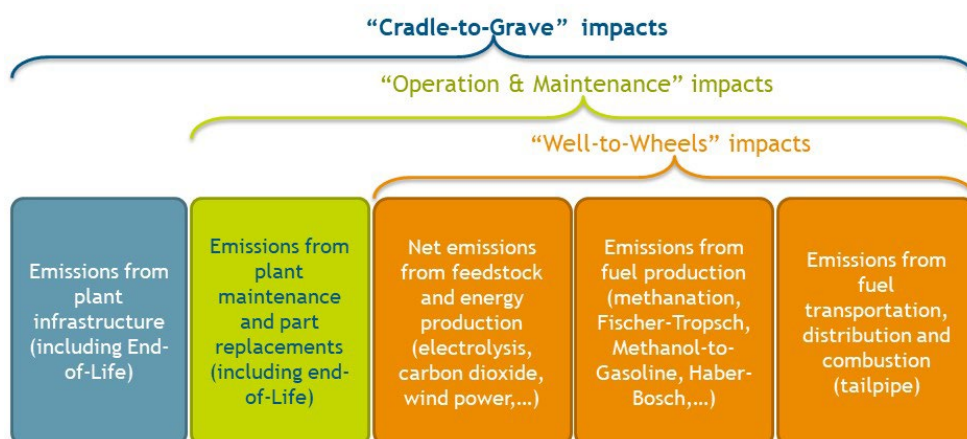
- Net emissions from the fuel production and use: Burdens and credits from energy consumed and produced during synthesis process (fuel burning, steam generation, CO<sub>2</sub> generation from synthesis reactions), transport (fuel burned and power consumed during distribution and storage) and utilisation (combustion);
- Net emissions from the fuel feedstock production: Burdens from energy consumed by the electrolyzers, carbon capture and purification, and power plants, including credits from CO<sub>2</sub> captured;



- Net emissions from building the infrastructure and manufacturing the equipment needed to produce the fuels: Burdens from energy and materials consumed to manufacture solar panels and wind turbines, and net credits from material recycling and energy recovery from incineration. Carbon Capture infrastructure and dismantling is not included but a recent study does not show it to be significant compared to the contribution of the use phase [Terlouw 2021].
- Net emissions from infrastructure maintenance and part replacements: Machine lubrication, turbine blades substitution, etc.

The CO<sub>2</sub> emissions results are also expressed on other scopes for reference purposes, as shown in Figure 1. Scopes such as “Well-to-Wheels” emissions (includes only for net emissions from fuel and feedstock production), and “Operation & Maintenance” (equivalent to the “Well-to-Wheels” impact plus the net emissions from maintenance and replacements).

**Figure 1:** Scopes of the e-fuels life cycle assessment for the present study



## 1.4. PRODUCTION PATHWAYS

The different e-fuels pathways considered in this study are described in this section. Annex 8.1 shows the detailed mass and energy requirements for each of the e-fuels pathways.

### 1.4.1. e-Hydrogen

E-hydrogen (also called green hydrogen when produced from electricity of renewable origin) is a fuel used in fuel cell electric vehicles, but it is also a feedstock for producing the rest of e-fuels. It can be produced by water electrolysis, represented by the following overall reaction:



There are different hydrogen electrolysis technologies, which can be carried out using low-temperature processes (at 50 to 80°C) or high-temperature processes (700 to 1000°C).

Commercially available, low-temperature processes include alkaline electrolysis (AEC) and proton exchange membrane electrolysis (PEM). In comparison, currently high-temperature electrolysis (SOEC) is less developed.

a) Alkaline Electrolysis Cells (AEC)

This is the state-of-the art industrial process for electrolytic hydrogen production. A 20-40% solution of KOH is used and the electrodes coated with Ni as catalyst. Alkaline electrolysis can be applied at normal pressure or under a pressure of up to 30 bars.

b) Polymer Electrolyte Membrane (PEM) Electrolysis

Over the last 20 years, PEM (Polymer Electrolyte Membrane) electrolysis has been developed. In contrast to the alkaline version, it uses pure water and no treatment or recycling of the KOH solution is necessary. PEM stacks are very compact and can be designed for pressures up to 100 bars.

The main drawbacks of this technology are the investment costs which are dominated by the high costs for materials like platinum and iridium. The system cost of PEM electrolyzers is currently about twice that of alkaline systems.

c) Co-electrolysis via high-temperature Solid-Oxide Electrolysis Cells (SOEC)

Higher temperature electrolysis at around 700-1000°C can reduce the electricity requirements as the energy needs can be covered in part by heat input. The electrolyzer uses steam and CO<sub>2</sub> as feeds to produce renewable syngas in only one process step. The integration of waste heat and CO<sub>2</sub> sources reduces electricity demand.

High-temperature electrolysis (SOEC - ion conducting solid oxide electrolysis) are already offered by companies such as Sunfire who offer modular designs, such as the Sunfire-Synlink SOEC technology [Sunfire 2018].

In this study, the low-temperature alkaline electrolysis cells (AEC) technology has been selected as a default technology to compare the different pathways in 2020, 2030 and 2050. In the 2050 Accelerated technology sensitivity scenario, the high-temperature solid-oxide electrolysis (SOEC) technology was selected. The efficiencies of the AEC technologies in 2020, 2030 and 2050 are based on average values from IEA [IEA 2019a]. These efficiencies take into account the electrical and heat efficiencies. The efficiency of SOEC has been taken from the technology provider Sunfire.

**Table 1:** Electrolysis technology and efficiency chosen for this specific study

	2020	2030	2050	2050 Accelerated technology
Electrolysis technology	100% Alkaline	100% Alkaline	100% Alkaline	100% SOEC Co-electrolysis
Electrolysis efficiency	66.5%	68%	75%	82% (Sunfire)

### 1.4.2. e-Methane

Synthetic methane can be obtained through the process called methanation, also known as the Sabatier reaction, which combines CO<sub>2</sub> and hydrogen at a temperature of up to 400°C, a pressure of 30 bar and the presence of a nickel or ruthenium catalyst, to produce methane and water. The reaction is exothermic and expressed as:



Table 2 shows the yields and energy consumptions of the methane synthesis modelled for this study. The data is based on assumptions by [Reiter 2015] and [Saint Jean 2015], where the amount of CO<sub>2</sub> required exceeds slightly the stoichiometric ratio of the reaction to favour the sense of the reaction towards the production of methane.

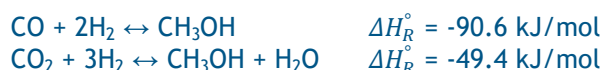
**Table 2:** Mass and energy balance of the methane synthesis process

CO <sub>2</sub> consumption	3.00	kg/kg fuel
H <sub>2</sub> consumption	0.50	kg/kg fuel
CO <sub>2</sub> emissions	0.25	kg/kg fuel
Methane production	1.00	kg/kg fuel
Water production	2.25	kg/kg fuel
Power consumption	1.15	MJ/kg fuel
Heat production	10.8	MJ/kg fuel

### 1.4.3. e-Methanol

Methanol in the present study is analysed as a standalone fuel but also as the main feedstock for the Methanol-to-Gasoline and the Methanol-to-Middle Distillates pathway.

Synthetic methanol from electricity can be either supplied via two-step synthesis using a synthesis gas (2-step route) or a one-step process that uses CO<sub>2</sub> directly as feedstock (direct route). The direct methanol synthesis requires a mixture of carbon dioxide and hydrogen in a molar ratio of 1:2.8 [Toyir 2009]. Main reactions are shown below, with a high selectivity for methanol as product.



Large-scale example of a synthetic methanol plant using the direct methanol synthesis is the George Olah plant in Iceland, run by Carbon Recycling International (CRI) with a capacity of 4,000 t/a [Stefansson 2015].

Table 3 shows the yields and energy consumptions of the methanol synthesis modelled for this study. The mass balances are based on [Stefansson 2015] and the energy balance is based on [JEC 2020].

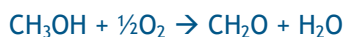
**Table 3:** Mass and energy balance of the methanol synthesis process

H <sub>2</sub> consumption	0.193	kg/kg fuel
CO <sub>2</sub> consumption	1.40	kg/kg fuel
Methanol production	1.00	kg
Water production	0.59	kg/kg fuel
Power consumption	1.07	MJ/kg fuel
Heat production	1.72	MJ/kg fuel

#### 1.4.4. e-Polyoxymethylene dimethyl ethers (OME<sub>3-5</sub>)

Poly(oxymethylene) dimethyl ethers, abbreviated as PODE or, more commonly, OME<sub>x</sub>, are oxygenates of the general structure CH<sub>3</sub>-O-(CH<sub>2</sub>O)<sub>x</sub>-CH<sub>3</sub>, where x is typically 3 to 5 for fuel applications. OME<sub>3-5</sub> are synthetic fuels that blended with diesel fuel in a ratio of 1:4 have experimentally shown strong potential in reducing vehicle pollution, in particular soot formation and indirectly also nitrogen oxides (NO<sub>x</sub>) [Härtl 2015]. This has also been studied in dual fuel applications [García 2019].

OME<sub>3-5</sub> are synthesized from methanol. Their production is complex and can go through alternative routes, but all require the intermediate production of formaldehyde via the following reactions [Schmitz 2016]:



Part of the formaldehyde is oxidized into water and carbon dioxide in a competing reaction:



At first, methanol then reacts with formaldehyde to produce the simplest oxymethylene, methylal:



Finally, the subsequent reaction of methylal with formaldehyde extends the size of the diether, until reaching a certain number of carbons depending on the operating conditions. These reactions are represented by:



where x typically has a size of 3 to 5, hence the name OME<sub>3-5</sub>.

Table 4 shows the yields and energy consumptions of the OME<sub>3-5</sub> process. The mass and energy balances are taken from [Schmitz 2016].

**Table 4:** Mass and energy balance of the OME<sub>3-5</sub> synthesis process

Methanol consumption	1.265	kg/kg fuel
O <sub>2</sub> consumption	0.531	kg/kg fuel
CO <sub>2</sub> production	0.141	kg/kg fuel
OME <sub>3-5</sub> production	1.000	kg
Water production	0.654	kg/kg fuel
Heat consumption	12.8	MJ/kg fuel

#### 1.4.5. e-Methanol-to-Gasoline

Once the e-methanol is available (see section 1.4.3), the production of gasoline requires two additional steps: (a) methanol to olefins (MTO), and (b) light olefin oligomerisation. These reactions are represented as:



The methanol-to-gasoline (MTG) technology was first developed by Mobil in the 1980's, using a multistage process to dehydrate & convert methanol at 300-400°C and 15-20 bar. The overall reaction is exothermic.

The dehydration reaction has high selectivity to water with minimal production of other oxygenates or carbon oxides. The water yield is thus 56-57 wt% on methanol. The hydrocarbon synthesis is a combination of oligomerisation (e.g. to branched aliphatics) and cyclisation to aromatics. The hydrocarbon product typically comprises 78-80% gasoline, 18-20% LPG, 1-2% fuel gas. The MTG gasoline is typically 50% paraffins, 20% olefins and 30% aromatics. The raw gasoline contains some heavy, highly substituted benzene derivatives (e.g. tetramethylbenzene, durene) so it requires hydrotreatment before use as road fuel. The LPG contains ~10% olefins. Upgrading (hydrotreating) of MTG gasoline is included in both the LCA and economic analysis.

Table 5 shows the *allocated* yields and energy consumptions required to produce 1 kg of e-gasoline with the Methanol-to-Gasoline process. It is an allocated balance, corresponding to the part of feedstock and energy associated to the gasoline only, so no co-products are shown. The total mass and energy balances are taken from [Gudde 2021].

**Table 5:** Mass and energy balance of the methanol-to-gasoline process

Methanol consumption	2.29	kg/kg fuel
Hydrogen consumption	0.001	kg/kg fuel
Gasoline production	1.00	kg
Water production	1.29	kg/kg fuel
Power consumption	0.710	MJ/kg fuel
Heat production	1.298	MJ/kg fuel

#### 1.4.6. e-Methanol-to-Kerosene

The conversion of methanol-to-kerosene, more generally referred to as methanol-to-middle distillates (MTGD), follows the same chemical pathway of the methanol-to-gasoline described in section 1.4.5.

MTO for C2= and C3= is commercially proven using MeOH from coal and gas; in principle, the same technology would apply to MeOH from other sources.

Light olefin oligomerisation also has been commercialised. PetroSA has operated its unique “COD” unit at the Mossel Bay facility to convert C3-C6 olefins from high-temperature (Fe-catalysed) Fischer-Tropsch conversion into gasoline+diesel. The plant - designed by Lurgi and commissioned in 1993 - also uses a zeolite-based oligomerisation catalyst.

Several commercial refining technologies exist for oligomerisation of C3= and C4= into C9+ olefins suitable for fuels, speciality alcohols, detergents, and plastics. Examples include Catalytic Condensation (UOP), Selectopol/Polyfuel/Polynaphtha (Axens), NexOctane (Neste/KBR), Dimersol (Axens). Commercial C2= oligomerisation technologies also exist, particularly for production of alpha-olefins for chemicals specialties.

Integrated MTGD technology is not commercially proven although licenses have been offered by Exxon-Mobil (MOGD) and Lurgi (MtSynfuels) primarily as an alternative to FT-synthesis. Patents show solid-acid aluminosilicate catalysts for both dehydration and oligomerisation.

As with MTG and MTO, the MTGD technology shows almost complete methanol dehydration to water and hydrocarbons. The hydrocarbon product contains ~90% liquids (gasoline & diesel) with 5-8% C3+C4 paraffins and 1-2% fuel gas. The liquid product is about 20-30% naphtha, the rest being diesel.

Table 6 shows the *allocated* yields and energy consumptions required to produce 1 kg of e-kerosene with the methanol-to-kerosene process. It is an allocated balance, corresponding to the part of feedstock and energy associated to the kerosene only, so no co-products are shown. The total mass and energy balances are taken from [Gudde 2021].

**Table 6:** Mass and energy balance of the methanol-to-kero/diesel process

Methanol consumption	2.32	kg/kg fuel
Hydrogen consumption	0.01	kg/kg fuel
Kerosene production	1.00	kg
Water production	1.31	kg/kg fuel
Power consumption	0.718	MJ/kg fuel
Heat production	1.314	MJ/kg fuel

#### 1.4.7. e-Ammonia

The main commercial method for producing ammonia is the Haber-Bosch process:



Today, most of the ammonia is produced from natural gas reforming and coal gasification. There is currently a combined production capacity of 110 million tonnes of methanol/a (90 plants).

Ammonia synthesis is an exothermic reaction that requires the use of a catalyst, high pressure (100-1,000 atm), and elevated temperatures (400-550° C).

Table 7 shows the yields and energy consumptions of the e-ammonia process. The mass and energy balances are taken from [Liu 2020] [Oxford 2015] [Reinert 2019].

**Table 7:** Mass and energy balance the ammonia synthesis process

N <sub>2</sub> consumption	0.822	kg/kg NH <sub>3</sub>
H <sub>2</sub> consumption	0.178	kg/kg NH <sub>3</sub>
Ammonia production	1.000	kg
Power consumption	2.16	MJ/kg NH <sub>3</sub>
Heat production	2.18	MJ/kg NH <sub>3</sub>

#### 1.4.8. e-Distillates: Fischer-Tropsch synthesis and CO<sub>2</sub> reduction via Reverse Water-Gas Shift

Fischer-Tropsch (FT) fuels, such as synthetic diesel, gasoline or kerosene from fossil-derived syngas are proven technologies at commercial scale. Some examples are gasification of coal, like Sasol's Coal-to-Liquid facility in Secunda (South Africa) with a capacity of 160,000 barrels per day and steam reforming of natural gas, like Shell's Pearl Gas-to-Liquid plant in Qatar with a capacity of 140,000 barrels per day.

So far, realised PtX projects using FT synthesis to produce hydrocarbons, like the Sunfire pilot plant in Dresden (Germany), are still in a demonstration/research scale with low capacities. Nordic Electrofuel together with Sunfire and Climeworks announced their intention to build a 20 MW plant (related to electricity input) by 2022 [Sunfire 2019].

The simplified FT reaction can be described as the following equation:



Beside alkanes, some alkenes, alcohols, and carboxylic acids are formed. For all products, the molar ratio of the syngas is approximately 2 mol H<sub>2</sub> to 1 mol CO. The product slate is predominantly influenced by the temperature and the catalyst of the FT reaction, on average resulting in lighter hydrocarbons for high temperatures FT (320-350° C) and heavier hydrocarbons for low temperatures FT (190-250° C).

To maximize the yield of transport fuels (gasoline, diesel, kerosene), a low temperature FT can be chosen combined with a hydrocracking step to convert the produced wax into LPG, gasoline, diesel, and kerosene, resulting in a product slate of 37% gasoline, 28% diesel, 32% kerosene and 3% LPG. The hydrocracking step is considered in both the LCA and economic analysis. The products from the hydrocracking reaction could be further upgraded via isomerization to improve the cold properties, and this stage could be done in the hydrocracking reaction adjusting the catalyst.

The Fischer-Tropsch reaction requires a mix of hydrogen and carbon monoxide, which means that the captured CO<sub>2</sub> must be reduced to CO prior to the reaction. This can be achieved through an equilibrium reaction called Reverse Water Gas Shift



(RWGS), an endothermic reaction where CO<sub>2</sub> is reformed with H<sub>2</sub> to produce CO and water. This reaction requires heat and runs at high temperatures ranged between 800 and 1,000°C, and pressures of up to 30 bar to favour the equilibrium to CO, instead of CO<sub>2</sub> and CH<sub>4</sub>. Some electricity is required to run the plant (compression). The RWGS plant is a net electricity and heat consumer.



The model used considers a complete conversion of CO<sub>2</sub>, assuming a set of purification, recycling of unreacted CO<sub>2</sub>, heating, and compression steps. The reactor technology is mature because of its use in the inverse process, the Water Gas Shift (WGS), largely used in the Steam Reforming reaction for hydrogen production from natural gas. The RWGS process, however, is not often used and thus has a TRL estimated at 7 as it will undergo some development before reaching TRL 9 [Detz 2019]. The energy efficiency of the process is estimated at 83%. Future plants are expected to be more efficient thanks to the development of improved methods like sorption enhanced H<sub>2</sub>O removal, currently at TRL 3. This expected technological progress is reflected in the base energy consumption for 2050.

Table 8 shows the *allocated* yields and energy consumptions required to produce 1 kg of e-diesel with the Fischer-Tropsch process. It is an allocated balance, corresponding to the part of feedstock and energy associated to the diesel only, so no co-products are shown. The total mass and energy balances for the Reverse Water-Gas Shift reaction are taken from [Detz 2019] and those for the Fischer-Tropsch reaction from [König 2016] and [de Klerk 2011].

**Table 8:** Mass and energy balance of the FT e-diesel synthesis process (incl. reverse water-gas shift)

Hydrogen consumption	0.493	kg/kg fuel
of which RWGS	0.169	kg/kg fuel
of which FT+Hydrocracking	0.324	kg/kg fuel
CO <sub>2</sub> consumption	3.715	kg/kg fuel
CO equivalent	2.364	kg/kg fuel
Gas burned	0.237	kg/kg fuel
FT Diesel	1	kg
Water production	2.971	kg/kg fuel
Power consumption	1.90	MJ/kg fuel
Heat production (net)	9.22	MJ/kg fuel

#### 1.4.9. Carbon capture

Three different scenarios of carbon capture are considered in the present study:

- CO<sub>2</sub> captured from a point source of high CO<sub>2</sub> concentration. The proxy unit for this case is an amine-based high pressure/low temperature capture unit of a Steam Reforming (SMR) pre-combustion off-gas stream with around 45% CO<sub>2</sub> by volume, as described in [Skrebergene 2015].
- CO<sub>2</sub> is captured from a point source of average CO<sub>2</sub> concentration, around 8.5% by volume. The proxy unit for this case is an amine-based capture plant as described in [IPCC 2005].

- CO<sub>2</sub> captured from the air via low temperature direct air capture (DAC) technology. The energy consumptions are taken from Climeworks [Beuttler et al. 2019].

Table 9 provides a summary of all power and heat consumptions assumed for the three proxy technologies of carbon capture, as well as the reference average CO<sub>2</sub> concentrations of each source taken from [IPCC 2005].

A common assumption for all three sources is that the CO<sub>2</sub> is considered as unavoidable waste and carries no carbon burden or cost at its source. Therefore, the only contribution to the carbon intensity of the CO<sub>2</sub> feedstock to the e-fuels synthesis processes is given by the capture and purification stage. Same consideration for the cost of CO<sub>2</sub>, whose value is derived from the CAPEX and OPEX of the carbon capture process only with no reference to a carbon price.

To ensure high purity of the CO<sub>2</sub> produced for the downstream synthesis reactions, an additional CO<sub>2</sub> liquefaction stage was incorporated to the carbon capture process. The main purpose of this operation is to eliminate traces of water and other contaminants. Energy consumption for carbon dioxide liquefaction is estimated at 0.104 kWh/kgCO<sub>2</sub> [Element Energy 2018].

**Table 9:** Energy consumptions and CO<sub>2</sub> concentrations for different carbon capture options

Source Stream of CO <sub>2</sub>	Concentrated	Average	Diluted
Proxy technology	Steam Reforming (SMR) pre-combustion gas	Natural Gas Power Plant (NGPP) flue gas capture	Direct Air Capture (DAC)
Power Consumption [MJ/kgCO <sub>2</sub> ]	0.14 <sup>(1)</sup>	0.27 <sup>(2)</sup>	1.44 <sup>(3)</sup>
Heat consumption [MJ/kgCO <sub>2</sub> ]	0.90 <sup>(1)</sup>	3.00 <sup>(2)</sup>	5.76 <sup>(3)</sup>
CO <sub>2</sub> concentration [by volume]	45%	8.5%	0.04%

Sources: (1) [Skrebergene 2015]  
(2) [IPCC 2005]  
(3) [Beuttler et al. 2019]

#### 1.4.10. Blending conditions

Most of the liquid e-fuels<sup>6</sup> are generally considered as ‘drop-in fuels’, meaning they are assumed compatible with the existing car fleet. This should be analysed in detail depending on the e-fuel. In Figure 2, the qualities of liquid e-fuels are compared with standard fuels.

##### a) Gasoline fuel standards

Figure 2 is showing the gasoline existing gasoline fuel standards (EN 228) versus the e-methanol-to-gasoline product properties.

<sup>6</sup> Liquid fuels = liquid state under standard temperature (0°C) and pressure (1 MPa) conditions.

Whilst methanol is a potential gasoline substitute, its Lower Heating Value (LHV) is significantly lower than the one of gasoline and even ethanol, and it produces corrosivity and issues with the material use in the car fuel feeding system. The use of pure e-methanol or higher blend rates requires adapted vehicles; hence e-methanol does not have drop-in capabilities. The product of the Methanol-to-Gasoline (MTG) process is a much better substitute for gasoline in spark-ignition engines and represents a gasoline blending component that can be upgraded to full EN 228 compliance by hydrogenation of polyaromatics. The hydrogenation process of MTG-based gasoline was taken into account in the present study.

#### b) Diesel fuel standards

Figure 3 shows the two existing diesel fuel standards, EN 15940 and EN 590:

- D EN 15940 is the fuel standard for paraffinic diesel. This specification was designed for HVO and GtL, and it is valid for e-diesel. It is similar to conventional diesel (EN590), except from the differences in density (class B 780-810 kg/m<sup>3</sup> versus EN 590 820-845 kg/m<sup>3</sup>). Some aspects to consider in the use of e-diesel are:
  - Improvement of the lubricity by additives
  - Cold properties adjustment through production process (isomerization and distillation)
  - Minor adjustments in the engine (fuel injection control and SCR post-treatment)
  - The impact on LCA of these adjustments in lubricity or cold properties are out of the scope of this project. EN 590 is the fuel standard for conventional diesel. It is possible for e-diesel to match the specification EN590 by blending with other higher-density components (e.g.: FAME, pyrolysis oil). Fischer-Tropsch e-fuels are paraffinic fuels, which require hydrocracking and isomerization to improve the cold properties and fit in the diesel standard EN 590. Paraffinic fuels have substantially higher cetane numbers ( $\geq 70$ ) and are (nearly) free from aromatics.

e-OME<sub>3.5</sub> requires blending with diesel components to meet the diesel fuel standards, with the potential of achieving ultra-low NO<sub>x</sub> and soot emissions levels.

#### c) Jet fuel standards

e-Jet (e-kerosene) must comply with the ASTM D7566 standard, which gathers the technical specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons and includes the technical specification of synthetic paraffinic kerosene from the Fischer-Tropsch process (SPK-FT) (Table 10). Currently, e-jet can be blended up to 50% by volume with conventional blending components or Jet A or Jet A-1 fuel certified to Specification ASTM D1655 (Standard Specification for Aviation Turbine Fuels). Final product, meaning aviation turbine fuel manufactured, certified, and released to all the requirements of ASTM D7566 (Table 11), should meet the requirements of Specification ASTM D1655 (Standard Specification for Aviation Turbine Fuels) and shall be regarded as Specification D1655 turbine fuel. Therefore, the final product does not present any differences with conventional aviation turbine fuel and hence, once the fuel is released according to ASTM D7566, the specific requirements of such specification will be no longer available, and any recertification shall be done in accordance with ASTM D1655.

**Figure 2:** Liquid e-fuel properties (compared to gasoline fuels standards).  
Source: [Shell 2018]

## 12 COMPARISON OF PTL FUELS WITH RELEVANT EN 228 FUEL PROPERTIES ...

	Gasoline fuel EN 228:2012	Methanol-to- Gasoline	Methanol	Ethanol
Research Octane number	$\geq 95$	92	114	130
Density @15 °C (kg/m <sup>3</sup> )	720 - 775	728 - 733	792	789
Reid vapour pressure (kPa)	45 - 60 (summer class A)	62	13	6
Oxygen content (% m/m)	$\leq 3.7$	n.a. *	50	34.7
Oxidation stability (Min)	$\geq 360$	260 - 370	n.a.	n.a.
Aromatic content (% v/v)	$\leq 35.0$	26.5	0	0
Distillation (°C)	$\leq 210$	29 - 209	65	78
Typical lower heating value (MJ/kg)	42.7-44.2	n.a. *	22.7	29.7
Typical flash point (°C)	-20	n.a. *	9	12

\* Likely similar to EN 228 Gasoline based on the other properties; n.a. = data not available

EN 228; Maus et al. 2014; EM 2017

**Figure 3:** Liquid e-fuel properties (compared to diesel fuel standards).  
Source: [Shell 2018]

## ... AND WITH SELECTED EN 590 FUEL PROPERTIES

	EN 590: 2013	EN 15940: 2016	DME	OME <sub>1</sub>	OME <sub>3</sub>	OME <sub>4</sub>	OME <sub>5</sub>	OME <sub>6</sub>
Cetane number	$\geq 51$	$\geq 70$	55 - 60	28	72	84	93	n.a.
Density @15 °C (kg/m <sup>3</sup> )	820 - 845	765 - 800	660	863	1035	1079	1111	1140
Polycyclic aromatic hydrocarbons (% m/m)	$\leq 8$	<1.1*	0	0	0	0	0	0
Flash point (°C)	> 55	> 55	-41	-32	54	88	115	n.a.
Lubricity, HFRR (60 °C) (µm)	460	460	n.a.	759	534	465	437	n.a.
Kinematic viscosity (40 °C) (mm <sup>2</sup> /s)	2 - 4.5	2 - 4.5	0.12 - 0.15**	0.36**	0.87	1.33	1.96	n.a.
Distillation (°C)	Ca. 180 - 360	Ca. 180 - 360	-24.8	42	155.9	201.8	242.3	273
Typical lower heating value (MJ/ kg)	42.9	44.1	28.4	23.3	19.6	19.0	18.5	17.7
Typical Oxygen content (% m/m)	< 1	< 0.5	34.8	42.1	48 ± 1		49.5	

\* Likely to be 0 due to EN 15940 specified Total Aromatic Content  $\leq 1.1$  % m/m  
\*\* Measured @ 25°; n.a. = data not available

Shell 2015; Lautenschütz et al. 2016; Wachtmeister et al. 2017

The table in Figure 2 shows that in the methanol-to-gasoline process, octane and Reid Vapour Pressure need to be improved to meet specification, with impact in terms of cost of upgrading (CAPEX, OPEX) and LCA emissions. This is out of the scope of this project, and it will be analysed in a third project (to be published).

**Table 10:** Liquid e-kerosene (paraffinic kerosene from Fischer-Tropsch, SPK-FT specification)

Characteristic	Unit	Limits		Norm
		Min	Max	
Total acidity	mg KOH/g	-	0.015	ASTM D3242
Volatility				
Distillation	°C			ASTM D86
10% vol	°C	-	205	
50% vol	°C	Inform		
90% vol	°C	Inform		
T90-T10	°C	22	-	
Final point	°C	-	300	
Residue	%v/v	-	1.5	
Loss	%v/v	-	1.5	
Simulated distillation	°C			ASTM D2887
10% vol	°C	Inform		
20% vol	°C	Inform		
50% vol	°C	Inform		
80% vol	°C	Inform		
90% vol	°C	Inform		
Final point	°C			
Inflammation point	°C	38.0	-	ASTM D56
Density 15°C	kg/m <sup>3</sup>	730	770	ASTM D4052
Freezing point Jet A	°C	-	-40.0	ASTM D5972
Thermal stability JFTOT (2,5 h a T control)				ASTM D3241
Temperature	°C	325	-	
Differential pressure drop	mm Hg	-	25	
Classification				
(1) Annex A1 VTR, color code VTR		Lower to 3, no marks or anomalies colour deposits		
(2) Annex A2 ITR o Annex A3 ETR, nm average in area of 2,5 mm <sup>2</sup>			85	
Cycloparafins	%m/m		15	ASTM D2425
Aromatics	%m/m		0.5	ASTM D2425
Parafins	%m/m	Inform		ASTM D2425
Carbon and Hydrogen	%m/m	99.5		ASTM D5291
Nitrogen	mg/kg		2	ASTM D4629
Water	mg/kg		75	ASTM D6304
Sulfur	mg/kg		15	ASTM D5453
Metals (Al, Ca, Co, Cr, Cu, Fe, K, Li, Mg, Mn, Mo, Na, Ni, P, Pb, Pd, Pt, Sn, Sr, Ti, V, Zn)	mg/kg		0.1 (metal)	ASTM D7111
Halogenates	mg/kg		1	ASTM D7359

**Table 11:** Jet A-1 specification

Characteristic	Unit	Limits		Norm
		Min	Max	
Aspect		Clear, shiny, free of solid materials and water at ambient temperature		
Total acidity	mg KOH/g	-	0.10	ASTM D3242
Aromatics content	%v/v	8	25.0	ASTM D1319
Total sulphur	%m/m	-	0.30	ASTM D4294
Total mercaptans	%m/m	-	0.003	ASTM D3227
Distillation	°C			ASTM D86
10% vol	°C	-	205	
50% vol	°C	Inform		
90% vol	°C	Inform		
T50-T10	°C	15	-	
T90-T10	°C	40	-	
Final point	°C	-	300	
Residue	%v/v	-	1.5	
Loss	%v/v	-	1.5	
Inflammation point	°C	38.0	-	ASTM D56
Density 15°C	kg/m <sup>3</sup>	775	840	ASTM D4052
Freezing point Jet A	°C	-	-40.0	ASTM D5972
Freezing point Jet A-1	°C	-	-47.0	ASTM D5972
Kinematic viscosity -20°C	mm <sup>2</sup> /s	-	8.000	ASTM D445
Smoking point	mm	25.0	-	ASTM D1322
Calorific value	MJ/kg	42.80	-	ASTM D4529
Corrosión lámina de cobre (3h a 50°C)	scale	-	Class 1	ASTM D130
Thermal stability JFTOT (2,5 h T control)				ASTM D3241
Temperature	°C	325	-	
Pressure drop	mm Hg	-	25	
Clasification				
Annex A1 VTR, colour code VTR		Lower than 3, without marks or anormal colour deposits		
Annex A2 ITR or Annex A3 ETR, nm average area 2.5 mm <sup>2</sup>			85	
Existing gums	mg/100 ml	-	7	ASTM D381
Water separation index				ASTM D3948
Without additive antistatic		85	-	
With additive antistatic		70	-	
Electric conductivity	pS/m	50	600	ASTM D2624
Lubricity	mm	-	0.85	ASTM D5001

## 1.5. BASE CASE ASSUMPTIONS

The main assumptions for the base cases taken for this study are described in Table 12.

The standard technology chosen for e-hydrogen production is alkaline electrolysis, with the only exception of the 2050 Accelerated Technology (AT) scenario, which uses co-electrolysis to produce syngas directly from CO<sub>2</sub> and water steam (see section 1.4.1).

The source of CO<sub>2</sub> is considered available onsite in all cases, from specific sources or combination of sources depending on the time horizon: In 2020 and 2030, a concentrated source, e.g. Steam Reforming (SMR) or Auto Thermal Reforming (ATR) off-gases, is considered as the main CO<sub>2</sub> source. In the 2050 and 2050 AT scenarios, CO<sub>2</sub> from atmosphere via Direct Air Capture (DAC) is assumed.

Regarding the transportation of the final e-fuels, the assumptions also change across the timeline: In 2020 and 2030, it is assumed that the transportation modes relying on liquid fuels (ships and trucks) will consume conventional fossil fuels only, supposing that not enough e-fuels will be available from commercial plants. However, in 2050 we consider that the liquid fuels used will be 100% e-fuels (e-diesel), assuming a big deployment of the technology following stringent directives for road and maritime transport.

**Table 12:** Base case assumptions

Base case parameter	2020	2030	2050	2050 AT
Electrolysis technology	100% Alkaline	100% Alkaline	100% Alkaline	100% Co-electrolysis
Electrolysis efficiency <sup>2</sup>	66.5%	68%	75%	82% (Sunfire)
Source of CO <sub>2</sub> <sup>1</sup>	100% Concentrated source	100% Concentrated source	100% Diluted source (DAC)	100% Diluted source (DAC)
Source of renewable energy for e-fuels production	North EU: Norway renewable mix Central EU: Germany renewable mix South EU: Spain renewable mix MENA: Kingdom of Saudi Arabia (KSA) renewable mix Africa: Morocco			
Source of energy for transport	Truck: Fossil fuels <sup>3</sup> Ship: Fossil fuels + Fuel transported <sup>4</sup>	Truck: Fossil fuels <sup>3</sup> Ship: Fossil fuels + Fuel transported <sup>4</sup>	Truck: e-diesel Ship: 100 % e-fuel transported <sup>5</sup>	

Notes:

<sup>1</sup>Proxies and concentrations for CO<sub>2</sub> sources: See chapter 1.4.9

<sup>2</sup>Based on average values from IEA 2019a

<sup>3</sup>Conventional diesel for trucks, low-sulfur marine gasoil (LSMGO) for ships

<sup>4</sup>For liquid e-H<sub>2</sub>, e-Methane (LNG) and e-NH<sub>3</sub>, boil-off contributes to ship propulsion (46%, 60% and 29% of total energy respectively)

<sup>5</sup>Only applies for e-H<sub>2</sub>, e-CH<sub>4</sub>, e-NH<sub>3</sub>, e-methanol, e-diesel. Ships use e-diesel for the rest (methanol-to-gasoline, methanol-to-kerosene, e-kerosene, OMEx) assuming that there will be enough e-fuel for harder-to-abate sectors, including maritime transport in 2050.

(100% use of e-diesel for maritime is aligned to the minimum requirements to meet the IMO's GHG intensity ambition in 2050: 50% total emissions reduction and 70% carbon intensity reduction, based on 2008 CO<sub>2</sub> emissions.

The first two assessments of this study (chapters 1 and 2) assume optimised sizes of the fuel synthesis plants, the renewable electricity generation plants (PV or wind) and storage capacities based on the results found in chapter 4, therefore considering the intermittency and seasonality of the renewable energy sources for each region. The synthesis fuel plants run at a constant capacity determined by the available full load hours of intermittent renewable energy available for each region (see section 1.5.1).



### 1.5.1. Electricity supply

The electricity supply for the e-fuels production in this study comes from renewable sources, more specifically wind offshore/onshore and photovoltaic. It is assumed that a direct connection to the renewable electricity source needs to be installed for the e-fuels production in the form of high voltage transmission systems for all regions for an average distance of 200 km. The sole exception is the particular case of central EU, where we assume that large areas occupied by former lignite power plants will be reallocated to the co-installation of renewable energy plants and fuel synthesis plants, therefore not requiring any transmission infrastructure. This assumption is based on a previous analysis of the potential of PV/wind hybrid power plants at multi-GW scale combined with e-fuel plants [IFOK et al. 2018].

There are two important aspects about electricity supply that are considered:

- For renewable fuels in transport, EU RED II regulations will require new assets for target accounting (principle of additionality).
- There are countries that export significant parts of their renewable power production (physical and/or through certificates), such as Norway. The electricity production mix of such regions can be significantly different to its use mix (i.e., including the European attribute mix for exported guarantees of origin).

Figure 4 shows the reference values of carbon intensity (GHG emissions) and Table 13 shows the full load hours (h/a) for the wind and photovoltaic electricity mixes of the different proxy countries covered by the study.

In general, for all kinds of electricity generation, GHG emissions can have three main origins:

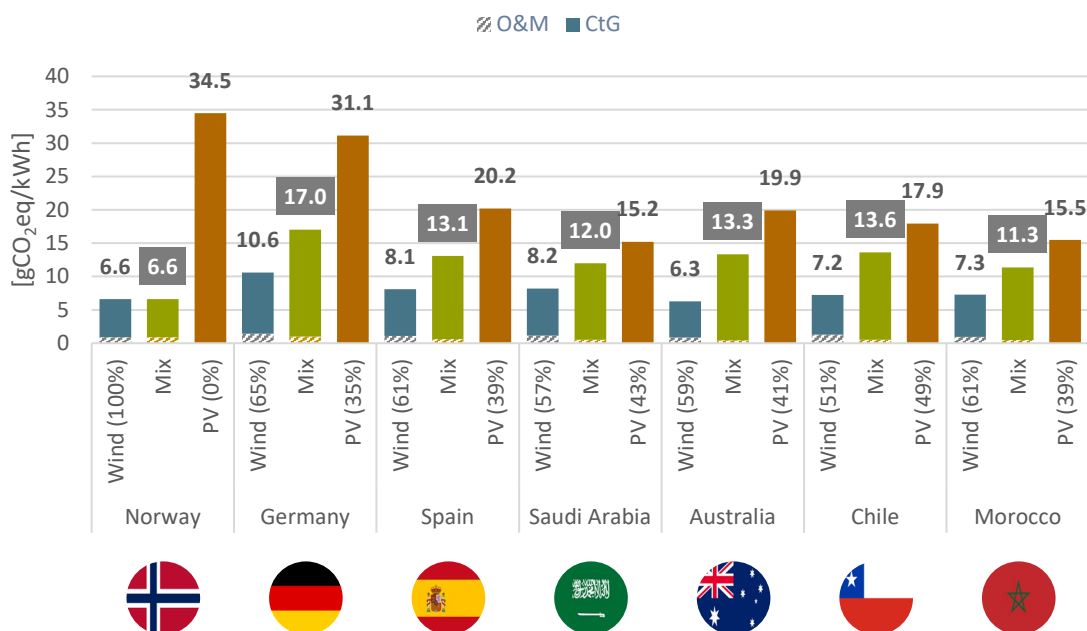
- Direct emissions (Well-to-Wheels, abbreviated as WtW), corresponding to GHG emitted from the energy resources consumed during the use phase. The CO<sub>2</sub> produced from the combustion of fossil-fuelled power plants would fall into this category. Renewable electricity generation has no direct emissions, so its WtW carbon intensity is assumed to be zero. This WtW scope is consistent with the GHG methodology chosen in the latest delegated acts of RED II (see section 5.7).
- Maintenance and replacement of moving parts (abbreviated as M&R) required for the equipment to operate during its use phase. This M&R is particular for wind electricity generation and includes, among other operations: oil changes, mechanical parts lubrication, and replacement of one of the wind turbine blades during its lifetime. The value of M&R emissions for wind electricity corresponds to roughly 15% of the total value. M&R emissions for photovoltaic electricity are considered equal to zero, mostly because no moving parts are involved in its operation.
- Infrastructure and equipment emissions (I&E), which include the production and recycling of the equipment (e.g. wind turbines and photovoltaic panels) during the equipment manufacturing and end-of-life phases. For wind turbines, their life cycle inventory includes the rotor (spinner + three blades), the nacelle, the tower, and the foundation of the turbines, as well as the wind system converter. The models are based on a 300 MW wind park, with a country-specific production capacity and an operational life of 20 years. The values assumed correspond to a mix of power generation from onshore/offshore technologies specific to each country in 2020. [Wind Europe 2020]. For photovoltaic panels, their GHG impact was calculated using a GaBi

model based on recent life cycle inventories from the IEA [IEA PVPS 2020] and include module manufacturing, inverter, mounting structure, and cables, as well as the construction and transportation of the panels. The values assumed are calculated based on average Global Tilted Irradiation (GTI) for the different locations taken from the EU's Photovoltaic Geographical Information System [PVGIS 2021] and assumed an average technology mix, largely dominated by mono- and multi-crystalline silicon panels (95%) [Fraunhofer 2021]. The end-of-life assumptions considers credits for materials recovered. The GHG impacts of power produced from photovoltaics obtained with our model shown in Figure 4 are roughly 50% lower than those found in the standard GaBi database, as they consider more recent energy and material consumptions. This reflects the high potential of further reductions due to PV technological progress.

The sum of these three contributions corresponds to the “Cradle-to-Grave” scope of emissions for electricity generation depicted in Figure 4. These reference carbon intensity values also consider the generation plant's own consumption (around 0.4%) and transmission losses related to the distribution of the electricity from the generation site to the production plant (around 5-6%).

The variation of GHG emissions from wind and photovoltaic power generation due to technology progress and energy efficiency improvement from economies of scale have not been considered in this techno-environmental study, but a reduction over time of the cost of the electricity they produce has been assumed in the economic analysis (Part 2).

**Figure 4:** Average GHG emissions per renewable electricity source (gCO<sub>2</sub>eq/kWh)



Note: Wind power technology: Mix (country-specific onshore/offshore)  
PV power technology: Mix (94% Mono/Multi-Si, 6% CdTe/CIGS). Single-axis tracking  
For Norway, 100% wind electricity is considered for this study  
Same electricity mixes assumed for 2020, 2030 and 2050. Only the electricity costs vary with time, not the electricity mixes.

The variations observed between countries relate to their specific geographic location and climate conditions, which determines the potential to the full load hours of each type of renewable electricity. As an example. The PV carbon intensity in Norway is higher than in the rest of the regions due to the lower full load hours of PV in Norway. However, the wind carbon intensity is lower than in other areas due to the higher full load hours of wind offshore in Norway.

The values used in our study are comparable to values referenced by Wood Mackenzie [Woodmac 2021], which reports 8 to 11 gCO<sub>2</sub>/kWh for onshore and 11-13 for offshore (no reference location specified), and to IPCC AR5 [IPCC 2018], which gives ranges of 7-8/11-12/35-56 gCO<sub>2</sub>/kWh for min/median/max values respectively for onshore/offshore sources. The wind renewable CTG emissions are completely dominated by the manufacturing emissions. The contribution of material and manufacturing to the overall emissions in wind energy is around 86.5%. According to Wood Mackenzie, “reducing the wind power’s life-cycle emissions would require using ‘green’ steel and concrete, but that will increase input costs and raise wind’s levelized cost of electricity” [Woodmac 2021].

Table 13 and Figure 5 show the equivalent full-load hours estimated for each type of renewable electricity used. The weighted average of full wind and PV electricity based on these full-load hours give the final carbon intensity used for each region in the GHG calculations. The impact of the buffer storage equipment required to counter the effects of wind and solar irradiation intermittence are small from a GHG emissions point of view, as the contribution of the storage equipment represents between 1% and 4% of the lifetime carbon emissions (not explicit in the figure). Buffer storage has a much more significant impact on the cost of fuel production. This is particularly true in the case where batteries are used as electricity buffer storage: The elevated cost of the infrastructure and partial replacement of the equipment has a significant impact on the overall cost (described in Part 2 of the study).

**Table 13:** Full load hours (h/a) per region

Region	PV	Wind onshore	Wind offshore	Total <sup>(1)</sup>
Norway			4,050 <sup>(2)</sup>	4,010
Germany	1,430 <sup>(3)</sup>	2,690 <sup>(4)</sup>		3,877
Spain	2,070 <sup>(3)</sup>	3,230 <sup>(5)</sup>		4,971
Saudi Arabia	2,406 <sup>(3)</sup>	3,190 <sup>(3)</sup>		5,227
Australia <sup>(6)</sup>	2,100	3,000		4,763
Chile <sup>(7)</sup>	2,700	2,800		5,137
Morocco <sup>(8)</sup>	2,300	3,600		5,511

Sources:

1) Includes curtailment between 1-7%, depending on the region (see section 0)

2) Real plants [BET 2019]

3) Aramco 2021

4) [Deutsche WindGuard 2015]

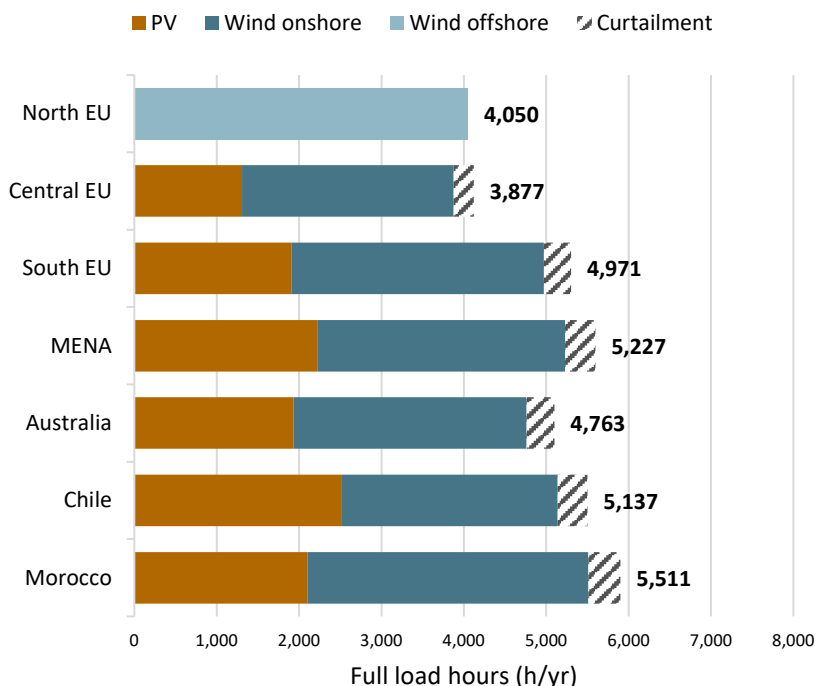
5) Real plant: [Ewwind 2020]

6) Real plants: Darlington Point, PV; Bungala Solar PV Plant, Port Augusta; Daydream, PV; Hornsdale Wind Farm; Sapphire Wind Farm; Collgar Wind Farm; Taltal Wind Farm; Atacama, wind; San Martias, wind

7) Real plants: Lalackama, PV; Lalackama II, PV; Amanecer Solar CAP plant, PV; Statkraft, wind;

8) Real plants: Noor Quarzazate IV, PV; Noor Laayoune, PV; Noor Boujdour, PV; Tarfaya wind farm; Akhfennir wind farm; Amogdoul wind farm

**Figure 5:** Full load hours per region including curtailment



As shown in Table 13, the regions with the most renewable energy full-load hours are Morocco, Chile, and Saudi Arabia (5,000-5,600 h/a), followed by Spain, Australia, Norway (4,000-5,000 h/a). Germany has the lowest full load hours (3,000-4,000 h/a) of all the regions of the study.

In Norway, 100% of renewable electricity is considered from offshore wind. All the other countries have a mix between PV and wind onshore.

In the calculation methodology, a 1-7% power curtailment is assumed depending on the region, to take into consideration the overproduction of PV and wind power generation that cannot be absorbed by the demand (see section 0).

The following additional assumptions related to the electricity consumption have been taken:

- Renewable electricity is used to cover the thermal energy requirements of the carbon capture process in the form of electric heaters with an efficiency of 90%.
- For the domestic cases, e-H<sub>2</sub> and e-CH<sub>4</sub> are compressed and transported by pipeline (intraregional transport), and for this it is assumed the use of electricity from the grid mix of the corresponding geographical zone. The composition of the grid mix is based on forecasts of the EU Energy Trend Reports for 2030 and 2050. The 2020 value is based on the actual energy mix of the proxy countries in 2017. The carbon intensities of the grid electricity mixes of each scenario have been calculated on the GaBi platform [Sphera 2021] and are presented in Table 14.
- The refuelling in service stations also uses the grid mix of the corresponding geographical zone shown in Table 14.

- CO<sub>2</sub> compression and liquefaction required during the e-fuel production processes (i.e. for CO<sub>2</sub> purification), as well as hydrogen liquefaction for long-distance transport use renewable electricity mix from the corresponding regional proxy. For the cost calculation in chapter 2, this includes a premium to a full cost of 25 ct/kWh of auxiliary electricity.
- For electrolysis and e-fuel synthesis, it is always assumed 100% renewable electricity from the corresponding country proxy for the 3 timelines (2020, 2030 and 2050).

**Table 14:** Grid mix GHG emissions per region considered

gCO <sub>2</sub> eq/kWh	North Europe	Central Europe	South Europe
2020 <sup>(1)</sup>	31.5	536.9	404.5
2030 <sup>(2)</sup>	25.0	539.3	189.5
2050 <sup>(2)</sup>	20.0	363.3	118.4

Values estimated using GaBi [Sphera 2021] based on electricity mixes.

Sources of the electricity mixes:

1) EU Reference Scenario

2) EU Energy Trends Report

### 1.5.2. Buffer storage

The buffer storage considered for all the base cases covering multiple geographies and timelines to operate the e-fuels facilities in a continuous basis are:

- H<sub>2</sub> buffer storage: In gaseous state at 10 MPa maximum pressure in natural gas pipeline segments of diameter 48-58):
  - 2 days of production for compressed hydrogen produced and consumed in Europe
  - Hydrogen via LH2 import: minimum part load 50% for all time horizons
  - Fischer-Tropsch synthesis: based on a minimum part load of 80% for 2020 and 2030, minimum part load of 50% for 2050
  - methanol synthesis, NH<sub>3</sub> synthesis, methanation: based on a minimum part load of 50% for all time horizons
- CO<sub>2</sub> buffer storage: In liquid state CO<sub>2</sub> at -25°C / 2 MPa pressure, in storage tanks. Conditions taken from [Element Energy 2018].
- Battery storage system

Table 15 shows the base case assumptions for H<sub>2</sub> buffer storage.

**Table 15:** H<sub>2</sub> buffer storage

Region	2020	2030	2050	Comment
<b>e-hydrogen</b>				
Europe-N	2.00	2.00	2.00	2 days to provide security of supply at the refueling station
Europe-C	2.00	2.00	2.00	
Europe S	2.00	2.00	2.00	
MENA	1.29	1.47	1.96	Minimum part load liquefier: 50%
<b>e-methane</b>				
Europe-N	2.80	2.74	2.70	Minimum part load: 50%
Europe-C	1.88	1.98	2.17	
Europe S	2.34	2.37	2.48	
MENA	1.34	1.55	2.04	
<b>e-methanol</b>				
Europe-N	2.90	2.87	2.89	Minimum part load: 50%
Europe-C	1.93	2.06	2.24	
Europe S	2.40	2.41	2.51	
MENA	1.31	1.52	2.09	
<b>e-OMeX</b>				
Europe-N	3.28	3.07	3.11	Minimum part load: 50%
Europe-C	2.19	2.26	2.43	
Europe S	2.71	2.67	2.71	
MENA	1.36	1.46	1.94	
<b>Methanol-to gasoline &amp; kerosene</b>				
Europe-N	2.88	2.84	2.86	Minimum part load: 50%
Europe-C	1.95	2.03	2.22	
Europe S	2.39	2.39	2.49	
MENA	1.35	1.53	2.02	
<b>e-ammonia</b>				
Europe-N	2.83	2.81	2.79	Minimum part load: 50%
Europe-C	1.89	1.96	2.12	
Europe S	2.43	2.46	2.59	
MENA	1.33	1.58	2.22	
<b>Pathways involving FT synthesis</b>				
Europe-N	7.09	6.45	2.78	Minimum part load: - 2020/2030: 80% - 2050: 50%
Europe-C	4.47	4.62	2.20	
Europe S	6.88	6.23	2.46	
MENA	2.87	3.30	2.18	

Only the H<sub>2</sub> buffer storage has been considered in this techno-environmental chapter because of the limited contribution of storage infrastructure emissions, but all three types of buffer storage are included in the economic study.

### 1.5.3. Fuel transportation

- Travel itineraries and transport distances

Distances travelled from the different regional zones assessed in the present study (MENA, South America, and Australia) are shown in Figure 6, which summarizes the general assumptions of the e-fuels transportation stage. These distances concern both the cases where e-fuels are produced in the continent (domestic supply) and when they are imported into Europe. The reference location of arrival in Europe used for the distance calculation is the Rotterdam port.

While the distance between the electricity production areas and the fuel manufacturing locations is estimated at 200 km (see section 1.5.1), the distance between production sites and international dispatching terminals of the exporting countries is assumed close to zero, hence negligible. We are assuming that the hydrogen production, carbon capture and fuel synthesis sites are collocated or very close to each other, except in the case where  $H_2$  is imported. A similar assumption is held for the distance between the reception terminal in Europe and the distribution nodes from which domestic networks dispatch the products to the local distribution depots. Liquefied hydrogen transported by ship is transferred to the distribution nodes without regasification, with the help of cryogenic pumps. The use of these pumps helps considerably to reduce energy losses related to changes of state, allows the use of a fleet of  $LH_2$  trucks and avoids relying on the implementation of a hydrogen pipeline network. Transporting hydrogen as a pressurized gas would require additional compression and reduce the energy efficiency of the pathway.

The first domestic distribution network is called the “Main grid”. It is assumed that e-fuels are transported via pipeline in this section of the supply chain, and for a fixed distance of 150 km. The transportation mode is pipeline for all liquid fuels and methane, with the exception of hydrogen and ammonia, which are transported via trucks. The distance of 150 km is based on the average ratio of total distance of pipeline installed in all countries covered in the scope and the total number of service stations.

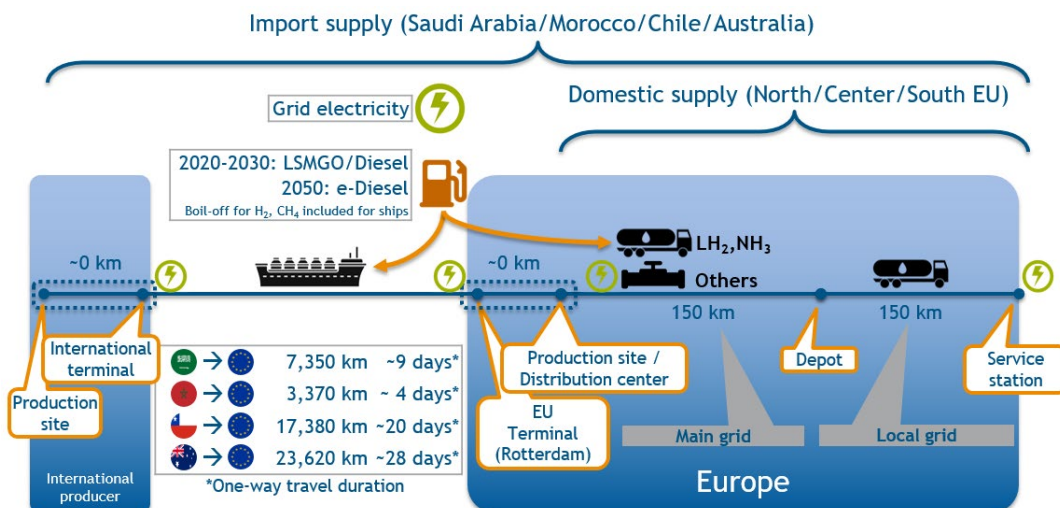
The second half of the supply network corresponds to the “Local grid”, in which the e-fuels are carried from the depots to the refuelling stations. An average distance of 150 km is also considered for this section. For the transfer of liquefied hydrogen ( $LH_2$ ) to the refuelling station the  $LH_2$  trailer is connected with the stationary  $LH_2$  tank by a flexible transfer line. The transfer is carried out without a cryogenic pump. A vaporizer mounted at the  $LH_2$  trailer elevates the pressure of the  $LH_2$  in the  $LH_2$  trailer leading to the transfer of the  $LH_2$  to the stationary  $LH_2$  tank [PRESLHY 2019].

During the vehicle tank filling operation, the stored  $LH_2$  is compressed via a cryogenic compressor, vaporized, and subsequently dispensed as  $CGH_2$ . A  $CGH_2$  buffer storage with a maximum pressure of 100 MPa is also installed. A description of this concept can be found in [Decker 2019]. The electricity consumption of the hydrogen refuelling station involving high pressure cryogenic pumps was estimated based on the technical specifications provided in the US Drive roadmap [US DRIVE 2017].

The same reference distance (300 km in total) has been considered for the 3 regions in EU (North, Centre and South of EU).



**Figure 6:** General assumptions for fuel transportation



- Energy for transportation

Besides the electricity consumption for compression and liquefaction explained in section 1.5.1, long-distance transport (ships) and road-transport (trucks) are assumed to run on fossil fuels (MGO and road diesel respectively) for horizons 2020 and 2030, and 100% on e-fuels for horizon 2050.

A sensitivity case including the transport in 2050 with 20% fossil fuel is considered in chapter 1.7.5.

In the case of ship transportation and for all time horizons, the boil-off of gaseous or highly volatile fuels contributes to the energy requirements of the ship. This is the case for liquefied hydrogen, liquefied methane (referred to as LNG, although it is technically not natural gas) and ammonia carriers, whose contribution to the total fuel represents 46%, 60%, and 29% of the total fuel respectively. The net fuel consumptions take into account specific requirements to keep these e-fuels at the appropriate transport conditions of pressure and temperature.

- Use of liquid energy carriers for hydrogen transportation

Section 1.7.4 of this report analyses the impact of producing e-fuels in Europe with hydrogen imported from the MENA region. The long-distance transport of hydrogen can be ensured in three different ways:

- As liquefied hydrogen. This pathway would require a highly energy-intensive hydrogen liquefaction stage, representing a consumption of 8 kWh<sub>e</sub>/kgH<sub>2</sub> (around 24% of its energy content based on its LHV), taken from a renewable energy mix in the country of origin. Transportation of LH<sub>2</sub> is based on assumptions from [Hank 2020].

- b) As ammonia. The same assumptions of ammonia production described in section 1.4.7 are used for this pathway, and transportation conditions as those for LPG transportation [Wärtsilä 2021b]. Once at destination port, the ammonia is converted back into hydrogen via an ammonia cracking process<sup>7</sup> represented by the reverse Haber-Bosch reaction:



Today, only small electric heated  $\text{NH}_3$  crackers exists mainly excluding  $\text{H}_2$  purification.  $\text{NH}_3$  cracking plants at scale are in the stage of design/engineering (TRL = 4).

- c) As methanol. The same assumptions of the single-step methanol production described in section 1.4.3 are used for this pathway, and transportation conditions as those for methanol carrier Millennium Explorer as described by Wärtsilä. Once at destination port, the methanol is converted back into hydrogen via steam reforming [Caloric 2021] represented by the reverse reaction of methanol synthesis:



Because the methanol synthesis uses an unavoidable source of  $\text{CO}_2$  as in the base case of methanol synthesis of our study, the  $\text{CO}_2$  emissions from this reaction are assumed to have a neutral GHG impact.

- d) As methylcyclohexane. This alternative requires the use of toluene as carrier molecule, and its reversible hydrogenation reaction to methylcyclohexane:



Our study assumes transportation conditions as described in [Lanphen 2019], and a hydrogenation/dehydrogenation conditions as described on [EQHHPP 1991].

## 1.6. BASE CASE RESULTS

### 1.6.1. Energy balances

#### 1.6.1.1. Synthesis from $\text{CO}_2$ captured from the air via Direct Air Capture (DAC)

Figure 7 shows the power and heat consumptions for each of the e-fuel pathways under the assumption that  $\text{CO}_2$  is captured from the atmosphere via a low temperature direct air capture (DAC) technology. The time horizon is 2050, for which the alkaline electrolyser efficiency is estimated at 75%.

The energy consumption (equal to the energy expended plus the energy contained in the fuel) is in all cases vastly dominated by electrolysis, counting for 58% ( $\text{OME}_{3-5}$ ) to 97% ( $\text{NH}_3$ ) of the total energy consumption (74% to 78% for drop-in liquid e-fuels). This share is responsible for the high dependency of power carbon intensity and costs on the values calculated for the e-fuels that will be explained in the following sections.

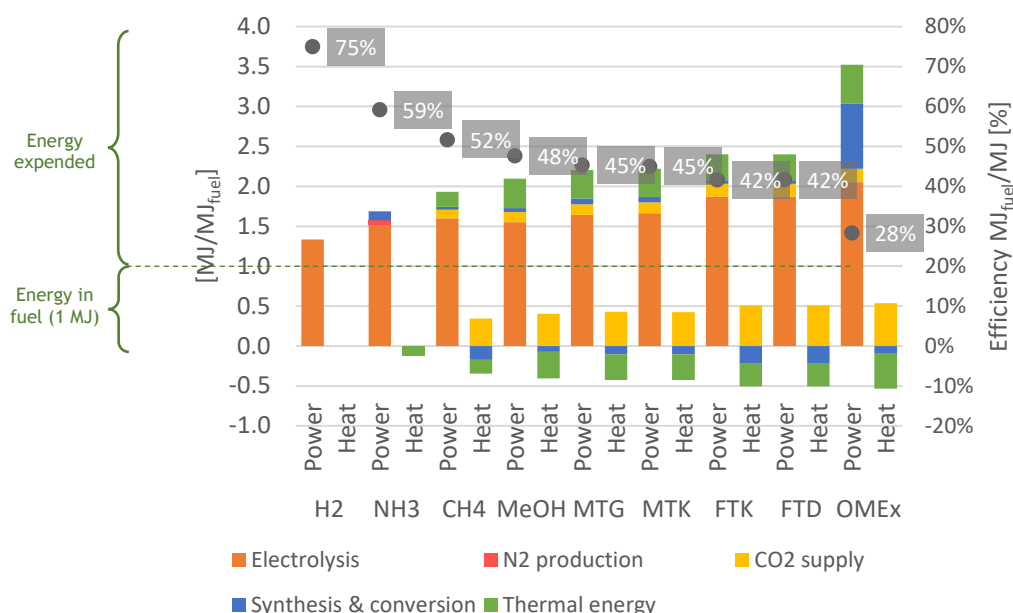
<sup>7</sup> For  $\text{NH}_3$  cracking, a 1.2507 MJ  $\text{NH}_3$  per MJ of  $\text{H}_2$  and 0.1446 MJ electricity per MJ of  $\text{H}_2$  is required according to [Jackson et al. 2019].

The study assumes heat integration implemented between the fuel synthesis and carbon capture plants, meaning that the thermal energy produced from the exothermic synthesis reaction and light ends burning (shown as negative consumptions on the Heat columns of each fuel) is transferred to the carbon capture facilities to be used for the CO<sub>2</sub> desorption operations. The heat requirements of the DAC units are only partially covered, so additional heat needs to be produced. Contrary to what happens to other synthesis processes, the heat produced in the ammonia synthesis is considered as not recovered and therefore not counted for its energy efficiency. This is because we assumed that recovered heat is used for the desorption stage in the carbon capture process, which is not relevant for ammonia production.

To limit the impact on greenhouse gas emissions, the supplementary heat is produced from electric heaters as described in section 1.5.1. This additional power consumption for heating purposes is represented in Figure 7 in a separate category “Thermal Energy”. The heat produced heaters is also shown with similar pattern as a negative consumption (production) of Thermal energy.

The energy efficiencies values can be read in the right axis of the graph. The energy efficiency is defined as the ratio between the energy contained in the fuel and the energy consumed to produce the fuel. It can be observed that as the fuel molecules increase in size and complexity from left to right, they show higher energy consumptions and lower energy efficiencies. Drop-in quality e-fuels compatible with the existing fleet being larger and more complex, this means that their compliance comes at a higher energy expense.

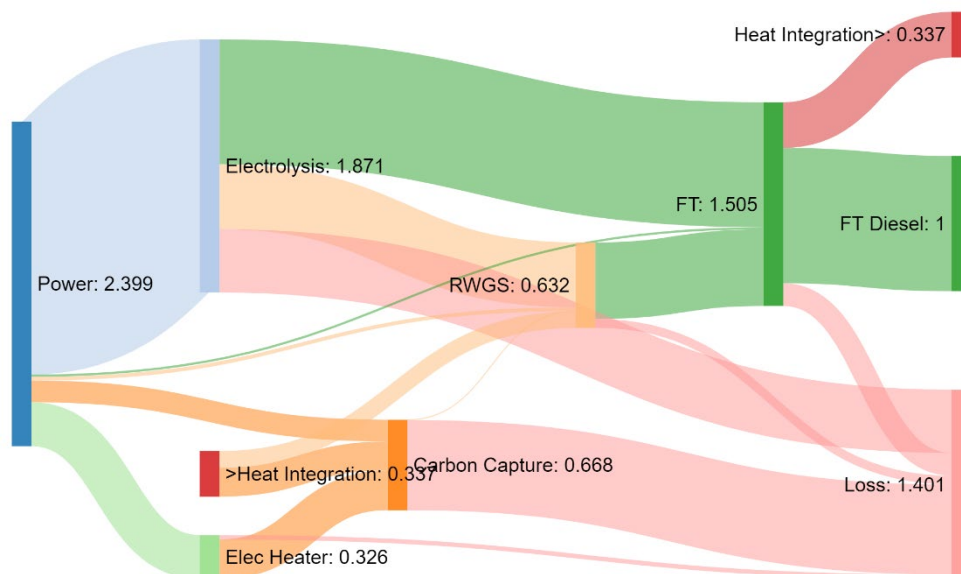
**Figure 7:** Power and heat consumption for the production of different e-fuels with CO<sub>2</sub> from Direct Air Capture (DAC) (Timeline: 2050)



Note: List of acronyms available in the Glossary and section 1.2. Thermal energy potentially recovered from NH<sub>3</sub> synthesis not included in its energy efficiency

To better understand the energy flows throughout the process, a Sankey diagram is shown in Figure 8 for the FT Diesel case using CO<sub>2</sub> from a diluted source (reference year: 2050) as an example. The Sankey diagrams for the rest of the pathways are shown in Annex 8.2.

**Figure 8:** Energy consumption to produce 1 MJ of FT e-diesel via Direct Air Capture (DAC)



In this diagram, the width of the arrows is proportional to the energy carried between the successive stages of fuel production, with losses represented explicitly with separate arrows. The values are all expressed in MJ for the production of 1 MJ of fuel based on its lower heating value. The net power consumption compared with the energy contained in the fuel produced defines the e-fuel energy efficiency. For the efficiency calculation, the energy consumption of the process is taken at the entrance of the different plants (electrolysis, carbon capture, RWGS, Fischer-Tropsch). Therefore, the efficiency excludes the efficiency of the power plants and any potential transmission losses.

The sole source of energy to produce FT e-diesel is electricity. The largest part of this electricity is required by the electrolyser, which produces hydrogen for both the RWGS and the FT reactions. Losses from the electrolysis in the form of low temperature heat are represented as a red band going to the Loss node. The rest of the electricity is consumed by the Carbon Capture (DAC) process, both by direct consumption as indirectly via an electric heater of 90% efficiency. Additional consumptions by the RWGS and FT reactions are observed, but they remain marginal compared to the others.

The Carbon Capture stage is the largest heat consumer across the production pathway, as it requires thermal energy to desorb the CO<sub>2</sub> captured. The electric heater and the heat released from the downstream synthesis processes provide this thermal energy, as shown in the diagram via the two “Heat Integration” nodes. The electricity consumption of the Carbon Capture stage is mostly used for compression and CO<sub>2</sub> liquefaction, as part of its purification process. All the energy provided to the Carbon capture to desorb and liquefy is assumed to be a loss as the CO<sub>2</sub> stream does not carry any heating value.

The RWGS converts  $H_2$  and  $CO_2$  into  $CO$  and  $H_2O$  by consuming heat and electricity. All the heat for this process is provided by the FT reactor downstream via the Heat Integration node. This heat is at a very high temperature required for the RWGS reaction, as it is generated from the burning of light ends produced during the FT and hydrocracking process. The  $CO$  stream, carrying some heating content, is sent to the FT node.

The FT step converts the syngas produced by the electrolyser and the RWGS into FT Diesel, releasing an important amount of energy from both the exothermic reaction, in the form of steam, and the burning of light ends, producing flue gases at very high temperature. The latter part is the one used for the RWGS reaction and the rest for the Carbon Capture step.

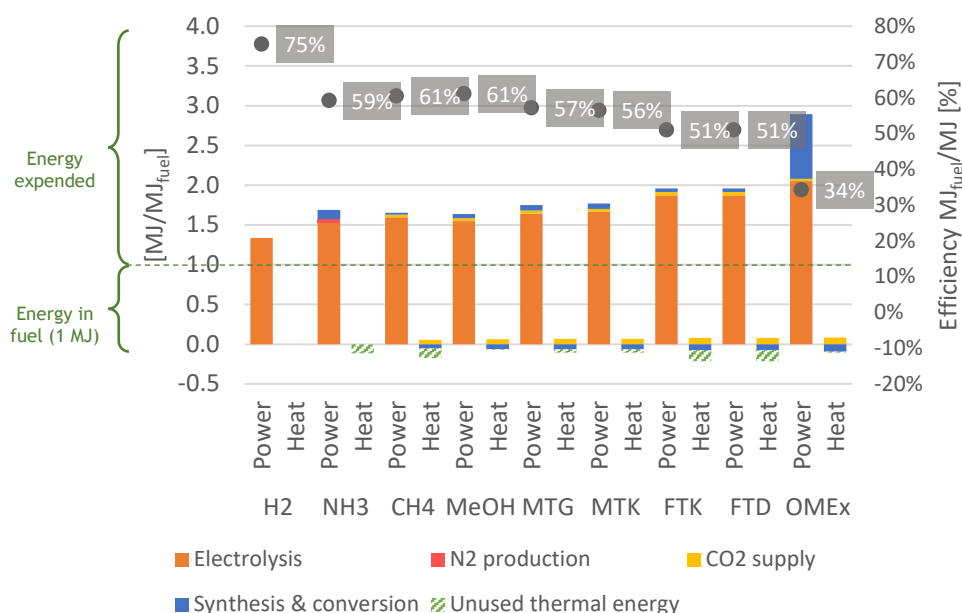
To further improve the overall energy efficiency of the FT e-diesel it could be envisaged to recover part of the low temperature heat produced at the electrolysis. This option is not analysed in the base cases, which use with low-temperature (LT) electrolysis. However, high-temperature (HT) electrolysis is included in the specific sensitivity case called "Advance Technologies". HT electrolysis uses heat, thus reducing the electricity demand. The energy consumptions for this sensitivity case are derived from Sunfire data for SOEC co-electrolysis with and analysed in section 1.7.1.

#### 1.6.1.2. Synthesis from $CO_2$ captured from a high concentration point source

Figure 9 shows a variation of the previous case, now supposing that the  $CO_2$  used for the fuel synthesis is extracted from a concentrated point source, like Steam Methane Reformer (SMR) or Autothermal Reforming (ATR) pre-combustion off-gases.

In this case the higher  $CO_2$  concentration requires less energy for its separation and purification. For all the e-fuel pathways, the heat from fuel synthesis is enough to cover the thermal requirements of the carbon capture process, so no external electric heating is needed. Efficiencies of all pathways fed with  $CO_2$  (all except e-hydrogen and e-ammonia) go up by about 10 percent points. This increase is based on the assumption that all the excess heat produced from the fuel synthesis exothermic reactions is a waste and does not provide any energy credits. The part of energy that is wasted is shown in Figure 9 as "Unused thermal energy".

**Figure 9:** Power and heat consumption for the production of different e-fuels with CO<sub>2</sub> from a concentrated point source (Timeline: 2050)



The former assumption implies that energy efficiencies could be further improved if excess heat was, for example, converted into high pressure (HP) steam and used in a process nearby, like in the case of an e-fuels plant integrated with a refinery. This would not only increase the energy efficiency of the e-fuel pathway but also have an impact on the carbon intensity and costs, as it could generate CO<sub>2</sub> and cost credits depending on the type of energy it would substitute. The impact of this additional energy saving is discussed in section 1.6.2.

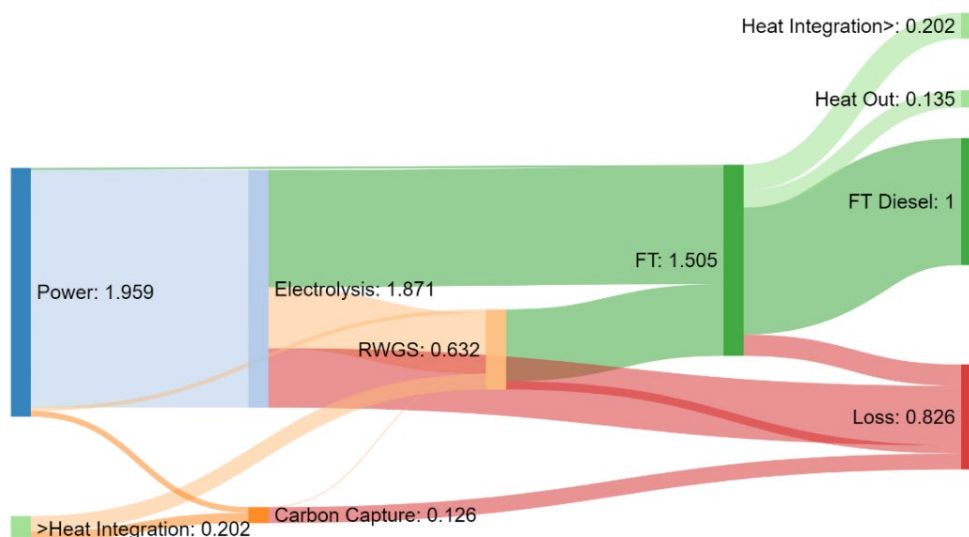
As in the case of air-captured CO<sub>2</sub>, we still confirm that the complexity of the chemical structure of the fuel molecules is inversely proportional to the efficiency. However, the advantage of ammonia over methane observed in the previous case is lost because the change of the source of carbon is only relevant for the latter.

A Sankey diagram was also generated for the FT e-diesel case under these conditions in Figure 10. The size of the carbon capture node is smaller than in Figure 8, consistent with the lower energy required to capture the CO<sub>2</sub>, which is around seven times lower than in the DAC case, as reported in Table 9.

The routing of the energy flows is the same as in the previous case, expect that now the heat released by the FT reactor is split in two parts: One effectively recycled to RWGS and Carbon Capture, marked as Heat Integration, and another that is left available of other process out of the pathway, marked as Heat Out.



**Figure 10:** Energy consumption to produce 1 MJ of FT e-diesel via Direct Air Capture (DAC)



#### KEY MESSAGES - ENERGY BALANCES

The energy consumption in the e-fuels production stage increases depending on the length and complexity of the synthesised molecules. The simplest molecules, like hydrogen, require less energy consumption than the more complex ones. As an example, for fuels synthesised from air-captured CO<sub>2</sub>, 1 MJ of FT e-diesel requires 2.1 times the energy needed to produce 1 MJ of e-hydrogen, while 1 MJ of the more complex molecule e-OME<sub>3.5</sub> needs 2.7 times that amount.

The opposite trend is observed for the e-fuel efficiency, defined as the ratio between the energy contained in the fuel and the energy used to produce the fuel. The simplest molecule, e-hydrogen, has an energy efficiency of 75% driven by the electrolysis efficiency. More complex molecules like FT e-diesel or FT e-kerosene have an energy efficiency of 42%. The lowest efficiency corresponds to the e-OME<sub>3.5</sub>, estimated at 28%. These values correspond to a carbon capture from DAC and 2050 timeline. If the carbon capture is from a concentrated source, the FTD and FTK efficiencies increase up to 51%, and in OMEx to 34%.

The energy losses in the e-fuel production processes are mainly originated from the electrolysis and the carbon capture steps. These losses are higher when fuels use CO<sub>2</sub> captured from the air than when they contain CO<sub>2</sub> from a concentrated point source (1.401 MJ/MJ<sub>fuel</sub> versus 0.826 MJ/MJ<sub>fuel</sub> respectively for a FT e-diesel), due to the energy required to concentrate the carbon (45% by volume of CO<sub>2</sub> in the concentrated source versus 0.04% CO<sub>2</sub> concentration in the air).

The study assumes heat integration between the fuel synthesis and carbon capture by default, with an electric heater producing any additional requirements. Heat integration differentiated by temperature level has been taken into account derived from literature.

A major criticism of any e-fuels scheme is the “wastage” of renewable electricity. A part of this waste could be reduced if part of the waste heat in electrolysis was used for the carbon capture or any other endothermic stage, increasing the total efficiency.

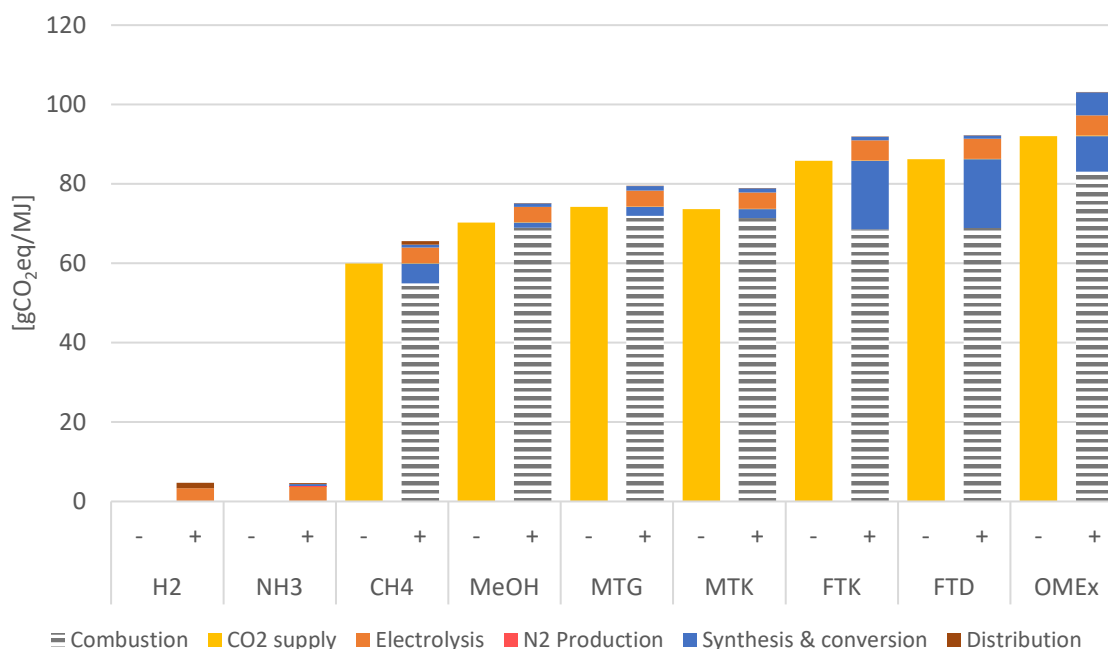


The energy and mass balances and the Sankey diagrams for all the e-fuels pathways are shown in the annexes 8.1 and 8.2 respectively.

### 1.6.2. GHG emissions

Figure 11 shows the balances of captured CO<sub>2</sub> versus emitted CO<sub>2</sub> for each of the e-fuels pathways (production, distribution, and combustion) for the timeframe 2050 in Northern Europe (Norway). This timeframe implies a high electrolysis efficiency and a mix of CO<sub>2</sub> sources as described in Table 12. The results are calculated on a Cradle-to-Grave basis, including all the burdens described in 1.3.2.

**Figure 11:** CO<sub>2</sub> captured vs CO<sub>2</sub> emitted [gCO<sub>2</sub>/MJ] by different e-fuels pathways (Case: North EU, 2050)



Note: The extra CO<sub>2</sub> captured/emitted in MTG or MTK vs MeOH is coming from the MTG and MTK synthesis step (from methanol to gasoline/distillates), which emits additional CO<sub>2</sub> because of the burning of a small quantity of light ends in the synthesis phase, to a much lower extent than the FT processes though.

The carbon credits and carbon emissions are displayed in separate columns for each fuel marked with a minus (-) and a plus (+) sign respectively. The graph can be read as follows:

- The yellow bars show the amount of CO<sub>2</sub> captured per MJ of fuel produced and distributed. This amount of carbon captured is not just dependent on the carbon content of the final fuel, but also includes the CO<sub>2</sub> emitted during the synthesis stage. e-Hydrogen and e-ammonia do not have any carbon capture contribution as they do not have any carbon atom in their structure.
- The striped bars correspond to the CO<sub>2</sub> emitted during the fuel combustion. This estimation excludes the impact of the engine efficiency, so it is calculated purely as an emission factor on an energy basis. Note that only CO<sub>2</sub> production is considered in this analysis - no other greenhouse gases (CH<sub>4</sub>, N<sub>2</sub>O) that could be present in the combustion exhaust are taken into consideration.

- The dark blue bars show the CO<sub>2</sub> emitted during the fuel synthesis. Some examples are the burning of light ends produced during the Fischer-Tropsch reaction (see section 1.4.8) or the oxidation of part of the intermediate reactant formaldehyde in the OME<sub>3-5</sub> synthesis process (see section 1.4.4). Also included in this category are indirect emissions from any resources used during the production phase, like oxygen for the OME<sub>3-5</sub> synthesis or emissions from wastewater treatment. As in the previous category, only emissions of CO<sub>2</sub> are considered in this category - no assumptions of CH<sub>4</sub> or N<sub>2</sub>O leaks have been considered for the fuel synthesis stage. This is justified by the lack of information currently available on specific pollutants from the processes.
- Other bar colors indicate emissions associated to hydrogen and nitrogen production, and the transport and distribution stage.

It can be observed that the emissions from combustion (striped grey) and the emissions from synthesis (dark green) balance with the captured carbon (yellow). This is equivalent to saying that the CO<sub>2</sub> emissions from burning the e-fuels and the CO<sub>2</sub> directly emitted by the synthesis plants could be assumed to be zero, as they benefit from credits of the CO<sub>2</sub> recovered from the air or the waste streams. This credit is the main reason why e-fuels produced from renewable energy sources are considered as low carbon fuels. From now on and for the rest of the analysis, these major contributing categories to the total CO<sub>2</sub> emissions (between 89% and 94%) will be excluded from the analysis. This will allow for a deeper interpretation of the remaining categories.

#### KEY MESSAGES - GHG EMISSIONS

Most of the emissions (> 89%) are balanced between the ones emitted in the process and e-fuel combustion in the tailpipe of the vehicle, and the ones captured (eg: 86 gCO<sub>2</sub> eq/MJ for FT diesel), so they can be neglected in terms of net emissions.

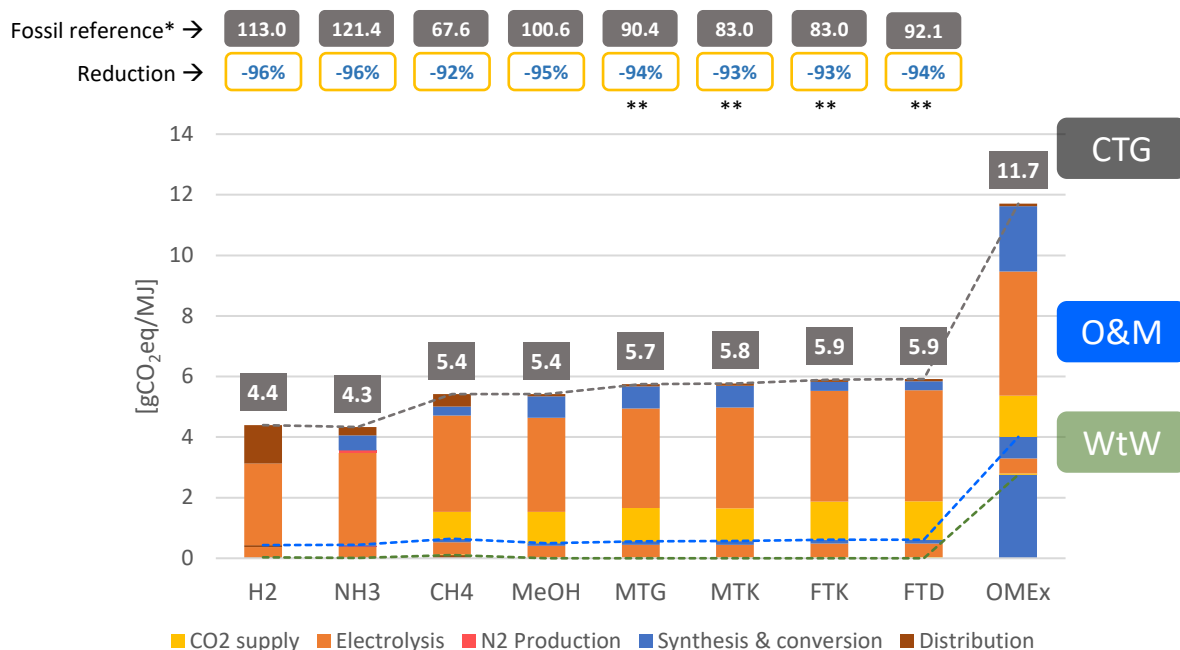
The remaining net emissions are < 10% (around 6 gCO<sub>2</sub> eq/MJ for the majority of e-fuels routes except from the OME<sub>3-5</sub>).

Figure 12 shows the Cradle-to-Grave net GHG emissions, expressed in gCO<sub>2</sub>eq/MJ of the different pathways, in Well-to-Wheel (WtW), Operation & Maintenance (O&M) and Cradle-to-grave (CTG) basis. The definitions of these categories are described in section 1.3.2 and Figure 1:

- WtW includes direct emissions of the fuel synthesis stage as well as feedstock and energy production and fuel transportation.
- O&M refers to emissions related to equipment maintenance for both fuel production and electricity generation. This includes manufacturing of spare mechanical parts and their end-of-life.
- CTG includes infrastructure building and manufacturing of equipment facilities necessary for the plants (synthesis plants, electrolyzers, power farms) including the end of life. Carbon capture infrastructure is not included in the GHG analysis (see section 1.3.2).

The contributions of different steps of the fuel life cycle are differentiated by colours, segregated by scope.

**Figure 12:** Cradle-to-grave GHG emissions of different e-fuel pathways (Case: North EU, 2050)



Based on these results, the fuels can be divided in three categories from the standpoint of GHG emissions:

- The group of hydrogen and lighter molecules (H<sub>2</sub>, NH<sub>3</sub>, CH<sub>4</sub> and MeOH), with values ranging between 4.3 and 5.4 gCO<sub>2</sub>/MJ.
- The group of drop-in liquid fuels (MTG, MTK, FTK, FTD), with carbon intensities fluctuating around the value of 6 gCO<sub>2</sub>/MJ.
- The molecule of OME<sub>3-5</sub> (OMEx), with a carbon intensity of almost twice the value of drop-in liquid fuels. This fuel is deemed to be used only blended with diesel-like fuels (see section 1.4.4).

In all groups without exception, we can observe the biggest contribution of the net GHG emissions for e-fuels: The hydrogen production, mostly dominated by the power consumption of this stage. Moreover, the largest share of H<sub>2</sub>-related emissions comes from the infrastructure required for power generation. Also significant in the case of e-hydrogen is the weight of the distribution stage, which requires large amounts of (renewable) electricity to liquefy and transport it. Well-to-Wheels emissions for this category are originated from the utilization of grid electricity for distribution operations at service operations (compression at service station, dispensing) and, in the case of CH<sub>4</sub>, also compression for the pipeline distribution network using grid electricity. Marginal contributions from the distribution infrastructure can be observed in the CTG level, mostly from hydrogen storage installation.

The drop-in fuels present all comparable contribution shares. The energy consumption required for the carbon capture stage does not contribute significantly to the total value, as it comes from renewable energy. Liquid fuel distribution does not contribute with more than 0.1 gCO<sub>2</sub>/MJ to the total GHG emissions thanks to the assumption of generalized use of e-fuels for the fleet of trucks transporting it.

However, the analysis of the sensitivity to the technology progress (subsection 1.6.2.2) will show some impact from road transport distribution.

The particular case of OME<sub>3-5</sub> is explained by mainly two factors: The very high energy requirements of the synthesis process compared to other fuels, and the utilization of a specific carbon-intensive resource, oxygen. The impact of oxygen is displayed under the WTW category, making it the only noticeable contribution of this scope.

#### KEY MESSAGES - GHG EMISSIONS

For Northern Europe, the net GHG emissions of the different e-fuels pathways in a CTG basis are between 4.3 and 5.9 gCO<sub>2</sub> eq/MJ (except from the e-OME<sub>3-5</sub>) and around 0.5 gCO<sub>2</sub>eq/MJ if we only count emissions from Operation & Maintenance only. The WTW emissions are almost zero because of the use of renewable energy for all operations except power for distribution. These values are similar in all the e-fuels pathways, because e-fuels that are less energy-intensive to produce (such as e-hydrogen) are more energy-intensive to transport.

The emissions from Operation & Maintenance (O&M) emissions represent around 9-12% of the total Cradle-to-grave (CTG) emissions. This means that roughly 90% of the total emissions are associated to the infrastructure required.

All the e-fuels pathways comply with the RED II limit for ReFuNoBio (28.2 gCO<sub>2</sub>eq/MJ) on a CTG basis, which determines a minimum 70% reduction in GHG versus the fossil reference defined in the RED II: 94 gCO<sub>2</sub>eq/MJ. It is important to note that the reduction rates assumed in the present study consider CTG emissions from all feedstocks, including renewable electricity. If emissions from manufacturing solar panels or wind turbines are excluded, the GHG reduction would be even higher.

Drop-in fuels, such as Methanol-to-Gasoline (MTG), Methanol-to-Kerosene (MTK), Fischer-Tropsch Kerosene (FTK) and Fischer-Tropsch Diesel (FTD), have slightly more CTG emissions (around 6 gCO<sub>2</sub>eq/MJ) than non-drop in fuels, such as methanol (MeOH), at 5.4 gCO<sub>2</sub> eq/MJ, even if the infrastructure for transport, storage, and delivery is already available. This is because the energy efficiency is the main driver of the drop-in e-fuel GHG emissions, even if their transport, storage and dispensing infrastructures are already available.

e-OME<sub>3-5</sub> GHG emissions are around 11.7 gCO<sub>2</sub>eq/MJ. The emissions are significantly higher than for the rest of e-fuels due to the higher complexity of the process that requires more energy consumption. However, OME<sub>3-5</sub> presents other benefits when blending with diesel components such as the low soot and NO<sub>x</sub> emissions.

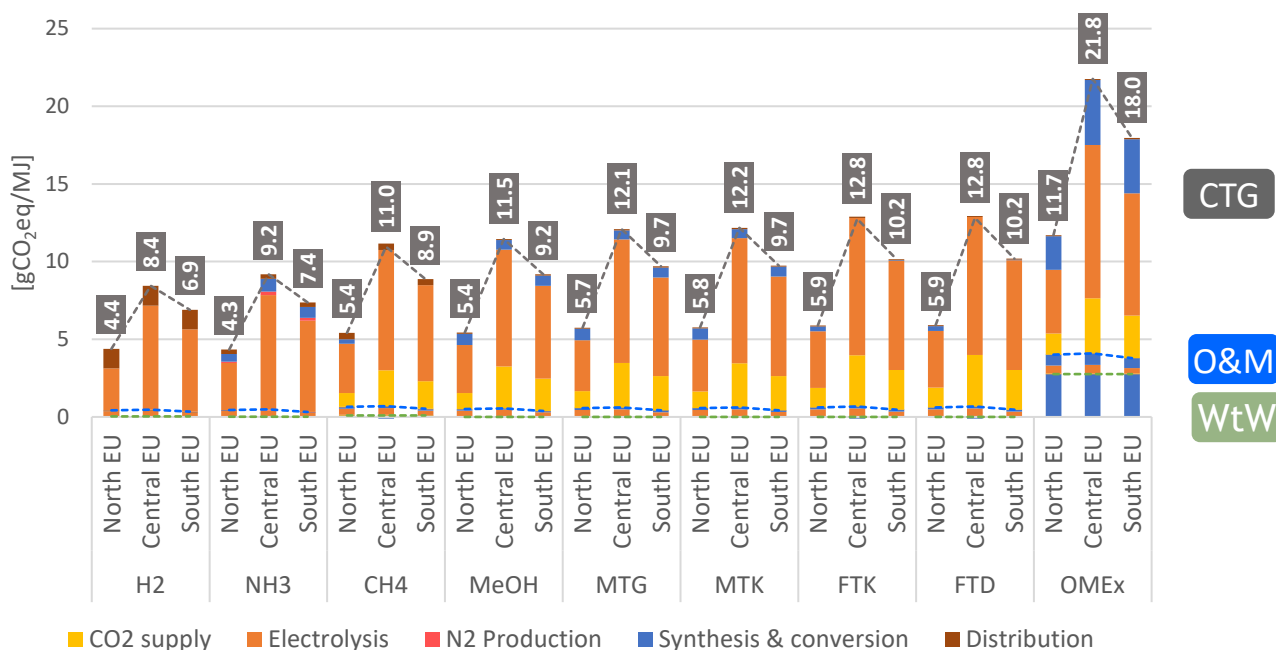
In the case of carbon source coming from a concentrated source, a quick sensitivity can demonstrate the potential benefits that could be obtained by using this excess heat as high-pressure (HP) steam (0.135 MJ). The energy credits obtained would represent an increase in efficiency from 51% to 53% in the FTK pathway. Furthermore, assuming the e-fuels plant is associated to a crude oil refinery, potential CO<sub>2</sub> credits could be attributed for avoided fuel gas burned if accounting for 74 gCO<sub>2</sub>/MJth x 0.135 MJth/MJ = 10 gCO<sub>2</sub>/MJfuel. This estimation considers an average thermal energy from gas in EU of 74 gCO<sub>2</sub>/MJth (GaBi database).

### 1.6.2.1. Impact of geographic locations

Figure 13 shows the e-fuels GHG emissions in three different regions of Europe in 2050. The WTW values are very similar among regions for all the e-fuels pathways, with very low values reflecting the emissions from distribution. The only exception is OMEx, with high WTW emissions coming from the supply of oxygen feedstock for the process.

At a CTG scope, the results appear lower in North Europe, followed by South and finally Central Europe. This is directly related to the carbon intensity of the renewable mix in the different regions (see Figure 4). In the case of South Europe (Spain), despite the higher full load hours (5,040 h/a), the carbon intensity due to the PV component is higher resulting in higher GHG emissions than in the North Europe (Norway). As in the base cases, the emissions related to hydrogen production are dominant for all the cases.

**Figure 13:** Cradle-to-Grave GHG Emissions from e-fuels production by region in Europe in 2050



**Figure 14:** Comparison of GHG Emissions from e-fuels produced in Southern Europe and Middle East in 2050

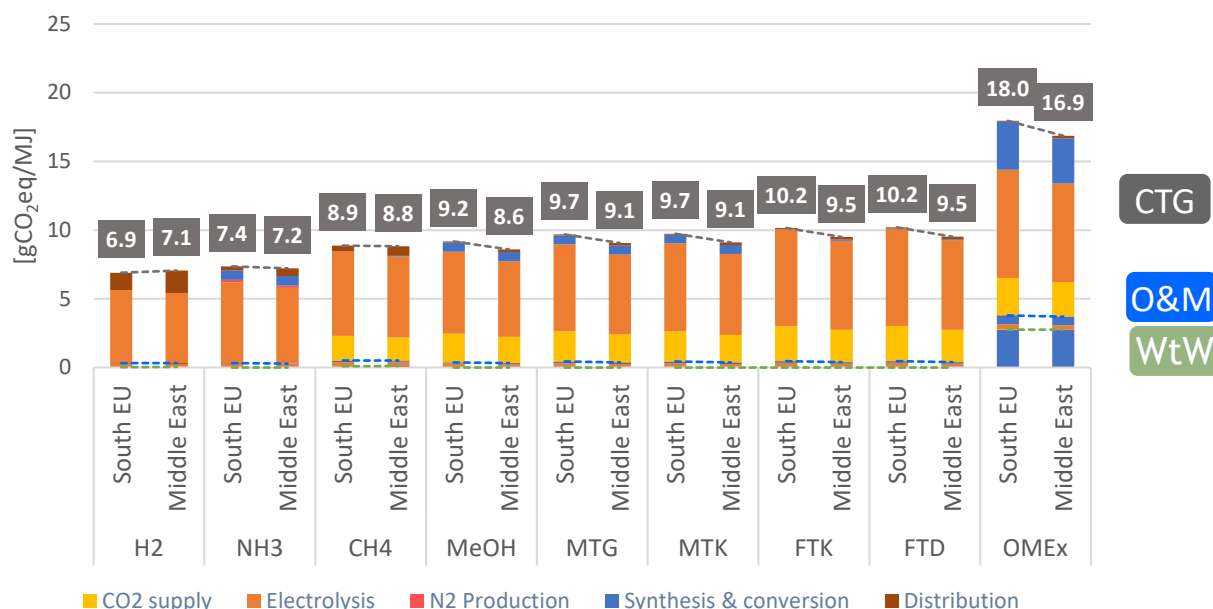


Figure 14 compares the emissions from producing e-fuels either in the South of Europe or in Middle East. This implies a change in the electricity mix but also in the distribution, adding supplementary steps to the supply chain (shipping over a distance of over 5,000 km + unloading). The results show little impact from this additional step, as in 2050 ships are fueled with e-diesel, so their GHG impact is marginal. Even in the case of hydrogen, the impact is barely noticeable (around 0.2 gCO<sub>2</sub>eq/MJ). The results suggest that the carbon intensity of the electricity used in the synthesis process is the dominant factor even when including long distance transport.

#### KEY MESSAGES - IMPACT OF GEOGRAPHIC LOCATION

The GHG emissions from Operation & Maintenance are very similar among regions for all the e-fuels pathways in 2050 (around 0.5 gCO<sub>2</sub>eq/MJ). However, the CTG GHG values show lower levels in North Europe (around 6 gCO<sub>2</sub>eq/MJ), followed by South (around 9.5 gCO<sub>2</sub>eq/MJ) and Central Europe (around 12.5 gCO<sub>2</sub>eq/MJ) in 2050. This is due to the differences in carbon intensity (defined by the lower full load hours of renewable electricity and the contribution of PV versus wind renewable electricity, as PV presents a higher CTG carbon emission).

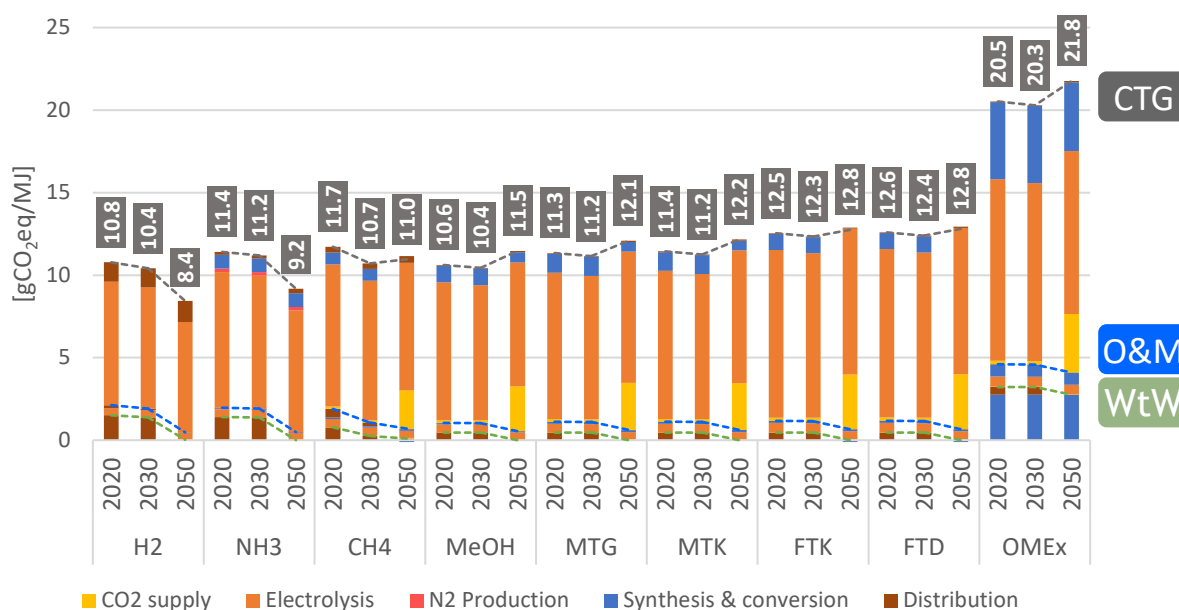
Long distance transport of fuels is not expected to increase significantly the GHG emissions of e-fuels. The carbon intensity of the electricity used will still be the most dominant factor.

#### 1.6.2.2. Impact of technology progress over time

The technology progress assumptions for the three timeframes evaluated in the study have been defined in chapter 1.5, Table 12. These include the increase in electrolyser efficiency, increase share of DAC versus concentrated source and use of e-fuels (e-diesel) for truck and ship transportation.

Figure 15 shows the GHG emissions over time in Central Europe for all the different e-fuel pathways. A progressive reduction of CTG GHG emissions is observed over time only for hydrogen and ammonia, while for carbon-based fuels they first drop and then increase. As an example, for FT Kerosene the CTG GHG emissions in gCO<sub>2</sub>eq/MJ for the FT Kerosene go from 12.5 in 2020 down to 12.3 in 2030 and then up to 12.8 in 2050. This is due to opposite effects overlapping: On one side, an improvement in electrolyser efficiencies and the generalization of the use of e-fuels for maritime and truck transport, which favour a decrease over time of H<sub>2</sub> supply and distribution emissions. On the other hand, the displacement of concentrated sources of CO<sub>2</sub> by the use of DAC which requires more energy-intensive operations to capture CO<sub>2</sub> from the atmosphere and results in a net increase of emissions by 2050. The contribution of Operation & Maintenance remains stable over time (around 0.5 gCO<sub>2</sub>eq/MJ for FT kero) until 2050. The WTW GHG emissions drop steadily until 2050 for all fuels as the emissions from the additional renewable electricity required for DAC is assumed to be 0 on a WTW basis.

**Figure 15:** Cradle-to-Grave GHG Emissions from e-fuels production in Central Europe in 2020, 2030 and 2050



### KEY MESSAGES - IMPACT OF TECHNOLOGY PROGRESS OVER TIME

A progressive reduction is observed over time for hydrogen and ammonia, but not for carbon-based e-fuels on a CTG basis (from 12.5 to 12.8 gCO<sub>2</sub>eq/MJ for FT kerosene between 2020 and 2050) because of the use of Direct Air Capture for CO<sub>2</sub> supply. The Operation & Maintenance emissions remain similar over time (0.5 gCO<sub>2</sub>eq/MJ for FT kerosene) until 2050 where the generalized use of e-fuels for maritime and truck transport is assumed.



## 1.7. SENSITIVITY ANALYSES OF KEY TECHNICAL FACTORS

### 1.7.1. Advanced Technology scenario (co-electrolysis)

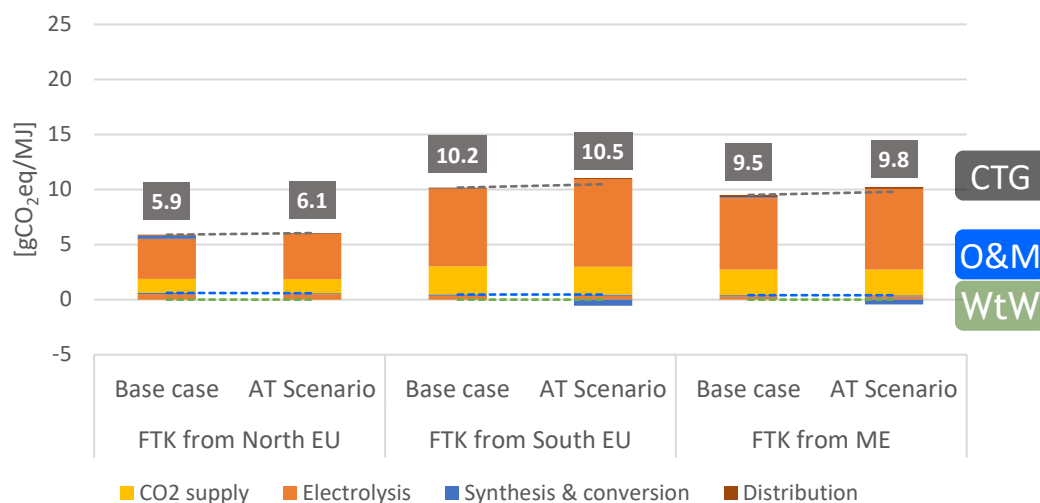
As indicated in Table 12, the Advanced Technology Scenario applied to the 2050 base cases implies the use of a different H<sub>2</sub> production technology known as co-electrolysis, with higher energy efficiency.

The co-electrolysis technology proposed by Sunfire for the Fischer-Tropsch pathways combines high temperature electrolysis (Solid Oxide Electrolysis Cells, also known as SOEC) with RWGS, producing syngas directly in one single step from water and a CO<sub>2</sub> stream (pure CO<sub>2</sub>), evolving from a 3- to a 2-stage process. Sunfire claims higher energy efficiency for this configuration, increasing by 15% points in the Fischer-Tropsch pathway and by 10% points in the methanol pathway [Sunfire 2019]. As a caveat, it is important to clarify that this basis is according to the technology developer estimation and should be verified when the first plant will be in operation.

The results in Figure 16 show the differences between the base case production of 2050 and the Advanced Technology (AT) Scenario. The AT cases show a slight increase of 2-3% of the CTG GHG emissions.

This counterintuitive result resides in the assumptions around cogeneration and the heat balance taken as a reference. The higher energy efficiency expected from the combination of electrolysis and RWGS applies to a case with no heat integration. In our study we have assumed already that the heat from the fuel synthesis processes can be used to cover part of the energy requirements from carbon capture. Co-electrolysis relies on a process that becomes more efficient at a higher temperature, which is translated into a net increase of the thermal energy demand. With no surplus energy available from the synthesis, this supplementary heat supply is covered with an increase of electricity consumption that increases the burden even further. The use of co-electrolysis would show actual benefits in a system where there is idle energy going to waste, like in the case where 100% concentrated CO<sub>2</sub> is used (see section 1.7.3).

**Figure 16:** Comparison of GHG emissions between the base case and the Advanced Technology scenario in 2050



#### KEY MESSAGES - ADVANCED TECHNOLOGY SCENARIO

The Advanced Technology (Co-electrolysis) cases show an increase of CTG GHG emissions. The reason is that the higher energy efficiency expected from the combination of electrolysis and RWGS applies to a case with no heat integration. Our study assumes already that the heat from the fuel synthesis processes can be used to cover part of the energy requirements from carbon capture. Co-electrolysis relies on a process that becomes more efficient at a higher temperature, which is translated into a net increase of the thermal energy demand. With no surplus energy available from the synthesis, this supplementary heat supply is covered with a supplement of electricity consumption that increases the burden even further. The use of co-electrolysis would show actual benefits in a system where there is idle energy going to waste, like in the case where 100% concentrated CO<sub>2</sub> is used.

### 1.7.2. Electricity source

- 100% wind source

Figure 17 shows the results of the GHG sensitivity analysis for four types of e-fuels when switching from a mixed power in Central Europe to a 100% onshore wind power source.

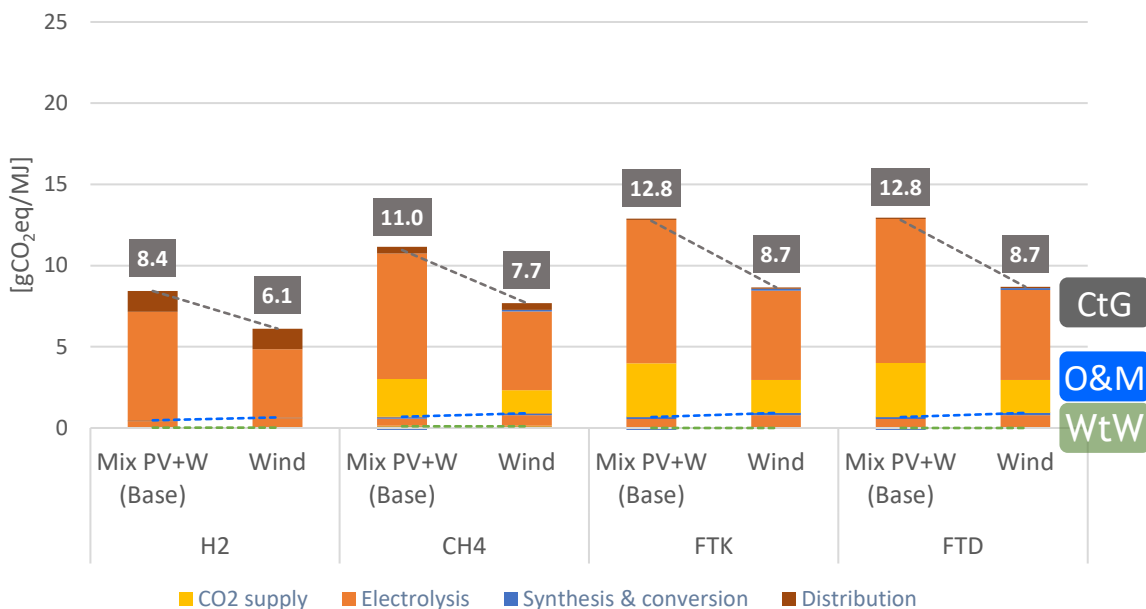
General trends show a decrease of GHG emissions when a full wind source is used exclusively, in accordance with Figure 4. The same trend applies for any of the regions studied and puts in evidence the advantage of wind over a mix of photovoltaic power when the electricity production emissions are indicated on a Cradle-to-Grave basis. The impact of the additional buffer storage operation is negligible for CO<sub>2</sub> emissions (around 0.2 gCO<sub>2</sub>eq/MJ, not explicit in the graph but included in the H<sub>2</sub> production category), as explained in section 1.5.1.

#### KEY MESSAGES - ELECTRICITY SOURCE (100% wind)

Cradle-to-Grave emissions show an advantage for the use of 100% wind onshore electricity (8.7 versus 12.8 gCO<sub>2</sub>eq/MJ in FT kero, equal to 32% GHG emissions reduction).

Operations & Maintenance emissions increase only very slightly in this case (from 0.3 to 0.6 gCO<sub>2</sub>eq/MJ in FT kero) because of the impact of the maintenance of wind turbines compared to the negligible operating emissions from the photovoltaic panel farms.

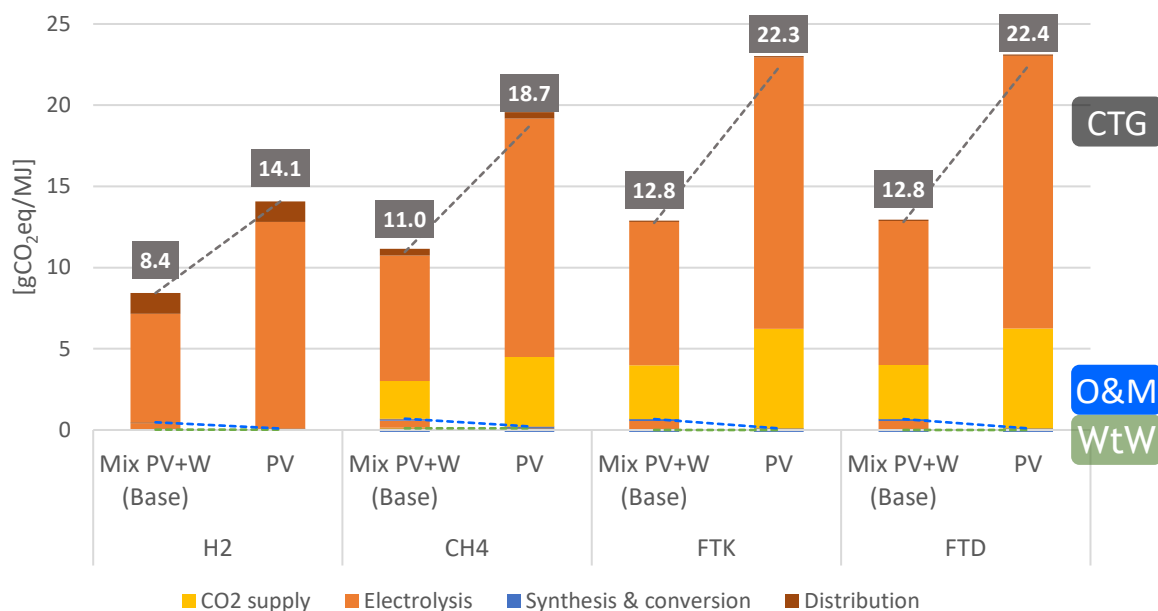
**Figure 17:** Comparison of GHG Emissions in Central Europe between a mixed and 100% wind power source



- 100% PV source

Figure 18 shows the results of the GHG sensitivity analysis for four types of e-fuels when switching from a mixed power in Central Europe to a 100% photovoltaic (PV) power source. General trends show a significant increase of GHG emissions on a CTG basis when a full PV source is used exclusively, in accordance with Figure 4. This effect is directly related to the bigger impact of solar panels manufacturing compared to wind turbines, due to the use of more energy intensive materials (silicon wafer) and a more energy intensive process in general. Contrary to what is observed for a switch to 100% wind, the impact on an O&M (WtW + maintenance) scope is actually lower than the renewable mix because of the very limited maintenance required during the lifetime of solar panels compared to wind turbines. Like in the case of wind turbines, the cost of additional hydrogen storage capacity is two orders of magnitude lower and remains marginal for GHG emissions.

**Figure 18:** Comparison of GHG Emissions in Central Europe between a mixed and a 100% photovoltaic power source



#### KEY MESSAGES - ELECTRICITY SOURCE (100% PV)

Cradle-to-Grave emissions show a disadvantage for the use of 100% PV electricity (22.4 versus 12.8 gCO<sub>2</sub>eq/MJ in FT kero, equivalent to a 75% GHG emissions increase) instead of a mix of renewable energy sources.

Well-to-Wheels-and-Maintenance emissions decrease in this case (from 0.6 to 0.1 gCO<sub>2</sub>eq/MJ in FT kero) because there is little maintenance in the photovoltaic panel farms.

#### • Sensitivity to other renewable sources

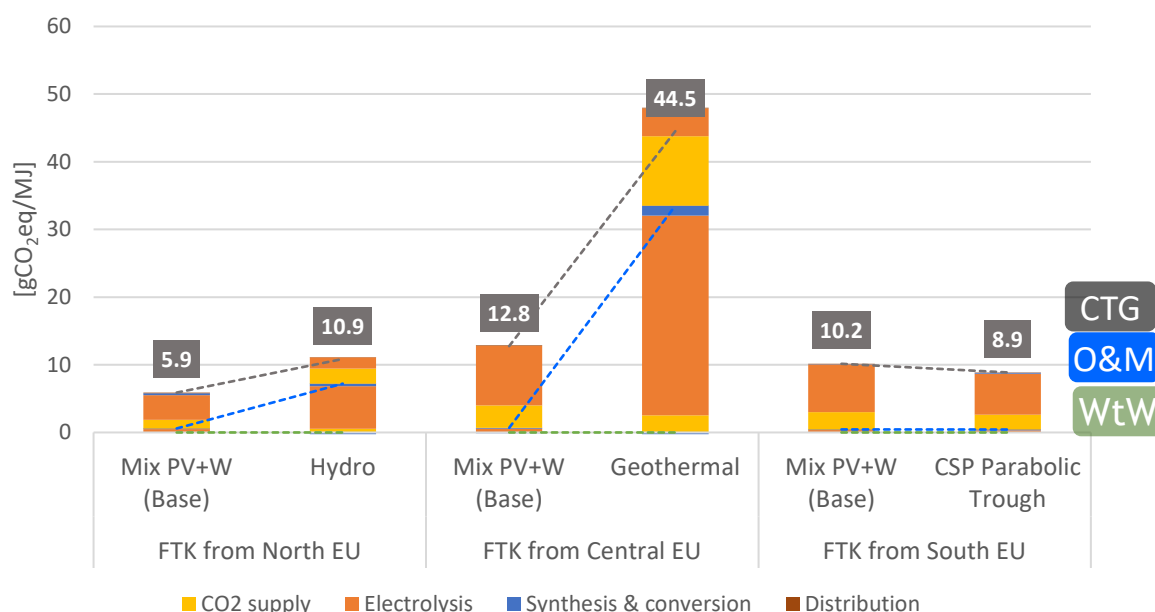
Figure 19 shows the results of the GHG sensitivity analysis of Fischer-Tropsch kerosene in 2050 three additional types of renewable energy in regions where they are particularly relevant: Hydropower in Northern Europe (14.1 gCO<sub>2</sub>eq/kWh), Geothermal in Central Europe (64.8 gCO<sub>2</sub>eq/kWh) and Concentrated Solar Power (CSP) using Parabolic Trough technology in Southern Europe (11.2 gCO<sub>2</sub>eq/kWh). The carbon intensity values for hydropower and geothermal power are taken from the GaBi databases [Sphera 2021]. The value for CSP was calculated from a GaBi model based on NREL's System Advisory Model (SAM) [NREL 2020].

The results show a net increase of GHG emissions for the the first two types of energy on a CTG basis and a decrease for Concentrated Solar Power, consistent with the power carbon intensities shown in Figure 4. With hydropower, the impact almost doubles for Northern Europe; for geothermal power it more than triples in Central Europe, and for CSP it is reduced by more than 12% in Southern Europe.

The reasons for these increased impacts lie on specific characteristics of each one of these renewable energies and the level of technology progress considered. The hydropower and geothermal energy pathways all show important additional contributions in the Well-to-Wheel scope, corresponding to direct emissions from the plant operations. Examples of this include methane produced at the bottom of hydropower reservoirs, where oxygen is low (anaerobic conditions) and bacteria decompose organic material [Deemer 2016] and CO<sub>2</sub> carried by fluids drawn from deep earth to produce geothermal power [Bonafin 2019]. For hydro and geothermal power, the increase with respect to a wind and PV mix also concerns the impacts related to energy and materials involved in infrastructure building (dams, drilling, rotating equipment, etc.)

In the case of concentrated Solar Power plants, the Parabolic Trough CSP pathway shows even lower CTG emissions than the mixed PV+Wind base case because of the lower energy requirements in its infrastructure compared to photovoltaic panels. The increasing efficiency of the solar technologies, along with higher steel recycling potentials will draw the carbon intensity of CSP to lower levels in the future, significantly reducing the impacts of fuels produced from it.

**Figure 19:** Comparison of GHG Emissions of fuels produced with various renewable energy sources



### 1.7.3. Use of alternative carbon dioxide sources

Figure 20 shows the results of a sensitivity analysis made on the use of different CO<sub>2</sub> source concentrations. The base case assumption, as described in Table 12, is the exclusive use of Direct Air Capture where CO<sub>2</sub> is at a very low concentration (0.04%). Three alternative scenarios were tested: One relying exclusively on a highly concentrated source (SMR off-gas), another on an average concentrated source (NGPP flue gas) and a third one using an equal part of each DAC, SMR and NGPP sources.

The difference between the two extreme cases (100% concentrated source and 100% diluted source of CO<sub>2</sub>) represent a gap of 0.8 gCO<sub>2</sub>eq/MJ for North EU and even 1.4 gCO<sub>2</sub>eq/MJ for a fuel produced in Middle East. The variation is proportional to the carbon intensity of the electricity used in each region. It can be observed that emissions from the CO<sub>2</sub> capture stage are the main source of variation between each scenario. While for the DAC case the emissions from this stage represent 21 to 25% of the total, they have no impact in the SMR case because of the absence of makeup heat production, as the heat available from the fuel synthesis reaction is enough to cover all the thermal energy requirements of CO<sub>2</sub> supply. The scenario with a mix of CO<sub>2</sub> sources is comparable to the average concentration case (NGPP).

**Figure 20:** Comparison of GHG Emissions from Fischer-Tropsch kerosene production from different CO<sub>2</sub> sources and different production locations

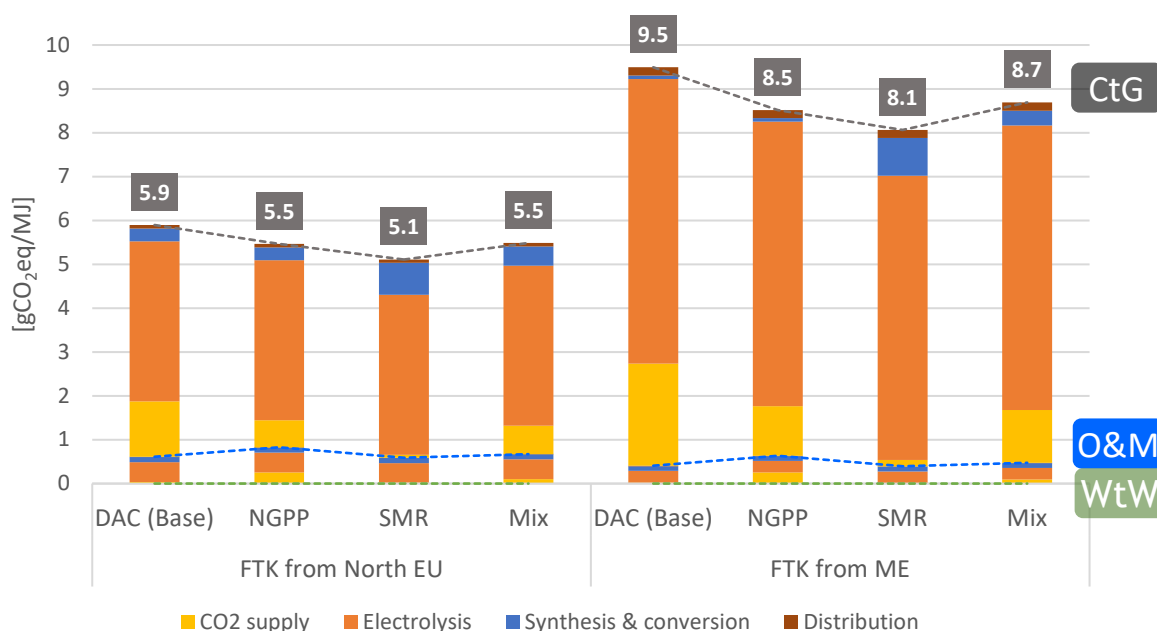


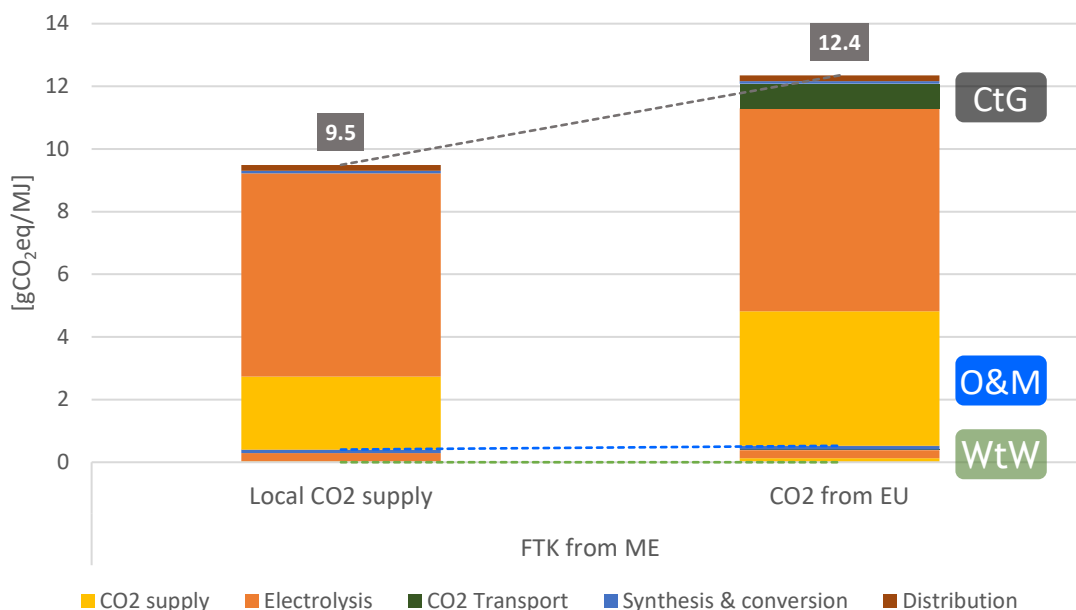
Figure 21 shows a particular case in which fuels are produced in Middle East, but instead of capturing CO<sub>2</sub> onsite and dispatching the fuels to Europe, the process uses CO<sub>2</sub> that is captured in Southern Europe, liquefied, and transported by ship to the synthesis plant in Middle East. This scenario intends to represent a hypothetical situation in which European regulations require e-fuel producing countries outside the region to use CO<sub>2</sub> captured in Europe to comply with the requirement of utilization of certified unavoidable CO<sub>2</sub>.

The consequences of such additional step in the supply chain represent an increase of about 30% of total GHG emissions on a Cradle-to-Grave bases in 2050, reflected in the larger size of the CO<sub>2</sub> Capture & Transport bar in both electricity plant maintenance and electricity plant infrastructure categories. This rise can be attributed to two factors:

- The absence of heat integration under this new configuration, since the thermal energy produced during the fuel synthesis cannot be used in the carbon capture process. This implies supplementary emissions from the electricity used to produce this missing energy in Europe. This is reflected as an increase of the Maintenance and Infrastructure contribution proper to renewable electricity.

- The additional maritime emissions linked to the liquefied CO<sub>2</sub> transport, from the e-fuels used to fuel the vessel. This is reflected as an increase of WtW emissions.

**Figure 21:** Comparison of GHG emissions of FT e-kerosene produced in South EU with H<sub>2</sub> from Middle East



#### KEY MESSAGES - CO<sub>2</sub> SOURCE

Cradle-to-Grave emissions from Fischer-Tropsch (FT) kerosene reach the lowest level when using a concentrated source of CO<sub>2</sub>, a decrease of about 15% respect to the base case diluted source (DAC).

The use of CO<sub>2</sub> captured in Europe and transported to Middle East for the production of e-fuels represents an increase of the carbon intensity of FT kerosene of about 30%, mostly related to the lack of heat integration and the use of supplementary e-diesel for shipping liquefied CO<sub>2</sub>.

#### 1.7.4. Use of alternative carriers for H<sub>2</sub> import to feed synthesis processes

Figure 22 shows the results of a sensitivity analysis on the particular case where Fischer-Tropsch Kerosene is produced in Southern Europe with hydrogen imported from Middle East in various forms: As liquefied hydrogen, as ammonia (from reaction between hydrogen and nitrogen), as methycyclohexane (from reaction between hydrogen and toluene) and as methanol (from a process identical to the production of e-methanol). It is assumed that in all these cases, the hydrogen is liquefied or added to the molecule carrier in Middle East and reconverted into hydrogen back at arrival in Europe at a centralized plant located next to the FT plant.

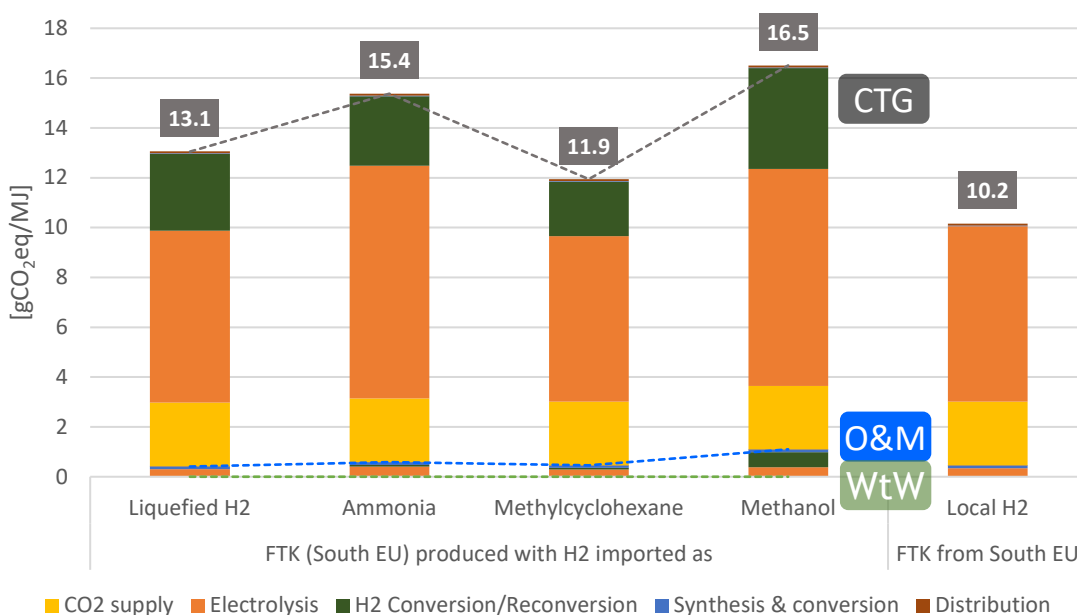


The impact is mainly dependent on the energy consumption and material losses in the process of conversion to and reversion from carriers in each case. The process of reversion (cracking) of ammonia into hydrogen considered in the present study assumes the use of ammonia itself as the main source of thermal energy, implying autoconsumption of 30% of the ammonia input. This explains its disadvantage compared to hydrogen liquefaction or methylcyclohexane (LOHC) pathway, in which there is no destruction of the molecule carrier (toluene used to produce methylcyclohexane can be recycled) or the energy required in the process is low or taken from an external power source instead of the feedstock itself. A similar observation can be made on the methanol carrier pathway, where the losses in the conversion and reversion processes increase the penalty from the conversion/reversion stage. The emissions from electrolysis also increase because of the additional hydrogen production required to cover for the losses in the processes.

The Liquefied H<sub>2</sub> case assumes the use of a Saudi Arabia renewable energy mix for the most energy intensive stage of the hydrogen supply chain. The results for this pathway are highly sensitive to the type of electricity used. For instance, switching to conventional power from fossil sources would increase the impact of this pathway by more than 7.5 times.

Further assessments need to be taken to consider multiple ways of increasing the efficiency of the different processes, but in general the advantages of carrying hydrogen in the form of a stable liquid under standard conditions does not compensate in terms of GHG emissions the high penalty of using intermediate conversion and reversion processes that reduce the energy efficiency of the supply chain.

**Figure 22:** Comparison of GHG emissions of FT e-kerosene produced from Middle East hydrogen transported via different carrier modes



### KEY MESSAGES - USE OF ALTERNATIVE H<sub>2</sub> CARRIERS

Cradle-to-grave emissions increase by 17 to 62% when hydrogen for the production of FT kerosene is imported in liquid form or via a liquid carrier from MENA. The additional burden is caused by a reduction of the energy efficiency and an increase of material losses.

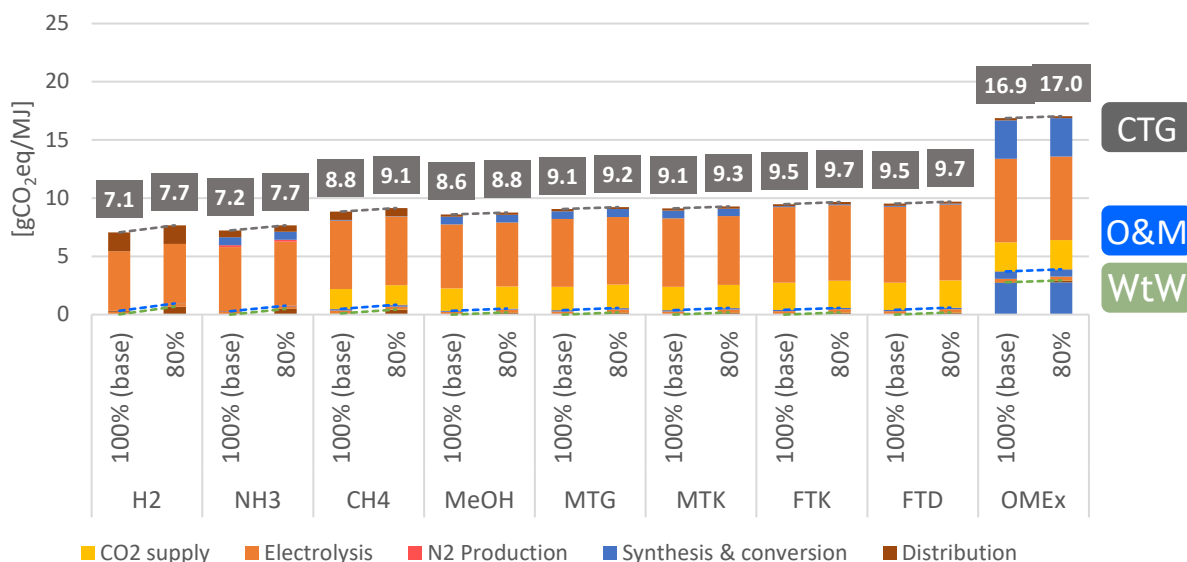
The results are highly dependent on the source of electricity used, in particular for hydrogen liquefaction. Technology progress could reduce the material losses from the reconversion processes and diminish the estimated impact.

### 1.7.5. Use of marine transport using only 80% e-diesel (2050)

Figure 23 shows the impact of a change on the marine transport default assumptions, which consider the use of 100% e-diesel in this time horizon when e-fuels are produced in the Middle East and are then transported by ship to Europe. The sensitivity tests the use of a blend of 80% e-diesel and 20% fossil marine gasoil, expected to be the minimum requirement to comply with the carbon reduction objectives of the IMO.

The consequences of this change affect more significantly pathways that have higher consumption of marine fuel per kg of fuel transported. For hydrogen, ammonia and methane the increase represents around 8%, 7% and 3% respectively under the conditions set in the study. For the rest of liquid fuels, the increase is only limited to about 2%.

**Figure 23:** Comparison of GHG emissions from Middle East imported fuels with different contents of e-diesel in marine fuel



### KEY MESSAGES - USE OF MARINE TRANSPORT USING ONLY 80% E-DIESEL (2050)

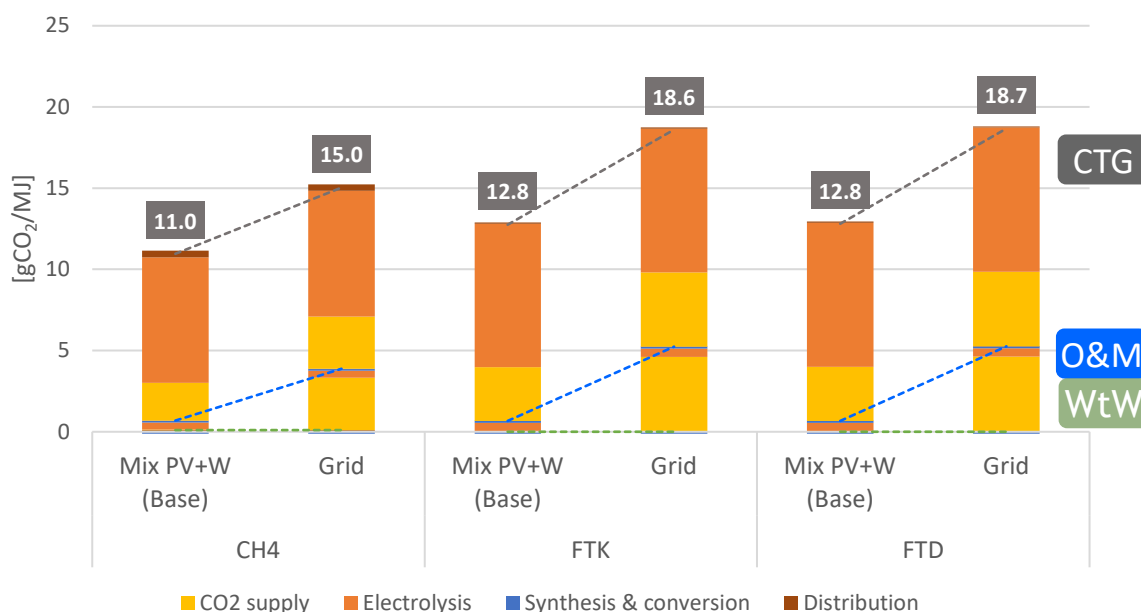
The consequences of this change affect more significantly pathways that have higher consumption of marine fuel per kg of fuel transported. For hydrogen, ammonia and methane the increase represents around 8%, 7% and 3% respectively under the conditions set in the study. For the rest of liquid fuels, the increase is only limited to about 2%.

### 1.7.6. Use of grid electricity for carbon capture

Figure 24 shows the impact of switching the type of electricity used in the carbon capture stage produced in Central Europe in 2050. The change affects the direct power consumption only and the electricity consumed in the electric furnaces to supply heat to the process.

Sensitivity cases were run for three different fuels: Methane, Fischer-Tropsch kerosene and Fischer-Tropsch diesel. In all the cases a net increase of emissions is observed, with higher increase rates for the fuels with higher requirements of CO<sub>2</sub> for producing 1 MJ of fuel. The use of electricity from the grid affects in particular the contribution of the WtW emissions, caused by the presence of fossil-powered plants with direct emissions in the mix.

**Figure 24:** Comparison of GHG emissions from fuels produced in Central EU with different power sources (renewable versus grid) for Carbon Capture



The use of grid electricity for generating supplementary heat for the carbon capture stage already increases the GHG emissions on a CTG basis by 37% to 46% for the three cases studied. If grid electricity were used for all the processes involved, water electrolysis for hydrogen production included, the GHG intensity of the e-fuels would rocket to levels comparable or even higher to their fossil equivalents: 82.8 gCO<sub>2</sub>/MJ for methane, 101.8 gCO<sub>2</sub>/MJ for FT kerosene and 102.2 gCO<sub>2</sub>/MJ for FT diesel.

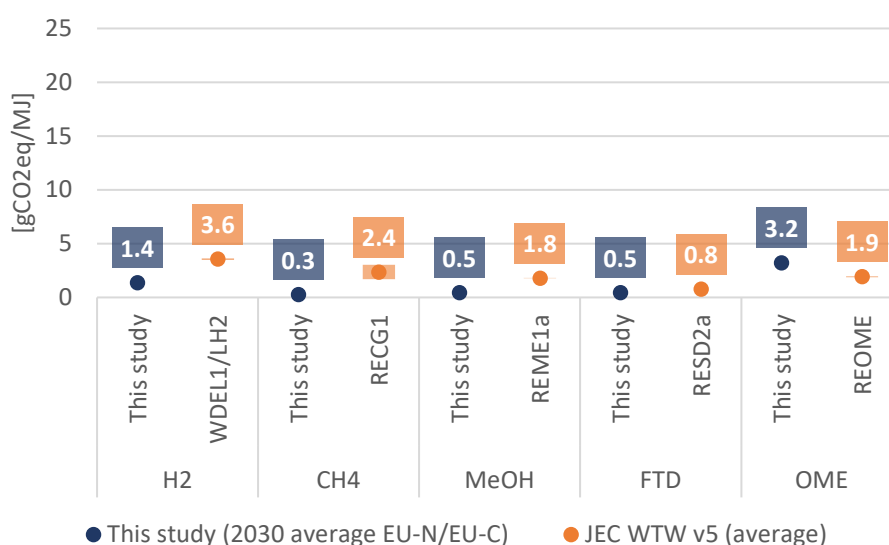
#### KEY MESSAGES - USE OF GRID ELECTRICITY FOR CARBON CAPTURE

Sensitivity cases were run for three different fuels: Methane, Fischer-Tropsch kerosene and Fischer-Tropsch diesel. In all the cases a net increase of GHG emissions between 37% and 46% is observed, with higher increase rates for the fuels requiring larger inputs of CO<sub>2</sub> per MJ. The use of electricity from the grid affects in particular the contribution of the WtW emissions, caused by the presence of fossil-powered plants with direct emissions in the mix.

## 1.8. GHG EMISSIONS VALUES COMPARISON WITH JEC WTW V5 STUDY

The base case results of our study were compared to the GHG emissions values of the JEC WTT study [JEC 2020] for five of the e-fuels of their scopes in common: Hydrogen, methane, methanol, syndiesel (FT diesel) and OME<sub>x</sub>. To ensure alignment of general conditions, the base case values from our study were taken from the 2030 timeframe instead of the default 2050. Also, the WTW emissions are shown instead of the CTG ones indicated in the data labels of all graphs. The comparison is displayed in Figure 25.

**Figure 25:** Comparison of average e-fuel GHG emissions (WTW 2030) of this study with JEC WTW v5



Note:

WDEL1/LH2: Electricity from wind energy, central electrolysis, H<sub>2</sub> liquefaction, liquid H<sub>2</sub> road transport to retail site, H<sub>2</sub> cryo-compression into vehicle tank (35 MPa).

RECG1: Synthetic methane (as CNG) from renewable electricity, CO<sub>2</sub> from flue gases

REME1a: Renewable electricity to methanol, CO<sub>2</sub> from flue gases

RES2a: Renewable electricity to synthesised diesel via high temperature electrolysis based on SOEC and FT route, CO<sub>2</sub> from flue gases

REOME: Renewable electricity to OME via methanol synthesis, formaldehyde synthesis, methylal synthesis, trioxane synthesis, and OME synthesis, CO<sub>2</sub> from biogas upgrading

Several differences in the assumptions must be taken into account to explain the disparities. Some examples of assumptions taken in the JEC WTW study compared to this study are:

- The electricity used for hydrogen liquefaction is assumed to come from the grid, while this study considers the use of renewable electricity instead (grid electricity is used for other operations like compression and dispensing).
- Road transport for hydrogen is assumed at 35 MPa, instead of 50 MPa in this study, which has an impact on the amount of hydrogen that can be transported and its GHG impact and cost.

- Energy consumption rates for  $H_2$  liquefaction and  $CH_4$  compression/dispensing are considered higher than the values used in this study (example: hydrogen liquefaction consumes  $0.24 \text{ MJ}_e/\text{MJ}_{H_2}$  in this study and  $0.30 \text{ MJ}_e/\text{MJ}_{H_2}$  in the JEC WTW study). The reasons for these differences are explained by the scope of the JEC WTW study, which uses current technology values, while this study anticipates when possible technology progress by the base case year 2050.
- The source of  $CO_2$  is flue gases, while this study assumes the use of a concentrated source (SMR pre-combustion gases) that require less energy.
- The electrolysis technology used for diesel synthesis (SOEC) is different from the one used in this study (alkaline).
- Emissions from  $O_2$  production, necessary for  $OME_x$  synthesis are not taken into account.

## 2. ECONOMIC ASSESSMENT

### 2.1. ECONOMIC MODELLING OF SELECTED E-FUELS PATHWAYS

Table 16 shows the list of base case pathways executed in this study.

**Table 16:** Overview of e-fuel pathways investigated in this study

N°	Fuel	Supply	Pathway code
1	e-Hydrogen	Europe (N)	H2EU-N
2	e-Methane	Europe (N)	CH4EU-N
3	e-Methanol	Europe (N)	MeOHEU-N
4	e-OMEx	Europe (N)	OMExEU-N
5	e-Gasoline (MTG)	Europe (N)	MTGEU-N
6	e-Kerosene (MTK)	Europe (N)	MTKEU-N
7	e-Ammonia	Europe (N)	NH3EU-N
8	e-Kerosene (FT)	Europe (N)	FTKEU-N
9	e-Diesel (FT)	Europe (N)	FTDEU-N
10	e-Hydrogen	Europe (C)	H2EU-C
11	e-Methane	Europe (C)	CH4EU-C
12	e-Methanol	Europe (C)	MeOHEU-C
13	e-OMEx	Europe (C)	OMExEU-C
14	e-Gasoline (MTG)	Europe (C)	MTGEU-C
15	e-Kerosene (MTK)	Europe (C)	MTKEU-C
16	e-Ammonia	Europe (C)	NH3EU-C
17	e-Kerosene (FT)	Europe (C)	FTKEU-C
18	e-Diesel (FT)	Europe (C)	FTDEU-C
19	e-Hydrogen	Europe (S)	H2EU-S
20	e-Methane	Europe (S)	CH4EU-S
21	e-Methanol	Europe (S)	MeOHEU-S
22	e-OMEx	Europe (S)	OMExEU-S
23	e-Gasoline (MTG)	Europe (S)	MTGEU-S
24	e-Kerosene (MTK)	Europe (S)	MTKEU-S
25	e-Ammonia	Europe (S)	NH3EU-S
26	e-Kerosene (FT)	Europe (S)	FTKEU-S
27	e-Diesel (FT)	Europe (S)	FTDEU-S
28	H2 (liquid)	MENA by ship	H2ME-Liq
29	e-Methane (LNG)	MENA by ship	NGME-Liq
30	e-Methanol	MENA by ship	MeOHME
31	e-OMEx	MENA by ship	OMExME
32	e-Gasoline (MTG)	MENA by ship	MTGME
33	e-Kerosene (MTK)	MENA by ship	MTKME
34	e-Ammonia	MENA by ship	NH3ME
35	e-Gasoline (FT)	MENA by ship	FTGME
36	e-Kerosene (FT)	MENA by ship	FTKME
37	e-Diesel (FT)	MENA by ship	FTDME
38	e-Kerosene (FT)	MENA by ship as e-crude	FTKMEE-crd
39	e-Kerosene (FT)	Europe (S) with H <sub>2</sub> from MENA by ship	FTKME-H2ex
40	e-Diesel (FT)	Europe (S) with H <sub>2</sub> from MENA by ship	FTDME-H2ex

### 2.1.1. Approach and economic modelling

The focus of the study are e-fuels production and distribution (Well-to-tank approach). Vehicles/fuel use combination (tank-to-wheel) is not part of the scope.

In line with the study objective of fundamental comparison of different e-fuels and pathways, a full cost assessment from the renewable power production to the final e-fuel dispensing has been carried out. Hence, no business case analysis, no net present value (NPV), or return on invest (ROI) have been calculated. Therefore, neither taxes/levies nor exemptions thereof, and no inflation have been taken into account (cost figures are given in today's purchasing power). Learning curves have been considered for technologies with potential for cost reductions from series production.

CAPEX is converted to an Equivalent Annual Cost via the Excel 'PMT' function using discount rate (baseline: 8%) and the depreciation time (process-specific lifetime). Annual costs for maintenance and repair are added. The resulting annual costs divided by average annual production volume result in the specific product costs (€/kWh electricity supply, €/t CO<sub>2</sub> supply, €/kWh intermediary product supply, etc.). The specific costs are aggregated according to pathway definition and expressed in € per unit of final energy.

All facilities, such as plants for power generation, synthesis and conversion/upgrading, are newly built (from scratch) and depreciated over their lifetime (in many cases some 25 years). The same applies for vehicles used for the transport of the final fuel. Conversion and upgrading are included in the economic assessment, aligned with the LCA assessment in the previous chapter of this report.

In case of cost data from earlier publications, these are converted to today's costs via Chemical Engineering Plant Cost Index (CEPCI)<sup>8</sup>. Inflation is not taken into account for future costs.

Costs for spare parts are part of annual O&M costs, i.e. no investment/discount rate is assumed for overhauls/spare parts.

New plants are assumed for each time horizon (Today, 2030, 2050), thus capturing the picture of cost reduction potentials over a series of projects over time.

### 2.1.2. Economic assumptions

For a description of the e-fuels pathways and plants investigated in this report, as well as the detailed CAPEX and OPEX assumptions, see ECONOMIC ANNEX 9.

Basic assumptions:

- For the base case, a production of 1 million t of e-diesel equivalent<sup>9</sup> per year has been assumed. The capacity depends on the availability of renewable electricity, the capacity of the electricity storage system (ESS), the H<sub>2</sub> buffer storage, the CO<sub>2</sub> buffer storage, and the flexibility of the e-fuel plant (see chapter 4).

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<sup>8</sup> The CEPCI is a dimensionless number used to calculate the CAPEX of chemical plants from one period to another. The CEPCI consists of a composite index assembled from a set of four sub-indices: equipment, construction labour, buildings, engineering, and supervision [Chemical Engineering 2022].

<sup>9</sup> Based on fuel properties of conventional diesel EN 590



- Discount rate: 8%
- Depreciation period: Lifetime (specified in Annex 9)
- The fuel demand of trucks and ships except gas carriers for the transport and distribution of the final fuel is met by conventional fuels (except for time horizon 2050 where 100% e-fuels are assumed in the e-fuel transport in the base case). Table 17 shows the cost assumptions for diesel and low sulphur marine gas oil (LSMGO).

**Table 17:** Costs of conventional fuels, natural gas, and fossil CO<sub>2</sub> emissions

	Unit	2020	2030	2050	Reference
Diesel	€/l	0.30	0.60	0.80	EC/Concawe*
	€/GJ	8.4	16.7	22.3	EC/Concawe*
LSMGO	€/t	328	657	903	EC/Concawe*
	€/GJ	7.7	15.4	21.1	EC/Concawe*
Natural gas	€/GJ	3.3	5.7	9.0	EU COM 2020
CO <sub>2</sub> price	€/t (base case)	25	130	250	IEA 2021
	€/t (sensitivity)	60			EC/Concawe*

\*Crude-oil prices taken from the European Commission Impact Assessment [EU COM 2020] and extrapolated by Concawe using historical factors

Throughout the supply chain there are electricity consumers which are not connected with the PtX plant such as refuelling stations and compressors within a hydrogen pipeline grid. Table 18 shows the cost assumptions for electricity and low and medium voltage level for the different regions inside Europe. Based on [Eurostat 04/2022] and [Eurostat 10/2022], the electricity prices for household (low voltage, LV) and non-household consumers (medium voltage, MV) are assumed to 25 ct/kWh<sub>e</sub> and 10 ct/kWh<sub>e</sub>, respectively.

**Table 18:** Costs of electricity for electricity consumers not connected with the PtX plant (€/kWh)

	Voltage level	2020	2030	2050
North EU (Norway)	LV	0.25	0.25	0.25
	MV	0.10	0.10	0.10
Central EU (Germany)	LV	0.25	0.25	0.25
	MV	0.10	0.10	0.10
South EU (Spain)	LV	0.25	0.25	0.25
	MV	0.10	0.10	0.10

The electricity demand of the PtX plants is met by 100% renewable energy. For North Europe offshore wind farms are assumed, for the other locations electricity from photovoltaic (PV) and wind power plants. In the regions assessed in this study wind power and photovoltaic are complementary. The electricity yield of PV is high in times when the yield of wind power is low and vice versa. A part of the electricity is curtailed depending on the region and the time horizon (see chapter 4), as the integration costs of this excess power typically exceed the gain from using it (economic curtailment).

The ratio of the rated capacity between PV and wind power of the PV/wind hybrid varies from region to region depending on the flexibility of the downstream processes and the decrease of CAPEX for renewable power plant, electricity storage, and other components of the e-fuel plant. The capacity of the PV/wind hybrid plant is adjusted to the capacity of the connected e-fuel plant.

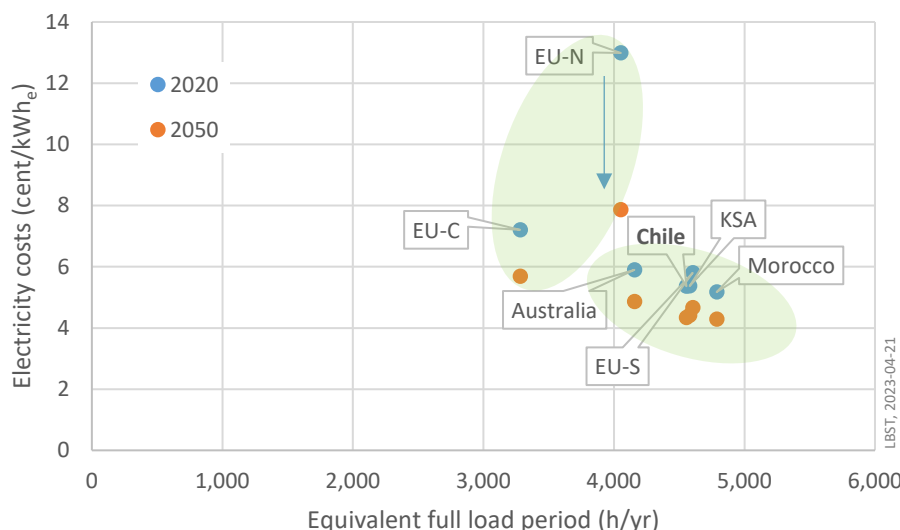
- An electricity storage system based on batteries, a H<sub>2</sub> buffer storage, and a CO<sub>2</sub> buffer storage have been applied. This storage capacity is region specific, a detailed cost minimisation is described in chapter 4. The hydrogen buffer storage consists of underground buried steel pipes with a diameter of 1,485 mm and a maximum pressure of 10 MPa. The CO<sub>2</sub> buffer storage consists of tanks where the CO<sub>2</sub> is stored at a temperature of -41 °C.
- The costs of renewable electricity shown in Table 19 have been calculated based on CAPEX, OPEX, and the equivalent full load period of photovoltaic (PV) and wind power plants in the different regions for pathways involving Fischer-Tropsch synthesis. The electricity costs for other pathways are slightly different because of different curtailment of renewable electricity. The calculation of the renewable electricity costs including the references is described in ECONOMIC ANNEX 9.2.

**Table 19:** Costs of renewable electricity in the different regions for pathways involving FT synthesis (€/kWh)

	2020				2030				2050			
	pV <sup>2)</sup>	Wind onshore <sup>2)</sup>	Wind offshore <sup>2)</sup>	Σ <sup>1)</sup>	pV <sup>2)</sup>	Wind onshore <sup>2)</sup>	Wind offshore <sup>2)</sup>	Σ <sup>1)</sup>	pV <sup>2)</sup>	Wind onshore <sup>2)</sup>	Wind offshore <sup>2)</sup>	Σ <sup>1)</sup>
Northern Europe (NO)			0.126 (4053 h/a)	0.130			0.084 (4053 h/a)	0.088			0.078 (4053 h/a)	0.079
Central Europe (DE)	0.055 (1426 h/a)	0.069 (2688 h/a)		0.072	0.043 (1426 h/a)	0.065 (2688 h/a)		0.064	0.037 (1426 h/a)	0.061 (2688 h/a)		0.057
Southern Europe (DE)	0.038 (2073 h/a)	0.047 (3231 h/a)		0.058	0.030 (2073 h/a)	0.044 (3231 h/a)		0.053	0.025 (2073 h/a)	0.042 (3231 h/a)		0.047
MENA (KSA)	0.032 (2406 h/a)	0.047 (3193 h/a)		0.054	0.026 (2406 h/a)	0.045 (3193 h/a)		0.048	0.022 (2406 h/a)	0.042 (3193 h/a)		0.044
Australia	0.037 (2100 h/a)	0.050 (3000 h/a)		0.059	0.030 (2100 h/a)	0.047 (3000 h/a)		0.053	0.025 (2100 h/a)	0.045 (3000 h/a)		0.049
Chile	0.029 (2700 h/a)	0.053 (2800 h/a)		0.054	0.023 (2700 h/a)	0.050 (2800 h/a)		0.047	0.019 (2700 h/a)	0.048 (2800 h/a)		0.043
Morocco	0.034 (2300 h/a)	0.043 (3600 h/a)		0.052	0.027 (2300 h/a)	0.040 (3600 h/a)		0.047	0.023 (2300 h/a)	0.038 (3600 h/a)		0.043

<sup>1)</sup> Including curtailment as described in chapter 4 and including HVDC in Southern Europe and regions outside Europe; <sup>2)</sup> Electricity cost without HVDC, 200 km (0.0009-0.011 €/kWh depending on region and time horizon)

**Figure 26:** Costs of renewable electricity in the different regions for pathways involving FT synthesis (€/kWh<sub>e</sub>)



- In North Europe there is a large potential for offshore wind. Therefore, in case e-fuels are produced in North Europe, the electricity generated by the offshore wind farm is transported via a sea cable to the coast (~80 km) where the e-fuel plant is located.
- In North Europe, 100% wind off-shore has been considered. While there is a high contribution of renewable electricity generated from hydropower today, new additional renewable power generation at large in future may rely on wind power. Besides, we wanted to explore the case of 100% wind off-shore to see how it compares versus PV/wind onshore in the rest of the regions in EU.
- In Germany, the installation of large-scale PV/wind hybrid power stations at former lignite mining regions are proposed. Therefore, in case e-fuels are produced in Central Europe, the e-fuel plant is located nearby the PV/wind hybrid power station.

Southern Spain, the Kingdom of Saudi Arabia (KSA), Australia, Chile, and Morocco are arid regions where water is scarce. Seawater desalination is required for water supply. New export-oriented PtX plants will likely to be located at the coast [Sasol 2021]. For e-fuels produced in Southern Europe, KSA, Australia, Chile and Morocco, it has been assumed that the renewable electricity is transported to the e-fuel plant at the coast via a high voltage direct current (HVDC) transmission line over a distance of 200 km.

- Concerning technical assumptions for PtX plants, respective CO<sub>2</sub> sources and transport modes, see Table 12 in chapter 1.5.

In 2050 the ships for the marine transport of final fuel are powered by 100% e-fuels. In the case of FT kerosene imported from MENA (pathway FTKME), the marine transport from Kingdom of Saudi Arabia to South Europe contributes to about 1.0 € per GJ of final fuel (1.9% of the total costs of fuel supply) if e-diesel is used for ship propulsion. If fossil fuel (LSMGO) were used, the cost for marine transport from Kingdom of Saudi Arabia (KSA) to South Europe will amount to about 0.6 € per GJ of final fuel (or about 1.1% of total costs of fuel supply).

**Table 20:** Baseline electricity supply - Resulting equivalent full load period for electricity cost calculation

	PV (h/yr)	Wind onshore (h/yr)	Wind offshore (h/yr)
Northern Europe (Norway)	-	-	4050 <sup>1)</sup>
Central Europe (Germany)	1430 <sup>2)</sup>	2690 <sup>3)</sup>	-
Southern Europe (Spain)	2070 <sup>2)</sup>	3230 <sup>4)</sup>	-
MENA (KSA)	2410 <sup>2)</sup>	3600 <sup>2)</sup>	-

1) Real plants: [BET et al. 2019] BET, Fichtner, Prognos: Vorbereitung und Begleitung bei der Erstellung eines Erfahrungsberichts gemäß § 97 EEG - Teilvorhaben If - Windenergie auf See; Juli 2019

2) Lilley, W. (Aramco), e-mail from 16 June 2021

3) [Deutsche WindGuard 2015, p30] Deutsche WindGuard: Kostensituation der Windenergie an Land in Deutschland - Update; Dezember 2015

4) Real plant: Ewind - Wind energy in Andalusia, Naturgy wind farm; 11 January 2020; <https://www.ewind.es/2020/01/11/wind-energy-in-andalusia-naturgy-wind-farm/73011>

- The hydrogen buffer storage consists of underground buried pipes with a diameter of 1,485 mm and a maximum pressure of 10 MPa. The CO<sub>2</sub> is liquefied and stored in tanks at a temperature of -41 °C.
- In regions where water is scarce e. g. in Middle East seawater desalination is required for the supply of water for the electrolysis plants. However, the impact of water desalination on the overall electricity consumption and the costs of e-fuel supply is low. Aquatech, a manufacturer of seawater desalination plants based on seawater reverse osmosis (SWRO) indicates an electricity consumption of less than 3 kWh per m<sup>3</sup> of desalinated water [Aquatech 2018].

The water requirement for hydrogen production via water electrolysis amounts to about 0.27 kg per kWh of hydrogen based on the LHV. As a result, the electricity requirement for seawater desalination will be 0.00081 kWh per kWh of hydrogen based on the LHV.

For 2020 we assume an efficiency of 66.5% for the production of hydrogen via water electrolysis which leads an electricity consumption of 1.503759 kWh/kWh of hydrogen based on the LHV. Adding water desalination would lead to 1.504569 kWh/kWh and to an efficiency of 66.46%, still 66.5% if rounded. The additional electricity consumption for water desalination is below the accuracy of the indicated efficiency of the electrolysis plant.

The CAPEX for a large water desalination plant based on SWRO located in Saudi Arabia is estimated at 1.5 million US\$ per million l of water per day [Almar 2016]. For the supply of hydrogen via liquid hydrogen (LH<sub>2</sub>) imported from KSA, the capacity of the water electrolysis plant would amount to about 1,470 MW of hydrogen based on the LHV. The water demand amounts to about 0.27 l of water per kWh of hydrogen based on the LHV. Then, the required capacity of the water desalination plant would amount to about 9.5 million l of desalinated water per day. Adjustment of the CAPEX to today's values via the CEPCI and

conversion to € would lead to about 14.3 million € or about 10 €/kW of hydrogen for the water desalination plant (<1% of the CAPEX of the electrolysis plant). Including the costs of renewable electricity in KSA and costs for maintenance and labour the water costs would amount to about 1.0 € per m<sup>3</sup> of water or 0.0010 € per l of water or <1% of total fuel production and supply costs.

Other sources report a large bandwidth for the CAPEX (0.36 to 1.65 million US\$ per million l of water per day) for large SWRO plants in Israel [ACWA 2019] (no techno-economic data for SWRO plants are presented for KSA; therefore, locations in Israel have been used as proxy). Application of the same assumptions used for KSA for pathways involving FT synthesis in this study leads to water costs of 0.52 to 1.22 € per m<sup>3</sup> (Table 21). [Saudi Gazette 2019] indicates a CAPEX of 700,000 US\$ for a SWRO plant with a capacity of 600,000 m<sup>3</sup> of water per day (1.17 million US\$ per million l of water per day) leading to about 0.90 € per m<sup>3</sup> of water.

**Table 21:** Water cost for water from seawater reverse osmosis (SWRO) plants

		Israel				KSA	
	Unit	Askelon	Hadera	Soreq	Ashdod	Rabigh 3	Reference
Award	-	2003	2007	2010	2011	2018	ACWA 2019; Saudi Gazette 2019
Capacity	m <sup>3</sup> /d	330,000	368,000	540,000	274,000	600,000	ACWA 2019; Saudi Gazette 2019
	m <sup>3</sup> /h	13,750	15,333	22,500	11,417	25,000	
CAPEX	US\$/ (m <sup>3</sup> /d)	360	1155	741	1653	1167	ACWA 2019; Saudi Gazette 2019
	€/ (m <sup>3</sup> /d)*	486	1193	730	1531	1049	
	million €	160	439	394	419	630	
Equivalent full load period	h/yr	5050					Assumption
Electricity consumption	kWh/m <sup>3</sup>	3.5					ACWA 2019
Electricity costs	€/kWh	0.054					ANNEX 9.2.2
Lifetime	yr	30					Assumption
Discount rate	-	8%					Assumption
O&M	-	4% of CAPEX/yr					Assumption
Water costs	-	0.52	0.99	0.68	1.22	0.90	

\*Adjusted to €<sub>2019</sub> via the CEPCI and conversion from US\$ to €

According to Almar Water Solutions, the water costs for seawater desalination via seawater reverse osmosis (SWRO) in the Arabian Gulf amount to 1.35 US\$ per m<sup>3</sup> of water and in the Red Sea 1.38 US\$ per m<sup>3</sup> of water. For the Mediterranean Sea, the cost of water supply is even lower (0.98 US\$/m<sup>3</sup>) [Almar 2016]. [ACWA 20WA 2019] indicates water costs of 0.53 to 0.70 US\$/m<sup>3</sup> based on bids for the Rabigh 3 SWRO plant. The reasons for the deviation to the calculated water costs depicted in Table 21 can be different assumptions for the discount rate, different equivalent full load periods, different electricity costs, and different assumptions for O&M costs.

In the EU the water prices range between 1.5 (Netherlands) and 2.0 (Germany) € per m<sup>3</sup> [Lauruschkus et al. 2015], although no seawater desalination is required. On the other hand, the water pipeline grid is included in these figures, which is not required if a seawater desalination plant is located onsite the electrolysis plant. As a rough estimate, the costs for water have been assumed to be 1.5 € per m<sup>3</sup> for all regions.

- In our calculations the use of water recycling has not been considered. Possible sources of reclamation include by-product water from chemical synthesis reactions and water captured from the air by DAC. Direct air capture of CO<sub>2</sub> leads to extraction of water from air as by-product. Up to 1 kg of water can be extracted per kg of CO<sub>2</sub> or about 3.8 kg per kg of liquid transportation fuel leading to a positive water balance.
- We have assumed very large (GW-scale) electrolysis plants and we assume high market penetration of e-fuels leading to huge amounts of oxygen which exceed the industrial oxygen demand. Therefore, no credit has been taken into account for the by-product oxygen as a conservative approach for the purpose of this study (covering very different fuels, suited for very different applications, and stretching over a far time horizons). There may be local opportunities for the use of by-product oxygen which is a topic for site-specific business-case analyses (out of scope of this study).
- For the electrolysis plants, all auxiliaries such as transformer, AC/DC converter, pumps, blowers, and storage tanks are included. Same for costs for civil and engineering work.
- The costs of CO<sub>2</sub> supply via extraction from flue gases and direct air capture (DAC) have been calculated. The costs of CO<sub>2</sub> going into the CO<sub>2</sub> extraction plant is zero as it is considered as waste. The calculation is described in the TECHNICAL ANNEX chapter 8.

The assumptions including learning curves and references for the calculation of CAPEX and OPEX are described in the ECONOMIC ANNEX chapter 9.

Generally, the costs are indicated per GJ of final fuel (1 GJ = 1,000 MJ). Table 22 shows a set of factors to convert GJ to other units.

**Table 22:** Conversion table

	MJ	kWh	kg H <sub>2</sub>	Nm <sup>3</sup> H <sub>2</sub>	kg CH <sub>4</sub>	Nm <sup>3</sup> CH <sub>4</sub>	kg methanol	kg NH <sub>3</sub>	l diesel	kg diesel
1 MJ	1	0.278	0.00834	0.0926	0.0200	0.0279	0.0502	0.0535	0.0279	0.0232
1 kWh	3.6	1	0.0300	0.333	0.0720	0.1005	0.181	0.1925	0.100	0.0835
1 kg H <sub>2</sub>	120.0	33.32	1	11.1	2.40	3.35	6.02	6.42	3.34	2.78
1 Nm <sup>3</sup> H <sub>2</sub>	10.80	3.00	0.090	1	0.216	0.301	0.542	0.577	0.301	0.250
1 kg CH <sub>4</sub>	50.0	13.89	0.417	4.63	1	1.40	2.51	2.67	1.39	1.16
1 Nm <sup>3</sup> CH <sub>4</sub>	35.82	9.95	0.299	3.32	0.716	1	1.797	1.915	0.998	0.830
1 kg methanol	19.93	5.54	0.166	1.85	0.398	0.556	1	1.066	0.555	0.462
1 kg NH <sub>3</sub>	18.7	5.19	0.156	1.73	0.374	0.522	0.938	1	0.521	0.434
1 l diesel	35.9	9.97	0.299	3.32	0.718	1.002	1.801	1.919	1	0.832
1 kg diesel*	43.13	11.98	0.360	3.99	0.862	1.204	2.164	2.306	1.202	1

\* Conventional diesel based on EN 590; FT diesel: 44.0 MJ/kg, 0.783 kg/l

### 2.1.3. Base case results from economic assessment

For 2020 and 2030 a concentrated source with a CO<sub>2</sub> concentration of 45% (flue gas from SMR plants as proxy) has been assumed for CO<sub>2</sub> supply. For 2050, Direct Capture of CO<sub>2</sub> from air has been assumed as base case both for e-fuels produced in Europe and in MENA (Kingdom of Saudi Arabia as proxy in the base case), assuming that Direct Air Capture will be technically developed and anything else may not be recognized by the EU regulations.

Sensitivities to the CO<sub>2</sub> source have been included in chapter 2.2.4.



### 2.1.3.1. E-fuels produced in Europe by zone

Figure 27 shows the base case results for e-fuels produced within Europe by zone (North, Central, South) for time horizon 2020.

**Figure 27:** Costs of e-fuels produced inside Europe by zone in 2020

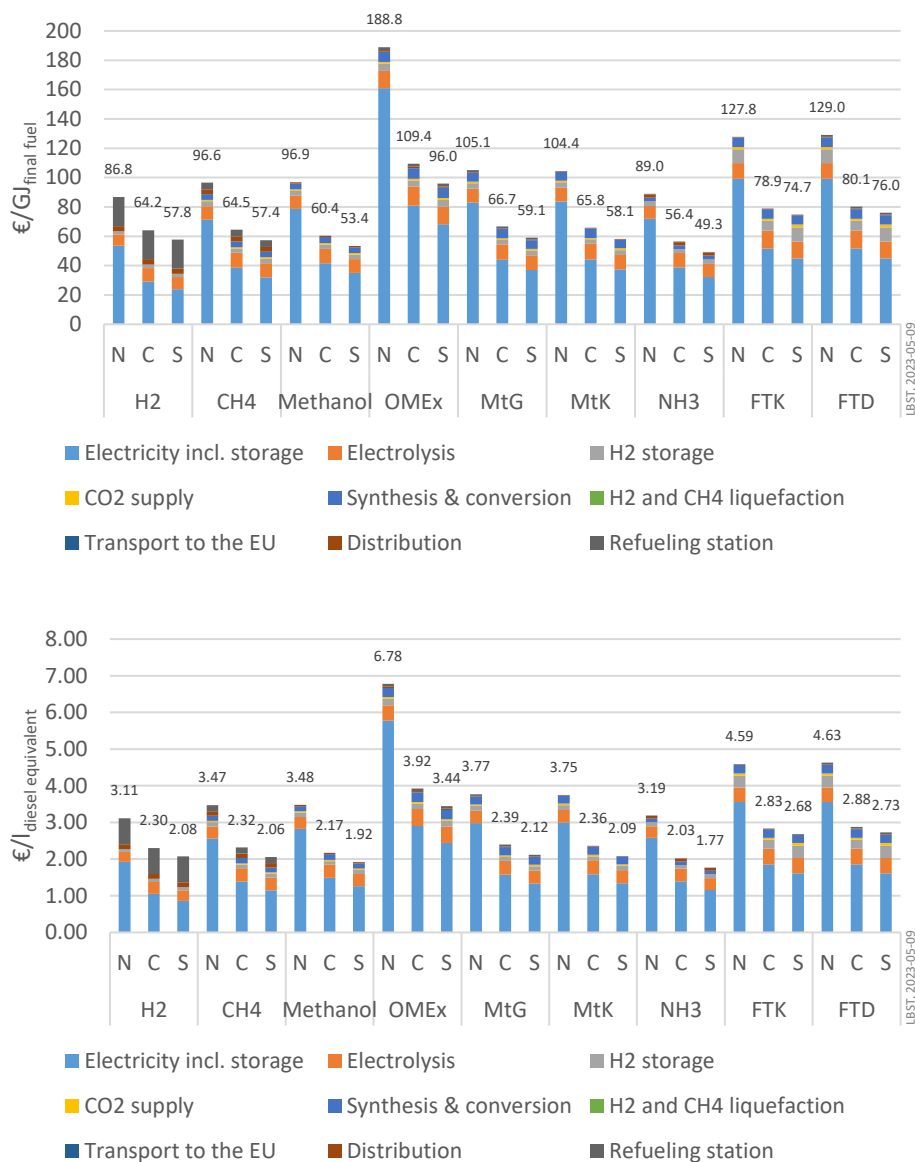


Figure 28 shows the base case results for e-fuels produced within Europe by zone (North, Central, South) for time horizon 2030.

**Figure 28:** Costs of e-fuels produced inside Europe by zone in 2030

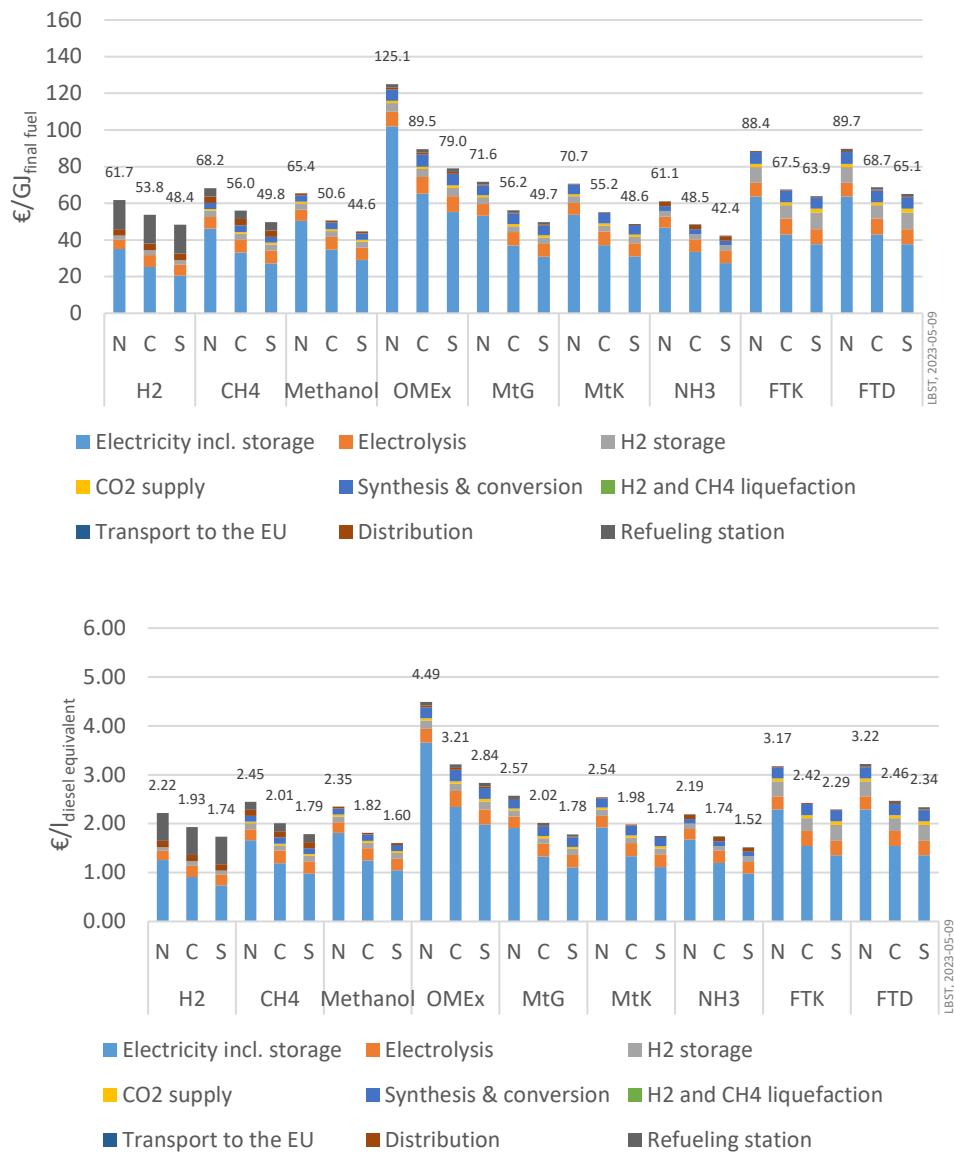
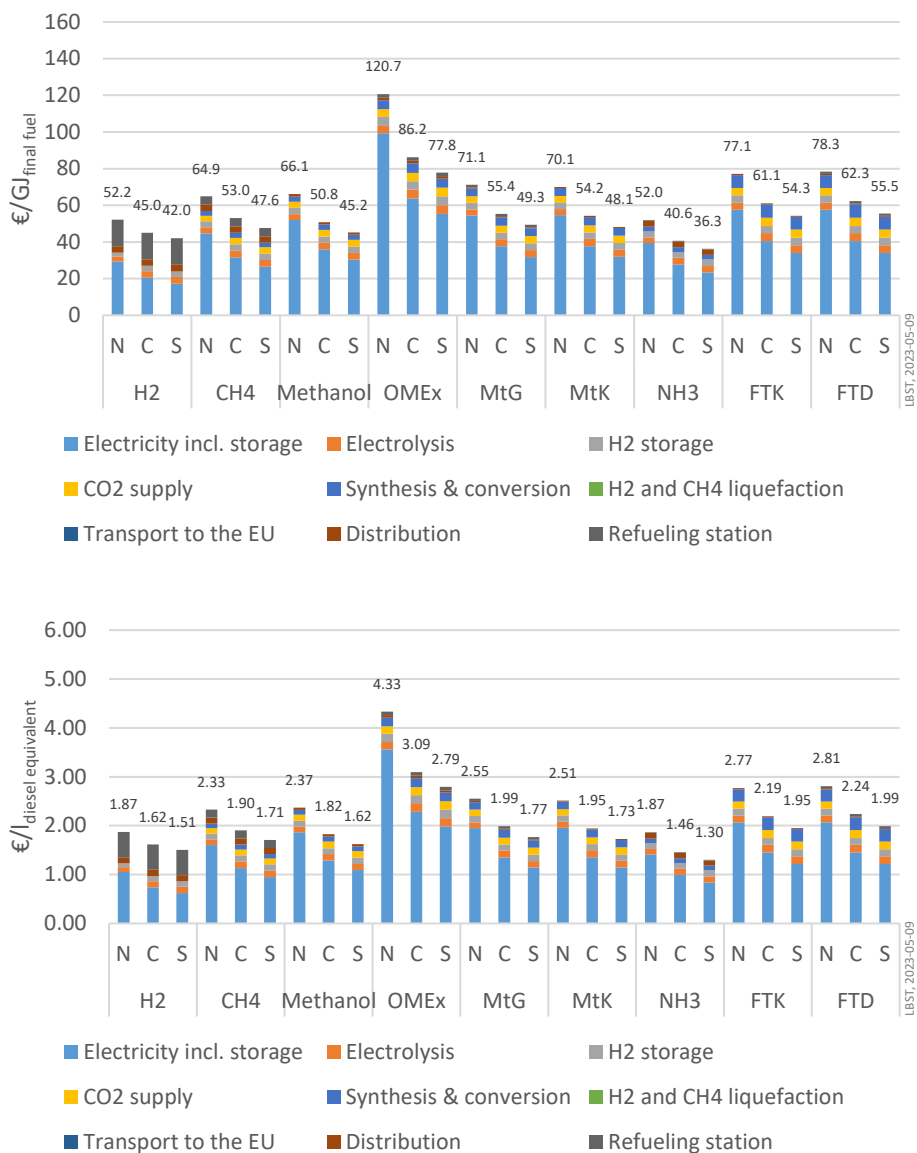


Figure 29 shows the base case results for e-fuels produced within Europe by zone (North, Central, South).

**Figure 29:** Costs of e-fuels produced inside Europe by zone in 2050



The electricity costs (blue bar) include the electricity consumed by the whole power-to-fuel plant including electrolysis, CO<sub>2</sub> supply and the further processing to final fuel. Furthermore, the electricity storage system (ESS) is included in the electricity costs. The costs for the other process steps of the power to fuel plant include CAPEX and OPEX (e. g. maintenance and repair). The cost for electricity has the highest share of the overall costs of fuel supply (up to around 70% without electricity storage) except in case of compressed gaseous hydrogen (CGH<sub>2</sub>) in South Europe (around 40%). The reason is that the capital costs per unit of final fuel for the refuelling station dispensing CGH<sub>2</sub> is higher than for other fuels.

Due to the low efficiency of the fuel supply chain the supply of OME<sub>x</sub> leads to the highest fuel costs per unit of final fuel.

The costs of fuel supply for kerosene generated via MTK process is lower than for kerosene generated via the FT route because the efficiency of the power-to-kerosene plant involving the MTK process is higher (~50% versus ~45%). It has to be noted that the TRL of the MTK process is lower than that for the production of kerosene via the FT route, so its estimate is less precise and will have to be confirmed with the first units in operation.

### 2.1.3.2. E-fuels produced in Europe by year

Figure 30 shows the base case results for e-fuels produced in North Europe by year.

**Figure 30:** Costs of e-fuels in North Europe by year

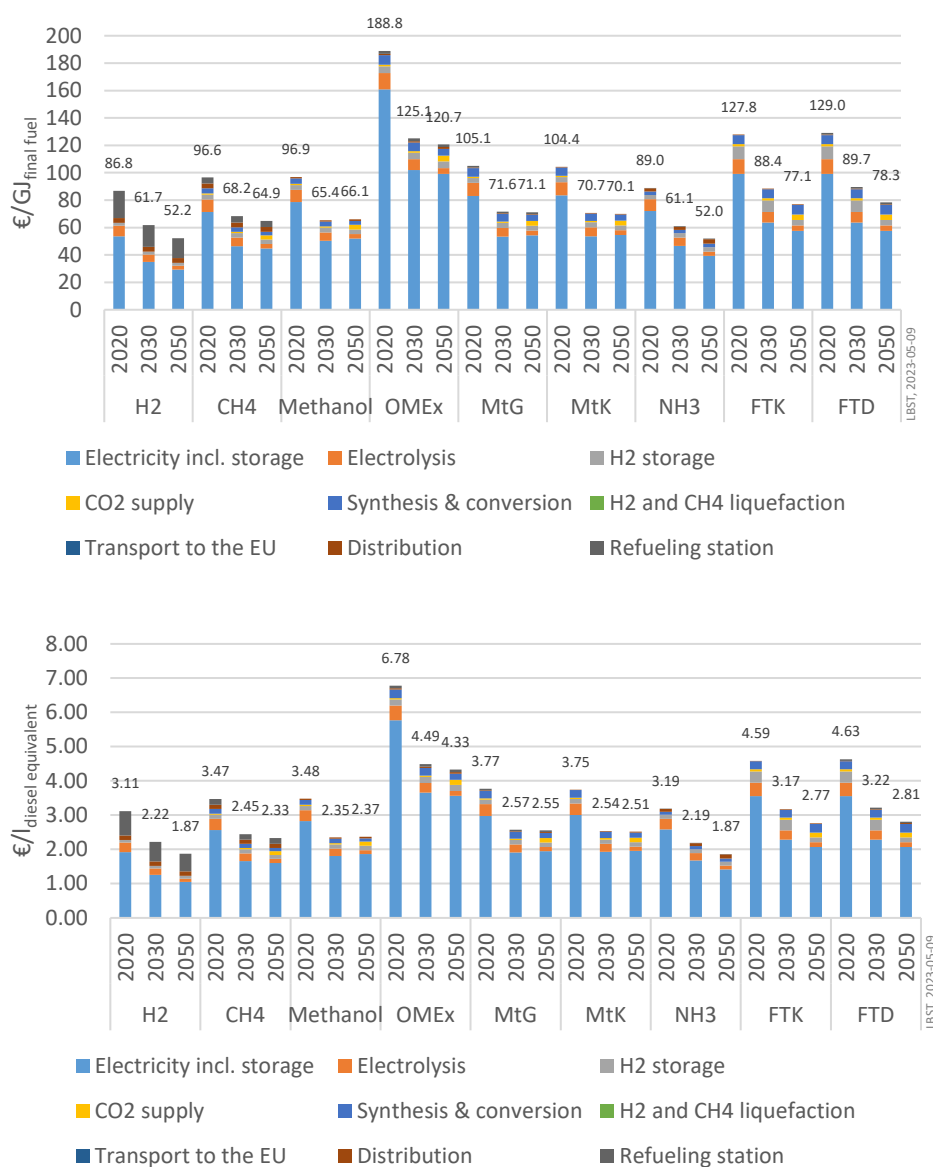


Figure 31: Costs of e-fuels in Central Europe by year

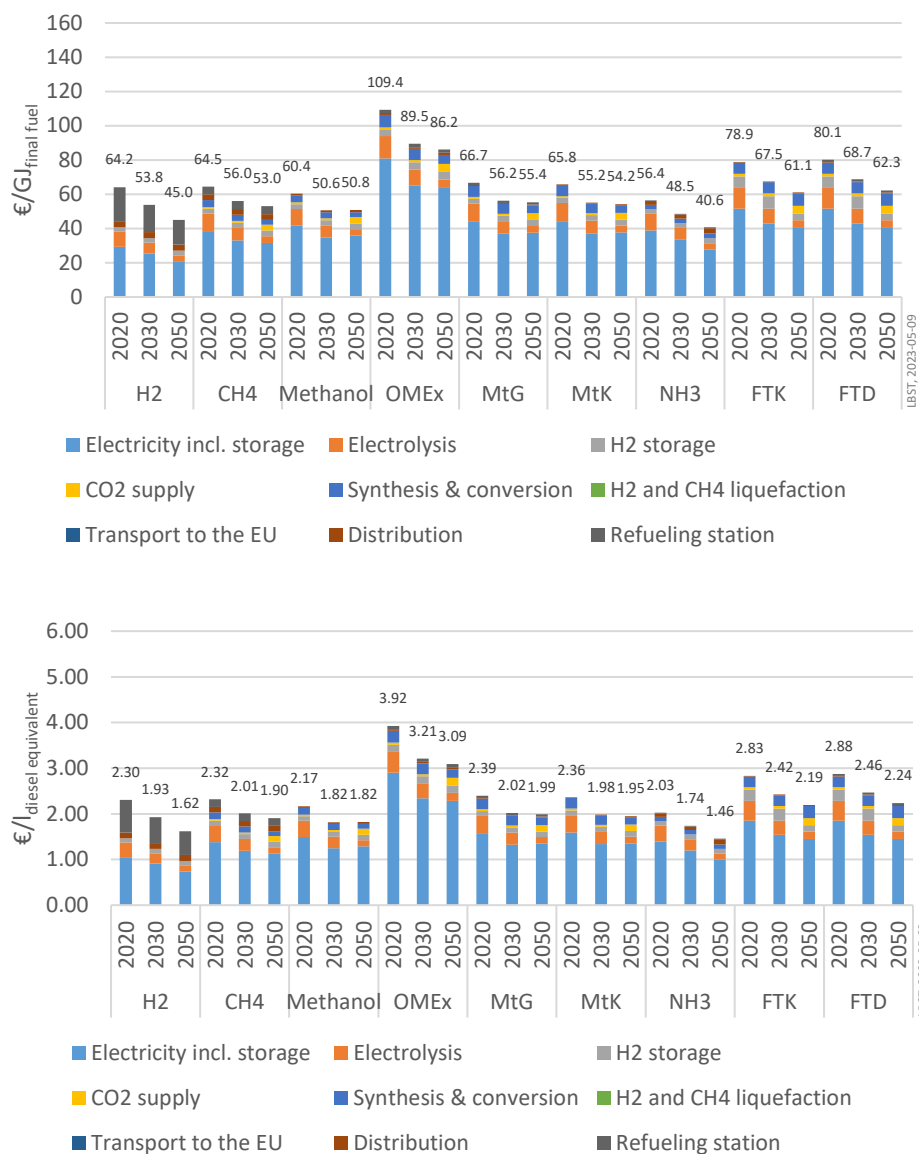
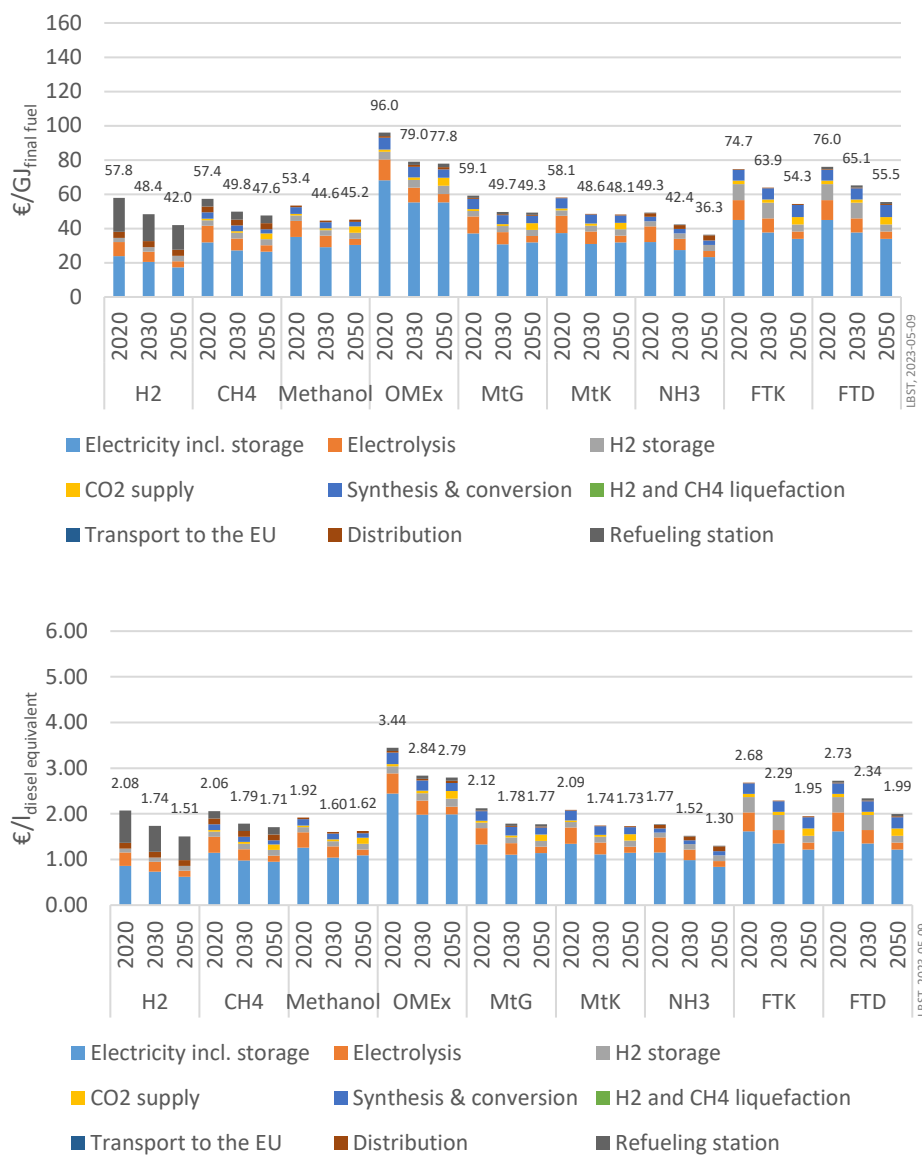


Figure 32 shows the base case results for e-fuels produced in South Europe by year.

**Figure 32:** Costs of e-fuels in South Europe by year

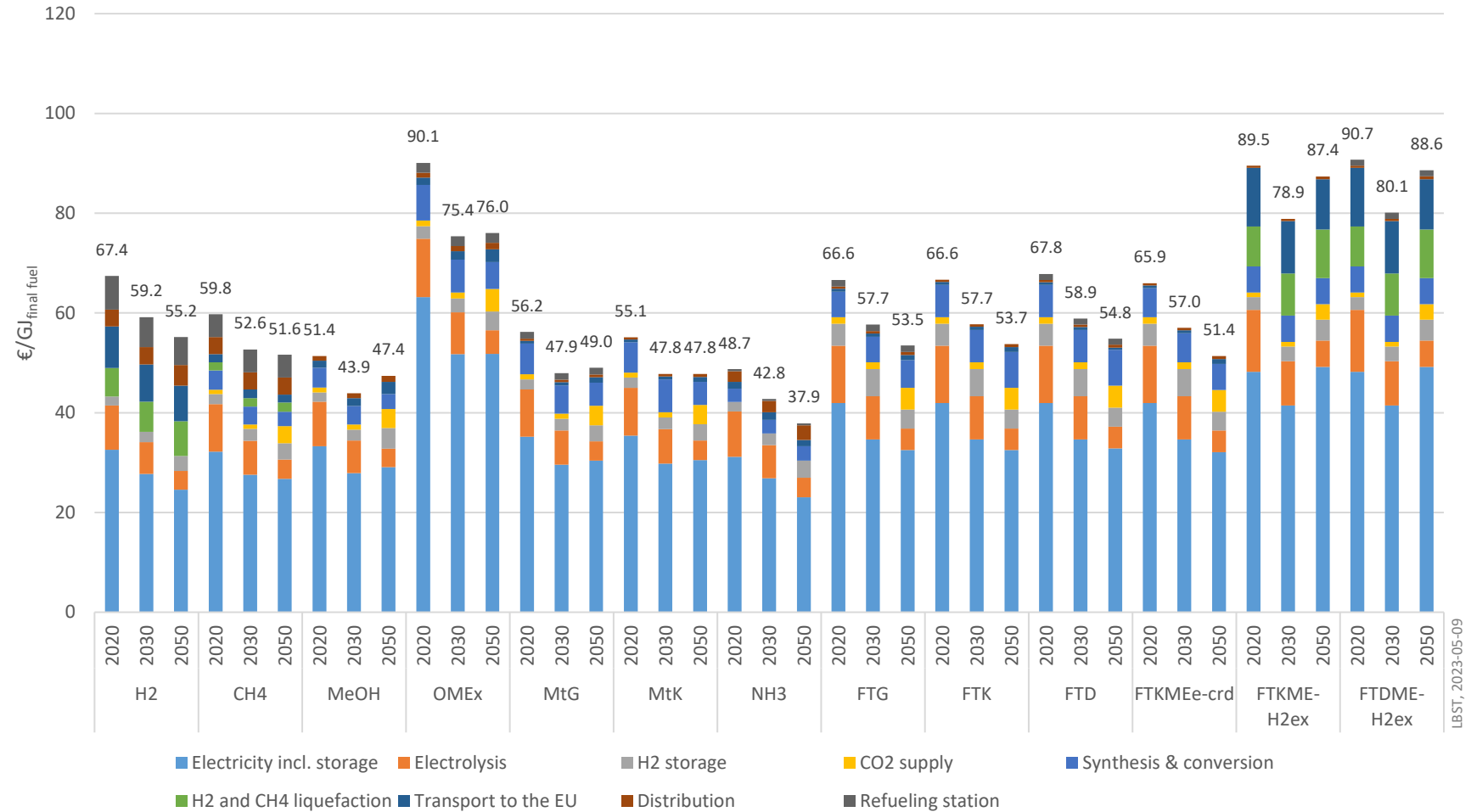


Decreasing costs of renewable electricity, learning curves and reduction in CAPEX of electrolyzers despite the less concentrated CO<sub>2</sub> sources leads to significant lower costs of fuel supply in 2050 versus 2020 (15-30% decrease) and 2030 (up to 15% decrease).

### 2.1.3.3. E-fuels produced in MENA and consumed in Europe

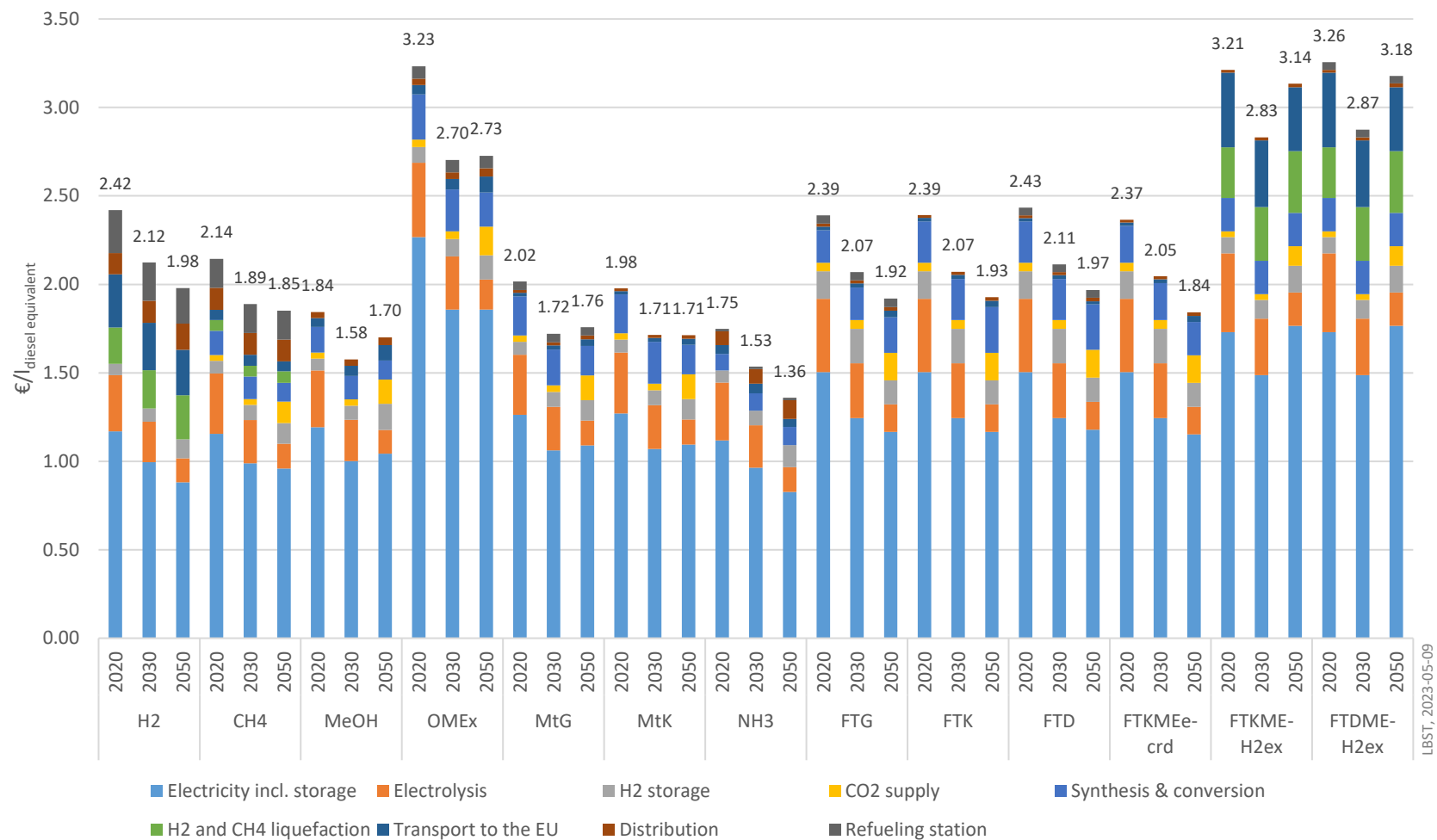
The Kingdom of Saudi-Arabia (KSA) is used as proxy region for a location in MENA. Figure 33 and Figure 34 show the costs for fuels produced in MENA and exported to South Europe (Spain).

**Figure 33:** Costs of e-fuels imported from MENA by year (€ per GJ)





**Figure 34:** Costs of e-fuels imported from MENA by year (€ per l of diesel equivalent)

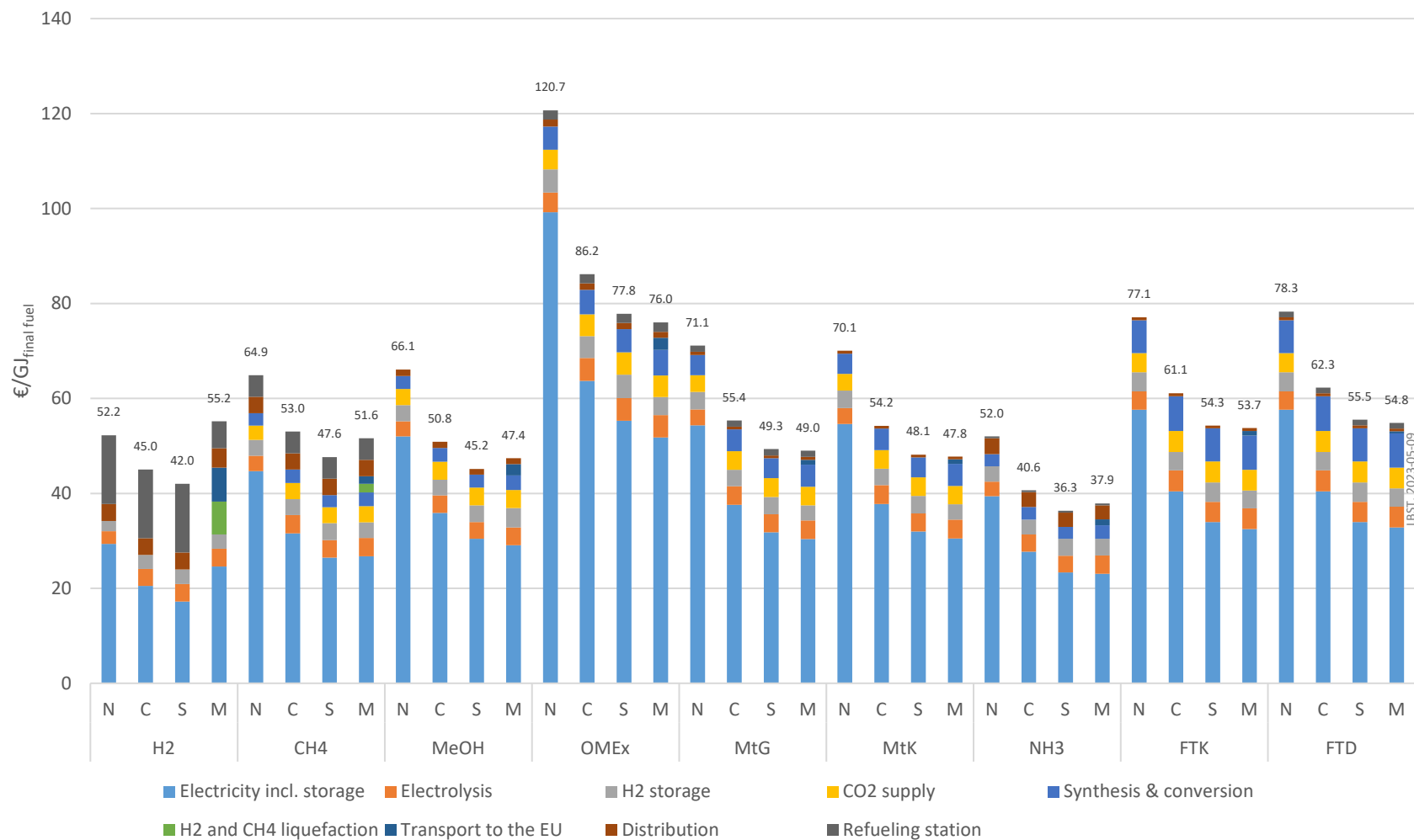


The supply of carbon containing fuels show no improvement because of the use of a diluted CO<sub>2</sub> source (DAC) instead of a purely concentrated source. Fischer Tropsch pathways using imported hydrogen from MENA (pathways FTKEME-H2ex and FTDME-H2ex) show an increase between 2030 and 2050. This is because of the use of a diluted CO<sub>2</sub> source (air) instead of a purely concentrated source, as well as the use of 100% H<sub>2</sub> for ship propulsion in 2050. This leads to a higher electricity demand for producing the additional H<sub>2</sub> requirements, and a higher CAPEX for CO<sub>2</sub> supply, which partly reduces the benefit of lower specific electricity costs and lower CAPEX for e-fuel plants in 2050.

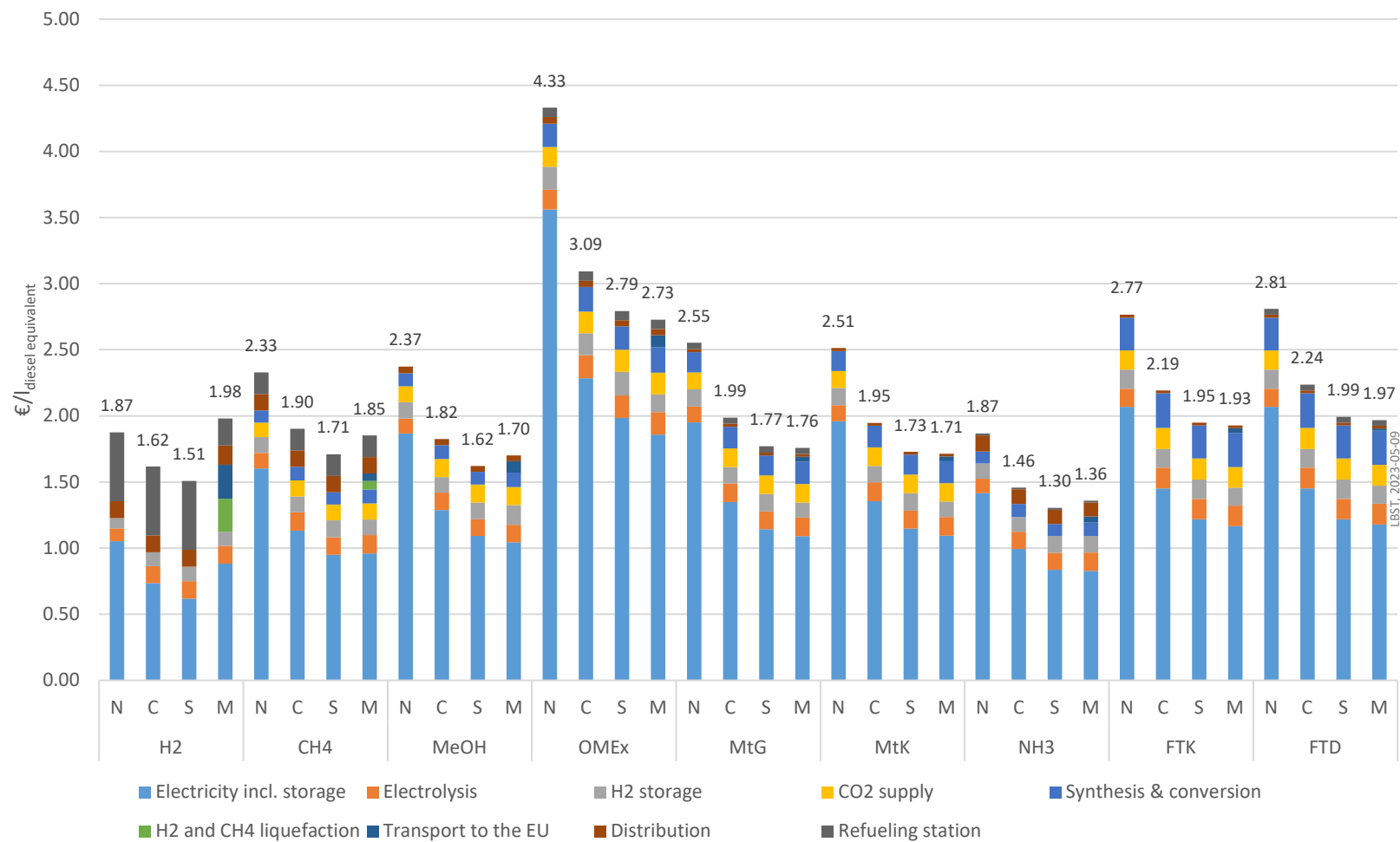
#### **2.1.3.4. E-fuels produced in EU and MENA by zone**

Figure 35 and Figure 36 shows the base case results for e-fuels produced by zone (North, Central, South, MENA) for time horizon 2050.

**Figure 35:** Costs of e-fuels by zone in 2050 (€ per GJ)



**Figure 36:** Costs of e-fuels by zone in 2050 (€ per l of diesel equivalent)



The supply of OME<sub>x</sub> leads to the highest costs of final fuel because the efficiency of this fuel supply chain is lower than for the other e-fuels.

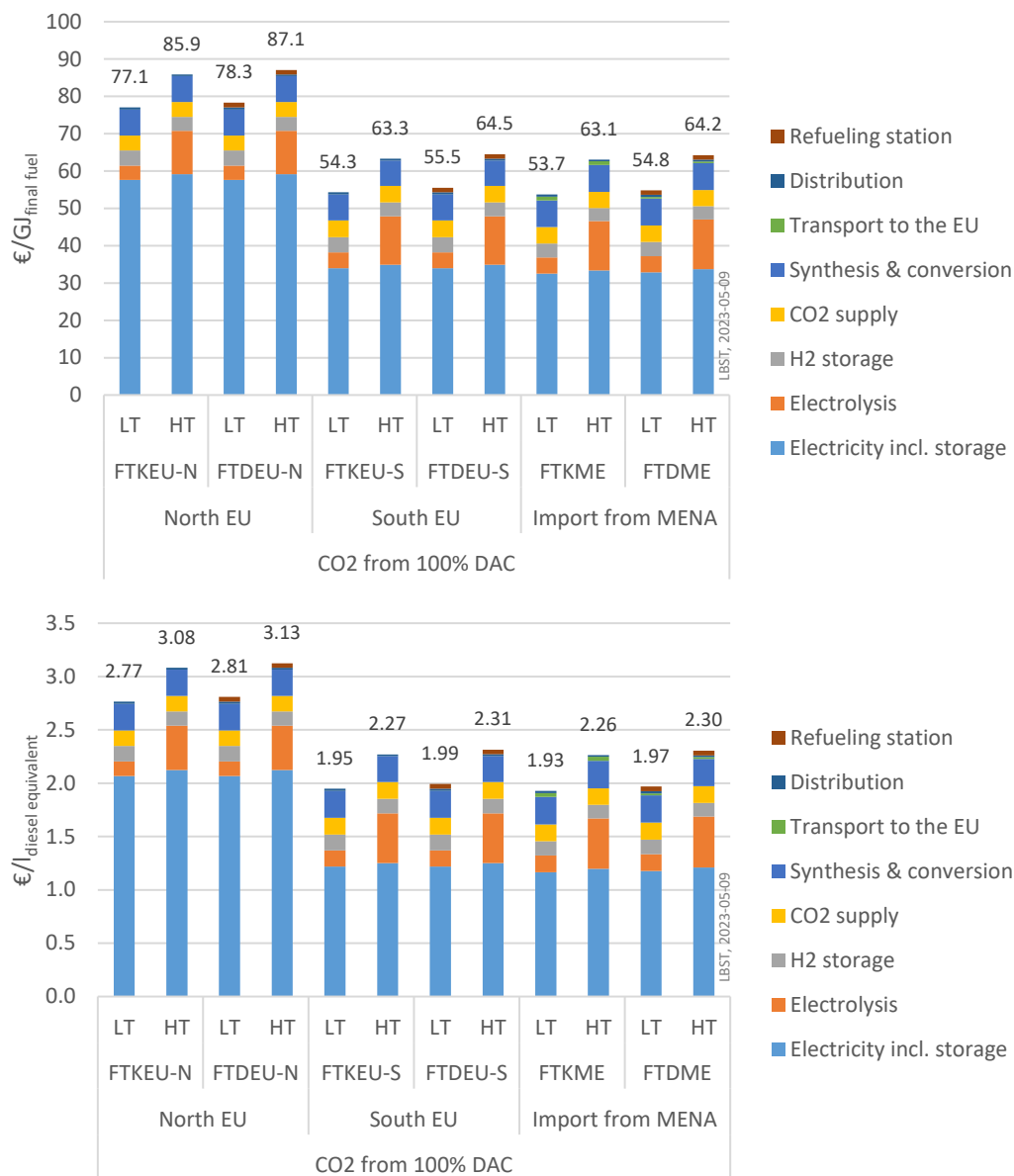
In the case of hydrogen produced inside Europe, the hydrogen is distributed via a hydrogen pipeline grid, compressed at the refuelling station, and dispensed to the vehicles. In case of hydrogen produced outside Europe and transported to Europe as liquefied hydrogen (LH<sub>2</sub>) the LH<sub>2</sub> is distributed inside Europe by truck. At the refuelling station, the LH<sub>2</sub> is compressed via a cryogenic pump, then vaporized and dispensed as compressed hydrogen (CGH<sub>2</sub>) to the vehicles.

The contribution of the refuelling station in the H<sub>2</sub> pathway is lower in the MENA case than in the case where hydrogen is generated in Europe. The reason is that in the case of H<sub>2</sub> delivery via LH<sub>2</sub>, both the CAPEX of the H<sub>2</sub> refuelling station and the electricity consumption per unit of dispensed hydrogen are significantly lower than for the case where the H<sub>2</sub> refuelling stations benefit from H<sub>2</sub> delivery via pipeline.

#### **2.1.3.5. E-fuels produced via co-electrolysis versus alkaline electrolysis**

Figure 37 shows the costs of fuel supply for selected pathways involving high-temperature co-electrolysis via solid oxide electrolysis cells (SOEC) compared to those involving alkaline electrolysis.

**Figure 37:** Cost of fuel supply of selected pathways involving co-electrolysis via SOEC compared to those involving alkaline electrolysis in 2050 (CO<sub>2</sub> from DAC)

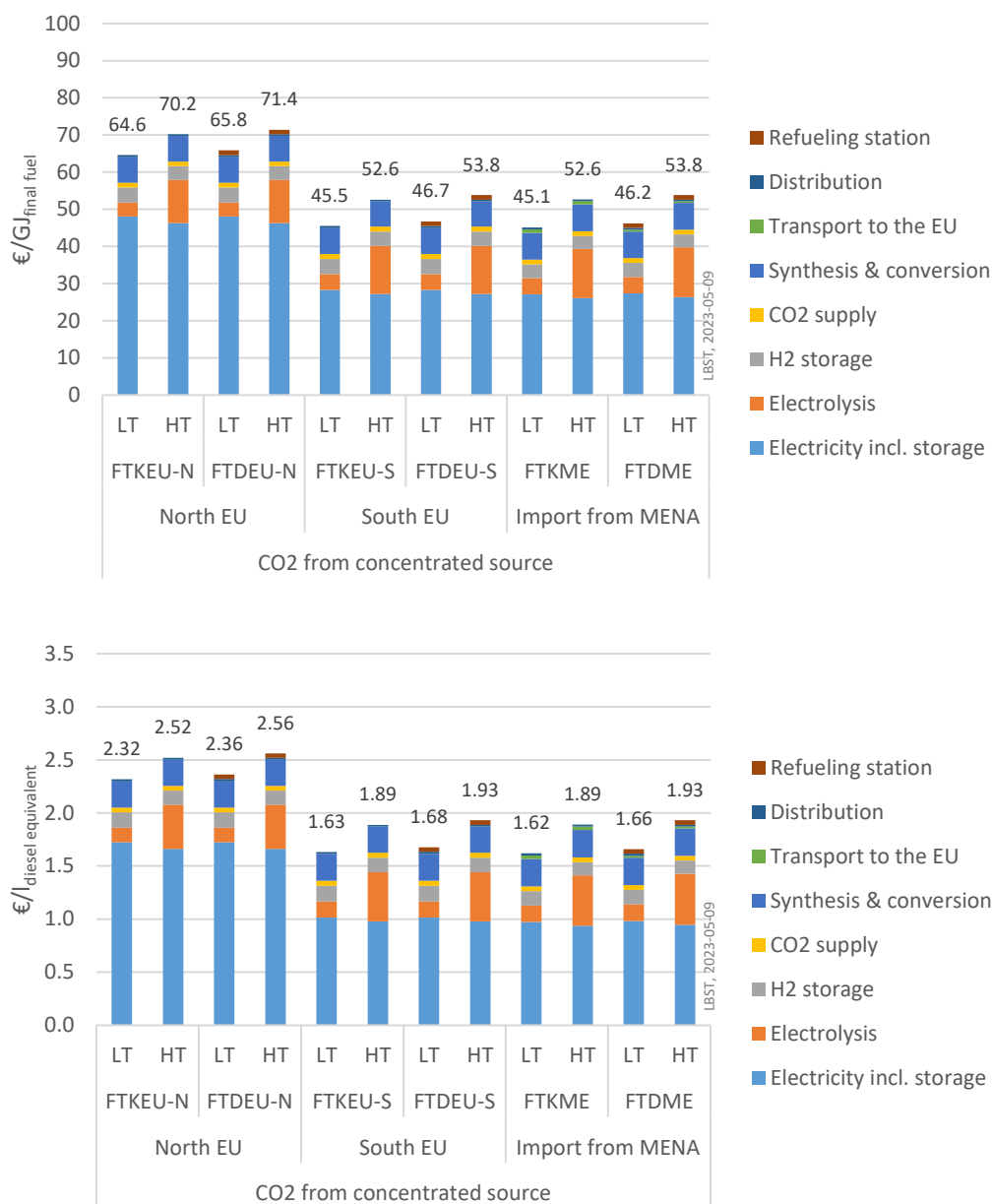


Based on the available data, high temperature co-electrolysis via SOEC has no advantage compared to low temperature electrolysis.

One reason is that the CAPEX for SOEC is significantly higher (see ECONOMIC ANNEX chapter 9.3). Another reason is that in the case SOEC is combined with direct air capture (DAC), large amounts of heat are already required for the DAC. Additional high temperature (>100 °C) heat for the steam supply for SOEC has to be generated by electrically heated steam generation. The total efficiency of co-electrolysis including steam supply amounts to 71.5% (efficiency based on the electricity input alone: 82.1%), which is lower than the efficiency assumed for alkaline electrolysis in 2050 (75%).

If CO<sub>2</sub> from concentrated sources is used, the electricity requirement for the whole PtL plant decreases but cannot compensate the higher CAPEX of the SOEC (Figure 38).

**Figure 38:** Cost of fuel supply of selected pathways involving co-electrolysis via SOEC compared to those involving alkaline electrolysis in 2050 (CO<sub>2</sub> from concentrated source)





### KEY MESSAGES - BASE CASE COST RESULTS

There is a strong correlation between energy efforts for fuel production and associated costs. E-fuels that are less energy-intensive to produce generally lead to lower costs of fuel production. The cost for electricity has the highest share of the overall costs of fuel supply (up to around 70%).

Based on the assumptions taken, this economic assessment of e-fuels towards 2050 shows that fuel supply costs range between 1.7 and 4.6 € per litre of diesel-equivalent in the short and between 1.4 and 2.8 € per litre of diesel equivalent in the long term if the outlier OME<sub>x</sub> is excluded. For OME<sub>x</sub>, the fuel supply costs range between 3.2 and 6.8 € per l of diesel equivalent in the short term and between 2.7 and 4.3 € per l of diesel equivalent in the long term.

E-fuels that are less energy-intensive generally lead to lower costs of fuel supply. Fuel costs per car-km for H<sub>2</sub> are lower than for conventional liquid fuels because Hydrogen fuel cell electric vehicles (FCEV) show a significantly lower fuel consumption due to a factor ~2 higher power-train efficiency. However, the powertrain analysis is out of the scope of this report.

## 2.2. SENSITIVITY ANALYSES OF KEY ECONOMIC FACTORS

For some selected pathways, a sensitivity analysis to key economic factors is carried out (Table 23). The pathways are described briefly in Table 16 in chapter 2.1 and detailed in the ECONOMIC ANNEX chapter 9.4. Note that similar parameter variations have been grouped together in case of few pathways (see below).

**Table 23:** Matrix of pathways and sensitivities analysed

	Pathway code	4.1: Different electricity price scenarios	4.2: Different discount rate	4.3: Electricity source: 100% Wind electricity	4.3: Electricity source: 100% PV electricity	4.4: CO <sub>2</sub> source: 100% DAC	4.4: CO <sub>2</sub> source: 100% SMR	4.4: CO <sub>2</sub> source: 100% NGCC	4.4: Use of CO <sub>2</sub> captured in EU for synthesis in MENA	4.5: Use of NH <sub>3</sub> as H <sub>2</sub> carrier to feed synthesis processes	4.5: Use of MCH as H <sub>2</sub> carrier to feed synthesis processes	4.5: Use of MeOH as H <sub>2</sub> carrier to feed synthesis processes	4.6: Longer transportation distance inside Europe	4.6: Other transport types inside Europe (truck, ship)	4.7: Long haul from North Africa (distance + CO <sub>2</sub> origin)	4.7: Long haul from Australia, Chile (distance only)	4.8: Larger/smaller e-fuels plant size
1	H2EU-N	X	X										X	X			X
2	CH4EU-N	X	X										X	X			X
3	MeOHEU-N	X	X														X
4	OMExEU-N	X	X														X
5	MTGEU-N	X	X														X
6	MTKEU-N	X	X														X
7	NH3EU-N	X	X														X
8	FTKEU-N	X	X	X	X	X	X	X					X	X			X
9	FTDEU-N	X	X														
28	H2ME-Liq	X	X												X	X	X

	Pathway code	4.1: Different electricity price scenarios	4.2: Different discount rate	4.3: Electricity source: 100% Wind electricity	4.3: Electricity source: 100% PV electricity	4.4: CO <sub>2</sub> source: 100% DAC	4.4: CO <sub>2</sub> source: 100% SMR	4.4: CO <sub>2</sub> source: 100% NGCC	4.4: Use of CO <sub>2</sub> captured in EU for synthesis in MENA	4.5: Use of NH <sub>3</sub> as H <sub>2</sub> carrier to feed synthesis processes	4.5: Use of MCH as H <sub>2</sub> carrier to feed synthesis processes	4.5: Use of MeOH as H <sub>2</sub> carrier to feed synthesis processes	4.6: Longer transportation distance inside Europe	4.6: Other transport types inside Europe (truck, ship)	4.7: Long haul from North Africa (distance + CO <sub>2</sub> origin)	4.7: Long haul from Australia, Chile (distance only)	4.8: Larger/smaller e-fuels plant size
29	CH4ME-Liq	X	X													X	X
30	MeOHME	X	X														X
31	OMExME	X	X														X
32	MTGME	X	X														X
33	MTKME	X	X														X
34	NH3ME	X	X														X
35	FTGME	X	X														
36	FTKME	X	X	X	X	X	X	X	X						X	X	X
37	FTDME	X	X														
38	FTKMEe-crd	X	X														X
39	FTKME-H2ex	X	X							X	X	X					X
40	FTDME-H2ex	X	X														X

Sensitivities have been calculated for the years 2020, 2030, and 2050. In this chapter, results are depicted for the year 2050. For the years 2020 and 2030, refer to respective sub-chapters 9.5 in the ECONOMIC ANNEX.

### 2.2.1. Different electricity cost scenarios

Two electricity cost variants have been assessed in this study:

- Optimistic (-50% of current assumptions)
- Pessimistic (+50% of current assumptions)

Figure 39, Figure 183, and Figure 184 show the results for different electricity price scenarios for 2020, 2030, and 2050 with CO<sub>2</sub> from concentrated source (flue gas from SMR as proxy) in 2020 and 2030, and CO<sub>2</sub> from a mix of sources in 2050. The result charts for the year 2050 is depicted hereunder. For the years 2020 and 2030, refer to ECONOMIC ANNEX chapter 9.5.1.

**Figure 39:** Sensitivity to different renewable electricity costs by region for 2050 (CO<sub>2</sub> from diluted CO<sub>2</sub> source)

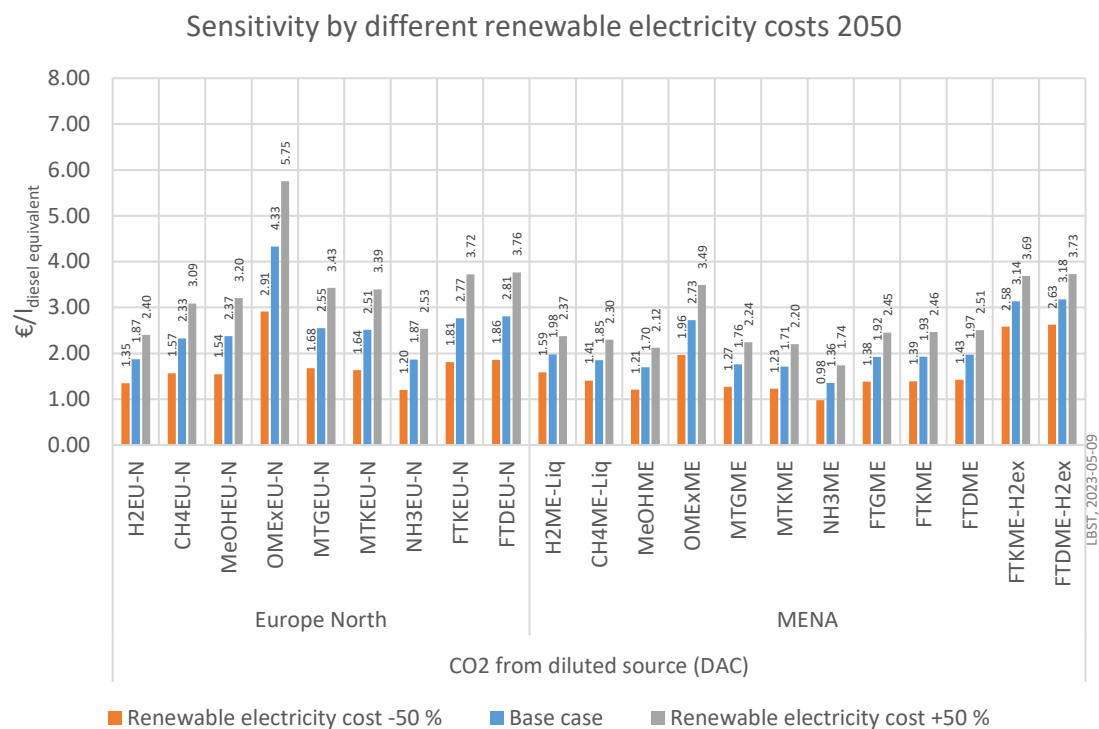
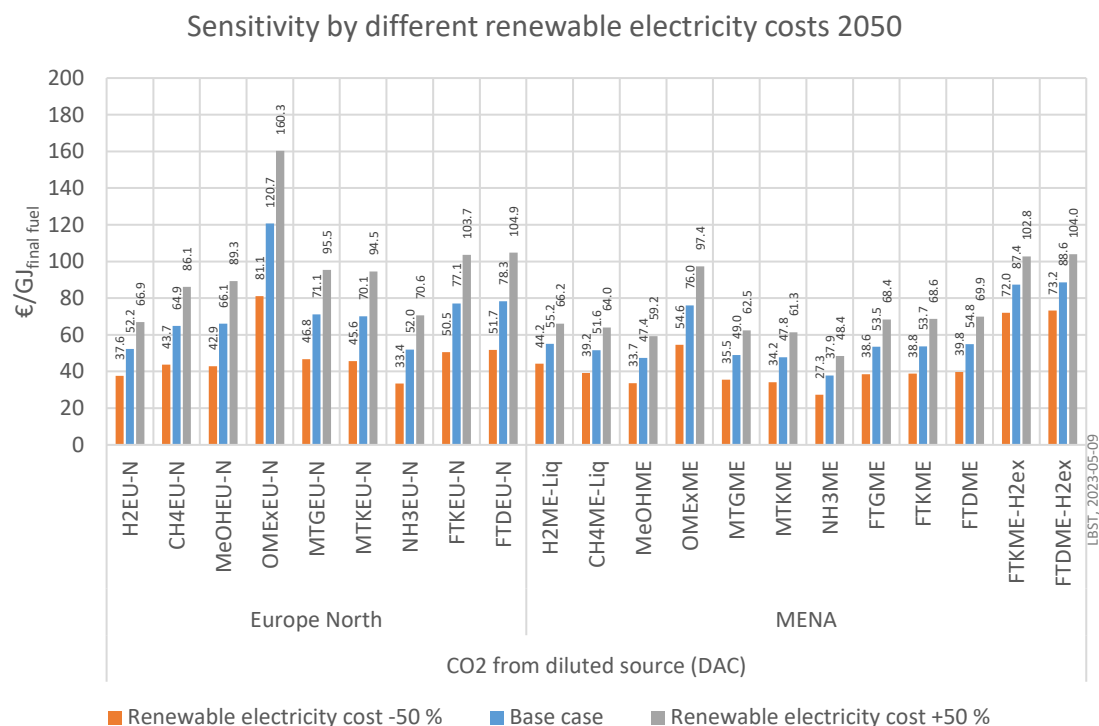
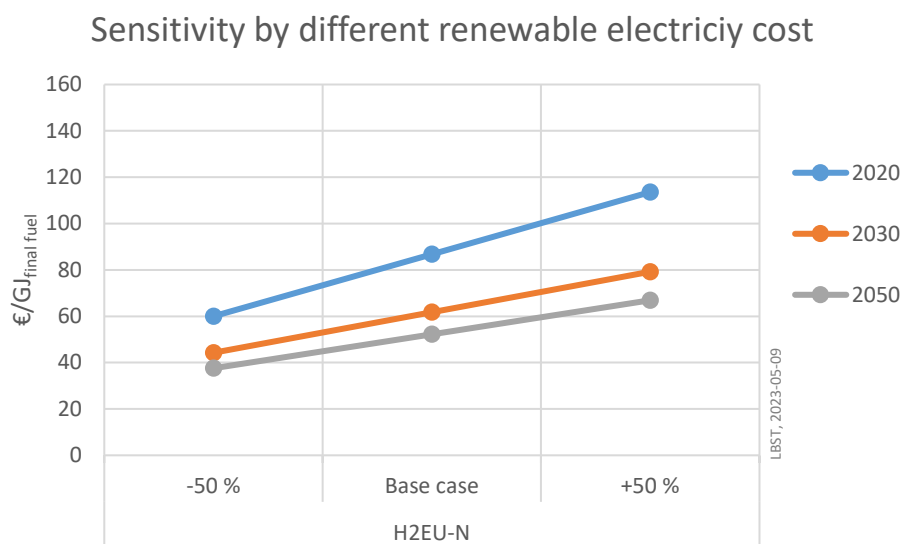


Figure 40 and Figure 41 show the sensitivity to different renewable electricity costs by year for selected fuels produced and consumed in North Europe.

**Figure 40:** Sensitivity to different renewable electricity costs by year for CGH<sub>2</sub> in North Europe (H2EU-N)



**Figure 41:** Sensitivity to different renewable electricity costs by year for Kerosene in North Europe (FTKEU-N)

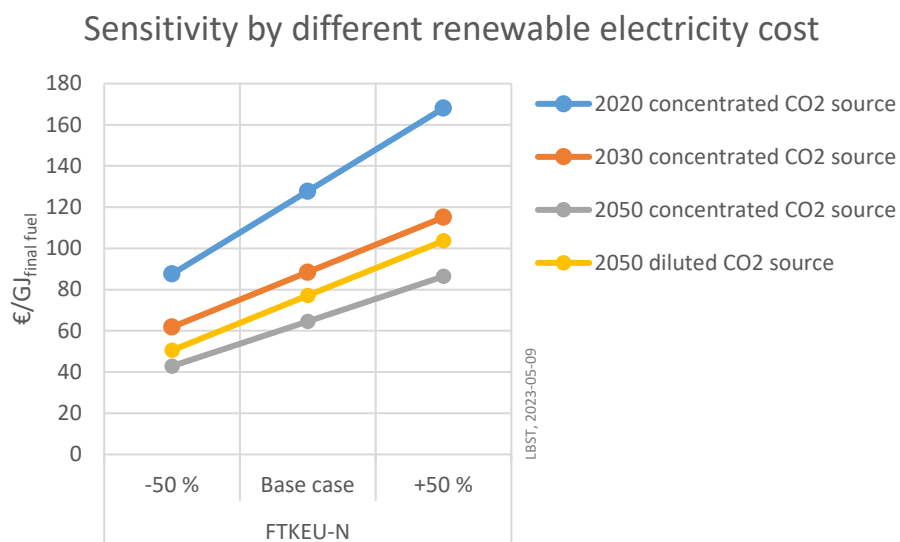
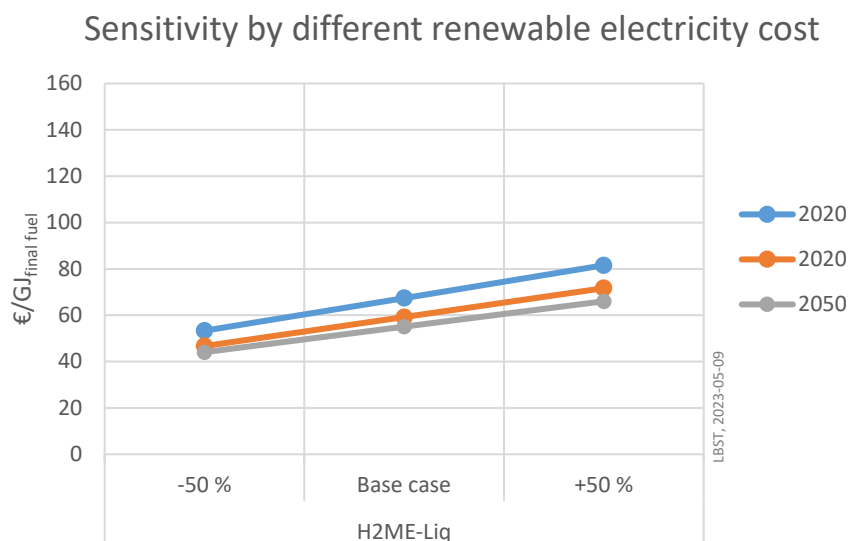
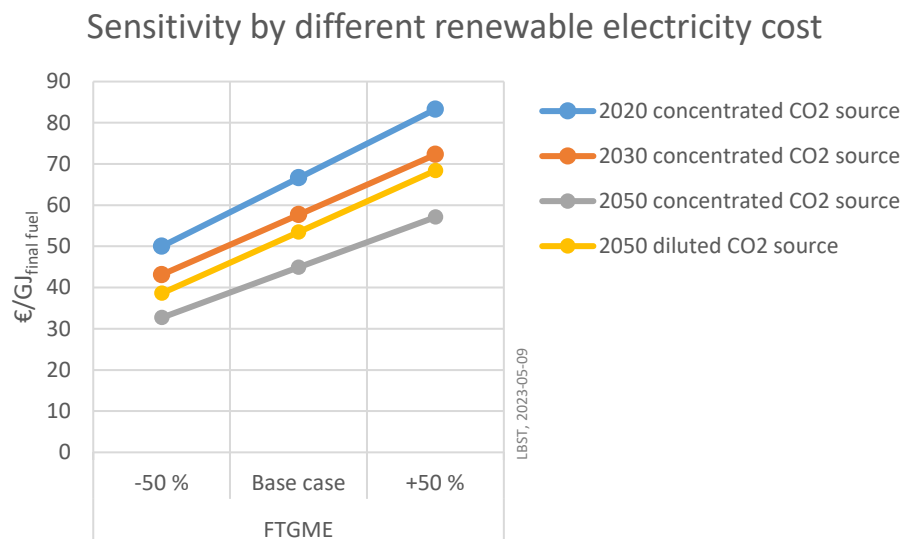


Figure 42, Figure 43, Figure 44, and Figure 45 show the sensitivity by different renewable electricity cost by year for the supply of selected fuels imported from MENA and consumed in in South Europe.

**Figure 42:** Sensitivity to different renewable electricity costs by year for LH<sub>2</sub> imported from MENA and dispensed as CGH<sub>2</sub> (H2ME-Liq)

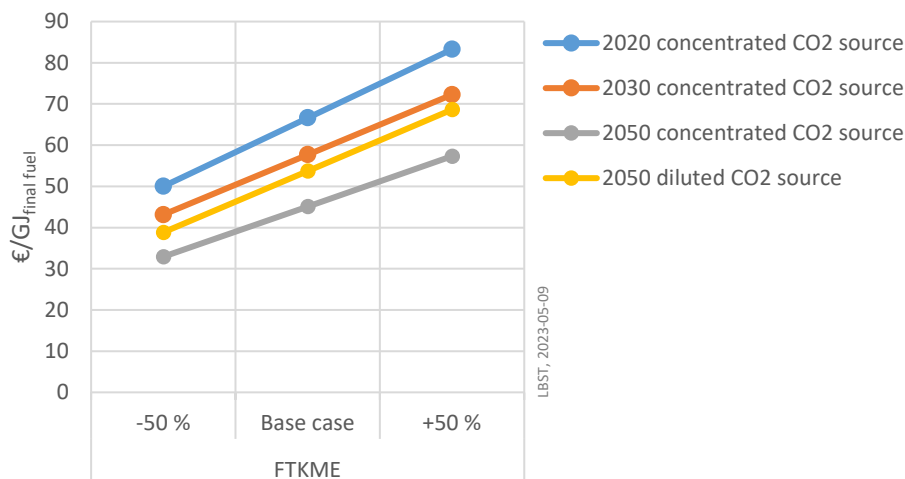


**Figure 43:** Sensitivity to different renewable electricity costs by year for FT gasoline imported from MENA (FTGME)



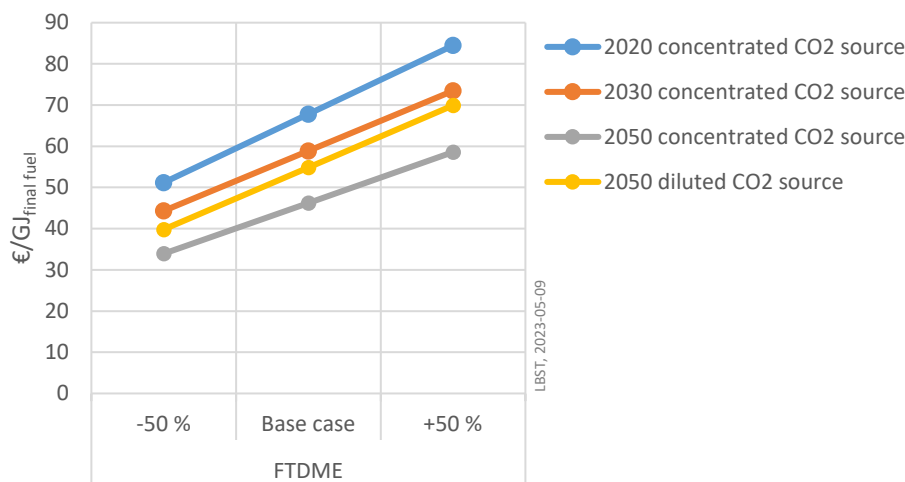
**Figure 44:** Sensitivity to different renewable electricity costs by year for FT kerosene imported from MENA (FTKME)

### Sensitivity by different renewable electricity cost



**Figure 45:** Sensitivity to different renewable electricity costs by year for FT diesel imported from MENA (FTDME)

### Sensitivity by different renewable electricity cost



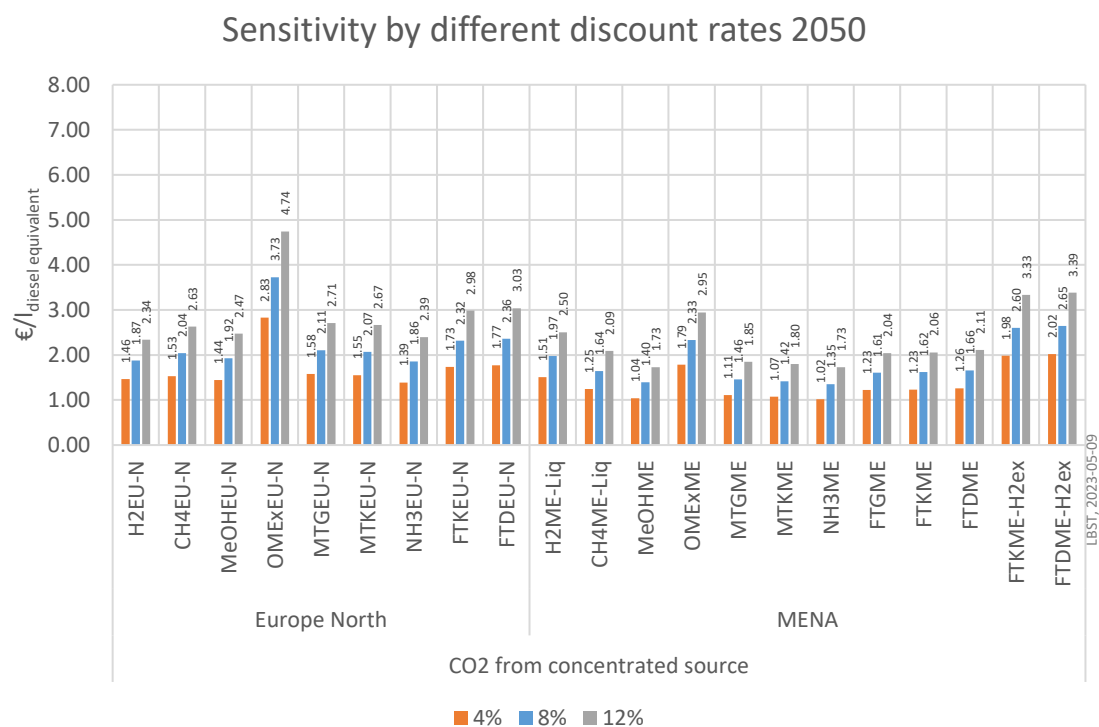
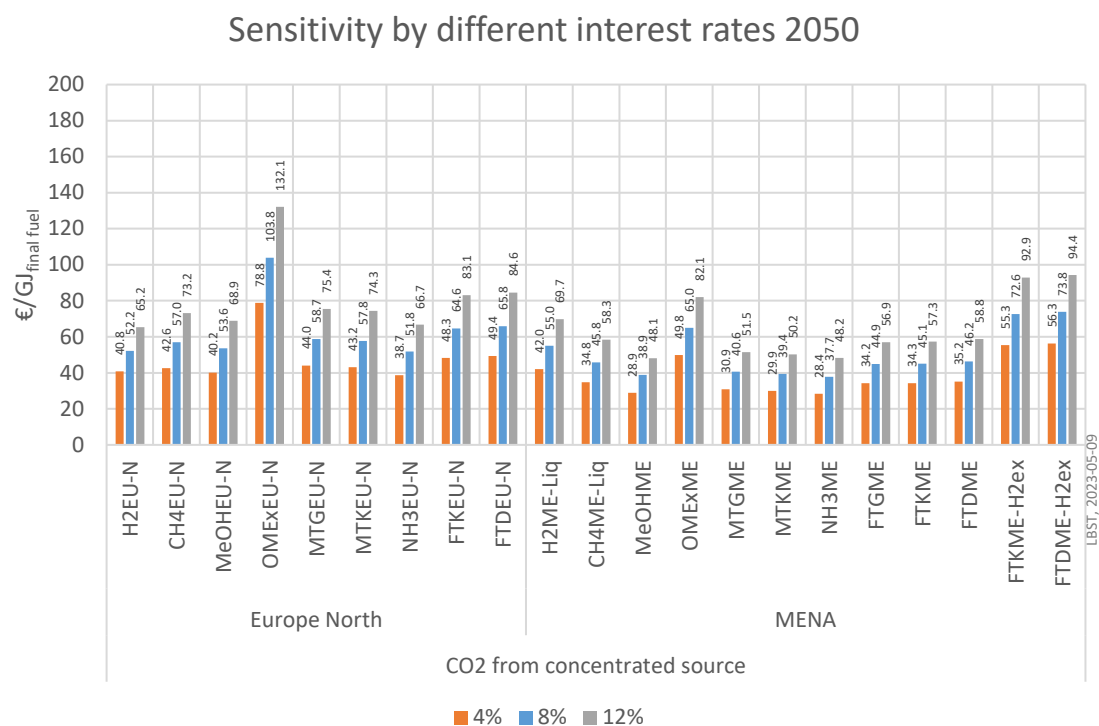
Variation of the electricity costs have a high impact on the overall cost of e-fuel supply.

## 2.2.2. Different discount rate

Two discount rate variants are compared to the baseline assumptions (8%):

- High (12%)
- Low (4%)

**Figure 46:** Sensitivity to different discount rates by region for 2050 (CO<sub>2</sub> from concentrated source)





**Figure 47:** Sensitivity to different discount rate by region for 2050 (CO<sub>2</sub> from diluted source)

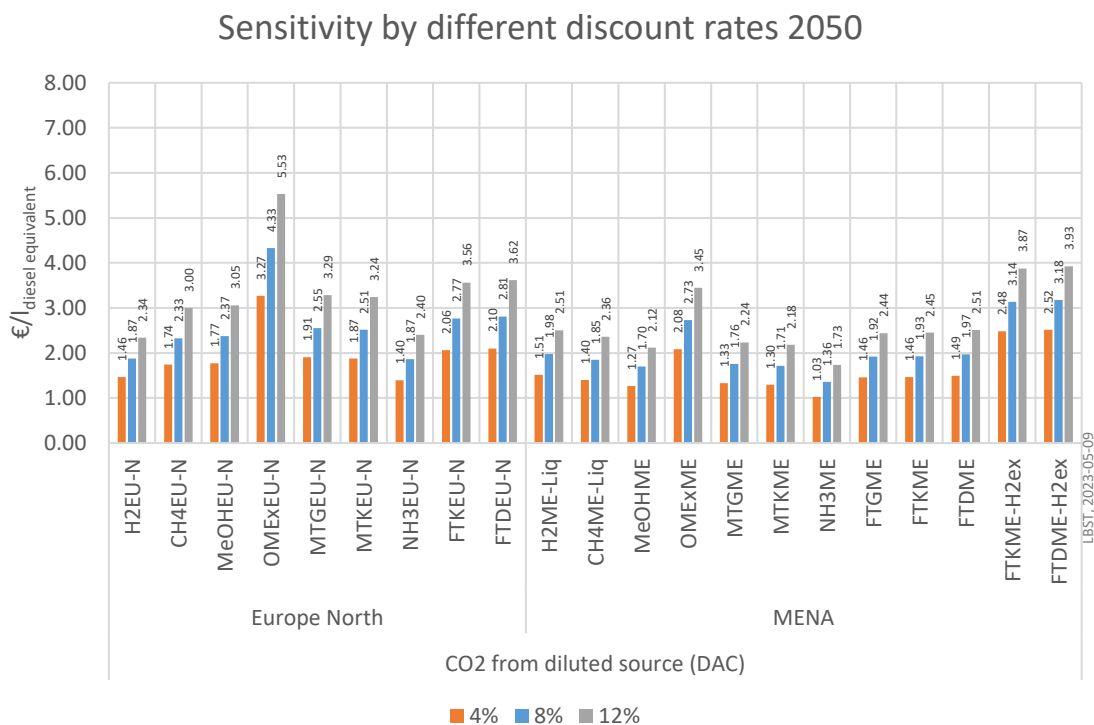
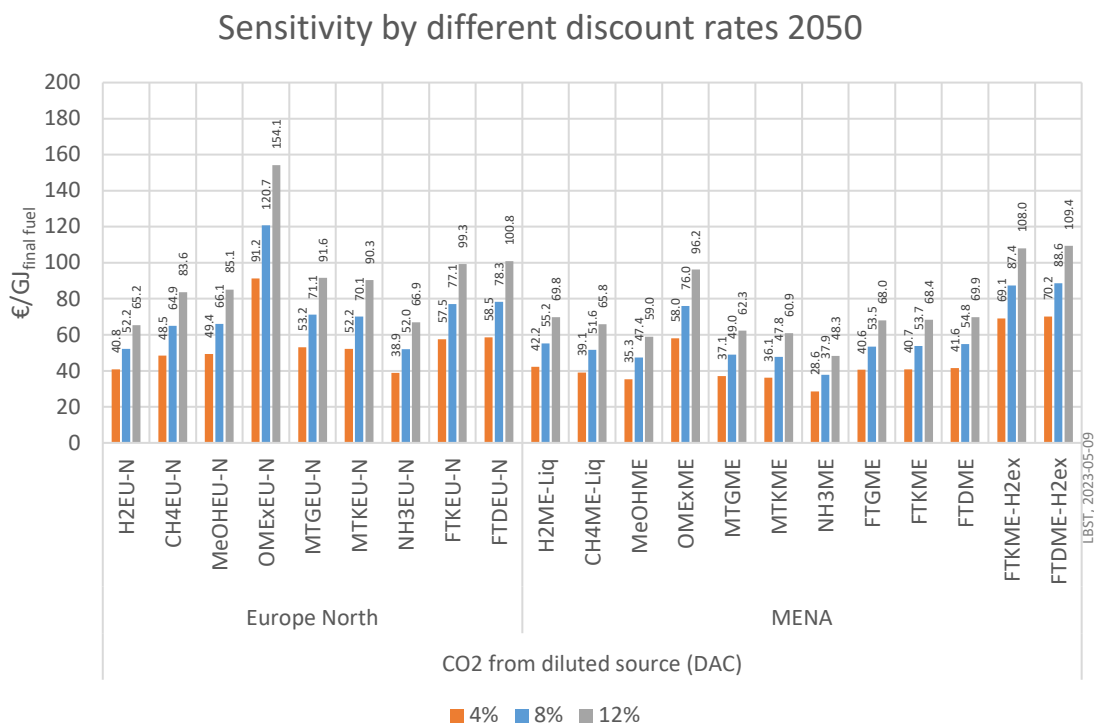
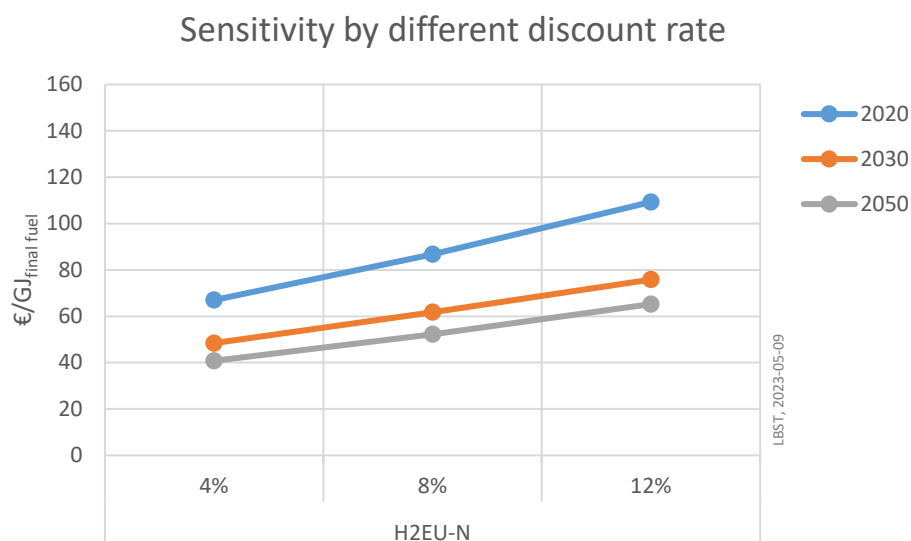


Figure 48 and Figure 49 show the sensitivity to different discount rates by year for selected fuels produced and consumed in North Europe.

**Figure 48:** Sensitivity to different discount rates by year for CGH<sub>2</sub> in North Europe (H2EU-N)



**Figure 49:** Sensitivity to different discount rates by year for kerosene in North Europe (FKEU-N)

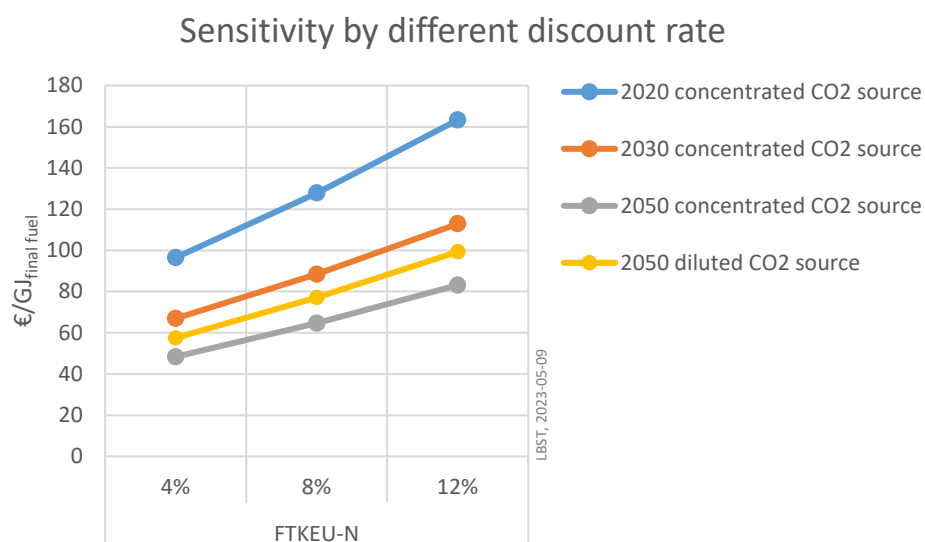
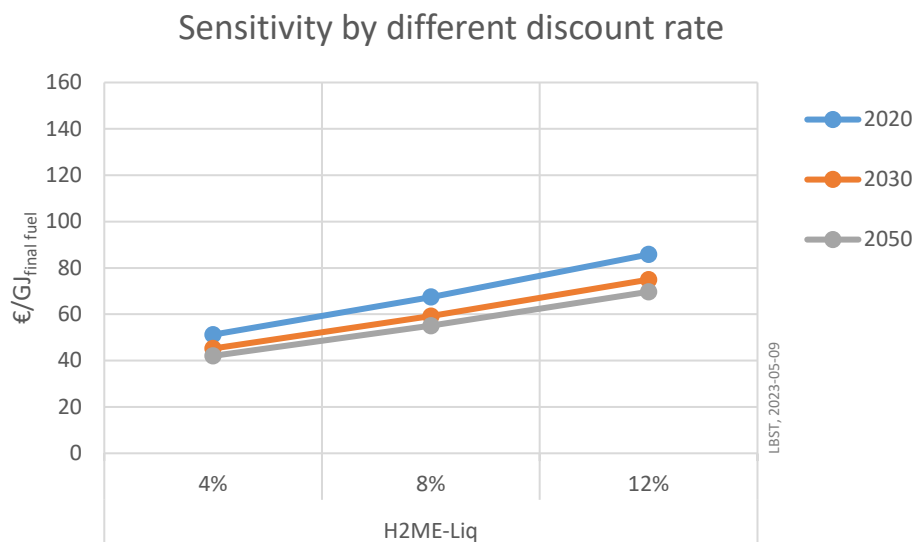
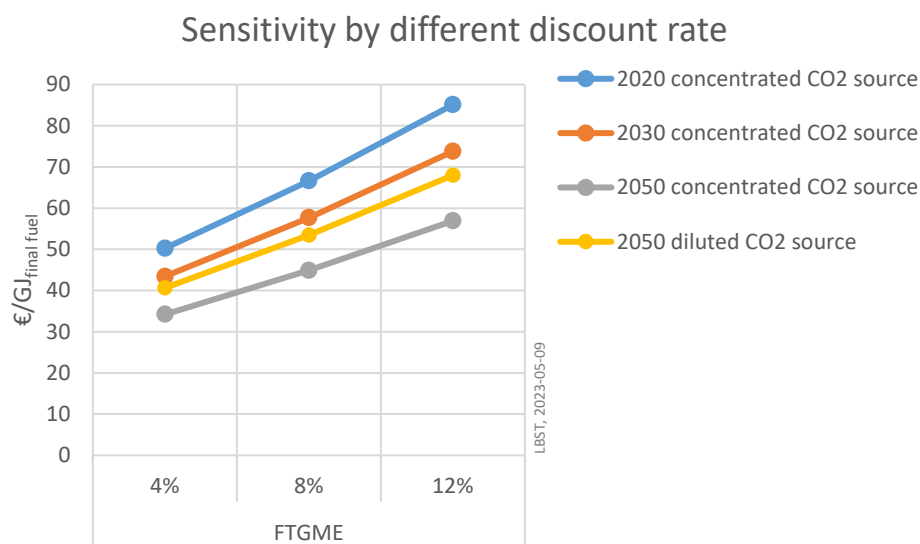


Figure 50, Figure 51, Figure 52, and Figure 53 show the sensitivity to different discount rates by year for the supply of selected fuels imported from MENA and consumed in in South Europe.

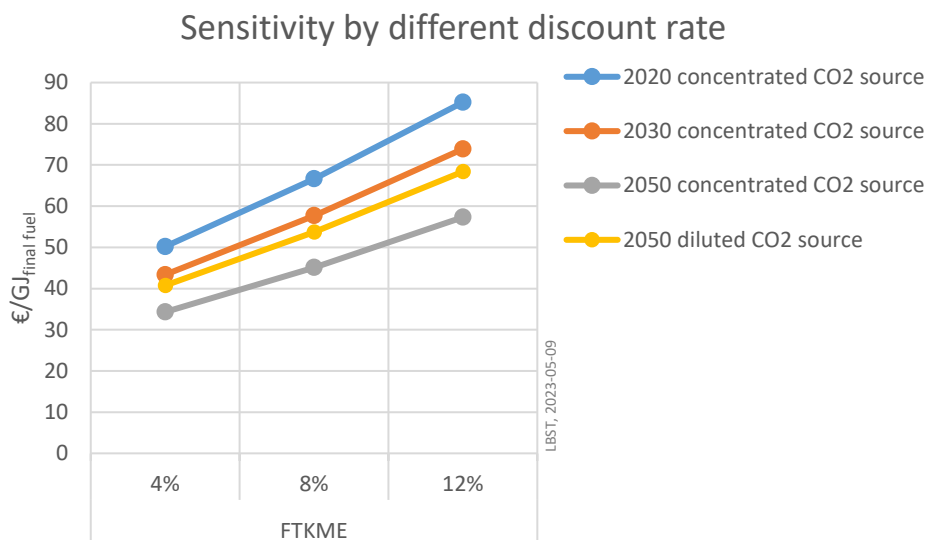
**Figure 50:** Sensitivity to different discount rates by year for LH<sub>2</sub> imported from MENA and dispensed as CGH<sub>2</sub> (H2ME-Liq)



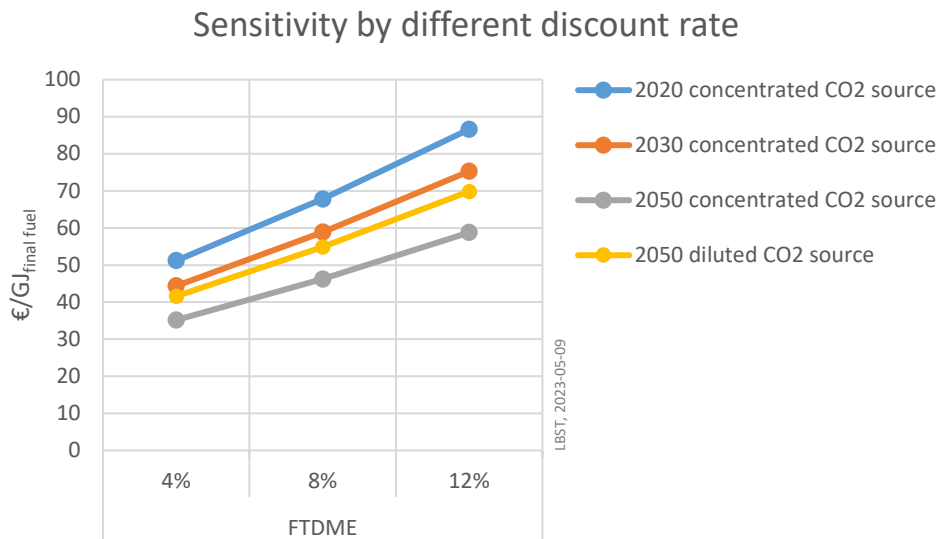
**Figure 51:** Sensitivity to different discount rates by year for FT gasoline imported from MENA (FTGME)



**Figure 52:** Sensitivity to different discount rates by year for FT kerosene imported from MENA (FTKME)



**Figure 53:** Sensitivity to different discount rates by year for FT diesel imported from MENA (FTDME)



Variation of the discount rate has a high impact on the overall cost of e-fuel supply, leading to similar results to the variation of the electricity cost in chapter 2.2.1.

### 2.2.3. Electricity source

For this sensitivity analysis, the electricity source has been changed for selected pathways (FT kerosene produced in North Europe and in MENA):

- 100% Wind electricity
- 100% PV electricity

In case of North Europe, offshore wind farms are used as electricity source in the base case. For sensitivity by electricity source, 100% onshore wind has been used as electricity source both for North Europe and MENA.

The references and a detailed description of the assumptions are presented in the ECONOMIC ANNEX, chapter 9.2.3.

**Table 24:** E-fuel costs in 2050 depending on electricity source

	FTKEU-N			FTKME		
	Base case (wind offshore)	100% wind (onshore)	100% PV	Base case (PV/wind hybrid)	100% wind	100% PV
<b>€/GJ<sub>final fuel</sub></b>						
Electricity costs	57.6	35.0	159.3	32.5	46.4	38.6
Electrolysis	3.8	3.9	6.8	4.3	5.0	6.6
H <sub>2</sub> storage	4.0	7.1	1.3	3.8	6.4	14.5
CO <sub>2</sub> supply	4.0	4.4	6.1	4.4	4.9	6.0
Synthesis & upgrading	6.9	6.4	13.6	7.2	7.3	7.7
Transport to the EU	0.0	0.0	0.0	1.0	1.0	1.0
Distribution	0.6	0.6	0.6	0.6	0.6	0.6
Refuelling station	0.0	0.0	0.0	0.0	0.0	0.0
<b>Total</b>	<b>77.1</b>	<b>57.4</b>	<b>187.7</b>	<b>53.7</b>	<b>71.6</b>	<b>75.0</b>
<b>€/l<sub>diesel equivalent</sub> (based on conventional diesel EN 590)</b>						
Electricity costs	2.07	1.26	5.72	1.17	1.67	1.38
Electrolysis	0.14	0.14	0.24	0.16	0.18	0.24
H <sub>2</sub> storage	0.15	0.25	0.05	0.14	0.23	0.52
CO <sub>2</sub> supply	0.14	0.16	0.22	0.16	0.18	0.22
Synthesis & upgrading	0.25	0.23	0.49	0.26	0.26	0.27
Transport to the EU	0.00	0.00	0.00	0.04	0.04	0.04
Distribution	0.02	0.02	0.02	0.02	0.02	0.02
Refuelling station	0.00	0.00	0.00	0.00	0.00	0.00
<b>Total</b>	<b>2.77</b>	<b>2.06</b>	<b>6.74</b>	<b>1.93</b>	<b>2.57</b>	<b>2.69</b>

**Figure 54:** E-fuel costs in 2050 depending on electricity source for FT Kerosene produced in North Europe and MENA

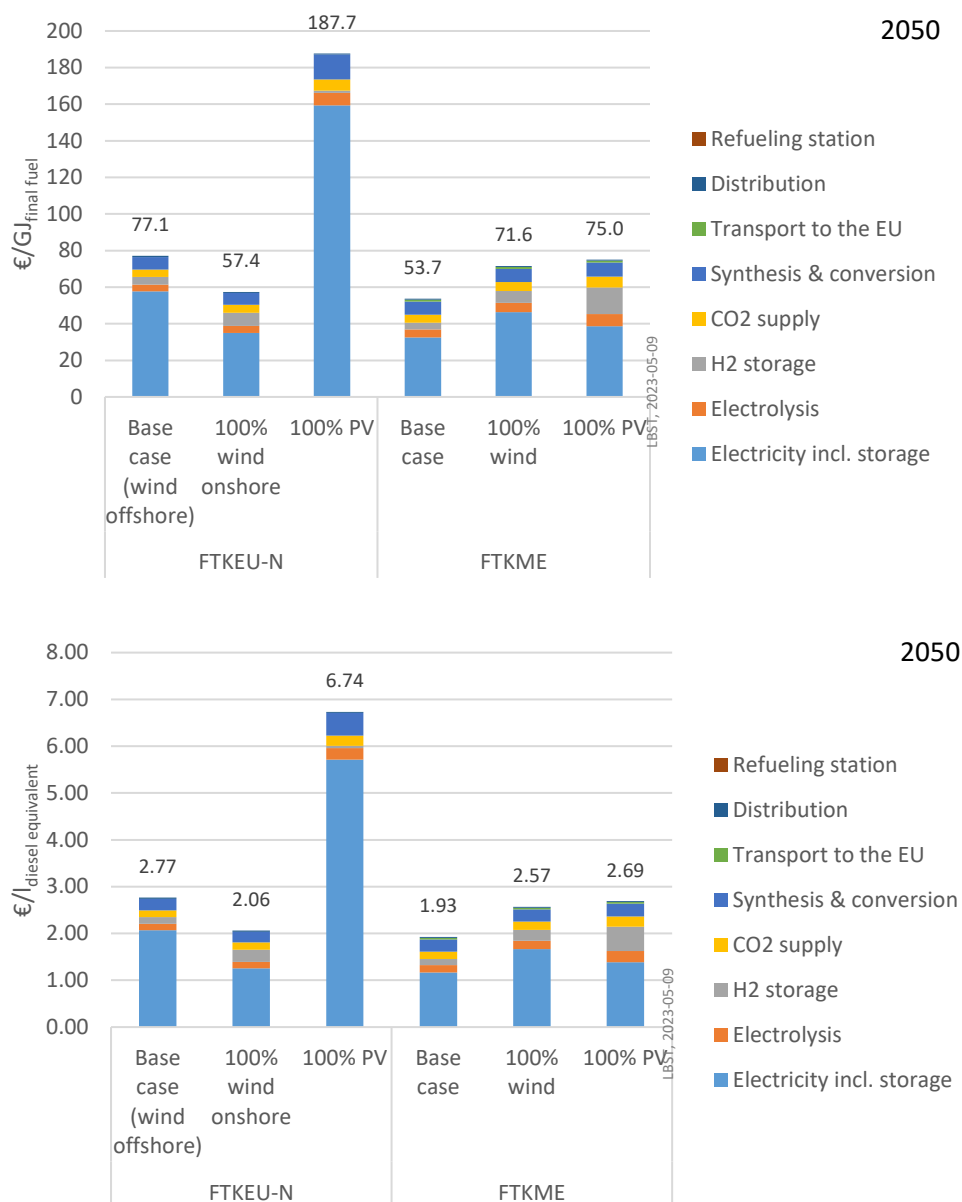
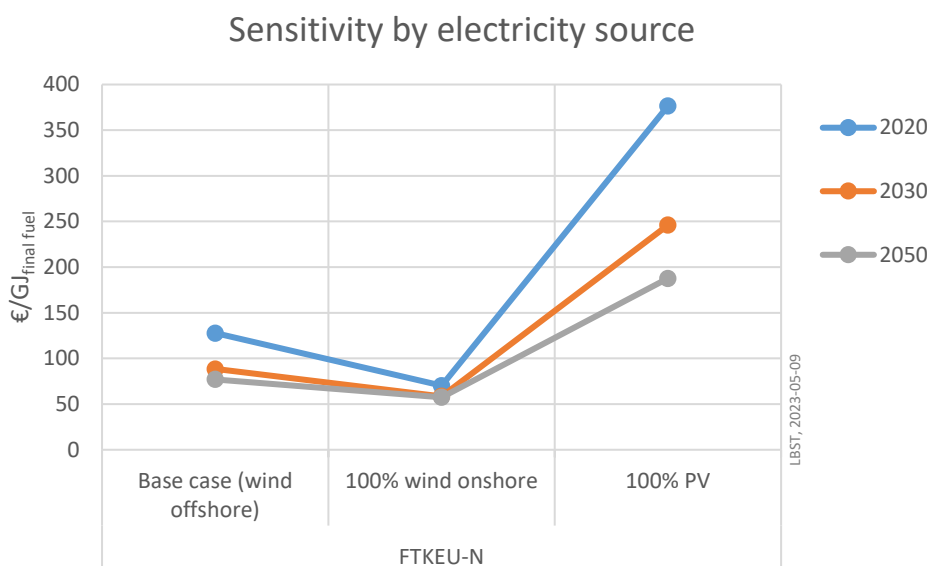
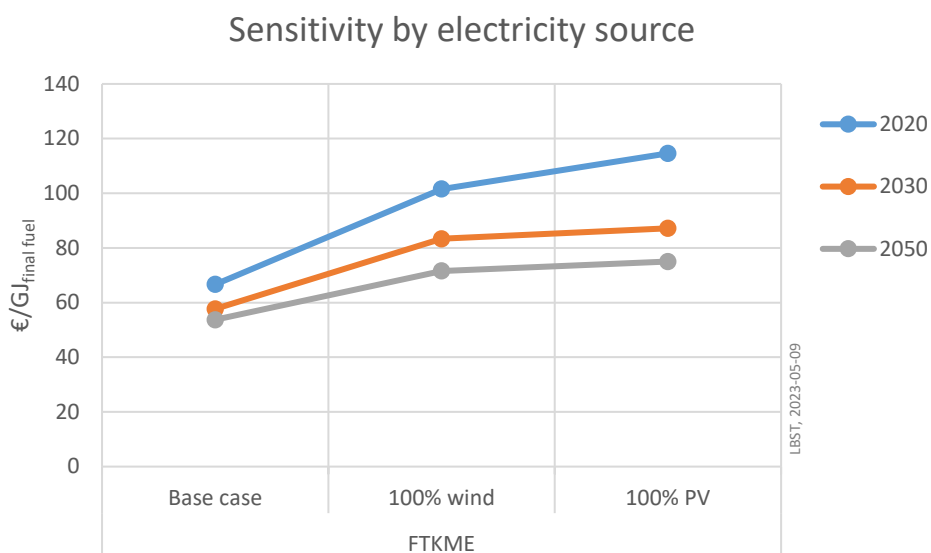


Figure 55 and Figure 56 show the costs of FT kerosene in North Europe and the costs of FT kerosene imported from MENA depending on the electricity source by year.

**Figure 55:** Costs of FT e-kerosene in North Europe depending on the electricity source by year



**Figure 56:** Costs of FT e-kerosene imported from MENA depending on the electricity source by year





For North Europe, 100% wind offshore is assumed as base case. The costs of electricity from offshore wind power are higher than those for onshore wind power. Based on the available data, the CAPEX and the OPEX for offshore wind are higher than those for onshore wind (see ECONOMIC ANNEX, chapter 9.2.1). The higher equivalent full load period cannot compensate the higher CAPEX and OPEX. Using hydropower with an equivalent full load period of 8000 h/yr would lead to lower costs of fuel supply, provided that the CAPEX for the hydropower plant is not significantly higher and as a result overcompensates the higher equivalent full load period. However, at least in Europe, the potential for hydropower is already largely exploited. Furthermore, the social acceptance for the construction of new large hydropower plants in the GW-scale is low.

100% PV in North Europe leads to high costs of e-kerosene due to low PV electricity yields in winter and a large electricity storage requirement (~1.0-1.2 days of full load operation compared to ~0.1 days in the base case).

For MENA, a PV/wind hybrid power station is assumed as base case. Wind and PV are complementary. High wind speeds often occur in periods where the solar irradiation is low and vice versa. As a result, the equivalent full load period of the power-to-fuel plant is higher in the base case in MENA. Wind only or PV only leads to a lower equivalent full load period of the power-to-fuel plant leading to higher capital costs and production costs.

#### 2.2.4. CO<sub>2</sub> source

In the base case, a concentrated CO<sub>2</sub> source with a CO<sub>2</sub> concentration of 45% (SMR as proxy) has been used for 2020 and 2030. For 2050, CO<sub>2</sub> from direct air capture has been used for e-fuels produced both in Europe and in MENA in the base case.

The following CO<sub>2</sub> sources have been assumed for sensitivity analysis:

- A mix of one third CO<sub>2</sub> from SMR, one third CO<sub>2</sub> from a mix of natural gas and lignocellulosic biomass fuelled power plants, and one third CO<sub>2</sub> from direct air capture for e-fuels produced in Europe. A mix of 50% concentrated source and 50% from DAC for fuels produced in MENA
- 100% concentrated CO<sub>2</sub> source (Steam methane reforming (SMR) or Autothermal reforming (ATR)) as proxy)
- 100% flue gas from of a mix of 50% natural gas and 50% wood fuelled power stations
- Use of CO<sub>2</sub> captured in EU (100% concentrated CO<sub>2</sub> source in 2020 and 2030, mix of CO<sub>2</sub> sources in 2050) for synthesis in MENA (pathway: CO<sub>2</sub>-EU).

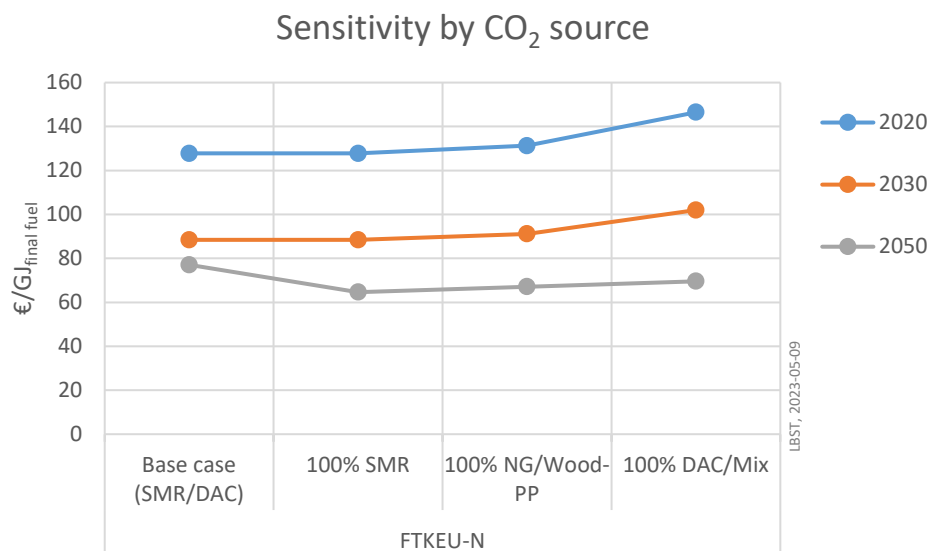
**Figure 57:** E-fuel costs in 2050 depending on CO<sub>2</sub> source for FT kerosene produced in North Europe and MENA



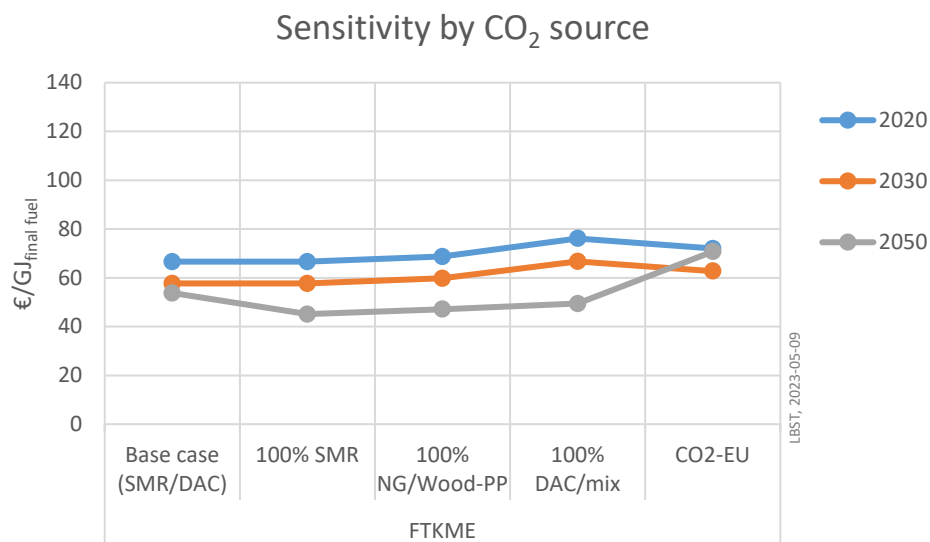
The electricity costs include the whole amount of electricity consumed by the power-to-liquid plant including electrolysis, hydrogen compressors, and CO<sub>2</sub> capture. If the CO<sub>2</sub> for the FT plant in MENA is captured in the EU (pathway 'CO<sub>2</sub>-EU'), electricity from the electricity grid in Southern Europe is used for CO<sub>2</sub> capture, leading to higher electricity costs for this process step.

Figure 58 shows the summarised e-fuel costs for FT kerosene produced and consumed in North Europe. Figure 59 shows the e-fuel costs for FT kerosene produced in MENA and consumed in South Europe. For 2020 and 2030 CO<sub>2</sub> from concentrated source has been assumed for the base case and CO<sub>2</sub> from diluted source (DAC) for sensitivity. For 2050 CO<sub>2</sub> from DAC has been assumed as base case and CO<sub>2</sub> from a mix of C sources for sensitivity.

**Figure 58:** E-fuel costs for FT kerosene in North Europe depending on CO<sub>2</sub> source by year



**Figure 59:** E-fuel costs for FT kerosene produced in MENA and consumed in South Europe depending on CO<sub>2</sub> source by year



The lowest e-fuel cost can be achieved with CO<sub>2</sub> from a concentrated source (SMR). CO<sub>2</sub> from direct air capture (DAC) leads to the highest fuel costs due to higher energy demand for the extraction of CO<sub>2</sub> from air and the higher CAPEX of the DAC plant.

For FT kerosene produced in MENA, the differences between the CO<sub>2</sub> sources are lower because the costs of renewable electricity are lower. CO<sub>2</sub> captured in the EU from concentrated CO<sub>2</sub> sources (SMR) and exported to MENA has only minor advantage compared CO<sub>2</sub> from a DAC plant in MENA for the time horizons 2020 and 2030. For 2050, the e-fuel costs for CO<sub>2</sub> captured in the EU from direct air capture

(DAC) and exported to MENA even leads to the highest costs of e-fuel supply. One reason is that in 2050 the ships for the transport of CO<sub>2</sub> and the transport of final fuel to South Europe are fuelled with e-diesel (pathway FTKME). Another reason is that a mix of CO<sub>2</sub> sources has been assumed for CO<sub>2</sub> capture in South Europe in 2050 instead of 100% direct air capture.

The CO<sub>2</sub> capture plant is integrated. Depending on the CO<sub>2</sub> source the heat demand is partly (CO<sub>2</sub> from a mix of natural gas and wood fueled power plants and CO<sub>2</sub> from DAC) or fully (CO<sub>2</sub> from concentrated sources such as SMR) supplied by the downstream FT synthesis. Table 25 shows the costs attributed to CO<sub>2</sub> supply per t of CO<sub>2</sub>. Cost of renewable electricity, capital, and maintenance are included. The net heat demand of CO<sub>2</sub> capture (gross heat demand minus heat supplied by downstream FT syntheses) is also supplied by electricity.

**Table 25:** Costs attributed to CO<sub>2</sub> supply for different CO<sub>2</sub> sources (€/t<sub>CO2</sub>)

	CO <sub>2</sub> source	2030	2050
FTKEU-N	100% SMR	32	25
	100% NG/wood PP	61	52
	100% DAC	177	158
FTKME	100% SMR	23	20
	100% NG/wood PP	45	42
	100% DAC	120	113
	CO <sub>2</sub> from EU*	79	123

\* CO<sub>2</sub> captured from a concentrated source in the South Europe and transported to MENA via ship

CO<sub>2</sub> from concentrated CO<sub>2</sub> sources shows the lowest costs, CO<sub>2</sub> from DAC shows the highest costs of CO<sub>2</sub> supply except in case of CO<sub>2</sub> from EU transported to MENA in 2050. The reason for the increasing costs for CO<sub>2</sub> from EU transported to MENA is, that in 2050 the fuel demand for ship propulsion is fully met by e-diesel.

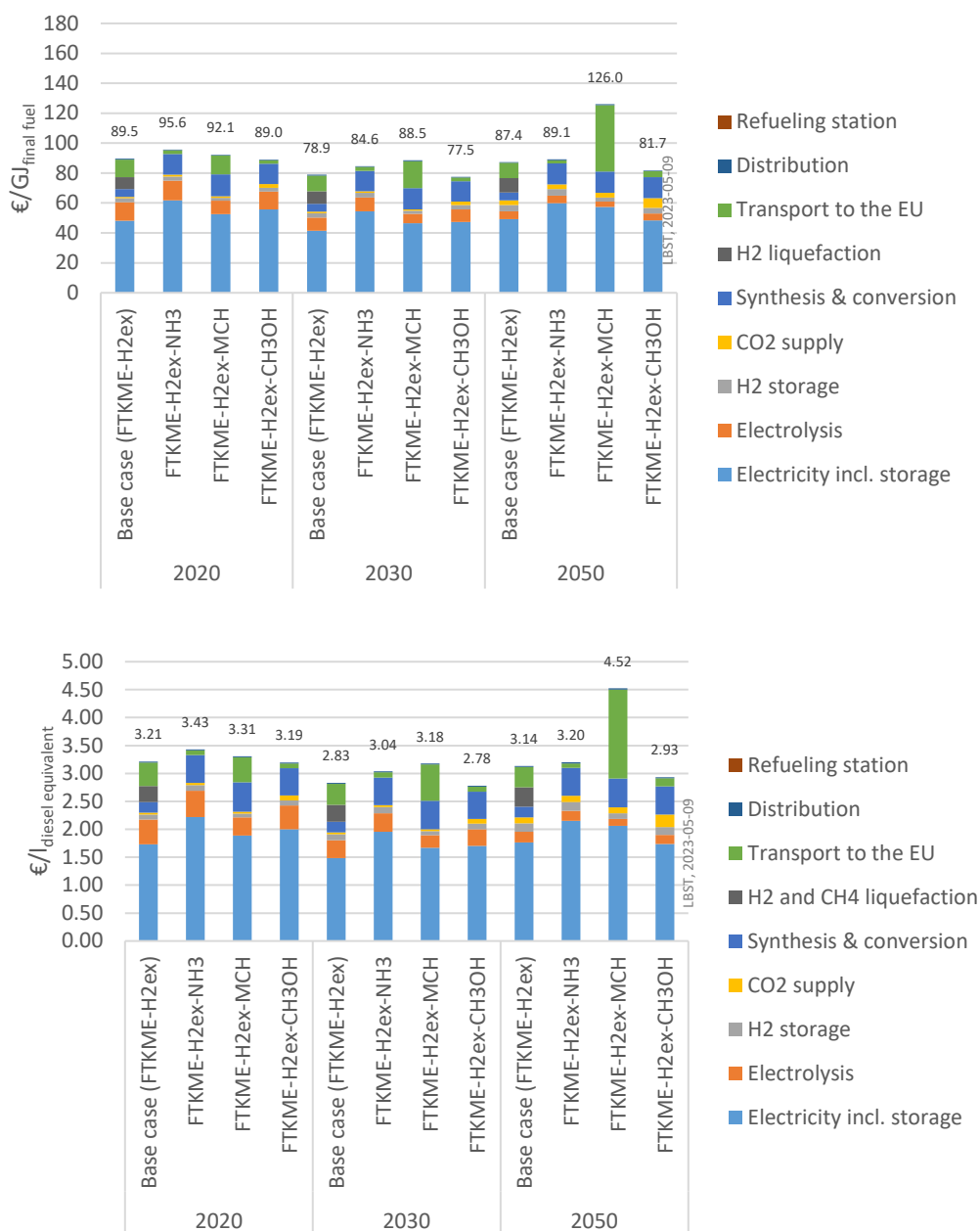
### 2.2.5. Use of Alternative carriers for H<sub>2</sub> import to feed synthesis processes

For these cases, South Europe (Spain) is used as destination proxy associated with:

- Use of ammonia (NH<sub>3</sub>) as H<sub>2</sub> carrier to feed synthesis processes
- Use of methylcyclohexane (MCH) as H<sub>2</sub> carrier to feed synthesis processes
- Use of methanol (MeOH) as H<sub>2</sub> carrier to feed synthesis processes

Figure 60 shows the e-fuel costs for alternative carriers for hydrogen transport to feed synthesis processes in South Europe.

**Figure 60:** Fuel costs depending on the use of alternative carriers for H<sub>2</sub> import to feed FT e-kerosene synthesis process



'H<sub>2</sub>ex' means that H<sub>2</sub> is transported to South Europe as liquefied hydrogen (LH<sub>2</sub>), ammonia (NH<sub>3</sub>) or methylcyclohexane (MCH) or methanol (CH<sub>3</sub>OH).

The synthesis of ammonia, the transport of ammonia, the reconversion of ammonia back to hydrogen, and finally the synthesis of FT kerosene leads to high energy losses, leading to high costs of the final fuel.

The reason for the increasing costs of fuel supply for pathway FTKME-H<sub>2</sub>ex-MHC is that renewable diesel from power-to-liquid via FT synthesis is used as fuel for ship propulsion. The low energy density of MCH increases the impact of higher costs for diesel for ship propulsion.

It has to be noted that today, there are no available or known processes to decompose ammonia at large-scale plant with a capacity of e. g. 200 t of hydrogen per day. Most commercially available solutions offer an electric-based furnace solution at a production capacity ranging from 1 to 2 t of hydrogen per day [Jackson et al. 2019].

In case of methylcyclohexane (MCH) as hydrogen carrier, the low energy density (hydrogen content 6.16% by mass at a density of 0.77 t/m<sup>3</sup> leads to 5.69 GJ of hydrogen per m<sup>3</sup> bound in MCH) leads to high costs for MCH transport.

Methanol as hydrogen carrier approximately also leads to higher costs of the final fuel than the transport of the liquefied hydrogen.

It also has to be noted that the electricity requirement for NH<sub>3</sub> cracking, MCH dehydrogenation, methanol steam reforming, the CO<sub>2</sub> supply, and the FT plant in Europe is met by grid electricity (~0.10 €/kWh). As a result, the costs of electricity per GJ of final fuel do not necessarily correlate with the efficiency of the whole fuel supply chain. The reason for this approach is that the processes located in the ARA (Amsterdam, Rotterdam, Antwerp) region in Europe are located at the port and not nearby the renewable power stations.

## 2.2.6. Variation of transportation inside Europe

- Longer transportation distance inside Europe
  - Liquid fuels and LH<sub>2</sub> imports: truck 300 km (base case: 150 km)
  - Gaseous fuels: wider-meshed pipeline grid (double pipeline distance per refuelling station compared to base case)
- Other transport types inside Europe (truck, ship)
  - Sensitivity on 2050 pathways, distance kept constant
  - Transport of gaseous fuels via CGH<sub>2</sub> / CNG trailer
  - Transport of liquid fuels via inland ship (barge)

### 2.2.6.1. Longer transportation distance inside Europe

The cost assumptions for the transport and distribution of the final fuel such as CAPEX and OPEX for pipelines, trucks, and ships are described in the ANNEX chapter 9.

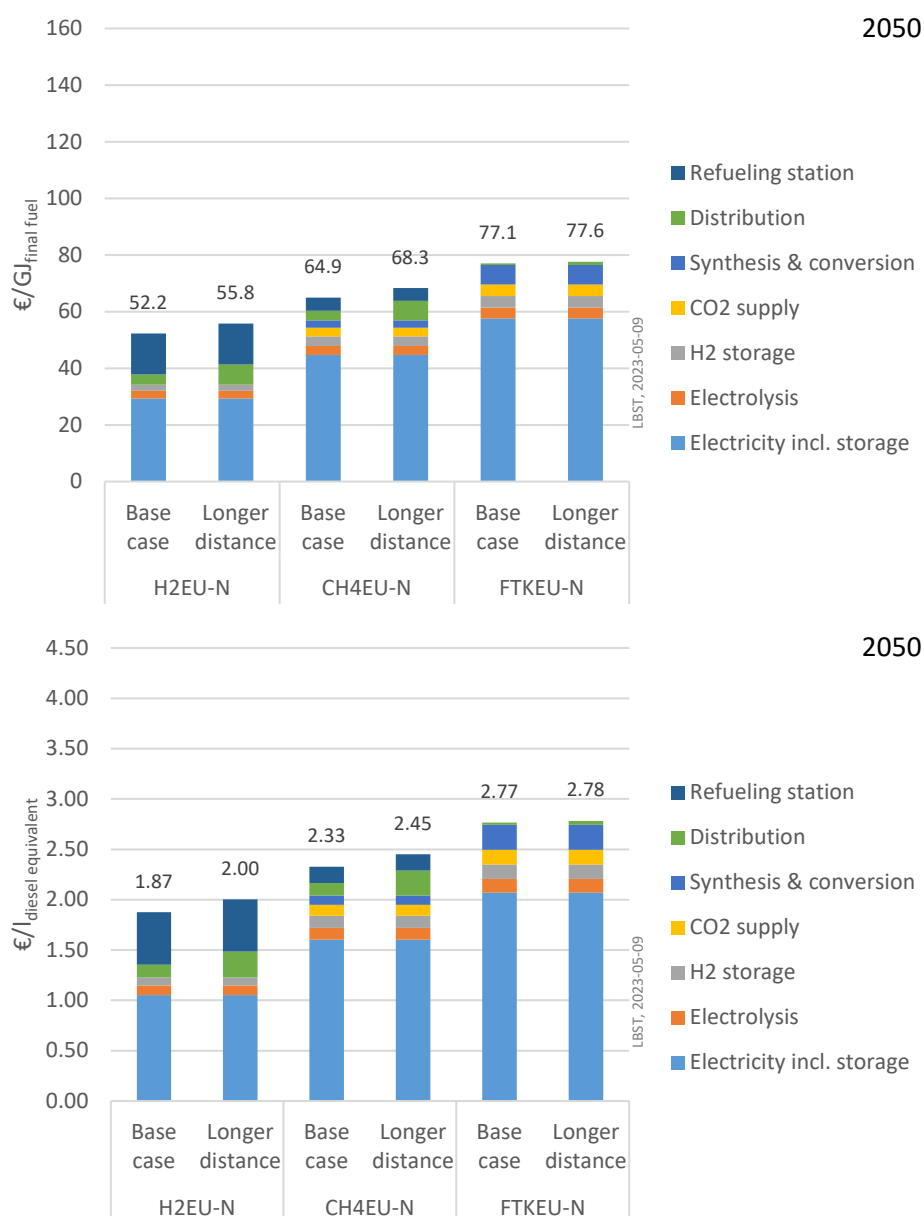
For e-hydrogen and e-methane, a wider pipeline grid for the same amount of final fuel has been assumed (double km per refuelling station). For liquid e-fuels, the distance for the transport via product pipeline and truck has been doubled (Table 26).

**Table 26:** Transport distances inside Europe for selected pathways

	Transport mode	Base case	Sensitivity
H2EU-N	H <sub>2</sub> pipeline grid	5.5 km/station	10.9 km/station
CH4EU-N	CH <sub>4</sub> pipeline grid	5.9 km/station	11.7 km/station
FKEU-N	Pipeline + truck	150 km + 150 km	300 km + 300 km

Figure 61 shows the influence of longer transportation distances inside Europe for 2050 (for 2020 and 2030, see Figure 191 and Figure 192 in ECONOMIC ANNEX chapter 9.5.5).

**Figure 61:** Influence of longer transport distance inside Europe on the fuel costs in 2050



The influence of longer transport distance on the fuel costs is low, especially in case of liquid fuels.

#### 2.2.6.2. Other transport types inside Europe (truck, ship)

For this sensitivity analysis, e-hydrogen and e-methane are distributed via CGH<sub>2</sub> or CNG trailer respectively, instead of via pipeline grid. In the case of e-kerosene, the product pipeline has been replaced by inland navigation. A distance of 500 km has been assumed because transport via ship is typically applied for longer distances.

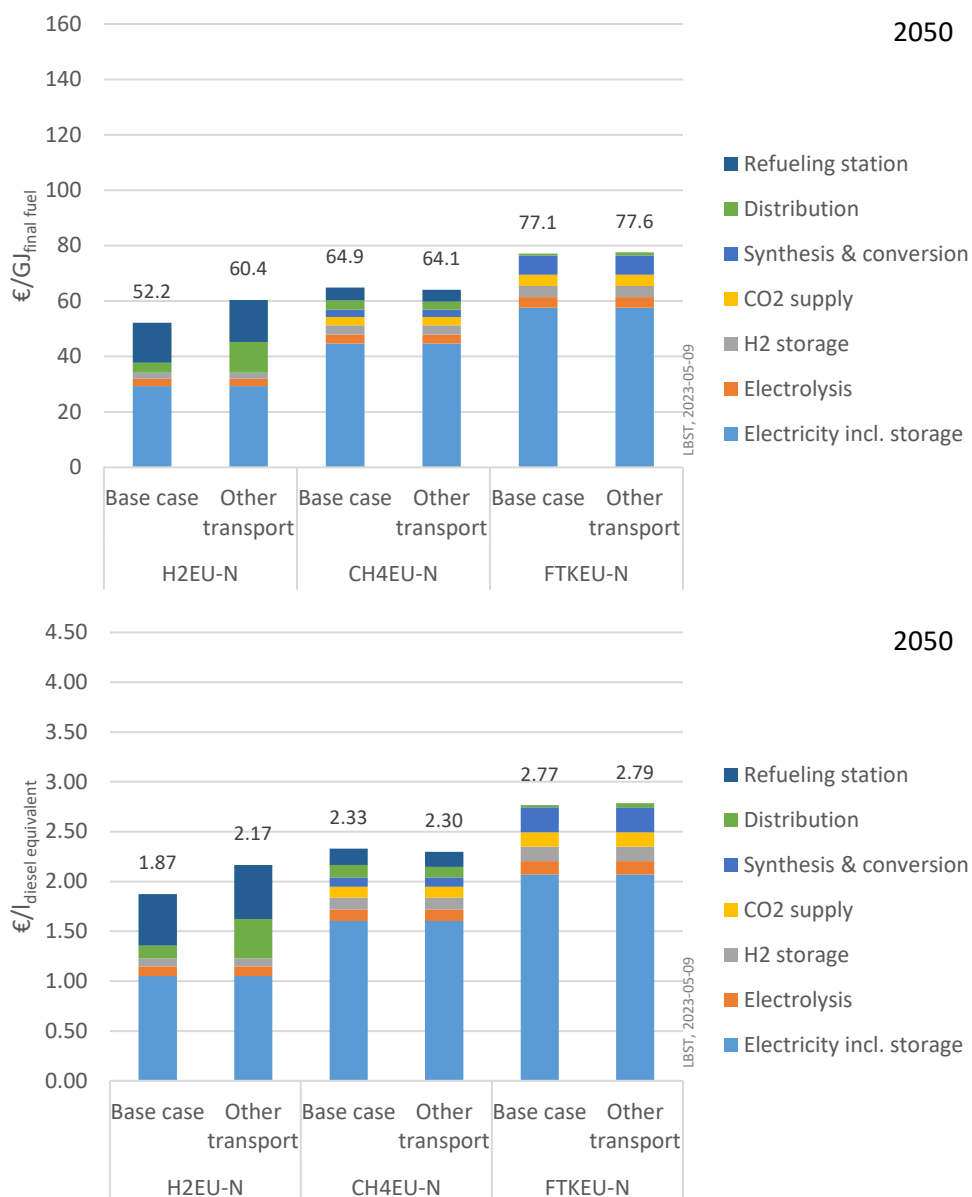
**Table 27:** Transport modes inside Europe for selected pathways

	Base case	Sensitivity
H <sub>2</sub> EU-N	H <sub>2</sub> pipeline grid 5.5 km/station	CCH <sub>2</sub> trailer 150 km
CH <sub>4</sub> EU-N	CH <sub>4</sub> pipeline grid 5.9 km/station	CNG trailer 150 km
FKEU-N	Pipeline 150 km + truck 150 km	Ship 500 km + truck 150 km

The CGH<sub>2</sub> is transported at a pressure of about 50 MPa leading to a transport capacity of 1.1 t of hydrogen (132 GJ related to the LHV). The CNG is transported at a pressure of 25 MPa leading to a transport capacity of about 9.55 t of methane (478 GJ related to the LHV).



**Figure 62:** Influence of other transport types inside Europe on the fuel costs in 2050



Except in case of pathway H2EU-N, the influence of other transport types inside Europe is low. The reason is the lower energy density of hydrogen leading to higher costs if distributed via CGH<sub>2</sub> trailer.

### 2.2.7. Long-haul from other potential sweet spots worldwide

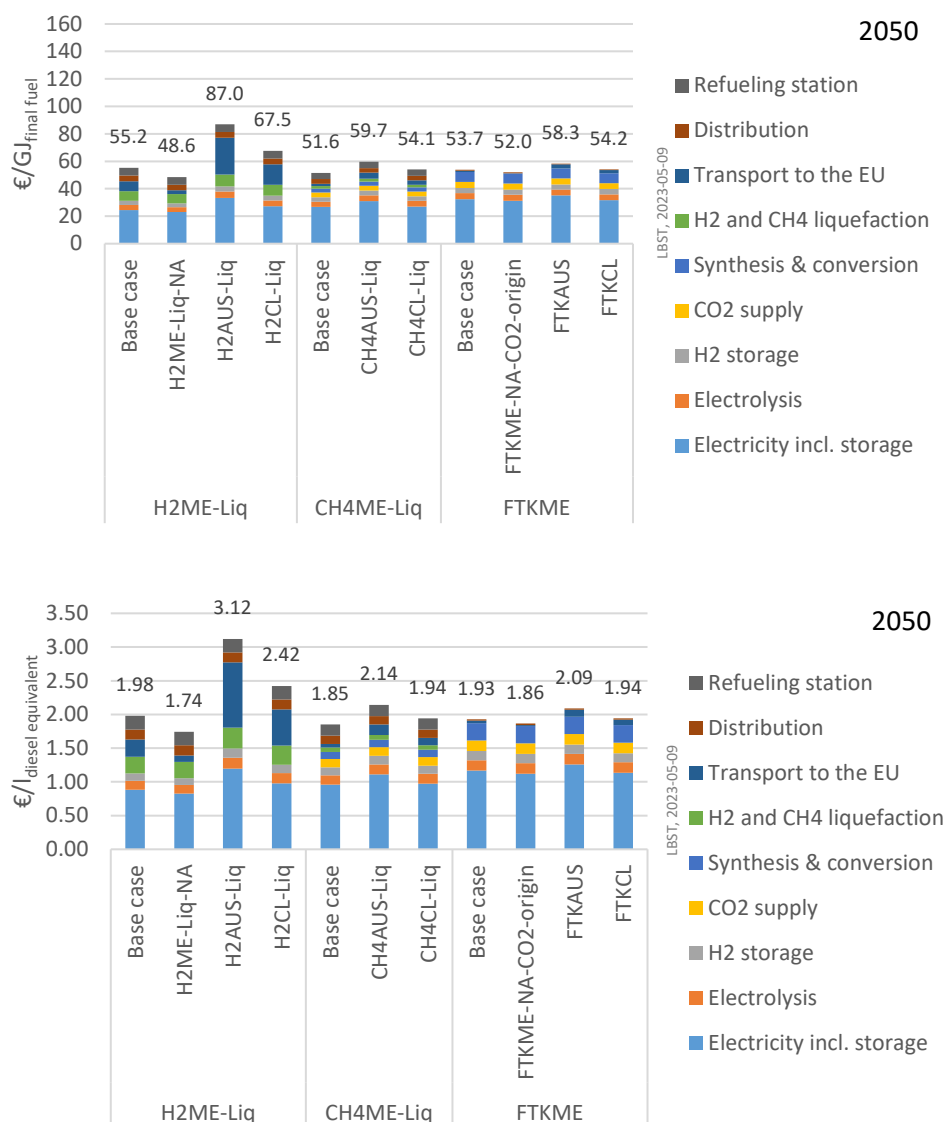
Rotterdam in the Netherlands as representative for the ARA (Amsterdam-Rotterdam-Antwerp) region is used as destination proxy.

The calculation approach made assumptions for CAPEX and OPEX to calculate the renewable electricity generation costs as with MENA (Saudi Arabia), but used equivalent full load hours adjusted to the country of origin (see ECONOMIC ANNEX, chapter 9.2.3).

- North Africa - NA (variation of distance)
  - Morocco as proxy country
  - Equivalent full load hours of hybrid renewable electricity generation (PV and wind onshore)
  - CO<sub>2</sub> origin: same as for KSA (100% DAC)
  - Transport distance from Morocco to ARA region: ~3,370 km
- Australia - AUS
  - Equivalent full load hours of hybrid renewable electricity generation (PV and wind onshore)
  - Transport distance from Australia to ARA region: ~23,620 km
  - CO<sub>2</sub> origin: same as for KSA (100% DAC)
- Chile - CL
  - Equivalent full load hours of hybrid renewable electricity generation (PV and wind onshore)
  - Transport distance from Chile to ARA region: ~17,380 km
  - CO<sub>2</sub> origin: same as for KSA (100% DAC)

Figure 63 shows the influence of long-haul marine transport from potential other sweet spots worldwide on the fuel costs for 2050 (for 2020 and 2030, see Figure 195, and Figure 196 in ECONOMIC ANNEX chapter 9.5.6).

**Figure 63:** Influence of long-haul marine transport from potential other sweet spots worldwide on the fuel cost in 2050



Long distance transport of LH<sub>2</sub> (e. g. from Australia) significantly increases the costs of e-fuel supply because of the boil-off losses resulting from longer days at sea. In case of liquid e-fuels, even very long transport distances lead to minor changes of fuel supply costs only.

## 2.2.8. Larger/smaller e-fuels plant size

For the base case, a fuel production of 1 million t of e-diesel equivalent<sup>10</sup> per year. Two variants have been assumed for sensitivity analysis:

- 0.2 million t per year
- 4 million t per year

The nameplate capacity (e.g. t of final fuel/h) of the e-fuel plants depends on the equivalent full load periods in the different regions.

<sup>10</sup> Based on conventional diesel EN 590

Figure 64 shows the influence of variation of the capacity of the e-fuels plants for 2050 (for 2020, see Figure 197 in ECONOMIC ANNEX chapter 9.5.7).

**Figure 64:** Influence of larger/smaller e-fuels plant capacity in 2050

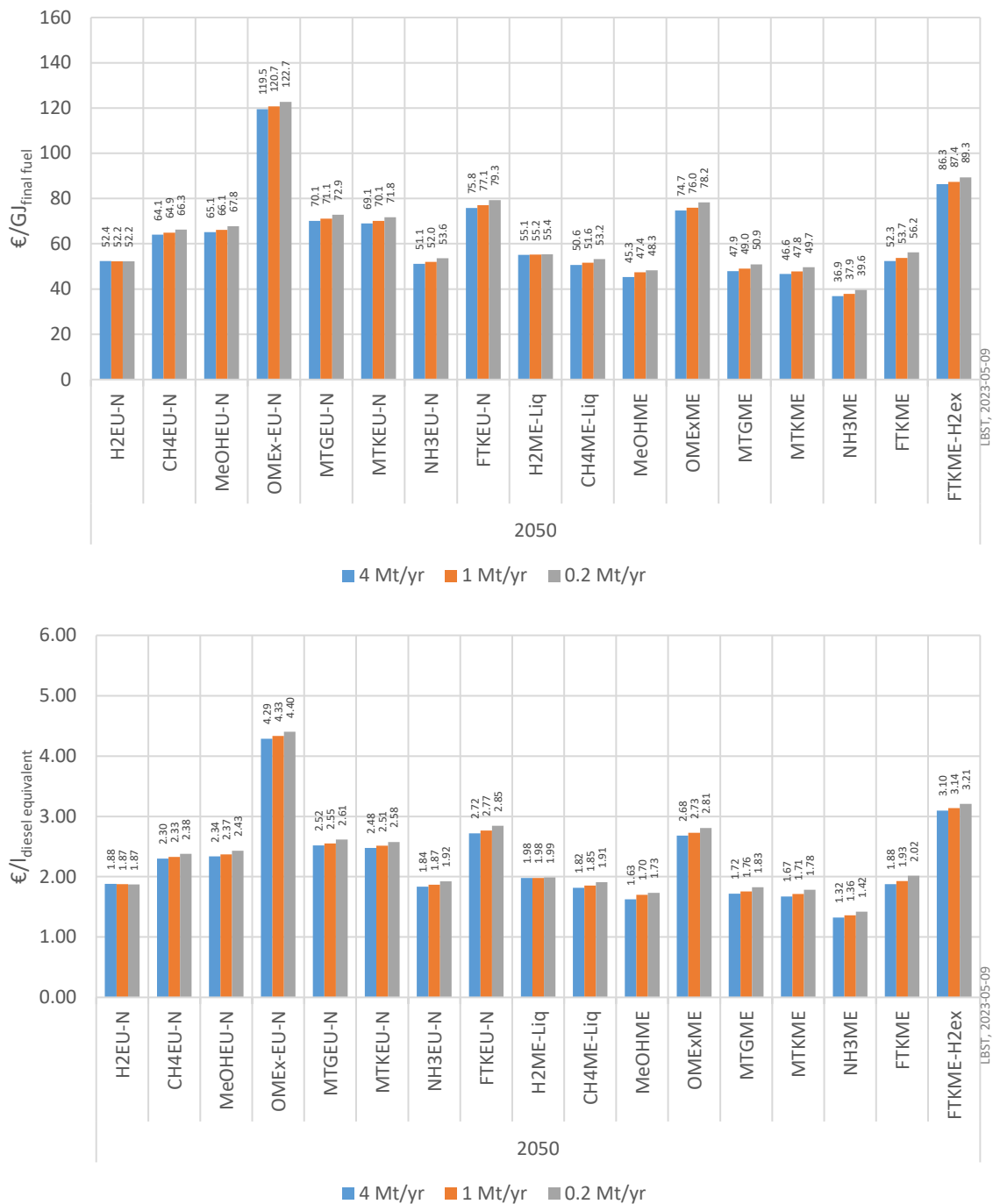
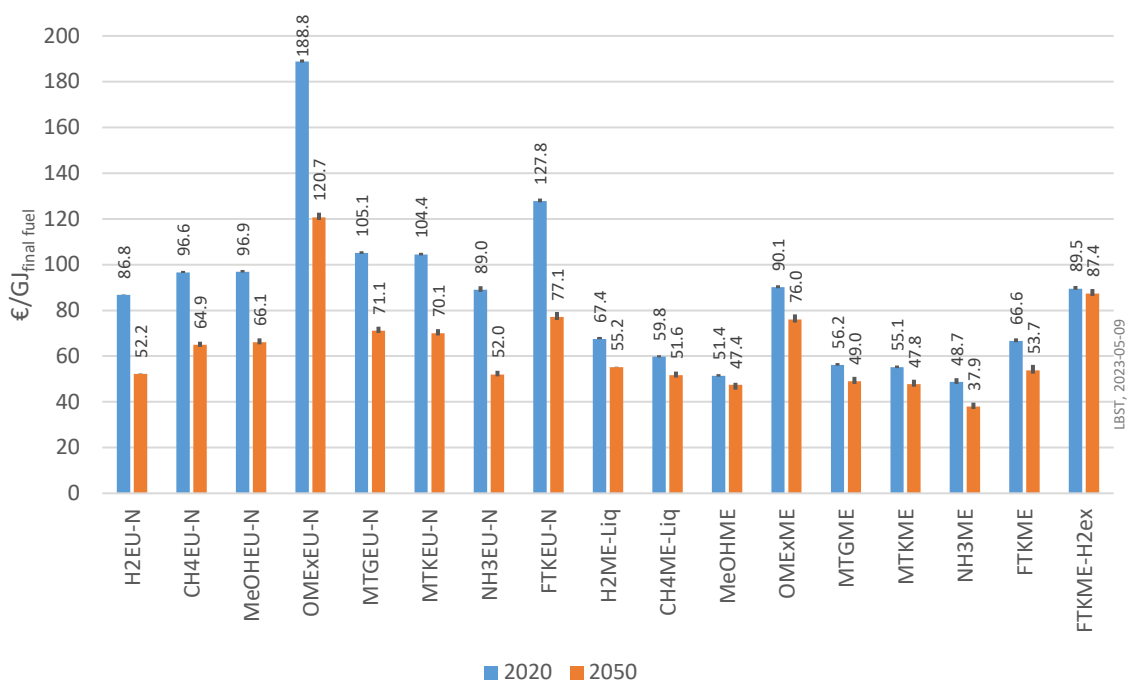


Figure 65 shows the influence of variation of the capacity of the e-fuels plant as uncertainty bars for the base case.

**Figure 65:** Influence of larger/smaller e-fuels plant capacity shown as uncertainty bars



The impact of larger/smaller e-fuels plant capacity is low for the capacities assumed in this study. Even the 0.2 million t per year plant requires an electrolysis plant with a capacity of between 550-1080 MW of electricity input, which is already very large. No further decrease of specific CAPEX is expected for electrolysis plants above 100 MW<sub>e</sub>. Electrolysis is a surface-related technology like PV panels. The decrease of specific CAPEX is only caused by the cost of auxiliary equipment such as converters and transformers.

Scaling by capacity has been applied for the DAC plant, the NH<sub>3</sub> synthesis plant, and some components of the FT synthesis plant such as the reverse water gas shift, pressure swing adsorption, and hydrocracking units (see ECONOMIC ANNEX, Table 129 in chapter 9.4.7).

### 2.2.9. Variation of CAPEX of alkaline electrolysis plant

In this sub-chapter, the downwards and upwards sensitivity of electrolyser CAPEX is shown for selected fuels based on literature sources quoting lower and higher electrolyser CAPEX.

Other publications refer to higher costs for 2020 than assumed for the base case. For instance, the Hydrohub GigaWatt Scale Electrolyser project led by an industrial and academia consortium estimated a in 2020 baseline CAPEX of about 1400/kW<sub>e</sub> with alkaline electrolyser [ISPT 2020]. Therefore, an upwards sensitivity of electrolyser CAPEX also is carried out.

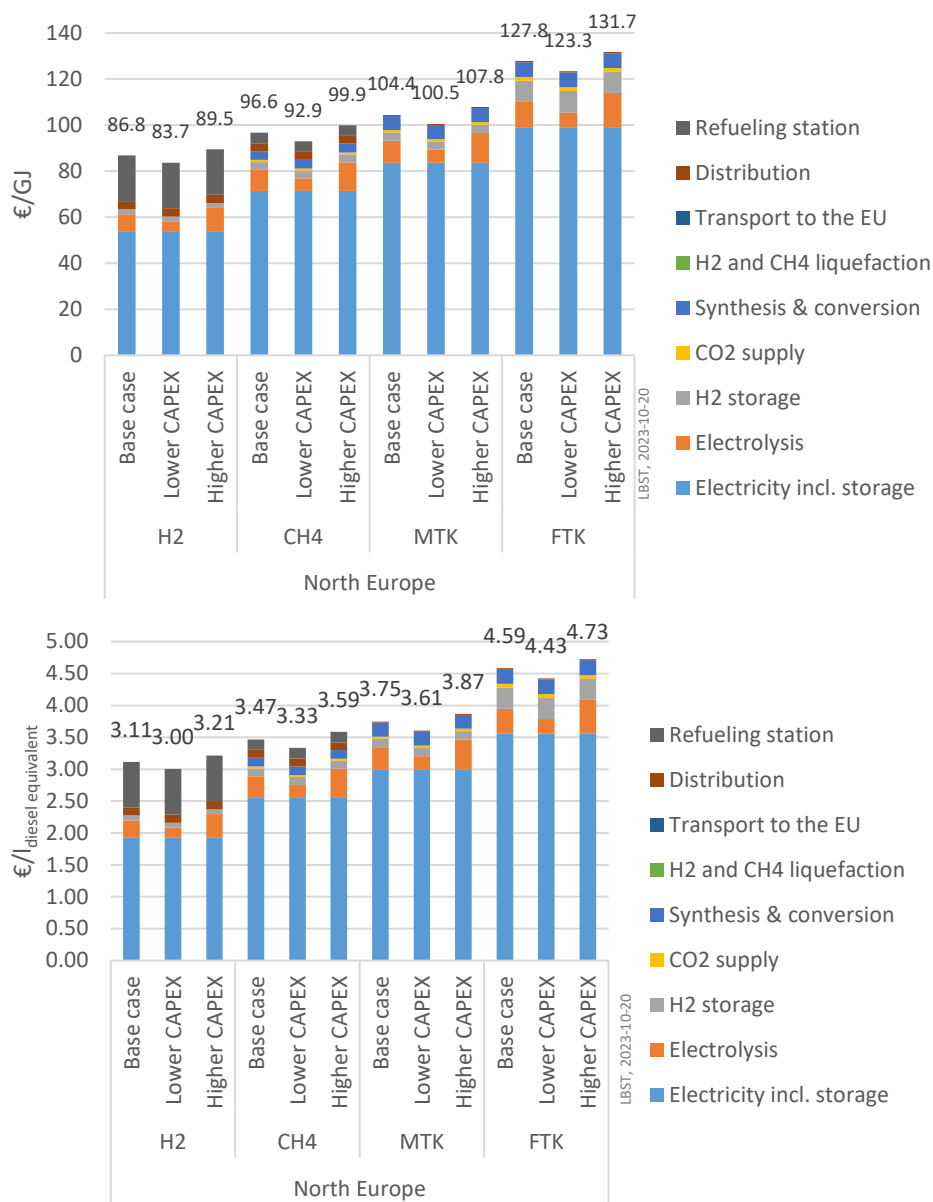
Table 28 shows the variation of the CAPEX for electrolysis plants.

**Table 28:** CAPEX of electrolysis plants (base case vs. sensitivity from literature)

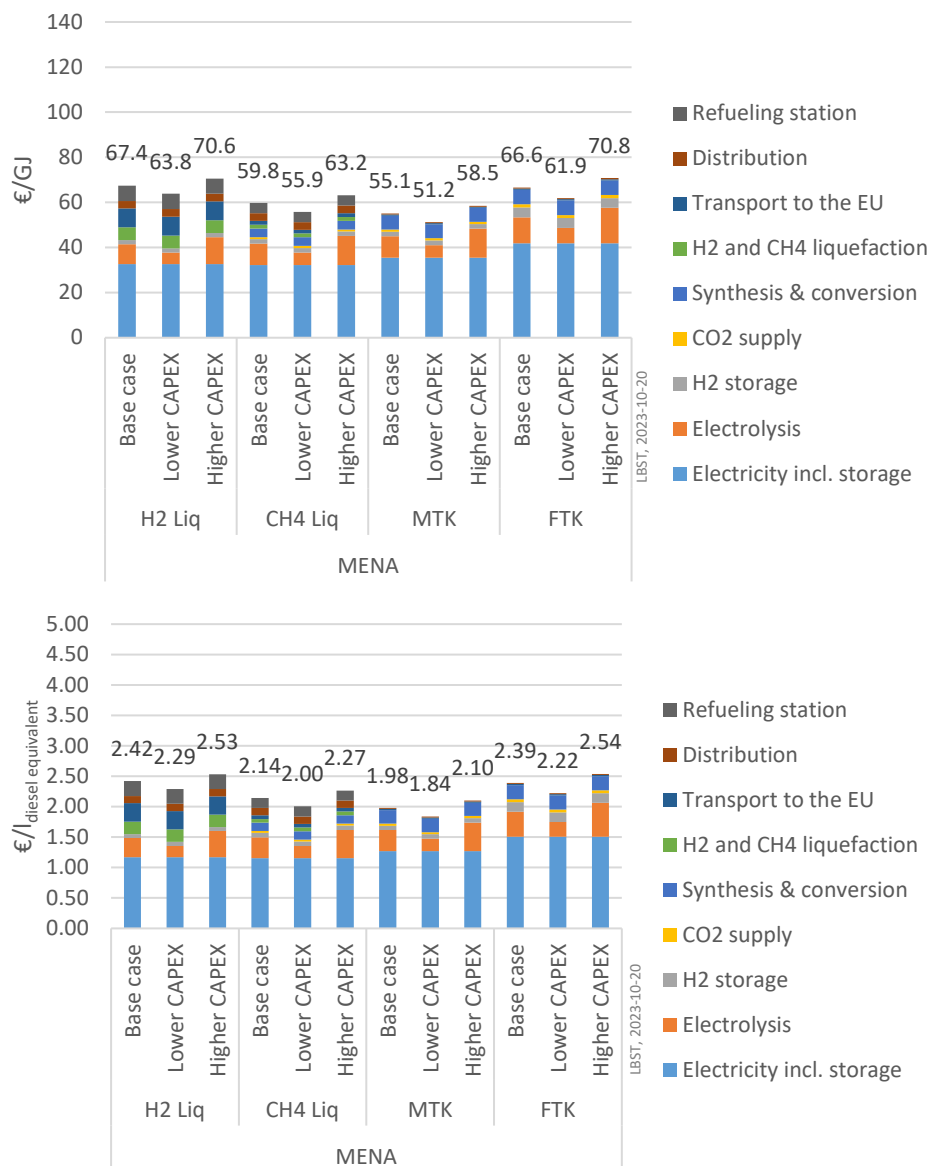
	Unit	2020	2030	2050
Base case	€/kW <sub>e</sub>	1027	710	393
Sensitivity lower CAPEX	€/kW <sub>e</sub>	680	450	315
Sensitivity higher CAPEX	€/kW <sub>e</sub>	1400	980	469
[IEA 2019d]	US\$/kW <sub>e</sub>	900	700	450
[ISE 2021]	€/kW <sub>e</sub>	~680	~450	-30%
[ISPT 2020]	€/kW <sub>e</sub>	1400	n. d. a.	n. d. a.

The CAPEX for electrolysis plants includes direct costs such as the electrolysis stack, power electronics, gas conditioning, and balance of plant and indirect costs (40% of direct costs) such as site preparation, engineering & design, project contingency, and up-front permitting costs.

**Figure 66:** Influence of electrolyzer CAPEX for selected fuels produced in North Europe for 2020

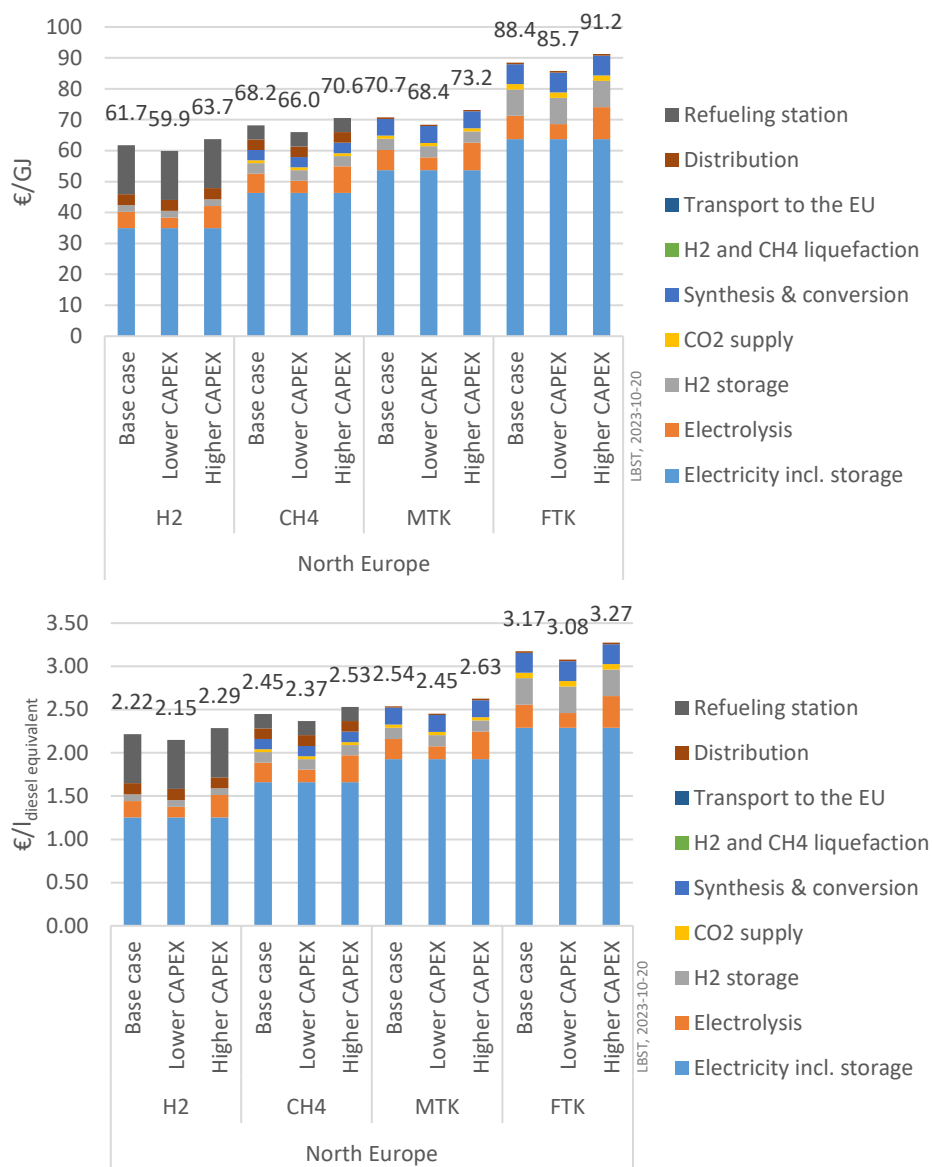


**Figure 67:** Influence of electrolyzer CAPEX for selected fuels produced in MENA and consumed in Europe for 2020

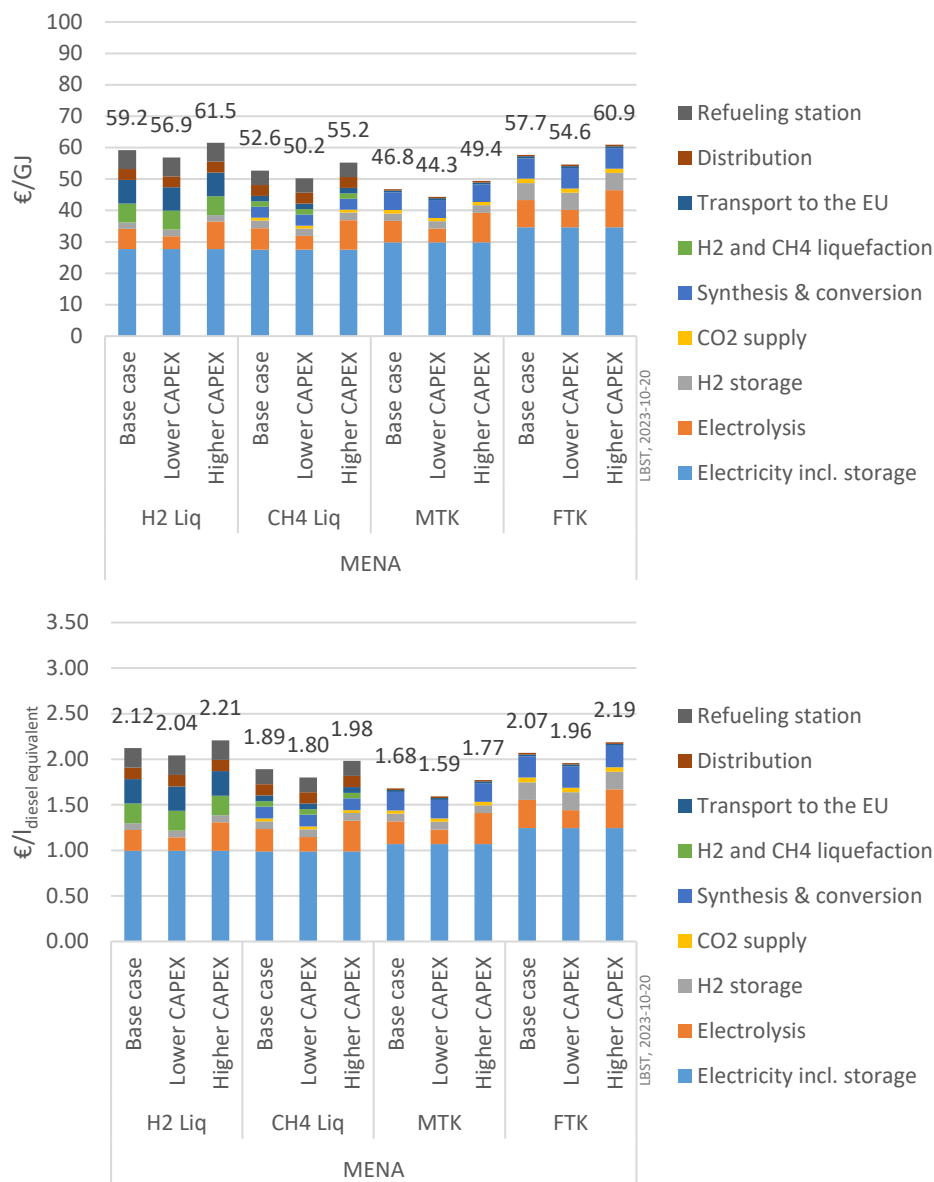




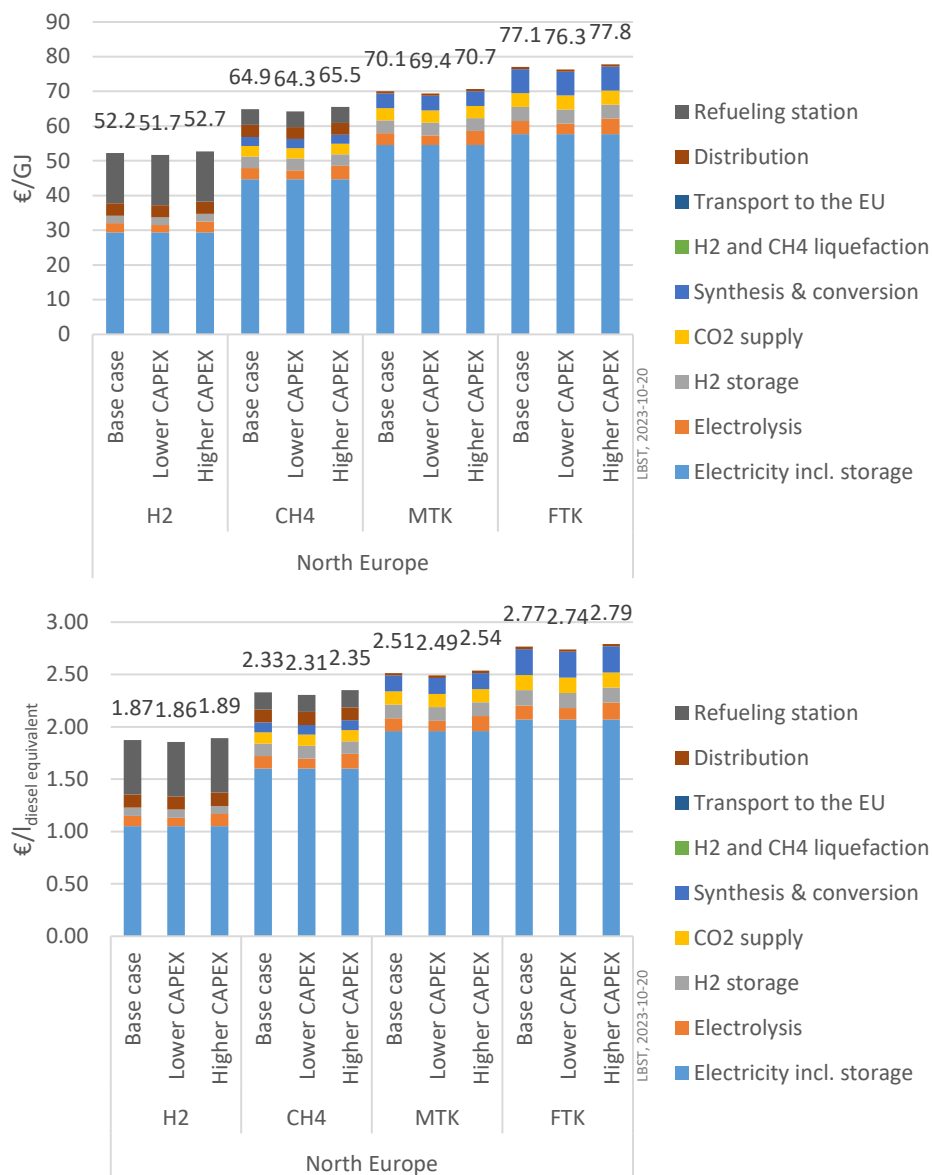
**Figure 68:** Influence of electrolyzer CAPEX for selected fuels produced in North Europe for 2030



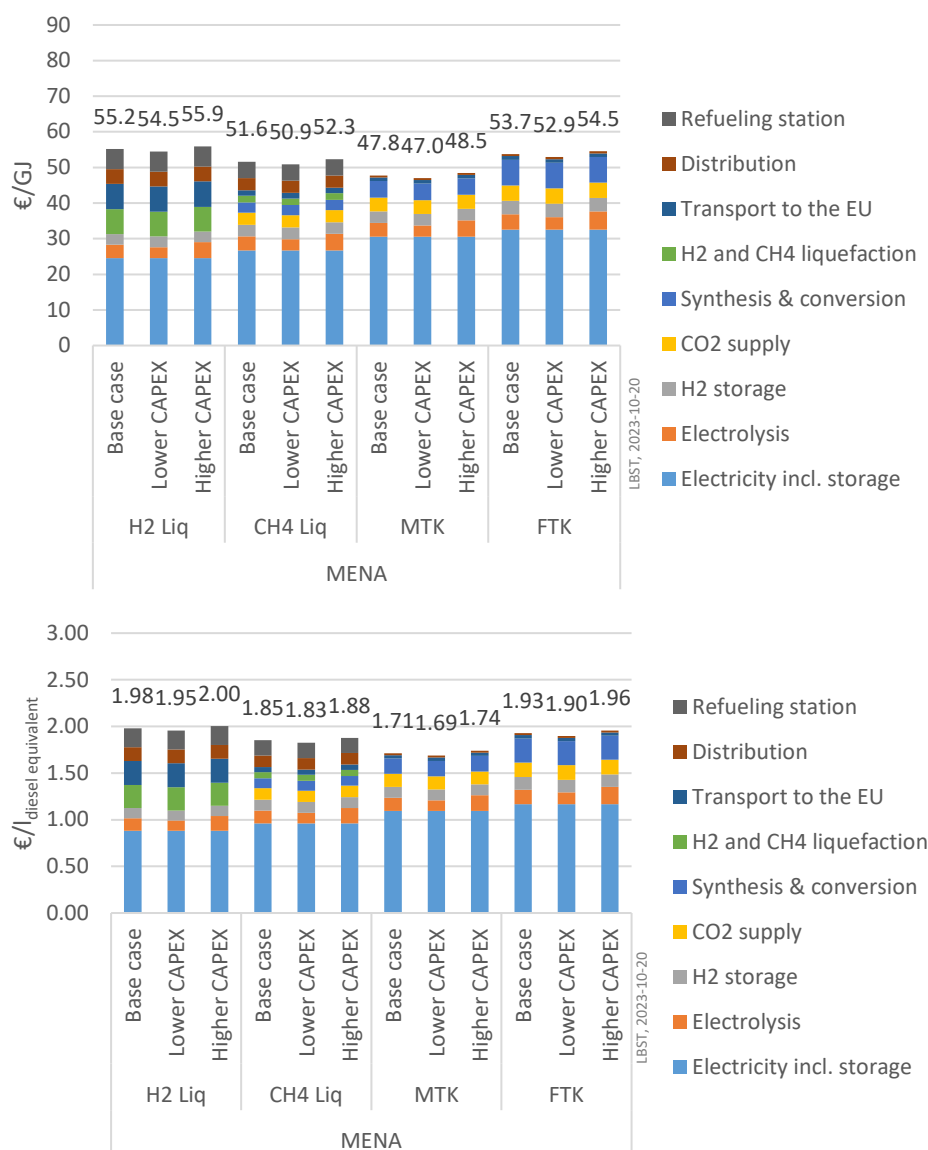
**Figure 69:** Influence of electrolyzer CAPEX for selected fuels produced in MENA and consumed in Europe for 2030



**Figure 70:** Influence of electrolyzer CAPEX for selected fuels produced in North Europe for 2050



**Figure 71:** Influence of electrolyzer CAPEX for selected fuels produced in MENA and consumed in Europe for 2050



The influence of a lower CAPEX for the electrolysis plant shown in Table 28 on the overall costs of fuel supply is low, especially in the long term.

The contribution from electrolyser cost to overall fuel supply costs is some 6-12% in base case across fuels, regions, and time. Reducing assumed electrolysis CAPEX by round about one third of the base case results in 5-8% cost contribution of electrolysis to the overall fuel supply cost. Increasing assumed electrolysis CAPEX by round one third of the base case results in 7-16% cost contribution of electrolysis to the overall fuel supply cost. There is an almost linear dependency of electrolyser costs depending on CAPEX.

Electrolysis plant costs quoted in the literature have a wide range and are mostly based on theoretical studies. It remains to be seen what actual costs for the hydrogen plant will be.

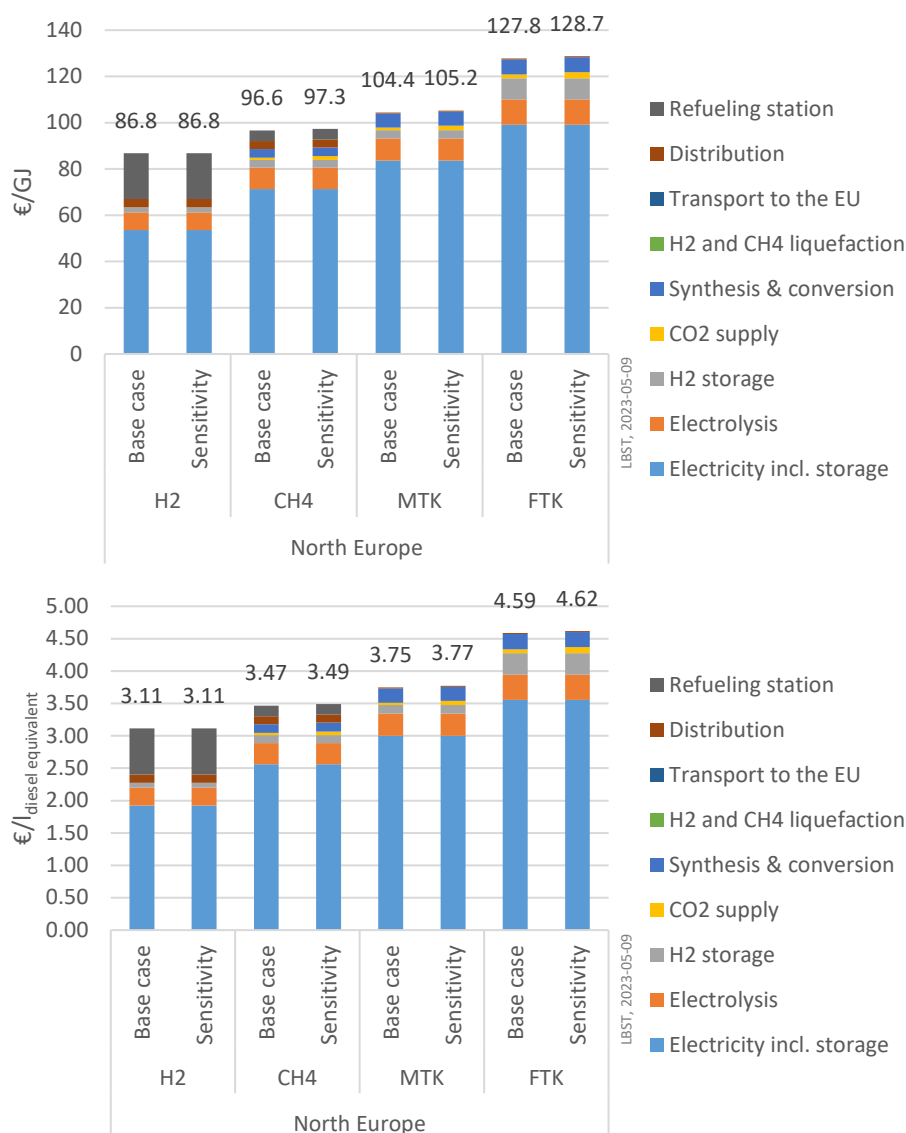
## 2.2.10. Add-on CO<sub>2</sub> price for concentrated CO<sub>2</sub> for e-fuels

As sensitivity additional costs added to the costs of CO<sub>2</sub> extraction from concentrated have been applied (add-on CO<sub>2</sub> costs). The following add-on-costs for CO<sub>2</sub> for e-fuels based on [IEA 2019d] has been assumed (assumption: 0.90 €/US\$):

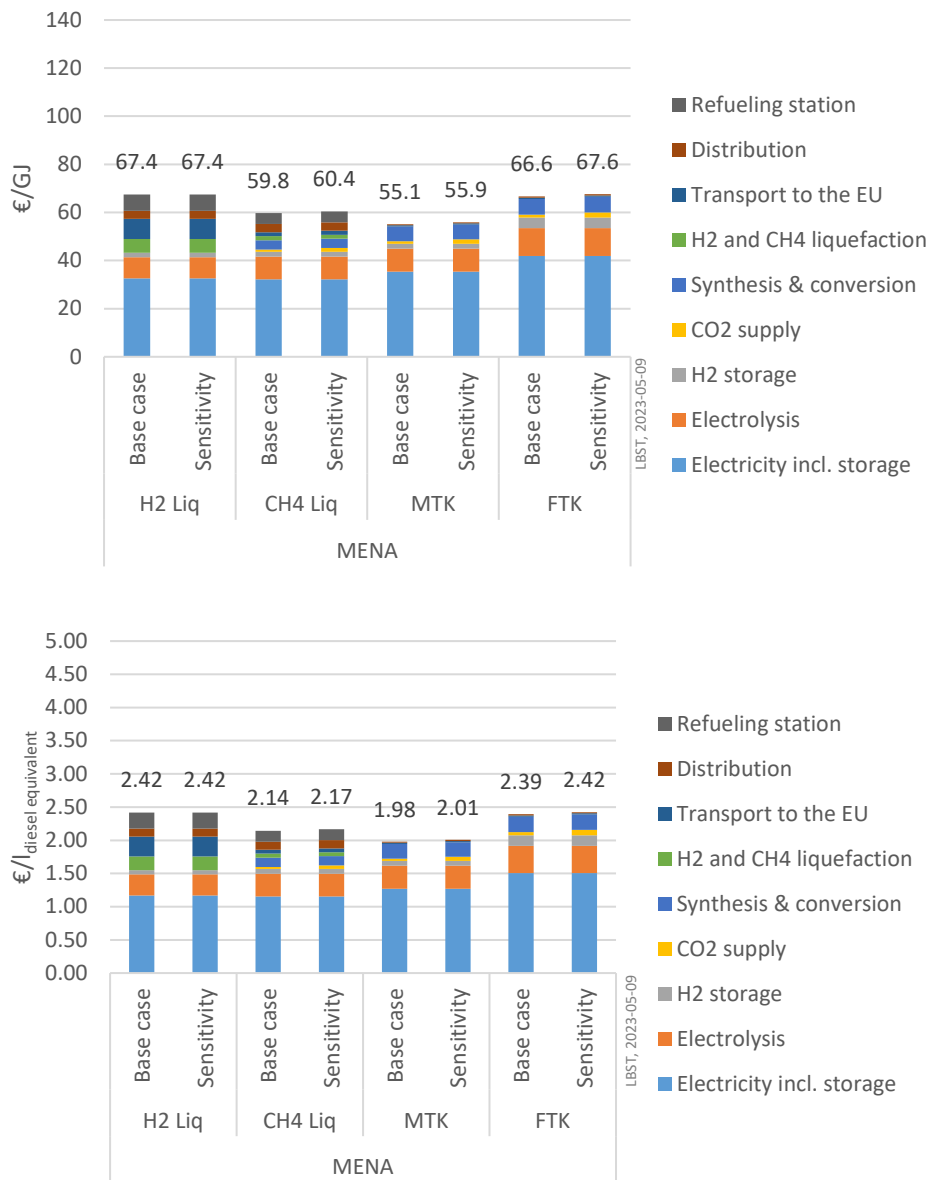
- Today: 19 €/t<sub>CO2</sub>
- 2030: 90 €/t<sub>CO2</sub>
- 2015: 144 €/t<sub>CO2</sub>

In 2050 CO<sub>2</sub> from direct air capture (DAC) has been assumed as base case. For sensitivity CO<sub>2</sub> from a concentrated source with add-on CO<sub>2</sub> costs for e-fuels have been applied.

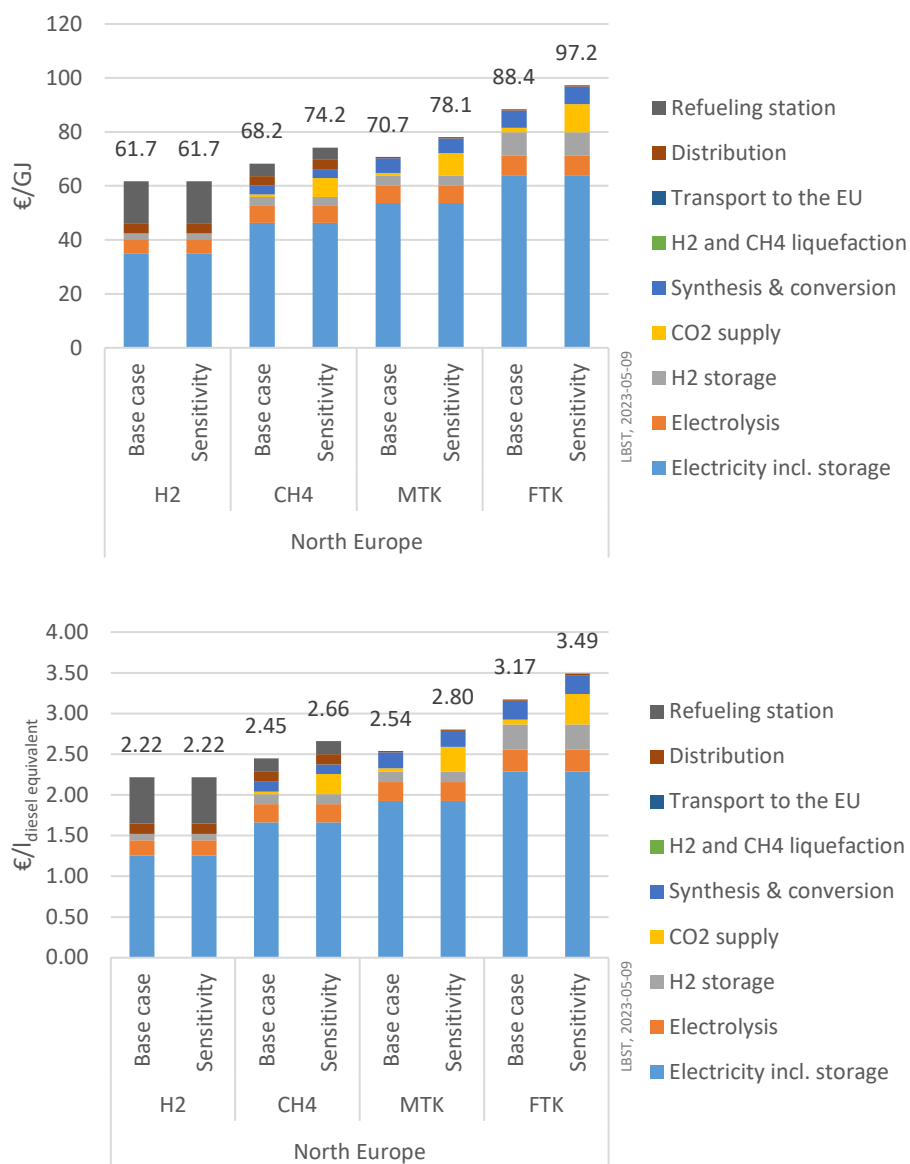
**Figure 72:** Sensitivity add-on-costs of CO<sub>2</sub> for e-fuels in North Europe for 2020



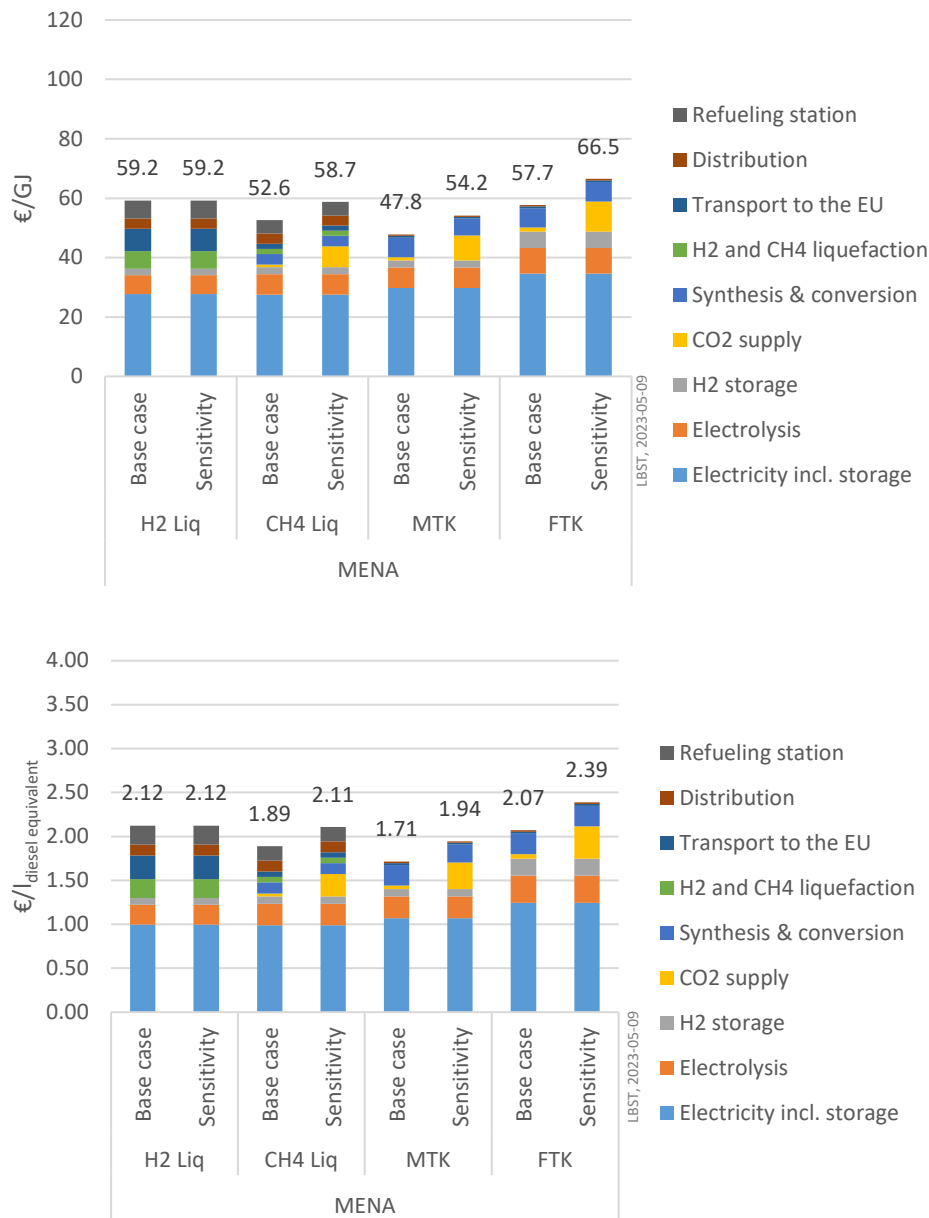
**Figure 73:** Sensitivity add-on-costs of CO<sub>2</sub> for e-fuels from MENA for 2020



**Figure 74:** Sensitivity add-on-costs of CO<sub>2</sub> for e-fuels in North Europe for 2030

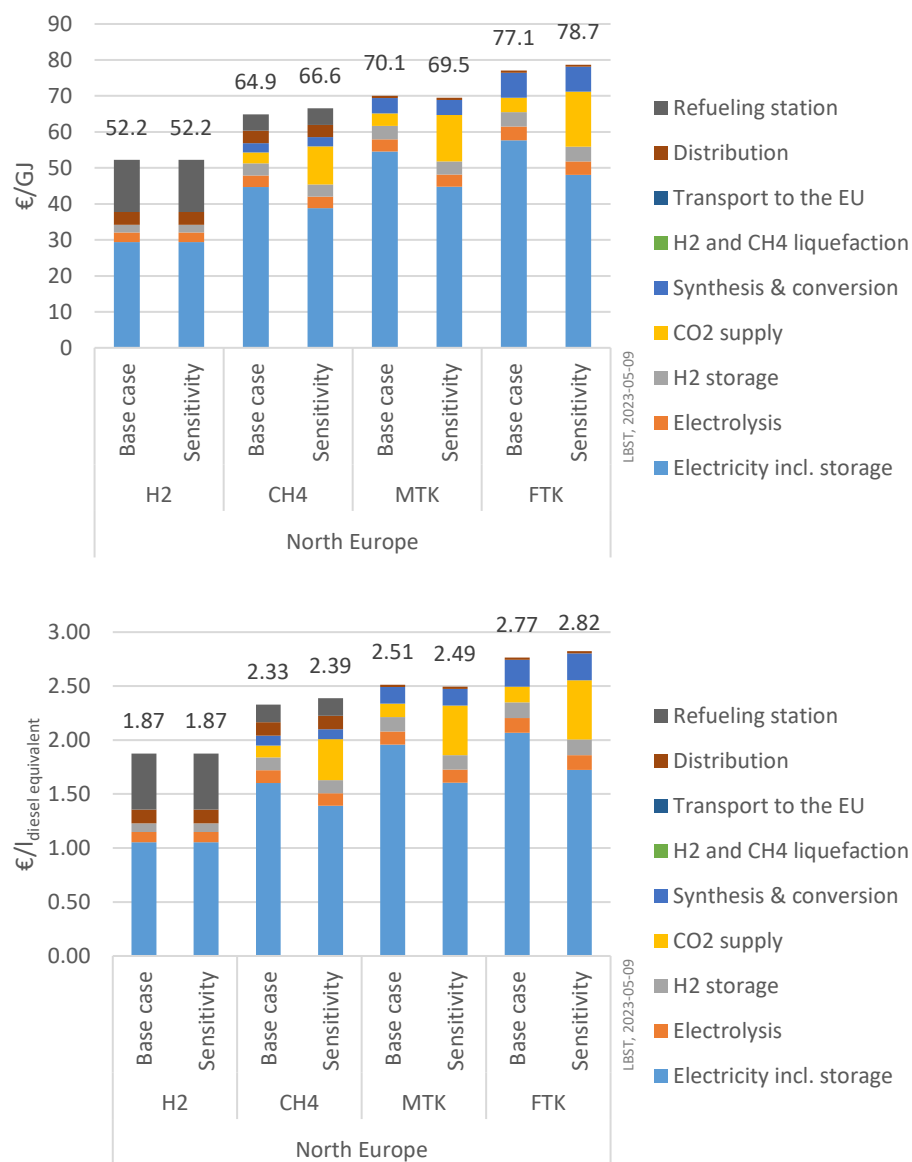


**Figure 75:** Sensitivity add-on-costs of CO<sub>2</sub> for e-fuels from MENA for 2030

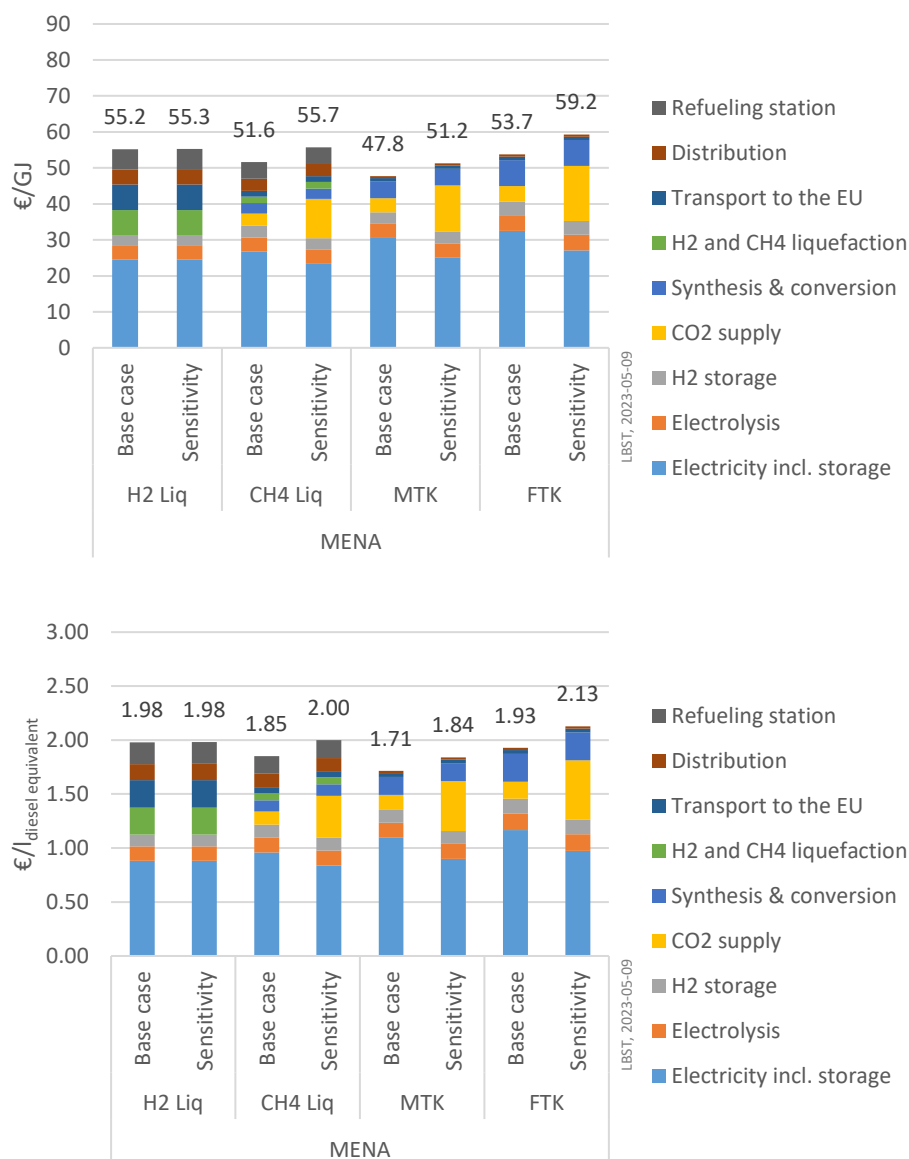




**Figure 76:** Sensitivity add-on-costs of CO<sub>2</sub> for e-fuels in North Europe for 2050 (base case: CO<sub>2</sub> from DAC)



**Figure 77:** Sensitivity add-on-costs of CO<sub>2</sub> for e-fuels from MENA for 2050 (base case: CO<sub>2</sub> from DAC)



In 2050 add-on CO<sub>2</sub> costs for CO<sub>2</sub> from concentrated CO<sub>2</sub> source leads to higher fuel costs than in the base case although CO<sub>2</sub> from DAC has been assumed where no add-on CO<sub>2</sub> costs are applied.

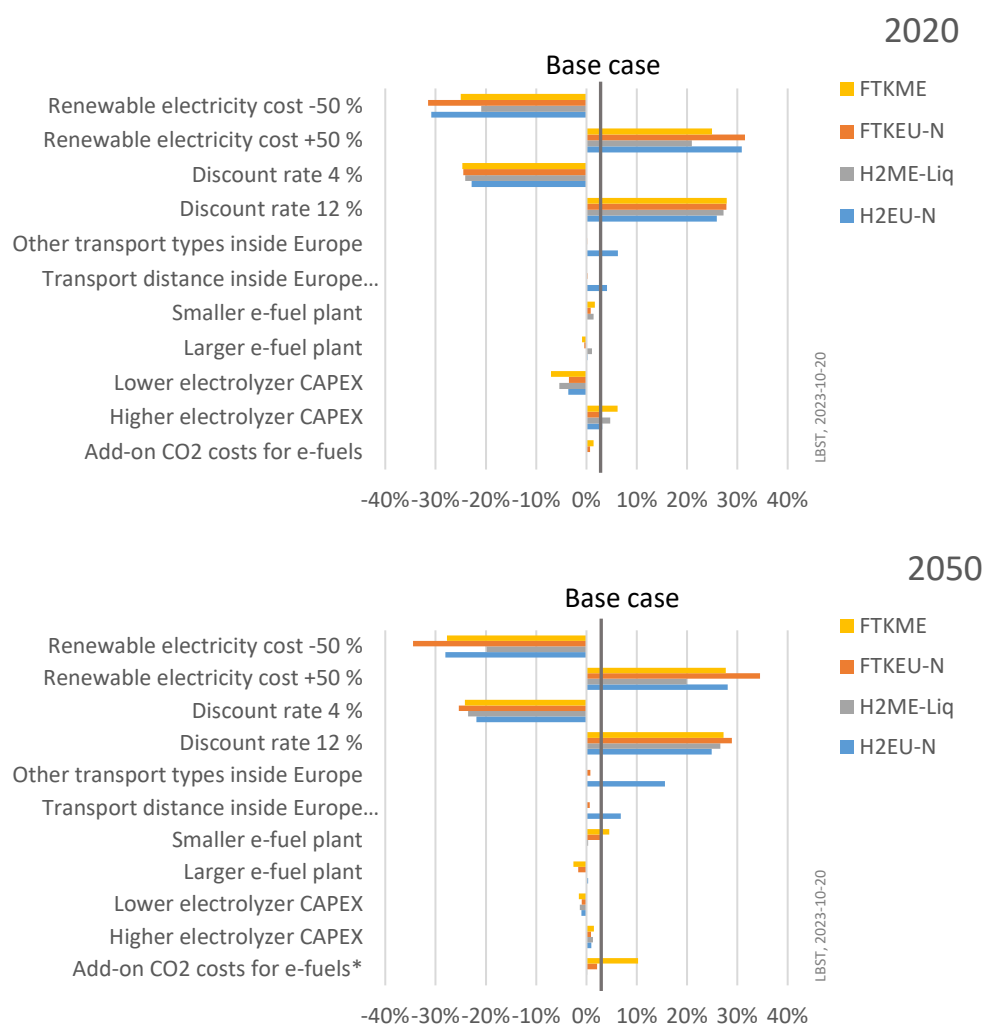
In 2050, the costs for hydrogen from MENA as transportation fuel are slightly influenced by add-on CO<sub>2</sub> costs because the trucks for LH<sub>2</sub> transport to the refueling stations are fueled with e-diesel.

## 2.2.11. Summary sensitivity analysis

Electricity costs and the discount rate have a significant impact on overall fuel supply costs. A 50% change of the electricity supply costs or the discount rate assumptions resulted in a change of about 25% of the supply cost. Other factors investigated, such as transport type and distance inside Europe or e-fuel plant size,

have only marginal impacts (single-digit percentage points). The cost impacts relative to the final production costs are very similar for 2020 and 2050 except in case of add-on costs for CO<sub>2</sub> for e-fuels. In 2050 CO<sub>2</sub> from direct air capture (DAC) has been assumed in the base case where no add-on CO<sub>2</sub> costs are applied. The sensitivities and impacts are shown for 2050 in Figure 78.

**Figure 78:** Sensitivity: impact of variation of selected parameters



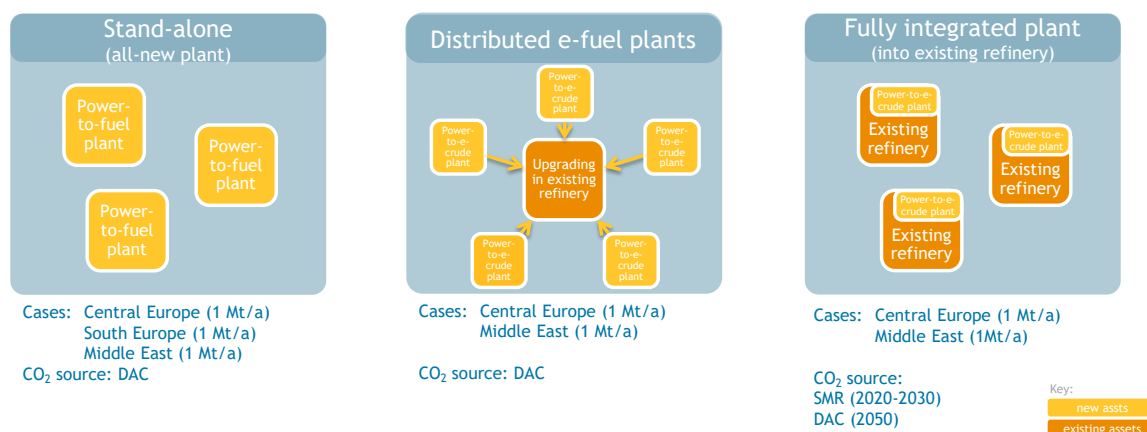
#### KEY MESSAGES - SENSITIVITY ANALYSIS

Electricity costs and discount rate have a significant impact on overall fuel supply costs. 50% change of electricity supply costs or discount rate assumptions resulted in about 25% supply cost. Other factors investigated, such as transport type and distance inside Europe, or e-fuel plant capacity, have only marginal impacts (single-digit percentage points).

### 2.3. STAND-ALONE PLANTS VERSUS DISTRIBUTED E-CRUDE PLANTS VERSUS FULLY INTEGRATED PLANTS

The motivation to look at this topic is to assess the potential role of existing refineries in e-fuel value chains. The use of existing refinery assets reduces the CAPEX and allows the transformation of incumbent energy industries. To assess this, three archetype supply chains as depicted in Figure 79 have been compared.

**Figure 79:** Distributed versus stand-alone/integrated plants



The **stand-alone** e-fuel plant (left box in Figure 79) consider all-new integrated plants for hydrogen production, synthesis to e-crude, and final upgrading as assumed in the base case in this study. In case of **distributed e-fuel plants** (middle box in Figure 79) new hydrogen production and synthesis to e-crude units, and e-crude upgraded in existing refineries. In case of the **full integrated e-fuel plant** (right box in Figure 79) the hydrogen production, synthesis to e-crude, and final upgrading is all fully integrated into an existing refinery.

Existing **refineries** can play a facilitating role in the energy transition to e-fuels. These have been bulk consumers of hydrogen for decades and offer valuable knowledge in many aspects of hydrogen infrastructure, storage and end-use. Switching natural gas-based hydrogen production at refineries to hydrogen from on-site electrolysis and/or supply via pipeline allows for an accelerated cost reduction path of electrolyser capex and/or deployment of H<sub>2</sub> pipelines. The additional costs for deploying several hundreds of megawatts of electrolyser capacity per average refinery site are amortised over a product output of many gigawatts resulting in marginal additional final product costs. Furthermore, the existing refining assets can, in part, be used to upgrade Fischer-Tropsch syncrude, allowing an efficient use of existing investments. Since refineries are complex, have diverse configurations, and differ in terms of supply infrastructure and products mix, refinery-specific feasibility studies are recommended to assess opportunities in the field.

For the stand-alone plant and the distributed e-fuel plant direct air capture (DAC) of CO<sub>2</sub> is assumed as CO<sub>2</sub> source. A concentrated CO<sub>2</sub> source (proxy: SMR) is used for the fully integrated plant into an existing refinery for 2020 and 2030. For 2050 DAC is also assumed for the e-fuel plant integrated into an existing refinery. The rationale is that if an e-fuel plant is integrated into an existing refinery, the most logical CO<sub>2</sub> source to use is a concentrated source from SMR on-site a refinery for example as it is already available in an existing refinery. The use of a concentrated CO<sub>2</sub> source is less energy demanding and cheaper than using more diluted sources, such as DAC. Concentrated CO<sub>2</sub> is considered as waste. It has to be noted that the

use of fossil CO<sub>2</sub> does not result in lower fossil CO<sub>2</sub> emissions in the refinery. Refinery fossil CO<sub>2</sub> emissions are not avoided and as a result the existing refinery still would have to pay for it. Otherwise, the e-fuel plant has to pay for it and these fossil CO<sub>2</sub> has to be taken into account in the e-fuel LCA part.

Looking at the concept of distributed e-fuel plants, there is a problem with e-crude stability (to be stabilised after synthesis by removing the light ends), corrosivity (due to the oxygenates) and viscosity for pathways with long-distance e-crude transport. Therefore, still some further processing via stabilization and mild hydrocracker is required at the e-crude plant site.

Refineries are typically highly complex processing plants that have been optimised over years or even decades to efficiently convert specific sorts of crude-oil into a portfolio of products. Thus, no refinery is like another. The level of analysis in this study does not allow for detailed analysis of different refinery configurations and their specific adaptability to use e-crude up to 100% of refinery oil input.

There are significant differences between Fischer-Tropsch (FT) syncrude and crude oil that in principle allows syncrude refining to be more efficient than crude oil refining.




FT syncrude consists of multiple product phases, has a high oxygen content, a high alkene content, high concentration of linear products, and little cyclic components. There are no sulphur and nitrogen compounds but some metal carboxylates. Therefore, additional processes for feedstock treatment to eliminate compound classes that are not compatible with the technology in existing refineries (e. g. hydrocrackers). As a consequence, modifications of the hydrocracker and fractionation technology could be required to deal with FT syncrude properties [de Klerk 2011].

A detailed analysis of the impact on existing refineries is outside the scope of this study.

Table 29 shows the case definitions and the assumptions behind. In case of stand-alone plants (base case) all components have to be built new with the associated CAPEX. In case of the distributed e-crude plants the e-crude plant requires mild hydrocracking including the associated CAPEX. Transport of e-crude to the existing refinery via pipeline has been assumed. For the process at the existing refinery site such as hydrocracking, fractionation, and utilities no CAPEX is required because these processes are already available at the existing refinery. Only maintenance and repair are taken into account.

In case of a fully integrated e-fuel plant into an existing refinery no mild hydrocracking is required. For hydrocracking, fractionation, utilities, and logistics no CAPEX is required because these processes are already available at the existing refinery. Only maintenance and repair are taken into account.

**Table 29:** Distributed versus standalone/integrated plants: Case definitions

	Standalone plant	Distributed e-crude plant (if far from refinery, example: MENA)	Fully integrated plant (into an existing refinery)
<b>Concept</b>	E-fuels plants as standalone/ independent entities, ensuring the whole process from hydrogen and CO <sub>2</sub> capture (if needed) up to quality upgrading. These are all-new plants that produce fuels ready to be commercialised.	E-fuels plants that depend on an existing oil refinery, with some form of synergy implemented (by-product utilization, sharing of upgrading units, utilities systems). Products from these plants are not ready to be commercialized (e-crude, off-spec, etc.). The plants could be physically next to or far from the refineries.	
<b>Plant size</b>	There is no difference between the plant sizes any of the configurations (contrary to a biorefinery)		
<b>Representation</b>			
<b>Processes involved</b>	DAC Electrolysis Synthesis Hydrocracking Fractionation/(Upgrading) Utilities & logistics	DAC Electrolysis Synthesis Mild hydrocracking ===== E-crude transport ===== Hydrocracking Fractionation/(Upgrading) Utilities & logistics	2020-2030: Concentrated source (SMR as proxy) 2050: DAC Electrolysis Synthesis ===== Hydrocracking Fractionation/(Upgrading) Utilities & logistics
<b>Legend</b> new existing (at the refinery)			

The difference between stand-alone and fully integrated plant into a refinery is that there are no capital costs for hydrocracking, fractionation (upgrading), utilities, and logistics in case of the fully integrated plant. Only OPEX is taken into account for these processes.

In 2050, the CAPEX for the stand-alone FT plant without H<sub>2</sub> and CO<sub>2</sub> supply amounts to about 1800-2000 million € including indirect cost. The CAPEX for the distributed FT e-crude plant without H<sub>2</sub> and CO<sub>2</sub> supply amounts to about 1400-1500 million €. The CAPEX of the FT plant fully integrated into an existing refinery without H<sub>2</sub> and CO<sub>2</sub> supply amounts to about 1000-1100 million € (see ECONOMIC ANNEX, chapter 9.4.17).

In 2050, the OPEX of the stand-alone FT plant amounts to about 119-125 million €/yr. In case of the distributed FT e-crude plant the OPEX including the OPEX share of the existing refinery for further processing amounts to about 146-147 million €/yr (slightly higher than for the stand-alone FT plant due to additional mild hydrocracker at the e-crude plant). The OPEX of the fully integrated FT plant including the OPEX share of the existing refinery amounts to about 134-135 million €.

Table 30 and Figure 80 show the results for the sensitivity for stand-alone e-fuel plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2020.

**Table 30:** Stand-alone e-fuel plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2020

No.	Pathway code	Stand-alone PtL plant (CO <sub>2</sub> from DAC)	Distributed e-crude plant (CO <sub>2</sub> from DAC)	Fully integrated plant into existing refinery (CO <sub>2</sub> from SMR)
€/GJ of final fuel				
17	FTKEU-C	90.8	90.1	77.3
18	FTDEU-C	92.0	91.4	78.5
26	FTKEU-S	84.9	-	-
27	FTDEU-S	86.1	-	-
36	FTKME	76.1	75.5	65.0
37	FTDME	77.3	76.7	66.2
38	FTKMEe-crd	-	75.5	-
€/l of diesel equivalent				
17	FTKEU-C	3.26	3.23	2.77
18	FTDEU-C	3.30	3.28	2.82
26	FTKEU-S	3.05	-	-
27	FTDEU-S	3.09	-	-
36	FTKME	2.73	2.71	2.33
37	FTDME	2.77	2.75	2.38
38	FTKMEe-crd	-	2.71	-

**Figure 80:** Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2020

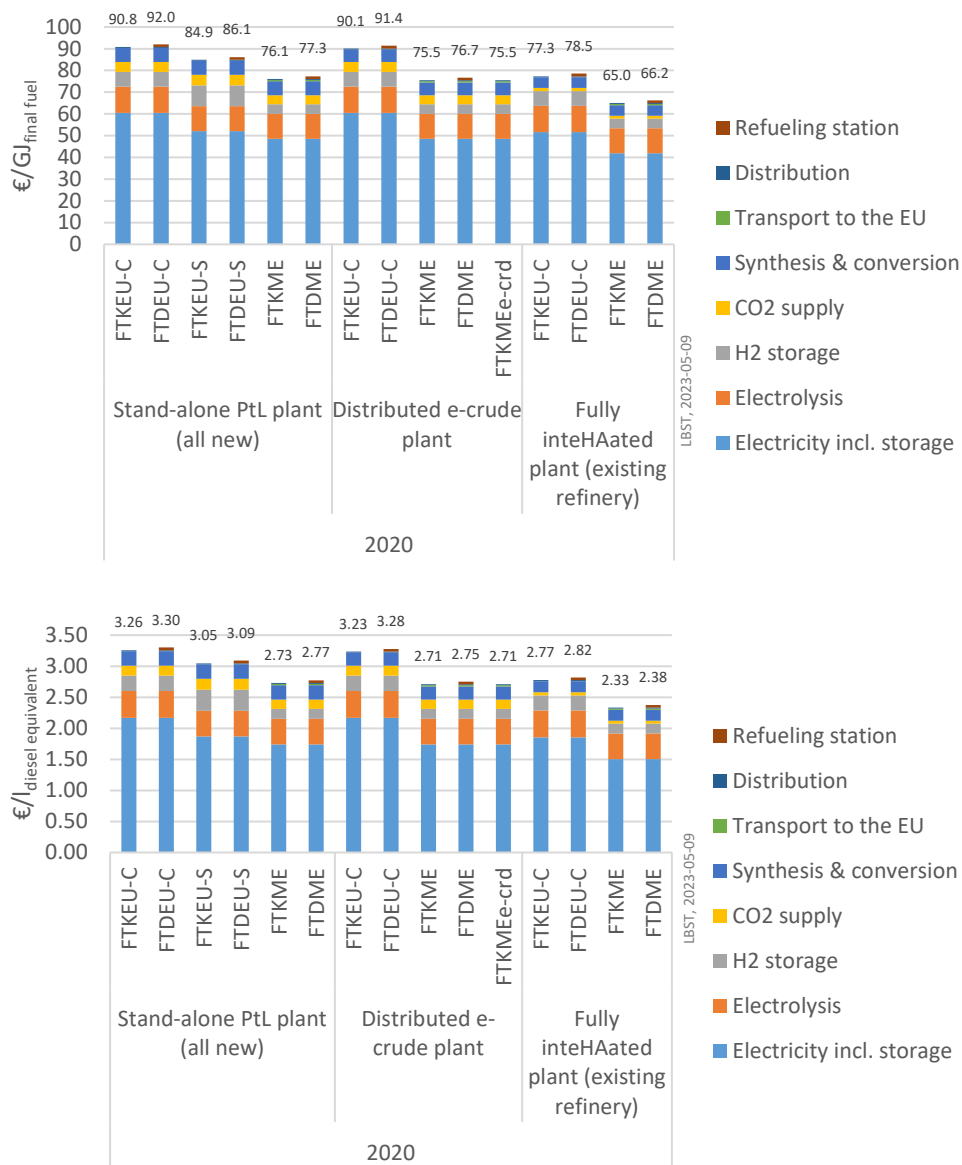




Table 31 and Figure 81 show the results for the sensitivity for stand-alone e-fuel plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2030.

**Table 31:** Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2030

No.	Pathway code	Stand-alone PtL plant (CO <sub>2</sub> from DAC)	Distributed e-crude plant (CO <sub>2</sub> from DAC)	Fully integrated plant into existing refinery (CO <sub>2</sub> from SMR)
€/GJ of final fuel				
17	FTKEU-C	78.4	77.8	65.9
18	FTDEU-C	79.6	79.0	67.1
26	FTKEU-S	73.5	-	-
27	FTDEU-S	74.7	-	-
36	FTKME	66.7	66.1	56.1
37	FTDME	67.9	67.3	57.3
38	FTKMEe-crd	-	66.1	-
€/l of diesel equivalent				
17	FTKEU-C	2.81	2.79	2.36
18	FTDEU-C	2.86	2.84	2.41
26	FTKEU-S	2.64	-	-
27	FTDEU-S	2.68	-	-
36	FTKME	2.39	2.37	2.01
37	FTDME	2.44	2.41	2.06
38	FTKMEe-crd	-	2.37	-

**Figure 81:** Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2030

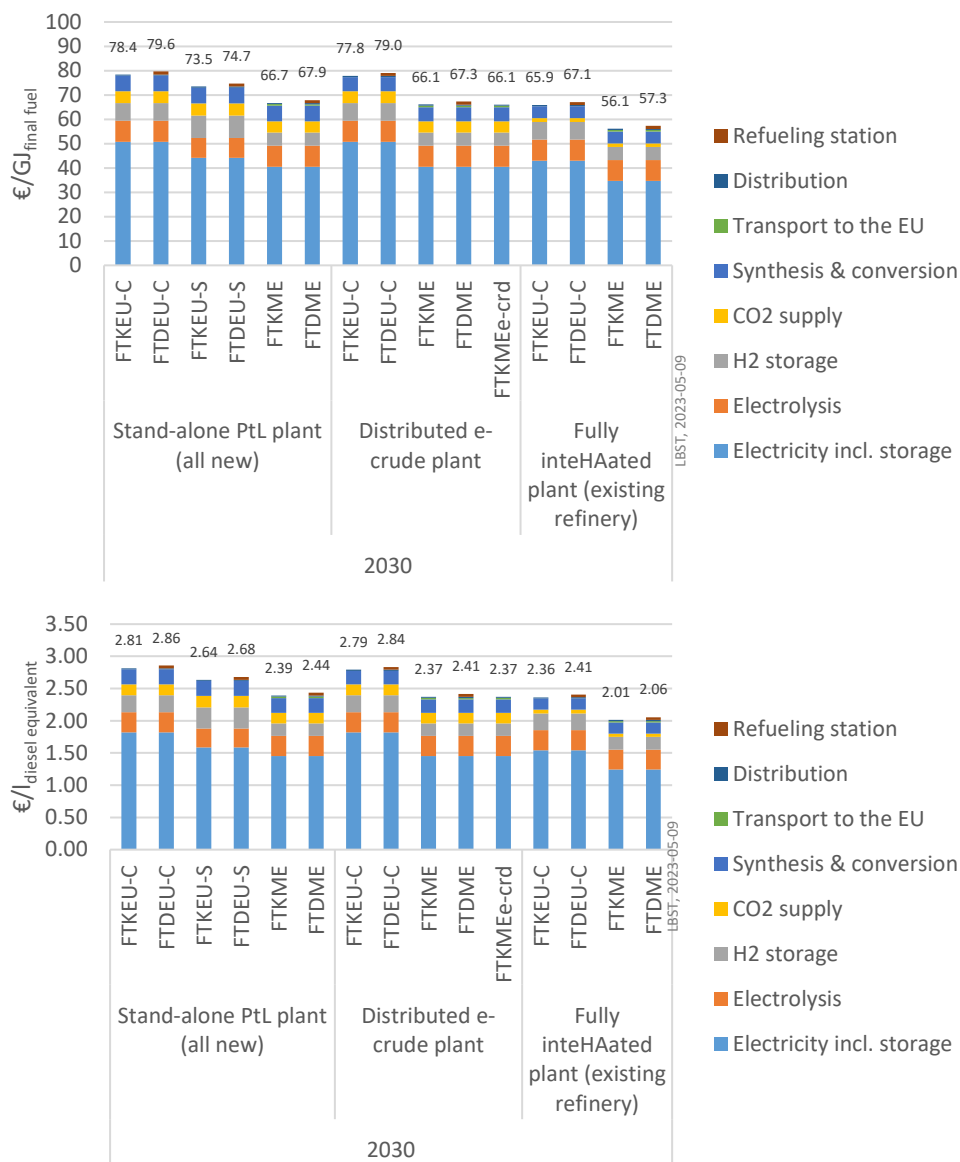
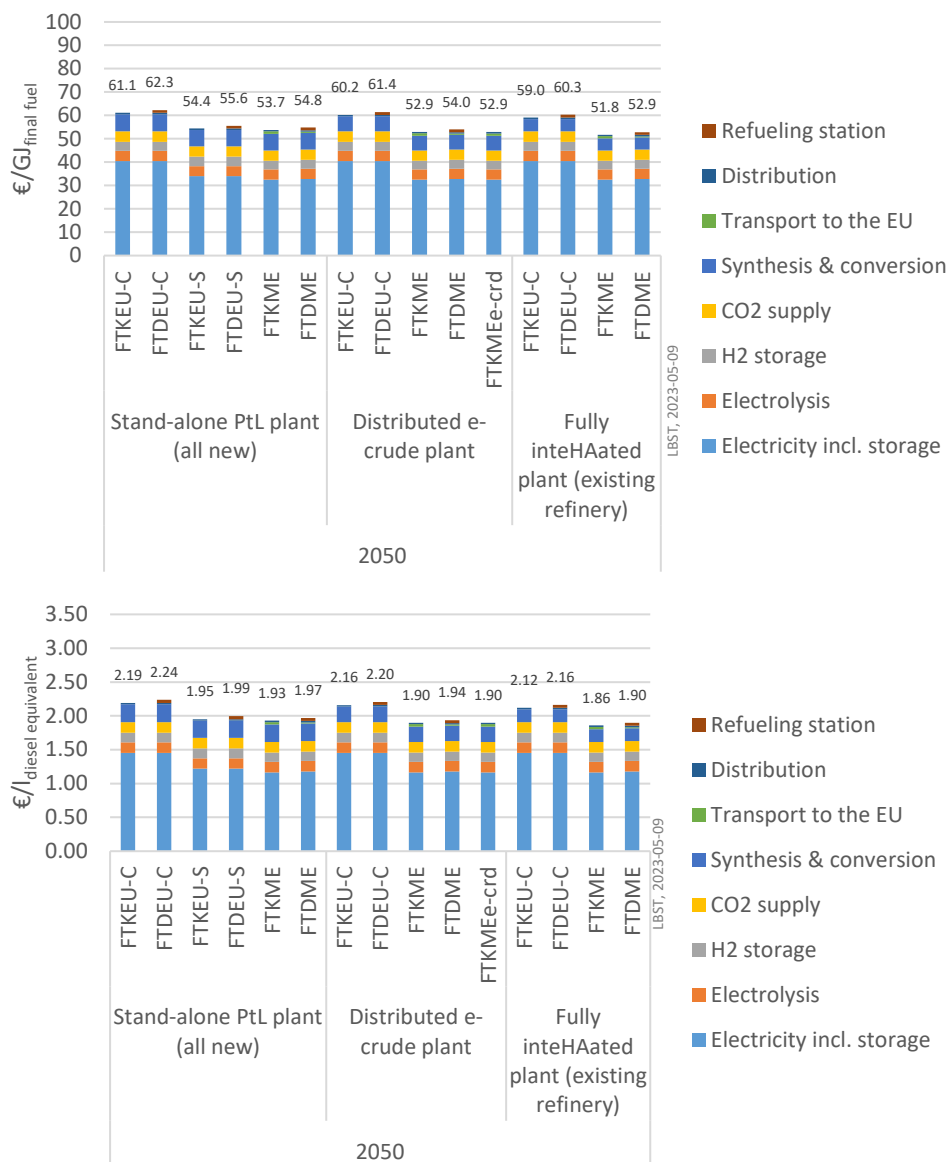


Table 32 and Figure 82 show the results for the sensitivity for stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2050.

**Table 32:** Stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2050

No.	Pathway code	Stand-alone PtL plant (CO <sub>2</sub> from DAC)	Distributed e-crude plant (CO <sub>2</sub> from DAC)	Fully integrated plant into existing refinery (CO <sub>2</sub> from DAC)
€/GJ of final fuel				
17	FTKEU-C	61.1	60.2	59.0
18	FTDEU-C	62.3	61.4	60.3
26	FTKEU-S	54.4	-	-
27	FTDEU-S	55.6	-	-
36	FTKME	53.7	52.9	51.8
37	FTDME	54.8	54.0	52.9
38	FTKMEe-crd	-	52.9	-
€/l of diesel equivalent				
17	FTKEU-C	2.19	2.16	2.12
18	FTDEU-C	2.24	2.20	2.16
26	FTKEU-S	1.95	-	-
27	FTDEU-S	1.99	-	-
36	FTKME	1.93	1.90	1.86
37	FTDME	1.97	1.94	1.90
38	FTKMEe-crd	-	1.90	-

**Figure 82:** Sensitivity stand-alone PtL plant versus distributed e-crude plant versus fully integrated plant into existing refinery for 2050



Concentrated CO<sub>2</sub> source for fully integrated plants existing refinery has the highest contribution to cost reduction compared to stand-alone and distributed e-crude plants. Lower CAPEX due to use of existing refineries has a low contribution to cost reduction under the assumption given. The reason for the cost reduction is the combination of both the lower CAPEX and lower cost of CO<sub>2</sub> supply. In the long-term (2050) diluted CO<sub>2</sub> source also is used for fully integrated e-fuel plants. Then the difference between the stand-alone e-fuel plant and the fully integrated e-fuel plant into an existing refinery is low.

In the short to medium term there may be advantages in utilizing existing refineries to minimize capital expenditure. There is a potential advantage of co-processing in the early e-fuel development. The lower the CAPEX, the higher the probability for a company to invest, aiming to have a return of invest in a shorter time. In the long-term (2050), when diluted CO<sub>2</sub> sources are also used for fully integrated e-fuel plants, then the difference between the stand-alone e-fuel plant and the e-fuel plant fully integrated into an existing refinery is low.

#### KEY MESSAGES - STAND-ALONE VS. DISTRIBUTED VS. INTEGRATED E-FUEL PLANTS

The analysis of a **stand-alone e-fuel plant** (all-new integrated plants for hydrogen production, synthesis to e-crude, and final upgrading) versus a **distributed e-fuel plants** (new hydrogen production and synthesis to e-crude units, and e-crude upgraded in existing refineries) versus a **full integrated e-fuel plant** (the hydrogen production, synthesis to e-crude, and final upgrading is all fully integrated into an existing refinery) have been conducted.

The difference between stand-alone and fully integrated plant into a refinery is that there are no capital costs for hydrocracking, fractionation (upgrading), utilities, and logistics in case of the fully integrated plant. Only OPEX is taken into account for these processes. However, these capital cost elements in the total e-fuel production costs have a low contribution (~3%). Concentrated CO<sub>2</sub> source for plants fully integrated into an existing refinery (instead of CO<sub>2</sub> from direct air capture (DAC)) has the highest contribution to cost reduction compared to stand-alone and distributed e-crude plants.

In the short to medium term there may be advantages in utilizing existing refineries to minimize capital expenditure. There is a potential advantage of co-processing in the early e-fuel development. The lower the CAPEX, the higher the probability for a company to invest, aiming to have a return of invest in a shorter time. In the long-term (2050), when diluted CO<sub>2</sub> sources are also used for fully integrated e-fuel plants, then the difference between the stand-alone e-fuel plant and the e-fuel plant fully integrated into an existing refinery is low.

### **3. COMPARISON OF RENEWABLE E-FUEL PRODUCTION COSTS VERSUS FUELS PRODUCED FROM NUCLEAR ELECTRICITY AND BIOFUELS**

#### **3.1. RESULTS FROM NUCLEAR ELECTRICITY VERSUS RENEWABLE E-FUEL PRODUCTION COSTS**

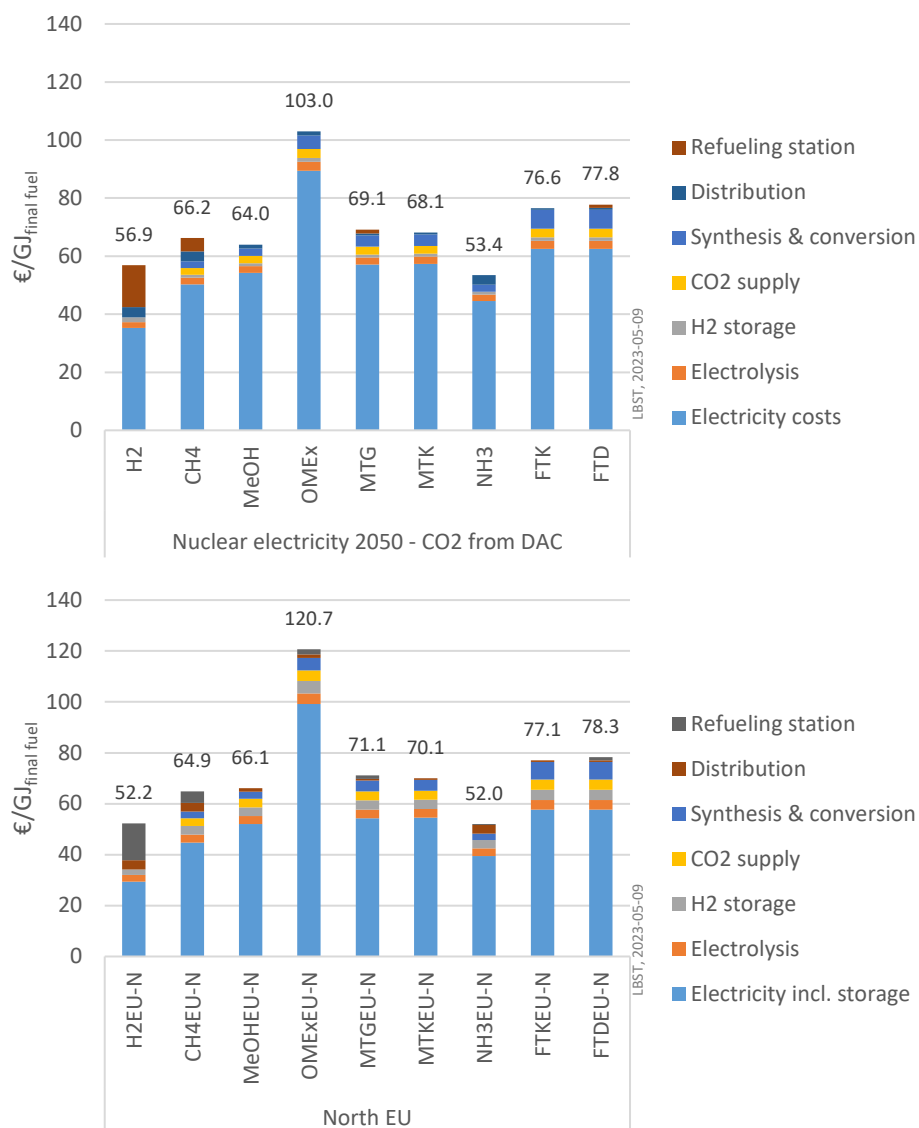
The costs of nuclear electricity have been calculated based on a new nuclear power station based on the European Pressurized Water Reactor (EPR). Based on the assumptions taken, the costs for nuclear electricity amount to about 94 € per MWh of electricity for all time horizons (see chapter 9.4.19 in the annex) taking into account a new nuclear plant. The equivalent full load period of the nuclear power plant and as a result the electrolysis plant connected with the nuclear power plant is assumed to be about 8000 h/yr. The charts show that nuclear electricity (based on a new nuclear plant) results in similar production costs than Norwegian offshore wind (based on new installations) in 2050.

In section 2.1.3., it was shown that e-fuel production in Norway (offshore wind) results in higher cost than in other regions (Germany, Spain, MENA) (mix of PV/wind onshore). Therefore, it can be concluded that e-fuels produced from nuclear electricity, based on a new nuclear plant, results in higher production costs than with renewable electricity for all the regions by 2050.

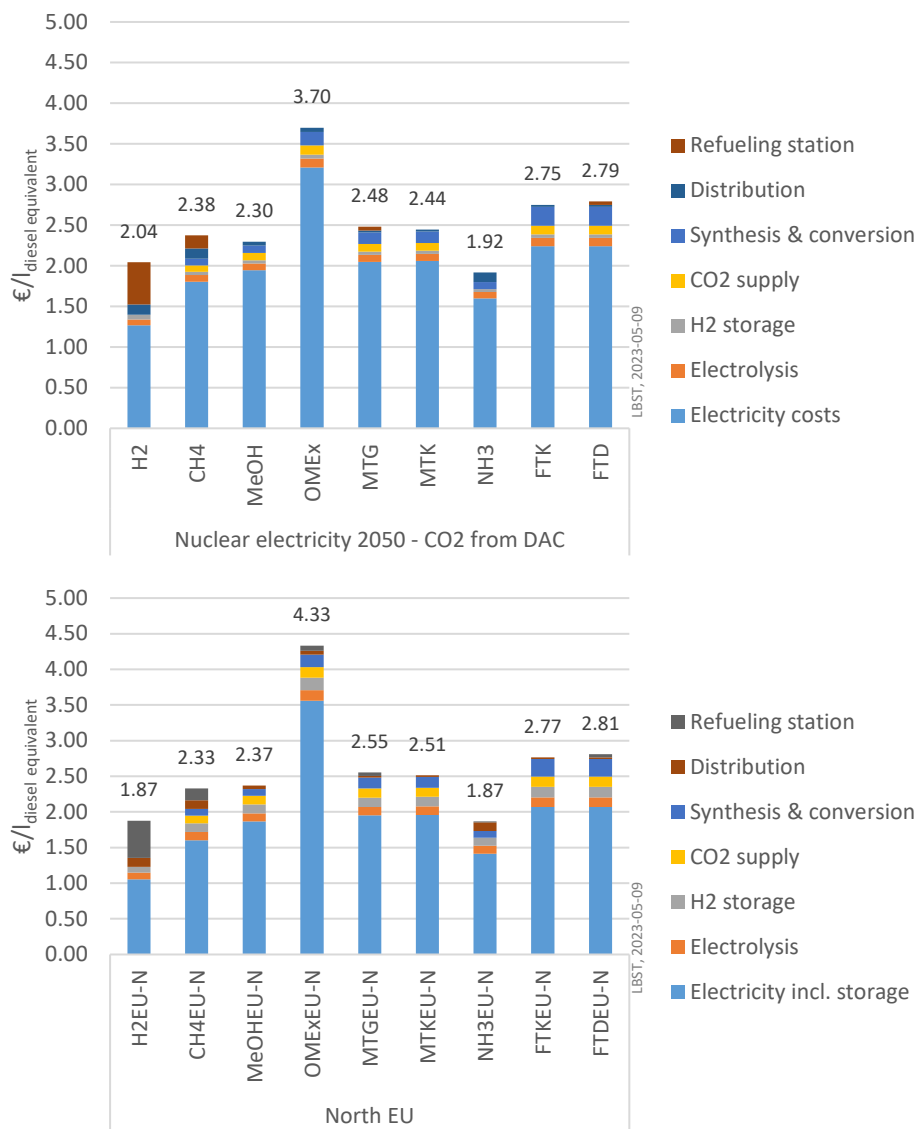
However, electricity produced from nuclear long-term operation by lifetime extension, instead of from a new nuclear plant, could be as low as 25 to 34 € per MWh, subject to CAPEX and full load hour assumptions taken in [IEA 2020b]. Further details are given in ECONOMIC ANNEX chapter 9.4.19.

Figure 83 and Figure 84 show the fuel costs for e-fuels from new nuclear plant electricity compared to the costs of e-fuels from renewable electricity from new offshore wind power in North Europe in 2050.

**Figure 83:** Costs of e-fuels from new nuclear plants electricity compared to e-fuels from new renewable electricity installations in 2050 - per GJ of final fuel



**Figure 84:** Costs of e-fuels from new nuclear plants electricity compared to e-fuels from new renewable electricity installations in 2050 - per l of diesel equivalent



It has to be noted that abatement costs refer to fuel supply (including embedded carbon), i.e. without use efficiencies. Fuel cell electric vehicles (FCEV) have a higher efficiency than vehicles with internal combustion engine (ICE), leading to lower fuel costs per km. However, the powertrain evaluation (TTW) is out of the scope of this project.

### 3.2. PRODUCTION COSTS AND ABATEMENT COSTS OF E-FUELS VERSUS BIOFUELS

This section is intended to provide a high-level cost comparison between e-fuels and biofuels based on acknowledged literature sources [IEA 2020] and [JEC 2020]. It is neither designed to assess their cost differentials with a converging set of assumptions nor differentials between costs and prices.



The greenhouse gas (GHG) production costs and abatement costs of selected e-fuels have been compared with those of selected biofuels.

For 2020, e-fuels are compared to biofuels produced from waste-based feedstocks with a well-established technology such as HEFA and 1<sup>st</sup> of a kind plant (FOAK) for advanced biofuels such as 2<sup>nd</sup> generation bioethanol. For 2050, biofuels from feedstocks with highest long-term potential and nth of a kind plant (NOAK) are used as the comparator.

Table 33 shows the costs of biofuels assumed in this study and which are based on [IEA 2020] representing global biofuel costs where e.g. climatic conditions allow for feedstock cultivation. For 2020, the data labelled as ‘current costs’ has been used. For 2050, the lower and upper values have been derived from the medium-term data for ‘Lower cost of capital’ indicated in [IEA 2020] because the bandwidth depicted for medium-term costs are already wide, covering a significant additional learning at the lower end. The medium-term costs in [IEA 2020] are based on 8% discount rate and a lifetime of 20 years which fits well with economic assumptions taken in this study for e-fuels.

**Table 33:** Costs of biofuels

E-fuel route	Biofuel comparators	2020	2050	Reference
e-methane	Bio-methane from anaerobic digestion	11.1-33.3 €/GJ 0.40-1.19 €/Nm <sup>3</sup> 9.4-22.0 CO <sub>2eq</sub> /MJ (waste)	9.4-31.4 €/GJ 0.34-1.12 €/Nm <sup>3</sup> 9.4-22.0 CO <sub>2eq</sub> /MJ (waste)	IEA 2020 JEC WTT v5
e-methanol	Biomass gasification + synthesis	17.2-31.1 €/GJ 343-620 €/t 18.6 g CO <sub>2eq</sub> /MJ (farmed wood)	11.7-26.1 €/GJ 232-520 €/t 18.6 g CO <sub>2eq</sub> /MJ (farmed wood)	IEA 2020 JEC WTT v5
e-gasoline	2 <sup>nd</sup> generation bio-ethanol*	28.6-43.9 €/GJ 0.61-0.93 €/l <sub>ethanol</sub> 17.8-22.8 g CO <sub>2eq</sub> /MJ (wheat straw, waste wood)	19.7-31.1 €/GJ 0.42-0.66€/l <sub>ethanol</sub> 17.8-22.8 g CO <sub>2eq</sub> /MJ (wheat straw, waste wood)	IEA 2020 JEC WTT v5
e-kerosene	HEFA/HVO (2020) Biomass gasification + synthesis (2050)	14.2-25.3 €/GJ 625-1115 €/t 11.1-16.1 g CO <sub>2eq</sub> /MJ (UCO)	15.6-31.1 €/GJ 686-1372 €/t 17.6 g CO <sub>2eq</sub> /MJ (farmed wood)	IEA 2020 JEC WTT v5

\*Blend wall applies, i.e. no full drop-in capability with gasoline fuel

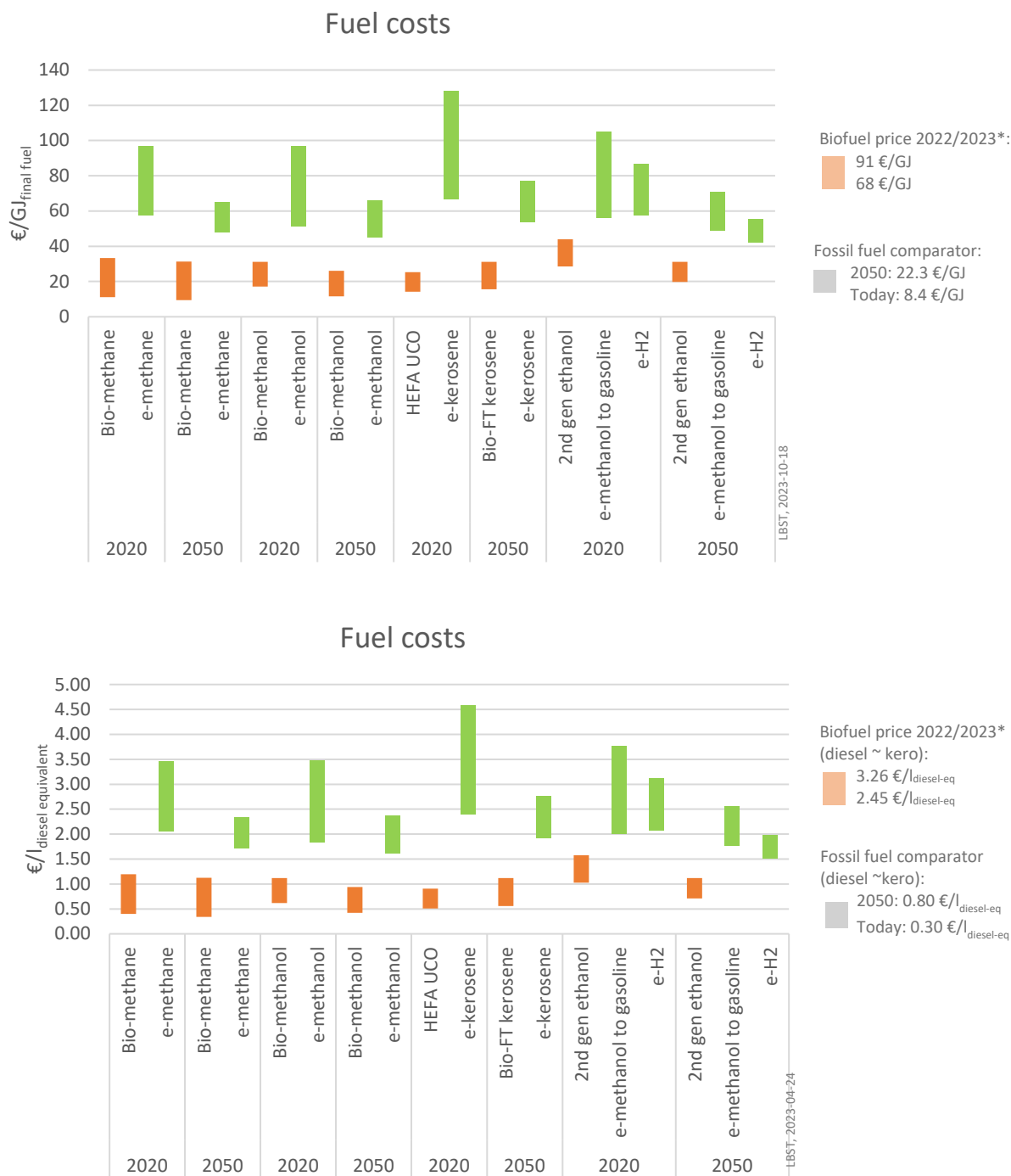
For the calculation of the greenhouse gas abatement costs, a fossil fuel comparator of 94 g/MJ as indicated in the actual Renewable Energy Directive of the EU [RED 2018] has been applied. The costs of fossil fuel are assumed to be 8.4 €/GJ (diesel as proxy, see Table 17 in chapter 2.1.2).

Figure 85 shows the costs of selected e-fuels (minimum and maximum costs of each energy product across regions and CO<sub>2</sub> sources within one timeframe) compared with selected biofuels (minimum and maximum costs as per Table 33) leading to the greenhouse gas production costs and abatement costs shown in Figure 86. Note

that current biofuel *prices*, e.g. for SAF-compatible hydroprocessed esters and fatty acids (HEFA) with some 3000-4000 US\$/t between April 2022 and April 2023 [Argus 2023], are traded at significantly higher prices than the biofuel costs indicated in Figure 85 because of renewable fuel quotas, constrained supply base (wastes and residues), and ramp-up pace.

For biofuels involving gasification and synthesis (2<sup>nd</sup> generation biofuels) recently announced project costs seem to be much higher than the CAPEX assumed in the study referenced in Figure 85 and Figure 86 for biofuel production. E.g. SunGas Renewables develops a green methanol facility in Louisiana with a capacity of 400,000 t of methanol per year (45.7 t of methanol/h or 253 MW of ethanol related to the LHV) and an investment of 2 billion € [Biomass Magazine 2023] (~7900 €/kW of methanol).

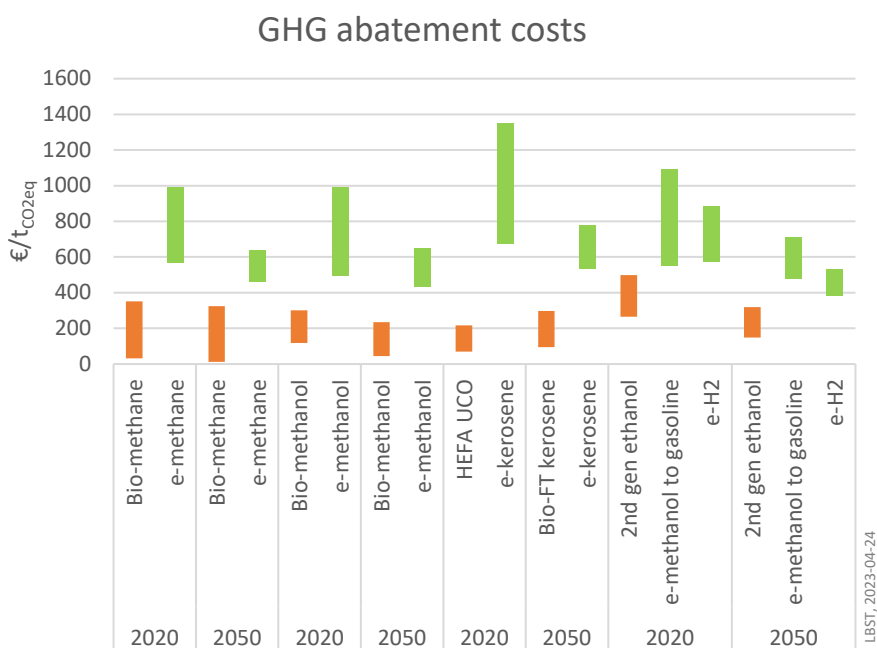
**Figure 85:** Cost bandwidths of selected e-fuels from this study (EU domestic and imports) compared with selected biofuels (global for suitable areas) derived from literature [IEA 2020] - per GJ final fuel and per litre diesel-equivalent



\* [Argus 2023]

Based on the assumptions taken, the ranges of fuel production costs for biofuels reported in [IEA 2020] are lower than those for e-fuels calculated in this study.

**Figure 86:** GHG abatement costs for selected biofuels (derived from IEA) and e-fuels (this study)



Based on the assumptions taken, the GHG abatement costs for biofuels are lower than those for e-fuels. The GHG abatement costs for e-fuels are decreasing from about 490-1350 in 2020 to some 380-780 €/t of avoided CO<sub>2</sub>-equivalent in 2050.

The decrease of the upper limit over time is higher than that of the lower limit of GHG abatement costs because the upper limit represents e-fuels from offshore wind farms where the cost decrease is higher than for onshore wind. Offshore wind power is at an earlier stage of development than onshore wind power. The lower limit represents e-fuel from MENA where the electricity costs are already rather low today.

The costs of e-fuels using renewable electricity are compared with fuels derived from natural gas with CCS is also analysed in Section 8.6.)

## KEY MESSAGES - COMPARISON OF E-FUELS PRODUCED FROM NUCLEAR ELECTRICITY AND BIOFUELS

1. E-fuels from nuclear electricity: The costs of nuclear electricity have been calculated based on a new nuclear power station based on the European Pressurized Water Reactor (EPR). Based on the assumptions taken, the costs for nuclear electricity amount to about 94 € per MWh of electricity for all time horizons (see chapter 9.4.19 in the annex) taking into account a new nuclear plant. The charts show that e-fuels produced from nuclear electricity (based on a new nuclear plant) results in higher production costs than from Norwegian offshore wind (based on new installations) in 2050.

In section 2.1.3., it was shown that e-fuel production in Norway (offshore wind) results in higher costs than in other regions (Germany, Spain, MENA) (mix of PV/wind onshore).

Therefore, it can be concluded that e-fuels produced from nuclear electricity, based on a new nuclear plant, results in higher production costs than with renewable electricity for all the regions by 2050.

2. Biofuels: The production costs and GHG abatement costs for biofuels are lower than those for e-fuels, based on the assumptions taken. In 2050 the costs of e-fuels supply ranges between 1.5 € per l of diesel equivalent for e-hydrogen in the best case and 2.8 € per l of diesel equivalent for FT kerosene in the worst case.

In 2050 the costs of biofuels range between 0.3 € per l of diesel equivalent (lower limit for bio-methane) and 1.1 € per l of diesel equivalent (upper limit for bio-methane, Bio-FT kerosene, and 2<sup>nd</sup> generation ethanol). The GHG abatement costs for e-fuels are expected to decrease from about 490-1350 in 2020 to some 390-780 €/t of avoided CO<sub>2</sub>-equivalent in 2050. The GHG abatement costs for biofuels are expected to decrease from 30-500 €/t of avoided CO<sub>2</sub> equivalent in 2020 to some 10-320 €/t of avoided CO<sub>2</sub> equivalent in 2050. The higher cost of abatement for e-fuels is attributable primarily to the cost of green hydrogen production as compared with biomass gasification. Taking FT liquid production, for example, the FT process step is broadly the same for the e-fuel and biofuel cases while the cost of producing green hydrogen is high owing to high input electricity costs and, to a lesser extent, high capex (electrolysis). By contrast, the capex of gasification plant is high while the input feedstock costs are relatively low. Over time electrolyser capex is likely to fall (perhaps more quickly than gasification plant capex), but while the cost of renewable electricity will also fall it is not expected to match the lower costs of biofuel feedstock.

Therefore, it can be concluded that biofuels result in lower production costs than e-fuels by 2030 and 2050. However, biofuels availability and supply chain, while respecting sustainability criteria and land/water requirements, was not analysed in this study (out of the scope).

## 4. INTERMITTENCY & SEASONALITY OF RENEWABLE ENERGY SUPPLY

The challenge in modelling intermittency of renewable power supplies is to determine suitable representatives given supply curves vary across a given geography (local climate conditions) as well as across time (inter-annual variations). Hence, in these kinds of analyses there is a trade-off between precision (single locality in a single year) and representativeness (well within the range of a region and across time).

This chapter explores the degree of variability in renewable power supplies with focus on wind and solar. The results of this analysis provide inputs for the broad assumptions used in chapters 1 and 2 including the mix of PV and wind, the amount of renewable curtailment, and the size of storage elements such as electricity storage based on battery systems, hydrogen storage, and CO<sub>2</sub> storage necessary for e-fuels production along with the cost impacts of production flexibility.

In this chapter, the production of final fuel is considered. In contrast to chapters 1 and 2, transport and distribution of the final fuel is not included. For example, in the case of hydrogen that is transported from KSA to Rotterdam, H<sub>2</sub> liquefaction is required for the transport of LH<sub>2</sub> via a LH<sub>2</sub> carrier, leading to additional CAPEX, OPEX, and electricity consumption. In the intermittency modelling the H<sub>2</sub> liquefaction is not considered for the optimization. Fuel demand fluctuations are also not considered as this is not specific to the new fuel pathways analyzed in this study. The studied geographies are given and thus not part of any global optimization.

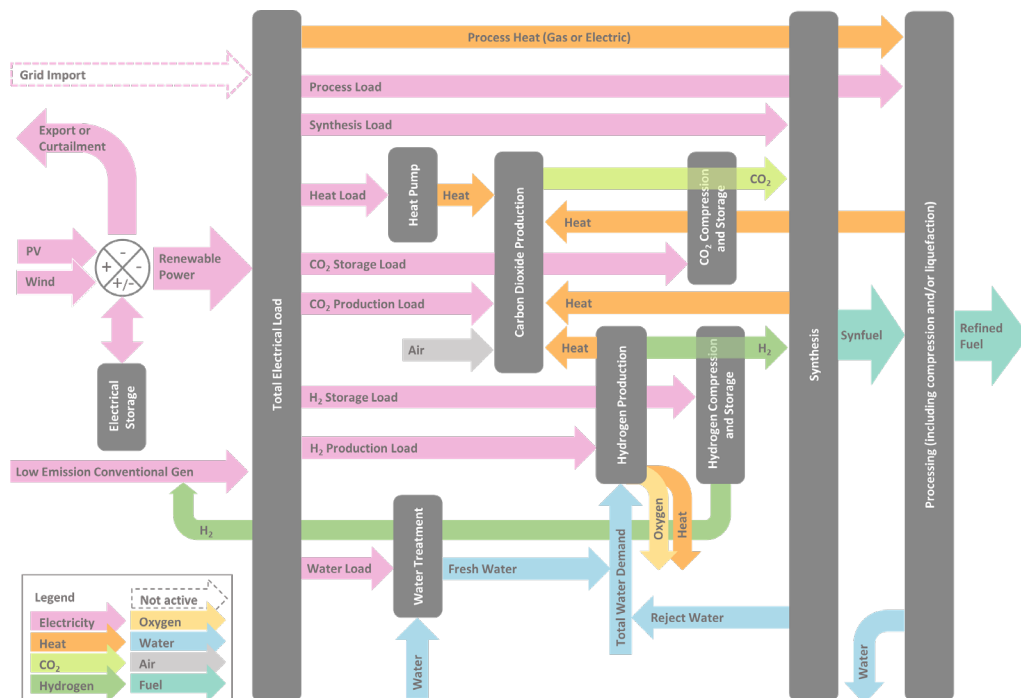
### 4.1. INTERMITTENCY MODELLING APPROACH

The impact of intermittency on the operational performance of an e-fuel plant and the energy storage requirement is determined through the application of a custom-built mixed integer linear program (see chapter 10 in the annex for a description of the model).

The model determines a least cost solution for a selected fuel production pathway considering potential options for electrical supply, hydrogen supply and carbon dioxide (or nitrogen for NH<sub>3</sub>) supply under a set of given constraints.

In this study, the system configuration is equivalent to a direct connection system with local storage to buffer intermittent supply. Renewable electricity is produced by PV and wind which can be stored in batteries or curtailed as required. Hydrogen (H<sub>2</sub>) is produced via electrolysis and can be stored locally in pressure vessels at a pressure of e. g. 10 MPa. Carbon dioxide (CO<sub>2</sub>) production assumes low temperature direct air capture (DAC) with local storage as liquefied CO<sub>2</sub> at temperatures below -25°C. The RED II delegated acts require either renewable CO<sub>2</sub> sources or DAC after 2041. Since the potential for concentrated CO<sub>2</sub> from renewable sources such as biomass power plants are limited, DAC is selected as CO<sub>2</sub> source for 2050.

**Figure 87:** General schematic representation of the custom system model



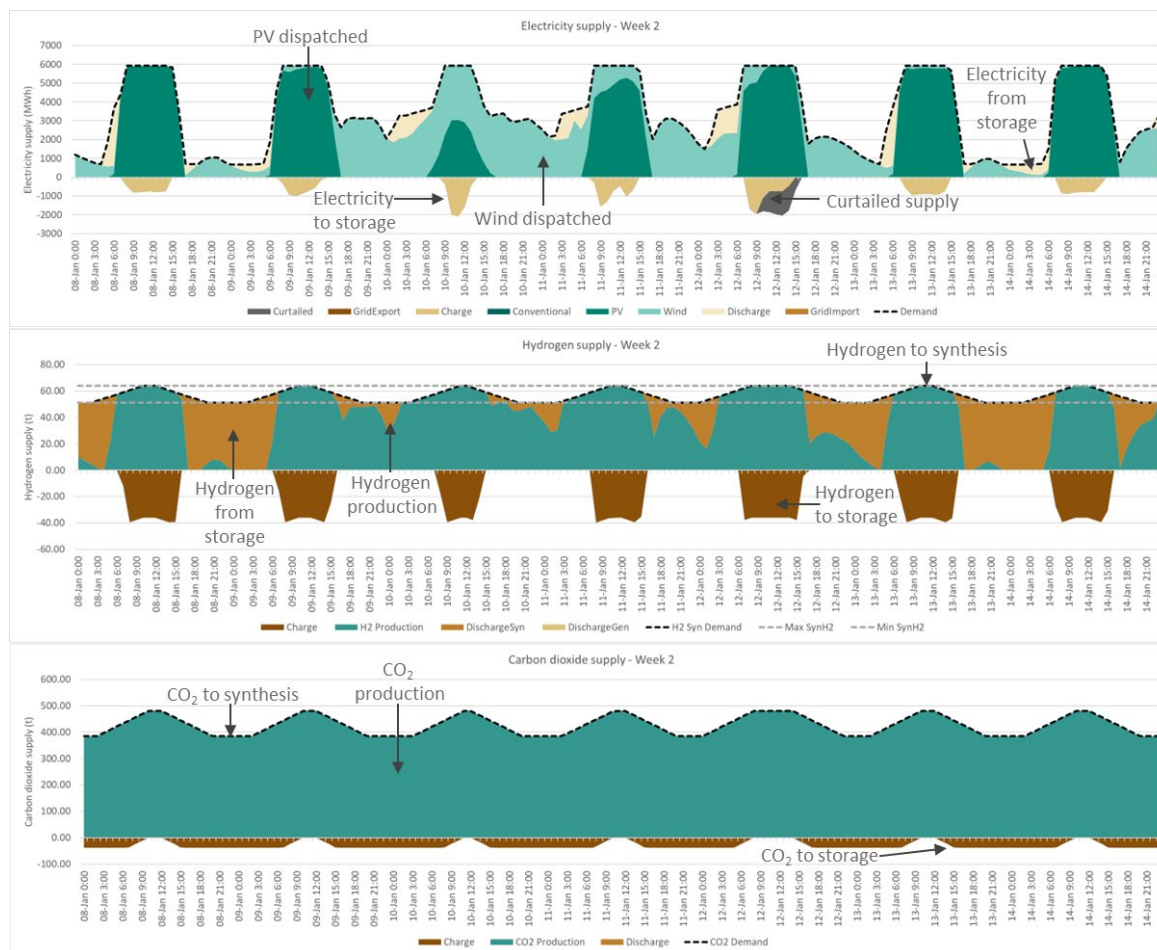
Key constraints on the model include the total amount of fuel produced per year and production rates expressed as a minimum operation point which sets the lower bound of operation at any time during the year and an hourly rate of change that sets how quickly the plant can move between the lower and upper bounds of operation. Other constraints include the rates of exchange in and out of the storage media. The size of each part of the system is dynamically determined to produce the lowest fuel production cost while meeting all constraints. Every part of the e-fuel plant is optimised including electricity storage system, electrolysis plant, H<sub>2</sub> storage, CO<sub>2</sub> storage, and synthesis plant.

These effects can be visualized in Figure 88, which illustrates the hourly operation of electrical generation, H<sub>2</sub> production and CO<sub>2</sub> production components over an illustrative one-week period. This example assumes limited flexibility on production with the lower bound set to 80% of the plant's fuel production capacity. In addition, the hourly rate of change in production is limited to 2.5% of the maximum production size. These limits are shown by the grey dashed lines representing the constraints placed on hydrogen supply to the synthesis plant.

In this study, 100% renewable power systems are considered. No import of electricity and no export of electricity from the grid is assumed (grid import = 0). No electricity from conventional generation such as coal, oil, natural gas power stations is used for the e-fuel plant.



**Figure 88:** Example of hourly electrical, hydrogen and carbon dioxide production



In this illustration, both PV and wind are utilized along with storage of electricity, H<sub>2</sub> and CO<sub>2</sub>. The figure shows that some of the renewable production is curtailed (grayed area in the Electricity supply graph) as it is cheaper not to produce this electricity (and as a result neither stored nor used for water electrolysis) than it is to build additional electrical storage. This is a part of least cost optimisation. The degree of curtailment is contingent on the profiles of renewable production, the costs of each element in the system and the dynamics of the synthesis production (i.e. minimal levels and hourly rates of change).

The figure also shows that the three different storage media (electrical, H<sub>2</sub> and CO<sub>2</sub>) act differently over time reflecting dynamic demand for each product, different operational exchange constraints and differences in cost assumptions. Generally, the batteries operate more quickly reflecting both their relatively high cost but also their ability to charge and discharge rapidly (up to 100% of rated capacity per hour e.g. 'Grid booster' in Kupferzell in Germany [Quanta 2023]). Hydrogen charge and discharge is more varied than carbon dioxide as it has much higher electrical input requirements and storage costs. Carbon dioxide with its cheaper capital cost for storage (relative to H<sub>2</sub>) tends to oversize storage (relative to stoichiometric ratios for synthesis). The model can force a secondary constraint that sets a maximum difference in the ratio of the CO<sub>2</sub> to H<sub>2</sub> storage sizes based on their stoichiometric ratio. This is an arbitrary figure that is set to a value of 5 here. This constraint is



occasionally binding depending on case structure (e.g. min operation levels etc.) reflecting the much lower costs of CO<sub>2</sub> storage in proportion to H<sub>2</sub>.

DAC operation remains very flexible (min operation 20%), although there is a CO<sub>2</sub> storage size limit (2 weeks of demand) since CO<sub>2</sub> storage is very cheap in terms of both capex and opex. CO<sub>2</sub> production and discharge rate from storage are also assumed to be limited. For the CO<sub>2</sub> liquefaction for storage and clean-up, a flexibility of 20% minimum part load is assumed.

The electricity consumption of the DAC plant amounts to about 0.4 kWh per kg of CO<sub>2</sub>, the heat demand amounts to 1.6 kWh per kg of CO<sub>2</sub>. The heat demand of the DAC plant is partly met by the heat from the synthesis (see annex 8.1). 8.1).

H<sub>2</sub> production is flexible. Manufacturers indicate 20% minimum part load for alkaline electrolyzers with ramp-up/ramp-down rates in the seconds to minutes, i.e. less than charging/discharging battery-electricity storage systems, but significantly faster than synthesis reactions.

Key input data for the model includes hourly renewable production profiles. These data were obtained from renewables.ninja website (<https://www.renewables.ninja/>) at various locations for the most recent full decade (2010-2019). Ten years of data were selected to better understand the impact of renewable intermittency on an intra-year and inter-year basis. For each system configuration a total of 10 separate cases were performed with the 10 different meteorological years. An average result was determined for each system configuration from the 10 meteorological years modelled. This approach differs from and compliments the approach in Chapter 2 which utilizes average capacity factors from existing plants that reflect several factors including differences in the types of plant built, local meteorological conditions, grid access etc. Here the technology choice is kept constant to focus on the impact of meteorological variation. This portion of the study only considers the costs of producing a fuel in a local region under the assumption of a self-contained system (i.e. as a direct connection plant). It does not consider aspects such as conversion in remote locations covered in Chapter 2.3.

PV production was assumed to be from a single axis tracking system set with a tilt angle equal to latitude. Production assumes 10% system losses. In addition, an inverter clipping ratio of 1.3 is assumed which limits maximum output of a 1kW DC system to 0.769 kW AC. Wind production assumed production profiles for a single Vestas V150-4000 unit with a hub height of 130 m (matching recent installations in the MENA region). Losses of 20% are assumed when converting the single turbine production to output more representative of an onshore wind farm. Losses of 30% were assumed for the offshore wind power plant to better match the capacity factors assumed in chapter 2). It is recognized that wind potential could be maximized by altering turbine and hub heights configurations, but the technology choice is held constant in this study for each location.

For Europe, hourly profiles were extracted at the geographical centre of each NUTS-2 region for the three countries of interest (nomenclature of territorial units for statistics (NUTS); <https://ec.europa.eu/eurostat/web/nuts/background>). Offshore wind was also determined by using the geographical coordinates of major existing offshore plants in the region. A statistical analysis was performed to find the region that best represents average land-based production for each country assuming an equal mix of PV and wind.

For MENA, renewable production assumed Saudi Arabia as a proxy location and data were extracted at multiple sites covering both coasts, the centre of the country and current renewable development sites. Again, an average was formed from all sites.

## 4.2. MODELLING PROCESS

One of the major uncertainties in the production of synthetic fuels relates to the potential constraints from the operational bounds on production as illustrated in Figure 88. Given these uncertainties, a range of potential conditions were considered here as displayed in Table 34. These modes were set to provide a spectrum of operational flexibility conditions with the upper and lower bounds described below:

- **Inflexible** operation that assumes minimum production levels at 80% of maximum capacity and a maximum change of 2.5% of maximum capacity per hour. These bounds are meant to generally represent existing types of Fischer-Tropsch synthesis plant today. While hydrogen cases have been run with these settings, this mode of operation is only relevant to hydrogen production if some form of end-use requires more steady-state conditions. Less flexible processes downstream the electrolysis plant lead to higher H<sub>2</sub> storage demand (and additionally a higher CO<sub>2</sub> storage demand e.g. in the case of Fischer-Tropsch synthesis).
- **Flexible** operation that assumes minimum production levels at 20% of maximum capacity and a maximum change of 20% of maximum capacity per hour. These conditions are meant to generally represent the type of performance seen in emerging micro-channel FT reactors (Wentrup et al., 2022). In the case of hydrogen, it also generally represents lower bounds of operation in existing electrolysis units.
- **Intermittent** operations where the only bound is on the total amount of fuel produced each year with plants able to turn on and off as required as long as total production is maintained. For simplicity, no additional costs for start/stop operation have been assumed in this analysis.

**Table 34:** Synthesis operational conditions

	Minimum operation (% rated capacity)	Change in hourly production (% rated maximum capacity)
Operational point 1 (inflexible)	80%	2.5%
Operational point 2	70%	5.5%
Operational point 3	60%	8.5%
Operational point 4	50%	11.5%
Operational point 5	40%	14.0%
Operational point 6	30%	17.0%
Operational point 7 (flexible)	20%	20.0%
Operational point 8 (intermittent)	0%	100%

In total, 6,720 cases were solved representing 4 locations, 7 fuels, 8 modes of operational flexibility, 10 years of meteorology and 3 different years for overnight construction (see Table 35).

**Table 35:** Modelling cases

Location		Fuel		Flexibility		Meteorological year		Build year
MENA South Europe Central Europe North Europe	X	FTK	X	Point 1	X	2010	X	2020 2030 2050
		MeOH		Point 2		2011		
		MTK		Point 3		2012		
		OMEx		Point 4		2013		
		CH <sub>4</sub>		Point 5		2014		
		H <sub>2</sub>		Point 6		2015		
		NH <sub>3</sub>		Point 7		2016		
				Point 8		2017		
						2018		
						2019		

### 4.3. MODELLING RESULTS

The results in this section supplements the work from Chapter 2 with a focus on considering how well the broad level assumptions used in that analysis compare with more site-specific outcomes from a detailed hourly economic dispatch model. These results provide context for further sensitivity analysis in Chapter 2.2. As such, the results focus on normalized production cost, the ratio of generation technologies, the degree of curtailed renewable generation and storage requirements.

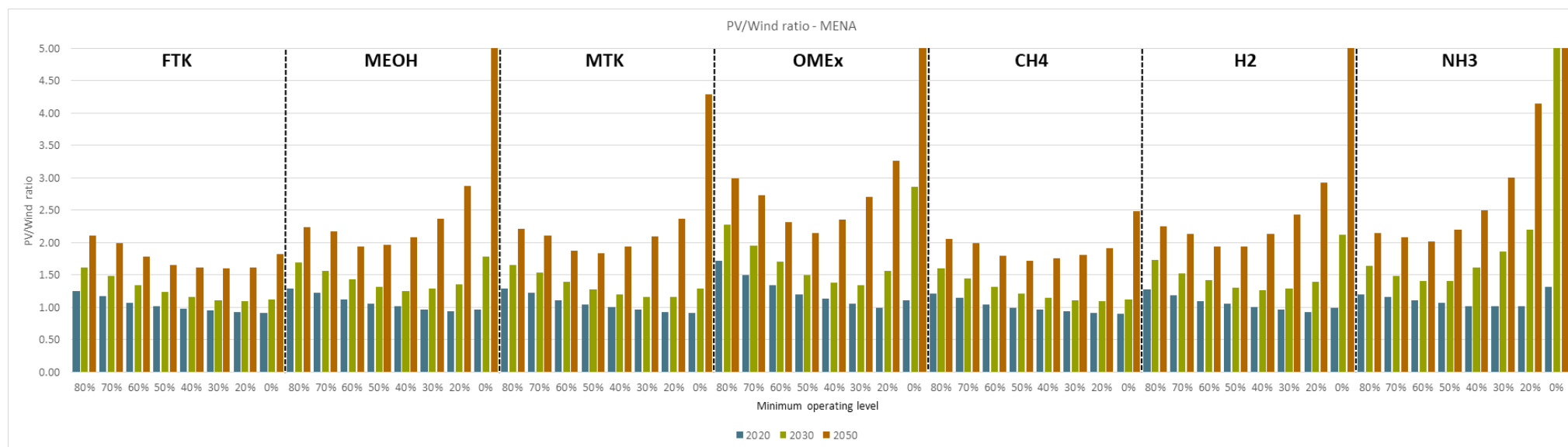
#### 4.3.1. Generation ratio

For the MENA region (see Figure 89, which shows the PV capacity in direct current divided by the wind capacity) there is a roughly equal mix of PV and wind for plant built in 2020. The exception is inflexible OMEx which sees a higher proportion of PV. The chart shows that PV becomes a more dominant source at this location in 2030 and more so in 2050 as capital costs for PV decrease in respect to onshore wind (see Table 59 to Table 63 in annex, chapter 9.2). This is most apparent in the MENA location as it has the highest capacity factors for PV of the four regions modelled. The highly flexible cases see an increase in PV in the later years as capital costs become cheaper and more economical to oversize compared to wind. Note that the charts are truncated to a ratio of 5 (i.e. 5 times more PV than wind) and for fully intermittent solutions the mix is dominated by PV for plant built in 2050.

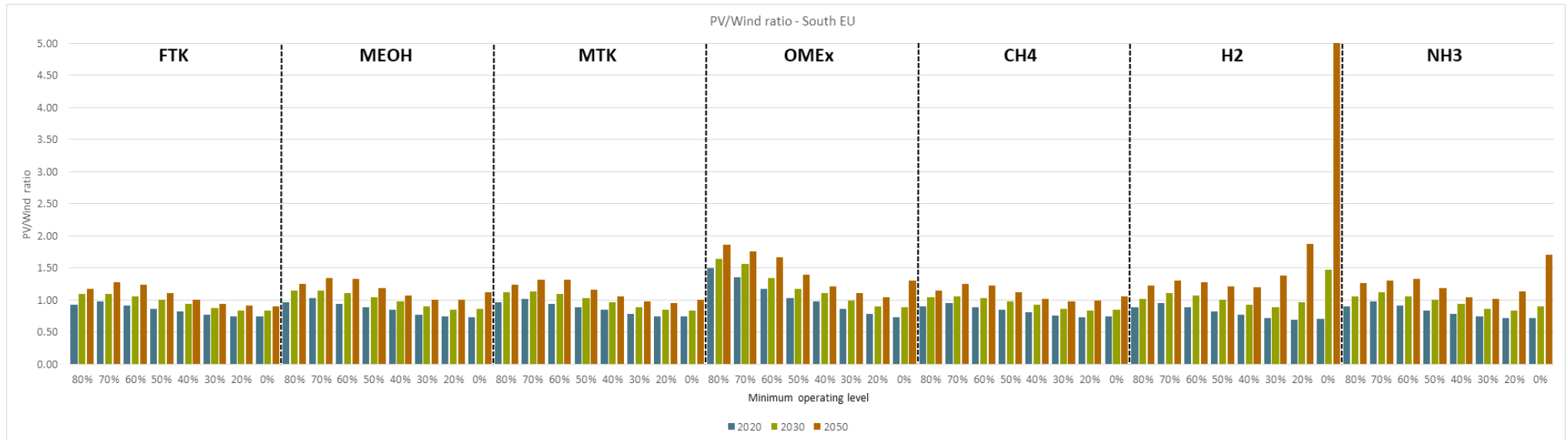
For south and central Europe, the mix of technologies is more equal across the range of operation and build years (see Figure 90 and Figure 91). For north Europe (see Figure 92) the mix is dominated wind which assumes the use of offshore units with higher capacity factors. However, the modelling still finds a role for PV in north Europe during the summer and shoulder periods of spring and autumn.

These results demonstrate that an equal mix of PV and wind is a reasonable approximation. However, the sensitivity modeling in section 2.2.3 covers 100% supply from PV or wind which can be a useful approximation in locations such as MENA in later years where high-capacity factors and lower capex drive more PV dominant solutions and in north Europe where offshore wind dominates supply.

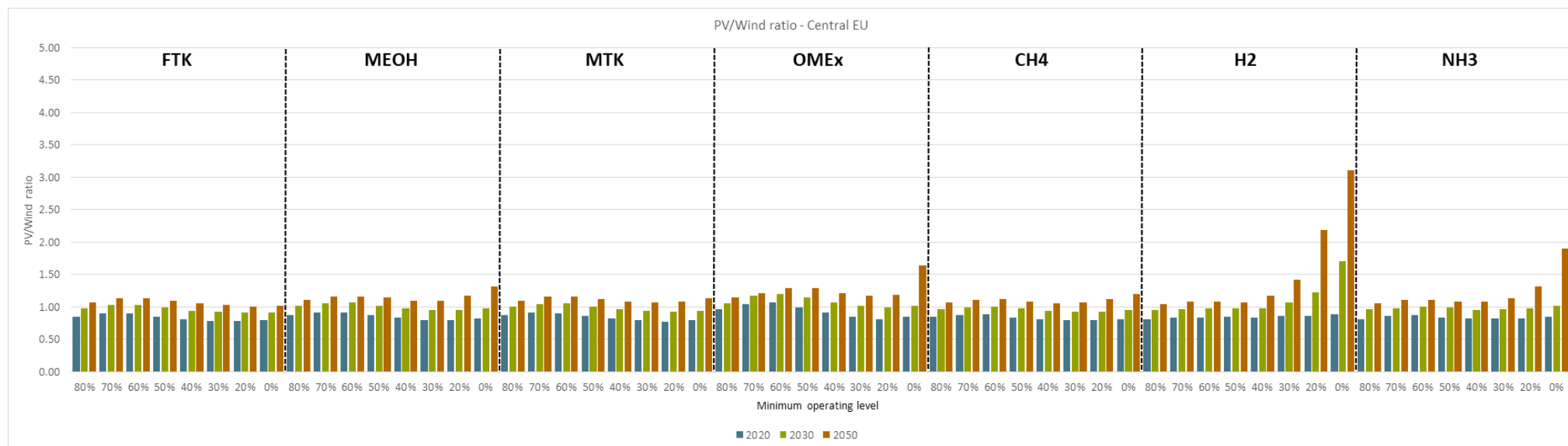
**Figure 89:** Generation ratio for MENA



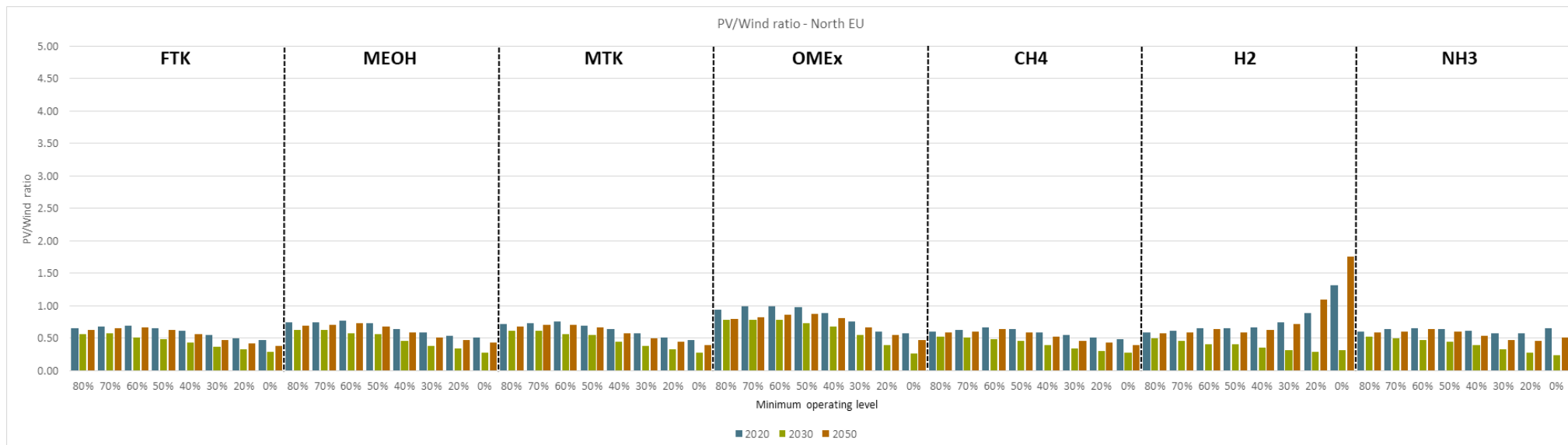
**Figure 90:** Generation ratio for South Europe



**Figure 91:** Generation ratio for Central Europe



**Figure 92:** Generation ratio for North Europe



The PV/wind ratio for least-cost production is driven by the parameter constellation of the CAPEX PV and wind, the equivalent full load hours, CAPEX of the electricity storage, CAPEX of electrolysis plant, CAPEX of H<sub>2</sub> storage, CAPEX of CO<sub>2</sub> storage, and CAPEX of synthesis processes. The CAPEX for renewable electricity and for various components of the e-fuel plant changes over time leading to different PV/wind ratios over time.

#### 4.3.2. Curtailed renewable energy

In this modelling, curtailment is based on dynamic sizing and economic dispatch of PV and wind.

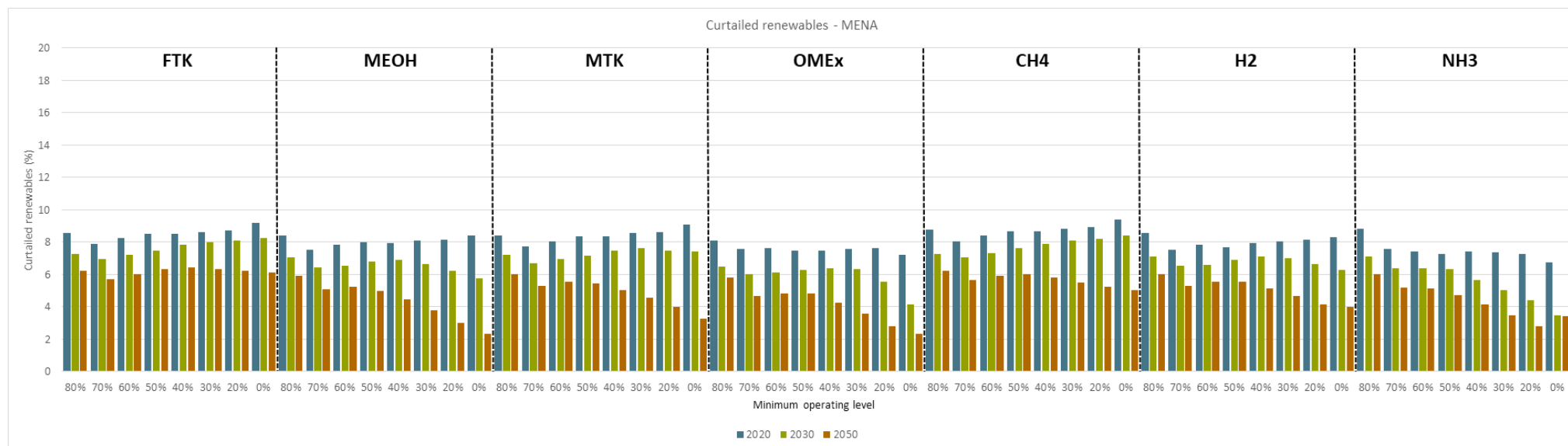
Figure 93 to Figure 96 shows that curtailment is highest for inflexible operation as system components need to be built large enough to ensure minimum production levels are met. Storage (as seen in section 4.3.3) plays an important role, however it is more economically efficient at some point to curtail electricity supply than to store excess in the form of chemical storage in batteries, H<sub>2</sub> and CO<sub>2</sub>.

In MENA (see Figure 93), the default value of 5% assumed in the last version of this study [Concawe et al. 2022] is reasonable with the average loss across all fuels and all operational conditions being around 6.6%. In south Europe (see Figure 94) the inflexible cases see a much higher degree of curtailment due to the impacts of lulls (periods with low wind speed and low solar irradiation) in renewable production leading to overbuilding of assets as discussed in section 4.3.1. For minimum operation points below 60% the default value is reasonable with an average loss around 6.7% across all fuels and operational points below this level. In Central Europe the default range is reasonable (see Figure 95) with the average loss across all operational points and fuels being 5.8%. In north Europe, the default value is conservative (see Figure 96) with losses only 2.6% on average across the range of fuel and conditions modelled.

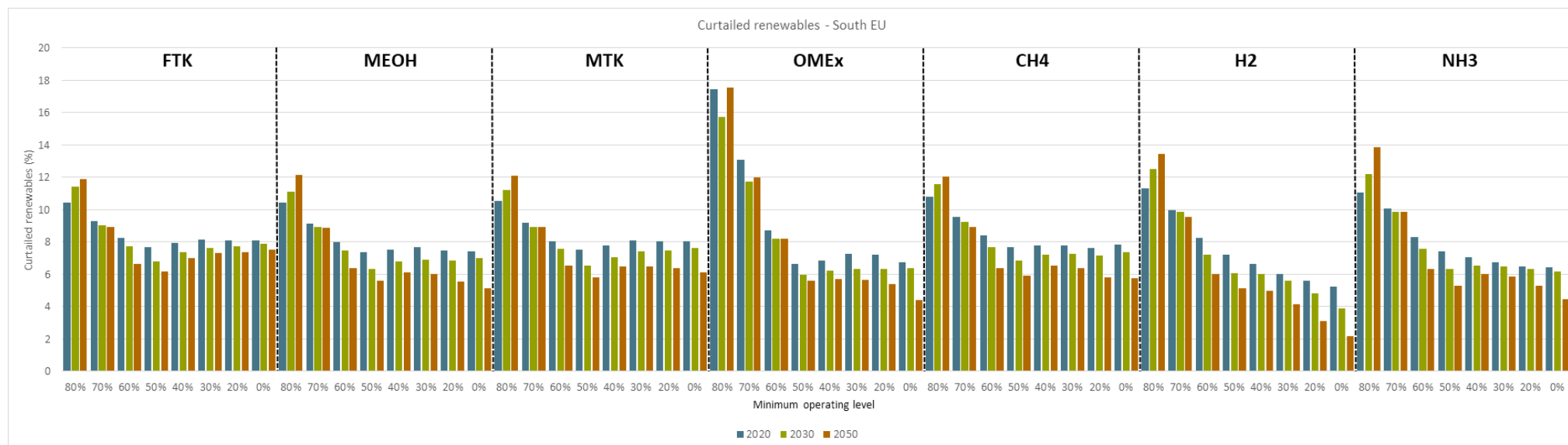
The electricity curtailment generally decreases towards 2050. One reason could be, that the costs of electricity storage decreases faster than the cost for renewable electricity generation.



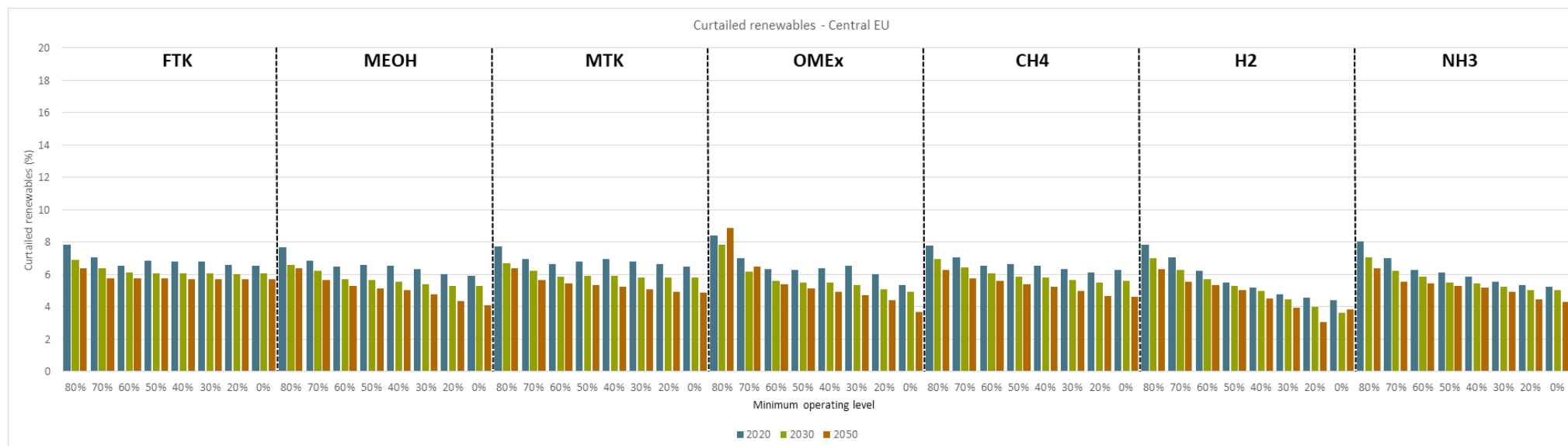
**Figure 93:** Curtailed renewable energy in MENA



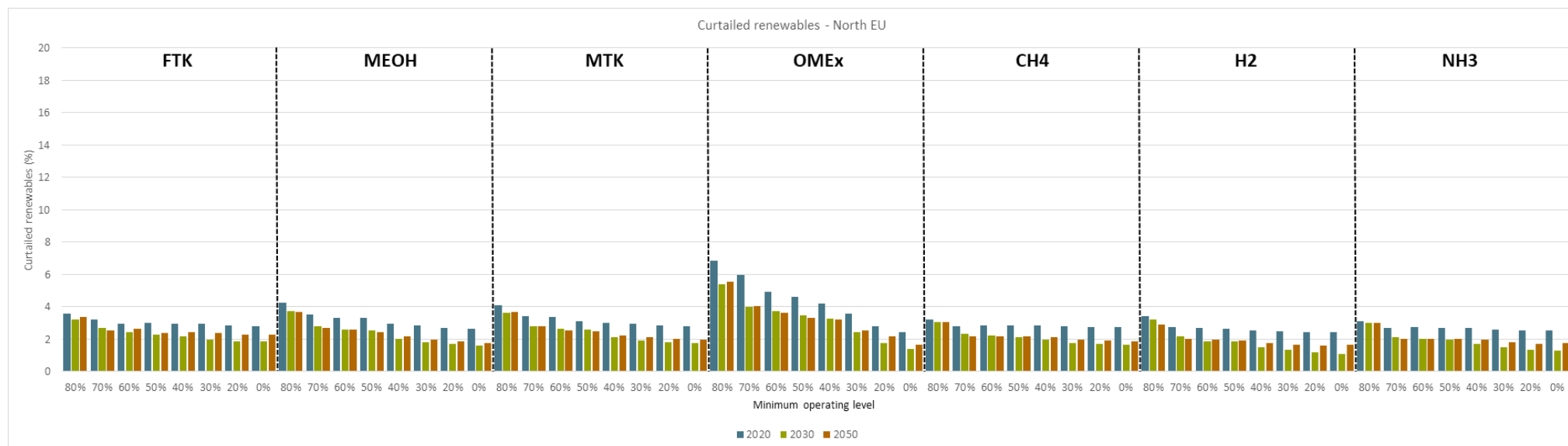
**Figure 94:** Curtailed renewable energy in South Europe



**Figure 95:** Curtailed renewable energy in Central Europe



**Figure 96:** Curtailed renewable energy in North Europe



### 4.3.3. Hydrogen storage

Figure 97 to Figure 103 provides an assessment of hydrogen storage requirements for the different fuel options under different levels of operational flexibility. The results here are expressed in daily equivalents for steady-state production.

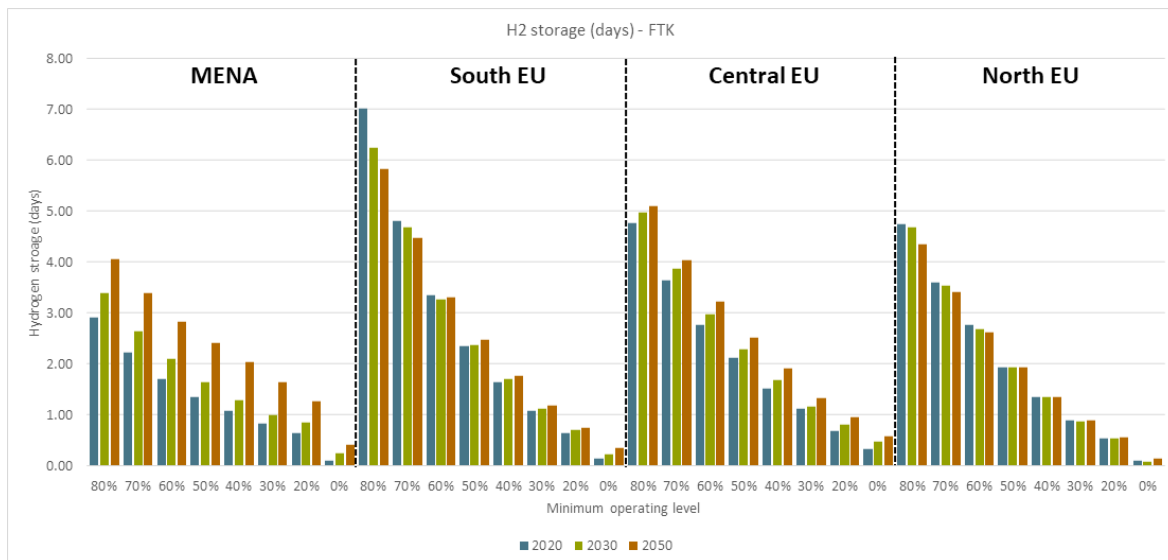
These charts show that there are minor differences in the amount of storage required for the different fuel types. The charts also demonstrate that as operational constraints are relaxed, the requirements for storage decrease substantially. The default value of 2 days storage occurs around the 50% minimum turndown point for each fuel type at each location. For less flexible plant, the requirements are roughly double the default assumption, while for flexible operation the requirements are roughly half default assumption.

Hydrogen storage increases as there is a move to more PV with lower costs but more intermittent operation. It's a trade-off between capital expenditure in both systems. In MENA and to a lesser extent central Europe, there is an increase in storage requirement for plants built in 2030 and 2050. This is a result of higher share of PV built in the 2030 and 2050 cases (see 4.3.1). South Europe sees the largest amount of storage for inflexible cases. This is an interesting result given the average capacity factor (for a hybrid wind and PV plant) for south Europe is slightly lower than MENA and higher than central Europe.

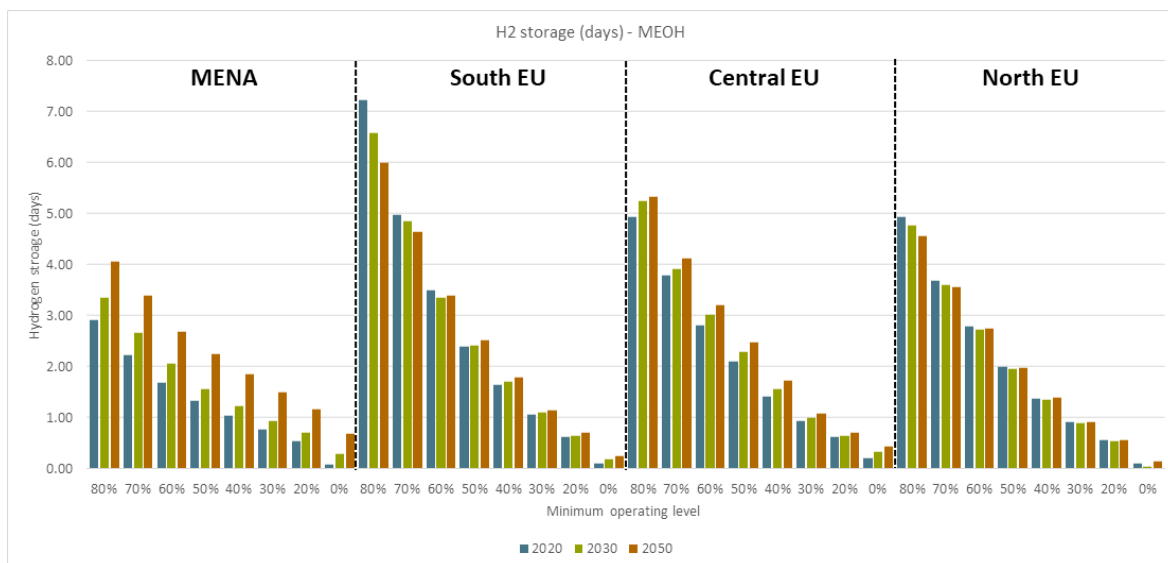
Analysis found these outcomes for south Europe which are driven by a small number of periods with relatively low renewable production. This is illustrated in Figure 104 and Figure 105 charts renewable production potential from an equal mix of PV and wind (ignoring dispatch impacts). These data represent a rolling 96-hr average. These charts illustrate that for this particular meteorological year, there is a period of sustained low renewable production in the south Europe site that forces the model to build larger storage capacity. This results in the storage being poorly utilized over the entire year. By contrast, the storage use in the central Europe location is small and better utilized. While overall renewable production potential is lower in the central Europe location, during this meteorological year, the site sees smaller and less pronounced periods change in productive capacity compared to the south Europe site. Similar outcomes are found in three of the ten meteorological years modeled at this site leading to higher overall average storage requirements.

These results highlight how detailed analysis can better estimate the sizing requirements for different system components. Analysis that assumes average capacity factors will invariably omit such detail. It should be cautioned however that the analysis here utilizes publicly available reanalysis meteorological data with its own inherent degree of accuracy. Project specific details require measurements of renewable potential along with tailored selection of production technologies to both provide more a more accurate view on these issues and to potentially alleviate their impact through better technology matching (e.g. different wind generation turbine options and different hub heights, changes to PV orientation etc.).

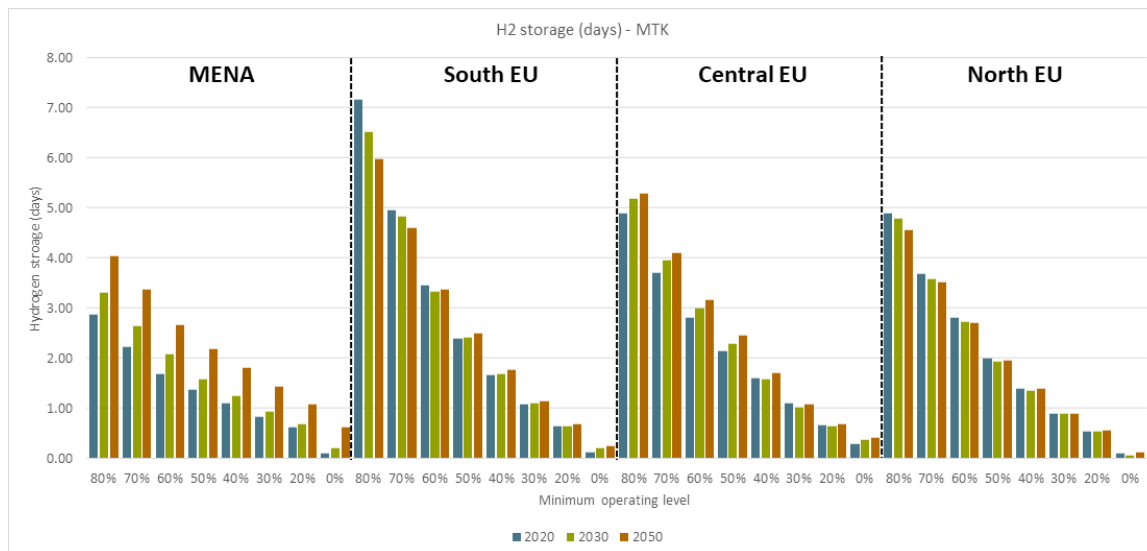
**Figure 97:** Hydrogen storage requirements for FTK



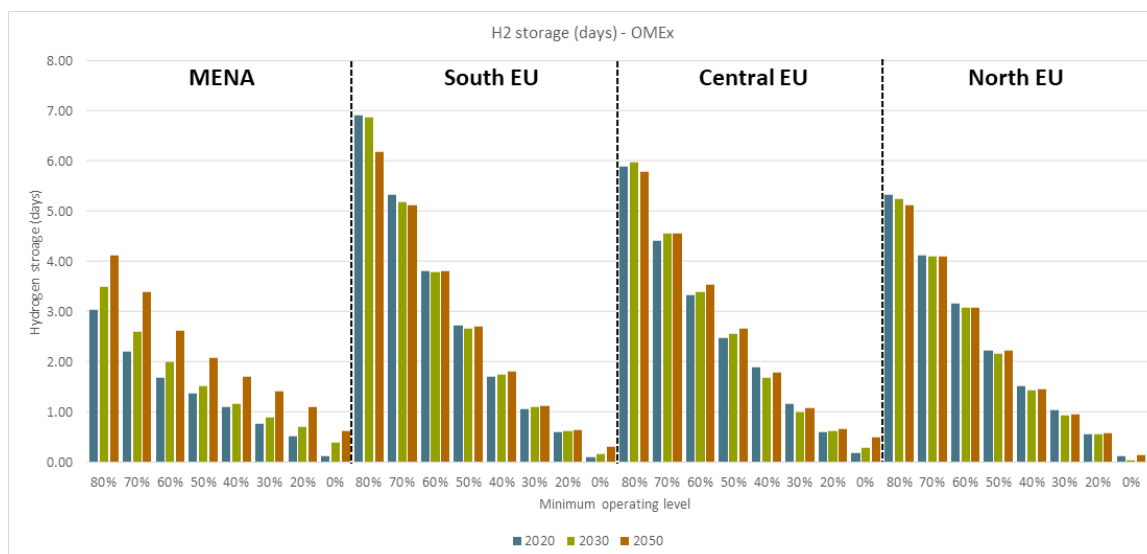
**Figure 98:** Hydrogen storage requirements for MEOH



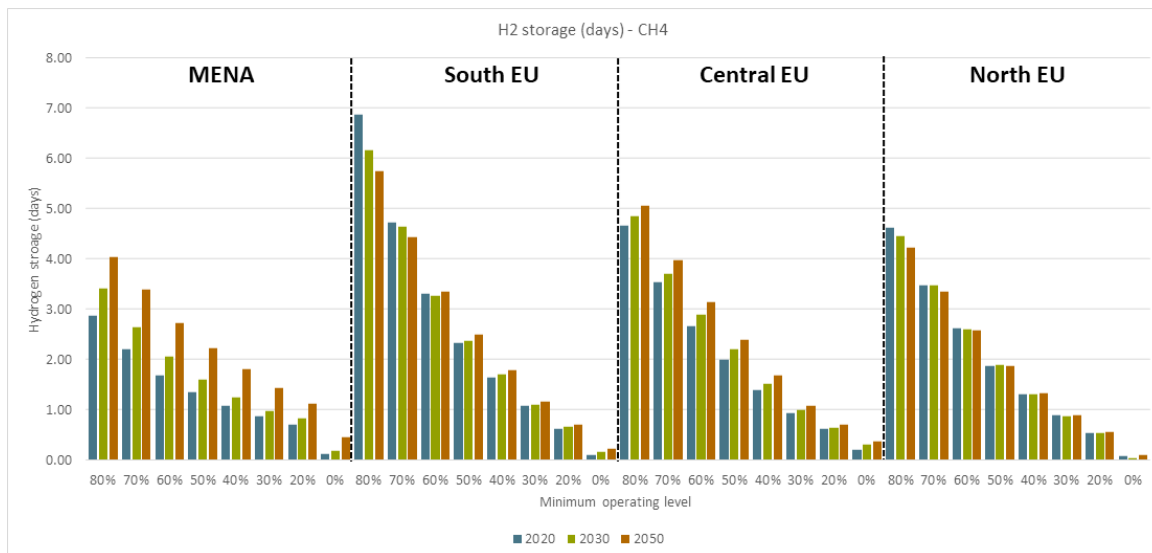
**Figure 99:** Hydrogen storage requirements for MTK



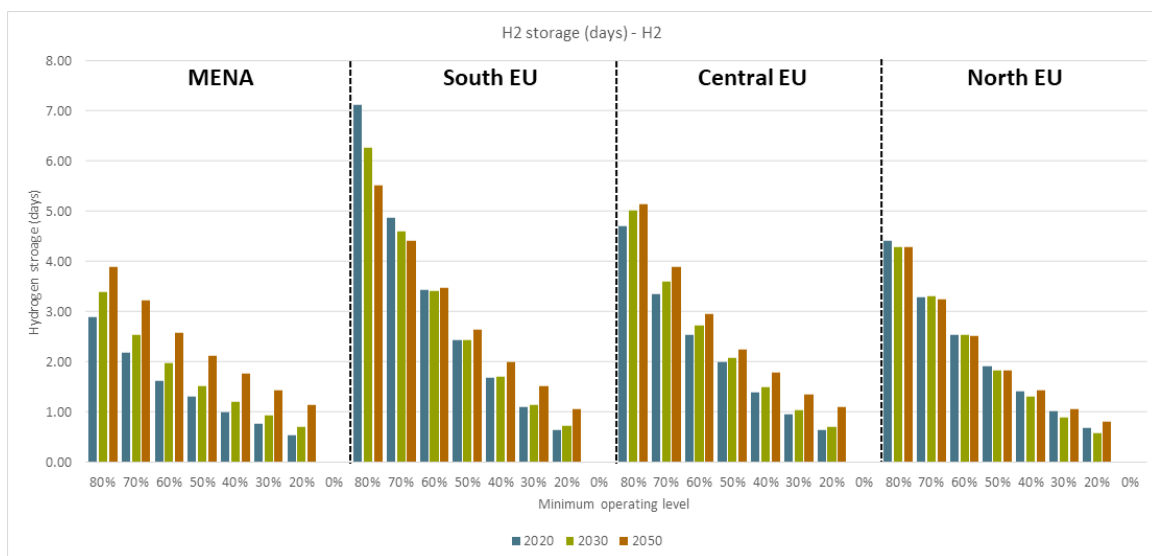
**Figure 100:** Hydrogen storage requirements for OMEx



**Figure 101:** Hydrogen storage requirements for CH<sub>4</sub>

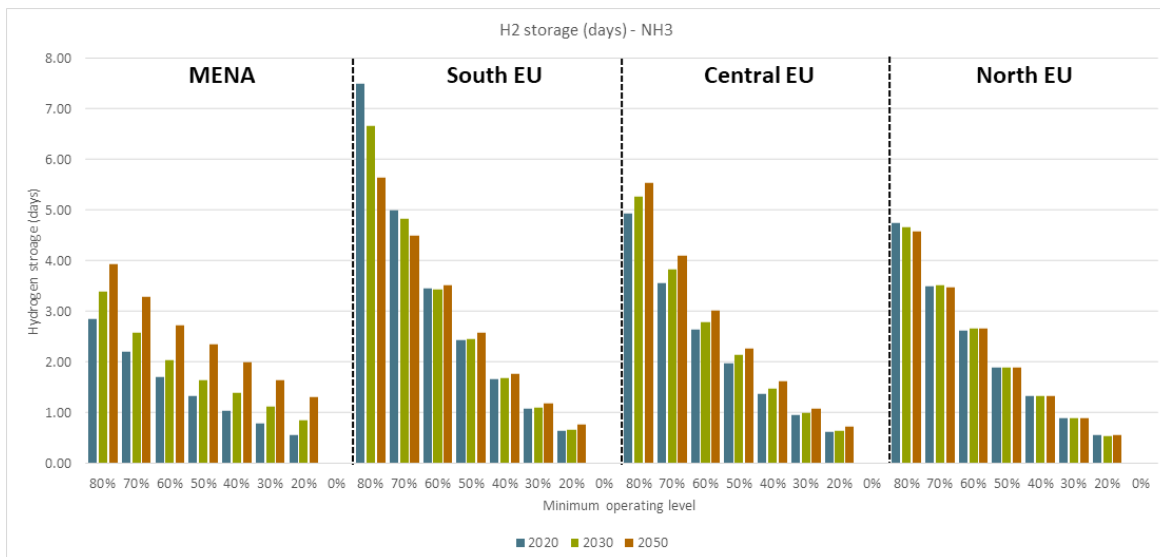


**Figure 102:** Hydrogen storage requirements for H<sub>2</sub>

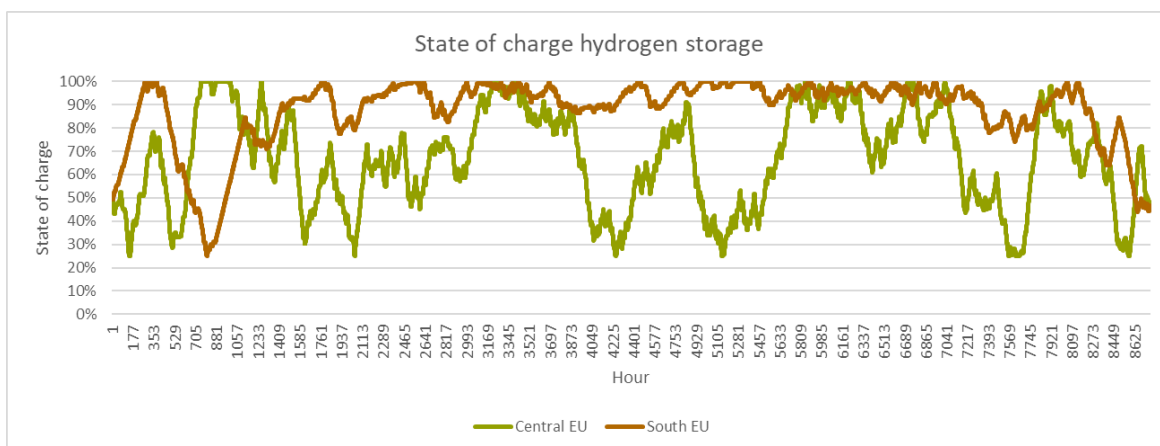




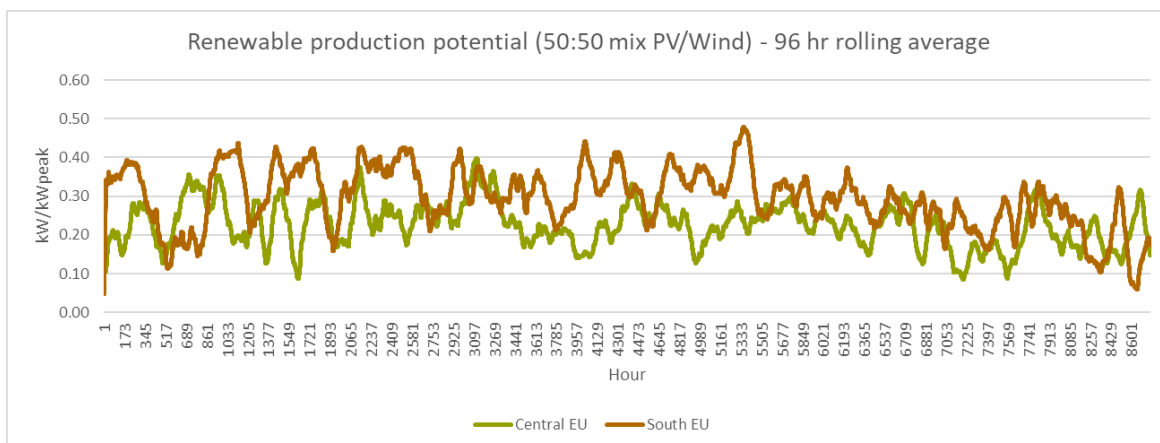
**Figure 103:** Hydrogen storage requirements for NH<sub>3</sub>



**Figure 104:** Hydrogen storage state of charge



**Figure 105:** Renewable production potential

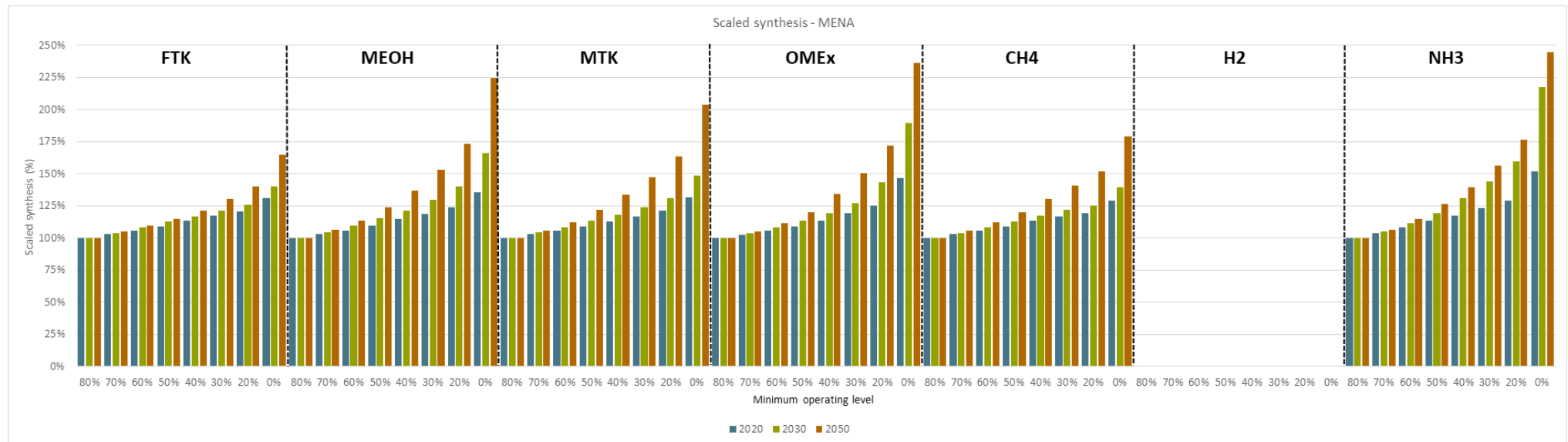


#### 4.3.4. Synthesis plant sizing

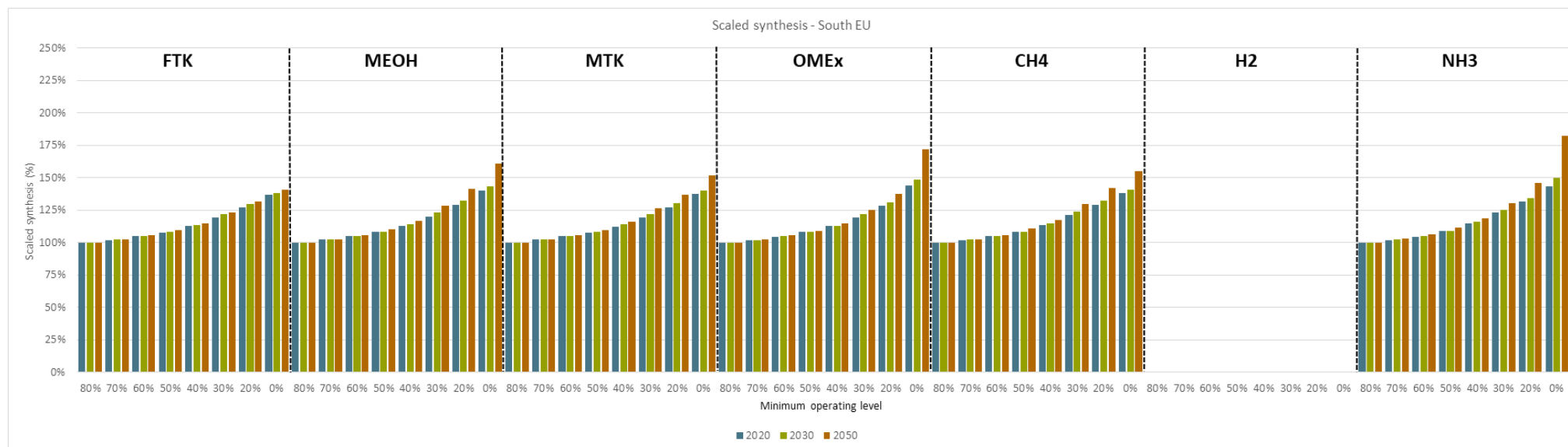
In general, as operational constraints are relaxed, the size of the synthesis plant increases with its load factor correspondingly decreasing. The plants need to be oversized to allow higher production in times of high renewable production to cover lower production in times of lower renewable production. The final size of the plant is a result of the balance between costs and load factors on all the different components in the system.

In Figure 106 to Figure 109 the normalized (scaled) synthesis plant size across the range of operational conditions for each location are provided based on the assumptions on minimum part load and maximum change rates in chapter 4.2. Here the size of plant is normalized to the inflexible case for each fuel type. These charts demonstrate that the synthesis plants need to be larger to accommodate for the wider range of operating conditions. The FTK route sees the smallest change due to its higher capex relative to other pathways.

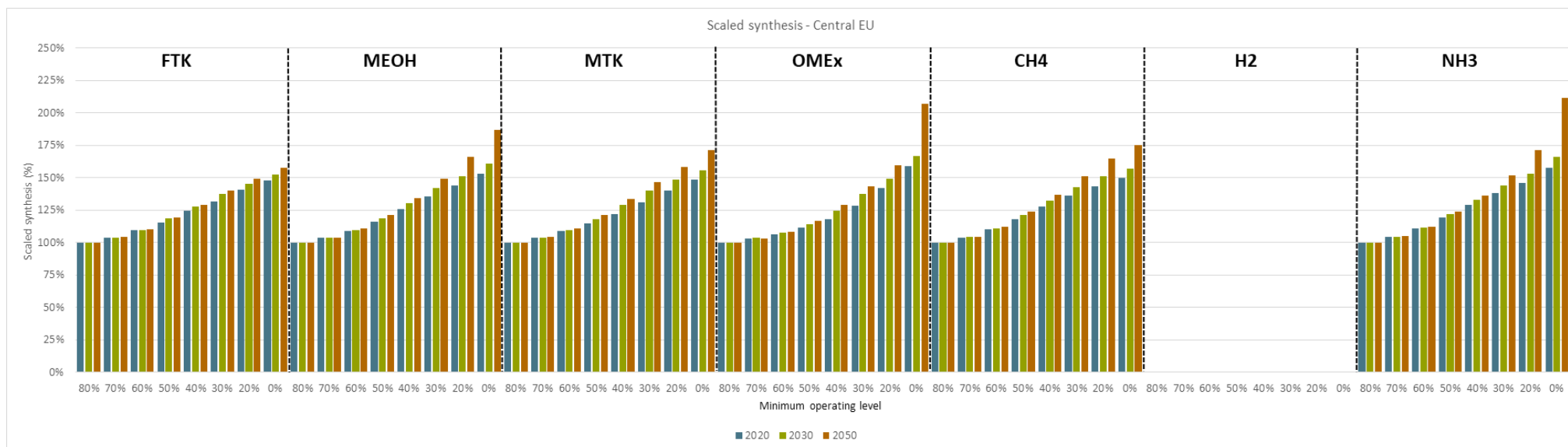
**Figure 106:** Synthesis plant sizing in MENA



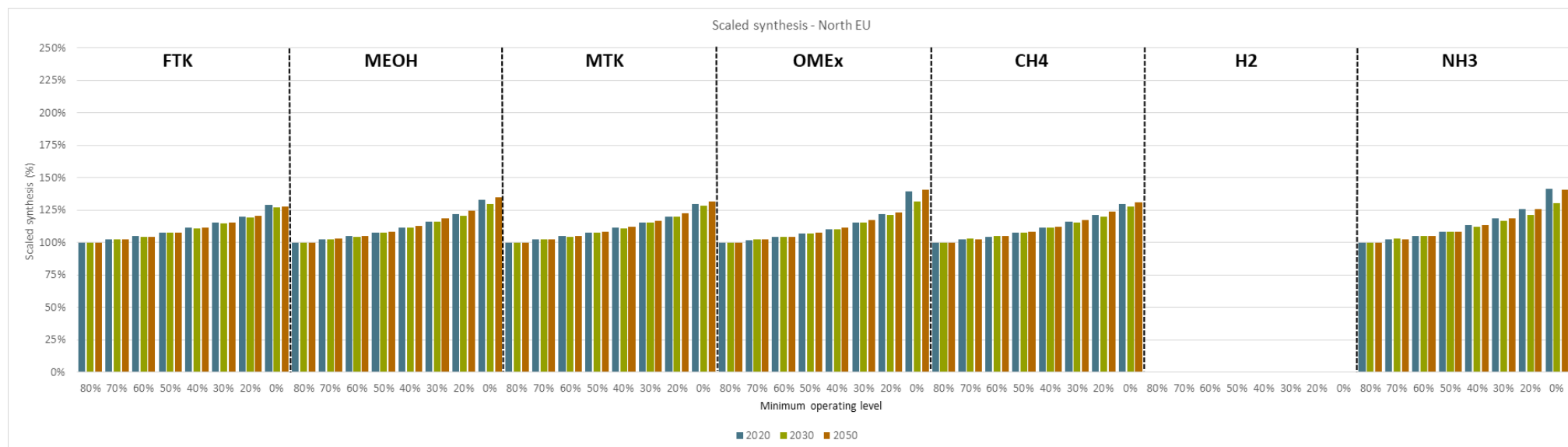
**Figure 107:** Synthesis plant sizing in South Europe



**Figure 108:** Synthesis plant sizing in Central Europe



**Figure 109:** Synthesis plant sizing in North Europe



#### 4.3.5. Production cost

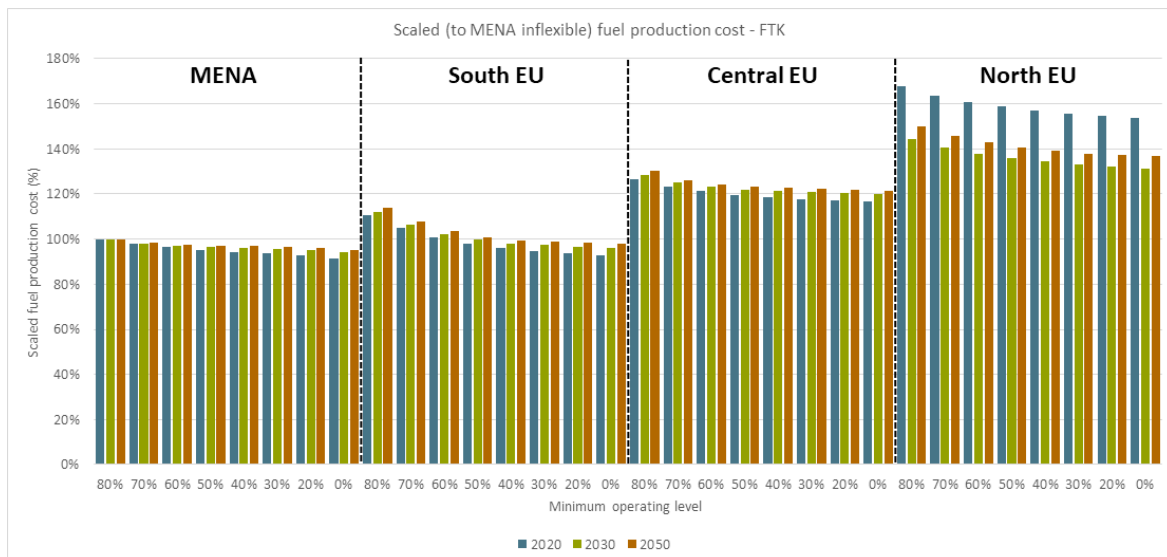
In this section, the impact of operational flexibility on the fuel production cost is considered. The results have been normalized to the inflexible case (80% minimum operation and 2.5% change per hour) for MENA as a reference. This is provided for each of the fuels and displayed in Figure 110 to Figure 116.

For the FTK, MeOH, MTK, OMEx and  $\text{NH}_3$  routes, the same basic pattern is repeated with MENA providing the cheapest production and north Europe the costliest. In 2030 and 2050 the scaled cost relative to MENA increases slightly in the European sites reflecting an increased role for cheaper PV in MENA (see 4.3.1) in the generation mix. The large change from 2020 to 2030 in north Europe reflects the improvement in offshore wind costs (see Table 49 in annex 9.2.1) relative to the improvements in cost in PV. In contrast, the  $\text{H}_2$  and to a lesser extent the  $\text{CH}_4$  routes have the lowest costs when produced in south Europe. This is a result of the additional capital costs and energy requirements to liquefy these fuels in MENA for export to Europe.

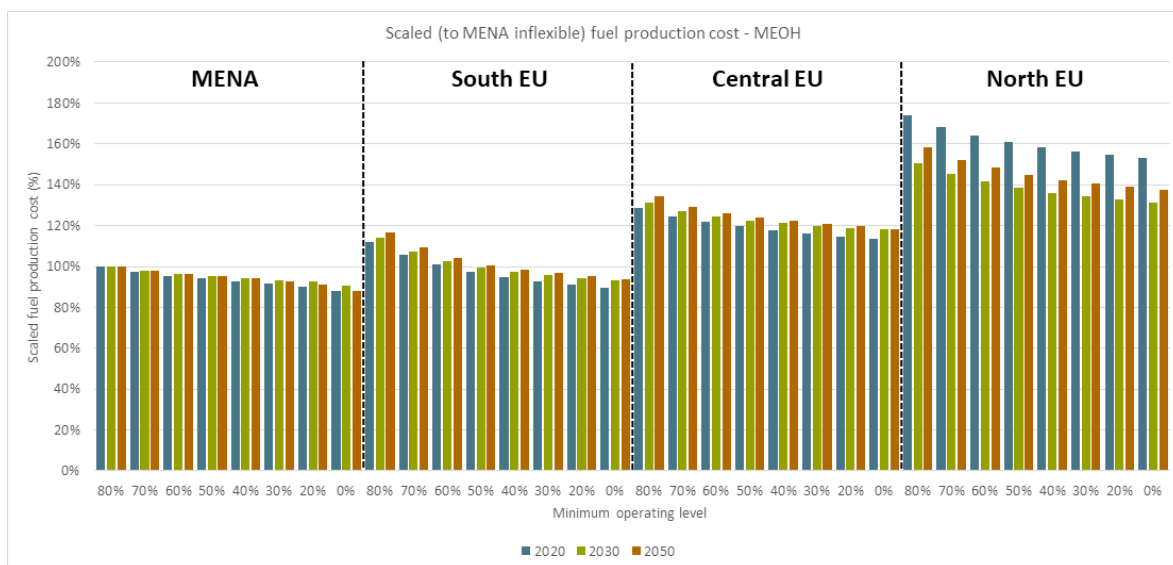
In general, as operational constraints are relaxed, the fuels become cheaper to produce. The relative change between operation increments, however, becomes smaller as operational flexibility is increased. As the synthesis process becomes more flexible, the components supplying electricity can be reduced in size, however the production components synthesis increase (see 4.3.4) to ensure overall fuel production is met. These results highlight that adding some degree of flexibility has distinct cost advantages, but that impact reduces as operational flexibility is increased due to the trade-off between the oversizing of different elements in the system. For the Fischer-Tropsch (FT) plant the same CAPEX is considered, independently if it is a conventional FT reactor or a microchannel reactor, assuming the increased cost will be compensated by improvement of the technology and its learning curve.

It should be noted here that the intermittent cases do not incorporate additional costs for starting and stopping the plant. Despite this, from a cost perspective, the intermittent solutions are similar in cost to the highly flexible cases that ensure operation is always above a minimum operation point, albeit at a low level. This clearly demonstrates that the plant operation does not need to be fully intermittent to deliver the lower production costs.

**Figure 110:** Normalized fuel production costs for FTK

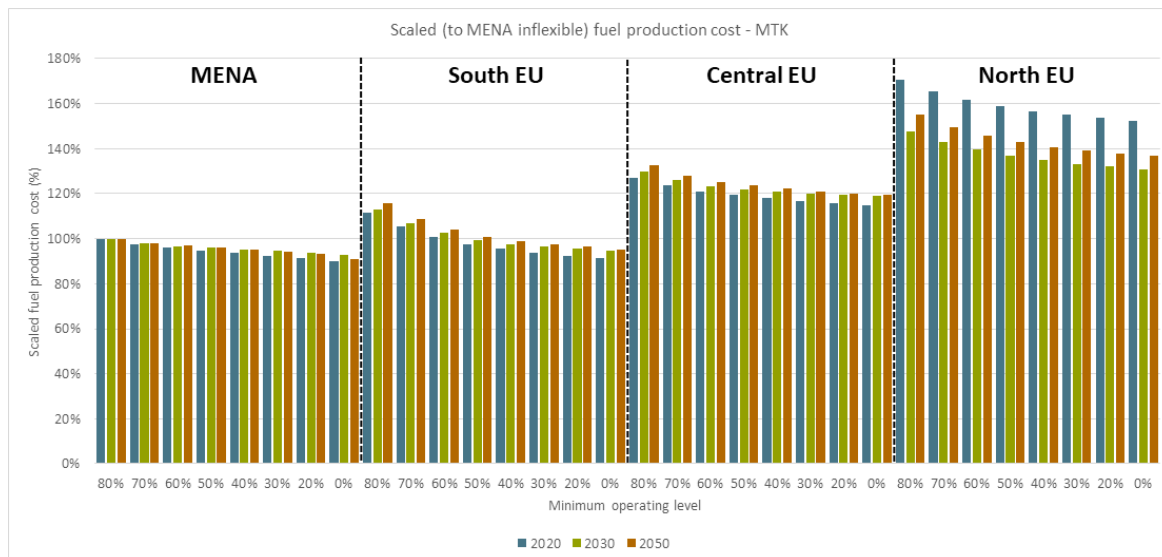


**Figure 111:** Normalized fuel production costs for MEOH

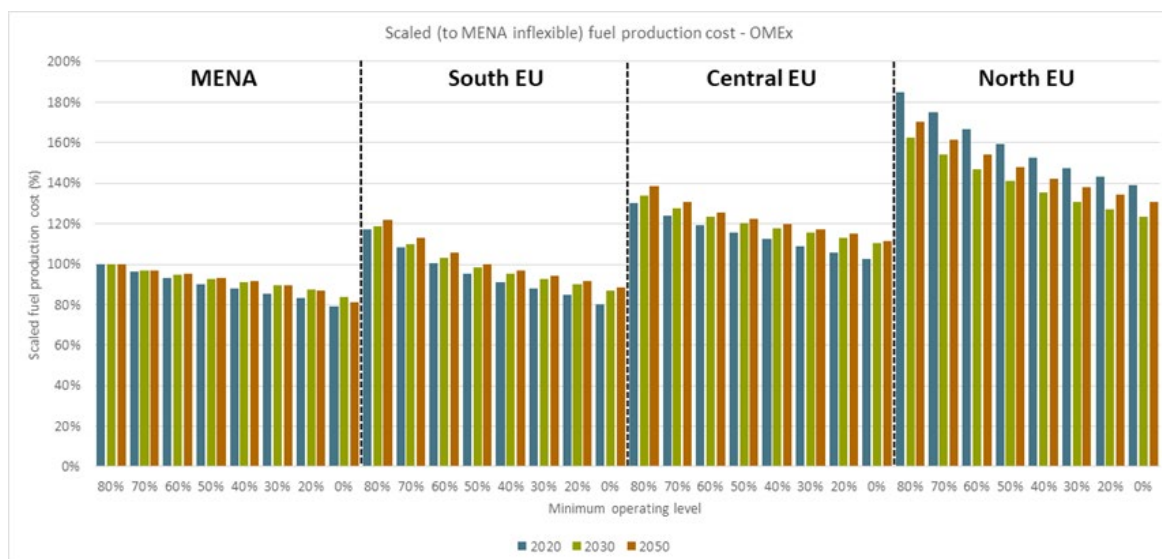




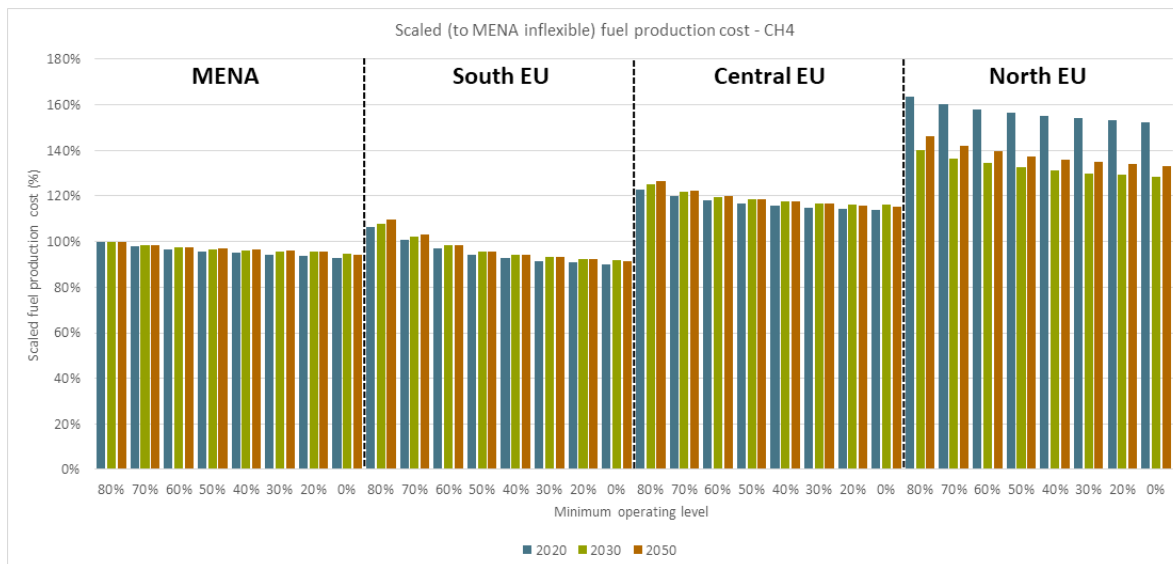
**Figure 112:** Normalized fuel production costs for MTK



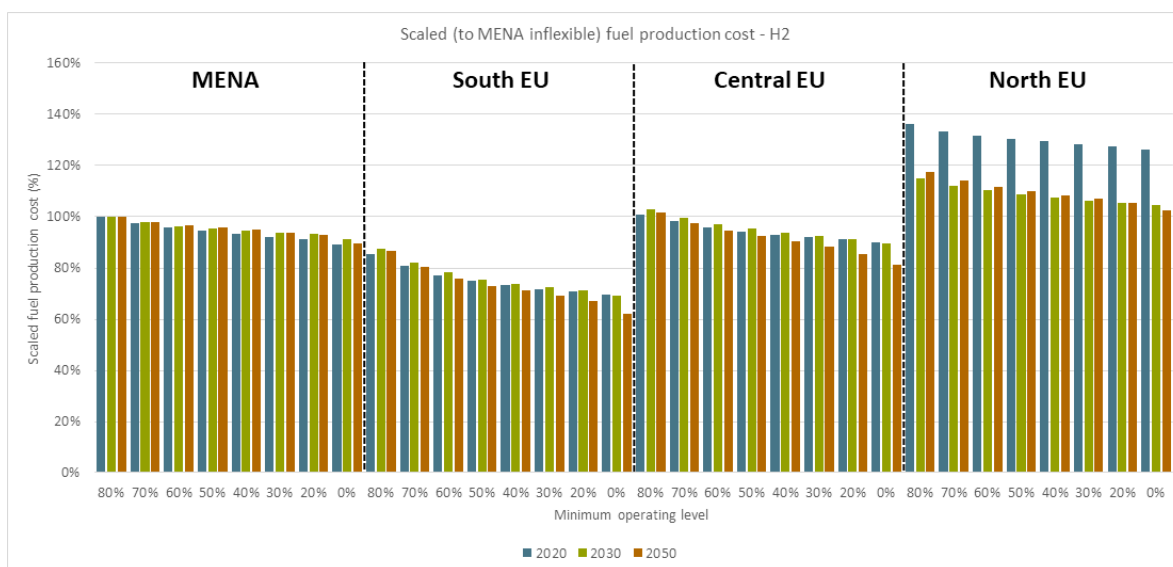
**Figure 113:** Normalized fuel production costs for OMEx



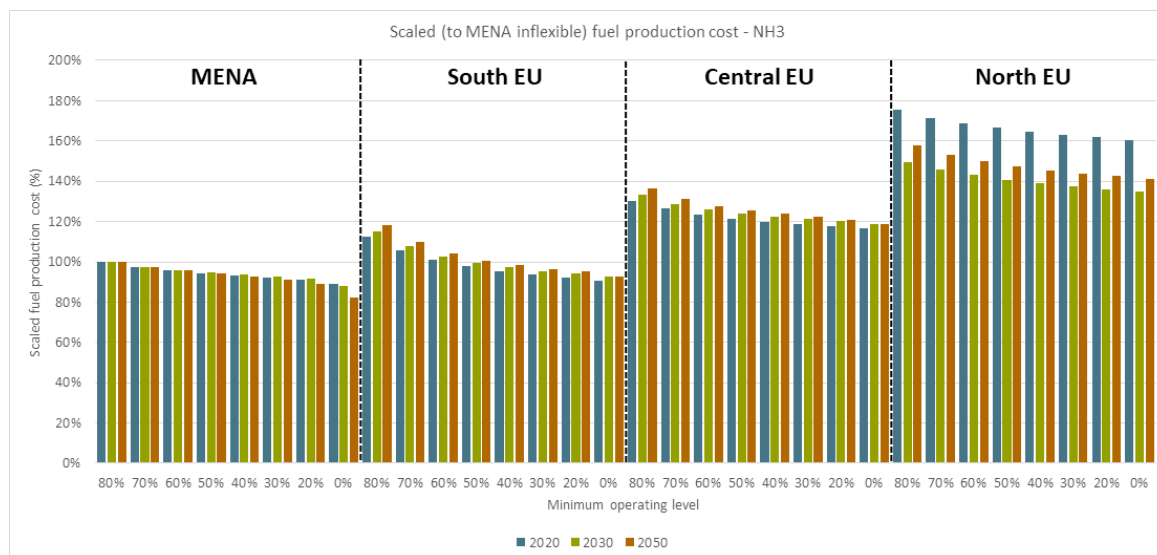
**Figure 114:** Normalized fuel production costs for CH<sub>4</sub>



**Figure 115:** Normalized fuel production costs for H<sub>2</sub>



**Figure 116:** Normalized fuel production costs for NH<sub>3</sub>

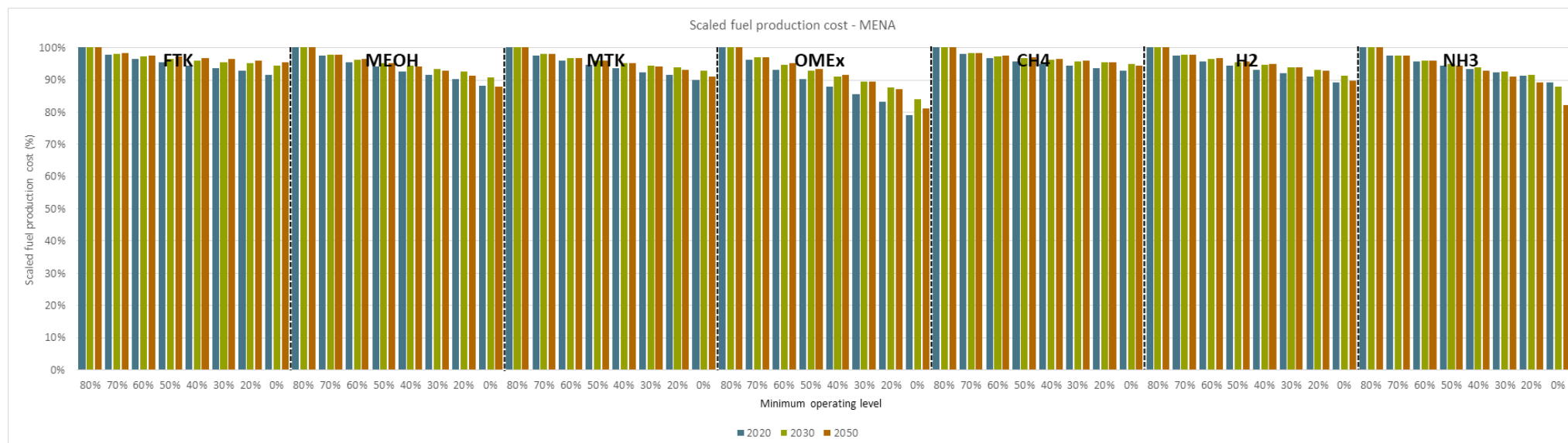


The cost impacts of operational flexibility for each fuel type for each region are displayed in Figure 116 to Figure 119. Here for each fuel type, the cost is normalized to the inflexible case (80% minimum operating level, using MENA as a reference) to highlight the production cost difference from changes to operational flexibility. As above, these charts illustrate that **increasing operational flexibility decreases overall production cost, but the relative change becomes smaller as the operational constraints are relaxed.**

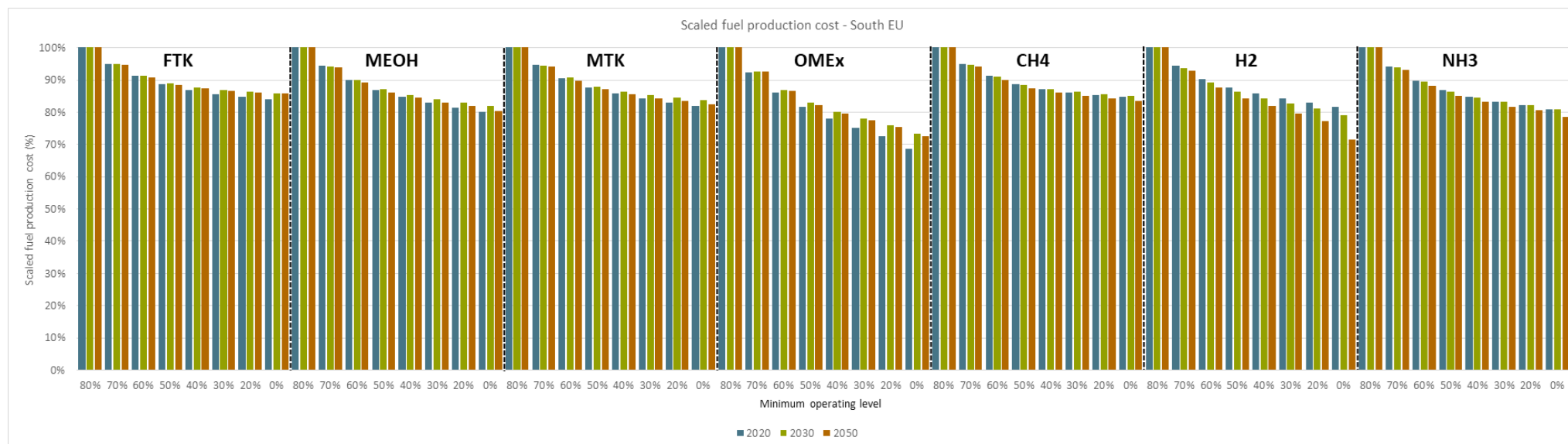
The improvement in costs with increased flexibility differs by final product type with higher reductions seen for those products with higher energy demands per energy of final production (see annex 8.2 for details), this is particularly evident for the OMEx pathway which has the highest input energy requirements due to additional heating demand. These impacts result from changes to curtailed renewable production (see 0) along with changes to the size of synthesis production (see 4.3.4). As operational constraints are relaxed, the system curtails less electrical production while synthesis plant increases to cater for the wider range of operation conditions while ensuring total production is met. The size reflects both the input energy to the synthesis process and the capital costs. The change is smallest for the FTK route as its capital costs are constant over time (see e.g. Table 130, Table 131, and Table 132 in chapter 9.4.7) while other routes see larger changes from assumptions of increased learning. The reason for the same capital costs for Fischer-Tropsch (FT) plant over time is that independently if it is a conventional FT reactor or a microchannel reactor, assuming the increased cost will be compensated by improvement of the technology and its learning curve.

The relative improvement between the inflexible and flexible operational points is highest in the south Europe location ranging from 14% to 25% (see 4.3.1 for a more detailed explanation of the intermittency impacts causing results at this site) and lowest in MENA ranging from 5% to 12%.

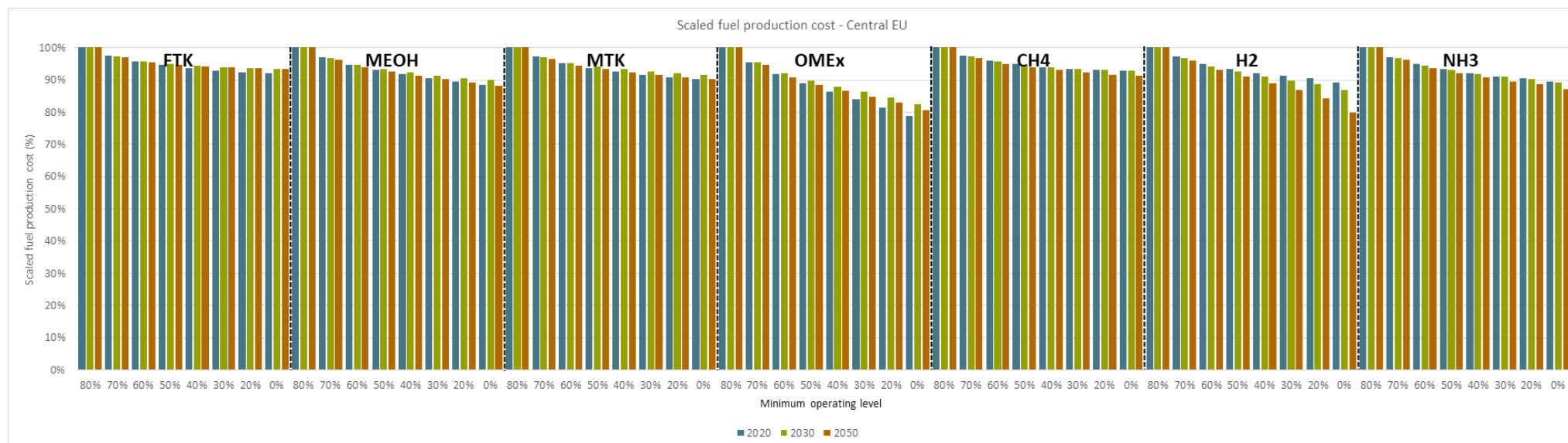
**Figure 117:** Normalized fuel production costs in MENA



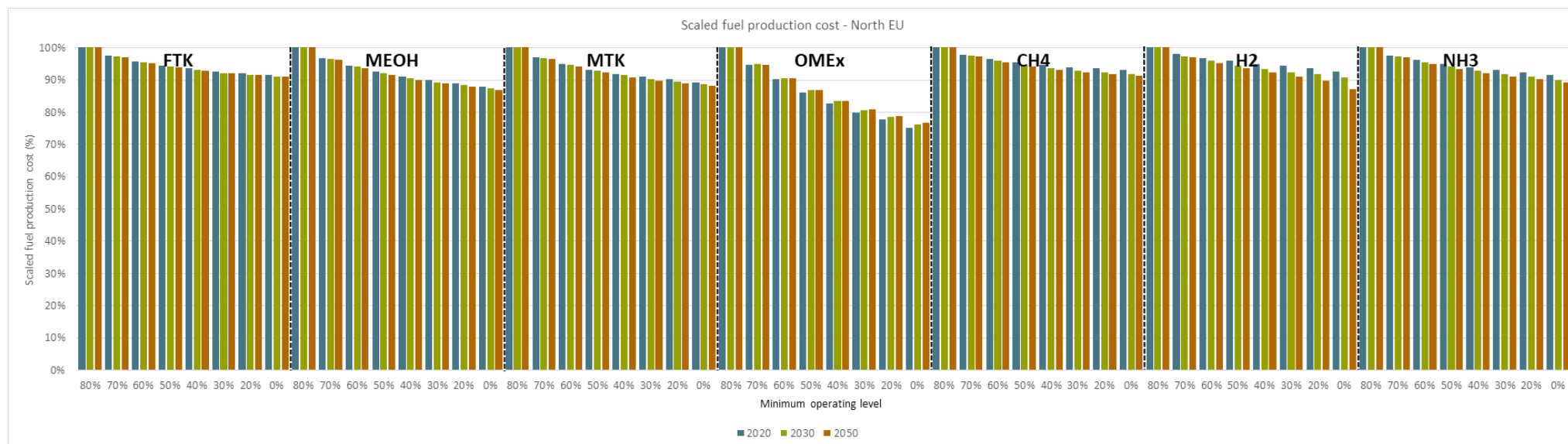
**Figure 118:** Normalized fuel production costs in South EU



**Figure 119:** Normalized fuel production costs in Central EU



**Figure 120:** Normalized fuel production costs in North EU



Results from chapter 4 have entered the techno-environmental assessment in chapter 1 and the economic assessment in Chapter 2. The flexibility assumptions for base cases are described in Table 15 (H<sub>2</sub> buffer storage).

**KEY MESSAGES - INTERMITTENCY & SEASONABILITY OF RENEWABLE ENERGY SUPPLY**

The intermittency of renewable sources and the flexibility of fuel production processes have a direct impact on the costs of e-fuel production.

PV and wind power are intermittent, but complementary to a large extent. Site-specific co-optimization allows to smooth the electricity supply.

Higher PV rate is related to higher H<sub>2</sub> and CO<sub>2</sub> storage requirements, except in regions with regular daily irradiation (batteries for day/night balancing).

A significant cost reduction in fuel production can be achieved with moderate flexibility of synthesis technologies.



## 5. CONTEXT OF E-FUELS IN THE FUTURE OF EUROPE - POTENTIAL DEMAND, FEASIBILITY, OPPORTUNITIES AND CHALLENGES

This chapter explores the context into which e-fuels may play in the future. For this, additional aspects are analysed to identify aspects such as potential demand, feasibility, opportunities and challenges for using e-fuels, and conditions that allow for e-fuel business cases.

### 5.1. POTENTIAL E-FUEL DEMAND IN EUROPE, CAPEX, LAND AREA AND ELECTRICITY REQUIREMENTS

The e-fuels exploratory scenario for 2050 were developed based on final energy demand data in the transport sector reported in the IEA World Energy Outlook 2022 [IEA 2022] based on the net zero emissions by 2050 scenario. This study includes a comprehensive analysis of how to transition to a net zero energy system by 2050, and includes a portion of synthetic hydrogen-based liquid fuels (e-liquids) and e-hydrogen in the global energy demand in 2050 for the transportation sector. The dataset provides a breakdown of the total energy demand in transport (1839 MTOE) by fuel at a global level.

Since no regional breakdown for Europe is provided by IEA World Energy Outlook, the European energy demand for transport was estimated to be 12% of the global data reported by IEA, based on shares derived from MESSAGEix-GLOBIOM 1.1 Net Zero 2050<sup>11</sup> and GCAM5.3\_NGFS Net Zero 2050<sup>12</sup>. It was further assumed that the share by fuel in Europe would be the same as at a global level, on the basis that by 2050 an equilibrium position should have been reached across the globe.

Exploratory scenarios in term of final energy demand (Table 36) were built considering two cases:

- **Low scenario:** in line with IEA expectations for e-fuels take-up
- **High scenario:** As above but with IEA forecast of biofuels and oil shifted to e-liquids and biomethane shifted to e-methane. This is intended as an exploratory scenario to assess potential upper bound for e-fuels demand.

The total e-fuels demand including e-liquids (e-gasoline, e-diesel, e-kerosene), e-hydrogen and e-methane represents 29% and 52% of the total EU final energy demand in transport in the low and high scenario respectively. **It should be emphasised that these are not intended to be forecasts of future e-fuels demand in transport but rather to provide a potential range within which e-fuels demand could fall.** The demand level actually reached will be dependent on multiple factors including policy settings and technical developments across production and end use applications.

<sup>11</sup> <https://www.iamcdocumentation.eu/index.php/MESSAGE-GLOBIOM>

<sup>12</sup> <https://data.ene.iiasa.ac.at/ngfs/#/workspaces>

**Table 36:** EU energy demand for transport: exploratory scenarios for 2050 [IEA 2021]

Fuel category	Low scenario	High scenario	Notes
	MTOE	MTOE	
Electricity	106	106	For transport
<b>e-liquids</b>	<b>23</b>	<b>72</b>	<b>e-fuels</b>
<b>e-methane</b>	<b>0</b>	<b>3</b>	<b>e-fuels</b>
Biofuels	29	0	Shifted to e-liquids in high scenario
Oil	20	0	Shifted to e-liquids in high scenario
Biomethane	3	0	Shifted to e-methane in high scenario
<b>e-hydrogen</b>	<b>40</b>	<b>40</b>	<b>e-fuels</b>
Natural gas	0	0	
<b>Total e-fuels</b>	<b>63</b>	<b>115</b>	
<b>Total</b>	<b>221</b>	<b>221</b>	

The report evaluates the requirements for generating e-fuels in three regions in Europe. In order to map the full variability of the electricity requirement, the authors evaluated the requirements when the entire production happens within each of these regions. The type of renewable energy used to generate the electricity for producing e-fuels is determined by the specific renewable energy resources available in each region. The three chosen locations and their associated type of renewable energy resource are: Wind in North Europe, PV/wind hybrid in Central Europe and PV/wind hybrid in South Europe. Regardless of the region and category of e-fuel, each e-fuel plant is designed to have an output capacity of 1 million tonnes of oil equivalent per year (MTOE/a). As a result, the number of plants required for a given scenario will be the same in each of the three regions as given in (Table 37).

**Table 37:** Number of e-fuels plants in each of the three locations evaluated

Number of plants	Low scenario	High scenario
e-liquids	23	72
e-methane	0	3
e-hydrogen	40	40
<b>Total e-fuels plants</b>	<b>63</b>	<b>115</b>

The renewable energy (in TWh) required to produce the e-fuels demand indicated by the exploratory scenarios was estimated using an average conversion efficiency for each fuel category (Table 38).

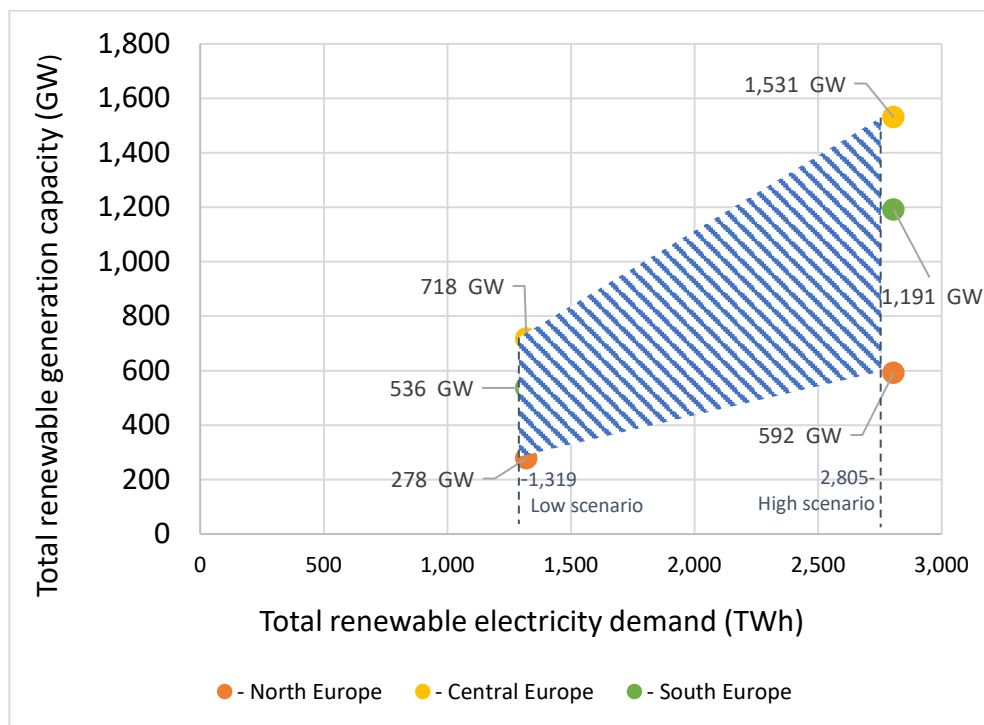
**Table 38:** Efficiencies used for evaluating the electric energy required for e-fuels in 2050

E-fuels category	Efficiency	Notes
	%	
e-liquids	41	via FT synthesis and CO <sub>2</sub> from DAC
e-methane	51	with CO <sub>2</sub> from DAC
e-hydrogen	74	on-site production

Depending on location (North, Central, or South EU) and renewable generation mix (Wind or PV/wind hybrid), a plausible envelope of renewable energy demand and electricity generation capacity required to meet the potential e-fuels demand was estimated as reported in the chart in Figure 121. The results show that the renewable energy demand ranges from 1319 TWh (low scenario) to 2805 TWh (high scenario) while the electricity generation capacity ranges from 278-592 GW (North Europe) and 718-1531 GW (Central Europe) depending on the demand scenario. According to this exploratory analysis, the actual required generation capacity could plausibly lie within the shaded envelope in Figure 121, depending on the final location of e-fuels plants in 2050 and the level of demand.

Comparing this estimation with the current situation, the renewable energy supply from wind, solar and hydro in 2019 in Europe was about 1500 TWh [IEA 2019c], representing between one quarter and one half of the predicted renewable energy needed for transport in 2050 in the low and high scenarios respectively. Meanwhile the current installed renewable generation capacity in Europe was 650 GW in 2021 [IRENA, Renewable Energy Statistics 2022]. Europe plans to rapidly increase the installed capacity and the European Commission, through the REPowerEU plan launched in 2022, has established ambitious targets of achieving 592 GW of solar capacity and 510 GW of wind capacity. This requires a build out rate of a similar order of magnitude to what would be required to meet the e-fuels demand in the scenarios in this study, i.e. in the hundreds of gigawatt range. However, there will be competing demands for renewable electricity and meeting e-fuels demand is likely to require additional renewables deployment over and above what is forecast by IEA.

**Figure 121:** Electricity generation capacity requirements depending on total renewable electricity demand for e-fuels in EU in 2050 based on (location/renewable energy type)



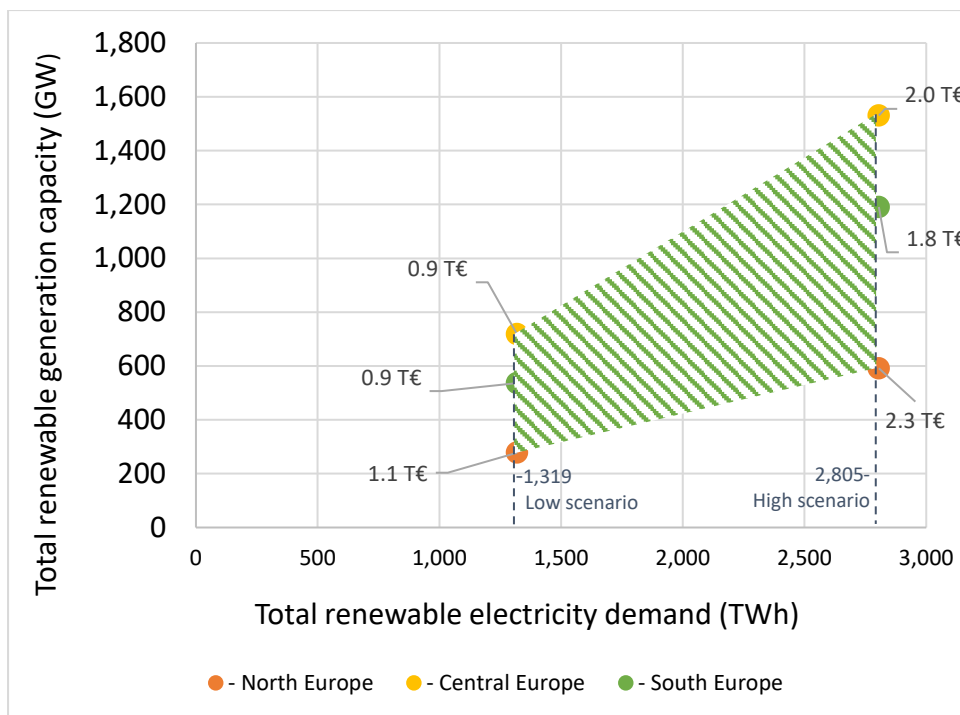
The CAPEX for each e-fuels plant based on e-fuels category and location (already estimated in this report and summarised in Table 39).

**Table 39:** CAPEX in (million €) for each fuel category in the three locations selected

E-fuels category	CAPEX		
	North Europe	Central Europe	South Europe
	Wind in North Europe	PV/wind hybrid in Central Europe*	PV/wind hybrid in South Europe
	million €	million €	million €
e-liquids	24489	21419	19161
e-methane	19943	16913	14963
e-hydrogen	12581	11429	10702

The overall required investment was calculated for each boundary of the scenarios, as depicted in Figure 122. The exploratory scenario analysis shows that the total investment by 2050 for e-fuels in transport lies between €0.9 and 1.1 trillion in the low scenario, and between €1.8 and 2.3 trillion in the high scenario. .

**Figure 122:** Total investment in trillion € required depending on capacity factors (location/renewable energy type) and renewable energy demand for e-fuels in EU in 2050



The average annual investment over the period (assuming constant annual levels) ranges from €33 - 67bn/year if plants are built in the most favourable location and from €40bn - €85bn/year in the least favourable location. By way of comparison, this represents approximately 0.2 - 0.4% (best case) and 0.3 - 0.6% (worst case) of the current GDP in the European Union (€15 trillion [World Economic Outlook Database]). This level of investments is typical for major infrastructure. For example, according to [VDI 2019] the cost of a new generation of telecommunication infrastructure is estimated between €300 - €500 billion for European coverage with 5G mobile network. Similarly, the cost of a new greenfield 400,000 bbl/day refinery is estimated at \$ - 10 billion [EIA 2015], making the annual investment for e-fuels equivalent to roughly 3 - 5 new refineries per year (considering the investment cost if all plants built in the most favourable location).

Assuming a standard e-fuels plant capacity in this study equates to an output of ~1Mtoe per annum in the low case scenario, the e-liquids demand estimate would require the construction of 2 plants per year in each year to 2050. This would rise to 4 plants per year in the high case. The required effort is significant but would be spread over multiple countries reducing the pressure on the supply chain in individual countries. In addition, an annual build out rate of between 10 GW and 57 GW of renewable power generation would be required. To put this into perspective, Europe added 19 GW of new wind capacity in 2022 [Wind Europe 2023] while global solar capacity additions reached over 192 GW in 2022 [IRENA 2023].

In order to frame the e-fuels scenarios investment boundaries in a larger context, according to McKinsey's study, the overall capital expenditure required to reach net zero is expected to be approximately €24 trillion over the next 30 years in EU-27 across all sectors, with 43% (€10 trillion) predicted to be on transportation only [McKinsey 2020]. Therefore, the e-fuels ranges predicted in this report represent about 9-11% (low scenario) and 18-23% (high scenario) of the overall investment required in the transportation sector. Higher investment levels still have been predicted by the EU Commission, with annual investment of €1.4 trillion required by the transportation sector [EC 2018], representing a total investment of roughly €40 trillion in the next 30 years. In this case, e-fuels may represent a percentage of 2-3% (best case) and 5-6% (worst case).

The gross area required for the generating capacity to meet the e-fuels demand in 2050 was estimated by considering averaged data of 2.5-5 MW/km<sup>2</sup> for wind farms [IRENA 2019b], and 30-36 MW/km<sup>2</sup> for solar PV [NREL 2018]. No additional land requirement was assumed for the e-fuels plants or DAC since these are small relative to renewable generation and can more likely use repurposed land.

**Table 40:** Area required for e-fuels demand in 2050 in EU, depending on the renewable energy location and source

Region	Total land required (km <sup>2</sup> )	
	Low scenario	High scenario
North Europe	74,000	156,000
Central Europe	110,000	238,000
South Europe	74,000	168,000

The data shows a maximum gross area requirement of roughly 238,000 km<sup>2</sup> (high demand scenario and PV/wind in Central Europe) and a minimum requirement of roughly 74,000 km<sup>2</sup> (low demand scenario for both Wind in Northern Europe and PV/wind in South Europe). The average value across all the scenarios and renewable energy location and type combination is around 100,000 km<sup>2</sup>. By way of comparison, between 50 and 170,000 km<sup>2</sup> would be required to produce the e-liquids portion of demand from rapeseed crop [ICCT 2018] although this figure would vary widely according to crop type, location and intensity of farming, and its net area occupancy would be ~100% of the gross area. Once again, to put these expected area requirements into perspective, the area of the North Sea is approximately 570,000 km<sup>2</sup>, of which roughly half is non-usable (owing to shipping routes, military exclusion zones, etc.), while the inland area of South Europe (Spain, Italy, Greece and Portugal and the Balkans) is 1.3Mkm<sup>2</sup> [World Bank]. The total European land area is about 4.6 million km<sup>2</sup>. (this is based on 3.99 million km<sup>2</sup> for EU to which has been added the UK (0.24 million km<sup>2</sup>), Switzerland (0.04 million km<sup>2</sup>) and Norway (0.37 million km<sup>2</sup>) giving 4.64 million km<sup>2</sup>), with urban areas representing on average 10% of the total land area [World Bank]. This suggests that between 2 and 3% of the total land area would need to be shared with renewables.

## KEY MESSAGES - POTENTIAL E-FUEL DEMAND IN EUROPE, CAPEX, LAND AREA AND ELECTRICITY REQUIREMENTS

The challenge involved in meeting e-fuels demand in both the high and low scenarios is significant. Vast amounts of investment are required and sizable amounts of resource must be mobilised but these are consistent with other major infrastructure investment.

High and low scenarios for e-fuels developed for this project suggest that demand for e-fuels in Europe could be in the range between 63 and 115 million tons of oil-equivalents. This would require the deployment of anywhere between 278 and 1,531 GW of new capacity depending on the geographic distribution, generation mix and demand scenario chosen. This compares with an installed renewables capacity today of around 650 GW which is still a small fraction of technical renewable power generation potential in Europe (see chapter 5.2.1.1).

The capex required to deliver this amount of e-fuels process plant and associated renewables would lie in the range €0.9 - 2.3 trillion or the equivalent of an annual investment of between 0.2 and 0.6% of EU GDP. This level of expenditure is consistent with other estimates of the investment required to achieve net zero and must be set against the operating cost benefits of switching to renewables (high capex but low opex cost profile) not to mention the benefits in terms of energy security. It is also comparatively low considering that the cost of a new generation of telecommunication infrastructure is estimated between €0.3 - 0.5 trillion in the case of European coverage with 5G mobile network.

While gross land use requirements are significant, being around 0.1 million km<sup>2</sup>, this represents a proportion of some 2% of the total usable European land area. The challenge involved in meeting e-fuels demand while significant is spread over a large region, mitigating the pressure on the supply chain.

The investment required must be set against the reduction in operating costs that would result from shifting away from fossil fuels as well as the costs of climate change, e.g. adapting to a significant rise in global temperatures. No absolute technical show-stopping concern was identified but consideration must be given to whether e-fuels represent the desired way to achieve net-zero ambitions where other alternatives, such a direct use of electricity, exist. Deployment of e-fuels plant and especially electricity generating capacity may have to be handled in a sensitive way recognising that there can be societal concerns over aspects such as changes in the visual landscape.

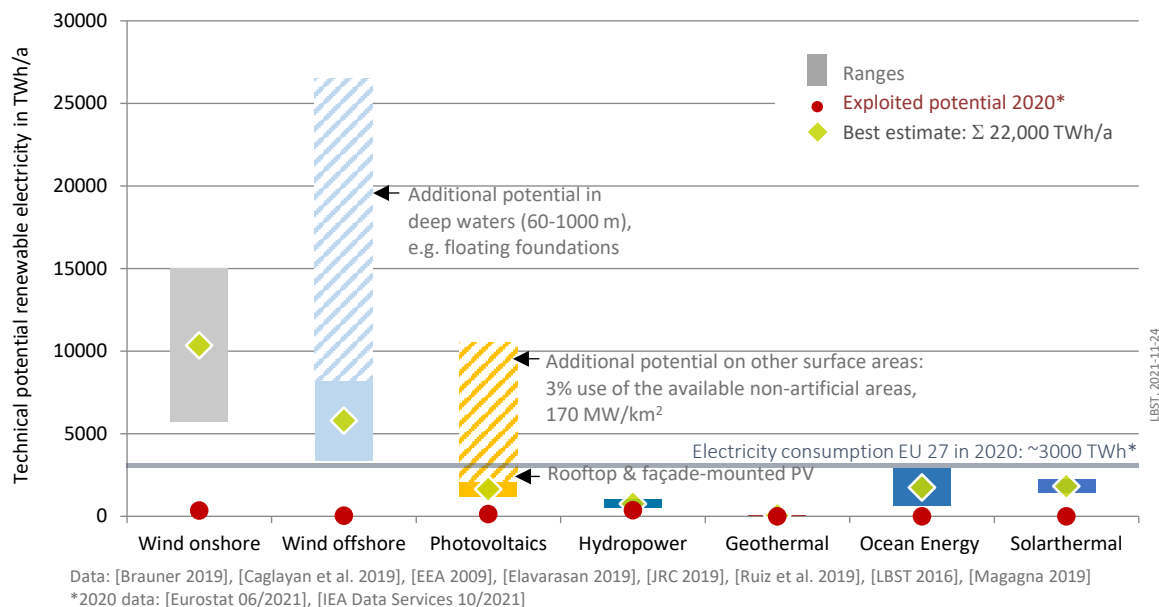
## 5.2. TECHNICAL AVAILABILITY AND POTENTIAL OF FEEDSTOCKS

The previous chapter explored the potential demand for e-fuels and what that represents in terms of required electricity and e-fuels supply capacity. This chapter explores the theoretical supply potential and whether there are any constraints which might limit the expansion of e-fuels.

### 5.2.1.1. Technical renewable electricity potentials

Figure 123 depicts the technical renewable electricity production potentials for Europe derived from a literature review. The bars indicate bandwidths of assumptions taken in literature e.g. for specific area demand and future power plant performance data.

**Figure 123:** Technical renewable electricity production potentials for Europe (Source: LBST based on literature review)



Summing up the bandwidth averages results in 22,000 TWh/a of renewable power production potential. Hence, conservative assumptions of European technical renewable power production potentials are sufficient to cover at least seven times today's electricity consumption. For comparison:

- If **today's transport fuel demand** of EU 28+ was completely provided with PtL (worst and **unrealistic case**, but just to put figures in perspective), this would result in a renewable electricity demand of ~12,000 TWh<sub>e</sub>/a, thereof ~1,600 TWh<sub>e</sub>/a for aviation.
- Assuming a **range of scenarios using 100% renewable energy use in all transport** for BEV charging, e-hydrogen, e-methane, and e-liquids in EU27+UK by 2050, according to [FVV 2021, p 69ff] this would result in 2,570 to 10,880 TWh<sub>e</sub>/a of renewable electricity demand.

The main limitation on exploiting the significant renewable electricity potentials in Europe may be social acceptance of mass deployment of wind and solar power plants.

Table 41 gives the techno-economic/'realistic' renewable electricity production potentials for PtX plants in the Middle East/North African regions derived from the PtX Global Potential Atlas<sup>13</sup>.

<sup>13</sup> <https://maps.iee.fraunhofer.de/ptx-atlas/>



**Table 41:** Techno-economic/'realistic' renewable electricity production potentials for PtX plants MENA (based on data from [IEE 2021])

TWh <sub>e</sub> /a	Hybrid (c.)	Hybrid (i.)	PV (c.)	PV (i.)	Region SUM
Algeria	-	370	-	599	969
Morocco	743	-	131	-	875
Tunisia	436	79	60	-	575
Saudi Arabia	1330	48	2419	196	3993
UAE	-	-	967	-	967
Tech. TOTAL	2509	497	3578	794	7378

Hybrid: suitable for wind & solar  
c.: along the coastline  
i.: along inland waters

According to the *PtX Global Potential Atlas*, the techno-economic/'realistic' potentials of e-H<sub>2</sub><sub>gas</sub> production in the MENA region is ~5000 TWh<sub>H2</sub> or 150 million t<sub>H2</sub> per year. This is a very conservative estimation as it incorporates infrastructure restrictions, such as limiting the distance to the coast, and restricting transport to inland waterways and existing pipeline infrastructures. Assuming a 67% conversion efficiency, the hydrogen production potential translates into renewable electricity supply potentials of 7378 TWh<sub>e</sub> per year. The main limitation to exploit this potential may be **political and energy security risks**, e.g. impacting discount rates for investment which are typically region and project specific.

According to [Bond et al. 2021], the share of solar & wind potential of Africa and Middle East is ~40% and ~8% of global technical potential, respectively, i.e. **huge**. The share of Europe is estimated to be ~3%, i.e. still huge compared to current and prospective renewable electricity demand.

High potentials of renewable electricity are available in South Europe (Spain), MENA, Australia, and Chile. However, there are also some regions in Central Europe e. g. at the Lusatia lignite mining region in Germany where large-scale PV-wind hybrid power could be installed for the supply of electricity for e-fuels. On the other hand, in densely populated regions with cold winters like Germany there is an increasing electricity demand of other sectors especially due to expansion of electrically driven heat pumps for heat supply. Therefore, for **liquid e-fuels where transport costs are low, less-densely populated regions with high renewable electricity potential such as the MENA region are an option**. The most cost-effective transport of gaseous e-fuels is via pipeline where topography allows for this option.

#### 5.2.1.2. Availability of concentrated CO<sub>2</sub> sources

The CO<sub>2</sub> source is an important determinant of the greenhouse gas balance of carbon containing e-fuels. Today, early in the deployment phase, there is a notion to utilize the most concentrated CO<sub>2</sub> sources that are available and unavoidable to save on process energy demands, reduce plant complexity, and lower asset investment. However, CO<sub>2</sub> emissions from fossil sources will be reduced towards 2050 and other

CO<sub>2</sub> sources will be required: direct air capture (DAC) of CO<sub>2</sub> from air, CO<sub>2</sub> from biogas upgrading, biomass fermentation to alcohols, and exhaust gas CO<sub>2</sub> from biomass fueled heat and power plants (biomass complying with sustainability criteria). Sustainability safeguards are necessary to avoid unintended collateral damage and to reduce risks for stranded investment in future. Table 42 depicts the different sustainability aspects for exemplary concentrated CO<sub>2</sub> sources.

**Table 42:** Sustainability and perspectives of different CO<sub>2</sub> sources

CO <sub>2</sub> sources	Renewability	Environmental sustainability	Alternative CO <sub>2</sub> uses	Towards carbon-neutrality; Risks	Eligible under EU RED II [RED II-DA 2023]
Extraction from air		Subject to renewable energy			
Biogas upgrading			Power-to-methane		
Solid biomass fired heat (& power) plants		Subject to feedstock & process	Bio-CCS	Other land or sustainable biomass uses	Complies with sustainability and greenhouse gas savings criteria/ CO <sub>2</sub> capture did not receive credits for emission savings
Fermentation to alcohols			Beverage industry		
Geothermal sources		Subject to geo-phys. CO <sub>2</sub> cycle	CO <sub>2</sub> re-injection (closed-loop)	Hot dry rock a potential no-go	CO <sub>2</sub> was previously released naturally
Cement, burnt lime or glass production		Subject to energy input; process-related emissions	Power-to-chemicals	Shift to alternative materials, recycling; Technology lock-in	CO <sub>2</sub> has been taken into account upstream in an effective carbon pricing system and is incorporated in the chemical composition of the fuel before 2041 (2036 for combustion of fossil fuels for electricity generation)*
Steel production (coke-based)		Subject to feedstock & process	Top-gas for heating and reduction	Shift to direct reduction with H <sub>2</sub> , recycling, alternative materials; Technology lock-in	
Fossil fuel firing			CCS	Phase-out; Technology lock-in	

\*No fuel combustion for the specific purpose of producing CO<sub>2</sub>

The potential of concentrated CO<sub>2</sub> sources such as biogas upgrading, and biomass fueled combined heat and power stations is subject to significant uncertainty in a changing energy and resource landscape. There are competing uses for wood and wood products other than wood-based bioenergy e. g. in households, and sustainable bioenergy potential is constrained especially in regions like MENA. Furthermore, bioenergy plants are too small to supply CO<sub>2</sub> for e-fuel plants with capacities envisaged here and these are sometimes not located in regions with high solar irradiation and wind speeds like the MENA region. However, the availability of biogenic CO<sub>2</sub> could be less constrained as suggested by the study by [Imperial College 2021] and would merit further investigation.

CO<sub>2</sub> is also avoidable in other ways. Primary steel plants can be converted from blast furnace to direct reduction iron (DRI) technology using renewable hydrogen and avoiding CO<sub>2</sub> emissions from primary steel production in the future. In case of CO<sub>2</sub> from geothermal plants it is subject to the geo-physical cycle. A closed water loop including re-injection of the CO<sub>2</sub> can avoid these CO<sub>2</sub> emissions.

By contrast, CO<sub>2</sub> from cement production often is considered unavoidable. In the Kingdom of Saudi-Arabia (KSA) about 43 million t of clinker<sup>14</sup> was produced in 2019 [KAPSARC 2020]. Approximately 560 kg of CO<sub>2</sub> can be captured per t of clinker [Gardarsdottir et al. 2019]. As a result, the potential for CO<sub>2</sub> from cement production for e-fuels in KSA would amount to about 24 million t per year sufficient for about 10 PtL plants with a capacity of 114 t of diesel equivalent/h based on Fischer-Tropsch synthesis in KSA generating about 273 PJ of final fuel per year (~6 million t/yr, see Table 43).

<sup>14</sup> Clinker is a pre-product for cement production

**Table 43:** Potential for CO<sub>2</sub> from cement production

	Unit	MENA (KSA)	MENA (Morocco)
Clinker production 2019	million t	43	3.1
Potential CO <sub>2</sub> captured	kg CO <sub>2</sub> /t <sub>clinker</sub>	559	559
	million t/yr	24.0	1.73
CO <sub>2</sub> demand FT synthesis	kg/MJ <sub>final fuel</sub>	0.0880	0.0880
Potential fuel production	PJ/yr	273	19.7
	million t/yr	6.33	0.457
Equivalent full load period PtL plant	h/yr	5319	4560
Capacity PtL plant	MW <sub>final fuel</sub>	1368	1368
	t/h	114	114
Number of PtL plants		10.4	0.9
Domestic demand gasoline, kerosene, diesel	PJ/yr	2267	243

The potential for CO<sub>2</sub> from clinker production in Morocco is much lower and the CO<sub>2</sub> potential from clinker production in both KSA and Morocco is insufficient to meet the local demand of transportation fuel (2267 PJ/yr in 2019 based on [KAPSARC 2021] and 243 PJ/yr in 2017 based on [IEA 2019b] respectively).

Furthermore, in the case of cement production using renewable energies in the future to meet the Paris Agreement, the remaining CO<sub>2</sub> released by the chemical reaction from the calcination of limestone for clinker production can be avoided via

- returning demolished concrete to the cement production process and thus closing the CO<sub>2</sub> loop [Heidelberg Cement 2021],
- increasing use of alternative construction materials, or
- avoiding cement production via extending the use-phase of concrete-made structures (e. g. renovation instead of dismantling and new construction).

Table 43 shows an overview of CO<sub>2</sub> from cement production.

According to a literature review by [Concawe 2019, p 46f], the CO<sub>2</sub> available from large point sources in 2030 seems to be sufficient to cover the foreseeable demand from the production of electricity-derived synthesised fuels and chemicals. Supply from concentrated CO<sub>2</sub> sources could be more constrained in the mid to long-term horizon (2050), subject to the sustainability assessment of large point sources (supply side) and scenarios for synthesised e-fuels production (demand side).

In the recently published [RED II-DA 2023] all previously discussed CO<sub>2</sub> sources are considered eligible for the production of e-fuels as long as they meet the minimum savings threshold of 70%. Exceptions are fuels that are deliberately combusted to specifically produce CO<sub>2</sub> and also captured CO<sub>2</sub> that has already received an emissions credit und other provisions of the law. Activities listed under Annex I of Directive 2003/87/EC (referring to the EU emissions trading scheme) are only eligible if the CO<sub>2</sub> is incorporated in the chemical composition of the fuel before 2041. For the combustion of fuels for electricity generation, this date is brought

forward to 2036. From 2041 onwards, only CO<sub>2</sub> captured from the air, from the production or combustion of biofuels, bioliquids or biomass fuels, as well as from geological sources will be eligible under RED II.

#### 5.2.1.3. Availability of water

The availability and sustainability of water that can be further processed to demineralized process water is subject to local conditions. Large point consumption such as for agriculture, beverage bottling or industry uses usually require an environmental impact assessment to achieve construction and operation authorisation.

Regions with high solar irradiation such as Southern Europe, North Africa and KSA often are affected by water scarcity. Seawater desalination will likely be required to supply water in a sustainable way in these regions for the various aspects of e-fuels production. Climate change is also increasingly felt in Central Europe with changing patterns of precipitation and water storage (snow, ice).

However, the water demand for the cleaning of PV panels is low. For MENA the water demand is indicated with 0.04 kg per kWh of electricity for PV power plants in 2020. It is expected that the water demand for the operation of PV power plants decreases to 0.03 kg per kWh until 2050. Dry cleaning of PV panels also is possible [SolarClean 2021] and considered a must in dry regions [PI Berlin 2018]. The water demand for wind power is negligible [DLR et al. 2021]. For water electrolysis about 0.27 kg of water per kWh of hydrogen is required (~75 kg per GJ of hydrogen). Furthermore, direct air capture (DAC) of CO<sub>2</sub> also extracts about one kg of water from the air per kg of CO<sub>2</sub>. As a result, a large fraction of the water demand of the e-fuel plant can be supplied by the DAC plant. Water is also released by the methanol and Fischer-Tropsch (FT) synthesis.

While water demand may be necessary for cooling, the cooling water demand of the Qatar GTL plant is met by the water released by the FT reaction [Shell 2021] and no water is imported and no water is exported. Furthermore, dry cooling towers can reduce the water demand for cooling.

**Table 44:** Water demand e-fuel plants

		H <sub>2</sub>	MTK	FTK
H <sub>2</sub> demand for synthesis & further processing	MJ/MJ <sub>final fuel</sub>	-	1.241	1.404
Water demand water electrolysis	kg/kWh <sub>final fuel</sub>	0.268	0.333	0.376
	m <sup>3</sup> /GJ <sub>final fuel</sub>	0.074	0.092	0.105
CO <sub>2</sub> demand	kg/MJ <sub>final fuel</sub>	-	0.074	0.088
Water extracted from air by DAC plant	kg/kgCO <sub>2</sub>	-	1	1
	m <sup>3</sup> /GJ <sub>final fuel</sub>	-	0.074	0.088
Net water demand e-fuel plant	m <sup>3</sup> /GJ <sub>final fuel</sub>	0.074	0.019	0.017
	l/l <sub>diesel equivalent</sub>	2.673	0.678	0.594

In case of H<sub>2</sub> generated in KSA, the annual water demand would amount to about 3.7 million m<sup>3</sup> per year for a water electrolysis plant with a capacity of 2878 MW of hydrogen based on the LHV supplying 1 million t of diesel equivalent to Europe

per year in 2050 (assumption:  $H_2$  carrier completely fueled with hydrogen). By contrast, in the case of MTK and FTK supplying the same amount of final fuel per year the annual net water demand would amount to about 0.7 to 0.8 million  $m^3$  per year if the e-fuel plant were located in KSA. This compares to current water consumption in KSA, which exceeded 8 million  $m^3$  per day (> 2920 million  $m^3$  per year) in 2019 [USSBC 2021].

In regions with water scarcity the net water demand of the e-fuel plant has to be supplied by seawater desalination plants. There are already seawater desalination plants operational and under construction in MENA. The CAPEX for the seawater desalination plant would amount to less than 1% of the CAPEX of the electrolysis plant (see chapter 2.1.2) and as a result, less than 1% of the total CAPEX of the e-fuel plant.

The water demand of e-fuel plants can be compared with capacity of current water desalination projects to give an idea about the scales this study is talking about. In Casablanca in Morocco a large seawater desalination plant with a capacity of 300 million  $m^3$  of drinking water per year is under construction. The plant will be operational by end of 2027 [MLN 2021]. Existing seawater desalination plants are located Laayoune, Boujdoor, Tan-Tan, and Sidi Ifni. Other seawater desalination plants are under construction including one in Agadir (144 million  $m^3$  per year), one in Al Hoceima, one in Safi, and one in Dakhla [MLN 2021]. The capacity of current water desalination projects is significantly higher than the water demand of individual large e-fuel plants. Water scarcity is a major problem in KSA, with around 40% of the water demand in 2019 being met by extraction of water from deep groundwater sources where far more water is extracted than recharged naturally. About 60% of the water demand is met by seawater desalination and only a small amount of the water comes from surface water and reclaimed wastewater [USSBC 2021]. As a result, expansion of seawater desalination is required regardless of large-scale e-fuel plants will be built in KSA in the future.

Specific water demand for electricity-based fuels is negligible compared to the water demand for energy crops [UBA 2022].

### Practical implementation examples

Suitable locations for e-fuel plants in North Europe are at the coast connected with high voltage direct current (HVDC) electricity transmission cables from large offshore wind power plants. For example, the company Nordic Blue Crude is just building a pilot plant for the production of synthetic jet fuel and other products in Herøya in Porsgrunn, 160 km Southwest of Oslo in Norway. Another pilot plant is the KEROSyN100 project at the Heide refinery in Germany nearby the North Sea coast (and nearby offshore wind farms) where synthetic kerosene will be produced.

It is also possible to build large-scale water electrolysis offshore nearby the offshore wind farms and transport the hydrogen via pipeline to the coast. From there the hydrogen can be distributed via a hydrogen pipeline grid. No active projects of this type as yet exist although a number of developers are studying offshore wind to hydrogen solutions, e.g. the Dolphyn Project [ERM 2022].

Former lignite mining regions e. g. in Bulgaria, Czech Republic, Germany, Greece, Poland, Romania may also be suitable locations for large scale onshore projects. These have the added benefit of providing these regions with welcome economic activity after the complete phasing out of brown coal.

**KEY MESSAGES** - Technical potentials for renewable power production in Europe (>22,000 TWh/yr) is a factor of seven of today's electricity demand and (~3000 TWh/yr) thus exceeds the foreseeable energy demand for all energy uses in a carbon-neutral future, in principle. However, exploiting this renewable power potential is subject to social acceptance of the significant infrastructure that would have to be built. The technical potentials in other regions of the world is even greater, but can be associated with geopolitical and energy security risks.

The use of concentrated (point) CO<sub>2</sub> sources lead to lower overall fuel costs, notably in the short-term when technologies for direct air capture are not yet available at-scale and are early in the learning curve but have higher emissions. The potential from industrial CO<sub>2</sub> sources, such as from steel production or cement, is set to decrease with novel production pathways, increased recycling efforts, and a general move towards a more circular economy.

Specific water demand for electricity-based fuels is negligible compared to water demand for energy crops as previously reported by [UBA 2022]. For regions that are prone to, or already face, water-supply stress, use of dry cooling towers and/or closed-loop water cycling is recommended (where needed) to minimise net water demand. Some direct air capture technologies also provide water that can reduce the net water demand from PtX plants. Despite the low specific water footprint, PtX production plants at-scale are significant point water consumers. Diligent assessment of water supply, demand, and reservoir characteristics are a relevant part in the preparation of environmental and social impact assessments (ESIA) accompanying plant approval processes. In the absence of sufficient fresh water supplies, desalination of sea water may be required but this adds marginally to the overall cost of the fuels.

### 5.3. AVAILABILITY OF EXISTING INFRASTRUCTURE

#### 5.3.1. Availability of hydrogen pipeline grids

There are several projects for the implementation of a hydrogen pipeline grid in Europe. Within the GET H<sub>2</sub> initiative a hydrogen pipeline backbone grid is planned in Germany [GET H<sub>2</sub> 2021]. The length of the hydrogen pipeline backbone grid will reach 130 km by 2023, 452 km by 2026, 1294 km by 2028, and 5900 km by 2030. The steps to realising this goal include:

- 2024: GET H<sub>2</sub> Nukleus
- 2025: Connection to The Netherlands
- 2026: Inclusion of a hydrogen storage and start of operation in Salzgitter
- 2030: Connection of elements

GET will form part of the European Hydrogen Backbone described in [Guidehouse 2021].

In addition to the German GET H<sub>2</sub> project, many H<sub>2</sub> transmission projects are being planned across Europe. An overview of ongoing projects can be found in [ECH2A 2023].



Existing projects are divided into the following six potential H<sub>2</sub> corridors and are also shown in Figure 124:

1. South Central H<sub>2</sub> corridor
2. Iberian H<sub>2</sub> corridor
3. North Sea H<sub>2</sub> corridor
4. Nordic Baltic H<sub>2</sub> corridor
5. Eastern H<sub>2</sub> corridor
6. South-eastern H<sub>2</sub> corridor

Many of these projects enter a commissioning year of 2030, some even as early as 2025.

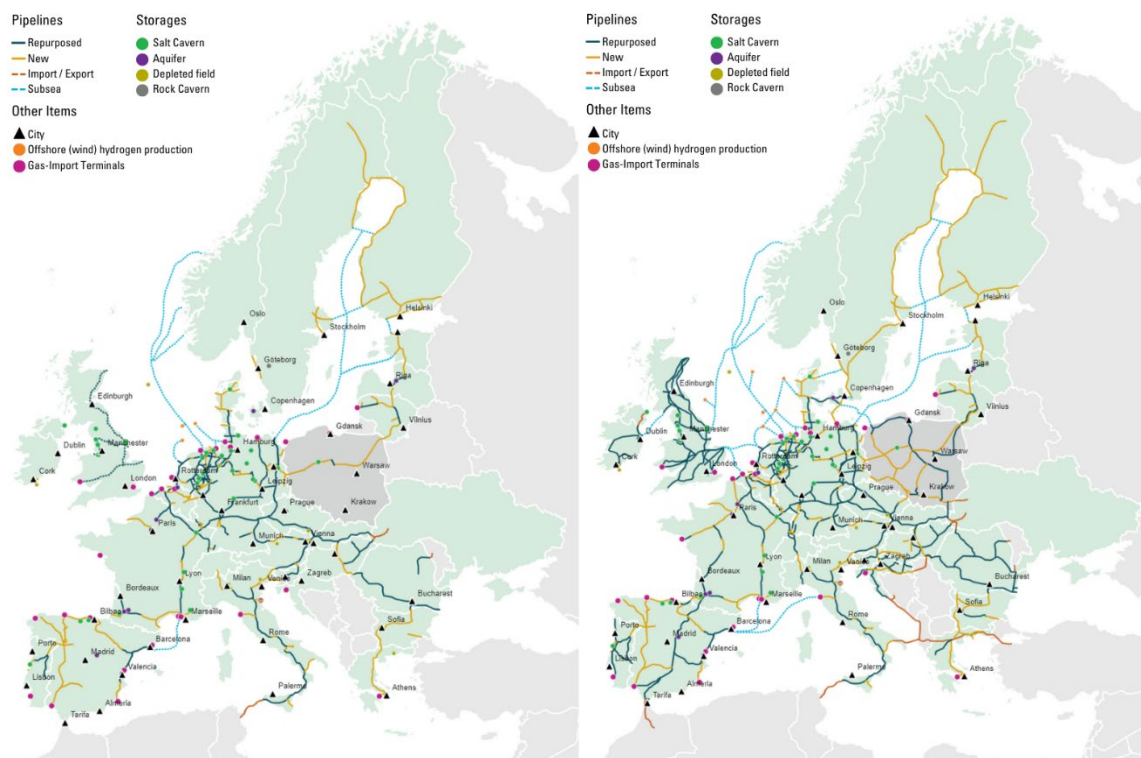
**Figure 124:** Six potential hydrogen transmission corridors



Source: LBST

In [EHB 2022] a roadmap for the development of a European hydrogen pipeline grid is described. The length of the hydrogen pipeline grid may reach 28,000 km by 2030 and 53,000 km by 2040 covering 28 European countries. The majority of the hydrogen pipeline grid would consist of repurposed natural gas pipelines as this was found technically feasible and more economical than building new pipelines. Since 2021, the European Union's REPowerEU and several national initiatives were brought forward which are reflected in an updated proposal for an European hydrogen backbone infrastructure as depicted in Figure 125 for 2030 (left map) and 2040 (right map).

**Figure 125:** Hydrogen backbone pipeline grid 2030 (left map) and 2040 (right map)



Source: EHB 2022

## 5.4. SAFETY, ENVIRONMENTAL AND SOCIAL CONSIDERATIONS





Safety and environmental regulations for drop in e-fuels (e-liquids and e-methane) are well established and it is not anticipated that any particular additional regulation will be required. Similarly, the regulatory picture for large scale production of hydrogen, ammonia and methanol are all subject to stringent regulation. Hydrogen also has a well-established set of norms for its use in transportation with clear requirements for hydrogen refuelling stations and fuel cell vehicles. Some further work will be required to deal with the specifics of hydrogen use in trucks but its use in buses is now relatively commonplace, mainly in China<sup>15</sup>. By contrast the use of both ammonia and methanol in distributed downstream applications is much less developed and the safety and environmental considerations for the use of both these fuels would need careful consideration. Ammonia, in particular, is highly toxic and harmful to life and, in addition, can result in major environmental damage if released.

Table 45 provides an overview of the toxicity and safety considerations associated with selected e-fuels.

<sup>15</sup> In their technology status report for 2020, NREL considered fuel cell-electric buses to be around technology readiness level (TRL) 7-8 [NREL 2021]. Up to September 2021, fuel cell buses have been accumulating 13 million km in operation in the European Union [HE & WaterstofNet 2022]. More than 1000 units of FCEV buses are shipped each year worldwide [E4tech 2021]. Following a first wave of battery-electric buses China has started rolling out fuel cell-electric buses with a fleet stock of about 4300 buses in 2020 [IEA 2020c].



**Table 45:** Toxicity classification of selected fuels and safety issues

	Methanol	Hydrogen (gas, liquefied)	Methane (gas, liquefied)	Ammonia (gas, liquefied)
Chemical formula	CH <sub>3</sub> OH	H <sub>2</sub>	CH <sub>4</sub>	NH <sub>3</sub>
Acute toxicity (oral, dermal)	Category 3	-	-	
Acute toxicity (eyes, central nervous system)	Category 1	-	-	
Acute toxicity (inhalation)		-	-	Category 3
Serious eye damage		-	-	Category 1
Skin corrosion/irritation		-	-	Category 1B
Carcinogenicity	-	-	-	-
Persistence	Readily biodegradable	Biodegradeable	Biodegradable	Readily biodegradable
Aquatic environment (acute)		-	-	Category 1
Aquatic environment (long term)		-	-	Category 2
Safety issues		Compressed gas, cryogenic burns	Compressed gas, cryogenic burns	Compressed gas
Flammable gases/liquid	Category 2	Category 1	Category 1	Category 2
				

In 2019 about 17.5 million t of NH<sub>3</sub> was transported by 71 NH<sub>3</sub> carriers worldwide. The energy content of these transported NH<sub>3</sub> amounts to 325 PJ based on the LHV. NH<sub>3</sub> is e.g. proposed as fuel for ship propulsion. According to [IEA 2015] 204.84 million t of oil equivalent or 8577 PJ of fuel were consumed by international navigation that year. If the fuel demand of the marine ships were substituted by NH<sub>3</sub> the amount of NH<sub>3</sub> handled worldwide and the associated risks would be increased significantly.

Further energy applications are being discussed to potentially use ammonia in future, such as NH<sub>3</sub> as a long-distance carrier of hydrogen (power to hydrogen to ammonia to hydrogen), NH<sub>3</sub> as fuel for inland waterway vessels, or for electricity generation via NH<sub>3</sub>-fuelled gas turbines. Expanding the use of NH<sub>3</sub> beyond today's use as feedstock for fertiliser and chemicals entails increasing today's risk surface potentially by several orders of magnitudes. Following the root-cause-principle, minimising the risk surface would require the production and storage of ammonia as close (site and time) as possible to its use. This principle, however, contradicts with today's notion for long-distance transport and storage of bulk NH<sub>3</sub> volumes.

#### 5.4.1. Human safety considerations in the use of ammonia

Ammonia has been in use globally for over 100 years resulting in an accumulation of safety experience, a mature set of international laws and regulations, and a sophisticated support sector providing ammonia users and first responders with safety equipment, training, and education.

Ammonia is toxic, causing irritation to humans at low concentrations and can be life threatening at high concentrations. Early detection at low concentrations is feasible through human smell and automated gas detection, even at low ppm levels is effective. However, the immediate consequences of ammonia spills can be more damaging, e.g. through skin impacts, dissolution in bodies of water will be toxic to aquatic life and in the worst case, can cause death by inhalation. Ammonia is flammable and when stored under pressure (<17 bar) presents an explosion risk but its low reactivity means high temperatures are required for ignition and it has a low flammability range in air.

A 2019 study by TU Delft and C-JOB provides a technical assessment of ammonia as a marine fuel and suggests that its risk profile is comparable to other marine fuels e.g. it is less flammable than LNG and is no more toxic to aquatic life than marine oil. Other studies suggest that safety and risk concerns for ammonia are comparable to those for petrol and diesel and lower than for LPG so the associated challenges may not be an obstacle to the implementation of ammonia fuel technologies. However, none of these studies take worst-case scenarios (unintended or intended incidents) into account that fully explore the potentially very high impacts.

In [Keinan 2017] the consequences of an accident or a terrorist attack of a  $\text{NH}_3$  carrier at Haifa in Israel has been described based on a report carried out by several scientists and engineers. Rupture of the studied ammonia ship would create a deadly cloud of ammonia, which could reach the entire metropolitan area of Haifa (Israel) and beyond. All the metropolitan areas of Haifa and its suburbs are within the range of a deadly  $\text{NH}_3$  cloud, even if the attack occurred when the ship was within the waiting area in the centre of the bay, i.e. away from the port. 600,000 inhabitants would have to be quickly evacuated, which is considered impossible due to the many affected people and paralyzed drivers blocking the roads [Keinan 2017]. After publication of the report, the Haifa Local Affairs Court ruled to empty the existing 12,000 t  $\text{NH}_3$  tank in Haifa [Jerusalem Post 2017]. The study also found that road accidents with  $\text{NH}_3$  laden trucks with a release of 20 tons of  $\text{NH}_3$  gas in urban area also can be disastrous [Keinan 2017].

The Haifa case study shows a number of adverse aspects in a single case. Each of these aspects raises concerns if the production, storage, transport, and use of ammonia is to be significantly further expanded in the future to also serve as a bulk energy carrier and fuel in the energy sector.

#### 5.4.2. Environmental considerations

Air pollutants arising from ammonia use need to be managed in line with air quality strategies. The UK Governments Clean Air Strategy noted ammonia as one of the five most damaging air pollutants. Nitrogen oxides ( $\text{NO}_x$ ) play a major role in climate change, as they have a greenhouse warming potential (GWP) almost 300 times that of  $\text{CO}_2$ . The GWP of  $\text{N}_2\text{O}$  is even higher than that of  $\text{NO}_x$  and the effects of its release are not well understood. Thermal  $\text{NO}_x$  emissions are produced on combustion of all fuels but the combustion of ammonia has the potential for higher  $\text{NO}_x$  emissions due to the additional nitrogen content of ammonia itself. Unburnt ammonia ‘slip’ can also arise in the exhaust. Ammonia itself is not a greenhouse gas but  $\text{NO}_x$  will react with ammonia emissions to form particulate matter ( $\text{PM}_{2.5}$ ) which is an important secondary air pollutant that can cause respiratory and cardiovascular issues.

The IMO regulates emissions of air pollutants from shipping MARPOL. Emission standards are commonly referred to as Tier I, II and III, and vessels must comply with  $\text{NO}_x$  limits in Emission Control Areas. Where possible, engine designers try to comply with  $\text{NO}_x$  emission regulations through improved combustion technology and

exhaust gas recirculation, as aftertreatment systems increase complexity and cost. However, all modern combustion engines are required to operate Selective Catalytic Reduction (SCR) systems in which ammonia stored in a urea solution (commonly marketed as “AdBlue”) is used to reduce NO<sub>x</sub> to nitrogen and water vapor and these can decrease emissions by over 90%. It is possible the SCR system could be modified to operate with the same ammonia used on board as fuel. NO<sub>x</sub> is also eliminated if ammonia is used in a fuel cell, as is particulate matter.

### 5.4.3. Current and required safety and environmental regulation

Health, safety, risk and the environment will all be critical considerations in the deployment of ammonia as an energy vector. Existing legislation varies in different parts of the world and necessary legislative changes and standardization will represent a major challenge. Currently, no jurisdiction has a legal approach that fully addresses both environmental and health and safety concerns in all applications although REACH has gone some way to setting out a harmonised approach [ECHA].

The US is highly dependent on ammonia as a feedstock for e.g. fertiliser and has thus established regulations and legislations focused on occupational safety, public security and transportation. In the US, the EPA (Environment Protection Agencies) and OSHA (Occupational Safety and Health Administration) are the main federal agencies with performance standards for environment and safety that apply to the use and consumption of toxic and explosive materials i.e. ammonia and ammonium nitrate, respectively. The EPA develops risk management programs (RMP) and are concerned with environmental impacts and health and safety of the public outside facilities, and the main regulation is RMP-40CFRPart68. The General Duty Clause is the threshold quantity above which prompts the enforcement of the RMP and this is 10,000 lbs (around 4.5 tonnes) for ammonia. This legislation will not apply e.g. to a fuel tank exemplifying the fact that new standards are required for expanded use of ammonia. OSHA is focused on process safety management and applies to workers and technicians within the bounds of facilities and the main regulation is 29 CFR 1910.119. ANSI (American National Standards Institute) has collaborated with the IIAR (International Institute of Ammonia Refrigeration) to establish rules and issue standards outlining good engineering and operating practices in the ammonia refrigeration industry. IIAR have 9 ANSI approved ammonia standards and have published the ‘ammonia data book’ and other guidelines and handbooks covering practical and technical information relating to the use of ammonia.

The EU has developed legislation and regulations surrounding the production, storage, mobility, and use of ammonia and the European Chemicals Agency (ECHA) has set workplace exposure limits for ammonia via directives such as EH40/2005. In the EU, the Gothenburg Protocol was implemented in 1999 to reduce acidification, eutrophication, and ground-level ozone and sets emission ceilings for Member States and includes control measures for reducing ammonia emissions from agriculture. Chinese regulations are heavily concerned with the impact that ammonia can have in bodies of water which is regulated by the GB 13458-2013 standard issued by the China’s Ministry of Ecology and Environment (MEE). In the EU, rail and waterway transport is favoured over road given the more effective risk mitigation.

Standards for ammonia synthesis, cracking and end use are all important and should be consistent with existing standards and common throughout the value chain and across all regulated industries. Many ammonia standards exist for current feedstock markets e.g. training, regulatory, safety, handling, environmental, emissions and product standards. However currently there is not a recognised fuel standard, and this will require a new set of components to facilitate its acceptance. These will include standards for purity testing and handling in fuel applications, as the current

regulatory and permitting landscapes are not clear. The Ammonia Energy Association (AEA) Fuel Standard Committee has developed a draft product specification to facilitate the acceptance of ammonia as a fuel which would mirror the industry standards today for C-grade (Commercial grade/Agricultural grade) ammonia which has 99.5% purity. This is the most consumed grade worldwide and would be of sufficient purity for use as a fuel and in power generation.

Due to ammonia's toxicity and reactivity, in marine settings the IGC Code specifies strict requirements on the materials that can be used to contain ammonia onboard as well as on design features required to minimize the risk of exposure. Double walled piping must be used in enclosed spaces in accordance with the IGF code, a ventilation system would have to be installed and the fuel tank located to be safe from grounding and away from areas with high risk from fire or mechanical damage. Given the rapid development in ammonia engine technology, IMO and ISO will need to develop applicable codes and safety standards as the use of ammonia as a fuel and the operation of ammonia-based engines are currently precluded under existing regulation. This will be a critical focus if, as some predict, use of ammonia as a marine fuel becomes widespread.

#### 5.4.4. Societal acceptance of e-fuels

One critical benefit from the use of liquid e-fuels is that it minimises the need for change on the part of the end-use. E-gasoline, e-kerosene and e-diesel can be produced as drop-in fuels and obviate the need for changes to end use applications using internal combustion engines. By contrast, gaseous e-fuels such as hydrogen will require a process of education in order to familiarise end-users with their safe use. That said, the use of hydrogen has been extensively tested in locations such as Asia, Europe and the USA where significant fleets of FCEV are seen. Similarly, fuel cell buses are now relatively commonplace and have seen general acceptance by the public from the very beginning [AcceptH<sub>2</sub> 2005].

Attitudes to the widespread use of ammonia as an energy vector has been researched by [Guati-Rojo et al 2021]. This revealed that perceptions of green ammonia among participants in both the UK and Mexico were surprisingly positive, but the authors add a note of caution to the results given the novelty of the concept. This would be a valuable avenue of future research.

#### KEY MESSAGES - SAFETY, ENVIRONMENT AND SOCIAL CONSIDERATIONS

Safety regulations are well established for "drop-in" fuels such as e-kerosene and a well-established standard for the handling of hydrogen has been in place in industry for decades. However, ammonia in particular is highly toxic and harmful to human life as well as presenting risks to the environment through its toxicity to aquatic life.

The use of ammonia and, to a lesser extent methanol, in distributed settings, densely populated areas or outside confined industrial spaces will therefore require significant changes to safety, security and environmental regulations. Public reluctance may exist and prove difficult to overcome, although recent academic research suggests that public acceptance may be higher than expected.

#### 5.5. NEW TECHNOLOGIES AVENUES FOR E-FUELS

A number of additional routes for the production of e-fuels, both liquid and gaseous, are being investigated but are not as well developed as the ones analysed in this report. Many of these new routes could be described as hybrid systems, combining hydrogen produced from electricity with carbon resulting from biological processes

or integrating solar-thermal heat into the PtX plant. This includes some relatively high TRL process like Lanzatech's steel gas fermentation reactor [AECOM & Fichtner 2021, p120] which can be operated with or without supplementary electrolytic hydrogen to produce ethanol. Despite the relatively high TRL this process has only been commercialised at small scale and will need to prove its ability to scale-up. Other processes remain at low TRL and small scale, such as hydrogen from photo-electrocatalytic (PEC) water splitting, despite this having been the subject of decades of research. Other processes like power-to-hydrogen coupled with biological methanation offer promise, too, but may suffer from poor heat integration owing to the absence of high temperature elements in the production chain.

In several economies, significant effort is being invested in industrialising electrolyser manufacture to bring costs down. This is considered a more important area for research than seeking fundamental technology breakthroughs as a robust foundation of technologies to proceed has been achieved over the past few decades. Thus, incremental improvements to existing electrolyser designs are being investigated and these may help to reduce costs or improve performance such as reducing platinum loadings in PEM electrolysers. This type of applied research benefits and goes hand-in-hand with technology deployment as could have been observed with e.g. photovoltaics and wind technology.

Novel electrolyser technologies are being investigated, notably anion exchange membrane (AEM) electrolysers, and some firms such as Enapter are already seeking to commercialise their designs. The principal benefit to AEM technology is cost given the absence of noble metal catalysts but with research and development at an early stage and performance still below that achievable with more established technologies, much research is still required.

With up-scaling and mass deployment of energy conversion technologies, the need for design-for-recyclability and considerations regarding materials and material loadings shift into focus. This area is driving research and innovation including breakthroughs also in existing technology domains.

Another strain of technology development with e-fuels is improved system integration. This may range from better heat integration (such as including external renewable heat sources like solar-thermal plants), use of storage (see chapter 1.5.2 on Buffer storage) and process integration (formerly several process steps are included in a single process step, such as high-temperature co-electrolysis).

Catalytic methanation has been assumed for the e-methane pathways in this study. An alternative approach is biological methanation which is being proposed in combination with CO<sub>2</sub> from biogas upgrading today. In the case of biological methanation specialised microorganisms (archae) convert H<sub>2</sub> and CO<sub>2</sub> to methane. This technology was successfully implemented at a first power-to-gas plant of that kind in the year 2015. Generally, biological methanation can be carried out in-situ within a fermenter for biogas generation or ex-situ in a separate reactor. If the CO<sub>2</sub> comes from a source other than biogas the biological methanation always would be carried out in a separate reactor. The biological methanation is carried out at a temperature of 65°C and a pressure of 0.1 MPa [MicrobEnergy 2020]. The technology is commercially available (TRL = 9).

A technology with low TRL of between 2 and 5 consists of photo-electrochemical cells (PEC). PEC combine photovoltaic electricity generation and electrolysis in a single process (integrated system). A photo-electrochemical cell has similarities to a photovoltaic cell (PV). A PV cell separates electrons and holes in the semiconductor material while the electric current via external loads recycles the



electrons. The PEC device separates anode and cathode via an electrolyte; it consumes the free electrons at the solar irradiated cathode by the formation of neutral hydrogen molecules from positive protons ( $H^+$ ), which are attracted by the cathode during the water splitting process. Negative oxygen ions (usually bound in negatively charged  $OH^-$  ions) are attracted by the anode where they are transformed in neutral oxygen molecules by stripping off their surplus electrons at the anode. A current recycles the electrons back to the anode. One general disadvantage of hydrogen production via PEC is that hydrogen has to be collected from the panels via an extensive grid consisting of a huge number of small diameter pipelines. It is challenging to keep this hydrogen collection grid tight. For small energy streams, as it is the case on panel area level, it is easier to collect electricity than to collect hydrogen. [JRC 2019b]

Ethanol can be generated by microbial fermentation of a mixture of  $CO$ ,  $CO_2$  and  $H_2$  by bacteria. The process is capable to use a wide range of gas compositions. Even pure  $CO$  can be used as feedstock but also a mixture of  $CO_2$  and  $H_2$ . A pilot plant has been built in New Zealand in 2008. Pre-commercial plants have been built at Baosteel in China in 2012, at Capital Steel in China in 2013, and at WBT in Taiwan in 2014. A commercial plant had been built in Shougang in China in 2018. Further commercial plants are under construction at AcelorMittal in Belgium, at Indian Oil in India, at Aemetis in the USA, and in Swayana in South Africa [LanzaTech 2018]. The TRL is 9. The ethanol can be processed further to jet fuel via the alcohol-to-jet (ATJ) process.

Twelve (former Opus 12) together with Emerging Fuels Technology (a developer of Fischer-Tropsch synthesis plants) develops a polymer electrolyte membrane (PEM) based electrolysis process, i.e. an integrated low-temperature co-electrolysis process, where  $CO$  and  $H_2$  is formed which are processed further to jet fuel. In summer 2021, the US Air Force tested and qualified jet fuel produced in this way [Twelve 2022] [Business Wire 2021]. However, lifetime is still an issue for co-electrolysis applying PEM [Weber 2021].

Another approach is to convert e-methane to syngas via dry reforming ( $CH_4 + CO_2 \rightarrow 2 CO + 2 H_2$ ) and convert this syngas to liquid hydrocarbons via FT synthesis (and some additional  $H_2$  to get the adequate  $H_2/CO$  ratio). Dry reforming is still at an early stage of research and development, especially the catalyst development [hte 2022].

#### KEY MESSAGES - CONTEXT OF E-FUELS IN THE FUTURE OF EUROPE. POTENTIAL DEMAND, FEASIBILITY, OPPORTUNITIES AND CHALLENGES

While some **new hybrid e-fuels routes**, combining e-hydrogen with bio-sources of  $CO_2$  and/or solar-thermal heat are under development, most of these have not been proven yet at scale. Similarly, some alternative electrolyser technologies e.g. anion exchange membrane, are being developed but none of these has yet been commercially deployed. Much of the research effort in PtX is going into process optimisation, such as integration of low-temperature heat from electrolyser operation or coupling with solar-thermal heat plants, and industrialisation aimed at bringing down manufacturing costs.

**Novel technology avenues** that are currently pursued for the production of electricity-based fuels include photo-electrochemical cells (PEC) for hydrogen production, microbial fermentation of a mixture of  $CO$ ,  $CO_2$  and  $H_2$  to ethanol, co-electrolysis of water and  $CO_2$  using polymer electrolyte membranes (PEM) and biological methanation. The technology readiness levels range between 2 to 5 and 9 for biological methanation, respectively.

## 5.6. POTENTIAL BARRIERS TO E-FUELS DEPLOYMENT AND RISK MATRIX ASSESSMENT

As part of this study, a structured assessment was carried out of the high-level supply side and demand side barriers preventing or hindering an increase in the supply of e-fuels to the level required to meet potential future demand in the agreed timescale. This took into account considerations relating to resource availability (including CO<sub>2</sub>), technology, economics, infrastructure, regulation, policy and market. The process followed is described below:

**Brainstorm risks and barriers:** Identified the largest possible number of potential risks and barriers “offline” from the project delivery group and the Technical Steering Committee members. This was developed into a risk register containing the group’s initial proposals for key barriers and risks.

**Initial grouping and prioritisation:** E4tech conducted a thematic grouping of the ideas generated in preparation for a workshop involving the stakeholders mentioned above.

**Workshop:** During a workshop, the themes, priorities and specific risks / barriers were reviewed, with the objective of arriving at a broad consensus on the scope of risks and barriers that were surfaced and to assign an impact and likelihood measure assessment based on stated or proposed policies for each risk / barrier, then discuss what interventions or mitigating actions could be employed to address each. These were grouped according to a PESTLE framework which breaks down issues into groups: Political, Economic, Social, Technical, Legal and Environmental.

The risk / barrier register developed is included in ECONOMIC ANNEX 9, while the most significant risks and barriers are replicated below. Table 46 shows the high impact factors, while Table 47 shows the high probability factors. Note that H indicates high, M indicates medium and L indicates low.

**Table 46:** High impact factors

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
<b>Political</b>	No, or weak political support for e-fuels	H	H for road, L for aviation	Encourage appropriate level of support, consistency of support
	Insufficient renewables capacity made available for e-fuels production because policy supports it's use for electricity first (note: separate issue from technical generation potential, technical deployment rate of generation capacity, and social acceptance issues)	H	H	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
<b>Economic</b>	Failure to achieve cost reductions	H	L	Support projects and R&D as appropriate to ensure cost reductions are realised
	Efuels higher production cost versus biofuels or fossil fuels	H	H for road, L for aviation	Need to combine efforts on lobbying for support policies and investments to reduce costs (see above). Could focus efforts in those sectors where benefits are likely to be greatest, e.g. aviation, and take advantage of possible "trickle down" into other sectors, e.g. HD road
<b>Technological</b>	Unable to optimise processes	H	L	Support projects and R&D as appropriate to ensure technology issues are overcome
	Inability to get high enough CO2 capture rates	H	H for CO2 based fuels, L for non-CO2 based	Support projects and R&D as appropriate to ensure technology issues are overcome
	Unknown ramp-up potential for electrolysis, carbon capture, fuel synthesis	H	M	Support projects and R&D as appropriate to ensure technology issues are overcome
<b>Legal</b>	Planning processes too complicated / time consuming	H	H for road, L for aviation	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels
	Lack of initiative for ASTM-approval of methanol route for PtL jet fuel	H	L	Work closely with ASTM and other relevant stakeholders (e.g. engine makers) from an early stage to get routes into the approval process

H = High, M = Medium; L = Low



**Table 47:** High probability factors

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
<b>Political</b>	No, or weak political support for e-fuels	H	H for road, L for aviation	Encourage appropriate level of support, consistency of support
	Lack of support to policies not aligned with the current green trend (ICE ban, push for EVs, etc.)	M	H for road, L for aviation	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
	Prioritization of renewable power capacities for other sectors	M	H	Make argument that all sectors need to decarbonise and some (e.g. aviation) have few alternatives to e-fuels
	Insufficient renewables capacity made available for e-fuels production because policy supports its use for electricity first (note: separate issue from technical generation potential, technical deployment rate of generation capacity, and social acceptance issues)	H	H	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
	Efuels higher production cost versus biofuels or fossil fuels	H	H for road, L for aviation	Need to combine efforts on lobbying for support policies and investments to reduce costs (see above). Could focus efforts in those sectors where benefits are likely to be greatest, e.g. aviation, and take advantage of possible "trickle down" into other sectors, e.g. HD road
	Reluctance of the population to have wind turbines, carbon capture units "in their yards"	M	H for renewables, low for industrial site, H for power transmission	Provide transparent information on the potential benefits of e-fuels in the sectors where they are anticipated for use, e.g. through independent studies and programme of "education"
	Inability to get high enough CO2 capture rates	H	H for CO2 based fuels, L for non-CO2 based	Support projects and R&D as appropriate to ensure technology issues are overcome
<b>Legal</b>	Planning processes too complicated / time consuming	H	H for road, L for aviation	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels

H = High, M = Medium; L = Low

The following key themes emerged from the workshop:

- There was a perceived need to distinguish between liquid e-fuels, which have CO<sub>2</sub> as an input, and hydrogen or ammonia since the treatment of different sources of CO<sub>2</sub> is likely to be a critical factor in market development.
- Similarly, it will be important to distinguish between sectors which are particularly hard to abate, e.g. aviation and shipping, and those where alternative solutions to e-fuels can be more readily used, e.g. light-duty road transport.
- Lack of strong policy measures is perhaps the most important potential barrier to e-fuels development but strong support is expected in aviation and shipping. The proposed changes to RED and ReFuelEU Aviation Regulation (see following section) provide specific support for e-fuels. However, these are yet to be ratified.
- Regulation and chain of custody of both CO<sub>2</sub> and electricity are likely to be critical factors and a lack of a clear regulatory framework would deter investment. The delegated acts (see following section) relating to CO<sub>2</sub> sources are yet to be ratified and should hopefully provide clarity on the sources that can be used in the production of e-fuels.
- A significant risk is posed by a lack of social acceptance of more renewable electricity generation and transmission capacity - this may tend to weaken support for e-fuels since lower efficiency implies greater required capacity.
- Failure to achieve cost reductions would deter e-fuel capacity build out but strong cost reductions are expected - if cost reductions are achieved and policy support is strong, a compelling business case for e-fuels is expected to emerge. A similar view to this was expressed with respect to overcoming technical challenges.
- Mitigating actions are expected to include providing input to the development of policy / regulatory support and programme of “education” on the benefits of e-fuels in addition to efforts to bring down costs and secure chains of custody.

#### KEY MESSAGES - POTENTIAL BARRIERS TO E-FUELS DEPLOYMENT

Perhaps the biggest **barrier** to e-fuels development would be a lack of sufficient policy support, although support is expected to be forthcoming for the hard to abate sectors such as aviation or navigation; in other sectors, support is likely to be weaker given the availability of alternatives, notably more direct electrification solutions. A wide package of policy support mechanisms exists already, e.g. REDII, but these have not historically supported e-fuels explicitly. However, as discussed in the next section, RED III, the Fit for 55 package, ReFuelEU Aviation and FuelEU Maritime aim to address these shortcomings.

This barrier could be somewhat mitigated through a programme of education and support to put the case for e-fuels relative to alternatives, leading to better policy incentive. Other barriers to e-fuels use include failure to achieve the necessary cost levels relative to both fossil fuels and biofuels, ability to scale up production fast enough to meet demand, as well as regulatory barriers such as chain of custody for electricity / CO<sub>2</sub> source and planning arrangements. Once again, policies to support demonstration projects as well as fundamental R&D are helping to break down cost barriers and regulations should be examined to ensure a level playing field for e-fuels relative to alternatives.

## 5.7. CONDITIONS FOR POTENTIAL BUSINESS CASES

The emergence of compelling business models for e-fuels will be dependent, at least in the short to medium term, on the policies in place to support their deployment. In the absence of strong policy, advanced sustainable fuels, including e-fuels, are unlikely to develop beyond the pilot or demonstration phase as the technology might not be competitive versus fossil alternatives. Over the long term the relative economics of e-fuels compared with alternative low carbon solutions is one of the criteria that will ultimately determine which fuels will be favoured. In the following section, the supporting policy and financing mechanisms are presented with particular reference to how they could impact the emergence of e-fuels.

### 5.7.1. Policy and regulation

#### 5.7.1.1. Renewable Energy Directive (RED)

The main legislation supporting the transition in the EU away from fossil fuels and towards low carbon alternatives is the RED, now in its third iteration (RED III). In September 2020, the Commission launched a consultation on the revision of RED II to align it with the European Green Deal, which is ultimately targeting climate neutrality by 2050. Subsequently, the Commission published its RED III proposal in July 2021 as part of the Fit-for-55 package, targeting 55% GHG emissions reduction by 2030. The European Parliament and Council agreed on a final RED III text in March 2023 after the trilogue negotiations.

The revised RED sees the overall target for countries to provide 42.5% of their energy supply from renewable sources by 2030 up from 32% in the original Directive, reflecting the new EU minimum 55% GHG reduction target by 2030 vs. 1990s level. The legislation contains an additional indicative 2.5% top-up that would allow 45% to be reached. The new legislation also includes a sub-target for in the transport sector, with Member States able to choose between:

- a binding target of 14.5% reduction of greenhouse gas intensity in transport from the use of renewables
- or a binding target of at least 29% share of renewables within the final consumption of energy in the transport sector

Member States independently adopt national frameworks and policies to comply with EU targets. Most of these frameworks are technology agnostic, meaning, for instance, that hydrogen is supported as well as other technologies such as batteries and biofuels. However, some Member States' policies also transpose specific sub-targets into their frameworks, which are not technology-neutral and reflect sub-targets prescribed in EU legislation.

At present, the transport sectoral target within RED is the only substantial piece of legislation that specifically supports the use of electricity-based hydrogen and derivative fuels, collectively termed “renewable fuels of non-biological origin” or RFNBOs. The RED III agreement sets a binding combined sub-target of 5.5% for advanced biofuels produced from feedstocks listed in annex 9A and RFNBOs in the share of renewable energies supplied to the transport sector by 2030. Within this target, there is a **minimum requirement of 1% of RFNBOs**. This sub-target includes RFNBO hydrogen used in refineries producing conventional fuels.

RED III includes double-counting for advanced biofuels and RFNBOs, meaning that every unit of fuel sold receives a 2x multiplier against the sub-target and target (if

the Member State chooses the 29% renewable energy share target), therefore halving the required supplied fuel. Renewable electricity used in transport receives a 4x multiplier. Furthermore, RFNBOs supplied to the maritime and aviation sectors receive an additional 1.5x multiplier, while advanced biofuels supplied to these sectors are multiplied by 1.2x.

Further, there is a cap on certain types of conventional biofuels which effectively limits their increased use, as follows:

- A cap on the use of waste oils and fats, which must not exceed 1.7% of energy supplied and is designed to limit the dependence on these sources; and
- A cap on the use of conventional biofuels derived from food or feed crops of 7%, aimed at limiting competition between food and fuel land uses.

While RFNBO's are more costly to produce than biofuels, RED III is designed to encourage the uptake of these fuels, through the sub-target of 1% of RFNBOs and additional multipliers in the aviation and marine sectors.

Some countries have gone beyond RED II's provisions and have set policies which support synthetic fuels further, e.g. NL, DE or the UK (now outside of the EU). It is possible that RFNBOs could receive additional support in future legislation, however, the introduction of ReFuelEU Aviation and Fuel Maritime indicate that support for e-fuels will likely be focussed on the aviation and maritime sectors, as outlined below.

There is also support for RFNBOs in industry with a minimum of 42% hydrogen in industry to be RFNBO by 2030 and 60% by 2035.

The Fit-for-55 package provides a further set of policy incentives for reducing emissions.

#### 5.7.1.2. EU Emissions Trading System (ETS)

Under the reform of the EU Emissions Trading System, as part of the Fit for 55 package, a separate Emissions Trading System for fuel combustion in road transport (as well as in buildings and additional sectors) has been introduced (ETS2). It is set to start operating in 2027 (with a possible delay by one year in the event of exceptionally high energy prices) with a linear reduction of the cap by 5.15% until 2028 and 5.38% from 2028. The price of allowances will be subject to stabilization mechanisms.

Intra-EU aviation, already covered by the ETS, will be subject to a gradual phase-out of free allowances in 2024 and 2025, being subject to full auctioning from 2026. The ETS revision has also introduced the allocation of 20 million allowances for free to support the uptake of sustainable aviation fuels by covering part of or all the price difference between fossil kerosene and the relevant eligible aviation fuels. These allowances may cover 95% of the price difference between the use of fossil kerosene and RFNBOs compliant with Directive 2018/2001, and 70% of the price difference between the use of fossil kerosene and hydrogen from renewable energy sources and advanced biofuels.

Shipping has also been included in the ETS with all intra-EU and half of extra-EU shipping emissions subject to ETS. The System will be phased in between 2024 and 2026, with the obligation to surrender allowances for 40% of verified emissions in 2024, 70% in 2025 and 100% in 2026.

#### 5.7.1.3. EU Taxation Directive

There is also potential for tax exemptions for SAF under a Energy Taxation Directive proposal, the value of which will increase to 2030. The proposed taxation rates are given in Annex I, Tables A & D, with the fossil kerosene tax proposed at €10.75/GJ (~\$559/tonne) by 2033 and 2G biofuels and RFNBOs tax proposed at €0.15/GJ (~\$8/tonne). Low-carbon hydrogen and related fuels will also benefit from that same rate for a transitional period of 10 years.

#### 5.7.1.4. ReFuelEU Aviation

A new legislative instrument, ReFuelEU Aviation, was agreed on in April 2023 and is designed to increase the share of sustainable aviation fuel (SAF) in aviation, placing a mandate on both airlines and fuel suppliers. An overall mandate for SAF uplift at EU airports is set at 2% by 2025, 6% by 2030 and 20% by 2035, up to a maximum of 70% by 2050. Of these amounts, 1.2% in 2030, and 5% in 2035 must be e-fuels, increasing to 35% by 2050. Assuming an EU aviation demand of around 45 Mtoe in 2030 [European Commission 2021], a 1.2% mandate would represent a PtL jet market of ~0.54 Mtoe or 51 ktonnes of SAF in 2030.

SAF supplied under ReFuelEU also counts towards MS targets under the proposed REDIII (with the RED 1.5 multiplier as explained above). However, it depends on Member States' implementation of RED III whether e-fuels supplied to the aviation sector can benefit from support under both policies.

Note that ReFuelEU Regulation allows aircraft operators to claim once (and once only) in a separate GHG scheme ("a scheme granting benefits to aircraft operators for the use of sustainable aviation fuels"), e.g. SAF reported under ReFuelEU can be claimed under EU ETS, and possibly under CORSIA.

#### 5.7.1.5. FuelEU Maritime

FuelEU Maritime sets out a regulation for a well-to-wake GHG target for ships. The scope covers:

- Vessels over 5,000 gross tonnage starting or ending journeys in the EU, excluding inland vessels, fishing, naval and government vessels. Small and medium size vessels below 5,000GT represent approx. 40% of the fleet but only 10% of the total emissions in the EU.
- Voyages that the regulation applies to are EU-to-non-EU port and non-EU-to-EU port for 50% of the energy consumed, as well as EU-to-EU port for 100% of the energy consumed (i.e anything arriving or departing from EU port rather than just intra-EU).

The regulation sets targets for GHG intensity of energy used on board which need to decrease by 2% by 2025; 6% by 2030; 14.5% by 2035; 31% by 2040; 62% by 2045; 80% by 2050. Shipping companies are responsible for monitoring and reporting.

Additionally, container ships and passenger ships will be required to connect to onshore power when at berth from 2030, unless covered by a set of exceptions, one of which is that they are already using zero carbon technologies (fuel cells, electricity, microgeneration with renewable and low carbon fuels). There is also an exemption proposed around availability of shore power at berth and incompatibility of shore power connections.

#### 5.7.1.6. Delegated Acts

In addition, crucial rules that affect power-to-liquids on renewability and additionality of the renewable electricity used, and on eligible sources of CO<sub>2</sub> have been adopted in 2023. A ‘delegated act’ is a piece of legislation that provides further details on the implementation and rules outlined in a Regulation or Directive. One of these delegated acts to RED defines rules for the electricity used in the production of RFNBOs. Another delegated act defines the GHG emissions savings calculation methodology for RFNBOs and recycled carbon fuels (RCFs), including the requirements for CO<sub>2</sub> sources used in RFNBO production.

RED III states that grid mix electricity should be assumed for RFNBOs unless the electrolyser is directly connected to a renewable energy installation which was built after or at the same time as the electrolyser, and the electrolyser is not connected to the grid or has not taken electricity from the grid. Rules for operators using renewable electricity via the grid, for example with a power purchase agreement have been developed through the delegated act on renewable electricity use for RFNBO production. The delegated act lays out four options for electricity used from the grid in the electrolyser to counted as renewable and therefore usable for RFNBO production:

- Electricity from grids that are >90% renewable can be counted as renewable up to the % share of renewables penetration in the grid.
- Electricity sourced via a PPA from a grid that has a carbon intensity of <18gCO<sub>2</sub>/MJ can be counted as renewable if it fulfils the geographical and temporal correlation requirements (see below).
- Electricity consumed during hours of downward redispatch can be counted as fully renewable.
- Electricity sourced via a PPA from a grid that is not low carbon as in the options above can be counted as renewable if it fulfils the additionality, geographical correlation and temporal correlation requirements.
  - The additionality rule requires that the renewable electricity installation came into operation less than 3 years before the electrolyser. This rule only applies from 2038 for installations coming into operation before 2028.
  - The temporal correlation rule requires that electrolysers must match their electricity consumption with the PPA electricity production each month until the end of 2029 and then each hour from 2030.
  - The geographical correlation rule requires that renewable electricity installations must be located in the same or interconnected bidding zone as the electrolyser.

The other delegated act relevant to RFNBOs is the one that defines the GHG emissions calculation methodology and sets the 70% GHG emissions savings threshold when compared to the fossil fuel comparator of 94 gCO<sub>2</sub>e/MJ. Furthermore, the delegated act outline which CO<sub>2</sub> are eligible for e-fuels production:

- Point source CO<sub>2</sub> captured from industrial installations until 2036. The end date is extended to 2041 in other cases than CO<sub>2</sub> stemming from the combustion of fuels for electricity generation.
- CO<sub>2</sub> captured from air.



- CO<sub>2</sub> stemming from the production or the combustion of biofuels, bioliquids or biomass fuels complying with the sustainability criteria set out in RED II.
- CO<sub>2</sub> stemming from the combustion of a RFNBO or RCF complying with the Delegated Acts.
- CO<sub>2</sub> stemming from a geological source of CO<sub>2</sub> that was previously released naturally.

The agreed RED III text includes a requirement for the European Commission to submit a report assessing the impact of these Delegated Acts by 2028.

### 5.7.2. Supply side factors

Ultimately, the viability of e-fuels will be determined by the ability to drive down their cost to the levels discussed in earlier sections of the report. In order for e-fuels to become competitive, significant cost reductions will need to be achieved. In the end it is likely to be a deployment at scale that will allow cost reductions to be achieved, although technological breakthroughs could potentially have an impact.

A variety of policy initiatives exist to support the roll out of capital projects and for research and development into technological and process improvements. These policies include the Important Project of Common European Interest (IPCEI) framework, which enables state aid funding for large cross-border projects. The European Hydrogen Strategy foresees the use of the IPCEI framework for hydrogen-related projects. Among the principal funds that support demonstration projects are the **EU Innovation Fund** and **InnovFin** which provide support to projects that deliver carbon reductions.

On 1 February 2023, the EU announced the Green Deal Industrial Plan (GDIP), published on 1 February 2023, aims to enhance the competitiveness of Europe's green industry support while aiding a fast transition to climate neutrality. More specifically, the plan aims to build a supportive environment for scaling up manufacturing capacities for key net-zero technologies (including electrolyzers), marking a shift from the EU's "technology neutral" stance. The GDIP has 4 pillars: A predictable and simplified regulatory environment; Speeding up access to finance; Enhancing skills; and Open trade and resilient supply chains.

A proposal for a Net Zero Industry Act (NZIA) was published on 16 March 2023. It identifies goals for net-zero industrial capacity and provides a regulatory framework suited for its quick deployment, ensuring simplified and fast-track permitting, promoting European strategic projects and developing standards to support the scale-up of technologies across the Single Market. NZIA includes ambitious EU manufacturing targets, sets a framework for faster project permitting and emphasises the goal of "buy European". It will facilitate access to financing through the creation of the European Hydrogen Bank with 4 objectives: Domestic market creation; Imports to the EU; Coordination and transparency; and Coordination of existing project financing.

Supporting research and development aim to accelerate the process of bringing technologies to market and bridging the gap to commercial deployment by proving technologies in the field. The EU has led the way in this area and has put in place the mechanisms to support research, development and demonstration projects in renewable energy, many of which include hydrogen and in some cases are dedicated to hydrogen. Two of the principal mechanisms for research and development

projects are the Fuel Cell & Hydrogen Joint Undertaking (FCH-JU) and the Horizon 2020 (H2020) programme.

#### KEY MESSAGES

A strong package of measures already exists to support low carbon fuels in transport under RED II. The proposed RED III introduces specific targets for RFNBOs and additional multipliers for use of RFNBO's in marine and aviation sectors. In addition, mode-specific transport legislation such as ReFuelEU Aviation (which has a specific target for synthetic aviation fuels or e-fuels) and FuelEU maritime (which has a specific RFNBO target which could be met with hydrogen-derived fuels) will enhance demand for RFNBO's in these sectors.

A variety of mechanisms are in place to support project development and to motivate players to develop the value chain. A large number of pilots and demonstration projects have been announced but few have reached FID as yet.



## 6. GLOSSARY

AEC	Alkaline Electrolysis
AEM	Anion exchange membrane
ARA	Amsterdam-Rotterdam-Antwerp
Boe	Barrels of oil equivalent
CAPEX	Capital expenditure
CC	Carbon capture
CCS	CO <sub>2</sub> Capture & Storage
CCU	CO <sub>2</sub> Capture & Utilisation
CEPCI	Chemical Engineering Plant Cost Index
CGH <sub>2</sub>	Compressed gaseous hydrogen
CH <sub>3</sub> OH	Methanol
CH <sub>4</sub>	Methane
CNG	Compressed Natural Gas
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
CTG	Cradle-to-grave
DC	Direct current
DAC	Direct Air Capture
EPR	European pressurized reactor
ETS	Emission Trading System
EU MRV	EU monitoring, reporting and verification
EU	European Union
FAME	Fatty acid methyl ester
FC	Fuel Cell
FCEV	Fuel cell electric vehicle
FCH-JU	Fuel Cell & Hydrogen Joint Undertaking (now: Clean Hydrogen JU)
FID	Final Investment Decision
FT	Fischer-Tropsch
FTD	Fischer-Tropsch diesel
FTK	Fischer-Tropsch kerosene
GHG	Greenhouse Gas(es)
GJ	Gigajoule (1 GJ = 1000 MJ, 1 kWh = 3.6 MJ)
GtL	Gas-to-liquid
GW	Gigawatt (1 GW = 1000 MW)

H <sub>2</sub>	Hydrogen
HP	High pressure
HT	High temperature
HVDC	High voltage direct current
HVO	Hydrotreated Vegetable Oil
ICE	Internal combustion engine
IEA	International Energy Agency
IMO	International Maritime Organization
IMO DCS	IMO Data Collection System
IPCEI	Important Project of Common European Interest
JEC	JRC-EUCAR-CONCAWE consortium
KSA	Kingdom of Saudi Arabia
kWh	Kilowatt hours (1 kWh = 1000 Wh = 3.6 MJ)
l	Liter
LCA	Life Cycle Analysis
LCH <sub>4</sub>	Liquefied Methane
LH <sub>2</sub>	Liquefied Hydrogen
LHV	Lower heating value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LSMGO	Low sulphur marine gas oil
LT	Low temperature
M&R	Maintenance and Replacement
MCH	Methylcyclohexane
MEA	Monoethanolamine
MENA	Middle East and North Africa
MeOH	Methanol
MS	Member State
MTG	Methanol-to-gasoline
MTGD	Methanol-to-gasoline and diesel (middle distillates)
MTK	Methanol-to-kerosene
MTOE	Million ton oil-equivalent
N <sub>2</sub>	Nitrogen
NGPP	Natural Gas Power
NH <sub>3</sub>	Ammonia
NH <sub>3</sub>	Ammonia
NREL	National Renewable Energy Laboratory

O <sub>2</sub>	Oxygen
OPEX	Operating expenditure
°C	Degree Celsius
OME <sub>x</sub>	Oxymethyleneether (also called polyoxymethylene dimethyl ethers)
PEM	Proton Exchange Membrane Electrolysis
PtL	Power to liquid
PtX	Power to something
PV	Photovoltaics
RED	Renewable Energy Directive
RFNBO	Renewable Fuels of Non-Biological Origin
RWGS	Reverse Water Gas Shift (also called reverse CO shift)
SAF	Sustainable Aviation Fuel
SCR	Selective Catalytic Reduction
SMR	Steam Methane Reformer
SOEC	Solide Oxide Electrolysis Cells
toe	tons of oil-equivalents
TWh	Terawatt-hour (1 TWh = 1000 GWh = 1,000,000 MWh)
UCO	Used Cooking Oil
WTW	Well-to-wheel

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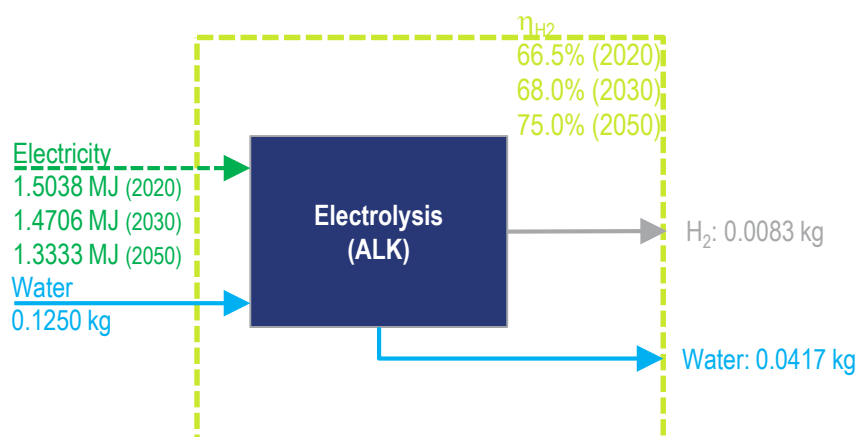
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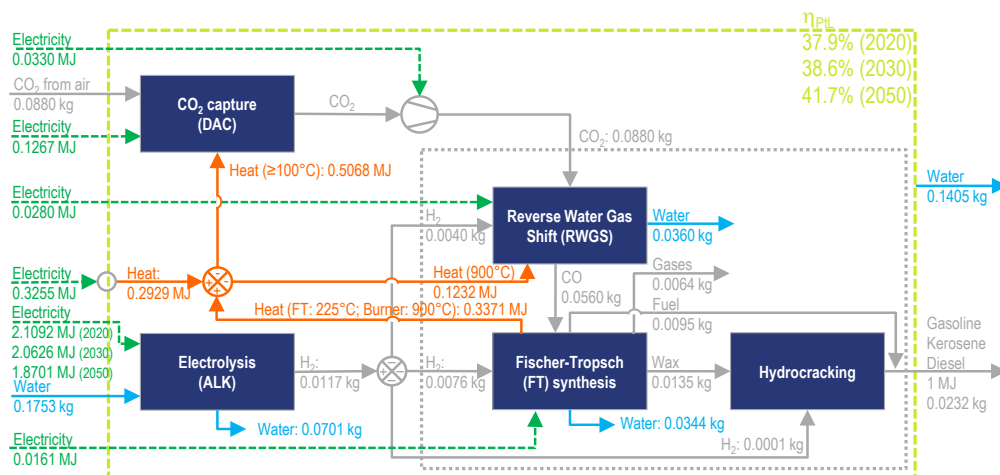
## 8. TECHNICAL ANNEX

### 8.1. ENERGY AND MASS REQUIREMENTS TO PRODUCE 1 MJ OF THE DIFFERENT E-FUELS PATHWAYS

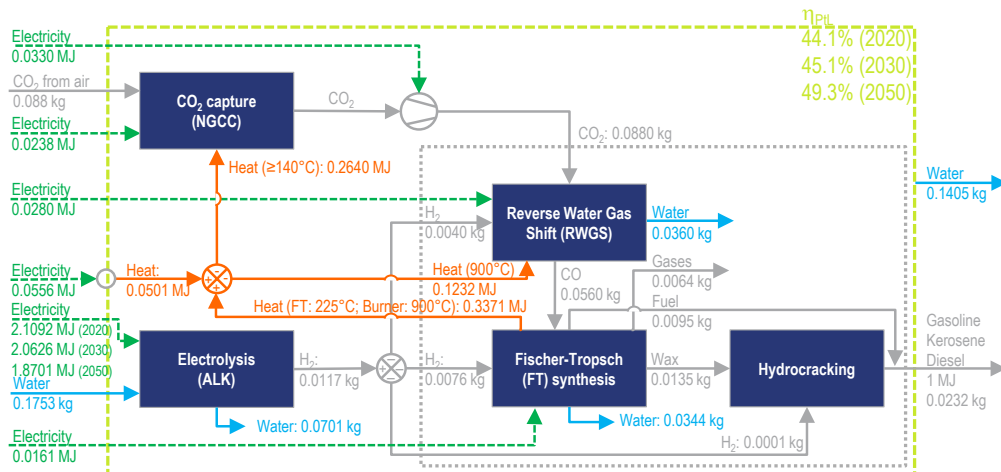
**Figure 126:** Energy and mass balance of hydrogen pathway



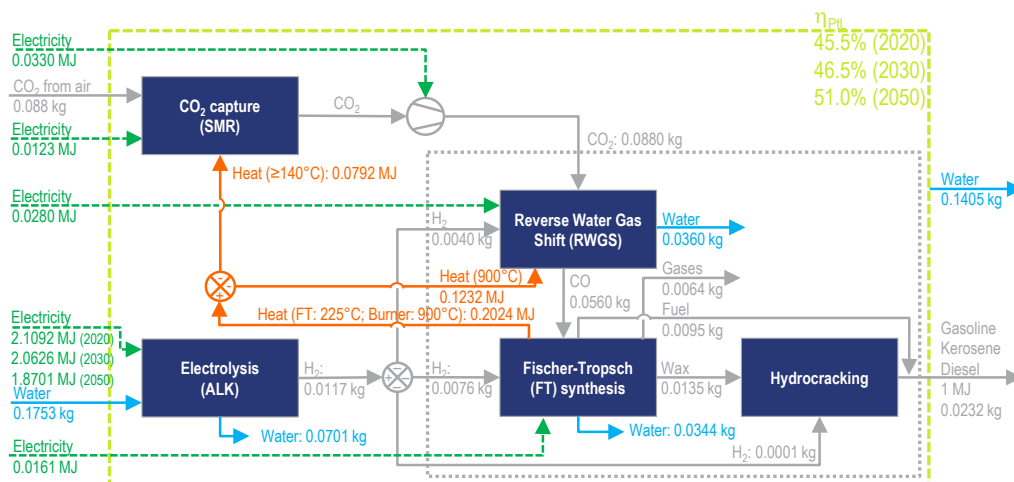
**Figure 127:** Energy and mass balance of e-FT Kerosene pathway (CO<sub>2</sub> from diluted source)



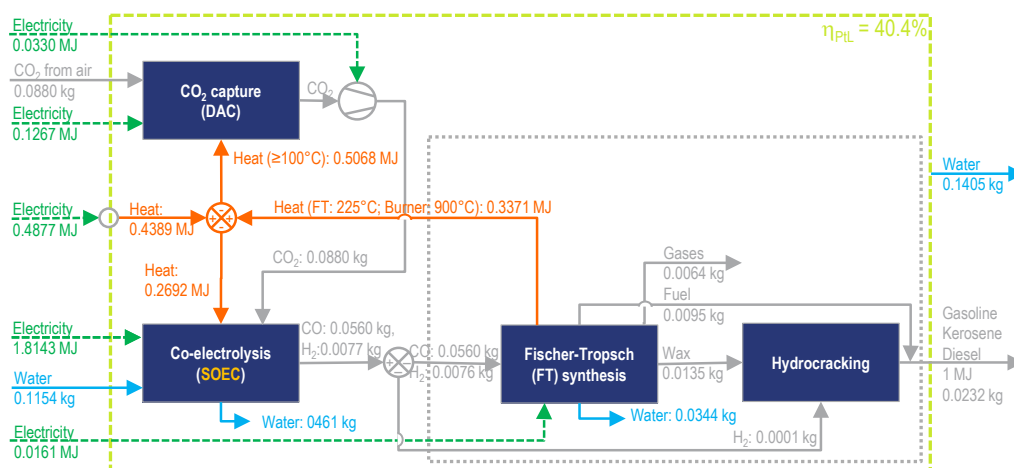
**Figure 128:** Energy and mass balance of e-FT Kerosene pathway (CO<sub>2</sub> from average concentrated source)



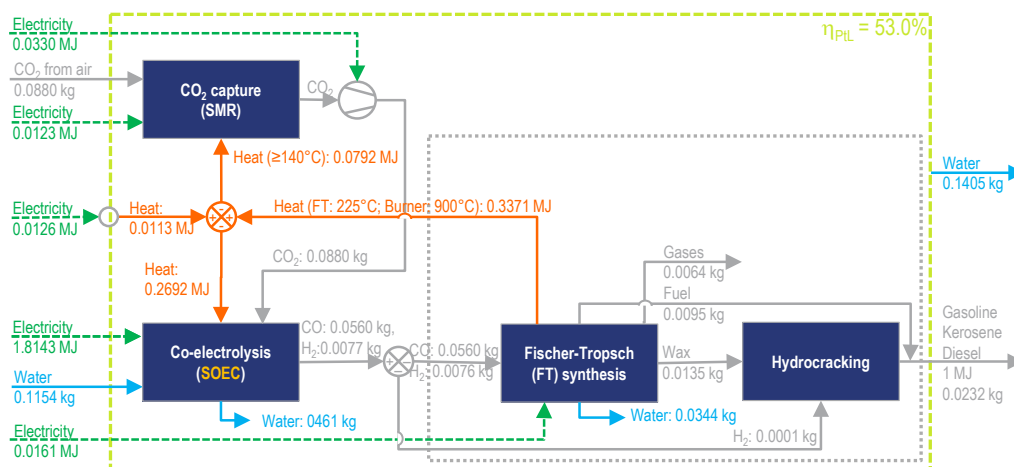
**Figure 129:** Energy and mass balance of e-FT Kerosene pathway (CO<sub>2</sub> from concentrated source)



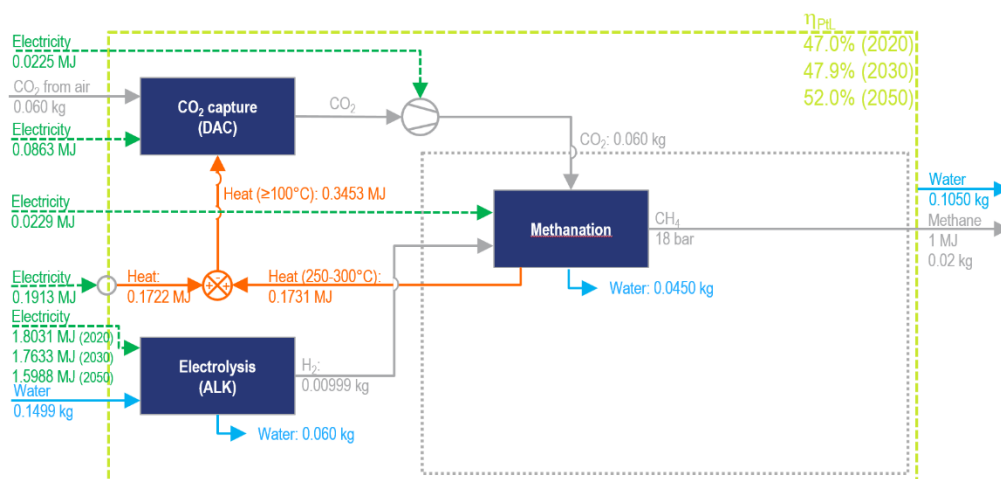
**Figure 130:** Energy and mass balance of e-FT Kerosene pathway (Co-electrolysis, CO<sub>2</sub> from diluted source)



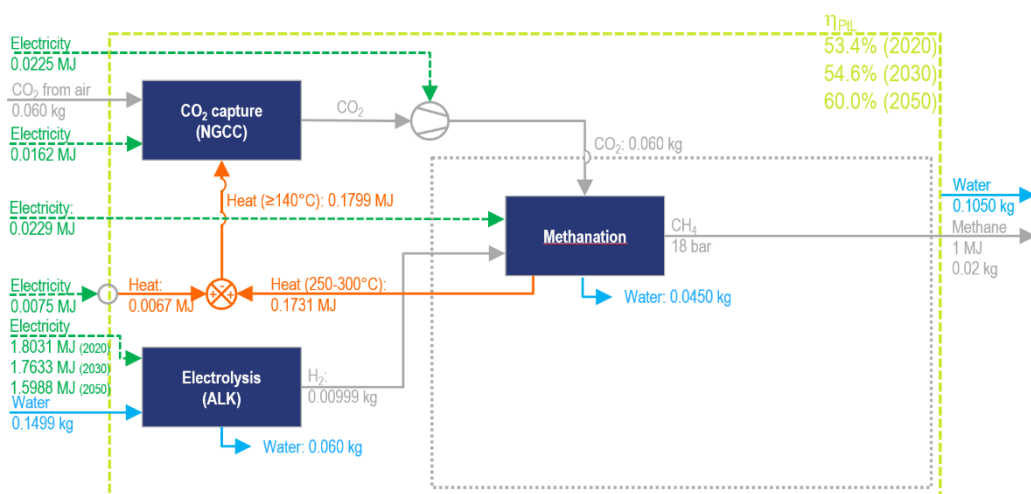
**Figure 131:** Energy and mass balance of e-FT Kerosene pathway (Co-electrolysis, CO<sub>2</sub> from concentrated source)



**Figure 132:** Energy and mass balance of e-Methane pathway (CO<sub>2</sub> from diluted source)

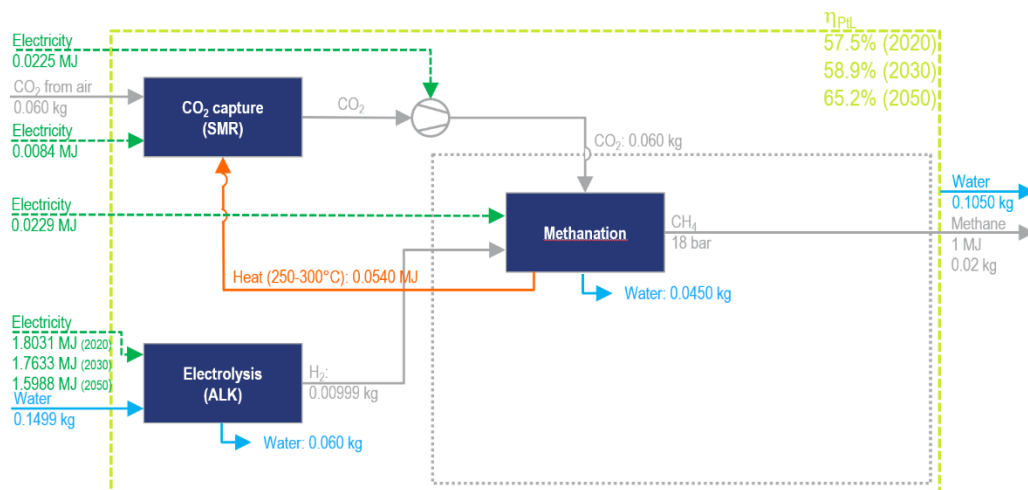


**Figure 133:** Energy and mass balance of e-Methane pathway (CO<sub>2</sub> from average concentrated source)

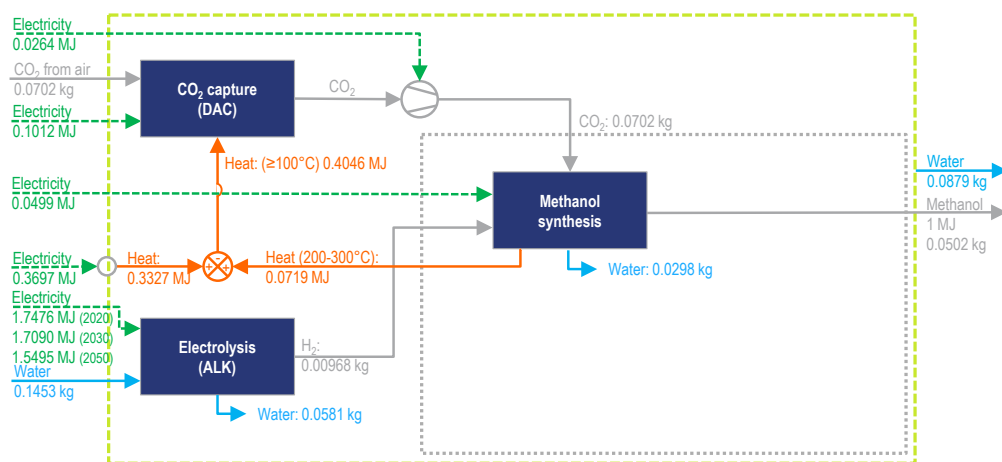




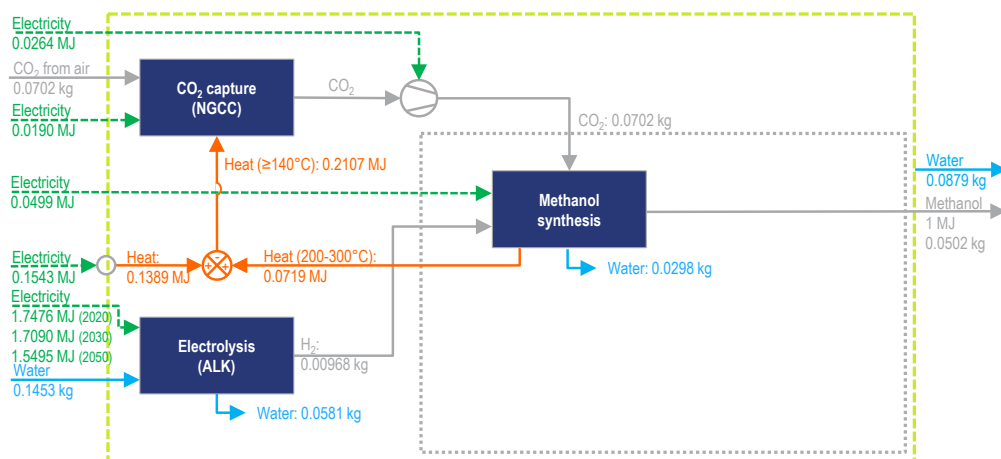
**Figure 134:** Energy and mass balance of e-Methane pathway (CO<sub>2</sub> from concentrated source)



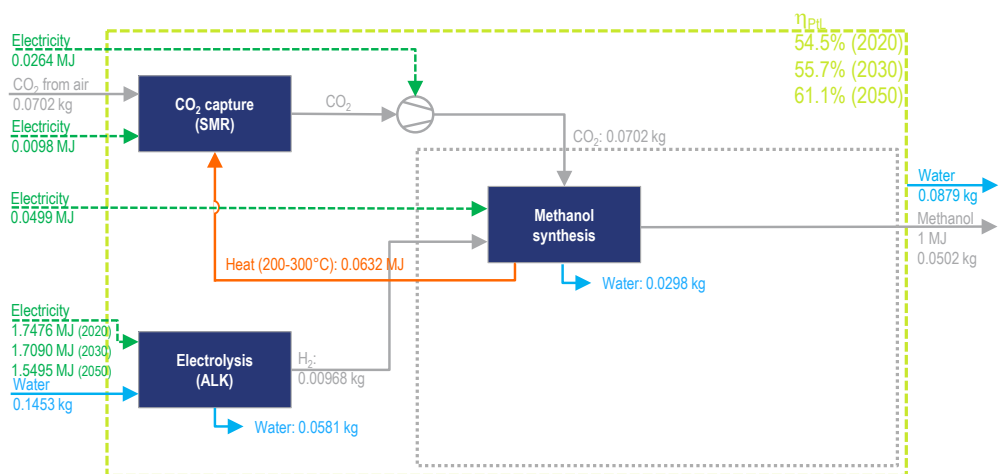
**Figure 135:** Energy and mass balance of e-Methanol pathway (CO<sub>2</sub> from diluted source)



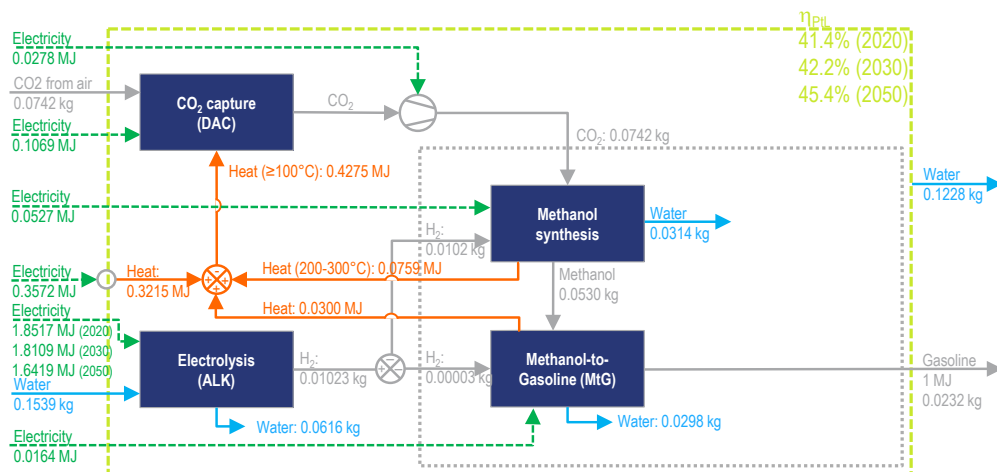
**Figure 136:** Energy and mass balance of e-Methanol pathway (CO<sub>2</sub> from average concentrated source)



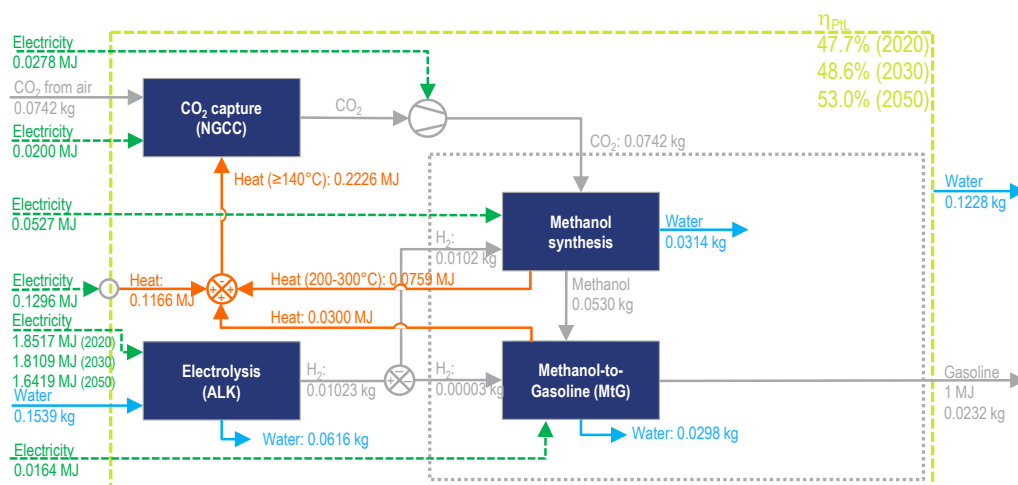
**Figure 137:** Energy and mass balance of e-Methanol pathway (CO<sub>2</sub> from concentrated source)



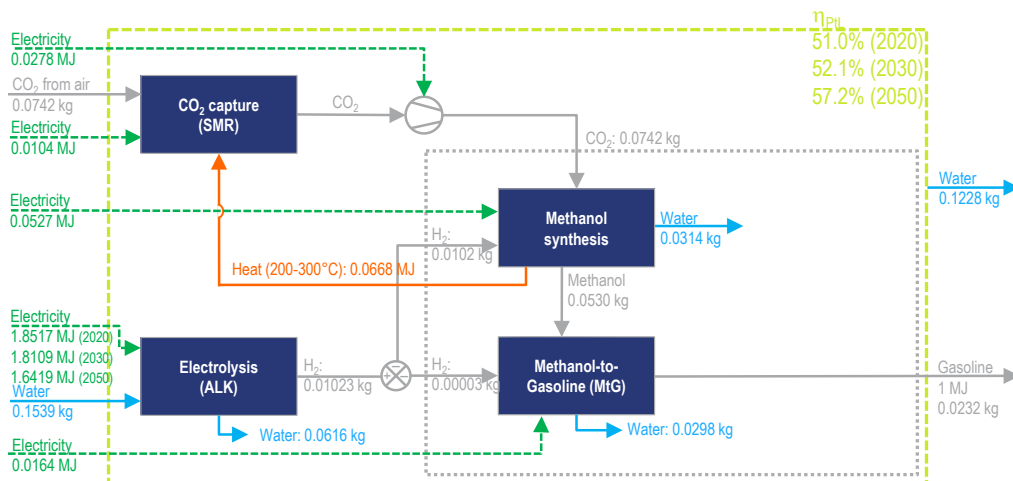
**Figure 138:** Energy and mass balance of e-MTG Gasoline pathway (CO<sub>2</sub> from diluted source)



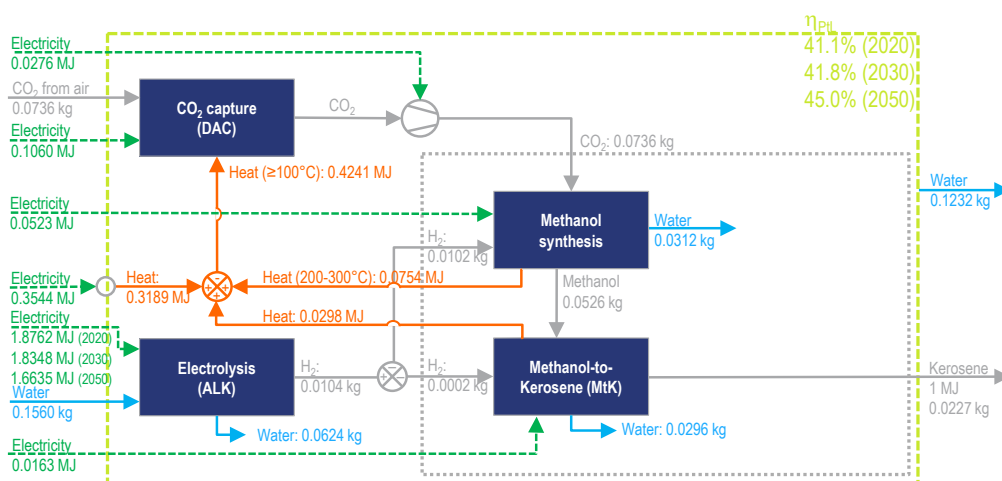
**Figure 139:** Energy and mass balance of e-MTG Gasoline pathway (CO<sub>2</sub> from average concentrated source)



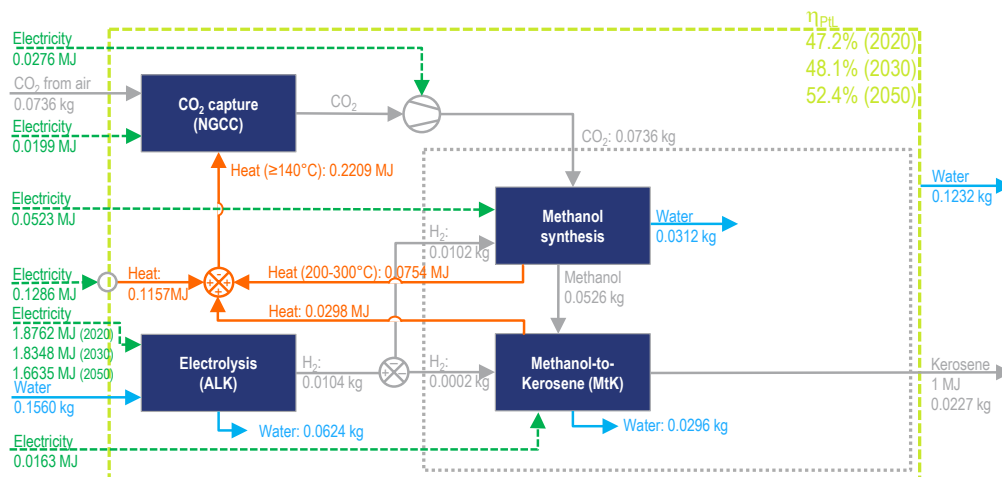
**Figure 140:** Energy and mass balance of e-MTG Gasoline pathway (CO<sub>2</sub> from concentrated source)



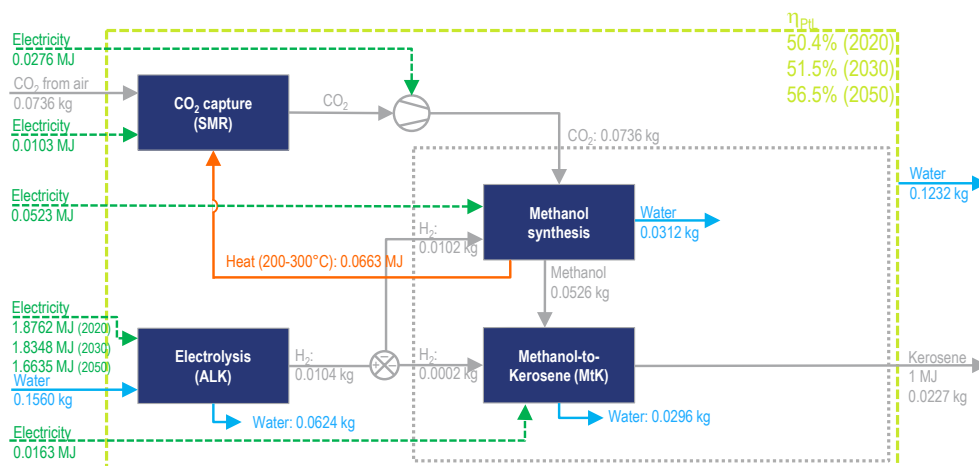
**Figure 141:** Energy and mass balance of e-MTK Kerosene pathway (CO<sub>2</sub> from diluted source)



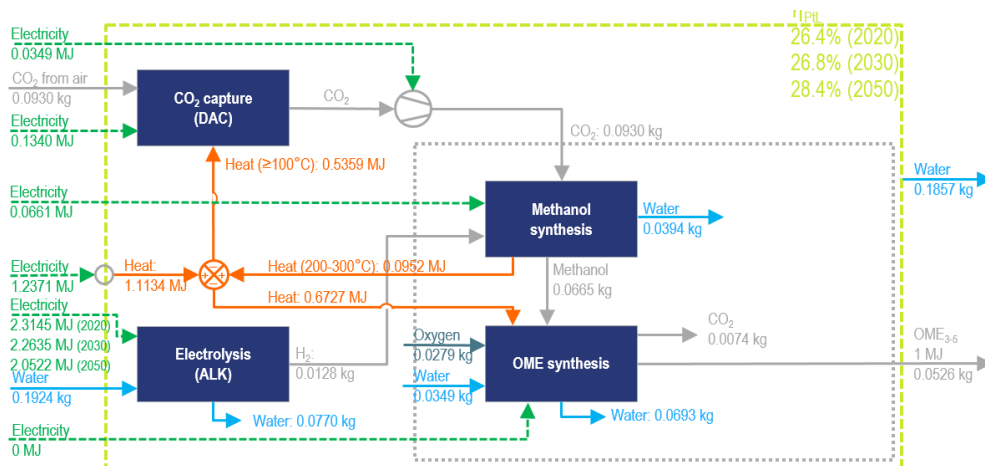
**Figure 142:** Energy and mass balance of e-MTK Kerosene pathway (CO<sub>2</sub> from average concentrated source)



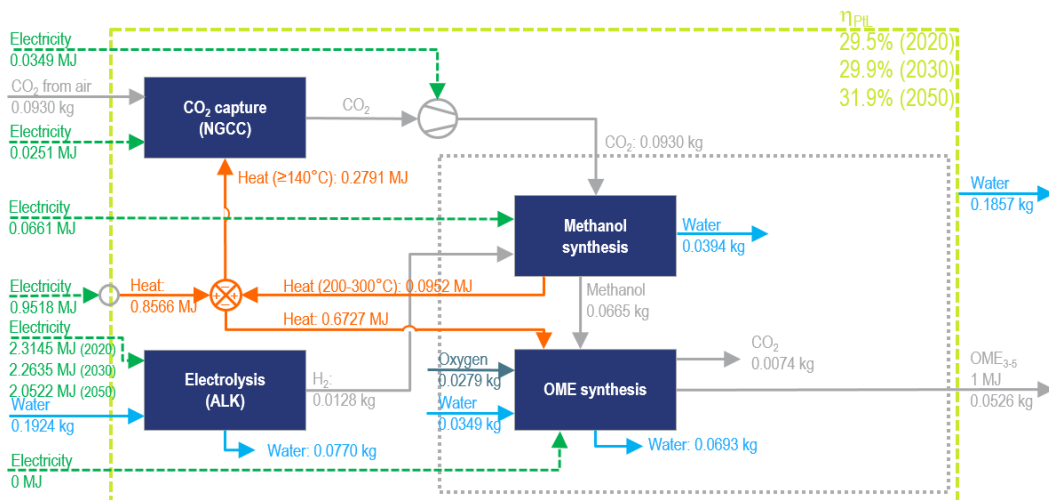
**Figure 143:** Energy and mass balance of e-MTK Kerosene pathway (CO<sub>2</sub> from concentrated source)



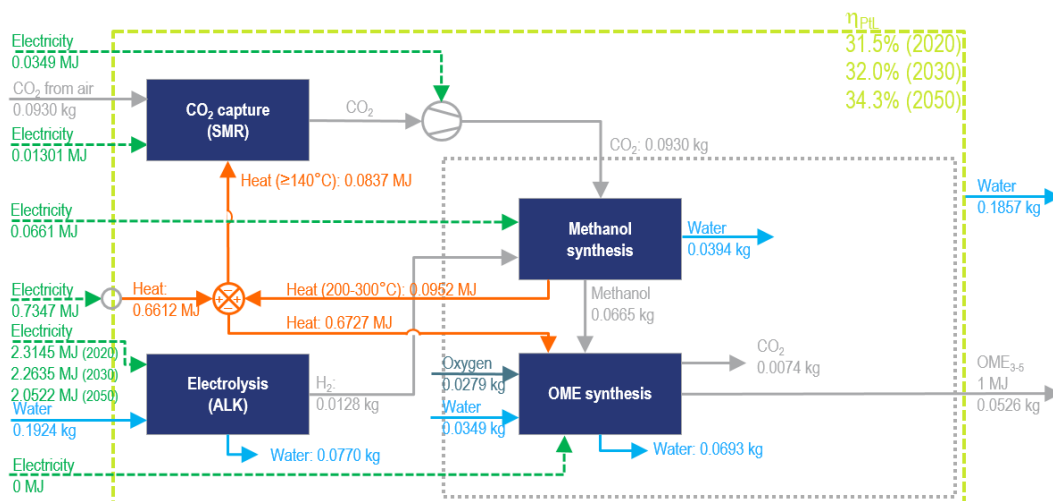
**Figure 144:** Energy and mass balance of e-OME<sub>3-5</sub> pathway (CO<sub>2</sub> from diluted source)



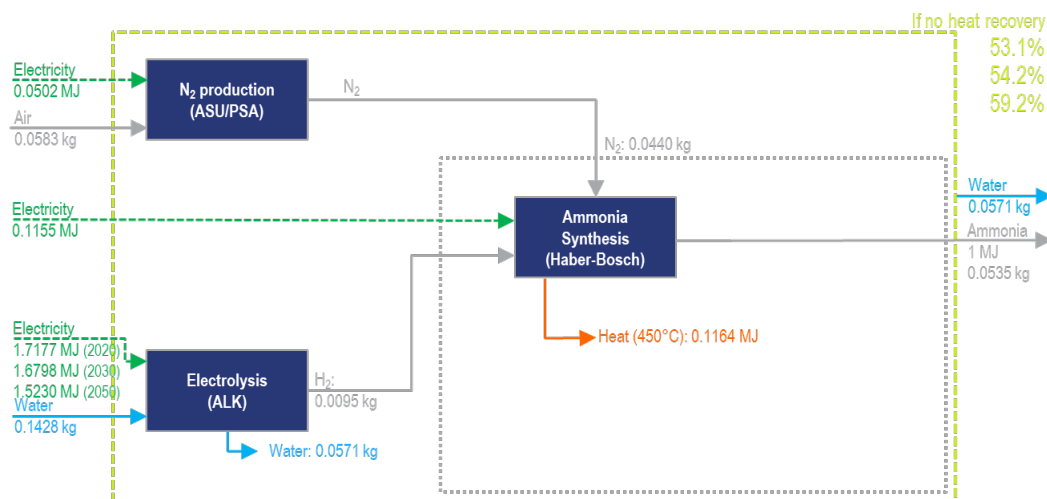
**Figure 145:** Energy and mass balance of e-OME<sub>3-5</sub> pathway (CO<sub>2</sub> from average concentrated source)



**Figure 146:** Energy and mass balance of e-OME<sub>3-5</sub> pathway (CC from concentrated source)

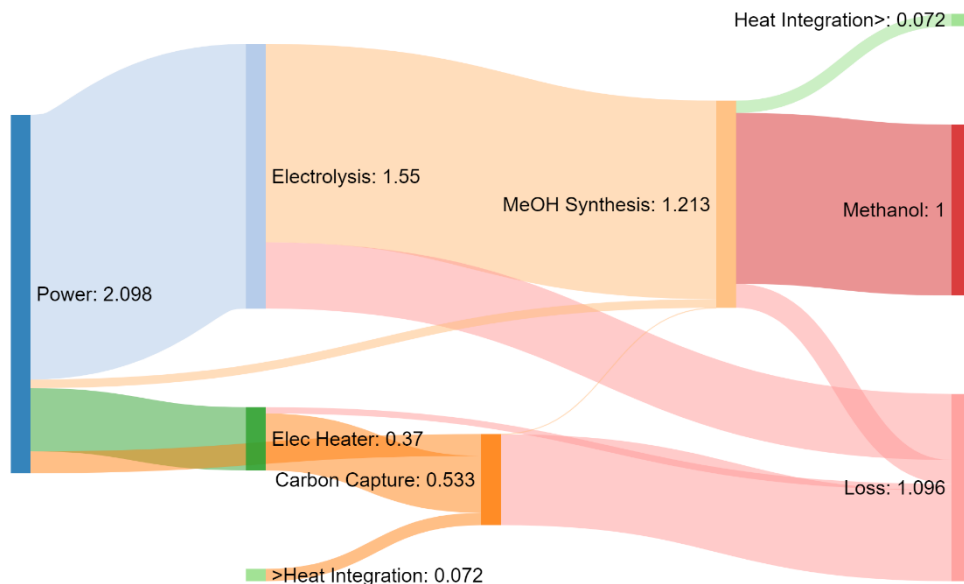


**Figure 147:** Energy and mass balance of e-Ammonia pathway (N<sub>2</sub> from air PSA)

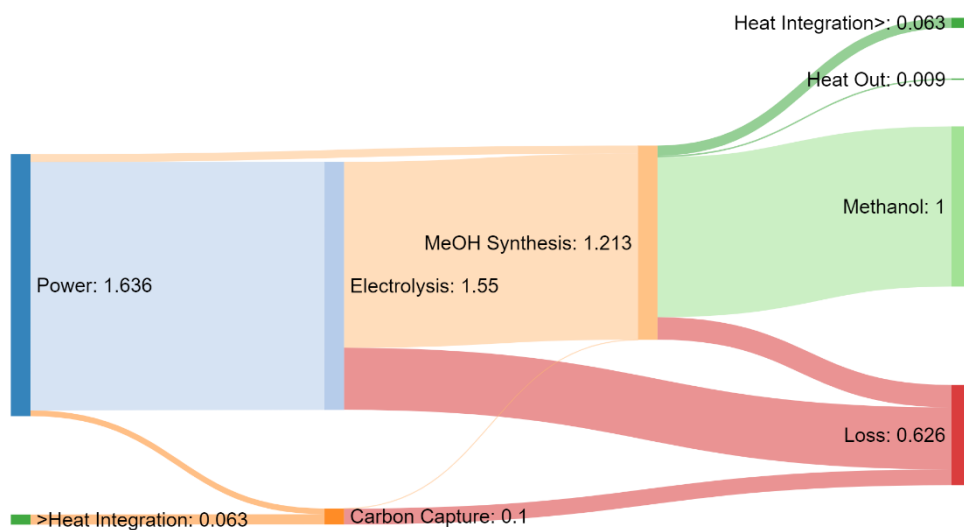


## 8.2. ENERGY EFFICIENCY OF E-FUEL PATHWAYS

**Figure 148:** Energy consumption for producing 1 MJ of e-Methanol (CC from diluted source)

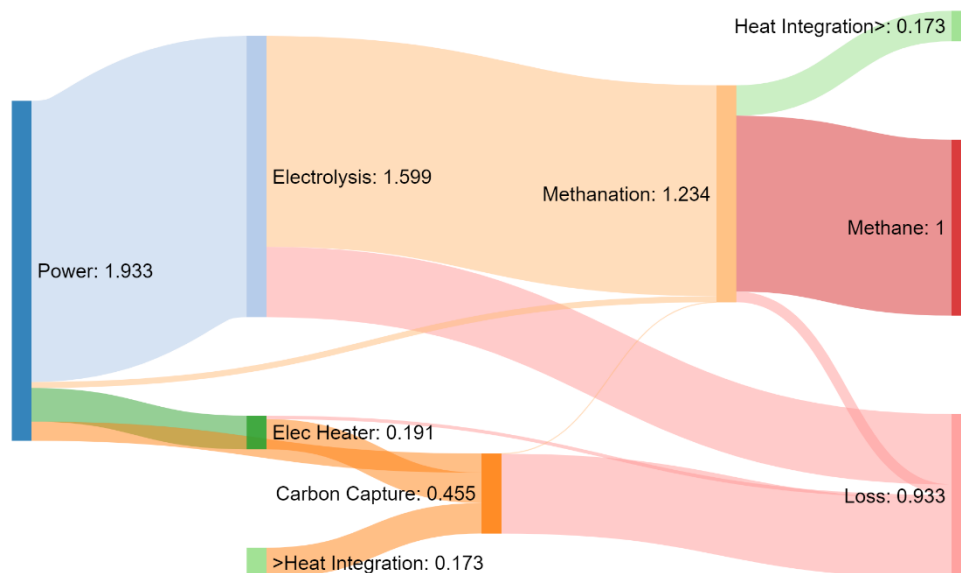


**Figure 149:** Energy consumption for producing 1 MJ of e-Methanol (CC from concentrated source)

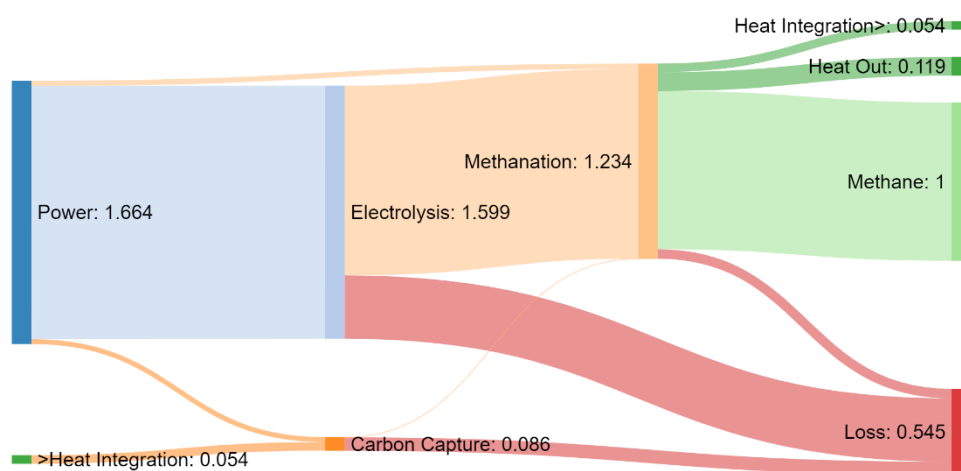




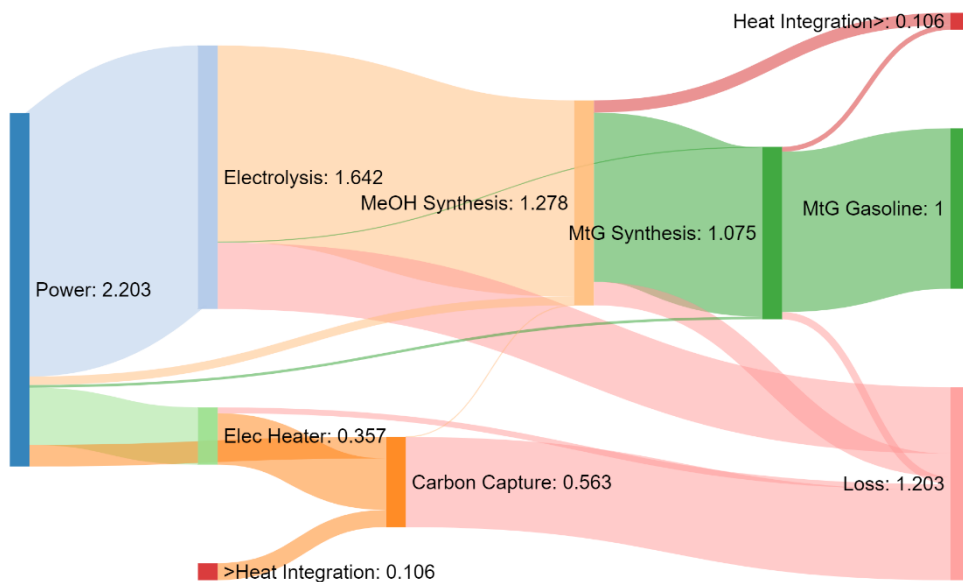
**Figure 150:** Energy consumption for producing 1 MJ of e-Methane (CC from diluted source)



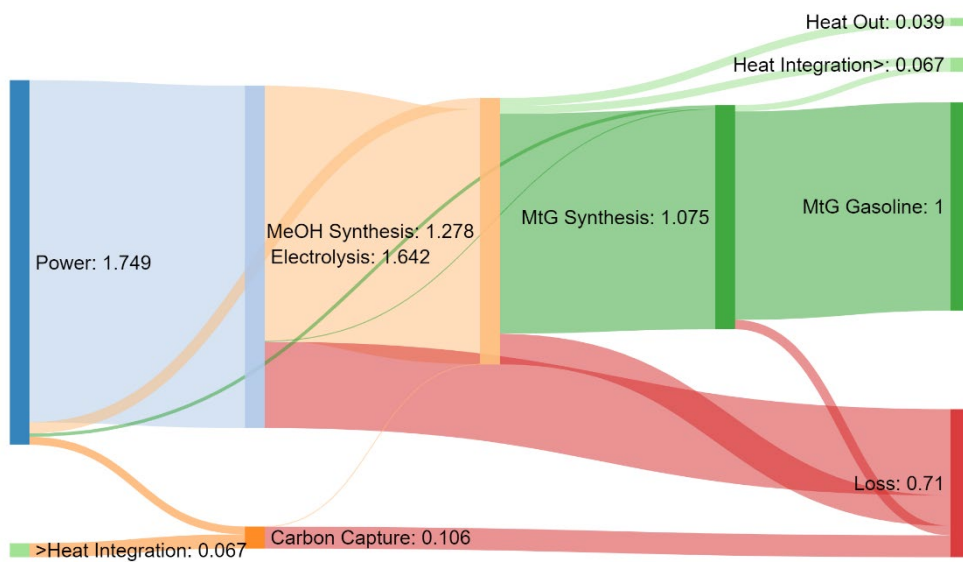
**Figure 151:** Energy consumption for producing 1 MJ of e-Methane (CC from concentrated source)



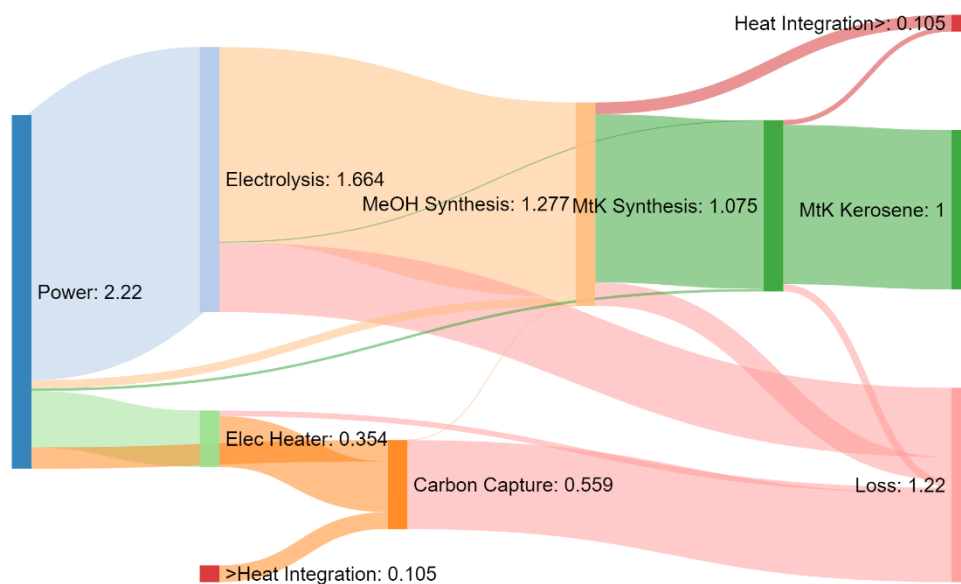
**Figure 152:** Energy consumption for producing 1 MJ of e-MTG Gasoline (CC from diluted source)



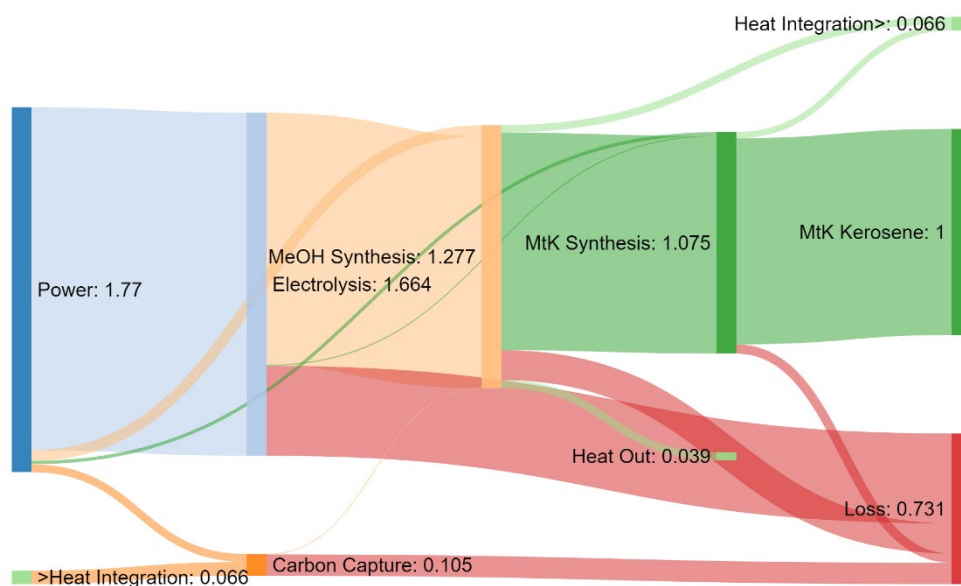
**Figure 153:** Energy consumption for producing 1 MJ of e-MTG Gasoline (CC from concentrated source)



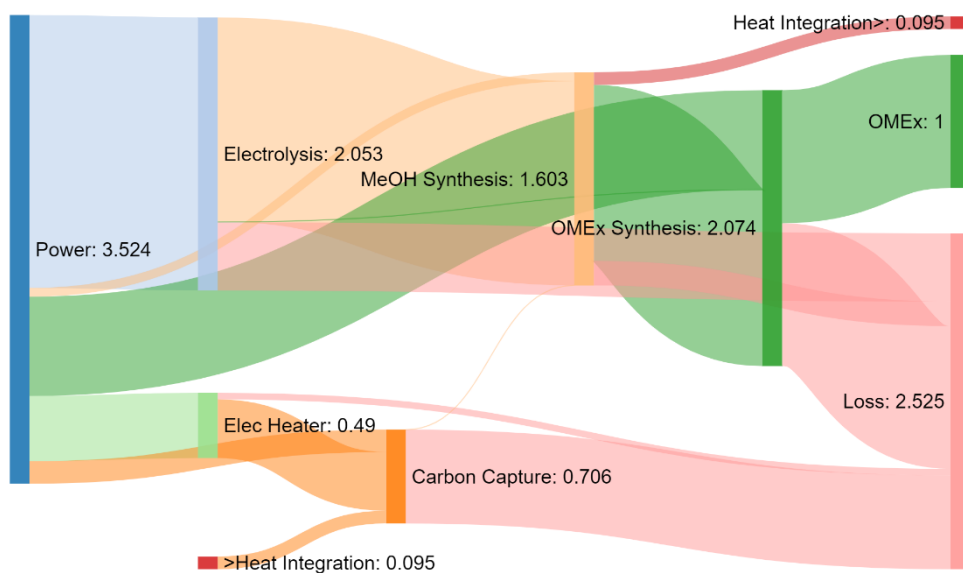
**Figure 154:** Energy consumption for producing 1 MJ of e-MTK Kerosene (CC from diluted source)



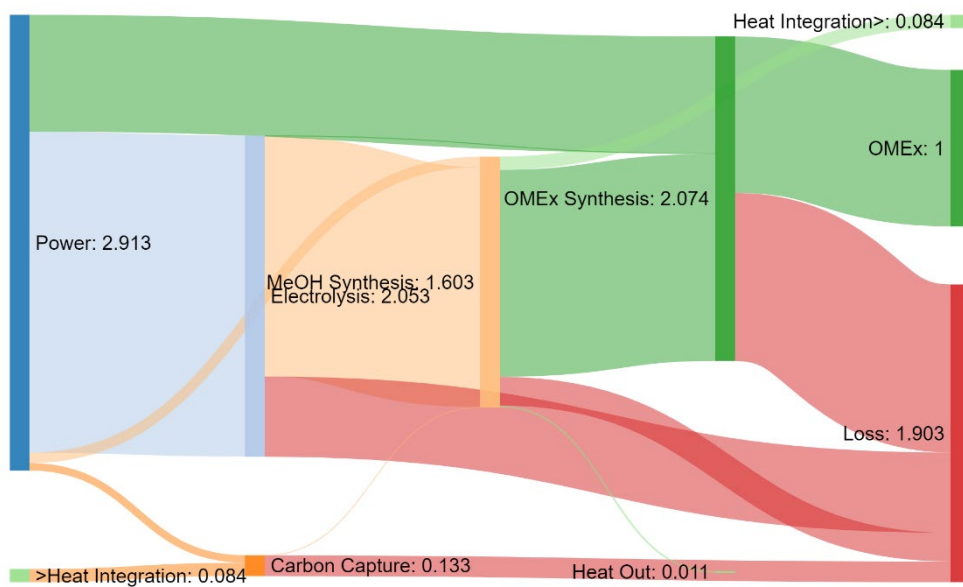
**Figure 155:** Energy consumption for producing 1 MJ of e-MTK Kerosene (CC from concentrated source)



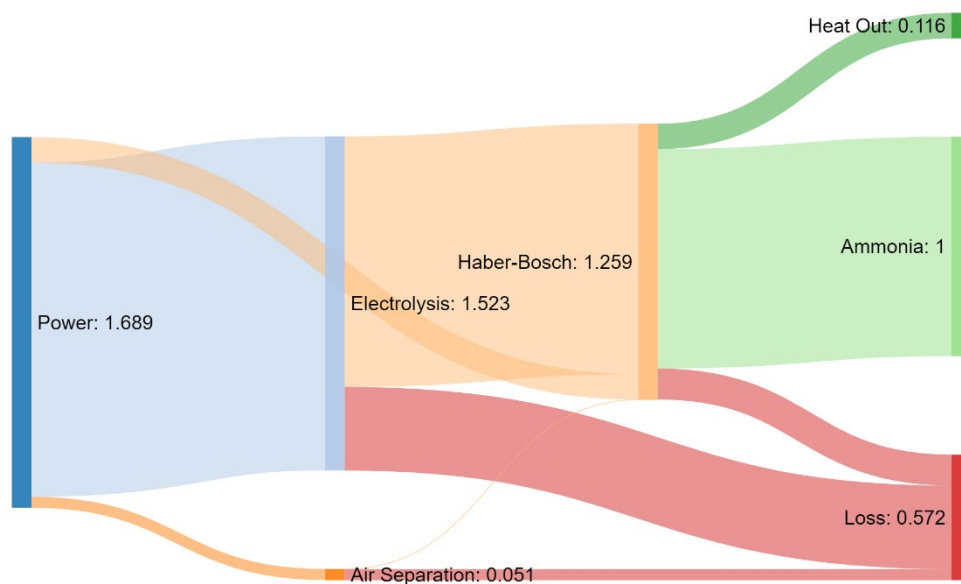
**Figure 156:** Energy consumption for producing 1 MJ of e-OME<sub>3-5</sub> (CC from diluted source)



**Figure 157:** Energy consumption for producing 1 MJ of e-OME<sub>3-5</sub> (CC from concentrated source)



**Figure 158:** Energy consumption for producing 1 MJ of e-Ammonia ( $N_2$  from air PSA)



## 9. ECONOMIC ANNEX

### 9.1. BASE CASES INVESTIGATED IN THIS STUDY

In the base case the production of final fuel of the PtX plants is set to 1 million t of diesel equivalent of final fuel per year. The installed capacity depends on the equivalent full load period of the PtX plant.

Table 48 shows the e-fuel pathways investigated in this study.

**Table 48:** Overview of e-fuel pathways investigated in this study

N°	Fuel	Supply	Pathway code
1	e-Hydrogen	Europe (N)	H2EU-N
2	e-Methane	Europe (N)	CH4EU-N
3	e-Methanol	Europe (N)	MeOHEU-N
4	e-OMEx	Europe (N)	OMExEU-N
5	e-Gasoline (MTG)	Europe (N)	MTGEU-N
6	e-Kerosene (MTK)	Europe (N)	MTKEU-N
7	e-Ammonia	Europe (N)	NH3EU-N
8	e-Kerosene (FT)	Europe (N)	FTKEU-N
9	e-Diesel (FT)	Europe (N)	FTDEU-N
10	e-Hydrogen	Europe (C)	H2EU-C
11	e-Methane	Europe (C)	CH4EU-C
12	e-Methanol	Europe (C)	MeOHEU-C
13	e-OMEx	Europe (C)	OMExEU-C
14	e-Gasoline (MTG)	Europe (C)	MTGEU-C
15	e-Kerosene (MTK)	Europe (C)	MTKEU-C
16	e-Ammonia	Europe (C)	NH3EU-C
17	e-Kerosene (FT)	Europe (C)	FTKEU-C
18	e-Diesel (FT)	Europe (C)	FTDEU-C
19	e-Hydrogen	Europe (S)	H2EU-S
20	e-Methane	Europe (S)	CH4EU-S
21	e-Methanol	Europe (S)	MeOHEU-S
22	e-OMEx	Europe (S)	OMExEU-S
23	e-Gasoline (MTG)	Europe (S)	MTGEU-S
24	e-Kerosene (MTK)	Europe (S)	MTKEU-S
25	e-Ammonia	Europe (S)	NH3EU-S
26	e-Kerosene (FT)	Europe (S)	FTKEU-S
27	e-Diesel (FT)	Europe (S)	FTDEU-S
28	H2 (liquid)	MENA by ship	H2ME-Liq
29	e-Methane (LNG)	MENA by ship	NGME-Liq
30	e-Methanol	MENA by ship	MeOHME
31	e-OMEx	MENA by ship	OMExME
32	e-Gasoline (MTG)	MENA by ship	MTGME
33	e-Kerosene (MTK)	MENA by ship	MTKME
34	e-Ammonia	MENA by ship	NH3ME
35	e-Gasoline (FT)	MENA by ship	FTGME
36	e-Kerosene (FT)	MENA by ship	FTKME

N°	Fuel	Supply	Pathway code
37	e-Diesel (FT)	MENA by ship	FTDME
38	e-Kerosene (FT)	MENA by ship as e-crude	FTKMEe-crd
39	e-Kerosene (FT)	Europe (S) with H <sub>2</sub> from MENA by ship	FTKME-H2ex
40	e-Diesel (FT)	Europe (S) with H <sub>2</sub> from MENA by ship	FTDME-H2ex

## 9.2. TECHNO-ECONOMIC DATA FOR RENEWABLE ELECTRICITY GENERATION IN THE DIFFERENT REGIONS

The PtX plants are directly connected with the renewable electricity generation plants. No public electricity grid is used. In some cases, an electricity transmission cable or line is required (sea cable in case of offshore wind, overhead HVDC transmission line in case of MENA).

### 9.2.1. Europe

For the calculation of the cost of renewable electricity in North Europe an offshore windfarm in the North Sea has been assumed. Table 49 shows the techno-economic data for electricity from offshore wind power.

**Table 49:** Renewable electricity costs in EU-North (base case) for FTK & FTD

	Unit	Wind offshore 2020	Wind offshore 2030	Wind offshore 2050	Reference
<b>Wind farm</b>					
Rated power	MW	6905	6888	6151	
Lifetime	yr	25	25	30	[IWES 2017]
Equivalent full load period	h/yr	4053	4053	4053	[BET et al. 2019]
Electricity generation	TWh/yr	27.99	22.92	24.93	
CAPEX	€/kW	3219	2137	2000	[BET et al. 2019]; [IRENA 2019b]*
	million €	22228	14718	12302	
Discount rate base case	-	8%	8%	8%	
Cost of capital wind farm	million €/yr	2082	1379	1093	
Operation & maintenance	€/ (kW*yr)	80	62	62	[BET et al. 2019]
	million €/yr	552	427	381	
<b>Transmission to onshore</b>					
Lifetime	yr	25	25	30	
CAPEX	million €	7941	4821	4306 <sup>(1)</sup>	[BET et al. 2019]
Cost of capital	million €/yr	744	452	382	
Operation & maintenance	million €/yr	159	96	86	[BET et al. 2019]
<b>Total</b>					
Annual costs	million €/yr	3537	2354	1943	
Curtailment	-	2.7%	3.9%	1.0%	chapter 4
Costs of electricity incl. curtailment supplied to e-fuel plant	€/kWh	0.130	0.088	0.079	

\*IRENA 2019b: 1400-2800 €/kW in 2050; equivalent full load period of 3770-5260 h/yr

<sup>(1)</sup> No further decrease of specific CAPEX for sea cable has been expected after 2030

For sensitivity analysis one variant of selected pathways involving electricity from North Europe has been calculated where the electricity for the e-fuel plants is derived from 100% onshore wind or 100% PV. For time horizon 2020 the CAPEX for onshore wind in North Europe has been derived from an existing wind farm in North Europe described in [NS Energy 2018]. The construction time was from 2018 to 2020.

For time horizon 2030 and 2050, learning curves have been applied for the CAPEX based on a learning rate (LR) of 0.05 indicated for onshore wind power and 0.15 for PV in [ISE 2018] and the cumulative installed capacity worldwide in 2018 (begin of construction of the Nysäter wind farm), 2030, and 2050 indicated in [REN21 2021], [IRENA 2019a], and [IRENA 2019b].

The CAPEX for the future can be calculated by:

$$CAPEX_{year\ n} = CAPEX_{year\ 1} \cdot \left( \frac{P_{year\ n}}{P_{year\ 1}} \right)^{\frac{\lg(1-LR)}{\lg(2)}}$$



where:

LR: Learning rate

P: Cumulative installed capacity

n: Target year

Example: Onshore wind power in North Europe in 2050:

$$CAPEX_{2050} = 1055 \frac{\text{€}}{\text{kW}} \cdot \left( \frac{5044 \text{ GW}}{568 \text{ GW}} \right)^{\frac{LN(1-0.05)}{LN(2)}} = 897 \frac{\text{€}}{\text{kW}}$$

Table 50 shows the cost of renewable electricity from 100% onshore wind in North Europe.

**Table 50:** Renewable electricity costs in EU-North (sensitivity: 100% wind onshore for FTK)

	Unit	Wind onshore 2020	Wind onshore 2030	Wind onshore 2050	Reference/ comment
Rated power	MW	7993	7707	7144	[Nysäter 2021]
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	3579	3579	3579	[Nysäter 2021]
Electricity generation	TWh/yr	28.61	27.58	25.57	
CAPEX	€/kW	1055	969	897	[NS Energy 2018]*
	million €	8431	7468	6411	
Discount rate base case		8%	8%	8%	
Cost of capital wind farm	million €/yr	790	700	601	
Operation & maintenance	€/(kW*yr)	48	48	48	[ISE 2018]
	million €/yr	383	369	342	
Annual costs	million €/yr	1173	1068	943	
Curtailment	-	10.4%	8.7%	8.7%	chapter 4
Costs of electricity incl. curtailment supplied to e-fuel plant	€/kWh	0.046	0.042	0.040	

\*Assumed for time horizon 2020 (2030 and 2050 calculated based on learning curves)

Table 51 shows the cost of renewable electricity from 100% PV in North Europe. Single axis sun tracking has been assumed for the PV plant. The equivalent full load period has been derived from the hourly production data from [Ninja 2021] for 2010-2019.

**Table 51:** Renewable electricity costs in EU-North (sensitivity: 100% PV for FTK)

	Unit	PV 2020	PV 2030	PV 2050	Reference/ comment
Rated power	MW	57473	53314	48418	
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	1119	1119	1119	
Electricity generation	TWh/yr	64.32	59.67	54.19	[Cossu et al. 2021]*
CAPEX	€/kW	637	468	361	
	million €	36610	24932	17501	
Discount rate base case		8%	8%	8%	
Cost of capital wind farm	million €/yr	3430	2336	1639	
Operation & maintenance	€/(kW*yr)	18	18	18	[Cossu et al. 2021]
	million €/yr	1045	970	881	
Annual costs	million €/yr	4475	3305	2520	
Curtailment	-	33.6%	29.4%	28.0%	chapter 4
Costs of electricity incl. curtailment supplied to e-fuel plant	€/kWh	0.105	0.079	0.065	

\*Assumed for time horizon 2020 (2030 and 2050 calculated based on learning curves)

For central Europe (Germany as proxy) a photovoltaic (PV)/wind hybrid power station has been assumed. PV and wind power are complementary to a large extent. High solar irradiation occurs at period with low wind speeds and vice versa. Some of the renewable electricity is curtailed depending on region, produced e-fuel, and time horizon (see chapter 4) because the integration costs of the last several percentage of excess power typically exceed the gain in using this 'excess' electricity (economic optimisation).

Large PV/hybrid power plants can be built e. g. in regions with (former) lignite mines in Germany. An analysis of the potential of PV/wind hybrid power plants at multi-GW scale combined with e-fuel plants can be found in [IFOK et al. 2018]. As an example, Table 52 shows the potential for PV and wind power in German coal mine.

**Table 52:** Potential for large PV and wind power plants in German lignite mine areas [IFOK et al. 2018]

	PV (MW)	Wind (MW)
Lusatia lignite mining region	8820-11894	1966-5149
Central German mining region	4491	13-1051
Rhineland mining region	1369	1162-1303

Single axis sun tracking has been assumed for the PV plant. The equivalent full load periods of the different regions have been derived from the hourly production data from [Ninja 2021] for 2010-2019.

**Table 53:** Renewable electricity costs in EU-Central in 2020 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				9.2%	chapter 4
Rated power	MW	6856	10568		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	1426	2688		[Deutsche WindGuard 2015]
Electricity generation	TWh/yr	9.78	28.41	34.67*	
CAPEX	€/kW	637	1521		[Cossu et al. 2021]; [Deutsche WindGuard & ZSW 2018]
	million €	4367	16073	20440	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	409	1506	1915	
Operation & maintenance	€/(kW*yr)	18	43		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	125	459	584	
Total	million €/yr	534	1965	2499	
	€/kWh	0.055	0.069	0.072	

\*Curtailment considered

For the calculation of the CAPEX of PV and onshore wind power for 2030 and 2050 learning curves have been applied based on learning rates and assumptions for cumulative installed capacity worldwide in the future indicated in [IRENA 2019a] and [IRENA 2019b]. For PV a learning rate of 0.15 and for onshore wind power a learning rate of 0.05 has been assumed based on [ISE 2018].

**Table 54:** Renewable electricity costs in EU Central in 2030 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailement				8.0%	chapter 4
Rated power	MW	7535	9816		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	1426	2688		[Deutsche WindGuard 2015]
Electricity generation	TWh/yr	10.74	26.38	34.17*	
CAPEX	€/kW	468	1397		
	million €	5224	13715	17239	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	330	1285	1615	
Operation & maintenance	€/(kW*yr)	18	43		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	137	426	563	
Total	million €/yr	467	1711	2178	
	€/kWh	0.043	0.065	0.064	

\*Curtailement considered

**Table 55:** Renewable electricity costs in EU Central in 2050 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailement				5.9%	chapter 4
Rated power	MW	7356	8580		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	1426	2688		[Deutsche WindGuard 2015]
Electricity generation	TWh/yr	10.49	23.06	31.58*	
CAPEX	€/kW	361	1294		
	million €	2659	11103	13762	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	249	1040	1289	
Operation & maintenance	€/(kW*yr)	18	43		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	134	373	507	
Total	million €/yr	383	1413	1796	
	€/kWh	0.037	0.061	0.057	

\*Curtailement considered

Southern Spain is an arid region. Hence, we apply a similar pathway setup for EU-South as in the cases of MENA, Chile, and Australia. The electricity generated by the PV/wind hybrid power plant is transported via a high voltage direct current (HVDC) transmission line over a distance of 200 km to the PtX plant at the coast (see chapter 9.2.2 and 9.2.3).

**Table 56:** Renewable electricity costs in EU-South in 2020 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailement				10.7%	chapter 4
<b>Electricity generation</b>					
Rated power	MW	7046	7593		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2073	3231		REVE 01/2020
Electricity generation	TWh/yr	14.61	24.53	34.95*	
CAPEX	€/kW	637	1111		[Cossu et al. 2021]; [REVE 01/2020]
	million €	4488	8437	12925	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	420	790	1211	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	128	350	479	
Subtotal	million €/yr	389	751	1141	
	€/kWh	0.038	0.047	0.048	
<b>Transmission to coast</b>					
Capacity	MW			7593	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			929	
Cost of capital	million €/yr			76	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
Subtotal	million €/yr			87	
	€/kWh			0.002	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2734	
Cost of capital	million €/yr			223	
Operation & maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			27	
Subtotal	million €/yr			251	
	€/kWh			0.007	
<b>Total costs of electricity</b>	€/kWh			0.058	

\*Curtailement considered

**Table 57:** Renewable electricity costs in EU-South in 2030 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailement				11.4%	chapter 4
<b>Electricity generation</b>					
Rated power	MW	7751	7099		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2073	3231		REVE 01/2020
Electricity generation	TWh/yr	16.07	22.94	34.54*	
CAPEX	€/kW	468	1021		
	million €	3625	7246	10870	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	340	679	1018	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	141	328	469	
Subtotal	million €/yr	481	1006	1487	
	€/kWh	0.030	0.047	0.043	
<b>Transmission to coast</b>					
Capacity	MW			7751	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			949	
Cost of capital	million €/yr			78	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
Subtotal	million €/yr			89	
	€/kWh			0.002	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2790	
Cost of capital	million €/yr			228	
Operation & maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
Subtotal	million €/yr			256	
	€/kWh			0.007	
<b>Total costs of electricity</b>	€/kWh			0.053	

\*Curtailement considered

**Table 58:** Renewable electricity costs in EU-South in 2050 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				6.2%	chapter 4
<b>Electricity generation</b>					
Rated power	MW	6736	6120		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2073	3231		REVE 01/2020
Electricity generation	TWh/yr	13.97	19.77	31.64*	
CAPEX	€/kW	361	945		
	million €	2435	5785	8220	
Discount rate base case		8%	8%	8%	
Cost of capital	million €/yr	228	542	770	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	123	282	405	
Subtotal	million €/yr	351	824	1175	
	€/kWh	0.025	0.042	0.037	
<b>Transmission to coast</b>					
Capacity	MW			6736	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			824	
Cost of capital	million €/yr			67	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			10	
Subtotal	million €/yr			77	
	€/kWh			0.002	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2425	
Cost of capital	million €/yr			198	
Operation & maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			24	
Subtotal	million €/yr			222	
	€/kWh			0.007	
<b>Total costs of electricity</b>	€/kWh			0.047	

\*Curtailment considered



### 9.2.2. MENA (KSA)

For MENA the equivalent full load periods both for PV and wind have been derived from the hourly production data from [Ninja 2021] for 2010-2019.

Analogous to [Fasihi et al. 2016] for MENA it has been assumed that the electricity generated by the PV/wind hybrid power plant is transported via a high voltage direct current (HVDC) transmission line over a distance of 200 km to the PtX plant which is located at the coast. The capacity of the plant depends on the e-fuel plant to be supplied with electricity, region, and time horizon (see chapter 4).

**Table 59:** Renewable electricity costs in MENA (KSA as proxy) in 2020 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				8.7%	chapter 4
<b>Electricity generation</b>					
Rated power	MW	7785	6359		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2406	3193		
Electricity generation	TWh/yr	18.73	20.30	35.65*	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	4959	7153	12112	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	465	670	1135	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	142	292	434	
<b>Subtotal</b>	<b>million €/yr</b>	<b>606</b>	<b>962</b>	<b>1569</b>	
	<b>€/kWh</b>	<b>0.032</b>	<b>0.047</b>	<b>0.044</b>	
<b>Transmission to coast</b>					
Capacity	MW			7785	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			953	
Cost of capital	million €/yr			78	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	<b>million €/yr</b>			<b>89</b>	
	<b>€/kWh</b>			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2802	
Cost of capital	million €/yr			229	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	<b>million €/yr</b>			<b>257</b>	
	<b>€/kWh</b>			<b>0.007</b>	
<b>Total costs of electricity</b>	<b>€/kWh</b>			<b>0.054</b>	

\*Curtailment considered

**Table 60:** Renewable electricity costs in MENA (KSA as proxy) in 2030 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				7.4%	chapter 4
<b>Electricity generation</b>					
Rated power	MW	8504	5448		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2406	3193		
Electricity generation	TWh/yr	20.46	17.40	35.05*	
CAPEX	€/kW	468	1033		
	million €	3977	5631	9607	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	373	527	900	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	155	250	405	
<b>Subtotal</b>	million €/yr	<b>527</b>	<b>778</b>	<b>1305</b>	
	€/kWh	<b>0.026</b>	<b>0.045</b>	<b>0.037</b>	
<b>Transmission to coast</b>					
Capacity	MW			8504	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			1041	
Cost of capital	million €/yr			85	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			12	
<b>Subtotal</b>	million €/yr			<b>98</b>	
	€/kWh			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			3061	
Cost of capital	million €/yr			250	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			31	
<b>Subtotal</b>	million €/yr			<b>281</b>	
	€/kWh			<b>0.008</b>	
<b>Total costs of electricity</b>	€/kWh			<b>0.048</b>	

\*Curtailment considered

**Table 61:** Renewable electricity costs in MENA (KSA as proxy) in 2050 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				6.6%	chapter 4
<b>Electricity generation</b>					
Rated power	MW	7724	5023		
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2406	3193		
Electricity generation	TWh/yr	18.58	16.04	32.34*	
CAPEX	€/kW	361	957		
	million €	2792	4808	7600	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	262	450	712	
Operation & maintenance	€/(kW*yr)	18	46		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	140	231	371	
<b>Subtotal</b>	million €/yr	<b>402</b>	<b>681</b>	<b>1083</b>	
	€/kWh	<b>0.022</b>	<b>0.042</b>	<b>0.033</b>	
<b>Transmission to coast</b>					
Capacity	MW			7724	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			945	
Cost of capital	million €/yr			77	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	million €/yr			<b>89</b>	
	€/kWh			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2780	
Cost of capital	million €/yr			227	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	million €/yr			<b>255</b>	
	€/kWh			<b>0.008</b>	
<b>Total costs of electricity</b>	€/kWh			<b>0.044</b>	

\*Curtailment considered

For sensitivity analysis variants for selected e-fuel pathways have been calculated for 100% PV and 100% onshore wind (chapter 2.2.3). The costs for electricity transport via HVDC per kWh of electricity increases due to the lower equivalent full load period compared to the combined PV/wind hybrid power station (Table 62 and Table 63).

**Table 62:** Renewable electricity costs in MENA (KSA as proxy) for 100% PV for FTK & FTD

	Unit	PV 2020	PV 2030	PV 2050	Reference
<b>Electricity generation</b>					
Rated power	MW	15623	15394	14134	
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	2406	2406	2406	
Electricity generation	TWh/yr	37.59	37.04	34.01	
CAPEX	€/kW	637	468	361	[Cossu et al. 2021]
	million €	9952	7199	5109	
Discount rate base case		8%	8%	8%	
Cost of capital PV plant	million €/yr	932	674	479	
Operation & maintenance	€/(kW*yr)	18	18	18	[Cossu et al. 2021]
	million €/yr	284	280	257	
<b>Subtotal</b>	<b>million €/yr</b>	<b>389</b>	<b>954</b>	<b>736</b>	
	<b>€/kWh</b>	<b>0.032</b>	<b>0.026</b>	<b>0.022</b>	
<b>Transmission to coast</b>					
Capacity	MW	15623	15394	14134	
Lifetime	yr	50	50	50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)	0.612	0.612	0.612	[Fasihi et al. 2016]
	million €	1912	1884	1730	
Cost of capital	million €/yr	156	154	141	
Operation & maintenance		1.2% of CAPEX/yr	1.2% of CAPEX/yr	1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	23	23	21	
<b>Subtotal</b>	<b>million €/yr</b>	<b>179</b>	<b>177</b>	<b>162</b>	
	<b>€/kWh</b>	<b>0.005</b>	<b>0.005</b>	<b>0.005</b>	
<b>Converters</b>					
Number of converters		2	2	2	
CAPEX	€/kW	180	180	180	[Fasihi et al. 2016]
	million €	5624	5542	5088	
Cost of capital	million €/yr	460	453	416	
Operation & Maintenance		1.0% of CAPEX/yr	1.0% of CAPEX/yr	1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	56	55	51	
<b>Subtotal</b>	<b>million €/yr</b>	<b>516</b>	<b>508</b>	<b>467</b>	
	<b>€/kWh</b>	<b>0.014</b>	<b>0.014</b>	<b>0.014</b>	
Curtailment	-	4.4%	4.5%	4.0%	chapter 4
<b>Total costs of electricity</b>	<b>€/kWh</b>	<b>0.053</b>	<b>0.046</b>	<b>0.042</b>	

**Table 63:** Renewable electricity costs in MENA (KSA as proxy) for 100% Wind for FTK & FTD

	Unit	Wind 2020	Wind 2030	Wind 2050	Reference
<b>Electricity generation</b>					
Rated power	MW	13181	12835	10854	
Lifetime	yr	25	25	25	
Equivalent full load period	h/yr	3193	3193	3193	
Electricity generation	TWh/yr	42.09	40.98	34.66	
CAPEX	€/kW	1125	1033	973	[REVE 10/2020]*
	million €	14828	13264	10388	
Discount rate base case		8%	8%	8%	
Cost of capital wind farm	million €/yr	1389	1243	973	
Operation & maintenance	€/(kW*yr)	46	46	46	[ISE 2018]
	million €/yr	606	590	499	
<b>Subtotal</b>	<b>million €/yr</b>	<b>1995</b>	<b>1833</b>	<b>1472</b>	
	<b>€/kWh</b>	<b>0.047</b>	<b>0.045</b>	<b>0.042</b>	
<b>Transmission to coast</b>					
Capacity	MW	13181	12835	10854	
Lifetime	yr	50	50	50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)	0.612	0.612	0.612	[Fasihi et al. 2016]
	million €	1613	1571	1328	
Cost of capital	million €/yr	132	128	109	
Operation & maintenance		1.2% of CAPEX/yr	1.2% of CAPEX/yr	1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	19	19	16	
<b>Subtotal</b>	<b>million €/yr</b>	<b>151</b>	<b>147</b>	<b>125</b>	
	<b>€/kWh</b>	<b>0.004</b>	<b>0.004</b>	<b>0.004</b>	
<b>Converters</b>					
Number of converters		2	2	2	
CAPEX	€/kW	180	180	180	[Fasihi et al. 2016]
	million €	4745	4620	3907	
Cost of capital	million €/yr	388	378	319	
Operation & Maintenance		1.0% of CAPEX/yr	1.0% of CAPEX/yr	1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr	47	46	39	
<b>Subtotal</b>	<b>million €/yr</b>	<b>435</b>	<b>424</b>	<b>358</b>	
	<b>€/kWh</b>	<b>0.010</b>	<b>0.010</b>	<b>0.010</b>	
Curtailment	-	13.4%	12.5%	5.3%	chapter 4
<b>Total costs of electricity</b>	<b>€/kWh</b>	<b>0.071</b>	<b>0.067</b>	<b>0.060</b>	

\*For 2020 (2030 and 2050 calculated based on learning curves)

### 9.2.3. Other sweet spots for renewable electricity worldwide

For sensitivity analysis long-haul potentials in other sweet spots (North Africa with Morocco as proxy, Australia, Chile) worldwide have been assessed. The equivalent full load periods of PV and wind have been derived from existing PV and wind power plants in Morocco (Table 64 and Table 65).

**Table 64:** Equivalent full load periods of PV plants in Morocco, Australia, and Chile

Region	PV plant	h/yr	Reference
North Africa (Morocco)	Noor Quarzazate IV, PV, 163 GWh/72MW	2263	[Masen 2019]
	Noor Laayoune, PV, 197 GWh/85MW	2318	[Masen 2019]
	Noor Boujdour, PV, 45 GWh/20 MW	2250	[Masen 2019]
	<b>Proxy</b>	<b>2300</b>	
Australia	Darlington Point 685 GWh/333 MW	2057	[Edify 2021a]
	Bungala Solar PV Plant, Port Augusta 570 GWh/275 MW	2072	[Power Technology 2017]
	Daydream 398 GWh/180 MW	2211	[Edify 2021b]
	<b>Proxy</b>	<b>2100</b>	
Chile	Lalackama I 160 GWh/60 MW	2666	[Enel 2021a]
	Lalackama II 50 GWh/18 MW	2777	[Enel 2021b]
	Amanecer Solar CAP plant up to 270 GWh/100 MW	2700	[Power Technology 2014]
	<b>Proxy</b>	<b>2700</b>	

**Table 65:** Equivalent full load periods of onshore wind power plants in Morocco, Australia, and Chile

Region	Wind farm	h/yr	Reference
North Africa (Morocco)	Tarfaya wind farm, 1000 GWh/301,3 MW	3319	[The Wind Power 2017]
	Akhfennir wind farm, 380 GWh/100 MW	3800	[NAREVA 2021a], [NAREVA 2021b]
	Amogdoul wind farm, 450 GWh/124 MW	3629	[Wind Energy - The Facts 2021]
	<b>Average proxy</b>	<b>3600</b>	
Australia	Hornsedale Wind Farm 1050 GWh/316 MW	3345	[NEOEN 2021]
	Sapphire Wind Farm 796.3 GWh/270 MW	2949	[CWP 2021]; [Wikipedia 8/2021]
	Collgar Wind Farm 665.8 GWh/222 MW	2999	[Collgar Wind Farm 2021] [Wikipedia 7/2021]
	<b>Proxy</b>	<b>3000</b>	
Chile	Statkraft 300 GWh/104 MW	2884	[REVE 04/2021]
	Taltal Wind Farm 300 GWh/99 MW	3030	[Enel 2021c]
	Atacama 2000 GWh/980 MW	2040	[Windpower Monthly 2020]
	San Martias (Biobio, North Chile) 358 GWh/107.5 MW	3330	[Renewables Now 2021]
	<b>Proxy</b>	<b>2800</b>	



The equivalent full load period combined with CAPEX and PPEX (maintenance, repair, labour, overhead) lead to the renewable electricity costs for the different regions shown in Table 66 to Table 74.

As a rough estimate it has been assumed that the curtailment of renewable electricity and the PV/wind ratio is the same as in KSA.

**Table 66:** Renewable electricity costs in Morocco in 2020 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				8.7%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	7785	6359		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2300	3600		Table 64, Table 65
Electricity generation	TWh/yr	17.90	22.89	37.26*	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	4959	7153	12112	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	465	670	1135	
Operation & maintenance	€/(kW*yr)	18	48		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	142	305	447	
<b>Subtotal</b>	<b>million €/yr</b>	<b>606</b>	<b>975</b>	<b>1581</b>	
	<b>€/kWh</b>	<b>0.034</b>	<b>0.043</b>	<b>0.042</b>	
<b>Transmission to coast</b>					
Capacity	MW			7785	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			953	
Cost of capital	million €/yr			78	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	<b>million €/yr</b>			<b>89</b>	
	<b>€/kWh</b>			<b>0.002</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2802	
Cost of capital	million €/yr			229	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	<b>million €/yr</b>			<b>257</b>	
	<b>€/kWh</b>			<b>0.007</b>	
<b>Total costs of electricity</b>	<b>€/kWh</b>			<b>0.052</b>	

\* Curtailment considered

**Table 67:** Renewable electricity costs in Morocco in 2030 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				7.4%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	8504	5448		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2300	3600		Table 64, Table 65
Electricity generation	TWh/yr	19.56	19.61	36.26*	
CAPEX	€/kW	468	1033		
	million €	3977	5631	9607	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	373	527	900	
Operation & maintenance	€/(kW*yr)	18	48		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	155	262	416	
<b>Subtotal</b>	million €/yr	<b>527</b>	<b>789</b>	<b>1316</b>	
	€/kWh	<b>0.027</b>	<b>0.040</b>	<b>0.036</b>	
<b>Transmission to coast</b>					
Capacity	MW			8504	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			1041	
Cost of capital	million €/yr			85	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			12	
<b>Subtotal</b>	million €/yr			<b>97</b>	
	€/kWh			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			3061	
Cost of capital	million €/yr			250	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			31	
<b>Subtotal</b>	million €/yr			<b>281</b>	
	€/kWh			<b>0.008</b>	
<b>Total costs of electricity</b>	€/kWh			<b>0.047</b>	

\*Curtailment considered

**Table 68:** Renewable electricity costs in Morocco in 2050 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				6.6%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	7724	5023		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2300	3600		Table 64, Table 65
Electricity generation	TWh/yr	17.76	18.08	33.49*	
CAPEX	€/kW	361	957		
	million €	2792	4808	7600	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	262	450	712	
Operation & maintenance	€/(kW*yr)	18	48		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	140	241	382	
<b>Subtotal</b>	million €/yr	<b>402</b>	<b>692</b>	<b>1094</b>	
	€/kWh	<b>0.023</b>	<b>0.038</b>	<b>0.033</b>	
<b>Transmission to coast</b>					
Capacity	MW			7724	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			945	
Cost of capital	million €/yr			77	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	million €/yr			<b>89</b>	
	€/kWh			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2780	
Cost of capital	million €/yr			227	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	million €/yr			<b>255</b>	
	€/kWh			<b>0.008</b>	
<b>Total costs of electricity</b>	€/kWh			<b>0.043</b>	

\* Curtailment considered

**Table 69:** Renewable electricity costs in Australia in 2020 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				8.7%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	7785	6359		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2100	3000		Table 64, Table 65
Electricity generation	TWh/yr	16.35	19.08	32.36*	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	4959	7153	12112	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	465	670	1135	
Operation & maintenance	€/(kW*yr)	18	45		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	141	286	428	
<b>Subtotal</b>	<b>million €/yr</b>	<b>606</b>	<b>956</b>	<b>1562</b>	
	<b>€/kWh</b>	<b>0.037</b>	<b>0.050</b>	<b>0.048</b>	
<b>Transmission to coast</b>					
Capacity	MW			7785	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			953	
Cost of capital	million €/yr			78	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	<b>million €/yr</b>			<b>89</b>	
	<b>€/kWh</b>			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2802	
Cost of capital	million €/yr			229	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	<b>million €/yr</b>			<b>257</b>	
	<b>€/kWh</b>			<b>0.008</b>	
<b>Total costs of electricity</b>	<b>€/kWh</b>			<b>0.059</b>	

\* Curtailment considered

**Table 70:** Renewable electricity costs in Australia in 2030 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				7.4%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	8504	5448		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2100	3000		Table 64, Table 65
Electricity generation	TWh/yr	17.86	16.35	31.66*	
CAPEX	€/kW	468	1033		[Cossu et al. 2021]; [REVE 10/2020]
	million €	3977	5631	9607	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	373	527	900	
Operation & maintenance	€/(kW*yr)	18	45		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	155	245	400	
<b>Subtotal</b>	<b>million €/yr</b>	<b>527</b>	<b>773</b>	<b>1300</b>	
	<b>€/kWh</b>	<b>0.030</b>	<b>0.047</b>	<b>0.041</b>	
<b>Transmission to coast</b>					
Capacity	MW			8504	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			1041	
Cost of capital	million €/yr			85	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			12	
<b>Subtotal</b>	<b>million €/yr</b>			<b>98</b>	
	<b>€/kWh</b>			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			3061	
Cost of capital	million €/yr			250	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			31	
<b>Subtotal</b>	<b>million €/yr</b>			<b>281</b>	
	<b>€/kWh</b>			<b>0.009</b>	
<b>Total costs of electricity</b>	<b>€/kWh</b>			<b>0.053</b>	

\*Curtailment considered

**Table 71:** Renewable electricity costs in Australia in 2050 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				6.6%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	7724	5023		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2100	3000		Table 64, Table 65
Electricity generation	TWh/yr	16.22	15.07	29.23*	
CAPEX	€/kW	361	957		[Cossu et al. 2021]; [REVE 10/2020]
	million €	2792	4808	7600	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	262	450	712	
Operation & maintenance	€/(kW*yr)	18	45		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	140	226	367	
<b>Subtotal</b>	million €/yr	<b>402</b>	<b>676</b>	<b>1078</b>	
	€/kWh	<b>0.025</b>	<b>0.045</b>	<b>0.037</b>	
<b>Transmission to coast</b>					
Capacity	MW			7724	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			945	
Cost of capital	million €/yr			77	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	million €/yr			<b>89</b>	
	€/kWh			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2780	
Cost of capital	million €/yr			227	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	million €/yr			<b>255</b>	
	€/kWh			<b>0.009</b>	
<b>Total costs of electricity</b>	€/kWh			<b>0.049</b>	

\* Curtailment considered]

**Table 72:** Renewable electricity costs in Chile in 2020 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				8.7%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	7785	6359		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2700	2800		Table 64, Table 65
Electricity generation	TWh/yr	21.02	17.80	35.46*	
CAPEX	€/kW	637	1125		[Cossu et al. 2021]; [REVE 10/2020]
	million €	4959	7153	12112	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	465	670	1135	
Operation & maintenance	€/(kW*yr)	18	44		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	142	280	421	
<b>Subtotal</b>	<b>million €/yr</b>	<b>606</b>	<b>950</b>	<b>1556</b>	
	<b>€/kWh</b>	<b>0.029</b>	<b>0.053</b>	<b>0.044</b>	
<b>Transmission to coast</b>					
Capacity	MW			7785	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			953	
Cost of capital	million €/yr			78	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	<b>million €/yr</b>			<b>89</b>	
	<b>€/kWh</b>			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2802	
Cost of capital	million €/yr			229	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	<b>million €/yr</b>			<b>257</b>	
	<b>€/kWh</b>			<b>0.007</b>	
<b>Total costs of electricity</b>	<b>€/kWh</b>			<b>0.054</b>	

\*Curtailment considered



**Table 73:** Renewable electricity costs in Chile in 2030 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				7.4%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	8504	5448		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2700	2800		Table 64, Table 65
Electricity generation	TWh/yr	22.96	15.26	35.37*	
CAPEX	€/kW	468	1033		[Cossu et al. 2021]; [REVE 10/2020]
	million €	3977	5631	9607	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	373	527	900	
Operation & maintenance	€/(kW*yr)	18	44		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	155	240	394	
<b>Subtotal</b>	<b>million €/yr</b>	<b>527</b>	<b>767</b>	<b>12944</b>	
	<b>€/kWh</b>	<b>0.023</b>	<b>0.050</b>	<b>0.037</b>	
<b>Transmission to coast</b>					
Capacity	MW			8504	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			1041	
Cost of capital	million €/yr			85	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			12	
<b>Subtotal</b>	<b>million €/yr</b>			<b>98</b>	
	<b>€/kWh</b>			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			3061	
Cost of capital	million €/yr			250	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			31	
<b>Subtotal</b>	<b>million €/yr</b>			<b>281</b>	
	<b>€/kWh</b>			<b>0.008</b>	
<b>Total costs of electricity</b>	<b>€/kWh</b>			<b>0.047</b>	

\*Curtailment considered

**Table 74:** Renewable electricity costs in Chile in 2050 for FTK & FTD

	Unit	PV	Wind	PV/wind hybrid	Reference
Curtailment				6.6%	Same as for KSA
<b>Electricity generation</b>					
Rated power	MW	7724	5023		Same as for KSA
Lifetime	yr	25	25		
Equivalent full load period	h/yr	2700	2800		Table 64, Table 65
Electricity generation	TWh/yr	20.85	14.07	32.62*	
CAPEX	€/kW	361	957		[Cossu et al. 2021]; [REVE 10/2020]
	million €	2792	4808	7600	
Discount rate base case		8%	8%	8%	
Cost of capital PV/wind	million €/yr	262	450	712	
Operation & maintenance	€/(kW*yr)	18	44		[Cossu et al. 2021]; [ISE 2018]
	million €/yr	140	221	362	
<b>Subtotal</b>	<b>million €/yr</b>	<b>402</b>	<b>671</b>	<b>1073</b>	
	<b>€/kWh</b>	<b>0.019</b>	<b>0.048</b>	<b>0.033</b>	
<b>Transmission to coast</b>					
Capacity	MW			7724	
Lifetime	yr			50	[Fasihi et al. 2016]
CAPEX	€/(m*kW)			0.612	[Fasihi et al. 2016]
	million €			945	
Cost of capital	million €/yr			77	
Operation & maintenance				1.2% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			11	
<b>Subtotal</b>	<b>million €/yr</b>			<b>89</b>	
	<b>€/kWh</b>			<b>0.003</b>	
<b>Converters</b>					
Number of converters				2	
CAPEX	€/kW			180	[Fasihi et al. 2016]
	million €			2780	
Cost of capital	million €/yr			227	
Operation & Maintenance				1.0% of CAPEX/yr	[Fasihi et al. 2016]
	million €/yr			28	
<b>Subtotal</b>	<b>million €/yr</b>			<b>255</b>	
	<b>€/kWh</b>			<b>0.008</b>	
<b>Total costs of electricity</b>	<b>€/kWh</b>			<b>0.043</b>	

\* Curtailment considered

### 9.3. TECHNO-ECONOMIC DATA FOR WATER AND CO-ELECTROLYSIS

For all pathways the same efficiency and the same cost data for the electrolysis plant have been assumed. Above 100 MWe no further cost reduction from upscaling is expected.

**Table 75:** CAPEX of alkaline water electrolysis plants above 100 MWe (€/kWe)

	2020	2030	2050	Reference
Stack	530	357	189	Zauner et al. 2019
Power electronics	75	47	27	
Gas conditioning	51	48	36	
Balance of plant	77	55	29	
<b>Subtotal direct CAPEX</b>	<b>734</b>	<b>507</b>	<b>281</b>	
Site preparation	15	10	6	H2A 2018
Engineering & design	59	41	22	
Project contingency	110	76	42	
Up-Front Permitting	110	76	42	
<b>CAPEX total</b>	<b>1027</b>	<b>710</b>	<b>393</b>	

Table 76 shows the summarized CAPEX for alkaline and co-electrolysis. The CAPEX for the co-electrolysis in has been derived from [Wolf 2020], [Zauner 2019], and [H2A 2018].

**Table 76:** Techno-economic data electrolysis plants in the base case

	Unit	2020	2030	2050	2050 AT
Technology	-	Alkaline	Alkaline	Alkaline	Co-electrolysis
Efficiency (LHV)	-	66.5%	68%	75%	82.1%
CAPEX total	€/kW <sub>e</sub>	1027	710	393	951
	€/kW <sub>H2</sub>	1544	1044	524	1158
Lifetime	yr	30	30	30	20

All auxiliaries such as transformer, AC/DC converter, pumps, blowers, and storage tanks are included. Costs for civil work, engineering, etc. are also included.

In [Zauner et al. 2019] the operating and maintenance costs for alkaline electrolysis are indicated with 2% of direct CAPEX per year including stack replacement. For co-electrolysis via SOEC the operating and maintenance costs are indicated with 5% of direct CAPEX per year including stack replacement [Zauner et al. 2019].

## 9.4. DESCRIPTION OF FUEL SUPPLY PATHWAYS

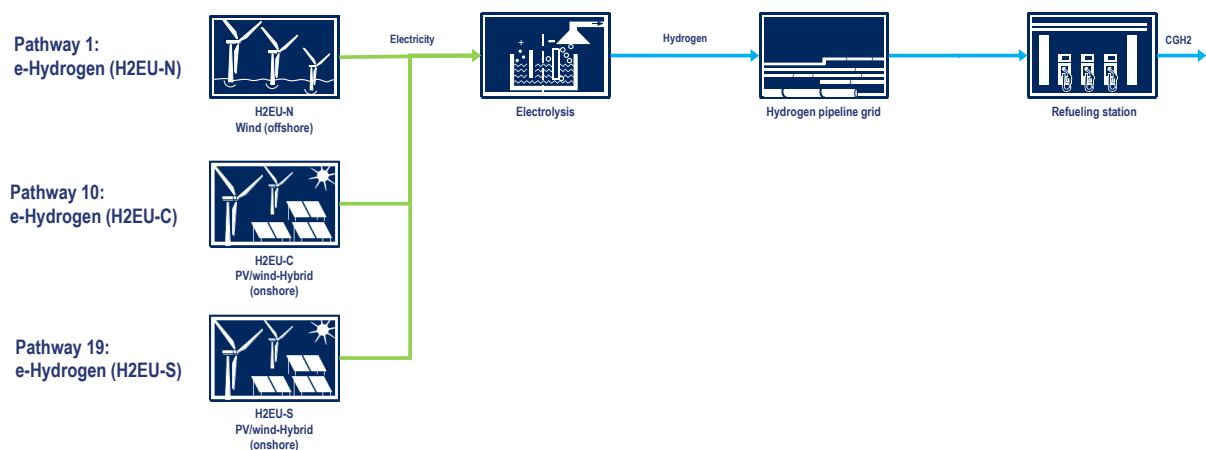
### 9.4.1. E-Hydrogen in the EU (H2EU-N, H2EU-C, H2EU-S)

Hydrogen is generated via water electrolysis, compressed, and stored in a stationary buffer storage at a pressure of 10 MPa to compensate fluctuations of renewable electricity supply. The hydrogen is transported and distributed to the refuelling stations via a hydrogen pipeline grid. At the refuelling station the hydrogen is compressed, pre-cooled, and dispensed to road vehicles with 70 MPa vehicle tanks.

Three variants have been taken into account:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

**Figure 159:** e-Hydrogen



The power-to-hydrogen plant generates 11.98 TWh of hydrogen or 1 million t of diesel equivalent per year based on the lower heating value (LHV). As a result, the capacity of the power-to-hydrogen plant depends on the region and the time horizon (see chapter 4).

A hydrogen buffer storage has been assumed to compensate fluctuations of the renewable electricity supply. In case of hydrogen as final fuel, also fluctuating demand has to be taken into account. Therefore, a hydrogen storage capacity of 2 days has been assumed for all pathways which supply hydrogen as final fuel.

A hydrogen storage loading compressor is required to elevate the pressure of the hydrogen leaving the electrolysis plant to 10 MPa which is the maximum pressure of the hydrogen buffer storage. The buffer storage consists of underground steel-made tubes with a diameter of 1485 mm which are typically used for natural gas storage today.

The CAPEX and costs for maintenance and repair for the compressor is based on a large hydrogen compressor with a capacity of 10,500 kg H<sub>2</sub>/h (~117,000 Nm<sup>3</sup>/h) described in [Planet et al. 2014]. The CAPEX for the hydrogen storage has been derived from [Jauslin Stebler 2013].

Table 77, Table 78, and Table 79 shows the techno-economic data for the hydrogen buffer storage including hydrogen storage loading compressor.

**Table 77:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for the supply of CGH<sub>2</sub> as transportation fuel in 2020

	Unit	H2EU-N	H2EU-C	H2EU-S	Reference/ comment
Capacity electrolysis	MW <sub>H<sub>2</sub></sub>	2041	2405	2188	
	Nm <sup>3</sup> /h	681,000	802,000	730,000	
Electricity input electrolysis	MW <sub>e</sub>	3070	3616	3291	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217			
CAPEX	million €	175	206	188	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.0	2.0	2.0	of full load operation
	million Nm <sup>3</sup>	32.7	38.5	35.0	Net storage capacity
CAPEX	million €	820	967	880	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			

**Table 78:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for the supply of CGH<sub>2</sub> as transportation fuel in 2030

	Unit	H2EU-N	H2EU-C	H2EU-S	Reference/ comment
Capacity electrolysis	MW <sub>H<sub>2</sub></sub>	2045	2511	2357	
	Nm³/h	682,000	837,000	786,000	
Electricity input electrolysis	MW <sub>e</sub>	3008	3692	3466	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm³	0.0649			
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217			
CAPEX	million €	175	215	202	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.0	2.0	2.0	of full load operation
	million Nm³	32.7	40.2	37.7	Net storage capacity
CAPEX	million €	822	1009	949	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			

**Table 79:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for the supply of CGH<sub>2</sub> as transportation fuel in 2050

	Unit	H2EU-N	H2EU-C	H2EU-S	Reference/ comment
Capacity electrolysis	MW <sub>H<sub>2</sub></sub>	2050	2765	2863	
	Nm <sup>3</sup> /h	684,000	922,000	954,000	
Electricity input electrolysis	MW <sub>e</sub>	2734	3687	3817	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217			
CAPEX	million €	176	237	245	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.0	2.0	2.0	of full load operation
	million Nm <sup>3</sup>	32.8	44.3	45.8	Net storage capacity
CAPEX	million €	824	1111	1151	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			

The hydrogen is transported to the refueling stations via a pipeline grid (Table 80). The CAPEX, cost of maintenance and repair, and the length of the hydrogen pipeline grid has been derived from [Krieg 2012]. The electricity consumption for hydrogen transport via pipeline has been derived from [Sphera 2021].

The 0.000864 MJ per km and kg of hydrogen indicated in [Sphera 2021] has been divided by the LHV of the hydrogen and multiplied with the average length of the transmission pipeline between the electrolysis plant and the local pipeline grid to get the electricity consumption per MJ of hydrogen. The electricity is supplied by the electricity grid at medium voltage (MV) level. It has been assumed that the transmission pipeline grid consists of three main pipelines per electrolysis plant.

**Table 80:** H<sub>2</sub> pipeline grid per electrolysis plant

	Unit	Value
H <sub>2</sub> throughput	TWh <sub>LHV</sub> /yr	11.98
Length transmission pipeline grid	km	782
	km/refueling station	1.4
Average length of main pipeline to electrolysis plant	km	261
CAPEX transmission pipelines	€/m	526
	million	411
Lifetime	yr	30
Length local pipeline grid	km	2351
	km/refueling station	4.1
CAPEX local pipeline grid	€/m	289
	million €	679
Lifetime	yr	30
Electricity consumption	MJ/MJ <sub>H<sub>2</sub>, LHV</sub>	0.00087
Maintenance & repair		5% of CAPEX/yr

Table 81 shows the techno-economic data for the hydrogen refuelling station for the dispensing of compressed gaseous hydrogen for fuel cell trucks with 70 MPa vehicle tanks. The CAPEX and the costs of maintenance and repair are based on data in [Parks et al. 2014] except the costs for approval. Learning curves have been applied to calculate the CAPEX for the different time horizons. The costs for the approval have been derived from the German safety inspection organization TÜV [Elliger 2016]. The costs for insurance have been derived from [HRSAM 2021].



**Table 81:** CGH<sub>2</sub> refueling station for CGH<sub>2</sub> trucks with 70 MPa vehicle tanks

	Unit	2020	2030	2050
H <sub>2</sub> throughput	GWh/yr	21	21	21
	kg H <sub>2</sub> /d	2500	2500	2500
Open days per year		250	250	250
Electricity consumption	MJ/MJ <sub>H<sub>2</sub></sub> , LHV	0.1106	0.1106	0.1106
Number of dispensers	-	2	2	2
<b>CAPEX</b>				
H <sub>2</sub> bulk storage	€	994,000	739,00	644,000
H <sub>2</sub> high pressure buffer	€	1,360,000	1,010,000	880,000
H <sub>2</sub> compressors	€	1,677,000	934,000	711,000
Pre-cooling	€	227,000	169,000	147,000
H <sub>2</sub> dispensers	€	189,000	141,000	122,000
Installation	€	1,334,000	897,000	751,000
Site preparation	€	289,000	194,000	163,000
Engineering & design	€	578,000	389,000	326,000
Contingency	€	289,000	194,000	163,000
Approval	€	2000	2000	2000
<b>Total</b>	<b>€</b>	<b>6,939,000</b>	<b>4,669,000</b>	<b>3,909,000</b>
<b>OPEX</b>				
Maintenance & repair		4% of compressor CAPEX/yr		
Insurance		1% of total CAPEX/yr		
Safety inspection	€/yr	1575	1575	1575
Dispenser calibration	€/yr	1432	1432	1432

The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

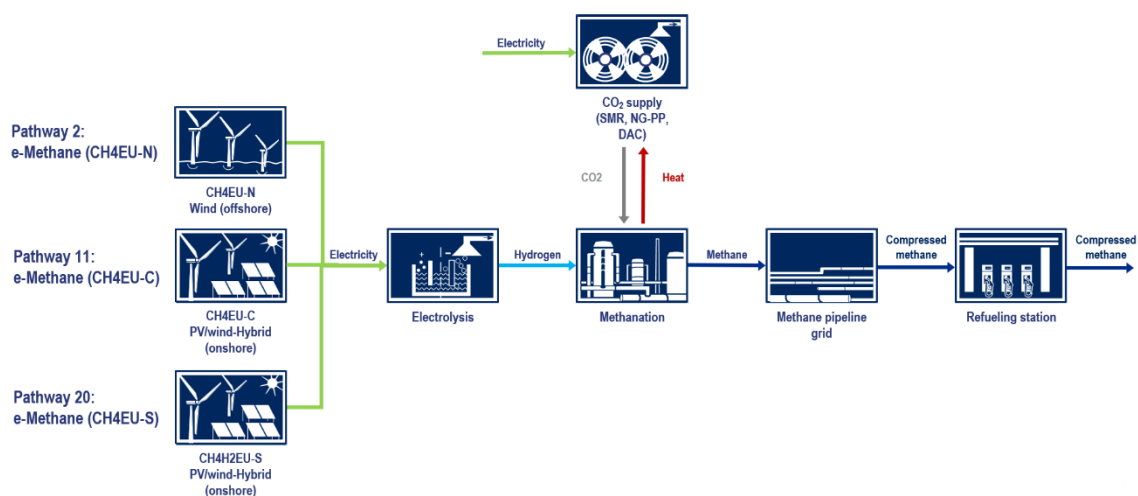
#### 9.4.2. E-Methane in the EU (CH<sub>4</sub>EU-N, CH<sub>4</sub>EU-C, CH<sub>4</sub>EU-S)

E-methane is created through the methanation process, where a chemical reaction converts carbon dioxide and hydrogen to methane. The hydrogen needed for the process is generated via electrolysis. The carbon dioxide can be produced by several routes, for example by direct air capture (DAC), from flue gas from steam methane reforming (SMR), or from flue gas from a mix of natural gas and biomass power stations (NG-PP). After the methanation process to methane is pressurized and transported through a pipeline grid to refuelling stations where the compressed methane is dispensed to road vehicles. The three different pathways only differ in the electricity needed for the electrolysis.

The following variants have been taken into account:

- In North Europe electricity from offshore wind power is used (e. g. in the North Sea at Norway)
- In Central Europe electricity from PV-/wind-hybrid power stations are used
- In South Europe electricity from PV-/wind-hybrid power stations are used

**Figure 160:** e-Methane



The power-to-CH<sub>4</sub> plant generates 11.98 TWh of methane or 1 million t of diesel equivalent per year based on the lower heating value (LHV). As a result, the capacity of the electrolyss plant depends on the region and the time horizon (see chapter 4).

An electricity storage system (ESS) has been applied to compensate short-term fluctuations of renewable electricity supply.

The storage capacity of the buffer storage (Table 82, Table 83, Table 84) depends on the flexibility of the e-fuel plant, the region, and the time horizon (see chapter 4.3.1). For the methanation plant a minimum part load of 50% for all time horizons has been assumed. Methane can be stored more easily than hydrogen due to higher energy density per m<sup>3</sup> of pressure vessel and the buffer storage is only used for bridging the lower flexibility of the methanation process.

**Table 82:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-methane in Europe in 2020

	Unit	CH4EU-N	CH4EU-C	CH4EU-S	Reference/ comment
Capacity electrolysis	MW <sub>H2</sub>	2447	2758	2591	
	Nm <sup>3</sup> /h	816,000	920,000	864,000	
Electricity input electrolysis	MW <sub>e</sub>	3680	4148	3896	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	210	236	222	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.8	1.9	2.3	of full load operation
	million Nm <sup>3</sup>	54.8	41.5	48.5	Net storage capacity
CAPEX	million €	1377	1041	1218	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

**Table 83:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-methane in Europe in 2030

	Unit	CH4EU-N	CH4EU-C	CH4EU-S	Reference/ comment
Capacity electrolysis	MW <sub>H2</sub>	2444	2852	2713	
	Nm <sup>3</sup> /h	822,000	951,000	905,000	
Electricity input electrolysis	MW <sub>e</sub>	3624	4194	3990	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	211	245	233	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.7	2.0	2.4	of full load operation
	million Nm <sup>3</sup>	54.0	45.2	51.4	Net storage capacity
CAPEX	million €	1356	1135	1292	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

**Table 84:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-methane in Europe in 2050

	Unit	CH4EU-N	CH4EU-C	CH4EU-S	Reference/ comment
Capacity electrolysis	MW <sub>H2</sub>	2479	2955	2829	
	Nm <sup>3</sup> /h	827,000	985,000	943,000	
Electricity input electrolysis	MW <sub>e</sub>	3305	3941	3772	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	213	253	243	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.7	2.2	2.5	of full load operation
	million Nm <sup>3</sup>	53.6	51.3	56.2	Net storage capacity
CAPEX	million €	1345	1287	1411	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

The hydrogen is sent together with CO<sub>2</sub> to a catalytic methanation process. The following reaction occur:



The reaction is exothermal. The temperature is about 250 to 300 °C [Etogas 2014].

For 2020 and 2030 a concentrated CO<sub>2</sub> source with a CO<sub>2</sub> concentration of 45% e. g. flue gas from steam methane reforming (SMR) plants is used for CO<sub>2</sub> supply. For 2050 a mix of CO<sub>2</sub> from SMR, flue gas from a mix of natural gas and biomass fuelled power plants, and from direct air capture of CO<sub>2</sub> is assumed in the base case.

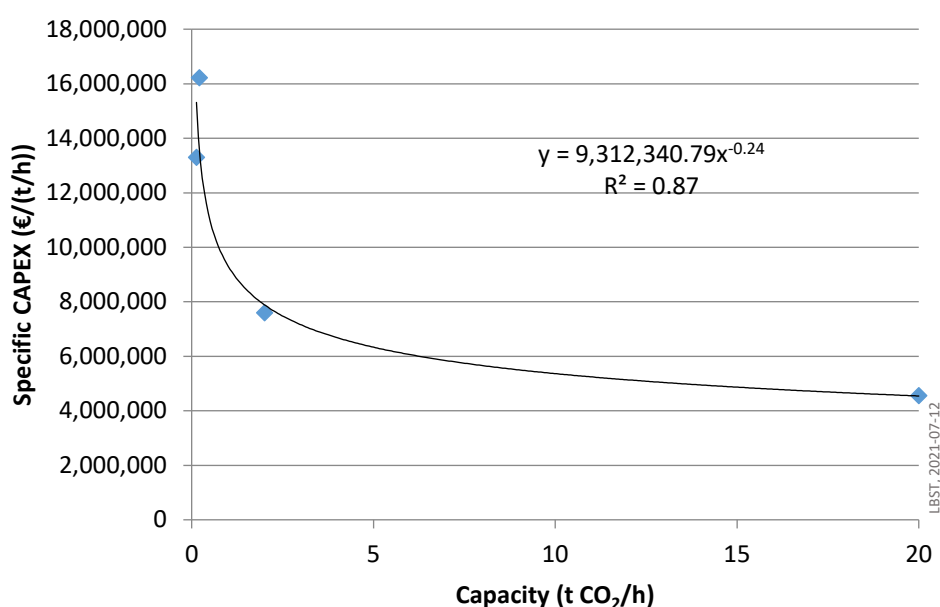
For 2020 and 2030 it has been assumed that the CO<sub>2</sub> from a concentrated source. The CO<sub>2</sub> concentration of this concentrated source is assumed to be 45 % e. g. flue gas from a steam methane reforming (SMR) plant. For 2050 CO<sub>2</sub> from a deluted CO<sub>2</sub> source has been assumed. CO<sub>2</sub> via direct air capture (DAC) of CO<sub>2</sub> represents the diluted CO<sub>2</sub> source.

The electricity and heat demand for the capture of CO<sub>2</sub> from a concentrated source with a CO<sub>2</sub> concentration of 45% have been derived from [Sphera 2021]. The CO<sub>2</sub> concentration of biogas leaving the fermenter ranges between 40 and 50% which is like the 45% above, Therefore, the CAPEX has been derived from biogas upgrading plant based on scrubbing with monoethanolamine (MEA) described in [KTBL 2012]. A scaling exponent of 0.7 has been used to take into account cost reduction by scale.

The electricity and heat demand for the capture of CO<sub>2</sub> from natural gas and biomass fueled power stations (average source of CO<sub>2</sub>) have been derived from [Sphera 2021]. The CAPEX and the costs of labour, maintenance, and repair has been derived from a CO<sub>2</sub> capture plant for natural gas power stations described [RECCS 2007] and a cement production plant described in [Gardarsdottir et al. 2019]. For the calculation of the CAPEX a scaling exponent of 0.7 has been used to take into account cost reduction by scale.

The electricity and heat demand for the DAC plant have been derived from [Beuttler et al. 2019]. The CAPEX for the DAC plant has been derived from [Climeworks 2015] and [Keufl 2019]. Figure 161 shows the specific CAPEX depending on the capacity of the DAC plant.

**Figure 161:** Specific CAPEX for direct air capture (DAC) of CO<sub>2</sub> depending on capacity



CO<sub>2</sub> liquefaction has been applied to provide pure CO<sub>2</sub> to avoid damage of methanation catalyst. Furthermore, a CO<sub>2</sub> buffer storage has been supplied to partly decouple CO<sub>2</sub> production and methanation. The techno-economic data for CO<sub>2</sub> liquefaction and storage is based on a capacity of 114 t CO<sub>2</sub>/h described in [Element

Energy 2018]. A scaling exponent of 0.7 has been assumed to calculate the CAPEX of the CO<sub>2</sub> liquefaction plant. The buffer storage has been scaled linearly.

Table 85, Table 86 and Table 87 show the techno-economic data for the supply of CO<sub>2</sub> for a methanation plant for the supply of 11.98 TWh of methane per year based on the LHV or 1 million t of diesel equivalent per year.

**Table 85:** CO<sub>2</sub> supply for a methanation plant in Europe 2020

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	441 (CH4EU-N) 497 (CH4EU-C) 467 (CH4EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	158 (EU-N) 172 (EU-C) 165 (EU-S)	401 (EU-N) 436 (EU-C) 418 (EU-S)	952 (EU-N) 1043 (EU-C) 995 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	1.92 (N) / 1.98 (C) / 1.92 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	57 (EU-N) 62 (EU-C) 60 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.7 (EU-N), 1.8 (EU-C), 6.0 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	23 (EU-N)** 13 (EU-C)** 40 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\* 0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub> stored

**Table 86:** CO<sub>2</sub> supply for a methanation plant in Europe 2030

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	444 (CH <sub>4</sub> EU-N) 514 (CH <sub>4</sub> EU-C) 489 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	159 (EU-N) 176 (EU-C) 170 (EU-S)	403 (EU-N) 447 (EU-C) 432 (EU-S)	958 (EU-N) 1070 (EU-C) 1030 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	1.92 (N) / 1.98 (C) / 1.98 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	58 (EU-N) 64 (EU-C) 62 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.9 (EU-N), 2.4 (EU-C), 5.7 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	24 (EU-N)** 17 (EU-C)** 40 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\* 0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub> stored



**Table 87:** CO<sub>2</sub> supply for a methanation plant in Europe 2050

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	447 (CH <sub>4</sub> EU-N) 533 (CH <sub>4</sub> EU-C) 510 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	160 (EU-N) 181 (EU-C) 175 (EU-S)	405 (EU-N) 458 (EU-C) 444 (EU-S)	962 (EU-N) 1099 (EU-C) 1063 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	1.92 (N) / 2.04 (C) / 1.98 (S)		
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	58 (EU-N) 65 (EU-C) 63 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	5.2 (EU-N), 3.0 (EU-C), 6.0 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	33 (EU-N)** 23 (EU-C)** 43 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\* 0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub> stored

Table 88 shows the techno-economic data for a methanation plant which produces 11.98 TWh of methane or 1 million t of diesel equivalent per year based on the LHV.

**Table 88:** Techno-economic data for a methanation plant in Europe

	Unit	CH4EU-N	CH4EU-C	CH4EU-S	Reference/comment
Capacity 2020/2030/2050	MW <sub>CH<sub>4</sub>, LHV</sub>	1690/1673/1675	1796/1810/1844	1615/1615/1648	
<b>Inputs</b>					
H <sub>2</sub>	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	1.198	1.198	1.198	
CO <sub>2</sub>	kg/MJ <sub>CH<sub>4</sub>, LHV</sub>	0.0600	0.0600	0.0600	
Electricity	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	0.0229	0.0229	0.0229	
<b>Outputs</b>					
CH <sub>4</sub>	MJ	1.000	1.000	1.000	
Heat (T = 250-300 °C)	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	0.072	0.072	0.072	
<b>Economic data</b>					
CAPEX 2020/2030/2050	€/kW <sub>CH<sub>4</sub>, LHV</sub>	792/704/541	792/704/541	792/704/541	[IEA 2019d] (880/782/601 US\$/kW <sub>CH<sub>4</sub>, LHV</sub> )
	million €	1338/1178/906	1422/1275/998	1279/1137/892	
Lifetime	yr	30	30	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	3% of CAPEX/yr	3% of CAPEX/yr	[IEA 2019d]
Variable O&M	€/GWh <sub>CH<sub>4</sub>, LHV</sub>	320	320	320	[Aramco 2021] (355 US\$/GWh <sub>CH<sub>4</sub>, LHV</sub> )

The methane is transported to the refuelling stations via a pipeline grid (Table 89). The CAPEX, cost of maintenance and repair, and the length of the pipeline grid has been derived from [Krieg 2012].

**Table 89:** CH<sub>4</sub> pipeline grid per methanation plant

	Unit	North EU
CH <sub>4</sub> throughput	TWh <sub>LHV</sub> /yr	11.98
Length transmission pipeline grid	km	782
	km/refueling station	1.4
Average length of main pipeline to electrolysis plant	km	261
CAPEX transmission pipelines	€/m	526
	million	411
Lifetime	yr	30
Length local pipeline grid	km	2351
	km/refueling station	4.4
CAPEX local pipeline grid	€/m	280
	million €	658
Lifetime	yr	30
Electricity consumption	MJ/MJ <sub>H2</sub> , LHV	0
Maintenance & repair		5% of CAPEX/yr

Table 90 shows the techno-economic data for the refuelling station for the dispensing of compressed gaseous methane for CNG trucks with 20 MPa vehicle tanks (typical maximum operating pressure for CNG vehicle tanks at 15°C).

The CAPEX and the costs of maintenance and repair are based on data in [LBST 2016] except the costs for approval. Compressed gaseous methane has similar properties a compressed natural gas (CNG). CNG refuelling stations are mature. No cost reductio has been assumed for the future. The costs for the approval have been derived from the German safety inspection organization TÜV [Elliger 2016]. The costs for insurance have been derived from [HRSAM 2021].

**Table 90:** Compressed gaseous methane refueling station for CNG trucks

	Unit	2020/2030/2050
CH <sub>4</sub> throughput	GWh/yr	22.4
Open days per year	-	250
Electricity consumption	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	0.0224
Number of dispensers	-	2
<b>CAPEX</b>		
Gas inlet line incl. gas drier	€	120,000
Dispensers	€	100,000
Sequencing block dispenser	€	16,000
CH <sub>4</sub> storage (3-bank)	€	175,000
CH <sub>4</sub> Compressor	€	450,000
Cooling system compressors	€	30,000
Recirculation cooling cycle	€	25,000
Control unit compressors	€	80,000
Odorization	€	30,000
Equipment for data transfer	€	10,000
Concrete made building	€	100,000
Gas outlet line	€	35,000
MF-Block PF	€	10,000
Installation	€	150,000
Civil work (roof, pay system)	€	280,000
Cables, piping, material transport, calibration	€	120,000
Project management, documentation	€	80,000
Other	€	30,000
Approval	€	2000
<b>Total</b>	<b>€</b>	<b>1843,000</b>
<b>OPEX</b>		
Maintenance & repair	€/yr	4902
Safety inspection storage vessels	€/yr	2880
Dispenser calibration costs	€/yr	1432
Insurance	€/yr	18830
<b>Total</b>	<b>€/yr</b>	<b>27483</b>

The electricity for the refueling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

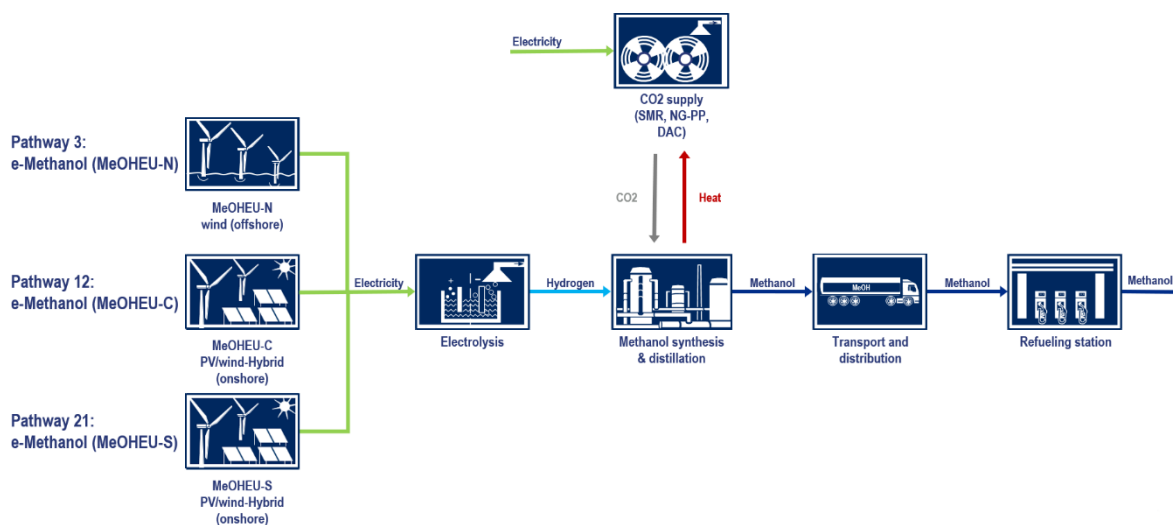
### 9.4.3. E-methanol in the EU (MeOHEU-N, MeOHEU-C, MeOHEU-S)

Methanol is produced by the catalytic reaction of carbon dioxide and hydrogen. The hydrogen is generated by water via electrolysis. The required carbon dioxide can be supplied either via a mix of natural gas and biomass fuelled power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR). The heat required by the CO<sub>2</sub> supply is partly originated as a by-product of the Methanol synthesis and distillation process. After the synthesis and the distillation process the methanol is transported and distributed via trucks. The trucks deliver the methanol to refuelling stations, at which the end user can access it.

(Three variants of electricity generation have been considered:

- Electricity from offshore wind power in North Europe e. g. in the North Sea at Norway
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain)

**Figure 162:** e-Methanol



The power-to-methanol plant generates 11.98 TWh of methanol or 1 million t of diesel equivalent per year based on the lower heating value (LHV). As a result, the capacity of the electrolyss plant depends on the region and the time horizon (see chapter 4).

An electricity storage system (ESS) has been applied to compensate short-term fluctuations of renewable electricity supply.

The capacity of the hydrogen buffer storage depends on the flexibility of the e-fuel plant, the region, and the time horizon (see chapter 4.3.2). For the methanol plant a minimum part load of 50% for all time horizons has been assumed. Table 91, Table 92, and Table 93 show the techno-economic data for H<sub>2</sub> buffer storage including H<sub>2</sub> storage loading compressor for power-to-methanol.

**Table 91:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol fin 2020.

	Unit	MeOHEU-N	MeOHEU-C	MeOHEU-S	Reference/ comment
Capacity electrolysis	MW <sub>H2</sub>	2372	2640	2493	
	Nm³ /h	791,000	880,000	831,000	
Electricity input electrolysis	MW <sub>e</sub>	3566	3970	3749	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm³	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	203	226	214	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.9	1.9	2.4	of full load operation
	million Nm³	55.1	40.9	47.9	Net storage capacity
CAPEX	million €	1383	1026	1202	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

**Table 92:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol fin 2030.

	Unit	MeOHEU-N	MeOHEU-C	MeOHEU-S	Reference/ comment
Capacity electrolysis	MW <sub>H2</sub>	2378	2752	2619	
	Nm³/h	793,000	917,000	873,000	
Electricity input electrolysis	MW <sub>e</sub>	3497	4046	3851	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm³	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	204	236	225	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.9	2.1	2.4	of full load operation
	million Nm³	54.5	45.4	50.4	Net storage capacity
CAPEX	million €	1370	1140	1267	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

**Table 93:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol fin 2050.

	Unit	MeOHEU-N	MeOHEU-C	MeOHEU-S	Reference/ comment
Capacity electrolysis	MW <sub>H<sub>2</sub></sub>	2403	2836	2734	
	Nm <sup>3</sup> /h	801,000	946,000	912,000	
Electricity input electrolysis	MW <sub>e</sub>	3204	3782	3646	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub></sub> , LHV	0.0217			
CAPEX	million €	206	243	234	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.9	2.2	2.5	of full load operation
	million Nm <sup>3</sup>	55.6	50.8	54.9	Net storage capacity
CAPEX	million €	1396	1276	1380	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			



For the supply of CO<sub>2</sub> for methanol synthesis (Table 94, Table 95, Table 96) the same basic data and the same references have been used as for the supply of CO<sub>2</sub> for methanation (chapter 9.4.2).

**Table 94:** CO<sub>2</sub> supply for a methanol synthesis plant in Europe in 2020

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	516 (CH4EU-N) 575 (CH4EU-C) 543 (CH4EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	177 (EU-N) 191 (EU-C) 183 (EU-S)	448 (EU-N) 483 (EU-C) 464 (EU-S)	1073 (EU-N) 1165 (EU-C) 1115 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	1.98 (N) / 2.04 (C) / 2.04 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	64 (EU-N) 69 (EU-C) 66 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.3 (EU-N), 1.7 (EU-C), 5.4 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	24 (EU-N)** 14 (EU-C)** 42 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 95:** CO<sub>2</sub> supply for a methanol synthesis plant in Europe in 2030

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	518 (CH <sub>4</sub> EU-N) 599 (CH <sub>4</sub> EU-C) 570 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	177 (EU-N) 196 (EU-C) 189 (EU-S)	449 (EU-N) 497 (EU-C) 480 (EU-S)	1076 (EU-N) 1202 (EU-C) 1157 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	1.98 (N) / 2.10 (C) / 2.05 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	64 (EU-N) 71 (EU-C) 69 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.9 (EU-N), 2.0 (EU-C), 6.2 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	29 (EU-N)** 17 (EU-C)** 50 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 96:** CO<sub>2</sub> supply for a methanol synthesis plant in Europe in 2050

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	523 (CH4EU-N) 617 (CH4EU-C) 595 (CH4EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	178 (EU-N) 200 (EU-C) 195 (EU-S)	452 (EU-N) 508 (EU-C) 495 (EU-S)	1084 (EU-N) 1230 (EU-C) 1196 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	1.98 (N) / 2.10 (C) / 2.04 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	65 (EU-N) 73 (EU-C) 71 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	4.4 (EU-N), 2.4 (EU-C), 5.9 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	33 (EU-N)** 21 (EU-C)** 49 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

Table 97 shows the techno-economic data for a methanol synthesis plant including compressors and methanol purification for the supply of 11.98 TWh of methanol or 1 million t of diesel equivalent based on the LHV.

**Table 97:** Techno-economic data for a methanol synthesis plant in Europe

	Unit	MeOHEU-N	MeOHEU-C	MeOHEU-S	Reference/comment
Capacity 2020/2030/2050	MW <sub>CH<sub>3</sub>OH, LHV</sub>	1659/1657/1659	1765/1776/1800	1606/1615/1634	
<b>Inputs</b>					
GH <sub>2</sub>	MJ/MJ <sub>CH<sub>3</sub>OH, LHV</sub>	1.161	1.161	1.161	
CO <sub>2</sub>	kg/MJ <sub>CH<sub>3</sub>OH, LHV</sub>	0.0702	0.0702	0.0702	
Electricity	MJ/MJ <sub>CH<sub>3</sub>OH, LHV</sub>	0.0499	0.0499	0.0499	
<b>Outputs</b>					
Methanol	MJ	1.000	1.000	1.000	
Heat (T = 250-300 °C)	MJ/MJ <sub>CH<sub>3</sub>OH, LHV</sub>	0.0720	0.0720	0.0720	
<b>Economic data</b>					
CAPEX 2020/2030/2050	€/kW <sub>CH<sub>3</sub>OH, LHV</sub>	768/672/500	768/672/500	768/672/500	[IEA 2019d] (854/747/555 US\$/kW <sub>CH<sub>3</sub>OH, LHV</sub> )
	million €	1274/1114/829	1356/194/900	1234/1086/817	
Lifetime	yr	30	30	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	3% of CAPEX/yr	3% of CAPEX/yr	[IEA 2019d]
Variable O&M	€/GWh <sub>CH<sub>3</sub>OH, LHV</sub>	1593	1593	1593	[Aramco 2021] (1770 US\$/GWh <sub>CH<sub>3</sub>OH, LHV</sub> )

The methanol is transported to a depot over a distance of 150 km via pipeline and from there distributed to the consumers e. g. a methanol fueled ferries via truck over a distance of 150 km.

Table 98 shows the technical and economic assumptions for the transport of methanol via pipeline. A pipeline for the transport of ethanol, gasoline, kerosene, and diesel has been used as proxy.

**Table 98:** Techno-economic data for the transport of methanol via pipeline

	Unit	Value	Reference/comment
Throughput	TWh <sub>LHV</sub> /yr	11.98	
Length	km	150	
Pipeline diameter	inch	16	[Appert & Favennic 2007]
	mm	406	
CAPEX			
Pipes, valves, piping equipment, installation cost	€/(inch*m)	5	[Appert & Favennic 2007]
Acquisition of right-of-way, compensation, reimbursement of damage, surveys and control	€/m	15	[Appert & Favennic 2007]
<b>Total</b>	€/m	95	
	million €	14.3	

Table 99 shows the techno-economic data for the transport of methanol via truck.

**Table 99:** Techno-economic data for the transport of methanol via truck

	Unit	Value	Reference/comment
Distance	km	150	
Payload	t	27	
	GJ methanol	538	
Fuel consumption	MJ/(kg fuel*km)	0.000834	[Sphera 2021]
	l diesel/100 km	31	
Average speed	km/h	50	
Operating time	d/yr	240	
Number of roundtrips per day		1	
Loading/unloading	h/d	1.5	
<b>Tractor truck</b>			
CAPEX	€	102,300	lastauto omnibus 2016
Lifetime	km	1,000,000	
Fixed O&M	€/yr	16,213	lastauto omnibus 2016
Variable O&M	€/km	0.1050	LBST & Hincio 2019
Labour costs driver	€/h	22.4	CGDD 2017
<b>Semitrailer</b>			
CAPEX	€	158,500	lastauto omnibus 2016
Lifetime	yr	15	
Fixed O&M	€/yr	12110	lastauto omnibus 2016
Variable O&M	€/km	0.0471	lastauto omnibus 2016
<b>Total costs of fuel transport</b>	<b>€/GJ</b>	<b>0.91</b>	

In case of ships bunkering can be carried out at a refuelling station (for small ships), via a bunkering ship, or directly from the truck.

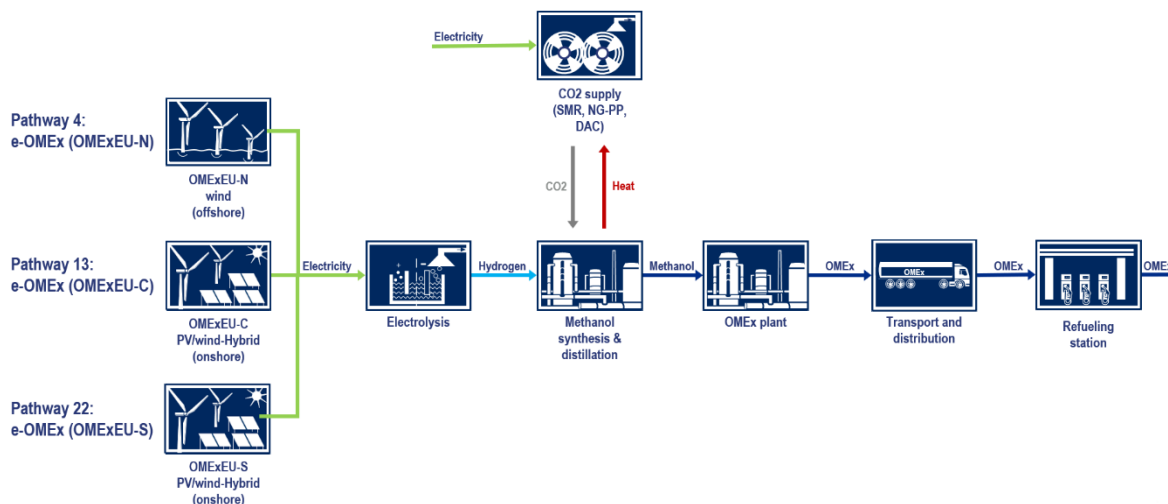
#### 9.4.4. E-OMEx in the EU (OMExEU-N, OMExEU-C, OMExEU-S)

OMEx is produced out of Methanol. The Methanol is synthesized via CO<sub>2</sub> and hydrogen, generated through electrolysis. The resulting heat of the methanol synthesis and distillation process is reused by the CO<sub>2</sub> supply. Carbon dioxide can be supplied either via flue gas from a mix of natural gas and biomass power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR). After distillation, the methanol is converted to OMEx at an OMEx plant and transported via Trucks to the refuelling stations. At this point the end user can access the e-fuel.

Three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

Figure 163: e-OMEx



The methanol demand and as a result the hydrogen demand of the OME synthesis influences the required capacity of upstream processes and as a result the CAPEX for electrolysis, hydrogen buffer storage (Table 100, Table 101, Table 102), CO<sub>2</sub> supply (Table 103, Table 104, Table 105), and methanol synthesis (Table 106) compared to the pathway for the supply of methanol as transportation fuel.

**Table 100:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol for OME<sub>x</sub> production in 2020.

	Unit	OMExEU-N	OMExEU-S	OMWxEU-S	Reference /comment
Capacity electrolysis	MW <sub>H2, LHV</sub>	3148	3480	3262	
	Nm <sup>3</sup> /h	1050,000	1160,000	1088,000	
	MW <sub>e</sub>	4733	5234	4905	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	270	298	280	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	3.3	2.2	2.7	of full load operation
	million Nm <sup>3</sup>	82.5	60.9	70.7	Net storage capacity
CAPEX	million €	2072	1530	1776	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			



**Table 101:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol for OME<sub>x</sub> production in 2030.

	Unit	OMExEU-N	OMExEU-S	OMWxEU-S	Reference / comment
Capacity electrolysis	MW <sub>H2, LHV</sub>	3129	3612	3378	
	Nm <sup>3</sup> /h	1043,000	1204,000	1126,000	
	MW <sub>e</sub>	4602	5312	4968	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	268	310	290	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	3.1	2.3	2.7	of full load operation
	million Nm <sup>3</sup>	76.8	65.3	72.2	Net storage capacity
CAPEX	million €	1929	1639	1813	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

**Table 102:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol for OME<sub>x</sub> production in 2050.

	Unit	OMExEU-N	OMExEU-S	OMWxEU-S	Reference /comment
Capacity electrolysis	MW <sub>H2, LHV</sub>	3174	3715	3641	
	Nm³ /h	1058,000	1239,000	1214,000	
	MW <sub>e</sub>	4232	4953	4854	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm³	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	272	318	312	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	3.1	2.3	2.7	of full load operation
	million Nm³	79.1	72.2	78.9	Net storage capacity
CAPEX	million €	1986	1814	1982	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

**Table 103:** CO<sub>2</sub> supply for a methanol synthesis plant for downstream OME synthesis in Europe in 2020

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	685 (CH <sub>4</sub> EU-N) 757 (CH <sub>4</sub> EU-C) 710 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	216 (EU-N) 231 (EU-C) 221 (EU-S)	546 (EU-N) 586 (EU-C) 560 (EU-S)	1331 (EU-N) 1437 (EU-C) 1368 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.16 (N) / 2.22 (C) / 2.16 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	78 (EU-N) 84 (EU-C) 80 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	2.5 (EU-N), 1.3 (EU-C), 5.1 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	24 (EU-N)** 14 (EU-C)** 51 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 104:** CO<sub>2</sub> supply for a methanol synthesis plant for downstream OME synthesis in Europe in 2030

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	681 (CH <sub>4</sub> EU-N) 786 (CH <sub>4</sub> EU-C) 735 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	215 (EU-N) 237 (EU-C) 226 (EU-S)	544 (EU-N) 602 (EU-C) 574 (EU-S)	1325 (EU-N) 1478 (EU-C) 1405(EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.16 (N) / 2.22 (C) / 2.16 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	78 (EU-N) 86 (EU-C) 82 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.3 (EU-N), 1.6 (EU-C), 6.3 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	32 (EU-N)** 18 (EU-C)** 66 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 105:** CO<sub>2</sub> supply for a methanol synthesis plant for downstream OME synthesis in Europe in 2030

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	691 (CH <sub>4</sub> EU-N) 808 (CH <sub>4</sub> EU-C) 792 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	217 (EU-N) 242 (EU-C) 239 (EU-S)	550 (EU-N) 613 (EU-C) 605 (EU-S)	1340 (EU-N) 1510 (EU-C) 1487(EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.16 (C) / 2.22 (C) / 2.22 (S)		
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	78 (EU-N) 88 (EU-C) 86 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.7 (EU-N), 1.4 (EU-C), 5.9 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	36 (EU-N)** 15 (EU-C)** 66 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 106:** Techno-economic data for a methanol synthesis plant for downstream OME synthesis in Europe

	Unit	OMExEU-N	OMExEU-C	OMExEU-S	Reference/comment
Capacity 2020/2030/2059	$MW_{CH_3OH, LHV}$	2122/2130/2137	2236/2263/2281	2112/2125/2133	
<b>Inputs</b>					
GH <sub>2</sub>	$MJ/MJ_{CH_3OH, LHV}$	1.161	1.161	1.161	
CO <sub>2</sub>	$MJ/MJ_{CH_3OH, LHV}$	0.0702	0.0702	0.0702	
Electricity	$MJ/MJ_{CH_3IH, LHV}$	0.0499	0.0499	0.0499	
<b>Outputs</b>					
Methanol	MJ	1.000	1.000	1.000	
Heat (T = 250-300°C)	$MJ/MJ_{CH_3OH, LHV}$	0.0720	0.0720	0.0720	
<b>Economic data</b>					
CAPEX 2020/2030/2050	$€/kW_{CH_3OH, LHV}$	769/672/500	769/672/500	769/672/500	[IEA 2019d] (854/747/555 US\$/ $kW_{CH_3OH, LHV}$ )
	million €	1630/1432/1068	1718/1521/1140	1622/1429/1066	
Lifetime	yr	30	30	30	[IEA 2019d]
Fixed O&M		3% of CAPEX/yr	3% of CAPEX/yr	3% of CAPEX/yr	[IEA 2019d]
Variable O&M	$€/GWh_{CH_3OH, LHV}$	1593	1593	1593	[Aramco 2021] (1770 US\$/ $GWh_{CH_3OH, LHV}$ )

OMEx is produced from methanol via formaldehyde, methylal<sup>16</sup>, and trioxane<sup>17</sup> as intermediate products. At first, a part of the methanol has to be converted into formaldehyde via partial oxidation. A part of formaldehyde is converted to methylal by reaction with methanol. The other part of the formaldehyde stream is converted to trioxane. Then, the methylal and the trioxane is converted to OMEx. Table 107 shows the summarized technoeconomic data for OMEx production from methanol.

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<sup>16</sup> also called dimethoxymethane (IUPAC name), Formal, Dimethylformal (DMFL), Formaldehyde dimethylacetal or Methylene dimethyl ether

<sup>17</sup> IUPAC name: 1,3,5-Trioxane

**Table 107:** Techno-economic data for a OME synthesis plant in Europe

	Unit	OMExEU-N	OMExEU-C	OMExEU-S	Reference/comment
Capacity 2020/2030/2050	MW <sub>OMEx, LHV</sub>	1601/1607/1613	1687/1707/1722	1594/1604/1609	
<b>Inputs</b>					
Methanol	MJ/MJ <sub>OMEx, LHV</sub>	1.3252	1.3252	1.3252	
Electricity	MJ/MJ <sub>OMEx, LHV</sub>	0.0000	0.0000	0.0000	
Heat	MJ/MJ <sub>OMEx, LHV</sub>	0.6727	0.6727	0.6727	
<b>Economic data</b>					
CAPEX 2020/2030/2050	€/kW <sub>OMEx, LHV</sub>	307/269/200	307/269/200	307/269/200	[Zimmermann et al. 2019] (341/299/222 US\$/kW <sub>OMEx, LHV</sub> )
	million €	492/432/322	518/459/344	490/431/322	
Lifetime	yr	30	30	30	[Zimmermann et al. 2019]
Fixed O&M		4.5% of CAPEX/yr	4.5% of CAPEX/yr	4.5% of CAPEX/yr	[Zimmermann et al. 2019]
Variable O&M	€/GWh <sub>OMEx, LHV</sub>	1350	1350	1350	[Aramco 2021] (1500 US\$/GWh <sub>OMEx, LHV</sub> )



The OMEx is transported to a depot over a distance of 150 km via pipeline and from there distributed to the refuelling stations.

For transport of OME the same pipeline data as for the transport of methanol (Table 98 in chapter 9.4.3) have been assumed.

For the transport via truck the different LHV of OME slightly influences the energy related transportation costs (0.98 €/GJ of OME versus 0.94 €/GJ of methanol). The payload is the same.

OME is suggested as fuel for diesel engines. Therefore, it has been assumed that OME is dispensed at refuelling stations like diesel.

**Table 108:** Techno-economic data for an OME refueling station

	Unit	Value	Reference/comment
Fuel output	million $l_{OME}/year$	6.30*	[UBG 2020]
	GWh <sub>LHV</sub> /yr	36	
Electricity consumption	MJ/MJ <sub>OME, LHV</sub>	0.0034	[JEC 2020]
CAPEX	million €	1.7	[Gau-Algesheim 2020]
Lifetime	yr	15	
Discount rate		8%	Base case
Capital costs	€/yr	199,000	
O&M	€/yr	22,000*	[eFinancialModels 2021]; [HRSAM 2021]
Electricity	€/yr	30,000	
Total	€/yr	251,000	
	€/GJ <sub>OME, LHV</sub>	2.0	
	€/l <sub>diesel equivalent</sub>	0.070	

\*3 dispensers, 2 hoses per dispenser, assumption: 6 refuellings/(hose\*h), 12 h/d, 365 d/yr, 40 l/refuelling; \*\*Maintenance: 5000 US\$ for a gasoline refuelling station with a capex of 1.8 million US\$ (equipment: 300,000 €; building: 1.5 million US\$) [eFinancialModels 2021]; Insurance: 1% of CAPEX/yr [HRSAM 2021]

The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

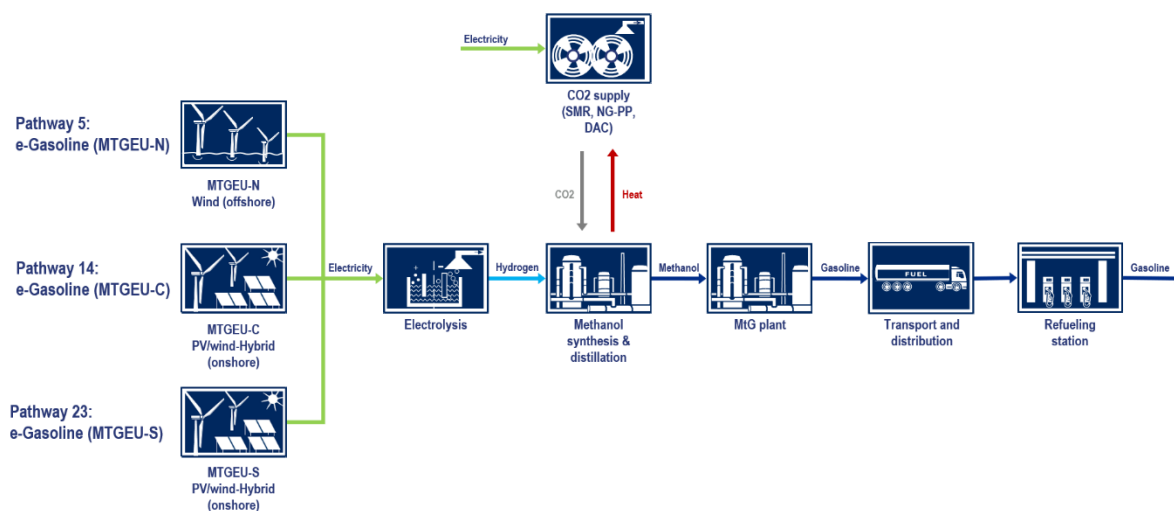
#### 9.4.5. E-Gasoline and e-kerosene via methanol-to-gasoline in the EU (MTGEU-N, MTG-C, MTG-S, MTKEU-N, MTKEU-C, MTKEU-S)

The generation of e-gasoline or e-kerosene both start with the production of hydrogen via electrolysis. The hydrogen is together with CO<sub>2</sub>, used to synthesis Methanol. At that process heat results as a by-product and is reused in the CO<sub>2</sub> supply. The carbon dioxide can be supplied through various procedures, either a mix of natural gas and biomass power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR) plants. After the Methanol is distilled, it can be converted into Gasoline or Kerosene via the methanol-to-gasoline (MTG) process. Transportation and distribution are executed via trucks. The Gasoline is delivered to refuelling stations where it is used to fuel road vehicles. The Kerosene is brought to storages at airports where it can be dispensed to airplanes.

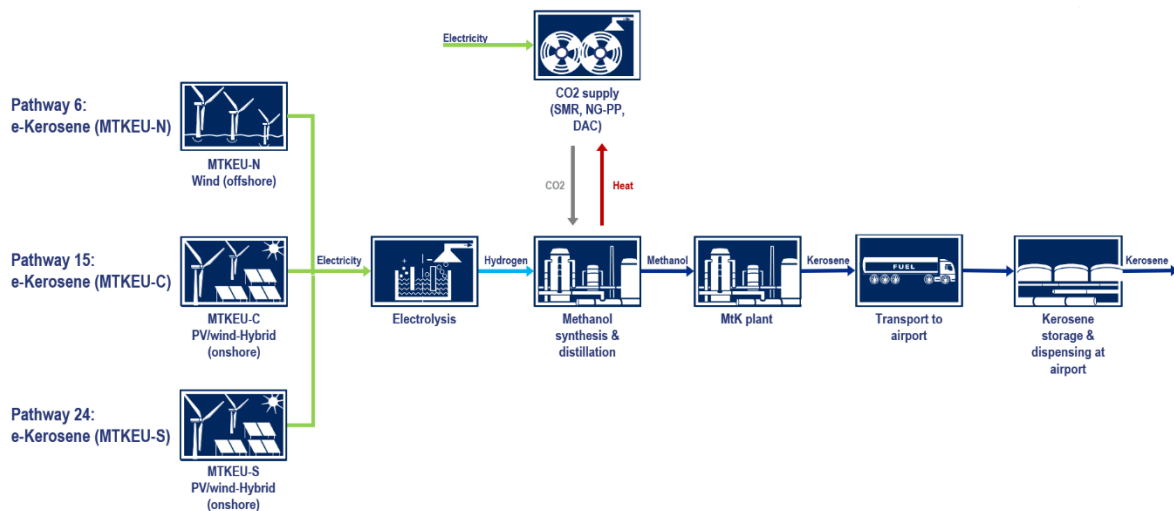
For these processes three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

**Figure 164:** e-Gasoline



**Figure 165:** e-kerosene



The methanol demand of the methanol-to-gasoline process and as a result the hydrogen demand for methanol synthesis influences the required capacity of upstream processes and as a result the CAPEX for electrolysis, hydrogen buffer storage (Table 109, Table 110, Table 111), CO<sub>2</sub> supply (Table 112, Table 113, Table 114), and methanol synthesis (Table 115) compared to the pathway for the supply of methanol as transportation fuel.

The minimum part load for the methanol plant is assumed to be 50% of full load operation.

**Table 109:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol for e-gasoline and -diesel production in Europe in 2020

	Unit	MTGEU-N	MTGEU-C	MTGEU-S	MTKEU-N	MTKEU-C	MTK-EU-S	Reference/comment
Capacity electrolysis	MW <sub>H<sub>2</sub>, LHV</sub>	2527	2817	2651	2550	2843	2675	
	MW <sub>e</sub>	3800	4236	3987	3834	4274	4023	
Compressor H <sub>2</sub> storage loading								
Suction / final pressure	MPa	3 / 10						
T (in) / T (intercooling)	K	313 / 333						H <sub>2</sub> leaving electrolyzer: 313 K
Efficiency compressor		80%						
Efficiency electric motor		90%						
Number of stages	-	2						
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649						
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217						
CAPEX	million €	217	242	227	219	244	229	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr						Planet et al. 2014
Lifetime	yr	30						
H <sub>2</sub> storage								
Maximum / minimum pressure	MPa	10 / 2.5						
Storage capacity	d	2.9	2.0	2.4	2.9	2.0	2.4	of full load operation
	million Nm <sup>3</sup>	58.2	44.0	50.8	58.7	44.4	51.3	Net storage capacity
CAPEX	million €	1462	1105	1276	1475	1115	1287	Jauslin Stebler 2013
Lifetime	yr	30						

**Table 110:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol for e-gasoline and -diesel production in Europe in 2030

	Unit	MTGEU-N	MTGEU-C	MTGEU-S	MTKEU-N	MTKEU-C	MTK-EU-S	Reference/comment
Capacity electrolysis	MW <sub>H2, LHV</sub>	2533	2912	2783	2556	2938	2809	
	MW <sub>e</sub>	3725	4282	4093	3759	4320	4130	
Compressor H <sub>2</sub> storage loading								
Suction / final pressure	MPa	3 / 10						
T (in) / T (intercooling)	K	313 / 333						H <sub>2</sub> leaving electrolyzer: 313 K
Efficiency compressor		80%						
Efficiency electric motor		90%						
Number of stages	-	2						
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649						
	kWh/kWh <sub>H2, LHV</sub>	0.0217						
CAPEX	million €	217	250	239	219	252	241	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr						Planet et al. 2014
Lifetime	yr	30						
H <sub>2</sub> storage								
Maximum / minimum pressure	MPa	10 / 2.5						
Storage capacity	d	2.8	2.0	2.4	2.8	2.0	2.4	of full load operation
	million Nm <sup>3</sup>	57.5	47.4	53.3	58.1	47.8	53.8	Net storage capacity
CAPEX	million €	1445	1191	1339	1458	1201	1351	Jauslin Stebler 2013
Lifetime	yr	30						

**Table 111:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power to methanol for e-gasoline and -diesel production in Europe in 2050

	Unit	MTGEU-N	MTGEU-C	MTGEU-S	MTKEU-N	MTKEU-C	MTK-EU-S	Reference/comment
Capacity electrolysis	MW <sub>H<sub>2</sub>, LHV</sub>	2562	3004	2896	2585	3031	3922	
	MW <sub>e</sub>	3416	4005	3862	3447	4041	3897	
Compressor H <sub>2</sub> storage loading								
Suction / final pressure	MPa	3 / 10						
T (in) / T (intercooling)	K	313 / 333						H <sub>2</sub> leaving electrolyzer: 313 K
Efficiency compressor		80%						
Efficiency electric motor		90%						
Number of stages	-	2						
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649						
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217						
CAPEX	million €	220	258	248	222	260	251	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr						Planet et al. 2014
Lifetime	yr	30						
H <sub>2</sub> storage								
Maximum / minimum pressure	MPa	10 / 2.5						
Storage capacity	d	2.9	2.2	2.5	2.9	2.2	2.5	of full load operation
	million Nm <sup>3</sup>	58.6	53.4	57.8	59.1	53.8	58.3	Net storage capacity
CAPEX	million €	1471	1340	1451	1485	1352	1464	Jauslin Stebler 2013
Lifetime	yr	30						

**Table 112:** CO<sub>2</sub> supply for a methanol synthesis plant for MTG in Europe in 2020

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	548 (CH4EU-N) 611 (CH4EU-C) 575 (CH4EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	184 (EU-N) 199 (EU-C) 191 (EU-S)	467 (EU-N) 504 (EU-C) 483 (EU-S)	1124 (EU-N) 1221 (EU-C) 1166 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.04 (N) / 2.10 (C) / 2.04 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	67 (EU-N) 72 (EU-C) 69 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.2 (EU-N), 1.7 (EU-C), 5.1 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	25 (EU-N)** 14 (EU-C)** 41 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 113:** CO<sub>2</sub> supply for a methanol synthesis plant for MTG in Europe in 2030

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	550 (CH <sub>4</sub> EU-N) 632 (CH <sub>4</sub> EU-C) 604 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	185 (EU-N) 204 (EU-C) 197 (EU-S)	468 (EU-N) 516 (EU-C) 500 (EU-S)	1120 (EU-N) 1244 (EU-C) 1203 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.04 (N) / 2.10 (C) / 2.10 (S)		
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	67 (EU-N) 74 (EU-C) 71 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	3.8 (EU-N), 1.9 (EU-C), 5.9 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	30 (EU-N)** 17 (EU-C)** 50 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>



**Table 114:** CO<sub>2</sub> supply for a methanol synthesis plant for MTG in Europe in 2050

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	556 (CH <sub>4</sub> EU-N) 652 (CH <sub>4</sub> EU-C) 628 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	186 (EU-N) 208 (EU-C) 203 (EU-S)	472 (EU-N) 528 (EU-C) 514 (EU-S)	1129 (EU-N) 1274 (EU-C) 1239 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yt	2.04 (N) / 2.10 (C) / 2.10 (S)		
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	67 (EU-N) 75 (EU-C) 73 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	4.4 (EU-N), 1.9 (EU-C), 5.5 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	35 (EU-N)** 17 (EU-C)** 49 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

The CO<sub>2</sub> supply for methanol to kerosene (MTK) is approximately equivalent to that for methanol to gasoline (MTG). Small differences occur from a slightly different methanol input (see Table 116).

**Table 115:** Techno-economic data for a methanol synthesis plant for downstream MTG and MTK process in Europe

		Unit	EU-N	EU-C	EU-S	Reference/comment
Capacity 2020/2030/2050	e-gasoline	$MW_{CH_3OH, LHV}$	1750/1748/1749	1845/1869/1893	1693/1700/1718	For MTG and MTK slightly different due to different methanol requirement of the MTG and MTK plants
	e-kerosene		1737/1735/1736	1831/1855/1879	1680/1687/1705	
<b>Inputs</b>						
H <sub>2</sub>		$MJ/MJ_{CH_3OH, LHV}$	1.161	1.161	1.161	
CO <sub>2</sub>		$MJ/MJ_{CH_3OH, LHV}$	0.0702	0.0702	0.0702	
Electricity		$MJ/MJ_{CH_3IH, LHV}$	0.0499	0.0499	0.0499	
<b>Outputs</b>						
Methanol		MJ	1.000	1.000	1.000	
Heat (T = 250-300 °C)		$MJ/MJ_{CH_3OH, LHV}$	0.0720	0.0720	0.0720	
<b>Economic data</b>						
CAPEX 2020/2030/2050		$€/kW_{CH_3OH, LHV}$	769/672/500	769/672/500	769/672/500	[IEA 2019d] (854/747/555 US\$/ $kW_{CH_3OH, LHV}$ )
	e-gasoline	million €	1345/1175/874	1418/1257/946	1301/1143/859	For MTG and MTK slightly different due to different methanol requirement of the MTG and MTK plants
	e-kerosene		1335/1167/868	1407/1247/939	1291/1134/852	
Lifetime		yr	30			[IEA 2019d]
Fixed O&M			3% of CAPEX/yr			[IEA 2019d]
Variable O&M		$€/GWh_{CH_3OH, LHV}$	1593			[Aramco 2021] (1770 US\$/ $GWh_{CH_3OH, LHV}$ )

The methanol is converted to gasoline or kerosene via a methanol-to-gasoline (MTG) or methanol-to-kerosene (MTK) process. The MTG or MTK process consists of DME synthesis, olefin syntheses, oligomerization, and hydrotreating.

**Table 116:** Techno-economic data for a MTG and MTK synthesis plant in Europe

		e-gasoline			e-kerosene			
	Unit	MTGEU-N	MTGEU-C	MTGEU-S	MTKEU-N	MKK-EU-C	MTKEU-S	Reference/comment
Capacity	MW <sub>final fuel, LHV</sub>	1657/1655/1656	1747/1770/1792	1603/1610/1627	1657/1655/1656	1747/1770/1792	1603/1610/1627	
Inputs								
Methanol	MJ/MJ <sub>final fuel, LHV</sub>	1.0562	1.0562	1.0562	1.0482	1.0482	1.0482	
Hydrogen	MJ/MJ <sub>final fuel, LHV</sub>	0.0036	0.0036	0.0036	0.0240	0.0240	0.0240	
Electricity	MJ/MJ <sub>final fuel, LHV</sub>	0.0164	0.0164	0.0164	0.0163	0.0163	0.0163	
Outputs								
Gasoline	MJ	1	1	1	1	1	1	
Heat	MJ/MJ <sub>final fuel, LHV</sub>	0.0300	0.0300	0.0300	0.0298	0.0298	0.0298	
Economic data								
CAPEX 2020/2030/2050	€/kW <sub>final fuel, LHV</sub>	307/269/200						[Zimmermann et al. 2019] (341/299/222 US\$/kW <sub>final fuel, LHV</sub> )
	million €	509/445/331	537/476/358	493/433/325	420/368/273	420/368/273	420/368/273	
Lifetime	yr	30						[Zimmermann et al. 2019]
Fixed O&M		4.5% of CAPEX/yr						[Zimmermann et al. 2019]
Variable O&M	€/GWh <sub>final fuel, LHV</sub>	1350						[Aramoco 2021] (1500 US\$/GWh <sub>final fuel, LHV</sub> )

The gasoline is transported to a depot over a distance of 150 km via pipeline and from there distributed to the refuelling stations. Table 117 shows the techno-economic data for the gasoline refuelling station.

**Table 117:** Techno-economic data for a gasoline refueling station

	Unit	Value	Reference/comment
Fuel output	million l <sub>gasoline</sub> /year	6.30*	[UBG 2020]
	GWh <sub>LHV</sub> /yr	56	
Electricity consumption	MJ/MJ <sub>gasoline, LHV</sub>	0.0034	[JEC 2020]
CAPEX	million €	1.7	[Gau-Algesheim 2020]
Lifetime	yr	15	
Discount rate		8%	Base case
Capital costs	€/yr	199,000	
O&M	€/yr	22,000*	[eFinancialModels 2021]; [HRSAM 2021]
Electricity	€/yr	30,000	
Total	€/yr	251,000	
	€/GJ <sub>gasoline, LHV</sub>	1.3	
	€/l <sub>gasoline</sub>	0.043	
	€/l <sub>diesel equivalent</sub>	0.047	

\*3 dispensers, 2 hoses per dispenser, assumption: 6 refuellings/(hose\*h), 12 h/d, 365 d/yr, 40 l/refueling; \*\*Maintenance: 5000 US\$ for a gasoline refuelling station with a capex of 1.8 million US\$ (equipment: 300,000 €; building: 1.5 million US\$) [eFinancialModels 2021]; Insurance: 1% of CAPEX/yr [HRSAM 2021]

The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

The kerosene is transported to a depot over a distance of 150 km via pipeline and from there transported to an airport.

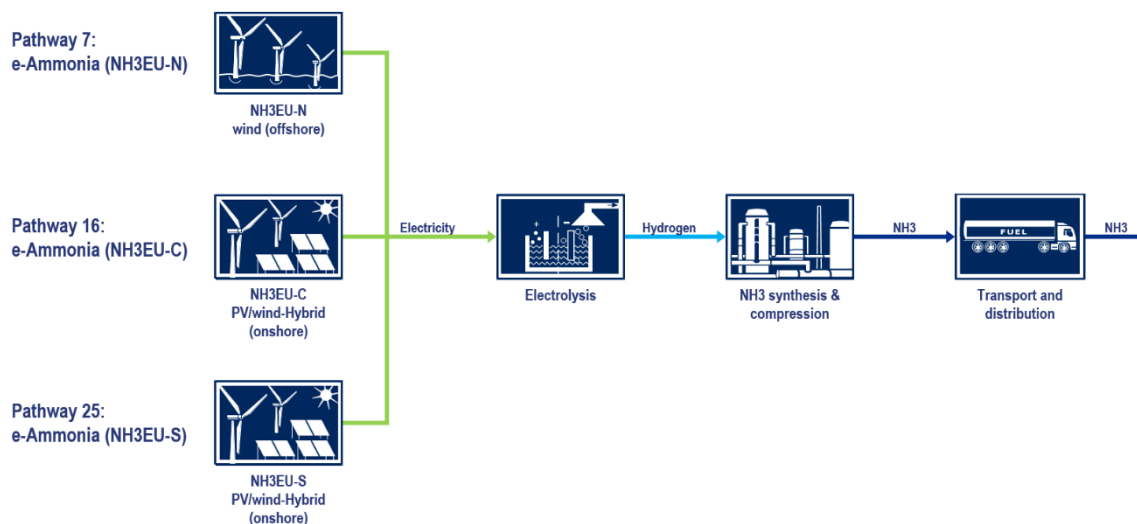
#### 9.4.6. E-Ammonia in the EU (NH3EU-N, NH3EU-C, NH3EU-S)

To generate ammonia, as a first step hydrogen is produced via water electrolysis. It is then synthesised to ammonia, compressed, and stored until it is transported and distributed through trucks to its end use.

For this process three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e.g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

Figure 166: e-Ammonia



The capacity of the power-to-ammonia plant is sufficient to produce 11.98 TWh of ammonia per year or 1 million t of diesel equivalent per year based on the lower heating value (LHV). The hydrogen demand of the downstream ammonia synthesis influences the electricity input of the electrolysis plant.

Table 118, Table 119, and Table 120 show the hydrogen buffer storage for ammonia synthesis assumed for 2020, 2030, and 2050, respectively. The hydrogen buffer storage is based on a minimum part load of 50% of full load operation of the ammonia plant.

**Table 118:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-ammonia in 2020

	Unit	NH3EU-N	NH3EU-C	NH3EU-S	Reference/ comment
Capacity electrolyses	MW <sub>H2, LHV</sub>	2306	2608	2430	
	Nm <sup>3</sup> /h	769,000	870,000	810,000	
	MW <sub>e</sub>	3468	3922	3654	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	198	224	208	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.8	1.9	2.4	of full load operation
	million Nm <sup>3</sup>	52.2	39.4	47.3	Net storage capacity
CAPEX	million €	1311	990	1187	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

**Table 119:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-ammonia in 2030

	Unit	NH3EU-N	NH3EU-C	NH3EU-S	Reference/ comment
Capacity electrolyses	MW <sub>H<sub>2</sub></sub> , LHV	2311	2701	2574	
	Nm <sup>3</sup> /h	771,000	901,000	858,000	
	MW <sub>e</sub>	3398	3972	3785	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub></sub> , LHV	0.0217			
CAPEX	million €	198	232	221	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.8	2.0	2.5	of full load operation
	million Nm <sup>3</sup>	51.9	42.4	50.6	Net storage capacity
CAPEX	million €	1303	1064	1271	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			



**Table 120:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-ammonia in 2050

	Unit	NH3EU-N	NH3EU-C	NH3EU-S	Reference/ comment
Capacity electrolyses	MW <sub>H2, LHV</sub>	2327	2789	2728	
	Nm <sup>3</sup> /h	776,000	930,000	910,000	
	MW <sub>e</sub>	3103	3719	3638	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	200	239	234	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.8	2.1	2.6	of full load operation
	million Nm <sup>3</sup>	52.0	47.3	56.4	Net storage capacity
CAPEX	million €	1307	1187	1418	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279			
Lifetime	yr	30			

Ammonia is synthesised at a temperature of 450°C and a pressure of 10 to 25 MPa via the following reaction:



The reaction is exothermal.

The techno-economic data of the ammonia synthesis plant in Table 121 include air separation for nitrogen supply.

**Table 121:** Techno-economic data for an ammonia synthesis plant in Europe

	Unit	NH3EU-N	NH3EU-C	NH3EU-S	Reference/ comment
Capacity 2020/2030/2050	$MW_{\text{NH}_3, \text{LHV}}$	1687/1682/1673	1811/1820/1840	1620/1624/1653	
<b>Inputs</b>					
GH2	$MJ/MJ_{\text{NH}_3, \text{LHV}}$	1.140	1.140	1.140	
Electricity	$MJ/MJ_{\text{NH}_3, \text{LHV}}$	0.1657	0.1657	0.1657	
<b>Outputs</b>					
Ammonia	MJ	1.000	1.000	1.000	
Heat	$MJ/MJ_{\text{NH}_3, \text{LHV}}$	-	-	-	Heat not used
<b>Economic data</b>					
CAPEX 2020/2030/2050	million €	928/926/922*	975/978/986*	902/903/914*	DECHEMA 2017
Lifetime	yr	30			
Fixed O&M		3% of CAPEX/yr			

In the base case, the equivalent full load is assumed to be the same as that of the electrolysis plant.

Ammonia becomes liquid at ambient temperature at a pressure of about 0.9 MPa (similar to propane). The pressurized ammonia is transported to the NH<sub>3</sub> ship bunkering terminal via truck over a distance of 300 km. The payload amounts to 21 t. Table 122 shows the techno-economic data for the transport of ammonia via truck.

**Table 122:** Techno-economic data for the transport of ammonia via truck

	Unit	2020/2030/2050	Reference/comment
Distance	km	300	
Payload	t	21	
	GJ NH <sub>3</sub>	393	
Fuel consumption	MJ/(kg fuel*km)	0.001072	[Sphera 2021]
	l diesel/100 km	31	
Average speed	km/h	50	
Operating time	d/yr	240	
Number of roundtrips per day		0.5	
Loading/unloading	h/d	1.5	Loading: 1.5 h Unloading: 1.5 h
<b>Tractor truck</b>			
CAPEX	€	102,300	lastauto omnibus 2016
Lifetime	km	1,000,000	
Mileage	km/yr	72,000	
Fixed O&M	€/yr	16,213	lastauto omnibus 2016
Variable O&M	€/km	0.1050	LBST & Hincio 2019
Labour costs driver	€/h	22.4	CGDD 2017
<b>Semitrailer</b>			
CAPEX	€	198,000	IEA G20 2019
Lifetime	yr	15	
Fixed O&M	€/yr	12110	lastauto omnibus 2016
Variable O&M	€/km	0.0471	lastauto omnibus 2016
<b>Total costs of fuel transport</b>	<b>€/GJ</b>	<b>2.16/2.30/3.36*</b>	

\*Depending on fuel costs

According to an international shipping company, storage tanks and pumping systems for NH<sub>3</sub> barges for NH<sub>3</sub> bunkering may be lower in cost than for LNG barges. However, NH<sub>3</sub> safety features may add costs to bunkering and receiving vessels that most probably result in bunkering and dispensing costs somewhere between HFO and LNG.

According to [Nordic Innovation 2021] the cost of handling a toxic fuel depends on both toxicity and flammability/explosiveness, and the measures to mitigate both. In the case of NH<sub>3</sub>, the toxicity risks are higher than for many other fuel options, but the flammability risks are lower, so that the overall costs are expected to be manageable. While liquid fuels such as methanol and marine gas oil (MGO) may be cheaper to handle, ammonia's handling costs should not differ from those of other gaseous fuels, such as liquefied natural gas (LNG), once first-of-a-kind technology deviations have been overcome.

The bunkering of ammonia is theoretically possible in parallel with cargo loading/unloading operation. But this must be authorized by the port authority. If not, this will end up in additional time in the port that is definitely a cost for the ship [Alfa Laval et al. 2020].

As a result, above quotes indicate that the cost of  $\text{NH}_3$  bunkering/dispensing are higher than those of HFO, likely closer to that of gaseous fuels (such as LNG), possibly also higher than LNG if established safety practices in ports during loading and unloading are not eased.

In the following an estimation of the costs has been carried out. An ammonia bunkering technology company and its project partners receives public funding for an ammonia bunkering terminal of about 8.6 million € for the refuelling of  $\text{NH}_3$  carriers [Yara 2021]. Typically, public funding amounts to about 50% of the total investment leading to a CAPEX of 17.2 million € for the ammonia bunkering terminal.

In [de Vries 2019] various concepts for  $\text{NH}_3$  fuelled  $\text{NH}_3$  carriers are described. The largest one has a  $\text{NH}_3$  transport capacity of 50,184 t and a fuel tank with 3516 t of  $\text{NH}_3$ . It has been assumed that at the bunkering facility 3164 t of  $\text{NH}_3$  is dispensed to the ship (90% of the fuel tank capacity). In [DNV 2021] 91 ship bunkering procedures have been assumed per year. As a result, 287,960 t of  $\text{NH}_3$  are dispensed per year or 1496 GWh of  $\text{NH}_3$  per year based on the LHV.

If the lifetime of the  $\text{NH}_3$  bunkering facility were assumed to be 15 years, the discount rate 8%, and the OPEX were assumed to be 5% of the CAPEX per year the specific costs of  $\text{NH}_3$  bunkering would amount to about 0.39 €/GJ of  $\text{NH}_3$  or 0.014 € per l of diesel equivalent or about 17 € per t of LSMGO equivalent.

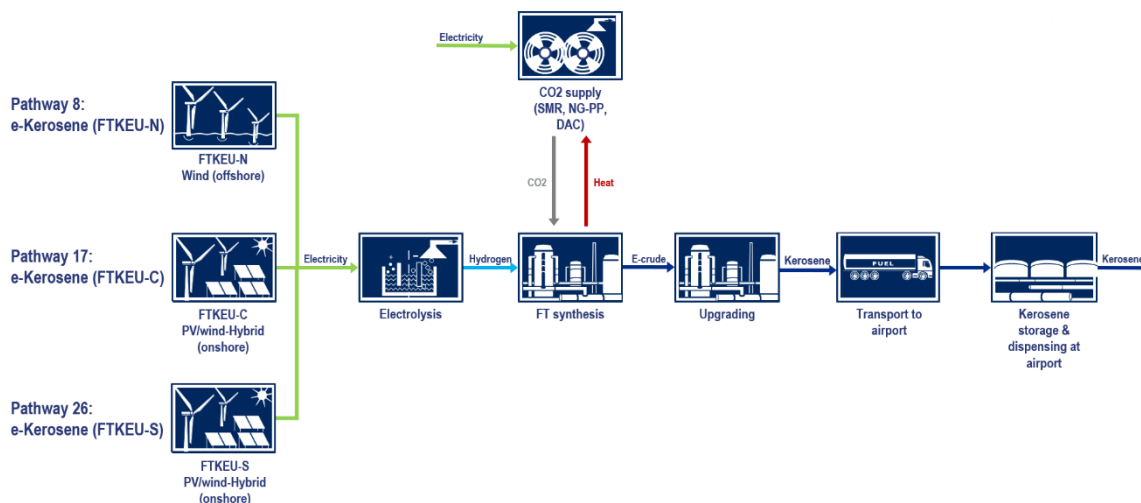
#### 9.4.7. E-Kerosene and e-diesel via Fischer-Tropsch route in the EU (FTKEU-N, FTKEU-C, FTKEU-S, FTDEU-N, FTDEU-C, FTDEU-S)

To generate e-kerosene and e-diesel initially there is hydrogen needed. This is produced via water electrolysis and then synthesised with carbon dioxide to e-crude through the Fischer-Tropsch process. The carbon dioxide can be supplied through various procedures, either a mix of natural gas and biomass power plants (NG-PP), direct air capture (DAC), or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is the by-product of the Fischer-Tropsch synthesis. The e-crude is converted into kerosene or diesel and then transported via truck to their respective destination. For kerosene this is the airport where it is stored and dispensed. Diesel is distributed to refuelling stations where it is utilized to fuel road vehicles.

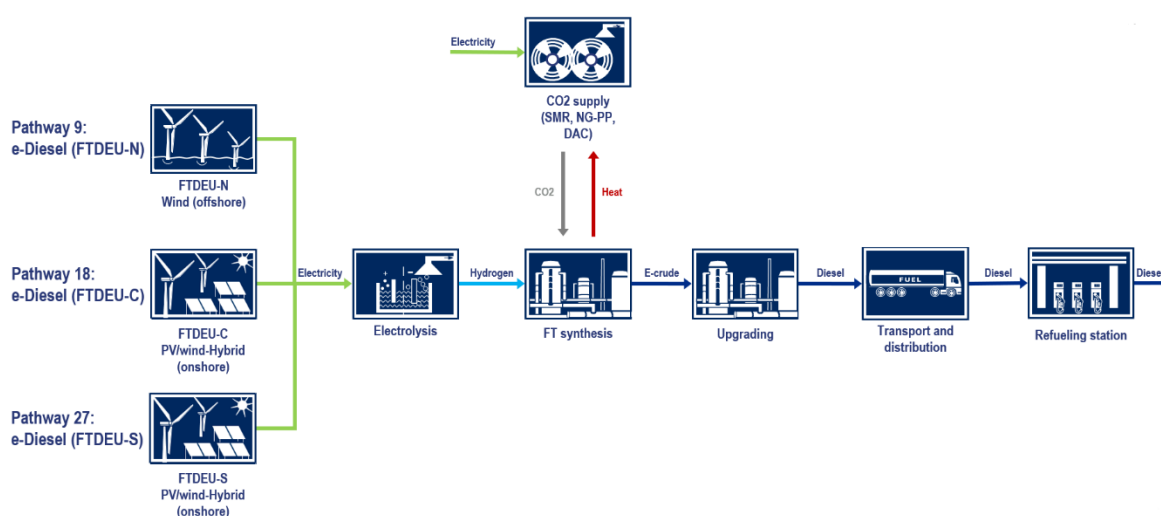
For these processes three variant electricity sources for the electrolysis have been considered:

- Electricity from offshore wind power in North Europe (e. g. in the North Sea at Norway)
- Electricity from PV-/wind-hybrid power stations in Central Europe e. g. Germany)
- Electricity from PV-/wind-hybrid power stations in South Europe e. g. Spain

**Figure 167:** e-Kerosene via Fischer-Tropsch route



**Figure 168:** e-Diesel via Fischer-Tropsch route



The capacity of the power-to-liquid plant is sufficient for the production of 11.98 TWh of diesel or kerosene per year or 1 million t of diesel equivalent per year based on the lower heating value (LHV).

The Fischer-Tropsch (FT) synthesis plant is less flexible than the methanation, the methanol, and the ammonia plant. For 2020 and 2030 the minimum part load amounts to 80% of full load. For 2050, a higher flexibility e. g. due to the introduction of new technologies such as microchannel reactors is expected. A minimum part load of 50% (same as for methanol synthesis) is assumed for 2050. Table 123, Table 124, and Table 125 show the techno-economic data for H<sub>2</sub> buffer storage including H<sub>2</sub> storage loading compressor for the FT plants in 2020, 2030, and 2050. The role H<sub>2</sub> buffer storage is to bridge rapid fluctuations of the electrolysis plant because the FT plant cannot follow the fluctuating electricity supply as fast as the electrolysis plant. In the base case, the equivalent full load period of the FT plant is assumed to be the same as that of the electrolysis plant. The equivalent full load period depends on the electricity source connected with the electrolysis plant and as a result from the region where the e-fuel plant is located.

**Table 123:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for FT plant in 2020 (minimum part load FT plant: 80%).

	Unit	EU-N	EU-C	EU-S	Reference/comment
Capacity electrolysis	MW <sub>H2, LHV</sub>	2906	3244	3084	
	Nm <sup>3</sup> /h	969,000	1,082,000	1,028,000	
	MW <sub>e</sub>	4369	4879	4637	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	249	278	264	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	7.1	4.5	6.9	of full load operation
	million Nm <sup>3</sup>	164.8	116.1	169.7	Net storage capacity
CAPEX	million €	4140	2916	4263	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279	279	279	
Lifetime	yr	30			

**Table 124:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for FT plant in 2030 (minimum part load FT plant: 80%).

	Unit	EU-N	EU-C	EU-S	Reference/comment
Capacity electrolysis	MW <sub>H<sub>2</sub>, LHV</sub>	2939	3402	3236	
	Nm <sup>3</sup> / h	980,000	1,134,000	1,079,000	
	MW <sub>e</sub>	4323	5003	4758	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217			
CAPEX	million €	252	292	277	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	6.5	4.6	6.2	of full load operation
	million Nm <sup>3</sup>	151.8	125.7	161.3	Net storage capacity
CAPEX	million €	3813	3158	4051	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279	279	279	
Lifetime	yr	30			

**Table 125:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for FT plant in 2050 (minimum part load FT plant: 50%).

	Unit	EU-N	EU-C	EU-S	Reference/comment
Capacity electrolysis	MW <sub>H2, LHV</sub>	2918	3398	3267	
	Nm <sup>3</sup> / h	973,000	1,133,000	1,089,000	
	MW <sub>e</sub>	3890	4530	4356	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H2, LHV</sub>	0.0217			
CAPEX	million €	250	291	280	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	2.8	2.2	2.5	of full load operation
	million Nm <sup>3</sup>	64.8	59.8	64.3	Net storage capacity
CAPEX	million €	1628	1503	1616	Jauslin Stebler 2013
	€/kg <sub>H2</sub>	279	279	279	
Lifetime	yr	30			

For sensitivity, for 2050 also a mix of concentrated, average, and diluted CO<sub>2</sub> source has been assumed. The average CO<sub>2</sub> source consists of a mix of flue gas from 50% natural gas power stations (~3% CO<sub>2</sub>) and 50% solid biomass fuelled power stations (~14% CO<sub>2</sub>) leading to an average CO<sub>2</sub> concentration of 8.5%.

Table 126, Table 127, and Table 128 show the techno-economic data for the CO<sub>2</sub> supply for the FT synthesis plants in 2020, 2030, and 2050.



**Table 126:** CO<sub>2</sub> supply for a FT plant in Europe in 2020

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	656 (CH <sub>4</sub> EU-N) 732 (CH <sub>4</sub> EU-C) 696 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	209 (EU-N) 226 (EU-C) 218 (EU-S)	530 (EU-N) 572 (EU-C) 552 (EU-S)	1288 (EU-N) 1400 (EU-C) 1347 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.10 (N) / 2.16 (C) / 2.16 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	76 (EU-N) 82 (EU-C) 79 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	18.7 (EU-N), 8.3 (EU-C), 24.4 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	173 (EU-N)** 86 (EU-C)** 240 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\* 0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 127:** CO<sub>2</sub> supply for a FT plant in Europe in 2030

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	663 (CH <sub>4</sub> EU-N) 768 (CH <sub>4</sub> EU-C) 730 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	211 (EU-N) 233 (EU-C) 225 (EU-S)	534 (EU-N) 592 (EU-C) 571 (EU-S)	1299 (EU-N) 1452 (EU-C) 1397 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.10 (N) / 2.22 (C) / 2.16 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	76 (EU-N) 85 (EU-C) 82 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	19.3 (EU-N), 10.9 (EU-C), 24.3 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	181 (EU-N)** 118 (EU-C)** 251 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\* 0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 128:** CO<sub>2</sub> supply for a FT plant in Europe in 2050

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source	-	SMR	Flue gas from power stations	DAC
Capacity	t/h	659 (CH <sub>4</sub> EU-N) 767 (CH <sub>4</sub> EU-C) 737 (CH <sub>4</sub> EU-S)		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	210 (EU-N) 233 (EU-C) 227 (EU-S)	531 (EU-N) 591 (EU-C) 575 (EU-S)	1292 (EU-N) 1450 (EU-C) 11408 (EU-S)
Maintenance & repair	-	2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance	-	2% of CAPEX/yr		-
Labour	million €/yr	2.10 (N) / 2.22 (C) / 2.16 (S)		-
Administration	-	30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	76 (EU-N) 84 (EU-C) 82 (EU-S)		
Fixed OPEX CO <sub>2</sub> liquefier	-	10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	4.3 (EU-N), 1.7 (EU-C), 5.1 (EU-S)		
CAPEX CO <sub>2</sub> storage	million €	40 (EU-N)** 18 (EU-C)** 53 (EU-S)**		
Fixed OPEX of CO <sub>2</sub> storage	-	5% of CAPEX/yr		

\* 0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

For FT synthesis CO is required. Therefore, a reverse water gas shift (RWGS) is required if the CO is derived from CO<sub>2</sub>. The following reactions occur:



The reaction proceeds exothermal.

FT synthesis can be classified into high temperature FT syntheses and low temperature FT synthesis. Low temperature FT synthesis is carried out at temperature of 225 °C and a pressure of 2.5 MPa [König et al. 8/2015]. In this study low temperature FT synthesis is assumed.

To maximize the share of liquid FT products the FT synthesis is operated in a way that to get a high hydrocarbon chain growth probability ( $\alpha$ ) leading to long-chain hydrocarbons (long-chain paraffins or waxes) are formed.

Application of a low temperature FT synthesis and a cobalt-based catalyst leads to  $\alpha$  of up to 95%. Furthermore, mainly linear alkanes are formed [König et al. 8/2015]. In case of the Shell Middle Distillate Synthesis (SMDS) process described in [Eilers et al. 1990] mainly linear heavy paraffins are formed at the FT synthesis stage. In a second step the heavy paraffins are cracked into the desired products gasoline, kerosene, and diesel. In [Eilers et al. 1990] this process is called ‘heavy paraffin conversion’ (HPC).

The CAPEX for the FT plant has been derived from [Becker et al. 2012], [König et al. 7/2015], and [Concawe 2021] via upscaling using different scaling exponents for different components. Furthermore, the cost data have been adjusted to 2019 values via the Chemical Engineering Plant Cost Index (CEPCI).

**Table 129:** CAPEX for a FT synthesis plant including RWGS with a capacity of 27.8 MW FT products (LHV) described in [Becker et al. 2012] and [König et al. 7/2015]\*

	CAPEX (million US\$ <sub>2009</sub> )	CAPEX (million € <sub>2019</sub> )	Scale factor
Burner	4.99	5.19	1.00
FT reactor	3.11	3.23	1.00
RWGS	3.59	3.74	0.65
PSA	1.34	1.39	0.70
Distillation	0.47	0.49	0.70
Wax hydrocracker	4.31	4.48	0.70
Distillate hydrotreater	2.41	2.50	0.70
Naphtha hydrotreater	0.66	0.69	0.70
Catalytic reformer/platformer	3.55	3.69	0.70
C5/C6 isomerisation	0.59	0.61	0.70
Total installed cost	25.02	26.01	-
<b>Total direct cost</b>	<b>28.03</b>	<b>29.13</b>	-
Engineering & design	3.64	3.79	-
Construction	3.92	4.08	-
Legal and contractor fees	2.52	2.62	-
Project contingency	4.20	4.37	-
<b>Total indirect costs</b>	<b>14.29</b>	<b>14.86</b>	-
<b>Total CAPEX</b>	<b>42.32</b>	<b>43.99</b>	-

\* Scaling factor for FT reactor and CAPEX for RWGS from [König et al. 7/2015]

In [Becker et al. 2012] the distillate and naphtha hydrotreater probably is used to remove double bonds. In this study the CAPEX for the wax hydrocracker has been replaced by a hydrocracker from [Concawe 2021] which includes fractionation and is scaled linearly. The distillation, the distillate hydrotreater, the naphtha hydrotreater, the catalytic reformer/platformer, and the C<sub>5</sub>/C<sub>6</sub> isomerisation has been removed for the FT plant for kerosene and diesel production (see grey-marked rows in Table 129). Upscaling of the remaining process leads to the CAPEX shown in Table 130, Table 131, and Table 132.

**Table 130:** Techno-economic data for a FT synthesis plant including RWGS in Europe 2020 (minimum part load FT plant: 80%)

	Unit	EU-N	EU-C	EU-S	Reference/comment
Capacity	MW <sub>FT products, LHV</sub>	1528	1526	1489	1 million t of diesel equivalent per year
<b>Inputs</b>					
H <sub>2</sub>	MJ/MJ <sub>FT products, LHV</sub>	1.4036	1.4036	1.4036	
CO <sub>2</sub>	kg/MJ <sub>FT products, LHV</sub>	0.0880	0.0880	0.0880	
Electricity	MJ/MJ <sub>CFT products, LHV</sub>	0.0441	0.0441	0.0441	
<b>Outputs</b>					
FT products	MJ	1	1	1	
Heat (T = 225 °C)	MJ/MJ <sub>CFT products, LHV</sub>	0.2139	0.2139	0.2139	
<b>CAPEX</b>					
Burner	million €	285	285	278	[Becker et al. 2012]
FT reactor	million €	178	178	173	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	51	50	50	
PSA	million €	23	23	23	[Becker et al. 2012]
Hydrocracker, recycle	million €	456	455	444	[Concawe 2021]
Total installed cost	million €	992	991	968	
<b>Total direct cost</b>	million €	1111	1110	1084	Total installed cost *1.12
Engineering & design	million €	144	144	141	13% of total direct cost
Construction	million €	156	155	152	14% of total direct cost
Legal and contractor fees	million €	100	100	98	9% of total direct cost
Project contingency	million €	167	167	163	15% of total direct cost
<b>Total indirect costs</b>	million €	567	566	553	
<b>Total CAPEX</b>	million €	1678	1676	1637	
	€/kW <sub>final fuel</sub>	1098	1098	1099	
Lifetime	yr	30			
Fixed O&M	-	3% of CAPEX/yr			
Variable O&M	€/GJ <sub>FT products, LHV</sub>	1.53			[Aramco 2021] 6120 US\$/GWh <sub>FT products</sub>

**Table 131:** Techno-economic data for a FT synthesis plant including RWGS in Europe 2030 (minimum part load FT plant: 80%)

	Unit	EU-N	EU-C	EU-S	Reference/comment
Capacity	MW <sub>FT products, LHV</sub>	1516	1516	1488	1 million t of diesel equivalent per year
<b>Inputs</b>					
H <sub>2</sub>	MJ/MJ <sub>FT products, LHV</sub>	1.4036	1.4036	1.4036	
CO <sub>2</sub>	kg/MJ <sub>FT products, LHV</sub>	0.0880	0.0880	0.0880	
Electricity	MJ/MJ <sub>CFT products, LHV</sub>	0.0441	0.0441	0.0441	
<b>Outputs</b>					
FT products	MJ	1	1	1	
Heat (T = 225 °C)	MJ/MJ <sub>CFT products, LHV</sub>	0.2139	0.2139	0.2139	
<b>CAPEX</b>					
Burner	million €	283	283	278	[Becker et al. 2012]
FT reactor	million €	176	176	173	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	50	50	50	
PSA	million €	23	23	23	[Becker et al. 2012]
Hydrocracker, recycle	million €	452	452	444	[Concawe 2021]
Total installed cost	million €	985	984	967	
<b>Total direct cost</b>	<b>million €</b>	<b>1103</b>	<b>1103</b>	<b>1083</b>	Total installed cost *1.12
Engineering & design	million €	143	143	141	13% of total direct cost
Construction	million €	154	154	152	14% of total direct cost
Legal and contractor fees	million €	99	99	97	9% of total direct cost
Project contingency	million €	165	165	162	15% of total direct cost
<b>Total indirect costs</b>	<b>million €</b>	<b>563</b>	<b>562</b>	<b>552</b>	
<b>Total CAPEX</b>	<b>million €</b>	<b>1666</b>	<b>1665</b>	<b>1635</b>	
	<b>€/kW<sub>final fuel</sub></b>	<b>1098</b>	<b>1098</b>	<b>1099</b>	
Lifetime	yr	30			
Fixed O&M	-	3% of CAPEX/yr			
Variable O&M	€/GJ <sub>FT products, LHV</sub>	1.53			[Aramco 2021] 6120 US\$/GWh <sub>FT products</sub>

**Table 132:** Techno-economic data for a FT synthesis plant including RWGS in Europe 2050 (minimum part load FT plant: 50%)

	Unit	EU-N	EU-C	EU-S	Reference/comment
Capacity	MW <sub>FT products, LHV</sub>	1659	1789	1621	1 million t of diesel equivalent per year
<b>Inputs</b>					
H <sub>2</sub>	MJ/MJ <sub>FT products, LHV</sub>	1.4036	1.4036	1.4036	
CO <sub>2</sub>	kg/MJ <sub>FT products, LHV</sub>	0.0880	0.0880	0.0880	
Electricity	MJ/MJ <sub>CFT products, LHV</sub>	0.0441	0.0441	0.0441	
<b>Outputs</b>					
FT products	MJ	1	1	1	
Heat (T = 225 °C)	MJ/MJ <sub>CFT products, LHV</sub>	0.2139	0.2139	0.2139	
<b>CAPEX</b>					
Burner	million €	310	334	303	[Becker et al. 2012]
FT reactor	million €	193	208	189	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	53	56	52	
PSA	million €	24	26	24	[Becker et al. 2012]
Hydrocracker, recycle	million €	495	534	484	[Concawe 2021]
Total installed cost	million €	1075	1157	1051	
<b>Total direct cost</b>	<b>million €</b>	<b>1204</b>	<b>1296</b>	<b>1177</b>	Total installed cost *1.12
Engineering & design	million €	157	169	153	13% of total direct cost
Construction	million €	169	181	165	14% of total direct cost
Legal and contractor fees	million €	108	117	106	9% of total direct cost
Project contingency	million €	181	194	177	15% of total direct cost
<b>Total indirect costs</b>	<b>million €</b>	<b>614</b>	<b>661</b>	<b>600</b>	
<b>Total CAPEX</b>	<b>million €</b>	<b>1818</b>	<b>1958</b>	<b>1778</b>	
	<b>€/kW<sub>final fuel</sub></b>	<b>1096</b>	<b>1094</b>	<b>1097</b>	
Lifetime	yr	30			
Fixed O&M	-	3% of CAPEX/yr			
Variable O&M	€/GJ <sub>FT products, LHV</sub>	1.53			[Aramco 2021] 6120 US\$/GWh <sub>FT products</sub>

For sensitivity analysis variants with smaller (production of final fuel: 0.2 million t of diesel equivalent per yr) and larger (production of final fuel: 4 million t of diesel equivalent per yr) e-fuel plants have been calculated. The change of capacity influences the CAPEX of the CO<sub>2</sub> supply and the FT plant per unit of final fuel (e. g. €/kW<sub>final fuel</sub>). The CAPEX of the electrolysis plant per unit of final fuel does not change (the CAPEX for the electrolysis plant is scaled linearly).

The diesel is transported to a depot over a distance of 150 km via pipeline and from there distributed to the refuelling stations. The kerosene is transported to a depot over a distance of 150 km via pipeline and from there transported to an airport.

Table 133 shows the techno-economic data for the diesel refuelling station.

**Table 133:** Techno-economic data for a diesel refueling station

	Unit	Value	Reference/comment
Fuel output	million $l_{\text{diesel}}$ /year	6.30*	[UBG 2020]
	GWh <sub>LHV</sub> /yr	63	
Electricity consumption	MJ/MJ <sub>diesel, LHV</sub>	0.0034	[JEC 2020]
CAPEX	million €	1.7	[Gau-Algesheim 2020]
Lifetime	yr	15	
Discount rate		8%	Base case
Capital costs	€/yr	199,000	
O&M	€/yr	22,000*	[eFinancialModels 2021]; [HRSAM 2021]
Electricity	€/yr	30,000	
Total	€/yr	251,000	
	€/GJ <sub>diesel, LHV</sub>	1.2	
	€/l <sub>diesel</sub>	0.043	

\*3 dispensers, 2 hoses per dispenser, assumption: 6 refuellings/(hose\*h), 12 h/d, 365 d/yr, 40 l/refuelling; \*\*Maintenance: 5000 US\$ for a gasoline refuelling station with a capex of 1.8 million US\$ (equipment: 300,000 €; building: 1.5 million US\$) [eFinancialModels 2021]; Insurance: 1% of CAPEX/yr [HRSAM 2021]

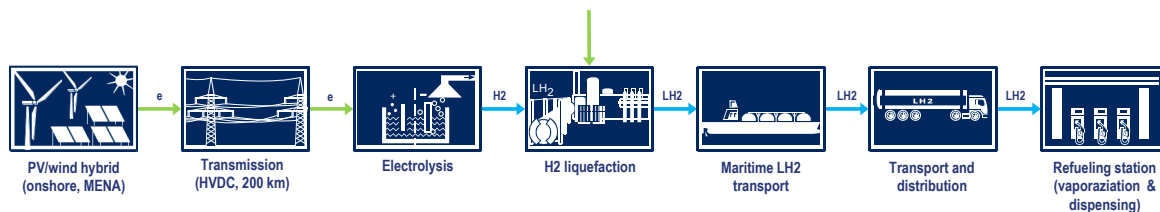
The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

#### 9.4.8. E-Hydrogen (liquid) from MENA via ship (H2ME-Liq)

Electricity from PV-/wind-hybrid power stations in MENA e. g. in the Kingdom of Saudi-Arabia (KSA). The electricity is transported via a high voltage direct current (HVDC) transmission line to the coast where the power-to-hydrogen plant is located. Hydrogen is generated through water electrolyses. It is then liquefied to be able to store larger quantities at once. The hydrogen is transported first via ship to South Europe e. g. Spain and after that further distributed to the refuelling stations via truck. At its destination, the liquid hydrogen is vaporized so it can be dispensed to road vehicles with 70 MPa vehicle tanks.



Figure 169: Liquefied e-hydrogen



At least a part of the hydrogen is required for propulsion of the LH<sub>2</sub> carrier. Furthermore, there is some hydrogen loss at the hydrogen liquefier. Therefore, the hydrogen production capacity and the rated power input into the electrolyser for the same output of final fuel delivered to Europe per hour (set to a production of 1 million t of diesel equivalent per year or 11.98 TWh of hydrogen per year<sup>18</sup>) is higher than for hydrogen generated in Europe.

A hydrogen buffer storage has been assumed to compensate fluctuations of the renewable electricity supply and the lower capability of the hydrogen liquefaction plant to follow fluctuating hydrogen supply. A hydrogen storage loading compressor is required to elevate the pressure of the hydrogen leaving the electrolysis plant to 10 MPa which is the maximum pressure of the hydrogen buffer storage. Similar as for hydrogen generated in Europe a buffer storage consisting of underground steel-made tubes with a diameter of 1485 mm has been assumed.

In the base case, the equivalent full load period of the hydrogen liquefaction plant is assumed to be the same as that of the electrolysis plant. The equivalent full load period depends on the electricity source connected with the electrolysis plant and as a result from the region where the e-fuel plant is located.

In chapter 4 (intermittency) hydrogen liquefaction, transport, and distribution is not included. The hydrogen liquefaction is less flexible than the electrolysis. To consider the lower flexibility of the hydrogen liquefaction plant a minimum part load of 50% of full load is assumed.

Table 134 shows the techno-economic data for the hydrogen buffer storage including hydrogen storage loading compressor.

<sup>18</sup> 1 million t \* 43.13/3.6 MWh/t

**Table 134:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor in MENA for the supply of CGH<sub>2</sub> as transportation fuel in the EU

	Unit	2020	2030	2050	Reference/comment
Capacity electrolysis	MW <sub>H<sub>2</sub>, LHV</sub>	2361	2492	2878	
	Nm <sup>3</sup> /h	787,000	831,000	960,000	
	MW <sub>e</sub>	3551	3665	3838	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217			
CAPEX	million €	202	214	247	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	1.3	1.5	2.0	of full load operation
	million Nm <sup>3</sup>	24.3	29.3	45.0	Net storage capacity
CAPEX	million €	610	735	1131	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			

In 2050 the LH<sub>2</sub> carrier is fuelled with 100% H<sub>2</sub> leading to additional hydrogen production in MENA.

Table 135 shows the techno-economic data for the hydrogen liquefaction plant. The CAPEX of a hydrogen liquefaction plant with a capacity of 50 t per day amounts to about 105 million €. The maximum capacity of the cold box is 200 t per day [Haberstroh 2019]. For a capacity of up to 200 t per day a scaling exponent of 2/3 is applied. For a capacity above 200 t per day (which is the case here) the CAPEX is scaled linearly.

**Table 135:** Hydrogen liquefaction for the supply of hydrogen as transportation fuel in MENA (KSA)

	Unit	2020	2030	2050	Reference/comment
Capacity	MW <sub>LH<sub>2</sub></sub>	2249	2374	2741	
	t LH <sub>2</sub> /h	67.5	71.2	82.3	
	t LH <sub>2</sub> /d	1620	1710	1974	
<b>Inputs</b>					
Hydrogen	MJ/MJ <sub>LH<sub>2</sub></sub>	1.05	1.05	1.05	Haberstroh 2019
Electricity	kWh/kgLH <sub>2</sub>	8.00	8.00	8.00	Sphera 2021
	MJ/MJ <sub>LH<sub>2</sub></sub>	0.2401	0.2401	0.2401	
	MJ/MJ <sub>final fuel</sub>	0.2464	0.2464	0.2464	Related to H <sub>2</sub> dispensed in the EU
CAPEX	million €	2143	2262	2612	Haberstroh 2019
Lifetime	yr	30	30	30	Haberstroh 2019
Maintenance & repair		2.5% of CAPEX/yr	2.5% of CAPEX/yr	2.5% of CAPEX/yr	
Labour	€/(FTE*yr)	60,000	60,000	60,000	Amec Foster Wheeler 2017
		38 persons*	38 persons*	40 persons	NHEG 1992
	€/yr	2.28	2.28	2.40	

\* Scaled from a liquefaction plant with a capacity of about 63 MW of LH<sub>2</sub> with a scaling exponent of 0.25 as indicated in [Hamelinck 2004]

For time horizon 2050 a higher capacity is required because the LH<sub>2</sub> carrier is fuelled with 100% H<sub>2</sub>.

The LH<sub>2</sub> is transported via ship from KSA to Rotterdam in the Netherlands via the Suez Canal over a distance of about 7350 km.

The maritime LH<sub>2</sub> transport includes the export terminal in KSA (Table 136), the LH<sub>2</sub> carrier (Table 137), and the import terminal in Europe.

The largest LH<sub>2</sub> tanks which are available today have a water volume of 3500 m<sup>3</sup> which has been assumed for 2020. For 2030 and 2050 it has been assumed that larger LH<sub>2</sub> tanks with a water volume of 11200 m<sup>3</sup> as planned by Kawasaki [Kawasaki 2020] are available. The uninstalled CAPEX for a LH<sub>2</sub> tank with a water volume of 3500 m<sup>3</sup> is indicated with 6.6 million US\$ [DOE 2015]. The CAPEX for installation has been assumed to be 30% of the uninstalled CAPEX. For the larger LH<sub>2</sub> tank the CAPEX have been calculated using a scaling exponent of 0.7. The 2015 US\$ have been converted to 2019 US\$ by application of the Chemical Engineering Plant Cost Index and then converted to €. The CAPEX for Jetty and loading arm/equipment has been derived from [Lanphen 2019].

**Table 136:** Export terminal

	Unit	2020	2030/2050
Number of tanks		40	12
Water volume per tank	m <sup>3</sup>	3500	11,200
Water volume total	m <sup>3</sup>	140,000	134,400
Filling ratio		0.90	0.90
LH <sub>2</sub> storage capacity total	t	8933	8576
<b>CAPEX</b>			
Jetty	million €	3	3
Loading arm/equipment	million €	1	1
Tanks	million €	334	226
Total	million €	338	230
Lifetime	yr	30	30

**Table 137:** LH<sub>2</sub> carrier

	Unit	2020/2030	2050	Reference
Water volume LH <sub>2</sub> tanks	m <sup>3</sup>	140,000	140,000	
Filling ratio		0.85	0.85	EQHHPP 1991
Payload LH <sub>2</sub>	t	8437	8437	
Bol-off rate		0.20 %/d	0.20 %/d	Kamiya et al. 2014
Speed	knots	18	18	Hank et al. 2020b
	km/h	33.3	33.3	
Fuel consumption	MJ/(kg H <sub>2</sub> *km)	0.001303	0.001303	Hank et al. 2020b
Share boil-off		46%	46%	
Residual fuel		LSMGO	H <sub>2</sub>	
CAPEX	million €	440	440	Hank et al. 2020b
Lifetime	yr	30	30	
Crew	million €/yr	0.79	0.79	Deloitte 2011
Maintenance & repair		2% of CAPEX/yr		
Suez Canal tonnage (SCNT)		105,000*	105,000*	LETH 2021
Suez Canal toll				
Laden	€/voyage	562,000	562,000	USMS 2021
Ballast	€/voyage	478,000	478,000	USMS 2021
Total	€/roundtrip	1,040,000	1,040,000	

\* Based on a Moss type LNG carrier (spherical tanks), 145,000 m<sup>3</sup>, 75,000 dwt

It has to be noted that deadweight tons (DWT) must not mixed up with LH<sub>2</sub> payload. The deadweight of a 133433 m<sup>3</sup> LH<sub>2</sub> carrier amounts to 72,339 t [Ahluwalia et al. 2020]. As a result, the deadweight of the LH<sub>2</sub> carrier in Table 137 amounts to about 76,000 t. The LH<sub>2</sub> payload is about 8400 t.

Suez Canal tonnage (SCNT) is a measure of the volume of the hull of the ship, not only the water volume of the LH<sub>2</sub> tanks. The Suez Canal toll depends on the SCNT [LETH 2021], [USMS 2021]. In [USMS 2021] the Suez Canal toll is indicated for various types of ships in SDR per SCNT (1 SDR = 1.4 US\$).

For the import terminal the same assumptions have been applied as for the export terminal (Table 136). From there the LH<sub>2</sub> is transported via truck to the refuelling stations over a distance of 300 km (Table 138).

**Table 138:** Techno-economic data for the transport of LH<sub>2</sub> via truck

	Unit	Value	Reference/comment
Distance	km	300	
Payload	t	3.5	
	GJ LH <sub>2</sub>	420	
Fuel consumption	MJ/(kg fuel*km)	0.006644	Sphera 2021
	l diesel/100 km	32	
Average speed	km/h	50	
Operating time	d/yr	240	
Number of roundtrips per day		0.5	
Loading/unloading	h/d	0.75	
<b>Tractor truck</b>			
CAPEX	€	102,300	lastauto omnibus 2016
Lifetime	km	1,000,000	
Mileage	km/yr	72,000	
Fixed O&M	€/yr	16,213	lastauto omnibus 2016
Variable O&M	€/km	0.1050	LBST & Hincio 2019
Labour costs driver	€/h	22.4	CGDD 2017
<b>Semitrailer</b>			
CAPEX	€	780,000	[Gardener Cryogenics 1994]; [Schmitz 1998]
Lifetime	yr	15	
Fixed O&M	€/yr	12110	lastauto omnibus 2016
Variable O&M	€/km	0.0471	lastauto omnibus 2016
<b>Total costs of fuel transport 2020/2030/2050</b>	<b>€/GJ</b>	<b>3.33/3.47/4.10</b>	

The CAPEX of the semi-trailer has been derived from [Gardener Cryogenics 1994] (LH<sub>2</sub> tank and equipment) and [Schmitz 1998] (chassis). The cost data from 1994 and 1998 have been converted to today's values via the Chemical Engineering Plant Cost Index (CEPCI).

At the refuelling station (Table 157) the LH<sub>2</sub> is compressed via a cryogenic compressor, vaporized, and subsequently dispensed as CGH<sub>2</sub>. A CGH<sub>2</sub> buffer storage with a maximum pressure of 100 MPa is also installed. A description of this concept can be found in [Decker 2019].

The CAPEX has been derived from [HRSAM 2021] except dispensers. According to [Parks et al. 2014] the CAPEX for dispenser used in the HRSAM model is too low. On the other hand, two instead of four dispensers are installed is assumed because the refuelling of fuel cell truck is assumed for this study. It has to be noted that the CAPEX indicated for the components of the refuelling station already the installation factors are already included.

Learning curves have been applied for various components of the refuelling station leading to a decrease of overall costs.

**Table 139:** LCGH<sub>2</sub> refuelling station for CGH<sub>2</sub> dispensing

	Unit	2020	2030	2050
H <sub>2</sub> throughput	GWh/yr	15.7	15.7	15.7
	kg H <sub>2</sub> /d	1013	1013	1013
Open days per year		250	250	250
Electricity consumption	MJ/MJ <sub>H<sub>2</sub></sub> , LHV	0.0005	0.0005	0.0005
Number of dispensers	-	2	2	2
<b>CAPEX</b>	€			
LH <sub>2</sub> tank	€	286,000	286,000	286,000
Dispensers	€	246,000	194,000	169,000
Electrical supply	€	76,000	76,000	76,000
CGH <sub>2</sub> storage	€	344,000	271,000	237,000
Evaporator	€	116,000	91,000	79,000
High pressure cryogenic pump	€	462,000	363,000	317,000
Balance of plant	€	100,000	100,000	100,000
<b>Initial capital costs</b>	€	<b>1,630,000</b>	<b>1,381,000</b>	<b>1,264,000</b>
Site preparation	€	81,000	69,000	63,000
Engineering & design	€	163,000	138,000	126,000
Project contingency	€	81,000	69,000	63,000
Up-front permitting costs	€	49,000	41,000	38,000
<b>Total</b>	€	<b>2,004,000</b>	<b>1,698,000</b>	<b>1,554,000</b>
<b>Operating &amp; maintenance</b>				
Labour	€/yr	80,600*		
Insurance		1% of total CAEX/yr		
Maintenance & repair for high pressure cryogenic pump		4% of total CAPEX/yr		
Maintenance & repair for other components		1% of total CAEX/yr		
Overhead		20% of labour		

\*Based on 25 €/h instead of 11 US\$/h indicated in [HRSAM 2021]

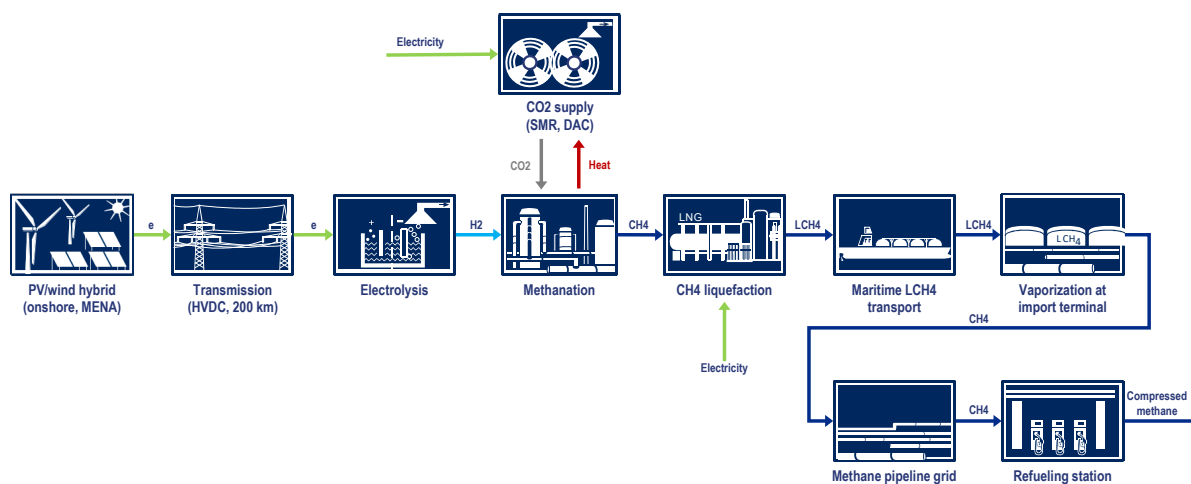
The electricity for the refuelling station is supplied by the electricity grid at low voltage (LV) level (0.4 kV).

#### 9.4.9. E-Methane from MENA via ship (CH<sub>4</sub>ME-Liq)

E-methane is generated via the methanation process, where a chemical reaction converts carbon dioxide and hydrogen to methane. The hydrogen needed for the process is generated via electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. The electricity is transported via a high voltage direct current (HVDC) transmission line to the coast where the power-to-hydrogen plant is located.

The carbon dioxide can be produced by several routes, for example by direct air capture (DAC) or from flue gas from steam methane reforming (SMR). The heat required for these processes is the reused by-product of the methanation. After the methanation process the methane is liquefied so that larger quantities can be stored at once. The liquid methane is then transported via ships. At the import terminal the methane is vaporized again, pressurized and transported through a pipeline grid to refuelling stations. Here compressed methane is dispensed to road vehicles.

**Figure 170:** e-Methane from MENA via ship



The hydrogen demand of downstream processes such as the methanation step and the boil-off loss during maritime transport of liquefied methane influences the hydrogen production capacity and the rated power input into the electrolyser for the same output of final fuel delivered to Europe per hour (set to a production of 1 million t of diesel equivalent per year or 11.98 TWh of final fuel for all pathways in the base case) is higher than for methane generated in Europe.

The storage capacity of the buffer storage (Table 140) is based on minimum part load of 50% of the methanation plant.

In the base case, the equivalent full load period of the methanation plant and the methane liquefaction plant is assumed to be the same as that of the electrolysis plant.



**Table 140:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-methane in MENA and liquefied methane export to Europe

	Unit	2020	2030	2050	Reference/ comment
Capacity electrolysis	MW <sub>H<sub>2</sub>, LHV</sub>	2540	2686	3006	
	Nm <sup>3</sup> /h	847,000	896,000	1002,000	
	MW <sub>e</sub>	3819	3950	4008	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217			
CAPEX	million €	218	230	258	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	1.3	1.6	2.0	of full load operation
	million Nm <sup>3</sup>	27.2	33.3	49.1	Net storage capacity
CAPEX	million €	682	837	1234	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			

For time horizon 2050 the capacity is slightly higher because the LCH<sub>4</sub> carrier is fueled with 100% methane.

**Table 141:** CO<sub>2</sub> supply for a methanation plant in MENA for 2020/2030/2050

	Unit	Concentrated	Average	Diluted
CO <sub>2</sub> capture				
CO <sub>2</sub> source		SMR	Flue gas from power stations	DAC
Capacity	t/h	458/484/542		
Electricity	MJ/kg CO <sub>2</sub>	0.14	0.27	1.44
Heat	MJ/kg CO <sub>2</sub>	0.90	3.00	5.76
CAPEX	million €	163/169/183	412/428/464	980/1022/1114
Maintenance & repair		2.5% of CAPEX/yr		2.5% of CAPEX/yr
Insurance		2% of CAPEX/yr		-
Labour	million €/yr	1.92/1.98/2.04		-
Administration		30% of operating and maintenance labour, maintenance labour 40% of maintenance		-
CO <sub>2</sub> liquefaction				
Electricity	MJ/kg CO <sub>2</sub>	0.38*		
CAPEX	million €	59/61/66		
Fixed OPEX CO <sub>2</sub> liquefier		10% of CAPEX/yr		
CO <sub>2</sub> storage				
CO <sub>2</sub> storage capacity	d	1.2/1.2/1.6		
CAPEX	million €	8/8/12**		
Fixed OPEX of CO <sub>2</sub> storage		5% of CAPEX/yr		

\*0.1042 kWh/kg of CO<sub>2</sub> at p (in) = ambient pressure; \*\*CO<sub>2</sub> storage: 551 £ or 589 € per t of CO<sub>2</sub>

**Table 142:** Techno-economic data for a methanation plant in MENA (KSA)

	Unit	2020	2030	2050	Reference/comment
Capacity	MW <sub>CH<sub>4</sub>, LHV</sub>	1727	1781	1897	
<b>Inputs</b>					
H <sub>2</sub>	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	1.198	1.198	1.198	
CO <sub>2</sub>	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	0.0600	0.0600	0.0600	
Electricity	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	0.0229	0.0229	0.0229	
<b>Outputs</b>					
CH <sub>4</sub>	MJ	1.000	1.000	1.000	
Heat (T = 250-300°C)	MJ/MJ <sub>CH<sub>4</sub>, LHV</sub>	0.173	0.173	0.173	
<b>Economic data</b>					
CAPEX	€/kW <sub>CH<sub>4</sub>, LHV</sub>	792	704	541	[IEA 2019d] (880/782/601 US\$/kW <sub>CH<sub>4</sub>, LHV</sub> )
	million €	1367	1254	1027	
Lifetime	yr	30			[IEA 2019d]
Fixed O&M		3% of CAPEX/yr			[IEA 2019d]
Variable O&M	€/GWh <sub>CH<sub>4</sub>, LHV</sub>	320			[Aramco 2021] (355 US\$/GWh <sub>CH<sub>4</sub>, LHV</sub> )

**Table 143:** CH<sub>4</sub> liquefaction in MENA (KSA)

	Unit	2020	2030	2050	Reference/comment
Capacity	MW <sub>LCH<sub>4</sub></sub>	1727	1781	1897	
	t LCH <sub>4</sub> /h	124.3	128.2	136.5	
	t LCH <sub>4</sub> /d	2983	3077	3277	at full load operation
<b>Inputs</b>					
Methane	MJ/MJ <sub>LCH<sub>4</sub></sub>	1.00	1.00	1.00	
Electricity	kWh/kg <sub>LCH<sub>4</sub></sub>	0.342	0.342	0.342	Ott et al. 2015
	MJ/MJ <sub>LCH<sub>4</sub>2</sub>	0.0246	0.0246	0.0246	
	MJ/MJ <sub>final fuel</sub>	0.0250	0.0250	0.0253	Related to CH <sub>4</sub> dispensed in the EU
CAPEX	million €	658	678	722	Hank et al. 2020b
Lifetime	yr	30			
Maintenance & repair, labour		2.0% of CAPEX/yr			Hank et al. 2020b

According to [Eurasian Ventures 2020] the CAPEX for LNG terminals with a 263,000 m<sup>3</sup> LNG storage including re-gasification ranges 200 and 400 million US\$. For the export terminal which has no re-gasification unit the lower value (200 million US\$) and for the import terminal the average value (300 million US\$) has been assumed. The lifetime has been assumed to be 30 years. For the transport of liquefied methane, a Moss type LNG carrier has been assumed (Table 144).

**Table 144:** LCH<sub>4</sub> carrier

	Unit	2020/2030	2050	Reference
Water volume LCH <sub>4</sub> tanks	m <sup>3</sup>	140,000	140,000	
Filling ratio		0.98	0.98	
Payload LCH <sub>4</sub>	t	57,624	57,624	
Bol-off rate		0.10 %/d	0.10 %/d	Hank et al. 2020b
Speed	knots	20	20	Hank et al. 2020b
	km/h	37.0	37.0	
Fuel consumption	MJ/(kg CH <sub>4</sub> *km)	0.0001872	0.0001872	Hank et al. 2020b
Share boil-off		60%	60%	
Residual fuel		LSMGO	CH <sub>4</sub>	
CAPEX	million €	152	152	Hank et al. 2020b
Lifetime	yr	30	30	
Crew	million €/yr	0.79	0.79	[Deloitte 2011]
Maintenance & repair		3.5% of CAPEX/yr		Hank et al. 2020b
Suez Canal tonnage (SCNT)		105,000*	105,000*	LETH 2021
Suez Canal toll				
Laden	€/voyage	562,000	562,000	USMS 2021
Ballast	€/voyage	478,000	478,000	USMS 2021
Total	€/roundtrip	1,040,000	1,040,000	

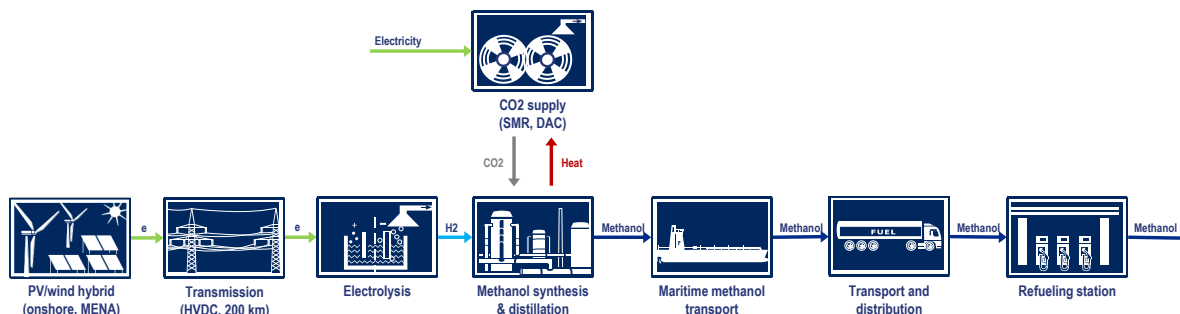
\* Based on a Moss type LNG carrier (spherical tanks), 145,000 m<sup>3</sup>, 75,000 dwt

At the import terminal the liquefied methane is re-gasified and injected into the natural gas grid. The pipeline grid and the same refuelling stations have been assumed as for e-methane generated in the EU (chapter 9.4.2).

#### 9.4.10. E-Methanol from MENA via ship (MeOHME)

Methanol is produced by the catalytic reaction of carbon dioxide and hydrogen. The hydrogen is generated by water via electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. The required carbon dioxide can be supplied either via direct air capture (DAC) or flue gas from steam methane reforming (SMR). The heat required by the CO<sub>2</sub> supply is partly originated as a by-product of the Methanol synthesis and distillation process. After the synthesis and the distillation process the methanol is transported first through ships and then distributed via trucks. The trucks deliver the methanol to refuelling stations, at which the end user can retrieve it.

**Figure 171:** e-Methanol from MENA via ship



The ship for methanol transport to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050).

The techno-economic data for the export terminal in Table 145 has been derived from [Lanphen 2019]. The number of tanks has been adjusted to the transport capacity of the methanol carrier. A filling ratio of 0.95 has been assumed as indicated for petroleum tanks in [Perdue 2009].

**Table 145:** Export terminal for methanol transport

	Unit	2020/2030/2050
Number of tanks		3
Water volume per tank	m <sup>3</sup>	50,000
Water volume total	m <sup>3</sup>	150,000
Filling ratio		0.95
Methanol storage capacity total	t	118,950
<b>CAPEX</b>		
Jetty	million €	3
Loading arm/equipment	million €	1
Tanks	million €	105
Total	million €	109
Lifetime	yr	50

Dedicated ships are built for the transport of methanol because the tanks and equipment have to be adapted to methanol (resistant against corrosion). Table 146 shows the techno-economic data of the methanol carrier. The payload for the methanol carrier has been derived Millennium Explorer which is one of the largest methanol carriers been built until now.

**Table 146:** Methanol carrier

	Unit	2020/2030/2050	Reference
Water volume methanol tanks	m <sup>3</sup>	120,000	Wärtsiläe 2021a
Filling ratio		0.95	Perdue 2009
Payload methanol	t	90,402	
Speed	knots	15	Hank et al. 2020b; Wärtsiläe 2021a
	km/h	27.8	
Fuel consumption	MJ/(kg CH <sub>3</sub> OH *km)	0.0000605	Sphera 2021
CAPEX	million €	54	Hank et al. 2020b
Lifetime	yr	30	
Crew	million €/yr	0.79	[Deloitte 2011]
Maintenance & repair		3.5% of CAPEX/yr	Hank et al. 2020b
Deadweight tons (DWT)	t	105,715	
Suez Canal tonnage (SCNT)		52,900*	LETH 2021
Suez Canal toll			
Laden	€/voyage	307,000	USMS 2021
Ballast	€/voyage	261,000	USMS 2021
Total	€/roundtrip	568,000	

\*For liquid fuel tankers the SCNT is about the half of the deadweight

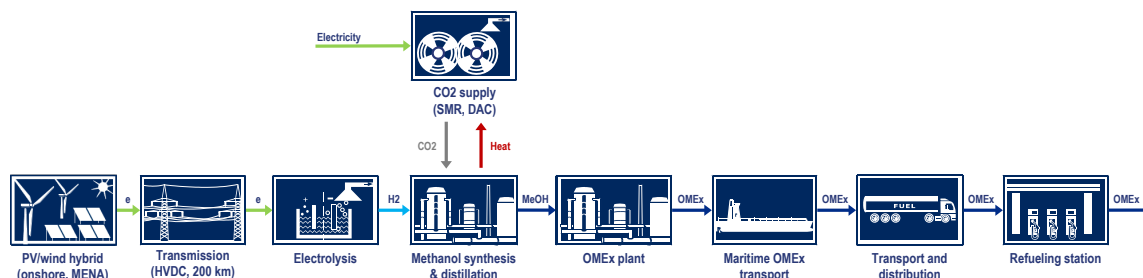
For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

Inside the EU the methanol is distributed to the consumers e. g. ships in the same way as for methanol produced in Europe (chapter 9.4.3).

#### 9.4.11. E-OMEx from MENA via ship (OMExME)

OMEx is produced out of Methanol. The Methanol is synthesized from the products carbon dioxide and hydrogen. The hydrogen is generated by water electrolysis, where the required electricity is produced through PV-/wind-hybrid power stations. The resulting heat of the methanol synthesis and distillation process is reused by the carbon dioxide supply. CO<sub>2</sub> is retrieved either via flue gas from direct air capture (DAC) or flue gas from steam methane reforming (SMR). After distillation, the methanol is converted to OMEx at an OMEx plant and transported firstly via ships and then distributed through trucks to the refuelling stations. At this point the end user can access the e-fuel.

**Figure 172:** e-OMEx from MENA via ship



The ship for OMEx transport to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050).

**Table 147:** Export terminal for OMEx transport

	Unit	2020/2030/2050
Number of tanks		3
Water volume per tank	m <sup>3</sup>	50,000
Water volume total	m <sup>3</sup>	150,000
Filling ratio		0.95
OMEx storage capacity total	t	159,986
CAPEX		
Jetty	million €	3
Loading arm/equipment	million €	1
Tanks	million €	105
Total	million €	109
Lifetime	yr	50

For the transport of OMEx the same ship as for methanol transport has been assumed. Table 148 shows the techno-economic data of the OMEx carrier. The density of OMEx significantly higher than that of methanol. Therefore, a lower filling ratio has been assumed than for methanol to avoid overloading of the ship.

**Table 148:** OMEx carrier

	Unit	2020/2030/2050	Reference/comment
Water volume OMEx tanks	m <sup>3</sup>	120,000	Wärtsiläe 2021a
Filling ratio		0.71	To avoid overloading
Payload methanol	t	90,872	
Speed	knots	15	Hank et al. 2020b; Wärtsiläe 2021a
	km/h	27.8	
Fuel consumption	MJ/(kg OMEx *km)	0.0000604	Sphera 2021
CAPEX	million €	54	Hank et al. 2020
Lifetime	yr	30	
Crew	million €/yr	0.79	[Deloitte 2011]
Maintenance & repair		3.5% of CAPEX/yr	Hank et al. 2020
Deadweight tons (DWT)		105,715	
Suez Canal tonnage (SCNT)		52,900*	LETH 2021
Suez Canal toll			
Laden	€/voyage	307,000	USMS 2021
Ballast	€/voyage	261,000	USMS 2021
Total	€/roundtrip	568,000	

\*For liquid fuel tankers the SCNT is about the half of the deadweight

For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

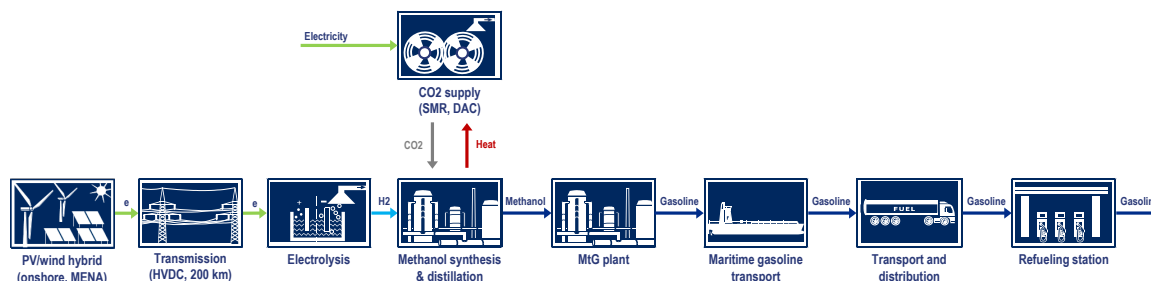
Inside the EU the OMEx is distributed to refuelling stations in the same way as for OMEx produced in Europe (chapter 9.4.4).

#### 9.4.12. E-Gasoline and e-kerosene from MENA via METHANOL-TO-GASOLINE and via ship (MTGME, MTKME)

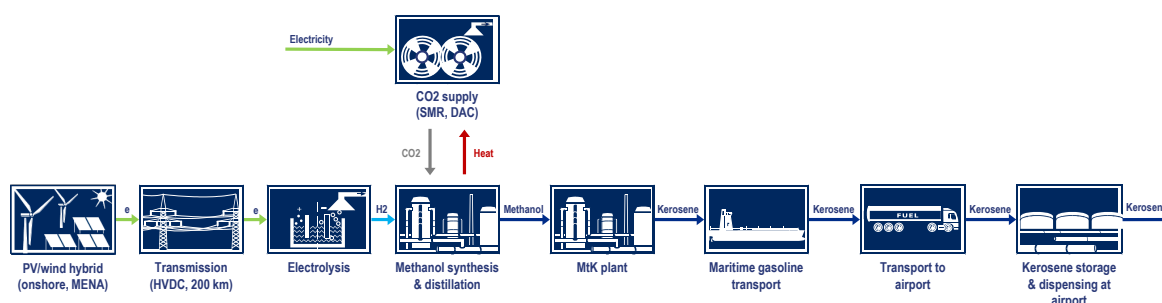
The generation of e-gasoline or e-kerosene both start with the production of hydrogen via electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. The hydrogen is together with CO<sub>2</sub>, used to synthesis Methanol. At that process heat results as a by-product and is reused in the carbon dioxide supply. The carbon dioxide can be supplied through various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. After the Methanol is distilled, it can be converted into Gasoline or Kerosene via the methanol-to-gasoline (MTG) process. Transportation is executed firstly via ships and then distributed via trucks. The Gasoline is delivered to refuelling stations where it is used to fuel road vehicles. The Kerosene is brought to storages at airports where it can be dispensed to airplanes.



**Figure 173:** e-Gasoline from MENA via ship



**Figure 174:** e-Kerosene from MENA via ship



The ship for gasoline and kerosene transport to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050).

**Table 149:** Export terminal for gasoline and kerosene transport

	Unit	Gasoline	Kerosene
Number of tanks		3	3
Water volume per tank	m <sup>3</sup>	50,000	50,000
Water volume total	m <sup>3</sup>	150,000	150,000
Filling ratio		0.95	0.95
OMEx storage capacity total	t	111,750	120,000
CAPEX			
Jetty	million €	3	3
Loading arm/equipment	million €	1	1
Tanks	million €	105	105
Total	million €	109	109
Lifetime	yr	50	50

The techno-economic data for the ship for the marine transport of gasoline and kerosene have been derived from [Hank et al. 2020b]. For the transport of crude oil base products like gasoline, kerosene, and diesel product tankers are used. The physical and chemical properties of the e-gasoline and e-kerosene are similar as those for crude oil-based gasoline and kerosene. Therefore, a product tanker can also be used for the transport of e-gasoline and e-diesel. Table 150 shows the techno-economic data of the product tanker for the transport of gasoline and kerosene.

**Table 150:** Product tanker for the transport of gasoline and diesel

	Unit	2020/2030/2050	Reference/comment
Water volume gasoline or kerosene tanks	m <sup>3</sup>	140,000	Hank et al. 2020b
Filling ratio		0.95	Perdue 2009
Payload gasoline/kerosene	t	90,872/99,085	
Speed	knots	15	Hank et al. 2020b
	km/h	27.8	
Fuel consumption	MJ/(kg gasoline or kerosene *km)	0.0000604	Sphera 2021
CAPEX	million €	54	Hank et al. 2020b
Lifetime	yr	30	
Crew	million €/yr	0.79	[Deloitte 2011]
Maintenance & repair		3 % of CAPEX/yr	Hank et al. 2020b
Deadweight tons (DWT)		110,000	
Suez Canal tonnage (SCNT)		55,000*	LETH 2021
Suez Canal toll			
Laden	€/voyage	265,000	USMS 2021
Ballast	€/voyage	195,000	USMS 2021
Total	€/roundtrip	460,000	

\*For liquid fuel tankers the SCNT is about the half of the deadweight

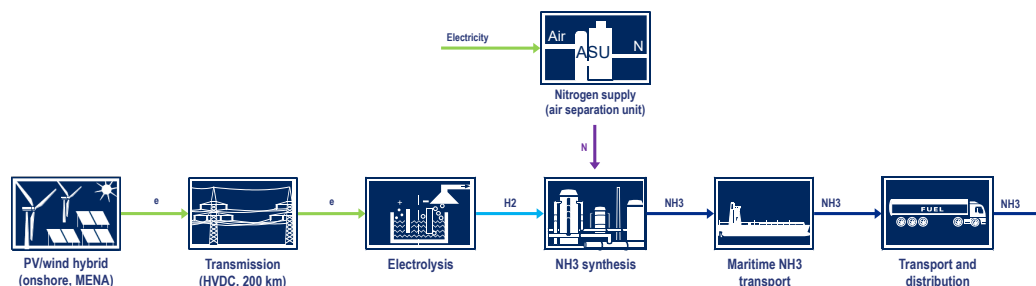
For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

Inside the EU the gasoline and kerosene are distributed to refuelling stations or an airport in the same way as for gasoline and kerosene produced in Europe (chapter 9.4.5).

#### 9.4.13. E-Ammonia from MENA via ship (NH<sub>3</sub>ME)

To generate ammonia, as a first step hydrogen is produced via water electrolysis. The electricity required in this process is produced through PV-/wind-hybrid power stations. It is then synthesised to ammonia, compressed, and stored until it is transported firstly via ship and then distributed through trucks to its final use.

**Figure 175:** e-Ammonia from MENA via ship



The transport of ammonia (NH<sub>3</sub>) involves a boil-off which is used for ship propulsion. Therefore, the capacities of the H<sub>2</sub> buffer storage (Table 151) and NH<sub>3</sub> synthesis plant (Table 152) upstream the NH<sub>3</sub> transport have to be higher than modelled in chapter 4 (intermittency) to supply the same amount of final fuel per year to Europe. For time horizon 2050 the capacity is slightly higher than for 2020 and 2030 because the NH<sub>3</sub> carrier is fueled with 100% ammonia.

**Table 151:** H<sub>2</sub> buffer storage with H<sub>2</sub> storage loading compressor for power-to-ammonia in MENA and export to Europe

	Unit	2020	2030	2050	Reference/comment
Capacity electrolysis	MW <sub>H<sub>2</sub>, LHV</sub>	2432	2615	3006	
	Nm <sup>3</sup> /h	811,000	872,000	1,002,000	
	MW <sub>e</sub>	3657	3845	4008	
Compressor H <sub>2</sub> storage loading					
Suction pressure	MPa	3			
Final pressure	MPa	10			
T (in)	K	313			H <sub>2</sub> leaving electrolyzer
T (intercooling)	K	333			
Efficiency compressor		80%			
Efficiency electric motor		90%			
Number of stages	-	2			
Electricity consumption	kWh/Nm <sup>3</sup>	0.0649			
	kWh/kWh <sub>H<sub>2</sub>, LHV</sub>	0.0217			
CAPEX	million €	209	224	258	Planet et al. 2014
Maintenance & repair		3% of CAPEX/yr			Planet et al. 2014
Lifetime	yr	30			
H <sub>2</sub> storage					
Maximum pressure	MPa	10			
Minimum pressure	MPa	2.5			
Storage capacity	d	1.3	1.6	2.2	of full load operation
	million Nm <sup>3</sup>	25.8	33.0	53.4	Net storage capacity
CAPEX	million €	648	829	1340	Jauslin Stebler 2013
	€/kg <sub>H<sub>2</sub></sub>	279			
Lifetime	yr	30			

**Table 152:** Techno-economic data for an ammonia synthesis plant in MENA (KSA)

	Unit	2020	2030	2050	Reference/ comment
Capacity	MW <sub>NH3, LHV</sub>	1755	1837	1983	
Inputs					
H2	MJ/MJ <sub>NH3, LHV</sub>	1.140			
Electricity	MJ/MJ <sub>NH3, LHV</sub>	0.1657			
Outputs					
Ammonia	MJ	1.000			
Heat	MJ/MJ <sub>NH3, LHV</sub>	-			Heat not used
Economic data					
CAPEX	million €	954*	985*	1039*	DECHEMA 2017
Lifetime	yr	30			
Fixed O&M		3% of CAPEX/yr			

\*Upscaled from a 2000 t NH<sub>3</sub>/d plant (433 MW NH<sub>3</sub> based on the LHV) assuming a scaling exponent of 0.7

For large-scale storage at the export terminal and maritime transport the NH<sub>3</sub> is cooled down to a temperature of -33°C [Hank et al. 2020a]. The techno-economic data for the export terminal in Table 145 have been derived from [Lanphen 2019]. The number of tanks has been adjusted to the transport capacity of the methanol carrier. A filling ratio of 0.98 has been assumed.

**Table 153:** Export terminal for NH<sub>3</sub> transport

	Unit	2020/2030/2050
Number of tanks		2
Water volume per tank	m <sup>3</sup>	50,000
Water volume total	m <sup>3</sup>	100,000
Filling ratio		0.98
NH <sub>3</sub> storage capacity total	t	66,836
<b>CAPEX</b>		
Jetty	million €	3
Loading arm/equipment	million €	1
Tanks	million €	100
Total	million €	104
Lifetime	yr	30

Practically all LPG carriers also can be used for the transport of  $\text{NH}_3$ . Fully-refrigerated LPG or  $\text{NH}_3$  carriers have a cargo space of up to about 100,000  $\text{m}^3$  [Wärtsilä 2021b]. The water volume of the  $\text{NH}_3$  tanks have been derived from the Crystal Marine built by Kawasaki.  $\text{NH}_3$  has a higher density than LPG. Therefore, the filling ratio have been set to 0.75 to avoid overloading of the ship.

**Table 154:**  $\text{NH}_3$  carrier

	Unit	2020/2030	2050	Reference
Water volume $\text{NH}_3$ tanks	$\text{m}^3$	80,138	80,138	Wärtsilä 2021b
Filling ratio		0.75	0.75	
Payload $\text{NH}_3$	t	40,991	40,991	
Bol-off rate		0.04%	0.04%	Hank et al. 2020b
Speed	knots	17	17	Wärtsilä 2021b
	km/h	31.5	31.5	
Fuel consumption	MJ/(kg $\text{NH}_3$ *km)	0.0000687	0.0000687	Sphera 2021
Share boil-off		29%	29%	
Residual fuel		LSMGO	$\text{NH}_3$	
CAPEX	million €	64	64	Lanphen 2019
Lifetime	yr	30	30	
Crew	million €/yr	0.79	0.79	[Deloitte 2011]
Maintenance & repair		4% of CAPEX/yr		Lanphen 2019
Deadweight tons /DWT)	t	53,395	53,395	
Suez Canal tonnage (SCNT)		45,801*	45801*	LETH 2021
Suez Canal toll				
Laden	€/voyage	253,000	253,000	USMS 2021
Ballast	€/voyage	215,000	215,000	USMS 2021
Total	€/roundtrip	468,000	468,000	

\*The SCNT is close to the vessels International Gross Tonnage which is indicated with 45801 for the LPG carrier Crystal Marine

For the import terminal the same techno-economic assumptions have been applied as for the export terminal.

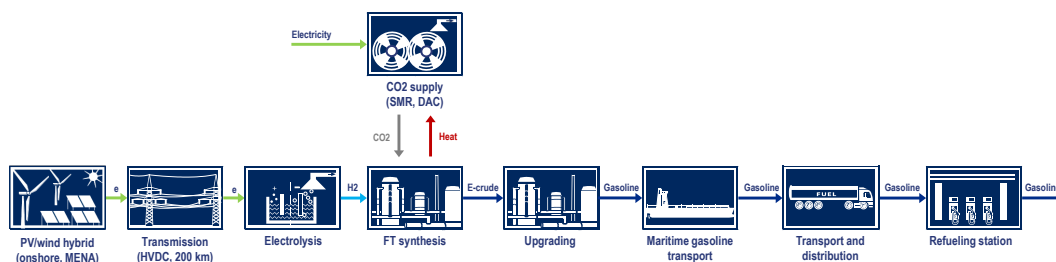
Inside Europe the  $\text{NH}_3$  is transported to the ship bunkering terminal in the same way as for  $\text{NH}_3$  produced in Europe.

#### 9.4.14. E-Gasoline, -kerosene, and -diesel from MENA via FT route and via ship (FTGME, FTKME, FTDME)

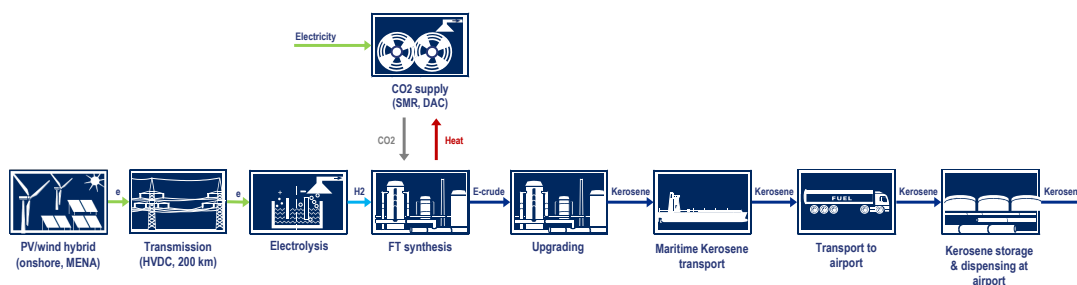
To generate e-kerosene, e-gasoline and e-diesel initially there is hydrogen needed. This is produced via water electrolysis. The electricity required in this process is produced by PV-/wind-hybrid power stations. The hydrogen is then synthesised with carbon dioxide to e-crude through the Fischer-Tropsch process. The carbon dioxide can be supplied by various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is

a by-product of the Fischer-Tropsch synthesis. The e-crude is converted into kerosene, gasoline or diesel and afterwards transported firstly via ships and then through trucks to their respective destination. For kerosene this is the airport where it is stored and dispensed. Diesel and gasoline are distributed to refuelling stations where they are utilized to fuel road vehicles.

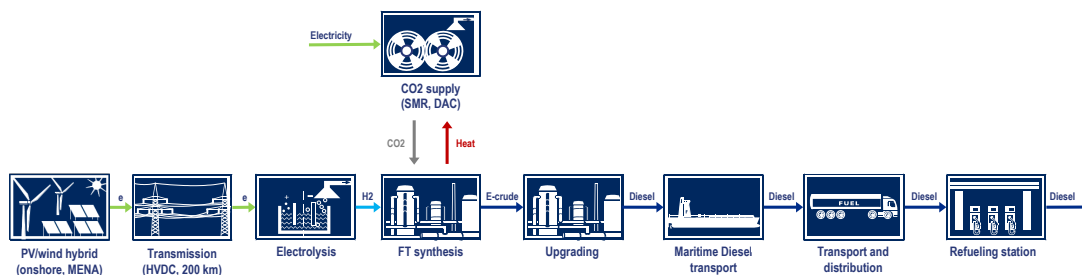
**Figure 176:** e-Gasoline from MENA via FT route and via ship



**Figure 177:** e-Kerosene from MENA via FT route and via ship



**Figure 178:** e-Diesel from MENA via FT route and via ship



The ship for the transport of gasoline, kerosene, and diesel to Europe consumes LSMGO (2020 and 2030) or e-diesel (2050). No gasoline, kerosene, or diesel loss occurs along the fuel supply chain except in case of 2050 for diesel where the ship is fuelled with e-diesel. In case of diesel some of the FT diesel is used in 2050 for ship propulsion leading to a slightly higher capacity than modelled in chapter 4 (intermittency) and as a result to a slightly higher CAPEX for the upstream processes.

For gasoline there are some differences in the CAPEX of the FT plant because it is optimized to the production of gasoline meeting the fuel specifications for Otto engines.

**Table 155:** Techno-economic data for a FT synthesis plant for gasoline production including RWGS in MENA (KSA)

	Unit	2020	2030	2050	Reference/comment
Capacity	MW <sub>FT products, LHV</sub>	1533	1530	1747	
Inputs					
GH <sub>2</sub>	MJ/MJ <sub>FT products, LHV</sub>	1.4036			
CO <sub>2</sub>	kg/MJ <sub>FT products, LHV</sub>	0.0880			
Electricity	MJ/MJ <sub>CFT products, LHV</sub>	0.0441			
Outputs					
FT products	MJ	1.0000			
Heat (T = 225°C)	MJ/MJ <sub>CFT products, LHV</sub>	0.2139			
CAPEX					
Burner	million €	286	285	326	Becker et al. 2012
FT reactor	million €	178	178	203	Becker et al. 2012; [König et al. 7/2015]
RWGS	million €	51	51	55	
PSA	million €	23	23	25	Becker et al. 2012
Distillation	million e	8	8	9	Becker et al. 2012
Wax hydrocracker	million €	74	74	81	Becker et al. 2012
Distillate hydrotreater	million €	41	41	45	Becker et al. 2012
Naphtha hydrotreater	million €	11	11	12	Becker et al. 2012
Catalytic reformer/platformer	million €	61	61	67	Becker et al. 2012
C5/C6 isomerization	million €	10	10	11	Becker et al. 2012
Total installed cost	million €	743	742	834	Becker et al. 2012
Total direct cost	million €	832	831	934	Total installed cost *1.12
Engineering & design	million €	108	108	121	13% of total direct cost
Construction	million €	117	116	131	14% of total direct cost
Legal and contractor fees	million €	75	75	84	9% of total direct cost
Project contingency	million €	125	125	140	15% of total direct cost
Total indirect costs	million €	424	424	476	
Total CAPEX	million €	1257	1255	1410	
Lifetime	yr	30			
Fixed O&M	€/yr	3% of CAPEX/yr			
Variable O&M	€/GJ <sub>FT products, LHV</sub>	1.53			[Aramco 2021] 6120 US\$/GWh <sub>FT products, LHV</sub>

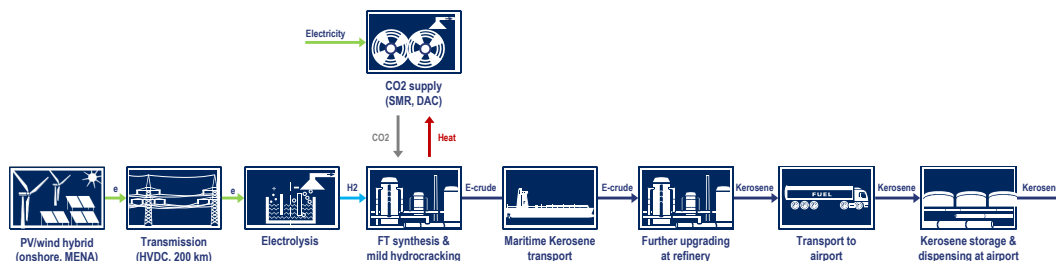
The gasoline, kerosene, and diesel is transported from KSA to Europe over a distance of 7352 km. For the port facilities and the product carrier the same assumptions have been applied as for gasoline and kerosene via the methanol-to-gasoline and methanol to-kerosene process (chapter 9.4.12). The differences between kerosene and diesel due to different density are small.

For the transport and distribution inside Europe the same assumptions have been applied as for e-gasoline, e-kerosene, and e-diesel produced inside Europe (chapter 9.4.5 and 9.4.7).

#### 9.4.15. E-Kerosene from MENA via FT route and via ship as e-crude (FTKME-e-crd)

To generate e-kerosene, hydrogen is needed. It is created via water electrolysis, where the electricity required for this procedure is produced by PV-/wind-hybrid power stations. The hydrogen is then synthesised with carbon dioxide to e-crude through the Fischer-Tropsch process. Also, a mild hydrocracking process is applied to the fuel. The carbon dioxide needed for the synthesis can be supplied through various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is a by-product of the Fischer-Tropsch synthesis. The e-crude is then shipped to a refinery where it is further upgraded and converted to kerosene. From there the kerosene is transported via trucks to airports where it is stored and dispensed.

**Figure 179:** e-Kerosene from MENA via FT route and via ship



The techno-economic data for the electrolysis plant, the hydrogen buffer storage and the CO<sub>2</sub> supply are the same as for the fully integrated stand-alone FT plant. The differences are at the FT synthesis stage and the further processing to final fuel. At the e-crude plant in KSA a mild hydrocracker is required to make the e-crude transportable.

Table 156 shows the CAPEX for a FT plant for e-crude production for a fuel production of 1 million t of diesel equivalent per year<sup>19</sup>. The CAPEX for the burner, FT reactor, PSA has been derived from [Becker et al. 2012]. The CAPEX for the RWGS has been derived from [König et al. 7/205]. The CAPEX for the mild hydrocracker has been derived from [Concawe 2021]. The CAPEX for the burner and FT reactor has been scaled linearly as indicated in [Becker et al. 2012] and [König et al. 7/2015]. For the calculation of the CAPEX of the RWGS a scaling exponent of 0.65 has been applied, and for PSA a scaling exponent of 0.70.

<sup>19</sup> The capacity of the FT plant differs depending on region and time horizon.



**Table 156:** CAPEX FT plant for e-crude production to produce 1 million t of diesel equivalent per year

Component	2020	2030	2050	SE	Comment
Capacity (MW <sub>e-crude, LHV</sub> )					
<b>CAPEX (million €)</b>					
Burner	286	285	326	1.00	
FT reactor	178	178	203	1.00	
RWGS	51	51	55	0.65	
PSA	23	23	25	0.70	
Mild hydrocracker	201	200	229	n. d. a.	179 €/ (t feed/yr) @ 8760 h/yr
Total installed cost	739	737	838		
<b>Total direct costs</b>	<b>827</b>	<b>826</b>	<b>939</b>		<b>Total installed cost *1.12</b>
Engineering & design	108	107	122		13% of total direct costs
Construction	116	116	131		14% of total direct costs
Legal and contractor fees	74	74	84		9% of total direct costs
Project contingency	124	124	141		15% of total direct costs
<b>Total indirect costs</b>	<b>422</b>	<b>421</b>	<b>479</b>		
<b>CAPEX total</b>	<b>1249</b>	<b>1247</b>	<b>1417</b>		

SE: scaling exponent

The e-crude is transported to South EU via ship. At the import terminal the e-crude is converted to the final fuel.

No cost of capital has been applied for the refinery because existing refineries has been assumed. The CAPEX for the refinery is only used for the calculation of the OPEX. Table 156 shows the CAPEX for the refinery components. The equivalent full load period of the refinery in the EU is (8000 h/yr) than that of the FT plant in MENA depending on the availability of renewable electricity leading to a lower capacity to get the same amount of final fuel per year (1 million t of diesel equivalent/yr).

**Table 157:** CAPEX of refinery components (hydrocracker, recycle) including fractionator

Component	CAPEX (Million €)	Comment
Total installed costs	447	408 €/t hydrocracker feed/yr); capacity: 1 million t feed/yr
<b>Total direct costs</b>	<b>500</b>	<b>Total installed cost *1.12</b>
Engineering & design	65	13% of total direct costs
Construction	70	14% of total direct costs
Legal and contractor fees	45	9% of total direct costs
Project contingency	75	15% of total direct costs
<b>Total indirect costs</b>	<b>255</b>	
<b>CAPEX total</b>	<b>766</b>	

Table 158 shows the assumptions for the operating and maintenance costs of the refinery.

**Table 158:** Operating and maintenance costs of the refinery

Component	Operating a maintenance cost	Reference
Labour	0.7% of CAPEX total/yr	Hedden & Jess 1994
Insurance	0.5% of CAPEX total/yr	
Maintenance & repair	1.9% of CAPEX total/yr	
Overhead	1.8% of CAPEX total/yr	
<b>Total</b>	<b>4.9% of CAPEX total/yr</b>	
	<b>37 million €/yr per FT plant in MENA</b>	
<b>Production of final fuel</b>	<b>43.1 PJ/yr</b>	
	<b>1 million t/yr</b>	

The operating and maintenance costs of the refinery only contributes to about 0.9 € per GJ of final fuel (or 0.031 € per l of diesel equivalent to the overall costs of fuel supply.

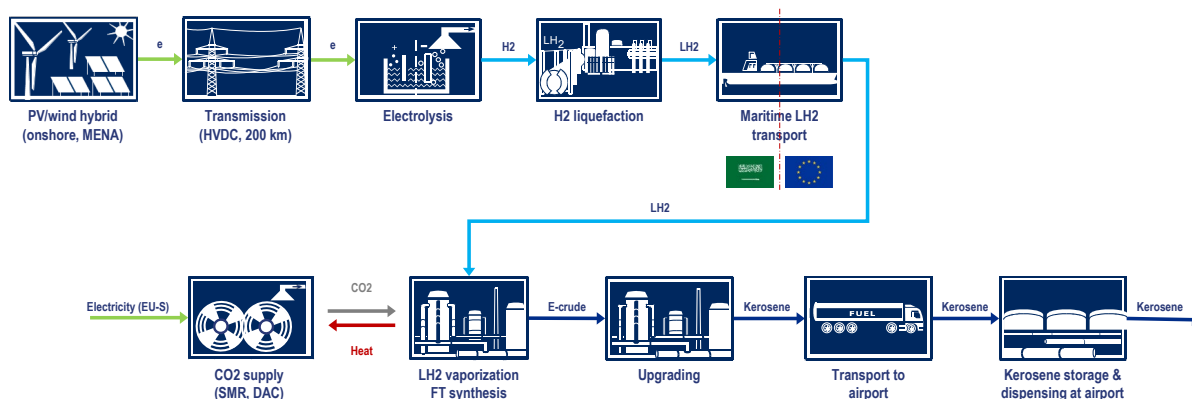
The final fuel is transported to a depot via pipeline over a distance of 150 km and from there 'via truck to the airport over a distance of 150 km.

#### 9.4.16. E-Kerosene and diesel via FT route with H<sub>2</sub> from MENA via ship (FTKME-H2ex, FTDME-H2ex)

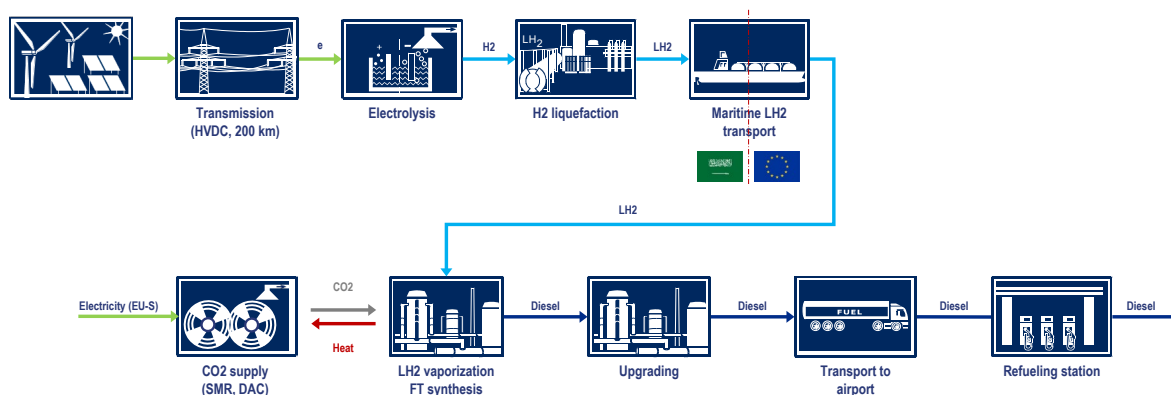
To generate e-kerosene and e-diesel, hydrogen is needed. It is created via water electrolysis, where the electricity required for this procedure is produced by PV-/wind-hybrid power stations. The hydrogen is liquefied to be able to store larger quantities at once. It is afterwards shipped to a facility where the liquid hydrogen is vaporised and then synthesized via the Fischer Tropsch process to e-crude or diesel. The carbon dioxide needed for the synthesis can be retrieved through various procedures, either direct air capture (DAC) or flue gas from steam methane reforming (SMR) plants. The heat used for these processes is a by-product of the

Fischer-Tropsch synthesis. The e-crude is then converted to kerosene. Kerosene and diesel are both transported via trucks. The destination of the kerosene are airports where it is stored and dispensed to airplanes, while the diesel is distributed to refuelling stations where it is utilized to fuel road vehicles.

**Figure 180:** e-Kerosene with H<sub>2</sub> from MENA via ship



**Figure 181:** e-Diesel with H<sub>2</sub> from MENA via ship



Due to the various process steps including hydrogen generation, hydrogen liquefaction, maritime LH<sub>2</sub> transport, FT syntheses and upgrading of the FT products to final fuel the capacity of the electrolysis plant is significantly higher for the same capacity of final fuel than for fully-integrated stand-alone power-to-fuel plants in KSA described in chapter 9.4.14.

For 2020 the electricity input of the electrolysis plant amounts to 4983 MW compared to 4624 MW for the fully integrated stand-alone power-to-fuel plants in KSA.

On the other hand, the capacity of the FT plant including upgrading to final fuel located in the EU is lower because the equivalent full load period is assumed to be 8000 h/yr. The reason is that the FT plant is fully decoupled from the electrolysis plant in MENA.

#### 9.4.17. Pathways involving decentralised e-crude plants and fully integrated FT plants into existing refinery

The stand-alone FT plant for Central Europe is described in Table 130 in chapter 9.4.7. For South Europe a larger FT plant has been assumed.

For the distributed e-crude plants and the fully integrated FT plant a location in Central Europe and MENA has been assumed. Table 159 shows the techno-economic data for the distributed e-crude plants and Table 160 for the fully integrated FT plant.

**Table 159:** Techno-economic data for a distributed e-crude plant based on FT synthesis including RWGS in Central Europe

	Unit	2020	2030	2050	Reference/comment
Capacity	MW <sub>FT products, LHV</sub>	1526	1516	1789	
Inputs					
GH <sub>2</sub>	MJ/MJ <sub>FT products, LHV</sub>	1.4036			
CO <sub>2</sub>	kg/MJ <sub>FT products, LHV</sub>	0.0880			
Electricity	MJ/MJ <sub>CFT products, LHV</sub>	0.0441			
Outputs					
FT products	MJ	1			
Heat (T = 225 °C)	MJ/MJ <sub>CFT products, LHV</sub>	0.2139			
CAPEX					
Burner	million €	285	283	334	[Becker et al. 2012]
FT reactor	million €	178	176	208	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	50	50	56	
PSA	million €	23	23	26	[Becker et al. 2012]
Mild hydrocracker	million €	200	198	234	[Concawe 2021]
Total installed cost	million €	736	731	858	
Total direct cost	million €	824	818	961	Total installed cost *1.12
Engineering & design	million €	107	106	125	13% of total direct cost
Construction	million €	115	115	135	14% of total direct cost
Legal and contractor fees	million €	74	74	86	9% of total direct cost
Project contingency	million €	124	123	144	15% of total direct cost
Total indirect costs	million €	420	417	490	
Total CAPEX	million €	1244	1236	1451	
Lifetime	yr	30			
Fixed O&M	million €/yr	3% of CAPEX/yr			
Variable O&M	€/GJ <sub>FT products, LHV</sub>	1.53			[Aramco 2021] 6120 US\$/GWh <sub>FT products</sub>

For e-crude plants located in Central Europe in 2020 and 2030 the fixed O&M amounts to 37 million € per year and the variable O&M amounts to 66 million € per year (fixed O&M in 2050: 44 million €). The OPEX share of the existing refinery amounts to about 37 million € per year. As a result, the total OPEX amounts to about 140 million € per year for the distributed FT plant combined with further processing of the e-crude in an existing refinery (2050: 147 million €/yr).

**Table 160:** Techno-economic data for an e-crude plant based on FT synthesis including RWGS in Central Europe for fully integration into existing refinery

	Unit	2020	2030	2050	Reference/comment
Capacity	MW <sub>FT products, LHV</sub>	1526	1516	1789	
Inputs					
GH <sub>2</sub>	MJ/MJ <sub>FT products, LHV</sub>	1.4036			
CO <sub>2</sub>	kg/MJ <sub>FT products, LHV</sub>	0.0880			
Electricity	MJ/MJ <sub>CFT products, LHV</sub>	0.0441			
Outputs					
FT products	MJ	1			
Heat (T = 225 °C)	MJ/MJ <sub>CFT products, LHV</sub>	0.2139			
CAPEX					
Burner	million €	285	283	334	[Becker et al. 2012]
FT reactor	million €	178	176	208	[Becker et al. 2012], [König et al. 7/2015]
RWGS	million €	50	50	56	
PSA	million €	23	23	26	[Becker et al. 2012]
Total installed cost	million €	536	532	624	
Total direct cost	million €	600	596	699	Total installed cost *1.12
Engineering & design	million €	78	77	91	13% of total direct cost
Construction	million €	84	83	98	14% of total direct cost
Legal and contractor fees	million €	54	54	63	9% of total direct cost
Project contingency	million €	90	89	105	15% of total direct cost
Total indirect costs	million €	306	304	356	
Total CAPEX	million €	906	900	1055	
Lifetime	yr	30			
Fixed O&M	million €/yr	3% of CAPEX/yr			
Variable O&M	€/GJ <sub>FT products, LHV</sub>	1.53			[Aramco 2021] 6120 US\$/GWh <sub>FT products</sub>

For an e-fuel plants located in Central Europe in 2020 and 2030 the fixed O&M amounts to 27 million € per year and the variable O&M amounts to 66 million € per year (fixed O&M in 2050: 32 million €/yr). The OPEX share of the existing refinery amounts to about 37 million € per year. As a result, the total OPEX amounts to about 130 million € per year for the FT plant fully integrated into an existing refinery (2050: 137 million €/yr).

#### 9.4.18. Fossil fuels involving CCS

For fossil fuels involving CCS natural gas is assumed as feedstock. The assumptions for the costs of natural gas, CO<sub>2</sub> emissions, and auxiliary electricity are shown in Table 17 and Table 18.

The methanol plant consists of autothermal reforming and downstream methanol synthesis and purification. This is the typical plant design applied for natural gas-to-methanol plants today. For FT kerosene and diesel partial oxidation with downstream FT synthesis is applied as typical for GTL plants.

For NH<sub>3</sub> syntheses the same natural gas via steam reforming plant is used as for the supply of H<sub>2</sub> as final fuel.

**Table 161:** H<sub>2</sub>, Methanol, and FTK/FTD from natural gas involving CCS

	Unit	H <sub>2</sub>	Methanol	FTK/FTD
Capacity	Nm <sup>3</sup> /h	100,000		
	MW <sub>LHV</sub>	300	1153	645
	t/h		208	
Natural gas consumption	MJ <sub>LHV</sub> /MJ <sub>LHV</sub>	1.446	1.641	1.789
Electricity consumption	MJ <sub>LHV</sub> /MJ <sub>LHV</sub>	-0.0014*	0.0315	0.0115
Water consumption	kg/MJ <sub>LHV</sub>	0.0372		
CO <sub>2</sub> capture rate		90%	90%	89%
CO <sub>2</sub> emissions at plant site	g/MJ <sub>LHV</sub>	8.2	2.5	3.3
CO <sub>2</sub> bound in the final fuel	g/MJ <sub>LHV</sub>	0	68.9	73.6/73.2
CAPEX	million €	398	386	614
Lifetime	yr	25	25	25
Equivalent full load period	h/yr	8000	8000	8000
OPEX				
Maintenance	million €/yr	4.6		
Labour costs	million €/yr	2.6		
Admin/general overhead	million €/yr	1.3		
Insurance	million €/yr	3.1		
Chemicals, catalysts, adsorbents	million €/yr	0.4		
OPEX total	million €/yr	12.0	11.6	20.9
References		AFW 2017	Collodi et al. 2016	IEA 2000

\* (-): credit for excess electricity

#### 9.4.19. Nuclear electricity

The techno-economic data for nuclear power are based on the so-called ‘European Pressurized Reactor’ (EPR) because all nuclear reactors which are under construction or recently started commercial operation in Europe are EPR (Flamanville in France, Hinkley Point in the United Kingdom, Olkiluoto in Finland).

The EPR is a third-generation concept for a pressurized water reactor. It has been developed by Areva, Électricité de France, and Siemens. Table 162 shows the techno-economic data for a nuclear power station based on the European Pressurized Reactor (EPR). No distinct decrease of CAPEX for newly built nuclear power plants has been detected in the last decades [Lovering et al. 2016]. For all time horizons the same CAPEX has been assumed for nuclear power.

**Table 162:** New nuclear power station

	Unit	Value	References
Capacity	MW <sub>e</sub>	1650	Areva 2014
CAPEX	billion €	10.9	WNN 2018
	€/kWe	6606	
Equivalent full load period	h/yr	8059	Areva 2014
Electricity generation	TWh/yr	13.3	
Lifetime	yr	60	Areva 2014
Costs of capital	million €/yr	880.7	
Burn-up rate	MWd/t <sub>UO<sub>2</sub></sub>	45,000	
	kWh/kg <sub>UO<sub>2</sub></sub>	1,080,000	
Efficiency		37%	Areva 2014
Costs of nuclear fuel	€/kg <sub>UO<sub>2</sub></sub>	1211	WNA 2018
	€/kWh <sub>e</sub>	0.00303	
	million €/yr	40.3	
Financial charges of the inventory	million €/yr	14.9	[LBST & Hincio 2019] based on [CourDeComptes 2012]
Nuclear waste disposal	million €/yr	31.3	
Last core	million €/yr	2.5	
Labor	million €/yr	56.8	
Pension reform & LT employee benefits	million €/yr	14.4	
Agent rate	million €/yr	3.2	
Overhead, central and support services	million €/yr	24.3	
Maintenance	million €/yr	102.0	
External consumption s (spare parts)	million €/yr	58.3	
Other costs and revenues	million €/yr	1.7	
Decommissioning	million €/yr	16.7	WNA 2018
Total costs	million €/yr	1247.0	
	€/kWh <sub>e</sub>	0.094	

In [IEA 2021] the levelized costs of nuclear electricity in the EU are indicated with 150 US\$ per MWh (134 € per MWh) in 2020, 120 US\$ per MWh (107 € per MWh) in 2030, and 115 US\$ per MWh (102 € per MWh) in 2050. [IEA 2021] indicated a decrease of CAPEX over time although the levelized costs of electricity are higher than assumed in this study for 2050 (94 €/MWh). The CAPEX is indicated with 6600 US\$/kWe in 2020, 5100 US\$ per kW in 2030, and 4500 US\$/kWe in 2050.

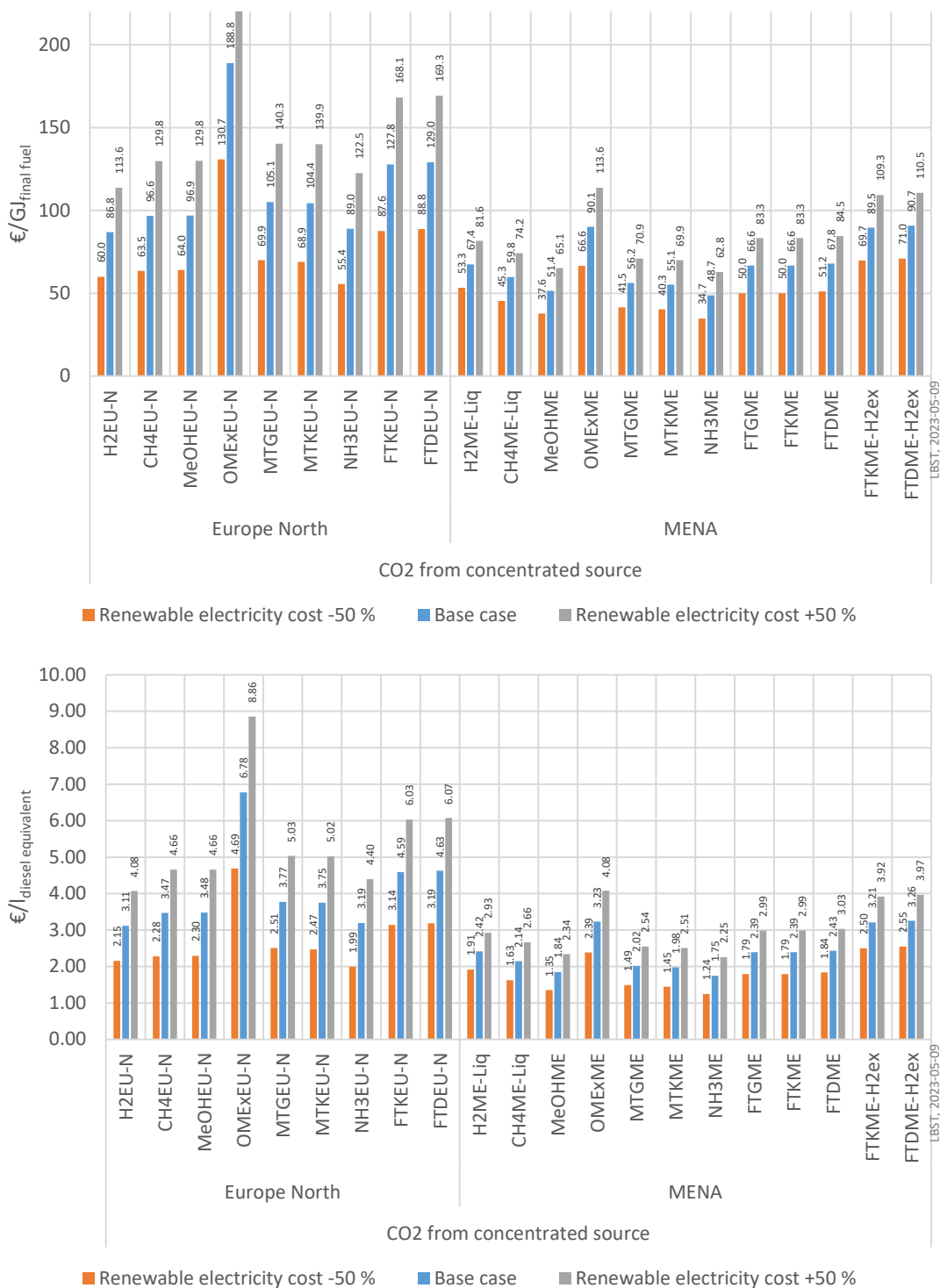
In [IEA 2020] the costs of nuclear electricity from existing nuclear power plants including CAPEX for long-term operation (LTO) with a lifetime extension of 20 years and a discount rate of 7% are indicated with 28.6 to 37.9 US\$ per MWh (0.025 to 0.034 €/kWh) depending on CAPEX and capacity factor [IEA 2020b].



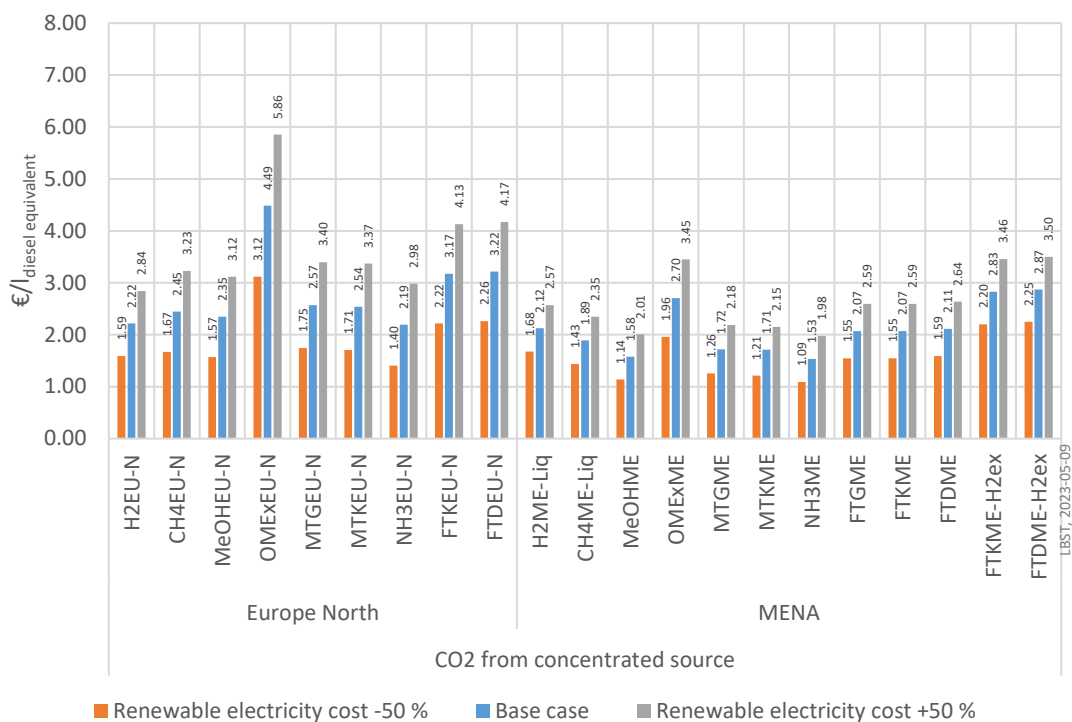
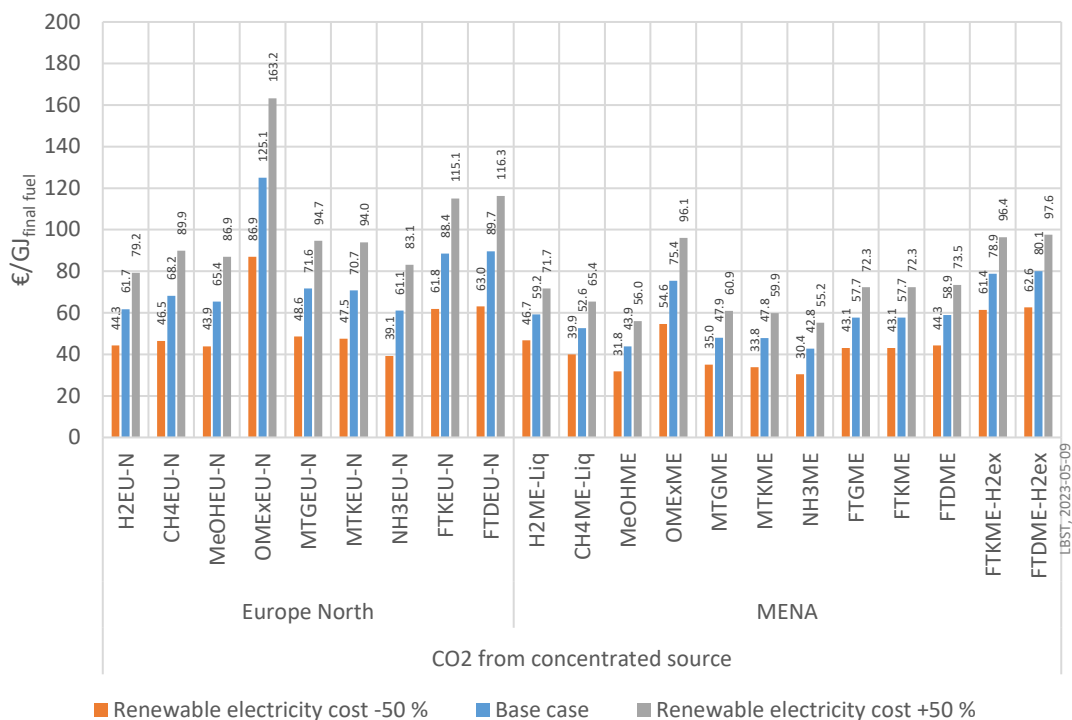
## 9.5. SENSITIVITY ANALYSES

### 9.5.1. Sensitivity to different renewable electricity costs

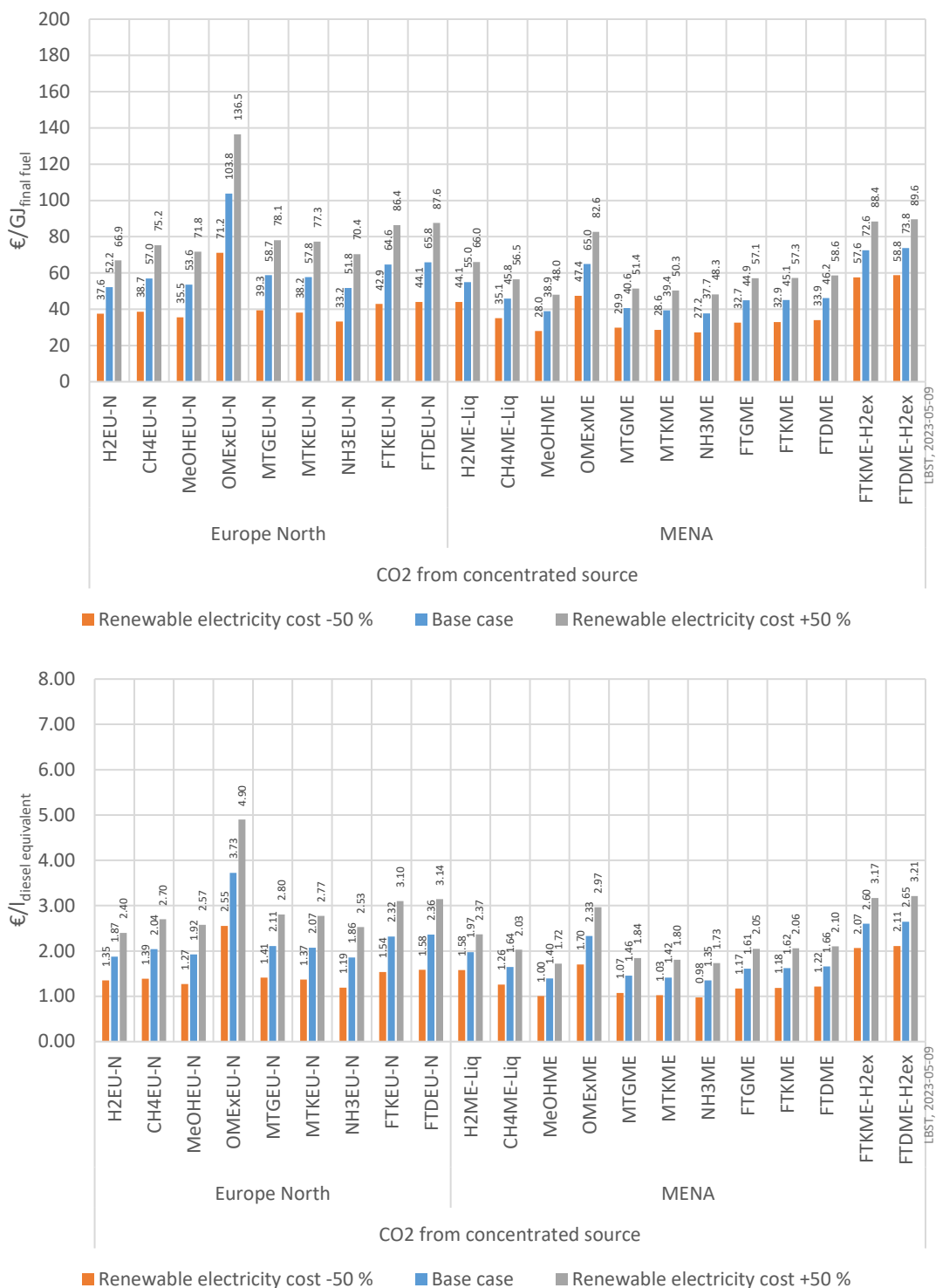
**Figure 182:** Sensitivity to different renewable electricity costs by region for 2020 (CO<sub>2</sub> from concentrated source)



**Figure 183:** Sensitivity to different renewable electricity costs by region for 2030 (CO<sub>2</sub> from concentrated source)

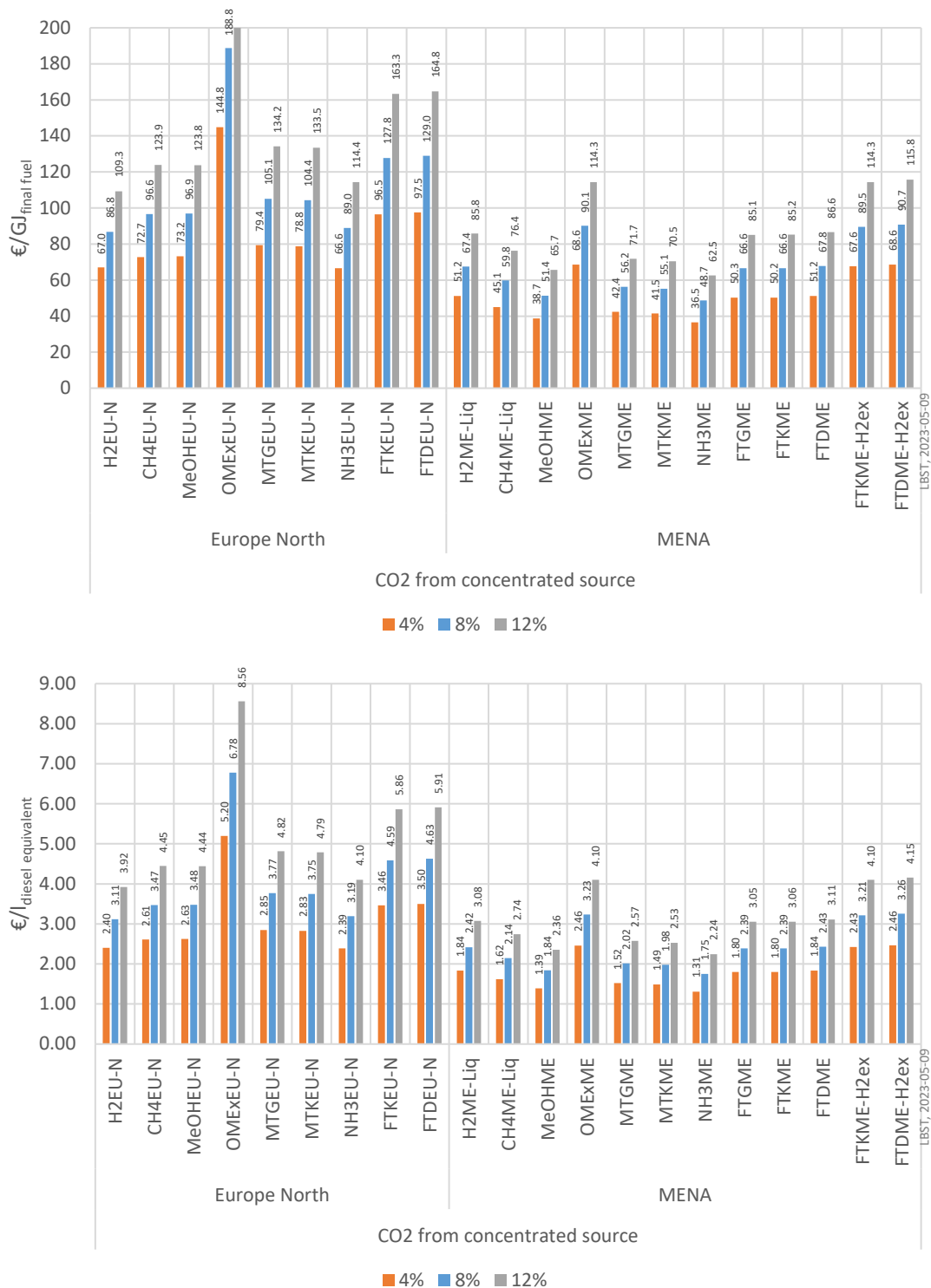


**Figure 184:** Sensitivity by different renewable electricity costs by region for 2050 (CO<sub>2</sub> from concentrated source)

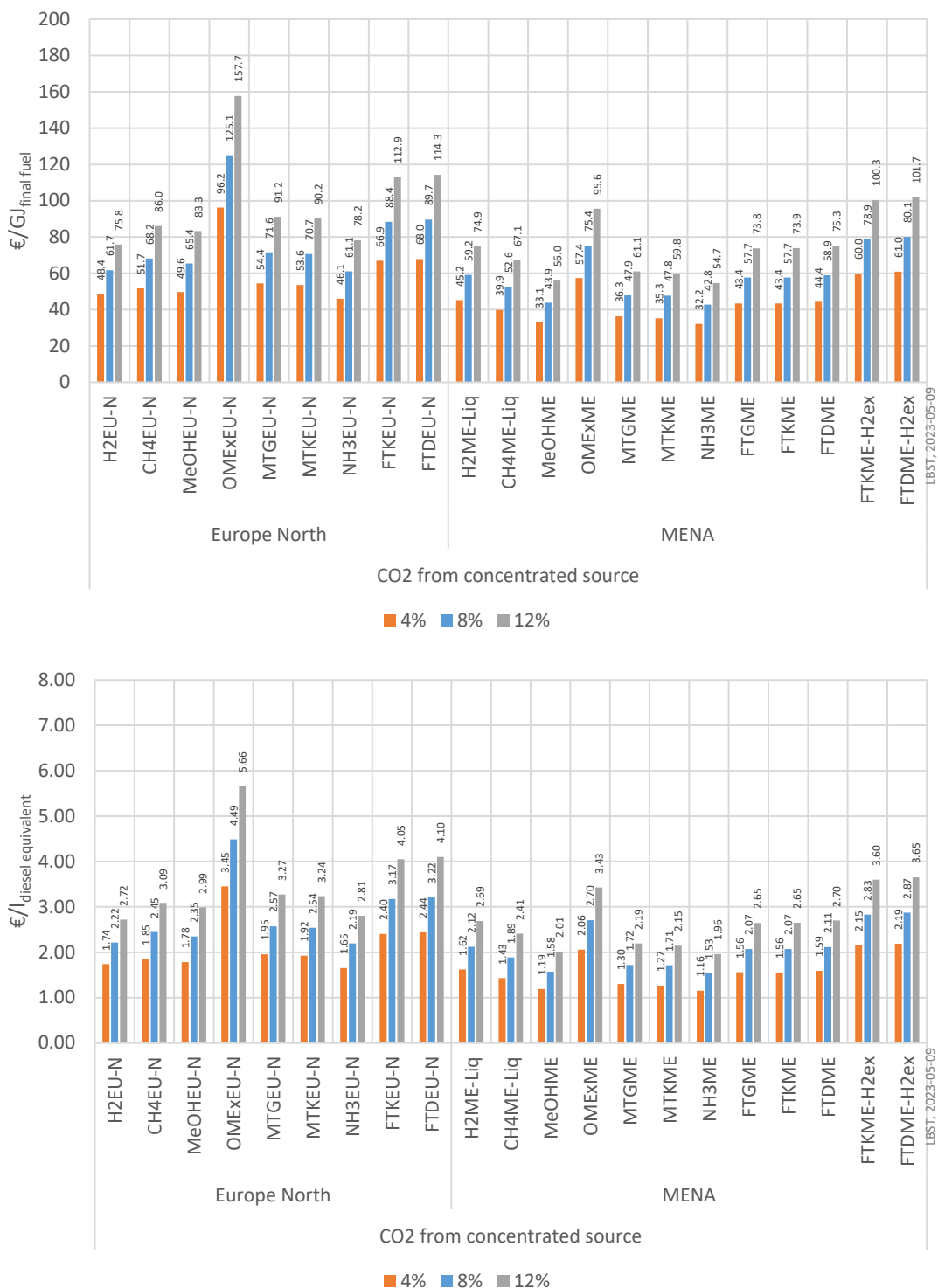


### 9.5.2. Sensitivity to different discount rates

**Figure 185:** Sensitivity to different discount rates by region for 2020 (CO<sub>2</sub> from concentrated source)



**Figure 186:** Sensitivity to different discount rates by region for 2030 (CO<sub>2</sub> from concentrated source)

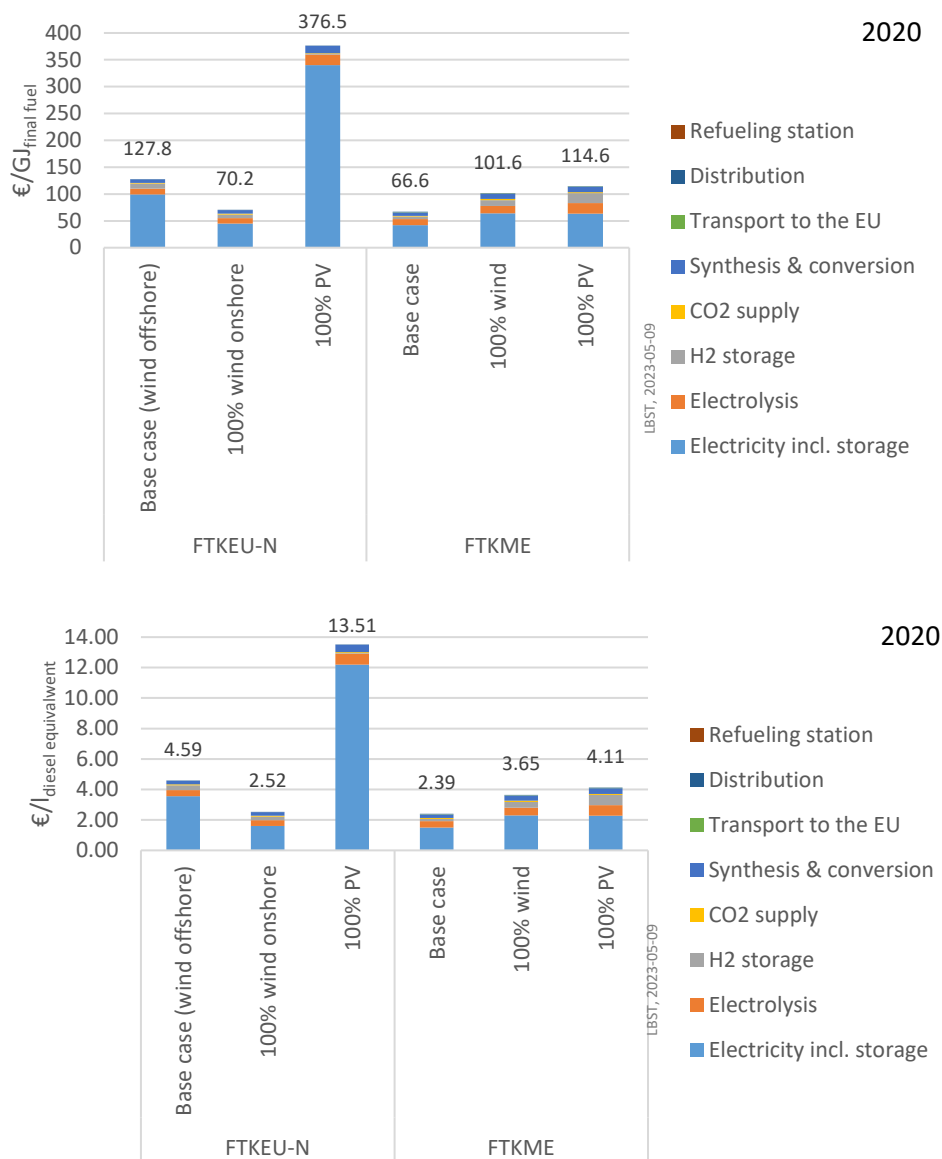


### 9.5.3. Sensitivity to electricity source

**Table 163:** E-fuel costs in 2020 depending on electricity source

	FTKEU-N			FTKME		
	Base case (wind offshore)	100% wind (onshore)	100% PV	Base case (PV/wind hybrid)	100% wind	100% PV
<b>€/GJ<sub>final fuel</sub></b>						
Electricity costs	99.1	44.7	339.9	41.9	64.2	63.6
Electrolysis	10.9	10.5	19.7	11.5	13.6	19.3
H <sub>2</sub> storage	9.2	6.7	1.3	4.4	10.7	18.5
CO <sub>2</sub> supply	1.7	1.5	1.6	1.3	2.2	2.0
Synthesis & upgrading	6.5	6.4	13.6	6.5	9.9	10.1
Transport to the EU	0.0	0.0	0.0	0.6	0.6	0.6
Distribution	0.4	0.4	0.4	0.4	0.4	0.4
Refuelling station	0.0	0.0	0.0	0.0	0.0	0.0
<b>Total</b>	<b>127.8</b>	<b>70.2</b>	<b>376.5</b>	<b>66.6</b>	<b>101.6</b>	<b>114.6</b>
<b>€/l<sub>diesel equivalent</sub> (based on conventional diesel EN 590)</b>						
Electricity costs	3.56	1.60	12.20	1.50	2.30	2.28
Electrolysis	0.39	0.38	0.71	0.41	0.49	0.69
H <sub>2</sub> storage	0.33	0.24	0.04	0.16	0.38	0.67
CO <sub>2</sub> supply	0.06	0.05	0.06	0.05	0.08	0.07
Synthesis & upgrading	0.23	0.23	0.49	0.23	0.36	0.36
Transport to the EU	0.00	0.00	0.00	0.02	0.02	0.02
Distribution	0.02	0.02	0.02	0.02	0.02	0.02
Refuelling station	0.00	0.00	0.00	0.00	0.00	0.00
<b>Total</b>	<b>4.59</b>	<b>2.52</b>	<b>13.51</b>	<b>2.39</b>	<b>3.65</b>	<b>4.11</b>

**Figure 187:** E-fuel costs in 2020 depending on electricity source for FT Kerosene produced in North Europe and MENA

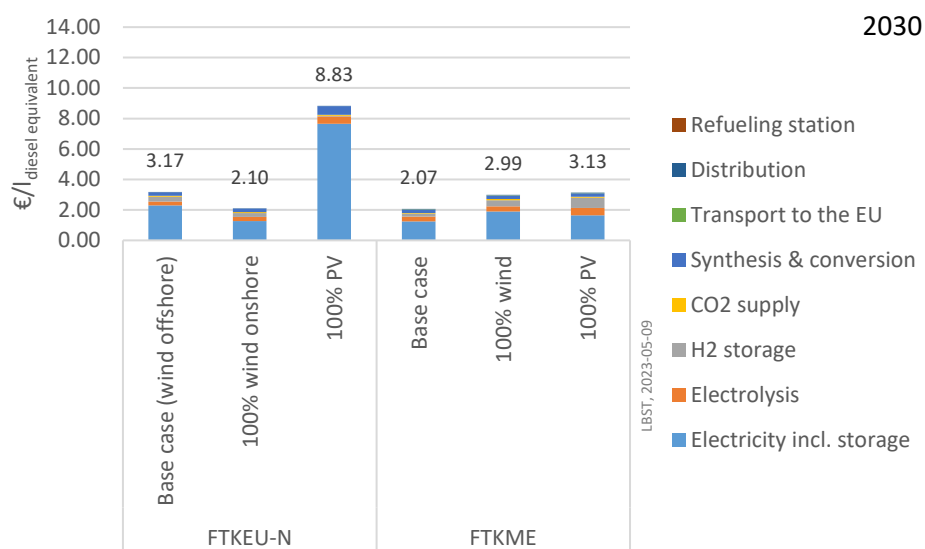
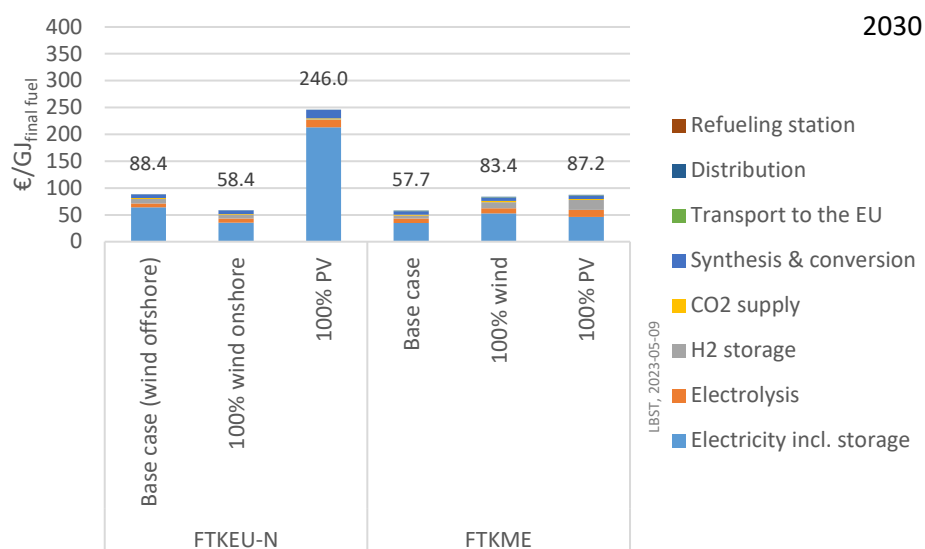


**Table 164:** E-fuel costs in 2030 depending on electricity source

	FTKEU-N			FTKME		
	Base case (wind offshore)	100% wind (onshore)	100% PV	Base case (PV/wind hybrid)	100% wind	100% PV
<b>€/GJ<sub>final fuel</sub></b>						
Electricity costs	63.8	35.6	213.3	34.7	52.7	46.1
Electrolysis	7.5	7.4	13.4	8.6	9.6	13.2
H <sub>2</sub> storage	8.5	7.1	1.3	5.4	11.2	18.5
CO <sub>2</sub> supply	1.7	1.5	1.6	1.4	2.3	1.8
Synthesis & upgrading	6.5	6.4	15.9	6.5	6.5	6.5
Transport to the EU	0.0	0.0	0.0	0.6	0.6	0.6
Distribution	0.5	0.5	0.5	0.5	0.5	0.5
Refuelling station	0.0	0.0	0.0	0.0	0.0	0.0
<b>Total</b>	<b>88.4</b>	<b>58.4</b>	<b>246.0</b>	<b>57.7</b>	<b>83.4</b>	<b>87.2</b>
<b>€/l<sub>diesel equivalent</sub> (based on conventional diesel EN 590)</b>						
Electricity costs	2.29	1.28	7.66	1.24	1.89	1.65
Electrolysis	0.27	0.26	0.48	0.31	0.34	0.47
H <sub>2</sub> storage	0.31	0.25	0.05	0.19	0.40	0.66
CO <sub>2</sub> supply	0.06	0.05	0.06	0.05	0.08	0.06
Synthesis & upgrading	0.23	0.23	0.57	0.23	0.23	0.23
Transport to the EU	0.00	0.00	0.00	0.02	0.02	0.02
Distribution	0.02	0.02	0.02	0.02	0.02	0.02
Refuelling station	0.00	0.00	0.00	0.00	0.00	0.00
<b>Total</b>	<b>3.17</b>	<b>2.10</b>	<b>8.83</b>	<b>2.07</b>	<b>2.99</b>	<b>3.13</b>

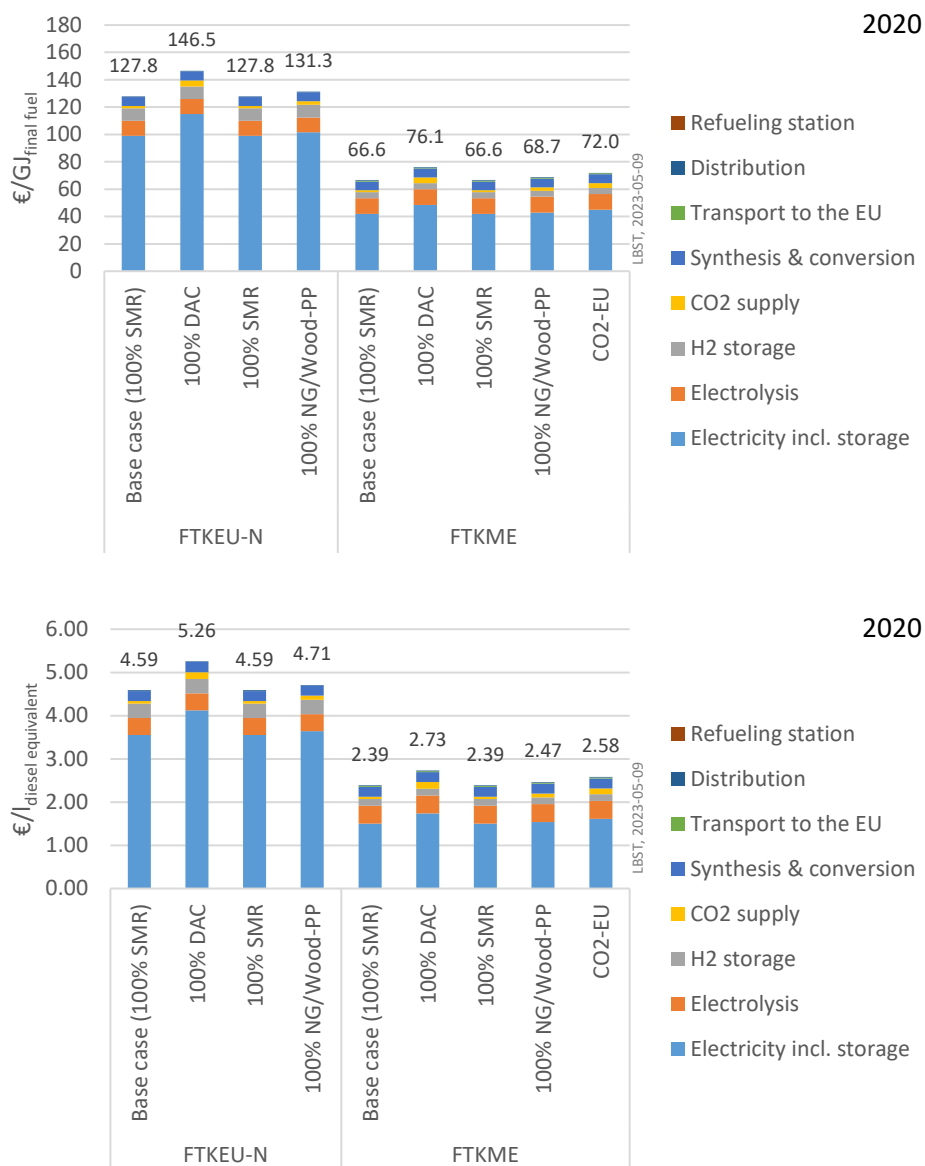


**Figure 188:** E-fuel costs in 2030 depending on electricity source for FT Kerosene produced in North Europe and MENA

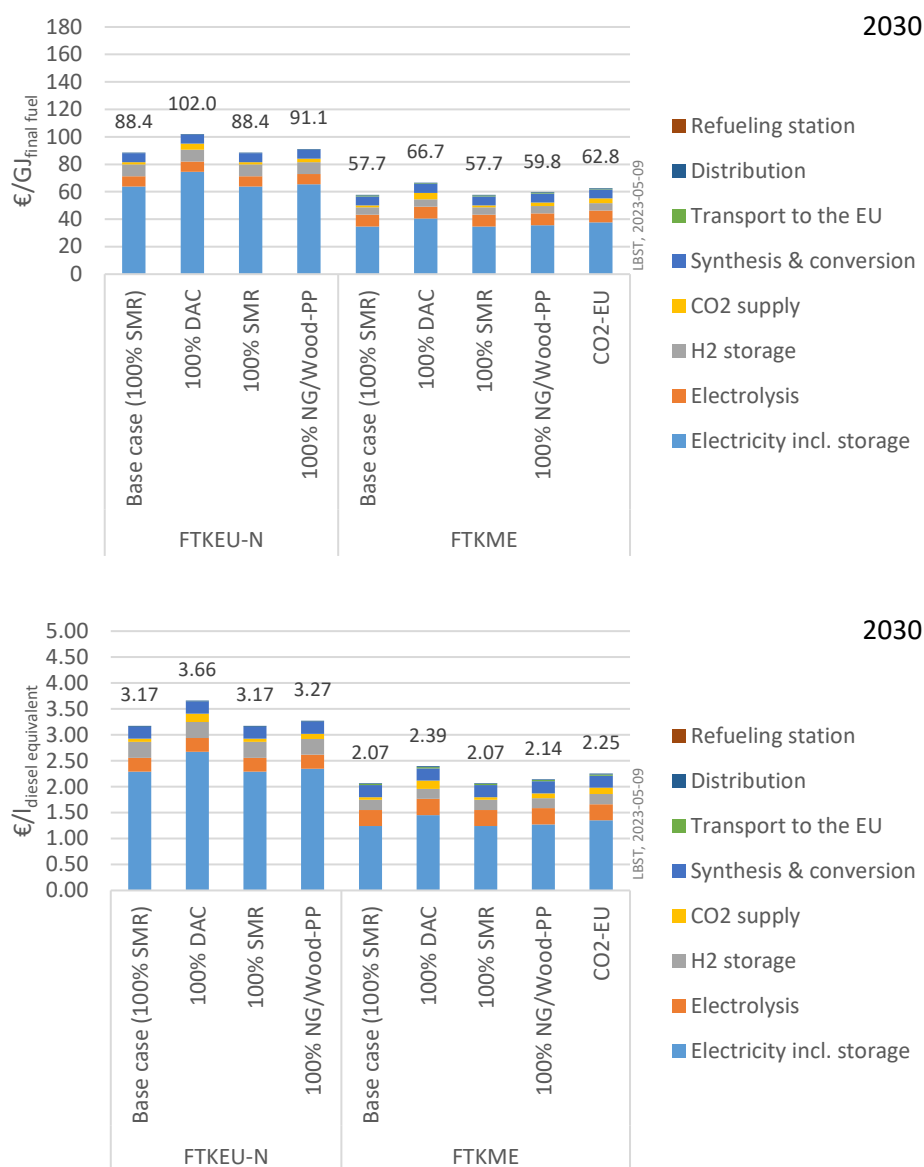


#### 9.5.4. Sensitivity to CO<sub>2</sub> source

**Figure 189:** E-fuel costs in 2020 depending on CO<sub>2</sub> source for FT kerosene produced in North Europe and MENA

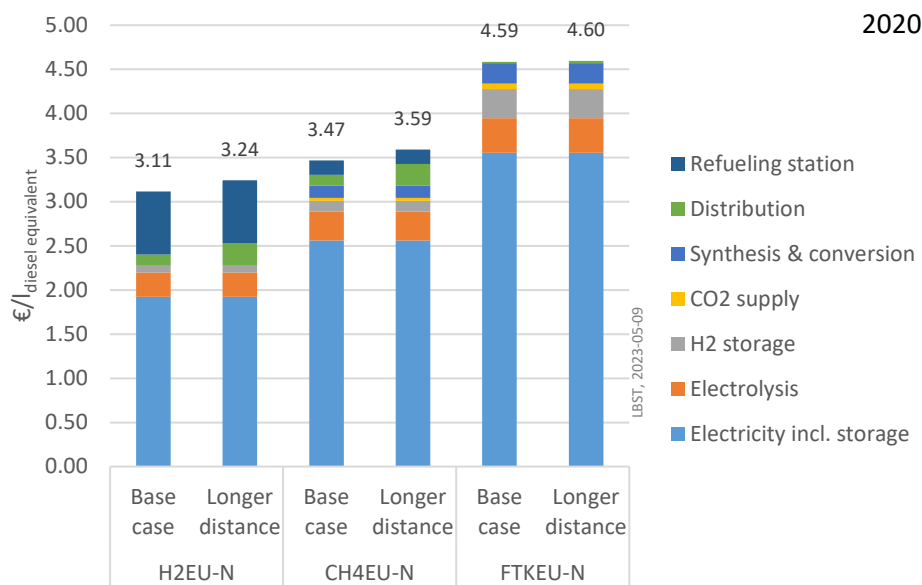
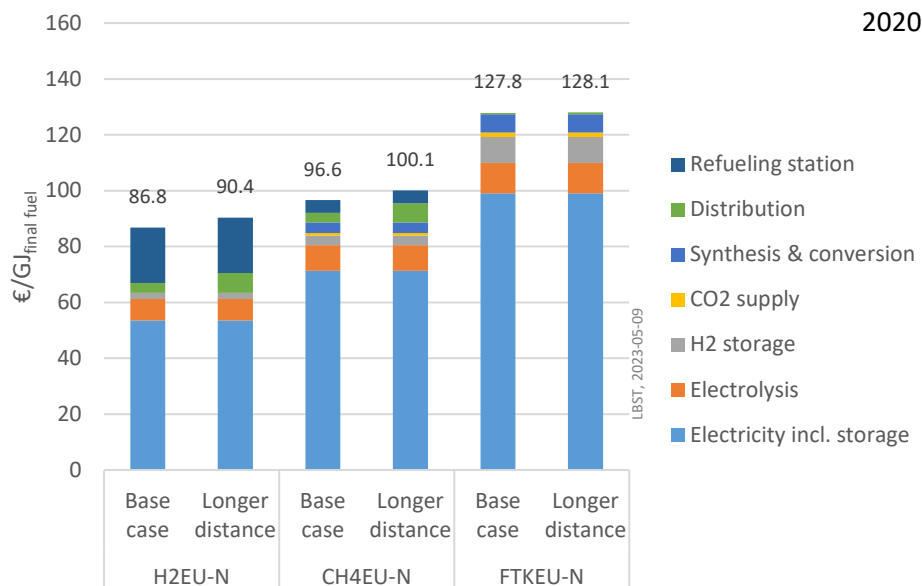


**Figure 190:** E-fuel costs in 2030 depending on CO<sub>2</sub> source for FT kerosene produced in North Europe and MENA

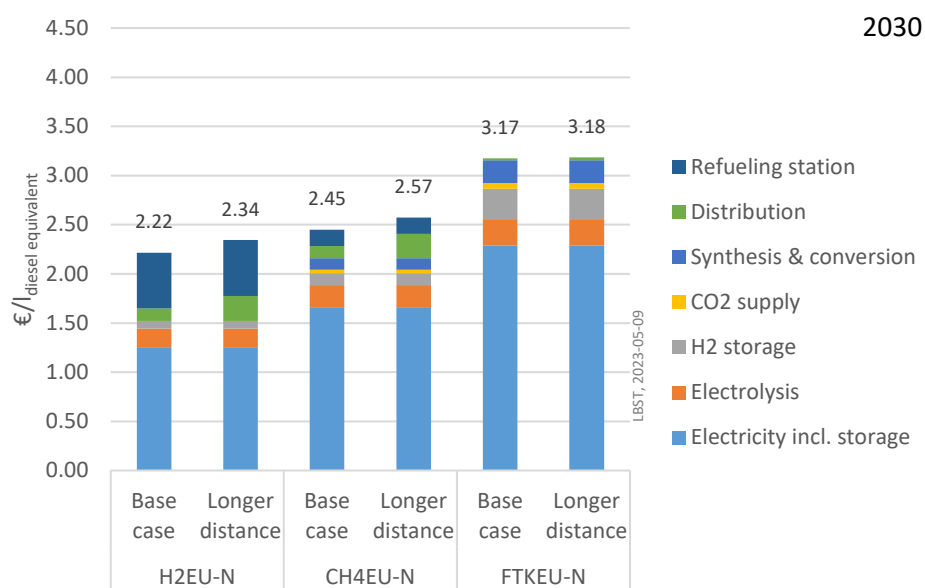
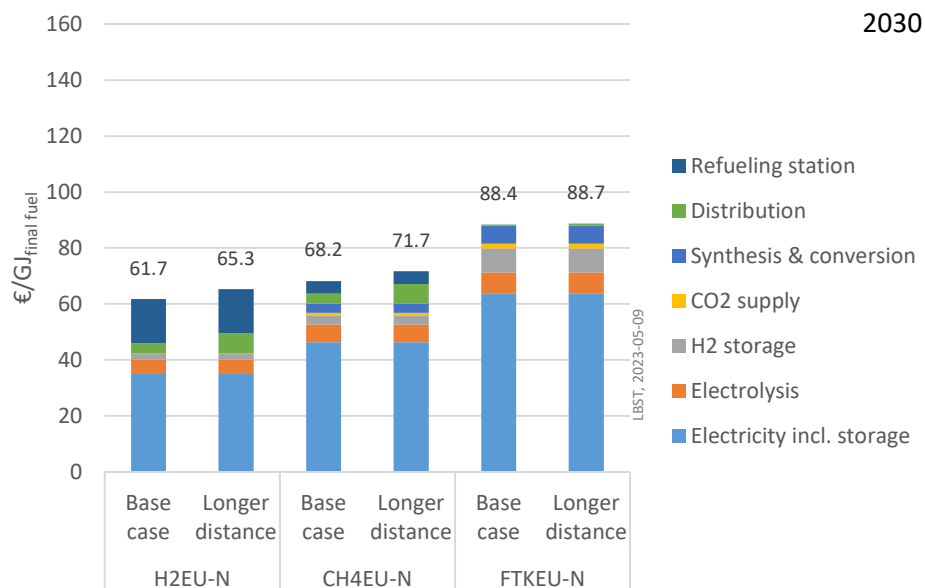


### 9.5.5. Variation of transportation inside Europe

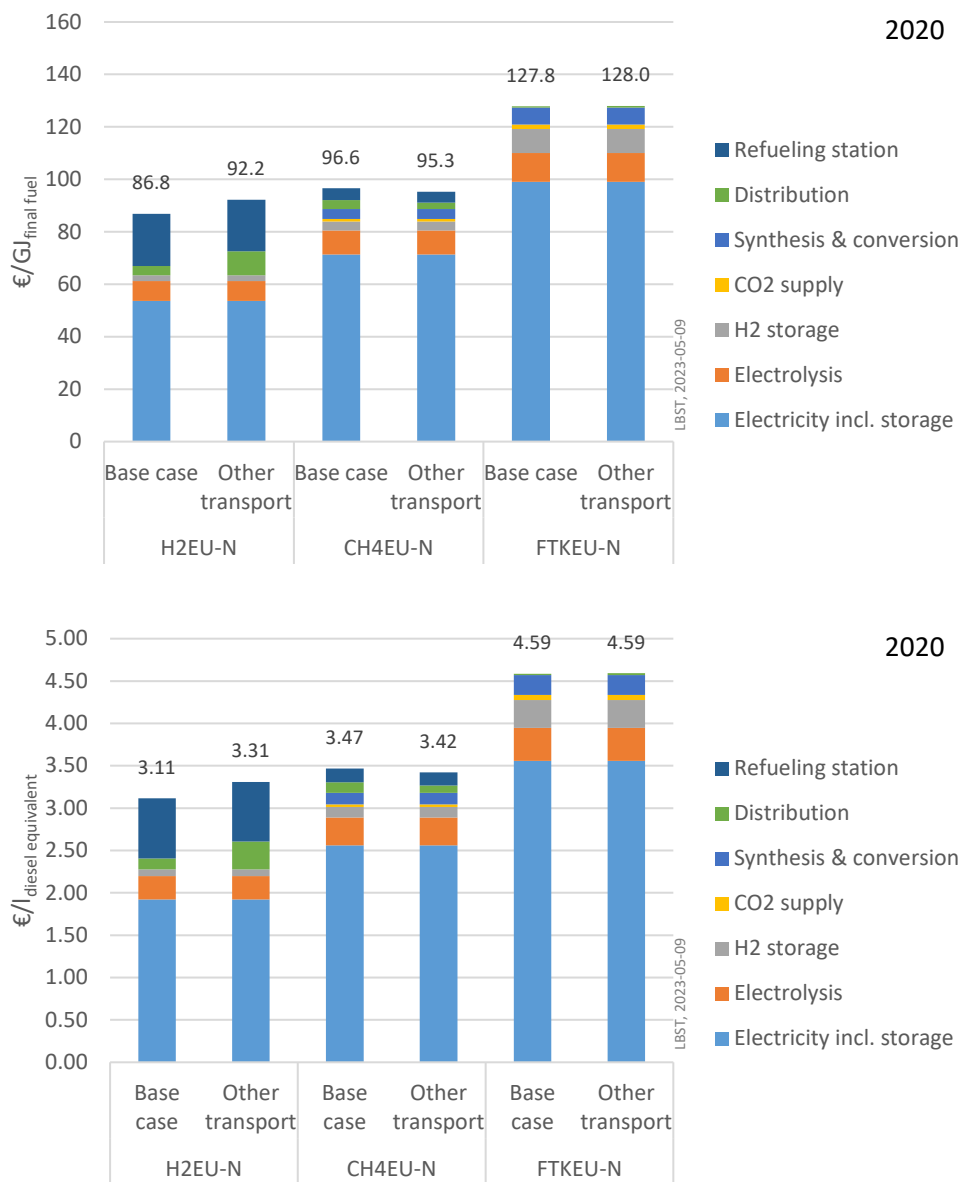
**Figure 191:** Influence of longer transport distance inside Europe on the e-fuel costs in 2020



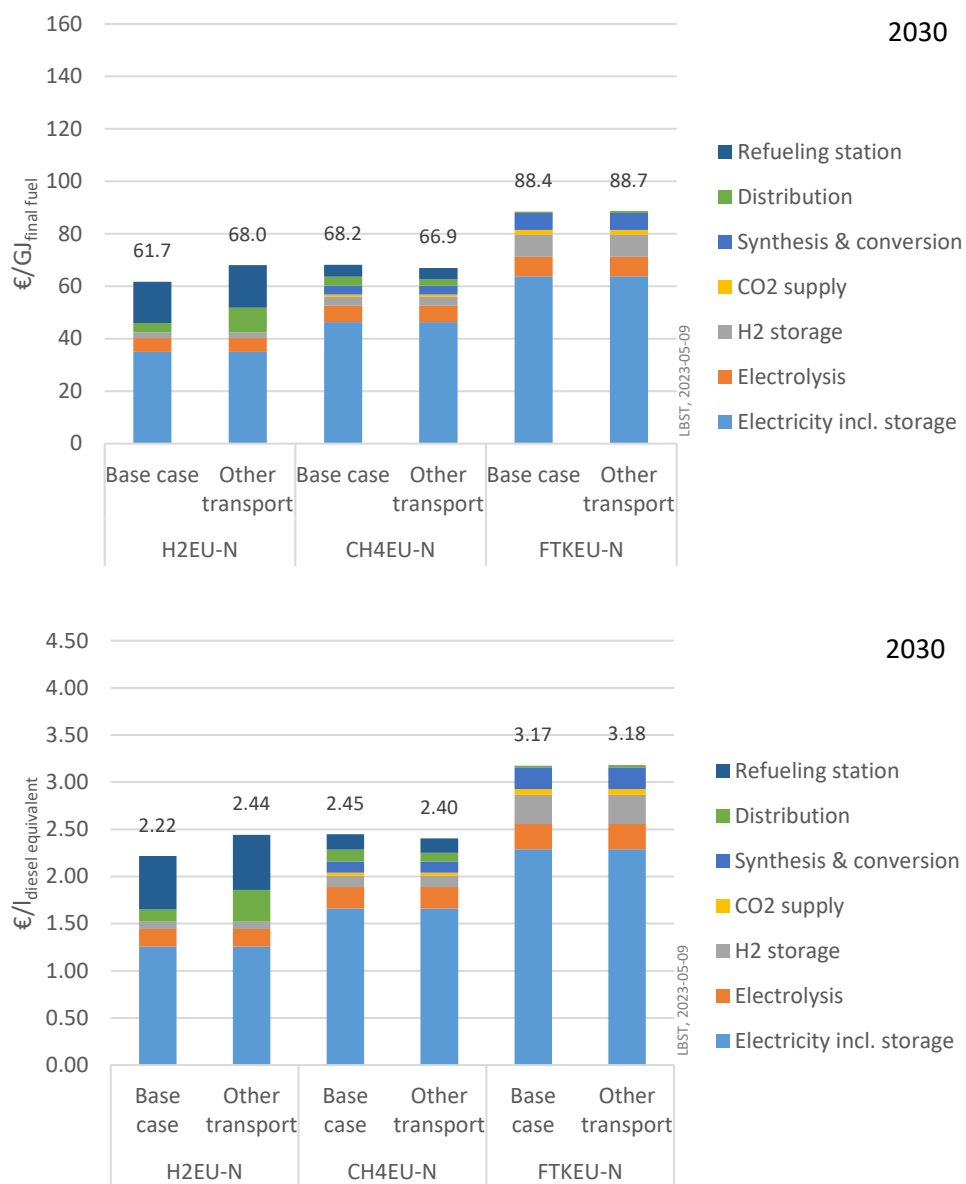
**Figure 192:** Influence of longer transport distance inside Europe on the fuel costs in 2030



**Figure 193:** Influence of other transport types inside Europe on the e-fuel costs in 2020

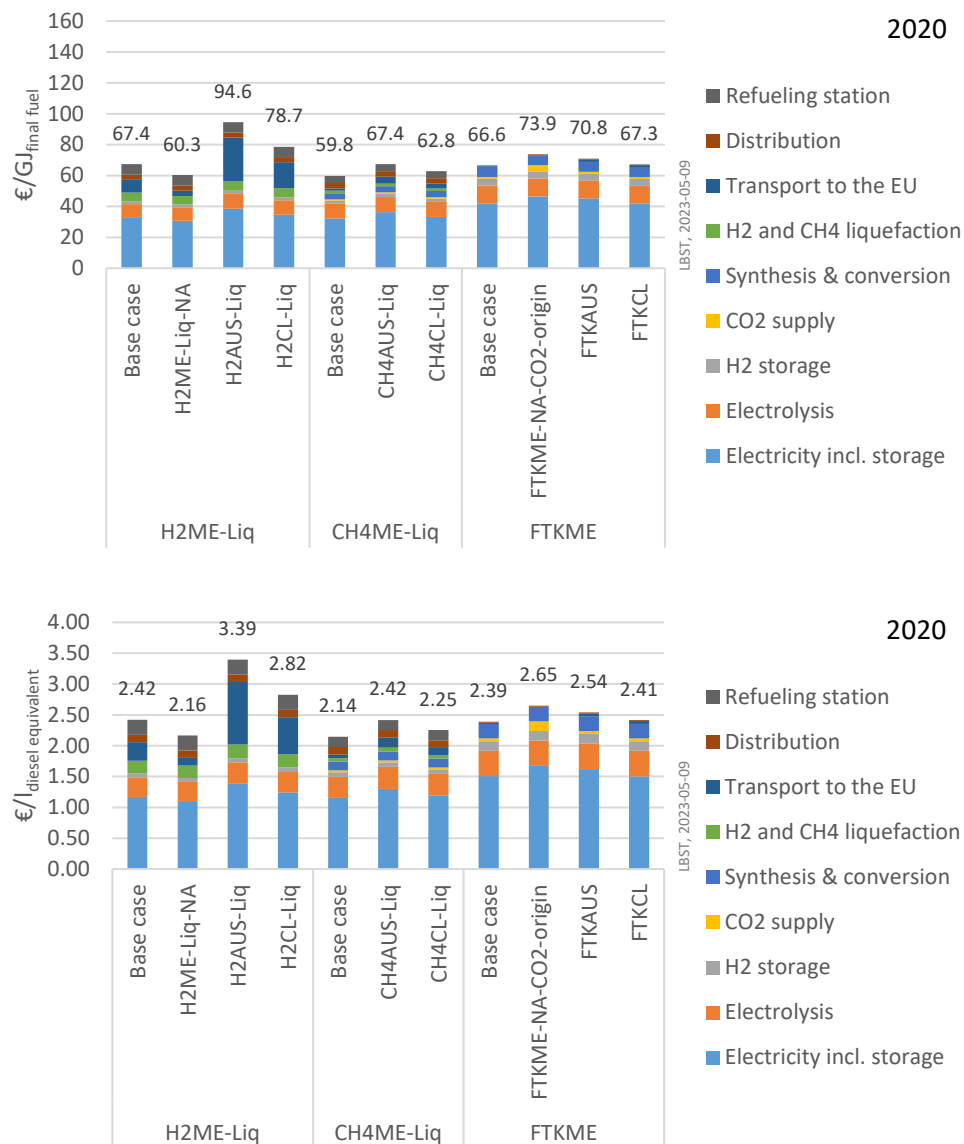


**Figure 194:** Influence of other transport types inside Europe on the e-fuel costs in 2030



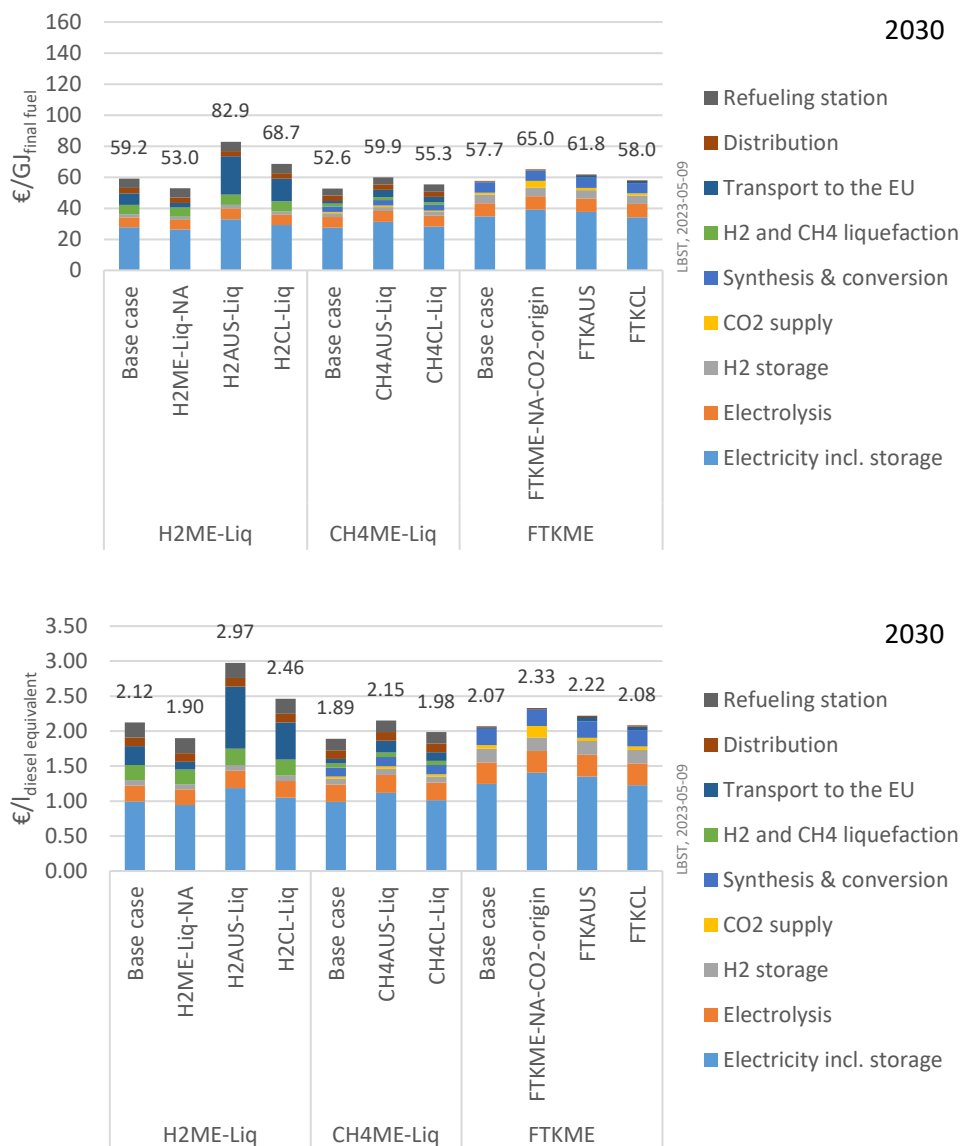
### 9.5.6. Long-haul from other other potential sweet spots worldwide

**Figure 195:** Influence of long-haul marine transport from potential other sweet spots worldwide on the e-fuel cost in 2020



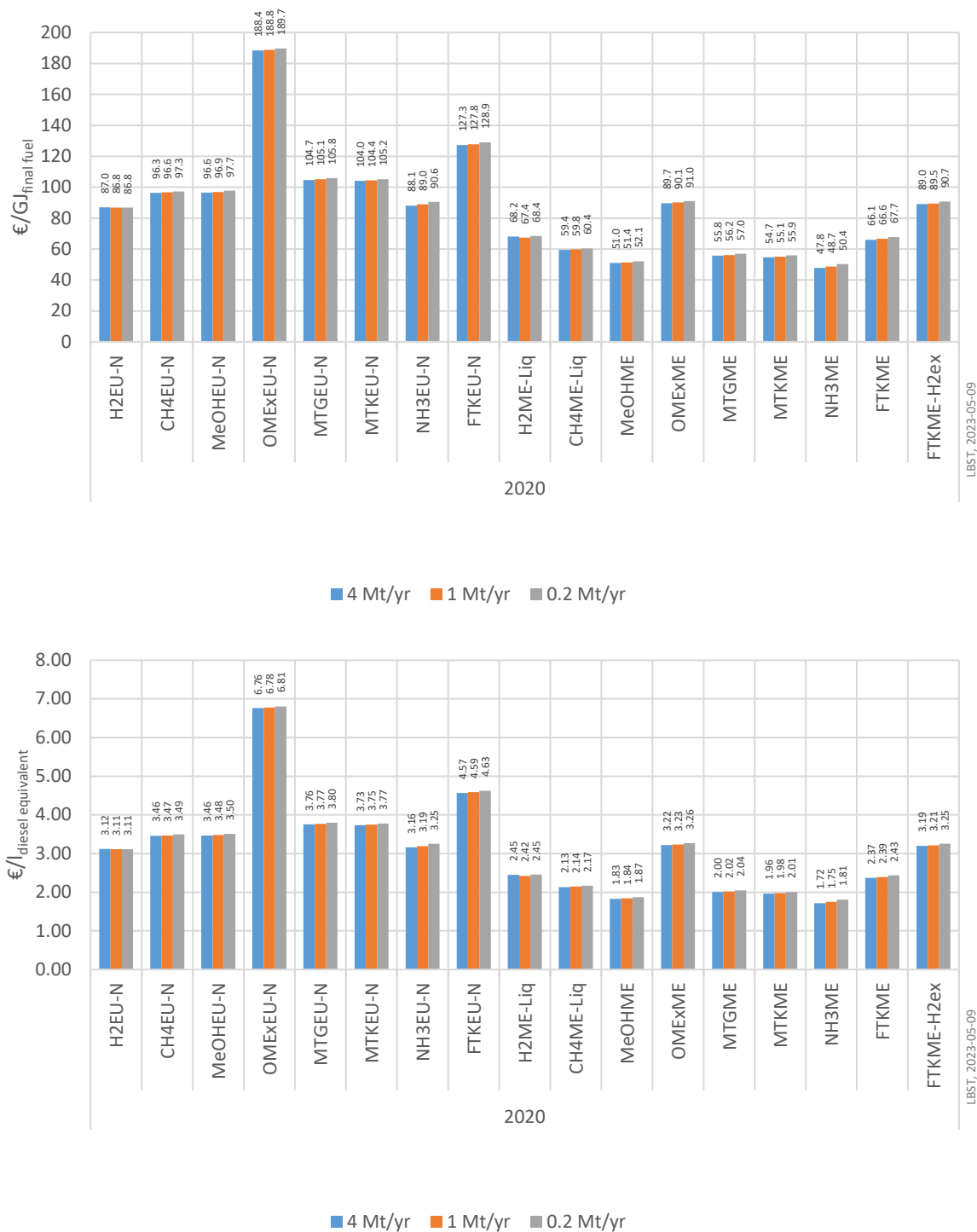


**Figure 196:** Influence of long-haul marine transport from potential other sweet spots worldwide on the fuel cost in 2030



### 9.5.7. Larger/smaller e-fuels plant size

Figure 197: Influence of larger/smaller e-fuels plant capacity in 2020



## 9.6. RESULTS FROM FOSSIL (WITH CCS) VERSUS E-FUEL PRODUCTION COSTS

The costs of e-fuels using renewable electricity are compared with fuels derived from natural gas with CCS. The carbon capture rate at the fuel production plant site amounts to about 90% except in case of the supply of natural gas as final fuel where all carbon from the natural gas is bound in the final fuel. In the case of hydrogen as final fuel, 90% of the carbon bound in the natural gas is captured and 10% is released at the steam reforming plant site.

In case of carbon containing synthetic fuels, a high fraction of the carbon bound in the natural gas is transferred into the final fuel and will be emitted during the use of the fuel (e.g. combustion in a vehicle).

For natural gas-based methanol, an autothermal reforming (ATR) process is used for synthesis gas production. Downstream the ATR a conventional methanol synthesis process is applied to generate methanol from CO and H<sub>2</sub> (in contrast to e-methanol where CO<sub>2</sub> and H<sub>2</sub> is fed into the methanol synthesis step).

For natural gas-based FT kerosene and diesel, a partial oxidation process is applied for synthesis gas production like at the GTL plant in Qatar to get the required H<sub>2</sub> to CO ratio for FT synthesis.

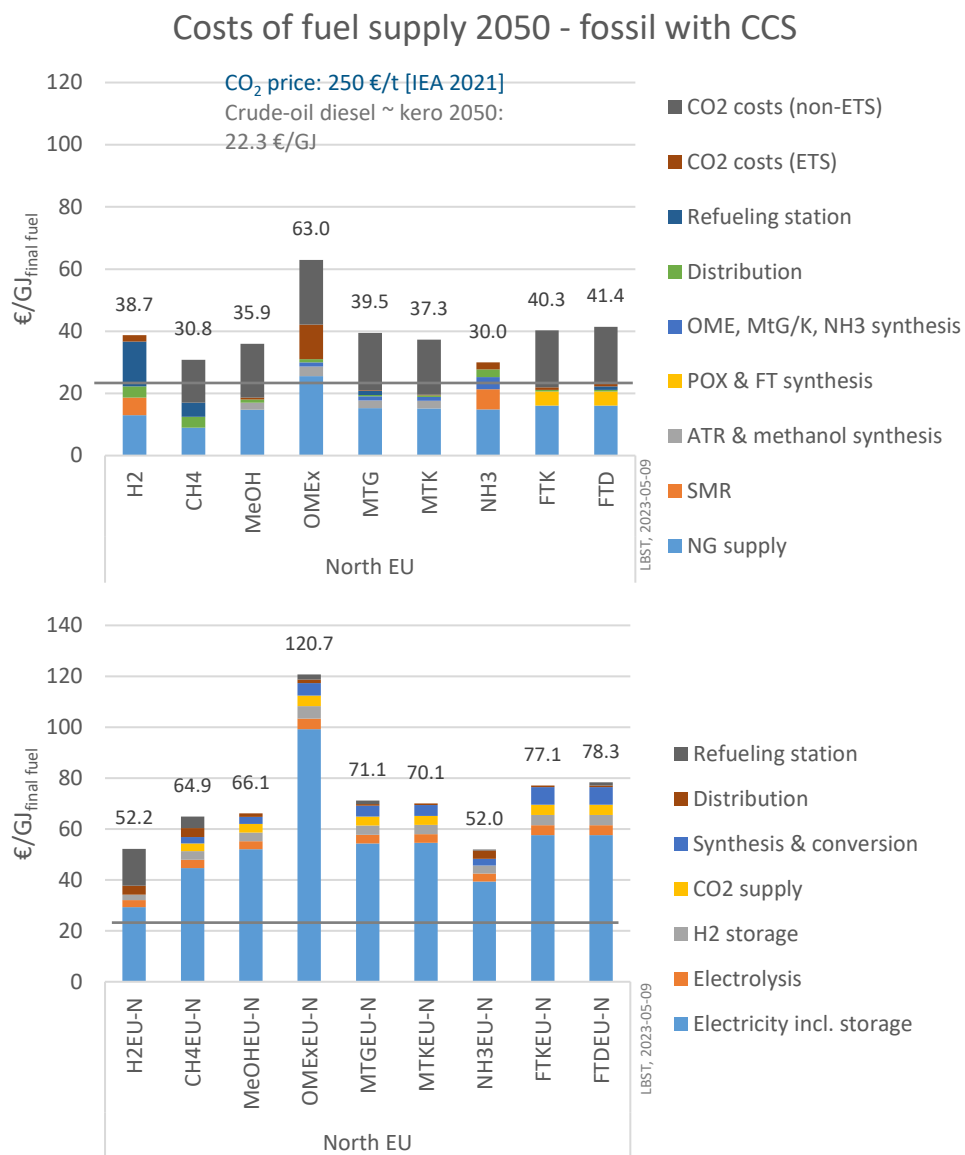
For OME synthesis, MTG process, MTK process and NH<sub>3</sub> synthesis, the same processes as for the e-fuels have been used.

The Emissions Trading System (ETS) price for CO<sub>2</sub> is applied for large industry, while non-ETS CO<sub>2</sub> prices are applied for CO<sub>2</sub> from combustion of the final fuel in the vehicle. A stronger inclusion of the transport sector into the ETS has been proposed in the European Commission's 'Fit-for-55' policy package mid 2021 [EC 2021].

To compare non-carbon containing fuels (like hydrogen) with carbon containing fuels like FT diesel, the combustion of the final fuel is taken into account for the CO<sub>2</sub> costs (Table 17 in chapter 2.1.2) besides the CO<sub>2</sub> emissions at the plant site (part which is not captured).

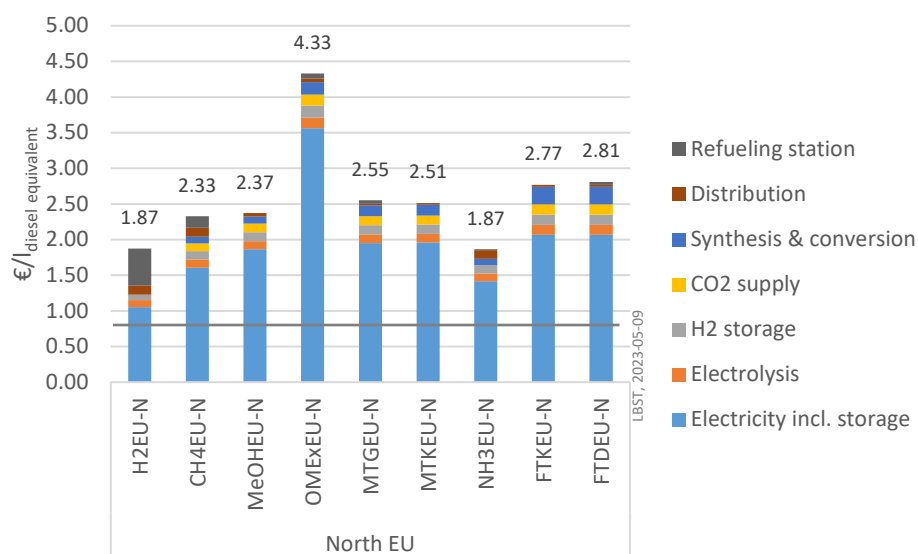
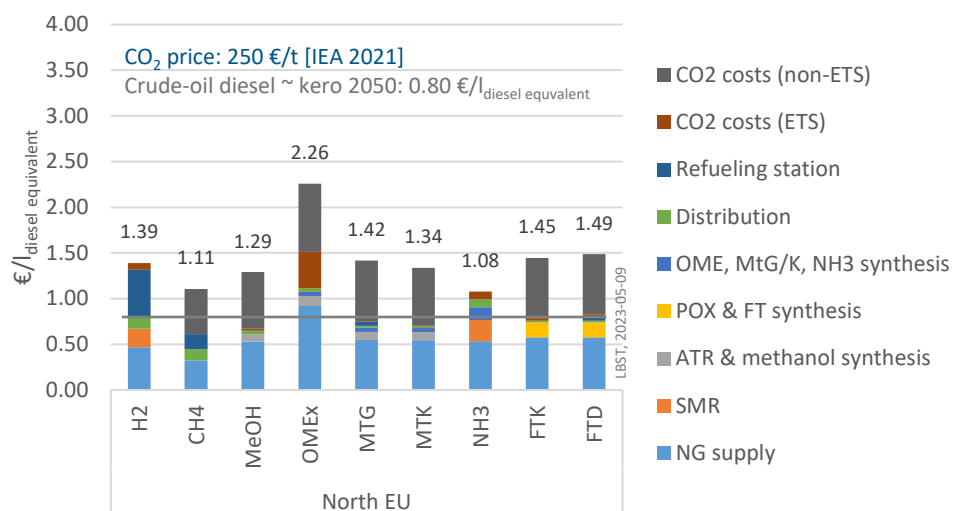
For 2050, a CO<sub>2</sub> price of 250 € per t is assumed as indicated in [IEA 2021]. As a sensitivity, a CO<sub>2</sub> price of 60 € per t is also assumed (Table 16 in chapter 2.1.2).

**Figure 198:** Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO<sub>2</sub> price: 250 €/t) - per GJ of final fuel

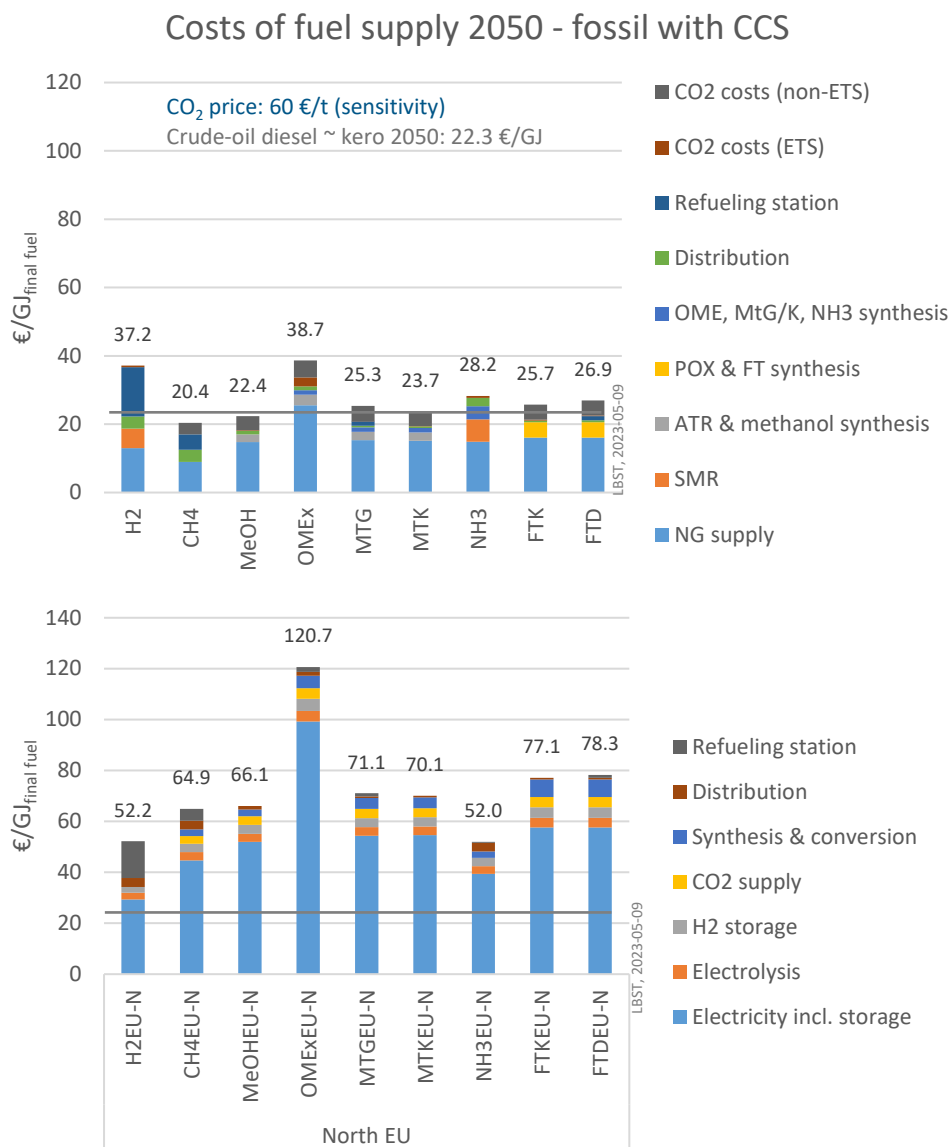


**Figure 199:** Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO<sub>2</sub> price: 250 €/t) - per l of diesel equivalent

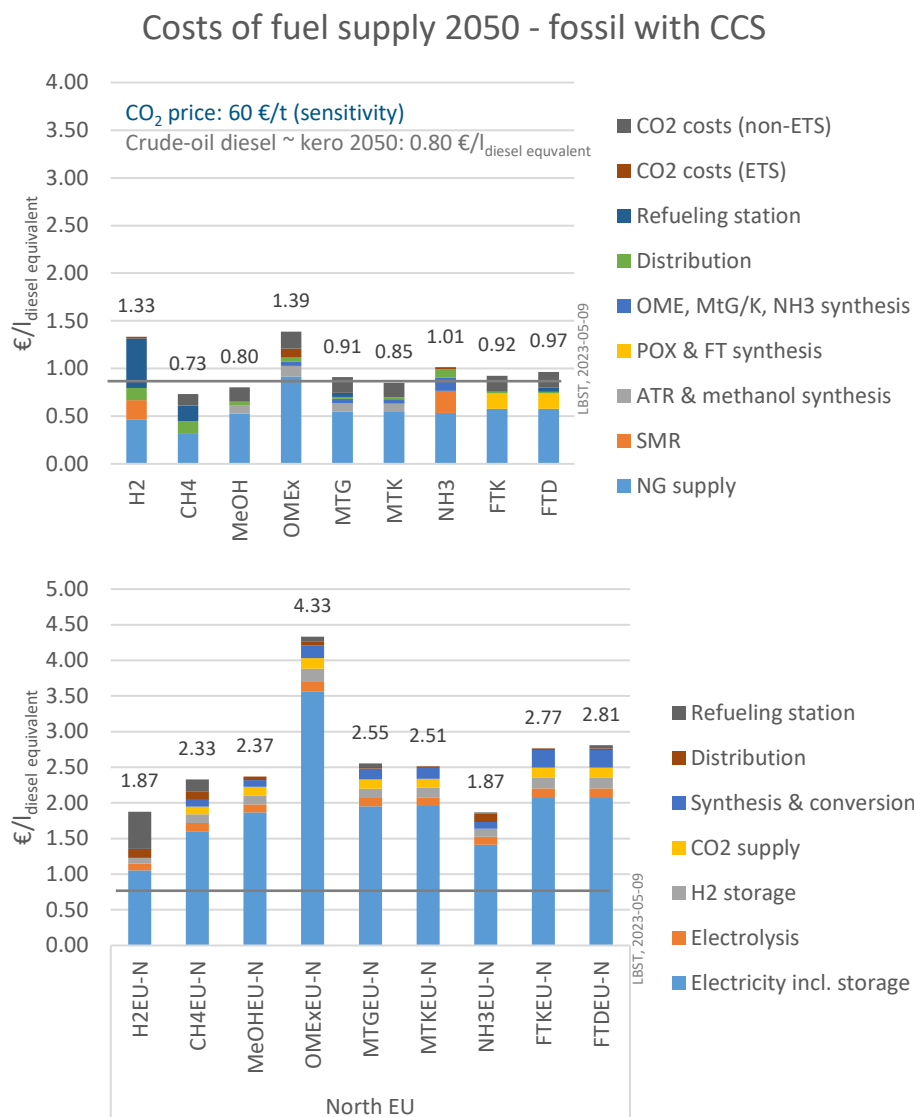
### Costs of fuel supply 2050 - fossil with CCS



**Figure 200:** Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO<sub>2</sub> price: 60 €/t) - per GJ of final fuel



**Figure 201:** Fuel costs of fossil low-carbon fuel production pathways involving CCS compared to fuel costs for e-fuel pathways in 2050 (CO<sub>2</sub> price: 60 €/t) - per l of diesel equivalent



It has to be noted that above costs refer to fuel supply (including embedded carbon), i.e. without use efficiencies. Fuel cell electric vehicles (FCEV) have a higher efficiency than vehicles with internal combustion engines (ICE), leading to lower fuel costs per km. However, the powertrain evaluation (TTW) is out of the scope of this project.

## 10. INTERMITTENCY MODEL DESCRIPTION ANNEX

The model is solved as a mixed integer linear program that minimizes the plant's net present cost (NPC) based over a defined project lifetime (e.g. 30 years by default) assuming that the operational performance of the system in each year is represented by the hourly production potential of PV and wind resources. The hourly production can use one or more years of meteorological data as input.

All assets are built in year 0 and replaced as required during the project life depending on their respective lifetimes. Partial replacement costs are considered. End-effects can be chosen from a perpetual lifetime or by using salvage costs (default) in the year following final fuel production. A simplified version of the model is provided below.

$$\min f = \sum_{y=1}^Y DF_y (TotalCapex_y + TotalFixedOpex_y + TotalVariableOpex_y)$$

Where,

$$\begin{aligned} TotalCapex_y = & (Capex_{PV_y} \times Cap_{PV}) + (Capex_{Wind_y} \times Cap_{Wind}) \\ & + (Capex_{ConvGen_y} \times Cap_{ConvGen}) + (Capex_{ESS_y} \times Cap_{ESS}) \\ & + (Capex_{DAC_y} \times Cap_{DAC}) + (Capex_{CO_2Comp_y} \times Cap_{CO_2Comp}) \\ & + (Capex_{CO_2Tank_y} \times Cap_{CO_2Tank}) + (Capex_{Heatpump_y} \times Cap_{Heatpump}) \\ & + (Capex_{H_2Production_y} \times Cap_{H_2Production}) \\ & + (Capex_{H_2Comp_y} \times Cap_{H_2Comp}) + (Capex_{H_2Tank_y} \times Cap_{H_2Tank}) \\ & + (Capex_{Synthesis_y} \times Cap_{Synthesis}) \\ & + (Capex_{Conversion_y} \times Cap_{Conversion}) + (Capex_{Boiler_y} \times Cap_{Boiler}) \end{aligned}$$

$$\begin{aligned} TotalFixedOpex_y = & (FixedOpex_{PV_y} \times Cap_{PV}) + (FixedOpex_{Wind_y} \times Cap_{Wind}) \\ & + (FixedOpex_{ConvGen_y} \times Cap_{ConvGen}) + (FixedOpex_{ESS_y} \times Cap_{ESS}) \\ & + (FixedOpex_{DAC_y} \times Cap_{DAC}) + (FixedOpex_{CO_2Comp_y} \times Cap_{CO_2Comp}) \\ & + (FixedOpex_{CO_2Tank_y} \times Cap_{CO_2Tank}) \\ & + (FixedOpex_{Heatpump_y} \times Cap_{Heatpump}) \\ & + (FixedOpex_{H_2Production_y} \times Cap_{H_2Production}) \\ & + (FixedOpex_{H_2Comp_y} \times Cap_{H_2Comp}) \\ & + (FixedOpex_{H_2Tank_y} \times Cap_{H_2Tank}) \\ & + (FixedOpex_{Synthesis_y} \times Cap_{Synthesis}) \\ & + (FixedOpex_{Conversion_y} \times Cap_{Conversion}) \\ & + (FixedOpex_{Boiler_y} \times Cap_{Boiler}) \end{aligned}$$



$$\begin{aligned}
 TotalVariableOpex_y &= (VariableOpex_{H_2Production} \times Vol_{H_2}) \\
 &+ (VariableOpex_{water_y} \times Vol_{water}) \\
 &+ (VariableOpex_{CO_2Production} \times Vol_{CO_2}) \\
 &+ (VariableOpex_{Heatump} \times Vol_{CO_2}) \\
 &+ (VariableOpex_{Synthesis_y} \times Vol_{SynFuel}) \\
 &+ (VariableOpex_{Conversion_y} \times Vol_{RefinedFuel}) \\
 &+ (VariableOpex_{Boiler} \times Vol_{RefinedFuel})
 \end{aligned}$$

$$DF_y = \frac{1}{(1+d)^y}$$

s.t

#### Generation Constraints

$$PV_t + Wind_t + ConvGen_t + ESS_{DIS_t} + Grid_{import} = Load_t + ESS_{CH_t} + Grid_{export}, \forall_t \in T$$

$$0 \leq PV_t \leq Cap_{PV} \times PV_{profile_t}, \forall_t \in T$$

$$0 \leq Wind_t \leq Cap_{Wind} \times Wind_{profile_t}, \forall_t \in T$$

$$0 \leq ConvGen_t \leq Cap_{ConvGen}, \forall_t \in T$$

$$0 \leq ESS_{DIS_t} \leq Cap_{ESS} \times I_{DIS_t}, \forall_t \in T$$

$$0 \leq ESS_{CH_t} \leq Cap_{ESS} \times I_{CH_t}, \forall_t \in T$$

$$I_{DIS_t} + I_{CH_t} \leq 1, \forall_t \in T$$

$$ESS_t = ESS_{t-1} + \eta^{CH} ESS_{CH_t} - \frac{ESS_{DIS_t}}{\eta^{DIS}}, \forall_t \in T$$

$$ESS_{Min} \leq ESS_t \leq ESS_{Max}, \forall_t \in T$$

$$Grid_{import_t} \leq ExchangeConstraint, \forall_t \in T$$

$$Grid_{export_t} \leq ExchangeConstraint, \forall_t \in T$$

#### Emission constraints

$$CO_{2import_t} = \sum_{t=1}^T Grid_{import_t} \times Grid_{CO_2}$$

$$CO_{2export_t} = \sum_{t=1}^T Grid_{export_t} \times Grid_{CO_2} \quad (\text{for net neutral constraint})$$

$$CO_{2\text{export}_t} = \sum_{t=1}^T Grid_{\text{export}_t} \times \frac{Grid_{CO_2}}{(1 - Grid_{\text{RenewableProportion}})} \quad (\text{for additive constraint})$$

$$\sum_{t=1}^T CO_{2\text{import}_t} + CO_{2H_2\text{Production}_t} + CO_{2\text{ConvGen}_t} + CO_{2\text{boiler}_t} + CO_{2\text{Synthesis}_t} - CO_{2\text{export}_t} \leq fuel_{CO_2} \times CO_{2\text{limit}}$$

### Load constraints

$$Load_t = Load_{DAC_t} + Load_{CO_2\text{PointSource}_t} + Load_{CO_2\text{Comp}_t} + Load_{\text{Heatpump}_t} + Load_{H_2\text{Production}_t} + Load_{H_2\text{Comp}_t} + Load_{\text{Synthesis}_t} + Load_{\text{Conversion}_t} + Load_{\text{Boiler}_t} + Load_{\text{Water}_t}, \forall_t \in T$$

### Synthesis production constraints

$$Synfuel_t \geq Synfuel\text{Production}_{\text{max}} \times \text{minOperation}, \forall_t \in T$$

$$Synfuel_t \leq Synfuel\text{Production}_{\text{max}}, \forall_t \in T$$

$$|\Delta Synfuel_t| \leq Synfuel\text{Production}_{\text{max}} \times \text{variation}_{\text{hourly}}, \forall_t \in T$$

$$Synfuel_{\text{Total}} = \frac{FinalFuel_{\text{Total}}}{(1 - \text{ConversionLossRefinement})}$$

$$\sum_{t=1}^T Synfuel_t = Synfuel_{\text{Total}}$$

### Feedstock constraints

#### Hydrogen

$$H_2\text{Production}_t + H_2\text{Store}_{\text{DIS}_t} = H_2\text{Demand}_t + H_2\text{Store}_{\text{CH}_t}, \forall_t \in T$$

$$H_2\text{Production}_t = Load_{H_2\text{Production}_t} / H_2\text{ProductionEff}, \forall_t \in T$$

$$H_2\text{Demand}_t = \left[ \frac{Synfuel_t}{(1 - \text{ConversionLossSynthesis})} \right] + \left[ \frac{ConvGen_t}{(1 - \text{ConvGenEfficiency})} \right], \forall_t \in T$$

$$H_2\text{Store}_{\text{CH}_t} = Load_{H_2\text{Comp}_t} / \text{CompressorEff}, \forall_t \in T$$

$$0 \leq H_2\text{Store}_{\text{DIS}_t} \leq Cap_{H_2\text{Store}} \times I_{\text{DIS}_t}, \forall_t \in T$$

$$0 \leq H_2\text{Store}_{\text{CH}_t} \leq Cap_{H_2\text{Store}} \times I_{\text{CH}_t}, \forall_t \in T$$

$$I_{\text{DIS}_t} + I_{\text{CH}_t} \leq 1, \forall_t \in T$$

$$H_2\text{Store}_t = H_2\text{Store}_{t-1} + \eta^{CH} H_2\text{Store}_{\text{CH}_t} - \frac{H_2\text{Store}_{\text{DIS}_t}}{\eta^{\text{DIS}}}, \forall_t \in T$$

### Carbon dioxide

$$CO_2Production_t + CO_2Store_{DIS_t} = CO_2Demand_t + CO_2Store_{CH_t}, \forall_t \in T$$

$$CO_2Production_t = Load_{CO_2Production_t} / CO_2ProductionEff, \forall_t \in T$$

$$CO_2Demand_t = \alpha \left[ Synfuel_t / (1 - ConversionLossSynthesis) \right], \forall_t \in T$$

$$CO_2Store_{CH_t} = Load_{CO_2Comp_t} / CompressorEff, \forall_t \in T$$

$$0 \leq CO_2Store_{DIS_t} \leq Cap_{CO_2Store} \times I_{DIS_t}, \forall_t \in T$$

$$0 \leq CO_2Store_{CH_t} \leq Cap_{CO_2Store} \times I_{CH_t}, \forall_t \in T$$

$$I_{DIS_t} + I_{CH_t} \leq 1, \forall_t \in T$$

$$CO_2Store_t = CO_2Store_{t-1} + \eta^{CH} CO_2Store_{CH_t} - \frac{CO_2Store_{DIS_t}}{\eta^{DIS}}, \forall_t \in T$$

### Heat constraints

$$WasteHeat_t + HeatPump_t = CO_2HeatDemand_t, \forall_t \in T$$

$$WasteHeat_t \leq (Synthesis_{HeatReleased_t} + Conversion_{HeatReleased_t} + Electrolysis_{HeatReleased_t}) \forall_t \in T$$

$$0 \leq HeatPump_t \leq Cap_{Heatpump} \times COP_{Heatpump}, \forall_t \in T$$

### Refining/Conversion

$$Boiler_{Heat_t} = Conversion_{HeatRequired_t}, \forall_t \in T$$

$$0 \leq Boiler_{Heat_t} \leq Cap_{Boiler} \times BoilerEff, \forall_t \in T$$

Where,

$Y$  = project lifetime

$y$  = year (note all temporal variable beyond 2040 are assumed to be at 2040 values)

$T$  = number of hours = 8760

$t$  = hour

$Capex$  = capital cost

$Cap$  = fixed capacity e.g. kW

$FixedOpex$  = fixed operational cost per year

$VariableOpex$  = variable operational costs per unit product e.g. per kWh

$DF$  = discount factor

$PV$  = photovoltaic generator

$Wind$  = wind turbine generator

$ConvGen$  = conventional generator (CCGT-CCS or Nuclear)

$ESS$  = electrical storage system

$DAC$  = direct-air capture plant

$CO_2Comp$  = compressor for  $CO_2$

$CO_2Tank$  = storage tank for  $CO_2$

*Heatpump* = Electrical compression heat pump  
*Boiler* = Electrical or gas boiler  
*BoilerEff* = Boiler efficiency = 0.8 if gas or 1 if electricity  
*H<sub>2</sub>Production* = Hydrogen production unit (alkaline electrolysis cells (AEC), proton exchange membrane (PEM), or steam-methane-reformer with carbon capture and storage (SMR-CCS))  
*H<sub>2</sub>Comp* = compressor for H<sub>2</sub>  
*H<sub>2</sub>Tank* = storage tank for H<sub>2</sub>  
*Synthesis* = Synthesis plant (Direct Methanation, Fisher-Tropsch or Direct Methanol)  
*Conversion* = Synthesis upgrade plant (Fisher-Tropsch upgrade, Methanol to Gasoline (MtG) or Methanol to OMEx)  
*Note: currently synthesis and conversion treated in a single step with combined costs and efficiencies*  
*SynFuel* = Synthetic fuel  
*SynConv* = Process of conversion/refining a synthetic fuel  
*Load* = electrical load  
*Grid<sub>import</sub>* = power derived from the electrical grid  
*Grid<sub>export</sub>* = power derived from the electrical grid  
*DIS* = discharge of storage element  
*CH* = charging of storage element  
*Grid<sub>CO2</sub>* = the average carbon content in the grid (g<sub>CO2</sub>/kWh) averaged over the project lifetime  
*Grid<sub>RenewablePortion</sub>* = the proportion of renewable in the grid averaged over the project lifetime  
*PV<sub>profile</sub>* = the hourly production profile for a nominal unit of installed PV  
*Wind<sub>profile</sub>* = the hourly production profile for a nominal unit of installed PV  
*I<sub>DIS</sub>* = binary switch for discharging for storage element  
*I<sub>CH</sub>* = binary switch for charging for storage element  
 $\eta^{CH}$  = efficiency of charging for storage element  
 $\eta^{DIS}$  = efficiency of discharging for storage element  
*a* = mass ratio of H<sub>2</sub> to CO<sub>2</sub> for a given type of synthesis reaction  
*H<sub>2</sub>Production* = hydrogen production from AEC, PEM or SMR-CCS  
*H<sub>2</sub>Store* = hydrogen storage  
*H<sub>2</sub>Demand* = hydrogen demand for synthesis process  
 $\Delta H_2 Demand$  = difference in hydrogen between step t and t-1  
*turndown<sub>H2</sub>* = maximum turn down rate for hydrogen production  
*CompressorEff* = conversion efficiency of electrical compressor  
*H<sub>2</sub>Total* = annual volume of hydrogen required to produce refined fuel product e.g. synthetic diesel  
*EnergyRatioSynthesis* = conversion efficiency of hydrogen energy to synthetic unrefined fuel e.g. methanol or synthetic crude  
*ConversionLoss* = the efficiency in energy terms for the conversion of unrefined synthetic fuel to final refined fuel product.  
*variation* = percentage change in hourly hydrogen production  
*Fuel<sub>Total</sub>* = annual volume of refined fuel product e.g. synthetic diesel  
*Fuel* = hourly production of refined fuel  
*Heat<sub>DAC</sub>* = heat required for DAC  
*Synthesis<sub>HeatReleased</sub>* = heat released from synthesis reactions  
*Synthesis<sub>HeatUsed</sub>* = portion of heat released from synthesis reactions used  
*Conversion<sub>HeatReleased</sub>* = heat released from conversion reactions  
*Conversion<sub>HeatUsed</sub>* = portion of heat released from conversion reactions used  
*Electrolysis<sub>HeatReleased</sub>* = heat released from electrolysis reactions  
*Electrolysis<sub>HeatUsed</sub>* = portion of heat released from electrolysis reactions used  
*HeatExchangeEff* = the assumed proportion of waste heat able to be usefully captured  
*Heat<sub>Heatpump</sub>* = heat provided by an electrical heatpump

$COP$  = Coefficient of performance = Heat released per unit of electricity provided to heatpump

$CO_{2import}$  =  $CO_2$  content in imported electricity

$CO_{2export}$  =  $CO_2$  credit for exported electricity

$CO_{2H2production}$  =  $CO_2$  released from SMR-CCS plant

$CO_{2ConvGen}$  =  $CO_2$  released from CCGT-CCS plant

$CO_{2Synthesis}$  =  $CO_2$  released from natural gas supply to synthesis processes

$CO_{2boiler}$  =  $CO_2$  released from industrial boiler with associated CCS

$fuelCO_2$  =  $CO_2$  content of final fuel product

$CO_{2limit}$  = Percent of  $CO_2$  from process embedded in final fuel (0% by default)

## 11. RISKS AND BARRIERS TO E-FUELS DEPLOYMENT ANNEX

**Table 165:** Risks and barriers to e-fuels deployment - workshop results

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
<b>Political</b>	No, or weak political support for e-fuels	H	H for road, L for aviation	Encourage appropriate level of support, consistency of support
	Lack of stable policies to support e-fuels			
	Lack of robust instruments to bolster e-fuels introduction**			
	Inconsistent approach to subsidies etc. across different countries	M	L	None. Policies likely to align anyway
	Lack of support to policies not aligned with the current green trend (ICE ban, push for EVs, etc.)			
	ICE ban			
	Political willingness for full electrification in road	M		
	Preference towards 'efficiency-first' principle, resulting in higher appraisal of battery and hydrogen fuel cell-electric powertrains*		H for road, L for aviation	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
	Priority in fostering zero-emission powertrains, such as battery and hydrogen fuel cell-electric powertrains*			
	Risk that policies are too specific and exclude e-fuels (either intentionally or by omission), e.g. limiting transport tailpipe emissions would favour specifically electric vehicles.	M		
	Risk that policies are not sufficiently specific and therefore become too complex to implement in a way that provides a level playing field.	M		
	Prioritization of renewable power capacities for other sectors	M	H	Make argument that all sectors need to decarbonise and some (e.g. aviation) have few alternatives to e-fuels
	Avoidance of EU energy dependence on other countries with high level of renewable energy resources	L	L	None
	Insufficient renewables capacity made available for e-fuels production because policy supports it's use for electricity first (note: separate issue from technical generation potential, technical deployment rate of generation capacity, and social acceptance issues)	H	H	Encourage support for e-fuels in appropriate sectors - i.e. those that are hard to abate - which could include heavy duty road
<b>Economic</b>	Failure to achieve cost reductions			
	Technology learning for renewable power and PtX conversion plants does not materialise into cost reductions estimated in the e-fuels study, e.g. because of increasing resource prices**			
	Availability of cheap CO2 sources	H	L	Support projects and R&D as appropriate to ensure cost reductions are realised
	Related to the previous, production cost could be a barrier			
	Lower purchasing power if power costs surge (Spain, Portugal)			
	Cost of research, especially if increasing because of lack of consensus between stakeholders			
	High CAPEX			
	Refiners fail to make the investments involved in integrating e-fuel plants with crude/biorefineries, thereby limiting the opportunities for e-fuels plants	L	L	None required
	Lack of suitable sites to locate e-fuels plants	M	L	Identify appropriate brown fields sites and prepare groundwork
	Much cheaper to locate e-fuels plants overseas	L	L	None. Shouldn't hinder general e-fuels development
	Deployment of renewable electricity capacity as well as limitation in electrical network connection (could limit the scale of the assets)	M	M	Start discussions with renewables suppliers and T&D operators to investigate potential constraints on electricity capacity and on ways to mitigate these
	Efuels higher production cost versus biofuels or fossil fuels alternatives become much more competitive	H	H for road, L for aviation	Need to combine efforts on lobbying for support policies and investments to reduce costs (see above). Could focus efforts in those sectors where benefits are likely to be greatest, e.g. aviation, and take advantage of possible "trickle down" into other sectors, e.g. HD road
	Low profitability business case			
	High commercial risk			
<b>Social</b>	No / low acceptance of carbonaceous fuels			
	Preference for alternative power trains			
	Efuels seen as greenwashing	M	M	Provide transparent information on the potential benefits of e-fuels in the sectors where they are anticipated for use, e.g. through independent studies and programme of "education"
	Negative perception of thermal engine technologies (bad publicity, lack of knowledge about technological progress)			
	Reluctance of the population to have wind turbines, carbon capture units "in their yards"	M	H for renewables, low for industrial site, H for power transmission	Provide transparent information on the potential benefits of e-fuels in the sectors where they are anticipated for use, e.g. through independent studies and programme of "education"
	Lack of social acceptance for further massive deployment of renewable power plants in Europe**	L	L	
	Lack of social/fiscal participation from local population in e-fuel deployment**	L	L	
	Risk of uneven distribution of economic benefits from local e-fuel deployments**	L	L	
	Poor social impact assessments (EIA), e.g. leading to unintended consequences in the local-economic or social domain**	L	L	Not required
	Acceptability of high-risk technologies at stake ex-ante/ex-post unintended or intended incidents, such as: ammonia for energy use at scale, nuclear power for e-fuels production, CO2 storage risk	L	L	
	Society not willing/not capable of paying for an e-fuel	L	L	

Category	Risk / Barrier Description	Impact	Likelihood	Mitigating actions
Technological	Unable to optimise processes	H	L	Support projects and R&D as appropriate to ensure technology issues are overcome
	Incompatibility of engines and fuels			
	Low process efficiency	M	L	Support projects and R&D as appropriate to ensure technology issues are overcome
	High energy consumption of some units like RWGS, still on low TRL			
	Low TRL in some parts of the process			
	Immature technology			
	First-of-a-kind risks	H	H for CO2 based fuels, L for non-CO2 based	Support projects and R&D as appropriate to ensure technology issues are overcome
	Inability to get high enough CO2 capture rates			
	Unknown ramp-up potential for electrolysis, carbon capture, fuel synthesis	H	M	Support projects and R&D as appropriate to ensure technology issues are overcome
	Required development of electrolyser assembly line production			
	Scale-up and deployment challenges			
	Up-scaling and commercialisation of RWGS and/or co-electrolysis (key elements in Fischer-Tropsch pathways)			
Legal	Direct air capture proves too challenging to achieve at reasonable costs	M	M	Support projects and R&D as appropriate to ensure technology issues are overcome
	Unable to design system to cope with intermittency	M	L	Support projects and R&D as appropriate to ensure technology issues are overcome
	Planning processes too complicated / time consuming	H	H for road, L for aviation	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels
	Lack of appropriate regulatory arrangements			
	Lack of regulatory predictability			
	Regulatory uncertainty			
	(Nationally-determined) sustainability certification systems are too heterogenic or incompatible	M	L	Policies likely to align anyway
	City or regional regs	L	L	Will resolve soon
	Delegated Acts in RED II pending			
	Ineffective chain of custody for inputs	M	L	No required
	Tail pipe regulation in CO2 standards regulation	M	L	Not required
	Crediting system not in place			
	If imported, risk of non-recognition of CO2 captured from outside EU			
	If local, risk of non-recognition of point source C as circular	H	L	Work closely with ASTM and other relevant stakeholders (e.g. engine makers) from an early stage to get routes into the approval process
	Lack of initiative for ASTM-approval of methanol route for PTL jet fuel			
Environmental	fuel accreditation and blend wall agreements	L	L	Policies likely to align anyway
	Ongoing CO2 impact			
	Ongoing air quality impact	M	L	Work with regulators / policymakers to ensure regulations are fit for purpose recognising the benefits of e-fuels
	Local pollution problems associated to thermal engines (particles, NOx, HCs, etc.)			
	Acceptability of CO2 sources	M	L	Work with regulators / policymakers / civil society to ensure regulations are fit for purpose and that the benefits of e-fuels are clearly articulated
	Risk of using avoidable CO2 emissions as feedstock to produce fuels			
	Lack of specification of carbon source eligible specifically	M	L	Developments in desalination should ensure this issue is minimised
	Plot plan requirement for PV, wind mills, DAC plants			
	Poor environmental impact assessments (EIA), e.g. resulting in excessive local water consumption**	L	L	Not required
	Water accessibility in desert areas			
	Gap/lack of consistency in GHG accounting systems, resulting in under reporting of GHG emissions (risk applicable to any energy activity, not just e-fuels)	L	L	Not required
	Sustainability criteria for e-fuels too weak to drive the uptake needed for cost reduction (versus alternatives like fossil+CCS pathways)			
* Risk/barrier for fuels used in combustion engines				
** Risks/barriers that are not necessarily specific to e-fuels projects, but rather common with major investment ventures				

H = High, M = Medium; L = Low

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